February 8, 2019

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

Dear Ms. Walli:

Re: 2019 Incremental Capital Module (ICM) Application, Interrogatory Responses from Halton Hills Hydro Inc., Board File no. EB-2018-0328

Halton Hills Hydro Inc. ("HHHI") hereby submits its responses to Interrogatories submitted by Board Staff ("Staff"), Vulnerable Energy Consumers Coalition ("VECC") and School Energy Coalition ("SEC") in proceeding EB-2018-0328.

HHHI has submitted the responses through RESS and couriered two (2) hardcopies of the pdf document to the Board.

In the event of any additional information, questions or concerns, please contact Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257 or David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 208.

Sincerely,

(Original signed)

David J. Smelsky, CPA, CMA, C.Dir.
Chief Financial Officer, HHHI

Cc: Arthur A. Skidmore, President & CEO, HHHI
Tracy Rehberg-Rawlingson, RAO, HHHI
Richard King, Ostler, Hoskins & Harcourt, Counsel to HHHI
Intervenors on Record in OEB proceeding EB-2018-0328

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ONTARIO ENERGY BOARD
IN THE MATTER OF AN APPLICATION BY

HALTON HILLS HYDRO INC. ("HHHI")

2019 ICM APPLICATION
INTERROGATORY RESPONSES FROM HALTON HILLS HYDRO INC.

Staff IR - 1

Ref: Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications – Chapter 3 Incentive Rate-Setting Applications, page 24

Excerpts from the above reference are reproduced below:

"*Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the capital budget.*"

As Halton Hills Hydro has noted, general ICM policy does not allow for the recovery of OM&A costs. For this exemption request, it should be incumbent on the distributor to demonstrate that the incremental OM&A costs are not minor expenditures. The OM&A expenses for 2017 as provided in '6. Rev_Requ_Check' of the ICM model is $6,007,592.

a) Given that the project OM&A costs of $131,515 is 2% of $6,007,592, please explain why OM&A costs for the new TS cannot be absorbed within total OM&A expenditures.

Response:

a. The OM&A expenses for 2017 as provided in '6. Rev_Requ_Check' of the ICM model $6,007,592 are the approved OM&A as per HHHI's last Cost of Service EB-2015-0074. Since HHHI's last Cost of Service, new and unanticipated costs have been incurred, well outside the 'envelop approach'. **Table IRR – 1** is a summary of actual OM&A expenses for 2016 and 2017 with 2018 Forecast and 2019 Budget.

Table IRR - 1 – Increased OM&A Costs

OM&A Expense	Actual 2016	Actual 2017	Forecast 2018	Budget 2019
Distribution Expenses - Operation	$ 1,460,237	$ 1,422,770	$ 1,726,686	$ 1,685,407
Distribution Expenses - Maintenance	$ 444,659	$ 283,003	$ 431,671	$ 421,352
Billing and Collecting	$ 1,097,634	$ 1,130,882	$ 1,232,265	$ 1,254,723
Administrative and General Expenses + LEAP	$ 3,122,905	$ 3,257,415	$ 2,685,142	$ 2,877,459
Total Eligible Distribution Expenses	**$ 6,125,435**	**$ 6,094,070**	**$ 6,075,764**	**$ 6,238,941**
OM&A as per EB-2015-0074	**$ 6,007,592**	**$ 6,007,592**	**$ 6,007,592**	**$ 6,007,592**
Variance over (under) ($)	**$ 117,843**	**$ 86,478**	**$ 68,172**	**$ 231,349**
Variance over (under) (%)	**1.96%**	**1.44%**	**1.13%**	**3.85%**

It is important to note, with reference to the annual Pacific Economics Group Report ("PEG Report") (Revised August 2018), HHHI continues to be one (1) of six (6) LDCs in Efficiency Group 1 for 2019 rates. This is the sixth (6th) consecutive year that HHHI has been in Group 1for efficiency.

As HHHI is already operating as one of the most efficient LDCs in the province, HHHI can no longer absorb any further incremental OM&A costs.

In addition, HHHI's achieved returns on equity for 2015, 2016 and 2017 that are well below the regulated deemed return on equity as per the **Table IRR – 2** below:

Table IRR - 2 - Achieved and Forecasted ROE

Year	Achieved ROE	Deemed ROE	+ / -3%
2015	6.70%	8.82%	-2.12%
2016	6.76%	9.19%	-2.43%
2017	6.98%	9.19%	-2.21%
2018 - Forecast	7.46%	9.19%	-1.73%
2019 - Budget[1]	9.18%	9.19%	-0.01%
2019 - Budget[2]	4.73%	9.19%	-4.46%

[1] - Assumes full approval of ICM including OM&A

[2] - Assumes ICM and OM&A denied

Further, there seems to be no sound policy basis for denying OM&A for needed capital projects. If a utility needs to augment its system for supply/reliability reasons between re-basing applications and that results in a material change in rate base with commensurate changes to OM&A responsibilities, why is it appropriate or even sensible to require a utility to work off their OM&A budget for their system without the new capital project? Clearly, it's a cost savings to consumers but there seems to be no balancing of consumer and utility interests.

Staff IR - 2

Ref: ICM Application page 18

Halton Hills Hydro has noted on page 18 that:

"*While the operating costs relating to the TS are direct increases to OM&A spending, it should be noted that customers will realize savings in monthly transformation connection costs as HHHI will be able to transfer some of the existing load to the new TS.*"

a) Has Halton Hills Hydro performed calculations for customer cost savings and bill impacts as it relates to the monthly transformation connection costs?

b) If the answer to 'a' is yes, please provide the calculations. If the answer to 'b' is no, please quantify the bill impacts and provide the calculations.

Response:

a. Yes

b. Transformation Connection cost avoidance has been calculated based on the forecasted load for the new MTS over the next thirteen (13) years. A summary of the projected amounts are shown below in **Table IRR - 3.**

Table IRR - 3 - Forecasted Avoided Transformation Charges

Year	HHH MTS#1 Forecasted Load (MW)	Hydro One Transformation Rate ($/kW)[1]		Forecasted Annual Avoided Transformation Connection Costs[3]	
	A	B	F=A*1000*B* months*E		
2019	11	$2.2500	$	139,536	
2020	15	$2.2725	$	280,008	
2021	23	$2.2952	$	423,276	
2022	26	$2.3182	$	488,041	
2023	29	$2.3414	$	552,149	
2024	33	$2.3648	$	629,067	
2025	37	$2.3884	$	711,367	
2026	40	$2.4123	$	795,250	
2027	44	$2.4364	$	880,739	
2028	49	$2.4608	$	977,899	
2029	54	$2.4854	$	1,091,110	
2030	60	$2.5103	$	1,226,972	
2031	67	$2.5354	$	1,388,199	
			$	9,583,614	G
Assumptions:					
Hydro One 2019 Transformation Rate per kW:			$	2.25	B
[1]Escalation of Transformation Rate:				1%	C
[2]Discount Rate:				5%	D
[3]Seasonal Diversity Factor (based on 2014-2018 data):				0.68	E
Present Value of Forecasted Avoided Costs (2019 value)			**$**	**6,325,319**	H=NPV(D,G)

Using the percentage class allocations based on total revenue and shown on Tab 7. Growth Factor – DEN_CALC in column S of the ICM Model, HHHI has calculated the forecasted five (5) year transformation connection cost avoidance by class (shown below in **Table IRR – 4**).

Table IRR - 4 - Allocation of Forecasted Cost Avoidance by Year

Rate Class	% of Savings	2019	2020	2021	2022	2023	Total Forecasted 5 Year Cost Avoidance
Residential	60.34%	84,196	168,957	255,405	294,484	333,166	1,136,208
General Service Less Than 50kW	12.13%	16,921	33,956	51,330	59,184	66,958	228,348
General Service 50 to 999 kW	15.37%	21,446	43,037	65,057	75,011	84,864	289,416
General Service 1,000 to 4,999 kW	10.29%	14,365	28,826	43,574	50,242	56,841	193,847
Unmetered Scattered Load	0.18%	248	497	751	866	980	3,343
Sentinel Lighting	0.40%	564	1,132	1,711	1,973	2,232	7,612
Street Lighting	1.29%	1,796	3,604	5,448	6,282	7,107	24,237
Forecasted Cost Avoidance by Year		**139,536**	**280,008**	**423,276**	**488,041**	**552,149**	**1,883,010**

The monthly forecasted cost avoidance per customer, per year is show below in **Table IRR – 5**.

Table IRR - 5 – Forecasted Cost Avoidance per Customer by Year

Rate Class	Units	2017 Actual Distribution Demand			Volumes		Forecasted Cost Avoidance per Bill					
		Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	kWhs	kWs	2019	2020	2021	2022	2023	Total Forecasted 5 Year Cost Avoidance
Residential*	Month	20,188	193,694,443		-	-	$ 0.52	$ 0.70	$ 1.05	$ 1.22	$ 1.38	$ 1,136,208
General Service Less Than 50kW	kWh	1,810	50,527,239		2,000	-	$ 0.67	$ 1.34	$ 2.03	$ 2.34	$ 2.65	$ 228,348
General Service 50 to 999 kW	kW	186	135,373,696	394,783	328,500	500	$ 27.16	$ 54.51	$ 82.40	$ 95.00	$107.48	$ 289,416
General Service 1,000 to 4,999 kW	kW	11	99,309,703	262,132	1,600,000	2,500	$ 137.00	$274.91	$415.58	$479.16	$542.10	$ 193,847
Unmetered Scattered Load	kWh	152	934,714		150	-	$ 0.04	$ 0.08	$ 0.12	$ 0.14	$ 0.16	$ 3,343
Sentinel Lighting	kW	173	260,238	704	650	1	$ 0.80	$ 1.61	$ 2.43	$ 2.80	$ 3.17	$ 7,612
Street Lighting	kW	4,674	1,128,400	3,155	94,033	251	$ 142.89	$286.73	$433.44	$499.76	$565.41	$ 24,237
Forecasted Cost Avoidance (5 Years)												**$ 1,883,010**

** Note: Residential Customers are billed on fully fixed*

Staff IR - 3

Ref: ICM Application page 18

Halton Hills Hydro has noted on page 18 that: "*For HHHI to further absorb $131,515 in additional and incremental OM&A costs, other programs may need to be reduced with a risk of decreased reliability.*"

a) Please provide a discussion on Halton Hills Hydro's plans if the ICM is denied.
b) Please provide a discussion on Halton Hills Hydro's plans if only the OM&A portion of the ICM is denied.
c) Please indicate if Halton Hills Hydro has evaluated the impact on reliability under the following two scenarios:
   i) ICM is denied
   ii) ICM capital costs are approved but incremental OM&A is denied.
d) If the answer to either part of question "c" is yes, please provide the evaluation. If the answer to either part of question "c" is no, please perform an evaluation on the scenario(s) listed in part "c" and provide it.

Response:

a. Denial of this ICM will be extremely consequential to HHHI. If this ICM is not granted, HHHI will be faced with significant negative cash flow leading to financial hardship. The denial of this ICM revenue requirement will have a direct negative impact to HHHI's financial viability and will cause HHHI to be non-compliant with the financial covenants as prescribed by the commercial lender.

b. Denial of the OM&A will likely have a negative impact on HHHI's reliability. Should only the OM&A portion of the ICM be denied, HHHI will be forced to materially reduce OM&A expenses in other areas in order to balance the envelop. Please see HHHI's response to OEB Staff IR – 1 part a for additional details.

c.

   i) Should the ICM be denied, HHHI will not meet the financial covenants as prescribe by the commercial lending institution.

Table IRR – 6

	$000's	
	ICM Denied	**ICM Approved May 1, 2019**
Free-cash flow	$ 2,019	$ 3,183
Total debt service (P&I)	$ 2,996	$ 2,996
Debt Service Coverage Ratio (DSC)	0.67	1.06
Required Financial Covenant	1.05	1.05
In compliance "YES", "NO"	**NO**	**YES**

ii) Please refer to HHHI's response to OEB Staff IR – 3 part b.

d. Please refer to HHHI's response to OEB Staff IR – 3 part c (i) concerning financial viability.

Staff IR - 4

Ref: Halton IRR EB-2015-0074 2-Staff-8
Halton IRR EB-2015-0074 1-Energy Probe-4

In Halton Hills Hydro's interrogatory responses provided during the 2016 Cost of Service application EB-2015-0074, Halton Hills Hydro provided an expected in-service date of 2018 and a capital cost of $19 million. In particular, Halton Hills Hydro provided the following as a breakdown of its forecasted $19 million capital expenditure:

"Land acquired and detailed design RFP issued in 2015. Expenditures in 2015 are estimated at $1M Forecast Expenditures: 2016: $6.4M / 2017:$8.3M / 2018:$3.3M"

a) Please explain the 24% increase in capital expenditures from $19,000,000 to $23,476,441.
b) Please provide actual capital expenditures for the TS for the years 2015-2018 and the forecasted costs for 2019.

Response:

a. The $19 million quoted in the IESO report was in 2014 dollars and was an estimated cost based on preliminary studies at the time without a detailed engineering design. In 2018 dollars, that equates to $21,887,000. Actual design did not begin until 2016. As per page 6 in HHHI's ICM Application, HHHI did not apply for an ACM at the time of the 2016 Cost of Service Application (EB-2015-0074) as "budgetary numbers were still very preliminary and not sufficiently robust for the inclusion in the DSP". As shown in HHHI's response to Staff IR-5, the independent consultant estimated the cost of MTS#1 at $25,268,526 (before capitalized interest in the amount of $794,000). HHHI was able to control costs resulting in the $23,476,441 submission which is $1,792,085 below the Engineer's budget (and includes the $794,000 capitalized interest costs).

   HHHI notes that the 2015 Northwest GTA IRRP Report 1 included in the original ICM application as Appendix C did not include the Appendices for the report. As such, HHHI has included those Appendices as **Appendix IRR – A** to complete the record.

b. Please see **Appendix IRR – B** for actual and forecasted costs for MTS#1.

Staff IR - 5

Ref: ICM Application Page 19 – Planning and Cost Savings / Efficiencies / Avoidance

On page 19, Halton Hills Hydro states: "*Through diligent procurement and project management, overall costs have remained under budget.*"

a) Please provide the budget for this project and the breakdown for the budget per year.

Response:

a. Please see **Appendix IRR - B** for the budget by year for this project.

Staff IR - 6

Ref: ICM Application Page 15 – Customer Engagement

Halton Hills Hydro notes that it began customer engagement activities as early as 2008.

a) Given that the initial engagement in 2008 was a decade ago, what customer engagement activities has Halton Hills Hydro completed recently? Also, please provide the information communicated with customers.
b) Does Halton Hills Hydro have any ongoing forms of customer communication?
c) Has Halton Hills Hydro explained the ICM process and bill impacts to customers during its customer engagement activities?
d) Has Halton Hills Hydro received any customer feedback in regards to the new TS?

Response:

a. Since the original customer engagement, the only direct engagement activities were to hand deliver letters to customers within the vicinity of the station to notify them of construction activities. However, the President and Chief Executive Officer made multiple annual public presentations to The Town of Halton Hills Council since 2015. These presentations have included discussions about the need and progress of the transformation station.

   As well, a substantive case for the transformer station was created as part of the IESO's GTA West Planning Region's Integrated Regional Resource Plan of 2015 (**Appendix IRR – A**). This report was created by the Northwest Greater Toronto Area Working Group which included stakeholders: IESO, Hydro One Brampton, Milton Hydro, Halton Hills Hydro Inc., Hydro One Networks Distribution and Hydro One Networks Transmission. This report reviewed the electricity supply requirements for the entire area over a 20 year period.

b. There is a section on the Halton Hills Hydro website dedicated to the transformer station project, https://haltonhillshydro.com/about/engineering/projects/transformer-station/ which provides an overview of the project as well as links to the Environmental Assessment and study area for alternative sites. The page has only had 30 views in the past year.

c. The full ICM application has been posted on HHHI's website per Ontario Energy Board requirements. This application includes bill impacts.

d. There has been no customer feedback to date.

   HHHI would like to note that the Board held a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters (EB-2011-0043) which was initiated in 2011. This consultation developed a regulatory framework for regional planning having regard to the principles articulated in earlier TSC consultations as well as the following:

- that an optimized solution is desirable as being the lowest cost in the long term;
- that a coordinated solution is desirable as allowing for a consideration of broader needs and for involvement by a larger set of stakeholders; and
- that cost responsibility for optimized solutions is attributed in an appropriate manner.

The result of the consultation was an IESO directed rotating five (5) year Regional Planning process that was to reflect the values of the OEB Renewed Regulatory Framework for Electricity Distributors ("RRFE"). As stated on page 1 of the IRRP,

> *"In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years. There is a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development in the long term.*
>
> *This IRRP identifies and co-ordinates the options to meet customer needs in the sub-region over the next twenty years. Specifically, this IRRP identifies investments for immediate implementation to meet near- and medium-term needs in the region, respecting the lead time for development"*

HHHI was involved through participation and input into the Northwest Greater Toronto Area Regional Planning Needs Assessment, Scoping Assessment, and Integrated Regional Resource Plan ("IRRP") Development. The recommendation of the IRRP was that HHHI MTS#1 should be built and commissioned for 2018. As such, HHHI followed the intent of the OEB RRFE in following and acting upon the IRRP recommendation.

Staff IR - 7

Ref: Table 5 – Site Option Evaluation Results

In Table 5, the acceptable site locations are all located south of Steeles Avenue, near 5th or 6th line.

a) Please elaborate the differences between options 2A, 2C and 2D based on the three criteria provided by Halton Hills Hydro.

Response:

a. Evaluation criteria for sites was based on the following three criteria:

   i. Technical–Related to proximity to demand and transmission connection, available land size, availability of distribution circuits.
   ii. Environmental (Physical and Social)–Related to terrestrial and aquatic ecology, existing/planned land uses, and cultural heritage.
   iii. Economic–Related to total cost for completion (design and build) of MTS with consideration for equipment required.

   As can be seen in the **Table IRR - 7** below, the primary difference between the sites is that both 2A and 2D would have required a new 230kV underground supply from south of the 401. Site 2D would have also necessitated the removal of a large forested area, with approximately one thousand (1,000) trees needing to be removed. An economic evaluation of these three (3) sites performed in 2008 indicated that the costs associated with connection to the transmission system for sites 2A and 2D would have been $16,000,000 whereas the transmission system connection costs for 2C were evaluated at $5,000,000. More details of this financial/ economic evaluation can be seen in the 2008 report entitled HHH MTS No1 Site Investigation (**Appendix IRR – C**). The entire table of all the sites evaluated can be found in the Environmental Assessment Report provided in **Appendix IRR – D**.

Table IRR – 7 – Criteria Evaluation by Site

Site 2A	Site 2C	Site 2D
Technical Summary		
Medium	*High*	*Medium*
Site can physically accommodate station. Requires new 230 kV underground supply from south of Hwy 401. Introduces operational complexity, possible reliability and safety issues with buried transmission circuits due to future development.	The 230 kV transmission circuits are available adjacent to the site, from the Halton Hills Generating Station. This reduces the operational complexity, safety risk of buried transmission circuits in public areas. Provides supply diversity with existing Hydro One station.	Requires new 230 kV underground supply from south of Hwy 401. Provides supply diversity with existing Hydro One supply.
Environmental (Physical and Social) Summary		
Low	*Medium*	*Low*
No physical environmental constraints have been identified that would limit development of this site. The potential to impact the socioeconomic environment is low due to the potential for disruption of traffic associated with construction for the few businesses and residences in the area. This site is currently zoned "prestige" industrial. The highest potential for impacting the physical and socioeconomic environment would result from need to construct a 1600 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	The potential to impact the physical environment is considered medium as the site is located adjacent to a watercourse where the potential for presence of coldwater fisheries has been identified. However site development will not encroach on the 15 m construction buffer previously identified for HHGS. A number of trees may be affected in an area identified as a cultural woodland although current development occurring at the site has already impacted this woodland. The potential to impact the socioeconomic environment is medium due to the removal of the barn currently existing on-site and also temporary impacts associated with the potential for disruption of traffic associated with construction for the residences and businesses in the area. This site is currently zoned prestige industrial. There are no interconnection effects associated with this site.	There is potential to impact the physical environment as the site currently exists as a hardwood woodlot with an identified potential for breeding birds. Development of this area would remove an existing remnant forest in an area with very few remaining. The potential to impact the socioeconomic environment is low with temporary impacts associated with the potential for disruption of traffic associated with construction for the residences and businesses in the area. This site is currently zoned prestige industrial. The potential for impacting the physical and socio-economic environment would also result from need to construct a 1600 m underground feed to connect to the existing grid as displacement and disruption to existing features would result. This would also have to be constructed under HHGS.
Economic Summary		
Low	*High*	*Low*
High cost due to distance from the transmission rightof-way south of Hwy 401.	The availability of 230 kV transmission circuits at HHGS eliminates substantial costs in new underground circuits.	High cost due to distance from the transmission right of way south of Hwy 401.

Staff IR - 8

Ref: ICM Application Page 19 – ICM Model

In table 7, Halton Hills Hydro has provided the amortization expense for the cost categories that make up the ICM. Halton Hills Hydro has noted:

"*Where applicable, HHHI has used the HHHI specific Kinetrics report (Kinetrics Inc. Report No: K-418022-RA-0001-R003 dated December 10, 2009) to determine useful lives and calculate amortization expense. Where a specific asset is not included in this report, HHHI has used the Board Kinetrics Report, dated July 2010, for recommended useful lives.*"

a) Please explain why the Board report dated July 2010 was not used as the primary source for determining useful lives given that it is more recent than the other report dated December 10, 2009.

b) The overall typical useful life of a power transformer, as given by the Board report on page 60, is 45 years. The typical useful life of a gas-insulated switchgear, as given by the Halton Hills Hydro Inc. specific report on page 39, is 40 years. Assuming a useful life of 40 years for the "TS Switchgear – Gas, Transformer" cost category and straight-line depreciation, the amortization expense should be $6,789,816 / 40 = $169,745.40, as opposed to $196,505 in Table 7. Please reconcile the difference and explain why Halton Hills Hydro used a shorter useful life duration.

c) Please provide the useful life Halton Hills Hydro has used for each of the cost categories in Table 7 and explain similar to part "b" the amortization expenses for the other cost categories.

d) If any part of the response provided in part "c" deviates from the useful lives provided in either of the Kinetrics Reports, please explain why.

Response:

a. The Kinetrics report (Kinetrics Inc. Report No: K-418022-RA-0001-R003 dated December 10, 2009), was a customized report reviewing the useful lives of the assets, and their components that are applicable specifically to the consortium, namely Halton Hills Hydro Inc., Enersource Corporation, Burlington Hydro, Oakville Hydro and Milton Hydro. With reference to EB-2011-0271 this Kinetrics report formed an integral part in transitioning to International Financial Reporting Standards (IFRS) and properly accounts for the useful lives of HHHI's and corresponding components.

b. HHHI's calculation takes into consideration asset componentization with varying useful life. Please refer to **Table IRR - 8** below:

Table IRR – 8 – TS Switchgear Amortization Calculation Comparison

ICM Cat.	Asset Classification	Asset Detail	Cost	Useful Life	Amoratization
HHHI Calculation					
1	Power Transformers	Overall	$ 3,747,855	35	$ 107,082
1	Power Transformers	Bushing	$ 553,251	20	$ 27,663
1	Power Transformers	Tap Changer	$ 399,551	20	$ 19,978
1	Station Metal Clad Switchgear	Overall	$ 2,089,160	50	$ 41,783
	TOTAL		**$ 6,789,816**		**$ 196,505**
OEB Staff Calculation					
	TS Switchgear		**$ 6,789,816**	40	**$ 169,745**

c. Please refer to **Table IRR -9** for the useful lives HHHI has used for each of the cost categories in Table 7.

Table IRR - 9 - Useful Lives

ICM Cat.	Category	Subcategory	OEB Kinectrics Report			HHH Kinectrics Report			HHH	Total Cost - Actual & Estimates	Dep Expenses	CCA Class	CCA Rate	CCA Amount
			MIN UL	TUL	MAX UL	MIN UL	TUL	MAX UL	UL	Total Cost				
1	Power Transformers	Overall	30	45	60	32	45	55	35	$ 3,747,855	$ 107,082	47	8%	$ 299,828
1	Power Transformers	Bushing	10	20	30				20	$ 553,251	$ 27,663	47	8%	$ 44,260
1	Power Transformers	Tap Changer	20	30	60	20	20	60	20	$ 399,551	$ 19,978	47	8%	$ 31,964
2	Station Service Transformer		30	45	55	32	45	55	45	$ 582,756	$ 12,950	47	8%	$ 46,620
2	Station Grounding Transformer		30	40	40				40	$ 245,592	$ 6,140	47	8%	$ 19,647
2	Station DC System	Overall	10	20	30					$ -	$ -			$ -
2	Station DC System	Battery Bank	10	15	15	10	20	30		$ -	$ -			$ -
2	Station DC System	Charger	20	20	30	20	20	30		$ -	$ -			$ -
1	Station Metal Clad Switchgear	Overall	30	40	60	40	50	60	50	$ 2,089,160	$ 41,783	47	8%	$ 167,133
2	Station Independent Breakers		35	45	60				45	$ 1,323,794	$ 29,418	47	8%	$ 105,904
2	Station Switch		30	50	60				50	$ 694,056	$ 13,881	47	8%	$ 55,524
2	Digital & Numeric Relays		15	20	20				20	$ 1,661,476	$ 83,074	47	8%	$ 132,918
2	Rigid Busbars		30	55	60				55	$ 780,800	$ 14,196	47	8%	$ 62,464
2	Steel Structure		35	50	90				50	$ 2,177,959	$ 43,559	47	8%	$ 174,237
2	Underground Primary Cable		35	40	60	30	40	60	40	$ 1,593,721	$ 39,843	47	8%	$ 127,498
3	Concrete Encased Duct Banks		35	55	80				55	$ 1,508,177	$ 27,421	47	8%	$ 120,654
4	Remote SCADA		15	20	30	10	15	15	15	$ 230,519	$ 15,368	45	45%	$ 103,734
3	Station Building	Station Building	50		75	30	50	80	50	$ 3,174,602	$ 63,492	47	8%	$ 253,968
3	Station Building	Parking	25		30				25	$ 278,975	$ 11,159	47	8%	$ 22,318
3	Station Building	Fence	25		60	30	35	45	35	$ 267,263	$ 7,636	47	8%	$ 21,381
3	Station Building	Roof	20		30	15	20	20	20	$ 332,253	$ 16,613	47	8%	$ 26,580
3	Wholesale Energy Meters		15		30	20	30	60	20	$ 313,067	$ 15,653	47	8%	$ 25,045
3	CT & PT		35		50	30	45	50	45	$ 534,614	$ 11,880	47	8%	$ 42,769
										$ 22,489,441	**$ 608,789**			**$ 1,884,447**
5	Land									$ 987,000	$ -			$ -
	Total Station Costs									**$ 23,476,441**	**$ 608,789**			**1,884,447**

d. Should a componentized item not form part of the HHHI's Kinetric report, the default is the OEB's Kinetric report.

Staff IR - 9

Ref: ICM Model, Tab 6 – Revenue Requirement Check
EB-2017-0045 IRR to OEB Staff Question #23 part a: Updated RRFW , Tab 5 – Utility Income

As part of Halton Hills Hydro's 2018 IRM rates application, Halton Hills Hydro submitted a revised Revenue Requirement Work Form to correct errors made in the 2016 Cost of Service application. In particular, Halton Hills Hydro made an adjustment of $339,393 under depreciation/amortization in tab 5 – Utility Income. A section of the table is reproduced below:

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$11,262,055	($1,308,064)	$9,953,992	$330,260	$10,284,251
2	Other Revenue	(1)	$1,210,681	($251,537)	$959,144	$0	$959,144
3	Total Operating Revenues		$12,472,736	($1,559,601)	$10,913,136	$330,260	$11,243,396
	Operating Expenses:						
4	OM+A Expenses		$6,754,806	($747,214)	$6,007,592	$ -	$6,007,592
5	Depreciation/Amortization		$2,356,442	($848,388)	$1,508,054	$339,393	$1,847,446
6	Property taxes		$104,440	$ -	$104,440	$ -	$104,440
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	

Halton Hills Hydro's depreciation/amortization expense should be $1,847,446 as per the 2018 adjustment. However, in tab 6 – Revenue Requirement Check of the ICM model, Halton Hills Hydro has put $2,022,154 in cell C47 for amortization expenses.

a) Please explain the different values, and if the $2,022,154 amount was made in error please update the ICM model.

Response:

a. The depreciation amount of $2,022,154 is the value net of Contributed Capital (Deferred Revenue), before fully allocated transportation equipment of $174,708.

Gross Depreciation	$	2,271,546
Less: Contributed Capital / Deferred Revenue	$	(249,392)
	$	2,022,154
Less: Fully allocated transportation equipment	$	(174,708)
Net Depreciation	$	1,847,446

Cells C20 and C47 on Tab 6. Rev_Requ_Check have been revised to reflect the Net Depreciation of $1,847,446 and the revised ICM model has been included as **Appendix IRR – E**.

Staff IR - 10

Ref: ICM Model, Tab 9 – Threshold Test

OEB staff notes that the calculated growth factor for Halton Hills Hydro is -1.49%. The negative growth rate is calculated using the difference between the total of the 2016 Board-Approved Distribution Demand of 516,203,452 kWh and the 2017 Actual Distribution Demand of 481,228,433 kWh.

a) Given that the purpose of the new TS is to accommodate planned growth, please explain the decrease in distribution demand and negative growth factor.

Response:

a. The negative growth is a result of the low 2017 revenue as compared to the 2016 Cost of Service expected revenue. The difference between the two (2) revenue years is $(156,094) and can be explained by i) the loss of two (2) customers in the General Service 1,000 to 4,999 kW class, ii) successful Conservation and Demand Management, and iii) a very mild 2017 resulting in lower consumption and usage. The calculations for i) and ii) are shown below:

i. Table IRR - 10 - General Service 1,000 to 4,999 Lost Revenue

GENERAL SERVICE 1,000 TO 4,999 kW	Customers or Connections	kWh	kW
2016 Board-Approved Distribution Load Forecast	13	112,173,675	302,644
2017 Actual Distribution Demand	11	99,309,703	262,132
Variance	(2)	(12,863,972)	(40,512)
@ 2017 Rates	185.55	-	3.4705
Variance ($) (12 months)	$ (4,453)	$ -	$ (140,597)
Total Variance ($)			$ (145,050)

ii. Table IRR – 11 – CDM Savings

YEAR	CDM Planned Savings by year (MWh)	Cumulative Planned Savings (MWh)	CDM Actual & Revised Forecasted Savings (MWh)	CDM Actual & Revised Forecasted Cumulative Savings (MWhs)	Cumulative Variance (MWh)
2015	3,246	3,246	5,818	5,818	2,572
2016	3,626	6,872	6,323	12,141	5,269
2017	2,699	9,571	7,896	20,037	10,466
2018	7,563	17,134	2,339	22,376	5242
2019	7,029	24,163	9,500	31,876	8222
2020	7,495	31,658	-	31,876	727

Staff IR - 11

Ref: Manager's Summary, page 22

On page 22, Halton Hills Hydro requests approval to create DVAs to track the costs and recovery costs related to the TS. Halton Hills Hydro will follow the Accounting Procedures Handbook (APH) and the ACM Report for these DVAs.

a) Please clarify if Halton Hills Hydro is requesting to establish DVAs beyond the generic accounts available in the APH.

b) If yes, please describe the requested accounts, discuss the causation, materiality and prudence of these accounts as per the Chapter 2 Filing Requirements for the 2019 Rate Applications, and provide the draft accounting orders.

Response:

a. HHHI is asking for USofA 1508 Other Regulatory Assets, Sub-account Incremental Capital Charges as currently available in the APH. HHHI would also like request a further sub-account to 1508 Other Regulatory Assets, Sub-account Incremental Capital Charges as they relate to the incremental OM&A costs and recovery.

b. Not applicable.

VECC IR - 1

Ref: Manager's Summary P4

The evidence indicates that in 2007, HHHI's load forecasts first identified the need for a new source of transmission supply. At that time, HHHI, together with the Town of Halton Hills, worked with the planned TransCanada Energy Halton Hills Generating Station ("HHGS") to identify a parcel of land adjacent to the new HHGS for possible construction of a new HHHI TS. The agreement with the HHGS was to build a transformer station on the land adjacent to the generating station and connect to the transmission system via HHGS's 230kV switchyard.

Based on the load forecasts in 2007, when was the new source of transmission supply needed and when was the new transformer station to be in-service?

Response:

Based on the 2007 forecast, the station was originally anticipated to be required by 2011. However, this forecast was prior to the economic downturn which had a significant impact on development projects in Halton Hills. After that time, HHH continued with feasibility studies and technical studies on the selected site. The load forecast was again reviewed in 2015 prior to commencing design work and a final load forecast study was completed in January 2017 prior to commencement of construction to ensure station commissioning would align with load requirements.

VECC IR - 2

Ref: Manager's Summary P4

HHHI is applying for an exemption to the general ICM policy in order to recover incremental Operating, Maintenance and Administration ("OM&A") costs in relation to the TS.

Is HHHI aware of any other LDC's that have applied for and been awarded OM&A costs related to an ICM for a new TS? If yes, please provide details.

Response:

HHHI is not aware of other LDC's that have successfully applied for and been awarded OM&A costs related to an ICM for a new TS. However, in Fesival Hydro's 2015 Cost of Service Application (EB-2014-0073), Festival Hydro requested recovery of incremental OM&A costs related to the Transformer Station they had commissioned between Cost of Service applications. In its decision, the OEB Board wrote:

> *"…the ICM process approved by the OEB does not contemplate approval of incremental OM&A expenses associated with the new asset. If Festival had considered that these incremental expenses should be approved nonetheless, it could have sought an exception to the general policy in the ICM process as part of its 2013 rates application in the timeframe when the costs were incurred. To approve these 2013 and 2014 expenses at this point would amount to retroactive ratemaking…. The OEB also notes that regardless of any advice that OEB staff might provide, only an OEB order can approve the accounting treatment of the expenses"*

As such, HHHI has proactively sought the exemption and recovery of incremental OM&A costs, by way of an OEB order, for the year the costs are determined to commence (the year of commissioning-2019) and the period of time up to the next HHHI Cost of Service application.

Please also see HHHI's response to Staff IR – 1.

VECC IR - 3

Ref: Manager's Summary P5

The evidence states "HHGS and HHHI filed the Form of Connection Agreement with the Board in November 2013."

Please provide a copy of the Connection Agreement.

Response:

Please see **APPENDIX IRR - F**.

VECC IR - 4

Ref: Manager's Summary P5

In February 2015, the Board issued a letter indicating that they would not reject the connection agreement. This assurance allowed HHHI to begin moving forward with the purchase of land, the design and construction of the TS. The land purchase (at the agreed upon 2007 price) was finalized in November of 2015.

Please provide a copy of the Board Letter in February 2015.

Response:

Please see **APPENDIX IRR - G**.

VECC IR - 5

Ref: Manager's Summary P6

In June 2017, HHHI updated its load forecast to verify the required in service date for the TS and to ensure prudent and timely spending. The updated load forecast confirmed a required in-service date of 2019.

Please provide the month of the forecast in-service date in 2019.

Response:

The updated load forecast did not provide a specific month for the in-service date but rather recommended that it is essential to have the new TS by the end of 2019 at the latest. Please see **Appendix IRR – H** for the updated 2017 load forecast.

It should be noted that the Steeles Avenue Prestige Industrial Corridor is expected to continue to grow beyond the term of the latest forecast and HHHI has constructed its MTS#1 to ensure long term supply for the area. Locating another transformer station to serve the Town of Halton Hills in the future will prove to be a significant challenge as any future locations will require installing feeders crossing at least two major highways at significant cost.

VECC IR - 6

Ref: Manager's Summary P14

Table 5 provides the results of the site evaluations and overall rankings. HHHI chose Option 2C.

Please explain how Option 2C compares to the parcel of land identified in 2007 for possible construction of a new HHHI TS.

Response:

Option 2C is the same parcel of land as originally identified in 2007. It was compared to ten (10) other sites along the Steeles industrial corridor. The main advantage of this site compared to all others reviewed was the significant cost saving opportunity to connect to the Hydro One transmission system without having to bring transmission lines under the 401.

VECC IR - 7

Ref: Manager's Summary P15

HHHI indicates that by utilizing an existing connection to Hydro One rather than building a new connection, HHHI realized several benefits related to Option 2C.

a) Please discuss if the same benefits exist for other Options in Table 5 on Page 14.

b) Please provide the incremental cost savings related to Option 2C.

Response:

a. The other sites identified did not have the benefit of being able to connect to the existing transmission connection and would have necessitated bringing supply across the 401. With sites 2A and 2D, there may have been opportunity to connect to the generating station, however, those sites would have both necessitated several easements through many individual parcels of land identified as prime developable commercial real estate and also through a public roadway. At the time of the study, there were no similar easements in Ontario and the risk of obtaining approvals and the increased risk of cable faults through inadvertent contact during future construction were considered too high. Site 2D was also disqualified due to the large forested area which would have necessitated the removal of approximately 1000 trees.

b. The cost savings identified in Table 2 of the MTS#1 Site Investigation Technical and Economic Evaluation of Alternate Methods – Station Sites (**Appendix IRR – I**) relate to transmission connection costs. Incremental cost savings compared to the surrounding sites range from $1,744,000 to $14,365,000.

VECC IR - 8

Ref: Manager's Summary P17

The evidence states "Through diligent procurement and project management, overall costs have remained under budget."

a) Please provide a cost variance analysis of budget versus actuals by year to demonstrate that overall costs have remained under budget.

b) Please a variance analysis of the project schedule, forecast versus actuals by year.

Response:

a. Please refer to **Appendix IRR – B**.

b. Please refer to **Appendix IRR – B**.

VECC IR - 9

Ref: Manager's Summary P19

HHHI states "Where applicable, HHHI has used the HHHI specific Kinetrics report (Kinetrics Inc. Report No: K-418022-RA-8 0001-R003 dated December 10, 2009) to determine useful lives and calculate amortization expense. Where a specific asset is not included in this report, HHHI has used the Board Kinetrics Report, dated July 2010, for recommended useful lives.

Please provide the impact if the Kinetrics Report, dated July 2010 was used instead of the December 10, 2009 Kinetrics Report.

Response:

Please refer to HHHI's response to OEB Staff IR – 8 part b.

VECC IR - 10

a) Please provide the original Business Case for the project.

b) Please provide the latest version of the Business Case for the project.

Response:

a. When load projections indicated that a new source of supply would be required to serve the town of Halton Hills, HHHI undertook a supply options study (**Appendix IRR – I**). This report analyzed the most economical option to supply Halton Hills and recommended building the Transformer Station as the most economical option.

b. The supply options study provided in **Appendix IRR - I** is the latest version. However, to ensure station construction coincided with load requirements, the HHHI Load Forecast was updated and is included as **Appendix IRR - H**. As well, a substantive case for the transformer station was created as part of the IESO's GTA West Planning Region's Integrated Regional Resource Plan of 2015 (**Appendix IRR – A**). This report was created by the Northwest Greater Toronto Area Working Group which included the IESO, Hydro One Brampton, Milton Hydro, Halton Hills Hydro Inc., Hydro One Networks Distribution and Hydro One Networks Transmission. This report reviewed the electricity supply requirements for the entire area over a 20 year period. This report recommended the following:

> *"Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018".*

SEC IR - 1

Ref: [p.11]

Please provide a forecast of the 2019 forecasted regulated ROE (assuming the TS project goes in-service as forecast but no ICM funding is granted).

Response:

Please see HHHI's response to OEB Staff IR – 1.

SEC IR - 2

Ref: [p.11]

Please provide the internal business case for the proposed TS project.

Response:

Please see HHHI's response to VECC IR – 10.

SEC IR - 3

Ref: [p.11]

Please update Table 3 to include the 2018 regulated ROE.

Response:

Please see HHHI's response to OEB Staff IR – 1.

SEC IR - 4

Ref: [p.12]

For each year until its next rebasing application, please provide the incremental revenue (excluding from any approved ICM rider) the Applicant forecasts to collect from additional capacity available after the proposed TS project goes in-service. Please provide the full supporting calculation.

Response:

HHHI's next re-basing is in 2020 for rates effective May 1, 2021. Due to forecasted growth, HHHI intends to maintain ownership and use of all additional capacity, thus resulting in zero ($0) incremental revenue from additional capacity available after the proposed TS project goes in-service.

SEC IR - 5

Ref: [p.12]

What is the capacity of the new TS and what is the expected utilization of that capacity for each of the next 10 years?

Response:

The capacity of MTS#1 is 115 MW. The expected utilization of the capacity over the next ten (10) years is shown in **Table IRR – 3** of OEB Staff IR – 2.

SEC IR - 6

Ref: [p.14]

Please provide a copy of all materials provided to the Applicant's Board of Directors related to the proposed TS project.

Response:

The HHHI Board of Directors has been very much involved in providing oversite in regards to the MTS#1 capital expenditures. **Appendix IRR – J** contains a schedule of Board meeting dates where MTS#1 was either an agenda item or part of the President and CEO update. In addition, **Appendix IRR – J** also contains materials from two (2) milestone events:

1. August 15, 2015 Purchase and Sale Agreement of Land
2. April 20, 2017 Final Budget approval in the amount of $25,268,526.

SEC IR - 7

Ref: [p.19]

Please provide a copy of all internal budgets for the project from conception to today and explain the variances between them.

Response:

Please see HHHI's response to OEB Staff IR - 4 part b.

SEC IR - 8

Ref: [p.21]

For each year between 2016 and 2019, please provide the Applicant's actual/forecast OM&A.

Response:

Please see replicated **Table IRR – 1** below.

Table IRR - 1 – Increased OM&A Costs

OM&A Expense	Actual 2016	Actual 2017	Forecast 2018	Budget 2019
Distribution Expenses - Operation	$ 1,460,237	$ 1,422,770	$ 1,726,686	$ 1,685,407
Distribution Expenses - Maintenance	$ 444,659	$ 283,003	$ 431,671	$ 421,352
Billing and Collecting	$ 1,097,634	$ 1,130,882	$ 1,232,265	$ 1,254,723
Administrative and General Expenses + LEAP	$ 3,122,905	$ 3,257,415	$ 2,685,142	$ 2,877,459
Total Eligible Distribution Expenses	**$ 6,125,435**	**$ 6,094,070**	**$ 6,075,764**	**$ 6,238,941**
OM&A as per EB-2015-0074	**$ 6,007,592**	**$ 6,007,592**	**$ 6,007,592**	**$ 6,007,592**
Variance over (under) ($)	**$ 117,843**	**$ 86,478**	**$ 68,172**	**$ 231,349**
Variance over (under) (%)	**1.96%**	**1.44%**	**1.13%**	**3.85%**

SEC IR - 9

Ref: [p.23]

Please revise table 11 to show distribution bill impacts only.

Response:

Table 11 has been revised to show distribution bill impacts only and is shown as **Table IRR –12**.

Table IRR – 12 – Revised Bill Impacts for Distribution Only

Rate Class	Volumes		% Change	% Change	% Change
	kWhs	kWs	(IRM Only)	(ICM Only)	(IRM & ICM)
Residential - Time of Use	750	-	2.65%	17.83%	20.48%
General Service Less Than 50 kW	2,000	-	1.11%	17.72%	18.82%
General Service 50 to 999 kW	328,500	500	1.20%	17.72%	18.92%
General Service 1,000 to 4,999 kW - Interval Meters	1,600,000	2,500	1.20%	17.72%	18.91%
Unmetered Scattered Load	150	-	1.31%	17.72%	19.03%
Sentinel Lighting	650	1	1.19%	17.72%	18.91%
Street Lighting	94,033	251	1.20%	17.72%	18.91%

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Appendix IRR – A

2015 Northwest GTA IRRP Report

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NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA West Planning Region | April 28, 2015

Independent Electricity System Operator

Integrated Regional Resource Plan

Northwest Greater Toronto Area Sub-Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Northwest Greater Toronto Area Working Group, which included the following members:

- Independent Electricity System Operator
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Northwest Greater Toronto Area Working Group assessed the adequacy of electricity supply to customers in the Northwest Greater Toronto Area Sub-Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Northwest Greater Toronto Area Sub-Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Northwest Greater Toronto Area Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Northwest Greater Toronto Area Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
CDM	Conservation Demand Management
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
IPSP	2007 Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	2013 Long-Term Energy Plan
MTO	Ministry of Transportation
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
OEB	Ontario Energy Board
OPA	Ontario Power Authority (merged with IESO as of January 1st 2015)
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	Provincial Policy Statement
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station
Working Group	

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Northern sub-region of the West Greater Toronto Area Region ("NW GTA" or "Northwest GTA") over the next 20 years. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group composed of the IESO, Hydro One Brampton, Milton Hydro, Halton Hills Hydro, Hydro One Distribution and Hydro One Transmission ("Working Group").

The NW GTA sub-region includes the municipalities of Brampton, Milton, Halton and the southern portion of Caledon. The other sub-region within the West Greater Toronto Area Region – Southwest GTA – underwent a Needs Screening and Scoping Assessment, which determined that needs in the area existed, but that they would be best addressed by the applicable distributors and transmitter for local capacity needs and through a bulk planning study for local restoration needs, rather than through an IRRP process.

Over the last 10 years, electrical demand in this sub-region has grown on average by 2.2% per year. Increasing electrical demand in densely populated urban areas and high growth rates in greenfield residential and commercial/industrial subdivisions have made this sub-region's growth rate one of the highest in Ontario. The official plans issued by the sub-region's municipalities indicate that this growth is expected to continue over the next 20 years in accordance with the province's "Places to Grow" policy.[1] There is a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development in the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

This IRRP identifies and co -ordinates the options to meet customer needs in the sub-region over the next twenty years. Specifically, this IRRP identifies investments for immediate implementation to meet near- and medium-term needs in the region, respecting the lead time

[1] Growth Plan for the Greater Golden Horseshoe, June 2013 Consolidated, https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=14

for development. This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the potential for technological change and the longer development lead-time, the plan maintains flexibility for long-term options and does not commit specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results can inform a decision should one be needed at that time.

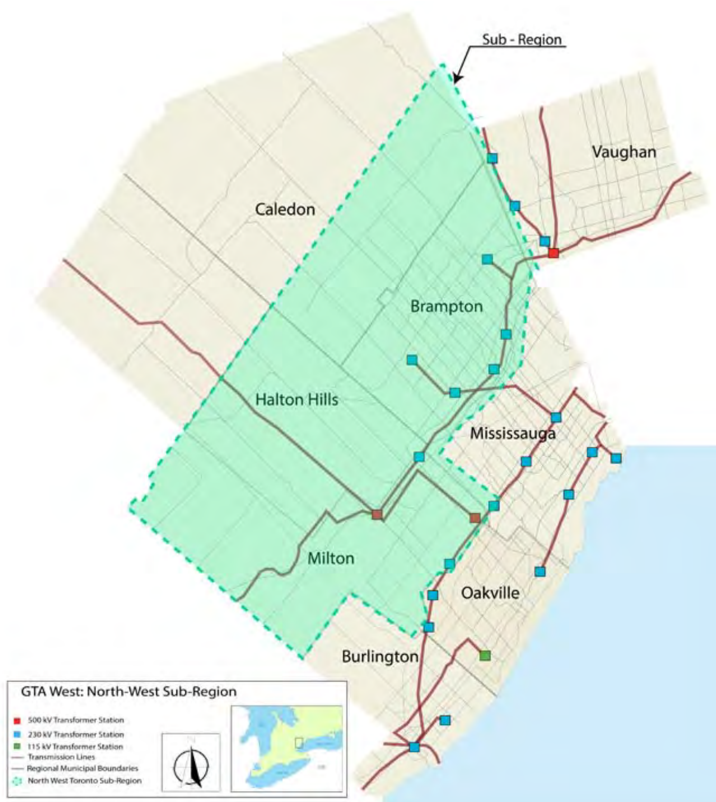
This report is organized as follows:

- A summary of the recommended plan for NW GTA is provided in Section 2
- The process and methodology used to develop the plan are discussed in Section 3
- The context for electricity planning in NW GTA and the study scope are discussed in Section 4
- Demand forecast scenarios, as well as conservation and distributed generation assumptions, are described in Section 5
- Near- and long-term electricity needs in NW GTA are presented in Section 6
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7
- Options for meeting long-term needs are discussed and near-term actions to support development of the long-term plan are provided in Section 8
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 9
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Northwest GTA IRRP addresses the region's electricity needs over the next 20 years based on the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near and medium term (0-10 years) and in the longer term (10-20 years). These two planning horizons are distinguished in the IRRP to reflect the level of commitment required over these time horizons. Plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility, and, in the near-term, it seeks to maximize the use of the existing electricity system where it is economic to do so. The NW GTA sub-region is highlighted in green in Figure 2-1, below.

Figure 2-1: West GTA Northern Sub-region (NW GTA)



For the near and medium term, the IRRP identifies specific investments to be implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to rise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead, near-term actions are identified to develop alternatives, keep key options open and engage with the communities, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform a decision at that time.

The needs or recommended actions comprising the near- to medium-term and long-term plans are summarized below and shown in Figure 2-2 below.

Figure 2-2: Summary of Plan Elements

The sections below provide more details on plan elements shown in the map. They have been sorted according to near/medium term and long term.

2.1 Near- / Medium-Term Plan

> **Near-/Medium-Term Needs**
>
> • Load restoration criteria exceeded in Northwest GTA—**2015**
>
> • Provide additional transformer station supply capability within the Halton TS service territory—**2018 for Halton Hills Hydro and 2020 for Milton Hydro**
>
> • Increase supply meeting capability of H29/30 circuits (supply to Pleasant TS) — **early-to-mid 2020s**
>
> • Address overloads on T38/39B (supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS) — **early-to-mid 2020s**

There are a number of elements that comprise the near- and medium-term plan. The first element of the plan is to maximize achievement of conservation targets. The plan also identifies several pockets in the study area that are currently at risk for not meeting targeted load restoration levels and recommends a course of action for addressing these needs. Two new step-down transmission facilities are recommended in the near term to ensure new customer connections can be accommodated in the Halton Hills and Milton service territories. Over the medium term, a transmission line upgrade is recommended to address emerging capacity needs in the Pleasant TS service area. The recommendations that comprise the near- and medium-term plan are described in further detail below.

Recommended Actions:

1. Implement conservation and distributed generation

Meeting the provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near-term plan. Peak-demand impacts associated with the provincial targets were assumed before identifying any residual needs, when developing the demand forecast. This is consistent with the provincial Conversation First Policy. These peak-demand impacts amount to approximately 130 megawatts ("MW") or 33% of the forecast demand growth during the first 10 years of the study. To ensure that these savings materialize, the local distribution companies' ("LDCs") conservation efforts should focus on measures that will balance the needs for energy savings to meet the Conservation First policy, while maximizing peak-demand reductions.

Monitoring conservation success, including measuring peak-demand savings, will be an important element of the near-term plan. This will lay the foundation for the long-term plan by reviewing the actual performance of specific conservation measures in the region and assessing potential for further conservation efforts.

Provincial programs that encourage the development of distributed generation ("DG"), such as the Feed-in Tariff ("FIT"), microFIT and Combined Heat and Power Standard Offer programs, can also contribute to reducing peak demand in the region. This will depend in part on local interest and opportunities for development. The LDCs and the IESO will continue their activities to support these initiatives and monitor their impacts.

2. Address restoration and T38/39B needs through bulk system study

A bulk system study is underway in the West GTA Region to address anticipated overloads on the bulk transmission system resulting from changes in provincial generation patterns and overall growth across the GTA in general and the West GTA Region in particular. Options considered as part of the bulk system study have the potential to provide benefits related to improving local restoration capabilities throughout the area as well as the medium-term T38/39B capacity needs. As a result, the Working Group agreed that these regional needs should be considered as part of the bulk system study. If these needs are not adequately addressed through the bulk system study and a bulk system plan, they will be revisited as part of the regional planning process.

3. Develop two new step-down stations to relieve Halton TS overloads

Action is required to provide additional supply capacity in the area served by Halton TS. This station is located on the south side of Highway 401 in the Town of Milton and supplies 27.6 kilovolt ("kV") power throughout Milton and southern Halton Hills. Based on current forecasts, additional 27.6 kV supply is required in the general vicinity of Halton TS by approximately 2018 for Halton Hills Hydro's service area and 2020 for Milton Hydro's service area.

Following the analysis included as Appendix E and summarized in Section 7.1.3, the most economic course of action is to construct two stations: one at the site of the current Halton Hills Generating Station ("GS") to supply Halton Hills Hydro by 2018 and one at the existing Halton TS to supply Milton Hydro loads by 2020. Based on the anticipated needs and assuming a three-year lead time for development and construction, it is recommended that Halton Hills Hydro begin development of the Halton Hills MTS at this time. Commencement of development and construction of Halton TS #2 (for supply to Milton Hydro) does not need to be initiated until 2017.

4. Upgrade H29/30 circuits (supply to Pleasant TS) to a higher rating

When load at Pleasant TS exceeds approximately 417 MW and one of the H29/30 circuits that supplies Pleasant TS is out of service, there is a potential for overloads on the companion circuit. Under the Expected Growth forecast, relief is anticipated to be required by about 2026, or as early as 2023 under the Higher Growth forecast. Hydro One has indicated that this line can be upgraded to accommodate over 500 MW of electrical demand at Pleasant TS, enough to accommodate the full rating of the station's step-down facilities, and deferring need until the long term. Assuming a two-year lead time for the replacement of these conductors, action is not expected to be required until the early 2020s.

Peak load should continue to be monitored at Pleasant TS and action pursued when actual demand increases from the current level of approximately 375 MW to approximately 400 MW. Assuming five to ten megawatts of demand growth per year, peak load is expected to occur approximately two years before the need date of 2026.

2.2 Long-Term Plan

Long-Term Needs
• Provide additional transformer and transmission line capacity in northern Brampton/southern Caledon to meet forecast demand growth

The long term plan assumes near-/medium-term needs are addressed as recommended in Section 2.1, above. If that is not done, the long-term plan will likely have to be modified. In the long term, continued load growth is expected to be significant, increasing peak summer demand in Northwest GTA from 1,220 MW to 1,580 MW during the study period. This is expected to trigger capacity needs in the northern Brampton/southern Caledon area. In broad terms, capacity needs refer to the ability of the power system to meet the peak electricity demands of end use customers. In this area, there are two main drivers that could trigger this capacity need:

- Overloads on the transformers at Pleasant TS and/or Kleinburg TS due to load growth beyond the step-down stations' capacity.
- An inability for the distribution system to deliver the required service quality as a result of limitations on the distribution network due to distances between transmission supply points (i.e., transformer stations) and new end-use customers located in northern Brampton and southern Caledon.

When new capacity is necessary in the northern Brampton/southern Caledon area, step-down transformer stations will be required in the general vicinity of the anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

Recommended Actions:

5. Continue Ongoing Work to Establish a New Transmission Corridor through Peel, Halton Hills and Northern Vaughan

The Ministry of Transportation ("MTO") recently began Phase 2 of an environmental assessment ("EA") to establish a new 400-series highway corridor running from the Highway 401/407 junction near Milton, north along the Halton Hills/Brampton border, through southern Caledon and northern Vaughan, terminating at Highway 400. The IESO and Hydro One have been working with MTO and municipal government staff to consider the establishment of a future transmission corridor in the general vicinity of this highway, consistent with government policy on coordinated and efficient use of land, resources, infrastructure and public service facilities in Ontario communities, outlined in the Provincial Policy Statement ("PPS"). This transmission corridor would provide supply capacity for northern Halton, northern Peel, and York Region in the long term and also enhance the capability of the West GTA bulk supply system.

To ensure the future viability of this option, the IESO and Hydro One will continue working with the Ministries of Energy, Transportation, Infrastructure and Municipal Affairs and Housing and related regional and municipal government staff.

6. Monitor Demand Growth, CDM Achievement and Distributed Generation Uptake

On an annual basis, the IESO will coordinate a review of conservation and demand management ("CDM") achievement, the uptake of provincial distributed generation projects and actual demand growth within the Northwest GTA sub-region. This review will be used to track the expected timing of the following needs to determine when a decision on implementation is required:

- Construction of Halton TS #2
- Upgrade of H29/30 circuits (supply to Pleasant TS) to a higher rating
- A new NW GTA electricity corridor

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a scoping assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a straightforward "wires" solution is the best option. If the latter applies, then a transmission- and distribution-focused Regional

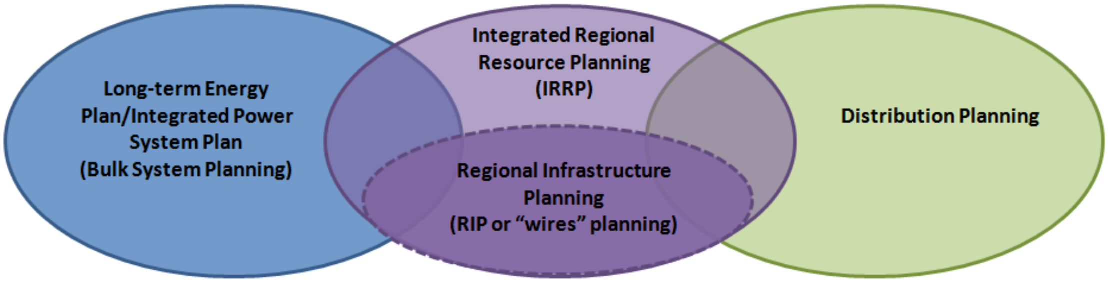
Infrastructure Plan ("RIP") is developed. The scoping assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

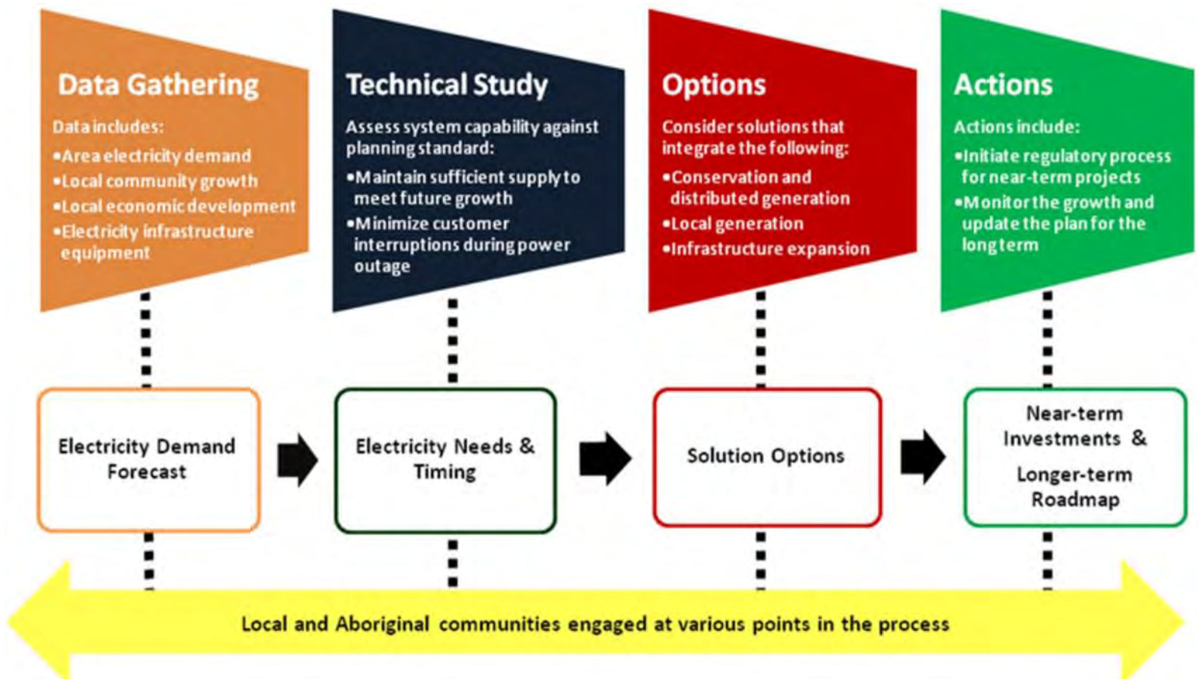
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Northwest GTA Working Group and IRRP Development

Through 2012, the IESO and area LDCs discussed local conditions, recent and expected customer growth trends and anticipated challenges. The participants for this planning process were:

- IESO
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Distribution
- Hydro One Transmission

Based on these discussions, the IESO and area LDCs agreed that an Integrated Regional Resource Planning process was appropriate for the area. The participants in the planning process became the Working Group that developed this IRRP.

The NW GTA IRRP process started in 2013 in response to strong growth in peak electrical demand throughout the sub-region. A major consideration for triggering an IRRP was the location of new growth: urban boundaries have been expanding northward throughout Halton and Peel regions, which has placed additional strain on a transmission system that is largely concentrated in the southern portion of the region.

The Northwest GTA IRRP is a “transitional” IRRP in that it began prior to the development of the OEB’s regional planning process; some of the work was completed before the new process and its requirements were known. Much of the work completed in the early days of the study focused on development of the load forecast and identifying needs and options. The approaches used in conducting these elements of the study were consistent with the new OEB process. As a result, the Terms of Reference were not revised, but an explanatory note was added to communicate the updated planning framework. These Terms of Reference are available on the IESO’s Regional Planning website.[2]

[2] http://powerauthority.on.ca/sites/default/files/planning/NW-GTA-Terms-of-Reference.pdf

4. Background and Study Scope

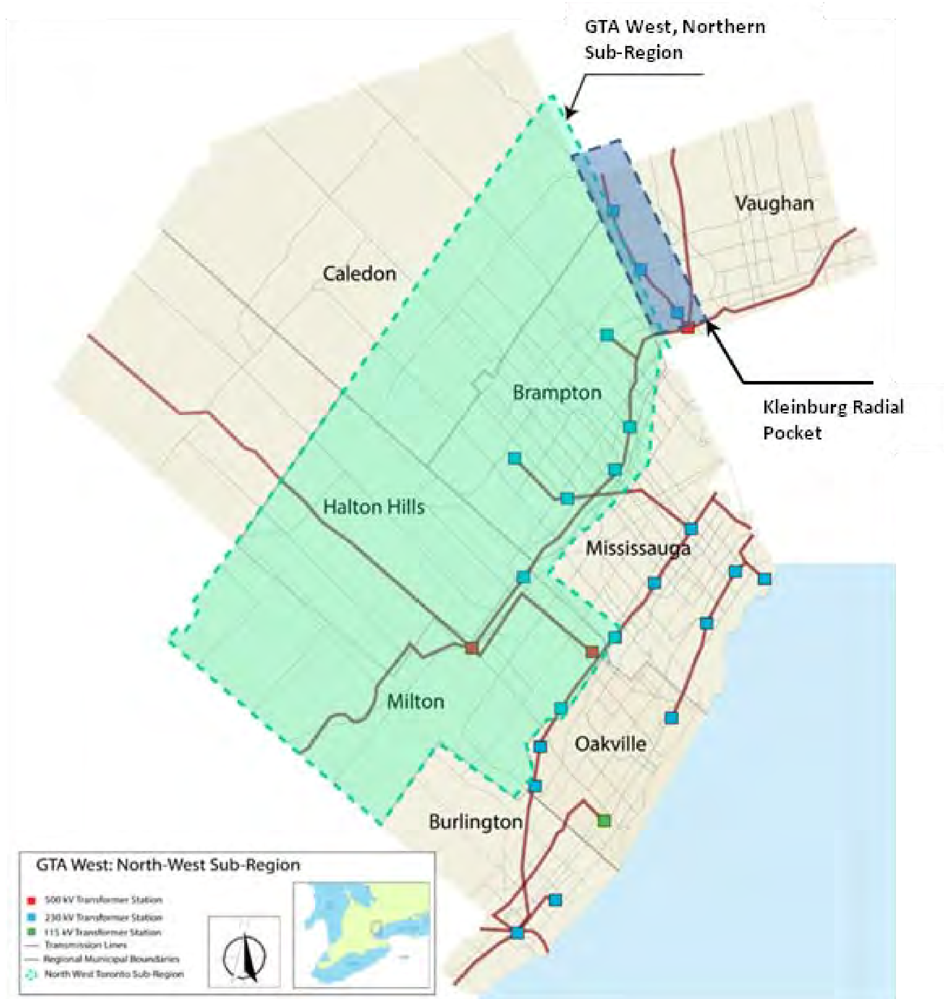
This report presents an integrated regional electricity plan for NW GTA for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2013, in recognition of the high electrical demand growth observed over the previous 10 years, expanding urban boundaries, limited existing electrical infrastructure and the requirement for coordination with ongoing bulk system planning in this sub-region.

To set the context for this IRRP, the scope of this IRRP and the region's existing electricity system are described in Section 4.1, the recommendations and implementation of the 2006 West GTA Supply Study are summarized in Section 4.2 and a brief introduction to the ongoing bulk system study is provided in Section 4.3.

4.1 Study Scope

The West Greater Toronto Area Region ("West GTA") roughly encompasses the municipalities of Mississauga, Oakville, Brampton, Milton, southern Halton Hills (including Georgetown and Acton) and southern Caledon (including Bolton and the areas south of the Greenbelt). Based on an early review of growth and existing infrastructure, this region was broken into two sub-regions: Northwest GTA, highlighted in green in Figure 4-1, below and Southwest GTA.

Figure 4-1: Northwest GTA Planning Sub-region



The Northwest GTA sub-region is roughly defined by the municipalities of Brampton, Milton, southern Halton Hills and southern Caledon. It is the focus of this IRRP.

Immediately adjacent to the Northwest GTA boundary is a short radial circuit (V43/44), which runs radially from Claireville TS and terminates at Kleinburg TS (Kleinburg radial pocket, highlighted in blue, above). Although the Kleinburg radial pocket is located within the GTA North Region, this pocket was included within the scope of the Northwest GTA IRRP for the following reasons:

- Electrical demand growth in this pocket is driven largely by new customers in southern Caledon, in particular the Town of Bolton. As a result, any capacity needs would have greater implications for customers in the Northwest GTA sub-region.

- The Northwest GTA sub-region is characterized by a large number of similarly configured radial pockets, meaning that restoration needs would be a common issue addressed across the entire planning area. The fact that there are so many radial pockets provides an opportunity for investigating common solutions.

The Southern sub-region of West GTA ("Southwest GTA") is not included in this IRRP. A separate Needs Assessment and Scoping Assessment were carried out for this sub-region in 2014. These assessments concluded that the sub-region's capacity needs would be best addressed directly by the distributor and transmitter, and restoration needs through a bulk transmission system study under development by the IESO. Some restoration needs for the Southwest GTA sub-region were also identified as part of the Scoping Assessment and will be considered as part of the bulk transmission system study already underway for West GTA (see Section 4.3, below, for more details). If these restoration needs are not resolved through the bulk transmission system study, they will be revisited as part of the regional planning process. Information on the Southwest GTA study, including links to the Needs Assessment and Scoping Assessment reports, is available on the IESO Regional Planning webpage.[3]

Growth in Peel region is expected to continue to expand northward into the undeveloped greenfield areas of north Brampton and south Caledon, farther from existing transmission assets. Within Halton region, the municipalities of Halton Hills and Milton are expected to see growth along underdeveloped areas to the north and south of Highway 401, the vicinity of James Snow Parkway and through southern Georgetown. The blue and orange highlighted areas in Figure 4-2 show these growth clusters:

[3] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

Figure 4-2: Anticipated Growth Clusters, by Municipality

The continued high growth shown in this forecast is consistent with the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 790,000 people living in the Peel and Halton regions by 2031. This represents an average annual population increase of 1.84% per year.

4.2 2006 West GTA Supply Study

The 2006 West GTA Supply Study was a joint study undertaken by Enersource Hydro Mississauga, Halton Hills Hydro Inc., Hydro One Brampton, Hydro One Networks Inc. Distribution, Milton Hydro and Hydro One Networks Inc. Transmission. This study was initiated in 2004, before the establishment of the OPA, but had a similar purpose to the current regional planning initiative, namely to identify the need for transmission capacity and voltage stability in West GTA and assess the capability of the transmission system to meet the load requirements for a 10-year study period (from 2005 to 2015). Several new transmission reinforcements were recommended and ultimately adopted, including:

- Extension of circuits V72/73R from Cardiff TS to Pleasant TS tap and construction of Hurontario SS with radial supply to Jim Yarrow MTS
- Construction of Winston Churchill MTS
- Construction of a third set of step down transformers (Dual Element Spot Network, or "DESN") at Pleasant TS
- Construction of a second DESN at Goreway TS

The measures undertaken as a result of the 2006 study have supported the continued electrical load growth in this area over the past decade. This IRRP builds upon the previous planning initiatives in this area, including the 2006 West GTA study, to ensure that the forecast electrical load growth in the area can continue to be met.

A copy of the report is available on Hydro One's Regional Planning website.[4]

4.3 Bulk Transmission System Study

A bulk system study was initiated by the IESO for West GTA in 2014 to identify and recommend solutions to address emerging bulk transmission system needs. These needs differ from those driving the regional plan, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. These needs include planned refurbishment and retirement of nuclear generation facilities, incorporating renewable generation in southwest Ontario and changes in electricity consumption patterns across the GTA. Due to the potential for overlaps between bulk and regional planning, as described in Section 3.1, it is important for regional planning to be coordinated with bulk system planning, particularly in the case of West GTA. The bulk system study will therefore account for regional needs that may be more efficiently solved through bulk system solutions.

The West GTA region is supplied by the 500 kV and 230 kV bulk transmission network with 500-230 kV transformation facilities at Claireville TS and Trafalgar TS. Load supply stations and major generating stations in the area are connected to the 230 kV network. The 500 kV transmission network is the backbone of the Ontario system and the 500-230 kV transformers provide the link between the 500 kV and the 230 kV networks. Milton SS, which is located in

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[4] http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/GTA%20West%20Supply%20Study%202006.pdf

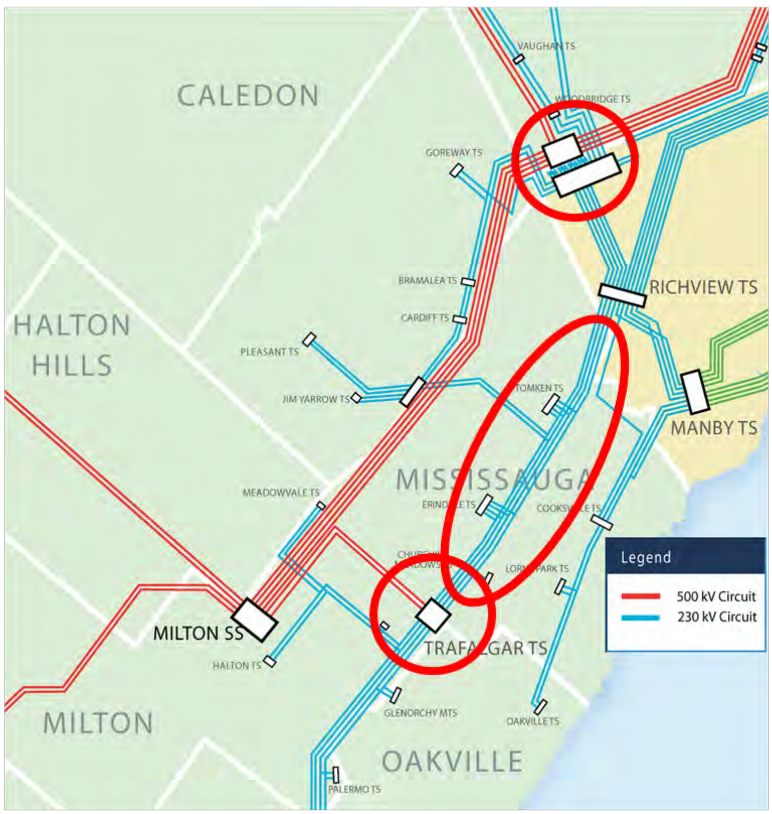
the area, provides switching for 500 kV circuits. Currently there are no 500-230 kV transformation facilities at this station.

The bulk system studies conducted indicate that the following facilities may require relief from overloads within the next 10 years:

- 500-230 kV transformers at Trafalgar TS
- 500-230 kV transformers at Claireville TS
- Trafalgar to Richview 230 kV lines

These three facilities are highlighted on the map below:

Figure 4-3: West GTA Bulk Facilities with Potential Needs



The two primary factors driving the overloads on the 500-230 kV transformers and the Trafalgar to Richview 230 kV lines are load growth in the GTA and changes in generation patterns across Ontario. While all growth within the GTA has some impact on the bulk system, growth within West GTA (the municipalities of Mississauga, Oakville, Milton, Halton Hills, Brampton and Caledon) has the greatest contribution due to proximity to the affected bulk facilities.

Specific contributors to changes in provincial generation patterns, particularly those driving bulk system needs in West GTA, include the completion of refurbishment of nuclear units at Bruce GS, significant uptake of renewable generation in southwestern Ontario, the planned retirement of nuclear generation at Pickering GS and the scheduled refurbishment of nuclear generation at Darlington GS. These changes are expected to result in increased inter-regional power flows into the GTA from the west towards the east through transmission facilities in West GTA. These higher inter-regional power flows contribute to overloads of the 500-230 kV transformers at Trafalgar TS and the Trafalgar-to-Richview 230 kV lines.

Based on the early results of the bulk system study, upgrades to the bulk transmission system in the area may be needed by 2020. These may include installing new autotransformers at Milton SS and new transmission infrastructure along existing transmission corridors. Because solutions to these bulk system needs are also capable of addressing several needs identified in this IRRP, in particular those associated with restoration capability, the scope of the bulk system study will include consideration for these local restoration needs. More details on the restoration needs within the Northwest GTA IRRP are available in Section 6.2. The Scoping Assessment for Southwest GTA is located on the IESO Regional Planning webpage.[5]

[5] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

5. Load Forecast

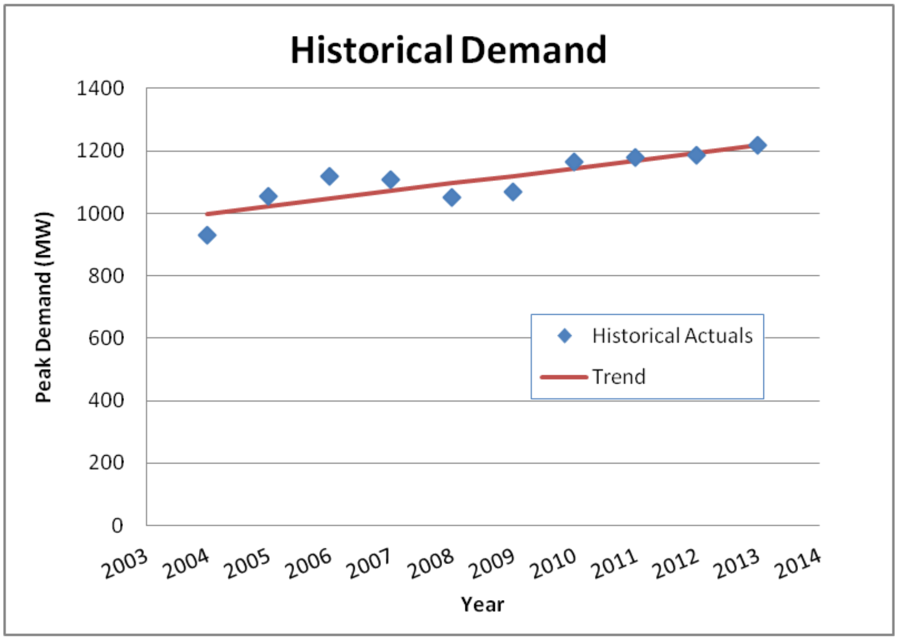
This section outlines the forecast of electricity demand within the Northwest GTA sub-region. It highlights the assumptions made for peak-demand load forecasts, the contribution of conservation to reducing peak demand and the role of distributed generation resources in supplying demand in this area. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This is different from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times. Within Northwest GTA, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the air conditioning loads of residential and commercial customers. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day.

5.1 Historical Demand

Growth within Northwest GTA has been strong over the past decade, largely driven by expanding urban boundaries and intensifying downtown cores. Within the study area, peak electrical demand has grown at an average of 2.2% over the past 10 years, representing an increase of approximately 220 MW for the study area after applying regression (see Figure 5-1, below):

Figure 5-1: 10-year Historical Peak Demand, with Trend Line



Growth has been particularly pronounced over the past five years, averaging 2.7% for the study area as a whole. Actual coincident peak demand for each LDC in the study area is shown below for the past five years, along with the resulting average percent growth:

Table 5-1: 5-year Historical Peak Demand and Average Percent Growth, by LDC (in MW)

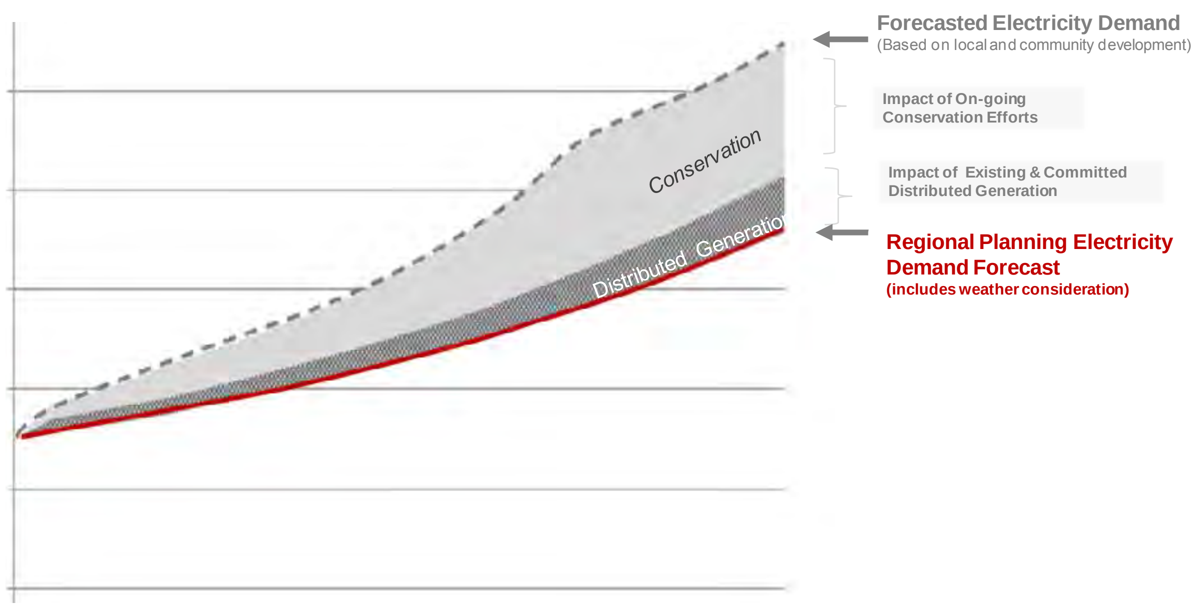
LDC	2009	2010	2011	2012	2013	Avg % Growth
Hydro One Brampton	739.35	800.67	807.70	810.65	825.55	2.32 %
Milton Hydro	130.82	143.42	156.18	156.93	168.28	6.05 %
Halton Hills Hydro	85.67	93.67	92.69	92.83	97.09	2.41 %
Hydro One Distribution (Caledon)	114.39	128.42	123.28	125.45	126.44	1.73 %
TOTAL	1070.24	1166.17	1179.85	1185.86	1217.36	2.74 %

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

A regional peak-demand forecast, illustratively shown in Figure 5-2, was developed for the 20-year planning horizon. LDCs provided gross demand forecasts, which were modified by the IESO to reflect (1) the impact that provincial conservation targets and distributed generation programs have on peak demand and (2) extreme weather conditions. Using a planning forecast that is net of provincial conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs.[6]

Figure 5-2: Development of Expected Growth Scenario



To account for the uncertainty associated with applying conservation assumptions based on long-term energy targets, two net demand forecast scenarios were developed to reflect a range of possible outcomes:

- An "Expected Growth" scenario was developed to reflect the full allocation of energy savings from targeted conservation, with assumptions made for the translation of

[6] This assumes that the conservation targets will be met and that the targets, which are energy-based, will produce estimated local peak demand impacts. Monitoring the actual peak demand impacts of conservation programs delivered by LDCs will be an important aspect of plan implementation.

energy to peak-demand savings. This scenario was the default forecast primarily used to identify regional needs.

- A "Higher Growth" scenario was developed assuming some combination of Higher Growth or lower projected peak-demand savings, resulting in a higher net electrical demand throughout the 20-year study period. More details on the assumptions used to develop this scenario are included in Section 5.4.

5.3 Gross Demand Forecast

Each participating LDC prepared gross demand forecasts at the transformer station level or bus level for multi-bus stations. Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs had cited alignment with municipal and regional Official Plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The gross demand forecasts provided by the LDCs are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. It is achieved through a mix of program-related activities, behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize results. The conservation savings forecast for West GTA are applied to the gross peak-demand forecast, along with distributed generation resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan that outlined a provincial conservation target of 30 terawatt-hours of energy savings by 2032. To represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak-demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak-demand impacts from the provincial targets in Northwest GTA. The resulting conservation assumed in the Expected Growth forecast is shown in Table 5-2. Additional conservation forecast details are provided in Appendix A.

Table 5-2: Peak MW Offset Due to Conservation Targets from 2013 LTEP, Select Years

	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031
Total	0.9 %	2.2 %	3.1 %	5.0 %	6.8 %	8.0 %	9.5 %	10.9 %	12.3 %	13.7 %
MW assumed	11.0	29.8	42.7	72.8	104.4	127.7	158.0	189.1	218.8	249.6

It is assumed existing demand response ("DR") already in the base year will continue. Assumptions related to potential DR projects that do not yet have a contract will be handled when considering solutions to needs and not during development of the load forecast.

For the Higher Growth forecast, half of the peak-demand reduction shown in Table 5-2 was accounted for in the forecast. Applying this uncertainty was done for several reasons:

- Conservation targets used to develop this forecast were based on the 2013 LTEP and were only developed for annual energy consumption. Converting annual energy savings into summer peak-demand savings requires several assumptions regarding load profiles, customer type and end-use of future conservation measures and activities. These additional assumptions all carry associated uncertainties, especially over a 20-year planning horizon.
- Historical achievement of peak-demand conservation targets has varied greatly across different years and programs. The OPA's 2013 Annual Conservation and Demand Management Report, submitted to the OEB in October 2014, showed that while energy targets have been largely successful, only 48% of the 2014 peak-demand target was achieved by the end of 2013. In a follow-up letter to LDCs sent December 17, 2014, the OEB noted that "A large majority of distributors cautioned the Board that they do not expect to meet their peak demand targets," and that, "the Board will not take any compliance action related to distributors who do not meet their peak demand targets."
- Similar higher net growth sensitivity scenarios have been developed for other planning initiatives to manage risk of insufficient power system capacity due to higher underlying growth or lower peak-demand effect of conservation initiatives. This is a practice that has been used successfully within other regional plans and has been used as evidence at rate hearings and other regulatory submissions.

5.5 Distributed Generation Assumed in the Forecast

The effect of existing distributed generation is assumed to be represented in the historical data points used by LDCs to develop their gross demand forecasts. The IESO accounted for future DG projects in cases where a contract was signed, but the project had not yet reached commercial operation as of the peak-demand date used by LDCs to build their forecasts.[7] The in-service date for future DG projects is based on the milestone date for commercial operation listed on the contract.

The IESO applied capacity factors for solar and wind technologies based on the data used in the most recent Methodology to Perform Long Term Assessment. All other generation types are assumed to be fully operational at peak. Based on the May 2013 Long Term Assessment,[8] wind and solar peak capacity factors were assumed at:

- Wind: 13.6%
- Solar: 34.0%

The resulting effective capacity of all new DGs was subtracted from the forecast load at the connecting station, as shown below:

Table 5-3: DG Capacity Assumed by Station

Station	Effective kW
BRAMALEA TS	1,538
GOREWAY TS	2,231
HALTON TS	510
JIM YARROW MTS	697
KLEINBURG TS	420
PLEASANT TS	1,705
TRAFALGAR TS	85
WOODBRIDGE TS	216

5.6 Planning Forecasts

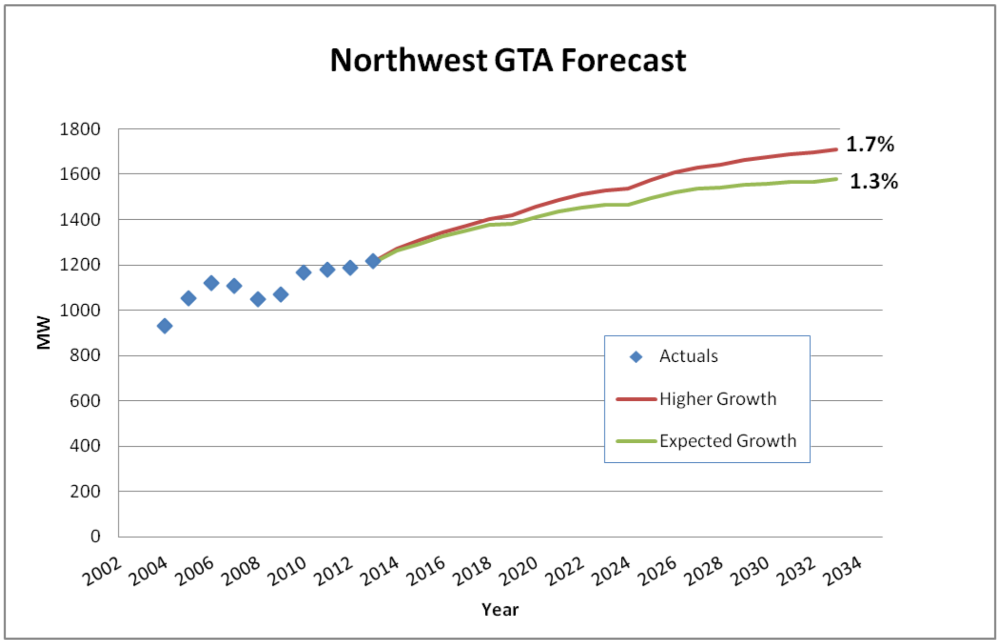
As described above, the IESO developed two planning forecasts:

- an Expected Growth forecast that considered the combined expected impact of conservation and distributed generation by station across the study area
- a Higher Growth forecast that was developed assuming half the peak conservation impact used in the Expected Growth forecast.

[7] For example, if the summer peak of July 17, 2012, was used to build the Gross Forecast and a FIT contract had come into service in September 2012, the contribution of this project would need to be accounted for in the net forecast.
[8] http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2013may.pdf.

The final forecasts were adjusted to account for typical LDC station loading and operational practices. Figure 5-3 shows both planning forecasts, along with historic demand in the area. Annual load by station is provided in Appendix A.

Figure 5-3: Historical Demand and Expected and Higher Growth Forecasts



Under the Expect Growth forecast, growth averages 1.68% per year in the near and medium term, but drops to 0.82% per year for the second decade. For the Higher Growth forecast, growth averages 2.06% per year for the first decade and drops to an average of 1.18% per year for the long term. Over the 20-year planning period, the Expected and Higher Growth forecasts average 1.3% and 1.7% per year, respectively.

6. Needs

Based on the demand forecasts, system capability and application of provincial planning criteria, the Northwest GTA Working Group identified electricity needs in the near-to-medium term and in the long term. This section describes these identified needs, grouped into three major categories: step-down capacity, supply security, and restoration and transmission line capacity. Each section begins with a brief description of the category, including how needs are identified, followed by details on each identified need.

6.1 Step-down Capacity Needs

Step-down transformer stations convert high voltage electricity from the transmission system into lower-voltage electricity for delivery through the distribution system to end-use customers. Several factors limit the amount of electricity that can be supplied to customers, including a step-down transformer's rating, the number of available distribution feeders and their capacity. These needs are identified by comparing the net station forecast to the ratings of the station's facilities (i.e., transformers and feeders). Where multiple LDCs or customers share electrical capacity at the same station, the amount of effective feeder capacity remaining for each is considered, as this may be a limiting factor. For this reason, if only a limited amount of capacity remains for a transformer, two LDCs may hit their supply limit at different times based on the amount of capacity remaining on their respective feeders.

The table below shows the anticipated years when load at several NW GTA stations is expected to reach installed capacity, based on the Expected Growth forecast and under the Higher Growth forecast.

Table 6-1: Step-down Capacity Need Dates, by Station and LDC

Station	LDC	Expected Growth	Higher growth
Halton 27.6 TS	Halton Hills Hydro	2018	2018
	Milton Hydro	2020	2019
Pleasant 44 kV TS	Hydro One Brampton, Halton Hills Hydro, Hydro One Distribution	2033	2026
Kleinburg 44 kV TS	Hydro One Distribution, Powerstream	--	2033

When a step-down station's capacity is reached, options for offloading the limiting station or asset include reducing net growth in the supply area (e.g., through enhanced conservation and/or DG measures), transferring loads through the distribution system to nearby stations with surplus capacity, or building a new step-down supply station to serve incremental growth. Typically, measures to reduce or transfer net demand growth are not able to defer the need for a new station indefinitely, so the cost of these measures must be compared to the value of deferring construction of a new station. These assessments are done by comparing the cost per megawatt of the added capacity provided by the various options.

Additional information on capacity-related needs for the identified stations is provided in the sections below.

6.1.1 Halton 27.6 kV TS

Halton TS is a 207 megavolt ampere ("MVA") capacity 27.6 kV station, with 12 feeders each capable of supplying about 15.5 MW to nearby loads (effective station capacity is therefore approximately 186 MW, based on LDC feeder loading practices). Three feeders are allocated to Halton Hills Hydro and nine to Milton Hydro. The highest peak experienced on this station within the past five years was 166 MW (in 2011), an increase of over 30 MW since 2006. Most recent peaks, namely 2013, were slightly lower as a result of temporary load transfers made by Milton Hydro to a new transformer station (Glenorchy MTS), which is providing temporary relief in the southern part of its service territory.

Figure 6-1: Halton TS and Surrounding Service Territory

Based on current forecasts, remaining capacity on the Halton Hills Hydro supply feeders will be exhausted by 2018. The remaining capacity allocated to Milton Hydro will be exceeded in 2020:

Table 6-2: Halton TS Station Loading by LDC, Expected Demand (in MW)

LDC	Max Capability	2014	2015	2016	2017	2018	2019	2020
Halton Hills Hydro	46.5	33.9	36.9	39.6	44.9	50.0	54.6	58.2
Milton	139.5	92.1	101.0	109.1	118.8	127.8	134.8	141.8

This forecast assumes that Milton Hydro makes full use of available load transfers to nearby stations. However, long-term supply from these adjacent stations is not a preferred option, as Milton's existing and future load centres are located close to Halton TS. Transporting energy through long distribution lines is not efficient, resulting in higher losses and lowering customer reliability. Likewise, near-term Halton Hills load growth is expected close to Halton TS, immediately north of Highway 401, followed by longer-term growth in the south Georgetown area, located approximately 10 km farther north. Figure 6-1, above, shows the existing transmission system assets in the vicinity of Halton TS, the approximate location of the near-term Halton Hills growth area, Milton growth area and Highway 401.

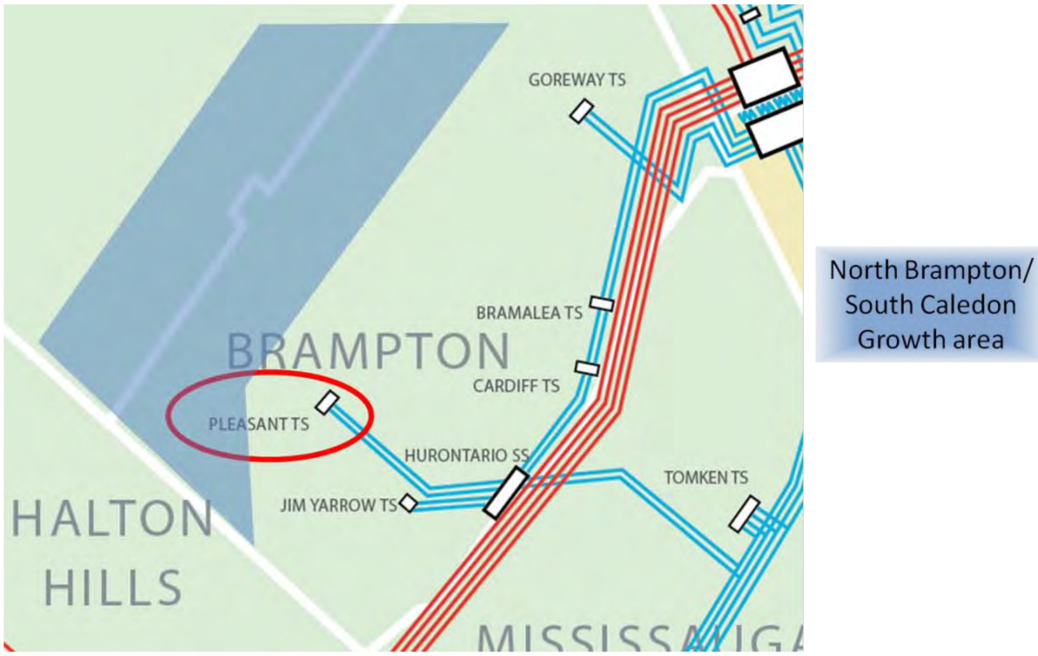
The following constraints must be accounted for when developing options for providing relief to Halton TS:

- **Lack of air rights over Highway 401.** Highway 401 bisects the Halton Hills/Milton growth pocket, with Halton TS (which currently supplies the majority of load in the area) located on the south side along with most of Milton's existing and anticipated customer load. The municipality of Halton Hills is located on the north side of Highway 401 and in the past, has received supply from Halton TS via several distribution feeders spanning over the highway. However, Halton Hills Hydro has informed the IESO that obtaining air rights for additional overhead distribution feeders represents a significant challenge. As an example, the 230 kV TransCanada transmission connection for Halton Hills Hydro GS (located close to Halton TS, but on the north side of Highway 401) was pursued as an undergrounded connection given the associated commercial challenges of spanning over Highway 401. As a result, it is assumed that future feeder crossings will be required to tunnel underneath the highway. The underground option is estimated to cost approximately $2 million per feeder.
- **Distribution voltages.** Step-down stations in the study area provide electrical supply at a voltage of either 27.6 kV or 44 kV. The selection of voltage is based on economics and technical requirements, such as how much electricity customers consume and the distance between major supply points and customer demand. Typically, 27.6 kV service is used for denser urban areas, while 44 kV service is used for rural areas and industrial zones. Almost all growth in the Milton/Halton growth pocket is expected to be served at the 27.6 kV level, which will require supply from a station capable of providing this voltage.
- **Transmission system connection availability and proximity to load centres.** Step-down transformer stations are supplied by high-voltage transmission lines and so must be directly connected to a high voltage circuit capable of providing the incremental forecast demand. To reduce reliance on long distribution lines, step-down stations are typically located close to growth centres.

6.1.2 Pleasant TS (44 kV)

Pleasant TS is a transformer station with two 230/27.6 kV step-down facilities and one 230/44 kV facility. This station is located in northern Brampton and supplies power to northwest Brampton, southwest Caledon and parts of Georgetown.

Figure 6-2: Pleasant TS and Surrounding Growth Areas



While electrical demand on the 27.6 kV system is expected to continue to grow, adequate 27.6 kV capacity is available for supplying the incremental 27.6 kV growth in the Pleasant TS service territory over the long term; however, this is not the case for the 44 kV system. Based on growth forecasts, an alternative supply may be required by 2033. The sensitivity analysis on the need date has shown it is very sensitive to small changes in net growth rates and could potentially move forward several years. For example, under the Higher Growth forecast, the need date is advanced to 2026, as shown in Table 6-3, below.

Table 6-3: Pleasant TS (44 kV) Transformer Capacity Demand in MW (by Need Dates)[9]

	Maximum Capability	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	148.1	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4
Higher Growth	148.1	144.9	147.3	149.1	150.6	151.6	152.8	154.5	156.2	158.1	161.0

[9] Note that these needs are only related to the capacity of the transformers at Pleasant TS. This station is also potentially limited by the ability of transmission circuits to deliver high-voltage power, as described in Section 6.3.1, below.

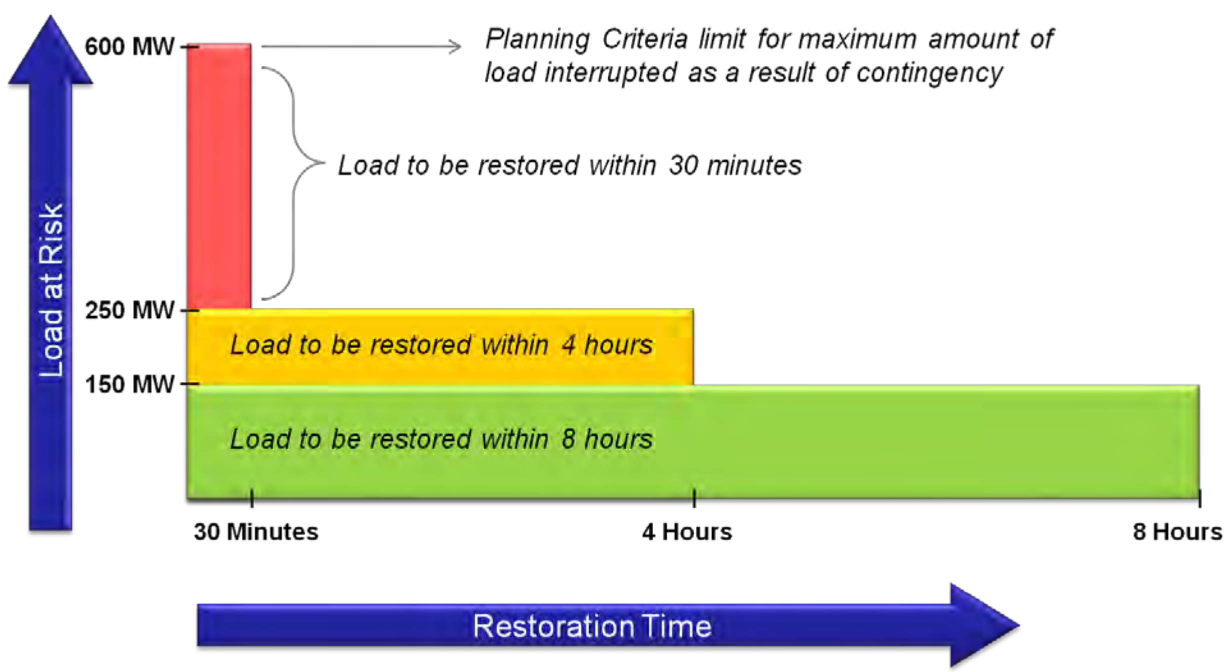
Actual loading on the 44 kV Pleasant TS will need to be reviewed during the next regional planning cycle given that the actual need date may vary from 2033. If new loads cannot be fully offset through conservation and DG initiatives, a new transmission line will be required to enable incremental capacity to be served, since there is no available transmission line capacity in the area that is able to accommodate a new step-down station.

6.2 Supply Security and Restoration Needs

Several areas within the NW GTA study area have been identified as being at risk for not meeting restoration levels as defined in the Ontario Resource and Transmission Assessment Criteria. ORTAC requires that, for the loss of two elements, any load in excess of 250 MW should be restored within 30-minutes and any load in excess of 150 MW should be restored within four hours. The assessment must also consider restoration of all loads within eight hours. These restoration levels are summarized in Figure 6-3, below.

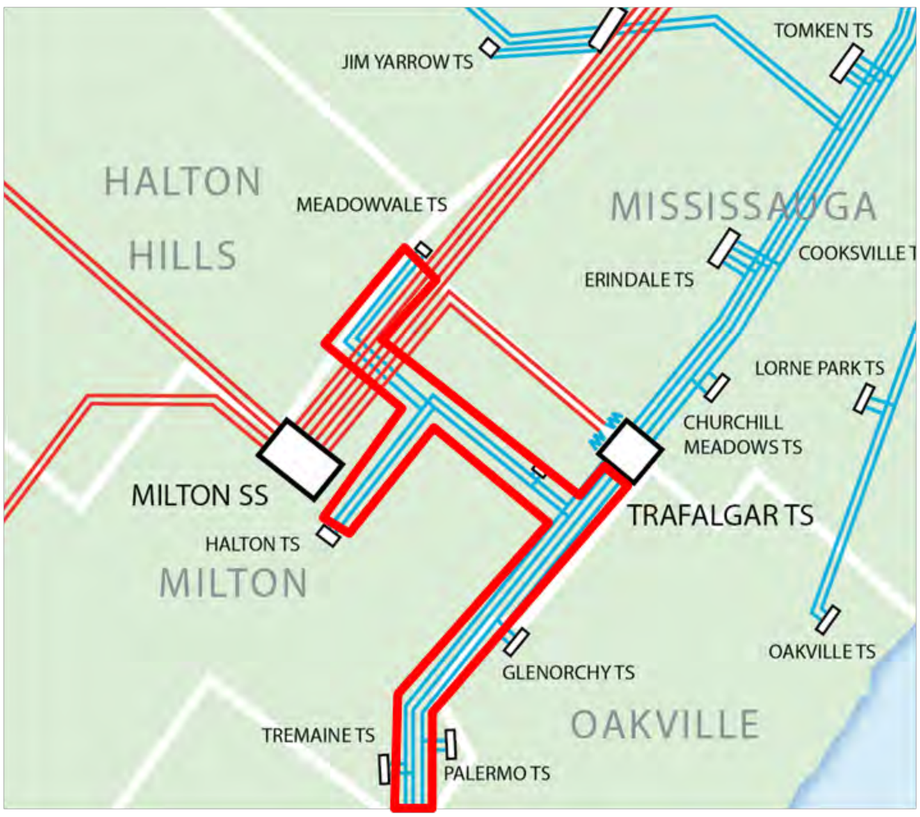
Because NW GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within eight hours for expected failure modes. As a result, this analysis will only focus on 30-minute and four-hour restoration capability.

Figure 6-3: ORTAC Load Restoration Criteria



Whenever the loss of two major power system elements has the potential to interrupt over 600 MW of load, the security criteria specified in ORTAC is not met. The IESO analyzed the security and restoration capabilities of the system in the study area by taking the sum of net forecasts from stations that would lose supply following the loss of two major power system elements. In this study area, the security criteria are not expected to be met in 2026 under the Expected Growth forecast for circuits T38/39B. These circuits run from Burlington to Trafalgar TS and supply the stations of Tremaine TS, Trafalgar DESN, Meadowvale TS and Halton TS. These facilities are shown in the following figure:

Figure 6-4: T38/39B and Surrounding Area



Because the majority of these stations serve the northern section of Halton and the transmission is configured in a largely radial path (no redundancy to restore loads through transmission), this area is referred to as the "Halton Radial Pocket." The table below shows the forecast peak load for this pocket, under the Expected Growth and Higher Growth scenarios:

Table 6-4: Halton Radial Pocket: T38/39B Station Loading (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Expected Growth	432	444	456	472	482	486	492	507	521	574	584	598	610
Higher Growth	435	449	462	478	487	495	510	527	543	599	613	629	645

The analysis performed shows that the Halton Radial Pocket may exceed ORTAC security criteria in the medium term. Given the high initial loads in the area, the need date is only mildly sensitive to assumptions in net growth rates, as demonstrated by a small (two-year) gap between the two scenarios.

Of the remaining restoration criteria, the 30-minute/250 MW restoration point is typically the most limiting, as it largely relies on the availability of remotely controlled equipment rather than manual actions by field operations staff.

Several sections of the study area are currently at risk of being unable to meet the 30-minute restoration criteria associated with loss of two power system elements. This is due in part to the configuration of the transmission system in the area, which relies on long radial circuits to connect northern loads to the more reinforced transmission grid to the south. The areas identified as being at risk for not meeting restoration criteria are shown in blue in Figure 6-5 below, with areas potentially at risk of not meeting security criteria (e.g., Halton Radial Pocket) over the next decade highlighted in red:

Figure 6-5: Areas with Potential Restoration Needs Within the Study Area

The extent of the restoration shortfall depends on the amount of load that can be restored through emergency distribution load transfers following a contingency. LDCs provided estimates of the load-transfer capability currently available to any given step-down station following the loss of transmission supply.

Table 6-5 below shows the forecast load levels and amount of available distribution load-transfer capability within 30-minutes of the loss of station supply for the four load pockets identified as having potential restoration needs. Also included is the restoration shortfall as per the ORTAC criteria. Results are provided for the most recent summer peak and the 2023 forecast under the Expected Growth and Higher Growth assumptions:

Table 6-5: 30-minute Restoration Capability and Needs (in MW)

Load Pockets	2013			2023 Expected Growth		2023 Higher Growth	
	Actual Demand	Available 30-minute Restoration	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall
1. Halton Radial Pocket: T38/39B Halton TS, Meadowvale TS, Trafalgar DESN TS, Tremaine TS, Halton CGS	409	146	13	574	178	599	203
2. Pleasant Radial Pocket: H29/30 Pleasant TS	354	52	52	398	96	418	116
3. Bramalea/ Cardiff Supply: Bramalea TS, Cardiff TS, Sithe Goreway	438	140	48	447	57	466	76
4. Kleinburg Radial Pocket: V43/44 Kleinburg TS, Vaughan 3 MTS, Woodbridge TS	380	122	8	458	86	467	95

It is also acceptable under ORTAC for distributors and transmitters to agree to a lower level of reliability, where it is agreed that "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified."[10] Solutions considered to address restoration needs in NW GTA must ensure that any investment developed to rectify the need

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

can be economically justified by accounting for the relative cost and benefit from the customer's perspective. This is discussed further in Section 7.1.3.2.

6.3 Transmission Capacity Needs

Transmission capacity needs arise when the electrical demands exceeds the capability of the transmission line to deliver the electrical energy. Facility limitations can manifest as constrained energy carrying capability (often referred to as thermal limitations) or the inability to deliver electrical service at the required power quality (such as voltage levels). These types of needs are triggered by growth in net load at stations within the study area. The Northwest GTA IRRP has identified two areas with potential transmission capacity needs emerging within the next 10 years: H29/30 circuits providing supply to Pleasant TS and T38/39B circuits providing supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. These areas and needs are described in greater detail below.

6.3.1 Supply to Pleasant TS

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. Two of the step-down stations output at 27.6 kV and one at 44 kV. Combined, these three stations reached an all-time peak demand of 375 MW in 2012. Although these assets have a maximum rated capacity of 515 MW, the transmission line serving this station (circuits H29/H30) is not capable of supplying this load.

Figure 6-6: H29/30 Supply to Pleasant TS

Based on the assessment carried out as part of the NW GTA IRRP, the maximum carrying capacity of the transmission line to Pleasant TS is approximately 417 MW. Since the need is dependent on the total loading of all three step-down facilities supplied by this line, the actual need date is sensitive to assumptions about the net growth rate. The table below summarizes forecast need dates under the Expected and Higher Growth scenarios:

Table 6-6: H29/30 Circuit Capacity Need Dates, Based on Net Load at Pleasant TS (in MW)

	Maximum loading	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	417	396	398	395	404	408	411	408	409	410	410	411	417
Higher Growth	417	414	418	418	431	439	445	446	449	452	455	458	465

Although the Expected Growth forecast shows a need date of 2033 (in red, above), growth is assumed to be offset by new conservation measures between the years 2026 and 2032, with peak demand stable between 408 MW and 410 MW (shown in orange). Given the risk that the energy-based conservation may not affect peak demand to this extent, it is recommended that solutions be pursued assuming a need date of 2026 for the Expected Growth forecast and 2023 for Higher Growth forecast. This recommended advancement is shown in Figure 6-7:

Figure 6-7: Recommended Advancement of H29/30 Supply to Pleasant TS Need Date

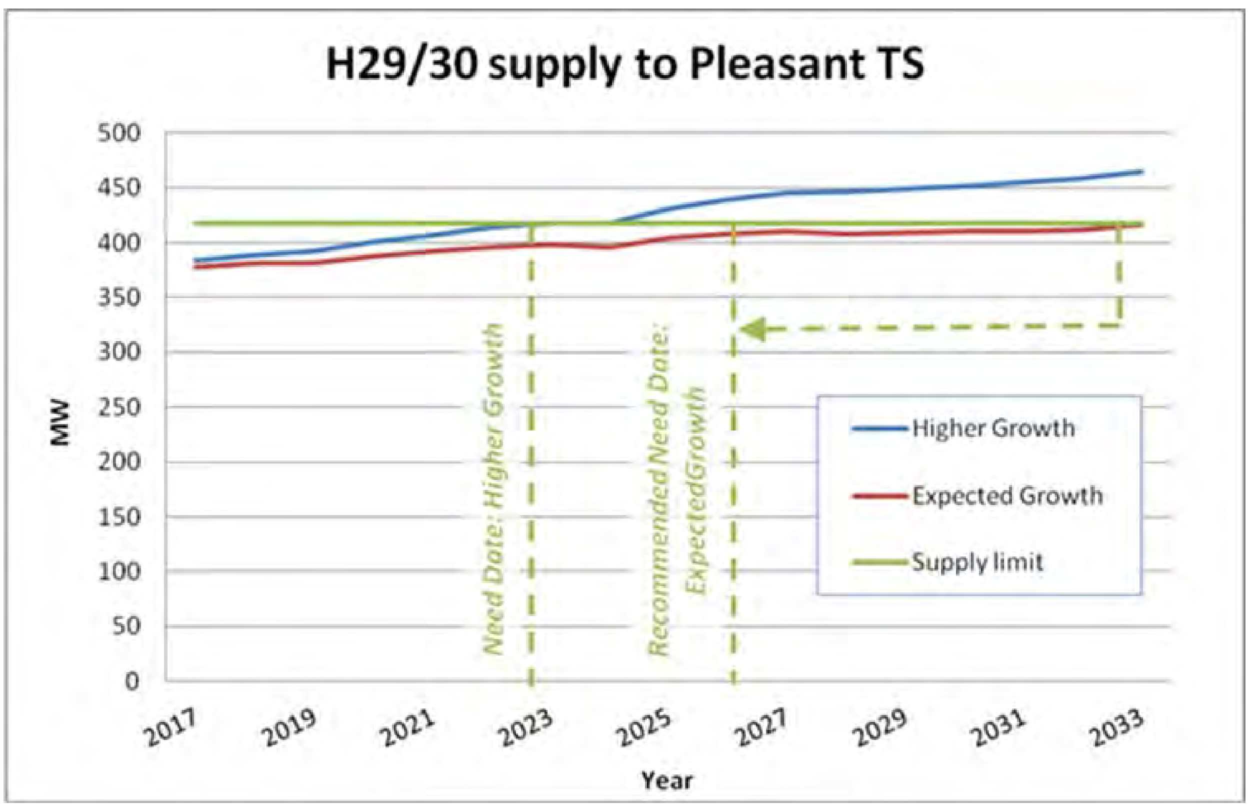


Figure 6-7 also shows that the need date under the Higher Growth forecast is less sensitive to small variations in demand, due to a stronger annual growth rate. As a result, it is not recommended that the need date be advanced under the Higher Growth forecast.

The H29/30 supply need was previously identified in 2007 through the System Impact Assessment ("SIA") for the third step-down station installed at Pleasant TS. The SIA conclusions noted that the supplying transmission lines (circuits H29/30) were expected to hit their thermal limit when the combined Pleasant TS loads hit approximately 408 MW.[11] The SIA required that a plan be put in place to mitigate this issue before load reached 408 MW. A second SIA prepared shortly thereafter for the Hurontario SS to Jim Yarrow MTS 230 kV transmission connection repeated this need, with a revised capacity for the transmission line of 412 MW.[12] Note that small variations in transmission line capability may occur between different studies, due to different assumptions used for running system models (as shown in the difference between H29/30 limits in the two SIAs and this IRRP).

6.3.2 Halton Radial Pocket

A large section of Halton region is currently supplied by two circuits, T38/39B, which span between Burlington TS and Trafalgar TS and contain a long radial section stretching north towards the Town of Milton. The peak load supplied by these two circuits was 410 MW, in 2013, representing the combined loads of Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. Growth among these stations is forecast to continue to increase at a net rate of over 3% per year for the coming 10 years. As a result, this area is expected to exceed ORTAC security criteria in the mid-2020s, once total load is above 600 MW (see Section 6.2, above). In addition, there is also a risk of exceeding line capacity (thermal constraints) beginning in the early-to-mid 2020s.

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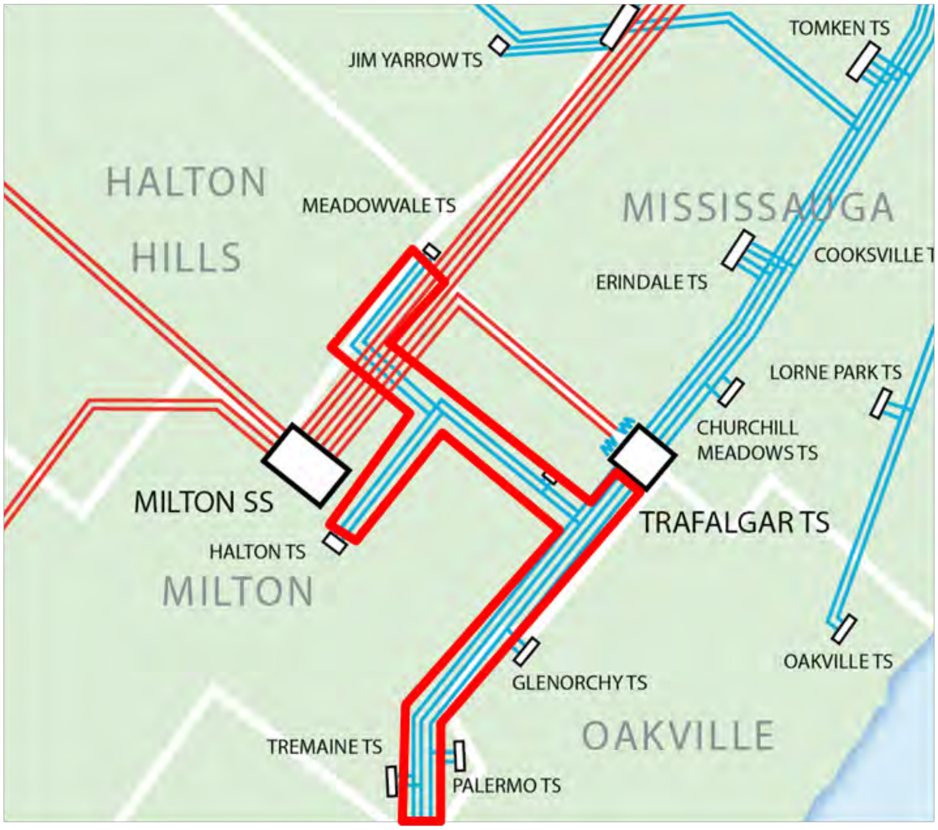
[11] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-231_R2.pdf.
[12] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-248_R2.pdf

Figure 6-8: T38/39B Halton Radial Pocket



Following the loss of either T38B or T39B, the companion circuit must be able to supply all the electrical demand of the connected stations. While the capacity to transmit power varies at different sections of the circuit (typical for long and branching circuits), load flows show that potential needs are observed when Halton Hills GS is out of service and the total radial pocket load exceeds approximately 528 MW. Table 6-7 shows the total net forecast demand of all stations supplied by the T38/39B circuits, with potential needs highlighted:

Table 6-7: T38/39B Circuit Loading (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Growth	432	444	456	472	482	486	492	507	521
Higher Growth	435	449	462	478	487	495	510	527	543

Overloading on the companion T38/39B circuit can be avoided by running Halton Hills GS, a 620 MW gas-fired power plant, during hours when the total area load exceeds 528 MW. This generation facility is located in southern Halton Hills and, in electrical terms, is at the furthest end of the T38/39B radial pocket. This means that any power output by Halton Hills GS reduces the amount of power transmitted into the area. T38/39B's potential overloading is one of the reasons Halton Hills GS was constructed in this area in 2010.

Due to the presence of local generation, the risk of exceeding the line capacity on T38/39B only occurs when there is a single circuit contingency and Halton Hills GS is unavailable. If either T38B or T39B and local generation are out of service, up to 150 MW of load shedding is permitted to prevent system overloads. ORTAC criteria allow this practice, given the low probability of occurrence. Applying this control action would eliminate the risk of system overloads for the duration of the study period under the Expected Growth forecast and until 2029 under the Higher Growth forecast. To ensure that any load interruptions have a minimal impact on customers, Special Protection Schemes can be designed in advance to ensure that critical loads are not impacted.

6.4 Needs Summary

The NW GTA is a rapidly growing area with an electrical system characterized by heavily loaded radial supply circuits. Within the near-to-medium term, growth is expected to continue northward into greenfield areas, further stressing a radial transmission system that is concentrated to the south. Both step-down stations and the supplying lines are expected to exceed their rated limits within the next decade and will require relief. Additionally, several restoration needs have been identified and will continue to worsen as electrical demand increases, potentially triggering a supply security need in the mid-2020s, when electrical demand in the radial pocket is forecast to exceed 600 MW. In the longer term, significant supply capacity is expected to be needed across a wide range of north Brampton and south Caledon, where no supporting power system infrastructure currently exists.

Table 6-8: Summary of Needs

	Near Term (2014-2018)	**Medium Term (2019-2023)**	**Long Term (2024-2033)**
Step-down Station Capacity	Halton TS • Halton Hills Hydro	Halton TS • Milton Hydro	Pleasant TS Kleinburg TS (Higher Growth)
Transmission Capacity	--	Supply to Pleasant TS (Higher Growth)	Supply to Pleasant TS (Expected Growth)
Supply Restoration	Halton Radial Pocket Pleasant Radial Pocket Cardiff/Bramalea supply Kleinburg Radial Pocket	--	--
Supply Security	--	--	Halton Radial Pocket

7. Alternatives for Meeting Near- and Medium-Term Needs

This section describes the alternatives considered in developing the near-term plan for Northwest GTA, provides details of and rationale for the recommended plan, and outlines an implementation plan.

7.1 Alternatives Considered

In developing the near-term plan, the Working Group considered a range of integrated options. The Working Group considered technical feasibility, cost and consistency with long-term needs and options in Northwest GTA when evaluating alternatives. Solutions that maximized the use of existing infrastructure were given priority.

The following sections detail the alternatives considered and comment on their performance in the context of the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets (see Section 5.4). Across the planning area, the LTEP energy reduction targets account for approximately 130 MW, or 33% of the forecast demand growth during the first 10 years of the study. Achieving the estimated peak-demand reductions of the provincial conservation targets defers several needs, including transmission line supply to Pleasant TS and Pleasant TS transformer capacity (more details provided below). Given the power system and customer benefits, conservation efforts should focus first on encouraging energy-saving measures that also offset peak demand. Maximizing savings in locations where there is potential to defer longer-term solutions should be a secondary consideration.

Although current LDC conservation targets are based on energy savings, peak-demand savings are required to defer the need for new infrastructure, especially in areas like Northwest GTA where new growth is outstripping the ability of the existing system to meet demand. As part of the Conservation First Framework 2015-2020, all Ontario LDCs are required to produce a conservation and demand management plan by May 1, 2015, outlining how they intend to meet their mandated energy savings targets within their allocated CDM budget.

Details on these plans have been provided by LDCs in Appendix D.

This IRRP will help inform the development and implementation of conservation programs by:

1. Identifying areas in the Northwest GTA where conservation will be most beneficial, and
2. Quantifying the expected benefit of achieving different levels of peak-demand reduction.

The latter is useful for determining whether the incremental cost of targeting peak-demand savings in one particular area is cost effective, given the expected societal benefit from the deferred investment.

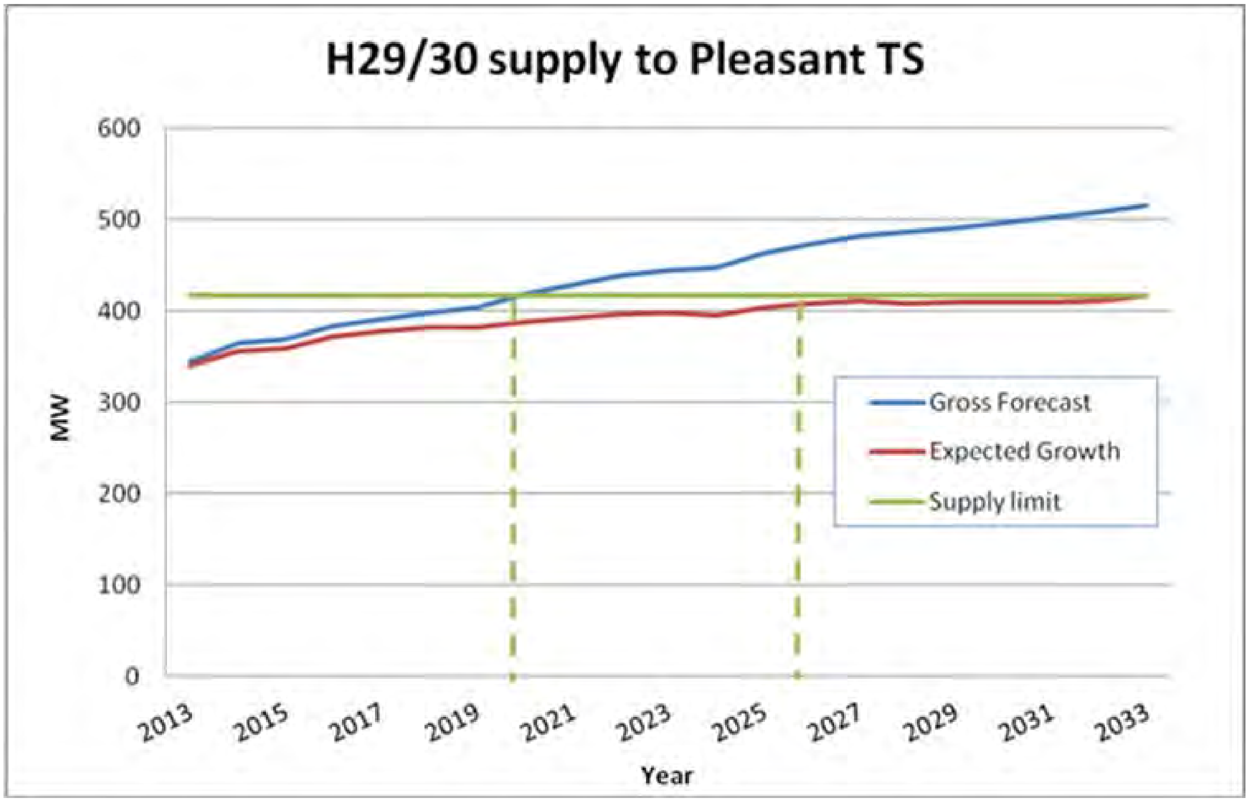
The examples below demonstrate the expected economic benefit from the achievement of the expected peak-demand savings from the LTEP energy reduction targets in two key areas in Northwest GTA: the Pleasant TS and Kleinburg TS service territories. While Pleasant TS and Kleinburg TS have been highlighted, peak-demand reductions will also benefit other parts of the study area, for example, by offsetting the need for distribution expansion. A breakdown of economic assumptions and calculations are provided in Appendix C.

Pleasant TS – Transmission line and step-down transformer needs

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. As mentioned in Sections 6.1.2 and 6.3.1, there are two potential capacity needs associated with this station: (1) limits on the transmission lines that supply electricity to the station and (2) limits on the step-down transformers that convert high voltage electricity from the transmission system to lower voltages for distribution to customers. Both of these needs can be deferred several years by reducing peak demand, as the gap in need dates under the different forecasts demonstrates.

The Expected Growth forecast assumes 65 MW of peak-demand reduction within the Pleasant TS service territory by 2026, primarily from conservation measures. Achieving these reductions successfully defers the need for relief on the H29/30 circuits supplying Pleasant TS by six years, from 2020 to 2026. As described in Section 7.1.3.3, once the capacity limit on H29/30 is reached, these circuits will need to be upgraded to a higher carrying capacity, which is estimated to cost approximately $6.5 million. The expected present day economic value of deferring this investment from 2020 to 2026 is approximately $1.45 million.

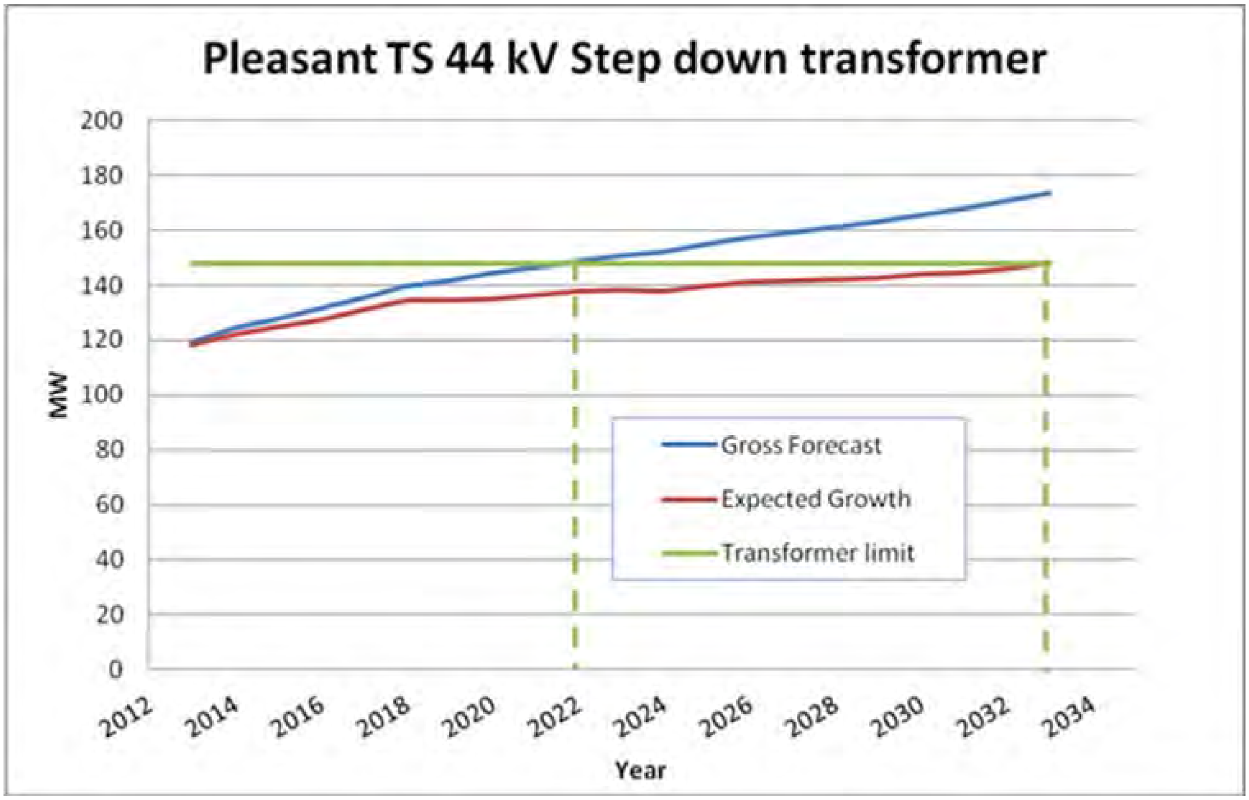
Figure 7-1: Effect of Conservation on H29/30 Needs



Of the three step-down facilities at Pleasant TS, the 44 kV transformers are expected to reach their maximum capacity first. While the LDCs' initial gross extreme weather forecast (the "Gross Forecast") originally anticipated a need date of 2022, the 25 MW of peak-demand reduction applied by the IESO in developing the Expected Growth forecast successfully defers the need for relief by 11 years. Assuming that the H29/30 needs are resolved through other means, such as upgrading the transformers, the expected present day economic value (based strictly on transmission infrastructure deferment) of the peak-demand effects of achieving provincial energy targets is approximately $11.60 million.

Note that this estimate is based only on deferring a $30 million step-down station and does not consider other system upgrades that may be required to ensure the new step-down station has adequate transmission supply. Thus, the actual benefit of deferring is expected to be higher, as new transmission facilities would be required to enable the connection and operation of this step-down station. Long-term supply options are described in greater detail in Section 8.1.1.

Figure 7-2: Effect of Conservation on Pleasant TS 44 kV Transformer Needs

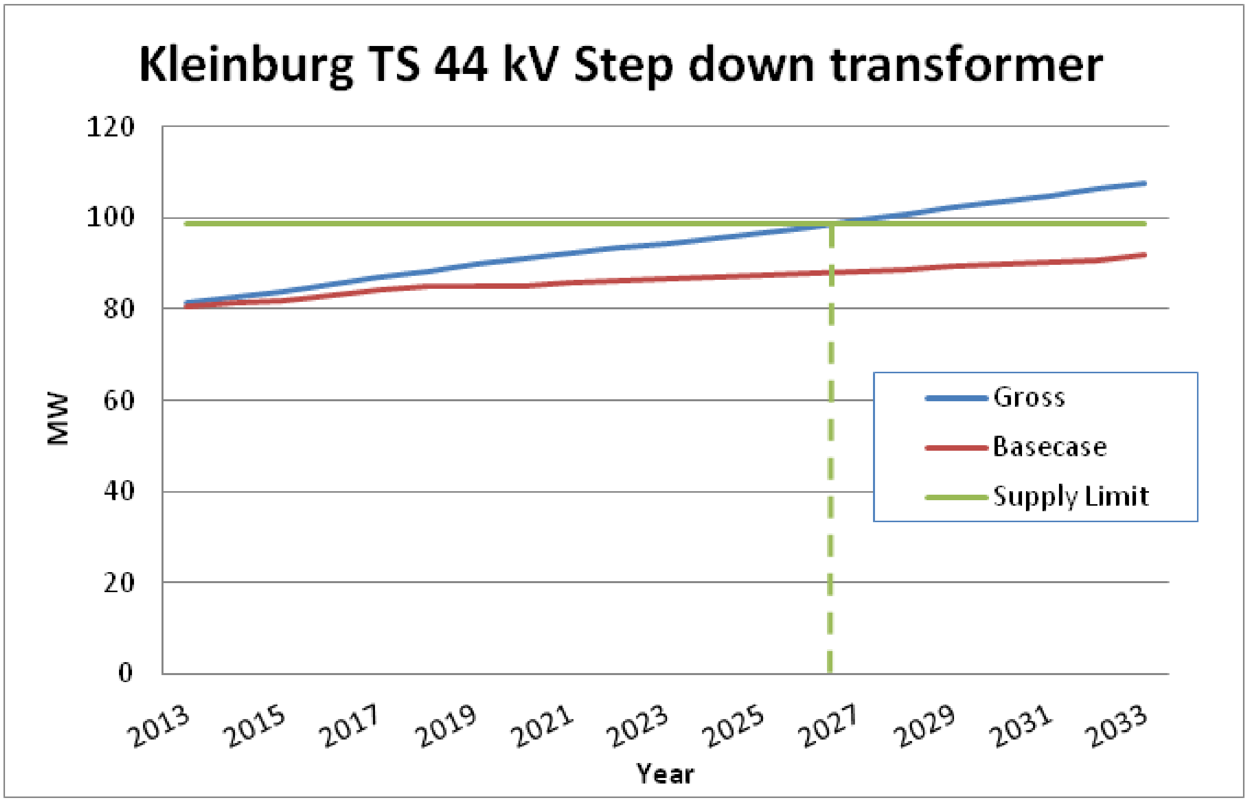


Kleinburg TS – Step-down transformer needs

Kleinburg TS has two step-down stations located at the same facility in northwest Vaughan, close to the boundary with Caledon. The station has a total load serving capacity of approximately 195 MW, shared between 27.6 kV and 44 kV loads. Demand on the station currently peaks at around 130 MW, or about 67% capacity. Load from Kleinburg TS primarily serves Hydro One Distribution customers, particularly in southern Caledon and the town of Bolton, which is expected to drive most new growth over the study period.

Based on the Gross Forecasts provided by LDCs, the 44 kV facilities at Kleinburg TS may hit their limit as early as 2027. In order to defer station overload needs beyond the current planning horizon, 10 MW of peak-demand reduction measures are required. The Expected Growth forecast developed in this IRRP already assumes that conservation programs will provide 15 MW of peak-demand reduction. The expected economic value of the peak-demand effects of achieving provincial energy targets estimated in the Kleinburg 44 kV service territory is approximately $6.53 million, assuming that achieving these targets successfully defers the need for a new $30 million step-down station from 2027 to 2034.

Figure 7-3: Effect of Conservation on Kleinburg TS 44 kV Transformer Needs



Although the Expected Growth forecast does not anticipate that Kleinburg TS (44 kV and 27.6 kV transformers) will reach their capacity limit before the end of the study period, relatively small changes in development levels could have a large effect on this facility's need date, due to the large greenfield areas within the Kleinburg TS service territory and a lack of alternate step-down stations to serve growth. As a result, actual loading on both step-down stations at this facility should be reviewed during the next regional planning cycle and needs revisited as required.

7.1.2 Local Generation

Large, transmission-connected generation and small-scale distribution-connected DG options were ruled out as viable alternatives for meeting near- and medium-term needs in Northwest GTA.

The most pressing near-term needs are associated with low voltage feeder capacity and step-down transformer capacity for Halton Hills Hydro and Milton Hydro (Halton TS). A transmission-connected generation project would not address this need given that the problem is at the distribution voltage level. Distribution-connected DG projects were determined to be technically, logistically and economically infeasible because the DG options would need to be optimally dispersed across a number distribution feeders such that existing feeder capacity is freed up to enable carrying forecast growth in electrical demand across the service territory. Developing and implementing such a complex solution within the time period of the need in this high-growth area was not determined to be practical.

A second set of identified needs for this sub-region are associated with restoration capability in four transmission/restoration pockets, as discussed in Section 6.2. Addressing restoration needs through large transmission-connected generation would require the implementation of a generation facility within Halton radial pocket, Pleasant TS, Cardiff/Bramalea and Kleinburg radial pocket. This solution was determined to be impractical from a technical and economic perspective, given the scale and number of facilities that would therefore be required within the region.

Transmission line capacity to Pleasant TS was also identified as a need in the 2023-2026 time period. Addressing this need through large-scale transmission-connected generation would require the implementation of a major facility in close proximity to Pleasant TS, which is located within a highly developed area of central Brampton. As discussed in Section 7.1.3.3, this need can best be met by upgrading an existing transmission line, with minimal cost and community impact. Since the large scale generation option would cost substantially more than the line upgrade option and result in significantly higher community impact, this option was not considered further.

In addition, because local generation would contribute to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the end of the decade at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

Small-scale, distributed generation was also rejected as a viable alternative for meeting the transmission line capacity need at Pleasant TS. Existing DG projects have already been accounted for in the forecast and contracted DG projects that are not yet in service have been assumed in the forecast based on their contracted in-service date. These future DG projects were applied by netting their expected contribution at peak load times, in a similar manner as conservation. Meeting the need for transmission line capacity to Pleasant TS through DG was rejected due to the availability of a low-cost, low community impact transmission solution (upgrading an existing line) as discussed in Section 7.1.3.3. This upgrade would be more economic and easier to implement than the option of small scale, DG.

Potential for meeting long-term needs, such as step-down transformer capacity needs at Pleasant TS or Kleinburg TS, will be reviewed as part of regular regional planning cycles closer to these facilities' expected need dates, while actual uptake will be monitored on a yearly basis.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," alternatives were considered by the Working Group to meet the near-term needs. Wires infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including lines, stations, or related equipment. These solutions are often characterized by high upfront capital costs, but have high reliability over the lifetime of the asset.

7.1.3.1 Halton TS Capacity Relief (Step-down Transformers and LDC Feeders)

There is a near-term need for additional step-down capacity to relieve overloading at Halton TS. Due to the near-term need, a separate product was prepared by the IESO and relevant LDCs concurrent to the IRRP process, to ensure a preferred solution could be identified, discussed and ultimately recommended with as short a lead time as possible. This paper, entitled "Transmission and Distribution Options and Relative Costs for Meeting Near-Term Forecast Electrical Demand within the NW GTA Study Area", is attached in Appendix E and considered three alternatives for meeting this need:

1. Distribution load transfers
2. Single step-down station (with enhanced distribution connections)
3. Two new step-down stations.

The two station solution, further described below, was ultimately recommended as the least costly of the feasible alternatives.

Distribution load Transfers

As an alternative to building new step-down stations to supply growing load in the vicinity of Halton TS, a number of neighbouring stations were considered for their ability to supply local demand through extensions of the low voltage (distribution) feeder network (See Figure 7-4). These options were rejected for the following reasons:

- **Palermo TS**: No remaining capacity is available at this station and as a result this station cannot be considered for providing load-transfer capability.
- **Glenorchy MTS**: This station is located too far south from the anticipated growth centers in Milton (approximately 9 km) to make this a preferable long-term supply option. However, this station can provide valuable flexibility in meeting near-term electrical demand. To minimize costs in the area, Oakville Hydro (the owner and operator of this station) has entered into a short-term leasing agreement with Milton Hydro, allowing Milton Hydro to use up to 40 MW of capacity until the year 2023, after which time Oakville Hydro anticipates requiring this capacity to meet their own growth. The 40 MW of Milton load currently being supplied by Glenorchy MTS will then require a suitable step-down station to provide this supply.
- **Trafalgar TS** (step-down facilities): Although approximately 30 MW of capacity remains at this station, it is approximately 12 km removed from Milton Hydro's growth centre and, as a result, is too far removed to be considered a suitable candidate. However, this station should be considered for meeting any long-term Milton Hydro load growth that may occur in the (currently largely rural) south eastern section of the municipality.
- **Tremaine TS**: This station is too far away to meet anticipated near-term growth in central Milton Hydro territory (the station is approximately 15 km from the growth centre) and, as a result, is not suitable for providing load-transfer capability to relieve Halton TS. Instead, Milton Hydro has been allocated two feeders (approximately 35 MW), which will be used to supply south Milton loads, primarily belonging to lower density and slower-growing customer pockets.
- **Jim Yarrow MTS**: This station is approaching its maximum capacity and is expected to be fully loaded by 2020. As a result, it was not considered a suitable station for transferring Halton TS area loads. Additionally, Jim Yarrow MTS is located too far from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level.
- **Pleasant TS**: Any load transfers to this station would advance thermal overloads anticipated on the supplying circuit in the mid-2020s. Additionally, Hydro One Brampton has indicated that new feeder egress is extremely limited and space for accommodating all anticipated feeders to serve Hydro One Brampton has already been obtained, limiting options for supply to other LDCs. Pleasant TS is also located too far

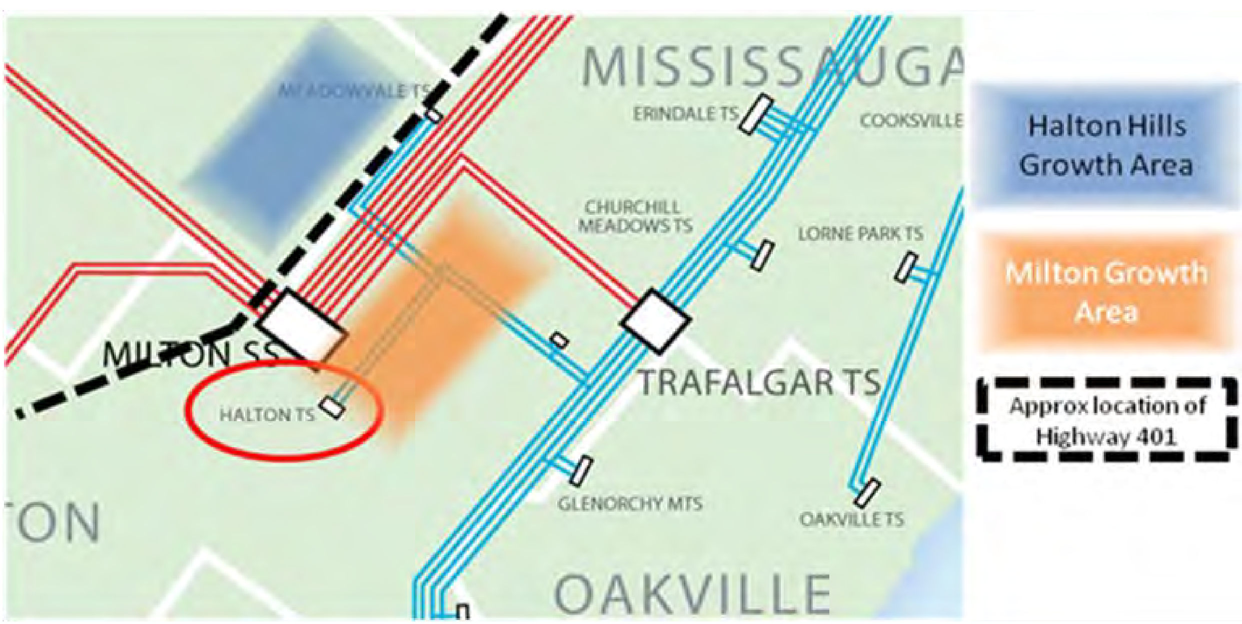
from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level. For these reasons, load transfers to Pleasant TS were not considered.
- **Meadowvale TS**: This station outputs at the 44 kV distribution level and so is not suitable for meeting growth currently supplied at the 27.6 kV level from Halton TS.

In addition to the specific reasons mentioned above, all distribution transfer options would require customers to be supplied by longer distribution connections than had they been supplied by a newer, closer station. Longer feeder connections result in poorer reliability, have the potential to trigger power quality issues and will require a greater investment in distribution infrastructure. Due to the unavailability of suitable stations, distribution load transfers were not considered as a potential solution to the Halton TS capacity need.

Single new step-down station (with enhanced distribution connections)

Under this alternative, a single step-down station is constructed on the south side of Highway 401 to meet load growth in both the Halton Hills Hydro and Milton Hydro service territories. Due to the challenges of acquiring air rights over Highway 401, it is assumed that the feeders for serving Halton Hills Hydro customers must be tunneled under the highway at a cost of $2 million per feeder.

Figure 7-4: Halton TS and Nearby Elements



Over the next 20 years, expected load growth in the Halton Hills territory will require the tunneling of eight distribution feeders. Additionally, under the Higher Growth forecast, a single step-down station will not provide sufficient capacity to meet expected long-term load growth in Milton and Halton Hills, so a second station would be required in 2028. As a result, the single station alternative performs poorer under high growth conditions than the two station alternative, as the latter allows the stations to be optimally sited for meeting growth and avoids the need for costly distribution investments.

This alternative also performs poorer than the two station alternative from the perspective of land use, as there would be a greater reliance on distribution infrastructure, especially through the eastern portions of Milton. Using more distribution lines can also contribute to lower customer reliability, as they are more prone to outages than equivalent transmission assets.

Two new step-down stations

This alternative consists of building two new step-down stations: one to provide long-term supply for Halton Hills Hydro loads and a second for Milton Hydro. The Halton Hills Hydro station is required in 2018 and would be located on the north side of Highway 401, while the Milton station, required in 2020, would be located on the south side. This solution eliminates the need to run distribution feeders across Highway 401, which would otherwise present a major technical and financial barrier to integrating a single new station. A suitable location has been found in existing electrical infrastructure facilities for both proposed stations: a new station north of Highway 401 located on the grounds of the TransCanada Halton Hills Gas Generation facility and a new station on the south side located within the existing Milton SS and Halton TS grounds.

After carrying out a net present value cost comparison (summarized in Table 7-1, below), the two station option proved more economic than the single station alternative and was adopted as the recommended outcome for meeting this need. A full list of economic assumptions and methodology is available in Appendix E.

Table 7-1: Cost of Providing Halton TS Capacity Relief, Alternative and Load Growth Scenarios

Alternative	Cost of Alternative, in $M 2014 (Expected Growth)	Cost of Alternative, in $M 2014 (Higher Growth)
Distribution load transfers	Not technically feasible	Not technically feasible
One new step-down station (Halton TS #2, and Halton TS #3 required under Higher Growth forecast)	$51.6	$67.9
Two new step-down stations (Halton Hills Hydro MTS + Halton TS #2)	$48.5	$49.9

Under the Expected Growth forecast, the cost of a second step-down station is also slightly less when considering the cost of additional feeders, including tunneling, required to supply Halton Hills Hydro loads from a single station located south of Highway 401. As a result, the two station alternative is slightly more economic. Under the Higher Growth forecast, a second station is required regardless, meaning the initial two station solution is much more economic since it eliminates the need for distribution expansion.

7.1.3.2 Restoration needs

As described in Section 6.2, four areas in the Northwest GTA sub-region are at risk for not meeting restoration criteria following the loss of two transmission elements. These are:

1. Halton radial pocket
2. Pleasant radial pocket
3. Bramalea/Cardiff supply
4. Kleinburg radial pocket

Figure 7-5: Areas with Potential Restoration Needs Within the Study Area

Possible infrastructure solutions were investigated and their conclusions discussed below.

Bulk transmission study underway

As described in Section 4.3, a bulk system study is underway for West GTA to address overload issues on the 500 kV and some 230 kV transmission assets in the area. Since the bulk transmission study will investigate major changes to the transmission system that can impact restoration capability, the regional restoration needs for the Halton radial pocket, Bramalea/Cardiff supply and the Kleinburg radial pocket will be factored into the bulk system analysis. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process.

Restoration needs for Pleasant TS are not being considered as part of the bulk study, as this pocket is not directly linked to any bulk system assets. The Pleasant TS restoration needs were considered separately as part of this NW GTA IRRP (see below).

Pleasant TS Restoration

Pleasant TS is served by a radial 230 kV two-circuit overhead transmission line that supplies approximately 375 MW of electrical demand during summer peak. The station itself includes three step-down transformers facilities (DESNs): one serving 44 kV distribution loads and two serving 27.6 kV loads. Growth in electricity demand in the area served by this station is expected to increase this demand to 400 MW by 2023 and 415 MW by 2033, the end of the study period. Under the Higher Growth forecast, electrical demand in these same years is forecast at 420 MW and 465 MW, respectively. Table 6-5 summarizes the ORTAC load restoration criteria and the degree to which these criteria are exceeded for the four areas with potential issues, including Pleasant TS. The Pleasant TS restoration need stems from the occurrence of a double circuit outage to the transmission line supplying the transformer station, which is a low probability event.

As mentioned in Section 6.2, the restoration criteria within ORTAC provide flexibility in cases where "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified." Since the radial supply facilities to Pleasant TS do not form part of the integrated bulk transmission system, a cost justification assessment was undertaken. Several jurisdictions within the electricity industry take guidance on cost justification for low probability/high-impact events by accounting for the cost risk (probability and consequence) of the failure event and determining if mitigating solutions can reduce the overall cost to customers. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of a supply interruptions to the affected customers
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost-justified.

The assessment for the Pleasant TS supply situation found that mitigating solutions were estimated to be significantly more costly to customers in the area than the status quo. This is primarily due to the low probability of the event occurring. As a result, it is not economically prudent to pursue a transmission- or distribution-based solution at this time. Details of this assessment can be found in Appendix C.

The existing long-term forecast indicates that the service area immediately to the north of Pleasant TS is expected to grow substantially over the next 20 years. As described in Section 8.1.1, supplying this long-term growth area will require the introduction of a new transmission supply line and transformer station in the 2026-2033 time period. Once this new supply point is introduced, it is expected that more economic restoration options for the low probability failure event to Pleasant TS would become available. This will be reviewed in updates to this plan.

7.1.3.3 Supply to Pleasant TS

As described in Section 6.3.1, the H29/30 circuits that supply Pleasant TS (shown below) are expected to reach their capacity limit in approximately 2026 under the Expected Growth forecast, or 2023 under the Higher Growth forecast. Conservation and distributed generation can reduce peak demand and defer this need, but a transmission-based solution is expected to be required in the medium to long term.

Figure 7-6: H29/30 Supply to Pleasant TS

Two transmission-based solutions are considered below: upgrading the existing H29/30 circuits to a higher rating and advancing the construction of a new transmission supply path into the area.

Upgrading circuits H29/30

The H29/30 circuits supplying Pleasant TS are currently rated at 1090 A,[13] which limits the maximum load-carrying capacity to approximately 417 MW. Based on a preliminary assessment performed by Hydro One, the asset owner, the existing towers are able to support a conductor large enough to carry 1400 A, or supply loads of over 500 MW. Since replacing the conductors would not require changes to the existing tower structures, the estimated preliminary cost of this upgrade is around $6.5 million.

This upgrade would fully address this need and allow the step-down transformer facilities at Pleasant TS to be loaded up to their maximum rated capacity.

Advancement of long-term transmission solution

As described in Section 8.1.1, there is a long-term need for new transmission infrastructure in northern Brampton/southern Caledon. As an alternative to upgrading circuits H29/30,

[13] Summer Long Term Emergency planning rating.

transmission investment could be made earlier to provide an alternative point of supply to serve growing loads in the current Pleasant TS service territory. Note that this option would require limiting the loading at Pleasant TS step-down facilities below their maximum ratings to avoid overloading the supplying circuits.

Based on high level planning estimates for the cost of new transmission infrastructure to supply the area north of Pleasant TS and the need dates from the Expected Growth forecast, the cost of advancing this investment to 2026 from 2033 is approximately $25 million:

Table 7-2: Cost of Advancing West GTA Transmission Corridor, Expected Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2026 in-service date (2014 $M)	2033 in-service date (2014 $M)
25 km new 2x230 kV transmission	$75	$54.3	$38.2
New step-down transformer	$30	$23.2	$16.3
Reconfigure Kleinburg, other circuit terminations	$10	$7.7	$5.4
TOTAL	**$115**	**$85.3**	**$59.9**
Advancement Cost:			**$25.4**

Under the Higher Growth forecast, this infrastructure is required in 2023 to address overloads on H29/30, a three-year advancement from the 2026 need date if H29/30 were upgraded:

Table 7-3: Cost of Advancing West GTA Transmission Corridor, Higher Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2023 in service (2014 $M)	2026 in service (2014 $M)
25 km new 2x230 kV transmission	$75	$62.7	$54.3
New step-down transformer	$30	$26.8	$23.2
Reconfigure Kleinburg, other circuit terminations	$10	$8.9	$7.7
TOTAL	**$115**	**$98.5**	**$85.3**
Advancement Cost:			**$13.2**

Based on this assessment, the cost of advancing the need date for a major new transmission corridor is two to four times more costly than upgrading the H29/30 conductors to a higher rating (estimated to be $6.5 million). Therefore, upgrading the H29/30 conductors is the recommended alternative.

Details on economic assumptions used in this analysis are available in Appendix C.

7.2 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term electricity needs of NW GTA. Successful implementation of this plan will address the region's electricity needs until the early-to-mid 2020s.

7.2.1 Conservation

As achieving demand reductions associated with the conservation targets is a key element of the near-term plan, the Working Group recommends that LDCs' conservation efforts focus on peak-demand reductions. Monitoring conservation success, including measuring peak-demand savings, is an important element of the near-term plan and will lay the foundation for the long-term plan by gauging conservation measures' performance and assessing the potential for further conservation efforts.

Particular attention should be directed to the areas with the highest value conservation potential, namely for reducing peak demand in the service areas supplied by Pleasant TS and, in the longer term, by Kleinburg TS.

Details on each LDC's conservation plan are provided in Appendix D.

7.2.2 Two Station Solution: Halton Hills Hydro MTS and Halton TS #2

Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

The Working Group recommends the transmitter, Hydro One, should initiate technical and engineering work for the development of Halton TS #2, at the site of the existing Halton TS, with a tentative in-service date of 2020. Based on the current load forecast and a typical three-year lead time from initiation of approvals to in-service date, construction of Halton TS #2 is not yet required. The Working Group recommends that actual load growth be monitored on an annual basis before a RIP is initiated.

7.2.3 Reinforcement of H29/30

The Working Group recommends the transmitter, Hydro One, should proceed with the preliminary work required to validate the technical, feasibility and cost for the replacement of conductors on the H29/30 circuits to a summer LTE planning rating of 1400 A. It is recommended that this measure be implemented before peak loads at Pleasant TS exceed approximately 417 MW. Based on the current load forecast, this may occur as soon as 2023 under the Higher Growth scenario. The Working Group recommends that actual load growth be reviewed annually and this issue be reassessed during the next iteration of the regional planning cycle.

7.2.4 Restoration Needs

Four pockets in the study area are at risk for not meeting ORTAC restoration criteria. The ongoing bulk system study will consider solutions to address these needs at three of the four pockets. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process. The fourth pocket, Pleasant TS, was considered as part of this IRRP; pursuing transmission- or distribution-based solution at this time is not economically prudent. Opportunities will be reassessed in updates to this plan.

7.3 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of Northwest GTA are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. Table 7-4 shows the plan's deliverables, timeframe for implementation and the parties responsible for implementation.

The Northwest GTA Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the region and to track progress toward these deliverables. In particular, the actions and deliverables in Table 7-4 with estimated timeframes for completion will require annual monitoring of system conditions to determine when projects must be initiated. Preliminary engineering and design work should be initiated at an appropriate time to ensure that the plan can be implemented as required.

Table 7-4: Implementation of Near-Term Plan for Northwest GTA

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and distributed generation	Develop CDM plans	LDCs	May 2015
	LDC CDM programs implemented	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification of programs, including peak-demand impacts and provide results to Working Group	LDCs	Annually
	Continue to support provincial distributed generation programs	LDCs/IESO	Ongoing
2. Develop new step-down station in Halton Hills	Design, develop and construct new step-down station in southern Halton Hills, at the Halton Hills GS site	Halton Hills Hydro	In-service spring 2018
3. Develop new step-down station in Milton	Design, develop and construct new step-down station in Milton at the existing Halton TS site	Hydro One	In-service spring 2020 (estimated)
4. Upgrade H29/30 conductors	Upgrade H29/30 circuits to higher rated conductors	Hydro One	2023-2026 (estimated)

8. Options for Meeting Long-Term Needs

The following sections describe various approaches for meeting the long-term electricity needs of Northwest GTA. The purpose in describing different approaches is not to advocate for one over another, but to present the factors that must be balanced when forming long-term electricity plans.

In the case of Northwest GTA, long-term needs are characterized by constraints on a system largely built to the south, while new development continues to expand northward, beyond the existing system's ability to meet new demand. These needs are not limited to the electricity system, as all forms of infrastructure will be challenged to accommodate expanding development. One major infrastructure initiative already underway is the development of the West GTA transportation corridor, led by the Ministry of Transportation. This project is working to identify and secure land for the development of a 400-series highway and transitway extending from Highway 400 (between Kirby Road and King-Vaughan Road) in the east to the Highway 401/407 ETR interchange area in the west, passing along the south Caledon border with Brampton and along the eastern Halton border with Peel.

More information on this project is available at http://www.gta-west.com/.

This proposed route aligns well with the long term electricity infrastructure needs described in this IRRP and provides the opportunity to plan for a transmission corridor in the general vicinity to meet the transmission needs. The coordination of these infrastructure facilities is consistent with the 2014 Provincial Policy Statement ("PPS").[14] The PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities. Regardless of the approach pursued to meet long-term electrical demand growth in Northwest GTA, there will remain a long-term need for new transmission infrastructure. Establishing the corridor at this time is recommended due to the unique opportunity provided by the simultaneous planning of the West GTA transportation corridor.

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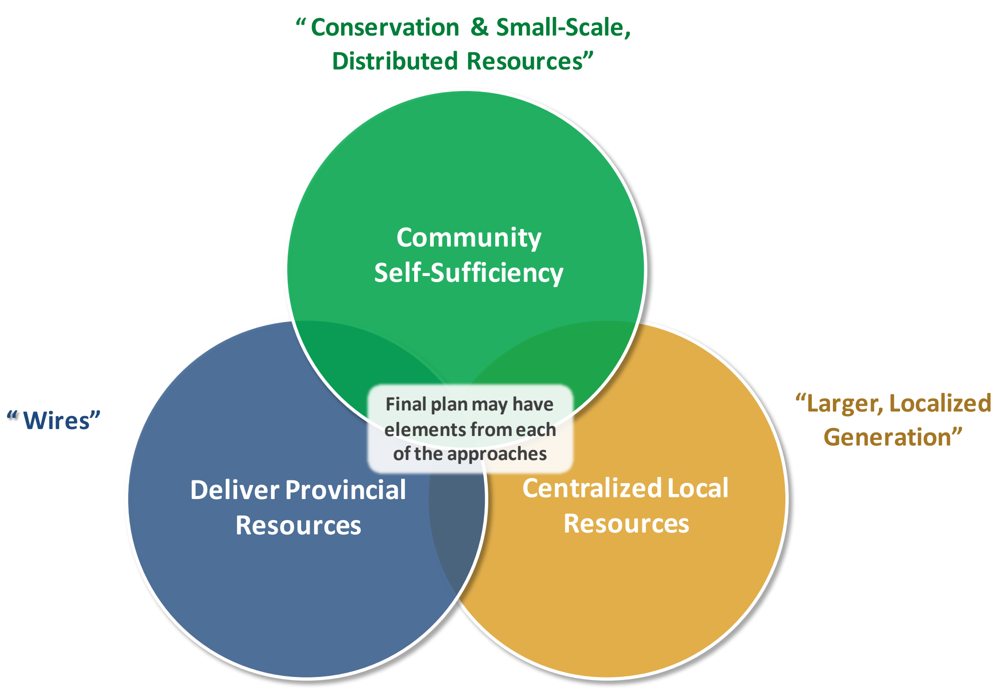
[14] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting distributed generation, greater emphasis on conservation as part of electricity system planning and increasing community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires"-based approaches to electricity planning, while still technically feasible, may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 8-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 8-1: Approaches to Meeting Long-Term Needs



The intent of this framework is to identify which approach is to be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches and there will necessarily be some overlap between them. For example, provincially mandated conservation targets will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. In fact, it is likely that all plans will contain some combination of conservation, local generation, transmission and distribution elements. Once a decision on the basic approach is made, the plan is developed around that approach, which affects the relative balance of conservation, generation and "wires" in the plan.

The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before long-term plan commitment decisions are required. The success of this approach depends on early action to explore potential and develop options and on the local community taking a lead role. This could be through a municipal/community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Details of how these three approaches could be developed to meet the specific long-term needs of Northwest GTA are provided in the following sections.

8.1.1 Delivering Provincial Resources

Under a "wires"-based approach, the traditional approach taken to address regional electricity needs, the long-term needs of Northwest GTA would be met primarily through transmission and distribution system enhancements. Due to the continued northern expansion of urban growth throughout the study area in general and through northern Brampton and southern Caledon in particular, it is anticipated that new transmission infrastructure will be required in this area in the long term. As described earlier, this could be triggered by one of three needs:

- Overloads on the H29/30 circuits providing supply to Pleasant TS
- Overloads on the transformers at Pleasant TS and/or Kleinburg TS and
- Limitations on the distribution network due to distances between transmission supply points (transformer stations) and new end use customers located in northern Brampton and southern Caledon.

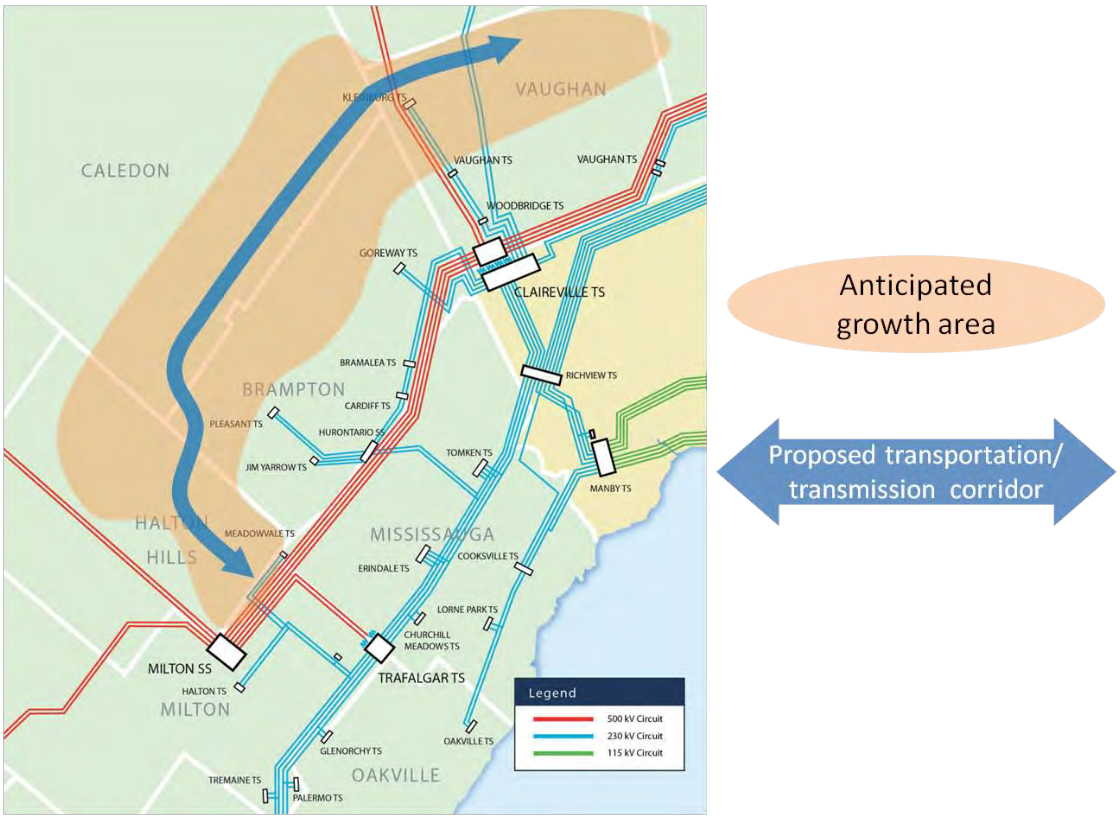
If peak reduction efforts, including conservation and distributed generation, are unable to defer these capacity needs (both circuit and transformer) and distribution solutions such as load transfers prove technically or economically infeasible, a new step-down transformer station will be required in the general northern Brampton/southern Caledon area. Since existing circuits are unable to supply this additional station demand, a new transmission corridor will also be required in this general service area.

In addition to these potential capacity issues, the need for new transmission infrastructure could also be triggered as a result of an inability to provide adequate power quality for new customers located in new development lands in northern Brampton and southern Caledon. These new development lands, shown in Figure 8-2, below, are distant from existing supply points such as Pleasant TS and Goreway TS, resulting in long distribution feeders that impact reliability and voltage performance. Hydro One Brampton has already experienced challenges in providing adequate voltage on the long feeders extending from Pleasant TS and Goreway TS to the existing growth areas in north Brampton. As loads to the north of existing transmission infrastructure develop further, there is a potential for distribution voltage performance to worsen.

When capacity needs arise in the northern Brampton/southern Caledon area, new step-down transformer stations will be required in the general vicinity of anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

A suitable location for this future transmission corridor is being assessed in the general vicinity of the proposed West GTA transportation corridor, currently under development by the Ministry of Transportation.[15] The alignment of these infrastructure facilities is consistent with the 2014 PPS.[16] The 2014 PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities.

Figure 8-2: Approximate West GTA Transportation Corridor Route and Greenfield Growth Areas



Long-term population projections and development plans are based on the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 473,000 people living in the Peel Region in 2031 than in 2011. The majority of this increase is expected in the northern municipalities of Brampton and Caledon, which collectively estimate a

[15] Up to date information on this project is available at http://www.gta-west.com/.
[16] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

population increase of over 360,000 between 2011 and 2031, based on a draft update to the Region of Peel official plan.

Figure 8-2 identifies the area of anticipated greenfield growth throughout Brampton and Caledon, in addition to the neighbouring municipalities of Halton Hills and Vaughan, both of which are also expected to support the West GTA transportation corridor.

Given the location of expected growth and other infrastructure developments in the area, the IESO recommends that a transmission corridor be planned in the vicinity of the proposed West GTA transportation corridor.

8.1.2 Large, Localized Generation

Addressing Northwest GTA's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs of the region. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a single-cycle combustion turbine technology, would be more cost-effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Based on the anticipated long-term needs for this area, this type of investment would likely only provide marginal benefit and would not be suitable for meeting capacity-related needs (those expected to trigger the need for new transmission infrastructure). This is because siting any large generator in the areas expected to experience capacity needs would still require the same basic transmission infrastructure to connect this facility to the grid. This means that enabling large, localized generation to meet long-term load growth would also require a duplication of the infrastructure needs described in Section 8.1.1, above, plus the added cost of the generator itself, with little additional benefit to the area.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Northwest GTA through a community self-sufficiency approach requires leadership from the community to identify opportunities and implement solutions. As this approach relies to a great degree on emerging technologies, there will be a need to develop and test out solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

One promising tool for identifying and studying emerging technologies in a region is through the development of a municipal energy plan. A municipal energy plan is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas emissions. A number of municipalities across the province are undertaking energy plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans to meet their goals. Municipal energy plans take an integrated approach to energy planning by aligning energy, infrastructure and land use planning. Innovative measures that have been investigated in similar urban settings include:

- Advanced fuel cell technologies
- Advanced storage technologies – particularly in combination with fuel cells
- Aggressive demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined heat and power opportunities
- Renewed consideration of the load serving entity/aggregator market model

The Working Group recognizes significant risks associated with this strategy, the most crucial being the necessity to successfully meet the growth in electricity demand with new and unproven load management and storage technologies.

Other key risks include demonstrating consumer value, cost recovery certainty for innovative technologies and the associated risk of asset stranding, risk/reward incentives and technological obsolescence as a causal factor for asset replacement.

Given the magnitude of the long-term capacity needs expected throughout northern Brampton, southern Caledon and parts of the neighbouring municipalities of Halton Hills and Vaughan, it is not expected that emerging or innovative technologies will be able to provide a technically feasible alternative to conventional infrastructure in the long term. As a result, it is recommended that while measures could be encouraged where a sound business case is available, a commitment to community self-sufficiency cannot replace the need for acquiring corridor rights for future transmission infrastructure in this area.

8.2 Recommended Actions and Implementation

There is a long-term need to provide electrical service to a significant new development area within the northern Brampton/southern Caledon area. Due to a lack of transmission in this area, new step-down stations cannot be accommodated until additional transmission infrastructure is built. Given the long lead times associated with this type of investment and the benefits of coordinating the planning of linear infrastructure corridors, it is recommended that work continue to establish a corridor for a future transmission near the planned West GTA transportation corridor. Coordinated planning for linear infrastructure corridors is consistent with the direction provided in the PPS. Actual construction of the transmission facilities would not be triggered until the need for the supply path and associated step-down capacity is identified within a near- to medium-term planning horizon. This may occur as a result of the need for additional step-down capacity to relieve existing stations (Pleasant TS and Kleinburg TS), or, as a result of power quality issues on the distribution system that may arise when customer loads are served by long feeders.

In November 2014, the OPA provided a letter to Hydro One supporting the long term need for this project, provided in Appendix F. Based on the analysis described in this letter, it was estimated that growth across these four municipalities will require the availability of new transmission infrastructure to support the increase in electrical demand (beyond the currently available system capacities) of 300-570 MW by 2031 and 570-950 MW by 2041. Given that the timeline is beyond the typical planning horizon for the IRRP and the affected area extends beyond the Northwest GTA, these electrical demand forecasts were based on the Places To Grow official plan and a range of demand per capita coefficients. Even under the most conservative of estimates, growth of this magnitude would require significant new transmission infrastructure to reliably serve new customer demand. As a result, it was recommended that sufficient corridor width be preserved to allow for the economic, safe and reliable construction, operation and maintenance of two double circuit 230 kV lines. The corridor may be required over the next 20 years, depending on the timing and location of the development in the area.

The use of undergrounded transmission lines (cables), as opposed to overhead lines, was not recommended as they are significantly more costly with costs ranging from five to ten times higher. Instead, cables are typically reserved for situations where overhead options are not feasible, such as in densely populated areas with no remaining right-of-way allowances. Identifying and preserving transmission rights-of-way early and well ahead of the forecast need can help electricity customers avoid costs associated with underground cables in the future. Allowing the area to develop without reserving an overhead transmission corridor and attempting to incorporate underground transmission facilities at a later date could result in hundreds of millions of dollars in additional costs when upgrading the system and is inconsistent with the PPS.

The IESO will continue to work with Hydro One and relevant municipal, regional and provincial entities to consider the planning of this long-term strategic asset.

Table 8-1: Summary of Solutions Considered for Near-, Medium- and Long-term Needs

Needs	Conservation	DR	DG	Wires Infrastructure
Near-term Needs				
Halton TS capacity relief	--	--	--	Yes
Restoration	--	--	--	Yes
Medium-term Needs				
Supply to Pleasant TS	Yes	Yes	Yes	Yes
Long-term Needs				
Pleasant TS capacity relief	Yes	Yes	Yes	--
Kleinburg TS capacity relief	Yes	Yes	Yes	--
New northern Brampton/southern Caledon supply	--	--	--	Yes

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the NW GTA IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the NW GTA IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities and will ensure this dialogue continues and expands as the plan moves forward.

Figure 9-1: Summary of NW GTA IRRP Community Engagement Process

Creating Transparency:

Creation of NW GTA IRRP Information Resources

- Dedicated NW GTA IRRP webpage created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing the Working Group members
- Dedicated webpage added to Hydro One website and information posted on LDC websites
- Self-subscription service established for NW GTA IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information provided to First Nation communities who may have an interest in the planning area
- Presentation and discussion with First Nation communities as requested
- Information provided to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation community meetings and Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee ("LAC")
- Formation of LAC to discuss longer-term options, including new transmission right of way
- Broader community outreach to be undertaken; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the NW GTA IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated webpage was created on the IESO (former OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the NW GTA IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the NW GTA IRRP was meeting with representatives from the municipalities and First Nation communities in the region. For the municipal meetings, presentations were made to the NW GTA area municipal planners and CAOs at three group meetings held in Halton Hills, Brampton and Milton. The IESO held a separate meeting with representatives of the Six Nations Elected Council.

During these meetings, key topics of discussion involved confirmation of growth projections for the area, addressing near- and medium-terms needs through the development of two new step-down stations, and the recommendation of a future transmission corridor to provide for longer-term capacity needs as a result of continued growth in the northern Brampton, southern Caledon, and Halton Hills area. Invitations to meet to discuss the NW GTA IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council. The IESO remains committed to responding to any questions or concerns from these communities.

Also discussed was a bulk system study that has been initiated for West GTA to identify and recommend solutions to address emerging bulk transmission system needs, primarily driven by the retirement of Pickering Nuclear GS.

Bringing Communities to the Table

This engagement will begin with a public webinar hosted by the working group to discuss the plan and potential approaches of possible long-term options. Presentations on the NW GTA IRRP will also be made to Municipal Councils and First Nation communities on request.

To further continue the dialogue, a West GTA local advisory committee will be established as an advisory body to the NW GTA Working Group, as well as the broader West GTA Region. The purpose of the committee is to establish a forum for members to be informed of the regional planning processes. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement, and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Note that LACs are formed on a regional basis, and will therefore encompass the entire West GTA planning region, including the municipalities of Mississauga and Oakville, which were not part of the NW GTA IRRP. Information on the formation of the West GTA LAC is available on the NW GTA IRRP main webpage.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[17] available on the IESO website.

Information on outreach activities for the NW GTA IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the NW GTA IRRP.

[17] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-Regional-energy-planning-review

10. Conclusion

This report documents an IRRP that has been carried out for NW GTA, a sub-region of the West GTA OEB planning region, and, combined with the planning activities for Southwest GTA, largely fulfils the OEB requirement to conduct regional planning in the West GTA Region.[18] The IRRP identifies electricity needs in the region over the 20-year period from 2014 to 2033, recommends a plan to address near- and medium-term needs and identifies actions to develop alternatives for the long term.

Implementation of the near-term plan is already underway, with the LDCs developing CDM plans consistent with the Conservation First policy and with development work initiated for a new step-down transformer station being developed by Halton Hills Hydro. A transmission solution to address additional capacity needs for Halton TS is required for 2020 under the Expected Growth forecast. This will be planned further by the transmitter through the RIP process. Additionally, the RIP should consider a "wires" solution to address overloading needs on H29/30, with a potential need date of 2023-2026.

To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community and monitor growth in the region. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for NW GTA.

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the long term. In addition, the NW GTA Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the long term under the Expected Growth forecast. If demand grows as anticipated, it may not be necessary to revisit the plan until 2020, in accordance with the OEB-mandated 5-year schedule. This would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

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[18] A bulk planning process underway for West GTA will consider the restoration needs described in this report.

NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the GTA West Planning Region | April 28, 2015

Independent Electricity System Operator

West GTA IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.4 describe the methodologies used by LDCs to prepare the gross demand forecast used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.5.

A.1.1 Hydro One Brampton

Brampton is a fast growing city which is now filling the perimeter areas with residential subdivisions. These new subdivisions are forecast to produce a significant load requirement for Hydro One Brampton.

Hydro One Brampton has 4 transmission stations located within the City boundaries. Three of the stations are owned and operated by Hydro One Networks and one (Jim Yarrow TS) is owned and operated by Hydro One Brampton. The stations exist in a U shape configuration with the bottom of the configuration bordering the 230KV HONI Transmission Corridor, located near the south boundary of the City.

New distribution feeders from the Goreway Transformer station and the Pleasant Transformer station (both geographically located south of Bovaird Drive) are required to supply all lands between Bovaird Drive and Mayfield Road, with lateral limits from Winston Churchill Blvd to Highway 50.

To accurately define the forecast, Brampton was divided into 4 – 27.6kV areas and 2- 44kV areas.

- The North West 27.6 area is supplied from Pleasant TS.
- The South West 27.6 area is supplied from Jim Yarrow TS.
- The North East 27.6 area is supplied from Goreway TS.
- The South East 27.6 area is supplied from Bramalea TS.
- The 44kV areas were divided into a West area and an East area.
- The 44 kV West area is supplied from Pleasant TS.
- The 44kV East area is supplied from Bramalea TS, Goreway TS and one D6M16 feeder from Woodbridge TS.

Housing, Employment and Population Data was obtained from the City of Brampton and applied to each of the study areas.

This data and others was obtained from many sources and fed into Hydro One Brampton's load forecasting software program (ITRON Metrix ND program). This program is an advanced statistics program used for the analysis and forecasting of time series data. The Metrix ND program was able to predict the future loading for the City of Brampton through regression analysis. It identified the load growth rates for each of the study areas.

Areas with the greatest load growth expectations will be the west side of Brampton (both the South and North Areas) and the Brampton North East.

Future load growth will place additional load on Jim Yarrow, Pleasant and Goreway Transmission Stations thus resulting in additional load on Hydro One Networks Transmission Systems.

Hydro One Brampton's challenge will be to supply the North areas of Brampton through the use of the distribution feeders from both Pleasant TS and Goreway TS without incurring voltage problems in the north central areas as load increases.

A.1.2 Milton Hydro

The Milton is the fastest growing community in Canada with a 56% growth rate and encompasses a land area of 366.61 square km. With an approximate population of 104,000 (2014 yearend), Milton is expected to grow to approximately 228,000 by 2031. Milton. These new subdivisions are forecast to produce a significant load requirement for Milton Hydro.

Milton is supplied by following:

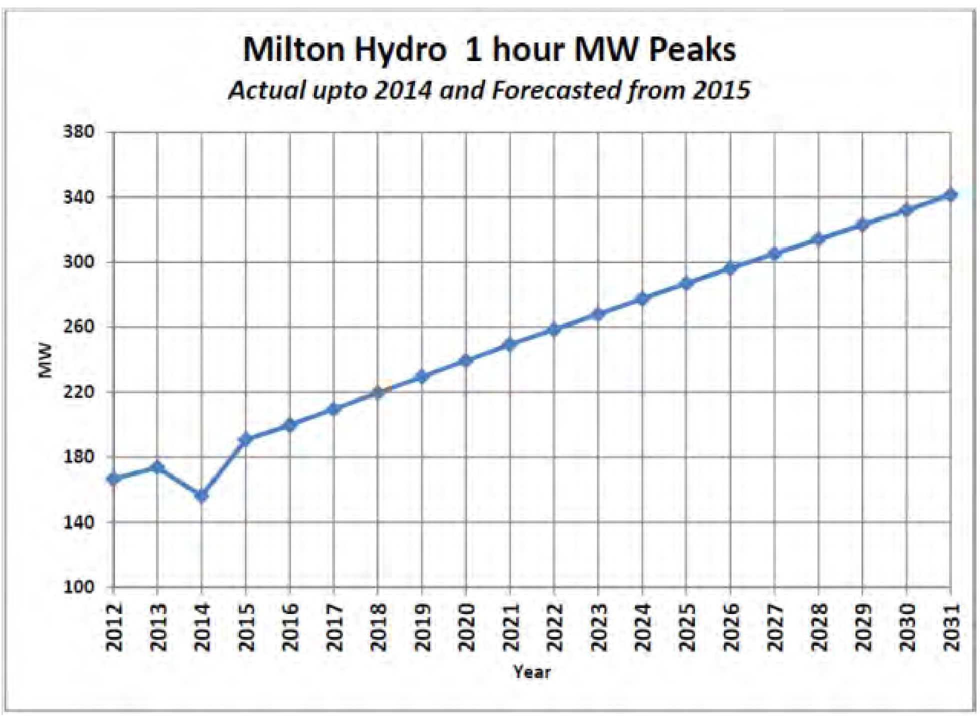
Owner	TS	Feeders
Hydro One	Halton TS	9
Hydro One	Palermo TS	2
Hydro One	Tremaine TS	2
Hydro One	Fergus TS	1
Oakville Hydro	Glenorchy MTS	2

Milton Hydro's load forecast was based on the following information, published June 2011:

"Halton Region's Best Planning Estimates of population, occupied dwelling units and employment, 2011 – 2031"

The Best Planning Estimates is a planning tool used to identify where and when development is expected to take place across the Region. The Best Planning Estimates represent good long term planning. This tool will assist the Region and the Local Municipalities in planning complete healthy communities including; the establishment of the supply of housing, type of housing and jobs across the Region. The Best Planning Estimates, also, provide direction in determining the timely provision of both hard infrastructure (roads, water and wastewater) and community infrastructure (schools, community recreation etc).

The area bounded by 401 south to 407 and Tremaine Road east to 407 will have the greatest load growth expectations Due to future load growth, Milton hydro will have reached its' allocated capacity by 2021.



A.1.3 Halton Hills Hydro

Halton Hills Hydro Inc.'s service territory extends to the municipal boundaries of the Town of Halton Hills and is comprised of two urban centres, Acton and Georgetown. The surrounding areas are rural with numerous hamlets spread throughout. There has been slow and steady residential growth mainly in east Acton and south Georgetown with some rural estate lot subdivisions. Commercial/Industrial growth has begun along the Steeles Ave./Hwy 401 corridor. Halton Hills Hydro is Supplied from three Hydro One owned Transformer Stations, all located outside of the Town of Halton Hills as follows:

- Fergus TS (230 - 44 kV) in Fergus
- Pleasant TS (230 - 44 kV) in Brampton
- Halton TS (230 - 27.6 kV) in Milton

These three transformer stations respectively service three main load pockets:

- Acton Urban
- Georgetown Urban and Halton Hills Rural
- Georgetown South (residential) and the Steeles Avenue/Hwy 401 commercial/industrial

Presently the loads supplied by Pleasant TS and Halton TS fall within the study area.

Original commercial/industrial load forecasts were developed for the Steeles Avenue corridor based on typical watts per square foot values for the total amount of developable land. In addition, a residential load forecast was created based on the Halton Region's population projections from 2008 to 2021.

Short and long term load forecasts are updated by fixed yearly increments based on current firm development plans and long range planning goals set by the Town of Halton Hills, Halton Region, and the Province of Ontario. In 2012 the Town of Halton Hills approved the "Vision Georgetown" Terms of Reference, a development plan that projects a population increase of 20,000 people by the year 2031.

A.1.4 Hydro One Distribution

Introduction and Background

The Town of Caledon is serviced by Hydro One Networks Inc Distribution and is a part of the Northwest GTA Electricity Supply Study area. There are two step-down transformer stations (230kV to 44kV and/or 27.6kV) involved in supplying the Town of Caledon, from which feeders are built to supply the area load directly or via step-down distribution stations. The two transformer stations are Pleasant TS and Kleinburg TS. Although Orangeville TS also supplies the Town of Caledon it is generally limited to the northern part of the town that falls outside of the study area.

Methodology for Reference Level Forecast

The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather-normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge, information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast.

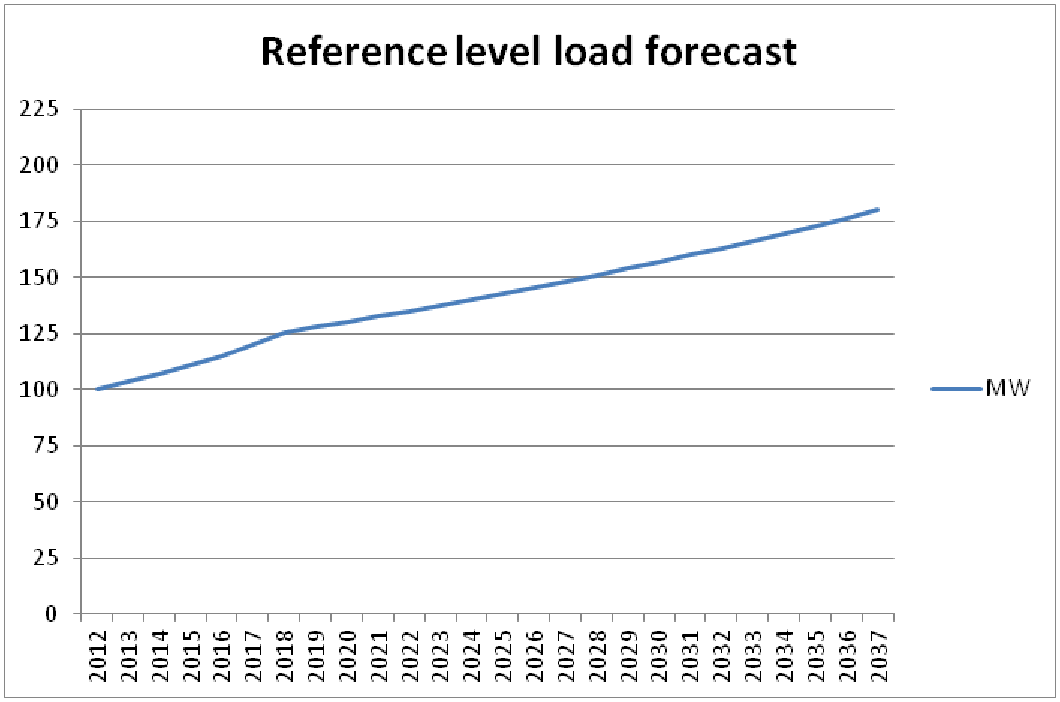
Methodology for Adding New Distribution Stations

Hydro One Distribution conducts distribution area studies to examine the adequacy of the existing local supply network in the next ten years and determine when new stations need to be built. These studies are performed on a needs basis, such as:

- Load approaching the planned capacity
- Issues identified by the field and customer
- Issues discovered during our 6-year cycle studies
- Additional supply required for large step load connections
- Poor asset condition

Reference Level Forecast

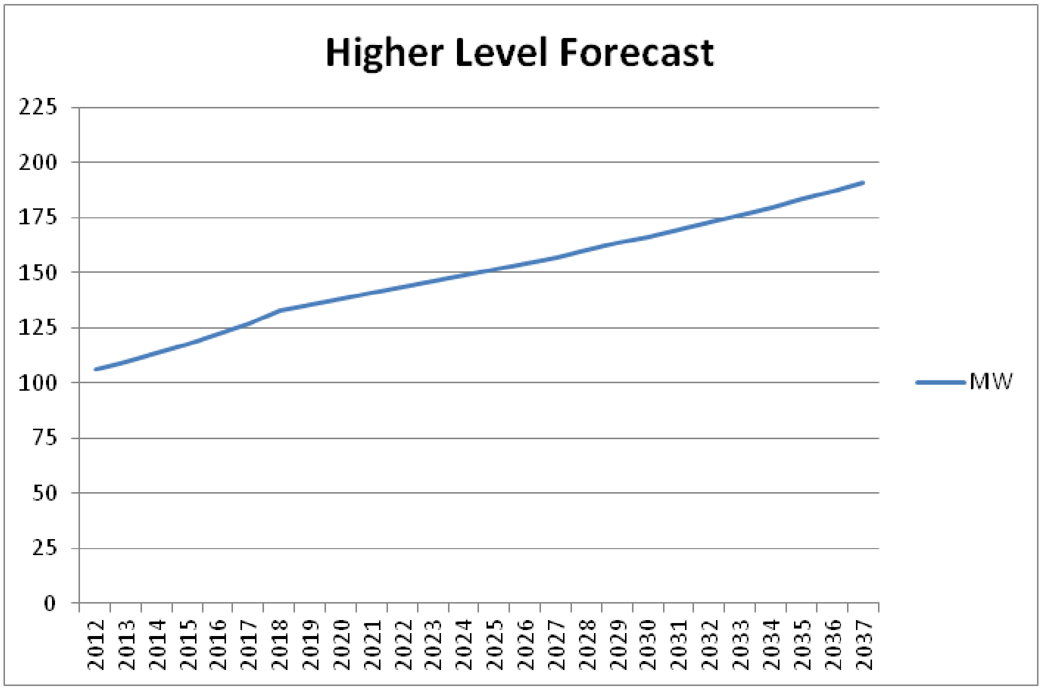
Reference load level below represents combined load of Kleinburg TS and Pleasant TS as they supply Caledon area for HONI Dx.



Methodology for Higher Level Forecast

The higher level forecast differs from the reference level by considering the expected weather impact on peak load under extreme weather conditions. As a result, an additional 6% is added to the reference level to obtain the higher level forecast.

Load level below represents combined load of Kleinburg TS and Pleasant TS as they supply Caledon area for HONI Dx.



A.1.5 Gross Demand Forecasts by TS

The following tables show the gross peak demand per station, as provided by LDCs. Where necessary, forecasts were adjusted to account for extreme weather conditions, defined by Hydro One Transmission as an electrical demand 6% above the median, or most likely, summer peak. Adjustments to extreme weather are done to ensure forecasts properly account for the risk of hotter than average conditions, which correlate to higher observed electrical demand associated with cooling loads.

Gross Demand	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea TS	348	357	359	359	360	359	365	367	368	368	367	367	374	375	375	377	375	378	381	383
Goreway TS	242	250	255	258	262	265	274	279	283	285	287	293	299	302	304	306	308	310	312	314
Halton TS	183	186	189	194	200	206	215	230	244	301	316	332	348	364	380	396	406	417	420	422
Jim Yarrow MTS	131	136	139	141	144	146	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Kleinburg TS	166	168	171	173	175	178	180	182	184	185	187	189	191	194	196	198	201	203	205	207
Pleasant TS	364	369	384	391	398	403	419	428	438	444	447	463	474	482	486	490	496	502	508	515
Tremaine TS	39	51	63	75	86	91	95	100	105	109	113	117	120	123	125	126	128	129	130	131
Woodbridge TS	138	138	138	138	139	139	139	139	139	140	140	140	140	140	141	141	141	142	142	142

Note that the gross demand is provided for the entire step down station, even where some loads serve areas outside the study area. As a result, the sum of peak electrical demands presented for these stations is higher than for the total NWGTA study area. The IESO used the most recently available forecasts from neighbouring LDCs when additional forecast information was required.

A.2 Conservation

The forecasted conservation savings included in the demand forecasts for the Northwest GTA IRRP were derived from the provincial conservation forecast, which aligns with the conservation targets described in the 2013 Long-Term Energy Plan (LTEP), "Achieving Balance: Ontario's Long Term Energy Plan". The LTEP set an electrical energy conservation target of 30 TWh in 2032, with about 10 TWh of the energy savings coming from codes and standards (C&S), and the remaining 20 TWh from energy efficiency (EE) programs. The 30 TWh energy savings target will also lead to associated peak demand savings. Time-of-Use (TOU) rate impacts and Demand Response (DR) resources are focused on peak demand reduction rather than energy savings and, as such, are not reflected in the 30 TWh energy target and are considered separately in forecasting.

To assess the peak demand savings from the provincial conservation targets, two demand forecasts are developed. A gross demand forecast is produced that represents the anticipated electricity needs of the province based on growth projections, for each hour of the year. This forecast is based on a model that calculates future gross annual energy consumption by sector and end use. Hourly load shape profiles are applied to develop province-wide gross hourly demand forecasts. Natural conservation impacts are included in the provincial gross demand forecast, however the effects of the planned conservation are not included. A net hourly demand forecast is also produced, reflecting the electricity demand reduction impacts of C&S, EE programs, and TOU. The gross and net forecasts were then compared in each year to derive the peak demand savings. In other words, the difference between the gross and net peak demand forecasts is equal to the demand impacts of conservation at the provincial level.

The above methodology was used to derive the combined peak demand savings, which was further broken down to three categories as shown in Table A-1. Peak demand savings associated with load shifting in response to TOU rates were estimated using an econometric model based on customers' elasticity of substitution and the TOU price ratio. The remaining peak savings were allocated between C&S and EE programs based on their energy saving projections, with about 1/3 attributed to C&S and 2/3 to EE programs.

The resulting peak demand savings in each year are represented as a percentage of total provincial peak demand in Table A-1, using 2012 as a base year (LDCs built their gross forecasts based on the observed peak for 2012).

Table A-1: Peak demand offset associated with Energy Targets, 2012 base year

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
C&S	0.2%	0.3%	0.7%	0.8%	1.2%	1.7%	2.1%	2.5%	2.7%	2.7%	2.9%	3.1%	3.3%	3.8%	4.2%	4.5%	4.9%	5.2%	5.5%	5.5%
TOU	0.4%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
EE programs	1.1%	1.4%	1.5%	1.7%	1.8%	2.7%	3.6%	3.7%	4.1%	4.7%	5.5%	5.9%	6.3%	6.6%	7.0%	7.2%	7.4%	7.9%	8.3%	8.3%
Total	1.7%	2.2%	2.8%	3.1%	3.6%	5.0%	6.3%	6.8%	7.4%	8.0%	9.0%	9.5%	10.2%	10.9%	11.9%	12.3%	13.0%	13.7%	14.4%	14.4%

These percentages were applied to the gross demand forecasts provided by the Northwest GTA LDCs at the transformer station level to determine the peak demand savings assumed in the planning forecast. This allocation methodology relies on the assumption that the peak demand savings from the provincial conservation will be realized uniformly across the province. Actions recommended in the Northwest GTA IRRP to monitor actual demand savings, and to assess conservation potential in the region, will assist in developing region-specific conservation assumptions going forward.

Existing DR resources are included in the base year and gross demand forecasts. Additional DR resources can be considered as potential options to meet regional needs.

A.2.1 Conservation Assumptions, by Station

The following tables show the expected peak demand impact of provincial energy targets, as assumed at each station for the purposes of the Expected Growth forecast. For the Higher Growth forecast, half of each value was assumed per station.

Table A-2: Peak demand offset associated with energy targets, by station (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea TS	5.8	8.0	10.0	10.9	13.1	17.9	23.0	24.8	27.1	29.4	33.1	35.0	38.1	41.1	44.5	46.4	48.6	51.9	55.0	55.4
Goreway TS	4.0	5.6	7.1	7.9	9.5	13.2	17.3	18.9	20.8	22.8	25.9	28.0	30.4	33.1	36.1	37.7	39.8	42.5	45.0	45.4
Halton TS	3.0	4.2	5.3	5.9	7.3	10.3	13.5	15.6	18.0	24.1	28.5	31.7	35.5	39.8	45.0	48.7	52.6	57.3	60.6	60.9
Jim Yarrow MTS	2.2	3.1	3.9	4.3	5.2	7.3	9.5	10.2	11.0	12.0	13.6	14.3	15.3	16.4	17.8	18.5	19.4	20.6	21.7	21.7
Kleinburg TS	2.7	3.8	4.8	5.3	6.4	8.9	11.3	12.3	13.5	14.8	16.9	18.0	19.5	21.2	23.2	24.4	26.0	27.9	29.6	30.0
Pleasant TS	6.0	8.3	10.7	11.9	14.5	20.1	26.4	29.0	32.3	35.5	40.4	44.2	48.3	52.7	57.7	60.4	64.2	69.0	73.5	74.4
Tremaine TS	0.6	1.1	1.8	2.3	3.1	4.5	6.0	6.8	7.7	8.7	10.2	11.1	12.2	13.4	14.8	15.6	16.5	17.7	18.8	19.0
Woodbridge TS	2.3	3.1	3.8	4.2	5.0	6.9	8.8	9.4	10.3	11.2	12.6	13.3	14.3	15.3	16.7	17.4	18.3	19.5	20.5	20.6

Note that the conservation offsets are provided for the entire step down station, even where a station serves load outside the study area. As a result, the conservation totals are higher than presented for just the study area. The IESO applied the same percentage conservation offsets to loads belonging to customers outside the NW GTA Study area that were served by these stations.

A.3 Distributed Generation

As of September 2013, the IESO (then OPA) had awarded 125 MW of distributed generation contracts within the NW GTA study area. Of these, 102 MW had already reached commercial operation. Since LDCs were producing their demand forecasts to align with actual peak demand, any DG already in service during the most recent year's peak hour would already be accounted for in gross forecasts. As a result, only contracts for projects that had not yet reached commercial operation when the forecasts were produced needed to be incorporated.

This left a field of 115 contracts, all for solar projects contracted through the Feed in Tariff (FIT) program. Contract information provided the installed capacity, generation fuel type, connecting station, and maximum commercial operation date ("MCOD") for each project. It was assumed that all active contracts would be connected on their MCOD. This was a conservative assumption, as some attrition would normally be expected from a field of 115 contracts. Since all contracts were for solar projects, an assumption was required for effective summer peak capacity, since local weather conditions can greatly impact the contribution of solar projects to meeting demand. For the NW GTA IRRP, the IESO relied upon the summer solar capacity contribution values, as described in section 3.2.2 of the *2014 Methodology to Perform Long Term Assessments*[1] (copied below):

> Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the simulated 10-year solar historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process of picking the lower value between actual historic solar data, and the simulated 10-year historic solar data will be incorporated into the SCC methodology until 10-years of actual solar data is accumulated, at which point the simulated solar data will be phased out of the SCC calculation.

Based on the current methodology, summer peak solar capacity contributions of 34% were assumed. After considering the anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions, by sub area and Station

The following tables show the expected peak demand impact of DG contracts active as of September 2013, but which had not reached commercial operation as of August 2012 (the peak point LDCs used to build their forecast). These contributions were subtracted from the gross demand forecasts on a station by station basis.

Station	Effective kW
BRAMALEA TS	1538
GOREWAY TS	2231
HALTON TS	510
JIM YARROW MTS	697
KLEINBURG TS	420
PLEASANT TS	1705
TRAFALGAR TS	85
WOODBRIDGE TS	216

[1] http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf

A.4 Planning Forecasts

Two planning forecasts were developed for the NW GTA IRRP: Expected Growth, and Higher Growth.

The Expected Growth forecast is the primary forecast for carrying out system studies and was based on gross demand forecasted by LDCs within their service territories. It was then adjusted by the IESO to account for the anticipated peak demand impacts of provincial energy targets, the effect of contracted DG, and the effect of extreme weather conditions. It is referred to as the Expected Growth forecast as it represents the most likely outcome based on currently available information and initiatives, both local and provincial.

To account for the uncertainty associated with long-term planning, a second forecast was developed to test sensitivity to need dates. This forecast was prepared by applying half of the anticipated peak demand impact of provincial conservation targets, to model some combination of higher underlying growth or lower peak demand effects of conservation initiatives. Accounting for this uncertainty was done for several reasons:

- The conservation targets used to develop this forecast were based on the 2013 LTEP, which were only developed for annual energy consumption. Converting annual energy savings into summer peak demand savings requires several assumptions regarding load profiles, customer type, and end-use of future conservation measures and activities. These additional assumptions all carry associated uncertainties, especially over a 20 year planning horizon.
- Historical achievement of peak demand conservation targets has varied greatly across different years and programs. The OPA's 2013 Annual Conservation and Demand Management Report, submitted to the OEB in October 2014, showed that while energy targets have been largely successful, only 48% of the 2014 peak demand target was achieved by the end of 2013. In a follow-up letter to LDCs sent December 17, 2014, the OEB noted that "A large majority of distributors cautioned the Board that they do not expect to meet their peak demand targets," and that, "the Board will not take any compliance action related to distributors who do not meet their peak demand targets."
- Similar higher net growth sensitivity scenarios have been developed for other planning initiatives to manage risk of insufficient power system capacity due to higher underlying growth or lower peak demand effect of conservation initiatives. This practice has been used successfully in other regional plans and as evidence at rate hearings and other regulatory submissions.

In both forecasts, the final demand allocated to Hydro One Brampton stations was adjusted between adjacent stations to account for typical station loading and operating practices. This balancing practice ensured that a station already at full capacity would continue at full utilization, even if incremental peak demand-reducing measures (such as conservation and DG) would have produced a net decrease in load. The IESO worked with Hydro One Brampton to understand and implement these adjustments consistent with expected operation.

The final Expected and Higher Net Demand forecasts are provided in Appendices A.4.1 and A.4.2, respectively.

A.4.1 Expected Growth Forecast, by TS (MW)

Note that loads below are full station loads. In some cases, this is inclusive of loads being served by other LDCs outside the NW GTA study area.

Expected Growth	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea TS	341	347	347	346	346	340	341	340	340	337	332	330	334	333	329	329	325	324	324	326
Goreway TS	236	242	247	249	252	251	257	260	262	262	261	266	269	270	269	270	269	269	269	271
Halton TS	173	176	179	184	190	194	200	213	224	276	285	298	310	322	332	344	350	356	355	357
Jim Yarrow MTS	128	132	135	136	138	138	143	145	146	146	145	148	150	150	150	150	150	150	150	150
Kleinburg TS	163	164	166	168	170	170	170	171	172	172	173	173	174	175	176	177	178	178	179	181
Pleasant TS	357	359	371	377	382	381	388	392	396	398	395	404	408	411	408	409	410	410	411	417
Tremaine TS	41	52	64	75	82	86	90	94	98	101	104	107	110	112	113	114	114	114	115	116
Woodbridge TS	136	135	135	135	136	134	134	133	133	132	132	131	131	131	130	130	130	129	129	129

A.4.2 Higher Growth Forecast, by TS (MW)

Note that loads below are full station loads. In some cases, this is inclusive of loads being served by other LDCs outside the NW GTA study area.

Higher growth	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea TS	344	351	352	352	352	349	352	353	353	352	349	348	353	353	351	352	349	350	352	354
Goreway TS	238	245	250	252	256	257	264	268	271	272	273	278	283	285	286	287	287	288	289	291
Halton TS	174	177	180	185	190	197	209	223	236	289	302	316	330	344	357	370	379	388	388	390
Jim Yarrow MTS	129	134	137	138	141	142	147	150	150	150	150	150	150	150	150	150	150	150	150	150
Kleinburg TS	164	166	168	170	172	173	175	176	177	179	180	181	183	184	186	187	189	190	192	194
Pleasant TS	360	363	377	383	389	391	401	407	414	418	418	431	439	445	446	449	452	455	458	465
Tremaine TS	42	54	66	78	83	87	91	96	100	104	108	111	114	116	118	119	120	120	121	122
Woodbridge TS	137	136	136	137	137	137	136	136	136	136	136	135	135	135	135	135	135	135	135	136

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Appendix B: Needs Assessment

Appendix B: Needs Assessment

B.1 System Load Flow Base Case Setup and Assumptions

The system studies for this IRRP were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the 2011 IPSP West GTA base case that was produced by the IESO to assist the former OPA for studies supporting West GTA analysis at the time. This load flow includes all eight Bruce nuclear units and the new 500 kV double-circuit line between the Bruce Complex and Milton SS. All the units at Darlington are assumed to be in-service, and all of the units at the Pickering generating station are assumed to be unavailable due to their scheduled retirement as early as 2020. Summer ambient conditions of 35°C and 0-4 km/hr wind for overhead transmission circuits were assumed in this study. For transformers, 10-day limited time ratings ("LTRs") are respected under post-contingency conditions.

In additional to the bulk system assumptions, the base case includes the following specific characteristics of the West GTA system:

- All four units at Sithe Goreway GS were included in the study. Under a local generation outage condition, the two largest generators (G12 and G13) are assumed to be out of service. One of the remaining two units, G15, is the steam turbine-generator ("STG"), and must be adjusted to 1/3 of its typical output when G12 and G13 are out of service, in order to account for the reduced availability of steam fuel. The Sithe Goreway GS runback scheme was accounted for in the analysis.
- All three units at the Halton Hills GS were included in the study. Under a local generation outage condition of the STG, all three generators are assumed out of service as there is no steam by-pass system installed at Halton Hills GS.
- Three interface limits were maintained throughout all cases to ensure a consistent flow along bulk system assets in West GTA. These limits were established based on best available information on expected Ontario generation patterns over the next 20 years:
    - Flow East Towards Toronto (FETT): 5000 MW
    - Negative Buchannan Longwood Import (NBLIP): 500 MW
    - Queenston Flow West (QFW): 1265 MW
- All capacitor banks at Halton TS, Pleasant TS, Bramalea TS, Goreway TS, Woodbridge TS, and Kleinburg TS were assumed to be in service.

In order to properly model the two new stations recommended for the near term (Halton Hills Hydro MTS in 2018 and Halton TS#2 in 2020), the basecase for West GTA was further modified to include these stations in their proposed locations:

- Halton Hills Hydro MTS was assumed as connecting to the Halton Hills GS high voltage switchyard
- Halton TS #2 was assumed as sharing the same 230 kV line connection as Halton TS

In both cases, stations were modeled using rating information for similarly sized facilities located close to the proposed station sites.

B.2 Application of ORTAC

In accordance with ORTAC, the system must be designed to provide continuous supply to a local area under specific transmission and generation outage scenarios. The criteria governing supply capacity for local areas are presented in Table B-1. For areas with local generation, such as the Halton Radial Pocket, ORTAC gives credit to the supply capacity provided by local generation by allowing controlled load rejection as an operational measure under specified outage conditions.

The system's performance in meeting these conditions is used to determine the supply capability of an area for the purpose of regional planning. Supply capability is expressed in terms of the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions specified by ORTAC.

Table B-1: ORTAC Supply Capacity Criteria for Systems with Local Generation

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Curtailment and Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N-0	Continuous	None
		N-1	LTE	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600 MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage), N-G refers to local generation not available (for example, out of service due to planned maintenance).

2. For two elements out, must initially be within STE (Short Term emergency ratings), and reduce to LTE (Long-term emergency rating) within time afforded be STE. LTE ratings are 50-hr rating for circuits, 10-day rating for transformers.

3. Only to account for the capacity of the local generating unit out of service.

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Appendix C: Analysis of Alternatives to Address Near-Term Needs

Appendix C: Analysis of Alternatives to Address Near-Term Needs

C.1 Options to Address Pleasant TS Restoration Need

Pleasant TS is served by a radial 230 kV two-circuit overhead transmission line that currently supplies approximately 375 MW of electrical demand during summer peak. The station itself includes three DESNstep-down transformers facilities: one serving 44 kV distribution loads and two serving 27.6kV loads. Growth in electricity demand in the area served by this station is expected to increase this demand to 400 MW by 2023 and 415 MW by 2033. Under the Higher Growth forecast, electrical demand in these years is forecast at 420 MW and 465 MW, respectively.

The Pleasant TS service territory is one of four areas in NW GTA that have been identified as being at risk for not meeting ORTAC restoration criteria, as summarized in Table 6.5 of the IRRP . Since restoration capability is assessed with consideration for up to two simultaneous outages on the transmission system, the only way to provide the restoration capability specified in ORTAC for a radially supplied station such as Pleasant TS is to have additional supply sources to which customer demand can be transferred. These supply sources could be at the transmission level, distribution level, or a combination of both. The customer demand or load levels that require restoration are specified in ORTAC Section 7.2.[2] Based on the analysis carried out, and described below, neither of these options can be economically justified.

As mentioned in Section 6.2 of the NWGTA IRRP, the restoration criteria within ORTAC provide flexibility in cases where "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified." Since the radial supply facilities to Pleasant TS do not form part of the integrated bulk transmission system a cost justification assessment was undertaken. Several jurisdictions within the electricity industry take guidance on cost justification for low probability / high impact events by accounting for the cost risk (i.e., the probability of an event occurring and the consequences if it does) of the failure event and determining if mitigating solutions can reduce the overall cost to customers. This is accomplished by:

1. Assessing the probability of the failure event occurring

[2] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of supply interruptions to the affected customers
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost justified.

To assess the economic justification of pursuing a transmission option to address the Pleasant TS restoration need, a high level assessment was conducted to compare the relative cost and benefit of such a solution. First, the extent of the existing risk needed to be quantified based on the supply line and load characteristics:

- Based on a typical outage rate for double circuit lines in southern Ontario of 0.19/km/yr (calculated from historical outage rates for N-2 and N-1-1 type contingencies), and the length of the H29/30 circuits (8.5 km), the coincident outage rate is estimated to be 0.016 per year.
- Currently, Pleasant TS only supplies approximately 375 MW of electrical demand at peak times, and is limited by the loading capability of H29/30 to approximately 417 MW. Assuming this loading constraint is removed (as discussed in Section 7.1.3.3), H29/30 could potentially carry up to approximately 520 MW if all three DESNs at Pleasant TS are fully loaded. In order to provide a conservative (highest possible) estimate of customer risk, 520 MW was assumed to be the sustained load at risk during an N-2 or N-1-1 contingency.
- Following a double circuit outage, LDCs served by Pleasant TS have the capability to transfer approximately 52MW within 30 minutes and 147 MW within 4 hours through the distribution system on a temporary emergency basis. The actual amount available under a future high load scenario would depend on several factors, including the operating condition at the time of the outage, and how the distribution network had been configured when connecting new loads. In order to develop a conservative estimate of future restoration capability, the current restoration capabilities were assumed to remain constant.
- Transmission outages within the GTA are typically of short duration, due to the proximity of repair crews. A typical outage of this nature will be expected to be restored within 4 to 8 hours.
- In order to consider the worst case scenario from a customer risk perspective, it is assumed that an outage would interrupt the maximum 520 MW of load that can be

supplied by Pleasant TS, of which 52 MW can be restored within 30 minutes, and 147 MW within 4 hours. Assuming this event occurs at a rate of 0.016 times per year, and lasts for 4 to 8 hours, this contingency represents a maximum of around 30.6 – 54.6 MWh of customer load at risk per year.

- In order to develop the cost risk of unserved energy, value of lost load ("VOLL"), represented in $/unserved energy, is used. Different jurisdictions and professional papers have proposed a wide range of possible values, based on factors such of the type of customer, duration of outage, approximate loss of GDP, and estimated economic consequences of historical blackouts.

A 2013 briefing paper prepared by London Economics International LLC for the Electric Reliability Council of Texas carried out an international literature review of VOLL studies. The executive summary noted:

> Average VOLLs for a developed, industrial economy range from approximately [US]$9,000/MWh to [US]$45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ([US]$0/MWh - [US]$17,976/MWh) than commercial and industrial ("C/I") customers (whose VOLLs range from about [US]$3,000/MWH to [US]$53,907/MWh).[3]

Assuming equal parts residential and commercial/industrial load within the Pleasant TS service territory, this would suggest that the VOLL could range anywhere from $1.50/kWh to $35.94/kWh. While this represents a large range, it is consistent with a 2006 Canadian example of VOLL that was used in a regulatory application to upgrade the Cathedral Square Substation in downtown Vancouver. In a supporting paper released by BCTC, a low and high value for VOLL was estimated to be $3.07/kWh and $35.57/kWh, after considering customer composition and provincial GDP.[4]

A VOLL of $30/ kWh is used in this analysis to provide a high estimate of the risk borne by local customers.

Using a VOLL of $30/kWh, the equivalent economic risk by the 30.6 – 50.4 MWh/yr Pleasant TS restoration vulnerability is approximately $917,000 – $1,638,000/yr. This roughly translates to a

[3] http://www.puc.texas.gov/industry/projects/electric/40000/40000_427_061813_ERCOT_VOLL_Literature_Review_and_Macroeconomic_Analysis.pdf

[4] http://transmission.bchydro.com/nr/rdonlyres/86da00e7-105f-4f72-8d3c-342c06919b8e/0/oorareliabilityassessmentofcathedralsquaresubstation.pdf

maximum present day risk of $12 – $22 million, when considering the 20 year planning horizon of this study.[5]

A transmission-based infrastructure solution would require the construction of a third transmission line to Pleasant TS. Given that the area surrounding this station has become densely developed in recent years and only limited egress remains on the H29/30 right of way, any new transmission infrastructure would require some or all of this new link to be constructed underground. This represents a significant incremental cost, as underground facilities are typically 5-10 times more expensive than equivalent overhead circuits, or a minimum of $10 million/km. Since Pleasant TS is approximately 5.5 km away from the nearest 230 kV transmission alternate connection point, accessing an alternate 230 kV connection point would require a minimum transmission investment of $50 million. Note that this estimate is conservative given recent cable investments in the area had a cost of approximately $14.2 million/km, plus $8.3 million for additional system upgrades.[6] As a result, there is no practical transmission reinforcement scenario that can provide a third supply source to Pleasant TS in an economic manner.

Alternatively, distribution transfer capability could be enhanced between Pleasant TS and surrounding stations' service territories. This would allow customers normally served by Pleasant TS to be restored by transferring the customers during a prolonged supply interruption. However, due to the long distances between Pleasant TS and nearby stations, full transfer of all customer loads would be technically infeasible. To satisfy ORTAC restoration criteria requiring any load above 250 MW to be restored within 30 minutes and load above 150 MW to be restored within 4 hours, a total of 125 MW of 30 minute restoration capability and 225 MW of 4 hour restoration capability would be required based on existing peak conditions. Over the study period, the restoration requirement increases to 165-265 MW for the Expected Growth forecast, and 215-315 MW for the Higher Growth forecast (30 minutes to 4 hours, respectively). LDCs have reported that the current restoration capability is approximately 50 MW within 30 minutes and 145 MW within 4 hours and that opportunities for creating additional transfer points are extremely limited due to the distribution system's configuration. Full distribution transfer of the levels of load required to meet ORTAC criteria is also technically infeasible given the distances of the adjacent transformer stations relative to the growth areas.

[5] Present value of annual risk, over 20 years, 4% interest rate
[6] http://www.hydroone.com/RegulatoryAffairs/Documents/Archives/EB-2007-0013/dec_order_Brampton_West_20071009.pdf

Based on this analysis, it is not technically or economically prudent to pursue a transmission- or distribution-based solution at this time. ORTAC recognize that in some circumstances planning the power system to meet the full restoration criteria may not be economically justified and provides flexibility for these situations.[7]

This analysis does not preclude affected LDCs from investigating opportunities for partial or incremental transfer capability, based on this type of analysis. In particular, as the distribution system is expanded to connect new customer loads, there may be opportunities for LDCs to strengthen interconnections between Pleasant TS and neighbouring stations' service territories. In addition, there is a long-term need for a new step-down station to serve Northern Brampton and southern Caledon, an area that is roughly north of Pleasant TS. Depending on the station's location, there may be potential to leverage this nearby supply point to economically provide improved restoration capability. Opportunities of this nature will be reassessed in updates to this plan.

Note that the assumptions used in this example were selected to provide highly conservative estimates (representing the highest possible risk to customers) in order to demonstrate that even under the most extreme circumstances, a transmission-based solution is not cost-effective given the relatively small magnitude of risk. If a similar probabilistic assessment is being used to justify investment, several assumptions should be revisited to provide more equal treatment of risk and potential benefit:

- The amount of load at risk for interruption should be calculated based on typical load duration curves, instead of assuming the annual peak demand is maintained throughout the duration of an outage.
- Where load is expected to increase over time, the annual risk should be tied to the forecast, and likewise increase over time.
- Actual customer composition should be used to estimate VOLL (or a range of VOLLs) specific to the area.

C.2 Deferment Value from Conservation Assumptions

Section 7.1.1 of the NW GTA IRRP contains several conservation value estimates arising from the deferral of specific infrastructure investments, outlined below:

- Conservation benefit of deferring H29/30 reconductoring

[7] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

- Conservation benefit of deferring Pleasant TS 44 kV capacity needs
- Conservation benefit of deferring Kleinburg TS 44 kV capacity needs

The deferral period was based on the initial extreme weather gross forecast provided by LDCs and applying expected peak demand savings from conservation targets and existing DG contracts (the Expected Growth forecast). For the purposes of this assessment, costs for infrastructure to address these needs were assumed as follows:

- Cost to reconductor H29/30: $6.5 million (preliminary estimate, in 2014 dollars)
- New step-down supply station to address capacity needs: $30 million (nominal planning estimate, in 2014 dollars)

It was assumed that the H29/30 need would be addressed through reconductoring, and not through the advancement of capacity infrastructure in the area (this alternative is described in greater detail in Appendix C.3). Additionally, the transmission infrastructure in the area surrounding Pleasant TS and Kleinburg TS is insufficient to accommodate a new step-down station, meaning the true cost of addressing these capacity needs is likely much higher than $30 million. However, since it is not clear which need will trigger the long-term development of new transmission infrastructure, only the new station costs were considered.

Additional assumptions are as follows:

Assumptions	
Financial Assumptions	
Inflation	2%
Real Social Discount Rate	4%
Dollar Year	2014
NPV Year	2014
Line Assumptions	
Life (years)	70
FOM as a Percent of Capital	1%
Station Assumptions	
Life (years)	45
FOM as a Percent of Capital	1%

Note that asset costs have been levelized over their respective asset lifetimes (45 years for stations, 70 years for lines), with only the costs falling within the study period considered (this attributes value to assets whose life extends beyond the study period). The study period for each deferral assessment is the original transmission asset in-service date plus the life of the asset. All costs have been converted to 2014 Canadian dollars. Results are also in 2014 dollars Canadian, present valued to 2014. Costs are considered from the original in-service year and onwards, but brought back to 2014 for consistency with other studies.

Inputs and final calculated deferment value for these three infrastructure investments are summarized as follows:

Investment	Deferral period	Cost, build time and asset lifespan	Deferment value
H29/30 econductoring	Deferred from 2020 to 2026 by 65 MW of conservation	$6.5 million line upgrade, one year build time and 70 year life.	$1.45 million
Pleasant 44 kV TS	Deferred from 2022 to 2033 by 25 MW of conservation	$30 million TS, two year build time and 45 year life.	$11.6 million
Kleinburg 44 kV TS	Deferred from 2027 to 2034 by 10 MW of conservation	$30 million TS, two year build time and 45 year life.	$6.53 million

C.3 Cost comparison of H29/30 infrastructure alternatives

In Section 7.1.3.3 of the NWGTA IRRP, a similar NPV calculation as above was performed to compare the cost of two alternatives to address H29/30 needs, expected in 2026. Note that this need date assumes the 65 MW of conservation assumed in the forecast is achieved and that the underlying growth is consistent with LDC forecasts. The first option is to upgrade the H29/30 circuits in 2026, at an estimated cost of $6.5 million (2014$). The second option is to advance the development of new supply capacity in the area such that the H29/30 circuits never become overloaded. Due to a lack of suitable transmission infrastructure in the area, providing new supply capacity would require new transmission infrastructure, as well as a new step-down supply station. For the purposes of this assessment, the following nominal costs were assumed:

- New double circuit transmission line: $3 M/km for approximately 25 km, for a total of $75 million (2014$)

- Station upgrade work (likely at Kleinburg TS) to configure connection to a new transmission line: $10 million (2014 dollars)
- New step down supply station: $30 million (2014 dollars)

If H29/30 is upgraded, the long-term capacity need is not expected until the Pleasant TS 44 kV step-down transformers reach their thermal limit, forecasted for 2033 under the expected growth forecast. Alternatively, if H29/30 is not upgraded, the need for additional supply capacity is advanced to approximately 2026. The cost of advancing this infrastructure is equal to the difference in present value costs of a 2026 in-service date versus a 2033 in-service date. Other assumptions used in this analysis are as follows:

Assumptions	
Financial Assumptions	
Inflation	2%
Real Social Discount Rate	4%
Dollar Year	2014
NPV Year	2014
Line Assumptions	
Build Time (years)	5
Life (years)	70
FOM as a Percent of Capital	1%
Station Assumptions	
Build Time (years)	3
Life (years)	45
FOM as a Percent of Capital	1%

Note that asset costs have been levelized over their respective asset lifetimes (45 years for the stations, 70 years for lines), with only the costs falling within the study period considered (attributes value to assets whose life extends beyond the study period). The study period for this assessment ends at the first transmission investment end-of-life. All costs have been converted to 2014 dollars Canadian. Results are also in 2014 dollars Canadian, present valued to 2014 (costs are considered from the original in-service year and onwards, but brought back to 2014 for consistency with other studies).

The difference of NPV under a 2026 and 2033 in-service date is provided in the table below, broken down by component:

Investment	Overnight Cost ($M)	2026 in service (2014 $M)	2033 in service (2014 $M)
25 km new 2x230kV transmission	$75	$54.3	$38.2
Reconfigure Kleinburg, other circuit terminations	$10	$7.7	$5.4
New step down transformer	$30	$23.2	$16.3
TOTAL	$115	$85.27	$59.91
		Advancement Cost:	**$25.4**

Based on this analysis, the present day cost of advancing the transmission infrastructure solution for Northwest GTA from 2033 to 2026 is approximately $25 million. Given that reconductoring H29/30 is estimated to cost $6.5 million, it is recommended that H29/30 be reconductored to address this need.

West GTA IRRP

Appendix D: Conservation

Appendix D: Conservation

D.1 LDC Conservation Plans

LDCs provided the following summaries to introduce their conservation plans for the years 2015-2020. Additional details can be found on each LDC's website.

D.1.1 Hydro One Brampton

A directive from the Ministry of Energy on March 31, 2014 outlined the new conservation framework for the years 2015-2020. This Directive has assigned a provincial energy reduction target of 7 TWh and an overall budget of 2.6 Billion, of which 1.8 Billion has be assigned to LDCs to implement and deliver provincial, regional and local electricity savings programs. Hydro One Brampton has been assigned a reduction target of 255.2 GWh to be achieved by Dec 31, 2020. This target is based on a provincial achievable potential study conducted by ICF Marbek on behalf of the IESO.

In an effort to reach this target, Hydro One Brampton has been provided a budget of up to 66.8 Million Dollars. This budget is to include all customer incentive payments, marketing, staffing resources program development and delivery

1. Hydro One Brampton's new Energy Conservation Plan will be submitted for IESO approval by May 1, 2015, and is not expected to be approved until July 1, 2015. Program implementation will commence as indicated in the approved plan (currently out for RFP). In an effort to maximize the cost-effectiveness of this plan, Hydro One Brampton can schedule different launch dates for each program. This plan can be reviewed and amended on an annual basis. Furthermore, the IESO will review the overall provincial targets with a midterm review in 2017.
2. As part of the development of the Conservation First CDM plan, Hydro One Brampton will engage neighbouring LDCs, Hydro One Networks and local gas companies in a collaborative effort as per the ministerial directive in an effort to utilize potential additionally funding available through the IESO to maximize the cost effectiveness.
3. Collaborate with neighbouring LDCs for continued engagement with Hydro One Brampton's business customers. Planned marketing initiatives include Energy into Action, PM Expo, Electrifest and HOB's own annual C&I breakfast with additional collaboration events under development.
4. Although the Ministry directive has set reduction targets as energy based. Hydro One Brampton's Conservation First Plan will endeavor to include programs that manage,

track and target regional peak demand loads in an effort to be consistent with regional demand requirements and forecasts.

D.1.2 Milton Hydro

Conservation will play a significant role in meeting Halton's future load growth. Based on the results and lessons learned from the previous CDM framework (2010-2014), Milton Hydro Distribution Inc. ("MHDI") is preparing a joint CDM plan with Halton Hills Hydro Inc. to meet its savings target under the Conservation First Framework (2015-2020). It should be noted that the new Conservation First Framework's targets are based on energy savings, not peak demand and accordingly CDM programs are not specifically aimed at peak demand reduction. Programs that do specifically target peak demand, such as DR3 and peaksaver PLUS®, will be under IESO auspices.

Demand reduction may be improved if the potential evolution of the existing microFIT program to a net metering program outlined in the Conservation First document proves to be the mechanism to increase customer participation.

To help meet its conservation goals under the new conservation framework in Ontario for 2015-2020, MHDI recently completed an achievable potential study that is helping to guide the development of the Joint CDM Plan. It provides guidance on targeted marketing efforts and pilot programs. MHDI is involved in the Toronto Region Conservation A conservation program, along with gas companies, Halton Hills Hydro, and Hydro One Brampton in a performance-based conservation program for institutional and commercial buildings, funded by the IESO. The expectation is that this program will reduce energy use through a combination of building retrofits, operational improvements and behavioural change.

MHDI expects to be an active participant in all provincial programs for residential, commercial and industrial sectors, including the Retrofit; HVAC Initiative; Coupons; Residential New Construction; Home Assistance Program; Small Business Lighting; High Performance New Construction; Energy Audits; Existing Building Commissioning; and the Process & System Upgrades Initiative Programs, including Combined Heat and Power Projects. Milton Hydro is currently exploring CHP opportunities with several customers that if successful will certainly help limit future load growth

To ensure that the provincial programs are as effective as possible, MHDI is exploring targeted marketing options to deliver the provincial programs and investigating a partnership between the Town of Milton and another municipality to hire an Embedded Energy Manager to drive energy savings.

Milton Hydro's target for the 2015-2020 timeframe is 46.84 GWh. MHDI has identified that there will be a gap between what the provincial programs are able to achieve and the energy savings target and as a result the Joint CDM Plan will include a placeholder for future energy efficiency programs that will close the gap.

D.1.3 Halton Hills Hydro

Conservation and Demand Management (CDM) will play a large role in meeting future load growth within the Region of Halton. Based on the success and lessons learned from the previous CDM framework (2010-2014), Halton Hills Hydro Inc. (HHH) is preparing a Joint CDM Plan with Milton Hydro to meet its savings target under the Conservation First Framework (2015-2020).

To help meet our conservation goals under the new conservation framework in Ontario for 2015-2020, HHH recently completed an achievable potential study, which is helping to guide the development of the Joint CDM Plan. It will provide guidance on targeted marketing efforts and pilot programs. One of the potential pilot programs that HHH is investigating is the invitation from TRCA to participate in a Performance-Based Conservation program in institutional and commercial buildings, funded by the IESO.

To meet its savings target, HHH will be an active participate in all provincial programs for residential, commercial and industrial sectors, including the Retrofit; HVAC Initiative; Coupons; Residential New Construction; Home Assistance Program; Small Business Lighting; High Performance New Construction; Energy Audits; Existing Building Commissioning; and the Process & System Upgrades Initiative Programs.

To ensure that the provincial programs are as effective as possible, HHH is exploring targeted marketing options to deliver the provincial programs, and could accommodate targeted geographic marketing in its service territory. HHH is also fostering partnerships with Union Gas (for the Home Assistance, Residential New Construction and High Performance New Construction Programs), and is also actively investigating a partnership with another Municipality to hire an Embedded Energy Manager.

Given the very aggressive savings target of 30.94 GWh, HHH anticipates that there will be a gap between what the provincial programs are able to achieve and the energy savings target. As a result, HHH anticipates that the Joint CDM Plan will include a placeholder for future energy efficiency programs that will make up this gap.

D.1.4 Hydro One Distribution

The Government of Ontario has identified Conservation & Demand Management (CDM) as the most cost-effective electricity supply option. Hydro One has been actively delivering CDM programs since 2005 and will look to build on its efforts over the years to provide its most comprehensive CDM offerings to date during the 2015-2020 Conservation First CDM Framework. While Hydro One will be working diligently towards achieving an ambitious 2020 energy savings target as part of the new CDM framework, it also recognizes the need and significance of delivering peak demand savings.

Hydro One will make CDM programs available to each of its customer segments, including low-income and First Nations customers. Hydro One is participating in a number of utility working groups developing enhancements to existing CDM programs. Once implemented, these program enhancements will help to drive both higher levels of participation and deeper savings opportunities for program participants. In addition to Province-Wide CDM programs, HONI also plans on developing local and regional CDM programs that will aim to help customers save on their bills and defer investments in its asset infrastructure.

As per the CDM Requirement Guidelines for Electricity Distributers released by the Government on December 19, 2014, Hydro One's distribution planning will incorporate its CDM plans at the outset of the planning process. Thus, distribution investments to increase the system capacity will only be implemented where CDM is not a viable option.

Hydro One is exploring a variety of program offerings that provide customer and electricity system benefits through energy efficiency, behavioural changes, load displacement, load shifting, demand response, and energy storage. Hydro One is willing to collaborate with local electricity utilities and gas utilities to develop programs and implement projects that will be cost-effective and benefit the greater electricity system.

D.2 Conservation Potential

The IESO is currently undertaking an Achievable Potential study to develop of an updated forecast for conservation potential in Ontario. The study will be used to inform:

- the 2015-2020 Conservation First Framework mid-term review, including developing aggregate and LDC-specific achievable potential estimate in 2020;
- short- and long-term planning and program design; and
- the 2016 Long Term Energy Plan (LTEP), including developing a 20-year provincial economic potential and achievable potential estimates.

The study is scheduled for to be completed by June 1, 2016. It will provide useful information to consider the potential for conservation to address identified needs in Northwest GTA in the next iteration of the planning cycle.

West GTA IRRP

Appendix E: Options to Address Halton TS Capacity Needs

Transmission and Distribution Options and Relative Costs for Meeting Near-Term Forecast Electrical Demand within the NW GTA Study Area

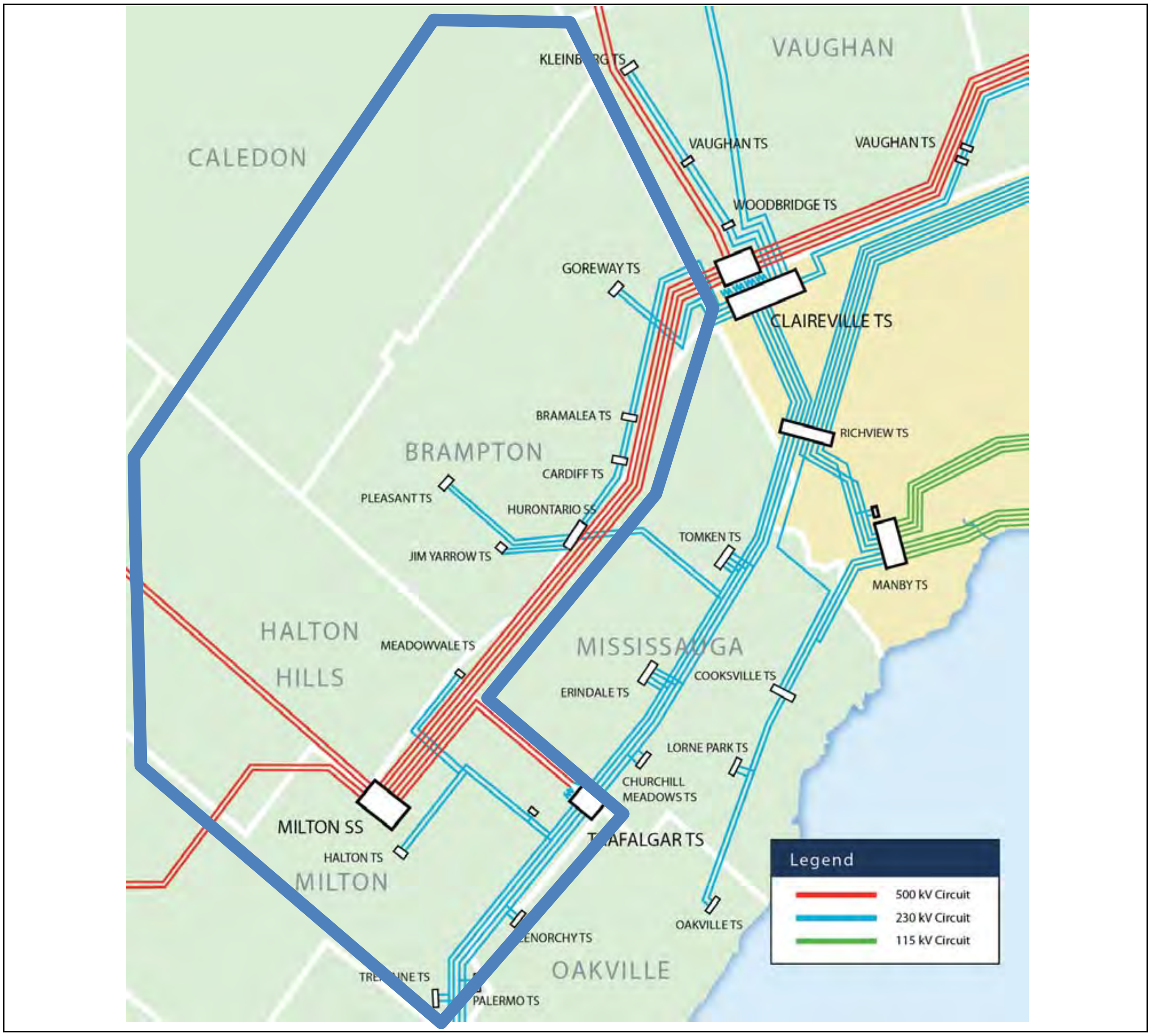
Purpose and Introduction

This analysis reviews the near- to medium-term need and timing for additional transmission and distribution capacity in the Northwest GTA study area and the relative costs of technically viable transmission and distribution options for meeting this need. This analysis was carried out as part of the Integrated Regional Resource Plan (IRRP) for the Norwest GTA (NW GTA), following the identification of capacity resource needs in the area. Additional information on the methodology used to identify the needs is available in Section 6 of the NW GTA IRRP and is summarized briefly in the sections below.

The study process identified:

- The magnitude and location of growth in electrical demand within the IRRP study area
- The capability of existing transmission and distribution facilities serving the various LDCs to meet the growth in electrical demand
- The transmission and distribution options available for meeting forecast electrical demand
- The relative cost of the transmission and distribution options

The NW GTA study area is outlined in the map below and includes the service territory of Brampton Hydro, Halton Hills Hydro, Milton Hydro and Hydro One for the Caledon area.



Load forecasts used to perform this analysis were provided to the OPA by LDCs, with a weather correction to extreme incorporated where necessary. An allocation of the provincial conservation targets outlined in the December 2013 LTEP has also been included in all forecasts. Uptake of DG through the FIT program and other projects has also been included. Additional information on the methodology used to prepare the net demand forecasts used in this study is available in the NW GTA IRRP.

Forecast Growth

Load growth within the overall study area has been at 2.2% over the last 10 years (2.7% within the past five years) and is forecast to continue at an average of 1.8% over the next decade, after accounting for the expected impact of provincial conservation targets.

Growth is expected to continue to expand northward into the undeveloped greenfield areas of north Brampton and south Caledon, further from existing transmission assets. In geographic terms, the municipalities of Halton Hills and Milton are expected to see growth in the developed areas to the north and south of Highway 401, the vicinity of James Snow Parkway, and through southern Georgetown. The highlighted areas in the following map show these areas as two major growth clusters:

Existing Transmission and Distribution Capacity Needs

Step-down transformer stations convert high voltage electricity supplied from the transmission system into lower voltage electricity for distribution to end use customers. The ratings of transmission lines, step-down transformers and the number of available distribution feeders limit the amount of electricity that can be supplied to customers from these supply points.

The table below shows the years that specific station assets are expected to exceed their load meeting capability, along with the LDCs that may be affected.

Transmission and Distribution Capacity Need dates, by facility and affected LDC

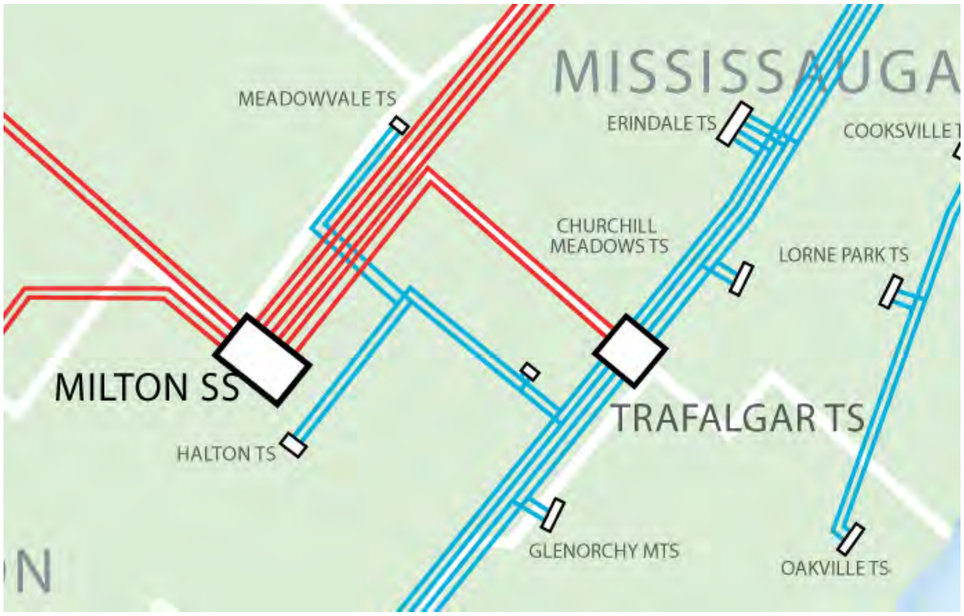
Facility	Limiting asset	LDC	Need Date – Expected Growth	Need Date – Higher Growth
Halton 27.6 TS	27.6 kV feeders	Halton Hills Hydro	2018	2018
	230/27.6 kV transformers	Milton Hydro	2020	2019
Halton radial pocket	Transmission Lines T38/39B (supply to Halton TS, Meadowvale TS, Trafalgar DESN, Tremaine TS)	Milton Hydro, HHH, Enersource, Oakville Hydro, Burlington Hydro	2023	2022
Pleasant TS	Supply circuits	HHH, Hydro One Brampton, Hydro One Distribution	2026	2023
Pleasant 44 kV TS	230/44 kV transformers	HHH, H1B, H1D	2033	2026
Kleinburg 44 kV TS	230/44 kV transformers	H1D, Powerstream	-	2033

Near Term Needs

Based on the net demand forecast being used in this analysis, the capacity of 27.6 kV feeders serving Halton Hills, and 230/27.6 kV transformers serving Halton Hills and Milton, are expected to be the first facilities to be exceeded in 2018 and 2020, respectively. The capacity of power system facilities serving Brampton and Caledon are expected to be exceeded later in the study period, likely the mid 2020s, led by constraints on dedicated transmission lines serving Pleasant TS. Load growth throughout the study area will continue to be monitored and capacity planning decisions for longer-term needs will be triggered when there is more certainty.

Halton TS

Within the current planning cycle, action is required to address the near-term need to provide additional supply capacity in the area currently served by Halton TS. This station is located on the south side of Highway 401 in the town of Milton and supplies 27.6 kV power throughout Milton and southern Halton Hills. The total rated capacity of this station is approximately 186 MW, which is spread across 12 feeders each capable of supplying about 15.5 MW. Three feeders are allocated to HHH and nine to Milton Hydro. The highest peak experienced on this station within the past five year was 166 MW in 2011.



Based on current forecasts, additional 27.6 kV supply is required in the general vicinity of Halton TS by approximately 2018 for HHH, and 2020 for Milton Hydro. The 10 year forecast is shown below, with potential capacity shortfalls highlighted in red:

Halton TS station loading by LDC, Expected Growth

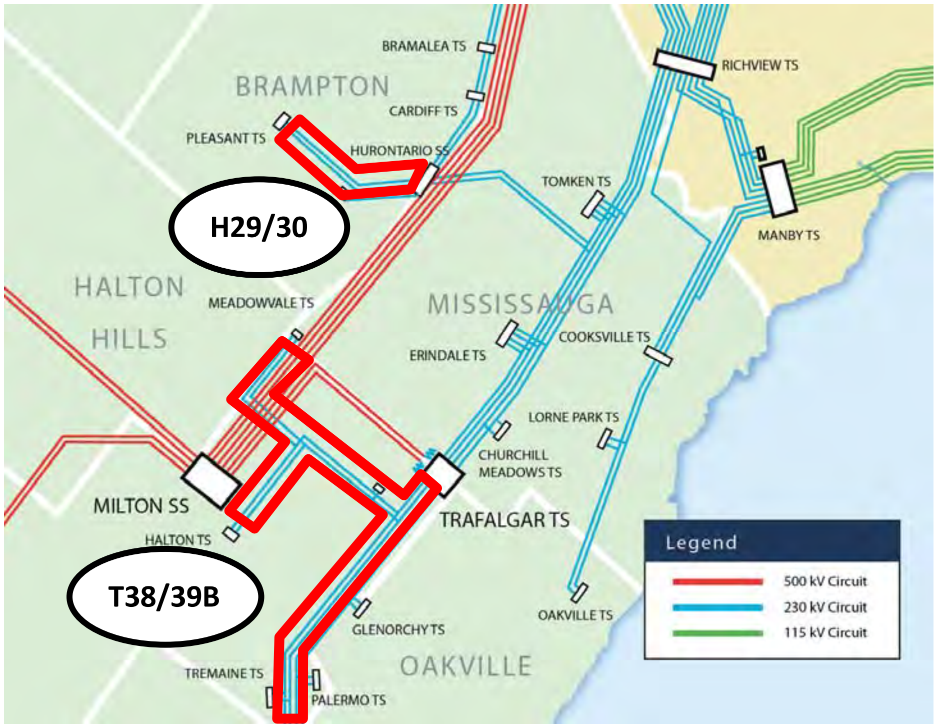
	Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
HHH	46.5	33.9	36.9	39.6	44.9	50.0	54.6	58.2	62.3	66.2	70.0
Milton	139.5	92.1	101.0	109.1	118.8	127.8	134.8	141.8	150.5	158.0	**205.7**

The Milton Hydro need date assumes that full use will be made of all available feeder capacity at Glenorchy MTS and Tremaine TS before triggering these new capacity requirements. The Halton TS forecast for Milton Hydro load jumps in 2023 to over 200 MW as a result of the expiry of a load transfer agreement between Milton Hydro and Oakville Hydro. This load transfer agreement allows for up to 40 MW of load to be temporarily served from Glenorchy MTS. In 2023, Oakville Hydro (the owner and operator of Glenorchy MTS), has forecast that it will require the 40 MW capacity to meet its own growth requirements.

Given the near-term nature of this need, transmission and/or distribution alternatives will be investigated for meeting this area's capacity shortfall.

Medium-Term Needs

Within the medium term, there is a potential need to address overloading on two radial supply pockets: the T38/39B circuits supplying Halton radial pocket, and the H29/30 circuits supplying Pleasant TS. These two areas are shown in the figure below.



T38/39B

Following the loss of one of the T38/38B circuits, which supply the Halton radial pocket, there is a potential for overloads on the companion circuit when Halton Hills GS is out of service and the total demand of connected stations exceeds approximately 528 MW. This need is being considered within an ongoing bulk system study underway for West GTA. As a result, further action will not be undertaken within this regional planning study until the outcomes of the bulk system study are known. Should the bulk system study not resolve this need, it will be revisited in the next planning cycle.

H29/30

Following the loss of one of the H29/30 circuits (supply to Pleasant TS), there is a potential for overloads on the companion circuit when the load at Pleasant TS exceeds approximately 417 MW. Options being considered to address this mid term need are discussed in Section 7.1.3.3 of the NW GTA IRRP.

Halton TS Supply Alternatives

In developing transmission and distribution options for providing relief to Halton TS, the following constraints must be accounted for:

- **Constrained air rights over Highway 401**. Highway 401 bisects the Halton Hills/Milton growth pocket, with Halton TS (which currently supplies the majority of load in the area) located on the south side along with most of Milton's existing and anticipated customer load. The municipality of Halton Hills is located on the north side of Highway 401 and, in the past, has received supply from Halton TS via several distribution feeders spanning over the highway. However, HHH has informed the IESO that obtaining air rights for additional overhead distribution feeders represents a significant challenge. As an example, the 230 kV TransCanada transmission connection for HHH GS (located close to Halton TS, but on the north side of Highway 401) was pursued as an undergrounded connection given the associated commercial challenges of spanning over Highway 401. It is assumed that future feeder crossings will be required to tunnel underneath the highway. The underground option is estimated to cost of approximately $2 million per feeder.

- **Distribution voltages**. Step-down stations in the study area provide electrical supply at either 27.6 kV or 44 kV. The selection of voltage is based on economics and technical feasibility, but will typically result in 27.6 kV service territories for denser urban areas and a separate 44 kV territory for the rural or industrial zones. The majority of growth in the Milton/Halton growth pocket is expected at the 27.6 kV level, which will require supply from a station capable of providing this voltage.
- **Available transmission supply for new step-down stations**. When step-down transformer stations have reached their maximum supply capacity, new supply points are required to serve incremental growth. These stations must be located on transmission lines to receive high-voltage supply.

Solutions must ensure that the full supply capacity requirements can be met for both LDC customers (Halton Hills Hydro and Milton Hydro) currently served by Halton TS. The table below shows the expected shortfall for each customer under the Expected Growth and Higher Growth scenario, for selected years over the 20-year planning period:

Halton TS station load in excess of capacity, by LDC and forecast

	2018	2020	2022	2024	2026	2028	2030	2032
Expected Growth								
Halton Hills Hydro	3.5	11.7	19.7	26.9	37.2	46.7	51.9	52.0
Milton Hydro	0.0	2.3	18.5	72.5	87.2	99.0	112.1	116.9
Higher Growth								
Halton Hills Hydro	4.5	13.7	22.3	30.6	42.0	53.0	59.2	60.3
Milton Hydro	0.0	9.7	27.9	85.0	102.3	117.7	133.7	141.8

At a minimum, 170 MW of new capacity will be required to meet Milton's and Halton Hills's load growth over the next 20 years. If net growth trends higher, required capacity could exceed 200 MW.

The following sections investigate the technical and economic feasibility of transmission and distribution options, including load transfers between existing step-down transformer stations, the incorporation of new step-down stations, and combinations of these options.

Distribution Load Transfer Alternatives

Where technically feasible, distribution transfers can be made on a short- or long-term basis to supply customer loads from stations outside their normal service territory. This practice is designed to prevent overloading at a strained facility. There are several stations in the general vicinity of Halton TS that are not expected to reach their full supply capacity within the study period. The technical and economic feasibility of transferring load from one TS service area to another should be investigated as a means of supplying growth in electrical demand.

Based on the review, it is likely that small amounts of additional capacity could be acquired from southern stations to supply Milton Hydro loads. However, growth in Milton is primarily anticipated in the area immediately surrounding the existing Halton TS. As a result, new feeder supply in the southern part of the service territory is not ideally situated for meeting long-term capacity needs due to costly distribution investment, increased losses, and worsened reliability.

Options for supplying Halton Hills Hydro loads from alternate stations are even more limited due to the long distances from existing infrastructure and the difficulty of traversing major highways with new distribution lines.

A review of nearby stations, and their potential for supplying load growth within the Halton TS service area, is provided below.

Palermo 27.6 kV TS:

Palermo TS is a fully utilized station currently supplying approximately 110 MW at peak. Of this, 20 MW serves Milton Hydro load within the study area. The rest serves customers from Oakville Hydro and Burlington Hydro. No remaining capacity is available at this station, and as a result this station cannot be considered for supplying load transfer capability.

Glenorchy 27.6 kV MTS

Glenorchy MTS is a 150 MW rated 27.6 kV station constructed in 2012 by Oakville Hydro to provide incremental capacity to their northern supply area after Palermo TS reached full operating capacity. In order to minimize costs in the area, Oakville Hydro entered into a short term leasing agreement with Milton Hydro, allowing them to use up to 40 MW of capacity until the year 2023. While Glenorchy is located too far south from the anticipated growth centers in Milton (approximately 9 km) to make this a preferable long-term supply option, this short-term capacity provides valuable flexibility in meeting near-term electrical demand. The above-mentioned load transfers are effective until 2023, after which Oakville Hydro requires the 40 MW of capacity for growth in northern Oakville. As a result, Glenorchy MTS is not considered effective for supplying incremental load growth in the Milton Hydro service territory beyond 2023.

Trafalgar 27.6 kV TS

Trafalgar TS currently serves 90 MW of Oakville Hydro load out of a maximum 120 MW of rated capacity. Two remaining feeder positions at this station are not currently allocated to any LDC, and as such are excellent candidates for supplying load growth in the surrounding area. However, Trafalgar TS is approximately 12 km removed from Milton Hydro's anticipated load growth centre (measured from the intersection of James Snow Parkway and Derry Road.), which is too far to make this a preferable long-term supply option. As a result, Trafalgar TS will not be considered for supplying load transfer capability to relieve Halton TS. However, this station should be considered for meeting any long-term Milton Hydro load growth that may occur in the south-eastern section of the municipality.

Tremaine 27.6 kV TS:

Tremaine TS was constructed in 2013 by Hydro One Networks Inc. to provide incremental capacity in the area after Palermo TS reached full operating capacity. Geographically, Tremaine is 9 km west of Glenorchy MTS and is intended to serve growth within Burlington Hydro and the southern sections of Milton Hydro's service territories. Similar to Glenorchy MTS, this station is too far south and west to provide long-term supply for meeting anticipated near-term growth in central Milton Hydro territory, and as a result is not suitable for providing load-transfer capability to relieve Halton TS. Instead, Milton Hydro has currently been allocated two feeders (approximately 35 MW) that will be used to supply south Milton loads, primarily belonging to lower density and slower-growing customer pockets.

Jim Yarrow 26.7 kV MTS

Jim Yarrow MTS is a 155 MW rated 27.6 kV station, owned and operated by Hydro One Brampton. Due to its relative proximity to Halton TS, it was screened as a possible source for capacity relief. However, this option was rejected as the station is heavily loaded (120 MW, or 80% of full capacity) and is expected to reach full capacity by 2020. Incremental loads beyond this date are expected to be served by Pleasant TS.

Pleasant 44 / 27.6 kV TS

Pleasant TS serves both 44 kV and 27.6 kV loads. All 27.6 kV loads are served within Hydro One Brampton's service territory, while 44 kV loads are shared between Hydro One Brampton, Hydro One Distribution, and Halton Hills Hydro. Any load transfers to this station would advance thermal overloads anticipated on the supplying circuit in the mid-2020s. Additionally, Hydro One Brampton has indicated that new feeder egress is extremely limited and space for accommodating all anticipated feeders to serve Hydro One Brampton has already been procured, limiting options for supply to other LDCs. For these reasons, load transfers to Pleasant TS are not considered.

Meadowvale 44 kV TS

Note this station is south of Highway 401 and has been dedicated to supplying 44 kV loads in north Mississauga. This station has a total capability of approximately 180 MW and the highest peak experienced on this station within the past 5 year was 160 MW in 2010. Aside from the mismatch of supply voltages, Meadowvale is also not suitable for supplying HHH service territory as it is south of the 401, and would therefore incur significant tunneling fees. Meadowvale TS was therefore not considered as a possible source for providing load transfer capability to relieve Halton TS.

New Transmission and Distribution Infrastructure Alternatives

Two potential supply alternatives have been investigated for providing the transformation and distribution capacity needed to meet anticipated growth within the study area. The first alternative considers building two separate stations, each located near the growth centers within the towns of Halton Hills and Milton. The second alternative assumes a single station is built to supply both service territories and feeders are extended to the growth centres. Since space is available for additional transformation at the existing Halton TS, this second alternative assumes the single station is located on this site.

Alternative 1, HHH MTS (2018) + Halton TS #2 (2020): Build a new 230/27.6 kV transformer station in the HHH service territory, and a second 230 / 27.6 kV transformer station in the Milton Hydro service territory

Given that HHH will require approx 70 MW over the study period, a smaller 50-83 MVA transformer station, with a typical capacity of 90 MW, was considered. This new station would supply HHH growth north of Highway 401. HHH has indicated that the station could be built for around $19 million (in 2014 dollars, including necessary system enhancements) and would be located on property adjacent to the Halton Hills GS site owned by TransCanada. This property is near the area of projected growth in electrical demand. It is assumed that costs for providing feeders from the HHH MTS site to the growth areas are the same for both Alternatives 1 and 2, because for Alternative 2 the new feeders from Halton TS would emerge in about the same location as HHH MTS. Feeder costs for supplying HHH can therefore be negated.

In order to meet Milton Hydro capacity needs, a second new transformer station would be required in 2020 in the same location as the existing Halton TS. This new station, Halton TS #2, is assumed to be a larger 75/125 MVA TS. This facility is estimated to cost $29 million, and be capable of supplying about 170 MW of load. This is sufficient to meet all anticipated Milton Hydro load growth over the study period. Feeder costs associated with supplying Milton Hydro growth are common among the two alternatives and therefore can be negated for this analysis.

Under the Higher Growth forecast, the same supply alternative will be adequate to meet anticipated electrical demand for both Halton Hills Hydro and Milton Hydro. As a result, the costs of this alternative are very similar under both growth scenarios, although the Higher Growth scenario has a slight advancement cost associated with building Halton TS #2 one year earlier to accommodate Milton Hydro supply needs.

Alternative 2, Halton TS #2 (2018) + Halton TS #3 (2028, high growth scenario only): Build Halton TS #2 in 2018 to serve both HHH and Milton Hydro loads

While this alternative would provide adequate capacity in the near- to medium-term, it is not considered an ideal location for HHH as the station would be located on the south side of Highway 401, with HHH's load located on the north side. Since no new distribution line air rights are available for crossing Highway 401, each 27.6 kV feeder supplied from Halton TS #2 to HHH would need to be placed under the highway. This is estimated to cost about $2 million per feeder. In the near term, this means accounting for the cost of four feeders under Highway 401. In the long term, assumed to be 2028, four additional feeders would need to be placed under Highway 401 to meet the next stage of anticipated growth.

Under athe Higher Growth forecast, the combined Milton and Halton Hills capacity shortfall will exceed 200 MW over the 20 year planning horizon, higher than the typical 170 MW capacity of a 75/125 MVA station. As a result, a second station would be required under this alternative in approximately 2028. This second station, Halton TS #3, is assumed to be built at the same site as the existing Halton TS, and be slightly smaller with 50/83 transformers and an approximate price of $25 million. Note that because of the common location, feeder costs are common under both the Expected Growth and Higher Growth forecasts.

Economic Comparison of Alternatives

A net present value (NPV) analysis using a 4% real social discount rate was carried out to economically compare the two alternatives. Results were present valued to 2018, the in-service year of the first transmission asset. The study period is from 2018 to 2062, 45 years, which is the planning assumption for station asset life. Asset costs have been levelized over the lifetime of the respective assets, with only the costs falling within the study period considered (this attributes value to assets whose life extends beyond the study period). All costs are based on planning level estimates and have been converted to 2014 dollars Canadian. Results are also in 2014 Canadian dollars.

The table below summarizes the major assumptions used for this analysis:

Assumptions for economic comparison of Alternatives

Transmission Asset	Cost ($2014)	Notes
HHH MTS (50/83)	$17.58 million	Alternative 1
2 x 230 kV breakers	$1.44 million	Alternative 1 Required to integrate HHH MTS
Halton TS #2 (75/125)	$29.00 million	Alternative 2
Halton TS #3 (50/83)	$25.00 million	Alternative 2, Higher Growth forecast
Distribution Asset	**Cost ($2014)**	**Notes**
27.6 kV feeder underground, (under 401)	$2 million / feeder	Alternative 2 Tunneling cost, incremental to spanning distance costs
4 x 27.6 kV feeder	$1.1 million / km	Multiply by km distances
Feeder route	**Approx distance**	**Notes**
Halton TS to HHH load centre	3.5 km	Alternative 2 HHH load centre is preferred location of HHH MTS
Financial		**Notes**
Generic inflation	2.00%	Generic planning assumption
Real Social Discount Rate	4.00%	Used to bring NPV results to NPV year
NPV year	2014	In-service date of first asset
Build time	2 yrs	Station build time, assumed complete at in-service year
Life	45 yrs	All transmission assets
FOM as a percent of capital	1.00%	Generic planning assumption

The following table shows that under these assumptions, and the Expected Net Growth forecast, the proposed HHH MTS supply alternative (Alternative 1) is about $3.0 million less costly than building a single central supply station (Alternative 2) with longer feeder connections.

Alternative comparison, Expected Net Growth forecast

	Alternative 1			**Alternative 2**		
	HHH MTS + Halton TS #2			**Halton TS #2**		
	Year	*Cost ($M)*	*NPV ($M)*	*Year*	*Cost ($M)*	*NPV ($M)*
New Stations						
HHH MTS	2018	$19.0	$20.3			
Halton TS #2	2020	$29.0	$28.2	2018	$29.0	$31.0
Halton TS #3				(not required)		
HHH Feeder Costs						
Near Term	2018			2018	$11.9	$12.8
Long Term	2028			2028	$11.9	$7.8
Total NPV						
			$48.5			**$51.6**

Costs associated with distribution losses have not been considered in this preliminary analysis. If such an analysis were conducted, it is expected that Alternative 1 would show the lowest losses as it results in the shortest distribution feeders.

A sensitivity analysis was also carried out on the same alternatives for the Higher Growth forecast. The Higher Growth forecast requires that a second station be provided under Alternative 2, since the proposed Halton TS #2 would itself become overloaded by 2028. Under these assumptions, Alternative 1 is lower cost than Alternative 2 by $17.9 million:

Alternative comparison, Sensitivity forecast

	Alternative 1			**Alternative 2**		
	HHH MTS + Halton TS #2			**Halton TS #2 + Halton TS #3**		
	Year	*Cost ($M)*	*NPV ($M)*	*Year*	*Cost ($M)*	*NPV ($M)*
New Stations						
HHH MTS	2018	$19.0	$20.3			
Halton TS #2	2019	$29.0	$29.6	2018	$29.0	$31.0
Halton TS #3				2028	$25.0	$16.3
HHH Feeder Costs						
Short Term	2018			2018	$11.9	$12.8
Long Term	2028			2028	$11.9	$7.8
Total NPV						
			$49.9			**$67.9**

This overall analysis indicates that Alternative 1 is the economic plan for the area.

West GTA IRRP

Appendix F: Options to Address Long-Term Capacity Needs

Assessment of the Long-Term Electricity Transmission System Requirements within Northwest GTA

Prepared by Power System Planning
Ontario Power Authority

November 10, 2014

ONTARIO POWER AUTHORITY

Assessment of the Long-Term Electricity Transmission System Requirements within Northwest GTA

Prepared by Power System Planning, Ontario Power Authority

November 10, 2014

Introduction and Purpose

In 2009, the OPA submitted comments to the Region of Peel's Official Plan Amendment in the form of a document entitled "Long-Term Electricity Transmission System Requirements within Peel Region". The purpose of those comments was to outline the need for setting aside land within the Region for a future transmission corridor which was deemed necessary for meeting projected growth in the long term.

In order to make optimal use of land, and in accordance with the Provincial Policy Statement, it was recommended that this transmission corridor align with the proposed GTA West transportation corridor, under development by the Ministry of Transportation ("MTO"). The map in Figure 1, below, shows the general location and route of this proposed transmission line, roughly connecting Milton Switching Station ("SS") in West GTA with Kleinburg Transformer Station ("TS") in North GTA. Although the 2009 comments had been provided for the Region of Peel (specifically the municipalities of Caledon and Brampton), sections of this corridor also pass through the Regions of Halton and York. Setting aside land for a contiguous future transmission corridor though Halton and York Regions provides similar benefits for these Regions.

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Figure 1: Approximate GTA West transportation corridor route, and existing electrical infrastructure

Source: OPA

Since 2009, several new developments have driven the need for an update to the original Assessment of Transmission Requirements for Peel Region:

- Revised regional population forecasts were published for the Greater Golden Horseshoe Places to Grow Plan in 2013. This new forecast projects higher growth throughout the Greater Golden Horseshoe, including Peel, Halton, and York Regions, and also extends the forecast period out to 2041. Since these population forecasts form the basis for electrical demand and regional electricity infrastructure requirements, the effect on the electricity needs of the area should also be revised.
- The original 2009 study only considered electricity needs in northern Peel Region, as the comments were intended for that Region's official plan. Since significant growth is also expected in the neighbouring areas, the current study area has been updated to encompass the municipalities of Brampton, Caledon, Halton Hills, and Vaughan (the "Study Area").

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- The generation mix in the province and broad growth patterns across the GTA have changed since 2009. This is expected to stress the bulk transmission system serving Halton, Peel, and York Regions. This effect on bulk transmission system infrastructure needs must also be factored into this assessment.
- The MTO has commenced stage 2 of their Environmental Assessment ("EA") for the future GTA West transportation corridor. A broad study area had previously been identified, and is expected to be narrowed as feasible routes are identified at or near the end of this stage. This places time pressure on the complementary transmission planning activities, as land that will no longer be identified in the study area of MTO's EA could be made available for development. These activities include EA filings and Public Information Centres ("PICs"), as it is more efficient to have these carried out on a similar timeline as the transportation project.
- The initial transmission needs study carried out in 2009 for northern Peel assumed a peak electricity demand contribution per capita which aligned with data available at that time. As a result of conservation initiatives, ongoing provincial targets, and the effect of natural conservation, it is expected that this demand intensity will decrease over the coming decades. Additional demand contributions have been considered in the current analysis to account for various demand scenarios.
- Distributed Generation ("DG") has become more prevalent in mixed use growth areas similar to this Study Area, due in part to initiatives such as the Feed in Tariff ("FIT") program. The current analysis accounts for the expected effect of these technologies based on existing uptake in other areas of the GTA.

The purpose of this document is to account for these new developments and identify the need for and geographic location of a transmission corridor which will enable growth in these Regions as well as provide the required levels of power system reliability across the GTA.

Growth Forecast for the Study Area

An amendment to the growth plan for the Great Golden Horseshoe (Places to Grow), originally released in 2006, was published in May 2013, to include updated population forecasts on a regional basis[1]. While the official growth forecast for each Region has been updated, the municipalities have not yet released an official amendment to their respective population forecasts. In order to present an updated allocation of future demand, municipal forecasts are required, and have been assumed as follows:

[1] https://www.placestogrow.ca/index.php?option=com_content&task=view&id=398&Itemid=14

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Table 1: Regional and Assumed Municipal Forecasts (May 2013), and 2011 census populations

	Census Population	Forecast Population		
	2011	Source	2031	2041
Region				
Peel	1,296,814	Places to Grow	1,770,000	1,970,000
Halton	501,669	Places to Grow	820,000	1,000,000
York	1,032,524	Places to Grow	1,590,000	1,790,000
Municipality				
Brampton	523,911	Draft Regional Plan[2]	833,000	919,000
Caledon	59,460	Draft Regional Plan	113,000	146,000
Halton Hills	59,008	Interpolation[3]	98,444	118,444
Vaughan	288,301	Interpolation	452,472	511,370
Total Study Area	**930,680**		**1,496,917**	**1,694,815**

Electrical Supply Capacity Needs for the Study Area

The analysis carried out in this section is high level in nature, and is intended to provide a general sense of the location and amount of new electrical demand expected in the Study Area (Brampton, Caledon, Halton Hills, and Vaughan) as a result of population increases. It is being undertaken to determine the need for future transmission facilities and corridors to ensure reliable and economic transmission and distribution infrastructure is available to support regional and municipal growth as well as provide for the integrity of the bulk transmission system across the GTA.

Electrical Demand

In order to estimate the increase in power demand across the Study Area resulting from the 2031 and 2041 population forecast, a conversion factor is required. While no standard metric exists, there are several possible sources which can be used to estimate electrical demand on a per capita basis.

This analysis will consider the values used in the 2009 transmission needs study, similar values based on more recent years' peak demand, and a projected energy intensity value based on long-term achievement of conservation targets.

[2] http://www.peelregion.ca/planning/officialplan/art/Draft-Allocation-of-Regional-Forecasts.pdf
[3] Assumes each municipality receives same % allocation of its Region's growth to 2041 as was allocated to 2031 in previous Regional Official Plans (11.1% of Halton Region growth to Halton Hills, and 29.45% of York Region growth to Vaughan)

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Table 2: Peak Demand Contributions per Capita

Source	Peak Demand	Comments
2009 Assessment of the Long-Term Electricity Transmission System Requirements within Peel Region	1.8-2.0 kW/person	Historic Ontario summer peak demand and population information was used to create a peak demand/person metric. This analysis showed demand for 2006 and 2007 had been 2.1 kW/person and 2.0 kW/person, respectively. These numbers were rounded down to 1.8-2.0 kW to be conservative.
2011 Brampton actual peak demand and population ratio	1.55 kW/person	2011 was selected as the most recent year with census data. Brampton has a lower employment/population ratio than Mississauga, which is causing a lower peak demand ratio.
2011 Brampton and Mississauga (combined) actual peak demand and population ratio	1.95 kW/person	2011 was selected as the most recent year with census data. Note that this is the closest representation of Peel load, as detailed LDC customer information is not available to the OPA, making it difficult to measure Caledon load directly.
2011 Halton Hills actual peak demand and population ratio	1.82 kW/person	2011 was selected as the most recent year with census data.
2011 Vaughan, Richmond Hill and Markham actual peak demand and population ratio	2.15 kW/person	2011 was selected as the most recent year with census data. Note that this is the closest representation of Vaughan load, as load transfers within the LDC make it difficult to measure one municipality's load directly.
Peak Demand by population forecast for Ontario, 2031, adjusted for 2013 Long-Term Energy Plan (LTEP) conservation targets	1.60 kW/person	Calculated based on the OPA anticipated net peak demand for 2031 after accounting for the effect of conservation targets (2013 LTEP[4]), and forecast 2031 Ontario population (revised March 2014).

Based on these possible peak demand factors, a range of 1.5-2.0 kW/person was selected to represent a wide range of outcomes. Taking these as a high and low bound, the total population increase for the Study Area can be represented as new peak demand in the Study Area.

[4] http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013

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At present, most new growth in north Brampton is being served by Pleasant TS and Goreway TS, which collectively have approximately 270 MW of remaining capacity. These stations are supplied from 230 kV lines extending through Brampton from the bulk transmission facilities to the south, as shown in Figure 1. Additionally, most new growth in south Caledon is supplied from Pleasant TS and Kleinburg TS, the latter of which has approx 65 MW of remaining capacity. The LDC for Halton Hills is also currently planning a new transformer station at the south end of its service territory, with a nominal supply capacity of around 90 MW. Additionally, the LDC for Vaughan has identified a suitable location for an additional supply station to meet mid-term growth projections, representing potential capacity of around 150 MW. If the increase in peak demand in each municipality is assumed to be supplied from remaining or planned station capacity first, then the total capacity required from new supply sources can be represented as follows:

Table 3: Estimated increase in population and associated power demand

	2031			2041		
	Population Increase (from 2011)	Associated New Peak Demand (MW)	Required New Peak Supply (MW)	Population Increase (from 2011)	Associated New Peak Demand (MW)	Required New Peak Supply (MW)
Total Study Area	566,237	849-1132	305-569	764,135	1146-1528	572-953

Based on this analysis, the required new transmission system capacity for meeting forecast population increases in this area is expected to range between 300-570 MW in 2031, and 570-950 MW in 2041. The areas anticipated to see the highest new demand are highlighted in Figure 2, below. These areas roughly encompass the greenfield sections of the Study Area, and also align well with the proposed transportation corridor:

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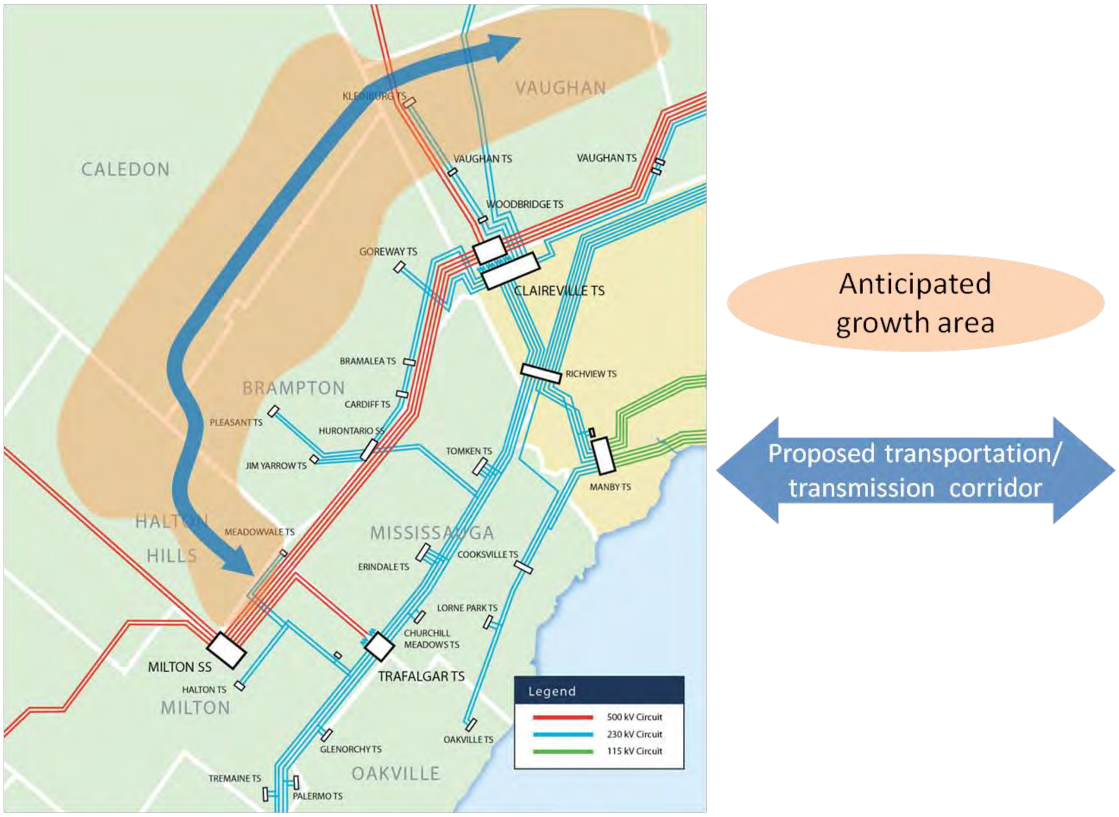
Figure 2: Approximate GTA West transportation corridor route, and greenfield growth areas



Source: OPA

Note that the estimated required peak capacity shown in Table 2 assumes that all new load is capable of being supplied from existing stations first. Due to technical limitations on the distribution system, some of these existing stations may not be capable of providing adequate service to new developments in the greenfield areas highlighted in Figure 2 above. For example, Brampton Hydro has informed the OPA that they are already experiencing challenges in providing adequate voltage on the long feeders extending from Pleasant and Goreway TSs to the growth areas in north Brampton.

Transmission Supply

Since a typical 230 kV step-down transformer station is capable of supplying up to 170 MW of load, this analysis indicates that 4-6 new stations are likely required to meet the Study Area's growth in the long term. In order to provide adequate supply to these new step-down stations, a minimum of two new double circuit 230 kV transmission lines will be required within the general vicinity of the Study Area's load growth centres. Technical details related to these facilities, including required corridor width, are to be provided by the transmitter.

It should be noted that use of undergrounded transmission lines (cables), as opposed to overhead lines, is significantly more costly with costs ranging from 5 to 10 times higher. As a result, cables are typically

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reserved for situations where overhead options are not feasible, such as in densely populated areas with no remaining right of way allowances. Identifying and preserving rights of way early and well ahead of the forecasted need can help electricity customers of municipalities avoid costs associated with underground cables in the future. Allowing the area to develop without reserving an overhead transmission corridor and attempting to incorporate underground transmission facilities at a later date would result in a minimum of $1 billion in additional costs when upgrading the system[5].

In addition to providing capacity for growth, new transmission facilities on this corridor will improve reliability within the Study Area, as well as the neighbouring municipality of Milton, and sections of northeast Mississauga, and northwest Toronto. Each of these areas is currently served by a single transmission supply path. Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Without this measure, each of these areas would continue to be at higher risk of prolonged power outages following major system contingencies.

Other Supply Alternatives

Two major supply alternatives were considered and ultimately rejected for serving the new supply capacity required in the Study Area; conservation and Distributed Generation (DG).

These alternatives can reduce electrical demand within the Study Area, but basic electrical service would still be required to connect new customers where future development is expected. Due to the distances between the growth areas and the existing transmission system, new transmission would be required to support the forecasted growth in electrical demand. Concerns have already been expressed by area LDCs regarding challenges in maintaining voltage levels across existing feeders due to the distance between transmission supply points and end use customers. As electrical demand near the edge of their service territories materializes, these power quality challenges will continue to worsen in the absence of new infrastructure.

While conservation and DG resources are not capable of eliminating the need for new transmission supply, they can be used for deferring the need for additional transmission supply facilities (step-down stations and transmission lines) in the area. As shown in Table 3, above, and the electricity demand analysis, lowering the per capita peak demand contribution from 2.0 kW/person to 1.5 kW/person can effectively reduce the need for new supply stations in the area from 6 to 4 in the long term. In particular, a long-term peak demand contribution of 1.5 kW/person aligns well with the 2013 LTEP net demand forecast which considers the effect of aggressive provincial conservation targets, assuming proportional allocation to the Study Area.

Distributed Generation can also play a role in managing specific transmission system constraints. However, based on the degree of DG uptake in recently developed areas within the GTA, the impact on

[5] Assuming a 50 km line, a nominal overhead cost of $5 million/km for two double circuit lines, and a factor of 5 for conversion to underground costs.

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electricity demand for this Study Area is expected to be around 10 MW. This is not enough to significantly impact the need for the transmission facilities described. Estimated future DG uptake for the Study Area was based on the existing amount per capita of DG contracts within the GTA, and assumes a uniform uptake in the Study Area based on the population forecast to 2041. The OPA is not currently aware of potential for large scale DG projects within the Study Area.

Bulk Transmission System Benefits

The bulk transmission system serving West GTA largely consists of the 500 kV network and 500/230 kV transformation points. The 500 kV transmission lines (shown in red in Figure 3, below), and the 500/230 kV existing and future transformation points are shown as larger white boxes. These facilities in turn serve the 230 kV transmission system (shown in blue in Figure 3), which supplies customer loads through step-down transformer stations (shown as smaller white boxes). Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk system's ability to serve local system demand within the mid term (see area shaded in red, below). One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. Plans for these new facilities had previously been identified as a preferred solution in the Integrated Power System Plan ("IPSP"). A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better utilization and integration of this new supply source, and could defer or avoid the need for additional bulk transmission investment in the North GTA.

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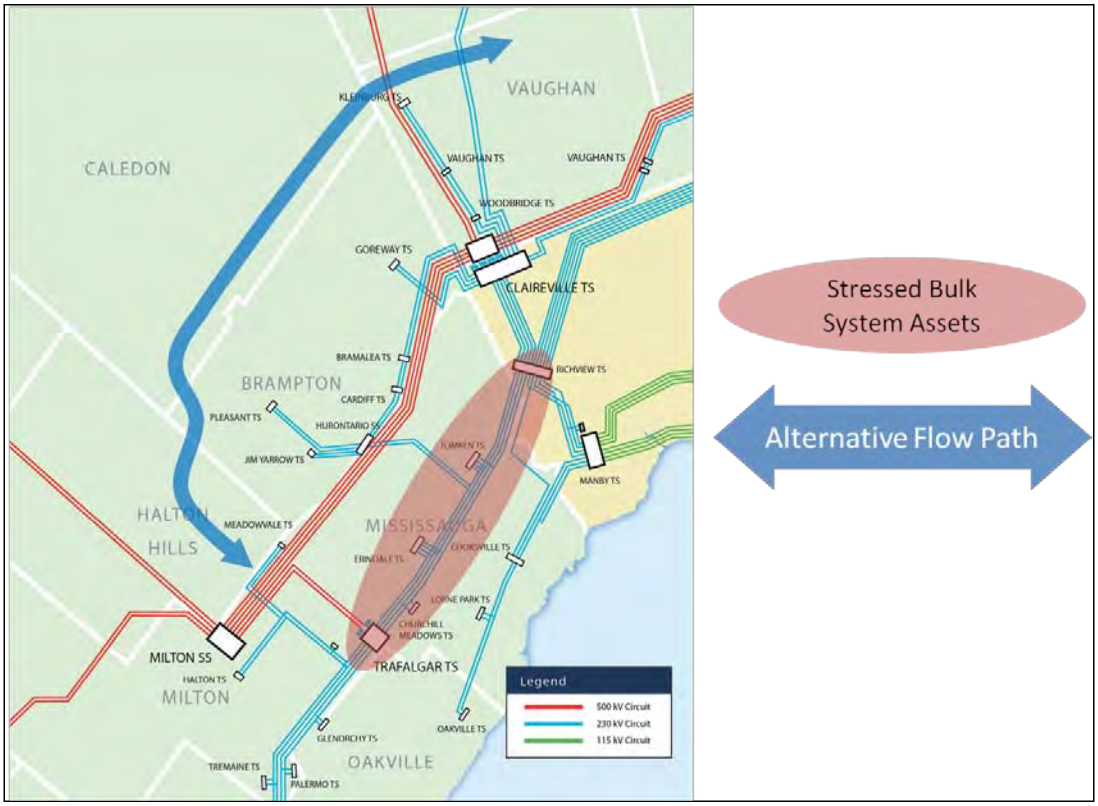
Figure 3: Approximate GTA West transportation corridor route, and stressed bulk facilities



Source: OPA

The bulk transmission system throughout West and North GTA is also experiencing other technical challenges. One such challenge is maintaining short circuit levels within the capability of the equipment. System reconfiguration may be required to address this situation. New 230 kV lines would facilitate this reconfiguration of the bulk transmission system in the area to address this need.

Conclusions

Due to the need for additional regional supply capacity, and the benefits which accrue to the bulk supply system, a future transmission corridor is required within the Northwest GTA Study Area. Given the location of expected growth and other infrastructure developments in the area, this corridor should be located adjacent to the proposed GTA West transportation corridor. The alignment of these infrastructure facilities is consistent with the 2014 Provincial Policy Statement[6] ("PPS"). The PPS, 2014, reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities. This corridor should provide for the economic, safe, and reliable construction, operation, and maintenance of two double circuit 230 kV lines.

[6] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

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Recommendations

The OPA recommends that the transmitter develop the necessary corridor requirements to accommodate the proposed transmission facilities (two double circuit 230 kV lines), and initiate the appropriate approvals process.

It is further recommended that provisions for this transmission corridor be included in relevant regional and municipal official plans.

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Appendix IRR – B

MTS#1 Budget and Capital Expenditures

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Appendix IRR - B - MTS#1 Budget and Capital Expenditures

HHHI - MTS#1 Transformer Station Construction Budget by Year																		
		Budget by Year					Actual by Year					Variance by Year Fav (Unfav)						
Component	Total Budget	2007-2015	2016	2017	2018	2019	2007-2015	2016	2017	2018	Forecast 2019	2007-2015	2016	2017	2018	Projected Variance 2019	Total Project	Variance from Total Budget Fav (Unfav)
2007-2015 Actuals																		
1.1) 2007-2015 Actual Costs	$ 428,700	$ 428,700					$ 428,674					$ 26	$ -	$ -	$ -	$ -	$ 428,674	$ 26
1.2) Land Acquisition	$ 987,000	$ 987,000					$ 980,479					$ 6,521	$ -	$ -	$ -	$ -	$ 980,479	$ 6,521
Engineering	$ 1,017,826		$ 689,715	$ 148,500	$ 107,751	$ 71,860	$ 65,343	$ 725,968	$ 13,586	$ 148,733	$ 127,733	$ (65,343)	$ (36,253)	$ 134,914	$ (40,982)	$ (55,873)	$ 1,081,363	$ (63,537)
Project Management	$ 300,000		$ 158,000	$ 62,000	$ 45,000	$ 35,000	$ 43,046	$ 84,598	$ 332,634	$ 92,902	$ 45,000	$ (43,046)	$ 73,402	$ (270,634)	$ (47,902)	$ (10,000)	$ 598,180	$ (298,180)
Major equipment	$ 9,200,000		$ -	$ 1,574,000	$ 6,130,300	$ 1,495,700			$ 509,459	$ 6,202,729	$ 632,859	$ -	$ -	$ 1,064,541	$ (72,429)	$ 862,841	$ 7,345,047	$ 1,854,953
Civil Construction	$ 6,025,000		$ -	$ 132,500	$ 4,427,500	$ 1,465,000			$ 1,209,593	$ 4,535,020	$ 502,211	$ -	$ -	$ (1,077,093)	$ (107,520)	$ 962,789	$ 6,246,824	$ (221,824)
Electrical	$ 2,650,000		$ -	$ 175,000	$ 1,775,000	$ 700,000				$ 1,822,681	$ 238,399	$ -	$ -	$ 175,000	$ (47,681)	$ 461,601	$ 2,061,080	$ 588,920
Transmission Connection Costs	$ 4,660,000		$ 92,000	$ 955,000	$ 3,140,000	$ 473,000			$ 723,894	$ 2,988,165	$ 228,735	$ -	$ 92,000	$ 231,106	$ 151,835	$ 244,265	$ 3,940,794	$ 719,206
Interest Capitalized	$ -	$ -	$ -	$ -	$ -	$ -		$ 45,773	$ 102,115	$ 439,871	$ 206,241	$ -	$ (45,773)	$ (102,115)	$ (439,871)	$ (206,241)	$ 794,000	$ (794,000)
Sub-Total	**$ 25,268,526**	**$ 1,415,700**	**$ 939,715**	**$ 3,047,000**	**$ 15,625,551**	**$ 4,240,560**	**$ 1,517,542**	**$ 856,339**	**$ 2,891,281**	**$ 16,230,101**	**$ 1,981,178**	**$ (101,842)**	**$ 83,376**	**$ 155,719**	**$ (604,550)**	**$ 2,259,382**	**$ 23,476,441**	**$ 1,792,085**

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Appendix IRR – C

HHH MTS No 1 Site Investigation (2008)

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MTS #1 SITE INVESTIGATION

Technical and Economic Evaluation of
Alternate Methods – Station Sites

April 2008

Prepared by
Costello Associates

1. Introduction

In order to meet forecasted customer demand, Halton Hills Hydro plans to design, construct, and operate a new 125 MVA municipal transformer station (MTS). This facility is planned to be in service no later than spring 2011. The proposed station will be a 230/27.6 kV MTS, located in the vicinity of Steeles Avenue and Trafalgar Road.

As part of the site selection process, a Class Environmental Assessment is underway as per *Ontario Regulation 116/01 – Electricity Projects.* This regulation requires the identification of alternate methods (such as routes or sites) in relation to known environmental, technical, and cost concerns. The purpose of this report is to review the technical and cost impacts of a list of preliminary sites under consideration for this project.

2. System Options

Hydro One Networks owns and operates the Halton TS substation, located near Main St East and 4th Line, in Milton. This station serves power to Milton Hydro and Halton Hills Hydro. Both utilities have been experiencing significant load growth in recent years. Load forecasts indicate that the Halton TS will reach its capacity limit in approximately 2011 – 2013.

Options for Halton Hills Hydro are:

a. Do nothing: This is not an acceptable option as the existing supply is inadequate to meet the increased electricity demand. Without additional capacity, loads beyond the capability of Halton TS cannot be connected to Halton Hydro's distribution system.

b. Expand Halton TS: Hydro One Networks could expand the existing station to provide additional capacity for Halton Hills Hydro. This option has been rejected as it is not possible to egress additional feeders from Halton TS northward into the Halton Hills service territory. The roadways around Halton TS are already congested with distribution pole lines servicing Milton Hydro and Halton Hills Hydro customers.

c. Build a new TS: Halton Hills Hydro is proposing to construct a new transformer station within the study area. The proposed Halton Hills Hydro MTS #1 would have two 50/83 MVA 230 – 27.6 kV transformers that would supply forecasted load growth for the next 25 years.

3. Site Selection for New MTS

In response to increased electrical demand, a Joint Planning Study was initiated in the summer of 2004. Participants included Hydro One Networks Inc., Enersource Hydro Mississauga, Hydro One Brampton, Milton Hydro Distribution, and Halton Hills Hydro. A final report titled "GTA West Supply Study" was published on February 16, 2006. The report recommended numerous transmission reinforcements to support anticipated load growth, including the need to add additional transformer station capacity along the Steeles Avenue corridor between James Snow Parkway and Trafalgar Road.

A preliminary physical survey of this area indicated eleven (11) possible locations for a new station, based solely on sites that had not yet been developed, and had enough physical space to accommodate a station. Each site was then evaluated based on relative economic and technical factors, in order to narrow the list alternate locations for detailed study.

4. Technical Requirements for the MTS Project

   Transformer stations and the distribution circuits that egress the station property are critical assets to the safe and reliable supply of electricity. Minimum technical conditions must be met, or the project (in a particular location) is not feasible.

   The technical review of alternate MTS locations is based on the following assumptions:

   a. The station is planned to be a 50/83 MVA, 230/27.6 kV, 8 feeder station. The emergency rating of this facility is to be 125 MVA.

   b. The forecasted demand of the commercial/industrial Steeles Ave corridor is approximately 68 MVA.

   c. Additional capacity will ultimately be required in Georgetown and Acton, as current water and sewage limitations are mitigated. The remainder of the MTS capacity will ultimately feed this load.

   d. 27.6 kV distribution circuits have a typical capacity of 17.7 MVA.

   e. Four distribution circuits will be required to service the Steeles Ave commercial/industrial load, based on current forecasts.

   f. Four distribution circuits will be required to service the future northern load – Georgetown and Acton areas.

   g. Halton Hills Hydro design standards permit up to four (4) distribution circuits on one pole line. This is based on structural demands as well as for reliability.

   h. Local distribution companies in Ontario are regulated by the Ontario Energy Board (OEB). The OEB's Distribution System Code (DSC) requires that distribution assets can not be built in another LDC's licensed territory without permission from the other LDC. The other LDC could deny access based on several factors, including possible conflict with their ability to service their own needs.

   i. Distribution egress is limited to one pole on each side of the public roadway, in close proximity to the MTS. Multiple pole lines are typically not permitted on the same side of the roadway in the public right of way, due to esthetics and the lack of physical space in the municipal right of way.

   j. The existing Halton TS is located on the western-edge of Halton Hills Hydro's supply area. It is preferred to locate a new facility in the middle or eastern-portion of the Steeles corridor, in order to provide redundancy of supply.

   k. Halton Hills Hydro is a local distribution company (LDC), inherently with expertise in distribution class equipment. Halton Hills Hydro has no expertise in high voltage underground cables, and has no capacity to install, maintain, or repair this equipment. Therefore, a site location that requires the ownership of 230 kV underground cables is not preferred. In the case where it is necessary to construct new 230 kV circuits from the transmission corridor northward to an alternate site, this study assumes that Hydro One Networks would own and maintain these circuits. It is also assumed, based on utility practice, that Hydro One would choose a direct route through land that would have minimal risk of interference from construction or development activities.

5. Technical Summary of Individual Sites

See Appendix A for drawings that show the location of each site (C005, C006, C007, and C008). See Appendix B for photographs of each location.

a. Site 1A – north side of Steeles, near James Snow Parkway
Registered Plan 20R-12541 Con 6 NS PT Lot 15

i. This site is adjacent to the Hydro One 500 kV transmission corridor. The transmission corridor will be expanded in the near future, and this may interfere with the feasibility of this location.
ii. This location is on the western-boundary of the supply area, and is very close to Halton TS. This would result in a lack of supply diversity for the bulk of the Halton Hydro supply area, and negatively impact reliability.
iii. This site is approximately 1800m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.
iv. This site requires dual 27.6 kV distribution circuits to be built the entire length of the Steeles Ave corridor (James Snow Pkwy to Trafalgar Road).
v. This site requires the relocation of the existing wholesale metering equipment for the Halton M29 and M30 feeders.
vi. Station egress to the overhead system would be more costly, given that the station is on the north side of Steeles Ave, and at least one of the distribution pole lines would be on the south side.
vii. The land parcel current available (without expropriation for the 500 kV corridor) is approximately 36 acres.

b. Site 1B – south side of Steeles, near James Snow Parkway
Registered Plan 20R-12446 Part 1 Con 5 N Lot 15

i. This site is adjacent to the Hydro One 500 kV transmission corridor. The transmission corridor will be expanded in the near future, and this may interfere with the feasibility of this location.
ii. This location is on the western-boundary of the supply area, and is very close to Halton TS. This would result in a lack of supply diversity for the bulk of the Halton Hydro supply area, and negatively impact reliability.
iii. This site is approximately 1500m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.
iv. This site requires dual 27.6 kV distribution circuits to be built the entire length of the Steeles Ave corridor (James Snow Pkwy to Trafalgar Road).
v. This site requires the relocation of the existing wholesale metering equipment for the Halton M29 and M30 feeders.
vi. The land parcel current available (without expropriation for the 500 kV corridor) is approximately 18 acres.

c. Site 1C – south side of Steeles, near 5th Line North
Registered Plan 20R-13141 Part 1 Con 5 NS PT Lot 15

i. This location is on the western-boundary of the supply area, and is very close to Halton TS. This would result in a lack of supply diversity for the bulk of the Halton Hydro supply area, and negatively impact reliability.

ii. This site is approximately 1500m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iii. This site requires dual 27.6 kV distribution circuits to be built for 90% of the length of the Steeles Ave corridor (James Snow Pkwy to Trafalgar Road).

iv. This site is very close to nearby commercial/industrial buildings.

v. The land parcel current available is approximately 9 acres.

d. Site 2A – south side of Steeles, near 5th Line South
Registered Plan 20R-13724 Con 6 NS PT Lot 15

i. This location is approaching the middle of the Steeles Ave. industrial/commercial corridor.

ii. This site is approximately 1600m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iii. This site requires dual 27.6 kV distribution circuits to be built for 60% of the length of the Steeles Ave corridor.

iv. This site is very close to nearby farm house.

v. The land parcel current available is approximately 68 acres (Site 2A and 2B).

e. Site 2B – south side of Steeles, near 5th Line South (east of site 2A)
Registered Plan 20R-13725 Con 6 NS PT Lot 15

i. This location is approaching the middle of the Steeles Ave. industrial/commercial corridor.

ii. This site is approximately 1600m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iii. As an alternative, the 230 kV supply could be fed underground from the Halton Hills Generating Station (HHGS). This potentially saves approximately 700m of dual underground transmission circuits, but is complicated by the need for easements through prime developable commercial real estate. These easements would need to extend through numerous individual parcels of land, as well as a public roadway.

We are not aware of a similar underground transmission application in Ontario at this time, and expect that it would be difficult to obtain approvals from land owners, municipal authorities, the Electrical Safety Authority, and regulatory agencies. Also, the increased risk of cable faults caused by inadvertent contact (excavation) could be a cause for concern for Trans Canada Energy (the owner of the HHGS).

iv. This site requires dual 27.6 kV distribution circuits to be built for 55% of the length of the Steeles Ave corridor.

v. The land parcel current available is approximately 68 acres (Site 2A and 2B).

f. Site 2C – south side of Steeles, near 6th Line South (HHGS Site)
Registered Plan 20R-25703 Part 30 Con 6 NS PT Lot 15

i. Transmission circuits are available at this location by tapping into the 230 kV bus at the HHGS. No additional underground 230 kV circuits are required to run south to the transmission corridor. The HHGS site is adjacent to the alternate MTS site, and therefore the 230 kV conductors do not have to bridge any third party property.

ii. This location is located near the middle of the Steeles Ave corridor, and requires dual distribution pole lines to be built for only 35% of the length of the corridor.

iii. Co-location with the generation plant will result in higher reliability, given the plant's ability to supply the local service area even if the transmission system is unavailable.

iv. The land parcel currently available is approximately 5 acres.

g. Site 2D – south side of Steeles, forested area near 6th Line South (west of HHGS Site) Registered Plan 20R-25703 Part 23 Con 6 NS PT Lot 15

i. This location is in the middle of the Steeles Ave. industrial/commercial corridor.

ii. Two options are available for the 230 kV supply to this site. The supply could originate from the transmission corridor south of Highway 401, or it could be fed underground from the HHGS. As mentioned above, this would require easements through prime developable commercial real estate, and coordination for construction and maintenance activities. These easements would need to extend through numerous individual parcels of land, and possibly a planned public roadway.

We are not aware of a similar underground transmission application in Ontario at this time, and expect that it would be difficult to obtain approvals from land owners, municipal authorities, the Electrical Safety Authority, and regulatory agencies. Also, the increased risk of cable faults caused by inadvertent contact (excavation) could be a cause for concern for Trans Canada Energy (the owner of the HHGS). For this reason, this study assumes that underground 230 kV transmission supply will originate only from the transmission corridor.

iii. This site requires dual 27.6 kV distribution circuits to be built for 50% of the length of the Steeles Ave corridor.

iv. This site would require the removal of approximately 1000 mature trees.

v. The land parcel current available is approximately 9 acres.

h. Site 3A – south side of Steeles, just west of Trafalgar Road
Con 7 NS PT Lot 15

i. This location fronts to Steeles Ave, and is situated in the eastern edge of the Steeles Ave. industrial/commercial corridor.

ii. This site is approximately 1600m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iii. The land parcel current available is approximately 13 acres.

i. Site 3B – south side of Steeles, just west of Trafalgar Road
Con 7 NS PT Lot 15

i. This location fronts to Trafalgar Road, and is situated in the eastern edge of the Steeles Ave. industrial/commercial corridor.

ii. This site is approximately 1400m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iii. This site requires two-pole line distribution to be built on Trafalgar Road, and a single pole line to be built heading west on Steeles Ave.

iv. The land parcel current available is approximately 48 acres.

j. Site 3C – Trafalgar Road, south side of Highway 401
Registered Plan 20R-10071

i. This location is near the eastbound exit to Trafalgar Road from Highway 401, on the south side of the highway.

ii. This site is potentially susceptible to salt spray from the highway. This impacts maintenance costs and reliability.

iii. This site is approximately 900m north of the transmission corridor, and would require a 230 kV underground dual-circuit feed.

iv. This site requires all eight distribution circuits (two-pole lines) to be built heading north on Trafalgar Road. Milton Hydro has an existing pole line on Trafalgar Road, and would be in conflict with feeder egress.

v. The land parcel current available is approximately 99 acres.

k. Site 3D – Trafalgar Road, Hornby Junction (ORC Land)
Registered Plan 20R-10071

i. This location is just north of the transmission corridor, facing Trafalgar Road.

ii. As this site is adjacent to the transmission corridor, the station could use overhead 230 kV conductors tapped from the tower structures.

iii. This site requires all eight distribution circuits (two-pole lines) to be built heading north on Trafalgar Road. Milton Hydro has an existing pole line on Trafalgar Road, and would be in conflict with feeder egress.

iv. The land parcel current available is approximately 80 acres.

6. Economic Factors for MTS Project

This study compares the relative site-specific costs for each alternate location. Project costs that would be the same regardless of the location of the facility are not considered in this comparison.

The site-specific factors that influence the relative cost of each location are:

a. Distance from transmission circuits. Costs are relative to the quantity of cables, excavation, and installation labour, and costs of land purchases or easements.

b. Distance from station switchgear to public roadway. Costs are relative to the quantity of cables, excavation, and installation labour.

c. Ability to connect to existing transmission infrastructure north of Highway 401. This avoids the cost of 230 kV underground circuits from the proposed station to the transmission corridor south of Highway 401. This also avoids the necessity to build a switching station at the transmission corridor junction.

d. Where the station is situated on Steeles Ave determines the quantity of distribution circuits that need to be rebuilt. As four circuits are required to run north at Steeles/Trafalgar, locating the station on the western boundary requires additional distribution plant to be built all along the Steeles Ave corridor.

e. Should the station be constructed south of Highway 401, it is likely that the distribution circuits would have to be constructed under the highway. There is a substantial incremental cost for directional boring and coordination with approval agencies.

7. Unit Costs

The following unit costs were used in the calculation of the relative costs for the alternate locations:

1	Transmission - connection to HHGS bus	$ 1,200,000
2	Transmission - connection to Hydro One Towers	$ 2,100,000
3	Transmission - 230 kV Underground Cable Installed per meter	$ 7,000
4	Transmission - Land rights for U/G Cable per meter	$ 370
5	Distribution - 1000 MCM Underground feeder per meter	$ 700
6	Distribution - new 28 kV overhead pole line per meter	$ 125
7	Distribution - rebuild/overbuild overhead pole line per meter	$ 500
8	Distribution - U/G Hwy 401 road crossing incl approvals, engineering	$ 700,000
9	Distribution - relocate 2 PME units	$ 80,000

Table 1

Transmission costs are based on estimates performed by Algal & Associates Ltd. See Appendix C for details.

8. Economic Ranking of Alternate Sites

Detailed cost analysis of individual sites is included in Appendix D. Table 2 shows the relative costs for each location under study:

Ranking	Site ID	Cost
1	2c	5,021,000
2	3d	6,765,000
3	3c	13,373,000
4	3b	14,731,500
5	3a	15,430,000
6	2b	16,630,000
7	1c	16,643,000
8	2d	16,730,000
9	2a	16,730,000
10	1b	16,923,000
11	1a	19,386,000

Table 2

9. Study Recommendations

   a. Site 2c (HHGS site) is the lowest cost location, and should be included in the short list for detailed study.

   b. Sites 3c and 3d are located in Milton, south of Highway 401. Egress along Trafalgar Road is not possible due to conflict with Milton Hydro infrastructure. The OEB regulations require permission from Milton Hydro in order to egress through their licensed service territory, and given the conflict with their existing plant, Milton Hydro cannot be expected to make this allowance. For this reason, sites 3c and 3d should be discarded.

   c. Sites 3a and 3b are adjacent to one another, and can be considered more or less equivalent from a technical and economical point of view (excluding land costs). These sites should be included as one option in the short list for detailed study.

   d. Site 1c is on the western-edge of the Steeles Ave. corridor, and is close to Halton TS. This would result in a lack of supply diversity for the bulk of Halton Hills Hydro's supply area, and would negatively affect reliability. In addition, dual distribution pole lines would have to be constructed for nearly the entire length of the Steeles Ave. corridor. For these reasons, site 1C should be discarded.

   e. Sites 2b and 2d are virtually equal from an economic and technical point of view. Given that site 2d is currently under development by Trans Canada Energy (owners of the HHGS), and there is opportunity to participate in the planning stages for the long-term use of this property, site 2d should be included in the short list for detailed study.

10. Conclusion

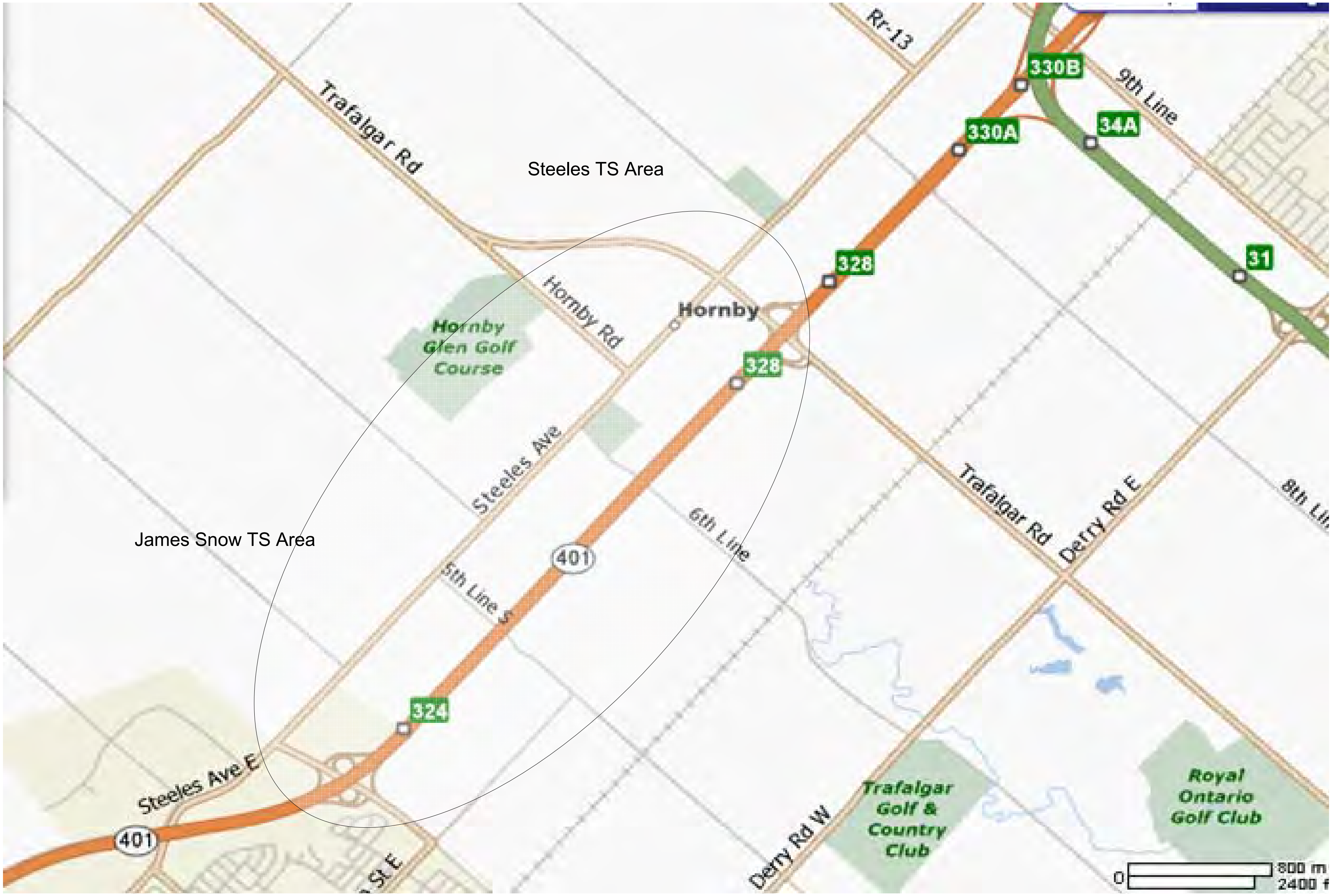
The following sites are recommended to be studied in detail, with the intention of selecting one of them as the “preferred alternative”:

a. Site 2c – The Halton Hills Generating Station property

b. Site 3a/3b – Steeles Ave. and Trafalgar Road intersection

c. Site 2d – Steeles Ave just west of HHGS site, in the forested area

Appendix A



REVISIONS			
REV	DESCRIPTION	DATE	BY

Costello Associates
Sudbury, ON
(705) 522-0501

www.costelloassociates.ca

Halton Hills HYDRO

MTS #1 Site Selection
GTA West Supply Study
Locations for new TS Capacity

C005

REVISIONS			
REV	DESCRIPTION	DATE	BY

Costello Associates
Sudbury, ON
(705) 522-0501

www.costelloassociates.ca

Halton Hills HYDRO

MTS #1 Site Selection
Alternate Location #1
James Snow PW & Steeles Ave

C006

REVISIONS			
REV	DESCRIPTION	DATE	BY

Costello Associates
Sudbury, ON
(705) 522-0501

www.costelloassociates.ca

Halton Hills HYDRO

MTS #1 Site Selection
Alternate Location #2
Steeles Ave - 5th to 6th Line South

C007

REVISIONS			
REV	DESCRIPTION	DATE	BY

Costello Associates
Sudbury, ON
(705) 522-0501

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Halton Hills HYDRO

MTS #1 Site Selection
Alternate Location #3
Trafalgar Road & Steeles Ave

C008

Appendix B


READY MACHINERY MOVERS
CONSTRUCTION ZONE
BEGINS
80
SPEED FINES DOUBLED IN CONSTRUCTION ZONES WHEN WORKERS PRESENT
Halton Hills Hydro
MTS #1 Site Alternatives
Site 1a


Halton Hills Hydro
MTS #1 Site Alternatives

Site 1b


Halton Hills Hydro
MTS #1 Site Alternatives
Site 1b

Halton Hills Hydro
MTS #1 Site Alternatives

Site 1c


Escarpment Country
Taylor Nursery
Halton Hills Hydro
MTS #1 Site Alternatives
Site 1c


Escarpment Country
Taylor Nursery
Halton Hills Hydro
MTS #1 Site Alternatives
Site 1c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 2a and 2b


60
Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


PUBLIC NOTICE
A DEVELOPMENT PROPOSAL HAS BEEN MADE BY HOPEWELL DEVELOPMENT (ONTARIO) INC. FOR A PLAN OF SUBDIVISION ON THE SITE TO ALLOW FOR THE DEVELOPMENT OF ONE OR MORE WAREHOUSE DISTRIBUTION CENTRES ON 32.27 HA (APPROXIMATELY 80 ACRES)
FILE: D/12HOPEWELL-24T-05003/H
FOR FURTHER INFORMATION CONTACT:
- TOWN OF HALTON HILLS
PLANNING AND DEVELOPMENT DEPARTMENT
TEL (905) 873-2600
OCTOBER 2005
Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 2c


HaltonHills Hydro
MTS #1 Site Alternatives
Site 2d


HaltonHills Hydro
MTS #1 Site Alternatives
Site 2d


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3a


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3a


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3a


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3b


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3b


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3c


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3d


Halton Hills Hydro
MTS #1 Site Alternatives
Site 3d

Appendix C

ALGAL & ASSOCIATES LTD.
#306-250 Merton St., Toronto, Ontario, M4S 1B1
Tel.: (416) 484-4200, Fax: (416) 484-8260 E-mail: algal@algal.ca

HALTON HILLS HYDRO- MTS#1 PROJECT-230/28kV DESN

ALTERNATIVE 2: Project to be installed far from Halton Hills G.S

This option requires additional extensive works & funds, as the nearest feasible tapping location could be almost 1.6 kilometres to the south connecting to 230kV transmission lines T38B/T39B, it also requires 230 kV underground cables passing 401 Highway. The additional works for this option are:

1- **Hydro One Tapping Connections approximate cost- 500,000 Dollars,** The cost covers engineering, construction and Outage required for tap connections from two 230 kV Hydro One circuits, including followings:

- Set of insulators.
- Set of connectors
- ACSR conductors (as required).
- Set of Hydro One's BPE transition towers.
- Civil works for BPE towers.
- Engineering by Hydro One.
- Outage.

2- **Junction facility for connecting 230 kV U/G cables to Hydro One's 230 kV tapping approximate cost- 1,600,000 Dollars**, The cost covers design, supply, construction, test & commissioning, including followings:

- 2 Motorized Disconnect Switches suitable for Cable Switching.
- 6 Single phase Surge Arresters.
- A pre-fabricated control house (3m x 4m)
- Set of Control Panel, Battery Charger, Batteries, AC/DC, lighting, etc..
- Set of steel structures, lightning protections.
- Grounding system.
- Gate, fence and a short access road.
- Contingency.

ALGAL
& ASSOCIATES LTD.
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3- **230 kV XLPE cables approximate cost- 11,000,000 Dollars,** for an estimated double circuit cable length of 1.6 kilometres, comprising design, supply, construction, test & commissioning of works, including but not limited to the followings:

- Survey of Cable route.
- Permitting.
- Traffic mitigation plan.
- Cables, splices, accessories and Cable Terminations.
- Mobilization.
- Civil works for trenches and splice pits.
- Highway 401 crossings.
- Cable installation.

Since for this option there will be no connections to the Halton Hills Power plant‘s 230 kV switchyard, therefore following is not required and shall be deducted from overall estimate:

4- **Extension/modifications on TransCanada 230 kV switchyard approximate cost- 1,200,000 Dollars**, The cost covers design, supply, construction, test & commissioning, including followings:

- Two 230 kV Circuit Breakers, adjacent Switches and outgoing feeders including Arresters, Switches & Cable Terminations.
- Set of Clamps & Conductors.
- Set of steel structures.
- Cabling, Grounding.
- Control & Protection system including modifications on original plan.
- Civil works.

Notes:

1- The above costs are budgetary and require additional reviews.
2- TransCanada outage costs are not included (if works to be done after starting Plant operation).
3- Cost of land for all and permitting for items 1,2 and 4 are not included.

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CONCLUSION: The overall approximate additional costs for this alternative will be:

o **Hydro One tapping connection**	**+500,000 $**
o **Junction Facility**	**+1,600,000 $**
o **230 kV XLPE cable**	**+11,000,000 $**
o **Less Modifications on 230 kV Switchyard**	**-1,200,000 $**
o **Total additional cost**	**11,900,000 $**

Appendix D

Halton Hills Hydro

Municipial Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Updated April 3, 2008

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Alternate Site List

No.	Site ID	Gateway Reference	Registered Plan	Legal Text	Registered Owner	Comments
1	1a	19	20R-12541	Con 6 NS PT Lot 15	Nonfredi Emidio	
2	1b	3	20R-12446 Part 1	Con 5 PT Lot 15	Panorama Investment Group	
3	1c	15	20R-13141	Con 5 NS PT Lot 15	1316137 Ontario Ltd	
4	2a	29	20R-13724	Con 6 NS PT Lot 15	824250 Ontario Ltd	
5	2b	29	20R-13725	Con 6 NS PT Lot 15	824250 Ontario Ltd	
6	2c	30	20R-25703 Part 30	Con 6 NS PT Lot 15	80000	HHGS Site
7	2d	30	20R-25703 Part 23?	Con 6 NS PT Lot 15	Trans Canada Energy	Forested area
8	3a	41		Con 7 NS PT Lot 15	662073 Ontario Ltd	
9	3b	41		Con 7 NS PT Lot 15	662073 Ontario Ltd	
10	3c	NA	20R-10071			South of Hwy 401
11	3d	NA	20R-5419		Hydro One	South of Hwy 401

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

No.	Site ID	Transmission Costs	Distribution Costs	Total Site Specific Costs
1	1a	$ 14,166,000	$ 5,220,000	$ 19,386,000
2	1b	$ 11,955,000	$ 4,968,000	$ 16,923,000
3	1c	$ 11,955,000	$ 4,688,000	$ 16,643,000
4	2a	$ 12,692,000	$ 4,038,000	$ 16,730,000
5	2b	$ 12,692,000	$ 3,938,000	$ 16,630,000
6	2c	$ 1,200,000	$ 3,821,000	$ 5,021,000
7	2d	$ 12,992,000	$ 3,738,000	$ 16,730,000
8	3a	$ 12,692,000	$ 2,738,000	$ 15,430,000
9	3b	$ 11,218,000	$ 3,513,500	$ 14,731,500
10	3c	$ 7,533,000	$ 5,840,000	$ 13,373,000
11	3d	$ 550,000	$ 6,215,000	$ 6,765,000

Halton Hills Hydro

Municipal Transformer Station #1 Project

Alternate Site Study - Economic Evaluation

No.	Site ID	Transmission Costs	Distribution Costs	Total Site Specific Costs
6	2c	$ 1,200,000	$ 3,821,000	$ 5,021,000
11	3d	$ 550,000	$ 6,215,000	$ 6,765,000
10	3c	$ 7,533,000	$ 5,840,000	$ 13,373,000
9	3b	$ 11,218,000	$ 3,513,500	$ 14,731,500
8	3a	$ 12,692,000	$ 2,738,000	$ 15,430,000
5	2b	$ 12,692,000	$ 3,938,000	$ 16,630,000
3	1c	$ 11,955,000	$ 4,688,000	$ 16,643,000
4	2a	$ 12,692,000	$ 4,038,000	$ 16,730,000
7	2d	$ 12,992,000	$ 3,738,000	$ 16,730,000
2	1b	$ 11,955,000	$ 4,968,000	$ 16,923,000
1	1a	$ 14,166,000	$ 5,220,000	$ 19,386,000

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	1a	Registered Plan:	20R-12541
		Park ID:	19

1. Economic Impact:

		Costs	
a) Transmission Costs:			
i. Transmission Circuit from Hydro One right of way	1800m	$ 12,600,000	
ii. Land costs for transmission circuit	1800m	$ 666,000	
iii. Connection to Hydro One towe 80000		$ 2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard		$ (1,200,000)	
			$ 14,166,000
b) Distribution Costs:			
i. Feeder Egress	150m	$ 840,000	
ii. Overhead new lines		$ -	
iii. Overhead rebuild lines to East (2)	4300m	$ 4,300,000	
iv. Overhead rebuild lines to West		$ -	
v. Relocate PME's		$ 80,000	
vi. 401 Road Crossing		$ -	
			$ 5,220,000
		Total:	**$ 19,386,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	1b	Registered Plan:	20R-12446 Part 1				
		Park ID:	3				
1. Economic Impact:				Costs			
a) Transmission Costs:							
i. Transmission Circuit from Hydro One right of way			1500m	$	10,500,000		
ii. Land costs for transmission circuit			1500m	$	555,000		
iii. Connection to Hydro One towei	80000			$	2,100,000		
iv.. Avoidance of 230 kV equipment in HHGS yard				$	(1,200,000)		
						$	11,955,000
b) Distribution Costs:							
i. Feeder Egress			105m	$	588,000		
ii. Overhead new lines				$	-		
iii. Overhead rebuild lines to East (2)			4300m	$	4,300,000		
iv. Overhead rebuild lines to West				$	-		
v. Relocate PME's				$	80,000		
vi. 401 Road Crossing				$	-		
						$	4,968,000
				Total:		**$**	**16,923,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	1c	Registered Plan:	20R-13141
		Park ID:	15

1. Economic Impact:

		Costs	
a) Transmission Costs:			
i. Transmission Circuit from Hydro One right of way	1500m	$ 10,500,000	
ii. Land costs for transmission circuit	1500m	$ 555,000	
iii. Connection to Hydro One towe 80000		$ 2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard		$ (1,200,000)	
			$ 11,955,000
b) Distribution Costs:			
i. Feeder Egress	105m	$ 588,000	
ii. Overhead new lines		$ -	
iii. Overhead rebuild lines to East (2)	3900m	$ 3,900,000	
iv. Overhead rebuild lines to West (1)	400m	$ 200,000	
v. Relocate PME's		$ -	
vi. 401 Road Crossing		$ -	
			$ 4,688,000
		Total:	**$ 16,643,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	2a	Registered Plan:	20R-13724
		Park ID:	29

1. Economic Impact:		Costs		
a) Transmission Costs:				
i. Transmission Circuit from Hydro One right of way	1600m	$	11,200,000	
ii. Land costs for transmission circuit	1600m	$	592,000	
iii. Connection to Hydro One towe 80000		$	2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard		$	(1,200,000)	
				$ 12,692,000
b) Distribution Costs:				
i. Feeder Egress	105m	$	588,000	
ii. Overhead new lines		$	-	
iii. Overhead rebuild lines to East (2)	2600m	$	2,600,000	
iv. Overhead rebuild lines to West (1)	1700m	$	850,000	
v. Relocate PME's		$	-	
vi. 401 Road Crossing		$	-	
				$ 4,038,000
		Total:		**$ 16,730,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	2b	Registered Plan:	20R-13725
		Park ID:	29

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way		1600m	$ 11,200,000	
ii. Land costs for transmission circuit		1600m	$ 592,000	
iii. Connection to Hydro One towe	80000		$ 2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard			$ (1,200,000)	
				$ 12,692,000

b) Distribution Costs:

i. Feeder Egress	105m	$ 588,000	
ii. Overhead new lines		$ -	
iii. Overhead rebuild lines to East (2)	2400m	$ 2,400,000	
iv. Overhead rebuild lines to West (1)	1900m	$ 950,000	
v. Relocate PME's		$ -	
vi. 401 Road Crossing		$ -	
			$ 3,938,000

Total: **$ 16,630,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	2c	Registered Plan:	20R-25703 Part 30
		Park ID:	30

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way		$	-		
ii. Land costs for transmission circuit		$	-		
iii. Connection to Hydro One towe 80000		$	-		
iv. Avoidance of 230 kV equipment in HHGS yard		$	1,200,000		
				$	1,200,000

b) Distribution Costs:

i. Feeder Egress	160m	$	896,000		
ii. Overhead new lines	200m	$	25,000.00		
iii. Overhead rebuild lines to East (2)	1500m	$	1,500,000		
iv. Overhead rebuild lines to West (1)	2800m	$	1,400,000		
v. Relocate PME's		$	-		
vi. 401 Road Crossing		$	-		
				$	3,821,000

Total:	**$**	**5,021,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site: 2d   Registered Plan: 20R-25703 Part 23?
Park ID: 30

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from HHGS		1600m	$ 11,200,000	
ii. Land costs for transmission circuit		1600m	$ 592,000	
iii. Connection to Hydro One towe	80000		$ -	
iv. Avoidance of 230 kV equipment in HHGS yard			$ 1,200,000	
				$ 12,992,000

b) Distribution Costs:

i. Feeder Egress	105m	$ 588,000	
ii. Overhead new lines		$ -	
iii. Overhead rebuild lines to East (2)	2000m	$ 2,000,000	
iv. Overhead rebuild lines to West (1)	2300m	$ 1,150,000	
v. Relocate PME's		$ -	
vi. 401 Road Crossing		$ -	
			$ 3,738,000

Total: **$ 16,730,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	3a	Registered Plan:	0
		Park ID:	41

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way	1600m	$	11,200,000	
ii. Land costs for transmission circuit	1600m	$	592,000	
iii. Connection to Hydro One towe 80000		$	2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard		$	(1,200,000)	
				$ 12,692,000

b) Distribution Costs:

i. Feeder Egress	105m	$	588,000	
ii. Overhead new lines				
iii. Overhead rebuild lines to East (1)	300m	$	150,000	
iv. Overhead rebuild lines to West (1)	4000m	$	2,000,000	
v. Relocate PME's		$	-	
vi. 401 Road Crossing		$	-	
				$ 2,738,000

Total:	**$ 15,430,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	3b	Registered Plan:	0
		Park ID:	41

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way		1400m	$ 9,800,000	
ii. Land costs for transmission circuit		1400m	$ 518,000	
iii. Connection to Hydro One towei	80000		$ 2,100,000	
iv. Avoidance of 230 kV equipment in HHGS yard			$ (1,200,000)	
				$ 11,218,000

b) Distribution Costs:

i. Feeder Egress	210m	$ 1,176,000	
ii. Overhead new lines (1)	300m	$ 37,500.00	
iii. Overhead rebuild lines to East	0m	$ -	
iv. Overhead rebuild lines to West (1)	4300m	$ 2,150,000	
v. Overhead rebuild lines to North on Trafalgar (1)	300m	$ 150,000	
vi. Relocate PME's		$ -	
vii. 401 Road Crossing		$ -	
			$ 3,513,500

Total: **$ 14,731,500**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site:	3c	Registered Plan:	20R-10071
		Park ID:	NA

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way	900m	$	6,300,000		
ii. Land costs for transmission circuit	900m	$	333,000		
iii. Connection to Hydro One towe 80000		$	2,100,000		
iv. Avoidance of 230 kV equipment in HHGS yard		$	(1,200,000)		
				$	7,533,000

b) Distribution Costs:

i. Feeder Egress	400m	$	2,240,000		
ii. Overhead new lines (2)	1000m	$	250,000.00		
iii. Overhead rebuild lines to East	0m	$	-		
iv. Overhead rebuild lines to West (1)	4300m	$	2,150,000		
v. Overhead rebuild lines to North on Trafalgar (1)	1000m	$	500,000		
vi. Relocate PME's		$	-		
vii. 401 Road Crossing		$	700,000		
				$	5,840,000

Total:	**$**	**13,373,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

Site: 3d | Registered Plan: 20R-5419
Park ID: NA

1. Economic Impact:

a) Transmission Costs:

i. Transmission Circuit from Hydro One right of way (assume overhead		$ -		
ii. Land costs for transmission circuit		$ -		
iii. Connection to Hydro One towe	80000	$ 1,750,000		
iv. Avoidance of 230 kV equipment in HHGS yard		$ (1,200,000)		
			$	550,000

b) Distribution Costs:

i. Feeder Egress	400m	$ 2,240,000		
ii. Overhead new lines (2)	1500m	$ 375,000.00		
iii. Overhead rebuild lines to East	0m	$ -		
iv. Overhead rebuild lines to West (1)	4300m	$ 2,150,000		
v. Overhead rebuild lines to North on Trafalgar (1)	1500m	$ 750,000		
vi. Relocate PME's				
vii. 401 Road Crossing		$ 700,000		
			$	6,215,000

Total:	**$**	**6,765,000**

Halton Hills Hydro

Municipal Transformer Station #1 Project
Alternate Site Study - Economic Evaluation

1	Land - cost per acre	$	400,000
2	Transmission - connection to HHGS bus	$	1,200,000
3	Transmission - connection to Hydro One Towers	$	2,100,000
4	Transmission - 230 kV Underground Cable Installed per meter	$	7,000
5	Transmission - Land rights for U/G Cable per meter	$	370
6	Distribution - 1000 MCM Underground feeder per meter	$	700
7	Distribution - new 28 kV overhead pole line per meter	$	125
8	Distribution - rebuild/overbuild overhead pole line per meter	$	500
9	Distribution - U/G Hwy 401 road crossing incl approvals, engineering	$	700,000
10	Distribution - relocate 2 PME units	$	80,000

Appendix IRR – D

Halton Hills Hydro MTS#1 Environmental Study Report

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Halton Hills Hydro
Municipal Transformer Station (MTS) #1

ENVIRONMENTAL STUDY REPORT

Prepared For:

Halton Hills Hydro Inc.

Prepared By:

SENES Consultants Limited

August 2008

Cover Photographs Courtesy of Costello Associates, 2008

Halton Hills Hydro Municipal Transformer Station (MTS) #1 Environmental Study Report

Prepared for:

Halton Hills Hydro Inc.

Prepared by:

SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4

August 2008

Printed on Recycled Paper Containing Post-Consumer Fibre

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1.0 INTRODUCTION

Transformer stations and the distribution circuits are critical assets to the safe and reliable supply of electricity. Halton Hills Hydro Inc. (Halton Hills Hydro) is proposing to design, construct, and operate a new 230/27.6 kV 125 MVA municipal transformer station (MTS) in order to address forecasted customer demand primarily in the Steeles Avenue corridor between Trafalgar Road and James Snow Parkway. The proposed undertaking would step down voltage from a transmission level to distribution level at 27.6 kV to provide a reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills (Halton Hills).

A Provincial Class Environmental Assessment (Class EA) for the proposed undertaking is subject to *Environmental Assessment Act* approval in accordance with the *Class EA for Minor Transmission Facilities*. The Class EA is conducted to identify the existing environment and evaluate a number of MTS alternative sites within a study area in order to select a preferred MTS site following a specified planning and design process.

1.1 PROPONENT - HALTON HILLS HYDRO

The proponent of the MTS Project is Halton Hills Hydro, located at 43 Alice Street in Acton, Ontario, who is responsible for the distribution of electricity to the service to the area shown in Figure 1.1. This area includes Acton, Georgetown, and Esquesing Township.

On April 1, 1980, Government Bill No. 119 went into affect dissolving the Acton and Georgetown Hydro Electric Commissions, and establishing the Halton Hills Hydro Commission. This also included a portion of the Ontario Hydro Rural service area of Esquesing Township.

Halton Hills Hydro is committed to providing safe, reliable, and economic distribution of electricity which is reflected in their core values of:

- Safety (Employee and Public);
- Customer Service;
- Reliability; and
- Profitability (Shareholder).

Halton Hills Hydro is responsible for the planning, construction, and operation of the proposed MTS. The development of the proposed MTS will assist Halton Hills Hydro in achieving their core values of reliability and customer service.

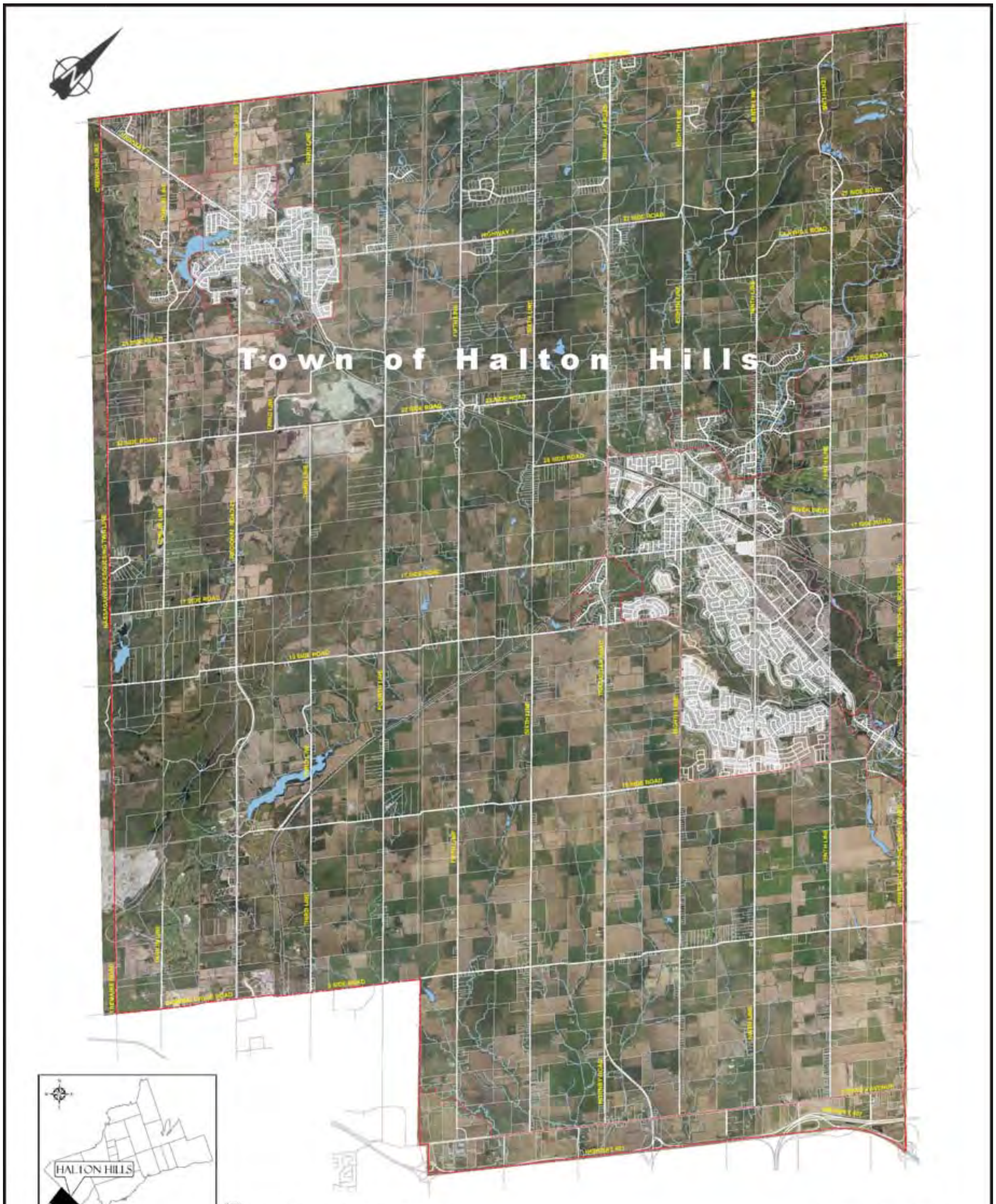


Figure 1.1

HALTON HILLS HYDRO SERVICE AREA

SOURCE: Adapted from Town of Halton, Finance Department Information Services, 2005

1.2 TIMING OF PROJECT

The proposed MTS is being planned for an in-service date of Spring 2011 as load forecasts indicate that the Halton Transformer Station (TS), owned by Hydro One, will reach capacity by approximately 2011 – 2013. Detailed engineering, equipment procurement, and construction of the MTS will occur over a period of 24 months to 36 months. Site construction is planned to commence in March 2010 with final commissioning in May 2011. The MTS is expected to operate for a period of approximately 40 years without a major refurbishment.

1.3 CLASS EA PROCESS

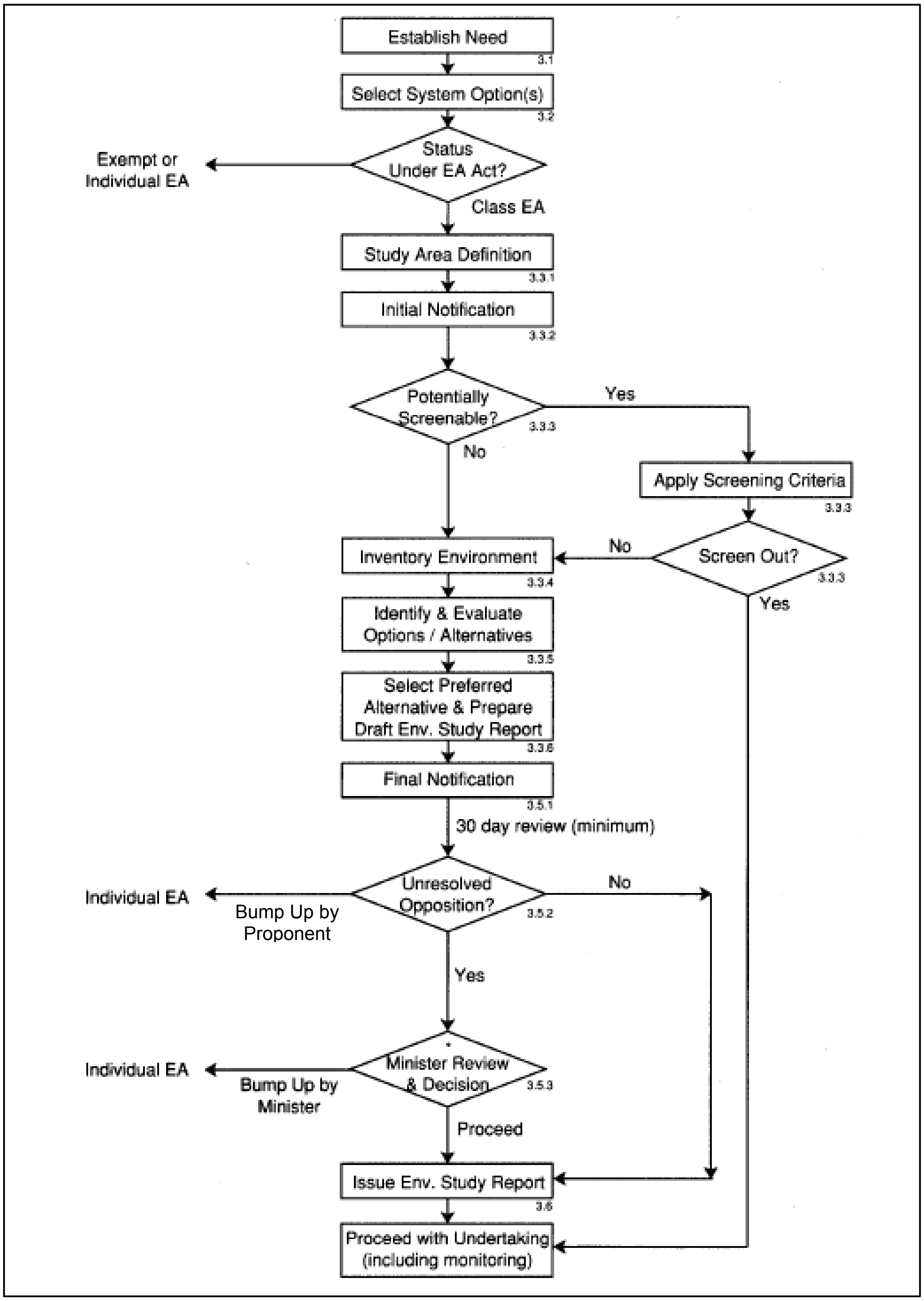
The Class EA process follows a predetermined methodology to document the information gathered and activities conducted through the study. The Class EA process for the proposed Halton Hills Hydro MTS project was conducted according to the requirements defined by the *Class EA for Minor Transmission Facilities (revision 6 April 1992)*.

The steps required to carry out a Class EA study include the following:

- establish need;
- evaluation of alternatives to the undertaking;
- definition of study area;
- initial stakeholder and public notification;
- environmental inventory;
- development of Project description;
- identification and evaluation of alternative methods;
- selection of preferred alternative;
- public consultation;
- preparation of Environmental Study Report (ESR); and,
- final notification.

The Class EA study process conducted for the proposed Halton Hills Hydro MTS is shown in Figure 1.2.

FIGURE 1.2
CLASS EA PROCESS FLOWSHEET



1.4 OTHER APPROVALS

Additional approvals/permits may potentially be required from the local municipality, region, conservation authorities, provincial agencies, and utility owners to proceed with the Project. The list provided below is not inclusive and will be modified, as required, during the detailed design phase:

- Utility owners – Agreements on construction procedures for crossing linear utilities (i.e., rail lines, water and sewer lines, gas pipelines);
- Regional and Local Municipalities – Approval and permits for road crossings, allowances/severances, site plans, removal of trees, vehicle restrictions and traffic mgmt plans, noise control, building permits;
- Conservation Halton – Fill, Construction and Alteration to Waterways permit, as required. Permit to cross Conservation Authority lands;
- Ministry of Environment – Noise and drainage approvals related to TS;
- Ministry of Culture – Stage II Assessment Clearance (if required);
- Ministry of Natural Resources – Work Permit Controls for clearing of a Forest or Woodland under the Forest Fires Prevention Act (if required); and
- Electricity Industry Agencies – (Independent Electricity System Operator (IESO); Hydro One Networks Inc (Hydro One); Electrical Safety Authority (ESA).)

2.0 PROJECT NEED

The need for the Project must be established and supported by documentation providing information on the extent to which the existing and future loads have or will tax the system, and the capabilities of the various transformer station components which comprise the electric distribution system. Awareness of need generally comes from these routine reviews which indicate weak spots or areas of concern in the system. More detailed studies are carried out to establish why, where and when the system will become inadequate, and determine the consequences of the inadequacy.

The *GTA West Supply Study* (February 2006), a joint utility planning study, was initiated by Hydro One in the summer of 2004 to assess the future requirements for additional electrical capacity in the Halton Region due to growing load forecasts and existing infrastructure at or near capacity. Five (5) local distribution companies (LDCs) that have customers within the GTA West and associated Hydro One areas participated in the study, including Hydro One Networks Inc., Enersource (Hydro Mississauga), Hydro One Brampton, Milton Hydro Distribution, and Halton Hills Hydro.

The final report for the GTA West Supply Study was completed 16 February 2006 and included the following conclusions:

- The "Do Nothing" alternative would load circuits above their acceptable ratings and therefore was not considered an acceptable alternative. The Independent Electricity Systems Operator's (IESO) Planning and Operating Standards would not be satisfied as a long range goal of the Conservation Bureau of the Ontario Power Generation Authority is power conservation and demand management (CDM) throughout the province.
- There was a need to reinforce the transmission system in the GTA West and upgrade several transformer stations to satisfy the high load growth in the area. The recommended transmission reinforcements required to support anticipated load growth included the need for additional transformer station capacity along the Steeles Avenue corridor between James Snow Parkway and Trafalgar Road.

The purpose of this study, undertaken by Halton Hills Hydro, addresses the need to plan for the reinforcement of the transmission system and additional transformer capacity due to the high load growth with this study and the identification of the alternatives to the undertaking.

3.0 ALTERNATIVES TO THE UNDERTAKING

Alternatives to the undertaking are functionally different means of addressing the stated electricity supply, demand problems and opportunities, and achieving the purpose of the undertaking.

The objectives used to identify the alternatives to the undertaking include, but are not limited to:

- Meeting the purpose of the undertaking as defined in the GTA West Supply Study; and
- Addressing the identified electricity supply and demand problems and opportunities.

The electric distribution system facility currently serving both Milton Hydro and Halton Hills Hydro is the Halton Transformer Station (TS), owned and operated by Hydro One Networks, located near Main St East and 4th Line in Milton. An increase in residential, commercial, and industrial development in this area in recent years has caused both local utilities to experience significant load growth. Load forecasts identified in the Hydro One *GTA West Supply Study* (February 2006) and the Halton Hills Hydro internal study, *Halton Hills Hydro – 2007 Long-term Load Forecast* indicate that the Halton TS will reach its capacity limit in approximately 2011 – 2013.

The system options considered by Halton Hills Hydro to address the need for added system capacity were:

- Do Nothing;
- Expand Halton TS; and
- Construct a new Halton Hills Hydro MTS.

The rationale for the preferred system options included:

a. ***Do nothing:*** Forecasted loads are anticipated to exceed the capability of Halton TS between 2011 and 2013 and without additional capacity cannot be connected to Halton Hill Hydro's distribution system. This option is not acceptable as development in the Steeles Avenue corridor would have to be limited as the existing supply is inadequate to meet the increased electricity demand that would occur as a result of this development.
b. ***Expansion of Halton TS:*** A system option consideration included the expansion of Hydro One Networks existing station to provide additional capacity for Halton Hills Hydro. The ability to expand the Halton TS is severely limited by existing infrastructure servicing Milton Hydro and Halton Hills Hydro customers. Routing of

the new circuits from the Halton TS to feed into the Halton Hills service territory would be difficult due to the number of distribution poles already present along the roadway in the vicinity of the TS. Since the initiation of this study, Milton Hydro and Hydro One Networks Inc. have initiated a study reviewing the potential for expansion of the Halton TS. This study is considered to be outside of Halton Hills Hydro's current mandate and therefore is not considered to be an acceptable option.

c. ***New Municipal Transformer Station (MTS):*** **This is the preferred system option.** A new MTS could be located in the vicinity of the Steeles Avenue corridor to address forecasted need for this area and also allow for future expansion into other areas serviced by Halton Hills Hydro outside of this corridor. The proposed Halton Hills Hydro MTS would consist of two (2) 50/83 MVA 230 – 27.6 kV transformers to supply forecasted load growth over the next 25 years for the Steeles Avenue Corridor and Georgetown. The remaining MTS capacity would be utilized to address future additional requirements of Georgetown and Acton.

Therefore, based on forecasted need, the construction of a new MTS is the preferred system option and provides the basis for further delineation of the Study Area.

4.0 STUDY AREA

The study area is defined to encompass potential locations for an MTS, which may accommodate the selected system option, warranting further consideration.

The *GTA West Supply Study* (2006) and the Halton Hills Hydro study (2007) identified the area along Steeles Avenue between Trafalgar Road and James Snow Parkway as an area with high forecasted load growth requiring additional MTS capacity due to increasing industrial development.

The Study Area limits, based on the above studies, were therefore focused on this section of Steeles Avenue from just east of Trafalgar Road to west of James Snow Parkway. The northern study area (Figure 4.1) limit is located approximately 1 km north of Steeles Avenue with the southern limit located approximately 1 km south of Highway 401, just north of the Hydro One transmission right-of-way (ROW).

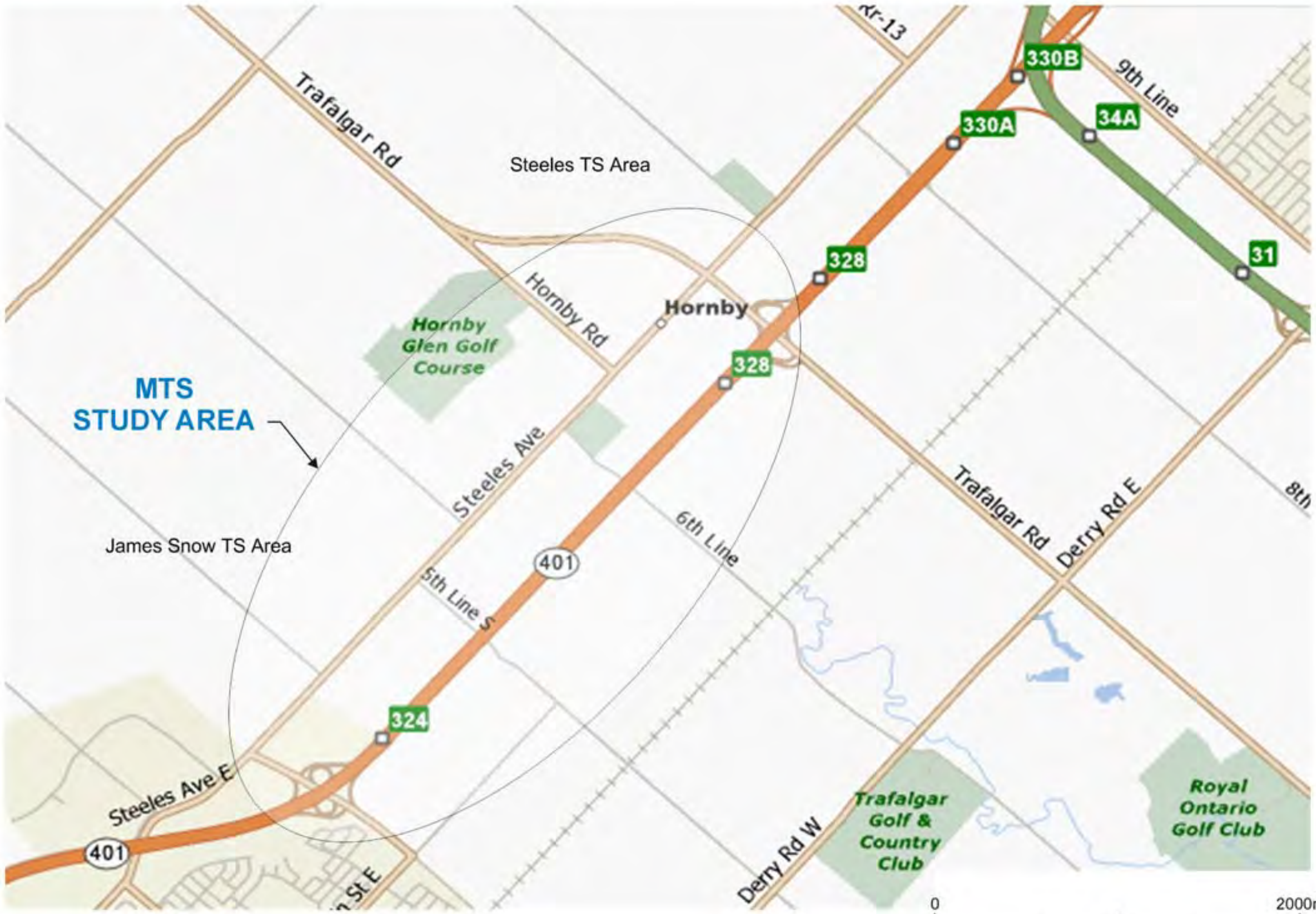


Figure 4.1

HALTON HILLS HYDRO MTS STUDY AREA

SOURCE: Costello Associates, Dwg. C005, 2008

5.0 ENVIRONMENTAL INVENTORY

Baseline information is collected through a review of published/unpublished documents, technical reports/studies and verbal/written inquiries for each of the technical, environmental, and economic components to obtain an understanding of the existing (baseline) conditions for the region and study area. This section provides an inventory of the environmental features in and around the study area through characterization of the natural heritage and socio-economic factors. The natural heritage and socio-economic factors for this inventory include:

- Climate;
- Physiography;
- Soils;
- Surface and Ground Water;
- Fisheries and Aquatic Habitat;
- Vegetation;
- Wildlife;
- Environmentally Significant Areas;
- Demographic Profile;
- Existing and Planned Land Uses;
- Recreation;
- Noise;
- Cultural Heritage Features (Built Heritage and Archaeological);
- Aesthetics; and
- First Nations.

An inventory of the baseline environmental features is described on a regional level and a study area level. The regional description identifies the environmental features found in the vicinity of the study area followed by the study area description which focuses on identifying only those environmental features present within the study area.

5.1 NATURAL HERITAGE

The study area for the proposed Halton Hills Hydro MTS is located within the Sixteen Mile Creek watershed in close proximity to the Niagara Escarpment (west and north) and the Great Lakes to the south. The following information provides a description of the climate, physiography, surface and ground water, fisheries and aquatic habitat, vegetation, wildlife, and the environmentally significant areas (ESAs) of the study area. The information provided in this section is taken from the Sixteen Mile Creek Watershed Plan (Gore and Storrie *et al.* 1996) and the Supporting Document 3: Natural Environment for the Proposed Halton Hills Generating Station (EEL 2007).

5.1.1 Climate

The study area is located within the Lake Ontario Climatic Region characterized by moderate temperatures and high humidity, due to the proximity to Lake Ontario and the Niagara Escarpment.

Summers tend to be warm to hot and humid with moderate winters. The mean annual temperature is 7.5^{o}C with recorded mean daily minimum and maximum temperatures of -6.3^{o}C (January) and 20.8^{o}C (July) respectively.

The prevailing winds are from the west and north, averaging 4.1 m/s (LBPIA 1996-2000 data), with recorded calms 5.7% of the time. Changes in the air flow of the Region occur frequently due to the location of the GTA within one of the major storm tracks of the continent.

Precipitation in the GTA is reasonably consistent throughout the year with an average of 792.7 mm/yr (684.6 mm - rainfall and 115.4 mm – snowfall) based on information collected at Toronto Lester B. Pearson International Airport. The maximum mean monthly rainfall is 79.6 mm occurring in August.

5.1.2 Physiography

The region and study area lies within the West St. Lawrence Lowland Physiographic Unit of the St. Lawrence Lowlands Physiographic Region (Bostock, 1970). The portion of the West St. Lawrence Lowland, associated with the region and study area, gradually ascends from Lake Ontario to Georgian Bay.

The study area is situated within the Peel Plain area of the Sixteen Mile Creek watershed characterized by clay soils and undulating topography (low relief) (Gore and Storrie *et al*., 1996). The plain is imperfectly drained and its’ formation attributed to temporary ponding of glacial waters and the resulting deposition of glacio-lacustrine sediments of gravel, sand, silt, and clay. The plain is characterized as bevelled till plains named for the flutings which can be clearly identified from aerial photographs.

5.1.3 Soils

The region and study area are situated on the South Slope and Peel Plain. The tills which form the surface of the South Slope and Peel Plain are primarily the silty sand Leaside Till in the east and the silty Halton Till in the west (EEL 2007). The tills are modified in the south by glaciolacustrine sands and shorelines of glacial Lake Iroquois (Iroquois Plain). In the north, the till plains are replaced by the highlands of the Oak Ridges Interlobate Moraine. Other surficial deposits, which are more local in scale, are post-glacial Holocene sediments, mainly alluvium deposited by rivers. Other minor recent sediments include those created by wind deposition, as well as organic and peat deposits in wetlands (Chapman and Putnam, 1984a).

The soils in and around the study area originated from the action of ice and water of the Wisconsinan glaciation such that the majority of the watershed is covered by unsorted deposits (till) laid down by moving ice. A large portion of the watershed consists mainly of clay silt loam with varying amounts of sand and gravel generally known as imperfectly drained Halton till.

Typical soils in the vicinity of the study area are described in the *Halton Hills Generating Station (HHGS) Environmental Review Report (ERR), Supporting Document 3 – Natural Environment* (EEL 2007) as Grey Brown Luvisols and Humic Gleysols.

5.1.4 Surface and Ground Water

Surface Water

The surface water features in the vicinity of the study area are part of the Northern Lake Ontario drainage basin (Chapman and Putnam, 1984). The watershed boundaries for the study area and surrounding vicinity within this basin are clearly defined by the Oak Ridges Moraine to the north and the Niagara Escarpment to the west.

The study area and the surrounding vicinity are located within the Sixteen Mile Creek watershed (Figure 5.1**)** which flows southeast from the headwaters near Highway 7 to its outlet at Lake Ontario. The watershed is comprised of three (3) drainage basins (i.e., West Branch; Middle and East Branches; and downstream reaches below the confluence of the two (2) upper drainage basins (Ecoplans Ltd., 1995; Gore & Storrie/Ecoplans, 1996)) encompassing nine (9) subwatersheds.

The study area is situated predominately within the Middle Branch of Sixteen Mile Creek with the west end of the study area entering the West Branch basin and the east end entering the East Branch basin. The Middle Branch's headwaters are located on the Niagara Escarpment flowing

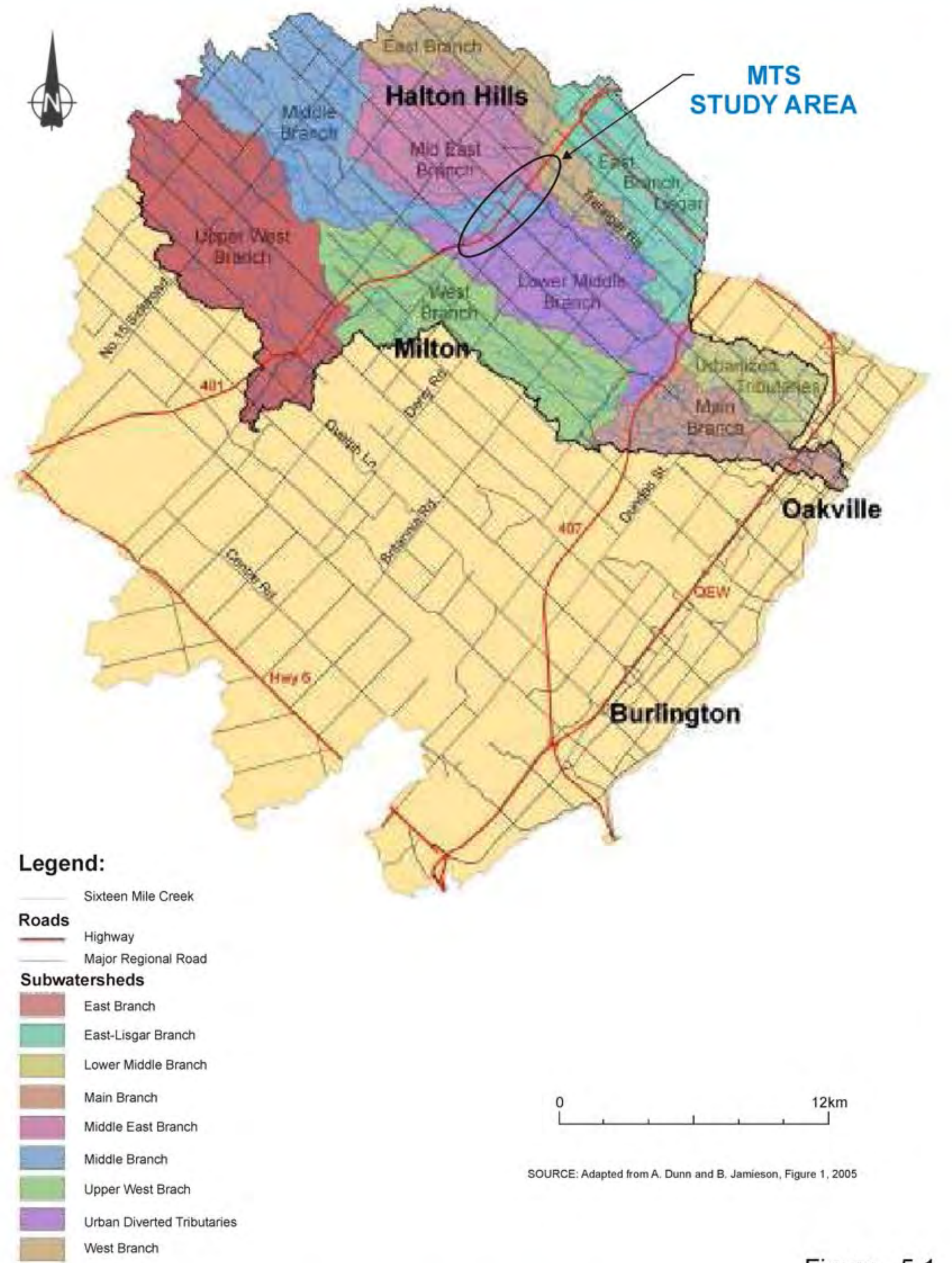


Figure 5.1

SIXTEEN MILE CREEK AND SUBWATERSHEDS

down through the base of the escarpment through Scotch Block Reservoir to join the West Branch downstream of Highway 401 near Sixth Line. Most of the headwater tributaries are, or were historically, groundwater fed. The West Branch's headwaters also originate on the Niagara Escarpment with the main stream channel and a portion of a tributary flowing through concrete channels constructed for flood control purposes. Several smaller tributary systems of the East Branch, many which are intermittent, drain to the combined East and Middle Branches above their confluence with the West Branch.

Water quality data using a suite of parameters for the eastern tributary of the Middle Branch upstream and downstream of Steeles Avenue were found by Dillon (2000) to be below their respective Provincial Water Quality Objectives (PWQOs), with the exception of total phosphorus and iron at a station downstream of the location of MTS site and aluminum at two (2) stations (upstream and downstream). Concentrations for organochlorine contaminants were also well below the PWQOs.

Groundwater

The extent over which groundwater features may exist generally require recognition of the resources on a regional basis although area-specific conclusions may be derived. Regional groundwater flows in a southerly direction towards Lake Ontario (Gore & Storrie, 1995) and consists of two (2) major aquifer systems (overburden and underlying bedrock). The majority of water wells obtain groundwater from the bedrock, as the overburden across most of the region is generally thin and does not yield adequate quantities of water.

The study area, as identified in the *HHGS ERR, Supporting Document 3 – Natural Environment* (EEL 2007) is located on the Till Complex (mainly Halton Till) overburden aquifer system and Queenston shale (underlying bedrock) aquifer systems. The majority of the wells located below the escarpment in the Peel Plain physiographic region are completed in the sand and gravel lenses.

Static groundwater levels range from 2 to 3 m below grade (Dillon, 2000).

5.1.5 Fisheries and Aquatic Habitat

The region lies within the Lake Ontario drainage basin (Chapman and Putnam, 1984a), with the immediate vicinity in and around the study area located within the Sixteen Mile Creek watershed. Sixteen Mile Creek provides coldwater and warmwater fish habitat which has been significantly affected by surrounding land use patterns including agriculture and urban development. The watershed in the upper reaches of the region are characterized as capable of supporting coldwater fisheries although a warming trend occurs as the creek moves downstream out of the headwater areas and into the agricultural and urban lands. As noted in the *HHGS ERR, Supporting Document 3 – Natural Environment (EEL, 2007)*, deterioration of fish habitat quality in the watershed is related to increases in temperature; siltation; sedimentation; reduction in in-stream, overhead and riparian cover contributing to loss of protective stream buffers; increased nutrient loading and alteration of channel morphology; and physical habitat structure and diversity.

The historical range of the native coldwater fisheries (brook trout) for the region occur across the entire headwaters of the watershed, extending as far downstream as Milton on the West Branch and downstream to Derry Road on the Middle Branch and East Branch (EEL 2007). Most upstream reaches of the West Branch and Middle Branch of Sixteen Mile Creek exhibit low water temperatures associated with groundwater discharge and habitat conditions capable of supporting coldwater fisheries (e.g., brook trout (*Salvelinus fontinalis*)) (Ecoplans Ltd.,1995). The upstream reaches of the East Branch also exhibit lower water temperatures. Water temperatures increase downstream from the headwater areas of all branches as they flow through agricultural and urban lands.

The study area is located within the Middle Branch, Main Eastern and Hornby Tributaries of Middle Branch of Sixteen Mile Creek, Subwatersheds 3 and 4 (Main Eastern and Hornby) respectively. The study area exists primarily in Type 3 – Warmwater Sportfish and Type 4 – Warmwater Baitfish designated reaches (Gore and Storrie *et al.*, 1996). The Type 3 designation is based on the presence of smallmouth bass although no sport fish were collected during field surveys. The water temperatures which indicated that stream temperatures are influenced by ambient air temperatures and direct solar radiation in open areas through pasture and cropland. The Type 4 designation applies to most of the remaining permanent or seasonal tributaries. Baitfish communities include a variety of forage species such as minnows, sucker, chub, and shiners.

The *HHGS ERR, Supporting Document 3 – Natural Environment (EEL 2007)* noted Ecoplans (1995) had identified two (2) of the headwater tributaries as potential coldwater areas due primarily to low baseflow temperatures and unconfirmed reports of brook trout northwest of Hornby, in the vicinity of Hornby golf course. Ecoplans (1995) had also identified a largely warmwater fish population of centrachids (sunfish) and cyprinids (minnow), including smallmouth bass, pumpkinseed, creek chub, shiners, and white suckers within this reach.

Upstream of Steeles Avenue, at Fifth Line, the Middle Branch is designated coldwater habitat based on the identification of young-of-year (YOY) Rainbow Trout and redside dace. An abundance of redside dace, commonly inhabiting cool, clear headwater streams, were identified approximately 4 km upstream of Steeles Ave (Fifth Sideroad east of Fifth line) by Ecoplans (1995) in addition to creek chub, blacknose dace, and white sucker. In contrast, only creek chub and pumpkinseed species caught further downstream, approximately 1 km north of Steele (SENES *et al.* 2007).

All fish species, with the exception of redside dace, noted here are considered to be common in Ontario and not tracked by the NHIC (2006b).

5.1.6 Vegetation

The study area and surrounding region is located in the transition zone between the Niagara Section (Carolinian Zone) of the Deciduous Forest Region to the south and the Huron-Ontario Forest Section of the Great Lakes-St. Lawrence Forest Region to the north (Rowe 1972). The Deciduous Forest Region forms a narrow band along the north shore of Lake Ontario in southwestern Ontario extending east to approximately Presqu'ile Peninsula. Representative species common to both the southern Carolinian forest and the Great Lakes-St. Lawrence Forest Region to the north and northwest are found in this area.

The natural vegetation of the Huron-Ontario Section of the Great Lakes-St. Lawrence Forest Region is dominated by mixed wood forests (Rowe 1972). This Section is characterized by a number of dominant broad-leaved species with eastern white pine (*Pinus strobus*), eastern hemlock (*Tsuga canadensis*), and balsam fir (*Abies balsamea*) owing to the transition between the southern deciduous forests and the northern coniferous forests in this area. Habitat fragmentation, as a result of intensive agriculture and urbanization, have left only vestiges of the original forest communities.

Dominant broad-leaved species identified include sugar maple (*Acer saccharum* ssp. *saccharum*), red and white oak (*Quercus ssp.)* and American beech (*Fagus americana*); and Carolinian species such as black walnut *(Juglans nigra*) and sycamore (*Plantanus occidentalis*).

The presence of a number of woodlots, associated with the Middle Branch of Sixteen Mile Creek and its tributaries, have been identified in the north portion of the study area (north of Steeles Ave.) (EEL 2007).

The dominant vegetation community in the area is agricultural in nature, primarily crop fields that are used for a rotation of corn (*Zea mays*), soybean (*Glycine max*), winter wheat (*Triticum aestivum*), hay and pasture (Dillon, 2000) although well established hedgerows are present in some fields.

5.1.7 Wildlife

Agricultural, woodlot and urban parkland in the study area provide habitat for those wildlife species fully habituated to human activities.

Mammals

The principal large wildlife species in the vicinity of the study area is considered to be the white-tailed deer (*Odocoileus virginianus*) likely as a result of the current mixed land uses in the area. Principle winter deer habitat is also available approximately 2 km north of the study area in Hornby Swamp Complex (Ecoplans Ltd., 1995).

Approximately 44 mammal species were identified within the Sixteen Mile Creek watershed, of which 31 were identified as native species (Dillon 2000). The species considered to be common within the study area include grey squirrel, ground hog, Eastern chipmunk, vole species, Eastern cottontail, striped skunk, red fox, coyote, raccoon, and red squirrel. No species present within the study area are considered to be at risk federally by COSEWIC (2007) or provincially by COSSARO (OMNR 2006a).

Avifauna

The avifauna in the vicinity of the study area, as documented in the HHGS *ERR, Supporting Document 3 – Natural Environment (EEL, 2007)*, was characterized on a watershed basis. The habitat of this area consists of diverse habitat consisting of active and abandoned agricultural fields and pasture, hedgerows, early successional vegetation and mature woodlots which could potentially support a diverse assemblage of bird species. Information on breeding birds within the Sixteen Mile Creek Watershed was taken from the Ontario Breeding Bird Atlas using 10x10 km Mercator Grid Squares. The study area is located within a 10 x 10 km square (17NU92) which does not contain any ESAs or large habitat areas, and is mainly open agricultural land. Small woodlots and riparian zones associated with East Sixteen Mile Creek tributaries provide the majority of the habitat cover and diversity with numerous tree nurseries and orchards providing habitat for some species.

Approximately 150 avian species were documented within the Sixteen Mile Creek watershed of which 88 species were likely or confirmed breeders. The 88 breeding bird species included 22 and 40 species considered locally rare and locally uncommon in Halton Region, respectively.

Six (6) species of the 22 locally rare species are considered to likely be breeding in the 10-km by 10-km grid encompassing the study area, with five of these species are ranked by NHIC (2006b) as common in Ontario. Twenty-three (23) of the 40 locally uncommon species are likely or confirmed to be breeders in the grid with all of these species identified as very common or common in Ontario (Dillon 2000).

Provincially rare and significant species identified were the Cooper's Hawk (confirmed breeder) and Orchard Oriole (probable breeder).

Herpetofauna

The term "herpetofauna" includes both reptiles and amphibians and are usually found in wetland areas accompanied by mature forest. The herpetofauna in the vicinity of the study area, as documented in the HHGS *ERR, Supporting Document 3 – Natural Environment (EEL 2007)*, was characterized on a watershed basis. Approximately 14 amphibians and 12 reptiles were identified within the Sixteen Mile Creek watershed. Jefferson salamander is designated as a threatened species federally by COSEWIC (2007), as well as provincially by COSSARO (OMNR 2006a). Northern map turtle, eastern ribbon and milk snake are designated as species of special concern federally by COSEWIC (2007), as well as provincially by COSSARO (OMNR 2006a). One (1) amphibian and four (4) reptile species are considered to be locally rare in Halton Region, with four (4) amphibians and one (1) reptile species considered locally uncommon.

5.1.8 Environmentally Significant Areas

Environmentally significant areas can be defined as wetlands, Areas of Natural and Scientific Interest (ANSIs) and Environmentally Sensitive Areas (ESAs) which provide important habitat for a variety of wildlife and plant species. Development and site alteration in or adjacent to these areas are not permitted unless no negative impacts on the natural features or their ecological functions can be demonstrated.

Wetlands, identified as Provincially Significant Wetlands (PSWs), are protected under the Wetlands Policy Statement, which was incorporated into the Provincial Policy Statement (OMMAH, 2005) in 2005, to ensure no net loss of these wetland areas whose function includes water storage and control to reduce erosion and flooding, assists in improving water quality, and provides areas for a range of recreational pursuits.

Areas of Natural and Scientific Interest (ANSIs), identified as either life science or earth science ANSIs, and Environmentally Sensitive Areas (ESAs) are natural areas identified by OMNR and conservation authorities and/or municipalities, respectively, for protection of their natural landscapes and/or features for heritage appreciation, scientific study or conservation education purposes.

The only wetland complex in the vicinity of the study area is the Hornby Swamp Complex (Class 7), approximately 18 ha in size, which is located adjacent to the northern (2 km) boundary of the study area.

There are no evaluated wetlands, Areas of Natural and Scientific Interest (ANSIs), or Environmentally Sensitive Areas (ESAs), identified or designated in the study area (Halton Region, 1978; Hanna, 1984; Geomatics, 1991, 1993; Halton Region and NSEI, 2005).

5.1.9 Noise

Noise levels experienced at a regional level are directly related to the type of land use in a particular area. Traffic noise associated with road infrastructure is considered to be the major source of noise generated in the region with the exception of industrial areas (e.g., manufacturing) or construction sites (e.g., urban development) where noise levels are elevated either periodically or daily above background traffic levels.

Publication NPC-205 of the Model By-Law defines and sets Sound Level Limits for Stationary Sources in Class 1 and 2 Areas (Urban) (MOE 1995) as follows:

A "Class 1 Area" is defined as:

> *an area with an acoustical environment typical of a major population centre, where the background sound level is dominated by the urban hum.*

A "Class 2 Area" is defined as:

> *an area with an acoustical environment that has qualities representative of both Class 1 and Class 3 Areas, and in which a low background sound level, normally occurring only between 23:00 and 07:00 hours in Class 1 Areas, will typically be realized as early as 19:00 hours.*

Other characteristics which may indicate the presence of a Class 2 Areas include:

- *absence of urban hum between 19:00 and 23:00 hours;*
- *evening background sound level defined by natural environment and infrequent human activity; and*
- *no clearly audible sound from stationary sources other than from those under assessment.*

Publication NPC-205 also states that the sound level limit must be established based on the principle of "predictable worst case" noise impact. Generally, the limit is based on the background sound level at the receptors and must represent the minimum background sound level that occurs or is likely to occur during the operation of the stationary source under assessment.

The sound level limits for a Class 1 and 2 Area, provided in Table 5.1, are established in Publication NPC-205. Energy equivalent sound levels identified in the table are measured in L_{eq}, in dBA. If the stationary source contains any noticeable features such as tonal components or buzzing, a 5 dB tonal penalty must be added to the noise level of the source as per NPC-104.

TABLE 5.1
MINIMUM VALUES OF ONE-HOUR L_{eq} or L_{LM} BY TIME OF DAY

Time of Day	One Hour L_{eq} (dBA)	
	Class 1 Area	Class 2 Area
07:00 - 19:00	50	50
19:00 - 23:00	47	45
23:00 - 07:00	45	45

The study area is predominately rural with an extensive road infrastructure and urban development to the east, west, and south. The background sound level is dominated by local traffic along Highway 401, Trafalgar Road, and Milton (south and west). The local traffic noise levels decline as you proceed further north in the study area and therefore the study area could be defined as either a Class 1 or Class 2 Area.

5.2 SOCIO-ECONOMICS AND LAND USE

The demographic profile, description of the existing and planned land uses, socio-economic features (community, business and recreation), and cultural heritage features are identified in a regional and study area context.

5.2.1 Demographic Profile

The Halton Hills is experiencing considerable growth as are other communities in transition across the Greater Toronto Area (GTA). The Halton Hills had an estimated 2006 population of 55,289, an increase of 14.7% in the 2001 population estimate. The majority of the population is relatively young between the ages of 25-44 (33.53%) with the population expected to reach 70,000 by 2021. Specific demographic profile information is not available for the study area.

5.2.2 Existing and Planned Land Uses

It is estimated that all lands currently used for rural land uses (i.e., agriculture, idle fields, and existing development) may be developed for urban uses over the long-term therefore increasing the current total urban land use from 15% to over 80% (Dillon 2000).

Existing Land Use

The existing land uses in Halton Region are identified in the Sustainable Halton Plan (Halton Region 2008) by five (5) land use types consisting of Greenbelt, Parkway Belt, Other Protected Greenlands, Rural Lands and Urban Areas. The existing land uses are as follows:

- The Greenbelt is defined as a broad band of permanently protected land set aside by the Provincial *Greenbelt Act* (2005) and the associated Greenbelt Plan comprised of the Niagara Escarpment Plan Area and Protected Countryside encompassing approximately 44% of the Region.
- The original Parkway Belt, defined as a multi-purpose utility corridor, urban separator, and linkage to an open space system, has over the past 25 years largely been removed from the Parkway Belt Plan (1978) with much of the remaining area now an integral part of the Greenbelt.
- Other Protected Greenlands include natural areas of regional significance which is not included in the Greenbelt or Parkway Belt Plan, as designated in the Regional Official Plan.
- Other “Rural Lands”, generally located south and east of the Greenbelt area and almost entirely located in the Towns of Milton and Halton Hills, are defined as most of the land outside of the Greenbelt or greenlands system that is not currently designated urban.
- Acton, Burlington, Georgetown, Milton, Oakville and the Halton Hills 401 Corridor employment area are all considered “Urban Areas” designated for residential, employment, commercial, and institutional uses.

Many of the former rural municipalities in the GTA have been transformed, due to rapid development in the GTA, into urban and semi-urban areas. Halton Hills is an example of this transformation as the former Equesing Township, and urban centres of Georgetown and Acton are considered an integral part of this Town. Milton is the largest urban centre adjacent to the west and south of this area.

The study area, as identified in the Halton Region Official Plan (2006) encompasses or is immediately adjacent to a number of land use designations including urban areas, agricultural areas, rural cluster, special policy, Greenlands A and B, private open space, prestige industrial, gateway and major parks and open space (Figure 5.2).

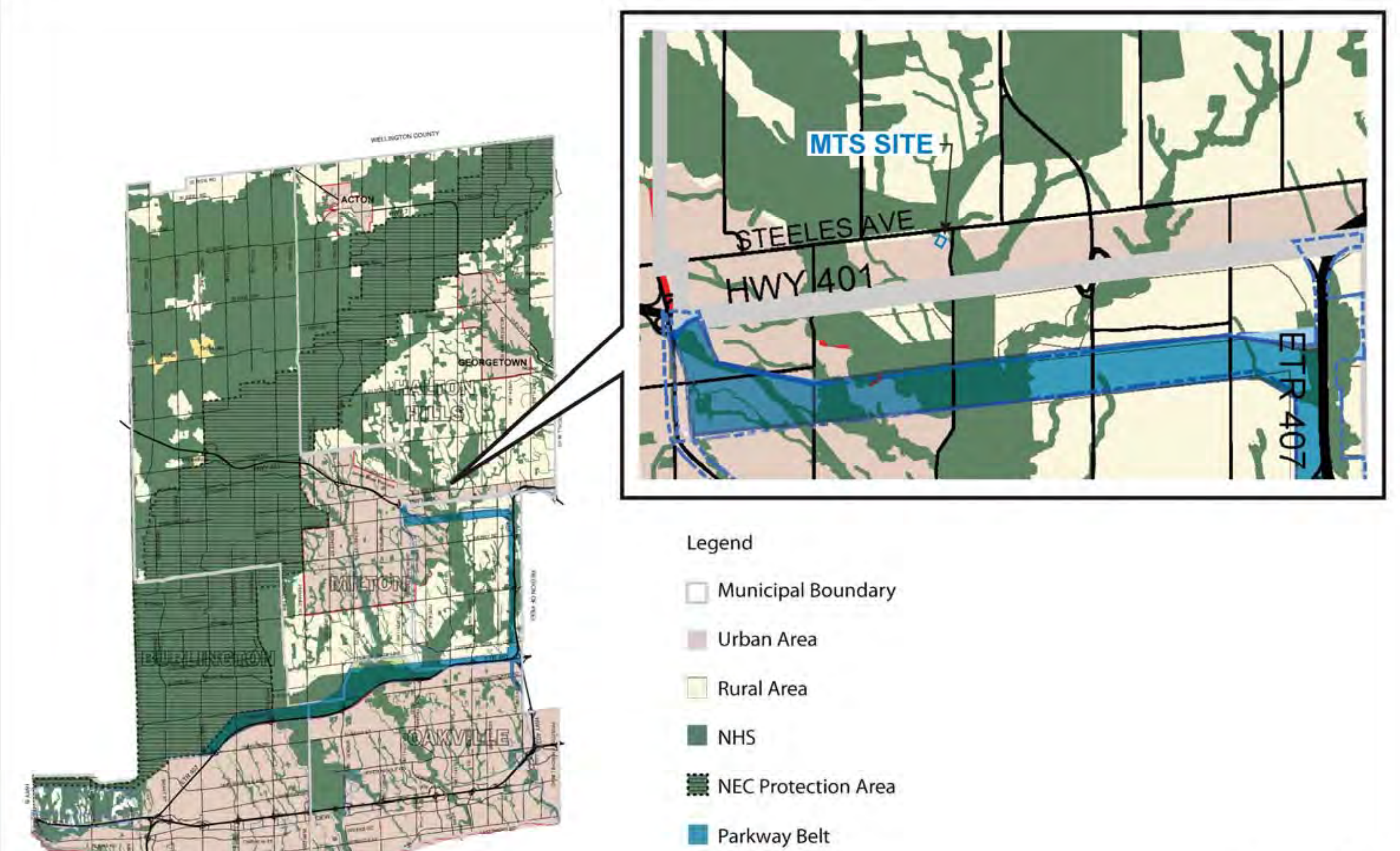


Figure 5.2

LAND USE DESIGNATIONS IN THE VICINITY OF STUDY AREA

SOURCE: Adapted From Town of Alton Hills Land Use Plan, Fig 1 2008

The Highway 401/407 Employment Area is located within the study area with Hornby located on the eastern boundary of this area. Hornby is designated a rural cluster (Halton Hills Official Plan) currently in transition from a predominately rural farming area, where historically residents had long-term business or agricultural ties to the community, to an integral part (gateway) of Halton Hills.

Land Use Planning

The Golden Horseshoe by the year 2031 is forecasted to reach a population size of approximately 3.7 million people and 1.8 million more jobs (based on 2001 Census data) as specified in the Provincial Growth Plan for the Greater Golden Horseshoe area. The Provincial Growth Plan identifies the Province's vision for the future forecasted growth of its municipalities, infrastructure required to support that growth, and the cultural and natural heritage resources to be protected. Halton Region is expected to accommodate an additional 780,000 people and 340,000 jobs (based on 2006 Census data) by 2031.

In response to the Growth Plan, Halton Hills is working with other local municipalities within the region on a long-term growth management strategy called Sustainable Halton Plan (formerly "Durable Halton Plan") intended to implement Places to Grow – the Greater Golden Horseshoe Area Growth Plan, the Greenbelt Plan and the 2005 Provincial Policy Statement into the Regional Official Plan and subsequently local official plans. This workplan addresses resource management (agriculture, natural heritage, aggregate resources, source protection) and growth management (intensification, land supply analysis, housing, economic development) within the context provided by the Growth Plan and other recent provincial initiatives.

According to Statistics Canada, Halton Hills, with an area of approximately 276.26 km^2, is designated as 81.5% urban and 18.5% rural. It is anticipated that new urban land and additional urban intensification will be required to meet the 2031 targets for the Region (Sustainable Halton, Draft 2008). A portion of Halton Hills, including the study area and the 401/407 Employment Area, is identified as part of the primary study area in the Sustainable Halton Plan. This Plan focuses on the potential for future growth within the primary study area to accommodate the forecasted increase in population and jobs. Currently the Halton Region (2006) Official Plan addresses anticipated growth to the year 2021 whereas Sustainable Halton, once adopted, would include planning initiatives to the year 2031. It is anticipated that a total of 3010 ha (residential, employment, community infrastructure), mainly within the primary study area, will be required to accommodate the 2031 population and employment targets.

Land use planning within the study area is currently focused on the portion of the 401/407 Employment Area located in the study area. The Highway 401/407 Employment Area, designated in the Halton Hills Official Plan (May 2008), is identified as an important component in the future development of Halton Hills. It is currently an area in transition characterized by a mix of commercial, industrial, agriculture, and residential uses with future plans for more intensive industrial/commercial/gateway development of the corridor.

5.2.3 Recreation

The recreation facilities in the vicinity of the study area are limited to the Hornby Glen Golf Course in the north portion of the study area and Hornby Park, immediately south of Steeles Avenue. Both of these recreation facilities are located within the study area.

Hornby Park functions as a recreational area for outlying areas as well as the larger surrounding communities due to its proximity to major transportation routes such as Highway 401, Steeles Avenue and Trafalgar Road and location away from concentrated residential development. The main eastern tributary of the Middle Branch of Sixteen Mile Creek runs through the park.

The parks facilities include a playground, pavilion with washroom facilities, and two (2) baseball diamonds (one (1) illuminated). There are no programmed uses of the park although it is typically used to host adult baseball leagues during the weekdays and on weekends for tournaments. The park is also used extensively for dog trials and as a staging area for cycling trips. Use of the park for cycling has become frequent enough that the Town is considering implementation of measures to manage this activity (SENES 2007).

The reconstruction of Steeles Avenue and increasing development in this corridor is anticipated to change current uses of the park including the relocation of the park access to the north corner of the park in the former location of the regional recycling depot.

The Hornby Glen Golf Course is located approximately 1 km north of Steeles Avenue on Hornby Road. This is a public golf course which is designated as private open space in the Halton Hills Official Plan.

5.2.4 Aesthetics

Aesthetics, as it relates to this study, is the visual impact that a proposed MTS will have on the surrounding existing environment to identify the level of compatibility and potential to change the landscape.

The region is a diverse rolling landscape, delineated to the west and north by the Niagara escarpment, consisting of pockets of forested areas, agricultural fields and hedgerows, and valley systems interspersed by sections of urban/ industrial development and associated infrastructure.

The study area as viewed from Highway 401 is dominated by open agricultural field (SENES 2007). The diversity of the study area may be seen from along Steeles Avenue starting in the west with agricultural fields and hedgerows interspersed with industrial buildings, proceeding east through a rolling landscape of mixed agricultural, residential, and parkland, into a more level landscape comprised of mixed residential and business, and terminating in the vicinity of Trafalgar Road with a predominately commercial environment interspersed with residential and agricultural uses.

5.2.5 Cultural Heritage Features

The Halton Hills Official Plan (2008) identifies approximately five (5) buildings within the study area limits that are identified as "Buildings with Historic Significance". Built heritage is defined in the Official Plan as an individual or group of significant buildings, structures, monuments, installations, or remains, which are associated with architectural, cultural, social, political, economic, or military history and identified as being important to a community. These resources may be designated or subject to a conservation easement under the *Ontario Heritage Act*, or listed by the federal or provincial governments or the Town.

Two (2) of the heritage buildings are located to the west of Fifth Line, one each north and south of Steeles Avenue, one (1) located on the Halton Hills Generating Station site, and the remaining two (2) located west of Trafalgar line on the south side of Steeles Ave.

A Stage 1 and 2 archaeological assessment (ASI 2006) of the Snoek and Ballard Lands was conducted in support of the Halton Hills Generating Station (HHGS). The Snoek and Ballard Lands are located south of Steeles Avenue and north of Highway 401 between Fifth Line South and Sixth Line South. The study identified two (2) previously registered sites (AjGw-20 and AjGx-19) within a two (2) km radius of these Lands. The Bradley site (AjGw-20) was described as an artifact collection from an Archaic and Paleo-Indian campsite with AjGx-19 (unnamed) representing an unknown component located north of Steeles Avenue and west of Trafalgar Road. This study also identified the presence of a nineteenth century farmstead recorded in the 1877 Illustrated Historical Atlas of Halton, Ontario (Walker & Miles, 1877). Archaeological assessment of the remainder of the study area was not conducted.

5.2.6 First Nations

Contact was made with the Ontario Native Affairs Secretariat during the HHGS ERR (SENES 2007) and it was determine that there were no claims in the vicinity of the HHGS site.

6.0 ALTERNATIVE MTS SITES

A number of alternative sites for the proposed MTS were identified and evaluated through the use of criteria reflecting known environmental, technical, and cost concerns. These criteria are applied to the environmental baseline inventory and value judgements made on the relative importance of various mapped environmental data types. An environmental, technical, and cost evaluation were then carried out based on the quantitative and qualitative effects associated with each of the alternative identified. Net environmental effects were addressed in the environmental evaluation through the consideration of net effects after mitigation is taken into account. This evaluation provides a basis for the determination of a preferred site to be studied in further detail.

Alternative sites chosen for this study were based on locations which would:

- provide adequate area and infrastructure in which to accommodate all components of a MTS station;
- were currently undeveloped; and
- in close proximity to a major transmission corridor.

A typical MTS requires approximately 1 ha of land with suitable vehicle access. The entire perimeter is fenced to prevent unauthorized access to high voltage components. Electrical equipment can be classified as either outdoor and indoor equipment.

High voltage equipment is typically placed outdoors in the main switchyard and includes two (2) incoming 230 kV circuit breakers, underground 230 kV cables, two (2) 230 kV air disconnect switches, two (2) step-down power transformers, and two (2) power capacitor banks.

The 28 kV distribution equipment is typically located indoors, along with protection and control systems. Eight (8) distribution feeders will leave the station to supply power to the Steeles Avenue corridor, in addition to areas where future residential development is anticipated.

Distribution egress is the infrastructure (poles, circuits, and lines) exiting the station and connecting directly to the municipalities distribution system for further distribution to the end users. Egress may be conducted through either an overhead or underground system. Distribution egress is generally limited to one (1) pole line, in close proximity to the MTS, on either side of a public roadway as multiple pole lines are generally not permitted on the same side of the roadway due to the aesthetics and lack of physical space in the municipal right-of-way.

The locations of the 11 alternative MTS sites are provided in Figure 6.1.

6.1 EVALUATION COMPONENTS AND CRITERIA

All 11 alternative sites must be evaluated equally in order to determine the location most suitable for siting the MTS facility. The evaluation of the sites is based on a number of environmental, technical, and cost concerns, and an associated set of criteria for each component, determined to be relevant and important considerations when siting a new MTS within the identified study area. Table 6.1 identifies the evaluation components and criteria and provides the rationale associate with each criteria used in evaluating the 11 alternative sites.

Figure 6.1

ALTERNATIVE MTS SITE LOCATIONS WITHIN THE STUDY AREA

TABLE 6.1
EVALUATION COMPONENTS AND CRITERIA

COMPONENT	CRITERIA	RATIONALE
TECHNICAL		
Operational Management and Constructability	• Proximity to Market. • Proximity to Transmission Grid Connection. • Potential for Station Egress (outlet). • Available Land Size. • Relocation of Existing Wholesale Metering Equipment. • Distribution Circuit Egress (outlet).	• Location of the station in relation to existing supply facilities and future anticipated loads. • The proximity and routing of transmission circuits may impact reliability, security, and public safety. • The location of the station to the distribution pole lines determines the length of the station feeder cables, and road crossings, if necessary. Road crossings require coordination with other underground utilities. • An adequate amount of physical space is required to accommodate station equipment, and provide enough grounding to ensure the safety of operating staff and the general public. • Existing wholesale metering equipment is installed on the western boundary of the Steeles Ave. corridor. This equipment may need to be related if the station were to be located to the west of the existing metering equipment. • Distribution egress (outlet) is limited by the number of circuits permitted in public right of ways, and physical limitations of poles and associated hardware.
ENVIRONMENT		
Potential to Affect Fisheries and Aquatic Biology	• Proximity or potential to affect water flow or quality of watercourses within or adjacent to site. • Proximity or potential to affect rare, threatened or endangered fish. • Potential to affect aquatic habitat within or adjacent to the site.	• Watercourses may include significant habitat for threatened and endangered aquatic species. Water that does not support fish may also be important in sustaining fish habitat or wildlife downstream. • Harmful alteration, disruption or destruction (HADD) of fish habitat is prohibited and related aquatic systems are important as water sources and corridors for adjacent terrestrial habitats.

TABLE 6.1 (Cont'd)
EVALUATION COMPONENTS AND CRITERIA

COMPONENT	CRITERIA	RATIONALE
Potential to Affect Wildlife and Terrestrial Biology	• Proximity or potential to affect a wooded area. • Proximity to ESA, ANSI, Greenlands, etc. (Natural Heritage). • Proximity to wetland areas. • Proximity or potential to affect rare, threatened or endangered wildlife.	• Presence or absence of wildlife species are indicators of the quantity and quality of habitat present (i.e., absence of species may indicated habitat degradation). • Woodlots (e.g., forested areas) provide wildlife habitat, and ecosystem protection features (soil and erosion). Removal of these features may result in removal of habitat or degradation in and adjacent to affected area. • ANSIs and ESAs (natural landscapes and features) are provincially/regionally significant areas protected under provincial legislation due to their value with relation to protection, natural heritage appreciation, and scientific studies or education. • Wetlands, depending on their class, may contain critical habitats, play an essential hydrological role or significant social/economic benefit. • Wildlife designated as rare, threatened, or endangered are protected under Federal legislation (SARA).
Potential to Affect Existing and Planned Land Use and Access	• Zoning. • Accessibility.	• Compatibility with Official Plan existing and planned land uses are considered. Re-zoning of a designated land use would require a separate process. • Sites located immediately adjacent to municipal, regional or provincial roads require no additional acquisition of land for access ROW.
Potential to Affect Socio-Economic (Community, Business, Agriculture, and Recreation)	• Types of business • Potential for interruption of business (includes agriculture). • Proximity to developed residential areas. • Proximity to recreational/park areas.	• Affect on business may depend on type of business in the area (Industrial vs. retail). • Short-term (construction) and long-term (operation). • Aesthetic issues as well as quality of life considered in or adjacent to residential areas. • Hazards associated with locating a site adjacent to a recreational or park area (includes types of recreational activities).

TABLE 6.1 (Cont'd)
EVALUATION COMPONENTS AND CRITERIA

COMPONENT	CRITERIA	RATIONALE
	• Potential to affect prime/priority agricultural lands. • Requirement for removal of buildings associated with agricultural operations.	• Avoid areas designated as prime /priority agricultural lands and associated buildings are considered valuable resources.
Potential to Affect Cultural Heritage (Archaeology and Built Heritage)	• Proximity or potential to affect Built Heritage Features. • Proximity or potential to affect areas of known archaeological significance	• Building or landscapes designated as built heritage features are considered a historic resource and protected under Provincial heritage, environmental and planning legislation. • Areas of archaeological significance are important component of our heritage and are protected under Provincial heritage, environmental and planning legislation.
ECONOMIC		
Project Cost	• Distance from transmission circuits. • Distance from station switchgear to public roadway. • Ability to connect to existing transmission infrastructure north of Highway 401. • Quantity of distribution circuits that need to be rebuilt based on the location of the station on Steeles Ave.	• Costs are relative to the quantity of cables, excavation, and installation labour, and costs of land purchases or easements. • Costs are relative to the quantity of cables, excavation, and installation labour. • Costs are relative to need for 230 kV underground circuits to connect to the transmission corridor and need to build a switching station at the transmission corridor junction. • Costs are relative to the quantity of distribution circuits required from the proposed location along Steeles Ave. to the distribution plant.

6.2 EVALUATION OF ALTERNATIVE SITES

The evaluation of the alternative sites was conducted to assess the quantitative and qualitative effects of locating the Project on a specific site. The description of the MTS (Section 6.0) components and the interaction with the existing baseline conditions (Section 5.0) were assessed to determine the potential effects using the criteria established (Table 6.1) for each component. Each component (technical, environmental, and economic) was evaluated using the results of the effects assessment and a qualitative ranking was given to each of the alternative sites based on professional experience (Table 6.2). An overall ranking for each of the alternative sites based on combining the rankings given to each of the technical, environmental, and economic components was then determined in order to identify the preferred site. The overall rankings given to each of the alternative sites is provided in Table 6.3 resulting in the identification of the preferred location (2C) as outlined in bold.

The rankings used in this evaluation are as follows:

- High Acceptability – No effects are associated or anticipated for this site based on identified criteria.
- Medium Acceptability – Few effects have been identified although the potential exists to prevent or mitigate these effects through implementation of alternative measures and/or methodologies.
- Low Acceptability - A number of effects have been identified although the potential for avoidance or mitigation is low.
- Unacceptable – Effects or limitations identified are considerable (numerous) and mitigation or avoidance is not possible, therefore precluding the site from further consideration.

TABLE 6.2
EVALUATION OF ALTERNATIVE SITES

Alternative Sites	**1A**	**1B**	**1C**	**2A**	**2B**	**2C**	**2D**	**3A**	**3B**	**3C**	**3D**
Technical Summary	***Unacceptable*** Site is constrained by potential for expansion of 500 kV transmission corridor. Provides limited redundancy with existing supply from Hydro One.	***Unacceptable*** Site is constrained by potential for expansion of 500 kV transmission corridor. Provides limited redundancy with existing supply from Hydro One.	***Low*** Provides limited redundancy with existing supply from Hydro One. Requires dual 27.6 kV pole lines to be built the length of Steeles Ave. corridor.	***Medium*** Site can physically accommodate station. Requires new 230 kV underground supply from south of Hwy 401. Introduces operational complexity, possible reliability and safety issues with buried transmission circuits due to future development.	***Unacceptable*** Soil stockpiles have been established on this site since initiation of the study.	***High*** The 230 kV transmission circuits are available adjacent to the site, from the Halton Hills Generating Station. This reduces the operational complexity, safety risk of buried transmission circuits in public areas. Provides supply diversity with existing Hydro One station.	***Medium*** Requires new 230 kV underground supply from south of Hwy 401. Provides supply diversity with existing Hydro One supply.	***Medium*** Requires new 230 kV underground supply from south of Hwy 401. Provides supply diversity with existing Hydro One supply.	***Medium*** Requires new 230 kV underground supply from south of Hwy 401. Provides supply diversity with existing Hydro One supply.	***Unacceptable*** Distribution egress along Trafalgar Road is not possible due to conflict with Milton Hydro distribution plant. This site is located in Milton, and Milton Hydro has rights to public right of ways.	***Unacceptable*** Distribution egress along Trafalgar Road is not possible due to conflict with Milton Hydro distribution plant. This site is located in Milton, and Milton Hydro has rights to public right of ways.
Environmental (Physical and Social) Summary	***Low*** No physical environmental constraints have been identified that would limit development of this site. There are no socio-economic impacts related to the site and current zoning is "prestige" industrial. However, the highest potential for impacting the physical and socio-economic environment would result from need to	***Unacceptable*** No physical environmental constraints have been identified that would limit development of this site. The socio-economic (zoning- OP) constraints for this site precludes it from further consideration. This site is designated in the Halton Hills OP as "gateway" which precludes development of	***Low*** No physical environmental constraints have been identified that would limit development of this site. There are no socio-economic impacts related to the site as this site is located within an industrial development and is currently zoned "prestige" industrial. The highest	***Low*** No physical environmental constraints have been identified that would limit development of this site. The potential to impact the socio-economic environment is low due to the potential for disruption of traffic associated with construction for the few businesses and residences in the area. This site is currently zoned	***Low*** No physical environmental constraints have been identified that would limit development of this site. The potential to impact the socio-economic environment is low due to the potential for disruption of traffic associated with construction for the few businesses and residences in	***Medium*** The potential to impact the physical environment is considered medium as the site is located adjacent to a watercourse where the potential for presence of coldwater fisheries has been identified. However site development will not encroach on the 15 m construction buffer	***Low*** There is potential to impact the physical environment as the site currently exists as a hardwood woodlot with an identified potential for breeding birds. Development of this area would remove an existing remnant forest in an area with very few remaining. The potential to impact the socio-economic environment is low with temporary impacts associated with the potential for disruption of traffic associated with	***Unacceptable*** No physical environmental constraints have been identified that would limit development of this site. The socio-economic (zoning-OP) constraints associated with this site, precludes it from further consideration. This site is designated in the Halton Hills OP as "gateway" which precludes development of this type. This area is also adjacent to a building of historic significance and to the Hornby Rural Cluster	***Unacceptable*** No physical environmental constraints have been identified that would limit development of this site. The socio-economic (zoning-OP) constraints associated with this site, precludes it from further consideration. This site is designated in the Halton Hills OP as "gateway" which precludes development of this type. This area is also adjacent to a building of historic significance and to the Hornby Rural Cluster	***Low*** No physical environmental constraints have been identified that would limit development of this site. Potential for socio-economic constraints is considered medium as this site is not currently accessible. The potential for impacting the physical and socio-economic environment would also be high as a result from need to construct	***Medium*** No physical environmental constraints have been identified that would limit development of this site. Potential for socio-economic constraints is considered medium as this site is not currently accessible. This property is also adjacent to ORC land (to south).

Alternative Sites	1A	1B	1C	2A	2B	2C	2D	3A	3B	3C	3D
	construct a 1800 m underground feed to connect to the existing grid as displacement and disruption to existing features would result	this type. The highest potential for impacting the physical and socio-economic environment would result from need to construct a 1500 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	potential for impacting the physical and socio-economic environment would result from need to construct a 1500 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	"prestige" industrial. The highest potential for impacting the physical and socio-economic environment would result from need to construct a 1600 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	the area. This site is currently zoned "prestige" industrial. The highest potential for impacting the physical and socio-economic environment would result from need to construct a 1600 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	previously identified for HHGS. A number of trees may be affected in an area identified as a cultural woodland although current development occurring at the site has already impacted this woodland. The potential to impact the socio-economic environment is medium due to the removal of the barn currently existing on-site and also temporary impacts associated with the potential for disruption of traffic associated with construction for the residences and businesses in the area. This site is currently zoned prestige industrial. There are no interconnection effects associated with this site.	construction for the residences and businesses in the area. This site is currently zoned prestige industrial. The potential for impacting the physical and socio-economic environment would also result from need to construct a 1600 m underground feed to connect to the existing grid as displacement and disruption to existing features would result. This would also have to be constructed under HHGS.	Area. There are no identified physical environmental constraints associated with development on this site. The potential for impacting the physical and socio-economic environment would also be high as a result from need to construct a 1500 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	Area. There are no identified physical environmental constraints associated with development on this site. The potential for impacting the physical and socio-economic environment would also be high as a result from need to construct a 1500 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	a 900 m underground feed to connect to the existing grid as displacement and disruption to existing features would result.	

Alternative Sites	1A	1B	1C	2A	2B	2C	2D	3A	3B	3C	3D
Cost Summary	***Unacceptable*** The highest cost option, as the location is the furthest away from the transmission right-of-way south of Hwy 401.	***Low*** High cost due to distance from the transmission right-of-way south of Hwy 401.	***Low*** High cost due to distance from the transmission right- of-way south of Hwy 401.	***Low*** High cost due to distance from the transmission right-of-way south of Hwy 401.	***Low*** High cost due to distance from the transmission right- of-way south of Hwy 401.	***High*** The availability of 230 kV transmission circuits at HHGS eliminates substantial costs in new underground circuits.	***Low*** High cost due to distance from the transmission right of way south of Hwy 401.	***Low*** High cost due to distance from the transmission right of way south of Hwy 401.	***Low*** High cost due to distance from the transmission right of way south of Hwy 401.	***Low*** High cost due to expense of constructing all eight distribution circuits under Hwy 401, and the length of these circuits running up Trafalgar Road to Steeles Ave.	***High*** Direct connection to the 230 kV aerial circuits south of Hwy 401 is less expensive than underground transmission circuits. Bulk of costs related to distribution feeders required along Trafalgar Road, under Hwy 401, to Steeles Ave.

TABLE 6.3
SUMMARY OF ALTERNATIVE SITE EVALUATION AND OVERALL RANKINGS

Alternative Site Identification and Location	**1A** North side of Steeles Avenue, near James Snow Parkway	**1B** South side of Steeles Avenue, near James Snow Parkway	**1C** South side of Steeles Avenue, near Fifth Line North	**2A** South side of Steeles Avenue, near Fifth Line South	**2B** South side of Steeles Avenue, near Fifth Line South (east of site 2A)	**2C** South side of Steeles, near Sixth Line South (HHGS site)	**2D** South side of Steeles Avenue, forested area near Sixth Line South (west of HHGS site)	**3A** South side of Steeles Avenue, just west of Trafalgar Road	**3B** South side of Steeles Avenue, just west of Trafalgar Road	3C Trafalgar Road, south side of Highway 401	3D Trafalgar Road, Hornby Junction (ORC Lands) – South of Highway 401
Technical Summary	***Unacceptable***	***Unacceptable***	***Low***	***Medium***	***Unacceptable***	***High***	***Medium***	***Medium***	***Medium***	***Unacceptable***	***Unacceptable***
Environmental (Physical and Social) Summary	***Low***	***Unacceptable***	***Low***	***Low***	***Low***	***Medium***	***Low***	***Unacceptable***	***Unacceptable***	***Low***	***Medium***
Cost Summary	***Unacceptable***	***Low***	***Low***	***Low***	***Low***	***High***	***Low***	***Low***	***Low***	***Low***	***High***
Overall Ranking	***Unacceptable***	***Unacceptable***	***Low***	***Low-Medium***	***Unacceptable***	***High-Medium***	***Low-Medium***	***Unacceptable***	***Unacceptable***	***Unacceptable***	***Unacceptable***

- Denotes preferred MTS site

7.0 PROJECT DESCRIPTION

The preferred MTS site was identified based on the results of the quantitative and qualitative analysis of the alternatives through a comparison of the advantages and disadvantages for each alternative in terms of environment, technical and cost. The selected MTS site had the most advantages and least disadvantages. A detailed study was then conducted to obtain additional information specifically related to the environment, technical, and cost components (and related factors) for the preferred MTS site. The remaining sections of this ESR (Sections 7 through 13) provide discussion on the detailed studies conducted for the preferred MTS site.

The general location and technical requirements of the Project are provided including land, size and type of equipment, description of building, connections to grid, operation, etc.

7.1 DESIGN PHASE

The design phase for the MTS Project will continue through April 2010, with detail design anticipated to commence upon completion of the 30-day review period for the ESR anticipated in October 2008. The proposed MTS is a 230/27.6 kV, eight (8) feeder station with an emergency rating of 125 MVA.

The station will be situated on approximately 1 ha of land adjacent to the Halton Hills Generating Station (HHGS) (Figure 7.1). The proposed outdoor arrangement (Figure 7.2), includes two (2) incoming 230 kV circuit breakers (located on the HHGS site), underground 230 kV cables feeding two (2) 230 kV air disconnect switches, two (2) step-down power transformers, and two (2) power capacitor banks for power factor correction. All outdoor equipment will be enclosed by an eight-foot chain link fence, topped with barbed wire. The MTS Project consists of a MTS site and access road from public roads to the site.

The location of the access road is unknown at this time. Discussions with TransCanada, Halton Hills, and Conservation Halton to determine a suitable location for the access road will be conducted during detail design.

A switchgear and control building will enclose the 28 kV distribution switchgear, and all of the station protection and control systems. The 28 kV switchgear will include eight (8) 28 kV feeder circuit breakers which will supply power to the distribution system.

Figure 7.1

AERIAL PHOTOGRAPH OF MTS SITE LOCATION

SOURCE: Costello Associates, Dwg. C008, 2008

Figure 7.2

LAYOUT OF MTS SITE

SOURCE: ALGAL & Associates Ltd., Dwg. AG-7095-GA1, 2008

The distribution system in the Steeles corridor area is primarily an overhead system. It is anticipated that the eight (8) new feeders will run underground from the MTS to the overhead system via underground duct banks. A four (4) distribution circuit is required to service the Steeles Ave commercial/industrial load, based on forecasted demand of approximately 68 MVA for the commercial/industrial Steeles Ave corridor, with an additional four (4) distribution circuits required to service the future northern load of the Georgetown and Acton areas. Halton Hills Hydro design standards permit up to four (4) distribution circuits on one (1) pole line. This is based on structural demands as well as reliability.

The transformers will be located within a lined containment area consisting of a vertical concrete wall around the perimeter of the transformer pad. The containment area extends well outside the transformer tank and radiators and sized to accommodate 100% of the volume of oil in the transformers plus accumulated water volume (snow and rain). The lining in the containment area is comprised of both clay and impermeable fabric liner overlaid by crushed limestone. The containment area is designed to direct runoff to a local drain where it can either be manually pumped or automatically removed. If an automatic pumping system is utilized, built-in oil sensors shut down the pumping system and raise alarms should oil be detected in the drain. The pumping system is constantly monitored in the utility control centre (24 hours).

7.2 CONSTRUCTION PHASE

The station construction is anticipated to start in April 2010, as soon as the site is sufficiently dry for heavy equipment. It is anticipated that up to thirty construction personnel will be on site at any given time.

Initial site preparation including site grading, underground services, foundations, footings, and duct bank construction is anticipated to occur over approximately three (3) months. Construction of the switchgear and control building, transformer pads, and yard equipment foundations will commence, following the completion of site preparation activities, and take approximately six (6) months followed by the installation of indoor switchgear and control systems in December 2011. Installation of high voltage outdoor electrical equipment will be initiated once the roadways, foundations, and transformer pads are completed. The interconnection of all electrical equipment will take place in the first quarter of 2011. Testing and commissioning of all systems is anticipated to occur over two (2) months following the completion of the interconnection of all electrical equipment currently scheduled for the first quarter of 2011. Commissioning and start-up of the station is scheduled for May 2011.

7.3 OPERATION AND MAINTENANCE PHASE

The station will operate automatically and requires no on-site personnel for regular day to day operation. The station control systems will be remotely monitored and controlled by the Halton Hills Hydro control room, located at the Halton Hills Hydro Office in Acton, in addition to being monitored by Hydro One Networks and the Independent Electricity System Operator (IESO).

Periodic maintenance inspections are required weekly or bi-weekly, depending on system conditions. Utility stations personnel typically visit MTS stations with small vehicles (i.e. pickup trucks or vans), for 30-45 minute inspections.

Major equipment maintenance is carried out typically every two (2) years. Given that a complete outage would interrupt power to customers, utilities often maintain half of the station every year. Maintenance activities include infrared inspections, oil testing, testing of circuit breakers, transformers, cables, and protection systems. Approximately ten to fifteen staff and contractors are on site one to two weeks per maintenance cycle.

8.0 ENVIRONMENTAL EFFECTS AND MITIGATION MEASURES

8.1 APPROACH

The identification of potential environmental effects associated with the construction and/or operation of a new MTS is conducted in phases. The first phase requires an understanding of the Project (Section 7.0) including a description of the facilities to be built (design) and the sequence of activities that will occur or be undertaken during the construction and operation of the MTS. The second phase involves the identification of the baseline environmental conditions occurring in and adjacent to the MTS site. The third phase involves the determination of the interaction between the MTS and the existing environmental conditions through the use of standard methodologies to predict the potential environmental effects (i.e., project footprint on vegetation communities, computer modelling of the predicted noise levels). The fourth phase identifies mitigation measures that may be implemented to prevent, minimize or mitigate any potential negative effects. These environmental effects remaining after the application of mitigation measures are net effects.

8.2 NATURAL ENVIRONMENT

8.2.1 Physiography/Soils

Existing Environmental Conditions

The MTS site is located on the Peel Plain, a bevelled till plain (Chapman and Putnam, 1984b) and is moderately flat, sloping gently to the east (SENES 2008a). A large portion of the site is described as disturbed/landscaped residential property which has been altered from its natural state as a result of past activities and erection of structures associated with a farm homestead. More recently, a portion of the MTS site was levelled and graded to accommodate a laydown area to assist in the construction of the HHGS (SENES 2007). The remaining northern portion of the site adjacent to the watercourse (northeast corner) slopes gently to the east.

The parent materials identified, during the investigations for the HHGS, were Oneida silt loam on fine textured glacial till, largely composed of ice ground materials from the underlying Ordovician rock formations (Gillespie *et al.*,1971). The Brunisolic Grey-Brown Luvisol soils (Great Group) are well-drained and slightly stony with a topographic slope of 5% to 9%.

Effects of Construction

The MTS is to be located adjacent to the HHGS where the physiography is fairly flat or has been previously levelled as a result of HHGS development activities. The remaining portion of the MTS site is currently in use either as a laydown area for the HHGS development or currently occupied by a barn, which is understood to be removed prior to construction of the MTS.

Construction of the MTS will require some additional grading as well as excavation to accommodate the transformer facilities. It is anticipated that the topsoil, and potentially a small amount of the subsurface layer, on a portion of the site will have been removed for the construction activities associated with the HHGS. Compression and mixing of soil horizons beneath the MTS facility is expected to occur as the area is subjected to loading from the facility. Excess subsurface material (silty clay glacial till), below the topsoil, to be excavated but not required for construction of the MTS facility will potentially be utilized for landscaping purposes in and around the facility.

The location of the access road is currently unknown but it is anticipated that compaction and mixing of the soil horizons beneath the access road location is expected to occur as a result of construction vehicle traffic.

Mitigation Measures and Net Effects

Compression and mixing of soil horizons beneath the MTS facility will be mitigated through the conduct of additional geotechnical studies, related to foundations, to determine the loading restrictions of the site and the type of foundation (gravel or concrete) most suitable for the conditions identified on-site. It is anticipated that although the location of the access road has not been determined, potential impacts to the soil can be addressed through the provision of a stabilizing material (e.g., crushed stone).

Effects during Operations

The activities associated with the operation of the MTS facility are not anticipated to create additional disturbance of soils or earth moving (excavation) activities that would affect the physiography or soils within or adjacent to the MTS site.

Mitigation Measures and Net Effects

The physiography or soils are not anticipated to be affected by the operation of the MTS facility and therefore no mitigation is required.

8.2.2 Surface Water

Existing Environmental Conditions

The main eastern tributary of the Middle Branch of Sixteen Mile Creek, one of the main watercourses in Subwatershed 4, is located adjacent to the northwest corner of the site (Figure 8.1). The portion of the main eastern tributary between Steeles Avenue and Sixth Line is approximately 50 m in length. The tributary flows from the north of Steeles Avenue and meanders in a southeasterly direction across the top of the preferred site proceeding approximately 1.5 km east of Lower Sixth Line, where it joins the Middle Branch of Sixteen Mile Creek. The south banks of the watercourse between Steeles Avenue and Lower Sixth Line are approximately 2 m in height, consisting of a silt and clay mixture.

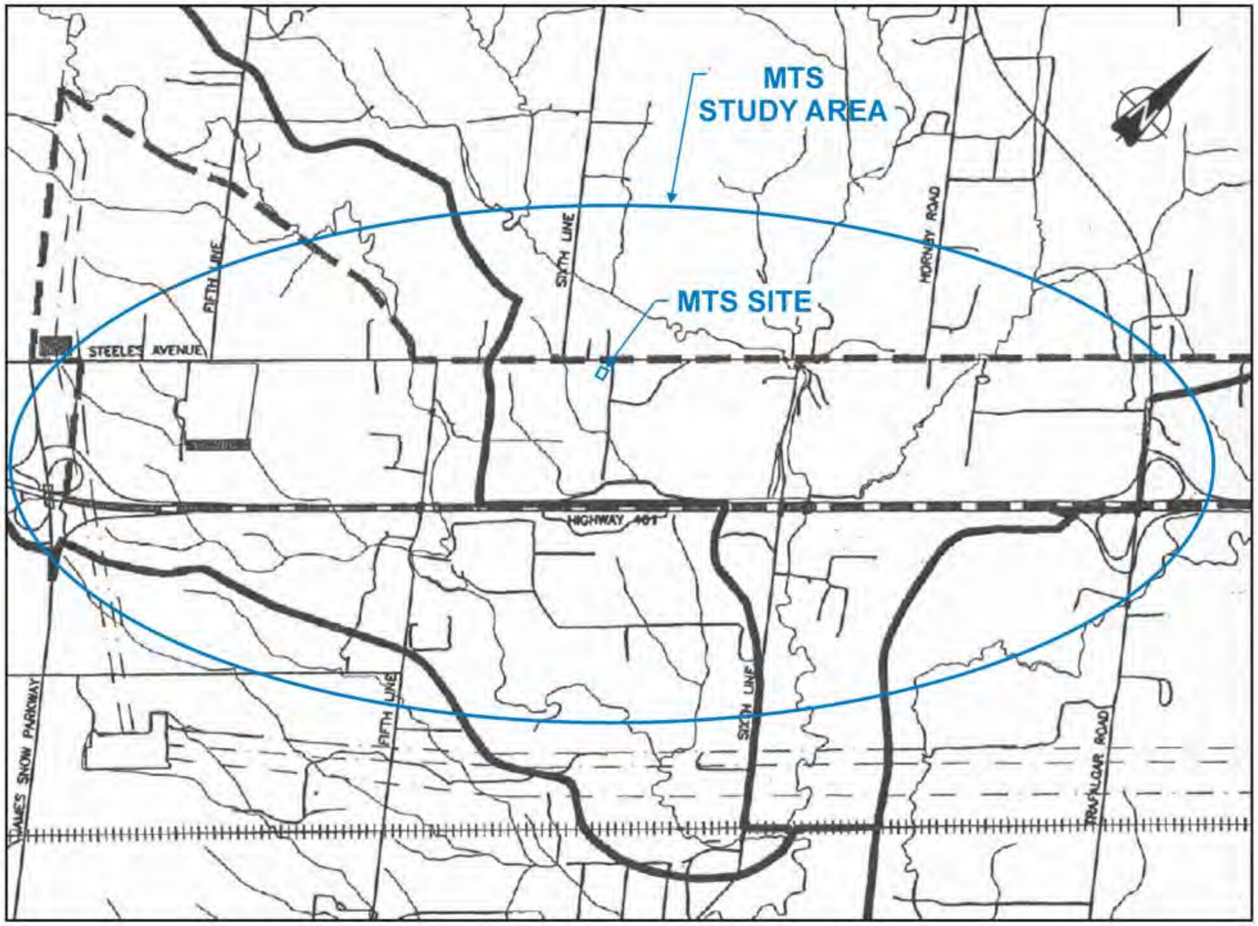


Figure 8.1

MAIN BRANCH AND TRIBUTARIES OF SIXTEEN MILE CREEK FOR HALTON HILLS HYDRO MTS STUDY AREA

SOURCE: Supporting Document 3, Natural Environment for Proposed Halton Hils Generating Station, EEL, 2007

The banks have been subjected to erosional forces at the toe of the slope causing bank angles to become overly steep and at risk of failure.

Historical hydrological data collected for Sixteen Mile Creek indicates that the largest stream flows occur in March and April (spring freshet) with lowest flows occurring from June to October.

A fisheries survey conducted on 26 June 2006, in support of the HHGS Project, included the collection of hydrologic, substrate and water quality information for the Main Eastern tributary. The data collected for Station 1 and Station 2 (upstream of Steeles Ave. and downstream of Sixth Line respectively) is presented in Table 8.1.

TABLE 8.1
HYDROLOGIC, SUBSTRATE, AND WATER QUALITY DATA FOR STATIONS 1 AND 2 ON MAIN EASTERN TRIBUTARY (EEL 2007)[1]

Parameter	Station 1[2]	Station 2[3]
Flow Velocity (m/s)	0.2	0.15
Mean Width (m)	3	2.5
Mean Depth (m)	0.2	0.3
Substrate Type (%):		
Boulder	0	10
Cobble	15	5
Gravel	30	10
Sand	30	40
Silt	10	35
Clay	15	0
Water Temperature (^{o}C)	18.9	18.1
Dissolved Oxygen (mg/L)	7.0	7.69
Oxygen Saturation (%)	76	82
Conductivity (µmhos/cm)	599	661
pH (units)	7.89	8.15
Water Colour	Blue/green	Blue-green
Water Clarity	clear	Turbid

[1]- Extraction of information contained in Table 2.8 of the HHGS *ERR, Supporting Document 3 – Natural Environment. 2007.*
[3] - Station location upstream of Steeles Avenue and west of Sixth Line North.
[2] – Station location downstream of preferred sit on east side of Lower Sixth Line.

Station 1, upstream of the MTS site and north of Steeles Avenue (above Sixth Line), had a mean channel width of 3 m, mean water depth of 0.2 m, and flow velocity of 0.20 m/s and a substrate predominately comprised of gravel/sand with some cobble, clay, and silt. Station 2, downstream of the MTS site, had a mean channel width of 2.5 m, mean water depth of 0.3 m and flow velocity of 0.15 m/s with a substrate predominately comprised of silty sand with some gravel, cobble, and boulders. At the time of the survey, the water in this section (Station 2) of watercourse adjacent to the preferred site was turbid, whereas both upstream and downstream locations appeared clear. This condition was also observed during surveys conducted 7 June 2006 in support of the HHGS Project.

Effects during Construction

Erosion/Run-off

The potential for erosion and/or run-off to occur due to the removal of vegetation, and exposure and/or excavation of subsurface soils for construction of the MTS facility is anticipated. All construction activities will be restricted to the area outside of the "Construction Limit Line" identified for the HHGS Project. The "Construction Limit Line" is determined by Conservation Halton as a 15 m allowance adjacent to the stable top of bank for a "major valley system" which includes a 7.5 m lot line setback and a further 7.5 m internal development setback for the portion of the main eastern tributary of the Middle Branch of Sixteen Mile Creek located adjacent to the MTS site. Drainage from the MTS facility is expected to be directed to the Subwatershed Impact Study (SIS) Stormwater Management Facility (SWMF) developed for the parcel of land within the 401 Corridor between Sixth Line South and Fifth Line South including a parcel of land north of Steeles Avenue and west of Sixth Line North. (SENES 2008a). The MTS site is located on this parcel of land.

Mitigation Measures and Net Effects

Submission of a grading and drainage plan is required as part of Halton Hills Site Plan Approval process. Erosion and sediment control measures implemented prior to initiation of construction activities and the direction of site run-off to the HHGS SWMF will ensure run-off associated with the construction of the MTS will be appropriately managed. Erosion and sediment control measures will include:

- Silt fences located downstream of the construction site with doubling of silt fences along the edge of the construction site adjacent to the watercourse;
- Excavation of drainage ditches around the perimeter and diversion channels in areas with increased erosion potential (i.e., down slopes, exposed areas) of the MTS site;
- Location of stockpiles at least 30 m from the watercourse; and
- Revegetation of areas no longer required for construction activities.

Spills/Releases

Spills to the environment of fuels, oils, lubricants and other liquids (e.g., paints) used during construction of the MTS is anticipated. The potential also exists for the release of liquid wastes (sanitary wastes from portable toilets, concrete) generated or chemical compounds used for construction. Solid waste, both construction and domestic, will be generated on-site on a daily basis.

Mitigation Measures and Net Effects

All large vehicles will be fuelled and any maintenance required performed off-site, where possible. Where large vehicles are to be fuelled on-site, spill kits will be made available in the case of a release to the environment. Small equipment will be fuelled and maintained in designated areas where spills may be contained. Spill prevention, containment, and clean-up measures will be developed by Halton Hills Hydro and implemented by all Contractors conducting work on-site. Spills occurring to the natural environment will be reported to the Ministry of the Environment in accordance with O. Reg. 675/98. All waste material will be handled in accordance with O. Reg. 347, where required. Arrangements for the collection of the sanitary waste generated on-site will be made for the duration of the construction period. All domestic and construction wastes will be collected and deposited on a daily basis in a designated area.

Effects during Operations

Erosion/Run-off/Stormwater

Erosion is not anticipated as exposed soil surfaces will be revegetated immediately following construction. Run-off from the facility and stormwater flows are not expected to affect the water quality of the main eastern tributary of Sixteen Mile Creek as drainage from the site will be directed to the HHGS SWMF. Measures will be implemented within the MTS site to prevent the movement of fuels, oils, sediment or other contaminants from leaving the site.

Mitigation Measures and Net Effects

No effects due to erosion are anticipated and therefore no mitigation is required. Run-off and stormwater flows will be directed to the HHGS SWMF and therefore any potential effects will be mitigated prior to being released to the main eastern tributary of Sixteen Mile Creek.

Spills/Releases

The potential exists for the release of transformer oil in the event of an equipment failure, although the possibility of this occurring is considered low. Spills of lubricants, fuels, and oils may occur during maintenance inspections anticipated to occur on a weekly or bi-weekly basis or during the major equipment maintenance generally conducted once every two (2) years.

Mitigation Measures and Net Effects

The transformers are contained by a full base liner within a vertical concrete wall around the perimeter of the transformer pad to prevent any liquids to seep into the soil below. The containment area is filled with crushed limestone and can accommodate 100% of the transformer oil plus accumulated water from snow and rain.

Water and oil is channelled to a manhole within the facility to allow for either manual pumping or automatic removal of water. Oil sensors shut down the pumping system and raise alarms should oil be detected in the manhole. The system is constantly monitored in the utility control centre (24 hours). The potential effects related to a spill or release from the MTS facility is addressed by the implementation of the containment and monitoring systems within the MTS facility and therefore the need for additional mitigation measures are not anticipated.

8.2.3 Groundwater

Existing Conditions

Groundwater resources within and adjacent to the MTS site were identified for the HHGS Study (EEL 2007) to flow in a north to northeast direction towards the main eastern tributary of the Middle Branch of Sixteen Mile Creek, located adjacent to the north boundary of the MTS site.

An overburden aquifer system and an underlying aquifer system, Till Complex and Queenston Shale respectively, comprise the two (2) main aquifer systems of the MTS site. As specified in EEL 2007, the Till Complex overburden aquifer system consists mainly of Halton Till with a sandy silt to silty clay composition and low permeability with groundwater yields generally obtained from the sand and gravel lenses. The groundwater is generally considered suitable for domestic purposes.

The Queenston Shale bedrock aquifer system, as identified in EEL 2007 for the HHGS study, forms the base of the groundwater flow system due to a confining layer of bedrock shale. The scarcity of high-yielding overburden aquifers classifies this aquifer system as regionally significant. Yields depend on a number of aquifer characteristics but are generally less than 1 L/s.

The static water levels, on the HHGS site were identified in the range of 2 m to 5 m below grade with very low groundwater recharge (50-100 mm/y). Groundwater levels were measured to be 0.23 m to 0.96 m below ground in June 2006 for geotechnical investigations conducted for the HHGS property (EEL 2007).

Potential Effects during Construction

High water table levels were identified for the HHGS site (EEL 2007) during geotechnical investigations although the local aquifers, from which area wells draw water, were measured at approximately 30 m below ground level. Additional geotechnical investigations for the MTS site are anticipated during detail design to confirm the information provided in the HHGS study and to determine the specific foundations to be used for the MTS. It is anticipated that the activities required to construct the foundations will not affect groundwater. If dewatering of construction areas is required, the appropriate permits or approvals to take water will be identified and obtained prior to the initiation of construction activities. The use of groundwater during the construction phase of the MTS in not anticipated and therefore groundwater flow or quantity is not expected to be affected.

Mitigation Measures and Net Effects

Construction of the transformer station is not expected to affect groundwater quality or quantity and therefore no mitigation measures are required.

Potential Effects during Operations

Groundwater is not required during the operation phase of this Project and therefore groundwater flow or quantity will not be affected.

Mitigation Measures and Net Effects

Operation of the MTS is not expected to affect groundwater quality or quantity and therefore no mitigation measures are required.

8.2.4 Fisheries and Aquatic Habitat

Existing Conditions

The Middle Branch of the Main Eastern Tributary of Sixteen Mile Creek is located adjacent to the north boundary of the MTS site (Figure 7.2). A fisheries resource survey was conducted on 26 June 2006, in support of the HHGS ERR, at four stations with a reach stretching from north of Steeles Avenue at Sixth line to the Canadian Pacific Railway Bridge (south of Highway 401) (EEL 2007). Stations #1 and #2 are immediately upstream and downstream of the MTS site and thus are identified in Table 8.2.

The Main Eastern tributary passes under Steeles Avenue, onto the HHGS site and more specifically along the north boundary of the MTS site, proceeding across Fifth Line South to Hornby Park. The study (EEL 2007) characterized the watercourse as having an active channel width of approximately 8 m, depth of 0.1 m with substrate consisting of silt, large cobbles and submerged aquatic vegetation.

The surveyed reach was identified as a typical warmwater fish community consisting largely of minnow, sunfish and perch species (EEL 2007) with the presence of young-of-year (YOY) warmwater species potentially indicating that this reach may also provide spawning and/or nursery habitat. Two (2) YOY rainbow trout and eggs were identified just downstream of the HHGS and MTS site possibly suggesting that this location may provide spawning and/or nursery habitat for this coldwater species.

Table 8.2 provides the species identified during the 26 June 2006 survey for Stations 1 and 2 on the middle branch of the main eastern tributary. All species are considered common in Ontario by NHIC (2006). The presence of watercress may indicate groundwater inputs to this reach as well as lower water temperatures when compared to stations located upstream and downstream.

The portion of Middle Branch running along the northern boundary of the MTS site (between Steeles Avenue and Sixth Line) is classified as redside dace survival habitat as part of the *"Redside Dace Recovery Strategy"* by Conservation Halton, based on the presence of redside dace approximately 2.5 km upstream of the MTS site (SENES 2008a). A 30 m meander belt setback was delineated to protect this habitat.

Effects during Construction

The removal of the vegetation and excavation of soils associated with the construction of the MTS may potentially increase the potential for gully or rill erosion to occur and therefore may result in increased levels of sediment to the Sixteen Mile Creek tributary adjacent to the northern boundary of the MTS site. A 15 m setback (as measured from the "stable" top of bank) precluding the construction of structures identified for the HHGS Project (ERR 2007), and the 30 m meander belt setback, also defined in the SIS study (SENES 2008a) will be observed for the MTS Project.

TABLE 8.2
FISH SPECIES RECORDED AT STATIONS 1 AND 2 IN THE MAIN EASTERN TRIBUTARY OF THE MIDDLE BRANCH OF SIXTEEN MILE CREEK (26 JUNE 2006)

	Station 1		Station 2	
Fish Species	**Number**	**Life Stage[1]**	**Number**	**Life Stage[1]**
Common shiner	5	J,A		
Bluntnose minnow	3	J,A	13	YOY, J, A
Blacknose dace	36	J,A	6	YOY, J, A
Creek chub	17	J,A	5	YOY, J, A
White sucker	22	YOY,J,A	30	YOY, J, A
Stonecat			1	J
Rainbow trout			2	YOY
Brook stickleback	1	A		
Rock bass		J	5	J,A
Pumpkinseed				
Smallmouth bass				
Rainbow darter	33	J,A	14	J, A
Fantail darter				
Johnny darter	30	YOY, J,A	35	J, A

[1] - Life stage: YOY = young-of-the-year; J = juvenile; A = adult.

Mitigation Measures and Net Effects

Silt fences and other sediment and erosion control measures will be identified and implemented prior to the initiation of construction activities. It is anticipated that no effects to fisheries or aquatic habitat will occur as a result of construction activities for the MTS and therefore no further mitigation measures are required.

Effects during Operations

The Halton Hills Official Plan (2008) and *O. Reg. 97/04: Regulation of Development, Interference with Wetlands and Alterations to Shorelines and Watercourses* (2006) require a 15 m allowance adjacent to the stable top of bank of major valley/watercourse systems to protect "Hazard Lands". As specified in Construction Effects above, no structure for the MTS will be located within 15 m of the stable top of bank of the watercourse or within the 30 m meander belt setback identified by Conservation Halton for the HHGS Study (ERR 2007). All stormwater runoff will be directed to the SWMF for the SIS site, identified in Section 8.2.2 prior to being released to the watercourse.

Mitigation Measures and Net Effects

It is anticipated that no effects to fisheries or aquatic habitat will occur as a result of the operation of the MTS and therefore no further mitigation measures are required.

8.2.5 Vegetation

Existing Conditions

The identification of vegetation communities on the MTS site are based on studies (EEL 2007) undertaken for the HHGS ERR using the Ecological Land Classification (ELC) system to an ecosite level (Lee *et al.* 1998). The MTS site is located predominately on a Cultural Woodland (CUW#5) which is characterized by historic anthropogenic disturbance, such as land clearing/agricultural use and subsequent abandonment. A residence, barn and other buildings (Figure 8.2) are associated with this community.

The cultural woodland is characterized by native trees, such as white ash (*Fraxinus americanus)*, black walnut (*Juglans nigra)*, yellow oak (*Q. muehlenbergii*), sugar maple (*A. saccharum)*, Manitoba maple (*A. negundo)*, American basswood (*Tilia Americana)* and honey locust (Gleditsia *triacanthos)*, as well as other non-native species (e.g., Norway spruce (*Picea abies*), white willow (*Salix alba*) and northern catalpa (*Catalpa speciosa*)). The ground cover is historically manicured lawn which has fallen to disuse in the immediate past.

The remainder of the MTS site was originally identified in EEL 2007 as agriculture area but it is anticipated that the area has been developed and is at least partial used as a laydown area for the HHGS Project (SENES 2008a).

Effects during Construction

A portion of the cultural woodland area and agricultural area identified in EEL 2007, on which the MTS and the access road is to be constructed, is currently in use as a laydown area for the HHGS and therefore the existing vegetation has already been removed. The remainder of the vegetation, with the exception of three (3) species, associated with the Cultural Woodland area to be affected are designated by the NHIC (2006b) as S5 (very common in Ontario)., and therefore will have a negligible effect on the overall populations in Ontario. Additionally, the removal of any black walnut or yellow oak, designated as S4 (common in Ontario and apparently

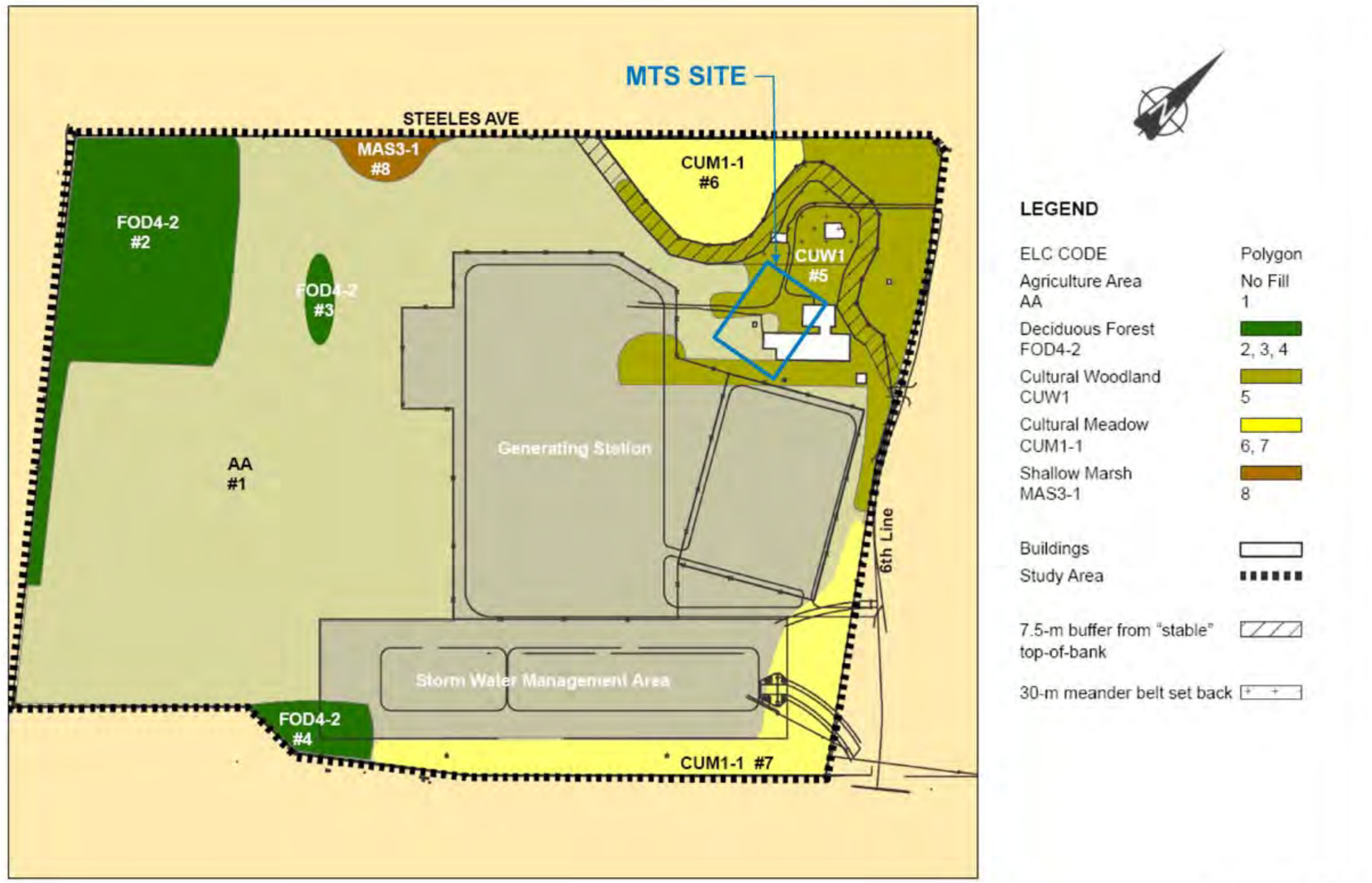


Figure 8.2

ELC FOR MTS SITE

SOURCE: Supporting Document 3, Natural Environment for Proposed Halton Hills Generating Station, EEL, 2007 secure), is anticipated to have a negligible effect on the general populations. It is anticipated that a number of honey locusts identified in the cultural woodland area during the SIS study (SENES 2008a) which are designated by NHIC (OMNR 2006b) as S2 (very rare in Ontario), are located in close proximity to the barn structure and may be impacted by the development of the MTS. The exact location of these trees will be confirmed during the development of the Site Plan and any and potential impacts/removals addressed through the development and implementation of a Landscaping Plan for the MTS to be determined in consultation with Halton Hills. The overall effect of construction of the MTS on vegetation is anticipated to be minimal.

Mitigation Measures and Net Effects

Compensation for the loss of any trees for this Project will be conducted in accordance with the Halton Hills Official Plan (2008) which requires a tree inventory and preservation plan be developed along with a proposed planting program. Halton Hills Hydro will also apply for a tree removal permit prior to construction, in accordance with Halton Region Tree By-law No. 121-05.

Effects During Operations

A landscape plan for the MTS site and the access road will be developed in accordance with the 401 Corridor Urban Design Guidelines, Conservation Halton (2005a) planting and tree preservation guidelines, and Halton Hills Standards through consultation with the Town of Halton Hills and Conservation Halton. The main purpose of the landscape plan is to replace native vegetation and enhance the aesthetics of the site to the passerby. The operation of the MTS and access road is not expected to affect the vegetation communities although a positive net benefit is expected to be derived through the development and implementation of a landscape plan.

Mitigation Measures and Net Effects

Operation of the MTS is not expected to affect the vegetation communities and therefore no further mitigation measures are required.

8.2.6 Wildlife

Existing Conditions

A total of 11 mammals, based on direct and indirect observations, were recorded for the HHGS site during a survey conducted on 28 June 2006 for the HHGS ERR (SENES 2007). Mammals identified included Virginia opossum (*Didelphis virginiana)*, eastern cottontail (*Sylvilagus floridanus)*, eastern chipmunk (*Tamias striatus)*, groundhog (*Marmota monax)*, eastern grey squirrel (*Sciurus carolinensis)*, meadow vole (*M. pennsylvanicus)*, coyote (*Canis latrans)*, red fox (*Vulpes vulpes)*, raccoon (*Procyon lotor)*, striped skunk (*Mephitis mephitis)* and white-tailed deer (*Odocoileus virginianus)*. All of these species are associated with areas of human disturbance and are not considered to be at risk federally by COSEWIC (2006) or provincially by COSSARO (OMNR 2006a).

The presence or absence of avifauna in one (1) area is difficult to assess, due to their increased mobility, unless nests are identified. Approximately 19 avian species were observed on the HHGS site, during a survey conducted 28 June 2006, with 15 species confirmed or identified as likely to be breeding in the 10-km by 10-km grid. Two of the 15 bird species were considered non-native/exotic with the remaining 13 considered very common in Ontario (SENES 2008a). A number of terrestrial bird species were considered to be likely locally residents that may nest on the HHGS site (EEL 2007).

Effects During Construction

The displacement of wildlife due to the conduct of construction activities is expected to be minimal based on the location of the MTS site next to the HHGS, and the level of disturbance currently occurring on and adjacent to the MTS site associated with the construction of the HHGS. Any effects are anticipated to be short-term as the wildlife identified in the survey may leave the area to avoid the noise and disturbance associated with construction activities returning once these activities have concluded.

The potential exists to affect avian resources, most of which are protected under the *Migratory Birds Convention Act*, as a number of trees in the vicinity of the barn, including a number of honey locust, may have to be removed to accommodate the MTS structures and access road. In accordance with the *Migratory Birds Convention Act*, vegetation clearing is not permitted in southern Ontario between 01 May and 31 July during the breeding season of migratory birds in order to avoid the destruction of nests. If clearing is to take place between these dates, a breeding bird survey must first be performed by a qualified avian biologist and a 50 m buffer restricting construction activities must be enforced and maintained around the any nests found until the young have left the nests.

The construction of the MTS is anticipated to have minimal effect on wildlife in the area. The construction of the access road is anticipated to also have minimal effect on wildlife in the area as the location will be determined in consultation with the Town of Halton Hills and Conservation Halton, if required.

Mitigation Measures and Net Effects

The clearing of vegetation should take place prior to 01 May or following 31 July to avoid the breeding bird season. If clearing activities are to be conducted during this period, a breeding bird survey must be completed by a qualified avian biologist. Any nests found during the survey must remain undisturbed and a 50 m buffer in which construction activities are prohibited observed until the young have fledged. The overall effect of the construction of the MTS on wildlife populations and/or wildlife-carrying capacity is anticipated to be minimal.

Effects during Operations

Operation of the MTS is not expected to further affect wildlife resources or wildlife-carrying capacity as wildlife and avian species may return to the areas with suitable habitat adjacent to the site (northeast corner of property on northeast side of tributary).

Noise generated by the MTS is not expected to affect the movement of wildlife back to the area as they have become accustomed to noise generated by human disturbance (e.g., highway and vehicle traffic, farming activities).

Bird collisions are not anticipated as the MTS will abut and have a much lower profile then the HHGS.

Mitigation Measures and Net Effects

No effect on wildlife populations and/or wildlife-carrying capacity is anticipated for the operation of the MTS.

8.2.7 Environmental Significant Areas

Existing Conditions

There are no ESAs, ANSIs or PSWs on or in the immediately vicinity of the MTS site. The closest classified area is the Class 7 Hornby Swamp located approximately 2 km north of the site (EEL 2007).

Effects During Construction

No effects are associated with construction activities as there are no ESAs located within or immediately adjacent to the MTS site.

Mitigation Measures and Net Effects

There are no effects related to construction and therefore no mitigation measures are required.

Effects During Operations

No effects are associated with the operation of the MTS as there are no ESAs located within or immediately adjacent to the MTS site.

Mitigation Measures and Net Effects

There are no effects related to operation of the MTS and therefore no mitigation measures are required.

8.2.8 Noise

Existing Conditions

The MTS site is located in a predominately rural area surrounded by road infrastructure to the north, east and south and urban development to southwest. The background sound level is characterized by local traffic along Highway 401 and Steeles Ave.

It is acknowledged that the HHGS site, currently under development, is expected to be operational at the time of commissioning of the MTS. The acoustic modelling for the MTS was conducted based on the background sound level characterized by local traffic only and did not include the noise generated by the operation of the HHGS (SENES 2008b). Further discussion on the effects of the HHGS on the noise modelling for the MTS is provided in the subsequent sections.

The Model Municipal Noise Control By-Law (MOE 1978) defines a receptor or point of reception as *"any point on the premises of a person where sound or vibration originating from other than those premises is received."* The point of reception may be located on any of the following existing, or zoned for future use premises:

- permanent, seasonal or rental residences;
- hotels/motels;
- nursing/retirement homes;
- hospitals;
- campgrounds; or
- noise sensitive buildings such as schools, day care facilities and places of worship.

The nearest point of reception to this MTS site is a residential property approximately 220 meters north-west of the nearest on-site noise source. A second receptor was identified is also a residential property to the west of the MTS site at a distance of approximately 300 m.

Effects During Construction

Potential sources of noise associated with the MTS construction activities are anticipated to occur over a nine (9) to 12 month period. Site grading, underground services, foundations, footings, and duct bank construction activities will occur over approximately three (3) months followed by the construction of the switchgear and control building, transformer pads, and yard equipment foundations over an additional six months. Installation of high voltage outdoor electrical equipment will commence once the roadways, foundations, and transformer pads are completed. Equipment utilized for these construction activities may include bulldozers, front-end loaders, small trucks, bobcats, backhoes, dump trucks, cement trucks and mobile cranes. Indoor construction activities, and the placement of transformers and other electrical equipment are not expected to generate the noise levels anticipated during the initial construction activities.

An increase in the noise levels for the surrounding environs, resulting from the conduct of these activities, are anticipated to be temporary and infrequent in nature and therefore the effects are expected to be minimal.

Construction Noise Limits

Specific sound emission standards for construction equipment are provided in *NPC Document #115* of the Ontario Model Municipal Noise Control By-law (MOE 1978).

Qualitative noise restrictions associated with various activities are set out in Halton Hills By-Law No. 93-177 "A By-Law with Respect to Noise" which states:

No person shall make*, cause or permit noise which disturbs or may disturb the quiet, peace, rest enjoyment, comfort or convenience of the inhabitants of the Town.*

As the by-law pertains to the construction of the MTS, more specifically the operation of machinery or equipment:

Any noise from any excavation or construction work, including the erection, demolition, alteration or repair of any building which disturbs or is likely to disturb the peace, quiet, rest, enjoyment, comfort or convenience of persons in any office or residential point of reception or of any person in the vicinity, arising between the hours of 6:00 p.m. of one day and 7:00 a.m. of the following day, unless the following day is a Sunday or holiday, in which case the time shall be 9:00 am.

Mitigation Measures and Net Effects

The potential noise sources associated with the MTS site were determined to be temporary and infrequent. Additionally, all construction activities will be conducted in accordance with standard construction practices and the Halton Hills By-law No. 93-177 and therefore no mitigation is required. All noise-related complaints received from the general public will be documented and investigated.

Effects during Operation

The acoustic assessment report was prepared in accordance with the format outlined in the Ontario Ministry of the Environment (MOE) document titled *Supporting Information for the Preparation of an Acoustic Assessment Report*, prepared by the Air and Noise Unit, Environmental Assessment and Approvals Branch, November 2003.

Noise sources

The two (2) transformer units were the only significant on-site sources of noise from the MTS identified by Halton Hills Hydro. The transformers are not expected to be located within a building structure. Insignificant noise sources were identified as the maintenance facilities, and periodic maintenance activities, which are expected to generate little to no noise and the on-site switch yard connected to the two (2) transformers, also considered an insignificant source of noise.

The HHGS is expected to be operational when the MTS is commissioned; however, it is anticipated that the noise generated by the MTS will be comparatively insignificant, as noted in the following paragraph:

A simple comparison was completed using an acoustic assessment previously conducted for the HHGS ERR (SENES 2007), which identified day and night-time sound levels at two (2) receptors locations to be in the order of 44.7 dBA and 47.8 dBA, respectively. The maximum noise impact from the MTS is 35.9 dBA (SENES 2008b) during the night at receptor R2. This is a minimum 8.8 dB difference between the existing HHGS noise and the contribution from the MTS resulting in a maximum increase in the receptor sound levels of approximately 0.5 dB due to the MTS operation. Increases of this magnitude are generally imperceptible to the human ear.

The acoustic modelling for this study was based only on the noise generated by the operation of the MTS.

Regulatory Requirements

The MTS must obtain a Certificate of Approval (C of A) (Air and Noise) through compliance with the noise guidelines stipulated in the Ministry of the Environment (MOE 1978) Model Municipal Noise Control By-law. The MTS is a stationary noise source, as defined in the By-law, must comply with the limits set out in Noise Pollution Control publication 205 (NPC-205) (MOE 1995).

As provided in Section 5.1.9 – Noise, Publication NPC-205 of the Model By-Law defines and sets Sound Level Limits for Stationary Sources in Class 1 and 2 Areas (Urban) (MOE 1995) as follows:

A "Class 1 Area" is defined as:

> *an area with an acoustical environment typical of a major population centre, where the background sound level is dominated by the urban hum.*

A "Class 2 Area" is defined as:

> *an area with an acoustical environment that has qualities representative of both Class 1 and Class 3 Areas, and in which a low background sound level, normally occurring only between 23:00 and 07:00 hours in Class 1 Areas, will typically be realized as early as 19:00 hours.*

Other characteristics which may indicate the presence of a Class 2 Areas include:

- *absence of urban hum between 19:00 and 23:00 hours;*
- *evening background sound level defined by natural environment and infrequent human activity; and*
- *no clearly audible sound from stationary sources other than from those under assessment.*

Publication NPC-205 also states that the sound level limit must be established based on the principle of "predictable worst case" noise impact. Generally, the limit is based on the background sound level at the receptors and must represent the minimum background sound level that occurs or is likely to occur during the operation of the stationary source under assessment.

The sound level limits for a Class 1 and 2 Area, provided in Table 8.3, are established by Publication NPC-205. Energy equivalent sound levels identified in the table are measured in L_{eq}, in dBA. If the stationary source contains any noticeable features such as tonal components or buzzing, a 5 dB tonal penalty must be added to the noise level of the source as per NPC-104.

No restrictions apply to a stationary source resulting in a one hour Leq lower than the minimum values for the time periods specified in Table 8.3.

TABLE 8.3
MINIMUM VALUES OF ONE-HOUR L_{eq} or L_{LM} BY TIME OF DAY

Time of Day	One Hour L_{eq} (dBA)	
	Class 1 Area	Class 2 Area
07:00 - 19:00	50	50
19:00 - 23:00	47	45
23:00 - 07:00	45	45

The MTS site and the two (2) receptors were determined to be located in a Class 1 Area.

Noise Assessment

The noise assessment was based on a 24 hours per day, 7 days per week, 365 days per year operation schedule using transformer noise data collected in accordance with ANSI Standard C57.12.90. The worst case one-hour operating scenarios assumed that the transformer units would operate continuously throughout the worst-case hour for both daytime and night-time hours. The worst-case hour is defined as the one-hour continuous operating period for the MTS during which the background noise is determined to be the lowest (both day and night timeframes).

The noise levels, based on the worst-case operating scenario, were modelled using the Cadna-A modelling software to assess whether the noise impact resulting from MTS operations would be in compliance with the limits identified in Table 8.3 at the receptor locations. Figures 8.3 and 8.4 provide the model-predicted sound level contours for the worst case daytime and night-time noise emission scenarios. The tabulated results of the acoustic assessment are provided below in Table 8.4.

The acoustic assessment results (Table 8.4) indicate that the model-predicted receptor sound levels pertaining to activities at the MTS site, while operating under the worst-case daytime and night-time noise emission scenarios (Figures 8.3 and 8.4), are in compliance with performance limits established in Table 8.3.

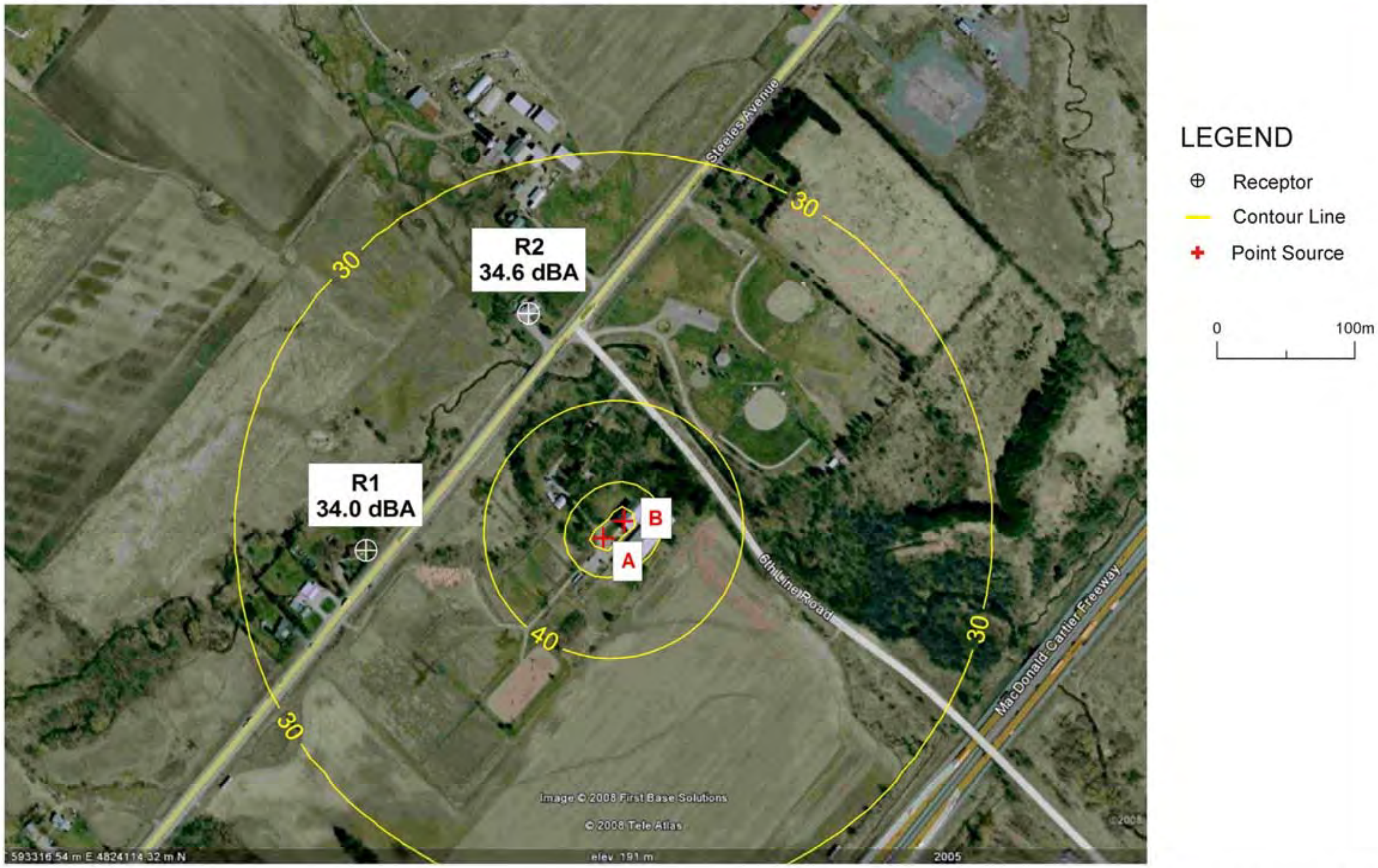


Figure 8.3

MODEL PREDICTED WORST CASE DAYTIME SOUND LEVEL CONTOURS AND RECEPTOR SOUND LEVELS

SOURCE: Acoustic Assessment For Halton Hills Hydro Inc. Municipal Transformer Station, SENES, 2008

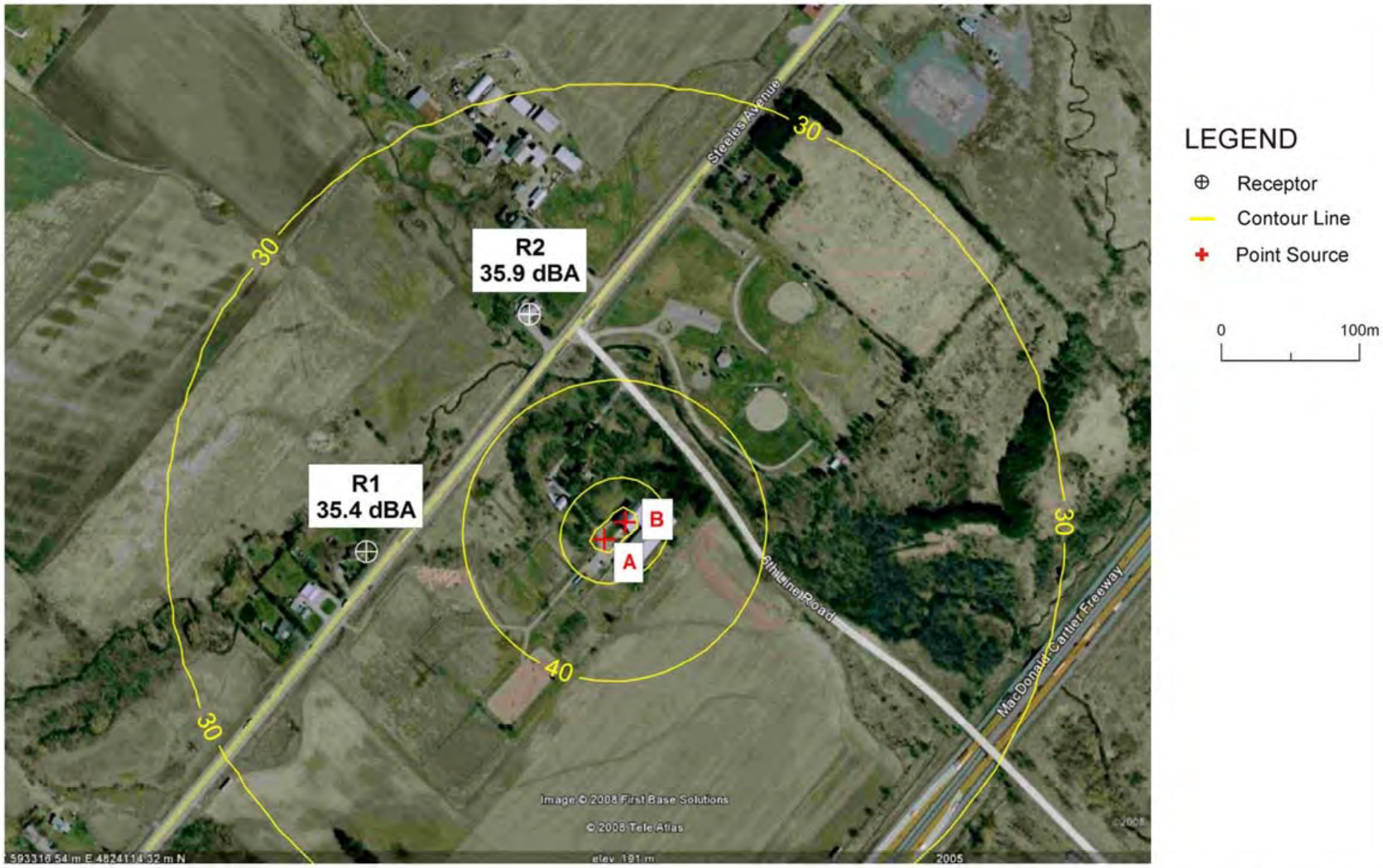


Figure 8.4

MODEL PREDICTED WORST CASE NIGHT-TIME SOUND LEVEL CONTOURS AND RECEPTOR SOUND LEVELS

SOURCE: Acoustic Assessment For Halton Hills Hydro Inc. Municipal Transformer Station, SENES, 2008

TABLE 8.4
ACOUSTIC ASSESSMENT SUMMARY TABLE

Receptor ID	Receptor Description	Sound Level at Receptor (L_{eq}, dBA)		Verified by Acoustic Audit (Yes/No)	Performance Limit (L_{eq}, dBA)		Compliance with Performance Limit (Yes/No)
		Day	Night		Day	Night	
R1	House	34.0	35.4	No	50	45	Yes
R2	House	34.6	35.9	No	50	45	Yes

Mitigation Measures and Net Effects

The results of the acoustic assessment indicates that operation of the MTS will not exceed performance limits established in the Ministry of the Environment's (MOE 1995) Model Municipal Noise Control By-law - Publication NPC-205 and therefore no mitigation is required.

8.3 SOCIO-ECONOMICS AND LAND USE

8.3.1 Existing and Planned Land Uses

Existing Conditions

The MTS site is located on a portion of the HHGS site which is currently under development for industrial use. The HHGS property is designated Urban Area in the Region of Halton's Official Plan (2006) and is identified in the Halton Hills OP (2008) as part of the 401/407 Employment Corridor. The planning of a 401/407 Employment Corridor is intended to promote development of a range of industrial, office, commercial, and institutional uses on full municipal services (Figure 8.5). The HHGS site is zoned M7 – Prestige Industrial by Halton Hills zoning By-law. The M7 zoning designation permits a wide range of uses including industrial uses within a wholly enclosed building.

The community of Hornby is located to the north and northeast of the HHGS site with many of the adjacent residents operating small businesses from their homes or involved in active agricultural practices. A number of the residents along the north side of Steeles Avenue have been involved in the planning for both the 401/407 Employment Corridor and the HHGS EA study and are aware of the land use changes proposed.

A vacant farmhouse, barn and other buildings associated with an agricultural history is present on-site. The vacant farmhouse is designated a building with historic significance and the barn was a former equestrian centre. The vacant homestead will remain although it is our understanding at the time of this report that the barn will be removed.

A Phase 1 Environmental Site Assessment, including the buildings, was completed in support of the HHGS EA Study for the site and no concerns/issues were identified (SENES 2007).

The northeast corner of the HHGS site is zoned "Greenlands" due to the presence of the middle branch of the main eastern tributary of Sixteen Mile Creek and the associated valley lands (EEL 2007). To the east of the site, the land is designated as Greenlands and Open Space encompassing Hornby Park (see Figure 8.5).

Effects of Construction

The HHGS ERR (2007) identified the area residents concerns as increased traffic, and nuisance effects associated with construction noise. It is anticipated that approximately 30 personnel will be on-site at any time during the construction period from April 2010 to commissioning in May 2011. It is anticipated that approximately 10 vehicles per hour will be accessing the MTS site during construction. The effects of construction traffic on local residences and Hornby Park users is anticipated to be minimal and will be confirmed upon final determination of the access road location. It is anticipated that the overall effects on existing land uses will be minimal. The effects of construction noise on existing land uses are addressed in Section 8.2.6.

The MTS is to be constructed in accordance with the Prestige Industrial (M7) zoning of the 401/407 Employment Corridor identified in Halton Hills Official Plan (2008) and therefore no effects on planned uses are anticipated.

Mitigation Measures and Net Effects

The location of the access road is unknown at the time of writing of this ESR and will be determined during detail design of the MTS through consultation with TransCanada, Halton Hills, Conservation Halton, and other interested stakeholders to determine the most suitable access route.

The effects of construction on planned land uses are not anticipated and therefore no further mitigation is required.

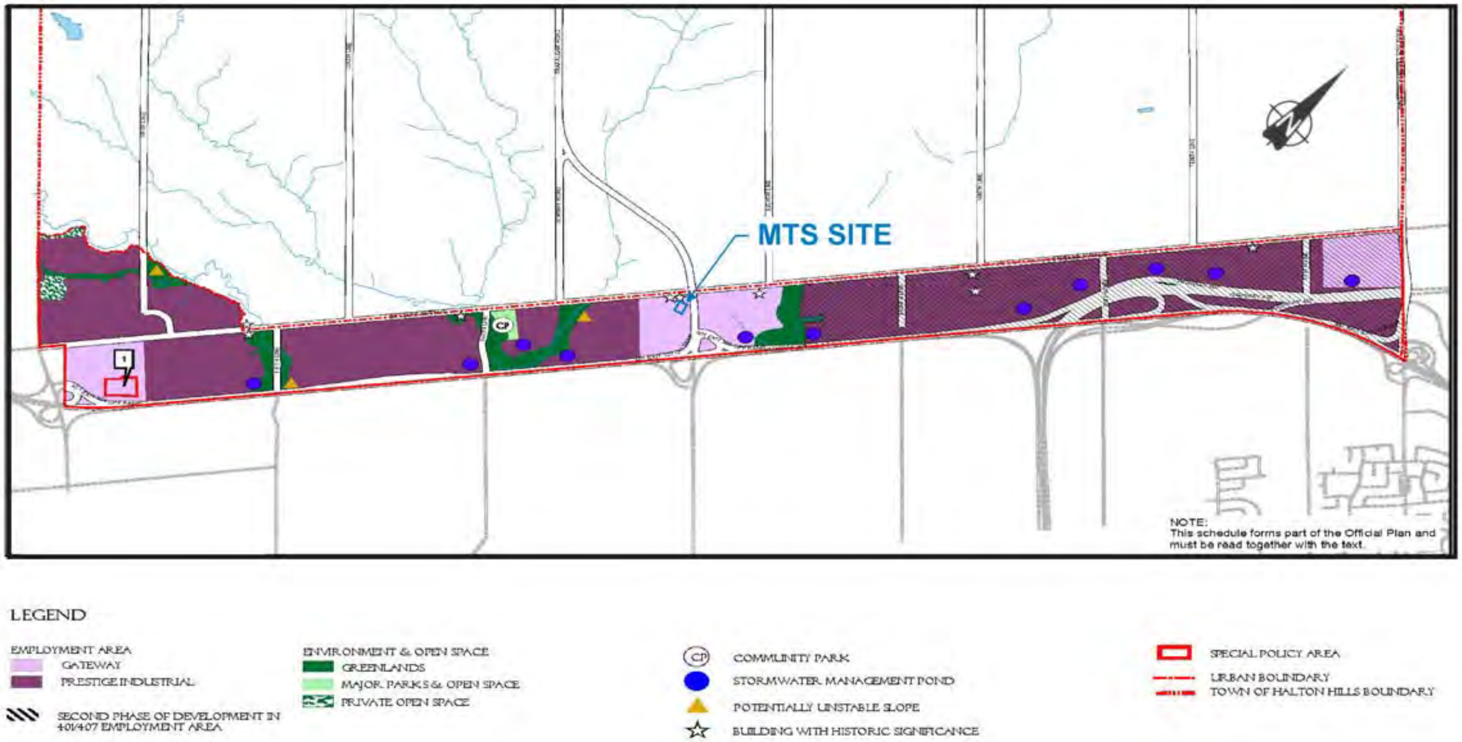


Figure 8.5

401/407 EMPLOYMENT AREA ZONING DESIGNATIONS

SOURCE: Adpated From Town of Halton Hills Official Plan Schedule A8, 2008

Effects of Operation

Only small vehicle traffic as required for maintenance purposes will be required on an infrequent basis for the operation of the MTS. The effects of operation as it relates to noise are provided in Section 8.2.6.

Mitigation Measures and Net Effects

The effects of operation, as it relates to an increase in traffic/nuisance on both planned and existing land uses are not anticipated and therefore no further mitigation is required.

8.3.2 Recreation

Existing Conditions

The site is located immediately to the west of Hornby Park which functions as a recreational area for outlying areas, as well as the larger surrounding communities, due to its proximity to major transportation routes such as Highway 401, Steeles Avenue and Trafalgar Road and location away from concentrated residential development. The main eastern tributary of the Middle Branch of Sixteen Mile Creek runs through the park.

The parks facilities include a playground, pavilion with washroom facilities, and two (2) baseball diamonds (one (1) illuminated). There are no programmed uses of the park although it is typically used to host adult baseball leagues during the weekdays and on weekends for tournaments. The park is also used extensively for dog trials and as a staging area for cycling trips. Use of the park for cycling has become frequent enough that the Town is considering implementation of measures to manage this activity.

The reconstruction of Steeles Avenue and increasing development in this corridor is anticipated to change current uses of the park including the relocation of the park access to the north corner of the park in the former location of the regional recycling depot.

Effects during Construction

The potential for construction traffic to affect park users is anticipated to be temporary, limited to daytime weekday hours, and not expected to change the current usage of the park. At this point in the Study, the final location and exit for the MTS access road has not been identified and may factor into the final determination of effects on park users. Evening and weekend park users are not expected to encounter construction traffic with the exception of those utilizing the park facilities close to the end of the day during the work week. It is anticipated, based on the number of construction vehicles and potential access locations that the overall effect on park users will be minimal.

Mitigation Measures and Net Effects

Consultation with TransCanada, Halton Hills, Conservation Halton, and interested stakeholders will be undertaken during detail design to determine the optimal access road location and access point for the MTS.

Effects during Operations

Operation of the MTS will not affect park users.

Mitigation Measures and Net Effects

The operation of the MTS will not affect park users and therefore no further mitigation is required.

8.3.3 Aesthetics

Existing Conditions

A wooded area located on the north and east portion of the site, which is part of the Sixteen Mile Creek valley system, currently provides a partial visual screen for views from Steeles Avenue and Sixth Line South. The HHGS site is currently under development and is clearly visible from Highway 401, Hornby Park, and adjacent residences and businesses.

Effects of Construction/Operation

The MTS will be located adjacent to the northeast corner of the HHGS and comparatively will be a much smaller structure. It was determined during the HHGS ERR, that until the 401/407 Employment Corridor was further developed, the HHGS would standout in the landscape (SENES 2007) as the capability of HHGS to blend into the surrounding landscape is minimal due to its proximity to Highway 401 and the limited potential for use of landscaping to screen the HHGS from view.

The visual impact of the MTS will be limited to the views from Steeles Avenue and Sixth Line where the existing natural feature is to be preserved and enhanced. The landscape plan for the HHGS Project provides for planting of trees along the north property limits to provide visual continuity of existing natural forms and enhance view corridors (SENES 2007). It is anticipated that the visual impact of the MTS will be minimal as the greatest visual impact will occur with the development of the HHGS and the MTS will be considered an integral part of the HHGS industrial landscape.

Mitigation Measures and Net Effects

A landscape plan to enhance the aesthetics of the MTS site and access road will be developed in accordance with the 401 Corridor Urban Design Guidelines, Conservation Halton (2005a) planting and tree preservation guidelines, and Halton Hills Standards through consultation with the Halton Hills and Conservation Halton.

8.3.4 Cultural Heritage Features

Existing Conditions

A vacant farmhouse, designated in the Halton Hills OP (Figure 9. as a building with historic significance, is located adjacent to the east of the MTS site. A Stage 2 Archaeological survey was conducted for the HHGS site and concluded that the site should be considered free of any archaeological planning concerns (ASI 2006).

Effects during Construction and Operations

The farmhouse will not be affected by the construction or operation of the MTS. The HHGS, including the site identified for the MTS, was considered as being free of any archaeological planning concerns and therefore the potential to affect archaeological resources is minimal.

Mitigation Measures and Net Effects

The construction or operation of the MTS is not anticipated to affect the identified cultural heritage features and therefore no mitigation measures have been identified. However, the potential exists for the unearthing of deeply buried cultural remains, including human burials, and therefore if during construction activities any previously undiscovered remains are unearthed all work will cease immediately and the archaeological staff at the Ontario Ministry of Culture will be notified immediately. If human remains, are unearthed, the Ontario Ministry of Culture and the Registrar of the Cemeteries Regulation Unit of the Ontario Ministry of Consumer and Commercial Relations will be contacted immediately.

8.3.5 First Nations

Effects of Construction and Operation

Construction and operation of the MTS is not anticipated to affect First Nations, as determined for the HHGS ERR (SENES 2007).

Mitigation Measures and Net Effects

The construction/operation of the MTS will not affect First Nations and therefore no further mitigation is required.

9.0 SUMMARY OF IMPACT, MITIGATION MEASURES AND NET EFFECTS

Table 9.1 summarizes the potential impacts, mitigation measures, and net effects associated with the construction and operation phases of the MTS Project. The mitigation measures are commitments to be fulfilled during the construction and operation of the MTS to order to achieve net effects identified in this table.

TABLE 9.1
SUMMARY OF POTENTIAL IMPACTS, MITIGATION MEASURES, AND NET EFFECTS

Potential Impact	Mitigation Measures	Net Effects
Construction		
Change in physiography /soils.	Additional geotechnical studies, to determine the loading restrictions and foundation type (gravel or concrete). Use of stabilizing material (e.g., crushed stone) on access road.	Negligible
Erosion and runoff to surface water.	Implementation of sediment and erosion control measures (silt fencing, sedimentation ponds) prior to initiation of construction activities. Development of Site Plan including grading and drainage plan. Stormwater management in accordance with plan for site developed for HHGS.	Negligible
Spills/Releases of fuel or other materials.	Fuelling will be performed off-site where possible. Fuelling of construction equipment will be performed in contained areas to prevent releases to the natural environment. Use of standard measures to prevent, contain and clean-up spills.	Negligible
Dewatering	Permit to Take Water	No effect
Waste	All waste will be disposed of in accordance with regulatory requirements. Waste collection procedures will be developed and adhered to by all on-site workers and contractors.	Negligible
Potential to affect fisheries and aquatic resources.	Observance of the 15 m construction setback and 30 m meander belt setback	No effect

TABLE 9.1 (Cont'd)
SUMMARY OF POTENTIAL IMPACTS, MITIGATION MEASURES, AND NET EFFECTS

Potential Impact	Mitigation Measures	Net Effects
Construction		
Removal of on-site vegetation.	Site plan including a tree inventory and landscaping plan. Landscaping of site to enhance aesthetics and blend MTS into the surrounding environment.	Net benefit
Displacement of nesting birds.	All clearing activities will be conducted in accordance with the *Migratory Birds Convention Act*. All clearing activities will occur prior to May 1 or after July 31 to avoid potential impacts with breeding birds. Trees will be planted as specified in the landscaping plan.	Net benefit
Access road location and exit on users of Hornby Park.	Consultation with Halton Hills, Conservation Halton, and TransCanada.	No effect.
Increase in traffic in vicinity of site	Consultation with Halton Hills, Conservation Halton, and TransCanada to determine optimal access location. Monitor and respond to complaints from residents.	Negligible
Noise from construction vehicles, equipment and development activities.	All activities conducted in accordance with Halton Hills By-law 93-177. Construction equipment will comply with NPC Document #115 specifying noise standards.	Negligible as closest receptors will not experience noise levels above the allowable standards.
Operations		
Spills/Releases of lubricants/transformer oils.	Transformer units are located within a containment area with oil/water separator and spill detector.	Negligible
Effect of releases of spills to aquatic environment	Sump located within the containment area for the transformer units.	No effects
Visual impact to local residents.	Landscaping plan will be implemented.	Negligible
Stormwater/Runoff on receiving water quality.	Implementation of the Stormwater Management Plan developed for the SIS site. Stormwater/runoff is directed to the Stormwater Management Facility developed for the SIS site	Negligible
Noise associated with operation of transformer units	Modelling for compliance with the Ministry of the Environment's (MOE) Model Municipal Noise Control By-law - Publication NPC-205	No effects

The quantifiable effects, identified in Table 9.1, are either localized in effect, short-term, infrequent, or do not represent a substantive or order of magnitude change from baseline conditions. The overall net effects of construction and operation are not considered to be significant.

10.0 PUBLIC AND STAKEHOLDER CONSULTATION

Public and stakeholder (includes government agencies) consultation was conducted in accordance with the requirements of the "Class EA for Minor Transmission Facilities" to provide an opportunity for those interested to actively participate in the study. The public consultation program for the Halton Hills Hydro MTS#1 study included the following points of contact:

- Initial Stakeholder Meetings;
- Notice of Study Commencement; and
- Public Information Centre.

Information applicable to public and stakeholder consultation is provided in Appendix A.

10.1 MUNICIPAL CONSULTATION

The Class EA Process provides for initial contact of those government agencies or stakeholders (e.g., conservation authorities) which may have an interest in the proposed project. Notification is conducted through the conduct of meetings with selected stakeholders, and notification of study commencement by letter mail. The meetings are conducted to introduce the stakeholder to the Project to obtain feedback on any potential issues that may be foreseen.

Initial stakeholder meetings were held with the Town of Halton Hills, Region of Halton, and Conservation Halton on 24 January 2008, 18 March 2008, and 28 March 2008, respectively. The meetings were conducted by Halton Hills Hydro/Costello Associates to introduce the project and team, and discuss any potential issues or concerns that the stakeholders may have with the project. A brief summary of the initial meetings with municipal government agencies and stakeholders is provided in Table 10.1.

TABLE 10.1
SUMMARY OF MUNICIPAL CONSULTATION

Government Group	Meeting Date	Topics Covered	Comments Raised
Town of Halton Hills	24 January 2008	• Need for additional electric distribution capacity based on projected growth • Proposed in-service date for new supply facility • Typical station construction process • Typical station appearance • Class EA for Minor Transmission Projects – process and timing • Study area and possible site locations • Zoning • Site Plan review process • Setback requirements • Storm water management	• Site access during construction and operation (quantity of personnel, vehicles, and access roads) • Zoning by-law and frontage requirements • Process for severances and variances • Urban design guidelines • Gateway designation of some of the alternate sites • Use of house on TCE property to comply with by-law • Method of feeder egress (overhead vs. underground, routing)
Region of Halton	18 March 2008	• Need for additional electric distribution capacity based on projected growth • Proposed in-service date for new supply facility • Typical station construction process • Typical station appearance • Class EA for Minor Transmission Projects – process and timing • Study area and possible site locations • Water and sewer servicing • Feeder egress • Firefighting • Site Access • Noise modeling	• Location of existing water and sewer for supply to proposed transformer station • Region practices for site servicing • No direct connections to 600mm main line • Concerns for creeks, CH is prime agency • strongly recommend pre-development consultation meeting • Construction and permanent access given sensitivities for traffic concerns • Well at house on TCE property – keep or remove • Region doesn't permit two water services on one tap line (could not have station services fed from neighbouring property) • For TCE site option, suggest permanent access from Sixth Line

TABLE 10.1 (Cont'd)
SUMMARY OF INITIAL STAKEHOLDER MEETINGS

Government Group	Meeting Date	Topics Covered	Comments Raised
Conservation Halton	28 March 2008	• Need for additional capacity by 2011 – 2012 • Class EA for Minor Transmission Projects – process and timing • Typical station construction process • Typical station appearance • Study area and possible site locations • Specific questions for sites that could be sensitive to Conservation Halton • Request for Sixteen Mile Creek Watershed Plan Study • Anticipated issues concerning creeks, servicing, feeder egress, site access	• Setback requirement from creek at TCE site • Discussion of construction and operation site access, and access to century home on TCE site • Feeder egress underground or overhead would require approval • TCE doing extensive landscaping in valley. Should feeders egress this area, work to coordinate landscaping • Directional boring under Creek would require approval • Conservation Halton prefers servicing at TCE site to be fed from TCE, not a separate service from Steeles Ave. Conflicts with Region. CH will discuss with Region • Requested study documents are Region documents • No insurmountable challenges foreseen.

10.2 NOTICE OF STUDY COMMENCEMENT

Public consultation is conducted through placement of a Study Commencement Notice in the local media. Stakeholders and the public were notified of the study commencement through a letter notice and media notice (Appendix A-1). The Notice of Study Commencement letter (Appendix A-1) was sent to contacts within the government agencies and stakeholder groups identified through other studies conducted for the study area. The letter contained an introduction to the project and study area, Class EA process, plans for conduct of public consultation activities, study commencement notice to the media, Project contacts, and an interest response page. The interest response page is to be returned by the recipient of the letter to more clearly identify their interest in the project and/or provide an alternative contact for that specific stakeholder group. The recipient is asked to check one of the following: no further contact required; study information or technical input required and technical/alternative contact. Eight (9) responses were received of which two (2) indicated no further contact was required; one (1) provided the Hydro One notification process and potential for interference with Hydro One facilities; four (4) indicated they would like to provide technical input on the Project with two (2) of the four (4) providing alternative contacts; one (1) indicated that ORC land was located in the vicinity of study area; and one (1) indicating paternity leave and provided an alternative contact person.

10.3 PUBLIC INFORMATION CENTRE

A public information centre (PIC) was held on 29 May 2008 at Hornby Glen Golf Course, 8286 Hornby Road, Hornby, Ontario from 4:30 p.m. to 7:00 p.m. The purpose of this open house was to:

- Introduce the proposed Halton Hills Hydro MTS, and the Class EA process to the community;
- Present the evaluation of the alternative MTS sites and the preferred location; and
- Provide an opportunity for the general public to become informed and comment on Study progress to date.

Agency and stakeholder consultation was conducted through letter notification (Appendix A-2). Notification of the public was achieved through placement of an advertisement (Appendix A-2) in the local media, hand-delivery of the notice to residents adjacent to the preferred MTS site, and posting of the notice in the local postal outlet.

The PIC display boards included information on:

- Objective of the PIC;
- Who is Halton Hills Hydro;
- Project overview;
- Class EA Process;
- Need for Project;
- Study Options;
- Location and Study Area for Alternative Sites;
- Evaluation Process for and Evaluation of Alternative Sites;
- Preliminary Preferred Site Selected;
- Details of Proposed Halton Hills Hydro MTS#1;
- Public Consultation Process; and
- Next Steps to be Conducted for Study.

Comment sheets and handouts of the information on the display boards were provided upon request. A copy of the display boards are provided in Appendix A-2. A total of eight (8) residents and six (6) agency representatives attended the PIC.

No comment sheets were received although three (3) requests (two (2) e-mail and one (1) letter) for PIC handouts, inclusion on Project mailing lists; and technical input on Project were received. The PIC handouts were sent to those individuals who had requested the information. Following the PIC, the powerpoint presentation of the PIC display boards was posted on the Halton Hills Hydro website.

11.0 PERMITS AND APPROVALS

The following provides a more detailed list of the notifications, permits, and approvals which may potentially be required to proceed with the Project. This list is not inclusive and will be modified following detailed assessment of the preferred site.

Regional and Municipal Permits/Approvals (Halton Region and Town of Halton Hills) **–** Site Plan Approval, zoning variances, building permits, and municipal water and sewer use in accordance with the *Planning Act*, R.S.O. 1990, c.P.14 and the respective regional and municipal Official Plans. The Site Plan Approval (Town of Halton Hills) includes a Tree Survey and Preservation Plan, and Landscape Plan.

Conservation Halton Permit – Location of MTS facilities and/or access road with respect to Ontario Regulation 162/06: Regulation of development, interference with wetlands and alterations to shorelines **and** watercourses.

Permit to Take Water (Ministry of Environment (MOE)) **–** Water use required for construction activities in excess of 50,000 L/day in accordance with Section 34 of the Ontario Water **Resources** Act (OWRA).

Certificate of Approval (C of A) - Industrial Sewage (MOE - EAAB) **–** Discharge of stormwater to a Stormwater Management Facility (SWMF) in accordance with the OWRA (Section 53).

Certificate of Approval (Noise**)** (MOE - EAAB) The MTS must obtain a Certificate of Approval (C of A) (Air and Noise) through compliance with the noise guidelines stipulated in the Ministry of the Environment (MOE) Model Municipal Noise Control By-law.

Preliminary Impact Assessment and Connection Authorization (IESO) - The Connection Assessment and Approval process allows the IESO to assess the impact of new or modified connections on the reliability of the integrated power system.

Connection Impact Assessment (CIA) (Hydro One) - A CIA is a detailed assessment of a project's impact to the grid. The results include a technical report outlining project feasibility, technical specifications needed for the project and the impacts the project would have on the distribution grid.

Connection Authorization (ESA) - Before connecting to the distribution system, the ESA inspects the MTS and provides a Connection Authorization to Hydro One.

12.0 MITIGATION AND MONITORING

The monitoring requirements for the MTS site will be conducted in accordance with the subwatershed impact study (SIS) completed for the site (SENES 2008). The SIS addressed the parcel of land within the 401 Corridor between 6th Line South and 5th Line South which includes the MTS site.

Erosion and sediment controls will be implemented throughout construction and into operation, as required, to ensure protection of the watercourse adjacent to the MTS site. Measures are to include, but not be limited to, silt fences, sediment traps (i.e., berms, geotextile, riprap), swale cut-off adjacent to valley and stream corridors, measure illustrated on final design drawings.

The basic principles utilized to minimize erosion and sedimentation will include:

- Minimization of disturbance to landscape (e.g., grading) and exposure time to potential erosive elements (i.e., wind, water);
- Implementation of sediment and erosion control measures prior to the initiation of construction activities;
- Scheduled inspections to ensure the sediment and erosion control measures (e.g., silt fences) are working effectively and reporting of conditions of the erosion and sediment control measures, including the timely repair or maintenance, as required;
- Edge monitoring to ensure there has been no encroachment on the wooded areas to be left undisturbed and that the protective fencing in maintained in good working order.

The SIS (SENES 2008) specifies the requirement for weekly monitoring of the sediment and erosion control measures in addition to monitoring during and after a major storm event.

A site-specific Emergency Response Plan will be developed to allow for a timely and effective response in the case of a release of oil, fuel or other hazardous materials to the environment. The Plan will include the process for responding to an emergency (involving situational assessment), defining and prioritizing critical issues, emergency action planning, and effective activation of resources (SENES 2008).

Measures to prevent spills during construction will include, but not be limited to, on-site spill kits; hazardous material containment facilities; fire protection; and disposal of solid wastes in accordance with applicable acts and regulations. Oil/grit separators will be incorporated into the design of the MTS site to address the potential for spills related to the commissioning and operation of the MTS.

The Tree Survey and Preservation Plan, and Landscape Plan, will be submitted for Site Plan Approval, addressing both the preservation of trees on the property as well as the newly planted vegetation, and include a long-term maintenance plan. Monitoring by a Certified Arbourist will be conducted every two (2) years, as a minimum, with the extent and duration of the monitoring program to be determined by the Certified Arbourist responsible for the implementation of the Plans. In accordance with the approved SIS (SENES 2008), any changes to the woodland areas or natural corridors will be assessed every five (5) years using aerial photography.

Additional monitoring requirements/responsibilities (i.e., SWM facility, Sixteen Mile Creek) will be developed during detail design in consultation with the responsible authorities and identified in the conditions of the permit/approval to address the environmental components where net effects have been identified. These monitoring programs are conducted to assess the effectiveness of the environmental mitigation measures and provide a degree of measure to the commitments of any required permits or approvals.

13.0 ENVIRONMENTAL ADVANTAGES AND DISADVANTAGES

The environmental advantages and disadvantages are identified and assessed in Table 13.1 to provide the basis on which to determine whether the negative net environmental effects of the project are acceptable when compared to the positive benefits, screening criteria, and impact assessment. Advantages are defined as positive net environmental effects and disadvantages are negative net environmental effects.

The key aspects associated with the development of the MTS may be summarized through the identification of the advantages and disadvantages in Table 13.1 which indicate, in part, that the MTS will be located on a site zoned industrial where development has been already been initiated. This is in direct contrast to other areas within and adjacent to the defined Steeles Avenue/ 401/407 Employment Corridor where industrial development has not yet been initiated and active agriculture may still be practiced.

The location of the MTS adjacent to the HHGS allows for safe, reliable interconnections, and facilitates the distribution of electricity, not only to the Steeles Avenue corridor, but to other areas within the Halton Hills service area (i.e., Acton, Georgetown) and potentially additional outlying areas in the future.

The development of the MTS adjacent to the HHGS will have less of an aesthetic impact on the surrounding landscape, and thus area residents, through a blending of purposes related to electrical development and on-site landscaping to enhance the existing natural environment.

The disadvantages relating to noise and traffic are considered short-term and/or infrequent relating directly to construction activities which will occur over a time period of approximately one (1) year. The location of the MTS to the watercourse is considered negligible as the 15 m construction setback and the 30 m meander belt setback, determined during the HHGS study (SENES, 2007), will be observed during the development of the MTS. Permits will be obtained prior to the removal of any trees from the MTS site and a net benefit will be recognized as landscaping/planting requirements for the site will be undertaken.

This overall conclusion of this analysis of the advantages and disadvantages clearly illustrates that the negative net effects, generally negligible or short-term, of the MTS are offset by the advantages of the Project, both in meeting a need to address the demand for electricity of a growing urban area and minimizing the potential effect to the natural environment by locating the MTS on a site with existing industrial development in close proximity to electrical generation.

TABLE 13.1
ADVANTAGES AND DISADVANTAGES OF THE MTS

Advantages	Disadvantages
Site is currently being developed for industrial purposes.	Location adjacent to a watercourse with identified potential for presence of coldwater fisheries (negligible).
230 kV transmission circuits are available adjacent to the site (HHGS) reducing the operational complexity, safety risk of buried transmission circuits to the public.	Removal of a number of trees in Cultural Woodland (negligible).
Assists in reducing capacity loading on Milton TS.	Short-term and infrequent construction noise on local residents (two (2) receptors) and Hornby Park users.
Provides supply diversity with existing Hydro One station.	Short-term disruption of traffic to residents, businesses and Hornby Park users associated with construction vehicles.
The availability of 230 kV transmission circuits at HHGS eliminates substantial costs in new underground circuits.	
The site is currently zoned for prestige industrial.	
There are no interconnection effects associated with this site.	
Allows for future expansion into other areas serviced by Halton Hills Hydro outside of this corridor.	
Employment opportunities for thirty construction personnel over a one (1) year plus period.	
Provides additional distribution capacity from GTA West transmission system to support anticipated load growth through additional transformer station capacity along the Steeles Avenue corridor between James Snow Parkway and Trafalgar Road.	
Short-term business opportunities for suppliers of building materials and equipment.	
Cultural Woodland previously affected by development of HHGS.	
Change in aesthetics of landscape lessened by proximity to HHGS.	
Active agricultural land or “Greenfield” site not affected.	
Site aesthetics enhanced through landscaping to natural areas on-site.	

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Appendix A - Public Consultation

Appendix A-1 – Notice of Study Commencement

Appendix A-2 – Public Information Centre #1

Appendix A-1

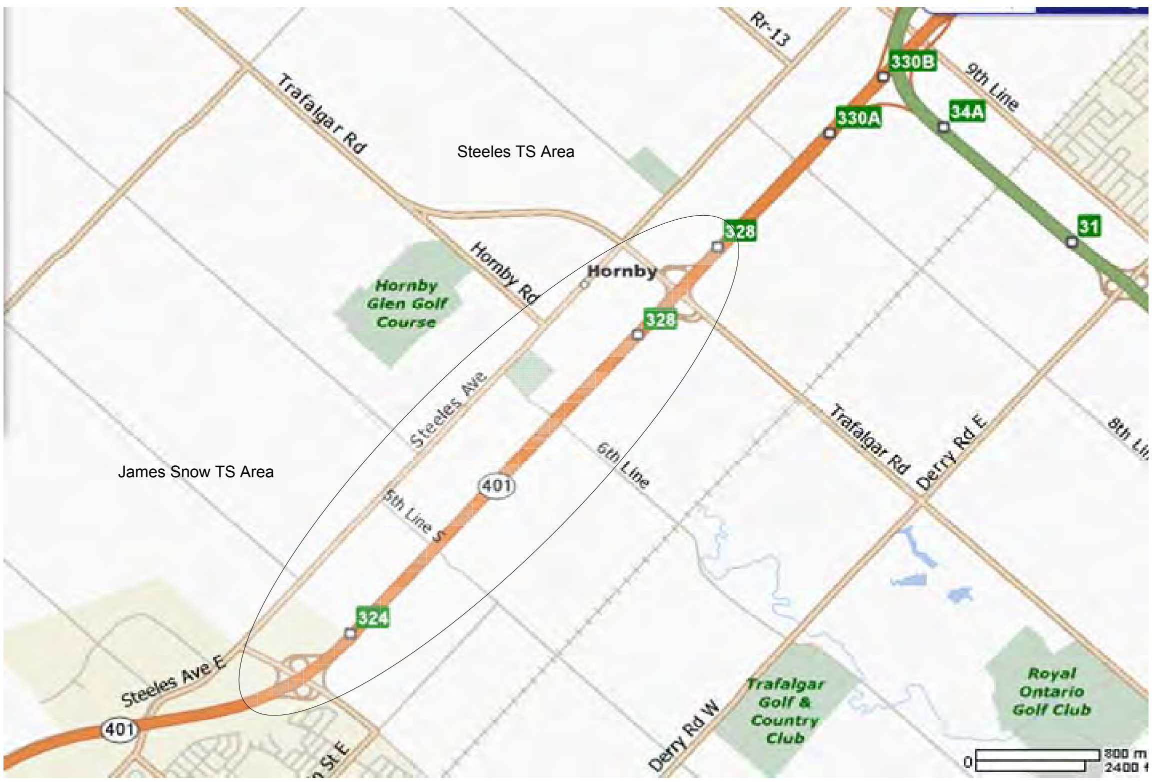
Notice of Study Commencement

Notice of Study Commencement

Halton Hills Hydro Transmission Station No. 1
Class Environmental Assessment

THE PROJECT

Halton Hills Hydro is initiating a plan to design, construct, and operate a 230/28 kV 125 MVA DESN municipal transformer station along the Steeles Avenue corridor between Trafalgar Road and James Snow Parkway. The proposed undertaking would connect to the existing distribution network at 27.6 kV to provide a reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills.



THE PROCESS

A Class Environmental Assessment (Class EA) for the proposed undertaking is required under *Ontario Regulation 116/01 – Electricity Projects* and subject to *Environmental Assessment Act* approval in accordance with the "Class EA for Minor Transmission Facilities". The Class EA is conducted to select a preferred site following a specified planning process to identify environmental effects and evaluate a number of alternative sites.

A comprehensive consultation process involving government agencies and the public will be initiated early in the study process by the Project Team commencing with stakeholder notification. A Public Information Centre (PIC), as part of the overall consultation process, is currently scheduled for Spring 2008 to provide opportunities for review and comment on Project initiatives. Notices providing the time and locations for each PIC will be published in local newspapers.

An Environmental Study Report (ESR) documenting the study results will be prepared and made available for a 30-day public review period nearing completion of the study. Notices informing the public of the commencement of this review period will also be published in local newspapers.

COMMENTS

If you would like to provide input to the study, request additional information, or have any questions related to the Project, please contact:

Ms. Kathryn Wherry
SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4
Phone: 905-764-9380 Ext. 435
E-mail: kwherry@senes.ca
Facsimile: 905-764-9386

Mr. Mike Maroschak, C.E.T.
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON
L7G 2A9
Phone: 519-853-3700 Ext. 240
E-mail: MikeM@haltonhillshydro.com
Facsimile: 519-853-5168

Information collected will be used in accordance with the *Freedom of Information and Protection of Privacy Act*. All comments will become part of the public record with the exception of personal information.

April 1, 2008

Agatha Garcia-Wright
Director, Environmental Assessment & Approvals Branch
Ministry of Environment
2 St. Clair Avenue West, 12A Floor
Toronto, Ontario
M4V 1L5

RE: HALTON HILLS HYDRO TRANSFORMER STATION - CLASS ENVIRONMENTAL ASSESSMENT

Dear Agatha,

Halton Hills Hydro Inc. is initiating a plan to design, construct, and operate a 230/28 kV 125 MVA DESN municipal transformer station in the Steeles Avenue corridor from Trafalgar Road to James Snow Parkway. The proposed undertaking would connect to the existing distribution network at 27.6 kV to provide a reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills.

A Class Environmental Assessment (Class EA) for the proposed undertaking is required under *Ontario Regulation 116/01 – Electricity Projects* and subject to *Environmental Assessment Act* approval in accordance with the "Class EA for Minor Transmission Facilities". The Class EA is conducted to select a preferred site following a specified planning and design process to identify environmental effects and evaluate a number of alternative sites.

A comprehensive consultation process involving government agencies and the public will be initiated early in the study process by the Project Team commencing with stakeholder notification. A Public Information Centre (PIC), as part of the overall consultation process, is currently scheduled for Spring 2008 to provide opportunities for review and comment on Project initiatives. Notices providing the time and locations for each PIC will be published in local newspapers.

Please review the attached information and return (fax or mail) page 3 to the undersigned indicating your agencies interest in participating in the study and the most appropriate contact for purposes of information collection and dissemination during the study.

If you have any further questions related to this Project or the information provided, please contact:

Ms. Kathryn Wherry
SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4
Phone: 905-764-9380, Ext. 435
E-mail: kwherry@senes.ca
Facsimile: 905-764-9386

Mr. Mike Maroschak, C.E.T.
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON
L7G 2A9
Phone: 519-853-3700, Ext. 240
E-mail: MikeM@haltonhillshydro.com
Facsimile: 519-853-5168

Yours truly,

Mike Maroschak, C.E.T.
Engineering Supervisor
Halton Hills Hydro Inc.

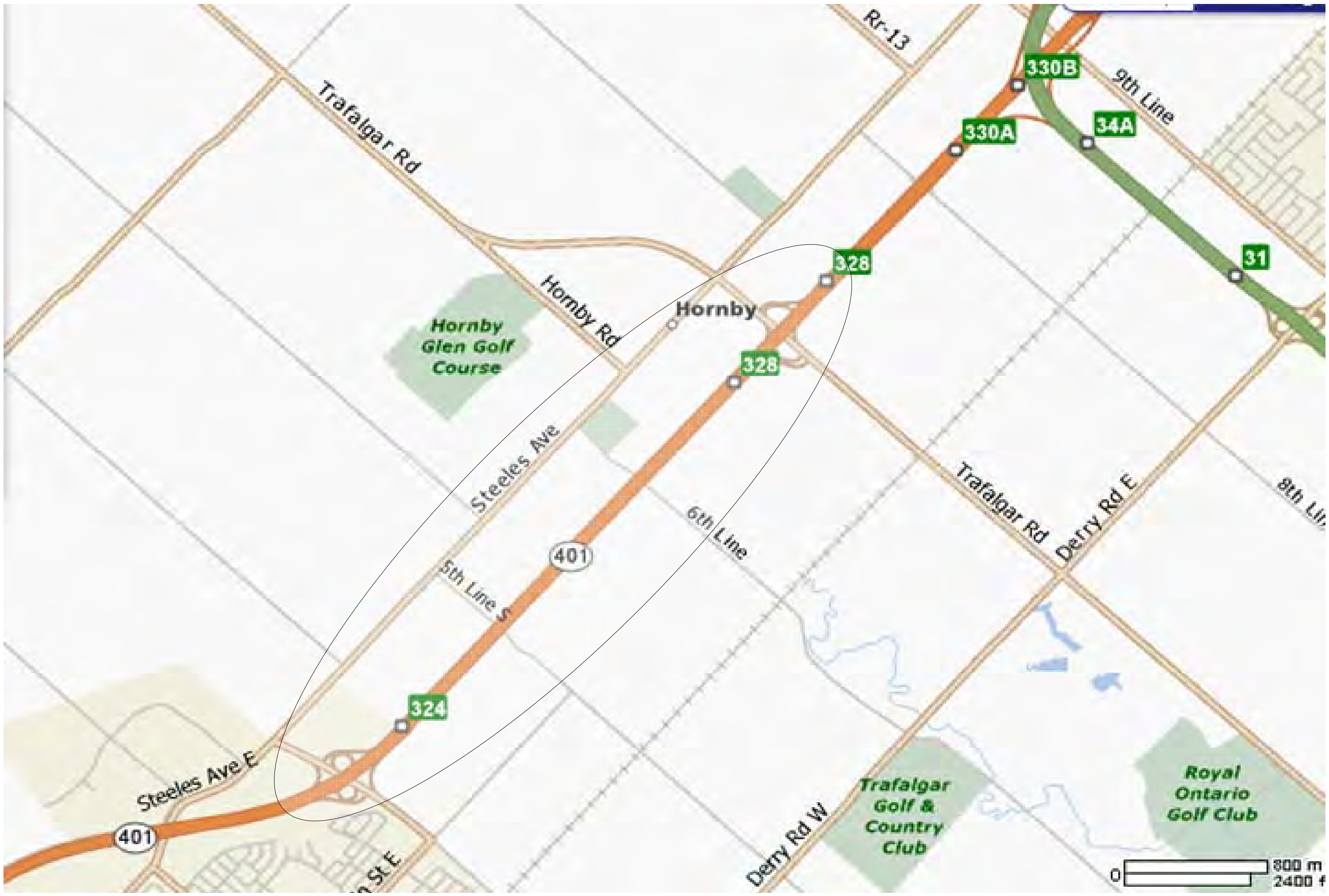
No further contact required ☐

Study information or technical input required ☐

Technical/Alternative Contact ______________________________
Name/Title/Contact Number

____
Signature

KEY PLAN


Rr-13
Trafalgar Rd
330B
9th Line
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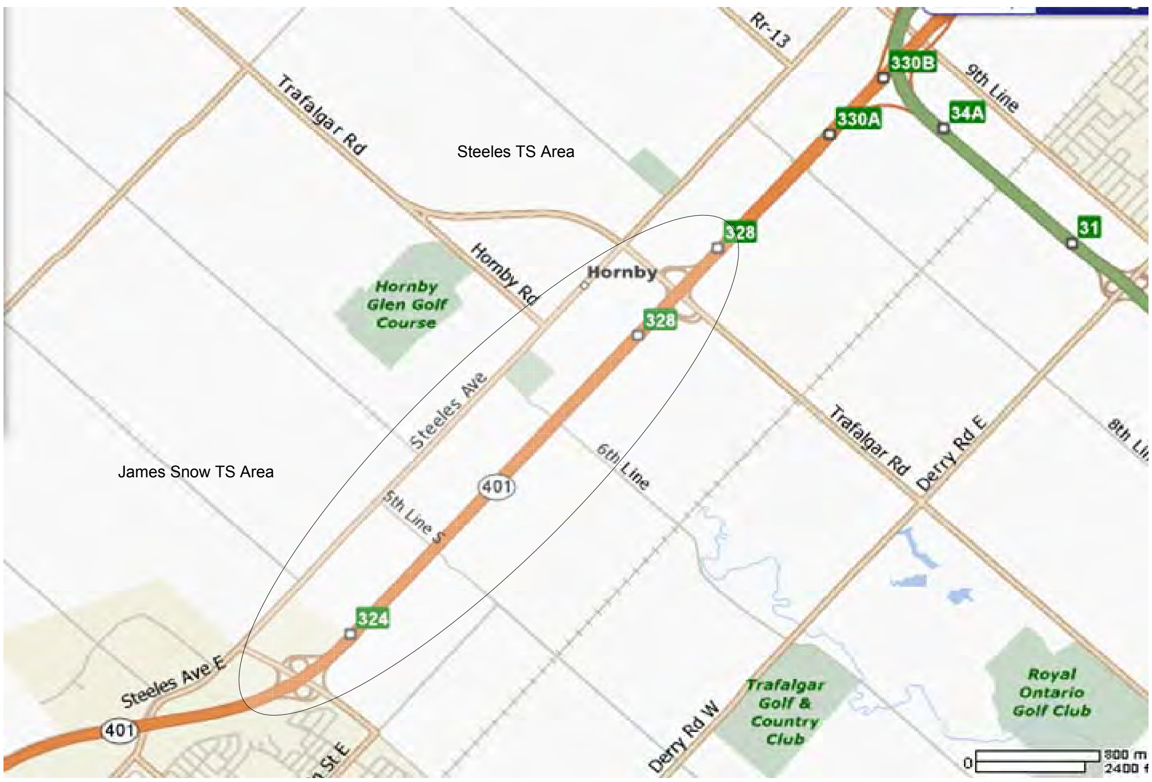
Appendix A-2

Public Information Centre #1

Halton Hills Hydro Municipal Transformer Station (MTS) No. 1
Class Environmental Assessment

NOTICE OF PUBLIC INFORMATION CENTRE

Halton Hills Hydro is initiating a plan to design, construct, and operate a 230/28 kV 125 MVA DESN municipal transformer station (MTS) along the Steeles Avenue corridor between Trafalgar Road and James Snow Parkway. The proposed undertaking would connect to the existing distribution network at 27.6 kV to provide a reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills.



The Class Environmental Assessment (Class EA) study will be conducted in accordance with "Class EA for Minor Transmission Facilities". The required consultation process was initiated for this study with the publication and notification of Study Commencement in the New Tanner on 27 March 2008, and the Georgetown Independent and Free Press on 2 April 2008. Additionally, as part of the on-going consultation process for this study, a Public Information Centre (PIC) will be held as follows:

Date: May 29, 2008
Time: 4:30pm to 7:00pm
Location: Hornby Glen Golf Course
8286 Hornby Road
Hornby, Ontario

The purpose of the PIC is to provide opportunities for review and comment on Project initiatives. Halton Hills Hydro staff and consultant representatives will be available at the PIC to provide clarification on the information displayed and receive comments.

If you would like to provide input to the study, request additional information, or have any questions related to the Project, please contact:

Ms. Kathryn Wherry
SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4
Phone: 905-764-9380 Ext. 435
E-mail: kwherry@senes.ca
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Mr. Mike Maroschak
Halton Hills Hydro Inc.
43 Alice Street
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Phone: 519-853-3700 Ext. 240
E-mail: MikeM@haltonhillshydro.com
Facsimile: 519-853-5168

Information collected will be used in accordance with the *Freedom of Information and Protection of Privacy Act*. All comments will become part of the public record with the exception of personal information.

April 1, 2008

Agatha Garcia-Wright
Director, Environmental Assessment & Approvals Branch
Ministry of Environment
2 St. Clair Avenue West, 12A Floor
Toronto, Ontario
M4V 1L5

RE: HALTON HILLS HYDRO TRANSFORMER STATION - CLASS ENVIRONMENTAL ASSESSMENT

Dear Agatha,

Halton Hills Hydro Inc. is initiating a plan to design, construct, and operate a 230/28 kV 125 MVA DESN municipal transformer station in the Steeles Avenue corridor from Trafalgar Road to James Snow Parkway. The proposed undertaking would connect to the existing distribution network at 27.6 kV to provide a reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills.

A Class Environmental Assessment (Class EA) for the proposed undertaking is required under *Ontario Regulation 116/01 – Electricity Projects* and subject to *Environmental Assessment Act* approval in accordance with the "Class EA for Minor Transmission Facilities". The Class EA is conducted to select a preferred site following a specified planning and design process to identify environmental effects and evaluate a number of alternative sites.

A comprehensive consultation process involving government agencies and the public will be initiated early in the study process by the Project Team commencing with stakeholder notification. A Public Information Centre (PIC), as part of the overall consultation process, is currently scheduled for Spring 2008 to provide opportunities for review and comment on Project initiatives. Notices providing the time and locations for each PIC will be published in local newspapers.

Please review the attached information and return (fax or mail) page 3 to the undersigned indicating your agencies interest in participating in the study and the most appropriate contact for purposes of information collection and dissemination during the study.

If you have any further questions related to this Project or the information provided, please contact:

Ms. Kathryn Wherry
SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4
Phone: 905-764-9380, Ext. 435
E-mail: kwherry@senes.ca
Facsimile: 905-764-9386

Mr. Mike Maroschak, C.E.T.
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON
L7G 2A9
Phone: 519-853-3700, Ext. 240
E-mail: MikeM@haltonhillshydro.com
Facsimile: 519-853-5168

Yours truly,

Mike Maroschak, C.E.T.
Engineering Supervisor
Halton Hills Hydro Inc.

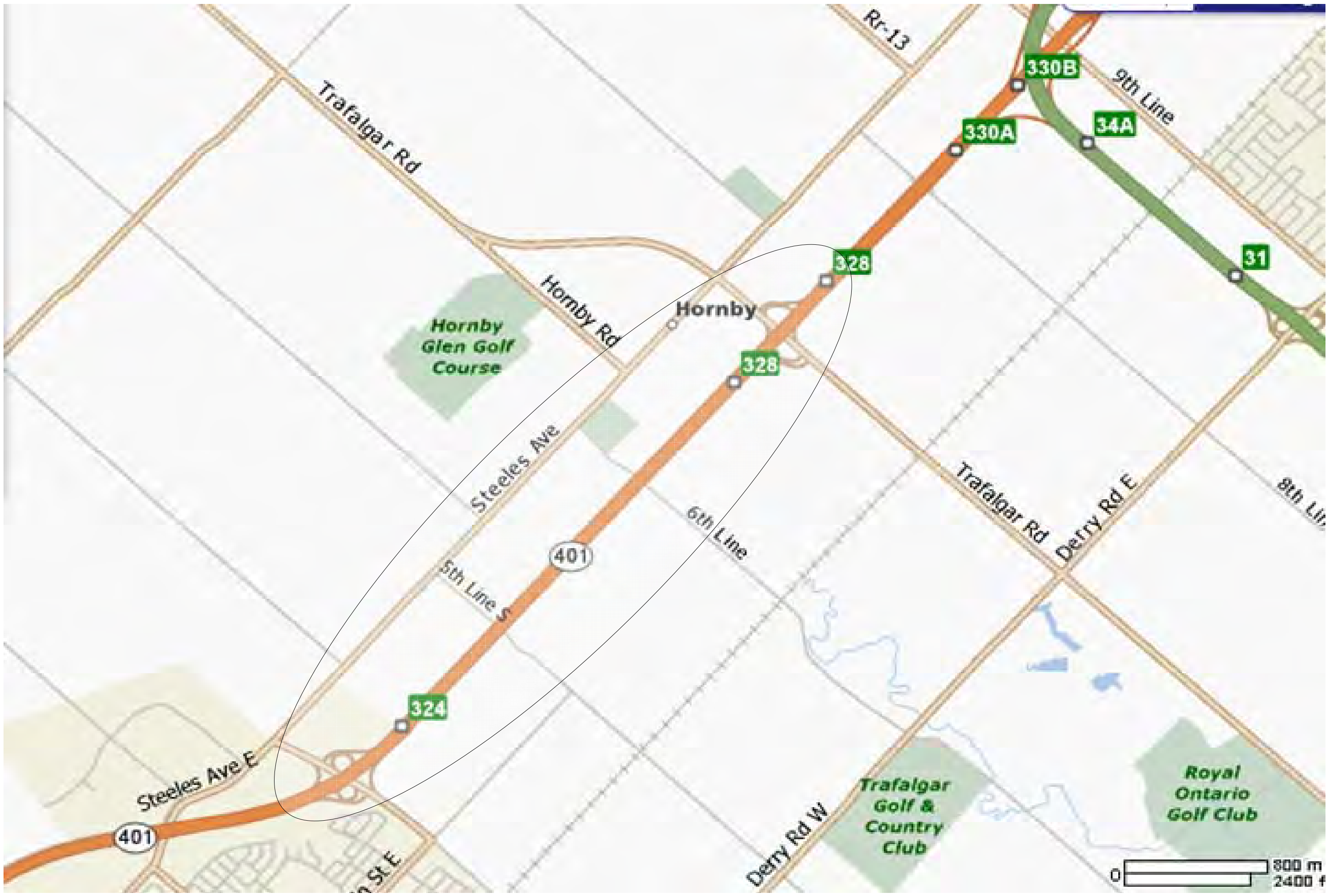
No further contact required ☐

Study information or technical input required ☐

Technical/Alternative Contact ______________________________
Name/Title/Contact Number

____
Signature

KEY PLAN


Rr-13
Trafalgar Rd
330B
9th Line
330A
34A
328
31
Hornby Rd
Hornby
Hornby Glen Golf Course
328
Steeles Ave
Trafalgar Rd
Derry Rd E
8th Li
6th Line
401
5th Line S
324
Steeles Ave E
401
Derry Rd W
Trafalgar Golf & Country Club
Royal Ontario Golf Club
0
800 m
2400 f

HALTON HILLS HYDRO MUNICIPAL TRANSFORMER STATION No. 1

CLASS ENVIRONMENTAL ASSESSMENT (CLASS EA)

PUBLIC INFORMATION CENTRE

Welcome

- Please sign-in to ensure receipt of future Project mailings.

- Please complete a Comment Sheet and either deposit it in the comment box or return by mail/fax or e-mail, if you would like to provide written comments.

All information is being gathered to assist Halton Hills Hydro in the planning process for this Project. All personal information, such as name, address, and telephone number, included on the comment sheets becomes part of the public record files for the Project and can be released to any person if requested under the Municipal Freedom of Information and Protection of Privacy Act, and the Environmental Assessment Act.

Halton Hills
HYDRO

Objective of Public Information Centre

- Introduce the Municipal Transformer Station (MTS) Project and the Provincial Class EA Process to the general public.

- Present the evaluation of the alternative MTS sites and the preferred location.

- Provide an opportunity for the general public to become informed and comment on Study progress to date.

Halton Hills HYDRO

Who is Halton Hills Hydro?

Halton Hills Hydro Inc. is located at 43 Alice Street, Halton Hills (Acton) Ontario. The service area is:

Halton Hills Hydro is committed to providing safe, reliable, and economic distribution of electricity.

Our core values are:

- Safety (Employee and Public);
- Customer Service;
- Reliability; and
- Profitability (Shareholder).

Our proposed MTS Project meets our core values in the area of reliability and customer service.

MTS #1 Project Overview

What?

- Provide an additional reliable source of power to address increased electricity demand as a result of new residential and industrial development in the Town of Halton Hills.

Where?

- Steeles Avenue corridor between Trafalgar Road and James Snow Parkway.

Why?

- Existing facilities are nearing capacity.

How?

- Design, construct, and operate a municipal transformer station that will step down voltage from a transmission level to distribution level.

Halton Hills HYDRO

Class EA Process

A Class Environmental Assessment (Class EA) for the proposed undertaking is required under Ontario Regulation 116/01 – Electricity Projects and subject to *Environmental Assessment Act* approval in accordance with the "Class EA for Minor Transmission Facilities".

Step 1

Establish Need

- Future system Condition
- Principal Considerations Determining System Adequacy
- System Analysis Methodology

System Options

- Do nothing
- Alternatives to Undertaking
- Select system options

Step 2

Define Study Area

Initial notification

Step 3

Identify and evaluate Options/ Alternatives

Environmental Inventory

Select Preferred Alternative

Public Information Centre (consultation)

Prepare Draft Environmental Study Report (ESR)

Final Notification

Step 4

30-day review period

Proceed with Undertaking

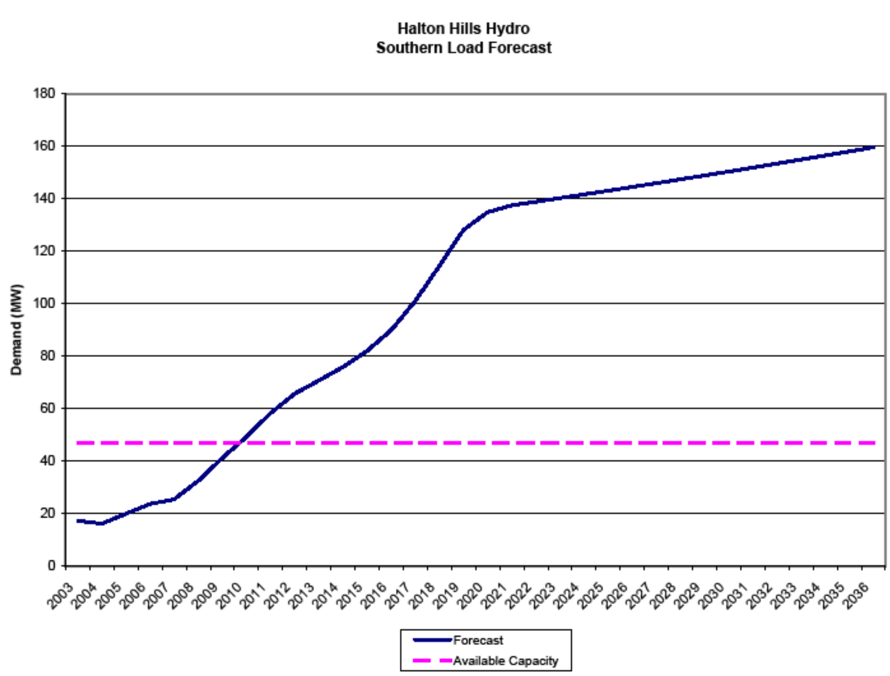
Issue Environmental Study Report (ESR)

Halton Hills
HYDRO

Need for Project

- Joint Planning Study initiated by Hydro One entitled "GTA West Supply Study" identified the need for additional transformer station capacity along the Steeles Avenue corridor between James Snow Parkway and Trafalgar Road to address future electricity needs.

- Study participants included:
  - Hydro One Networks Inc.;
  - Enersource (Hydro Mississauga);
  - Hydro One Brampton;
  - Milton Hydro Distribution; and,
  - Halton Hills Hydro.



Halton Hills HYDRO

Study Options to Undertaking

Three (3) study options considered:

Option 1 – Expand Halton Transformer Station (Hydro One) near Main St East and 4th Line in Milton.

Option 2 – Build a New Transformer Station.

Option 3 – Do Nothing.

Study Results

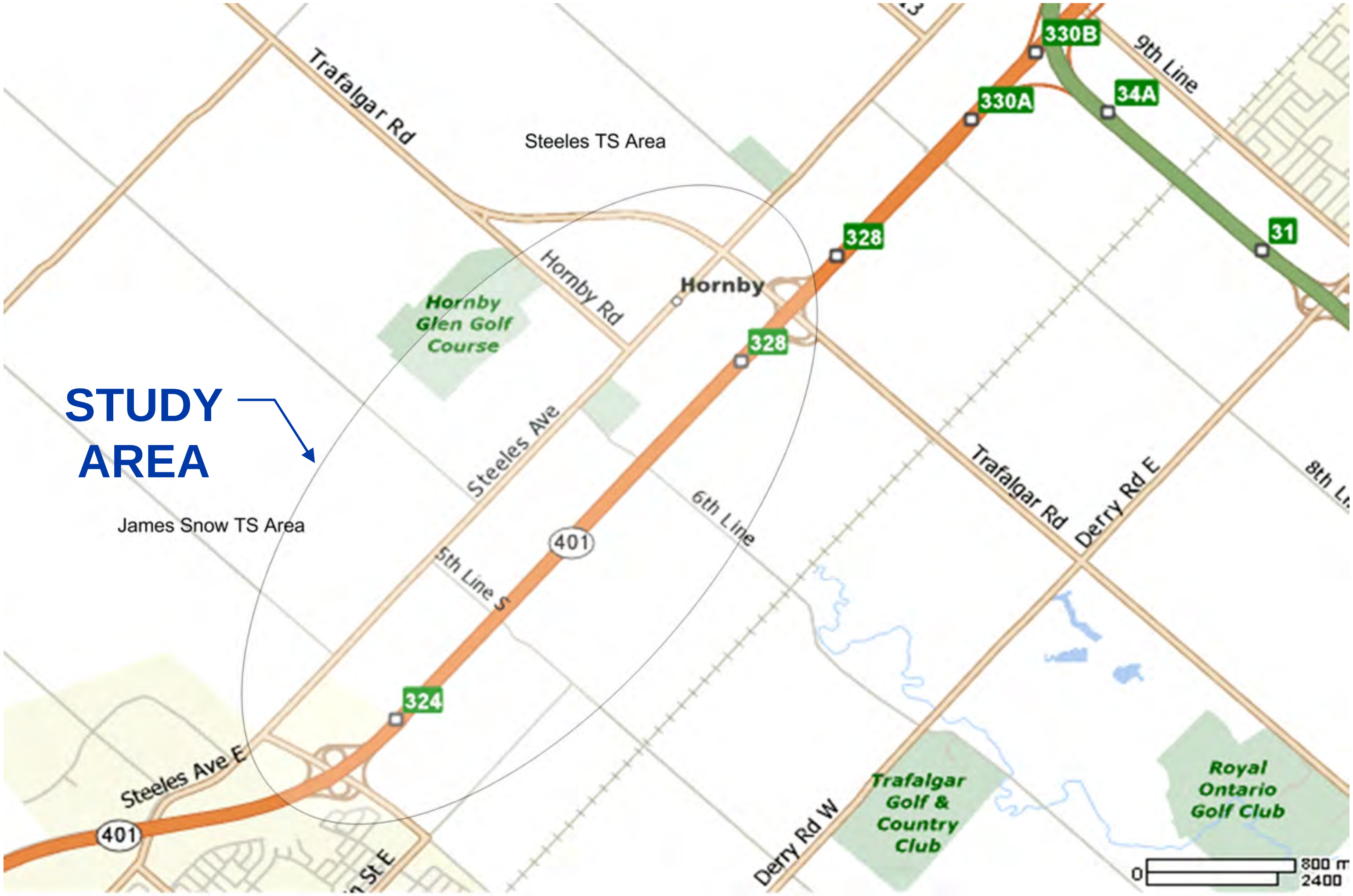
Option 1 – Unacceptable - Infrastructure limitation in area does not allow additional feeders out of Halton Transformer Station into the Halton Hills Hydro service territory.

Option 3 - Unacceptable - The existing supply will not meet the future increased electricity demand of the Halton Hills Hydro service territory.

Option 2 **- Accepted - Build a New Transformer Station was the preferred study option.**

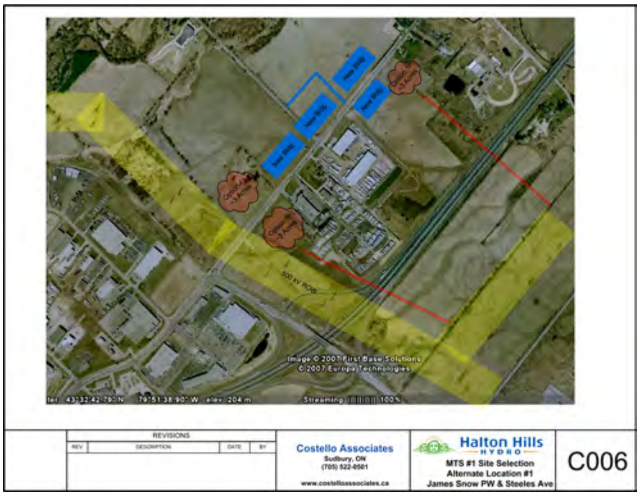
Halton Hills HYDRO

Study Area for Alternative Sites

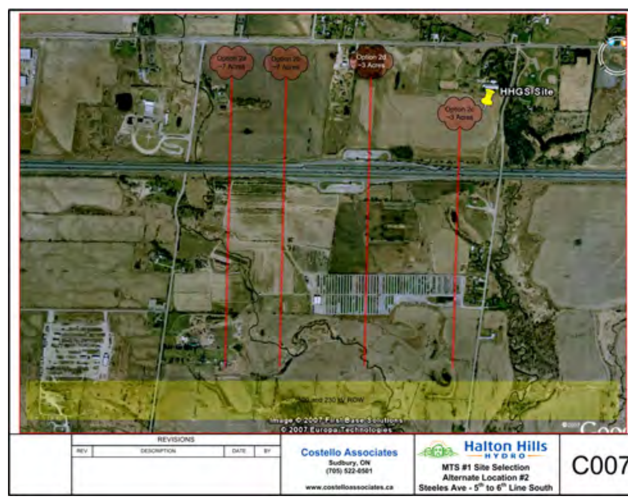


11 Alternative Site Locations

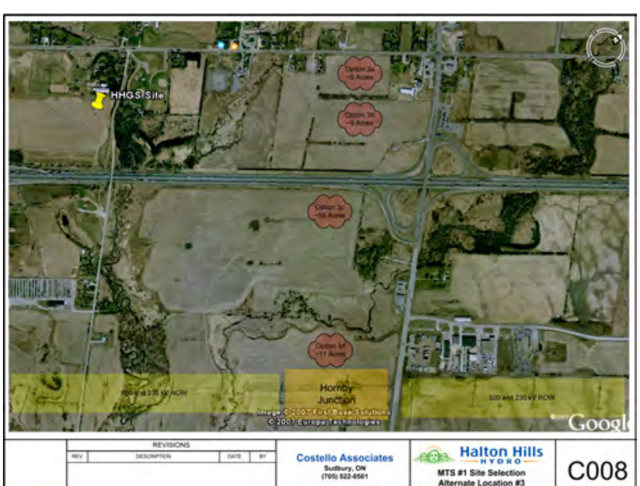
James Snow Pkwy. and Hwy 401
Sites 1a, 1b, 1c



Steeles Ave. between Fifth Line South and Sixth Line South
Sites 2a, 2b, 2c, 2d



Steeles Ave. and Trafalgar Rd.
Sites 3a, 3b, 3c, 3d



Process for Evaluation of Alternative Sites

Evaluation Criteria

Developed based on known concerns for the following three (3) components:

- **Technical** –Related to proximity to demand and transmission connection, available land size, availability of distribution circuits.
- **Environmental (Physical and Social)** – Related to terrestrial and aquatic ecology, existing/planned land uses, and cultural heritage.
- **Economic** – Related to total cost for completion (design and build) of MTS with consideration for equipment required.

Evaluation Process

1. Assess each of the alternative site locations for the potential effects on each component.
2. Determine an overall qualitative ranking for each of the alternative sites.
3. Select a preliminary preferred site to be studied in further detail.

Halton Hills
HYDRO

Evaluation of Alternative Sites

Table 1: Evaluation of Alternative Sites

Alternative Site Identification and Location	1A North side of Steeles Avenue, near James Snow Parkway	1B South side of Steeles Avenue, near James Snow Parkway	1C South side of Steeles Avenue, near 5th Line North	2A South side of Steeles Avenue, near 5th Line South	2B South side of Steeles Avenue, near 5th Line South (east of site 2A)	2C South side of Steeles, near 6th Line South (HHGS site)	2D South side of Steeles Avenue, forested area near 6th Line South (west of HHGS site)	3A South side of Steeles Avenue, just west of Trafalgar Road	3B South side of Steeles Avenue, just west of Trafalgar Road	3C Trafalgar Road, south side of Highway 401	3D Trafalgar Road, Hornby Junction (ORC Lands) – South of Highway 401
Technical Summary	*Unacceptable*	*Unacceptable*	*Low*	*Medium*	*Unacceptable*	*High*	*Medium*	*Medium*	*Medium*	*Unacceptable*	*Unacceptable*
Environmental Summary	*Low*	*Unacceptable*	*Low*	*Low*	*Low*	*Medium*	*Low*	*Unacceptable*	*Unacceptable*	*Low*	*Medium*
Cost Summary	*Unacceptable*	*Low*	*Low*	*Low*	*Low*	*High*	*Low*	*Low*	*Low*	*Low*	*High*
Overall Ranking	*Unacceptable*	*Unacceptable*	*Low*	*Low-Medium*	*Unacceptable*	*High-Medium*	*Low-Medium*	*Unacceptable*	*Unacceptable*	*Unacceptable*	*Unacceptable*

Evaluation Rankings:

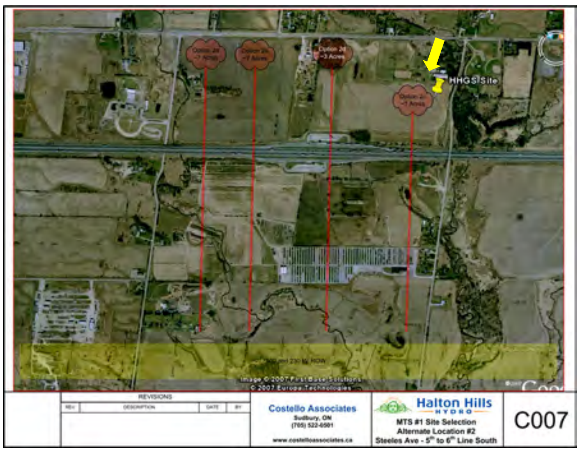
High Acceptability – No effects are associated or anticipated for this site based on identified criteria.
Medium Acceptability – Few effects have been identified although the potential exists to prevent or mitigate these effects through implementation of alternative measures and/or methodologies.
Low Acceptability - A number of effects have been identified although the potential for avoidance or mitigation is low.
Unacceptable – Effects or limitations identified are considerable (numerous) and mitigation or avoidance is not possible, therefore precluding the site from further consideration.

Halton Hills HYDRO

Preliminary Preferred Site Selected

Site 2C

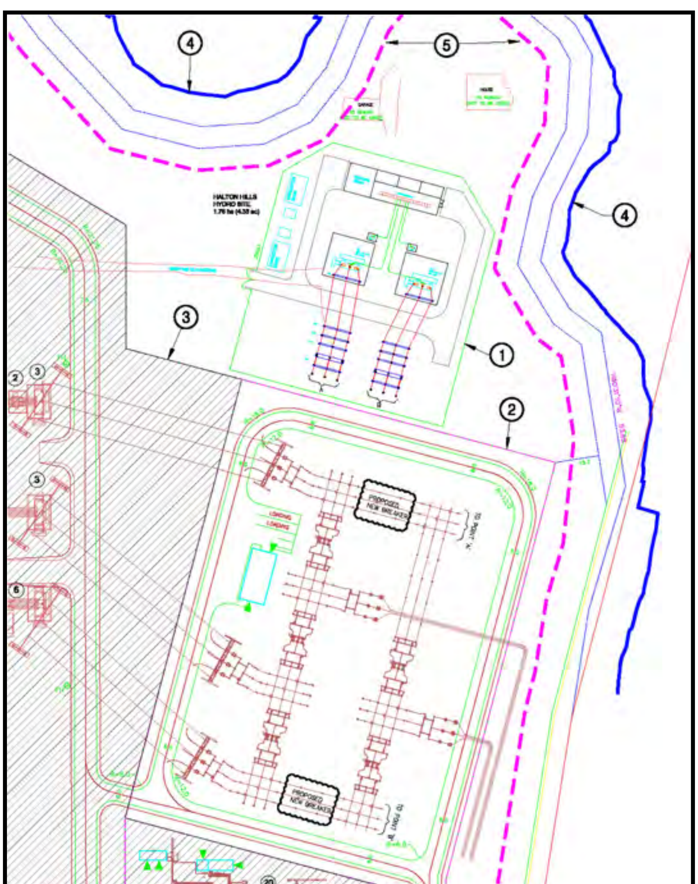
(as highlighted on Table 1: Evaluation of Alternative Sites)



Location:
Northeast corner of Halton Hills Generating Station Site.
-southwest of Eastern Sixteen Mile Creek Tributary and century home

Land Area Required:
1.76 ha (4.35 ac)

Site Layout



Attributes of Preferred Site

- Highest overall ranking and highest ranking for each of technical, environmental, and economic components.
- Located on industrial zoned site.
- Close proximity to electricity supply.
- Close proximity to market demand.

Halton Hills HYDRO

Details of Proposed Halton Hills Hydro MTS #1

Design, construct, and operate a municipal transformer station that will step down voltage from a transmission level to distribution level.

Construction

- **Anticipated Start Date:** March 2010
- **Construction Period:** 14 to 18 months
- **Number of Personnel:** Approximately 30

Operation

- **Commissioning:** May 2011
- **Expected Years of Operation:** 40+ years
- **Number of Permanent On-site Personnel:** 0

Halton Hills HYDRO

Public Consultation

Public consultation is a key component of a Class EA Study which is undertaken at various stages of the Study through different media.

- Newspaper notices and direct mailings to key government agencies and directly affected landowners/stakeholders at study commencement, public information centre (PIC), and study completion.
- PIC to present study findings and seek public input to the study.
- Communication between the public and the Project Team through informal discussions, meetings, and written correspondence.
- Filing of the Environmental Study Report (ESR) for public review and comment at the end of the study.

If you would like to provide input to the study, request additional information, or have any questions related to the Project, please contact:

Ms. Kathryn Wherry
SENES Consultants Limited
121 Granton Drive, Unit 12
Richmond Hill, Ontario
L4B 3N4
Phone: 905-764-9380 Ext. 435
E-mail: kwherry@senes.ca
Facsimile: 905-764-9386

Mr. Mike Maroschak
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON
L7J 2A9
Phone: 519-853-3700 Ext. 240
E-mail: MikeM@haltonhillshydro.com
Facsimile: 519-853-5168

Halton Hills HYDRO

Next Steps

- Receive and evaluate public comments on preferred site selection.
- Conduct detailed studies on selected Preferred Site for technical, environmental, and economic components.
- On-going consultation with public and government agencies.
- Prepare an ESR documenting the study results.
- Initiate a 30-day public review period nearing completion of the study to allow interested parties to review and comment on the ESR.

Halton Hills HYDRO

Appendix IRR - E

2018 ICM Model – revised 20190208

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Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 4.20

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	
Name of Contact and Title	David Smelsky, Chief Financial Officer
Phone Number	519-853-3700 x 208
Email Address	dsmelsky@haltonhillshydro.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2019**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Halton Hills Hydro Inc. is applying:	**3**
Halton Hills Hydro Inc. is applying for:	**ICM Approval**
Last Rebasing Year:	**2016**
The most recent complete year for which actual billing and load data exists	**2017**
Current IPI	**1.20%**
Strech Factor Assigned to Middle Cohort	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**0.90%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2017 Actual Distribution Demand}}{\text{Revenues Based on 2016 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 999 kW
4	GENERAL SERVICE 1,000 TO 4,999 kW
5	UNMETERED SCATTERED LOAD
6	SENTINEL LIGHTING
7	STREET LIGHTING

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2017 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2017 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	20,188	193,694,443		23.48	0.0034	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	1,810	50,527,239		28.37	0.0102	0.0000
GENERAL SERVICE 50 TO 999 kW	$/kW	186	135,373,696	394,783	86.83	0.0000	3.8580
GENERAL SERVICE 1,000 TO 4,999 kW	$/kW	11	99,309,703	262,132	185.55	0.0000	3.4705
UNMETERED SCATTERED LOAD	$/kWh	152	934,714		7.97	0.0054	0.0000
SENTINEL LIGHTING	$/kW	173	260,238	704	9.47	0.0000	35.9050
STREET LIGHTING	$/kW	4,674	1,128,400	3,155	2.30	0.0000	1.5523

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Calculation of pro forma 2016 Revenues. No input required.

Rate Class	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	2017 Actual Distribution Demand			Current Approved Distribution Rates										
Total	**0**	**0**	**0**	**D**	**E**	**F**	**0**	**0**	**0**	**0**	**K = G / J**	**L = H / J**	**M = I / J**	**0.0%**
RESIDENTIAL	20,188	193,694,443		23.48	0.0034	0.0000	5,688,171	658,561	0	6,346,732	89.6%	10.4%	0.0%	61.5%
GENERAL SERVICE LESS THAN 50 kW	1,810	50,527,239		28.37	0.0102	0.0000	616,196	515,378	0	1,131,574	54.5%	45.5%	0.0%	11.0%
GENERAL SERVICE 50 TO 999 kW	186	135,373,696	394,783	86.83	0.0000	3.8580	193,805	0	1,523,077	1,716,881	11.3%	0.0%	88.7%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	11	99,309,703	262,132	185.55	0.0000	3.4705	24,493	0	909,729	934,222	2.6%	0.0%	97.4%	9.0%
UNMETERED SCATTERED LOAD	152	934,714		7.97	0.0054	0.0000	14,537	5,047	0	19,585	74.2%	25.8%	0.0%	0.2%
SENTINEL LIGHTING	173	260,238	704	9.47	0.0000	35.9050	19,660	0	25,277	44,937	43.7%	0.0%	56.3%	0.4%
STREET LIGHTING	4,674	1,128,400	3,155	2.30	0.0000	1.5523	129,002	0	4,898	133,900	96.3%	0.0%	3.7%	1.3%
Total	**27,194**	**481,228,433**	**660,774**				**6,685,864**	**1,178,986**	**2,462,980**	**10,327,831**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Applicants Rate Base

Last COS Rebasing: 2016

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	81,716,296	A			
Add: CWIP Re-based Opening	$	4,516,245	B			
Re-based Capital Additions	$	7,708,601	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	-$	4,516,245	F			
Gross Fixed Assets - Re-based Closing	$	89,424,897	G			
Average Gross Fixed Assets				$	85,570,597	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	28,972,192	I			
Re-based Depreciation Expense	$	1,847,446	J			
Re-based Disposals	$	-	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	30,819,638	M			
Average Accumulated Depreciation				$	29,895,915	N = (I + M) / 2
Average Net Fixed Assets				**$**	**55,674,682**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	75,531,774	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**5,664,883**	R = P * Q
Rate Base				**$**	**61,339,565**	S = O + R

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$	2,453,583	W = S * T
Deemed Long Term Debt %	56.00%	U	$	34,350,156	X = S * U
Deemed Equity %	40.00%	V	$	24,535,826	Y = S * V
Short Term Interest	1.65%	Z	$	40,484	AC = W * Z
Long Term Interest	2.89%	AA	$	992,720	AD = X * AA
Return on Equity	9.19%	AB	$	2,254,842	AE = Y * AB
Return on Rate Base			**$**	**3,288,046**	AF = AC + AD + AE

Distribution Expenses

OM&A Expenses	$	6,007,592	AG			
Amortization	$	1,847,446	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	-	AJ			
Low Voltage			AK			
Transformer Allowance			AL			
Property Tax	$	104,440	AM			
			AN			
			AO			
				$	**7,959,478**	AP = SUM (AG : AO)

Revenue Offsets

Specific Service Charges	-$	375,470	AQ			
Late Payment Charges	-$	120,000	AR			
Other Distribution Income	-$	252,074	AS			
Other Income and Deductions	-$	211,600	AT	**-$**	**959,144**	AU = SUM (AQ : AT)

Revenue Requirement from Distribution Rates	**$**	**10,288,380**	AV = AF + AP + AU

Rate Classes Revenue

Rate Classes Revenue - Total (Sheet 5)	$	10,327,831	AW
Difference	-$	39,451	AZ = AV - AW
Difference (Percentage - should be less than ±1%)		-0.38%	BA = AZ / AW

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2016 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2016 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	**Billed Customers or Connections**	**Billed kWh**	**Billed kW**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Service Charge Revenue**	**Distribution Volumetric Rate Revenue kWh**	**Distribution Volumetric Rate Revenue kW**	**Total Revenue By Rate Class**	**Service Charge % Revenue**	**Distribution Volumetric Rate % Revenue kWh**	**Distribution Volumetric Rate % Revenue kW**	**Total % Revenue**
Total	**0**	**0**	**0**	**D**	**E**	**F**	**0**	**0**	**0**	**0**	**$K = G / J_{total}$**	**$L = H / J_{total}$**	**$M = I / J_{total}$**	**0.0%**
RESIDENTIAL	19,971	205,578,737		23.48	0.0034	0.0000	5,627,029	698,968	0	6,325,997	53.7%	6.7%	0.0%	60.3%
GENERAL SERVICE LESS THAN 50 kW	1,967	58,991,538		28.37	0.0102	0.0000	669,645	601,714	0	1,271,359	6.4%	5.7%	0.0%	12.1%
GENERAL SERVICE 50 TO 999 kW	206	136,566,740	362,031	86.83	0.0000	3.8580	214,644	0	1,396,719	1,611,363	2.0%	0.0%	13.3%	15.4%
GENERAL SERVICE 1,000 TO 4,999 kW	13	112,173,675	302,644	185.55	0.0000	3.4705	28,946	0	1,050,326	1,079,272	0.3%	0.0%	10.0%	10.3%
UNMETERED SCATTERED LOAD	144	895,971		7.97	0.0054	0.0000	13,772	4,838	0	18,610	0.1%	0.0%	0.0%	0.2%
SENTINEL LIGHTING	175	461,109	628	9.47	0.0000	35.9050	19,830	0	22,548	42,379	0.2%	0.0%	0.2%	0.4%
STREET LIGHTING	4,649	1,535,681	4,282	2.30	0.0000	1.5523	128,299	0	6,647	134,946	1.2%	0.0%	0.1%	1.3%
Total	**27,124**	**516,203,452**	**669,585**				**6,702,165**	**1,305,520**	**2,476,241**	**10,483,925**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2017 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	A	B	C	D	E	F	0	0	0	0	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	0.0%
RESIDENTIAL	23.48	0.0034	0.0000	20,188	193,694,443		5,688,171	658,561	0	6,346,732	55.08%	6.38%	0.00%	61.5%
GENERAL SERVICE LESS THAN 50 kW	28.37	0.0102	0.0000	1,810	50,527,239		616,196	515,378	0	1,131,574	5.97%	4.99%	0.00%	11.0%
GENERAL SERVICE 50 TO 999 kW	86.83	0.0000	3.8580	186	135,373,696	394,783	193,805	0	1,523,073	1,716,877	1.88%	0.00%	14.75%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	185.55	0.0000	3.4705	11	99,309,703	262,132	24,493	0	909,729	934,222	0.24%	0.00%	8.81%	9.0%
UNMETERED SCATTERED LOAD	7.97	0.0054	0.0000	152	934,714		14,537	5,047	0	19,585	0.14%	0.05%	0.00%	0.2%
SENTINEL LIGHTING	9.47	0.0000	35.9050	173	260,238	704	19,660	0	25,277	44,937	0.19%	0.00%	0.24%	0.4%
STREET LIGHTING	2.30	0.0000	1.5523	4,674	1,128,400	3,155	129,002	0	4,898	133,900	1.25%	0.00%	0.05%	1.3%
Total							**6,685,864**	**1,178,986**	**2,462,977**	**10,327,827**				**100.0%**

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Ontario Energy Board

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2016**	
Price Cap IR Year in which Application is made		**3**	n
Price Cap Index		**0.90%**	PCI
Growth Factor Calculation			
Revenues Based on 2017 Actual Distribution Demand		**$10,327,831**	
Revenues Based on 2016 Board-Approved Distribution Demand		**$10,483,925**	
Growth Factor		**-1.49%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	81,716,296	
Add: CWIP Opening	$	4,516,245	
Capital Additions	$	7,708,601	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	4,516,245	
Gross Fixed Assets - Closing	$	89,424,897	
Average Gross Fixed Assets	$	85,570,597	
Accumulated Depreciation - Opening	$	28,972,192	
Depreciation Expense	$	1,847,446	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	30,819,638	
Average Accumulated Depreciation	$	29,895,915	
Average Net Fixed Assets	$	55,674,682	
Working Capital Allowance			
Working Capital Allowance Base	$	75,531,774	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	5,664,883	
Rate Base	**$**	**61,339,565**	RB
Depreciation	**$**	**1,847,446**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2017	**90%**
Price Cap IR Year 2018	**90%**
Price Cap IR Year 2019	**90%**
Price Cap IR Year 2020	**90%**
Price Cap IR Year 2021	**90%**
Price Cap IR Year 2022	**91%**
Price Cap IR Year 2023	**91%**
Price Cap IR Year 2024	**91%**
Price Cap IR Year 2025	**91%**
Price Cap IR Year 2026	**91%**

Threshold CAPEX — $Threshold\ Value\ \times d$

Price Cap IR Year 2017	**$**	**1,662,747**
Price Cap IR Year 2018	**$**	**1,664,972**
Price Cap IR Year 2019	**$**	**1,667,184**
Price Cap IR Year 2020	**$**	**1,669,382**
Price Cap IR Year 2021	**$**	**1,671,568**
Price Cap IR Year 2022	**$**	**1,673,740**
Price Cap IR Year 2023	**$**	**1,675,898**
Price Cap IR Year 2024	**$**	**1,678,044**
Price Cap IR Year 2025	**$**	**1,680,177**
Price Cap IR Year 2026	**$**	**1,682,298**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2016	Price Cap IR Year 1 2017	Price Cap IR Year 2 2018	Price Cap IR Year 3 2019	Price Cap IR Year 4 2020	Price Cap IR (Deferred Rebasing) Year 5 2021	Year 6 2022	Year 7 2023	Year 8 2024	Year 9 2025	Year 10 2026
Distribution System Plan CAPEX	$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827						
Materiality Threshold		$ 1,662,747	$ 1,664,972	$ 1,667,184	$ 1,669,382	$ 1,671,568	$ 1,673,740	$ 1,675,898	$ 1,678,044	$ 1,678,044	$ 1,678,044
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 9,433,192	$ 5,237,242	$ 28,968,640	$ 6,480,445	$ -	$ -	$ -	$ -	$ -	$ -

Project Descriptions:	**Type**	**Test Year 2016**	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**	**Year 5 2021**	**Year 6 2022**	**Year 7 2023**	**Year 8 2024**	**Year 9 2025**	**Year 10 2026**	**Total**
TS Switchgear - Gas, Transformer	**New ICM**				$ 6,789,816								**$ 6,789,816**
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**				$ 9,060,154								**$ 9,060,154**
Duct & Civil, Building	**New ICM**				$ 6,408,952								**$ 6,408,952**
SCADA & DC System	**New ICM**				$ 230,519								**$ 230,519**
Land	**New ICM**				$ 987,000								**$ 987,000**
													$ -
													$ -
													$ -
													$ -
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													$ -
													$ -
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 23,476,441**
Maximum Allowed Incremental Capital			$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441

	Test Year 2016	Price Cap IR Year 1 2017	Year 2 2018	Year 3 2019	Year 4 2020
Distribution System Plan CAPEX	$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827
Materiality Threshold		$ 1,662,747	$ 1,664,972	$ 1,667,184	$ 1,669,382
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 9,433,192	$ 5,237,242	$ 28,968,640	$ 6,480,445

Project Descriptions:	**Type**	**Test Year** 2016	**Year 1 2017** Proposed ACM/ICM	**Year 1 2017** Amortization Expense	**Year 1 2017** CCA	**Year 2 2018** Proposed ACM/ICM	**Year 2 2018** Amortization Expense	**Year 2 2018** CCA	**Year 3 2019** Proposed ACM/ICM	**Year 3 2019** Amortization Expense	**Year 3 2019** CCA	**Year 4 2020** Proposed ACM/ICM	**Year 4 2020** Amortization Expense	**Year 4 2020** CCA
TS Switchgear - Gas, Transformer	**New ICM**		$ -	$ -	$ -	$ -			**$ 6,789,816**	$ 196,505	$ 543,185	$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**		$ -	$ -		$ -			**$ 9,060,154**	$ 243,061	$ 724,812	$ -		
Duct & Civil, Building	**New ICM**		$ -			$ -			**$ 6,408,952**	$ 153,855	$ 512,716	$ -		
SCADA & DC System	**New ICM**		$ -			$ -			**$ 230,519**	$ 15,368	$ 103,734	$ -		
Land	**New ICM**		$ -			$ -			**$ 987,000**	$ -	$ -	$ -		
			$ -			$ -			$ -			$ -		
			$ -			$ -			$ -			$ -		
			$ -			$ -			$ -			$ -		
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			$ -			$ -			$ -			$ -		
			$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441	$ 608,789	$ 1,884,447	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR

		Year 5 2021	Year 6 2022	Year 7 2023	Year 8 2024
Distribution System Plan CAPEX		$ -	$ -	$ -	$ -
Materiality Threshold		$ 1,671,568	$ 1,673,740	$ 1,675,898	$ 1,678,044
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

		Year 5 2021			Year 6 2022			Year 7 2023			Year 8 2024		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	**New ICM**	$ -			$ -	$ -		$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**	$ -			$ -	$ -		$ -			$ -		
Duct & Civil, Building	**New ICM**	$ -			$ -			$ -			$ -		
SCADA & DC System	**New ICM**	$ -			$ -			$ -			$ -		
Land	**New ICM**	$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
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		$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

Price Cap IR

		Year 9 2025	Year 10 2026
Distribution System Plan CAPEX		$ -	$ -
Materiality Threshold		$ 1,678,044	$ 1,678,044
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -

		Year 9 2025			Year 10 2026		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	**New ICM**	$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**	$ -			$ -		
Duct & Civil, Building	**New ICM**	$ -			$ -		
SCADA & DC System	**New ICM**	$ -			$ -		
Land	**New ICM**	$ -			$ -		
		$ -			$ -		
		$ -			$ -		
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		$ -			$ -		
		$ -			$ -		
		$ -			$ -		
		$ -			$ -		
Total Cost ofACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Incremental Capital Adjustment **Rate Year:** **2019**

Current Revenue Requirement

Current Revenue Requirement - Total	$	10,288,380	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$23,476,441	$ 23,476,441	B
Depreciation Expense	$ 608,789	$ 608,789	C
CCA	$ 1,884,447	$ 1,884,447	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	23,476,441	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	608,789	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	23,172,047	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	926,882	G = D * E
Deemed Long-Term Debt	56.0%	F	$	12,976,346	H = D * F
	Rate (%)				
Short-Term Interest	1.65%	I	$	15,294	K = G * I
Long-Term Interest	2.89%	J	$	375,016	L = H * J
Return on Rate Base - Interest			$	390,310	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	9,268,819	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.19%	O	$	851,804	Q = P * O
Return on Rate Base - Total			$	1,242,114	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	608,789	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	851,804	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	608,789	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	1,884,447	V
Incremental Taxable Income			-$	423,854	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	112,321	Y = W * X
Grossed-Up Taxes/PILs			-$	152,818	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	1,242,114	AA
Amortization Expense - Total	S	$	608,789	AB
Grossed-Up Taxes/PILs	Z	-$	152,818	AC
Incremental Revenue Requirement		$	1,698,085	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Calculation of incremental rate rider. Choose one of the 3 options:

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	55.08%	6.38%	0.00%	935,240	108,280	0	1,043,520	20,188	193,694,443		4.31	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.97%	4.99%	0.00%	101,314	84,738	0	186,052	1,810	50,527,239		4.66	0.0017	0.0000
GENERAL SERVICE 50 TO 999 kW	1.88%	0.00%	14.75%	31,865	0	250,421	282,286	186	135,373,696	394,783	14.28	0.0000	0.6343
GENERAL SERVICE 1,000 TO 4,999 kW	0.24%	0.00%	8.81%	4,027	0	149,576	153,603	11	99,309,703	262,132	30.51	0.0000	0.5706
UNMETERED SCATTERED LOAD	0.14%	0.05%	0.00%	2,390	830	0	3,220	152	934,714		1.31	0.0009	0.0000
SENTINEL LIGHTING	0.19%	0.00%	0.24%	3,232	0	4,156	7,388	173	260,238	704	1.56	0.0000	5.9034
STREET LIGHTING	1.25%	0.00%	0.05%	21,210	0	805	22,016	4,674	1,128,400	3,155	0.38	0.0000	0.2552
Total	**64.74%**	**11.42%**	**23.85%**	**1,099,279**	**193,847**	**404,959**	**1,698,085**	**27,194**	**481,228,433**	**660,774**			
							1,698,085						
							From Sheet 11, E93						

Rate Rider Calculation

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	From Sheet 8	From Sheet 8	Col C * Col I total	Col D* Col I total	Col E* Col I total		From Sheet 4	From Sheet 4	From Sheet 4	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.45%	0.00%	0.00%	$ 1,124,339	$ -	$ -	$ 1,124,339	20,188	193,694,443	-	$ 4.64	$ -	$ -
GENERAL SERVICE LESS THAN 50 KW	5.97%	4.99%	0.00%	$ 109,161	$ 91,300	$ -	$ 200,461	1,810	50,527,239	-	$ 5.03	$ 0.0018	$ -
GENERAL SERVICE 50 TO 999 KW	1.88%	0.00%	14.75%	$ 34,333	$ -	$ 269,816	$ 304,149	186	135,373,696	394,783	$ 15.38	$ -	$ 0.6835
GENERAL SERVICE 1,000 TO 4,999 KW	0.24%	0.00%	8.81%	$ 4,339	$ -	$ 161,161	$ 165,500	11	99,309,703	262,132	$ 32.87	$ -	$ 0.6148
UNMETERED SCATTERED LOAD	0.14%	0.05%	0.00%	$ 2,575	$ 894	$ -	$ 3,469	152	934,714	-	$ 1.41	$ 0.0010	$ -
SENTINEL LIGHTING	0.19%	0.00%	0.24%	$ 3,483	$ -	$ 4,478	$ 7,961	173	260,238	704	$ 1.68	$ -	$ 6.3607
STREET LIGHTING	1.25%	0.00%	0.05%	$ 22,853	$ -	$ 868	$ 23,721	4,674	1,128,400	3,155	$ 0.41	$ -	$ 0.2750
Total	71.11%	5.04%	23.85%	$ 1,301,083	$ 92,195	$ 436,322	$ 1,829,600	27,194	481,228,433	660,774			
			100.00%										
							$ 1,829,600						

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Appendix IRR – F

HHGS & HHHI Connection Agreement

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November 11, 2013

SENT BY COURIER & ELECTRONIC MAIL (BoardSec@ontarioenergyboard.ca)

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

Dear Ms Walli:

Halton Hills Hydro Inc. ("HHH") and TransCanada Energy Ltd. ("TCE")
Connection Agreement Submission (Halton Hills Generating Station)
Subsection 4.0.2.1(2), Ontario Regulation 161/99

Pursuant to subsection 4.0.2.1(2) of O. Reg. 161/99, we are jointly submitting to the Board a form of connection agreement (the "**Connection Agreement**") agreed upon by our respective companies regarding the connection of HHH's distribution system to the TCE switchyard located at the Halton Hills Generating Station (the "**TCE Facility**"). We are also enclosing an Amended and Restated Memorandum of Understanding ("**MOU**") between TCE and HHH which establishes a framework for subsequent steps in the connection process. This MOU is submitted as background information to assist the Board in its review of the Connection Agreement.

Pursuant to subsection 4.0.2.1(2) of O. Reg. 161/99, once HHH's distribution assets are connected to the TCE Facility, TCE would be exempt from a variety of provisions of the *Ontario Energy Board Act, 1998* (as amended) (the "**OEB Act**"), provided the Board does not make an order rejecting the enclosed the Connection Agreement. There are no explicit criteria or factors in O. Reg. 161/99 to guide the Board's discretion as to whether to reject the Connection Agreement or not. Consequently, the Board's discretion must be guided by the applicable statutory objectives as set out in subsection 1(1) of the OEB Act, namely:

- protecting the interests of consumers with respect to electricity prices;

- protecting the interests of consumers with respect to the adequacy, reliability and quality of electricity service;

- promoting economic efficiency and cost effectiveness in the transmission and distribution of electricity; and

- facilitating the maintenance of a financially viable electricity industry.

In HHH's and TCE's submission, the connection of HHH's distribution system to the TCE Facility will further these statutory objectives, and consequently, we respectfully ask that the Board should refrain from making an order rejecting the Connection Agreement.

Background

In HHH's 2008 cost of service application, it was noted that the industrial growth expectations for the Highway 401 corridor at the south end of HHH's service area were significant, and would result in a commensurate increase in electrical load. Based on these projections, it was apparent at the time that HHH would need a new connection point to the IESO-controlled grid (i.e., the transmission system) in the area. During the development of the Halton Hills Generation Station, HHH and TCE discussed locating a new HHH transformer station on land immediately adjacent to the TCE Facility, and providing HHH with an option to connect to meet HHH's expected load growth in the area. TCE made provision for this potential connection by leaving sufficient space in the design and layout of their ring bus for two additional circuit breakers.

Plans to establish the connection were temporarily suspended later in 2008 due to the economic downturn. Today, HHH has approximately 30% remaining capacity on its existing distribution feeders that originate from Halton TS. This capacity could disappear virtually overnight with a return to the economic conditions that prevailed prior to 2008. Indeed, growth in the south end of HHH's service area has picked up recently, with the establishment of the new Toronto Premium Outlet Mall (4MW load) and plans for 1,000,000 square feet of warehouse space. Recognizing that the design, build and commissioning of a new transformer station will take a minimum of two years to complete, HHH re-initiated discussions with TCE in 2011 to move forward with plans for establishing the new connection point.

Discussions

Since 2011 HHH and TCE have had numerous meetings with representatives from the Independent Electricity System Operator ("**IESO**"), Hydro One Networks Inc. ("**HONI**"), the Ministry of Energy, and Ontario Energy Board staff. At these meetings, a variety of issues were discussed as part of the project planning and development phase, namely:

- technical issues and requirements related to making the connection;

- regulatory issues and requirements related to making the connection; and

- financial and other benefits associated with making the connection.

The Ministry of Energy is supportive of the project, and demonstrated its support by enacting O. Reg. 219/13, which amended O. Reg. 161/99 to provide for the regulatory exemptions associated with the connection of HHH's distribution system to the TCE Facility. The proposed amendment was posted on the Environmental Registry website on May 10, 2013. No comments were received during the comment period (which ended June 24, 2013). The amendment was adopted and consolidated with O. Reg. 161/99 on July 19, 2013.

The Form of Connection Agreement

Negotiations between TCE and HHH on a Connection Agreement were completed in October 2013. The form of Connection Agreement has been approved by both TCE and HHH, and is attached hereto as Appendix A. The Connection Agreement will be signed at the time the physical work is complete and the connection is ready for operation. Until then, and subject to the Board's disposition of this matter, HHH and TCE will continue to work cooperatively together through the project development and construction phases. During this time period, a number of other agreements will be entered into between HHH and TCE (e.g., Land Purchase Agreement, Project Development Agreement, Metering Agreement, etc.). The MOU between TCE and HHH (attached as Appendix B) is meant to provide a road-map for TCE and HHH through the project development and construction phases, and will be updated and amended as the parties deem necessary.

The Connection Agreement is based on the Board's standard form of connection agreement for load customers in Appendix 1 of the Board's Transmission System Code ("**TSC**"). As such, it provides for the typical rights and obligations that govern connections between loads and rate-regulated transmitters that are required to use the TSC's version of the Connection Agreement. Further, HHH is protected in the event that TCE decides to sell either its entire Halton Hills Generating Station or its generator connection line alone – specifically: (a) section 5.2 of the Connection Agreement ensures that any TCE successor that takes ownership of the entire Halton Hills Generating Station is bound by the terms of the Connection Agreement; and (b) section 28 of the Connection Agreement provides HHH with a right of first refusal should TCE attempt to sell the generator connection line alone.

Benefits

There are two major benefits associated with the connection of HHH's distribution system to the TCE Facility:

- the connection will satisfy HHH's need for a new connection point to provide adequate, reliable electricity supply in the southern region of HHH's service area; and

- there are significant cost savings associated with connecting to the TCE Facility, which accrue entirely to HHH's ratepayers largely because HHH is gaining access for use of TCE's existing generator connection line which runs south from the

Halton Hills Generating Station under Highway 401 connecting to the IESO-controlled grid

- this arrangement between TCE and HHH translates into a smaller rate base for HHH, and the consequent savings that flow from that.

Neither TCE nor HHH reap any financial benefit from the connection. TCE is not charging HHH for the connection of HHH's distribution system to the TCE Facility. Under the terms of the Connection Agreement, if TCE has any capital and operating costs associated with making the connection those costs will be covered by HHH. However, TCE receives no other revenues or payments from HHH or its ratepayers. From HHH's perspective, it is ensuring that it will meet its obligation to customers to provide adequate, reliable power in the most cost-effective manner possible.

Conclusion

The connection of HHH's distribution system to the TCE Facility allows for a more efficient connection solution that would result in decreased costs for HHH's customers when compared to other alternatives, while still providing for OEB oversight to protect the interests of HHH's customers with respect to the adequacy, reliability and quality of electricity service.

Any additional questions or clarifications should be directed to the undersigned.

Yours very truly,

Art Skidmore
President & CEO, HHH
Tel: 1-519-853-3700, ext.225
Email: askidmore@haltonhillshydro.com

Terry Bennett
Vice President, TCE
Tel: 416-869-2133
Email: terry_bennett@transcanada.com

c: David J. Smelsky (HHH CFO)
Tracy Rehberg-Rawlingson (HHH Regulatory Affairs Officer)
Brian Kelly (TCE Market Affairs)
Margaret Kuntz (TCE Market Affairs)
Krista Favot (TCE Senior Legal Counsel)
Richard King (Osler, Hoskin & Harcourt LLP)

APPENDIX A

Form of Connection Agreement

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CONNECTION AGREEMENT

This Connection Agreement is made this ■ day of ■, 2013,

BETWEEN

(1) TransCanada Energy Ltd., a business organization duly incorporated under the laws of Canada ("TCE")

(2) Halton Hills Hydro Inc., a business organization duly incorporated under the laws of Ontario ("HHH")

(each a "Party" and collectively the "Parties").

RECITALS

WHEREAS HHH requires an additional connection point to support system growth;

AND WHEREAS TCE and HHH have worked together to develop an innovative solution to allow HHH to connect its facilities (the "HHH Facilities") to the TCE switchyard located at TCE's Halton Hills Generating Station (the ""TCE Facility");

AND WHEREAS the connection of the HHH Facilities to the TCE Facility ("Connection") will result in significant cost savings for HHH's customers;

NOW THEREFORE in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

PART ONE - GENERAL

1 DEFINITIONS

1.1 In this Agreement, unless the context otherwise requires:

1.1.1 "Access Line" means the 1.6 km underground double circuit connection that connects TCE's substation facility to the Hydro One Networks Inc. ("Hydro One") 230 kV circuits T38B and T39B between the Halton TS and Hornby Junction;

1.1.2 "Affiliate" means, in relation to a Party, any company or corporation which: (a) directly or indirectly controls such Party; (b) is directly or indirectly controlled by such Party; or (c) is directly or indirectly controlled by a company or corporation which directly or indirectly controls such Party; where "controls", "controlled by" and "under common control with" mean the possession directly or indirectly through one or more intermediaries, of more than 50% of the outstanding voting stock of the company in question, or the power to direct or cause the direction of management policies of, any person, whether through ownership of stock, as a general partner or trustee, by contract or otherwise;

1.1.3 "Agreement" means this connection agreement and all of the Schedules;

1.1.4 "Confidential Information" in respect of a Party means (a) information disclosed by that Party to the other Party under this Agreement that is in its nature confidential, proprietary or commercially sensitive and (b) information derived from the information referred to in (a), but excludes information described in section 21.1;

1.1.5 "Controlling Authority" in respect of a Party means the person appointed by that Party as responsible for performing, directing or authorizing changes in the condition or physical position of electrical apparatus or devices;

1.1.6 "Cure Period" means the period of time given to a Defaulting Party for the purposes of remedying an Event of Default, determined in accordance with section 19.2.1;

1.1.7 "Default Notice" has the meaning given to it in section 19.1.1;

1.1.8 "Defaulting Party" means a Party in relation to whom an Event of Default has occurred or is occurring;

1.1.9 "End of Cure Period Notice" has the meaning given to it in section 19.2.3;

1.1.10 "Event of Default" means, in respect of a Party, any of the following:

(a) any material breach of this Agreement by that Party; or

(b) an Insolvency/Dissolution Event occurs in relation to the Party;

1.1.11 "Force Majeure Event" in respect of a Party means any event or circumstance, or combination of events or circumstances: (a) that is beyond the reasonable control of that Party; (b) that adversely affects the performance by the Party of its obligations under this Agreement; and (c) the adverse effects of which could not have been foreseen and prevented, overcome, remedied or mitigated in whole or in part by the Party through the exercise of due diligence and reasonable care, provided however that the lack, insufficiency or non-availability of funds shall not constitute a Force Majeure Event;

1.1.12 "Insolvency/Dissolution Event" in respect of a Party, means any of the following:

(a) in the case of a voluntary insolvency/dissolution, if the Party shall (i) apply for or consent to the appointment of a receiver, receiver/manager, interim receiver, trustee, administrator, or liquidator (or person having a similar or analogous function under the laws of any jurisdiction) of itself or of all or a substantial part of its assets; (ii) be unable, or state or admit in writing its inability or failure, to pay its debts generally as they become due; (iii) make a general assignment for the benefit of its creditors, or make or threaten to make a sale in bulk of all or a substantial part of its assets; (iv) commit an act of bankruptcy under the *Bankruptcy and Insolvency Act* (Canada) or under any existing or future law relating to bankruptcy and insolvency; (v) commence any proceeding or other action under any existing or future law relating to bankruptcy, insolvency, reorganization, or relief of debtors seeking to have an order for relief entered with respect to it, or seeking to adjudicate it bankrupt or insolvent, or seeking reorganization, arrangement, adjustment, moratorium, winding up, liquidation, dissolution, composition, compromise or other relief with respect to it or its debts or an arrangement with creditors, or file an answer admitting the material allegations filed against it in any bankruptcy, insolvency, or reorganization proceeding; or (vi) take any corporate action for the purpose of effecting any of (i) to (v);

(b) in the case of an involuntary insolvency/dissolution, if any proceeding or other action shall be instituted in any court of competent jurisdiction seeking in respect of the Party or of all or a substantial part of its assets (i) an adjudication in bankruptcy or for reorganization, dissolution, winding up or liquidation; (ii) a composition, compromise, arrangement or moratorium with its creditors, or other relief with respect to it or its debts; (iii) the appointment of a trustee, receiver, receiver/manager, interim receiver, administrator or liquidator (or person having a similar or analogous function under the laws of any jurisdiction); or (iv) any other similar relief under any existing or future law relating to bankruptcy, insolvency, reorganization or relief of debtors;

(c) an application is made for the winding up or dissolution or a resolution is passed or any steps are taken to pass a resolution for the winding up or dissolution of the Party, except as part of a bona fide corporate reorganization; or

(d) the Party is wound up or dissolved, except as part of a bona fide corporate reorganization, unless the notice of winding up or dissolution is discharged;

1.1.13 "Lender" in respect of HHH means a bank or other entity whose principal business is that of a financial institution and that is financing or refinancing HHH's Facilities;

1.1.14 "Non-defaulting Party" means a Party that is not experiencing an Event of Default;

1.1.15 "Party Losses" means any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of a Party, including where occasioned by a judgment resulting from an action instituted by a third party;

1.1.16 "Schedule" means a schedule listed in section 3.2.1 and any additional schedules created by the Parties under section 3.3.1;

1.1.17 "Supporting Guarantee" has the meaning given to it in the "Glossary of Terms" of the "utility work protection code" referred to in the document entitled "Electrical Utility Safety Rules", published by the Electrical and Utilities Safety Association of Ontario Incorporated (now the Infrastructure Health and Safety Association) and revised January, 2009, as may be amended from time to time; and

1.1.18 "Work Protection" means a state or condition whereby an isolated or isolated and de- energized condition has been established for work on facilities and will continue to exist, except for authorized tests, until the work relating thereto has been completed.

1.2 In this Agreement, unless the context otherwise requires, each of the following words and phrases shall have the meaning given to it in the Transmission System Code (whether or not capitalized in the Code or in this Agreement): "assigned capacity"; "available capacity"; "Board"; "business day"; "connect"; "connection facilities"; "connection point"; "contracted capacity"; "circuit breaker"; "emergency"; "facilities"; "fault"; "forced outage"; "good utility practice"; "isolate"; "isolating device"; "licence"; "load shedding"; "maintenance"; "outage"; "planned outage"; "promptly"; "protection system"; "protective relay"; "reliability"; "reliability organization"; "reliability standards"; "renewable generation"; "single contingency"; "site"; "transmission facilities"; "transmission service"; "transmission system" and "work".

2 INTERPRETATION

2.1 Words and phrases contained in this Agreement (whether or not capitalized) that are not defined herein shall have the meanings given to them in the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A, the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B, or in any regulations made under either of those Acts, as the case may be.

2.2 Headings are for convenience only and shall not affect the interpretation of this Agreement.

2.3 In this Agreement, unless the context otherwise requires:

(a) words importing the singular include the plural and vice versa;

(b) words importing a gender include any gender;

(c) words importing a person include: (a) an individual, (b) a company, sole proprietorship, partnership, trust, joint venture, association, corporation or other private or public body corporate; and (c) any government, government agency or body, regulatory agency or body or other body politic or collegiate;

(d) a reference to a person includes that person's successors and permitted assigns;

(e) a reference to a Party includes any person acting on behalf of that Party;

(f) a reference to HHH's Facilities is limited to such facilities as are relevant to HHH's connection to TCE's Facilities under this Agreement, and vice versa;

(g) a reference to a body, whether statutory or not, that ceases to exist or whose functions are transferred to another body is a reference to the body that replaces it or that substantially succeeds to its powers or functions;

(h) a reference to a document (including a statutory instrument) or a provision of a document includes any amendment or supplement to, or any replacement of, that document or that provision;

(i) the expression "including" means including without limitation, and the expressions "include", "includes" and "included" shall be interpreted accordingly; and

(j) where a word or phrase is defined in this Agreement, including by virtue of the application of section 1.2, or in any document referred to in section 2.1, other parts of speech and grammatical forms of the word or phrase have a corresponding meaning.

2.4 Except when an emergency is anticipated or is occurring, if the time for doing any act or omitting to do any act under this Agreement expires on a day that is not a business day, the act may be done or may be omitted to be done on the next day that is a business day.

3 SCHEDULES

3.1 Incorporation of Schedules

3.1.1 The Schedules form a part of, and are hereby incorporated by reference into, this Agreement.

3.2 Schedules

3.2.1 The following are the Schedules to this Agreement:

Schedule A	-	Single Line Diagram, Description of HHH's Connection Point(s) and Details of Specific Operations
Schedule B	-	[intentionally left blank]
Schedule C	-	Cure Periods for Defaults

Schedule D	-	Fault Levels and Modifications
	-	Attachment D 1
Schedule E	-	General Technical Requirements
Schedule F	-	Additional Technical Requirements for Tapped Transformer Stations Supplying Load
Schedule G	-	Protection System Requirements
Schedule H	-	[intentionally left blank]
Schedule I	-	Exchange of Information
Schedule J	-	[intentionally left blank]
Schedule K	-	Contacts for Purposes of Notice

3.3 **Additional Schedules**

3.3.1 The Parties may by mutual agreement append such additional Schedules to this Agreement as may from time to time be required.

3.3.2 In the event of an inconsistency or conflict between a provision of an additional Schedule referred to in section 3.3.1 and a provision of this Agreement or of a Schedule referred to in section 3.2.1, the provision of this Agreement or of the Schedule referred to in section 3.2.1 shall prevail to the extent of the inconsistency or conflict.

4 NOTICE

4.1 Method of Giving Notice and Effective Date

4.1.1 Subject to section 4.1.3, any notice, demand, consent, request or other communication required or permitted to be given or made under or in relation to this Agreement shall be given or made by courier or other personal form of delivery; by registered mail; by facsimile; or by electronic mail.

4.1.2 A notice, demand, consent, request or other communication referred to in section 4.1.1 shall be deemed to have been duly given or made as follows:

(a) where given or made by courier or other form of personal delivery, on the date of receipt;

(b) where given or made by registered mail, on the sixth day following the date of mailing;

(c) where given or made by facsimile and a complete transmission report is issued from the sender's facsimile transmission equipment, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a business day or, if the transmission is on a day which is not a business day or is after 5:00 pm (addressee's time), at 9:00 am on the following business day; and

(d) where given or made by electronic mail, on the day and at the time when the notice, demand, consent, request or other communication is recorded by the sender's electronic communications system as having been received at the electronic mail destination, if a business day, or if that time is after 5:00 pm (addressee's time) or that day is not a business day, at 9:00 am on the following business day.

4.1.3 Any notice, demand, consent, request or other communication required or permitted to be given or made under Schedule A shall be given or made in accordance with the notice provisions contained in that Schedule.

4.2 **Address for Notice**

4.2.1 Any notice, demand, consent, request or other communication given or made under section 4.1.1 shall be addressed to the applicable representative of the Party identified in Schedule K. A Party may, upon written notice given to the other Party in accordance with section 4.1.1, from time to time change its address or representative for notice, and Schedule K shall be deemed to have been amended accordingly.

4.2.2 Any notice, demand, consent, request or other communication given or made under section 4.1.3 shall be addressed in accordance with Schedule A.

4.3 **Exception**

4.3.1 Sections 4.1 and 4.2 are subject to such other provisions of this Agreement that expressly require or permit notices, demands, consents, requests or other communications to be given or made by alternative means or to be addressed to other specified representatives of the Parties.

5 ASSIGNMENT

5.1 Subject to sections 5.2 and 5.3, no Party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement without the prior written consent of the other Party, which consent may not be unreasonably withheld or delayed.

5.2 TCE may, without the prior written consent of HHH, assign or transfer its rights or obligations under this Agreement:

(a) if all or substantially all of TCE's Facilities are assigned, transferred or sold, provided that the assignee agrees to be bound by the terms of this Agreement; or

(b) to an affiliate of TCE provided that such affiliate agrees to be bound by the terms of this Agreement.

5.3 HHH may, without the prior written consent of TCE, assign by way of security only all or any part of its rights or obligations under this Agreement to a Lender. HHH shall promptly notify TCE upon making any such assignment.

6 FURTHER ASSURANCES

6.1 Each Party shall promptly execute and deliver or cause to be executed and delivered all further documents in connection with this Agreement that the other Party may reasonably require for the purposes of giving effect to this Agreement.

7 WAIVER

7.1 A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. No waiver will be inferred or implied by any failure to act or by the delay in acting by a Party in respect of any default, breach or non-compliance or by anything done or omitted to be done by the other Party. The waiver by a Party of any default, breach or non-compliance under this Agreement shall not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-compliance, whether of the same or any other nature.

8 AMENDMENTS

8.1 Any amendment to this Agreement (including Schedules) shall be made in writing and duly executed by the Parties.

8.2 HHH must notify the Ontario Energy Board of any material amendments to this Agreement or any Schedules.

8.3 In the event of an inconsistency or conflict between a provision of an amendment to a Schedule made under section 8.1 and a provision of this Agreement, the provision of this Agreement shall prevail to the extent of the inconsistency or conflict.

9 SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of, and be binding on, the Parties and their respective successors and permitted assigns.

10 ENTIRE AGREEMENT

10.1 Except as expressly provided herein, this Agreement, together with the Schedules, constitutes the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the subject-matter hereof.

11 GOVERNING LAW

11.1 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

12 COUNTERPARTS

12.1 This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed either in original or faxed form and the Parties shall adopt any signatures received by a receiving facsimile machine as original signatures of the

Parties; provided, however, that any Party providing its signature in such manner shall promptly forward to the other Party an original signed copy of this Agreement which was so faxed.

PART TWO - REPRESENTATIONS AND WARRANTIES

13 REPRESENTATIONS AND WARRANTIES

13.1 HHH's Representations and Warranties

13.1.1 HHH represents and warrants to TCE as follows, and acknowledges and confirms that TCE is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority, and capacity to enter into this Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of HHH; (ii) any contracts or instruments to which HHH is bound; or (iii) any laws applicable to it;

(d) any individual executing this Agreement, and any document in connection herewith, on behalf of HHH has been duly authorized to execute this Agreement and has the full power and authority to bind HHH;

(e) this Agreement constitutes a legal and binding obligation on HHH, enforceable against HHH in accordance with its terms;

(f) other than the facilities listed in Schedule H, HHH's Facilities meet the technical requirements of this Agreement; and

(g) it holds all permits, licences and other authorizations that may be necessary to enable it to carry on its business.

13.1.2 HHH shall promptly notify TCE of any circumstance that does or may result in any of the representations and warranties set forth in section 13.1.1 becoming untrue or inaccurate during the term of this Agreement.

13.2 TCE's Representations and Warranties

13.2.1 TCE represents and warrants to HHH as follows, and acknowledges and confirms that HHH is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority, and capacity to enter into this Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of TCE; (ii) any contracts or instruments to which TCE is bound; or (iii) any laws applicable to it;

(d) any individual executing this Agreement, and any document in connection herewith, on behalf of TCE has been duly authorized to execute this Agreement and has the full power and authority to bind TCE;

(e) this Agreement constitutes a legal and binding obligation on TCE, enforceable against TCE in accordance with its terms;

(f) other than the facilities listed in Schedule H, those of TCE's Facilities that are relevant to, or may have an impact on, HHH's Facilities meet the technical requirements of this Agreement; and

(g) it holds all permits, licences and other authorizations that may be necessary to enable it to carry on its business.

13.2.2 TCE shall promptly notify HHH of any circumstance that does or may result in any of the representations and warranties set forth in section 13.2.1 becoming untrue or inaccurate during the term of this Agreement.

PART THREE - LIABILITY AND FORCE MAJEURE

14 LIABILITY

14.1 TCE shall not be liable for any Party Losses of HHH whatsoever arising out of any act or omission of TCE under this Agreement or on any other basis of legal liability unless such Party Losses relate to bodily injury (including death) and are the result of wilful misconduct or gross negligence of TCE.

14.2 Subject only to section 26.13.6 and not withstanding any other provision to the contrary, TCE shall not be liable for any damage to HHH's Facilities and/or property howsoever suffered or incurred resulting from the operation of TCE's Facilities, HHH's Facilities or the Connection, or the action or inactions of TCE, its affiliates and their respective directors, officers, employees, contractors, subcontractors or representatives.

14.3 Notwithstanding any other provision to the contrary, in no event shall TCE be liable to HHH, whether as claims in contract or in tort or otherwise, for loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including punitive or exemplary damages.

14.4 Subject to sections 26.13.6, 26.13.7 and 22.5 and except as otherwise expressly provided in this Agreement**,** HHH shall not be liable for any Party Losses of TCE whatsoever arising out of any act or omission of HHH under this Agreement unless such Party Losses result from the willful misconduct or negligence of HHH and/or to the extent any amounts are recoverable under a policy or policies of insurance in place by HHH.

14.5 Each Party has a duty to mitigate any Party Losses relating to any claim for indemnification from the other Party that may be made in relation to that other Party. Nothing in this section 14.5 shall require the mitigating Party to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

14.6 Each Party shall give prompt notice to the other Party of any claim with respect to which indemnification is being or may be sought under this Agreement.

14.7 Once the design and engineering work related to the Connection contemplated in this Agreement is more advanced, TCE, in its sole discretion, may revisit these liability provisions and advise HHH if TCE is willing to negotiate amendments to these liability provisions.

15 FORCE MAJEURE

15.1 No Liability Where Force Majeure Event Occurs

15.1.1 Subject to sections 15.1.2 to 15.1.4, a Party shall not be liable to the other Party for any failure or delay in the performance of any of its obligations under this Agreement in whole or in part to the extent that such failure or delay is due to a Force Majeure Event.

15.1.2 The Party invoking a Force Majeure Event shall only be excused from performance under section 15.1.1:

(a) for so long as the Force Majeure Event continues and for such reasonable period of time thereafter as may be necessary for the Party to resume performance of the obligation; and

(b) where and to the extent that the failure or delay in performance would not have been experienced but for such Force Majeure Event.

15.1.3 Nothing in this section 15 shall excuse a Party from performing any of their respective emergency-related obligations in the event of an emergency.

15.1.4 A Party may not invoke a Force Majeure Event unless it has given notice in accordance with section 15.2.

15.2 Obligations Where Force Majeure Event Occurs

15.2.1 Where a Party invokes a Force Majeure Event, it shall promptly give notice to the other Party, which notice shall include particulars of:

(a) the nature of the Force Majeure Event and, if known, of its duration;

(b) the effect that the Force Majeure Event is having on the Party's performance of its obligations under this Agreement; and

(c) the measures that the Party is taking, or proposes to take, to alleviate the impact of the Force Majeure Event.

Such notice may be given verbally, in which case the notifying Party shall as soon as practicable thereafter confirm the notice in writing.

15.2.2 Where a Party invokes a Force Majeure Event, it shall use all reasonable endeavours to mitigate or alleviate the effects of the Force Majeure Event on the performance of its obligations under this

Agreement. Nothing in this section 15.2.2 shall require the mitigating Party to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

15.2.3 Where a Party invokes a Force Majeure Event, it shall notify the other Party in writing as soon as practicable of the cessation of the Force Majeure Event and of the cessation of the effects of the Force Majeure Event on the Party's performance of its obligations under this Agreement.

16 INSURANCE

16.1 Each Party shall, at its sole cost and expense, obtain and maintain at all times during the term of this Agreement and the terms of all of the transactions detailed herein, sufficient insurance to cover any Party Losses.

PART FOUR - DISPUTE RESOLUTION

17 DISPUTE RESOLUTION

17.1 Exclusivity

17.1.1 Subject to sections 17.1.2:

(a) the dispute resolution procedure set forth in this section 17 shall apply to all disputes between HHH and TCE arising under or in relation to this Agreement; and

(b) the Parties shall comply with the procedure set out in this section 17 before taking any other civil or other proceeding in relation to the dispute.

17.1.2 Nothing in section 17.1.1 shall prevent a Party from seeking urgent or interlocutory relief from a court of competent jurisdiction in the Province of Ontario in relation to any dispute between them arising under or in relation to this Agreement.

17.2 Duty to Negotiate

17.2.1 Any dispute between HHH and TCE referred to in section 17.1.1 shall be referred to a designated senior representative of each of the Parties for resolution on an informal basis as quickly as possible.

17.2.2 The designated senior representatives of the Parties shall attempt in good faith to resolve the dispute within thirty days of the date on which the dispute was referred to them. The Parties may by mutual agreement extend such period.

17.2.3 If a dispute is settled by the designated senior representatives of the Parties, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties. The subject matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of terms of the settlement.

17.2.4 If a Party fails to comply with the terms of settlement referred to in section 17.2.3, the other Party may submit the matter to arbitration under section 17.3.1.

17.3 Submission of Unresolved Disputes to Arbitration

17.3.1 If the designated senior representatives of the Parties cannot resolve the dispute within thirty days (or such longer period as extended pursuant to section 17.2.2), either Party may submit the dispute to binding arbitration under sections 17.4 and 17.5 by notice to the other Party.

17.4 **Selection of Arbitrator(s)**

17.4.1 The Parties shall use good faith efforts to appoint a single arbitrator for purposes of the arbitration of the dispute. If the Parties fail to agree upon a single arbitrator within ten business days of the date of the notice referred to in section 17.3.1, each Party shall within five business days thereafter choose one arbitrator. The two arbitrators so chosen shall within twenty days select a third arbitrator.

17.4.2 Where a Party has failed to choose an arbitrator under section 17.4.1 within the time allowed, the other Party may apply to a court to appoint a single arbitrator to resolve the dispute.

17.4.3 No person shall be appointed as an arbitrator unless that person:

(a) is independent of the Parties;

(b) has no current or past substantial business or financial relationship with either Party, except for prior arbitration; and

(c) is qualified by education or experience to resolve the dispute.

17.5 **Arbitration Procedure**

17.5.1 The arbitrator(s) shall provide each of the Parties with an opportunity to be heard orally and/or in writing, as may be appropriate to the nature of the dispute.

17.5.2 The *Arbitration Act, 1991* (Ontario) shall apply to an arbitration conducted under this section 17.

17.5.3 The arbitrator(s) shall make due provision for the adequate protection of Confidential Information that may be disclosed or may be required to be produced during the course of an arbitration in a manner consistent with the confidentiality obligations of section 21.

17.5.4 All proceedings relating to the arbitration of a dispute shall be conducted in private unless the Parties agree otherwise.

17.5.5 Unless the Parties otherwise agree, the arbitrator(s) shall render a decision within ninety days of the date of appointment of the last to be appointed arbitrator, and shall notify the Parties of the decision and of the reasons therefore.

17.5.6 The decision of the arbitrator(s) shall be final and binding on the Parties and may be enforced in accordance with the provisions of the *Arbitration Act, 1991* (Ontario). The Party against which the decision is enforced shall bear all costs and expenses reasonably incurred by the other Party in enforcing the decision.

17.5.7 Subject to section 17.5.8, each Party shall be responsible for its own costs and expenses incurred in the arbitration of a dispute and for the costs and expenses of the arbitrator(s) if appointed to resolve the dispute.

17.5.8 The arbitrator(s) may, if the arbitrator(s) consider it just and reasonable to do so, make an award of costs against or in favour of a Party to the dispute. Such an award of costs may relate to either or both the costs and expenses of the arbitrator(s) and the costs and expenses of the Parties to the dispute.

17.5.9 If a dispute is settled by the Parties during the course of an arbitration, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties, and either Party may request that the arbitrator(s) record the settlement in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario). The subject-matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of the terms of the settlement.

17.5.10 If a Party fails to comply with the terms of settlement referred to in section 17.5.9, the other Party may submit the matter to arbitration under section 17.3.1 if the settlement has not been recorded in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario).

PART FIVE - TERM, TERMINATION AND EVENTS OF DEFAULT

18 TERM AND TERMINATION

18.1 Coming Into Force

18.1.1 This Agreement shall come into force on the date first mentioned above and shall remain in full force and effect until terminated in accordance with this Agreement.

18.2 Termination Without Cause by HHH

18.2.1 HHH may, if it is not then a Defaulting Party to whom a Default Notice has been delivered, terminate this Agreement at any time during the term of this Agreement by giving TCE six months' prior written notice setting out the termination date. In the event that TCE requires more than six months prior written notice in order to comply with a regulatory or contractual requirement related to the Connection, TCE shall advise HHH of such requirement and this Agreement shall terminate on a termination date agreed to by the Parties.

18.2.2 Where HHH gives notice to terminate under section 18.2.1, TCE shall disconnect all of HHH's Facilities at all connection points on the termination date specified in that notice or on such other date as the Parties may agree in writing.

18.2.3 Section 20.5 shall apply in relation to the disconnection of HHH's Facilities under section 18.2.2.

18.3 Termination for Cause by Either Party

18.3.1 Termination of this Agreement by a Party by reason of an Event of Default occurring in relation to the other Party shall be effected in accordance with section 19.

18.4 Provisions Relating to Termination Generally

18.4.1 Termination of this Agreement for any reason shall not affect the liabilities of either Party that were incurred or arose under this Agreement prior to the time of termination.

18.4.2 Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it, including injunctive relief.

18.5 Rights and Remedies not Exclusive

18.5.1 The rights and remedies set out in this Agreement are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to a Party at law or in equity.

18.5.2 Nothing in this section 18.5 shall be interpreted as affecting the limitations of liability set forth in section 14 or the obligation of a Party to comply with section 17 while this Agreement is in force.

18.6 **Survival**

18.6.1 Sections 18.4 and 18.5 shall survive termination of this Agreement.

19 EVENTS OF DEFAULT AND TERMINATION FOR CAUSE

19.1 **Occurrence of an Event of Default**

19.1.1 If an Event of Default occurs in relation to a Party, the Non-defaulting Party may, without prejudice to its other rights and remedies as provided for in this Agreement or at law or in equity, serve the Defaulting Party with a notice specifying the Event of Default that has occurred and the applicable Cure Period ("Default Notice").

19.2 **Curing Events of Default**

19.2.1 Upon receipt of a Default Notice, the Defaulting Party shall be entitled to remedy the Event of Default specified in the Default Notice:

(a) for an Event of Default that has an impact that is referred to in Schedule C, within the applicable Cure Period specified for that impact in Schedule C, calculated from the date of the receipt of the Default Notice; or

(b) for an Event of Default that does not have an impact that is referred to in Schedule C, within a period of twenty business days from the date of receipt of the Default Notice.

The Parties may agree to a Cure Period that is longer than the Cure Period that would otherwise apply under section 19.2.1(a) or 19.2.1(b).

19.2.2 During the Cure Period, the Defaulting Party shall diligently seek to remedy the Event of Default specified in the Default Notice.

19.2.3 If the Non-defaulting Party considers that the Defaulting Party is not, during the Cure Period, diligently seeking to remedy the Event of Default, the Non-defaulting Party may serve the Defaulting Party with a notice ("End of Cure Period Notice") to that effect. If, within ten business days of receiving the End of Cure Period Notice, the Defaulting Party has not commenced to diligently seek to remedy the Event of Default, the Cure Period shall end on the fifth business day following the date of receipt of the End of Cure Period Notice, and section 19.3.1 shall apply.

19.2.4 An Event of Default shall be considered remedied when:

(a) the Event of Default has been remedied to the reasonable satisfaction of the Non-defaulting Party; and

(b) the Defaulting Party has reimbursed the Non-defaulting Party for all costs of enforcement or recovery or attempted enforcement or recovery, including reasonable legal costs and expenses, reasonably incurred by the Non-defaulting Party in relation to the Non-financial Default.

19.3 **Right to Terminate and Disconnect**

19.3.1 Subject to section 19.3.2, where an Event of Default has not been remedied prior to the expiry of the applicable Cure Period, including in accordance with section 19.2.3, the Non-defaulting Party may, without prejudice to its other rights and remedies as provided for in this Agreement or at law or in equity, terminate this Agreement by written notice to the Defaulting Party. Such termination shall take effect on the date on which the termination notice is delivered to the Defaulting Party.

19.3.2 TCE may not terminate this Agreement under section 19.3.1 or, subject to section 19.3.5, disconnect HHH's Facilities under section 19.3.3 in relation to an Event of Default by HHH where the issue of HHH's default has been referred to the dispute resolution process referred to in section 17 and the dispute has not been finally resolved.

19.3.3 TCE may disconnect all of HHH's Facilities on or after the date on which this Agreement terminates under section 19.3.1.

19.3.4 Section 20.5 shall apply in relation to the disconnection of HHH's Facilities under section 19.3.3.

19.3.5 Nothing in this section 19 shall prevent TCE from disconnecting HHH's Facilities where permitted by section 19.4 or section 20.3.1, even if TCE is a Defaulting Party at the relevant time.

19.4 **Specific Termination Right of TCE**

19.4.1 After the effective date of this Agreement, if there is a change in any law (including the Market Rules) or approval that results in TCE no longer being exempt as a transmitter and from all associated regulatory obligations, TCE shall have the right to terminate this Agreement. If TCE has knowledge of a pending change in law that will result in termination under this provision, TCE will act reasonably to provide HHH with adequate notice of such termination.

19.5 **Lender's Right of Substitution**

19.5.1 Where a Default Notice has been served on HHH, an agent or trustee for and on behalf of a Lender ("Security Trustee") or a receiver appointed by the Security Trustee ("Receiver") shall upon notice to TCE be entitled (but not obligated) to exercise all of the rights and obligations of HHH under this Agreement and shall be entitled to remedy the Event of Default specified in the Default Notice within the applicable Cure Period. TCE shall accept performance of HHH's obligations under this Agreement by the Security Trustee or Receiver in lieu of HHH's performance of such obligations, and will not exercise any right to terminate this Agreement under section 19.3.1 due to an Event of Default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges its intention to be bound by the terms of this Agreement and such acknowledgment is received within 30 days of the date of receipt by HHH of the Default Notice.

PART SIX - DISCONNECTION AND RECONNECTION

20 DISCONNECTION

20.1 **Voluntary Permanent Disconnection by HHH**

20.1.1 HHH may at any time voluntarily and permanently disconnect its HHH Facilities from TCE's Facilities provided that HHH is not then a Defaulting Party to whom a Default Notice has been delivered.

20.1.2 HHH shall give TCE notice in writing of its intention to voluntarily disconnect the HHH Facilities under section 20.1.1 no less than ten days before the date on which HHH wishes to disconnect.

In the event that TCE requires more than ten days written notice of disconnection in order to comply with a regulatory or contractual requirement related to the Connection, TCE shall advise HHH of such requirement and the Parties shall establish a mutually acceptable date for disconnection.

20.1.3 Section 20.5 shall apply in relation to the disconnection of HHH's Facilities under section 20.1.1.

20.2 **Voluntary Temporary Disconnection by HHH and Reconnection**

20.2.1 Where practical, HHH shall notify TCE prior to temporarily disconnecting its HHH Facilities from TCE's Facilities.

20.2.2 TCE shall, at HHH's request, reconnect HHH's Facilities to TCE's Facilities following a voluntary temporary disconnection under section 20.2.1 once TCE is reasonably satisfied that all requirements of this Agreement are met, that all payments due to be paid by HHH under this Agreement have been made and that HHH agrees to pay all reasonable reconnection costs charged by TCE. In addition to the foregoing, any reconnection by TCE shall be subject to IESO and/or Hydro One approval.

20.3 **Disconnection by TCE**

20.3.1 TCE may disconnect HHH's Facilities at any time throughout the term of this Agreement in any of the following circumstances:

(a) where required to comply with a decision or order of an arbitrator or court;

(b) during an emergency or where necessary to prevent or minimize the effects of an emergency;

(c) where required by an order or direction from the IESO given in accordance with the Market Rules or by order or direction from Hydro One;

(d) when necessary, in TransCanada's sole opinion, acting reasonably, to prevent endangering the safety of any person, to prevent damaging equipment or property, or to prevent violating any applicable law; or

(e) when required to satisfy TCE's obligations to the Ontario Power Authority under its Clean Energy Supply Contract.

20.3.2 Section 20.5 shall, to the extent applicable, apply in relation to the disconnection of HHH's Facilities under section 20.3.1.

20.4 **Reconnection after Disconnection by TCE**

20.4.1 Where HHH's Facilities have been disconnected under section 20.3 during an emergency, TCE shall reconnect HHH's Facilities to TCE's Facilities when it is reasonably satisfied that the emergency has ceased and that all other requirements of this Agreement are met.

20.4.2 Where HHH's Facilities have been disconnected under section 20.3 other than during an emergency, TCE shall reconnect HHH's Facilities to TCE's Facilities when:

(a) it is reasonably satisfied that the reason for the disconnection no longer exists;

(b) HHH agrees to pay all reasonable reconnection costs;

(c) where the actions of HHH gave rise to the disconnection, TCE is reasonably satisfied that HHH has taken all necessary steps to prevent the circumstances that caused the disconnection from recurring and has delivered binding undertakings to TCE to that effect; and

(d) any decision or order of a court or arbitrator that requires a Party to take action to ensure that such circumstances shall not recur has been implemented and/or assurances have been given to the satisfaction of TCE that such decision or order will be implemented.

20.4.3 Reconnection under this section 20.4 shall be effected in accordance with the procedures agreed between the Parties.

20.5 **Provisions Applicable to Disconnection Generally**

20.5.1 Promptly after the coming into force of this Agreement, the Parties shall develop appropriate operating and decommissioning procedures for HHH's Facilities. The Parties shall comply with those operating and decommissioning procedures in relation to any disconnection of HHH's Facilities.

20.5.2 Where HHH's Facilities are disconnected, each Party shall be entitled to decommission and remove its assets associated with the Connection. Each Party shall, for that purpose, provide the other Party with all necessary access to its site at all reasonable times.

20.5.3 HHH shall pay all reasonable costs, including the costs of removing any of TCE's equipment from HHH's Facilities, that are directly attributable to the disconnection and, where applicable, the subsequent decommissioning of HHH's Facilities. TCE shall not require the removal of the protection and control wiring within HHH's Facilities.

20.5.4 In order to avoid the requirement to disconnect pursuant to section 20.3.1(e) above, TCE shall use commercially reasonable efforts to successfully negotiate a test protocol with the Ontario Power Authority that ensures that the results of any required capacity testing will take into account the impact of the HHH load on test results, and will not require TCE to disconnect HHH during the testing period. If such testing protocol can be reached and is satisfactory to TCE, in TCE's sole opinion, TCE shall not disconnect HHH during any capacity check test pursuant to its Clean Energy Supply with the Ontario Power Authority.

PART SEVEN - EXCHANGE AND CONFIDENTIALITY OF INFORMATION

21 EXCHANGE AND CONFIDENTIALITY OF INFORMATION

21.1 For purposes of this Agreement, "Confidential Information" does not include:

(a) information that is in the public domain, provided that specific items of information shall not be considered to be in the public domain merely because more general information is in the public domain and provided that the information is not in the public domain as a result of a breach of confidence by the Party seeking to disclose the information or a person to whom it has disclosed the information; or

(b) information that is, at the time of the disclosure, in the possession of the receiving Party, provided that it was lawfully obtained from a person under no obligation of confidence in relation to the information.

21.2 Subject to section 21.3, each Party shall treat all Confidential Information disclosed to it by the other Party as confidential and shall not, without the written consent of that other Party:

(a) disclose that Confidential Information to any other person; or

(b) use that Confidential Information for any purpose other than the purpose for which it was disclosed or another applicable purpose contemplated in this Agreement.

Where a Party, with the written consent of the other Party, discloses Confidential Information of that other Party to another person, the Party shall take such steps as may be required to ensure that the other person complies with the confidentiality provisions of this Agreement.

21.3 Nothing in section 21.2 shall prevent the disclosure of Confidential Information or this Agreement:

(a) by TCE to its directors, officers, employees, lawyers, accountants, engineers, consultants, agents and advisers or those of its Affiliates, who have a need to know such information in order to carry out the terms of this Agreement;

(b) by HHH to its directors, officers, employees, lawyers, accountants, engineers, consultants, agents and advisers who have a need to know such information in order to carry out the terms of this Agreement. HHH shall not be permitted to disclose Confidential Information to any Affiliate or to any directors, officers, employees, lawyers, accountants, engineers, consultants, agents and/or advisers of any Affiliate without the written consent of TCE, which shall not be unreasonably withheld; as required by TCE to third parties, including but not limited to any governmental authority and any service provider with whom TCE has contracted with, provided any such persons have a need to know such information in order to carry out the terms of this Agreement or in relation to the Connection or in relation to TCE Facilities;

(c) where required under this Agreement, by law or regulatory requirements;

(d) where required by order of a government, government agency, regulatory body or regulatory agency having jurisdiction;

(e) if required in connection with legal proceedings, arbitration or any expert determination relating to the subject matter of this Agreement, or for the purpose of advising a Party in relation thereto;

(f) as may be required during an emergency or to prevent or minimize the effects of an emergency; or

(g) by HHH to a Lender or prospective Lender.

21.4 The Parties acknowledge and agree that the exchange of information, including Confidential Information, under this Agreement is necessary for maintaining the reliable operation of TCE's Facilities and the Connection. The Parties further agree that all information, including Confidential Information, exchanged between them shall be prepared, given and used in good faith and shall be provided in a timely and cooperative manner.

21.5 Each Party shall comply with its information exchange obligations as set out in this Agreement, including in Schedule I. In addition, each Party shall provide the other with such information as the other may reasonably require to enable it to perform its obligations under this Agreement.

21.6 Each Party shall as soon as practicable notify the other Party upon becoming aware of a material change or error in any information previously disclosed to the other Party under this Agreement. The Party shall provide updated or corrected information as required to ensure that information provided to the other Party is up to date and correct.

PART EIGHT - ACCESS SERVICE AND CONNECTION COSTS

22 ACCESS SERVICE AND CONNECTION COSTS

22.1 TCE grants to HHH the right to connect its Steeles Transformer Station to TCE's switchyard located at TCE's Halton Hills Generating Station to allow for the access (the "Access Service") by HHH's Facilities to Hydro One's transmission system through TCE's Access Line.

22.2 HHH shall be entitled to load access only and shall not be permitted to supply power to the Hydro One transmission system via TCE's Access Line.

22.3 If the supply of generation operating in HHH's service area grows to a point where a reverse flow situation exists and HHH contemplates using the TCE's Access Line for delivery of electricity to the Hydro One transmission system, TCE will permit such usage of the Access Line only after it has reviewed the impact on its operations and, in its sole opinion, has agreed to allow the Connection and Access Line to be used for this purpose.

22.4 TCE shall not charge HHH for the Access Service.

22.5 Notwithstanding section 22.4 and section 14.4, HHH shall reimburse TCE for all costs associated with the Connection and Access Service including but not limited to:

(a) TCE's capital costs required to make the Connection;

(b) any incremental capital costs, operations, maintenance and administration expenses directly attributable to the Connection or Access Service that may arise during the term of this Agreement;

(c) any costs, losses or damages that TCE may incur that arise from any agreement TCE enters into with Hydro One, the Ontario Power Authority, the Independent Electricity System Operator, the Ontario Energy Board, the Ministry of Ontario or any other such authority, that is required as a result of the Connection contemplated in this Agreement;

(d) any lost revenue(s) as it relates to IESO settlement and/or site specific losses associated with the Connection; and

(e) any future costs incurred by TCE as a result of the Connection due to any change in law, including any Market Rule changes.

22.6 TCE shall invoice HHH for the costs set out in section 22.5, and HHH shall pay such invoice within 30 days of receipt.

22.7 HHH shall have the right, at its sole expense, to examine the records of TCE that are reasonably necessary to verify the accuracy of any invoice rendered under the Agreement.

PART NINE - TECHNICAL AND OPERATING REQUIREMENTS

23 FACILITY STANDARDS

23.1 HHH shall ensure that its facilities:

(a) meet all applicable requirements of the Ontario Electrical Safety Authority, subject to any exemption that may have been granted to or that may apply to HHH;

(b) conform to all applicable industry standards, including those of the Canadian Standards Association, the Institute of Electrical and Electronic Engineers, the American National Standards Institute, and the International Electrotechnical Commission;

(c) are constructed, operated and maintained in accordance with this Agreement, HHH's licence, the Market Rules, all applicable reliability standards, good utility practice and any other requirements that TCE requires to prevent or minimize any effects or impacts to TCE's Facilities, operations or business;

(d) are constructed with due regard for the safety of HHH's employees and the public; and

(e) do not materially reduce the reliability or performance of TCE's Facilities or the Hydro One transmission system, in TCE's sole opinion acting reasonably.

23.2 TCE and HHH shall fully cooperate to ensure that any modeling data required by this Agreement for the planning, design and operation of connections are complete and accurate. TCE and HHH shall also cooperate on any testing that the Parties agree is required when one Party believes, on reasonable grounds, that the accuracy of such data is in question. Such testing shall be conducted at a time that is mutually agreed upon by the Parties. The Party conducting such tests shall promptly report the results to the other Party.

23.3 HHH shall, at TCE's request, permit TCE to participate in the commissioning, inspection, and testing of HHH's Facilities so as to enable TCE to ensure that HHH's Facilities will not adversely affect the reliability or operations of TCE's Facilities.

23.4 Where section 23.3 applies, the commissioning, inspection or testing of HHH's Facilities shall be conducted at a time that is mutually agreed by HHH and TCE. If the commissioning, inspection or testing is required to be rescheduled by reason of TCE's failure to attend, TCE shall pay all reasonable costs incurred by HHH in respect of the rescheduling of the commissioning, inspection or testing activity.

23.5 TCE shall, at HHH's reasonable request, permit HHH to participate in the commissioning, inspection, and testing of TCE's Facilities so as to enable HHH to ensure that TCE's Facilities will not adversely affect the reliability or operations of HHH's Facilities.

23.6 Where section 23.5 applies, the commissioning, inspection or testing of TCE's Facilities shall be conducted at a time that is mutually agreed by HHH and TCE. If the commissioning, inspection or testing is required to be rescheduled by reason of HHH's failure to attend, HHH shall pay all reasonable costs incurred by TCE in respect of the rescheduling of the commissioning, inspection or testing activity.

24 ADDITIONAL REQUIREMENTS

24.1 Each Party shall comply with their respective obligations as set out in Schedules E, F and G. Each Party shall ensure that its facilities meet the technical requirements set out in Schedules E, F and G.

24.2 In the event that this Agreement is entered into prior to the completion of any of the Hydro One COVER report, the Customer Impact Assessment report, or the System Impact Assessment report, and any of these reports require the HHH Facilities (or associated facilities) to be constructed or operated other than as originally planned, HHH and TCE shall work together to ensure that the HHH Facilities (and associated facilities) are constructed and operated in accordance with such reports.

25 OPERATIONAL STANDARDS AND REPORTING

25.1 As of the date of this Agreement, the fault levels at all connection points applicable to HHH's Facilities and the assumptions underlying those fault levels, are set out in section D.1 of Schedule D. TCE shall update such fault levels as may be required under this Agreement or in response to a request by HHH under section 25.2, and the Parties shall amend Schedule D accordingly.

25.2 HHH acknowledges that the fault levels at connection points applicable to HHH's Facilities will change from time to time, and agrees that it may not rely upon the fault levels as specified section D.1 of Schedule D. Where HHH reasonably requires confirmation of the fault levels at a connection point applicable to HHH's Facilities, HHH shall submit a request to that effect to TCE. TCE shall then provide HHH with the current fault levels.

25.3 HHH shall promptly report to TCE any changes in its facilities that could materially affect the performance of TCE's Facilities.

25.4 HHH shall promptly report to TCE any and all incidents involving the automatic operation of HHH's Facilities' protective relays that affect TCE's Facilities.

25.5 TCE shall promptly report to HHH any changes in its facilities that could materially affect the Connection or Access Service.

25.6 Where TCE provides HHH with a new available fault current level, HHH shall, at its own expense, upgrade its facilities as may be required to accommodate the new fault current level.

26 OPERATIONS AND MAINTENANCE

26.1 Work on Site of Other Party

26.1.1 When a Party is conducting work at the other Party's site, the working Party shall:

(a) subject to section 26.1.2, comply with all of the host Party's practices and requirements relating to occupational health and safety and environmental protection;

(b) comply with all applicable laws relating to occupational health and safety and environmental protection; and

(c) comply with all of the host Party's reasonable practices and requirements relating to security of the host Party's site, including where agreed to by the Parties, entering into an access agreement on reasonable terms relating to security of the host Party's site.

26.1.2 When a Party is conducting work at the other Party's site, the working Party shall comply with its own practices and requirements in relation to occupational health and safety and environmental protection:

(a) to the extent permitted by the host Party, which permission shall not be granted unless the host Party is satisfied that the working Party's practices and requirements provide for a level of safety or protection that equals or exceeds its own; or

(b) to the extent that the host Party has not made its practices or requirements known to the working Party.

26.2 **General**

26.2.1 Each Party shall ensure that its facilities are operated and maintained only by persons qualified to do so.

26.2.2 Each Party shall operate and maintain its facilities in accordance with Schedule A.

26.3 **Controlling Authorities**

26.3.1 The Controlling Authority for each Party is the person identified as such in Schedule A. A Party may, by written notice to the Controlling Authority of the other Party, from time to time change its Controlling Authority, and the Parties shall amend Schedule A accordingly.

26.3.2 A Party shall comply with any request received from the Controlling Authority of the other Party.

26.3.3 HHH acknowledges TCE's obligations under a Connection Agreement with Hydro One, and HHH agrees to comply with all directions and instructions of TCE as may be necessary for TCE to comply with its obligations under the Connection Agreement with Hydro One.

26.3.4 TCE and HHH will work with the IESO, Hydro One and any other governmental authority to address the applicable metering and settlement requirements for each of TCE and HHH, and the TCE Facilities and HHH Facilities.

26.3.5 TCE shall make available reliability statistics and outage mitigation plans to HHH for review by the Ontario Energy Board as required.

26.4 **Communication Between the Parties**

26.4.1 Except as otherwise provided in this Agreement, all communications between the Parties relating to routine operating and maintenance matters shall be exchanged between the Parties' respective Controlling Authorities in accordance with the contact information set out in Schedule A, or as otherwise specified in Schedule A.

26.4.2 Each Party shall provide the other Party with a communications protocol to be used by that other Party in emergency situations. The protocol shall include the name of the Party's site emergency coordinator.

26.5 **Switching**

26.5.1 Each Party shall, through its Controlling Authority, develop a written protocol that establishes the conditions for, and the coordination of, switching in respect of equipment under its control.

26.5.2 The Parties shall, through their respective Controlling Authorities, approve one another's switching protocols.

26.5.3 A Party may, with the consent of the other Party, appoint an employee of the other Party as its designate for switching purposes, provided that orders to operate must be issued by the Party's Controlling Authority.

26.5.4 TCE may issue to HHH, and HHH shall comply with, such switching instructions as may be required to maintain the security and reliability of TCE's Facilities.

26.5.5 The Controlling Authorities of the Parties shall, prior to the time at which any switching activity is to occur, agree upon procedures for such switching activity.

26.6 **Isolation of Facilities at HHH's Request**

26.6.1 A Party shall not, other than in an emergency, operate an isolating disconnect switch except on prior notice to the other Party.

26.6.2 If HHH requires isolation of its own facilities or of facilities under TCE's control, HHH's Controlling Authority shall deliver a written notice to that effect to TCE's Controlling Authority. The written notice shall contain the following:

(a) a request that TCE's Controlling Authority provide a Supporting Guarantee;

(b) TCE's assigned equipment operating designations, if applicable; and

(c) HHH's assigned equipment operating designations, if TCE's equipment operating designations have not been assigned.

26.6.3 After the written notice referred to in section 26.6.2 has been delivered, HHH's Controlling Authority may request, and TCE shall ensure, that the isolation and subsequent reconnection of HHH's relevant equipment is done on a timely basis, provided that such isolation and reconnection activities do not interfere with or impact TCE's Facilities, in its sole discretion, acting reasonably. The Parties shall bear their own costs and expenses associated with such isolation and reconnection.

26.6.4 TCE may, provided that it has given advance notice to HHH, lock the isolating disconnect switch in the open position in any of the following circumstances:

(a) where necessary to protect TCE's personnel or equipment and TCE has received a Supporting Guarantee from HHH, in which case the lock shall be under TCE's control for the duration of the Supporting Guarantee;

(b) where the operation of TCE's equipment interferes with the operation of HHH's equipment;

(c) where equipment owned by either Party interferes with the operation of TCE's Facilities; or

(d) where TCE has been directed by the IESO to do so in accordance with the Market Rules.

26.7 **Isolation of Facilities at TCE's Request**

26.7.1 If TCE requires isolation of its own facilities from HHH's Facilities or isolation of facilities under HHH's control, TCE's Controlling Authority shall deliver a written notice to that effect to HHH's Controlling Authority. The written notice shall contain a request that HHH's Controlling Authority provide a Supporting Guarantee that identifies HHH's assigned equipment operating designations.

26.7.2 After the written notice referred to in section 26.7.1 has been delivered, TCE's Controlling Authority may request, and HHH shall ensure, that the isolation and subsequent reconnection of TCE's relevant equipment is done on a timely basis. The Parties shall bear their own costs and expenses associated with such isolation and reconnection.

26.8 **Alternative Method of Isolation**

26.8.1 A Party may establish its own Work Protection in place of obtaining a Supporting Guarantee from the other Party.

26.8.2 The Party whose facilities are required in order to establish Work Protection shall provide the other Party with access to those facilities.

26.8.3 Establishing Work Protection shall be limited to the hanging of tags and the locking of devices.

26.9 **Forced Outages**

26.9.1 Where the forced outage of the facilities of one Party adversely affects the facilities of the other Party, the Controlling Authority of the Party experiencing the forced outage shall promptly notify the Controlling Authority of the other Party of the forced outage.

26.9.2 The Controlling Authority of a Party shall have sole authority to identify the need for and to initiate a forced outage of that Party's facilities.

26.10 **Planned Work**

26.10.1 Where planned work to be performed by a Party may affect the safety of the other Party's personnel, the Party performing the work shall provide the other Party with all required Work Protection documentation and related notices in writing or by such other means as they may agree in writing.

26.10.2 Where planned work on the facilities of a Party (a) requires the participation or cooperation of the other Party; or (b) could adversely affect the normal operation of the other Party's facilities, the other Party shall use commercially reasonable efforts to accommodate the planned work and shall negotiate in good faith the reasonable procedures to do so.

26.10.3 HHH shall be responsible for all costs associated with any impact that planned work by TCE on TCE Facilities may have on HHH's Facilities.

26.10.4 HHH shall be responsible for all costs associated with any impact that planned work by HHH on its facilities may have on TCE's Facilities. For any planned HHH work in respect of which TCE has been provided sufficient notice, TCE will provide HHH a budget outlining its estimated costs and expenses related to the HHH work. Such budget will be provided by TCE to HHH for planning purposes only and, despite a budget being provided, HHH shall be responsible to pay any costs exceeding the budget. TCE will make reasonable efforts to advise HHH in a timely manner if it becomes aware that actual costs will materially depart from estimates in the budget

26.10.5 HHH shall take all reasonable steps to ensure that all anticipated and planned outages of its facilities for each calendar year are submitted to TCE by October 1st of the preceding year.

26.10.6 All planned work on HHH's Facilities that may affect TCE's Facilities shall be scheduled by HHH with TCE's Controlling Authority.

26.10.7 For certain planned work by HHH on its facilities, to be mutually agreed upon by both Parties, HHH's Controlling Authority shall submit a request to TCE's representative identified in Schedule A, including a request to provide a Supporting Guarantee where applicable. Such request shall be submitted in writing and shall be submitted at least four days in advance of the planned work or within such other period as the Parties may agree.

26.10.8 Where HHH plans work on its facilities that requires that multiple feeder breakers, a station bus or a whole transformer station be operated, HHH's Controlling Authority shall submit a request to TCE's representative identified in Schedule A, including a request to provide a Supporting Guarantee where applicable. Such request shall be submitted in writing and shall be submitted at least ten days in advance of the planned work or within such other period as the Parties may agree.

26.10.9 Where TCE plans work on its facilities that directly affects HHH's Facilities and that requires that multiple feeder breakers, a station bus or a whole transformer station be operated, TCE's Controlling Authority shall give notice of the planned work to HHH's representative identified in Schedule A. Such notice shall be submitted in writing and shall be submitted at least ten days in advance of the planned work or within such other period as the Parties may agree.

26.10.10 Where TCE plans work on its facilities that directly affects HHH's Facilities and that requires a feeder breaker to be opened or operated, TCE's Controlling Authority shall give notice of the planned work to HHH's representative identified in Schedule A. Such notice shall be submitted in writing and shall be submitted at least four days in advance of the planned work or within such other period as the Parties may agree.

26.10.11 HHH will provide TCE with HHH isolation plans for any HHH equipment maintenance. HHH will provide TCE with HHH meter data and disconnect positions electronically to the HHGS Control Room DCS.

26.10.12 The Controlling Authority of a Party may submit to the other Party a written request for permission to re-schedule planned work that has been previously notified to or scheduled with that other Party. Such request must be given in writing at least two business days prior to the date on which the planned work was originally scheduled to occur.

26.10.13 If a Party's request to re-schedule cannot be reasonably accommodated by the other Party and the Parties cannot agree on an alternate date, the matter shall be submitted to the dispute resolution process set out in section 17.

26.11 **Shutdown of HHH's Facilities**

26.11.1 HHH's Controlling Authority shall promptly notify TCE's Controlling Authority in the event that HHH's Facilities are shut down for any reason. TCE shall investigate and determine the cause of the shutdown, using available evidence including input from HHH's staff.

26.11.2 Once TCE is satisfied that reconnection of HHH's Facilities following a shutdown will not adversely affect TCE's Facilities or the Hydro One transmission system, TCE shall notify HHH as soon as practicable that it may reconnect its facilities to TCE's Facilities. HHH shall not reconnect its facilities to TCE's Facilities following a shut down until authorized to do so by TCE's Controlling Authority.

26.12 **Emergency Operations**

26.12.1 During an emergency or in order to prevent or minimize the effects of an emergency, a Party may without prior notice to the other Party take whatever immediate action it deems necessary to ensure public safety or to safeguard life, property or the environment.

26.12.2 Where a Party takes action under section 26.12.1, it shall promptly report the action taken and the reason for that action to the other Party's Controlling Authority.

26.12.3 During an emergency or in order to prevent or minimize the effects of an emergency, TCE may interrupt supply to HHH's Facilities in order to protect the stability, reliability or integrity of TCE's Facilities or to maintain the availability of those facilities. In such a case, TCE shall notify HHH as soon as possible of its facilities' emergency status and of when to expect the resumption of normal operations. TCE shall notify HHH once TCE determines that HHH's Facilities may be reconnected. HHH shall not reconnect its facilities until authorized to do so by TCE.

26.12.4 In the event that the Independent Electricity System Operator directs TCE to undertake any load shedding involving the HHH Facilities, TCE shall advise HHH of such direction, and HHH shall comply with such direction from the Independent Electricity System Operator.

26.13 Access to and Security of Facilities

26.13.1 Each Party shall ensure that its facilities are secure at all times. Where a Party's facilities are located on the site of another Party, the Parties shall cooperate to ensure the security of those facilities in accordance with section 26.1.1(c).

26.13.2 Each Party shall be entitled to access the site or facilities of the other Party at all reasonable times where required in order to carry out work on its facilities or where otherwise permitted or required under this Agreement, provided that such access shall at all times be under the supervision and control of the host Party. Such access shall be effected in accordance with sections 26.13.4 and 26.13.5.

26.13.3 Each Party shall, to facilitate the exercise by the other Party of its access rights, provide that other Party with all applicable access procedures, including procedures relating to access codes and keys.

26.13.4 Where a Party wishes to exercise its right of access to the site or facilities of the other Party, the accessing Party shall provide reasonable prior notice to the host Party of the date, time and location of access and of the nature of the work to be undertaken. Where the accessing Party's access cannot reasonably be accommodated by the host Party, the Parties shall agree on another date and time for access.

26.13.5 Where a Party is exercising its right of access, the Party shall:

(a) comply with the obligations set out in section 26.1;

(b) ensure that any person that will have access to the host Party's site or facilities has been properly trained;

(c) comply with the procedures provided to it by the host Party under section 26.13.3;

(d) not damage or interfere with the host Party's property (provided that the exercise of the right of access shall not itself be considered interference); and

(e) not interact with representatives of the host Party other than the person designated for such purpose by the host Party or as may be permitted by that designated person.

26.13.6 Where an accessing Party causes damage to or loss of any property of the host Party, the accessing Party shall promptly notify the host Party. Notwithstanding any provision of section 14, <u>if the damage or loss is caused by the wilful misconduct of the accessing Party</u>, the accessing Party shall pay to the host Party the host Party's reasonable costs of repairing such property or, if such property cannot be repaired, of replacing such property.

26.13.7 Nothing in this section 26.13 shall prevent or restrict a Party from doing any of the following in an emergency or where required to prevent or minimize the effects of an emergency:

(a) interfering with the property of the other Party that is on its site; or

(b) accessing the site of the other Party without notice.

Where a Party takes such action and causes damage to or loss of the property of the other Party, the acting Party shall promptly notify the other Party and the acting Party shall pay to the other Party the other Party's reasonable costs of repairing such property or, if such property cannot be repaired, of replacing such property.

27 INSPECTION, TESTING, MONITORING AND NEW, MODIFIED OR REPLACEMENT HHH FACILITIES

27.1 General Requirements

27.1.1 HHH shall inspect, test and monitor its facilities to ensure continued compliance with all applicable instruments and standards referred to in paragraphs (a) to (c) of section 23.1.

27.1.2 Each Party shall maintain complete and accurate records of the results of all performance inspection, testing and monitoring that it conducts in fulfillment of its obligations under this Agreement. Such records shall be maintained by HHH for a minimum of seven years.

27.1.3 Each Party shall, at the request of the other, provide the other Party with the records referred to in section 27.1.2. Without limiting the generality of the foregoing, HHH shall, at TCE's request, provide TCE with:

(a) test certificates certifying that HHH's Facilities have passed all relevant tests and comply with all applicable instruments and standards referred to in paragraphs (a) to (c) of section 23.1; and

(b) copies of any certificates of inspection or other applicable authorizations or approvals received from the Ontario Electricity Safety Authority in relation to HHH's Facilities.

27.2 New, Modified or Replacement HHH Facilities

27.2.1 Each Party shall, at the request of the other Party, permit the requesting Party to inspect, test or witness the commissioning of any new, modified or replacement facilities where the requesting Party reasonably considers that such new, modified or replacement facilities may adversely affect the performance of its facilities.

27.2.2 Where section 27.2.1 applies, the inspection, testing or commissioning shall be conducted at a time that is mutually agreed upon by the Parties. If the inspection, test or commissioning is required to be rescheduled at the request of a Party or by reason of a Party's failure to attend, the Party shall, at the request of the other Party, pay all reasonable costs incurred by the other Party in respect of the rescheduling of the inspection, testing or commissioning activity.

27.2.3 Each Party shall, at the request of the other Party, provide the requesting Party with test certificates, including any certificates of inspection or other applicable authorizations or approvals that the Ontario Electrical Safety Authority may have issued, certifying that its new, modified or replacement facilities have passed the relevant tests and comply with all applicable instruments and standards referred to in paragraphs (a) to (c) of section 23.1.

27.2.4 Each Party shall provide the requesting Party such technical parameters as may be required to assist in ensuring that the design of its Facilities shall be consistent with the requirements applicable to the requesting Party's facilities as set out in this Agreement.

27.2.5 Neither Party shall make any modifications to its facilities of a type that is specified in Schedule D without the prior approval of the other Party.

27.2.6 Where either Party considers that a type of modification that is not already specified in Schedule D is likely to have a material adverse effect on its facilities, it shall so notify the other Party. The Parties shall then negotiate in good faith appropriate amendments to Schedule D.

28 RIGHT OF FIRST REFUSAL

28.1 **Right of First Refusal**

28.1.1 In the event that TCE has received an offer which it wishes to accept from an arm- length third party to purchase only the Access Line, it shall first provide HHH with notice in writing offering the Access Line for sale to HHH at the price and on terms and conditions offered by the third party (the "Sale Terms").

28.1.2 HHH shall upon receipt of TCE's notice in writing have 10 days within which to elect in writing to purchase the Access Line at the Sale Terms including the HHH Conditions. Should HHH agree to offer to purchase the Access Line, its offer must include a condition that TCE will receive the same standard of service and same rates that it would currently receive from Hydro One or the applicable transmission utility for transmission service through the Access Line.

28.1.3 In the event that HHH elects not to purchase the Access Line, then TCE may at any time thereafter dispose of the Access Line on terms equivalent to the Sale Terms or better.

28.1.4 Notwithstanding anything to the contrary, HHH shall not be entitled to any right of first refusal, if TCE receives an offer to purchase all or substantially all of its facilities, which includes the Access Line.

TransCanada Energy Ltd.	**Halton Hills Hydro Inc.**
Per: ______________________________	Per: ______________________________
Name:	Name:
Title:	Title:

Per: ______________________________

Schedule A -

SINGLE LINE DIAGRAM, DESCRIPTION OF THE CONNECTION POINT(S) AND DETAILS OF SPECIFIC OPERATIONS

A.1 SINGLE LINE DIAGRAM AND CONNECTION POINT(S)

[to be inserted by the Parties]

A.2 LIST OF FACILITIES ON THE PROPERTY OF THE OTHER PARTY

A.2.1 The following HHH Facilities are located on the TCE site:

[to be completed by the Parties]

A.2.2 The following TCE Facilities are located on the HHH site:

[to be completed by the Parties]

A.3 TELEPHONE CONTACT

A.3.1 Either Party has the right to change the position designations and telephone numbers listed below with immediate effect at any time by notice in writing delivered to the other Party by fax or other telegraphic means. Any employee of a Party with apparent authority may deliver such a notice to the other Party.

Day to Day Operations

For the operation of the TCE Facilities and the HHH Facilities:

	TCE	HHH
Operating Contacts:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Outage Planning:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		

Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		

Contract Administration for Operating Services

	TCE	HHH
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		
Position:		
Name:		
Location:		
Phone Number:		
Fax Number:		

A.4 OWNER AND OPERATING CONTROL

A.4.1 A Party may change its designated controlling authority set out below at any time during the term of the Agreement, subject to the following conditions:

(a) TCE may change its designated controlling authority only for the TCE Facilities;

(b) HHH may change its designated controlling authority only for the HHH Facilities;

(c) either Party shall notify the other in writing of any change in its designated controlling authority at least ten business days before implementing a change; and

(d) notification of any changes to the controlling authority shall be exchanged between TCE and HHH as follows:

TCE	**HHH**
[to be completed by Parties]	**[to be completed by Parties]**

A.4.2 HHH:

(a) owns: **[to be completed by Parties]**

(b) has operating control of: **[to be completed by Parties]**

A.4.3 TCE:

(a) owns: **[to be completed by Parties]**

(b) has operating control of: **[to be completed by Parties]**

A.5 Metering Facilities Diagram

This diagram is based on the protection, control, and metering diagram.

A.6 Normal Operations

This Schedule shall include HHH-specific Information during normal operations.

A.7 Emergency Operations

This Schedule would include HHH specific Information during Emergency operations.

A.8 Re-verification Schedules-Protection and Control (sample only)

A.8.1 HHH shall re-verify its station protections and control systems that can impact on TCE's Facilities. The maximum verification or re-verification interval must match TCE's interval period for most of the 115 kV transmission system elements including transformer stations and transmission lines, and certain 230 kV transmission system elements; and two (2) years for all other high voltage elements. The maintenance cycle can be site specific. Any testing shall be done during TCE outages.

A.8.2 HHH shall advise TCE at least fourteen (14) business days' notice of its intention to conduct a reverification test, so that the TCE's protection and control staff and system performance staff (if required) can observe:

(a) re-verification of protection equipment settings specified in this Agreement;

(b) relay recalibration;

(c) test tripping of station breakers that impact on the TCE/HHH interface measurement and analysis of secondary AC voltages and currents to confirm measuring circuit integrity as well as protection directioning; and

(d) measurement and analysis of secondary AC voltages and currents to confirm measuring circuit integrity.

Note: All tests must be coordinated and approved ahead of time through the normal outage planning process.

A.8.3 The following specific actions are required:

(a) observe all station protections that trip and open the "enter the devices that interface with TCE" for proper operation; and

(b) confirm that settings approved by TCE are applied to the following protections:

(i) over and under voltage;

(ii) transformer differential;

(iii) transformer phase and ground backup protection;

(iv) line protections;

(v) breaker or HVI failure protection; and

(vi) transfer and remote trip protections.

A.9 General Protections (sample only) [NTD: This section to be revisited once engineering design is complete]

1 There are no line protections at Site.

2 Transformer faults are cleared by the high voltage (HV) and medium voltage (MV) breakers.

3 The transformer protection sends a block to TCE's transformer station or switching station to prevent out of zone tripping.

4 Breaker failure protection sends transfer trip and it is then cascaded to other stations.

5 Under Frequency Load Shedding relays that operate as follows:

[Set out Particulars]

A.10 Telecommunication Facility Details for Protection and Control Applications (sample only)

A.10.1 Telecommunication Medium

The communication medium used will be two (2) leased telephone circuits from Bell Telephone and these circuits are the responsibility of HHH.

A.10.2 Types of Telecommunication Channels

2 Blocking Channels

2 Transfer Trip Channels

A.10.3 Ownership of Telecommunication Terminal Equipment

The terminal equipment located at a given facility is owned by HHH. The communication medium (leased telephone circuits) is considered to be owned by HHH. Therefore, HHH is responsible for the restoration of the failed communication medium.

The terminal equipment located at a switching station is owned by TCE.

A.10.4 Responsibility for Work and Costs Associated with Breakdown and Routine Maintenance

If maintenance is required on the terminal equipment located at HHH's Facilities, HHH will bear all incurred costs.

If maintenance is required on terminal equipment located at sites owned by TCE, TCE will bear all incurred costs. If maintenance or repair is required on the leased telephone circuits, HHH will incur all associated costs. These costs will include charges by Bell Telephone and TCE if its personnel are required to participate in any of the related activities.

A.10.5 Reverification Schedule

Routine Maintenance on communication equipment and the communication channels must be performed every two years.

A.10.6 Inventory of Communication Equipment

The provision of spare communication equipment is HHHs' responsibility and will be located at its site.

A.10.7 Failure of Communication Equipment

If a communication failure affects either the transfer trip channels or the blocking channels; TCE will decide whether or not HHH should remain connected to the high- voltage system. TCE must advise HHH, through the appropriate communication protocol outlined in this code, of the situation, the choices available to HHH and the risks involved. Since TCE will take the decision according to its own interests, HHH can choose to remain or separate from the high-voltage system at its own risk.

A.10.8 Mean Time for Repairs

The mean time for repairs will be within two working days, dependent on the availability of staff of Bell Telephone and TCE.

A.10.9 Provision of Purchase Order by HHH to TCE

HHH will provide TCE's designated leader with a purchase order, so that TCE may apply appropriate charges to HHH.

Schedule B -

[Intentionally left blank]

Schedule C -

CURE PERIODS FOR DEFAULTS

C.1 The Cure Period for an Event of Default shall depend on the impact of the Event of Default, determined by the Non-defaulting Party as follows:

Impact of Default	Description	Cure Period
Safety - Immediate	An Event of Default that could result in immediate injury or loss of life (e.g., exposed wires, destroyed station fence, etc.).	Promptly
Safety - Potential	An Event of Default that could result in injury or loss of life if a single contingency were to occur (e.g., substandard grounding)	Promptly
Environment B Immediate	An Event of Default that could result in immediate adverse effects on land, air, water, plants, or animals	Promptly
Asset Integrity	An Event of Default that could adversely affect the ability of an asset to operate within prescribed ratings (voltage, thermal, short circuit) or be maintained to required standards for the purpose of prolonging the lifespan of the asset or satisfying safety or environmental requirements	Promptly
Environmental - Potential	An Event of Default that could, if a single contingency were to occur, result in adverse effects on land, air, water, plants, or animals	30 days
Power Quality	An Event of Default that could result in a variation in electric power service that could cause the failure or improper or defective operation of end-use equipment, such as voltage sag, overvoltage, transients, harmonic distortion and electrical noise	30 days

C.2 Where an Event of Default can have more than one impact and the impacts have different Cure Periods, the shortest of the Cure Periods shall apply.

Schedule D -

FAULT LEVELS AND MODIFICATIONS

D.1. FAULT LEVELS

[to be completed by the Parties and updated as required, using Attachment D1 or an amended version of Attachment D1 if desired]

D.2. MODIFICATIONS

D.1.1 In accordance with sections 28.2.5 and 28.2.6, the following modifications to HHH’s Facilities may not be made by HHH without the prior approval of the TCE:

[to be completed by the Parties]

Attachment D1

Fault Levels
(as permitted by section D.1 of Schedule D)

Supply Voltage (kV)	Tx Connection Point Number	Tx Connection Point	Fault Level (kA)

Schedule E -

GENERAL TECHNICAL REQUIREMENTS

E.1 Guidelines of Reliability Organizations

E.1.1 HHH and TCE shall follow all reliability organizations' standards as they may be amended from time to time.

E.1.2 TCE shall provide to HHH, upon request, the address and contact persons at the relevant reliability organization.

E.2 Isolation from TCE's Facilities

E.2.1 HHH shall provide an isolating disconnect switch or device at the point or junction between TCE and HHH, i.e., at the point of the interconnection, which physically and visually opens the main current-carrying path and isolates HHH's Facilities from TCE's Facilities.

E.2.2 The isolating disconnect switch shall meet the following criteria:

(a) it shall simultaneously open all phases (i.e., group-operated open/close) to the connection;

(b) it shall be lockable in the open position only;

(c) when the device is used as part of the HVI failure protection system, it shall be motor-operated and equipped with appropriate control circuitry; and

(d) it shall be suitable for safe operation under the conditions of use.

E.3 Protection and Control

E.3.1 The protection systems, which protects TCE's Facilities system elements, shall be capable of minimizing the severity and extent of disturbances to TCE's Facilities while themselves experiencing a first-order single contingency such as the failure of a relay protection system to operate or the failure of a breaker to trip. In particular:

(a) the elements designated by TCE as essential to system reliability and security shall be protected by two protection systems. Each system shall be independently capable of detecting and isolating all faults on those elements. These elements shall have breaker failure protection, but breaker failure protection need not be duplicated. Both protection systems shall initiate breaker failure protection;

(b) to reduce the risk of both systems being disabled simultaneously by a single contingency, the protection system designs shall not use components common to the two systems;

(c) the use of two identical protection systems is not generally, recommended, because it increases the risk of simultaneous failure of both systems due to design deficiencies or equipment problems;

(d) the protection systems shall be designed to isolate only the faulted element. For faults outside the protected zone, each protection system shall be designed either not to operate or to operate selectively in coordination with other protection systems;

(e) HHH protection settings for protections affected by conditions on the TCE Facilities shall be coordinated with those of the transmission system;

(f) protection systems shall not operate to trip for stable power swings following contingencies that are judged by protection system designers as not harmful to the transmission system or HHH;

(g) the components and software used in all protection systems shall be of proven quality for effective utility application and following good utility practice;

(h) critical features associated with the operability of protection systems and the high voltage interrupting device (HVI) shall be annunciated or monitored;

(i) the design of protection systems shall facilitate periodic testing and maintenance. Test facilities and procedures shall not compromise the independence of the redundant protection systems. Test switches shall be used to eliminate the need to disconnect wires during testing;

(j) the two protection systems shall be supplied from separate secondary windings on one voltage transformer or potential device and from separate current transformer secondary windings, i.e., from two separate current transformers;

(k) separately fused and monitored DC sources shall be used with the two protection systems. For all generating Facilities connected to the transmission system, two separate DC station battery banks shall be required to provide the required degree of reliability; and

(l) protection system circuitry and physical arrangements shall be designed to minimize the possibility of incorrect operations from personnel error.

E.3.2 Specific protection and control practices and equipment requirements are set out in Schedule G of this Agreement.

E.3.3 TCE and HHH should apply protection systems, using the typical tripping matrix for transmission system protection shown in Exhibit E.2, of this Schedule E.

E.4 Insulation Coordination

E.4.1 Equipment connected to TCE's Facilities shall be protected against lightning and switching surges. This shall include station shielding against direct lightning strokes, surge protection on all wound devices, and cable/overhead interfaces.

E.4.2 A tap connected to a shielded transmission circuit shall also be shielded. 1.4.3. TCE shall review surge arrester ratings.

(a) TCE shall provide all relevant Information, e.g., ratings, to HHH upon request. TCE, however is not responsible for the adequacy of design or correctness of the operation of any equipment or apparatus including the surge arrester(s).

E.5 Grounding

E.5.1 Grounding installations shall be capable of carrying the maximum foreseeable fault current, for the duration of such fault currents, without risking safety to personnel that may be present on site when a fault occurs, damage to equipment, or interference with the operation of the transmission system.

E.5.2 Each transformer, switching, or generating station shall have a ground grid on which all metallic structures, metallic equipment and non-energized metallic equipment are solidly connected. The size, type and requirements for the ground grid are site-specific, depending on such factors as soil conditions, station size, and short-circuit level.

E.5.3 TCE shall review the ground potential rise (GPR) study submitted by HHH at HHH's cost. HHH shall comply with the Bell System Practices as they may be amended or modified from time to time and the IEEE standard 487 as it may be amended or modified from time to time for providing special high- voltage protection devices on metallic communication cables. TCE assumes no responsibility for the adequacy of design or correctness of the operation of any equipment or apparatus associated with HHH's installation.

E.5.4 The placement of any additional grounding points on the transmission system shall require the approval of TCE. TCE shall give its approval if it is satisfied that the reliability of its transmission system is not affected.

E.6 Telemetry, Monitoring, and Telecommunications

E.6.1 TCE shall advise HHH of the performance and details of required telemetering facilities that serve them. Some requirements depend on the size and specific location of the connection to the transmission system. As a minimum, telemetry shall be required for the flow of real and reactive power through circuits and transformers, the voltages at selected points, and the status (open or closed) of switching elements.

E.6.2 TCE may require HHH to install monitoring equipment to track the performance of its facilities, identify possible protection system problems, and provide measurements of power quality. As required, the monitoring equipment shall perform one or several of the following functions:

(a) sequence of events recording (SER) to record protection related events at a connection time synched via satellite clock;

(b) digital fault recording (DFR) to permit analysis of transmission system performance under normal and abnormal conditions time synched via satellite clock; or

(c) power quality monitoring (PQM) to record voltage transient surges, voltage sags and swells, voltage unbalance, supply interruptions, frequency variations and other voltage and current waveform monitoring.

E.6.3 HHH's telecommunications facilities shall be compatible with those of TCE and have similar reliability and performance characteristics. At TCE's discretion, some or all of the following functions may require telecommunication: protective relaying; system control and data acquisition (SCADA); voice communication; and special protection systems (e.g., generation rejection or runback).

E.6.4 Telecommunication facilities, design details, and performance requirements, associated with HHH' Facilities, shall be provided at the HHH's expense.

E.6.5 HHH shall bear all costs, without limitation, of providing the same telemetry data required under the Market Rules, associated with its facilities to TCE and providing all required connection inputs to TCE's disturbance-monitoring equipment, except:

(a) where the connection inputs to TCE's disturbance-monitoring equipment are of mutual benefit to HHH and TCE, in which circumstance HHH and TCE shall share the cost of providing the data in proportion to the benefits received; or

(b) where the connection inputs to TCE's disturbance-monitoring equipment are required only for TCE's benefit, in which case the transmitter shall pay all of the costs associated with providing the data.

E.7 Inspecting and Commissioning Procedures

E.7.1 HHH shall ensure that any new or replacement equipment that they own is inspected and tested before initial connection to the transmission system. The initial verification tests shall confirm that the connection of HHH facility to TCE's Facilities:

(a) does not pose any safety hazards;

(b) does not adversely affect operation of the transmission system in a material manner; and

(c) does not violate any requirement of this Agreement.

E.7.2 TCE has the right to inspect HHH's facility and witness commissioning tests related to any new or replacement equipment that could reasonably be expected to adversely affect TCE's Facilities. The initial verification shall include high-voltage interrupting devices, line disconnect switches, the line and bus connections from the dead-end structure to HHH's facility, power transformers, surge arresters, DC batteries, and station service systems, protection, metering, and communication systems. HHH shall have the right to the inspection reports relating to such facility.

E.7.3 TCE assumes no responsibility for the adequacy of design or correctness of the operation of any equipment or apparatus associated with HHH's installation. TCE shall notify HHH of its findings regarding any potential problems or limitation of such equipment or apparatus owned by the HHH, without any responsibility.

E.7.4 HHH shall advise TCE of the commissioning program in writing, thirty business days before it proposes to begin the commissioning tests. The written notice shall include the connection commissioning schedule, the proposed test procedure, the test equipment to be used, and the transmission system conditions required, and also the name of the individual responsible for coordinating the proposed tests on HHH's behalf.

E.7.5 Within fifteen business days of receiving the notice, TCE shall notify HHH that it:

(a) agrees with the proposed connection commissioning program and test procedures; or

(b) requires changes in the interest of safety or maintaining the reliability of the transmission system, and that such changes shall be sent to HHH promptly.

E.7.6 If TCE requires changes, then the Parties shall act in good faith to reach agreement and finalize the commissioning program within a reasonable period.

E.7.7 HHH shall submit the results of the commissioning tests to TCE and must demonstrate that all its equipment complies with this Agreement.

E.7.8 If the commissioning test reveals non-compliance with one or more requirements of this Agreement, HHH whose equipment was tested shall promptly meet with TCE and agree on a process aimed at achieving compliance.

E.7.9 TCE may withhold permission to complete the commissioning and subsequent connection of HHH to TCE's Facilities if the relevant equipment fails to meet any technical requirement stipulated in this Agreement.

E.7.10 All reasonable costs incurred or associated with TCE's witnessing of the verification tests shall be borne by HHH.

E.8 Procedures for Maintenance and Periodic Verification

E.8.1 TCE may specify the maintenance criteria and the maximum time intervals between verification cycles for those parts of HHH's Facilities that may materially adversely affect TCE's Facilities. The obligations for maintenance and performance re-verification shall be stipulated in the appropriate schedule to this Agreement.

E.8.2 Test switches shall be provided to isolate current and potential transformer input to the relays as well as a set of switches to isolate the relays tripping outputs from the power equipment control circuitry.

E.8.3 The reasonable cost of conducting maintenance and verification tests shall be borne by HHH.

E.8.4 TCE may appoint a representative to witness relevant maintenance and verification tests and HHH shall permit the representative to be present while those tests are being conducted.

E.8.5 To ensure that TCE's representative can witness the relevant tests, HHH shall submit the proposed test procedures and a test schedule to TCE not less than ten business days before it proposes to carry out the test. Following receipt of the request, TCE may delay for technical reasons the testing for as long as ten business days. TCE will use best efforts to make the required test date.

E.8.6 The reasonable costs associated with the witnessing of verification tests by TCE's representative shall be borne by HHH.

E.8.7 If a verification test reveals that the electrical equipment or protective relay system covered under the operations schedule does not comply with requirements, HHH shall:

(a) promptly notify TCE of that fact;

(b) promptly advise TCE of its proposed remedial steps and its timetable for their implementation;

(c) diligently undertake appropriate remedial work and provide TCE with monthly reports on progress; and

(d) conduct further tests or monitoring on completing the remedial work, to confirm compliance with the relevant technical requirements.

E.8.8 TCE's reasonable costs associated with witnessing the performance tests following remedial work shall be borne by HHH.

E.8.9 HHH shall make their maintenance records and verification test results, including up-to-date as-built drawings, available to TCE upon request.

Exhibit E.1

Protection System Symbols and Devices

Protection Systems - Symbols and Device Functions

51B	Transformer Phase Backup
50 / 51	Instantaneous / Timed Overcurrent
51V	Voltage Controlled Overcurrent
64	Line Ground Protection
79-25	Synchronizing Relay
A21 / B21	Line Phase Protection - A&B Group
A27 / B27	Undervoltage - A&B Group
A59 / B59	Overvoltage - A&B Group
A64-27 / B64-27	Ground Undervoltage - A&B Group
A64-59 / B64-59	Ground Overvoltage - A&B Group
A81U / B81U	Underfrequency - A&B Group
A81O / B81O	Overfrequency - A&B Group
A87 / B87	Transformer Differential - A&B Group
F	Failure Protection
L1, L2	Supply Line
T1, T2	Power Transformer
RT/TT	Remote or Transfer Trip for HVI Device Failure Protection
	Circuit Breaker
	Circuit Breaker with Reclosure
HVI	HV Interrupting Device a) Circuit Breaker b) Circuit Switcher c) Vacuum Interrupter
	Motor Operated Disconnect Switch
 H	HV Transformer Bushing
 X	LV Transformer Bushing

Exhibit E.2

Typical Transmission System Protection Tripping Matrix

The following is a simplified tripping matrix showing the breakers that trip for different protection systems on the transmission system based on a single line supply to a HHH station or TCE's tapped transformer station operating, at the high voltage side, above 50 kV. The type of HHH station configuration and other site- specific factors will influence the desired tripping matrix. The same approach can be applied to large 44-kV developments. In some applications, it may be desirable to trip the MV breaker for Line ZI/T operations instead of the HV Breaker.

	INITIATING PROTECTION							
PROTECTION FUNCTION	LINE ZI	LINE ZT	TTR LOCAL	XFRM	BUS	B/F HV	FRAME LEAK *	B/F MV
TRIP HV BREAKERS	T	T		T	T	T	T	T
HV BREAKER FAILURE	I	I		I	I			
HV AUTO-RECLOSE	C	C		C	C	C	C	C
TRIP MV BREAKERS			T	T	T	T	T	T
MV BREAKER FAILURE			I	I	I		I	
MV AUTO-RECLOSE					C	C	C	C
TTT	S					S	S	
OPEN XFR DISC				I				
RIP ADJACENT HV ZONES						I		
RIP ADJACENT MV ZONES								I

T – trip breakers
I – initiate
C – cancel
S – send signal
HV – high voltage

TTR/T – transfer trip receive/transmit
ZI/T – impedance instantaneous/timed
B/F – breaker failure

MV – medium voltage

* - Frame leakage protection is normally associated with 500kV breakers

All transmission system elements, including breakers, in the zones of protection shall be fitted with redundant protection systems if devices operated at more than 50 kV, except as noted.

All breakers in the zone of protection that includes devices operated at more than 50 kV shall be fitted with the non-redundant breaker failure-protection systems. Transmission system reliability, as determined by the IESO, may require breaker failure protection on the transformer MV breaker.

HHH must be able to isolate (self-contain) his internal problems without having a major impact on the transmission system. Under certain circumstances, HV breakers may not be required for load HHH step-down transformers, provided that a motorized disconnect switch and redundant communication channels and paths are provided to isolate the transformer at the terminal stations if a fault occurs in the transformer zone of protection.

Medium-voltage buses require either duplicated differential protection or a single differential protection with an overcurrent backup.

Schedule F -

ADDITIONAL TECHNICAL REQUIREMENTS FOR TAPPED TRANSFORMER STATIONS SUPPLYING LOAD:

(a) TCE's Tapped Transformer Stations; and

(b) HHH's Tapped Transformer Stations

F.1 Supply Considerations

F.1.1 A high-voltage interrupting (HVI) device shall provide clearing of faults in HHH's system. HVIs shall be provided with appropriate back-up protection. The HVI shall be a circuit breaker located at the connection point unless TCE authorizes another device or location.

F.1.2 TCE shall determine, in consultation with HHH, the supply voltage to HHH. The 115 kV or 230 kV voltage shall be generally used for supply of HHH with a peak demand of 20 MW or more.

F.1.3 Tapped transformers of TCE's or HHH's shall have adequate on-load tap- changer or other voltage-regulating facilities to operate continuously within normal variations on the transmission system as set out in the Market Rules and to operate in emergencies with a further transmission system voltage variation of V six per cent (V 6%).

F.1.4 The neutrals of the power transformer primary windings at transmission system tapped stations are normally not grounded. TCE shall approve grounded transformers by exception only.

F.1.5 A transmission system breaker of HHH shall not autoreclose without TCE's approval.

F.1.6 HHH shall not manually energize a TCE line without TCE's approval.

F.1.7 To meet the minimum general requirements for all equipment connected to the transmission system, HHH may have to install any necessary equipment, including, for example, capacitors and filters.

F.2 Protection Requirements

F.2.1 The typical technical requirements for HHH protection shall be followed, as presented in Exhibit E.1 of Schedule E and Exhibits F.1 and F.2 of this Schedule F.

F.2.2 Line protections are required when transformers connected to separate supply circuits are operated in parallel on the low-voltage side, or if a large synchronous infeed exists at the low-voltage bus.

F.2.3 Directional current sensing relays may be required to detect infeed into faults within the transmission system and isolate HHH's contribution to the fault. Distance or impedance (21) relays as specified in Exhibit F.2 of this Schedule F, usually serve this need.

F.2.4 If the transformer is connected ungrounded wye or delta on the primary, then ground undervoltage (64-27) and ground overvoltage (64-59) protections as shown in Exhibit F.2 of this Schedule F are required to detect ground faults.

F.2.5 Where TCE has accepted transformers connected wye-grounded on the primary (Yg/D or Yg/Yg), a ground-overcurrent relay (64) as indicated in Exhibit F.2 of this Schedule F, connected in the transformer neutral, may be used for detection.

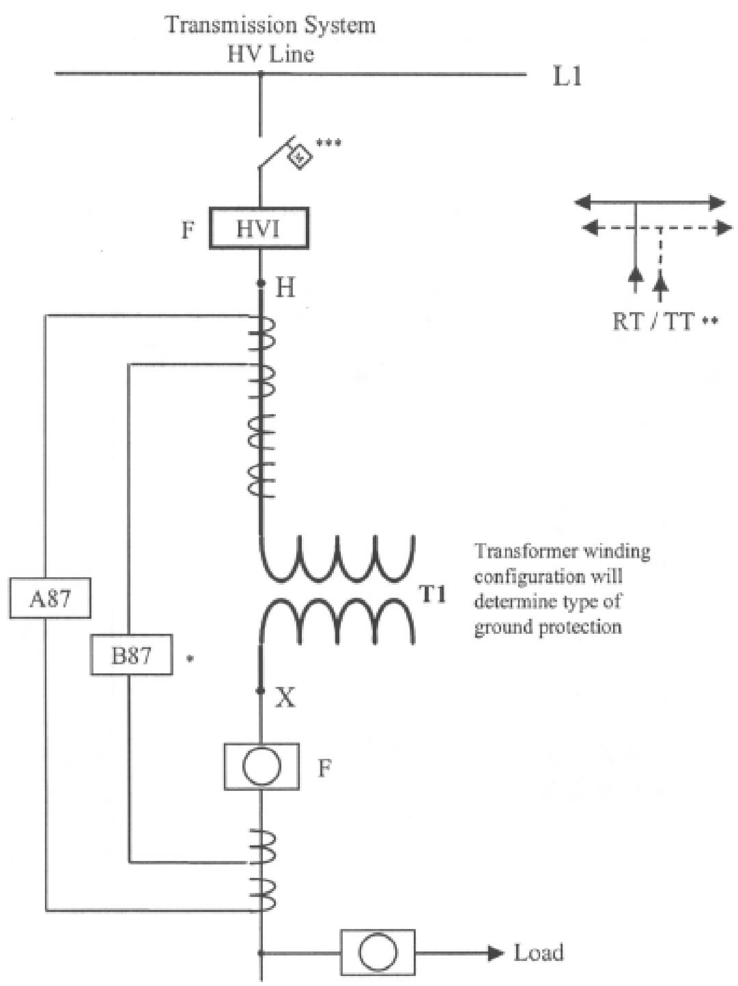
F.2.6 Where remote/transfer trip circuits are used for transformer faults to trip TCE's line breakers at the terminal stations, HHH shall use a motor- operated transformer disconnect switch at its station to provide a point of separation from the transmission system. Energization of remote/transfer trip and opening of the disconnect switch (89) shall be initiated simultaneously, provided that a short time delay is required in opening a disconnect switch if it is not designed to open under load, from the protection circuits. Full opening of the disconnect switch shall block sending of remote trip.

F.2.7 For a DC remote trip on a 115-kV system, HHH shall provide all necessary equipment associated with one monitored teleprotection channel between its station and one of the supply terminal stations or tapped stations. Industry standard relays and associated equipment that is compatible with the TCE's remote trip equipment shall be used. A 115-kV transfer trip shall have a similar requirement, except that audio- tone equipment shall be used instead of the DC battery voltage.

F.2.8 For a DC remote trip on a 230-kV system, HHH shall provide all necessary equipment associated with two monitored teleprotection channels between its station and one of the supply terminal stations or tapped transformer stations. Normally two circuits in the same cable would be acceptable, but two separate cables going by and following separate routes may be required. HHH shall use industry standard relays and associated equipment that is compatible with TCE's remote trip equipment. A 230-kV transfer trip shall have a similar requirement, except that audio-tone equipment shall be used instead of the DC battery voltage.

Exhibit F.1

Typical Single-Line Protection Requirements



NOTES:

* System security may dictate two transformer differential protections. If not required, a HV backup relay, 51B, is acceptable provided satisfactory setting can be applied.

** RT/TT may require duplication

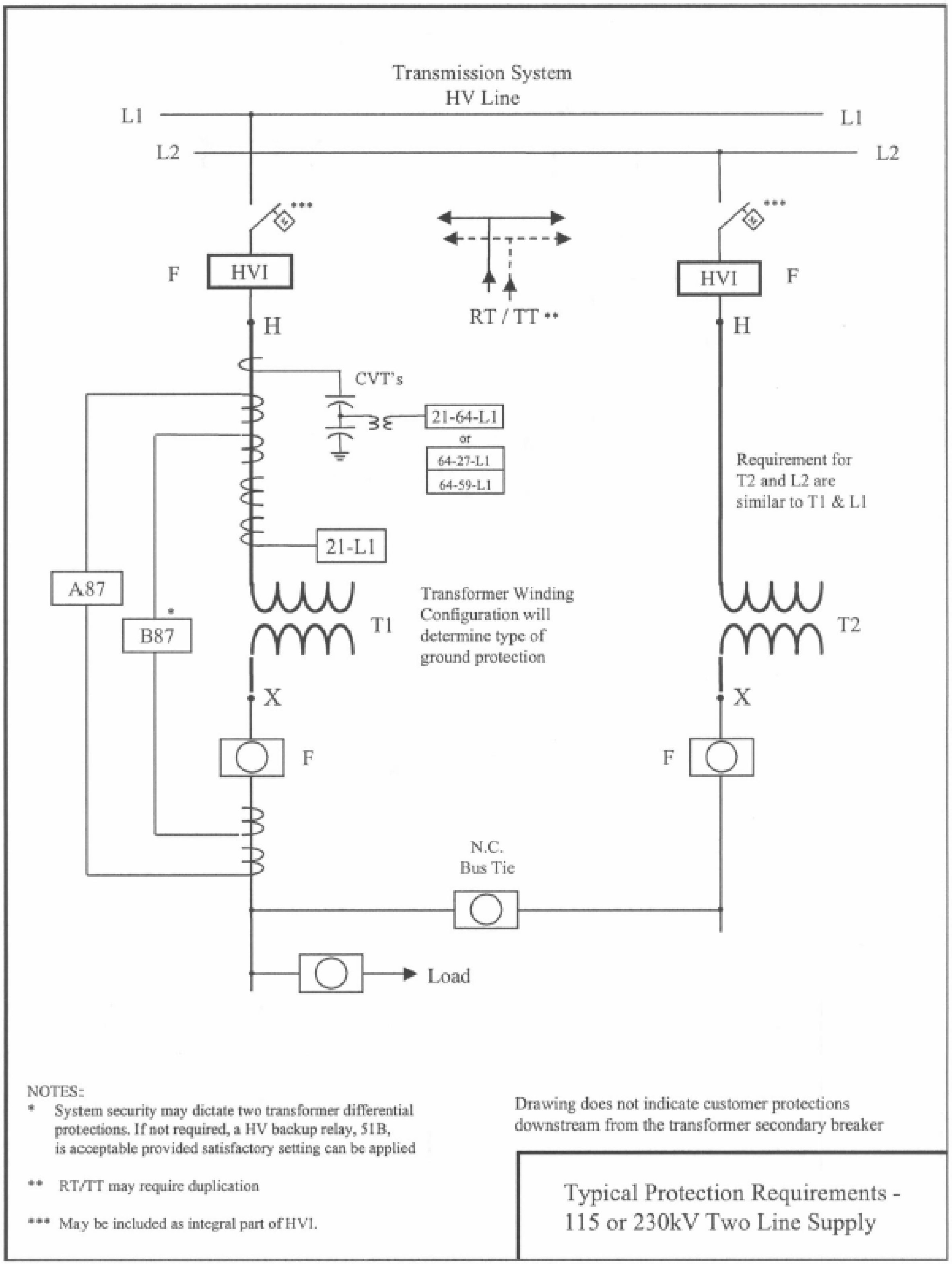
*** May be included as integral part of HVI.

Drawing does not indicate customer protections downstream from the transformer secondary breaker

Typical Protection Requirements - 115 or 230kV Single Line Supply

Exhibit F.2

Typical Two Line Protection Requirements



Schedule G -

PROTECTION SYSTEM REQUIREMENTS

G.1 Telecommunications

G.1.1 The telecommunication facilities, used for protection purposes, shall have a level of reliability consistent with the required performance of the protection system.

G.1.2 TCE shall specify telecommunication channel media and protective systems.

G.1.3 Telecommunication circuits used for the protection and control of TCE's Facilities shall be dedicated to that purpose.

G.1.4 Where each of the dual protections protecting the same system element requires communication channels, the equipment and channel for each protection shall be separated physically and designed to minimize the risk that both protections might be disabled simultaneously by a single contingency.

G.1.5 Telecommunication systems shall be:

(a) designed to prevent unwanted operations such as those caused by equipment or personnel;

(b) powered by the station's batteries or other sources independent from the power system; and

(c) monitored in order to assess equipment and channel readiness.

G.1.6 Major disturbances caused by telecommunication failures shall have annual frequency of less than 0.002 per year from the dependability aspect and less than 0.002 per year from the security aspect.

G.1.7 Telecommunication protection for a single transmission system circuit shall have an unavailability less than forty two (42) minutes per year, and for two circuits it shall be less than four (4) minutes per year.

G.1.8 The telecommunication false-trip rate used as part of a protection system for a single transmission system circuit shall be not more than 0.1 false trips per year, and for two circuits it shall be not more than 0.001 false trips per year.

G.1.9 Total transmission system circuit trips coincident with telecommunications failure shall be not more than 0.001 per year.

G.2 Test Schedule for Relaying Communication Channels

G.2.1 Communication channels associated with protective relaying shall be tested at periodic intervals to verify that the channels are operational and that their characteristics lie within specific tolerances. The testing consists of signal adequacy tests and channel performance tests.

(a) Signal adequacy test intervals are:

(i) Channels - for Protection (unmonitored) at one (1)-month intervals; and

(ii) Channels - for Protection (monitored) at twelve (12)-month intervals.

(b) Channel performance testing on leased communication circuits shall be conducted at 24-month intervals, while intervals for testing power line carrier equipment shall be equipment-specific.

G.3 Verification and Maintenance Practices

G.3.1 HHH shall perform routine verifications of protection systems on a scheduled basis in accordance with applicable reliability standards. The maximum verification interval is four years for most 115-kV elements, most transformer stations, and certain 230-kV elements and two years for all other high- voltage elements. All newly commissioned protection systems shall be verified within six months of the initial in-service date of the system.

G.3.2 Routine verification shall ensure with reasonable certainty that the protections respond correctly to fault conditions.

G.3.3 An electrically initiated simulated-fault clearing check is mandatory to verify new protections, after any wiring or component changes are made to a protection, and for routine verification of a protection.

G.3.4 HHH shall ensure that the functional testing of protection and metering can be properly performed and that all verification readings are obtainable.

G.3.5 TCE shall co-ordinate the initial verification upon receipt of the approved and final set of drawings. The initial verification shall be used during the final commissioning phase of the station and shall be used as a basis for future periodic verifications.

G.3.6 TCE and HHH shall agree upon the final functional test procedures before the tests begin. If they cannot agree, the supply or continuity of supply shall depend on the performance of the tests that TCE shall require.

G.3.7 Before the initial functional tests are performed, HHH shall supply TCE with written documentation that shall readily provide confirmation that appropriate verifications have been completed and that all calibrations, tests, etc., have been performed. For components that may affect the transmission system (such as relays, meters, etc.), HHH must satisfy TCE that the proper settings have been applied.

G.3.8 HHH shall make available to TCE records of relay calibrations and protection verifications, so that records of the facility's performance can be maintained. The specific records required shall be identified in this Agreement.

G.4 Functional Tests and Periodic Verification

G.4.1 Upon verification that HHH's static tests on protection and control equipment, outlined in this Agreement, have been satisfactorily completed, a series of tests shall be performed with the equipment in a dynamic mode. These tests shall ensure that the equipment performs correctly when it should and also that it will not operate improperly.

G.4.2 These tests are here described only in general terms, since the specific tests to be performed will differ depending on the particular station configuration, the components or equipment used, and the design philosophy of the circuitry.

G.4.3 For DC circuitry checks, the logic of the auxiliary circuitry shall be thoroughly checked with the DC applied and the initiating devices suitably energized to initiate the process. When primary relays are the initiating device, the initiation shall be achieved by secondary injection of appropriate electrical quantities to the measuring elements. In certain cases where the sequence of operation is critical, monitoring by a portable sequence-of-events recorder may be required for proper analysis. Operation/tripping of all interrupting/isolating devices shall always be verified, as well as annunciation and target operation.

G.4.4 “On potential” checks shall follow all necessary preliminary procedures. The main equipment shall be energized but not placed on load. HHH shall check all readings of potentials, including determination of correct phasing/phase rotation. The test must also demonstrate that all equipment performs as expected when energized and is in condition to have primary load applied.

G.4.5 HHH shall make “On-Load” checks following the application of appropriate load, voltage, current, phase angle or crossed wattmeter readings at the appropriate instrument transformer outputs or protection input points, to ensure that all quantities are appearing as required with respect to magnitude, phase relation, etc. These checks are to determine that relays are properly connected and that the watt and var checks of all indicating and referenced equipment are correct. At times it may be necessary to repeat some or all tests, e.g., relay performance, using load currents.

G.5 Failure Protection for High-Voltage Interrupting Devices (HVIs)

G.5.1 Provisions shall be made to clear the fault in case the HVI fails to isolate the fault. The requirements for HVI failure protection vary depending on the maximum permissible fault duration and the location of the Connection. Some portions of the transmission system are designed and operated to more stringent requirements to avoid adversely affecting neighbouring transmission systems.

G.5.2 In general, the transmission system will require the HVI failure protection to be achieved by using remote or transfer trip circuits.

G.5.3 In portions of the transmission system having less stringent requirements, the HVI failure protection may be achieved by opening the motor-operated disconnect switch. If the disconnect switch experiences a flashover, the line protection at the TCE Facilities shall operate to isolate the fault.

G.5.4 Automatic ground switches are not acceptable for any new installations for triggering line protection operation following the failure of a HVI.

G.5.5 When circuit switchers are used, the interrupter and disconnect switch shall operate independently. Protections that trip the interrupter shall simultaneously initiate opening of the disconnect switch, provided that a short time delay is required in opening a disconnect switch if it is not designed to open under load .

G.5.6 The DC voltage supplied to the interrupter and disconnect switch shall be fed from separately fused and monitored DC supplies: that is, by two (2) DC cables to the control cabinet.

G.6 Instrument Transformers

G.6.1 Current transformer output shall remain within acceptable limits for all anticipated fault currents and for all anticipated burdens connected to the current transformer.

G.6.2 Current transformers shall be connected so that adjacent relay protection zones overlap.

G.6.3 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their accuracy over the specified primary voltage range.

G.6.4 For each independent protection system, separate current and voltage transformer or potential device secondary windings shall be used, except on low-voltage devices.

G.6.5 Interconnected current transformer secondary wiring and voltage transformer secondaries shall each be grounded at only a single point.

G.7 Battery Banks and Direct Current Supply

G.7.1 HHH shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours for a single battery system or at least six hours for each of the batteries in a two battery system.

G.7.2 Critical DC supplies shall be monitored and annunciated such as relay protection circuits and high voltage interrupters (HVIs).

G.7.3 For all generating facilities connected to the transmission system, two separately protected (fuse/breaker) and monitored DC station battery systems are required.

G.7.4 For tap transformer stations, one protected (fuse/breaker) monitored DC station battery system is required unless two systems are specified by TCE.

G.7.5 Where two battery systems are required, there shall be a battery transfer scheme.

G.7.6 Where the use of a single battery system is allowed, the following conditions shall be met:

(a) it can be tested and maintained without removing it from service;

(b) each protection system shall be supplied from physically separated and separately fused direct current circuits; and

(c) no single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.

Schedule H -

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Schedule I -

EXCHANGE OF INFORMATION

I.1 INFORMATION TO BE PROVIDED BY TCE

I.1.1 Subject to section I.1.2, TCE shall, at HHH's request, provide the following information to HHH provided that such information is available at the relevant time:

(a) feeder amperes per phase;

(b) bus voltage;

(c) real and reactive power flow per feeder (where available; otherwise per bus level);

(d) feeder breaker open/close status;

(e) feeder breaker recloser blocked/not blocked status;

(f) bus tie breaker open/close status;

(g) capacitor bank breaker open/close status; and

(h) transformer/bus breaker open/close status.

I.1.2 HHH shall be entitled to the information referred to in section I.1.1 only to the extent that:

(a) the information relates specifically to the connection of its own facilities;

(b) the information is relevant to the connection of its own facilities; and

(c) TCE is not prohibited by its confidentiality obligations from providing that information to HHH.

I.1.3 TCE shall provide HHH with the following additional information:

(a) at HHH's request, a "relay and breaker trip report" for any operation of a breaker or transfer trip relay and that includes the date and time of the breaker or transfer trip operation and reclose or close, the cause of the incident if known and the quantity of load lost; and

(b) [any additional information items as determined by the Parties to be required based on site specific considerations]

I.1.4 TCE may provide information under section I.1.1 or I.1.3 by means of posting the information on a website that is dedicated to HHH.

I.2 INFORMATION TO BE PROVIDED BY HHH

I.2.1 To the extent that it has not already been provided to TCE, HHH shall provide TCE with the same technical information provided to the IESO during any connection assessment and facility registration processes associated with HHH's Facilities or any new, modified or replacement HHH Facilities. Such information shall be provided in the form outlined in the applicable sections on the IESO's public website.

I.2.2 HHH shall provide TCE with updated versions of the technical information referred to in section I.2.1 in the event of a material change in such information.

I.2.3 HHH shall provide TCE with such information as TCE may reasonably require in order to perform a HHH Impact Assessment.

I.2.4 To the extent that it has not already been provided to TCE under another section of this Agreement or is not reasonably expected to already be known by TCE, HHH shall provide TCE with the date and time at which HHH's Facilities are connected or reconnected to, or disconnected from, TCE's Facilities.

I.2.5 HHH shall notify TCE in the event that its facilities are not being operated or maintained in accordance with the requirements of this Agreement.

I.2.6 HHH shall provide TCE with the following additional information:

(a) the date and time at which any of HHH's supply circuit breakers or high voltage interrupting switches automatically trips;

(b) information pertaining to the operation of any of HHH's automatic protective relays that has an impact on TCE's Facilities;

(c) changes in HHH's operating setup or operating diagrams relative to the information contained in Schedule A or any updates or amendments thereto;

(d) at TCE's request, line and load data required for protective relay settings;

(e) at TCE's request, protective relay settings on equipment protection systems;

(f) at TCE's request, load data required for the purposes of settlement under section 26.3.4; and

(g) at TCE's request, annual facility performance data as may be required to enable TCE to meet its reporting obligations to any reliability organization.

I.3 INFORMATION TO BE PROVIDED BY EITHER PARTY

I.3.1 Each Party shall provide the other with the following information:

(a) any temporary or permanent changes in the configuration of the Party's facilities that may affect the security of those facilities, load distribution, protective relay settings or other parameters;

(b) details of defective equipment or hazardous conditions that may become known to the Party's Controlling Authority but not to the Controlling Authority of the other Party;

(c) planned changes in the Party's facilities that affect the operation of those facilities; and

(d) such other information as the other Party may reasonably require for the purpose of fulfilling its obligations under this Agreement.

I.3.2 Where applicable, the Parties shall amend Schedule A to reflect any information provided by a Party to the other under this Schedule.

Schedule J -

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Schedule K -

CONTACTS FOR PURPOSES OF NOTICE

[To be completed by the Parties]

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APPENDIX B

TCE – HHH MOU

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AMENDED AND RESTATED MEMORANDUM OF UNDERSTANDING

This Amended and Restated Memorandum of Understanding ("**MOU**") is made and entered into as of the 17th day of June, 2013 (the "**Effective Date**") by and between TransCanada Energy Ltd. (hereinafter called "**TransCanada**") and Halton Hills Hydro Inc. (hereinafter called "**Halton Hills**", and collectively with TransCanada referred to as the "**Parties**" or each individually as a "**Party**").

WHEREAS TransCanada owns and operates the 683 MW nominal capacity Halton Hills Generating Station (the "**Facility**"), a Combined Cycle Power Plant located in the 401-407 Prestige Industrial Corridor of the Town of Halton Hills;

AND WHEREAS Halton Hills wishes to construct a new transformer station (the "**Transformer Station**"), and to connect such Transformer Station to TransCanada's 230kV switchyard at the Facility (the "**Connection**");

NOW THEREFORE, subject conditions in this MOU the Parties hereby agree as follows:

1 Conditions to Proceed:

(a) Notwithstanding anything to the contrary in this MOU, the obligations of the Parties under this MOU (except for Sections 4 and 9) are conditional upon:

(i) Each Party satisfying the requirements of the Ontario Energy Board ("**OEB**"), the Independent Electricity System Operator ("**IESO**"), the Ministry of Energy ("**MOE**"), Hydro One and the Ontario Power Authority ("**OPA**") in respect of the Connection,

(ii) the approval or making of a regulation by the Ontario government exempting TransCanada from being a transmitter and from all of the associated regulatory obligations resulting from the construction and operation of the Connection, such regulations to be in a form and content satisfactory to each Party;

(iii) the approval of each Party's Board of Directors for the Connection and the associated transactions by a date no later than the date upon which the design and engineering of the connection is substantially complete.

(iv) the approval of each Party of the conditions imposed on such Party by the OEB as a result of the OEB hearing process regarding the Connection.

(collectively, referred to as the "**Conditions to Proceed**").

The Parties agree to use reasonable efforts to obtain and/or satisfy the Conditions to Proceed.

2 <u>Transformer Station and Site Purchase</u>: Halton Hills will design, construct, own and operate the Transformer Station. TransCanada and Halton Hills agree to negotiate the purchase of land owned by TransCanada for the construction of the Transformer Station (the "**Land Purchase Agreement**").

3 <u>Design, Engineering and Construction of Connection</u>: The Parties will negotiate an agreement (the "**Project Development Agreement**") setting forth:

(a) the responsibilities of the Parties relating to the design, engineering and construction of the Connection. Such Connection shall be designed, engineered and constructed in manner that satisfies the technical, reliability, safety and operational requirements of the

Parties, Hydro One, the IESO and any other applicable governmental authority having jurisdiction over such Connection;

(b) the obligation of any third party performing any work on TransCanada's site to comply with all of TransCanada's site requirements, policies, rules and guidelines; and

(c) Notwithstanding anything to the contrary, Halton Hills will be responsible for all costs and expenses associated with the design, engineering and construction of the Connection and all work ancillary to the Connection. This shall include all costs associated with the equipment required in the Facility switchyard and any costs incurred by TransCanada with respect to its efforts and services to complete the Connection.

4 Reimbursement of Costs incurred by TransCanada: By November 30, 2012, TransCanada will provide Halton Hills with an estimated budget ("**Budget**") for TransCanada costs and expenses associated with TransCanada's efforts to achieve the Conditions to Proceed, the design, engineering and construction of the Connection, and any other work and services provided by TransCanada to complete any of the transactions contemplated in this MOU, including, but not limited to, any fees paid to utilities, regulatory and governmental authorities, the costs of consultants, contractors, legal and other third party service providers (the "**TransCanada Costs**"). Such Budget is provided by TransCanada to Halton Hills for planning purposes only and, despite a Budget being provided, Halton Hills shall be responsible to pay any TransCanada Costs exceeding the Budget. TransCanada will make reasonable efforts to advise Halton Hills in a timely manner if actual costs materially depart from estimates in the Budget. TransCanada shall invoice Halton Hills on or before the tenth (10th) business day of each month for all TransCanada Costs incurred in the preceding month. Halton Hills shall pay any such invoice rendered by TransCanada within fifteen (15) business days of receiving an invoice. If Halton Hills fails to pay an invoice on time, the unpaid amount shall bear interest at a rate equivalent to the prime rate plus 2 percent (2%) per annum.

5 Connection Agreement between Halton Hills and TransCanada: The Parties will negotiate an agreement setting forth the terms surrounding the use, operation, maintenance and termination of the Connection (the "**Connection Agreement**"). TransCanada will not seek any compensation or charge for the use of the Connection except any incremental maintenance or operations costs associated with the Connection. This shall include the maintenance associated with the equipment in the switchyard and any incremental Hydro One connection costs associated with the Connection. TransCanada assumes no liability for any claims (including any liability in regard to meeting the electricity needs of Halton Hills) that are in relation to the Connection, the Facility, the switchyard and the 230 KV underground connections to Hydro One and the Transformer Station.

6 Metering and Settlement: The Parties will work with the IESO, Hydro One and any other governmental authority to address the metering and settlement requirements of each Party's respective facilities. If necessary, the Parties will negotiate an agreement to ensure that either Party's facilities do not impact the metering and settlement of the other Party's facilities (the "**Metering Agreement**"). Any fees and costs associated with addressing and satisfying the metering and settlement requirements of the Parties, IESO, Hydro One and any other governmental authority having jurisdiction over such matters will be paid by Halton Hills. The Parties agree that the Facility is not providing any power or generation services to the Connection or to any other facilities of Halton Hills.

7 Hydro One Review Process: The Parties will ensure that the Connection is submitted for Hydro One's [COVER] process to ensure such Connection is acceptable to Hydro One from a technical basis. Any fees and costs relating to any changes required as a result of Hydro One's review will be paid by Halton Hills.

8 Termination: This MOU will terminate (with the exceptions of Section 4 and 9) when any of the following events occur:

(a) the Conditions to Proceed have not been met by June 30, 2014;

(b) one Party notifies the other that the Connection cannot be reasonably or feasibly designed, engineered and constructed without adversely impacting the business of the notifying Party or the operations of its facilities, as determined by the notifying Party in its sole discretion;

(c) one Party notifies the other that one or more of the Conditions to Proceed will adversely impact the business of the notifying Party or the operations of its facilities;

(d) by mutual agreement of the Parties;

(e) upon execution of the Land Purchase Agreement, the Project Development Agreement, the Connection Agreement and if necessary, Metering Agreement.

9 Confidential Information: Neither Party shall disclose the terms or conditions of this MOU to a third party (other than to either Party's employees, counsel or representatives, or those of its affiliates, who in each case, have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or in connection with any court or regulatory proceeding or request applicable to such Party; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation. The confidentiality obligation hereunder shall not apply to any information that was or hereafter becomes available to the public other than as a result of a disclosure in violation of this Section 9.

10 Notices: Any notice, demand or other communication required or permitted to be given to any Party shall be in writing and shall be personally delivered to such Party or sent by facsimile to the address of such Party:

(a) In the case of TransCanada:

TransCanada Energy Ltd.
200 Bay Street
24th Floor, South Tower
Toronto, ON
M5J 2J1
Attention: Mr. Brian Kelly

Fax: (416) 869-2114
Email: Brian_Kelly@transcanada.com
Phone: (416) 869-2183

(b) In the case of Halton Hills:

Mr. Arthur A. Skidmore, CMA
President & CEO
Halton Hills Hydro Inc.
43 Alice Street
Acton, Ontario, L7J 2A9

Fax: (519) 803-1312
Email: askidmore@haltonhillshydro.com
Phone: (519) 853-3700, xt. 225

11 General:

(a) This MOU contains the entire agreement between the Parties with respect to the subject matter hereof and supercedes any and all prior understandings, correspondence or memoranda of understanding between the Parties and replaces in its entirety the MOU entered into between the Parties dated October 15, 2012.

(b) Nothing contained herein shall be construed as creating any partnership, agency or joint and several liabilities between the Parties.

(c) This MOU may not be assigned by either Halton Hills or TransCanada without the prior consent in writing of the other.

(d) Sections 4, 9, and 10 and obligations thereunder shall survive the termination of this MOU.

(e) This MOU shall be governed by and construed in accordance with the laws of the Province of Ontario.

(f) This MOU may be executed and delivered in counterparts with same effect as if both Parties had signed and delivered the same copy, and when each Party has executed and delivered a counterpart, all counterparts together constitute one MOU. Delivery of a copy of this MOU by facsimile or electronic mail is good and sufficient delivery.

Agreed to in accordance with the above this 28th day of October 2013

TRANSCANADA ENERGY LTD.

Per: [signature]

Name: **Geoff Murray**
Title: Vice President Western Power Growth
I have authority to bind the corporation

Per: [signature]

Name: **Ken Tate**
Title: **Vice Presi[illegible]**
I have authority to bind the corporation

HALTON HILLS HYDRO INC.

Per: [signature]

Name: Arthur Skidmore
Title: President and CEO
I have authority to bind the corporation

Reviewed by:	
Business	BK
Legal	KLF

Appendix IRR – G

Letter from the OEB dated February 9, 2015

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Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-481-1967
Facsimile: 416-440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416-481-1967
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BY EMAIL

February 9, 2015

Art Skidmore, President & CEO
Halton Hills Hydro Inc.
43 Alice Street
Halton Hills, ON L7J 2A9
askidmore@haltonhillshydro.com

Terry Bennett, Vice-President, Power Development
TransCanada Energy Ltd.
8th Floor – 55 Yonge Street
Toronto, ON M5E 1J4

Dear Sirs,

Re: Halton Hills Hydro Inc. ("HHHI") and TransCanada Energy Ltd. ("TCE") Connection Agreement - Subsection 4.0.2.1(2), Ontario Regulation 161/99

Background

On November 11, 2013 the Board received a Connection Agreement between HHHI and TCE in respect of the connection of HHHI's distribution system to the TCE switchyard located at the Halton Hills Generation Station (the "Connection Agreement").

Subsection 4.0.2.1(2) of Ontario Regulation 161/99[1] provides an exemption (among others) to the requirement of a transmitter, in this case TCE, to hold a transmission licence[2,3] in respect of TCE's activities relating to the transmission system that connects HHHI's transformer station to the IESO-controlled grid. The exemption from the requirement to hold a licence is contingent on the existence of four circumstances, one of which is that TCE enters into a

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[1] Amended by Ontario Regulation 219/13 to add the relevant exemption on July 19, 2013.
[2] Section 57(b) of the *Ontario Energy Board Act, 1998*.
[3] The Regulation also exempts the transmitter from sections 71, 78, 80, 81 and 86 of the *Ontario Energy Board Act, 1998*, provided the requirements of the subsection are met.

connection agreement with HHHI on or after July 1, 2013, submits the connection agreement to the Board and the Board has not made an order rejecting the connection agreement.

The Regulation does not provide specific guidance as to what the Board should consider in determining whether or not it will make an order rejecting the Connection Agreement. The Board has therefore reviewed the Connection Agreement in light of its relevant statutory objectives to determine whether the terms and conditions contained in the Connection Agreement, are, in their totality, in the public interest. In particular, the relevant statutory objective in the current context is found in section 1(1)1 of the *Ontario Energy Board Act, 1998*: “To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.”

Information Requests

On January 20, 2014, the Board sought additional information from and posed clarifying questions of the HHHI and TCE in the areas generally related to safety, reliability, and quality of electrical service to the customers of HHHI with respect to the Connection Agreement.

The Board also sought input from Hydro One, the IESO, and the OPA with respect to the Connection Agreement. On February 3, 2014, the Board received replies from each of the parties noted above.

Both the OPA and IESO referenced the need for the proposed connection to undergo the IESO’s Connection Assessment and Approval process, but did not otherwise outline any know or potential adverse impacts of the connection.

Although Hydro One indicated that it did not anticipate any adverse impacts to Hydro One as a result of the proposed Connection Agreement, it did propose a number of changes to the Connection Agreement. Hydro One also proposed to amend the existing generator connection agreement between Hydro One and TCE to incorporate all provisions of the load version of the connection agreement by way of appendix.

On April 30, 2014, HHHI and TCE filed a joint response to the comments of the OPA, the IESO and Hydro One, including comments on Hydro One’s proposed changes to the Connection Agreement and its suggestion that the existing generator connection agreement between TCE and Hydro One be amended. HHHI and TCE agreed to make certain amendments to the Connection Agreement, but refused to make other proposed amendments. TCE refused to amend its generator connection agreement with Hydro One or to enter into a separate load connection agreement with Hydro One.

The amendments to both the Connection Agreement and to the existing Hydro One/TCE generator connection agreement suggested by Hydro One do not raise matters that warrant rejection of the Connection Agreement. With the exception of amendments to the Connection Agreement that HHHI and TCE agreed to make on April 30, 2014, the Board will not require any further amendments to the Connection Agreement or any other agreement.

The Board's Review

To assess whether the Connection Agreement will ensure adequate and reliable service to HHHI's distribution customers, the Board has reviewed the proposed Connection Agreement and related responses to information requests. In particular, the following factors were considered:

- The terms and conditions in the Connection Agreement are sufficient to ensure adequate and reliable electrical service to HHHI's distribution customers, including taking into account mitigation of outages, mitigation of risks, and providing for sufficient reporting of reliability information.

- The connection will undergo the IESO's SIA and CAA processes which will evaluate impacts of the connection on upstream transmission system and provide further means of confirmation that customers will not be adversely impacted by the proposed connection.

- The connection will also undergo Hydro One's COVER process to confirm that the facility has been designed adequately and will operate in the manner expected.

The Board concludes that the Connection Agreement will ensure adequate and reliable electrical service to HHHI's distribution customers.

Considerations of the cost of the connection assets will be conducted in the normal fashion upon the first application for rebasing of rates subsequent to the assets being put in service.

Conclusion

In accordance with subsection 4.0.2.1(2) of Ontario Regulation 161/99[4], the Board will not make an order rejecting the Connection Agreement as filed with the Board on November 11, 2013 provided that it is amended as agreed to by HHHI and TCE on April 30, 2014 and that the final executed version contains all schedules and appendices. HHHI and TCE shall file with the Board a copy of the final and executed version of the Connection Agreement as soon as it is available.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

cc. Richard King, Osler, Hoskin & Harcourt (counsel to Halton Hills Hydro Inc.)
Brian Kelly, TransCanada Energy Ltd.
Margaret Kuntz, TransCanada Energy Ltd.
Christie Innes, TransCanada Energy Ltd.
Susan Frank, Hydro One Networks Inc.
Terry Young, Independent Electricity System Operator
Michael Lyle, Independent Electricity System Operator

[4] Amended by Ontario Regulation 219/13 to add the relevant exemption on July 19, 2013.

Appendix IRR – H

Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System – January 11, 2017

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Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System

Load Forecast of 27.6kV Distribution System of Halton Hills Hydro Inc.

Prepared for:
Matthew Wright, System Planning Supervisor
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON. L7L 2A9

Prepared by:
Stantec Consulting Ltd.
300 W - 675 Cochrane Drive
Markham, ON L3R 0B8

January 11, 2017
133560158.200
Revision 1.0

Sign-off Sheet

This document entitled Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System was prepared by Stantec Consulting Ltd. (“Stantec”) for the account of Halton Hills Hydro Inc. (the “Client”). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec’s professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Prepared by ______________________________ AMIR
(signature)

Amir Tashakori, P.Eng.

Reviewed by ______________________________
(signature)

Mike Voll

Revision Record

Revision	Description	Prepared by		Checked by		Approved by	
A	Report format draft	A. Tashakori	AT	M.Voll	MV	M.Voll	11/22/16
B	Issued for Review	A. Tashakori	AT	M.Boloorchi	MB	M.Voll	12/9/2016
C	Final Report Issue	A. Tashakori	AT	M.Boloorchi	MB	M.Voll	12/20/16
D	Revised Final Report including Client Comments	M.Voll	MV	A.Tashakori	AT	M.Voll	01/11/17

Table of Contents

Executive Summary

This load forecast has been performed for three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230kV-27.6kV transformer station (TS), which are supplying Halton Hills Hydro's (HHH) southern territory.

Forecasting the load growth on each of the above feeders, has been performed for a 10-year period, starting from 2016, based on the methodology, assumptions, load records and information as described herein.

Because of the effect of the provincially mandated conservation target, a stable load growth rate has been considered for load growth projection during the 10-year study period. Two growth rates have been used to develop the expected growth forecast and higher growth forecast scenarios. The combined expected impact of conservation and distributed generation by station across the study area, has been considered to develop the expected growth forecast. However, for the higher growth forecast, half of the peak-demand reduction due to the conservation target was accounted for in the forecast. In addition, other expected loads, as specified by HHH are added to the calculated load of each year. Planned load growth in Georgetown South (the Vision Georgetown document) is added to the closest feeder (41M30).

Studies show that by 2020, assuming a high load growth forecast, the feeders will be overloaded, as each 27.6 kV feeder can only supply about 15.5 MW to nearby loads, and new feeders will be needed to avoid equipment overloading or load shedding and unwanted service interruption at peak time. This conclusion is valid if load transfer between feeders (e.g. from 41M21 to 41M29 or vice versa or between other feeders) is possible. Otherwise, new feeders are needed earlier when any of the feeders has reached its maximum allowed load, with no (further) possibility of load transfer to other feeders.

Abbreviations

CCAP	Climate Change Action Plan
GHG	Greenhouse Gases
HHH	Halton Hills Hydro (Client)
HONI	Hydro One Networks Inc.
LF	Loss Factor
OPO	Ontario Planning Outlook
PF	Power factor
TS	Transformer/Transmission Station

Glossary

Diversity Factor	The ratio of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system. The diversity factor is always 1 or greater.
Maximum Demand	The greatest of all the demands that have occurred during a specified period of time; determined by measurement over a prescribed time interval.

1.0 INTRODUCTION

Halton Hills Hydro Inc. (HHH) wishes to develop a load forecast for their distribution system. This report addresses the first section of their system associated with the 27.6kV system.

The goal of this report is to prepare a load forecast for each small area which is supplied by each of the three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230 kV-27.6kV transformer station (TS), thereby increasing the accuracy of the analysis. The intent is to structure this report in such a way as to facilitate the streamlined integration of other feeder systems in the future.

Total Halton Hills load is around 87MW and almost 35% of it is on the 27.6 kV feeders. Halton TS has 12 feeders and three of them (41M21, 41M29, and 41M 30) belong to HHH. The Halton TS is already expanded to its full capacity and there is not enough space for adding new feeders. The IESO IRRP [6] concludes that by 2018, two new transmission substations are required for serving the future loads in Milton and Halton Hills. Based on the technical and economic considerations, one of stations should be on the north side of the 401 highway (serving Halton Hills), and the other one on the south side of the 401 highway (for serving Milton). In this way, a minimum or no crossing of the highway for distribution lines is expected.

2.0 METHODOLOGY

For the current studies, available historical records on HHH 27.6 kV loads and other load forecasting reports as addressed in the references are analyzed to provide a basis for each feeder's load, load growth rate and annual load increase. Then, with a calculated basis of each feeder load and growth rate, the load for the perspective years, (period of 2017 to 2026) for each feeder is calculated.

The Climate Change Action Plan (CCAP) is very high level and although some of the referenced tables within this report detail a high rate of substitution of gas and oil with electricity, the total load growth rate is still below the calculated growth rate in this report (see Section 4.0). In addition, any significant, referenced loads within the CCAP, such as new transportation electrification facilities, have already been accounted for in this load forecast. For this reason, input from the CCAP does not impact this load forecast.

In this study the following formula is used for load forecasting:

$$Y_n = Y_{n-1} * (1+r_n) + Y_{ne}$$

In which;

Y_n: Load at year n;

Y_{n-1}: Load at year n-1;

r_n: Load growth rate at year n; and

Y_{ne}: Expected load at year n;

Note: The expected load at year n (Y_{ne}), is the load that is not forecasted in the load growth rate calculation. This load (except for the Vision Georgetown anticipated loads), is only considered in the load forecasting with higher growth rate.

3.0 ANALYZING LOAD RECORDS

Table 1 below summarizes the load history received from HHH. Table 1 outlines a maximum demand for each feeder at each year in the period of 2005 to 2016. As shown, for the first five years, the total 27.6 kV distribution system maximum demand is not provided, therefore, diversity factors and load growth rates have only been calculated based on information given for the period of 2010 to 2016. The 2016 maximum demand is calculated from current records since the maximum demand occurs in the summer. Monthly data has been provided under Appendix A.

Table 1 – Maximum Demand for Each Feeder and for 27.6 kV Distribution System within the Period of 2005 to 2016 Based on HHH Historical Data

Year	41M21 (MW)	41M29+ 41M30 (MW)	Total (MW)	Diversity factor
2005	19.9	-	NA	
2006	17.0	18.8	NA	
2007	17.7	8.3	NA	
2008	16.8	17.1	NA	
2009	17.5	25.2	NA	
2010	20.2	18.4	28.5	1.353
2011	19.2	19.0	30.1	1.272
2012	19.6	18.9	30.0	1.282
2013	14.3	20.3	30.9	1.120
2014	17.3	20.8	29.2	1.306
2015	17.7	20.4	29.5	1.293
2016	15.3	26.9	31.4	1.343
Annual Load Growth Rate			**1.65%**	

3.1 NORTHWEST GTA FORECAST

The IESO IRRP [6] states that “Under the Expected Growth forecast, growth averages 1.68% per year in the near and medium term, but drops to 0.82% per year for the second decade. For the Higher Growth forecast, growth averages 2.06% per year for the first decade and drops to an average of 1.18% per year for the long term. Over the 20-year planning period, the Expected and Higher Growth forecasts average 1.3% and 1.7% per year, respectively.”

Figure 1 below shows both planning forecasts, along with historic demand in the Northwest greater Toronto Area including the Halton Hills Hydro distribution system.

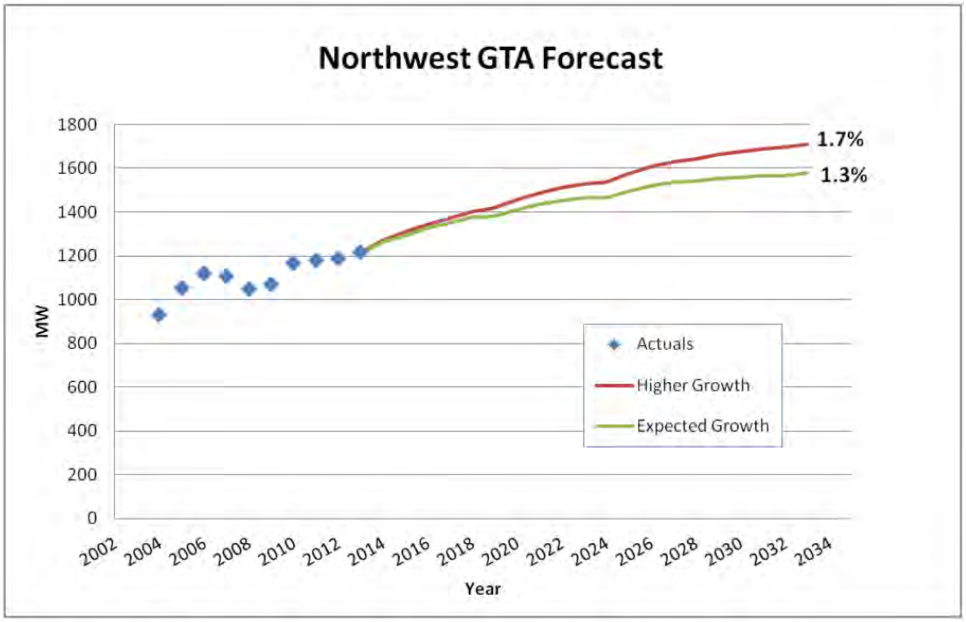

Figure 1 – Historical Demand and Expected and Higher Growth Forecasts from IESO Report [6]

Review and analysis of the information, given in Table 1 above, indicates that:

1. The maximum annual peak demand occurs between July and September.
2. The growth rate of maximum demand during the period of 2010 to 2016 is around 1.65%, based on the maximum demand of 28.5MW at 2010.

The calculated actual load growth rate (1.65%) is comparable to the IESO forecasted expected rate (1.68%). As stated above, as per the IESO IRRP [6], the expected load growth rate and high load growth rate for the mid-term planning period are 1.65% and 2.06%. The mid-term planning period is a ten-year period starting from 2015 [6]. After the mid-term, as per the IESO IRRP [6], there will be a decrease in load growth rate for the years beyond 2025. The maximum demand growth rate, for the mid-term and long-term planning periods, are summarized in Table 2 below and is compared with the calculated maximum demand growth rate for the period of 2010-2016 only.

Table 2 – Load Growth Rate for Different Periods and Scenarios (Mid-Term and Long Term)

Period	2015-2025 Mid-Term(1)	2026-2035 Next Medium-Term(1)	2015-2035 Long-Term(1)	Calculated Growth Rate for 2010-2016
Expected	1.68%	0.82%	1.3%	1.65%
Highest	2.06%	1.18%	1.7%	Not calculated

(1) Reference: Integrated Regional Resource Plan, Northwest Greater Toronto Area Sub-Region, IESO 2015

4.0 ONTARIO CLIMATE CHANGE ACTION PLAN (CCAP)

The purpose of Ontario Climate Change Action Plan is to reduce pollution and Greenhouse Gases (GHG) by reduction of oil and gas usage. Based on this plan, the IESO has conducted studies which are combined with load forecast studies for Ontario to investigate if the IESO-controlled grid has sufficient capacity to supply the new loads. This IESO Ontario Planning Outlook (OPO) [7] report details the target energy consumption (in TWh) which will be required to meet the objectives of the CCAP.

There are four outlooks presented in the IESO report, A through D. Outlook A is related to the minimum increase of electrical load and outlook D is related to the maximum load increase, (maximum energy consumption that will be transferred from oil and gas to electricity). As per Outlook D, which represents the highest increase in electrical load, the maximum energy consumption is forecasted to be 198 TWh by 2035, while it has been 144.5 TWh in 2015. It is expected most of this additional load will be related to heating devices and will be added to the winter load. However, based on the preliminary calculation as given in Table 3 below, the summer maximum demand is still higher than the winter maximum demand, and shall therefore be considered as the annual maximum demand.

Table 3 – 27.6 kV Feeders Load Considering Climate Change Action Plan

Ontario 2015 Load (TWh)	Ontario 2035 Outlook D Load (TWh)	HHH 2035 Load (0.43% of Ontario Load) (TWh)	HHH 2035 Maximum Load, Load Factor =0.7 (MW)	27.6kV Feeders load-35% of Total HHH Load (MW)
144.5	198	0.843	137.4	48.1

5.0 LOAD FORECASTING FOR PERIOD OF 2016 TO 2025

The maximum annual demand of each feeder, for the period of 2010 to 2026, based on the expected growth rate of 1.65% is shown in Table 4 below and based on the higher growth rate of 2.06% is given in Table 5. Please note that both Table 4 and Table 5 include anticipated additional loads in addition to load forecasts associated with Vision Georgetown [3], which is based on an average, linear annual growth rate over the forecasting period.

For the purposes of this assessment, a 27.6 kV feeder is assumed to be at full capacity when it reaches 15.5 MW.

Table 4 – Expected Load Forecast with 1.65% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW									
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Feeder																		
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.2**	**13.4**	**13.6**	**13.9**	**14.1**	**14.3**	**14.7**	**14.9**	**15.2**	**15.4**	**15.7**	**15.9**	**16.2**	**16.4**	**16.7**
41M21 Base Load Calculation[1]		12.8	13.0	13.2	13.4	13.6	13.9	14.1	14.3	14.6	14.8	15.0	15.3	15.5	15.8	16.1	16.3	16.6
Expected Annual load growth[1]			0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.1**	**9.3**	**9.4**	**9.6**	**9.8**	**11.4**	**11.5**	**11.7**	**11.9**	**12.0**	**12.2**	**12.4**	**12.6**	**12.8**	**12.9**
41M29 Base Load Calculation[1]		8.8	9.0	9.1	9.3	9.4	9.6	9.8	9.9	10.1	10.2	10.4	10.6	10.8	10.9	11.1	11.3	11.5
Expected Annual load growth[1]			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
Expected new loads			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.1**	**7.2**	**7.3**	**7.5**	**8.6**	**13.4**	**15.7**	**16.4**	**18.8**	**23.6**	**26.4**	**29.3**	**32.1**	**34.9**	**37.7**
41M30 Base Load Calculation[1]		6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8	8.0	8.1	8.2	8.4	8.5	8.7	8.8	8.9
Expected Annual load growth[1]			0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.15
Expected new loads without Vision Georgetown								1.00	5.68	7.89	8.44	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.68	5.36	8.04	10.71	13.39	16.07
Total		28.5	29.0	29.4	29.9	30.4	30.9	32.4	39.1	41.9	43.0	45.8	51.1	54.3	57.6	60.8	64.1	67.4

1- Load growth rate 1.65%

Table 5 – High Load Forecast with 2.06% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW									
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Feeder																		
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.3**	**13.6**	**13.9**	**14.1**	**14.4**	**14.7**	**15.1**	**15.5**	**15.8**	**16.1**	**16.4**	**16.8**	**17.1**	**17.5**	**17.8**
41M21 Base Load Calculation[1]		12.8	13.0	13.3	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.7	16.0	16.3	16.7	17.0	17.3	17.7
Expected Annual load growth[1]			0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.2**	**9.4**	**9.6**	**9.8**	**10.0**	**11.7**	**11.9**	**12.1**	**12.3**	**12.5**	**12.7**	**13.0**	**13.2**	**13.5**	**13.7**
41M29 Base Load Calculation[1]		8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	10.8	11.1	11.3	11.5	11.8	12.0	12.3
Expected Annual load growth[1]			0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25
Expected new loads									1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.2**	**7.3**	**7.5**	**7.6**	**8.8**	**13.6**	**16.0**	**16.7**	**19.1**	**24.0**	**26.9**	**29.7**	**32.6**	**35.4**	**38.3**
41M30 Base Load Calculation[1]		6.9	7.0	7.2	7.3	7.5	7.6	7.8	7.9	8.1	8.3	8.4	8.6	8.8	9.0	9.2	9.3	9.5
Expected Annual load growth[1]			0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19
Expected new loads without Vision Georgetown								1.000	5.683	7.893	8.442	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.679	5.357	8.036	10.71	13.39	16.07
Total		28.5	29.1	29.7	30.3	30.9	31.6	33.2	40.0	43.0	44.2	47.2	52.6	56.0	59.5	62.9	66.4	69.8

1- Load growth rate 2.06%

6.0 CONCLUSIONS AND RECOMMENDATIONS

Preliminary load analysis and load forecast results are presented within Table 1 to Table 5 of this report. The load forecast is done for a 10-year period from 2017 to 2026. Ten years' forecast is considered as a mid-term load forecast.

As shown in Table 5 above, feeder overloading will begin in 2017; however, the addition of new feeders may not be required considering the load transfer capability between the feeders. Nevertheless, this load transfer capability will end by the end of 2019 and the addition of a new feeder will then be needed. This new feeder cannot be provided through expansion of the existing Halton TS #1; as there is no space for further expansion. Therefore, it is essential to have the new Halton TS by the end of 2019 at the latest. This assessment is consistent with Table 6-1 in the IESO IRRP where, for meeting both the Expected and Higher Growth scenarios, a new 27.6 kV step-down station serving Halton Hills Hydro is required, approximately by 2018.

7.0 REFERENCES

[1] HHH_Map_Operators_276k_Oct28_2016_R2.

[2] HHH Historical Loading for Halton TS spreadsheet. (Appendix A)

[3] Vision Georgetown Second Status Update – Phase 2 File D08 VI (Vision Georgetown)

[4] Load Forecast - Engineering Dec 2016 spreadsheet (Appendix B)

[5] Halton_Appl_Exhibit- 2_Rate_Base_Part_2_Distribution_System_Plan_ 20151 (HHH DSP).

[6] NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN, Part of the GTA West Planning Region | April 28, 2015 (IESO IRRP)

[7] Ontario Planning Outlook, a technical report on the electricity system prepared by IESO September 1,2016 (IESO OPO)

[8] Ontario Energy Board HHH 2015 Yearbook

[9] Ontario’s Five Year Climate change action plan 2016-2020

APPENDIX A

Halton TS Non-Coincident Peak Data

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APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2005	1	12569		19.9	N/A	N/A	
	2	10505					
	3	10547					
	4	9961					
	5	11754					
	6	19470					
	7	19876					
	8	18531					
	9	16766					
	10	13336					
	11	11938					
	12	13547					
2006	1	12039		17.0	18.8	N/A	
	2	12220					
	3	12220					
	4	13416	7196				
	5	15272	7614				
	6	14747	18759				
	7	16974	7796				
	8	13268	7997				
	9	9333	7714				
	10	9920	6967				
	11	10427	3436.59				
	12	11834	3628				
2007	1	11150	3647	17.7	8.3	N/A	
	2	11911	3894				
	3	10607	7036				
	4	9399	7179				
	5	12709	8072				
	6	17736	8338				
	7	17269	8305				
	8	16613	8162				
	9	15740	7859				
	10	13777	7670				
	11	12655	4406				
	12	14139	7705				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2008	1	12277	4227	16.8	17.1	N/A	
	2	12369	5331				
	3	10889	6991				
	4	9479	15214				
	5	9628	8074				
	6	16597	8498				
	7	16821	8546				
	8	15356	8857				
	9	14992	8666				
	10	11030	8658				
	11	14011	5080				
	12	12990	17082				
2009	1	13273	5370	17.5	25.2	N/A	
	2	11801	5351				
	3	10742	25163.97				
	4	9961	8848				
	5	10566	9037				
	6	17181	8942				
	7	12783	9506				
	8	17499	9455				
	9	12525	9262				
	10	10781	9206				
	11	12492	5511				
	12	13832	8830				
2010	1	13070	5783	20.2	18.4	28.5	1.353
	2	12265	6051.07				
	3	11019	9364.61				
	4	10167	9369.99				
	5	17181	9577.28				
	6	19115	9632.73				
	7	20177	9843.35				
	8	17889	10092.41				
	9	12574	11311.95				
	10	10090	9326.1				
	11	11643	5747.26				
	12	5321	18401.33				

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APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2011	1	0	17390.52	19.2	19.0	30.1	1.272
	2	9832	17982.13				
	3	11061	19039.72				
	4	9757	9938.61				
	5	15275	10488.84				
	6	16807	10792				
	7	19229	11428.18				
	8	15868	11212.11				
	9	12207	18939.35				
	10	10605	9831.06				
	11	12322	12430.49				
	12	12754	10123.93				
2012	1	12098	15960.39	19.6	18.9	30.0	1.282
	2	12630	16376.61				
	3	10712	8971.07				
	4	10166	9548.55				
	5	15939.48	16456.39				
	6	18747.7	15533.37				
	7	19560.37	13947.49				
	8	13033.31	14548.21				
	9	12830.36	18862.84				
	10	8457.87	16588.05				
	11	9575.57	11576.78				
	12	10251.92	11046.94				
2013	1	9717.87	8954.72	14.3	20.3	30.9	1.120
	2	9333.01	8342.63				
	3	8849.7	11290.85				
	4	7814.83	17082.68				
	5	11022.26	20319.96				
	6	13392.46	15731.27				
	7	14310.85	17503.37				
	8	12302.06	17081.87				
	9	13240.45	17333.31				
	10	11244.17	13753.65				
	11	9703.96	13497.86				
	12	9950.76	13793.46				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2014	1	9659.04	18128.47	17.3	20.8	29.2	1.306
	2	9028.08	10463.17				
	3	8880.1	13682.56				
	4	7110.23	13339.36				
	5	9785.89	14587.96				
	6	17310.46	15518.23				
	7	17157.82	16483.61				
	8	12064.32	17297.18				
	9	12414.99	17459.62				
	10	7675.92	14249.08				
	11	12702.03	20777.79				
	12	13745.19	11213.94				
2015	1	9116.33	18578.88	17.7	20.4	29.5	1.293
	2	182.83	19572.69				
	3	1008.02	19399.21				
	4	11141.01	19618.02				
	5	17670.6	13082.79				
	6	10805.76	14492.41				
	7	13576.47	16403.37				
	8	13546.53	16322.33				
	9	14583.26	20421.72				
	10	7744.21	18695.73				
	11	8963.28	19064.56				
	12	9240.78	18536.17				
2016	1	9619.74	9685.66	15.3	26.9	31.4	1.343
	2	8802.41	9468.35				
	3	8397.16	12551.15				
	4	8240.88	19181.35				
	5	12319.27	14539.07				
	6	14538.61	26920.07				
	7	14832.44	25791.96				
	8	14539.58	16426.29				
	9	15305.4	17024.98				
	10	7892.03	13665.48				
	11	N/A	N/A				
	12	N/A	N/A				
Annual Load Growth Rate						1.651%	

APPENDIX B

Halton Load Forecast Data

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APPENDIX B
HALTON LOAD FORECAST DATA

Load Forecast - Engineering (Dec. 2016)

Development Name	# of Lots	Proposed Feeder	Number of Transformers	Size of Transformation (kW)	Number of Connections	Customer Specified Demand Load (kW)	Estimate Load kW (Low)	Estimate Load kW (Medium)	Estimate Load kW (High)	Connection Date (Estimated)
First Gulf @ Cleve Court	1	41M29	1	2500	1-2	1540	924	1232	1540	2017
Building A - West Bridge Drive			1	1000	1	n/a	750	775	800	2017
Building B - West Bridge Drive			1	2000	1	n/a	1500	1550	1600	2017
Building C - West Bridge Drive	3	41M30	1	3000	1	1900	1425	1472.5	1520	2017
Toronto Premium Outlets	1		3-4	2500-3500	6	n/a	1300	1450	1600	2018
Toronto Premium Outlets	1	41M30	1	750	1	667	500.25	516.925	533.6	2017
Halton Hills Village Phase 5 & 6 (Residential)					50	n/a	125	175	225	2017
Halton Hills Village Phase 5 & 6 (Residential)					91	n/a	227.5	318.5	409.5	2018
Halton Hills Village Phase 5 & 6 (Residential)					122	n/a	305	427	549	2019
Halton Hills Village Phase 5 & 6 (Residential)					141	n/a	352.5	493.5	634.5	2020
Halton Hills Village Phase 5 & 6 (Residential)	649		74	50	169	n/a	422.5	591.5	760.5	2021
Halton Hills Village Phase 5 & 6 (School)	1	41M30	1	300	1	n/a	150	195	240	? (see Note1)
Region of Halton Water Pump Station (Trafalgar Road)	1	41M21	1	150	1	90	72	90	108	2018
Norval Development Area (F4 in HHHI DSP)	300-400	41M30	45-50	50	?	n/a	1200	1560	1920	? (see Note1)
Broccolini, 11400 Steeles Avenue	1	41M30	1	1000	1	1250	750	1000	1250	2016
9 Brigden Gate	1	41M29	1	750	1	274	164.4	219.2	274	2017
29 Brownridge Drive	1	41M30	1	500	1	n/a	375	387.5	400	2017/2018
Premier Gateway Phase 1B	Study phase only. No siginficant land use concepts yet. Potential of commerical development to replace developable lands frozen by MTO for 400 series highway.									
Town Surplus Land (Halton Hills Drive).	?	41M21	?	DSP identifies connection to 27.6kV, Support Trafalgar Road MS Better.						
Vision Georgetown (Residential Lots)	7000	New TS	784	50	7000	n/a	19600	25480	31360	2021-2031
Vision Georgetown (Elementary School)	6	New TS	6	500	6	n/a	1800	2100	2400	2021-2031
Vision Georgetown (High School)	1	New TS	1	1000	1	n/a	600	700	800	2021-2031
Vision Georgetown (Municipal Public Building)	1	New TS	1	500	1	n/a	250	325	400	2021-2031
Vision Georgetown (Grocery Stores)	1	New TS	1	1000	1-2	n/a	500	650	800	2021-2031
Vision Georgetown (Gas Stations)	2	New TS	2	150	1-2	n/a	150	180	210	2021-2031

Revised November 16, 2016 - First Gulf (Cleve Court) and TPO Parking Garage. TPO demand load increased from original estimate, see comments in "Customer specified Demand Load" for both sites.
Revised December 14, 2016 - Modified anticipated connection horizon for highlighted cells. Expanded Halton Hills Village Phase 5 & 6 to 5 years connection horizon and included approximate connection per year based on current information. Estimated load for HHVH Ph 5 & 6 is based on

Note 1: Connection date for load forecasting in current report is considered 2020.

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Appendix IRR – I

Transformer Station Supply Options Study – April 2010

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Transformer Station Supply Options Study

Preliminary Report

Prepared for:

Halton Hills Hydro

Prepared by

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April 2010

PRIVATE INFORMATION

1 Executive Summary

Costello Associates has been retained by Halton Hills Hydro (HHH) to assist with the study of capacity alternatives required to meet forecasted load growth in their southern supply area. The scope of this work includes the review of the HHH load forecast, coordination with Hydro One Networks (HON) for the provision of pool-funded station options, preparation of preliminary budgets for self-build station options, assessment of operational impacts, development of project schedules, coordination of financial and regulatory impact analysis performed by others, and to make recommendations for the supply of new capacity.

Costello Associates was initially contacted to assist with this project in September 2007. At that time, HHH believed that new supply capacity would be required around 2011 to meet planned development in the Steeles Road area. The local HON transformer station, "Halton TS", which supplies both Milton Hydro and HHH, would not be able to meet summer peak demand conditions after 2010. In the past two years, with the downturn in the economy, development has not progressed at the rate initially forecasted, and current expectations are that new capacity will be required by 2014.

At the time of our engagement in 2007, Trans Canada Energy (TCE) was in the early stages of developing their 683 MW natural gas-fired generating plant on Steeles Ave. HHH negotiated the provision of land adjacent to the generating plant to possibly accommodate a new municipal transformer station. We assisted HHH in conducting preliminary engineering reviews and a class environmental assessment of this site to determine its suitability for hosting a municipal transformer station. With the generating plant scheduled to be in service in 2010, TCE is looking for a commitment by HHH for the purchase of this parcel of land.

We are in the final stages of completing our detailed supply options study for this project. We have been asked to provide this preliminary report to support the decision to acquire this land parcel from TCE.

Based on the information available at this point, we believe that HHH should option or purchase this TCE land to mitigate the risk of having no cost effective alternatives to a self-build project. The HON alternative is effectively contingent on Milton Hydro participating at expansion of Halton TS. Without Milton Hydro's participation, HHH would be responsible for all of the project costs. As it stands, with HHH being assigned less than 50% of the total HON project costs, we evaluate this alternative as an equal cost option to HHH building a new station.

Municipal utilities have repeatedly demonstrated that they can design, construct, and operate transformer stations for less cost than HON. The addition of a transformer station adds to the asset base of the LDC, and provides the greatest shareholder value. This option also provides the lowest financial risk to HHH with respect to the recent economic downturn and the uncertainty of the pace of future load development.

2 Transformer Stations

2.1 Role of a Transformer Station

The role of a transformer station (TS) within the overall power grid is illustrated in Figure 1. Electricity is generated at nuclear, hydroelectric, fossil fuel, wind, and other facilities throughout Ontario. Bulk power is routed over long distances via the transmission system at high voltages (i.e. 115, 230, and 500 kV). Transformer stations are used to step the voltage down from the transmission system to the distribution voltage level. There are presently over 300 transformer stations owned by both Hydro One and municipal utilities throughout Ontario.

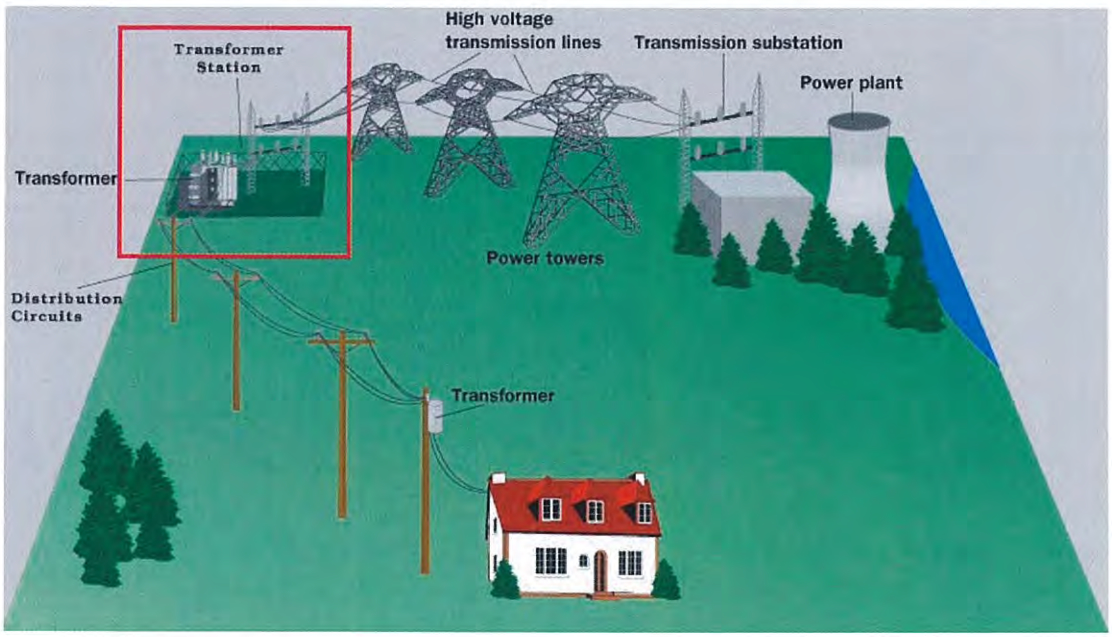

Figure 1

2.2 Potential Impact of Supply Constraints

The creation of additional transformer station capacity is a lengthy process. As a minimum, the shortest time frame possible from the decision to move forward to the in-service date is approximately two years. Items in this process contributing the most uncertainty to the timeline are land acquisition, environmental assessment and transformer delivery.

Accordingly, appropriate lead time ahead of actual need for supply is required in order to be ready when the load begins to materialize. A planning time of two to three years is necessary to accomplish this.

If load growth were to begin to materialize before additional supply capacity was made available, the existing supply infrastructure would be forced to perform beyond its rated capacity. The resulting impacts to the new HHH customers could include low voltage problems during high use periods and in order to prevent excessive overloading of equipment, or in the event of equipment failure, rotational blackouts may be ordered by Hydro One. As well, there would be an inability to deliver supply at the pace of growth, and therefore, a delay effect on growth. Should any of these problems occur, the reliability and customer service indicators for HHH would be negatively affected.

These undesirable situations can be avoided through commitment to additional supply facilities two to three years in advance of the customer growth. Although an inexact science, load forecasts based on expected community growth are the most critical tool for deciding when to begin.

2.3 LDC Experiences with Overloaded TS's

Historically, Ontario Hydro proactively reviewed transformer station loading, and worked with distribution utilities to add capacity whenever it was required. There have been several instances in the past ten years whereby Hydro One transformer stations have been operating well over published LTR ratings. In at least two cases, this has led to critical problems for distribution utilities:

August 2001 – Norfolk TS, Simcoe ON: a high voltage bushing on one of the station power transformers failed, causing the unit to be tripped off. The station had a published LTR of 65 MW, but was loaded to over 95 MW. Hydro One initiated rotational blackouts throughout Norfolk County, which lasted for three days. The failure occurred at the peak of tobacco harvest. See Figure 3 for the Simcoe Reformer newspaper article.

July 1, 2001 – Beamsville TS: the station suffered the failure of one of two power transformers. Beamsville TS had been operating above its published LTR rating. We understand the local fire department was requested to cool the overloaded transformer with water, in an attempt to control the temperature of the transformer. Fortunately, this cooling controlled the internal temperatures and rotating blackouts were not required.

Transformer station failures are rare, but it is important to recognize the potential impacts of operating the station beyond published ratings. Hydro One has the right (and responsibility) to ensure that their transformers are not damaged by overloading, and will therefore take necessary action to keep the load on a given transformer within its LTR in the event of the failure of either its partner transformer or equipment elsewhere on the grid.

3 Need for Additional Capacity

3.1 Remaining Capacity

HHH operates a 27.6 kV distribution network in the southern part of its service territory, and parts of Georgetown. This network is supplied by the HON-owned Halton Transformer Station, located at the intersection of James Snow Parkway and Main St. HHH currently has three feeders from this station that run through Milton Hydro's franchise territory, across Highway 401, and enter HHH's territory at Steeles Avenue.

The Halton TS also feeds the majority of Milton Hydro's service territory. Based on current load forecasts of both utilities, Halton TS will run only have enough capacity to meet the summer demand up to 2013. By the following summer, the station is forecasted to be overloaded by almost 6 MW unless relief is provided by a new facility.

3.2 Load Forecast

HHH regularly updates its short and long term load forecasts based on current firm development plans and long range planning goals set by the Town of Halton Hills, the Region of Halton, and the Province of Ontario.

The 2009 summer peak demand of the 27.6 kV network in the HHH southern supply area was roughly 27 MW. The short term load forecast, based on current planning information, anticipates about 21 MW of additional capacity to come online by the summer of 2013. If Milton Hydro's load also develops as expected, all of the remaining capacity at Halton TS will be consumed in 2013.

Conservative long term forecasts estimates show the southern supply area demand growing by 98 MW, for a total load of 125 MW over the next thirty years. Halton TS can accommodate 21MW of additional HHH load by 2013, leaving the balance of 77 MW to be supplied by a new facility.

4 Supply Options

4.1 Historical Practice

Prior to the opening of the electricity market, Ontario Hydro typically constructed new transformer station facilities proactively as demand required. These facilities were provided at no direct cost to the distribution utilities, as station costs were pooled and recovered through regulated transmission charges. Costs for related distribution improvements such as feeder ducts and cables were the responsibility of the LDC. The financial evaluation of projects considered the overall transmission and distribution costs, with each entity responsible for their own portion.

4.2 Transmission System Code

In 2002, as part of the industry changes associated with the passing of the Electricity Act and market opening, the Transmission System Code came into effect and we moved to a "user pay" approach. Costs for projects specifically attributable to one or more customers are recovered as part of the regulated connection process. Connecting customers have the choice to undertake certain contestable work or have HON provide services, at the connecting customer's cost.

In the case of municipal utilities requiring new transformer station capacity, three basic options exist:

1. HON designs, constructs, and operates the new station. An economic evaluation is performed by HON, whereby the net present value of the future incremental load revenue is compared to the cost of construction, operation, and maintenance cost of the station. If there is a shortfall in load revenue, the LDC pays the difference up front in the form of a capital contribution to Hydro One.

2. The LDC designs and constructs the new station according to HON's technical standards, and turns the station over to HON prior to energization. HON would reimburse the LDC for "reasonable costs" less the cost to oversee and administer the project. The economic evaluation described in the scenario above is used to calculate cost recovery. This option could be used if the LDC believed it could construct a transformer station exactly the same as Hydro One would, and do it for less cost. To the best of our knowledge, no LDC has exercised this option.

3. The LDC designs, constructs, owns, and operates the new station. The station asset would become part of the LDC distribution asset base, and the LDC would earn the regulated rate of return for the value of the station. Some or all of the capital cost of the project would be offset by a reduction in transmission charges payable to HON.

4.3 Comparison of Connection Options

	Principle	Pool-funded Option	LDC Build/ Turn Over to HON	LDC Self-Build Option
1	Overall capital cost	×	◘	✓
2	Risk of load growth – true up payments	×	◘	✓
3	Increase LDC asset base	×	×	✓
4	Control of system capacity	×	×	✓
5	Operating flexibility	◘	◘	✓
6	Lower transmission charges	×	×	✓
7	Lower upfront capital requirements	✓	◘	×
8	Burden on resources – project management, engineering, operating expertise	✓	×	×

Legend: ✓ = Best ◘ = Better × = Least

Table 1

Additional comments on Table 1:

1. LDC's typically build municipal transformer stations for significantly less cost than HON. Historically LDC cost savings were in the range of 20 – 30%, however with recent pricing from HON, the savings are even greater.
2. Should the LDC load not materialize as fast as forecasted, HON could collect additional payments from the connecting customer. If the LDC owned the transformer station, cost is recovered in the distribution rate base, on the book value of the station asset. The amount of load on a municipal transformer station does not affect the recovery of costs and return on equity.
3. Municipal transformer stations are capitalized and placed in the distribution asset base. This provides an opportunity for the LDC to add significant value to the asset base in a single project. This option delivers the highest increase in Shareholder value.
4. The control of system capacity refers to the LDC taking total responsibility for transformer station and distribution system capacity, such that LDC planning ensures that there is sufficient capacity at all times.
5. Operating flexibility refers to day to day system operation, for events such as placing hold-offs, storm response, detailed SCADA information, and maintenance coordination. HON stations are controlled from the Ontario Grid Control Centre (OGCC), and major events across the province are prioritized. A relatively small problem in Oakville's service territory may not receive prompt attention from the OGCC if there are larger system issues elsewhere.

6. LDC's that build their own transformer stations avoid the transformation tariff from HON, currently $1.62 / kw. This rate is predicted to rise to $1.83 / kw by 2010. This is a pass through cost via retail transmission charges, but does have an impact on the total end cost to local retail customers.

7. HON pool-funded stations require less up front capital from the LDC as opposed to the LDC building the station. Some capital contribution may be necessary depending on the total capital cost of the project and the value of the incremental load revenue over the 25 year economic horizon.

8. The design and construction of municipal transformer station requires dedicated and experienced resources. Many LDC's do not have internal expertise in stations, its staff may be fully engaged in other activities, or do not wish to take on the responsibility for a project of such magnitude.

9. We are not aware of any connecting customer that has built a transformer station according to HON specifications and turned the station back to HON at time of energization. We expect that although this may seem to be a lower cost alternative compared to HON building the station, HON would impose engineering and administration charges that would be subtracted from the purchase price. We also expect that there would be some growing pains with the development of this process, possibly resulting in delays and higher costs.

4.4 Proposed Alternatives for Additional Capacity

4.4.1 Halton Hills Hydro MTS #1 – TCE Site

MTS #1 is a proposed 125 MVA municipal transformer station, owned by HHH, located adjacent to the TCE site. This station is to be ready for service in the spring of 2014, prior to the summer peak load.

The station is configured as a typical Ontario Hydro "DESN" station, with two 50/66.7/83.3 MVA power transformers, with 28 kV secondary windings. Municipal utilities have been utilizing 36 kV class gas insulated switchgear (IEC rated), manufactured in Europe with special features to ensure compatibility with North American standards. This switchgear would be configured with eight (8) feeder breakers, and two breakers for power factor correction capacitors.

The fundamental advantage of this alternative is that the 230 kV transmission system has already been extended by TCE north of Highway 401 to the TCE site, and would be available to HHH at minimal cost. If HHH were to build a station north of Highway 401 on another site, a new 230 kV tap would have to be constructed at an estimated cost of over $20M (over and above the $21M cost of the station itself).

The total cost of the station, including metering, land, feeders, sales taxes, and 10% contingency, is budgeted at $21M (based on a preliminary budget).

This station would provide enough capacity to service all of the forecasted growth in the southern supply area for the next 30 years. It also provides a reserve of about 40MW of capacity for unforeseen load growth.

4.4.2 Hydro One "Halton 2 TS"

Halton 2 TS is a proposed HON-owned 170 MVA (153 MW) station, to be constructed on the Halton TS site in Milton. HON has made an offer to design and construct this station, to be ready for service in 2014. This station would provide new capacity for HHH and Milton Hydro.

This station is proposed to have twelve feeders; five dedicated to HHH, and seven for Milton Hydro. Each feeder is typically rated at 16 MW; therefore about 80 MW has been allocated to Halton Hills. This matches the present conservative load forecast for the southern supply area (but does not provide for unforeseen growth).

The total quoted cost of the project from Hydro One is approximately $26.5M, however the cost of certain features and components have been excluded from the budget. No costs have been allowed for feeders, revenue metering, property, or tie switches. We estimate an additional one to two million dollars of costs will be ultimately allocated by Hydro One, to be recovered from the two LDC's as part of the capital contribution (or as a direct cost if constructed by each LDC). This results in a total project cost of $27.5M - $28.5M. This compares directly in features and operating configuration with the HHH MTS #1 above, with a budget of $21M.

In addition, Halton Hills would have to route these new feeders through Milton Hydro's service territory, and across Highway 401. This area is presently congested with Halton TS feeders, and it is likely that the new feeders would have to be constructed underground, and pass underneath Highway 401. Preliminary estimates of costs to egress Milton and Hwy 401 are in the range of $2.5 – 4M depending on construction techniques.

Note that this alternative could only reasonably be considered by HHH if Milton Hydro commits to co-funding this project. Milton Hydro is exploring alternate sources of transmission supply in their southeast and southwest sides of their service territory, and there is no assurance that this option has any priority with them. This is a high risk issue for HHH.

4.4.3 Hydro One "Halton 2 – Half Station Alternative"

HON has also offered Milton Hydro and HHH a second pool-funded alterative which provides far less than the industry standard level of reliability and security. HON calls this the "half-DESN alterative". This design utilizes one incoming transmission circuit (instead of two), one power transformer (instead of two), and one incoming circuit breaker (instead of two). This design has no redundancy, and would expose HHH customers to numerous momentary outages for routine events such as lightning strikes. Commercial and industrial customers would likely accept not such an arrangement. This could also affect new customer's desire to locate in this area.

The capital contribution for this alternative reduces from about $6M to about $5M.

Hydro One presumably has offered this alternative in an attempt to provide a lower cost alternative. Unfortunately, the capital contribution has not lowered significantly. We had expected a larger reduction in capital contribution.

In any case, we would not support this configuration at any cost savings as the design inherently provides a lower level of security and reliability compared to industry standard DESN stations.

This design would cause the connected HHH customers to have a significantly less secure power source as compared to neighboring utilities.

4.4.4 Halton Hills Hydro MTS #1 – New Site

A fourth alternative for new capacity would be for HHH to build a new station somewhere in the Steeles Avenue area around Trafalgar Road. The Class Environmental Assessment performed by Senes Consultants in 2008 identified several sites that could potentially be used to site a new station.

The main disadvantage of this alternative is that HHH would have to extend the 230 kV transmission circuits from the transmission corridor south of Highway 401 to the Steeles Ave area. Although we have not done any costs estimates for this line connection, we understand that the TCE costs may have been in the order of $20M.

This alternative would result in a total project cost of about $36.5M, and therefore this alternative is considered to be unfeasible.

5. Economic Considerations

5.1 *Halton Hills Hydro MTS #1*

The budget for this station includes of the cost of the substation itself, plus the costs of connecting it to the adjacent TCE generating plant. The current budget for the 125 MVA station is $16.5M, and the cost of modifications to the TCE switchyard and connections to HHH's station are in the range of $4.5M. The preliminary total budget for this project is $21M.

5.2 *Hydro One "Halton 2 TS" Alternative*

Since this station is to be shared with Milton Hydro, HHH has been assigned project cost responsibility in proportion to the number of assigned feeders. In HON's budget proposal, they have assigned 42.7% of the total project cost responsibility to HHH ($12M). Considering the cost of feeder egress over/under Hwy 401 (est. $2.5M), the total cost responsibility for HHH is $14.5M.

Based on the revenue derived from new load (paid to HON through regulated transmission charges over the life of the station), HON estimates the need for a capital contribution of $5.68M in order for Hydro One to recover all capital, maintenance, and operational costs associated with this project. We estimate that the capital contribution will be slightly higher (about $6.3M) due to the inclusion of the additional $1 - 2M of costs that Hydro One excluded from their preliminary proposal.

The $14.5M cost responsibility for HHH is comprised of a capital contribution of about $6.3M, feeder egress of $2.5M, and a load revenue guarantee of $5.7M (present value capital portion only).

HHH would be obligated to guarantee Hydro One load revenue for the next 25 years, regardless of the actual load on the station. Any shortfall in revenue due to the actual load being less than the 2009 forecast supplied to Hydro One would result in the requirement for additional payments to be made to Hydro One. In other words, HHH would have to make a guarantee to HON without any guarantee from the HHH ratepayers. All of the risk is borne by HHH – HON has no risk.

This is a major risk for HHH and its shareholder.

Finally, as mentioned earlier, this alternative can only be reasonably considered if Milton Hydro decides to support the project and commit to covering a major portion of the project costs. Milton Hydro has several alternatives for providing additional capacity to their service territory, and most of the new load growth in Milton is expected to be in their southern supply area. Halton TS is located in the northern part of their service territory. It is possible that Milton will not be interested in this project.

Milton Hydro will likely not be in a position to commit to new supply alternatives until 2011 or 2012 – well beyond the timeline for HHH to commit to purchasing the TCE land.

5.3 *Avoided Transmission Charges*

Another factor to be considered is the avoidance of transformation charges that are normally paid to Hydro One when they own the TS. LDC's collect retail transmission charges from their customers and effectively pay Hydro One at the wholesale transmission level. These are "pass-through" charges that impact the total cost of the LDC's customer bill. If HHH constructs a MTS, there would be a reduction in the wholesale transmission charges paid to Hydro One. At the current OEB approved rates, without escalation, a conservative estimate of the present value of 25 years of avoided charges is approximately $8.3M.

The Hydro One Transmission and Connection charge savings will not benefit the electricity customer immediately. The process for passing this savings on to the customer would involve applying to the OEB to refund the balance of these payments accumulated in regulatory liabilities on HHH's balance sheet through an adder to rates. Likely the OEB would approve the refund of these accumulated balances to customers over a number of years.

5.4 *Comparison of Station Costs*

	Item	Halton Hills Hydro MTS #1 (125 MVA)	Hydro One "Halton 2 TS" (170 MVA)
1	Total Cost of Project	$21M	$27.5 – 28.5M
2	Total allocated capital cost	$21M	$14.5M
3	Cost per MW	$0.187M	$0.181M
4	Cost per feeder	$2.631M	$2.9M
5	Allowance for contingency	$1.5M	$0.25M
6	Avoided transmission charges	$8.3M	$0

Table 2

6. Conclusion

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Appendix IRR – J

HHHI Board of Directors Materials

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Dates of Transformer Station Discussions with the HHH Board:

Feb 28, 2014 - Agenda item
Apr 24, 2014 - CEO report
May 22, 2014 - Agenda item
Aug 28, 2014 - Other business item
Oct 23, 2014 - CEO report
Nov 27, 2014 - CEO report – joint letter to the OEB refuting Hydro One's legal argument and asking the Board to make a decision of "Not disapproving the connection agreement between HHH and TCE"

Mar 6, 2015 - Agenda item
Apr 16, 2015 - CEO report
Jun 19, 2015 - CEO report
Aug 5, 2015 - Agenda item – P&S Agreement, Supply Options Study Report, IESO Report
Oct 29, 2015 - CEO report
Nov 26, 2015 - CEO report

Jan 21, 2016 - Agenda item
Mar 4, 2016 - CEO report
Sept 21, 2016 - CEO report
Nov 24, 2016 - CEO report

Jan 29, 2017 - Agenda item
Apr 20, 2017 - Agenda item – HHH Board approved final budget of $25,268,526
Jun 14, 2017 - Management presentation by Jennifer Gordon, Project Manager and Matt Wright, System Planning Supervisor and HHH Board tour of transformer station
Aug 17, 2017 - Agenda item
Nov 16, 2017 - Agenda item

Apr 19, 2018 - Agenda item
Jun 27, 2018 - CEO report
Sept 13, 2018 - Agenda item – HHH Board tour of transformer station
Nov 29, 2018 - Agenda item

Halton Hills HYDRO

To: The Board of Directors of Halton Hills Hydro Inc.

Date: July 31st, 2015

From: Arthur A. Skidmore CMA

Subject: Transformer Station Update

Board Members:

I am pleased to report that this important reliability project is starting to move forward for the corporation.

Enclosed in this report you will find:

- Near complete Purchase and Sale Agreement with Trans Canada Energy (see Exhibit #1)
    - We expect to execute the PSA within the week and hopefully close within sixty days

- Supply Options Study Report from 2010 (see Exhibit #2)
    - Costello and Associates have been retained as Project Consultant
    - Initial report on Options (Item 5.3) is the most important, $8.3M avoided cost to customer. Station cost estimate was preliminary at that time, updated station cost to be $14-$16M.

- Update Information to Supply Options Study Report (see Exhibit #3)
    - New avoided costs at Present Value = $10.3M

- IESO Report (see Exhibit #4)
    - Pertinent section of report dealing with HHH

We have finally kicked off the Transformer Station project. Looking forward to the milestone developments over the next three years.

EXHIBIT #1.

THIS AGREEMENT is made as of the ___ day of _____ 2015.

BETWEEN:

TRANSCANADA ENERGY LTD.

(the "**Vendor**")

- and -

HALTON HILLS HYDRO INC.

(the "**Purchaser**")

RECITALS:

The Vendor has agreed to sell the Property (as hereinafter defined) to the Purchaser and the Purchaser has agreed to buy the Property from the Vendor on the terms and subject to the conditions of this Agreement.

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, the following terms have the following meanings:

"**Acceptance Date**" means the date on which the Vendor executed and accepted this Offer;

"**Adjustments**" means the items set out in Section 6.3;

"**Agreement**" means the Offer as accepted by the Vendor;

"**Applicable Laws**" means any and all applicable federal, provincial and municipal statutes, by-laws, rules, regulations, codes, orders, published policies and published guide-lines;

"**Buildings**" means all buildings, structures, erections, fixtures, appurtenances and improvements constructed or affixed to the Lands and include the House;

"**Business Day**" means any day other than a Saturday, Sunday or statutory holiday in the Province of Ontario;

"**Closing Date**" or "**Closing**" has the meaning attributed thereto in Section 2.3;

"**Completion Notice**" has the meaning attributed thereto in Section 2.3;

"Conditional Period" means the period from the Acceptance Date to 5:00 p.m. on the day which is ninety (90) days after the Acceptance Date;

Comment [AM1]: HHH should be able to complete the due diligence in 90 days.

"**DRA**" has the meaning attributed thereto in Section 2.4;

"**Deposit**" means the sum of $10,000.00 to be submitted within five (5) Business Days of acceptance by the Vendor of this Offer, payable by certified cheque or bank draft or wire transfer to the Vendor's Solicitors, to be held in an interest bearing trust account as provided in Section 2.5, pending the Closing or other termination of this Agreement and to be credited on account of the Purchase Price on Closing;

"**Encumbrance**" means any security interest, lien, charge, pledge, encumbrance, mortgage, title retention agreement, easement, encroachment, right-of-way, restrictive covenant, license, lease, agreement or any other claim of any nature or kind, whether financial or otherwise;

"**Environmental Laws**" means all applicable federal, provincial and municipal statutes, laws, ordinances, rules, regulations, regulatory policies, and by-laws (relating in full or in part to the protection or preservation of the environment, product liability and employee and public health and safety and includes, without limitation, those Environmental Laws relating to the storage, generation, use, handling, manufacture, processing, labelling, advertising, sale, display, transportation, treatment, release and disposal of Hazardous Substances that apply to the Property;

"**Equipment**" has the meaning attributed thereto in Section 3.8;

"**HST**" means the tax payable pursuant to Section 165 of the *Excise Tax Act;*

"**Hazardous Substance**" means any substance, sound, vibration, ray, heat, odour, radiation, energy, which is or is deemed to be, alone or in any combination, a pollutant, contaminant, source of pollution or contamination, waste of any nature, hazardous substance, hazardous material, toxic substance, dangerous substance or dangerous good as identified in any Environmental Law;

"**House**" means the residential dwelling and related garage located on the Property as at the Acceptance Date;

"**Offer**" means this document, including all schedules, executed by the Purchaser and delivered to the Vendor;

"**Lands**" means the lands in the Town of Halton Hills, Ontario, containing approximately 4.34 acres, approximately 3.4 of which are usable acres. of land, being Part of Lot 15, Concession 6, Trafalgar, New Survey shown as Parts 30 and 31 on Reference Plan 20R-17731;;

"**Leases**" means all offers to lease, agreements to lease and leases granted by or on behalf of the Vendor to possess or occupy space within the Property now or hereafter, in each case as amended, renewed or otherwise varied, and any amendments to Leases;

"**Permitted Encumbrances**" means the Encumbrances, matters and other instruments listed on Schedule "A" attached hereto;

"**Property**" means the Lands and Buildings;

"**Purchase Price**" means the sum of Nine Hundred and Sixty-Five Thousand, Six Hundred Dollars ($965,600.00);

"**Purchaser's Solicitors**" means Arnold, Foster LLP Attention: Herbert T. Arnold; and

"**Vendor's Solicitors**" means Fasken Martineau DuMoulin LLP.

ARTICLE 2
OFFER, PRICE, PAYMENT AND CLOSING

2.1 Offer

The Purchaser offers to purchase the Property from the Vendor for the Purchase Price on the Closing Date on the terms and conditions set out in this Agreement.

2.2 Payment of the Purchase Price

The Purchase Price shall be paid as follows:

(a) by payment of the Deposit to the Vendor within five (5) Business Days following acceptance by the Vendor of this Offer; and

(b) by payment on Closing, to the Vendor or as the Vendor may direct, of the balance of the Purchase Price by certified cheque or bank draft or wire transfer, drawn on a Schedule I Canadian Chartered Bank, subject to the Adjustments.

2.3 Closing Date

The transactions contemplated by this Agreement shall be completed within thirty (30) but not less than ten (10) days after the Conditional Period on a Business Day to be determined by the Vendor as set out in written notice from the Vendor (the "Completion Notice") to the Purchaser (the "Closing Date").

2.4 Time and Place of Closing

The Vendor and Purchaser covenant and agree to cause their respective solicitors to enter into a document registration agreement (the "**DRA**") to govern the electronic submission of the transfer/deeds for the Property to the applicable Land Registry Office. The DRA shall outline or establish the procedures and timing for completing all registrations electronically and provide for all closing documents and closing funds to be held in escrow pending the submission of the transfer/deeds to the Land Registry Office and their acceptance by virtue of each registration document being assigned a registration number. The DRA shall also provide that if there is a problem with the Teraview electronic registration system which does not allow the parties to electronically register all registration documents on Closing, the Closing Date shall be deemed to be extended until the next day when the said system is accessible and operating for the applicable Land Registry Office applicable to the Property.

2.5 Deposit

The following shall apply in respect of the Deposit:

(a) prior to Closing the Deposit shall be held by the Vendor's Solicitors, in trust, in an interest bearing trust account or term deposit, pending completion of this transaction or earlier termination of this Agreement;

(b) if the transaction of purchase and sale which is contemplated in this Agreement is not completed for any reason, except the default of the Purchaser, the Deposit together with any accrued interest thereon shall be returned to the Purchaser;

(c) if the transaction of purchase and sale which is contemplated in this Agreement is not completed as a result of the default of the Purchaser, then and in such event, the Deposit together with any accrued interest thereon shall be non-refundable to the Purchaser and shall be payable to the Vendor without prejudice to the Vendor's other rights and remedies at law and in equity, if any; and

(d) the Deposit and any accrued interest shall be credited on account of the Purchase Price on Closing or, at the option of the Purchaser, the accrued interest on the Deposit may be paid directly to the Purchaser on Closing.

ARTICLE 3
INSPECTION RIGHTS

3.1 Preliminary Deliveries

Within ten (10) days after the Acceptance Date, the Vendor covenants to deliver to the Purchaser at the Vendor's expense:

(a) a copy of any existing boundary property plan of the Property in the Vendor's possession or under its control;

(b) a copy of all environmental or other studies of the Property which are in the Vendor's possession or under its control;

(c) copies of any current realty tax assessment notices and tax bills relating to the Property and details of any outstanding tax appeals or reassessments;

(d) copies of all outstanding work orders, deficiency notices, directives and letters of non-compliance issued by any governmental authority affecting the Property in the Vendor's possession; and

(e) executed authorizations to all relevant governmental authorities having jurisdiction permitting inquiries by the Purchaser or the Purchaser's Solicitors as to outstanding realty taxes, work orders, compliance with by-laws, etc. and authorizing the release of any and all information on file in respect of the Property but prohibiting any inspection of the Property by such authorities.

3.2 Access to the Property

During ordinary business hours on Business Days during the Conditional Period and thereafter until the Closing Date, the Vendor shall permit the Purchaser, its employees, engineers, surveyors, consultants and other agents access to the Property for the purpose of making reasonable soil, ground-water, environmental or other inspections, tests, measurements or surveys in, on or below the Property, at the Purchaser's risk and at the Purchaser's sole cost and expense, provided that the Purchaser shall have first given the Vendor 48 hours' notice of its need for such access. The Purchaser agrees to indemnify and save harmless the Vendor with respect to any loss, damage, charge, cost, expense and claim arising out of injury to any person or damage to the Property or property thereon which the Vendor may incur by reason of any such access, inspections, tests, measurements or surveys.

Prior to entry, the Purchaser shall provide the Vendor with evidence of liability insurance coverage, satisfactory to the Vendor, acting reasonably.

During the Conditional Period, the Purchaser may undertake such inquiries of federal, provincial, municipal and local authorities as it deems prudent or necessary to determine whether the Property is subject to any environmental restrictions, prohibitions, conditions, controls or limitations.

3.3 Conditional Period

This Agreement shall be conditional for the benefit of the Purchaser until the end of the Conditional Period upon the Purchaser being satisfied in its sole and unfettered discretion as to the environmental and soil condition of the Property, including satisfaction with a geotechnical study, obtaining satisfactory access arrangements from the Property over adjacent lands to a public road for ingress, egress and any utilities and that the Property is otherwise suitable for its purposes. The Vendor will cooperate with the Purchaser in respect of any application the Purchaser may make to Hydro One Networks, the Independent Electricity System Operator, the Ontario Energy Board, the Electrical Safety Authority or any municipality or other authority.

The conditions contained in this Section 3.3 are for the benefit of the Purchaser and may be waived by the Purchaser in part or in full. If at the end of the Conditional Period, the Purchaser has not waived in writing or satisfied the conditions contained in this Section 3.3, then this Agreement shall be terminated and, save as provided in Section 2.5 and Sections 3.4 and 3.5, the parties shall have no further rights and obligations under this Agreement. The Purchaser shall have the right to give written notice of termination of this Agreement to the Vendor at any time during the Conditional Period, if the Purchaser determines in its sole and unfettered discretion that it will not be able to satisfy the conditions contained in this Section and upon giving such notice, this Agreement shall be terminated and, save as provided in Section 2.5 and Sections 3.4 and 3.5, the parties shall have no further rights and obligations under this Agreement.

3.4 Return of Documents/Restoration of Property

If this Agreement is terminated by the Purchaser pursuant to Section 3.3, the Purchaser shall immediately return to the Vendor all documents which were delivered to it pursuant to Section 3.1 together with all copies thereof.

Following its inspection and tests, the Purchaser shall forthwith restore the Property to its original state, at the Purchaser's expense. If the Purchaser does not complete this transaction and fails to complete such restoration within 15 days of completion of its investigations and tests, the Vendor shall be entitled to restore the Property at the Purchaser's expense, the cost of such restoration, together with a management fee of 10% of the actual costs incurred, shall be payable forthwith on demand, and such cost and fee shall constitute a charge on the Deposit and may be deducted therefrom.

The Purchaser shall provide to the Vendor forthwith following receipt by the Purchaser, copies of any and all reports, studies, etc. commissioned by the Purchaser in respect of the Property.

3.5 Confidentiality

Both prior to the Closing Date and, if this Agreement is terminated for any reason whatsoever, after the Closing Date, the Purchaser, for itself, its employees, engineers, surveyors, consultants and other agents agrees that they shall not, except as required by law, or except to its consultants, advisors, agents, lenders, affiliates and solicitors in order to facilitate the completion of the transaction contemplated by this Agreement, disclose to anyone or use for any purpose other than the purpose contemplated by the Agreement any information concerning the Vendor and the Property whether such information was disclosed by the Vendor or obtained by the Purchaser, its employees, engineers, surveyors, consultants and other agents through its investigations and inquiries.

3.6 Planning Act Compliance

The Purchaser represents and warrants to the Vendor that it is acquiring the Property for the purposes of an electricity distribution line within the meaning of the *Ontario Energy Board* Act, 1998 and as such the transfer of the Property to the Purchaser will be in compliance with the *Planning Act*, R.S.O. 1990, and that no severance consent in connection with the conveyance of the Property to the Purchaser will be required notwithstanding the Vendor's ownership of adjacent lands.

This transaction is therefore exempt from the subdivision control provisions of the *Planning Act.*

3.7 House

The Purchaser agrees to accept the House on Closing in its then "as-is where-is" condition.

3.8 Right of First Refusal

The Purchaser agrees on Closing to grant to the Vendor a right of first refusal to purchase the Property. Such right of first refusal shall be on the terms and conditions as set out in the form attached hereto as Schedule "B" (the "Right of First refusal Agreement").

ARTICLE 4
REPRESENTATIONS, WARRANTIES AND CONDITIONS

4.1 Vendor's Representations and Warranties

The Vendor represents and warrants that:

(a) there are no current Leases affecting any part of the Property and on the Closing Date the Property will not be subject to any Leases;

(b) the Vendor is the sole beneficial owner of the Property and does not hold registered title to the Property as bare trustee or nominee for any other person;

(c) as at the Acceptance Date there are no accounts that are due and owing for work or services performed or materials placed or furnished upon or in respect of the servicing, repair or maintenance of the Property at the request of the Vendor as at the Acceptance Date, and any accounts owing for work or services performed or materials placed or furnished upon or in respect of the servicing, repair or maintenance of the Property at the request of the Vendor after the Acceptance Date will be paid in the normal course by the Vendor;

(d) the Vendor has not received any written notice of any proceeding with respect to or in connection with the expropriation or rezoning of the Property;

(e) the Vendor is not now and will not be at the Closing Date a non-resident of Canada for the purposes of Section 116 of the *Income Tax Act*;

(f) as at the Acceptance Date, there is no litigation existing or to the knowledge of the Vendor pending in respect of the Property for which the Purchaser would become liable after the Closing Date;

(g) as at the Acceptance Date, to the best of its knowledge and belief, the Vendor has received no written notice of non-compliance with Applicable Laws in respect of the Property;

(h) as at the Acceptance Date, except as may be disclosed in any environmental studies or reports provided pursuant to Section 3.1, to the best of the Vendor's knowledge and belief , the Vendor has not caused or permitted the release, spill or discharge of any Hazardous Substances on the Property in excess of concentrations permitted by Environmental Laws during the period of its ownership of the Property; and

(i) as at the Acceptance Date, except as may be disclosed in any environmental studies or reports provided pursuant to Section 3.1, the Property has not been used by the Vendor as a landfill or waste disposal site during the period of its ownership of the Property.

The representations and warranties contained in this Section 4.1 shall survive the Closing Date. The Purchaser shall promptly notify the Vendor of any fact, matter or thing of which it becomes aware which might constitute a breach of a representation or warranty of the Vendor hereunder. If any one or more of the representations or warranties of the Vendor are not true in any material respect at or prior to Closing, the Purchaser may terminate this Agreement by notice to the Vendor and in such event the obligations of the Vendor and the Purchaser under this Agreement (save and except for the obligation in Section 2.5, 3.4 and 3.5) shall be at an end and the parties shall have no further rights or obligations under this Agreement. Except as expressly set forth in this Agreement, the Purchaser acknowledges and agrees that the Vendor is not making and has not made at any time any representations or warranties of any kind or character, expressed or implied, with respect to the Property. The Purchaser acknowledges and agrees that upon Closing, the Vendor shall sell and convey to the Purchaser and the Purchaser shall accept the Property "as is, where is" except as expressly provided in this Agreement. The Purchaser acknowledges and agrees that the Property is landlocked and that the Purchaser will satisfy itself during the Conditional Period that it can arrange, at its sole expense, with the Corporation of the Town of Halton Hills for suitable access to the Property by way of an easement (or otherwise) over the adjacent lands owned by the Corporation of the Town of Halton Hills.

Except as expressly set forth in this Agreement, it is understood and agreed that Vendor is not making and has not at any time made any warranties or representations of any kind or character, express or implied, with respect to the Property, including, but not limited to any warranties or representations as to:

(a) description, nature, quality, quantity, size, state or condition, habitability, merchantability or fitness for a particular purpose or as to the current or future physical or structural condition or value of the Property or its suitability for rehabilitation or renovation;

(b) the income, use, operation or any other matter or thing affecting or relating to the Property or title thereto or the transactions contemplated hereby;

(c) the current or future real estate tax liability, assessment or valuation of the Property;

(d) the potential qualification of the Property for any and all benefits conferred by federal, provincial or municipal laws, whether for subsidies, special real estate tax treatment, insurance, mortgages, or any other benefits, whether similar or dissimilar to those enumerated;

(e) the compliance of the Property in its current or any future state with Applicable Laws and the heritage status of the House;

(f) soil conditions;

(g) the environmental condition of the Property or the compliance of the Property with Environmental Laws or any release or absence of Hazardous Substances, in, on, above, beneath at, to or from the Property, the Purchaser acknowledging that the House contains mould; or

(h) the state of title to the Property, including access to the Property.

4.2 Purchaser's Representations and Warranties

The Purchaser represents and warrants that:

(a) The entering into of the Agreement and the performance by it of the terms thereof will not result in a violation by it of the provisions contained in its constating documents or any agreement by which it is bound;

(b) It has the requisite power, capacity and authority to enter into the Agreement and perform the terms thereof and the completion of the transaction contemplated by the Agreement will have been by the date of Closing duly authorized by all necessary corporate action; and

(c) It is registered under the provisions of the *Excise Tax Act* relating to the harmonized sales tax ("HST") and its registration number is 867429623 RT 0001.

4.3 Purchaser's Covenant

The Purchaser covenants and agrees that,

(a) subsequent to the Closing, neither the Purchaser nor any related person or affiliate (within the meaning of the Securities Act (Ontario)) will directly or indirectly object to or oppose in any way the use or development of the Vendor's adjacent lands, including official plan or zoning by-law amendments, plans of subdivision or site plan approvals.

(b) Neither it nor its successors or assigns will alter the grading or change the elevation or contour of the Lands except in accordance with drainage plans approved by the Director of Infrastructure of the Town of Halton Hills.

(c) it will abide by the requirements of Owner of the Property as detailed in Schedule C attached hereto to the extent applicable to Purchaser and to the Property.

4.4 Conditions of Closing for Purchaser

The following are conditions of the obligation of the Purchaser to complete the transaction of purchase and sale contemplated by this Agreement:

(a) all representations and warranties of the Vendor shall be true and complete as at the date of Closing in all material respects and the Vendor shall have delivered to the Purchaser an officer's certificate that such representations and warranties are true and complete as at the date of Closing in all material respects;

(b) the Vendor shall have delivered to the Purchaser all of the deliveries contemplated by Section 6.1; and

(c) all Encumbrances against the Property have been discharged except Permitted Encumbrances, and except for any Encumbrances which have been accepted by the Purchaser in writing.

4.5 Failure to Satisfy Conditions

The conditions described in Section 4.4 are for the benefit of the Purchaser only. If any one of such conditions is not satisfied, the Purchaser may by notice in writing delivered to the Vendor declare this Agreement to be terminated and the Deposit shall be returned to the Purchaser with any accrued interest thereon. Provided that any or all of such conditions may be waived in whole or in part by the Purchaser and without prejudice to its right of termination in the event of the non-fulfillment of any other such condition or conditions, any such waiver to be by notice as aforesaid.

4.6 Condition of Closing for Vendor

The following are conditions of the obligation of the Vendor to complete the transaction of purchase and sale contemplated by this Agreement:

(a) the Purchaser shall have delivered to the Vendor all of the deliveries contemplated by Section 6.2.

4.7 Failure to Satisfy Conditions

The conditions described in Section 4.6 are for the benefit of the Vendor only. If any one of such conditions is not satisfied, the Vendor may by notice in writing delivered to the Purchaser declare this Agreement to be terminated. Provided that any or all of such conditions may be waived in whole or in part by the Vendor and without prejudice to its right of termination in the event of the non-fulfillment of any other such condition or conditions, any such waiver to be by notice as aforesaid.

ARTICLE 5
TITLE

Except as specifically disclosed herein, the title to the Property shall be good and free from all Encumbrances except Permitted Encumbrances. The Purchaser is not to call for the production of any title, deed, abstract, survey or other evidence of title which is not in the possession of the Vendor except as hereinbefore provided. The Purchaser is to be allowed until the end of the Conditional Period to examine the title to the Property at its own expense. If within such time period, the Purchaser furnishes to the Vendor notice in writing setting forth in reasonable detail any valid objections and which the Vendor shall be unwilling or unable to remove or correct, and which the Purchaser will not waive, the Purchaser may terminate this Agreement by delivering notice in writing to the Vendor to this effect and this Agreement shall, upon delivery of such notice and notwithstanding any intermediate acts or negotiations, be terminated and the Deposit (together with any interest accrued thereon) shall be returned to the Purchaser and neither party shall be liable for any costs or damages of the other. Save as to any valid objections so made by such day, the Purchaser shall be conclusively deemed to have accepted the Vendor's title to the Property.

ARTICLE 6
COMPLETION OF PURCHASE

6.1 Vendor's Deliveries

On Closing, the Vendor shall deliver to the Purchaser on payment of the Purchase Price the following:

(a) a transfer/deed to the Property in registrable form;

(b) a certificate confirming that the Vendor is not a non-resident of Canada within the meaning of Section 116 of the *Income Tax Act* (Canada);

(c) an officer's certificate from the Vendor confirming the truth and completeness as at the date of Closing in all material respects of the representations and warranties of the Vendor set forth in Section 4.1;

(d) a statement of adjustments;

(e) an undertaking to readjust;

(f) the Right of First Refusal Agreement;

(g) original copies, to the extent available, of the preliminary deliveries contemplated by Section 3.1; and

(h) such further documentation relative to the completion of this transaction as is customary in a transaction of the nature of the transaction contemplated by this Agreement and as the Purchaser or its solicitors may reasonably require.

6.2 Purchaser's Deliveries

On Closing, the Purchaser shall deliver to the Vendor the following:

(a) the balance of the Purchase Price;

(b) a certificate concerning the Purchaser's registration under the *Excise Tax Act* and an undertaking to self assess and an indemnity respecting the Vendor's liability for HST pursuant to Section 6.5;

(c) the covenants referred to in Section 4.2

(d) to the extent required by the Vendor or by any Permitted Encumbrance, an agreement assuming the obligations under such Permitted Encumbrance;

(e) the Right of First Refusal Agreement;

(f) an undertaking to readjust; and

(g) such further documentation relative to the completion of this transaction as is customary in a transaction of the nature of the transaction contemplated by this Agreement and as the Vendor or its solicitors may reasonably require.

6.3 Adjustments

The Purchase Price will be adjusted by apportioning as between the Purchaser and the Vendor as of the Closing Date all real property taxes and utilities, if any. The Vendor will prepare a draft statement of adjustments and submit it to the Purchaser at least five (5) days before the Closing Date. The Vendor and

Purchaser agree to readjust the adjustments made on Closing, if necessary as soon as reasonably convenient.

6.4 Insurance Risk

The Property shall be and remain until Closing at the risk of the Vendor and thereafter shall be at risk of the Purchaser.

6.5 HST

(a) The Purchase Price is exclusive of any HST;

(b) The Purchaser agrees that the Purchaser shall be liable, shall self-assess and remit to the appropriate governmental authority all HST payable in connection with the transfer of Property made pursuant to this Agreement and shall indemnify and save harmless the Vendor from and against such HST together with any penalties and interest thereon or other costs and expenses suffered by the Vendor which may arise as a result of any failure by the Purchaser to comply with this provision.

(c) The Purchaser shall on the Closing Date provide the Vendor with an officer's certificate concerning registration under the *Excise Tax Act* (Canada).

ARTICLE 7 GENERAL

7.1 Canadian Funds

All dollar amounts referred to in this Agreement are in Canadian funds unless otherwise provided.

7.2 Extended Meanings

In this Agreement, words importing the singular number include the plural and vice versa and words importing the masculine gender include the feminine and neuter genders.

7.3 Entire Agreement

This Agreement constitutes the entire agreement between the parties hereto pertaining to the subject matter hereof and supersedes all prior and contemporaneous agreements, understandings, negotiations and discussions, whether oral or written, of the parties and there are no warranties, representations or other agreements between the parties in connection with the subject matter hereof except as specifically set forth herein.

7.4 Headings

Article and Section headings are not to be considered part of this Agreement and are included solely for convenience of reference and are not intended to be full or accurate descriptions of the contents thereof.

7.5 Successors and Assigns

All of the terms and provisions in this Agreement shall be binding upon and shall enure to the benefit of the parties hereto and their respective successors and assigns.

7.6 Planning Act

This Agreement shall be effective to create an interest in the Property only if the subdivision control provisions of the *Planning Act* are complied with by the Vendor on or before Closing.

7.7 Time of the Essence

Time hereof shall in all respects be of the essence.

7.8 Tender

Any tender of documents or money hereunder may be made upon Vendor or Purchaser or their respective solicitors on Closing. Money may be tendered by bank draft or cheque certified by a chartered bank or trust company.

7.9 Residency of Vendor

The Purchaser shall be credited towards the Purchase Price with the amount, if any, which it shall be necessary for the Purchaser to pay to the Receiver General in order to satisfy the Purchaser's liability in respect of tax payable by the Vendor under the non-residency provisions of the *Income Tax Act* by reason of the sale of the Property. The Purchaser shall not claim such credit if the Vendor delivers on Closing the prescribed certificate or a statutory declaration by an officer on the Vendor having knowledge that the Vendor is not then a non-resident of Canada.

7.10 Notice

Any notice, demand or other communication (in this Section, a "**Notice**") required or permitted to be given or made under this Agreement shall be in writing and shall be sufficiently given or made if:

(a) delivered in person during normal business hours of the recipient on a business day and left with a receptionist or other responsible employee of the recipient at the relevant address set forth below; or

(b) except during any period of actual or imminent interruption of postal services due to strike, lockout or other cause, sent by registered mail:

to the Vendor at:

TransCanada Energy Ltd.
450 - 1st St. SW
Calgary, AB T2P 5H1
Attention: Manager, Land - Leslie Thomas
Phone: 403-920-5845

and:

TransCanada Energy Ltd.
Royal Bank Place, 200 Bay Street

24th Floor
Toronto, ON M5J 2J1

Attention:
Facsimile: 416-869-2056

With a copy to:

Vendor's Solicitors at:

Suite 2400, Bay Adelaide Centre, Box 20
333 Bay Street
Toronto, Ontario, M5H 2T6

Facsimile:

to the Purchaser at:

Halton Hills Hydro Inc.
43 Alice Street
Acton, Ontario L7J 2A9
Attention: Art Skidmore
Facsimile: 519-853-5592

with a copy to:

Arnold, Foster LLP
Barristers & Solicitors
232A Guelph Street,
Georgetown, Ontario L7G 4B1

Attention: Herbert T. Arnold
Facsimile: 905-873-4962

Each notice sent in accordance with this Section shall be deemed to have been received at the time it was delivered:

(a) at the beginning of business on the third business day after it mailed (excluding each day on which there is any interruption of postal services due to strike, lockout or other cause);

Addresses for notice may be changed by giving notice in accordance with this section.

7.11 Article Counterparts and Facsimile Transmission

This Agreement may be executed in any number of counterparts. Each executed counterpart shall be deemed to be an original; all executed counterparts taken together shall constitute one agreement. An executed counterpart of the Agreement may be transmitted by facsimile machine and the transmitted copy may be executed and/or amended by the receiving party and transmitted to the other party. Transmission of a counterpart of the agreement shall constitute notice of the execution or amendments shown thereon; execution or other amendment of a transmitted counterpart shall be as binding as execution or amendment of an original counterpart.

7.12 Broker

The parties acknowledge and agree that no agent or broker has facilitated or provided advice in relation to this transaction or this Agreement. Each party hereto agrees that if any person or entity makes a claim for brokerage commissions or finder's fees related to the sale of the Property by Vendor to Purchaser, and such claim is made by, through or on account of any acts or alleged acts of said party or its representatives, said party would protect, indemnify, defend and hold the other party free and harmless from and against any and all loss, liability, cost, damage and expense (including reasonable legal fees) in connection therewith. The provisions of this Section 7.12 shall survive the Closing or any termination of this Agreement.

7.13 Assignment

The Purchaser shall not be entitled to assign this Agreement or any of its rights or benefits under this Agreement, in whole or in part, without the prior written consent of the Vendor, which consent may be withheld in the Vendor's sole and unfettered discretion. No consent shall be required for an assignment to The Corporation of the Town of Halton Hills provided that notice of any such assignment shall be provided to the Vendor not less than five (5) Business Days prior to Closing Date. As a condition of any such assignment by the Purchaser, the assignee shall execute an agreement in favour of the Vendor to assume all of the obligations of the Purchaser under this Agreement.

7.14 Time for Acceptance

The Purchaser agrees that this Offer shall be irrevocable by it until 5:00 p.m. Toronto time, on day of 2015 after which time, if not accepted, this Offer shall be null and void and the Deposit, if paid, shall be returned to the Purchaser without interest or deduction.

DATED this day of , 2015.

HALTON HILLS HYDRO INC.

By:_________________________
Name:
Title:

I have authority to bind the Corporation

The undersigned hereby accepts the above offer on the terms and conditions set forth therein.

DATED this of .

TRANSCANADA ENERGY LTD.

By:______________________________
Name:
Title:

By:______________________________
Name:
Title:

We have authority to bind the Corporation

SCHEDULE "A"

Permitted Encumbrances

1. The reservations, limitations, exceptions, provisos and conditions, if any, expressed in the original grants from the Crown, preluding, without limitation, the reservation of any mines and minerals in the Crown or in any other person;

2. Liens for taxes, rates, assessments, governmental charges or levies and public utility rates or charges not yet due and delinquent;

3. Any encroachments either onto the Property by improvements on adjoining lands or by improvements on the Property onto adjoining lands and any discrepancies in the legal descriptions of the Property or adjoining lands which are shown on any survey;

4. Any registered, easements or rights-of-way for sewers, drains, gas, steam and water mains or electric light and power over the Property and provided they do not materially impair the use of the Property or the proposed use of the Property by the Purchaser;

5. Any registered municipal subdivision agreements, development agreements of site plan agreements, and registered agreements with publicly regulated utilities provided such have been complied with, or security has been posted to ensure compliance and completion, as evidenced by a letter from the relevant municipality or regulated utility and further provided that any such agreement does not materially impair the use of the Property or the Purchaser's intended use of the Property;

6. Any other easements for the supply of utility services to the Property or to adjacent properties; and

7. Easements in favour of the Vendor, the Regional Municipality of Halton Hills, and the Corporation of the Town of Halton Hills.

SCHEDULE "B"

RIGHT OF FIRST REFUSAL AND RIGHT OF FIRST OFFER AGREEMENT

THIS AGREEMENT made as of this <@> day of<@>, 2015.

B E T W E E N:

HALTON HILLS HYDRO INC.

(hereinafter called "**HHH**")

OF THE FIRST PART;

- and -

TRANSCANADA ENERGY LTD.

(hereinafter called "**TCE**")

OF THE SECOND PART;

WHEREAS TCE, as Vendor, entered into a Purchase Agreement dated July <@>, 2015, with HHH, as Purchaser, with respect to the property legally described as being parts of Lot 15, Concession 6, Trafalgar, New Survey, Town of Halton Hills, being part of PIN 25073-0068 (LT) designated as Part 30 on Reference Plan 20R-17731 and part of PIN 25073-0113 (LT) designated as Part 31 on Reference Plan 20R-17731 (the "**Property**");

AND WHEREAS the Purchase Agreement provided that TCE would be granted a continuous right of first refusal and a continuous right of first offer to purchase the Property;

AND WHEREAS the parties have agreed to enter into this Agreement in accordance with the provisions of the Purchase Agreement.

NOW THEREFORE in consideration of the covenants as herein contained and other good and valuable consideration, the parties hereto agree as follows:

ARTICLE 1
RIGHT OF FIRST REFUSAL

1.1 If, at any time and from time to time it is HHH's intention to sell or otherwise dispose of the Property or any part thereof (and for the purposes of this Agreement, a sale of an interest in the Property or a lease of the entire Property for a period in excess of twenty (20) years shall be considered as a sale of the Property), the following provisions shall apply:

1.2 HHH shall deliver to TCE written notice (the "**Sale Notice**") setting forth in reasonable detail the terms and conditions on which HHH is prepared to offer the Property or such portion thereof for sale.

1.3 TCE shall have the right for ten (10) Business Days from the date of receipt by it of the Sale Notice to agree to purchase the Property or such portion thereof (as the case may be) from HHH on the terms and conditions set forth in the Sale Notice. Such right shall be exercised by written notice delivered to HHH and, on receipt thereof by HHH, TCE and HHH shall be deemed to have entered into an agreement of purchase and sale with respect to the Property or such portion thereof, on the terms and conditions contained in the Sale Notice and, unless the parties agree otherwise, the closing date shall be sixty (60) days after the date of receipt by TCE of the Sale Notice, unless such date is not a Business Day, in which event the closing date shall be on the next Business Day.

1.4 If TCE fails to deliver written notice to HHH of its election to exercise its right of first refusal within the ten (10) Business Day period after receipt of the Sale Notice, HHH shall for a period of six (6) months from the date of giving the Sale Notice be free to offer the Property or such portion thereof (as the case may be), for sale to a third party and to enter into an agreement of purchase and sale at a purchase price no lower and upon terms and conditions no more favourable than those specified in the Sale Notice and, in that event, HHH shall not be required to comply with the provisions contained in Article 2 herein.

1.5 If HHH does not enter an agreement of purchase and sale within the six (6) month period referred to in Paragraph 1.4, or, if HHH does enter into an agreement of purchase and sale but such agreement fails to close, HHH agrees that it will not offer to sell the Property or such portion thereof (as the case may be) unless and until it shall have again complied with the terms and conditions required of it pursuant to this Article 1.

1.6 If, during the six (6) month period referred to in Paragraph 1.4, HHH receives an offer to purchase the Property or a portion thereof (as the case may be) which it is ready and willing to accept, but which is at a lower price or upon more favourable terms and conditions than those specified in the Sale Notice, HHH shall deliver a Sale Notice to TCE as required herein and TCE shall then have the right of first refusal to purchase the Property or such portion thereof (as the case may be) as is provided in Article 2, but in such case, TCE shall have five (5) Business Days after receipt of the terms of the Offer (as hereinafter defined in Article 2) within which to exercise its right of first refusal.

ARTICLE 2
RIGHT OF FIRST OFFER

2.1 HHH hereby covenants and agrees to and with TCE that, if HHH, at any time, receives a bona fide offer to sell or dispose of the Property or any part thereof (the "**Offer**") which HHH is ready and willing to accept, TCE shall have the right of first refusal to meet the same and to purchase the Property or such portion thereof as is specified in the Offer at the same price and upon and subject to the same terms and conditions as those contained in the Offer. HHH shall forward a copy of the Offer to TCE together with written notice (the "**Offer Notice**") confirming HHH's willingness to accept such terms and that the Offer is, to the best of HHH's knowledge, bona fide. TCE shall, from the time of receipt by it of the Offer Notice have ten (10) Business Days within which to exercise its right of first refusal by giving to HHH written notice electing to purchase on the terms and conditions of the Offer. TCE's election to purchase shall constitute a binding agreement to purchase between TCE and HHH on the terms and conditions of the Offer. If TCE fails to give written notice to HHH within such ten (10) Business Day period of its intention to exercise its right of first refusal, HHH shall then be free, for a period of thirty (30) Business Days thereafter, to enter into an agreement of purchase and sale, at a price no lower than and subject to such terms and conditions no more favourable than those contained in the Offer. If HHH does not enter into such a purchase agreement within the aforesaid thirty (30) Business Day period, it may not thereafter sell or agree to sell the Property or portion thereof, unless and until HHH shall have again complied with the terms and conditions of this Agreement.

2.2 Upon completion of any sale of any portion of the Property by HHH to a third party (after compliance with the terms and conditions of this Agreement), TCE's right of first refusal and right of first offer pursuant to this Agreement shall terminate with respect to such portion of the Property, however, its right of first refusal and right of first offer under this Agreement shall remain in full force and effect with respect to the remainder of the Property and all subsequent Offers.

ARTICLE 3
GENERAL

3.1 Time shall be of the essence of this Agreement.

3.2 This Agreement and everything herein contained shall be binding upon and shall enure to the benefit of the respective successors and permitted assigns of the parties hereto and the provisions hereof shall be read with all necessary grammatical changes and with all necessary changes of gender and number and all provisions herein shall be deemed to be covenants and time shall in all respects be of the essence.

3.3 No alteration or amendment to this Agreement shall be binding upon the parties hereto unless in writing signed by both TCE and HHH.

3.4 This Agreement shall be construed in accordance with and governed by the laws of the Province of Ontario and the Courts of Ontario shall be the exclusive forum for the settlement of any disputes.

3.5 Any notice required or permitted to be given under this Agreement or any tender or delivery of documents may be given by electronic delivery, personal delivery, by prepaid registered mail, as follows:

(a) to TCE at:

TransCanada Energy Ltd.
450 - 1st Street SW
Calgary, Alberta T2P 5H1

Attention: Manager, Land – Leslie Thomas

Phone: 403-920-5845

and to:

TransCanada Energy Ltd.
Royal Bank Place, 200 Bay Street, 24th Floor
Toronto, Ontario M5J 2J1

Attention: <@>

Phone: : <@>

(b) to HHH at:

Halton Hills Hydro Inc.
43 Alice Street
Acton, Ontario L7J 2A9

Attention: Art Skidmore

Facsimile: 519-853-5592

No notice or other document will be deemed to have been given or delivered under this paragraph until actually received at the address or number referred to above, whether by mail, facsimile or otherwise. Either party may change its address for notice by a notice given under this paragraph.

3.6 It is agreed that there is no representation, warranty, collateral agreement or condition affecting this agreement or the Property or supported hereby other than as expressed herein in writing.

3.7 This Agreement shall be effective to create an interest in the Property only if the applicable subdivision control provisions of the Planning Act, 1990 are complied with and HHH shall be solely responsible for the costs incurred in making any application for consent thereunder and for the costs of satisfying any conditions which are a requirement to obtain any consent authorizing the sale of the Property or any portion thereof as a separate parcel.

3.8 HHH hereby consents to the registration of this Agreement or notice thereof by TCE against title to the Property.

IN WITNESS WHEREOF, the parties hereto have executed this agreement as of the date first above written.

HALTON HILLS HYDRO INC.

By: ______________________________

Name:

Title:

I have authority to bind the Corporation

TRANSCANADA ENERGY LTD.

By: ______________________________

Name:

Title:

By: ______________________________

Name:

Title:

I/We have authority to bind the Corporation

Grading and Drainage

24. (1) Until Final Acceptance, the Owner agrees that it will be responsible for the drainage of all the Lands and shall, on the sale of any part of the Lands, reserve such rights as are necessary to enable the Owner to enter and undertake modifications to the surface drainage features of the Lands in accordance with the drainage patterns proposed by this Agreement.

(2) If the Director of Infrastructure Services deems it necessary to rectify the drainage at any time prior to Final Acceptance and the Owner fails to make such rectification when so instructed by the Director of Infrastructure Services, the Town may, at its option, undertake the correction of such drainage situation and all costs thereof shall be charged back to the Owner and shall include an administration fee of fifteen percent (15%) of the cost of labour, equipment and materials.

(3) The Owner agrees that neither it nor its successors or assigns will alter the grading or change the elevation or contour of the Lands except in accordance with drainage plans approved by the Director of Infrastructure Services.

(4) The Owner shall attach a copy of Section 24 of this Agreement to all agreements of purchase and sale of any part of the Lands, and shall include in all such conveyances, a covenant executed by the purchaser of any part of the Lands and binding on its successors and assigns in which the purchaser agrees not to alter the grading or change the elevation or contour of the land described in the conveyance except in accordance with drainage plans approved by the Director of Infrastructure Services.

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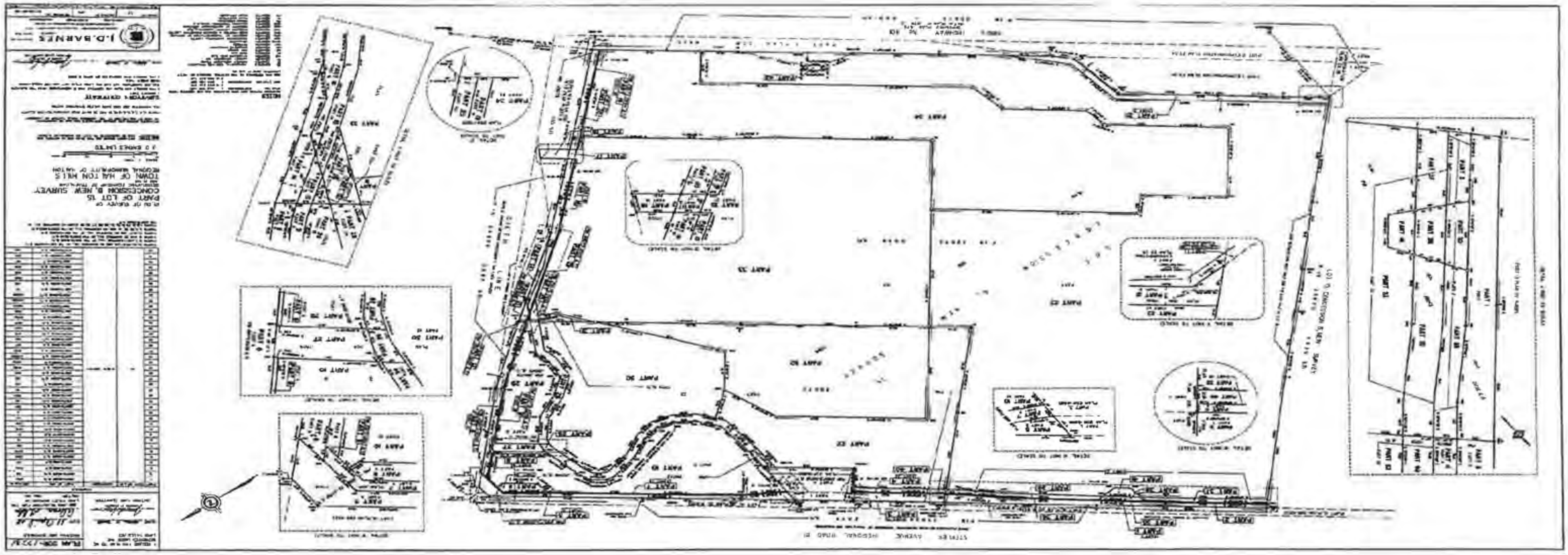

EXHIBIT #2

Transformer Station Supply Options Study

Preliminary Report

Prepared for:

Halton Hills Hydro

Prepared by

Costello Associates
158 Pond Hollow Drive
Sudbury, ON
P3E 6L2

www.costelloassociates.ca

April 2010

PRIVATE INFORMATION

1 Executive Summary

Costello Associates has been retained by Halton Hills Hydro (HHH) to assist with the study of capacity alternatives required to meet forecasted load growth in their southern supply area. The scope of this work includes the review of the HHH load forecast, coordination with Hydro One Networks (HON) for the provision of pool-funded station options, preparation of preliminary budgets for self-build station options, assessment of operational impacts, development of project schedules, coordination of financial and regulatory impact analysis performed by others, and to make recommendations for the supply of new capacity.

Costello Associates was initially contacted to assist with this project in September 2007. At that time, HHH believed that new supply capacity would be required around 2011 to meet planned development in the Steeles Road area. The local HON transformer station, "Halton TS", which supplies both Milton Hydro and HHH, would not be able to meet summer peak demand conditions after 2010. In the past two years, with the downturn in the economy, development has not progressed at the rate initially forecasted, and current expectations are that new capacity will be required by 2014.

At the time of our engagement in 2007, Trans Canada Energy (TCE) was in the early stages of developing their 683 MW natural gas-fired generating plant on Steeles Ave. HHH negotiated the provision of land adjacent to the generating plant to possibly accommodate a new municipal transformer station. We assisted HHH in conducting preliminary engineering reviews and a class environmental assessment of this site to determine its suitability for hosting a municipal transformer station. With the generating plant scheduled to be in service in 2010, TCE is looking for a commitment by HHH for the purchase of this parcel of land.

We are in the final stages of completing our detailed supply options study for this project. We have been asked to provide this preliminary report to support the decision to acquire this land parcel from TCE.

Based on the information available at this point, we believe that HHH should option or purchase this TCE land to mitigate the risk of having no cost effective alternatives to a self-build project. The HON alternative is effectively contingent on Milton Hydro participating at expansion of Halton TS. Without Milton Hydro's participation, HHH would be responsible for all of the project costs. As it stands, with HHH being assigned less than 50% of the total HON project costs, we evaluate this alternative as an equal cost option to HHH building a new station.

Municipal utilities have repeatedly demonstrated that they can design, construct, and operate transformer stations for less cost than HON. The addition of a transformer station adds to the asset base of the LDC, and provides the greatest shareholder value. This option also provides the lowest financial risk to HHH with respect to the recent economic downturn and the uncertainty of the pace of future load development.

2 Transformer Stations

2.1 Role of a Transformer Station

The role of a transformer station (TS) within the overall power grid is illustrated in Figure 1. Electricity is generated at nuclear, hydroelectric, fossil fuel, wind, and other facilities throughout Ontario. Bulk power is routed over long distances via the transmission system at high voltages (i.e. 115, 230, and 500 kV). Transformer stations are used to step the voltage down from the transmission system to the distribution voltage level. There are presently over 300 transformer stations owned by both Hydro One and municipal utilities throughout Ontario.

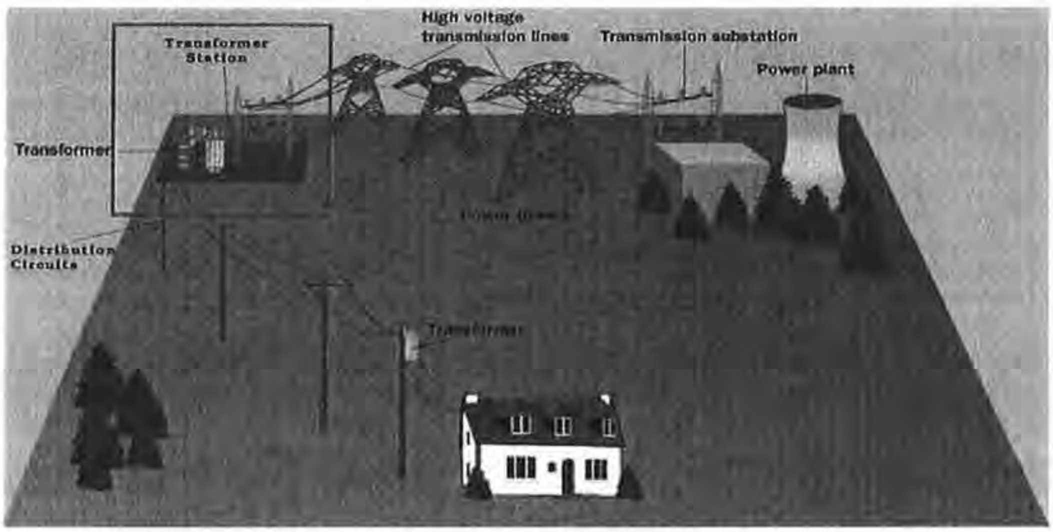

Figure 1

2.2 Potential Impact of Supply Constraints

The creation of additional transformer station capacity is a lengthy process. As a minimum, the shortest time frame possible from the decision to move forward to the in-service date is approximately two years. Items in this process contributing the most uncertainty to the timeline are land acquisition, environmental assessment and transformer delivery.

Accordingly, appropriate lead time ahead of actual need for supply is required in order to be ready when the load begins to materialize. A planning time of two to three years is necessary to accomplish this.

If load growth were to begin to materialize before additional supply capacity was made available, the existing supply infrastructure would be forced to perform beyond its rated capacity. The resulting impacts to the new HHH customers could include low voltage problems during high use periods and in order to prevent excessive overloading of equipment, or in the event of equipment failure, rotational blackouts may be ordered by Hydro One. As well, there would be an inability to deliver supply at the pace of growth, and therefore, a delay effect on growth. Should any of these problems occur, the reliability and customer service indicators for HHH would be negatively affected.

These undesirable situations can be avoided through commitment to additional supply facilities two to three years in advance of the customer growth. Although an inexact science, load forecasts based on expected community growth are the most critical tool for deciding when to begin.

2.3 LDC Experiences with Overloaded TS's

Historically, Ontario Hydro proactively reviewed transformer station loading, and worked with distribution utilities to add capacity whenever it was required. There have been several instances in the past ten years whereby Hydro One transformer stations have been operating well over published LTR ratings. In at least two cases, this has led to critical problems for distribution utilities:

August 2001 – Norfolk TS, Simcoe ON: a high voltage bushing on one of the station power transformers failed, causing the unit to be tripped off. The station had a published LTR of 65 MW, but was loaded to over 95 MW. Hydro One initiated rotational blackouts throughout Norfolk County, which lasted for three days. The failure occurred at the peak of tobacco harvest. See Figure 3 for the Simcoe Reformer newspaper article.

July 1, 2001 – Beamsville TS: the station suffered the failure of one of two power transformers. Beamsville TS had been operating above its published LTR rating. We understand the local fire department was requested to cool the overloaded transformer with water, in an attempt to control the temperature of the transformer. Fortunately, this cooling controlled the internal temperatures and rotating blackouts were not required.

Transformer station failures are rare, but it is important to recognize the potential impacts of operating the station beyond published ratings. Hydro One has the right (and responsibility) to ensure that their transformers are not damaged by overloading, and will therefore take necessary action to keep the load on a given transformer within its LTR in the event of the failure of either its partner transformer or equipment elsewhere on the grid.

3 Need for Additional Capacity

3.1 *Remaining Capacity*

HHH operates a 27.6 kV distribution network in the southern part of its service territory, and parts of Georgetown. This network is supplied by the HON-owned Halton Transformer Station, located at the intersection of James Snow Parkway and Main St. HHH currently has three feeders from this station that run through Milton Hydro's franchise territory, across Highway 401, and enter HHH's territory at Steeles Avenue.

The Halton TS also feeds the majority of Milton Hydro's service territory. Based on current load forecasts of both utilities, Halton TS will run only have enough capacity to meet the summer demand up to 2013. By the following summer, the station is forecasted to be overloaded by almost 6 MW unless relief is provided by a new facility.

3.2 *Load Forecast*

HHH regularly updates its short and long term load forecasts based on current firm development plans and long range planning goals set by the Town of Halton Hills, the Region of Halton, and the Province of Ontario.

The 2009 summer peak demand of the 27.6 kV network in the HHH southern supply area was roughly 27 MW. The short term load forecast, based on current planning information, anticipates about 21 MW of additional capacity to come online by the summer of 2013. If Milton Hydro's load also develops as expected, all of the remaining capacity at Halton TS will be consumed in 2013.

Conservative long term forecasts estimates show the southern supply area demand growing by 98 MW, for a total load of 125 MW over the next thirty years. Halton TS can accommodate 21MW of additional HHH load by 2013, leaving the balance of 77 MW to be supplied by a new facility.

4 Supply Options

4.1 Historical Practice

Prior to the opening of the electricity market, Ontario Hydro typically constructed new transformer station facilities proactively as demand required. These facilities were provided at no direct cost to the distribution utilities, as station costs were pooled and recovered through regulated transmission charges. Costs for related distribution improvements such as feeder ducts and cables were the responsibility of the LDC. The financial evaluation of projects considered the overall transmission and distribution costs, with each entity responsible for their own portion.

4.2 Transmission System Code

In 2002, as part of the industry changes associated with the passing of the Electricity Act and market opening, the Transmission System Code came into effect and we moved to a "user pay" approach. Costs for projects specifically attributable to one or more customers are recovered as part of the regulated connection process. Connecting customers have the choice to undertake certain contestable work or have HON provide services, at the connecting customer's cost.

In the case of municipal utilities requiring new transformer station capacity, three basic options exist:

1. HON designs, constructs, and operates the new station. An economic evaluation is performed by HON, whereby the net present value of the future incremental load revenue is compared to the cost of construction, operation, and maintenance cost of the station. If there is a shortfall in load revenue, the LDC pays the difference up front in the form of a capital contribution to Hydro One.

2. The LDC designs and constructs the new station according to HON's technical standards, and turns the station over to HON prior to energization. HON would reimburse the LDC for "reasonable costs" less the cost to oversee and administer the project. The economic evaluation described in the scenario above is used to calculate cost recovery. This option could be used if the LDC believed it could construct a transformer station exactly the same as Hydro One would, and do it for less cost. To the best of our knowledge, no LDC has exercised this option.

3. The LDC designs, constructs, owns, and operates the new station. The station asset would become part of the LDC distribution asset base, and the LDC would earn the regulated rate of return for the value of the station. Some or all of the capital cost of the project would be offset by a reduction in transmission charges payable to HON.

4.3 *Comparison of Connection Options*

	Principle	Pool-funded Option	LDC Build/ Turn Over to HON	LDC Self-Build Option
1	Overall capital cost	×	◘	✓
2	Risk of load growth – true up payments	×	◘	✓
3	Increase LDC asset base	×	×	✓
4	Control of system capacity	×	×	✓
5	Operating flexibility	◘	◘	✓
6	Lower transmission charges	×	×	✓
7	Lower upfront capital requirements	✓	◘	×
8	Burden on resources – project management, engineering, operating expertise	✓	×	×

Legend: ✓ = Best ◘ = Better × = Least

Table 1

Additional comments on Table 1:

1. LDC's typically build municipal transformer stations for significantly less cost than HON. Historically LDC cost savings were in the range of 20 – 30%, however with recent pricing from HON, the savings are even greater.
2. Should the LDC load not materialize as fast as forecasted, HON could collect additional payments from the connecting customer. If the LDC owned the transformer station, cost is recovered in the distribution rate base, on the book value of the station asset. The amount of load on a municipal transformer station does not affect the recovery of costs and return on equity.
3. Municipal transformer stations are capitalized and placed in the distribution asset base. This provides an opportunity for the LDC to add significant value to the asset base in a single project. This option delivers the highest increase in Shareholder value.
4. The control of system capacity refers to the LDC taking total responsibility for transformer station and distribution system capacity, such that LDC planning ensures that there is sufficient capacity at all times.
5. Operating flexibility refers to day to day system operation, for events such as placing hold-offs, storm response, detailed SCADA information, and maintenance coordination. HON stations are controlled from the Ontario Grid Control Centre (OGCC), and major events across the province are prioritized. A relatively small problem in Oakville's service territory may not receive prompt attention from the OGCC if there are larger system issues elsewhere.

6. LDC's that build their own transformer stations avoid the transformation tariff from HON, currently $1.62 / kw. This rate is predicted to rise to $1.83 / kw by 2010. This is a pass through cost via retail transmission charges, but does have an impact on the total end cost to local retail customers.

7. HON pool-funded stations require less up front capital from the LDC as opposed to the LDC building the station. Some capital contribution may be necessary depending on the total capital cost of the project and the value of the incremental load revenue over the 25 year economic horizon.

8. The design and construction of municipal transformer station requires dedicated and experienced resources. Many LDC's do not have internal expertise in stations, its staff may be fully engaged in other activities, or do not wish to take on the responsibility for a project of such magnitude.

9. We are not aware of any connecting customer that has built a transformer station according to HON specifications and turned the station back to HON at time of energization. We expect that although this may seem to be a lower cost alternative compared to HON building the station, HON would impose engineering and administration charges that would be subtracted from the purchase price. We also expect that there would be some growing pains with the development of this process, possibly resulting in delays and higher costs.

4.4 Proposed Alternatives for Additional Capacity

4.4.1 Halton Hills Hydro MTS #1 – TCE Site

MTS #1 is a proposed 125 MVA municipal transformer station, owned by HHH, located adjacent to the TCE site. This station is to be ready for service in the spring of 2014, prior to the summer peak load.

The station is configured as a typical Ontario Hydro "DESN" station, with two 50/66.7/83.3 MVA power transformers, with 28 kV secondary windings. Municipal utilities have been utilizing 36 kV class gas insulated switchgear (IEC rated), manufactured in Europe with special features to ensure compatibility with North American standards. This switchgear would be configured with eight (8) feeder breakers, and two breakers for power factor correction capacitors.

The fundamental advantage of this alternative is that the 230 kV transmission system has already been extended by TCE north of Highway 401 to the TCE site, and would be available to HHH at minimal cost. If HHH were to build a station north of Highway 401 on another site, a new 230 kV tap would have to be constructed at an estimated cost of over $20M (over and above the $21M cost of the station itself).

The total cost of the station, including metering, land, feeders, sales taxes, and 10% contingency, is budgeted at $21M (based on a preliminary budget).

This station would provide enough capacity to service all of the forecasted growth in the southern supply area for the next 30 years. It also provides a reserve of about 40MW of capacity for unforeseen load growth.

4.4.2 Hydro One "Halton 2 TS"

Halton 2 TS is a proposed HON-owned 170 MVA (153 MW) station, to be constructed on the Halton TS site in Milton. HON has made an offer to design and construct this station, to be ready for service in 2014. This station would provide new capacity for HHH and Milton Hydro.

This station is proposed to have twelve feeders; five dedicated to HHH, and seven for Milton Hydro. Each feeder is typically rated at 16 MW; therefore about 80 MW has been allocated to Halton Hills. This matches the present conservative load forecast for the southern supply area (but does not provide for unforeseen growth).

The total quoted cost of the project from Hydro One is approximately $26.5M, however the cost of certain features and components have been excluded from the budget. No costs have been allowed for feeders, revenue metering, property, or tie switches. We estimate an additional one to two million dollars of costs will be ultimately allocated by Hydro One, to be recovered from the two LDC's as part of the capital contribution (or as a direct cost if constructed by each LDC). This results in a total project cost of $27.5M - $28.5M. This compares directly in features and operating configuration with the HHH MTS #1 above, with a budget of $21M.

In addition, Halton Hills would have to route these new feeders through Milton Hydro's service territory, and across Highway 401. This area is presently congested with Halton TS feeders, and it is likely that the new feeders would have to be constructed underground, and pass underneath Highway 401. Preliminary estimates of costs to egress Milton and Hwy 401 are in the range of $2.5 – 4M depending on construction techniques.

Note that this alternative could only reasonably be considered by HHH if Milton Hydro commits to co-funding this project. Milton Hydro is exploring alternate sources of transmission supply in their southeast and southwest sides of their service territory, and there is no assurance that this option has any priority with them. This is a high risk issue for HHH.

4.4.3 Hydro One "Halton 2 – Half Station Alternative"

HON has also offered Milton Hydro and HHH a second pool-funded alterative which provides far less than the industry standard level of reliability and security. HON calls this the "half-DESN alterative". This design utilizes one incoming transmission circuit (instead of two), one power transformer (instead of two), and one incoming circuit breaker (instead of two). This design has no redundancy, and would expose HHH customers to numerous momentary outages for routine events such as lightning strikes. Commercial and industrial customers would likely accept not such an arrangement. This could also affect new customer's desire to locate in this area.

The capital contribution for this alternative reduces from about $6M to about $5M.

Hydro One presumably has offered this alternative in an attempt to provide a lower cost alternative. Unfortunately, the capital contribution has not lowered significantly. We had expected a larger reduction in capital contribution.

In any case, we would not support this configuration at any cost savings as the design inherently provides a lower level of security and reliability compared to industry standard DESN stations.

This design would cause the connected HHH customers to have a significantly less secure power source as compared to neighboring utilities.

4.4.4 Halton Hills Hydro MTS #1 – New Site

A fourth alternative for new capacity would be for HHH to build a new station somewhere in the Steeles Avenue area around Trafalgar Road. The Class Environmental Assessment performed by Senes Consultants in 2008 identified several sites that could potentially be used to site a new station.

The main disadvantage of this alternative is that HHH would have to extend the 230 kV transmission circuits from the transmission corridor south of Highway 401 to the Steeles Ave area. Although we have not done any costs estimates for this line connection, we understand that the TCE costs may have been in the order of $20M.

This alternative would result in a total project cost of about $36.5M, and therefore this alternative is considered to be unfeasible.

5. Economic Considerations

5.1 *Halton Hills Hydro MTS #1*

The budget for this station includes of the cost of the substation itself, plus the costs of connecting it to the adjacent TCE generating plant. The current budget for the 125 MVA station is \$16.5M, and the cost of modifications to the TCE switchyard and connections to HHH's station are in the range of \$4.5M. The preliminary total budget for this project is \$21M.

5.2 *Hydro One "Halton 2 TS" Alternative*

Since this station is to be shared with Milton Hydro, HHH has been assigned project cost responsibility in proportion to the number of assigned feeders. In HON's budget proposal, they have assigned 42.7% of the total project cost responsibility to HHH (\$12M). Considering the cost of feeder egress over/under Hwy 401 (est. \$2.5M), the total cost responsibility for HHH is \$14.5M.

Based on the revenue derived from new load (paid to HON through regulated transmission charges over the life of the station), HON estimates the need for a capital contribution of \$5.68M in order for Hydro One to recover all capital, maintenance, and operational costs associated with this project. We estimate that the capital contribution will be slightly higher (about \$6.3M) due to the inclusion of the additional \$1 - 2M of costs that Hydro One excluded from their preliminary proposal.

The \$14.5M cost responsibility for HHH is comprised of a capital contribution of about \$6.3M, feeder egress of \$2.5M, and a load revenue guarantee of \$5.7M (present value capital portion only).

HHH would be obligated to guarantee Hydro One load revenue for the next 25 years, regardless of the actual load on the station. Any shortfall in revenue due to the actual load being less than the 2009 forecast supplied to Hydro One would result in the requirement for additional payments to be made to Hydro One. In other words, HHH would have to make a guarantee to HON without any guarantee from the HHH ratepayers. All of the risk is borne by HHH – HON has no risk.

This is a major risk for HHH and its shareholder.

Finally, as mentioned earlier, this alternative can only be reasonably considered if Milton Hydro decides to support the project and commit to covering a major portion of the project costs. Milton Hydro has several alternatives for providing additional capacity to their service territory, and most of the new load growth in Milton is expected to be in their southern supply area. Halton TS is located in the northern part of their service territory. It is possible that Milton will not be interested in this project.

Milton Hydro will likely not be in a position to commit to new supply alternatives until 2011 or 2012 – well beyond the timeline for HHH to commit to purchasing the TCE land.

5.3 Avoided Transmission Charges

Another factor to be considered is the avoidance of transformation charges that are normally paid to Hydro One when they own the TS. LDC's collect retail transmission charges from their customers and effectively pay Hydro One at the wholesale transmission level. These are "pass-through" charges that impact the total cost of the LDC's customer bill. If HHH constructs a MTS, there would be a reduction in the wholesale transmission charges paid to Hydro One. At the current OEB approved rates, without escalation, a conservative estimate of the present value of 25 years of avoided charges is approximately $8.3M.

The Hydro One Transmission and Connection charge savings will not benefit the electricity customer immediately. The process for passing this savings on to the customer would involve applying to the OEB to refund the balance of these payments accumulated in regulatory liabilities on HHH's balance sheet through an adder to rates. Likely the OEB would approve the refund of these accumulated balances to customers over a number of years.

5.4 Comparison of Station Costs

	Item	Halton Hills Hydro MTS #1 (125 MVA)	Hydro One "Halton 2 TS" (170 MVA)
1	Total Cost of Project	$21M	$27.5 – 28.5M
2	Total allocated capital cost	$21M	$14.5M
3	Cost per MW	$0.187M	$0.181M
4	Cost per feeder	$2.631M	$2.9M
5	Allowance for contingency	$1.5M	$0.25M
6	Avoided transmission charges	$8.3M	$0

Table 2

EXHIBIT #3

Halton Hills Hydro

Typical Avoided Transformation Charges   July 20 2015

Summary of Sensitivity Analysis Cases
Based on 2010 Load Forecast

Case	Calculation Date	Initial Demand Cost/kW	Escalation Rate	Avoided Transformation Charges
1	2010	$ 1.62	0%	$8,321,942.87
2	2015	$ 2.00	0%	$10,274,003.54
3	2015	$ 2.00	1%	$12,075,006.07
4	2015	$ 2.00	2%	$13,569,650.92

EXHIBIT 4

Particular attention should be directed to the areas with the highest value conservation potential, namely for reducing peak demand in the service areas supplied by Pleasant TS and, in the longer term, by Kleinburg TS.

Details on each LDC's conservation plan are provided in Appendix D.

7.2.2 Two Station Solution: Halton Hills Hydro MTS and Halton TS #2

Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

The Working Group recommends the transmitter, Hydro One, should initiate technical and engineering work for the development of Halton TS #2, at the site of the existing Halton TS, with a tentative in-service date of 2020. Based on the current load forecast and a typical three-year lead time from initiation of approvals to in-service date, construction of Halton TS #2 is not yet required. The Working Group recommends that actual load growth be monitored on an annual basis before a RIP is initiated.

7.2.3 Reinforcement of H29/30

The Working Group recommends the transmitter, Hydro One, should proceed with the preliminary work required to validate the technical, feasibility and cost for the replacement of conductors on the H29/30 circuits to a summer LTE planning rating of 1400 A. It is recommended that this measure be implemented before peak loads at Pleasant TS exceed approximately 417 MW. Based on the current load forecast, this may occur as soon as 2023 under the Higher Growth scenario. The Working Group recommends that actual load growth be reviewed annually and this issue be reassessed during the next iteration of the regional planning cycle.

7.2.4 Restoration Needs

Four pockets in the study area are at risk for not meeting ORTAC restoration criteria. The ongoing bulk system study will consider solutions to address these needs at three of the four pockets. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process. The fourth pocket,

Table 7-4: Implementation of Near-Term Plan for Northwest GTA

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and distributed generation	Develop CDM plans	LDCs	May 2015
	LDC CDM programs implemented	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification of programs, including peak-demand impacts and provide results to Working Group	LDCs	Annually
	Continue to support provincial distributed generation programs	LDCs/IESO	Ongoing
2. Develop new step-down station in Halton Hills	Design, develop and construct new step-down station in southern Halton Hills, at the Halton Hills GS site	Halton Hills Hydro	In-service spring 2018
3. Develop new step-down station in Milton	Design, develop and construct new step-down station in Milton at the existing Halton TS site	Hydro One	In-service spring 2020 (estimated)
4. Upgrade H29/30 conductors	Upgrade H29/30 circuits to higher rated conductors	Hydro One	2023-2026 (estimated)

Halton Hills
HYDRO

To: The Board of Directors of Halton Hills Hydro Inc.

Date: April 11, 2017

From: Arthur A. Skidmore CPA, CMA

Subject: Transformer Station Update

Board Members:

The Transformer Station project has been very busy in the first quarter of 2017:

- Site Plan Application filed with the Town of Halton Hills March 22, 2017;
- Phase 1 Construction Tender awarded to K-Line. Pre-Construction meeting held at TCE switchyard. Work scheduled for April 17-20 and scope includes installation of pre-cast footings/piers for 230 kV HV disconnect switches;
- HHH/TCE Project Development Agreement completed and signed in advance of Phase 1 construction start;
- Meeting between Veridian and HHH held and facilitated by Costello Associates to explore possible collaboration between two concurrent MTS projects. First initiative was with Transformer Tenders - sent out simultaneously with request to add discount if utilities award to the same vendor;
- Power Transformer Tender responses received March 27 - Siemens, PTI Manitoba, ABB, Hyundai (See Budget);
- 230 kV HV Breaker specification completed and tender being prepared;
- 230 kV Disconnect Switch Tender responses received March 28 from two vendors;
- Conference call with IESO to follow up on SIA. Due to the staged construction in TCE switchyard and the fact that disconnects will be connected to the transmission system in the fall of 2017, equipment registration is required as soon as possible;
- Hydro One is currently undertaking the CIA process and determining whether or not the COVER process needs to be broken up into stages;
- IESO metering conference call took place. No major issues with metering arrangements proposed;
- Weekly construction conference calls being held with TCE and HHH/Costello.

Final Budget

	2017 Budget Final	2016 +/- 25% Budget	Original 2007
2007-2015 Actual Costs	$428,700	$428,700	$428,700
Land Purchase Actual Costs	$987,000	$987,000	$987,000
TCE Fees	$360,000	$318,000	Not Estimated
Design & Administration	$1,361,826	$1,104,000	$715,000
Construction	$8,200,000	$8,100,100	$7,252,000
2 Power Transformers Tendered Cost	$3,415,000	$4,900,000	$3,400,000
Switchgear	$2,000,000	$1,900,000	$2,110,000
Protection & Control	$2,466,000	$1,400,000	$802,400
Testing & Commissioning	$700,000	$800,000	$150,000
Connection to TCE	$4,300,000	$3,500,000	$2,670,000
Feeder Egress	$700,000	$700,000	$320,000
Approvals	$350,000	$300,000	$150,000
Total Project Cost	**$25,268,526**	**$24,437,800**	**$18,985,100**

Board Approvals Required:

Purchase Category	Comments	2017 Costs	Total Costs
Power Transformers	Contract to be awarded in May. 2017 costs anticipated to be 30% of total purchase price. Costs based on lowest bid received.	$1,024,500	$3,415,000
Switchgear	Tenders to be issued in May. 12 month lead time. Estimated Costs.	$400,000	$2,000,000
Construction General Contract	Tenders to be issued in May. Contract to be awarded by end of June to have contractor ready to begin work in July in preparation for September construction. Estimated costs included all civil, electrical and construction within TCE's switchyard.	$1,167,500	$13,335,000
Total Estimated 2017 costs.		$2,592,000	