NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

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

ieso
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:

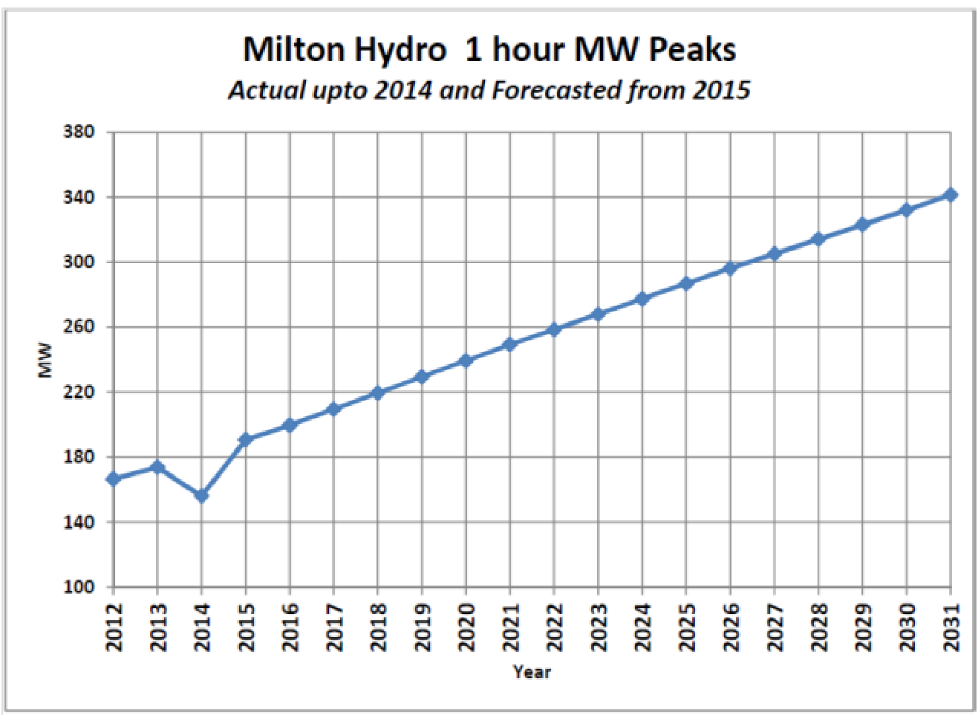
Owner	TS	Feeders
Hydro One	Halton TS	9
Hydro One	Palermo TS	2
Hydro One	Tremaine TS	2
Hydro One	Fergus TS	1
Oakville Hydro	Glenorchy MTS	2

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.

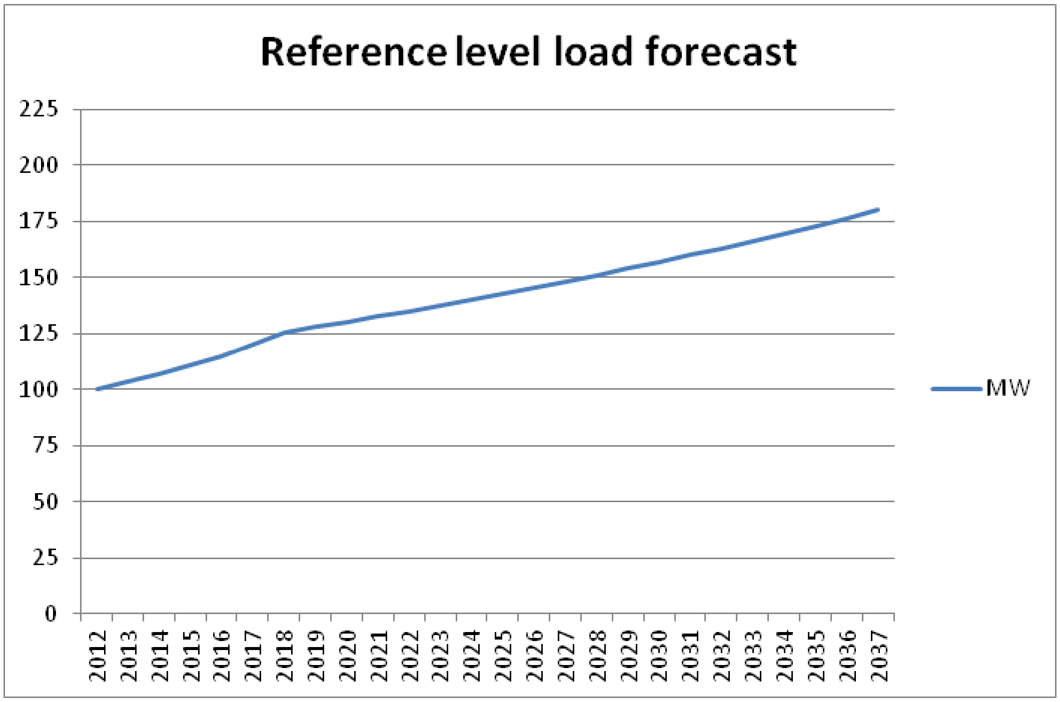
Methodology for Adding New Distribution Stations

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

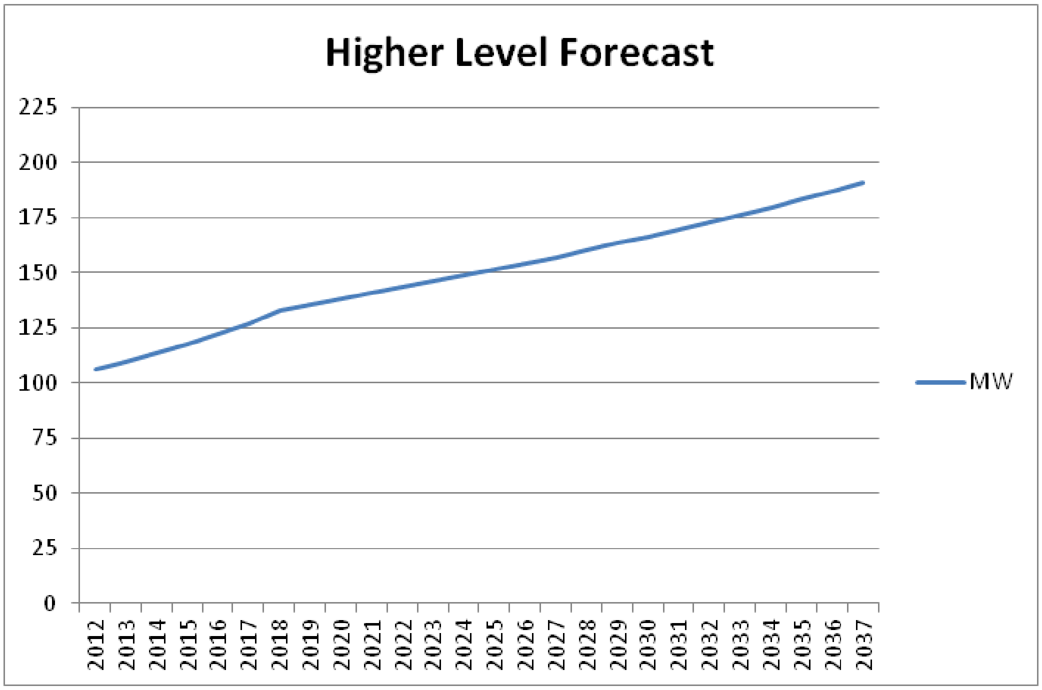
Reference load level below represents combined load of Kleinburg TS and Pleasant TS as they supply Caledon area for HONI Dx.



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

West GTA IRRP

Appendix B: Needs Assessment

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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

<table>
<tr><th colspan="2">Pre-contingency</th><th>Contingency[1]</th><th>Thermal Rating</th><th>Maximum Permissible Load Curtailment and Load Rejection</th></tr>
<tr><td rowspan="6">All transmission elements in-service</td><td rowspan="3">Local generation in-service</td><td>N-0</td><td>Continuous</td><td>None</td></tr>
<tr><td>N-1</td><td>LTE</td><td>None</td></tr>
<tr><td>N-2</td><td>LTE[2]</td><td>150 MW</td></tr>
<tr><td rowspan="3">Local generation out-of-service</td><td>N-0</td><td>Continuous</td><td>None</td></tr>
<tr><td>N-1</td><td>LTE</td><td>150 MW[3]</td></tr>
<tr><td>N-2</td><td>LTE[2]</td><td>>150 MW[3]
(600 MW total)</td></tr>
</table>

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.

West GTA IRRP

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:	

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.

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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

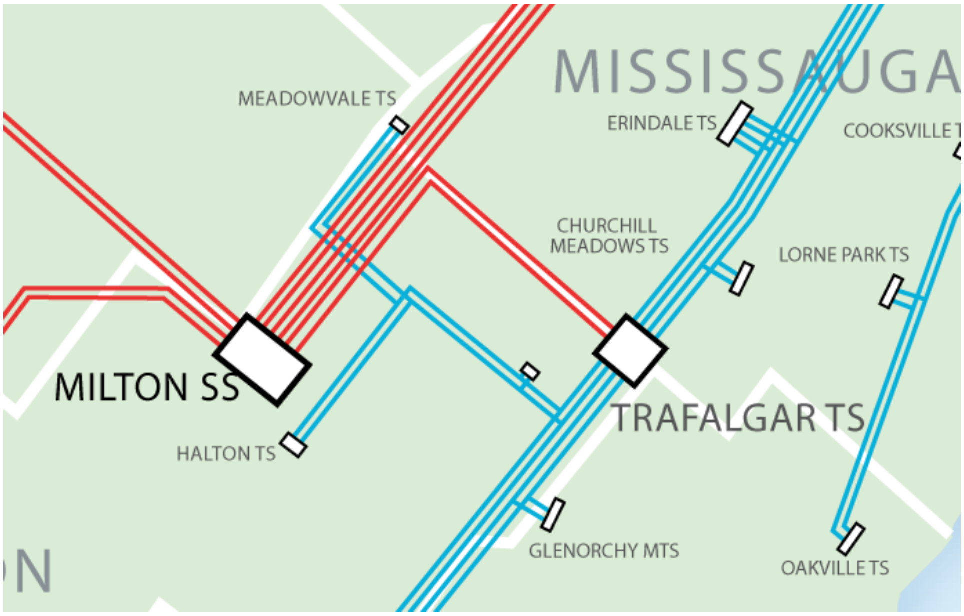
Facility	Limiting asset	LDC	Need Date – Expected Growth	Need Date – Higher Growth
Halton 27.6 TS	27.6 kV feeders	Halton Hills Hydro	2018	2018
	230/27.6 kV transformers	Milton Hydro	2020	2019
Halton radial pocket	Transmission Lines T38/39B (supply to Halton TS, Meadowvale TS, Trafalgar DESN, Tremaine 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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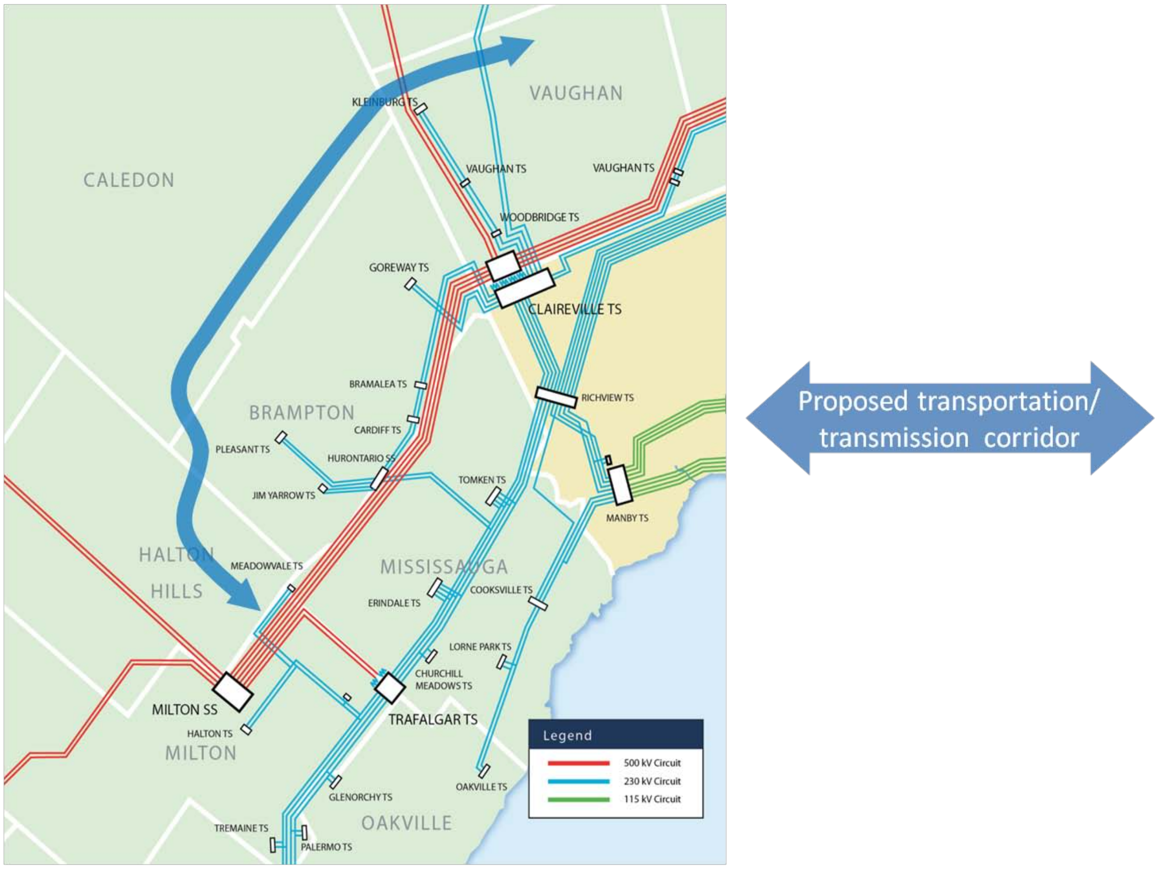
Figure 1: Approximate GTA West transportation corridor route, and existing electrical infrastructure



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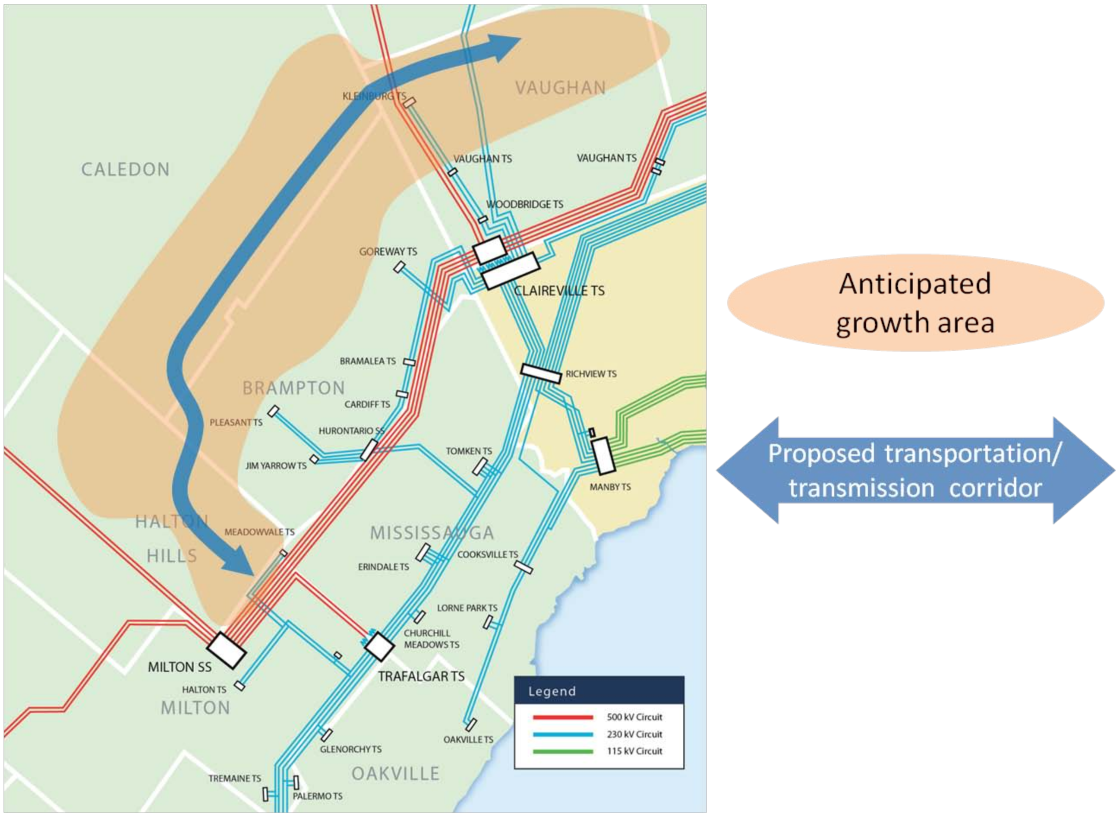
Figure 2: Approximate GTA West transportation corridor route, and greenfield growth areas



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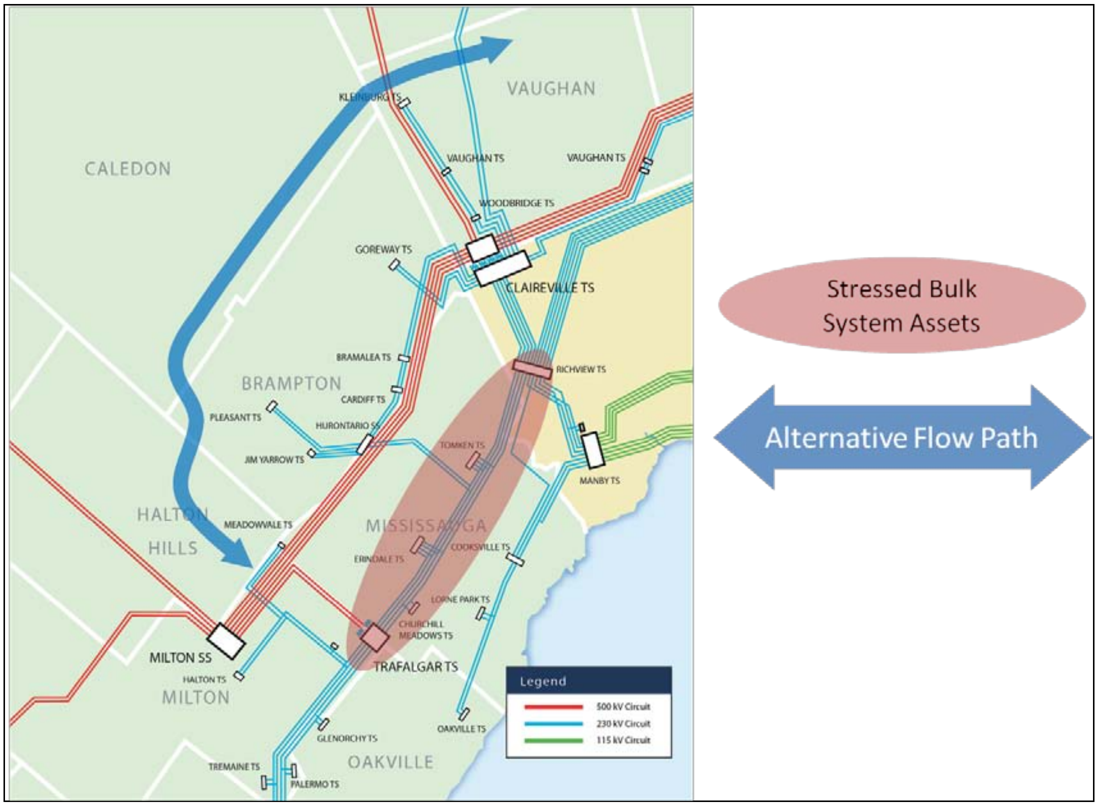
Figure 3: Approximate GTA West transportation corridor route, and stressed bulk facilities



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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