EB-2012-0064

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B; and in particular section 78 thereof;

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited ("THESL") for an Order or Orders approving a change to its rates for 2012-2014.

ENVIRONMENTAL DEFENCE

CROSS-EXAMINATION REFERENCE BOOK (THESL 2012-2014 Rates)

February 15, 2013

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[1] http://www.cleanairalliance.org/files/brenmer.pdf

[2] http://www.cleanairalliance.org/files/active/0/Letter%20to%20Councillor%20PaulaFletcher.pdf

[3] "Powering Toronto's Electricity Future," Remarks by Colin Andersen, CEO, Ontario Power Authority, to the Toronto Board of Trade, October 25, 2012 <http://www.powerauthority.on.ca/sites/default/ files/news/Andersen-Board-of-TradeOct-25-2012.pdf>.

[4] Referred to in H.R. (Bob) Bach, P.Eng., *Toronto Hydro-Electric System Conservation and Demand Management in Downtown Toronto*, prepared for Environmental Defence, December 7, 2012, pg. 11.

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Note: Tabs 11, 12, 18, 20, and 22 to 25 contain excerpts of the relevant materials. Complete versions are available in the relevant Board file.

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[5] http://www.cleanairalliance.org/files/active/0/Mayor%20Miller%20to%20Energy%20&%20Infrastructure %20Minister%20Duguid,%2010.02.18.pdf

Electricity Infrastructure and Economic Development in Toronto

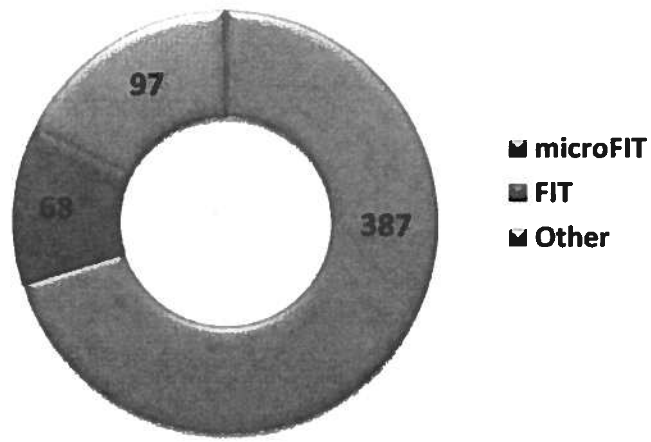
City of Toronto
Economic Development Committee

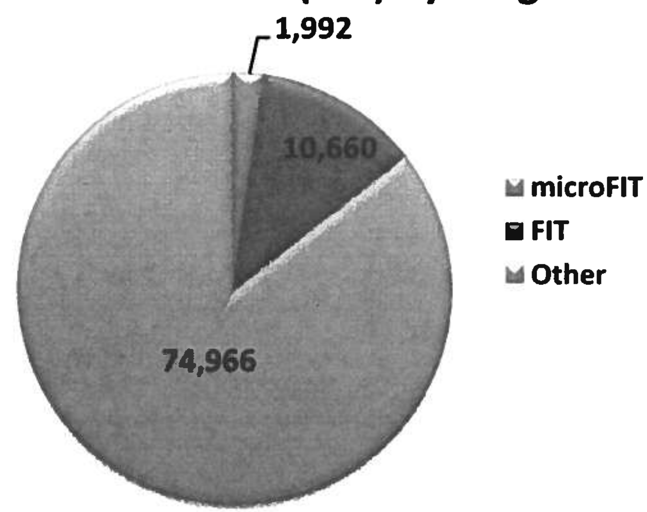
October 16, 2012

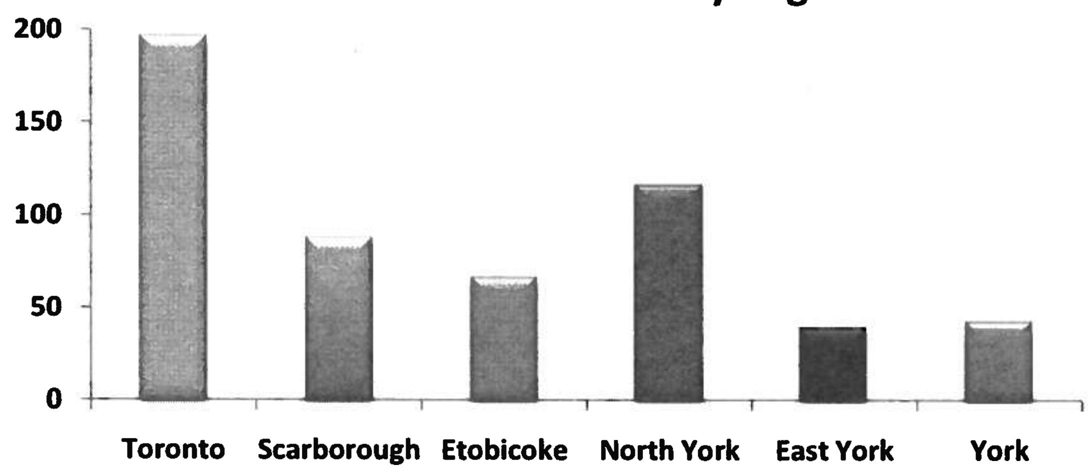
Anthony Haines
President & CEO
Toronto Hydro Corporation

TORONTO HYDRO

Grid Management
Distributed Generation in Toronto







- Total Number of Projects = 552
- Total Connected DG = 87.6 MW

Legend
- microFIT: ≤10 KW
- FIT: >10 kW ≤ 10 MW
- Other: Gas co-gen, diesel back-up systems, and fuel cell

TORONTO HYDRO

Toronto Hydro-Electric System Limited
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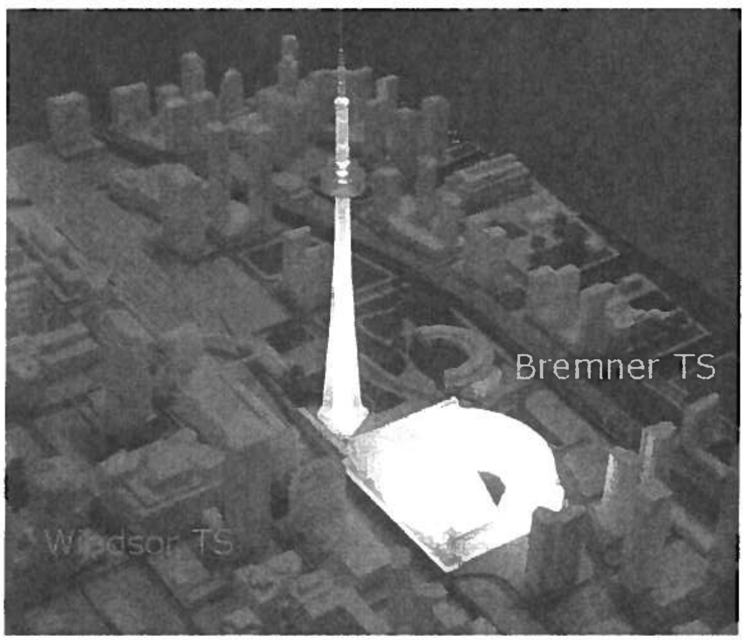
Tab 4
Schedule B17
Appendix 2
Filed: 2012 May 10
Updated: 2012 Oct 31
(14 pages)

Appendix 2: Load Growth

In Downtown Toronto Area

Figure 1 Downtown Core (photo courtesy Myles Burke Architectural Models)



Contents

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1. Introduction:

1.1 Purpose[1]

This appendix further discusses load growth of Toronto downtown transformer stations based upon stated assumptions and THESL methodology. The primary purpose of this appendix is to demonstrate the load growth in proximity of the Bremner Transformer Station by examining forecasts, historical data and proposed customer connections in the Toronto downtown area circumscribed by the service areas of the five downtown transformer stations.

Two important components of the THESL load forecast are the natural load growth and the new customer connection requests. In this document, THESL validates the assumptions associated with calculation of natural load growth in the downtown Toronto core (2% growth per year). THESL also examines the magnitude of actual customer connection requests and future developments in the City of Toronto.

Table 1 Load Forecasts (MVA) by Station

Station	Station Rating	Year															
		2011[2]	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Cecil	224	187	183	186	190	195	199	202	207	211	215	220	225	228	234	238	244
Esplanade	198	180	180	184	189	188	191	194	200	203	207	210	216	220	225	229	232
Strachan	175	138	138	143	150	153	157	160	164	166	170	174	176	179	183	187	192
Terauley*	240	190	193	196	201	205	209	213	217	222	226	230	234	240	244	250	254
Windsor	340	311	310	316	322	329	335	340	348	355	363	371	378	385	392	399	407
Total	1177	1006	1004	1025	1052	1070	1091	1109	1136	1157	1181	1205	1229	1252	1278	1303	1329

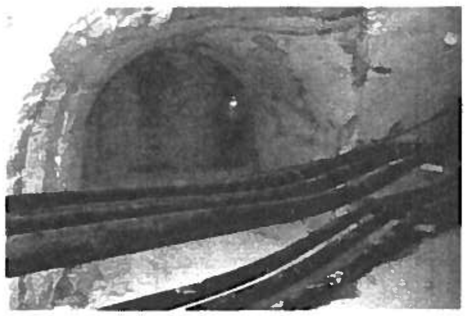
[1] This document is not replacement for official THESL stations load forecast which includes all THSEL's Stations

[2] In May's ICM submission, the 2011 to 2017 load data had been issued as a forecasted number (based on the 2011 load forecast). With this update, the 2011 load data has been updated to show the actual, historic data for that year. The 2012 to 2017 load data are forecasted numbers (based on the 2012 load forecast).

1.2 Background

THESL distributes electricity to its customers in downtown corridor via 13.8kV feeders from the 115kV/13.8kV substations. This appendix does not focus on transmission planning issues directly nor does it reflect transmission capacity limitations. However, it is worth noting that the new Bremner TS has for many years been included in HONI plan to meet the future load growth of the Toronto downtown area. For example, Figure 2 below indicates a 'break out' at HONI's existing Front Street tunnel, installed in 2007 with the intention of connecting said tunnel to Bremner TS.

Figure 2 Existing break out at HONI transmission tunnel for Bremner TS tunnel



The resolution of the transmission capacity issue of downtown Toronto is considered in ongoing cooperative planning between THESL and HONI.

2. Load Growth methodology

2.1 Forecasting Process

As the purpose of the forecast is to assess station bus capacity adequacy, the summer and winter maximum peak demands are forecast, rather than monthly peak demands.

The process for calculating peak demands follows three steps:

a) Historical summer/winter peak demand for a bus is weather corrected,

b) New loads are added to the weather- corrected demands according to the build-up formula, and

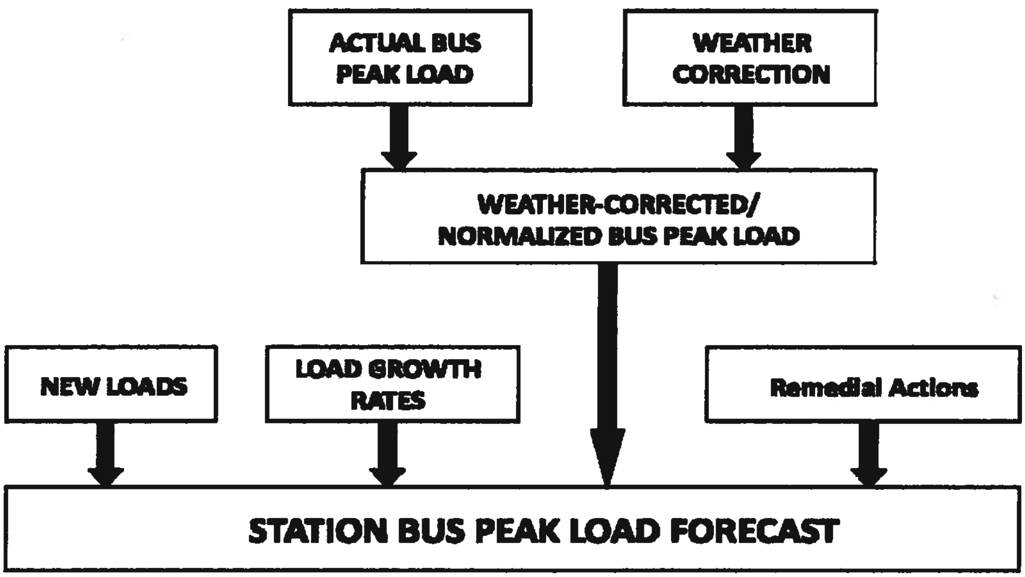
c) Growth rates are applied to obtain annual peak demand forecasts for the Study period. The natural growth rate for the first two years of the study period is assumed to be zero. The forecast increase in demand is exclusively driven by new customer connections.

When projected load for a station bus exceeds the bus capacity during the first five years of the study period, remedial action is proposed and then the forecast is repeated to include the remedial action.

The following alternatives are considered, in order of preference, to remedy the bus/station capacity shortfall:

1. Load transfer to another bus or station;
2. Upgrade of station bus capacity;
3. Upgrade of station transformer capacity;
4. Station expansion, i.e. new bus;
5. New station.

Figure 3 Forecasting Methodology Schematics



2.2 Model

2.2.1 Weather Sensitivity

THESL normalizes downtown station bus peak demands to a mean daily temperature of 27°C for the summer forecast. The summer forecast is the most restrictive. This temperature is the average of the recorded mean daily temperature of the days that the buses reached highest peak demand over the period of 1998 to 2008.

A linear regression model is used to calculate bus weather sensitivity (b) and the intercept parameter (a) from historical daily peak load (Y) and daily mean temperature (X) observations. The mathematical equation is:

$$Y = bx + a$$

Where,

Y = the daily peak load (MVA)

b = the slope of the trend line (MVA/°C),

X = the daily mean temperature (°C), and

a = the y-axis intercept (MVA).

The daily station bus peak demand data is obtained from station revenue metering. Daily mean temperature data is obtained from Environment Canada's Monthly Meteorological Summary Report. Since extreme temperature-load behaviour is of interest, only data for the summer and winter months are used for the regression model. Data for the months of June, July and August are used for the calculation of bus summer-season sensitivity. Data for the months of December, January and February are used for bus winter-season sensitivity. Weekends and holidays are excluded from model data as they differ dramatically from the weekday loads

If 'N' is the number of Y-X readings, then the value of 'b', bus weather sensitivity(MVA/ C°) can be found by using the Method of Least Squares, as follows:

$$b = \frac{N \times \left\{ \sum_{i}^{N} (X_i Y_i) \right\} \left(\sum_{i}^{N} (X_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (X_i^2) \right\} - \left(\sum_{i}^{N} (X_i) \right)^2}$$

Using spreadsheet programs, bus weather sensitivity calculations and normalization of starting bus peak demands are performed.

2.2.2 Peak Demand Growth Rate

To determine demand growth rate, five year actual peak load data for the five downtown transformer stations was studied. Load growth rates are determined using a Time-Trend model. The relationship between x and y in the Time-Trend model is exponential, taking the form y = ab^{x}. After taking natural logarithms of the equation it becomes:

$$\mathrm{In}\, y = \mathrm{In}\, a + x\, \mathrm{In} b$$

Where 'In a' and 'In b' represent the constants in the equation. 'In y' and 'x' now have a linear relationship and the Least Squares method can be applied. The equation can be simplified as:

$$Y = A + Bx$$

Where,

A = 'In a' as described before,

B = 'In b' which is the slope of the trend line,

x = time (i.e.; 2007, 2008, 2009, ...)

Y = the natural logarithm of bus summer/winter peak load (MVA).

The annual peak load data is obtained from station revenue metering. As with the weather sensitivity model in section 2.2.1, the extreme temperature-load behaviour of the Time-Trend model is of interest. Data for the months June, July and August were used for calculation of the summer peak load, and data for the months of December, January and February are used for bus winter peak load. If 'N' is the number of data, then the value of 'B', which is the slope of the line, can be found by using the Method of Least Squares. The following equation is used to compute the slope 'B'.

$$B = \frac{N \times \left\{ \sum_{i}^{N} (x_i Y_i) \right\} - \left(\sum_{i}^{N} (x_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (x_i)^2 \right\} - \left(\sum_{i}^{N} (x_i) \right)^2}$$

Table 2: 5 Year Historical load data

x_i	2007	2008	2009	2010	2011[2]
Cecil	169	164	176	181	187
Strachan	118	104	119	117	138
Windsor	284	277	295	303	311
Terauley	194	194	188	185	190
Esplanade	168	164	169	176	180
Sum (MVA)	**933**	**903**	**947**	**962**	**1006**
Y_i **: ln (load)**	**6.84**	**6.81**	**6.85**	**6.87**	**6.91**

The value for *B* was established using the actual five year peak load.

$$B = \frac{N \times \{\sum_{2007}^{5} x_i Y_i\} - (\sum_{2007}^{5}(x_i))(\sum_{2007}^{5}(Y_i))}{N \times \{\sum_{2007}^{5}(x_i)^2\} - (\sum_{2007}^{5} x_i)^2} = 0.0214$$

The original exponential model $y=ab^x$ can be re-written as $y=a(1+g)^x$, where g is the annual growth rate. Thus, the bus percentage growth rate '**g**' is calculated using equation:

$$g = (e^{B} - 1) \times 100\ \%$$

The growth rate for the past five years based upon a *B* of 0.0214 was determined.

$$g = 2.16\%$$

2.2.3 Assumptions

2.2.3.1 New Customer Connections Load Build-up

New customer load is included in the forecast only for known projects for which THESL has been approached for service connections.

---

[2] Actual data as of April 2012.

The following load build-up guidelines are used in absence of customer load build-up:

Table 3 Load Build Up

Proposed Load	% Load Build Up		
	Year 1	Year 2	Year 3
Up to 0.5 MVA	100%		
0.6 MVA to 2 MVA	70%	30%	
Over 2 MVA	60%	20%	20%

Based upon past experience, not all projects materialize and those that do materialize usually overestimate their peak demand. Therefore prospective new customer peak demand estimates are reduced by 50% to achieve a more realistic peak demand estimate. Section 2.3.3 shows a subset of new customer requests received by THESL.

2.2.3.2 Load Growth Rate for New Loads

For new customer loads, a zero percent growth rate is used for the first two years of the forecast period.

2.2.3.3 Conservation and Demand Management (CDM)

The Ontario Power Authority and THESL have both developed and implemented complementary projects over the past few years. The major program portfolios are:

1. Conservation
2. Demand Response
3. Distributed Energy

In the shorter term, where committed projects are known, the potential impact of the project is taken into account in the forecasts. Committed generation projects are easier to quantify, as their location and size are clear and potential contributions could be estimated from signed agreements. At this time, THESL takes into consideration new committed generation projects that are over 10MW in size when performing the forecast. Once the unit is in service, in the absence of physical assurance of operation, the actual impact on the bus load is reflected in the actual historical bus load data and therefore it is accounted for in the forecast. Where CDM projects are installed and commissioned, the actual impact on bus load is reflected in the actual historical bus load data, and therefore accounted for in the forecasts.

2.3 Anticipated Growth

For the first three years of forecast period new loads are added only when THESL has direct knowledge of new customer connections by means of requests. This mechanism enables THESL to forecast the immediate need of distribution system while forecasting long term growth using a calculated load growth rate.

Downtown Toronto is a focal point of development, growth and urbanization. Toronto has recently experienced a surge of both residential and non-residential growth with construction cranes maintaining a constant presence on the City's skyline. As result, increases in electrical demand will be experienced by THESL in the near future.

2.3.1 City of Toronto Vision

Toronto's Official Plan, which came into force in June 2006, is a road map for how the city will develop over the next 20 years. Most of the new developments will take place in target areas such as the downtown Toronto area. As result of the Official Plan, Toronto's development industry is strong and continually invests in new projects in the City. In the 4½ years after Official Plan came into force, 1,696 development projects, with 106,848 residential units and over 4.23 million m^2 of non-residential gross floor area ("GFA") proposed, have been submitted to the City Planning Division for approval.

Figure 4: Downtown and Central Waterfront development Activity

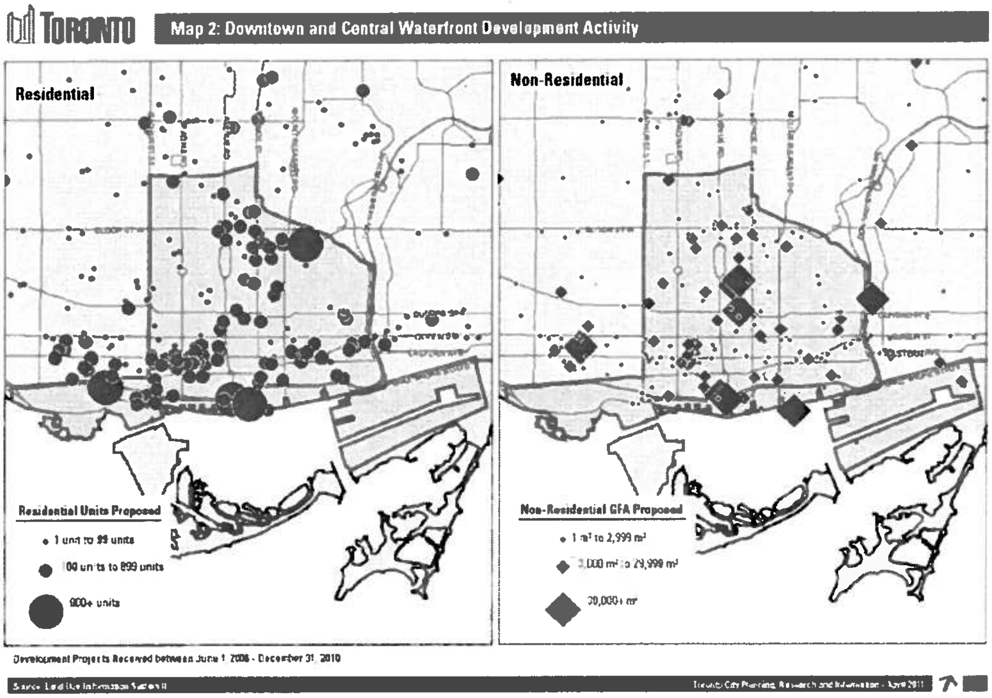


Figure 5: Proposed Development in City of Toronto

Table 3: Proposed Development in City of Toronto

Applications Received between June 1, 2006 and December 31, 2010

	Number of Projects	% of Projects	Proposed Residential Units	% of Proposed Res Units	Proposed Non-Residential GFA (m²)	% of Prop. Non-Res GFA
City of Toronto	1,696		106,848		4,231,517	
Growth Areas						
Downtown and Central Waterfront	204	12.0%	34,533	32.3%	977,153	23.1%
Centres	55	3.2%	11,298	10.6%	225,838	5.3%
Etobicoke Centre	*12*	*21.8%*	*2,333*	*20.6%*	*46,641*	*20.7%*
North York Centre	*26*	*47.3%*	*4,113*	*36.4%*	*81,269*	*36.0%*
Scarborough Centre	*9*	*16.4%*	*3,684*	*32.6%*	*49,798*	*22.1%*
Yonge/Eglinton Centre	*8*	*14.5%*	*1,168*	*10.3%*	*48,130*	*21.3%*
Avenues	246	14.5%	29,463	27.6%	661,934	15.6%
Other Mixed Use Areas	104	6.1%	10,240	9.6%	134,963	3.2%
All Other Areas	1,087	64.1%	21,314	19.9%	2,231,628	52.7%
Stage of Development						
Projects Submitted (not approved)	490	28.9%	53,219	49.8%	1,347,671	31.8%
Projects Approved (no permits issued)	472	27.8%	36,790	34.4%	1,472,440	34.8%
Projects with Permits Issued	734	43.3%	16,839	15.8%	1,411,406	33.4%

Source: City of Toronto, City Planning: Land Use Information System

The Downtown and Central Waterfront area are two of the driving forces of development in the City of Toronto. Over 34,500 units and 977,000 m² of non-residential GFA were proposed in the area between June 2006 and December 2010. This is almost one- third of the residential units and one- quarter of the non-residential GFA proposed in the entire city. Figure 4 shows the distribution of residential units and non-residential GFA throughout the Downtown. Despite these large magnitudes of development, anticipated load for these projects is not included in the forecast due to unknown construction and occupancy timeline as well as absence of customer connection for proposed projects.

2.3.2 New Building Permit Applications and Zoning Applications

A large number of building permit applications and zoning applications for significant developments have been submitted to the City of Toronto. Since these projects are in early stages of development, new customer connection requests have not yet been submitted to THESL and therefore, additional demands for such projects are not included in the forecast. A number of large proposed developments in the proximity of Windsor TS and Bremner TS are summarized in Table 4. Although there is not any accurate information on load requirements of proposed projects, conservative estimates were made based on gross floor area (GFA) to quantify impact of the developments on the THESL distribution system.

Table 4: Selected New Building Permit and zoning applications

Address	Add. Load (kVA)	Address	Add. load (kVA)
<confidential customer information>	3,326	<confidential customer information>	976
<confidential customer information>	3,226	<confidential customer information>	681
<confidential customer information>	2,799	<confidential customer information>	754
<confidential customer information>	2,486	<confidential customer information>	TBD
<confidential customer information>	2,386	<confidential customer information>	TBD
<confidential customer information>	2,278	<confidential customer information>	TBD
<confidential customer information>	1,386	<confidential customer information>	TBD
<confidential customer information>	1,210	<confidential customer information>	TBD
<confidential customer information>	1,182	<confidential customer information>	TBD
<confidential customer information>	1,147	<confidential customer information>	TBD
<confidential customer information>	1,020	<confidential customer information>	TBD
<confidential customer information>	988	<confidential customer information>	TBD

If GFA is unavailable, additional load is denoted by 'TBD'

2.3.3 New Customer Connections

Toronto Hydro has received customer connection requests for 65.9 MVA of additional loads for both existing building and new buildings in the proximity of the future Bremner station and existing Windsor station. The geographical location of the requests is shown in Table 5. As mentioned earlier, customer connection requests have been accounted for in the load forecast using applicable assumptions.

Table 5: Customer Connection Requests in Proximity of Future Bremner TS

Request Date	Customer Name	Customer Address	Additional Load (KVA)
May 17, 2010	<confidential>	<confidential>	14500
August 2, 2012	<confidential>	<confidential>	10000
June 12, 2011	<confidential>	<confidential>	8000
July 11, 2011	<confidential>	<confidential>	5241
November 1, 2012	<confidential>	<confidential>	4600
September 26, 2011	<confidential>	<confidential>	3792
October 16, 2008	<confidential>	<confidential>	3500
April 4, 2011	<confidential>	<confidential>	2800
May 16, 2011	<confidential>	<confidential>	1801
January 30, 2012	<confidential>	<confidential>	1487
July 3, 2012	<confidential>	<confidential>	1250
February 26, 2010	<confidential>	<confidential>	1200
July 11, 2011	<confidential>	<confidential>	1500
March 16, 2012	<confidential>	<confidential>	1049
July 11, 2011	<confidential>	<confidential>	1209
February 11, 2011	<confidential>	<confidential>	750
February 3, 2012	<confidential>	<confidential>	750
Various	Incremental requests	Various (not mapped)	2470

Energization dates may vary depending on infrastructure (Service dates 2011 to 2014)

Figure 6 Downtown Toronto Load Growth

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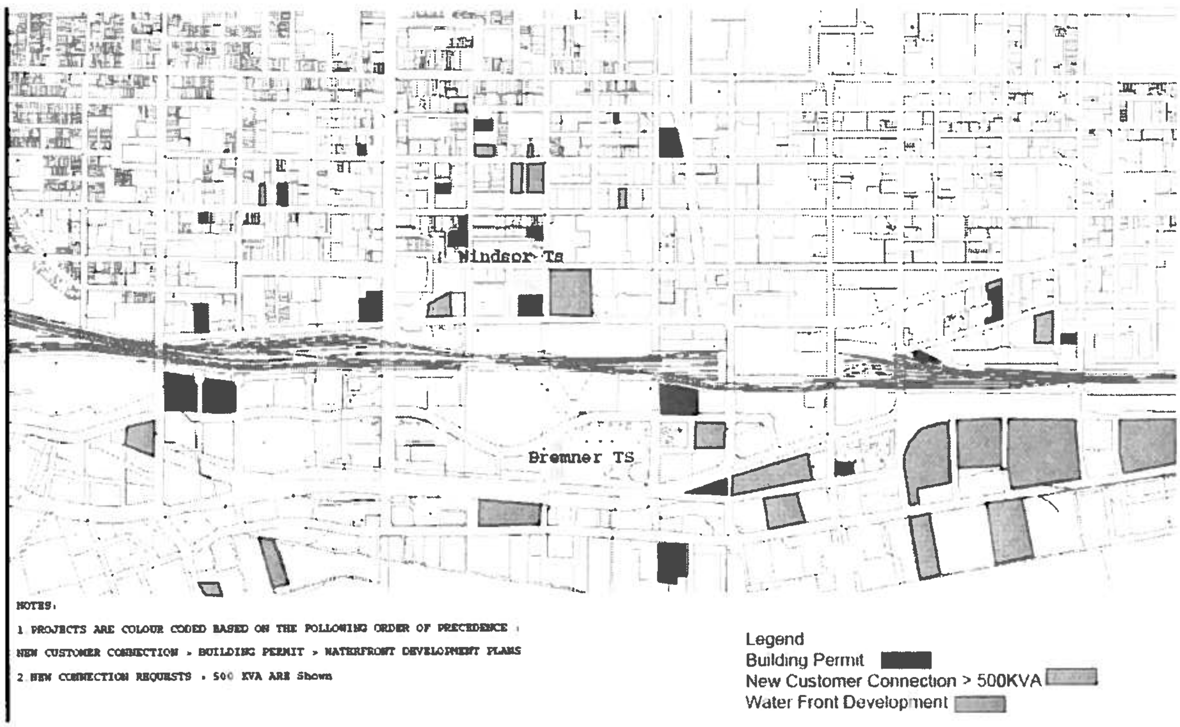
Figure 6 Downtown Toronto Load Growth



3. Summary

The natural load growth in the downtown core has been set at 2% since 2009 for the purposes of the load forecast. In previous sections, THESL has shown that load growth over the last 5 years is 2.16%, validating the load growth assumptions.

It should be noted that over the last 4 years, THESL has experienced an elevated growth rate of approximately 3.5% in the downtown core as a result of the local construction boom. This growth is consistent with the City of Toronto Official Plan and THESL customer connection requests.

Therefore, the 2% natural growth assumptions used in THESL midterm load forecasts to 2030 can be characterized as conservative.

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 4
Schedule B17, Appendix 3
ORIGINAL (40 pages)

NAVIGANT
CONSULTING

TORONTO HYDRO

Business Case Analysis

Downtown Toronto-Electric Supply Evaluation

Prepared for:

Toronto Hydro Electric System, Limited

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April 2012

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Overview

Background and Scope

New station capacity is needed to provide greater operating flexibility, improve reliability, and meet growing electric demand in downtown Toronto. Reliability of supply in downtown is critical, as this area includes major office complexes and the Toronto Stock Exchange. The existing Windsor station that serves downtown Toronto was originally constructed in 1950, and cannot be expanded to accommodate new transformation capacity. Further, the Windsor station requires refurbishment, and new station capacity or back-up ties are needed to enable Toronto Hydro-Electric System Limited (THESL) to install these upgrades without compromising station reliability.

Navigant Consulting Inc. (NCI) was engaged by THESL to investigate solutions to meeting the long-term electrical demand for downtown Toronto. It includes an independent assessment of station supply options to reliably serve downtown electrical demand. Among the options considered, NCI investigated the benefits of expanding existing stations in downtown Toronto. It also includes an evaluation of a new station located on a site adjacent to the Roundhouse Railway yard, otherwise known as the Bremner Transformer Station (TS). Our assessment addresses risk and need, including the potential for conservation and demand management (CDM) to defer the need for new station capacity.

Methodology

The approach NCI employed to evaluate supply options includes a technical and economic evaluation of alternatives. It includes a projection of need dates for station capacity, a risk assessment of existing facilities, and reliability analysis. Both demand and supply-side options are examined, and alternatives are compared using present value economic analysis.

Most of the technical data, cost and economic assumptions in our study are based on prior studies conducted by THESL. NCI independently reviewed these assumptions for reasonableness, and introduced new data and analyses where none existed or was insufficient to develop findings and recommendations. The analysis includes an independent risk assessment based on current industry practices and reliability criteria.

From our evaluation, we recommend a course of action to ensure reliability of electricity supply is maintained to critical downtown Toronto businesses and other retail customers. Our analysis examines need from a station supply perspective, but does not offer recommendations with regard to the Hydro One Network Incorporated transmission system, or regional power supply.

NAVIGANT
CONSULTING

System Adequacy and Risk Assessment

The following describes NCI's assessment of need for expansion and reinforcement of electric supply stations serving downtown Toronto. The analysis examines demand and supply options for meeting long-term station capacity and reliability requirements, and includes a risk assessment of applicable alternatives.

Statement of Need

The City of Toronto is the fifth largest metropolitan area in terms of population in North America. The load density and type of load served suggest continuity of service to downtown electric load cannot be compromised: it includes Toronto's financial district, large office complexes, numerous high rises, and major tourist destinations. The economic impact of a major disruption of electric service is underscored by recent outages in New York City, Western United States and central U.S. and southern Canada in 2003. The economic impact of the 2003 Midwest event alone is estimated at $50 billion (U.S. dollars). Accordingly, reliability of electric supply to the City of Toronto and downtown is essential to the economic health of the region.

Total electric demand in downtown Toronto is approximately 2000 MW. Approximately 350 MW of this load is served by highly reliable, complex electrical distribution supply systems configured in a network or grid arrangement. Currently, five stations serve approximately 1000 MW of the downtown Toronto load, including those that serve secondary network grids. One of the oldest stations, Windsor TS, was constructed in 1950 and serves critical high density loads including the financial district, 9 of the 10 tallest buildings in Toronto, medical centers, and several government buildings.

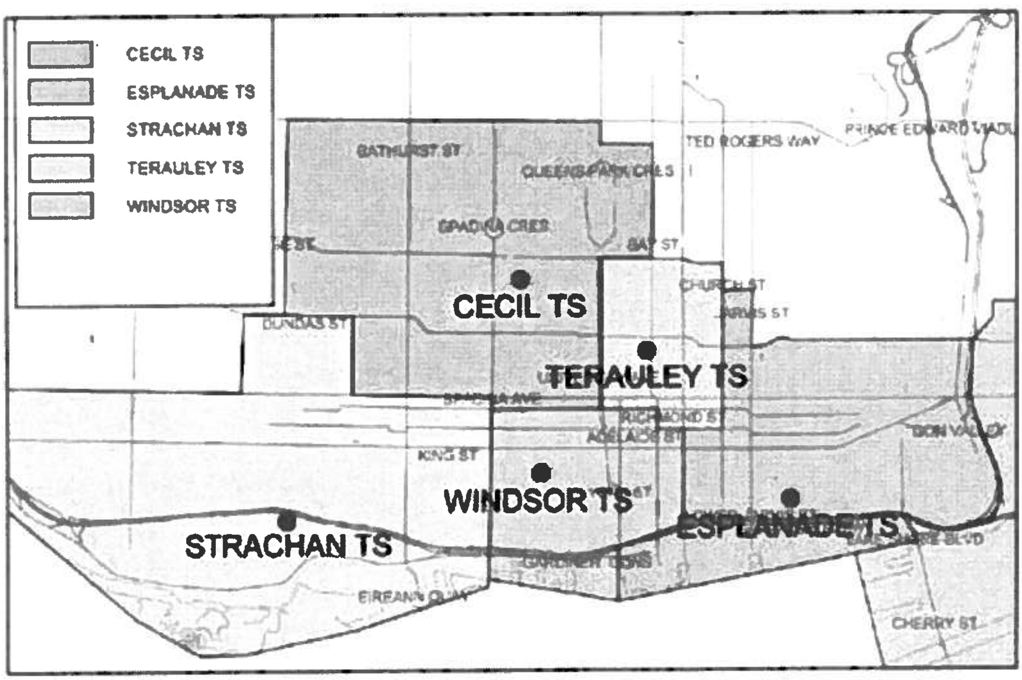
Because of age, condition, and limited functionality, some equipment at Windsor has become obsolete and should be replaced. Further, although station equipment is well-maintained, replacement parts are difficult to obtain. The switchgear should be replaced regardless of which option is selected to meet future demand. Significantly, there are no feeder ties to adjacent stations and virtually no back-up feeder positions to serve Windsor loads while switchgear sections are out of service and sequentially replaced.

Surplus firm capacity of the five stations that serve downtown Toronto also is diminishing and new station capacity will be needed over the next seven years. Notably, the composite peak demand is expected to exceed the combined capability of these five stations by 2019. The original design criterion for these stations also do not address low probability, high impact events involving the loss of the entire station; extended outages likely would result if a major breakdown were to occur. These factors, when combined with the magnitude and criticality of load served, increased outage exposure, and the unavailability of back-up supply to accommodate required equipment replacement, underscore the need for new station capacity in downtown Toronto.

Electric Supply to Downtown Toronto

The total peak demand of the THESL system is about 5,000 MW. The total downtown Toronto load served (i.e., the former Toronto Hydro service area) is approximately 2,000 MW; about one-half or 1,000 MW is supplied by five stations in the core of downtown Toronto. Figure 1 highlights the location of these five stations and areas served. All stations are fed by 115kV transmission lines - most of these are underground.[1]

Figure 1: Downtown Toronto Stations & Electric Supply



[1] Transmission supply lines serving THESL load are owned and operated by Hydro One Networks, Inc (HONI).

NAVIGANT CONSULTING

Design Standards and Planning Criteria

The following describes planning criteria THESL employs in the planning and design of its electric power delivery system. Planning criteria are listed separately for transmission lines, stations and distribution feeders, with emphasis placed on facilities serving downtown Toronto.

Transmission

Generally, THESL does not own or operate network transmission lines and stations and therefore is not responsible for the establishment of planning, loading and reliability criteria for the high voltage system. Network transmission assets serving THESL stations are owned and operated by Hydro One Networks, Inc (HONI). Most stations located outside downtown Toronto are served by overhead 230kV lines, whereas most downtown stations, including the five cited in this study, are served by a combination of overhead and underground 115kV lines. In 2007, HONI constructed an underground tunnel in downtown Toronto to accommodate new transmission cables that will tie John (Windsor) and Esplanade TS. The tunnel runs on the south side of the Windsor station and is designed to readily interconnect to a new station in downtown Toronto – the tunnel includes duct banks with a tap designed to accommodate new transmission cable.

Although THESL is not responsible for the transmission planning and design criteria, it works closely with HONI, the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO), and participates in joint planning sessions to jointly coordinate and plan for the continuity of supply to THESL stations. THESL also has opined on transmission reliability in prior investigations conducted by the IESO.[2] Most important, THESL must design its station and distribution system with consideration given to the design and contingency criterion applied to the transmission system. For example, if a loss of key transmission lines or transformers were to cause the entire or partial loss of station capacity, then THESL would need to design its system in a manner to ensure back-up feeders and station capacity were available.

Currently, the 115kV and 230kV transmission system that serves downtown and outlying THESL stations is designed based on a single contingency (n-1) criteria; that is, the loss of any single line element, at peak, will not result in a loss of supply, create insufficient capacity or cause unacceptably low voltages to stations served by the 115kV and 230kV system.[3] The

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[2] For example, THESL offered its comments to the IESO *Stakeholders Engagement Plan SE-50 for Supply to Large Urban Centres* in a letter dated February 28, 2008.

[3] Reliability standards are set forth in Section 7 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

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network configuration of the 115kV and 230kV system enables HONI to achieve this objective.[4] However, transmission lines that serve Toronto have become increasingly loaded, which has decreased the margin under which the system is able to meet first contingency criterion.

Stations

THESL planning criteria specify that all downtown stations must be able to serve projected load for a single contingency; that is, a loss of a single station transformer, incoming supply line or switchgear bus section will not cause loss of load (also referred to as n-1 criteria). THESL employs a Dual Element Spot Network Design (DESN) standard for downtown stations, with each bus supplied by two transformers. Stations typically include four 100 MVA 115/13.8kV transformers (owned by HONI). A maximum of 10 to 16 feeders are allowed per switchgear bus. Under this design, the 13.8kV station bus rating typically is the limiting element from a capacity standpoint. Net firm station capacity is derated to 95 percent of the projected future peak to account for unanticipated loads or weather anomalies. For the loss of a single transformer, the utilization of the remaining transformers in service is increased above nameplate ratings to a level where transformer loss-of-life is at an acceptable level. These practices and criteria are consistent with industry practices.[5]

THESL's planning criteria allow for the loss of any single major station element, at peak, without full or partial loss of load. An Emergency Preparedness exercise conducted in May 2006 suggested that THESL's planning criteria should include a requirement that outages caused by a partial or full loss of a station should be restored within 24 hours. However, without adjacent TS switchgear ties in downtown Toronto, this objective cannot be met for a major outage at several stations. This finding prompted THESL to conduct studies that examined remediation options.[6] A determination was made that about 60MVa of surplus or additional capacity would be needed to provide sufficient capacity for the loss of any single switchgear line-up in a station serving downtown load, with the construction of dedicated TS switchgear tie capacity to enable inter-station switchgear load transfers, capacity that is currently not available. The issue is addressed later under demand and supply alternatives.

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[4] In addition to HONI transmission lines, the Portland Energy Center provides contingency support to downtown transmission lines, and is a critical resource needed to ensure continuity of supply.

[5] Some North American urban utilities serving critical, high density loads have adopted second contingency (n-2) station planning criterion.

[6] In June 2006, THESL prepared a response that included a plan to create back-up capability via two new feeders and a new "Satellite" station and new feeder ties. A follow-up study, Toronto Hydro Internal Report, Interties to Provide Backup Capacity to Downtown Stations, issued in November 2006, outlined options for enhancing feeder tie capability.

Distribution Feeders

Outside of the former downtown Toronto system, most THESL's feeders are rated 27kV and designed in a radial "open loop" configuration. The open loops include several transfer switches and normally open feeder ties that are suitable for inter-station load transfers. In the event of a contingency loss of station transformation capacity, these ties can be utilized to transfer load to other nearby stations where sufficient transformation capacity exists to carry the load. Many of the 27kV feeders and transfer switches are located overhead.

The mostly underground 13.8kV system in downtown Toronto predates the overhead 27kV open loop design located in the amalgamated distribution systems. Unlike the 27kV system, downtown stations and radial 13.8 kV distribution feeders rely on the 115kV voltage transmission system to maintain reliability to downtown customers. The current downtown 13.8kV design criterion excludes reservation of feeder capacity to back-up load from other stations. This design configuration has no inter-station feeder ties, which limits load transfer among downtown stations.[7] Thus, the loss of a downtown station would result in significant and extended loss of load until repairs are completed and the station returned to service.[8] Notably, lack of space in the downtown area for underground feeder-tie switch installations and the absence of spare conduit or underground duct bank systems is a major deterrent to creating feeder ties where none currently exist.

About 350 MW of high density load in downtown Toronto is served by low voltage secondary grid networks. These networks operate in a looped arrangement such that a loss of any single element will not cause overloads or loss of load. A substantial portion of secondary network load in downtown Toronto is served from the Windsor station.

Conformance with Industry Planning Criteria

As noted, planning guidelines for stations in Ontario (and adopted by THESL) are based on a single contingency (n-1) planning criterion. Station bus design includes transfer busses with full feeder back-up capability reserved for maintenance or when outages occur. As noted, many

[7] The absence of feeder ties and reliance on incoming supply to maintain reliability does not address the complete loss of a station, which usually is deemed a very low probability, but high impact event. However, the near full utilization of station bus capacity and deterioration of equipment has increased outage exposure and the probability of station outages.

[8] Three recent events highlight the exposure caused by the loss of downtown stations. In January 2009, one of the coldest days of the year, the Dufferin station was shut down due to flooding caused by the operation of HONI's transformer fire protection system. Over 34,000 customers were interrupted, some up to 24 hours. A similar flooding event occurred at the Terauley station in January 2005, causing an interruption of service to over 3,500 downtown customers for ten hours. Lastly, a TS transformer failure at Windsor on October 14, 2010 caused an interruption of service to several downtown high rise buildings and retail centers during daytime business hours.

downtown loads are served by secondary grid (lower load density) or spot (highest load density such as high rise buildings) networks. Each of these design practices is consistent with common utility practices for urban areas.

The single contingency criterion that THESL applies to station transformers is less conservative than other large utilities serving critical, high density loads. For example, the City of Manhattan (Consolidated Edison Company of New York) applies a second contingency (n-2) criterion for lines and stations serving the Island of Manhattan. Similar criterion has been adopted for critical government and commercial load centers in Washington, D.C. by the Potomac Electric Power Company, Houston, and other large cities worldwide, such as downtown Tokyo.

Demand Forecast

The 2011 non-coincident peak demand of the five stations serving downtown Toronto was approximately 980 MW. Table 1 presents the 2011 actual peak and 10-year forecast for the downtown core (5 stations) and the remainder of Toronto, which indicates downtown load will increase by over 200 MW by 2021. The majority of downtown load is commercial, mostly large office complexes and load associated with the financial and business districts.

Table 1: Downtown Toronto Peak Demand Forecast (MVA)

	Year										
Area Served	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Downtown Core	982	1,000	1,029	1,051	1,071	1,099	1,122	1,145	1,168	1,190	1,217
Remaining Toronto	4319	4352	4431	4488	4541	4591	4647	4693	4741	4795	5084
Total System	5301	5352	5460	5539	5612	5690	5769	5838	5909	5985	6066

Source: Total system and downtown core station load forecasts supplied by THESL

Remaining Toronto load is estimated by assuming the composite peak of the 5 core stations is coincident with the total system peak. Notably, the five stations that serve the heart of downtown Toronto supply 20 percent of the total area load – the remaining 80 percent is served by 30 other stations. The high ratio of load served per station for the five downtown stations underscores the need to maintain reliability at levels equal to or higher than other sections of Toronto. Also, most downtown load is served by underground cable, including all secondary networks.

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Conservation and Demand Management (CDM)

In response to a Provincial mandate to reduce the composite Ontario peak by 1330 MW by 2014 via CDM[9], THESL proposes to implement a wide range of CDM programs for 2012 and beyond, culminating in 286 MW of peak load reduction between 2011 and 2014. Program results and forecasted savings for THESL and downtown Toronto are presented in Table 2.[10] By 2014, new CDM in an amount equal to approximately 6 percent of the annual peak load will be installed. As an alternative to new station capacity, options for increasing firm CDM penetration or the introduction of new programs are considered later in this report.

Table 2: Downtown Toronto CDM Firm Demand (MW)

CDM Program	Year			
	2011	2012	2013	2014
Downtown Core	9	12	16	21
Remaining System	34	48	63	83
Total CDM	43	60	79	104
Cumulative CDM	**43**	**103**	**182**	**286**

Station Capacity

Table 3 lists station effective firm transformation capacity for the five stations that serve downtown Toronto. The net capability reflects THESL and HONI planning criteria, which specifies that all downtown stations must be able to serve entire station load for a single contingency outage; that is, a loss of a single station transformer or bus section. Net firm capacity is de-rated to 95 percent to account for unanticipated loads or weather anomalies.

Table 3: Downtown Toronto Station Capacity

Station	Original Construction	Number of XFMRs	Transformer Rating (MVA)[11]	Firm Station Capacity
Cecil	1969	4	236	224
Esplanade	1992	3	207	198
Strachan	1955	4	184	175
Terauley	1929	4	240	240
Windsor	1950	6	356	340

[9] http://www.powerauthority.on.ca/sites/default/files/page/17069_minister_directive_20100423.pdf
[10] The station forecast presented in Table 1 reflects the CDM peak load savings presented in Table 2. Values for downtown Toronto are derived by allocating total THESL CDM projections on a pro rata basis using area peak load.
[11] Transformer ratings based on nameplate ratings. Net effective transformer capacity is based on the loss of a single transformer (n-1). This upper rating is the Summer Limited Time Rating (LTR), which assumes 10 days would be needed to install a replacement transformer. Recent experience indicates actual time for replacement is up to 90 days.

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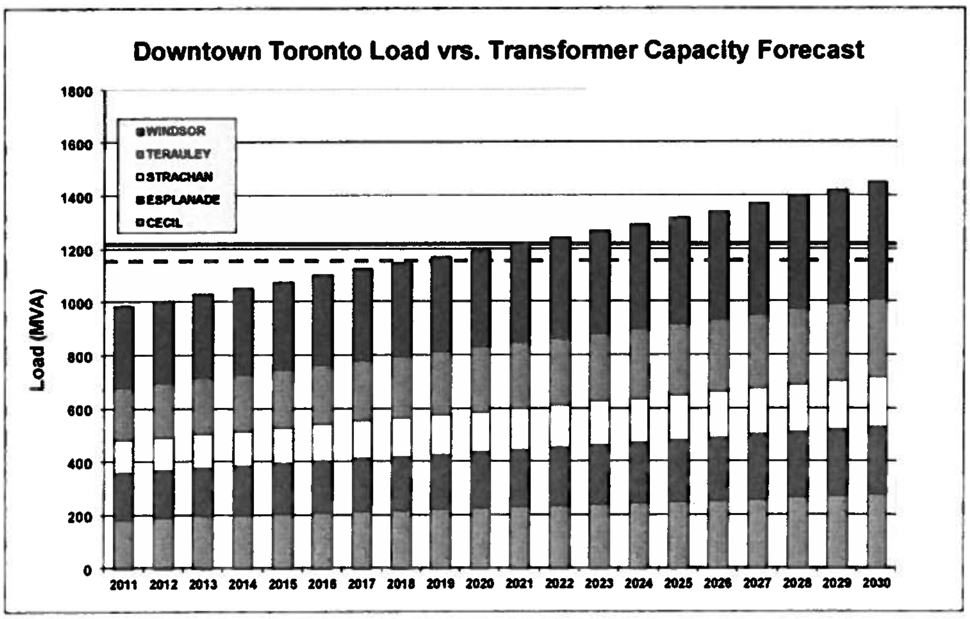
For the loss of a single transformer, the utilization of the remaining transformers in service is increased above nameplate ratings to reflect higher short-term ratings, which is consistent with current industry practices.[12] Notably, net firm capacity for most downtown stations excludes mutual support for adjacent stations, as there no feeder tie transfer capability between these stations.

Projected Capacity Need

A comparison of the firm transformer capacity of the existing five stations versus projected peak demand is presented in Figure 2. The forecast incorporates and reflects savings achieved by prior CDM programs. However, future CDM is not included due to the lack of assurance of *firm* peak demand reduction. On an aggregate basis, the collective capacity of these stations is well utilized, as the 2011 actual peak is about 80 percent of the total station capacity. This percentage increases to about 90 percent by 2015. By 2019, the composite area peak will exceed the total capacity of these five stations when the 95 percent loading criterion is applied. By 2030, this capacity deficit increases to almost 300 MW, indicating that additional capacity will be needed at more than one station in the downtown core.

Figure 2: Downtown Toronto Firm Capacity Surpluses/Deficits[13]



[12] Some North American urban utilities serving critical, high density loads have adopted second contingency (n-2) station planning criterion.

[13] The solid line represents maximum transformer rating. The dashed is the 95% future loading criteria that THESL uses to project the need date for additional capacity to account for extreme weather or unanticipated loads.

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On an individual basis, upper loading limits on two of five stations (Windsor, Esplanade) will be exceeded by 2018 and four by 2021. Table 4 compares annual station projected peak load versus transformation and switchgear capacity to year 2026 (overloads are highlighted light yellow). The first year of capacity deficits occur in 2017, when the composite station rating at Windsor will be exceeded. Hence, reinforcement in the form of additional transformation capacity or transfer of load via 13.8kV feeders to another station will be needed to avoid overloads. Because Esplanade and Windsor require feeder expansion to permanently transfer load, a solution that addresses capacity limitations at one station, to a large extent, can be viewed as a solution to both. However, feeder loadings and increased growth likely will create a need for additional transformation capacity at Esplanade, Windsor or at a new station in downtown Toronto.

Table 4: Year of Capacity Deficit by Station (MVa)

Station	Station Rating	Year															
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Cecil	224	182	189	196	199	203	207	212	216	220	224	229	233	239	242	248	252
Esplanade	198	175	173	177	182	187	192	196	199	204	208	212	216	221	225	230	234
Strachan	175	122	127	130	131	133	140	143	147	151	153	157	159	163	166	169	172
Terauley*	240	199	205	211	215	220	225	229	234	238	243	248	252	258	263	269	273
Windsor	340	304	306	315	324	328	335	342	349	355	362	371	377	383	391	399	405

*Terauley is restricted by transmission line capacity to 240 MVA
Source: Toronto Hydro 2012 Station Load Forecast

Notably, by 2017, the first year of a station overload, total downtown demand will be over 90 percent of the composite rating of the five stations that serve downtown load. This high level of utilization increases the potential risk that there will be insufficient capacity if a major outage involving multiple transformers or station busses, or combination thereof, were to occur; particularly if loads are higher than the current forecast. For example, if a major heat wave were to occur, loads would be higher as would the likelihood of incipient failure due to heating of station equipment. Good utility planning suggests that THESL should proactively address projected area transformer capacity deficits that are expected to occur over the next ten years and as early as 2017.[14] Service reliability and the impact of outages are discussed in the follow section.

Equally important is the compelling need to change out obsolete and heavily loaded switchgear busses at Windsor. One of the primary reasons new station capacity is needed downtown is to provide back-up support while switchgear is sequentially removed and upgraded at Windsor. Several of the busses at Windsor will soon be overloaded. Table 5 presents Windsor bus load

[14] Station bus capacity will be exceeded by 2017 at Windsor.

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forecast, indicating overloads by 2014. Because of the grid network configuration and load location, further balancing of load among the busses is difficult.

Table 5: Windsor Substation Bus Loading Forecast

	Firm Capacity Rating (MVA)		Year					
Bus Section	100%	95%	2011 Act	2012	2013	2014	2015	2016
A11-12	69	66	55	56	58	59	60	61
A13-14	41	39	34	34	35	38	39	40
A15-16	69	66	67	66	68	69	70	72
A17-18	49	47	42	42	43	41	41	42
A3-4	64	61	49	50	52	56	57	58
A5-6	64	61	57	58	59	61	62	63

Risk Assessment

The potential for and impact of major events on reliability of supply to downtown Toronto is highlighted in the following risk assessment. It includes a condition assessment of critical equipment at Windsor.

Outage Scenarios and Area Reliability

The greatest outage risk to customers in downtown Toronto is a catastrophic outage, such as a loss of multiple transmission supply lines, station transformers or bus sections at one of the five critical downtown stations. The original design criteria for THESL stations also do not address low probability, high impact events involving the loss of the entire station. In particular, the exposure at Windsor is of particular concern as the equipment, although well-maintained, is older, the load density and load served is high, and because of the lack of back-up capability.

The simultaneous loss of multiple equipment, commonly referred to as common mode failures, is a low risk, high impact event. However, the risk and consequences of equipment failure and lengthy outages at Windsor and other downtown stations are increasing, both due to increased loading on already heavily loaded equipment, and the length of time that would be needed to restore service following an outage. As noted, there is no back-up capability from adjacent stations via feeder ties. Accordingly, a major failure at Windsor and other area stations would cause loss of supply and load unserved until repairs were completed. For a major common mode failure, repairs could require an extended period to complete. For example, a loss of multiple transformers at Windsor would require removal and installation of spare transformers within an enclosed structure in a busy section of downtown. The time for removal, transport, and reconnection of an extremely large and heavy 100 MVA transformer would be up to 90 days or longer. Similarly, a fire on a station bus in an enclosed structure could take equally long to repair.

Specific common mode failures relevant to facilities serving downtown include:

- Loss of two or more transformers due to catastrophic faults, overloads due to unanticipated heat waves, or fires causing collateral damage to adjacent devices,
- A fire caused by high fault currents and interrupter failure, spreading to adjacent bus sections,
- Equipment failure caused by sabotage or third-party impacts,
- Loss of several major incoming transmission supply lines, thereby interrupting service to one or more stations, and
- Loss of several primary feeder sections, located within a manhole or vault.

Such events, while infrequent, are not unprecedented. Examples of catastrophic events similar to those cited above include:

- Loss of major secondary networks in downtown Manhattan (Washington Heights)
- Loss of major station in Queens, New York due to multiple and cascading cable failures
- Loss of downtown Chicago load ("Chicago Loop") due to multiple transmission cable failures and subsequent station loss
- Loss of service to major sections of downtown Vancouver
- Loss of service to the City of Auckland, New Zealand due to cascading loss of cross-channel 69kV transmission cables

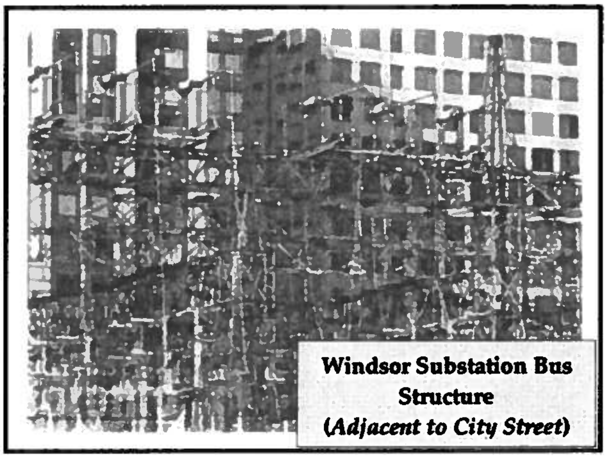
The economic, social and political consequences of these events were significant, and resulted in extensive financial loss and follow-up mitigation by the utility. We anticipate a major event causing lengthy load loss in downtown Toronto would result in similar economic and financial consequences, particularly if such an event were to impact the financial and business districts.

The impact of such an event likely would impair the image of Toronto as a leading urban center, causing unwanted attention and a tarnished reputation, both within and outside of Ontario. Notably, THESL previously experienced the loss of the Windsor station due to a transformer failure, and the Terauley and Dufferin stations due to flooding. Although the economic consequences were not as significant as the events listed above, these provide examples of how entire stations can be interrupted by contingencies.

Windsor Station Assessment

The Windsor Station, originally constructed in 1950, contains some of THESL's oldest equipment -- some obsolete -- yet serves what arguably might be deemed the most critical and sensitive load in the GTA (Greater Toronto Area). There are six 13.8kV switchgear busses, each of which has few or no spare feeder positions to unload other feeders or pick up load from other switchgear line-up, either for feeder outages or maintenance. Compounding this problem is the absence of interior and floor space to add new or expand existing switchgear busses.

Expanding the building is not an option, as it borders adjacent streets on two sides, the incoming HONI high voltage switchyard and transformer station on another, and private property under development and not for sale on the other (it also is not in a desirable location for new switchgear). Expanding the building upward also is not an option, as the installation of switchgear on the upper floors would pose major cable routing and logistical problems during construction. It also is not consistent with common utility station design practices.



Windsor Substation Bus Structure
(Adjacent to City Street)

Further complicating expansion is the highly occupied basement, which contains medium and low voltage cable throughout the floor and attached to concrete walls. Adding additional cables presents significant routing and placement issues. The following photos readily illustrate the building confinement and crowded space that obviates the potential for any meaningful expansion at Windsor.

Figure 3: Windsor Station Cable Congestion

The above factors collectively present major obstacles to expanding the station to accommodate new transformation or switchgear and feeder capacity. High station loads and the inability to install new switchgear busses also restrict THESL's ability to replace obsolete switchgear, as there are no spare switchgear feeder positions or feeder ties to carry the load while switchgear busses are sequentially replaced, a lengthy construction process during which outage exposure would increase significantly, as the loss of a single source (transformer or switchgear bus) could lead to extensive load loss until repairs were completed.

In addition, several of the switchgear busses have feeders dedicated to serving secondary networks. Secondary networks are designed using single contingency (n-1) criteria, such that a loss of one primary 13.8kV feeders will not cause overloads on the grid connected low voltage secondary grid, or spot networks connected to these primary feeders. Extreme care must be exercised when transferring primary feeders serving network load to avoid primary or secondary main cable overloads. The limited spare feeder capacity and absence of spare feeder positions create considerable operational challenges to operating personnel responsible for maintaining service continuity during and after load transfers, including assurance that network secondary mains do not become overloaded during switching operations.

The continued use of existing switchgear busses that use air blast or magnetic interrupters is not an option, as these are not arc resistant and spare parts are increasingly difficult to obtain. THESL previously extended the life of the air-blast breakers by replacing the air supply system in the early 1990's. Despite these efforts and ongoing proactive maintenance, these station switchgear busses have become heavily loaded and outage exposure will increase over time. The potential for major outages and collateral damage is greater with switchgear utilizing air blast and magnetic breakers, as they are not constructed using arc resistant interrupting medium found on currently available equipment.

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Supply Alternatives

Possible demand and supply alternatives are presented below. Each option is analyzed from a technical and economic perspective. A recommended course of action is provided based on the results described herein.

Alternatives considered for meeting long-term electrical demand for downtown Toronto include both demand and supply-side options. Supply-side options include expanding or adding new station capacity, whereas demand-side options include conservation and demand management (CDM). We also investigate the implications and viability of a status quo option, which assumes no additional station or feeder capacity, and current levels of CDM.

Status Quo Option

The Status Quo option assumes that existing station and feeder capacity would be used to the extent possible to serve future load. It includes rebalancing of feeder and transformer load via use of spare switchgear and transformer capacity. We do not view this option as viable, as transformer and feeder loading are reaching upper limits, and therefore, cannot accommodate additional load. The absence of firm feeder ties between and among substations is a primary deterrent to serious consideration of a status quo option. Also, it does not address the compelling need to replace obsolete switchgear at Windsor, a task that would cause THESL to violate its single contingency criteria for up to a year without back-up ties to transfer load from 13.8kV feeders normally supplied by Windsor. Importantly, there is no back-up source -- if one of the switchgear busses at Windsor were to fail catastrophically while another was out of service for replacement, a lengthy outage likely would ensue. Given the two to five year lead time needed to plan, design, procure equipment and construct major new facilities, THESL should proceed expeditiously to minimize risk exposure.

A variation of the Status Quo option is to transfer load among existing busses at Windsor. However, there is minimal spare bus capacity, and any shifting of load will do little to address long-term capacity needs at Windsor and other area stations. Further, it does not provide a remedy to the absence of sufficient back-up capacity to enable replacement of obsolete switchgear. This option also violates THESL's single contingency design criterion.

Targeted CDM

A significant portion of downtown Toronto load is commercial, and includes the financial district, many high rises and several tourist destinations. THESL has actively promoted CDM in downtown Toronto, including commercial lighting and heating, ventilation and air conditioning (HVAC) programs. These savings are reflected in the current load forecast. However, additional savings via these programs are limited, as THESL has identified and implemented cost-effective CDM opportunities in downtown Toronto. For example, aggressive change-out of commercial lighting and replacement of low-efficiency air conditioning now limits the opportunities for additional CDM.

The analysis presented in Table 6 assesses the extent to which targeted CDM – beyond existing levels - would potentially defer need dates for additional station capacity. The analysis assumes the maximum amount of additional CDM that THESL could reasonably add by 2014 is fifty percent above levels proposed or already achieved in downtown Toronto

Table 6: Targeted CDM – Impact on Station Need Dates

Station	Year												
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1) Windsor													
Net Firm Surplus Capacity	36	34	25	16	12	5	-2	-9	-15	-22	-31	-37	-43
Base CDM	3	4	5	7	7	8	9	10	11	13	15	16	18
Targeted CDM	1	2	2	3	4	4	5	5	6	6	7	8	9
Firm Cap & Targeted CDM	**37**	**36**	**27**	**19**	**16**	**9**	**3**	**-4**	**-9**	**-16**	**-24**	**-29**	**-34**
(2) Esplanade													
Net Firm Surplus Capacity	23	25	21	16	11	6	2	-1	-6	-10	-14	-18	-23
Base CDM	3	4	5	7	7	8	9	10	11	13	15	16	18
Targeted CDM	1	2	2	3	4	4	5	5	6	6	7	8	9
Firm Cap. & Targeted CDM	**24**	**27**	**23**	**19**	**15**	**10**	**7**	**4**	**0**	**-4**	**-7**	**-10**	**-14**
(3) Windsor & Esplanade													
Net Firm Surplus Capacity	59	59	46	32	23	11	0	-10	-21	-32	-45	-55	-66
Base CDM	5	7	10	13	15	16	18	21	23	26	29	33	37
Targeted CDM	3	4	5	7	7	8	9	10	11	13	15	16	18
Firm Cap. & Targeted CDM	**62**	**63**	**51**	**39**	**30**	**19**	**9**	**0**	**-10**	**-19**	**-30**	**-39**	**-48**

While this amount of CDM may be cost-effective and provide benefits independent of area capacity needs, even a fifty percent increase is insufficient to materially defer the date for additional station capacity. Because the additional amount of CDM that could be achieved is uncertain, it is not advisable to defer new capacity for the few years the need date might be extended. Further, additional CDM does not address the need to replace obsolete switchgear at Windsor, where substantial back-up capacity is needed to accommodate load transfers while the switchgear is replaced.

Distributed Generation

Distributed generation (DG) generally is included as one of the resource options under CDM, and the 6,300 MW demand reduction targeted for the province by 2025 includes substantial amounts of DG. A recent study completed for THESL and the OPA evaluated the potential for

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DG to provide support to the transmission system and high voltage substation, and to provide back-up to near-term station upgrades.[15]

The results of the study indicated significant technical potential for DG in Toronto, but amounts likely to be installed as uncertain. Estimates of the potential market penetration for customer-connected distributed generation in Central and Downtown Toronto ranged from 140 MW in the medium term to more than 550 MW in the long-term. Attachment I presents ranges of market potential and penetration by technology type.

Several studies recently were completed to determine whether DG would be able to support the downtown area. These included identifying methods to reduce barriers to DG penetration. One of the key findings of these studies is the difficulty in siting DG in dense downtown load areas, particularly on secondary grid networks. (A substantial amount of Windsor load is on secondary networks.) The ability to install rotating devices (e.g., synchronous generators) is limited by fault current limits, and by the likely de-sensitization of network protectors, which are not designed to accommodate generators. (Network protectors will quickly open and isolate circuits under reverse power flow conditions, whether due to steady-state power flows from the generator or transient fault currents caused by generator fault contribution for primary or secondary cable faults.) Further, programs introduced in the U.S. have seen limited success due to a physical assurance requirement adopted by utilities.[16]

The results of the DG study indicate there is considerable uncertainty that customers will install DG in an amount sufficient to back up Windsor or to defer station capacity needed to serve downtown Toronto. Further, the use of intermittent sources such as wind and PV may not provide firm reliability capacity in amounts sufficient to meet Ontario and THESL capacity planning criterion. Accordingly, DG as an option is speculative and not determined to be a viable near-term option at this time. However, if the follow-up activities described above result in a finding that DG will likely be added in amounts sufficient to defer energy delivery facilities, the DG option should be reconsidered.

Expand Existing Stations and Inter-Station Transfer Capability

Of the five stations serving downtown Toronto, only Strachan and Esplanade are suitable for expansion. The primary factor limiting expansion at Cecil, Terauley and Windsor is space: each of these stations is enclosed with no space available to install new transformers and switchgear.

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[15] The study responded to a request by the Ontario Energy Board in its EB-2007-0680 decision that Toronto Hydro investigate distributed generation in its service territory as a supply alternative.

[16] Physical assurance is a requirement that customers that own generation guarantee the generators will operate when needed, and agree to allow the utility to interrupt an equal amount of customer load in the event the generator is not started or unable to operate.

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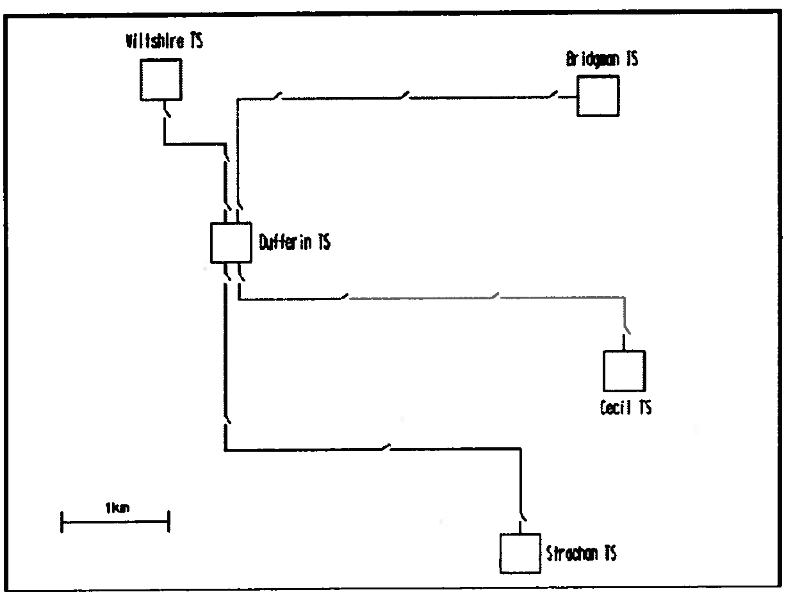
In particular, the absence of spare switchgear positions to accommodate new 13.8kV distribution feeders and limited ability to transfer load between switchgear busses are major limitations at Windsor. Terauley is another nearby station with surplus firm capacity. However, the Terauley station also has transmission loading limits, and would not be able to pick-up the additional 60 MW of load from Windsor while station switchgear is replaced.

The Strachan and Esplanade sites each have sufficient space to accommodate new transformers and feeder positions. These stations are located in areas targeted for development and are electrically close to downtown load and the Windsor station. However, a considerable amount of new underground 13.8kV feeder capacity would be needed to transfer load from Windsor to these two stations. Nonetheless, the expansion of Esplanade and Strachan should be considered as a potentially viable option for meeting capacity deficiencies in downtown Toronto. Of these stations, Esplanade is a superior near-term choice as it can accommodate more new feeders than Strachan, as Strachan only has space to add one new switchgear line-up (16 feeders) compared to three (48 feeders) for Esplanade.

Over time, THESL proposes to reconfigure downtown distribution system to improve operating flexibility and reliability. These changes include installation of feeder ties where practicable and cost-effective. One example where feeder ties are proposed is the Dufferin TS. It would include the installation of remotely-operated load break switches at Dufferin and on several feeders to enable transfers between Dufferin and the Bridgeman, Cecil, Strachan and Wiltshire stations. A simplified diagram of proposed feeder ties at Dufferin is illustrated in Figure 4.

Figure 4: Proposed Dufferin Feeder Ties in Downtown Toronto



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Expand Esplanade

The cost to expand the number of feeders and ties to Windsor from the Esplanade station (2km) to pick up Windsor loads is about $1.4 million per feeder. Up to 48 new feeders (about 250 MW total) would be needed at a cost of approximately $67.3 million. In addition, Esplanade contains some equipment that may need to be upgraded to bring it to current HONI standards. These upgrades would include new transformers, switchgear, bus structure, protection and controls and site work. Most of these costs would be contributions to HONI, as it owns each of the stations. Additional costs would be borne by THESL for low voltage switchgear, structures and exit feeders.[17] The amount of the HONI station upgrades is estimated at $44.4 million; THESL station equipment adds another $34.2 million, for a total project cost of $146 million. The $67.3 million for new feeders and tie points would occur over time, concurrent with station capacity deficiencies. Because planning, design, permitting and review activities have not started at Esplanade, the earliest the station could be in service is 2016.

Expand Strachan

The cost to expand the number of feeders and ties to Windsor from the Strachan station (2.2 km) to pick up Windsor loads also is estimated at $1.4 million per feeder. Up to 16 new feeders (about 80 MW total) would be needed at a cost of approximately $22.4 million. Strachan also contains old equipment and some of it would need to be upgraded to bring it to current HONI standards. Similar to Esplanade, most of these costs would be contributions to HONI, as they own each of these stations. Additional costs would be borne by THESL for low voltage switchgear, structures and exit feeders.[18] The amount of the HONI station upgrades is estimated at $21.8 million; THESL station equipment adds another $11.4 million, for a total project cost of $55.7 million. The $22.4 million for new feeders and tie points also would be spent concurrent with station capacity deficiencies. Because planning, design, permitting and review activities have not started, the earliest the station could be in service is 2016.

Construct New Station

Reinforcement of downtown Toronto has been under investigation for well over a decade. In 1996, THESL and HONI completed the Toronto Integrated Electrical Service (TIES) study, which identified long-term strategies to relieve John, Windsor, Esplanade and Terauley TS loadings by establishing a new station in the Roundhouse Park (also referred to as the Railway Lands Station). Subsequent studies included the construction of a new Railway Lands station (i.e., the new Bremner station) to supply customer load while the John to Esplanade transmission tie was upgraded from 115kV to 230kV (Figure 5).

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[18] Existing equipment at Strachan is very old and would be replaced as part of a capacity and refurbishment program that HONI likely would mandate.

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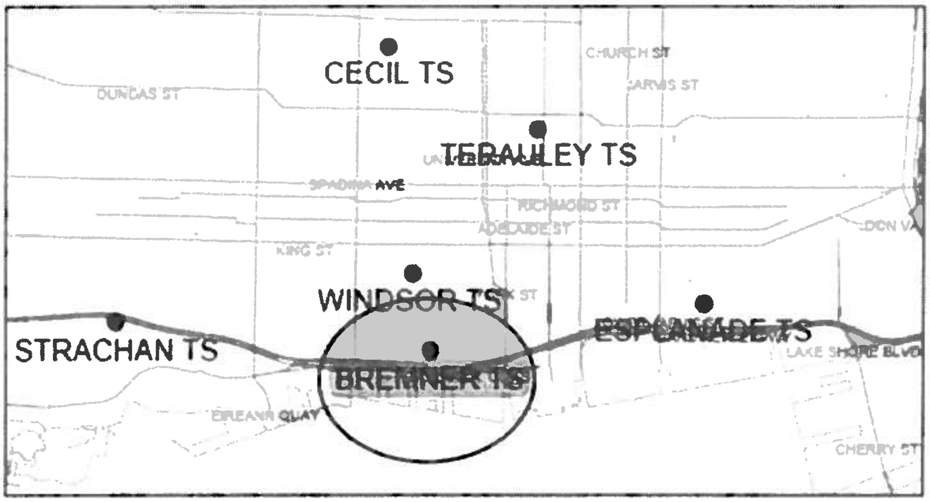
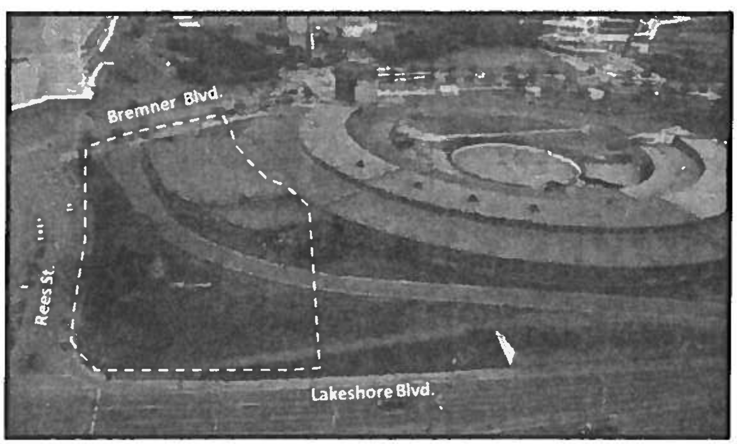
Figure 5: Proposed Location for New Bremner Station



One of the primary challenges to constructing a new station in the downtown area is land acquisition. Land cost is usually at a premium and many sites often are not the best choice from an electrical perspective -- the best choice is to locate stations in load centers as opposed to peripheral locations. Recently, THESL purchased from HONI a parcel of land adjacent to the Railroad Round House yard, which electrically is in the downtown core where additional capacity is needed. THESL has worked closely with the City of Toronto to ensure a new substation would blend in with the surrounding area.

Figure 6: Proposed Downtown Site for New Substation



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Detailed engineering is nearly complete for the electrical layout and configuration of the proposed Bremner site. Appendix A includes a depiction of the proposed layout, which includes fully enclosed structures and underground transmission and feeder exit cables. Initially, the station would be equipped to supply up to 72MVA of load, with expansion capability up to 300 MVA.

The costs of the new Bremner, and the upgraded Esplanade and Strachan stations, including distribution upgrades and HONI capital contributions, are summarized in Table 7.

Table 7: Cost Estimate – Station and Distribution Upgrade Options

Description	Cost (2012 $Million)		
	Esplanade	Strachan	Bremner
Station and Distribution System	$34.2	$11.4	$135
Capital Contribution to Hydro One	$42.5	$21.8	$60
Distribution Ties (Complete build-out)	$67.3	$22.4	
Total	**$146**	**$55.7**	**$195**

Specific components included in the Bremner estimate are highlighted below for the first phase of the project, with ultimate build-out potential in the parenthetical. The station would be designed to initially supply 72 MVA of firm demand, with expansion capability of up to almost 300 MVA. Unlike all other 115kV or 230kV supply stations (except for Cavanaugh, which is owned by THESL), THESL would own the following equipment.

- Station site and building
- 115kV switchgear
- 115kV bus within station
- 115kV/13.8kV transformers 13.8kV metalclad switchgear 13.8kV feeders (16, ultimately up to 64)
- Protection and ancillary equipment

Equipment that would be owned by HONI includes:

- 115kV breakout tap at John-Esplanade tunnel
- Underground cable circuits (2 – 115kV)
- 115kV interface equipment

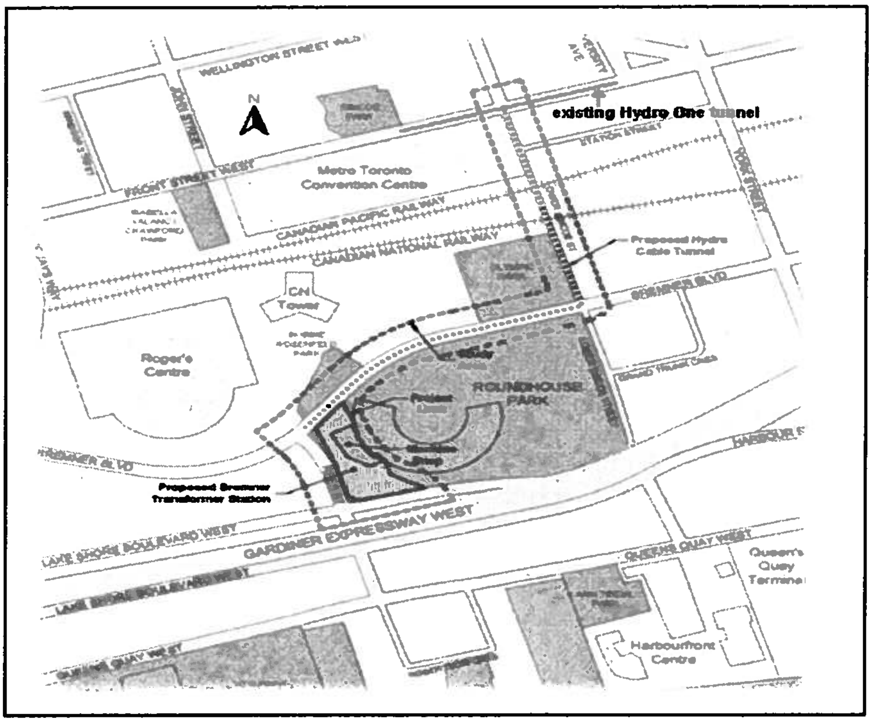
As noted, all transmission cables and 115kV switchgear and busses will be rated 230kV for potential conversion if 230kV transmission supply is later expanded to downtown Toronto.

Transmission Supply Considerations

The impact of expanded station capacity or the installation of a new station on the area 115kV system is an important consideration in the evaluation of alternatives. From a capacity standpoint, the existing 115kV system can accommodate additional station loads at each of the existing five downtown stations.[19]

The construction of a new station at Bremner would require new 115kV lines to interconnect to the existing transmission system. The first stage of the proposed interconnection is illustrated in Figure 7. Figure 7 also presents the electric one-line diagram of the 115kV interconnection between the John and Hearn stations. Notably, the proposed 115kV cable tie between John and Esplanade is located 600 meters from Bremner. Discussions with HONI confirm the Bremner station can be fed by tapping directly into the proposed John-Esplanade line, and then routing two new 230kV cables operated at 115kV into the new station. As noted, the existing tunnel and duct bank has a break out tap designed to accommodate a tap line to a new station.

Figure 7: Transmission Interconnection



<u>Bremner Interconnection: One-Line Diagram</u>

[19] This conclusion is based solely on the ability of the 115kV system to accommodate new load. It does not address the capability of the 230kV bulk system to accommodate new load or to limit fault current to within design limits.

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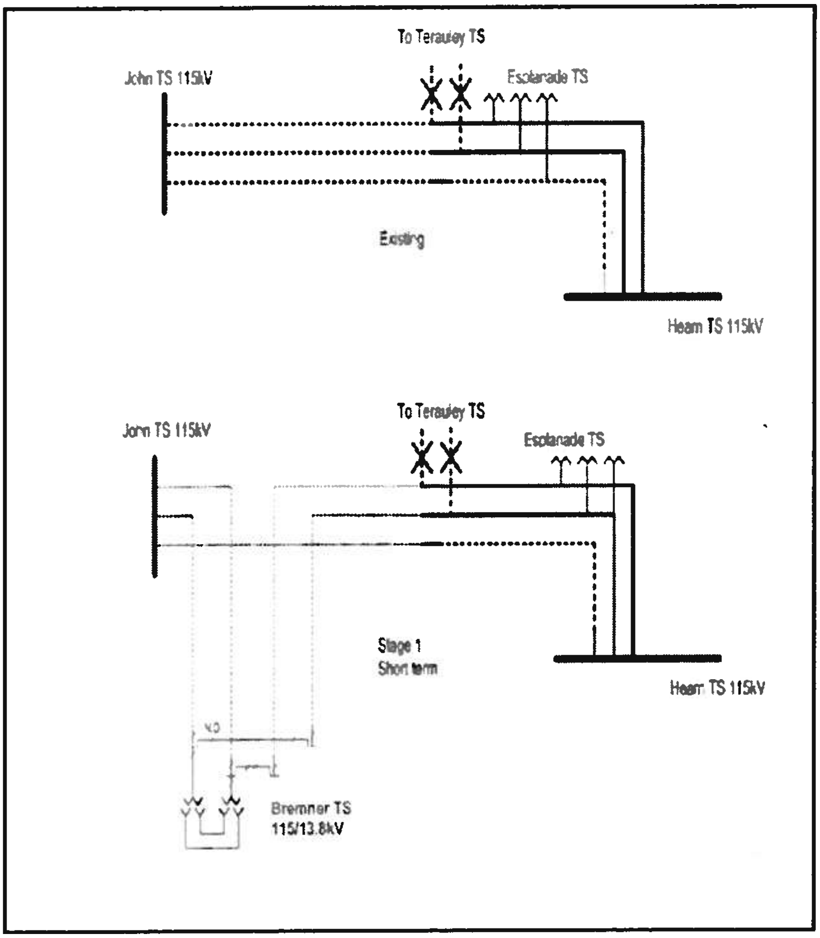

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Assessment of Supply Alternatives

Methodology

NCI performed life-cycle economic analyses of project alternatives using THESL economic and financial data. Alternative supply options considered include the proposed Bremner TS, upgraded adjacent stations (Esplanade and Strachan), distributed generation and targeted CDM. Each alternative and resulting business case was assessed using an evaluation framework comparable with other THESL capital projects. This approach ensures project ranking and evaluation factors were applied consistently among alternatives. In particular, the ability of each alternative to meet minimum reliability criteria with regard to the level of "firm, reliable" capacity over time was a key factor in the evaluation of alternatives.

Technical Evaluation

The following summarizes alternatives from a technical perspective, including an assessment of how each option impacts area reliability. In addition, the ability of each option to address the need to replace switchgear at Windsor is analyzed. Each option is evaluated based on the assumption that each must achieve minimum design and planning criteria to be viable.

Area Reliability

Of greatest concern is the Status Quo option, which will cause reliability to seriously degrade and violate the minimum reliability set forth in THESL's planning guidelines; that is, the ability to serve peak demand under first contingency conditions, a criterion that has been adopted by many urban utilities. The addition of a new substation or increased substation transformation capacity will avoid degradation in reliability, and in fact, will enhance area reliability by providing first and second contingency support for critical downtown load centers. Major utilities in North America have adopted second contingency design criteria for major urban centers similar to Toronto.

The addition of a new station at Bremner would substantially reduce outage exposure, particularly for low probability, high impact events such as the complete loss of the station. Such events have occurred with increasing frequency at other North American utilities, with profound economic consequences. A loss of a core downtown station such as Windsor likely would cause major outages lasting for more than 24 hours. The economic impact likely would be in the tens of millions of dollars, with the City's image as a leading metropolitan center tarnished by the event. The option of expanding Esplanade has higher risk than Bremner, as it would not be in service until 2016, thereby delaying critical switchgear upgrades at Windsor.

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Targeted CDM may be able to defer by a few years, at most, the need for additional capacity, but not in an amount to address reliability concerns. Further, CDM does not provide the back-up support needed to replace critical switchgear at Windsor.

Distribution System Impacts

A significant advantage that would result from the installation of a new station at Bremner is the ability to provide back-up via 13.8kV underground feeders -- currently, these ties do not exist. Benefits include improved operating flexibility and maintenance scheduling. Most important, it would provide enhanced reliability -- second contingency support would be provided to key stations -- in downtown Toronto. These ties can be developed at relatively low cost, and are essential to enable timely and reliable replacement of obsolete switchgear at Windsor. The development of feeder ties is consistent with THESL's long-term plan to create ties among several downtown stations, each of which will improve operating flexibility and reliability.

Operations and Maintenance Considerations

As noted throughout this report, additional station capacity is needed to enable reconstruction and upgrade of low-voltage switchgear at Windsor. This will be accomplished via use of switchgear feeder ties to other stations in downtown Toronto, tie capacity that presently does not exist. The construction of a new station at Bremner with inter-station switchgear ties to adjacent stations (Windsor and Esplanade in the short term) also will facilitate maintenance between these stations. For example, for transformer maintenance it may be more practical to transfer load to Bremner TS switchgear from Windsor TS switchgear via feeder ties.

Assessment & Economic Evaluation of Supply Alternatives

Based on the above assessment, the only viable options to meet Windsor switchgear replacement and capacity needs are the construction of a new station at Bremner or the expansion of Esplanade in 2016, followed by capacity expansion at Strachan in 2021: the difference is one of timing based on economics as a new downtown station will be needed by 2030 even if both Esplanade and Strachan are upgraded. These two alternatives are described as Options 1 and 2, respectively. Each of these two options was compared using net present value economic analysis.[20] The capital cost of each option in 2012 dollars appears in Table 7. However, if upgrading Strachan and Esplanade in 2016 and Strachan in 2021 is selected, additional feeder capacity and tie points will be required in order to unload Windsor. Feeder upgrades are not required for the new Bremner station as existing duct banks and cables could be easily re-routed to the new station.

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[20] The NPV analysis includes present worth costs for all station and distribution upgrades between 2012 and 2030.

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Base Case Costs

Equipment procurement and construction costs for Bremner are based on a three-year project schedule and in-service date of 2014. Further, an additional $77 million will be needed to expand transformation capacity at Bremner from 2016 to 2030 due to load growth in the downtown core. An additional year is needed for permitting and design for an in service date of 2016 for Esplanade. A 4-year schedule also is assumed for upgrades at Strachan in 2021. Option 2 also includes approximately two new feeders (10 MVA) over each year of the study to serve core downtown load. Economic and financial assumptions are based on NCI and THESL estimates, and prior studies; including sensitivity analysis. The sensitivity cases include increasing and decreasing price escalation and discount rates by one percent and 1.5% respectively. In all cases, the total cost of each option is based on the 2012 NPV of the annual cost streams.

The results of the base cases economic analysis, summarized in Table 8, indicate that for the base case and price sensitivity analyses, Option (1) produces superior economic results with Option (2) 18 percent higher on a net present value basis. Option (2) is more expensive as additional transformation capacity would still be needed at Strachan about 5 years after Esplanade is upgraded.

Table 8: Economic Comparison of Alternatives (NPV)

Options	(1) 2014 Bremner-Phase 1 2021 Bremner –Phase 2 2030 Esplanade	(2) 2016 Esplanade 2021 Strachan 2030 Bremner	Difference (NPV) (2) – (1)	Difference (Percent)
Base case	$281	$333	$51	18%
Price Sensitivity:				
Price escalation 6%	$303	$374	$71	24%
Price escalation 4%	$262	$297	$34	13%
Discount rate 4.5%	$319	$403	$84	26%
Discount rate 7.5%	$251	$278	$27	11%

Notes:

(1) All results in millions of dollars (net present value of all investment costs over 18 years)
(2) Base case assumptions include discount rate of 6 percent and real price escalation rate of 5 percent

Sensitivity Analysis – HONI Station Costs

Because the level of certainly of cost estimates for HONI upgrades is less than the cost of THESL upgrades, additional sensitivity analysis was conducted by varying the portion of HONI costs at Strachan, Esplanade and Bremner. The sensitivity cases include a 25 percent cost reduction for HONI's portion of the Esplanade and Strachan station upgrades. Table 9 presents these results, which confirms that Option (1) – Construct Bremner in 2014, is the preferred option. As well, the risk associated with the additional time needed to design, approve and construct the

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HONI stations still makes the Bremner options superior even if the results of the economic analyses are the same.

Table 9. Economic Analysis – Capital Cost Sensitivity for HONI Upgrades

Options	(1) 2014 Bremner-Phase 1 2021 Bremner –Phase 2 2030 Esplanade	(2) 2016 Esplanade 2021 Strachan 2030 Bremner	Difference (NPV) (2) – (1)	Difference (Percent)
Base case	$281	$333	$51	18%
25% reduction in cost for HONI upgrades: Esplanade & Strachan	$266	$288	$22	8%

From the base case and sensitivity analysis, NCI recommends that THESL proceed with the development of the new Bremner station. Our recommendation is based on several compelling factors, including an available site in a critical downtown location, the electrically central location of the station, the ability to back-up feeders from adjacent substations and the need to provide back-up to Windsor while switchgear is replaced.

Environmental Factors and Site Selection

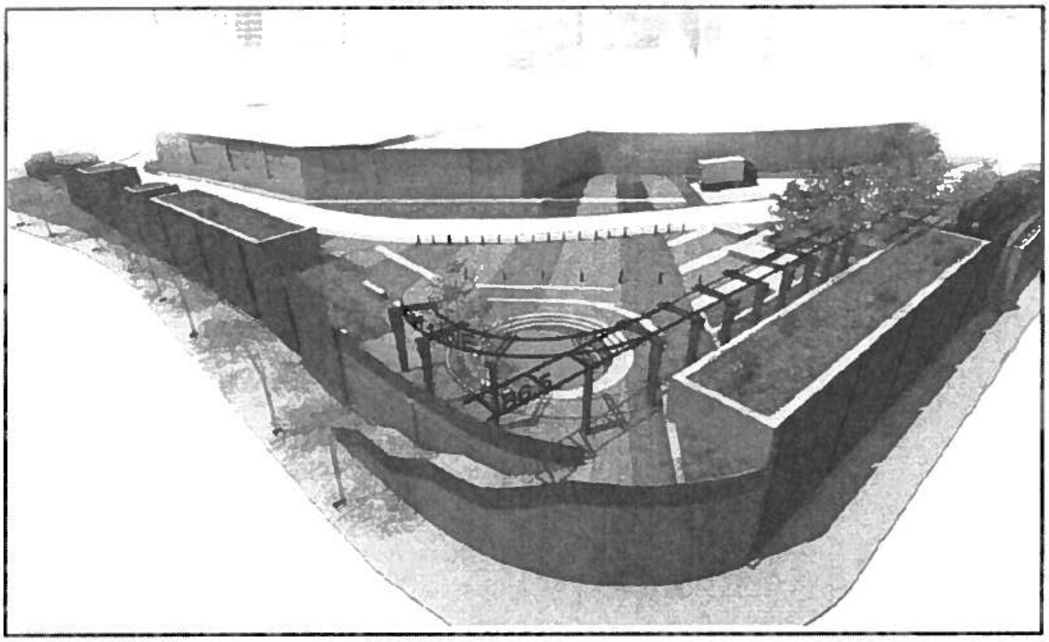
This section highlights our investigation of environmental impacts associated with development of the proposed Bremner Substation. It includes an assessment of the net impacts on environmental, aesthetics, traffic, and other locational factors.

Site Selection and Aesthetics

The proposed Bremner station is located on Railway lands and adjacent to the Roundhouse station. Recognizing the historical significance of the site, THESL has created an integrated design to ensure the new station blends aesthetically with other current and proposed uses for the property. Similar to other downtown stations, most equipment at the proposed Bremner station will be enclosed, visually separate from public viewing corridors. The aesthetics of the building enclosure will improve the appearance of the area. Figure 8 illustrates the conceptual design of the proposed Bremner station, whose enclosure integrates well with the existing Roundhouse design, construction and public access. (Attachment II provides additional details.)

The site roughly measures 50 by 100 meters, and is located at the intersection of Bremner Boulevard and Rees Street. It is located opposite of the CN Tower and Rogers Centre. Notably, most electrical equipment will not be visible from the public view shed, as major equipment such as transformers, breakers and the station bus will be located at street-level, below the public walk lanes and enclosed by walled sections (lower level). Equipment installation and access for maintenance is enhanced by the adjacent roadways, which provides for easy egress for vehicles and equipment. Further, the need for noise mitigation (e.g., transformer hum) is minimized by background noise created by vehicular traffic on the nearby Gardiner Expressway.

Figure 8: Proposed Bremner Station Enclosure



Environmental Assessment

The Bremner station, unlike other HONI and THESL stations, will include gas-insulated transformers and breakers, thereby eliminating the need for oil containment equipment and enclosures. The station design and construction also will comply with all relevant sections of the Ontario Energy Board's (OEB) Distribution System Code and applicable safety codes.

The impact on area traffic will be minimal as the site is unmanned and crew visits are infrequent. Crew visits include monthly site inspections and planned maintenance of electrical equipment. Planned maintenance of major equipment typically is performed annually.

Summary Assessment and Conclusions

The construction of new 115/13.8kV stations in Toronto is uncommon, as the last new station constructed was Gerrard in 1998. The results of our investigation indicate new station capacity is needed to serve downtown Toronto by 2017. Of the options considered, the construction of a new station adjacent to the Railway yards site with an in-service date of 2014 is the best choice from an economic and technical perspective. The new Bremner TS would be located in an ideal location in the downtown core, which would improve area reliability and enhance operating flexibility. Once constructed, another new station likely will not be needed for another 25 years.

Specific results and findings supporting our recommendation include the following:

1. Installation of a new station at the proposed Bremner site will provide back-up to the Windsor station to enable replacement of equipment without compromising reliability. It will allow THESL to replace the critical station equipment at the existing Windsor station, at task which is prohibitively expensive and difficult without adequate supplemental or back-up capacity from adjacent stations.

2. The downtown Toronto area will need additional station capacity by 2017. The existing five stations serve nearly 1000 MW of critical load and cannot accommodate new demand without additional station capacity, either by expanding existing or adding new stations.

3. The upgrade and expansion of three of the five existing stations and associated underground distribution feeders in the downtown is neither practical nor cost-effective. Expansion of the Esplanade and Strachan stations and installation of feeder ties in 2016 and 2021 would meet capacity needs and provide sufficient capability to unload Windsor; however, a new station will be needed in downtown Toronto by 2030. Further, expansion of these stations in the near-term is not a cost-effective solution to meeting near-term area reliability or capacity needs.

4. Current Conservation and Demand Management (CDM) programs will not defer the need for additional station capacity in downtown Toronto. Accelerated efforts and targeted CDM also will not materially defer the need for station capacity in downtown Toronto. A large DG unit with firm capability could defer the need for new capacity; however, there is no indication at this time that firm DG in amounts needed to meet capacity deficits will be installed to prior to need dates, nor does it provide the back-up needed to replace switchgear at Windsor.

5. Of the options considered for a new station, the Railway yards site is preferred as it is centrally located in high density load area, on land which has been purchased, will have minimal noise impact, provides easy access to electric equipment, and minimizes the amount and cost of new transmission taps from HONI 115kV system.

6. Installation of the new Bremner station would enhance reliability in critical downtown load centers to be consistent with those of utilities serving other large North American urban centers. Installation of a new Bremner substation will enable THESL to achieve a level of reliability in Toronto similar to utilities that serve major urban centers in North America and cities worldwide. The other options evaluated generally do not provide the same level of reliability benefit.

7. Of all capacity expansion options considered, installation of a new station at Bremner in 2014, followed by additional transformer in 2021, and the expansion of Esplanade in 2030 is the preferred solution based on net present value economics.

8. The installation of a new station at Bremner will improve operating flexibility, including the ability to transfer load via inter-station switchgear ties, which will facilitate maintenance and reduce outage restoration time.

9. The site and enclosure where the Bremner station equipment will be located is highly desirable from an electrical standpoint, as it is located in area where load density is highest, and where electric demand is most likely to increase. Because vacant land is at a premium in the downtown area, another suitable site may not be available if the Railway land is not used by THESL for a new station.

10. The proposed Bremner site has been designed to blend favorably with the Railway Roundhouse and will improve the overall appearance and public access to proposed enhancements.

For the above reasons, NCI recommends that THESL proceed with the development of the proposed Bremner station, consistent with currently proposed design and construction time frames.

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Attachment 1: Distributed Generation Potential in Toronto

Technical Potential and Expected Market Penetration of DG (MW)
(Listed by Technology)

	Technical Potential (MW)							
Project Size	Diesel Backup w/ SCR	Gas Engine	CHP	Fuel Cell CHP	Multi-Residential CHP	Micro-CHP	Non-Residential PV	Residential PV
100-500 kW	60	60	170	-	84	210	1,000	300
0.5 - 1 MW	40	40	90	-	-			
1-5 MW	60	60	230	150	-			
5-10 MW	20	20	150		-			
Total	180	180	640	150	84	210	1,000	300
Expected Range on Market Penetration (MW)	36-90	12-70	31-224	4-35	5-19	3-84	2-27	1-3

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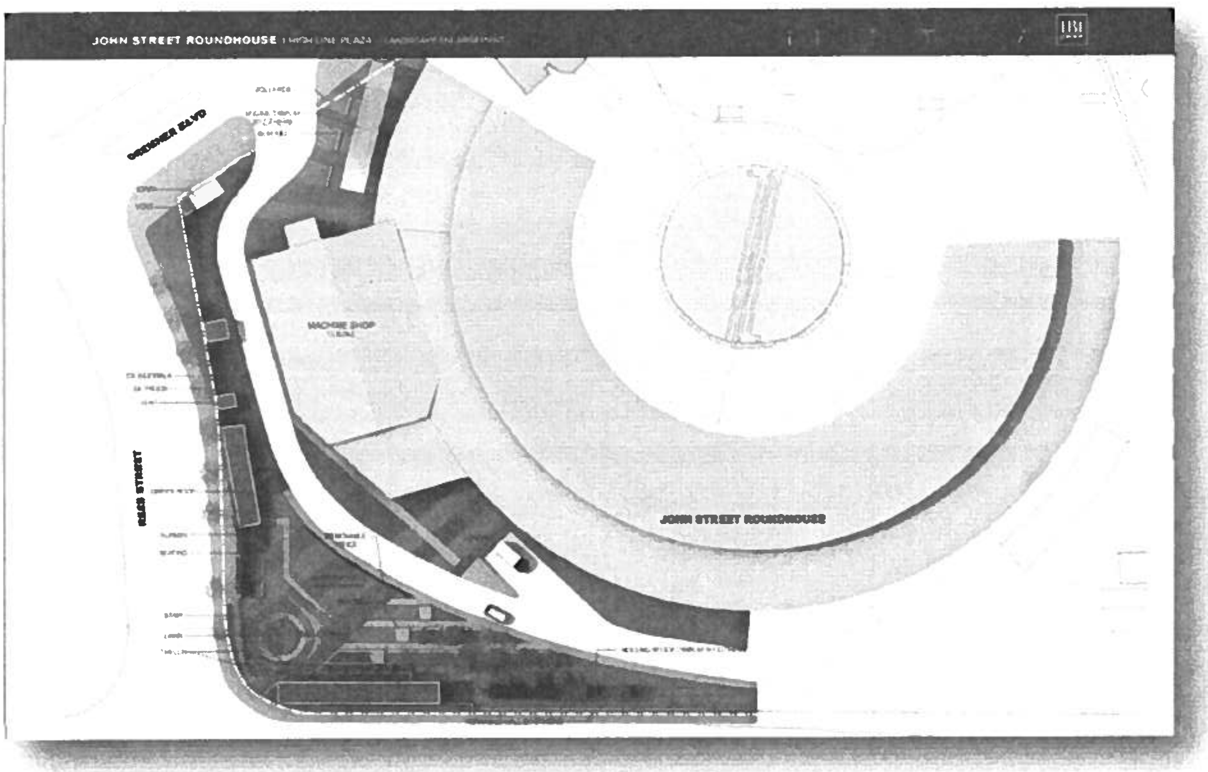
Attachment 2: Proposed Bremner Station Site Layout



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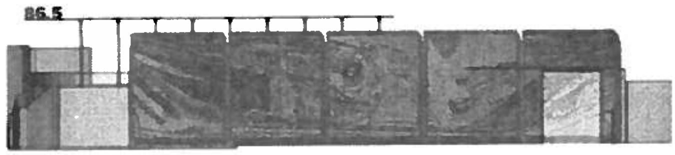
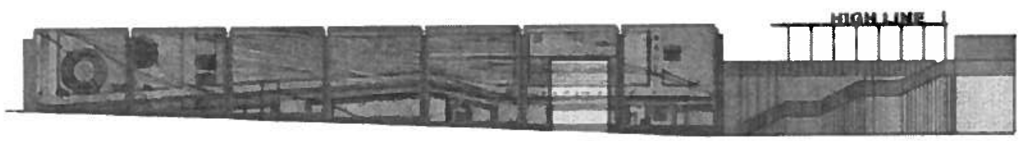
Bremner Station Site Layout – Cross-Sectional View

LAKE SHORE BOULEVARD ELEVATION



REES STREET ELEVATION



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Attachment 3: Report Revisions

Table 10. Revision History

November, 2009	Prepared as feasibility study
March 15th, 2012	Revised/Updated
April 17, 2012	Final Report Issued

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References

1. Toronto Hydro, *Distribution System Planning Guidelines*, November, 2007.
2. Toronto Hydro, *Distribution Construction Standards*, Various dates.
3. *Analysis of Failure Rates of Air Blast Breakers As A Function of Age And Usage*, 2003 IEEE Bologna PowerTech Conference, June 23-26, Bologna, Italy; George Anders, Henry KM Aciejewski, Bruno Jesus, Faruqr Emtulla.
4. Toronto Hydro Internal Report, *Interties to Provide Backup Capacity to Downtown Stations*, November, 2006.
5. Toronto Hydro-Electric System Limited, Hydro One Networks Inc. *Transformer Stations Planning Report*, December 11, 2008.
6. Navigant Consulting Inc., *Distributed Generation in Central and Downtown Toronto*, July 28, 2009.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 1:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 7, Table 1

Please provide the annual non-coincident demands of the Downtown Core for each year from 2000 to 2010 inclusive. Please break out the demands by each of the five transformer stations; and for each transformer station please break-out the demands by rate class.

RESPONSE:

Annual historic non-coincident demands for 2000 to 2010 for the five transformer stations that supply the downtown core are summarized below. THESL is not able to further break out the demands by rate class for each station.

STATION	NON-COINCIDENT PEAK (MVA)											
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
CECIL	145	150	161	149	148	158	159	169	168	177	180	188
ESPLANADE	158	157	165	156	153	159	165	168	162	170	197	180
STRACHAN	104	104	115	115	117	110	121	118	109	121	118	137
TERAULEY	215	229	234	239	224	231	229	194	201	188	225	190
JOHN / WINDSOR	304	307	313	289	289	300	303	284	283	300	303	311
TOTAL PEAK DEMAND	926	947	988	948	931	958	977	933	922	956	1,023	1,006

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 2:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 7, Table 1

Please provide the annual coincident demands of the Downtown Core for each year from 2000 to 2011 inclusive. Please break out the demands by each of the five transformer stations and for each transformer station please break out the demands by rate class.

RESPONSE:

Annual coincident demands for the five transformer stations that supply the downtown core have only been utilized since 2008. This information is summarized in the table below. THESL is not able to further break out the demands by rate class for each station.

STATION	COINCIDENT PEAK (MVA)			
	2008	2009	2010	2011
CECIL	164	176	181	187
ESPLANADE	164	169	176	180
STRACHAN	104	119	117	138
TERAULEY	194	188	185	190
JOHN/WINDSOR	277	295	303	311
TOTAL PEAK DEMAND	903	947	962	1,006

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 3:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 7, Table 1

Please provide the forecast coincident demands of the Downtown Core for each year from 2012 to 2021. Please break out the demands by each of the five transformer stations and for each transformer station please break out the demands by rate class.

RESPONSE:

The forecast coincident demands for the five transformer stations that supply the downtown core have been reproduced in the table below, based on information provided in Tab 4, Schedule 17, page 10-11 as well as Tab 4, Schedule 17, Appendix 2 and 3. THESL is unable to break out the demands by rate class.

Station	Station Rating	Year										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cecil	224	182	189	196	199	203	207	212	216	220	224	229
Esplanade	198	175	173	177	182	187	192	196	199	204	208	212
Strachan	175	122	127	130	131	133	140	143	147	151	153	157
Terauley	240	199	205	211	215	220	225	229	234	238	243	248
Windsor	340	304	306	315	324	328	335	342	349	355	362	371
Total	1177	982	1000	1029	1051	1071	1099	1122	1145	1168	1190	1217

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 4:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 3

Please provide a precise description of the service boundaries of each of the five downtown transformer stations, for example by listing the portions of the streets that constitute the boundaries between the service areas.

RESPONSE:

The following are the primary voltage boundaries between stations as shown in Tab 4, Schedule B17 Appendix 3 Figure 1. The nearest streets have been used to indicate the boundaries.

- Boundary between Cecil TS and Strachan TS: Dundas St W, Euclid Ave, and Queen St W
- Boundary between Strachan TS and Windsor TS: Spadina Ave
- Boundary between Windsor TS and Esplanade TS: Yonge St, Gardiner Expressway, and York St
- Boundary between Esplanade TS and Terauley TS: Church St and Adelaide St E
- Boundary between Windsor TS and Cecil TS: Richmond St W
- Boundary between Windsor TS and Terauley TS: Richmond St W, Bay St, and Adelaide St W

Station service boundaries are dynamic due to system modifications, and are therefore subject to change.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 5:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 3

Please provide an Excel spreadsheet with the demands of each of the five downtown transformer stations for every five minute interval in 2011.

RESPONSE:

Please refer to the loading information provided in response to PP interrogatories 1 to 3 (Tab 6F, Schedules 9-1 to 9-3). Planning for capacity increases is based on peak load demands. Data of finer granularity (such as loading at five-minute intervals) has not been used in Appendix 3, nor is it relevant to the business case presented. Furthermore, THESL cannot release loading data using five-minute intervals as it could potentially indirectly reveal confidential customer information.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 6:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 10, Table 4

Please provide all of the reports and analyses in Toronto Hydro's possession that justify its load forecasts for each of the downtown transformer stations.

RESPONSE:

Please refer to the following reports and analyses as justification of the load forecasts for each of the downtown transformer stations:

1) Load Growth – In Downtown Toronto Area (Tab 4, Schedule B17, Appendix 2)
2) Navigant Consulting: Downtown Toronto-Electric Supply Evaluation (Tab 4, Schedule B17, Appendix 3)
3) Excerpts from THESL's 2011 Load Forecast that are relevant to this production request: formed the basis for the information in the Bremner ICM application (attached as Appendix A)
4) Excerpts from THESL's 2012 Load Forecast that are relevant to this production request: an updated version of the 2011 load forecast (attached as Appendix B).

For the purposes of the Bremner TS ICM business case, the 2012 Load Forecast is not materially different from the 2011 Load Forecast.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 7:

Reference(s): **Reference: Tab 4, Schedule B17, Appendix 3, page 10, Table 4**

Has Toronto Hydro estimated the potential for incremental cost-effective energy efficiency and demand response options to reduce the demands of the downtown transformer stations between 2012 and 2026? If yes, please provide these estimates for each year from 2012 to 2026 inclusive and please break out the results by the service areas of each of the five transformer stations and for each transformer station please break out the demands by rate class. Please also provide the reports and analyses that support your estimates.

RESPONSE:

No, THESL has not developed an estimate of additional incremental energy efficiency and demand response options for the area served by the five downtown transformer stations. THESL's projections of the impact of energy efficiency and demand response activities are limited to province wide programs funded by the OPA until the end of 2014, as there is currently no mechanism for funding incremental energy efficiency and demand response programs on a localized basis. The estimated impact of the current OPA-funded programs is shown in Tab 4, Schedule B17, Appendix3, Table 2 (page 8).

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 8:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 17**

According to the Navigant Business Case Analysis:

> "The results of the study indicated significant technical potential for DG in Toronto, but amounts likely to be installed as uncertain. Estimates of the potential market penetration for customer-connected distributed generation in Central and Downtown Toronto ranged from 140 MW in the medium term to more than 550 MW in the long-term….
>
> One of the key findings of these studies is the difficulty of siting DG in dense downtown load areas, particularly on secondary grid networks….. The ability to install rotating devices (e.g., synchronous generators) is limited by fault current limits, and by the likely de-sensitization of network protectors, which are not designed to accommodate generators."

After Hydro One has completed its short-circuit upgrades at its Leaside, Hearn and Manby Transformer Stations, how many megawatts (MW) of natural gas-fired generation capacity will it be technically possible to install in the Downtown Core? Please break out this estimate according to the service areas of each of the five downtown transformer stations.

RESPONSE:

From a distribution system perspective, technical constraints are based on either short circuit levels (fault current), thermal capacity, or reverse power flow. The distribution system limits currently are Windsor TS (53 MW DG), Terauley TS (43 MW DG), Cecil TS (30 MW DG), Esplanade TS (19 MW DG) and Strachan TS (29 MW DG). This

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

totals 174 MW of synchronous DG as an area limit, ignoring any upstream transmission (Hydro One) constraints.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 9:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Please describe Toronto Hydro's programs, budgets and timetables to increase the amount of natural gas-fired generation capacity that can be installed in the Downtown Core.

Please quantify the incremental amount of natural gas-fired generation capacity (MW) that will be able to be installed in the Downtown Core in each year between 2012 and 2021 as a result of Toronto Hydro's actions.

Please break out your incremental capacity estimates by year and for the service areas of each of the five downtown transformer stations.

RESPONSE:

While THESL has no incentive programs to increase DG capacity in the downtown core, it does have a dedicated interconnections team which supports requests for new generation capacity, consistent with the Distribution System Code and other IESO and OEB requirements. THESL expects to prepare a GEA Plan submission to the OEB which aims to enable renewable generation and development of its smart grid.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 10:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 10 & 17**

According to the Navigant Business Case Analysis:

> "The results of the DG study indicate there is considerable uncertainty that customers will install DG in an amount sufficient to back up Windsor or to defer station capacity needed to serve downtown Toronto."

Please provide your estimates of the amount of the incremental natural gas-fired generation capacity that would be needed, in each year from 2017 to 2026 inclusive, to back up Windsor and defer station capacity needed to serve downtown Toronto.

RESPONSE:

The rationale for Bremner TS is primarily based on reliability and capacity.

1) Reliability:

   Windsor TS is a six-bus arrangement, each typically with a 69MVA capacity, with heavy loading on each bus reaching 85% station capacity in 2011. The required firm incremental DG needed to support one of these buses is estimated at 86 MW (assuming a PF=1.0) to allow a 25% reserve margin for DG outages. This 86 MW DG would potentially allow switchgear upgrades at Windsor to address reliability issues with a multi-year program.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

2) Capacity:

Bremner TS load is forecast to reach 116 MVA by 2026 and would require a further 145 MW DG to satisfy capacity due to area growth (using a 25% reserve and assuming a PF=1.0).

In total, there is expected to be a need for 86 MW (for reliability) and 145 MW (for capacity), or a total of 231 MW of new firm DG capacity tied directly to the Windsor TS bus. The fault capacity of the upstream system would need to accommodate approximately six times this value, or 1,386 MVA, which will not be available even after Leaside/Manby/ Hearn upgrades.

In addition, a DG solution in such a dense urban environment would likely create substantial air/noise emissions and would likely not provide the inherent reliability of paired transmission circuits.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 11:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Please describe Toronto Hydro's actions to persuade the Ontario Power Authority to contract for natural gas-fired distributed generation capacity to back up Windsor and to defer the need for additional transformer station capacity to serve downtown Toronto.

Please provide copies of all your correspondence with the OPA on this issue.

RESPONSE:

THESL is not directly advocating that the OPA contract for DG to back up Windsor TS. Work has been initiated on the Toronto Regional Plan, which involves the OPA, IESO, THESL and Hydro One. THESL expects that the Toronto Regional Plan will examine transmission, generation and conservation options. Results are expected to be available in mid-2013.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 12:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Would Toronto Hydro be willing to own and operate natural gas-fired generation capacity in downtown Toronto to back up Windsor and to defer the need for new transformer station capacity, if the Ontario Energy Board were to permit the inclusion of these assets in its rate base? If no, please explain why not.

RESPONSE:

THESL cannot provide a categorical response (i.e., 'yes' or 'no') because the question as posed is hypothetical and does not specify an adequate level of detail concerning other important factors which would bear on the decision. THESL has not previously considered this question because the arrangement is not permitted under current rules. If the hypothetical arrangement were to become permitted under changed rules, THESL would need to consider several other contingent factors including siting and financial feasibility, risks, and the extent to which generation capacity would defer the need for transformer station capacity, before it could come to a position on the proposal. Any further comment at this time would be purely speculative.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 13:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Has Toronto Hydro had any discussions with the City of Toronto regarding the City of Toronto owning such generation, with Toronto Hydro being responsible for operation and maintenance?

Have there been any similar discussions held with Enwave? If yes, please provide copies of all of your correspondence with the City of Toronto and/or Enwave on this issue.

RESPONSE:

THESL has not had discussions with the City of Toronto regarding the City owning gas-fired generation. Over the past decade, THESL has had exploratory discussions with Enwave regarding gas-fired generation opportunities in Toronto, but is not aware of any correspondence on this subject.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 14:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 11

According to the Navigant Business Case Analysis:

> "The greatest outage risk to customers in downtown Toronto is a catastrophic outage, such as the loss of multiple transmission supply lines…" (see Tab 4, Schedule B17, Appendix 3, page 11)

According to the Ontario Power Authority's Integrated Power System Plan:

> "An extreme event resulting in a Leaside station loss would result in the isolation of the Leaside system from the rest of the network for potentially several days….This leaves about 300 MW of load that would be unsupplied and rotating outages for this load would be required." (see EB-2007-0707, Exhibit E, Schedule 5, page 21)

Please fully describe Toronto Hydro's programs and budgets to eliminate or mitigate the risk of unsupplied load in Toronto in the event of the loss of Hydro One's Leaside Transformer Station.

RESPONSE:

The risk of unsupplied load from Bremner TS will be mitigated by having transmission line connections from both the West at John TS and from the East at Esplanade TS. There will also be redundant transformers and a high level of bus inter-connectivity at the station.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

Leaside TS is a Hydro One-owned station separate and distinct from Bremner TS. THESL does not have programs designed to eliminate or mitigate risks impacting Hydro One-owned facilities, but does routinely cooperate with Hydro One, the OPA, and the IESO in developing solutions to electricity supply issues affecting the Toronto area.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 15:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 11

Please provide your best estimate of the number of megawatts (MW) of diesel back-up generating capacity in the downtown core.

Please provide a break-out of your estimate according to the service areas of each of the five downtown transformer stations.

RESPONSE:

Based on discussions with industry suppliers and building owners, THESL estimates that approximately 150 MW of diesel back-up generation capacity exists in the downtown core. A break-out by service area of each of the downtown transformer stations is not available.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 16:

Reference(s): Tab 4, Schedule B17, Appendix 3, pages 15 & 16

Please state the number of peaksaver and peaksaver plus customers in the service areas of each of the five downtown transformer stations in 2011 and during the summer of 2012.

Please state the days during 2011 and 2012 when these customers were curtailed and please provide for each day the resulting reductions in the demands of

a) peaksaver; and
b) peaksaver plus customers

for each of the five downtown transformer stations.

RESPONSE:

The estimated number of ***peaksaver*** customers in the service areas of the five downtown transformer stations is detailed below. The ***peaksaverPlus*** program has only recently (September 2012) started, as THESL was awaiting ESA approval to commence installation of the equipment.

Transformer Station	Total Number of *peaksaver* Customers as of 2012
Cecil	234
Esplanade	186
Strachan	466
Terauley	25
Windsor	34
DOWNTOWN TOTALS	945

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

The *peaksaver* events in 2011 and 2012 are detailed below:

Event Day	Transformer Station	OPA-Assigned Reduction (kW)	THESL Actual Reductions (kW)
Jul-21-2011	Cecil	131	168
	Esplanade	104	134
	Strachan	261	336
	Terauley	14	18
	Windsor	19	24
DOWNTOWN TOTALS		529	680
Jun-20-2012	Cecil	131	176
	Esplanade	104	140
	Strachan	261	350
	Terauley	14	19
	Windsor	19	26
DOWNTOWN TOTALS		529	709
Jul-06-2012	Cecil	131	164
	Esplanade	104	130
	Strachan	261	326
	Terauley	14	18
	Windsor	19	24
DOWNTOWN TOTALS		529	662

Note:

The OPA credited reductions are based on provincial averages, as compared to THESL values which are based on measured actuals.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 17:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 15 & 16**

Please state the potential number of peaksaver and peaksaver plus customers in the service areas of each of the five downtown transformer stations.

RESPONSE:

THESL has an expected growth in the total number of residential demand response (RDR) customers (***peaksaver*** and ***peaksaverPlus***) customers of 25% by the end of 2014. As THESL does not have specific growth information at the transformer level, the data below has been extrapolated from this growth target for information purposes. The total number of potential RDR customers was determined by data analysis of single family residences that have air conditioning in the areas served by the five transformers.

Transformer Station	Total Number of Existing RDR Customers	Total Number of Potential RDR Customers	THESL Forecasted New RDR Customers by End of 2014	THESL Forecasted RDR Customers by End of 2014
Cecil	234	919	59	293
Esplanade	186	720	46	232
Strachan	466	1,837	118	584
Terauley	25	99	6	31
Windsor	34	124	8	42
DOWNTOWN TOTALS	945	3,700	238	1,183

Please note that the ***peaksaver*** program ended in August 2011 and was replaced by the ***peaksaverPlus*** program going forward.

Panel: Capital Projects

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 18:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 15 & 16**

Please provide a break-out of the number of the Ontario Power Authority's ("OPA") non-residential demand response program participants (e.g., DR1, DR2, DR3) in the service areas of each of the five downtown transformer stations in 2011 and the summer of 2012.

Please state the days during 2011 and 2012 when these customers were curtailed and please provide for each day the resulting reductions in demand for each of the five downtown transformer stations.

RESPONSE:

Information regarding specific DR-3 participants is not available to THESL due to contractual obligations between the aggregators and participants. There has been no DR1 and DR2 program participation in THESL's service territory.

DR-3 was activated on the following days in 2011:
May 31, June 6, June 7, June 8, July 11, July 21, July 22, August 2, August 4, November 21, and November 22.

To date, DR-3 has been activated on the following days in 2012:
June 20, June 21, July 17, September 5, and September 6.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 19:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 15 & 16**

Has Toronto Hydro requested funding from the OPA for incremental conservation and demand management programs to defer the need for new transformer station capacity in downtown Toronto?

If yes, please provide copies of all your correspondence with the OPA on this issue.

If no, please explain why not.

RESPONSE:

No. The OPA only funds programs that address provincial conservation demand reduction targets. These programs are available to all local distribution companies and are by their nature not designed to address local distribution issues and constraints.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 20:

Reference(s): Tab 4, Schedule B17, Appendix 3, pages 15 & 16

According to the Navigant Business Case Analysis:

> "Equally important is the compelling need to change out obsolete and heavily loaded switchgear busses at Windsor. One of the primary reasons new station capacity is needed downtown is to provide back-up support while switchgear is sequentially removed and upgraded at Windsor. Several of the busses at Windsor will soon be overloaded. Table 5 presents Windsor bus load forecast, indicating overloads by 2014. Because of the grid network configuration and load location, further balancing of load among the busses is difficult." (pages 10 & 11)
>
> "Current Conservation and Demand Management (CDM) programs will not defer the need for additional station capacity in downtown Toronto. Accelerated efforts and targeted CDM also will not materially defer the need for station capacity in downtown Toronto. A large DG unit with firm capability could defer the need for new capacity; however, there is no indication at this time that firm DG in amounts needed to meet capacity deficits will be installed to prior to need dates, nor does it provide the back-up needed to replace switchgear at Windsor." (page 29)

According to Table 4 of the Navigant Business Case Analysis, the peak demand at Windsor in 2011 was 304 MW. How long would it take to replace a switchgear bus at Windsor? How many MW of capacity would be lost while a switchgear bus is being replaced? How many MW of conservation and demand management or distributed generation is needed to provide back-up when a switchgear bus at Windsor is replaced?

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

RESPONSE:

A switchgear replacement project such as the planned replacement of A5-6 at Windsor TS could span up to three years. This would include all engineering, procurement, construction and commissioning processes. The entire capacity of the existing bus would be lost during replacement. For a Windsor TS bus, this is 72MVA. THESL does not accept the premise of the question that conservation and demand management or distributed generation could provide back-up when a switchgear bus at Windsor TS is replaced. In theory, at least 72MVA of firm, highly reliable capacity would need to be installed locally to support the replacement of a Windsor TS bus.

Jack Gibbons

From:	Yianni Soumalias <YSoumalias@enwave.com>
Sent:	December-12-12 8:41 AM
To:	'Jack Gibbons'
Subject:	FW: Enwave CW Tunnels
Attachments:	20121212082718411.pdf

Hi Jack,

The attached document indicates where Enwave's CW Tunnels are located.

The rest of our CW distribution system is direct buried which is why I have only included the tunnels.

Please let me know if you require anything further.

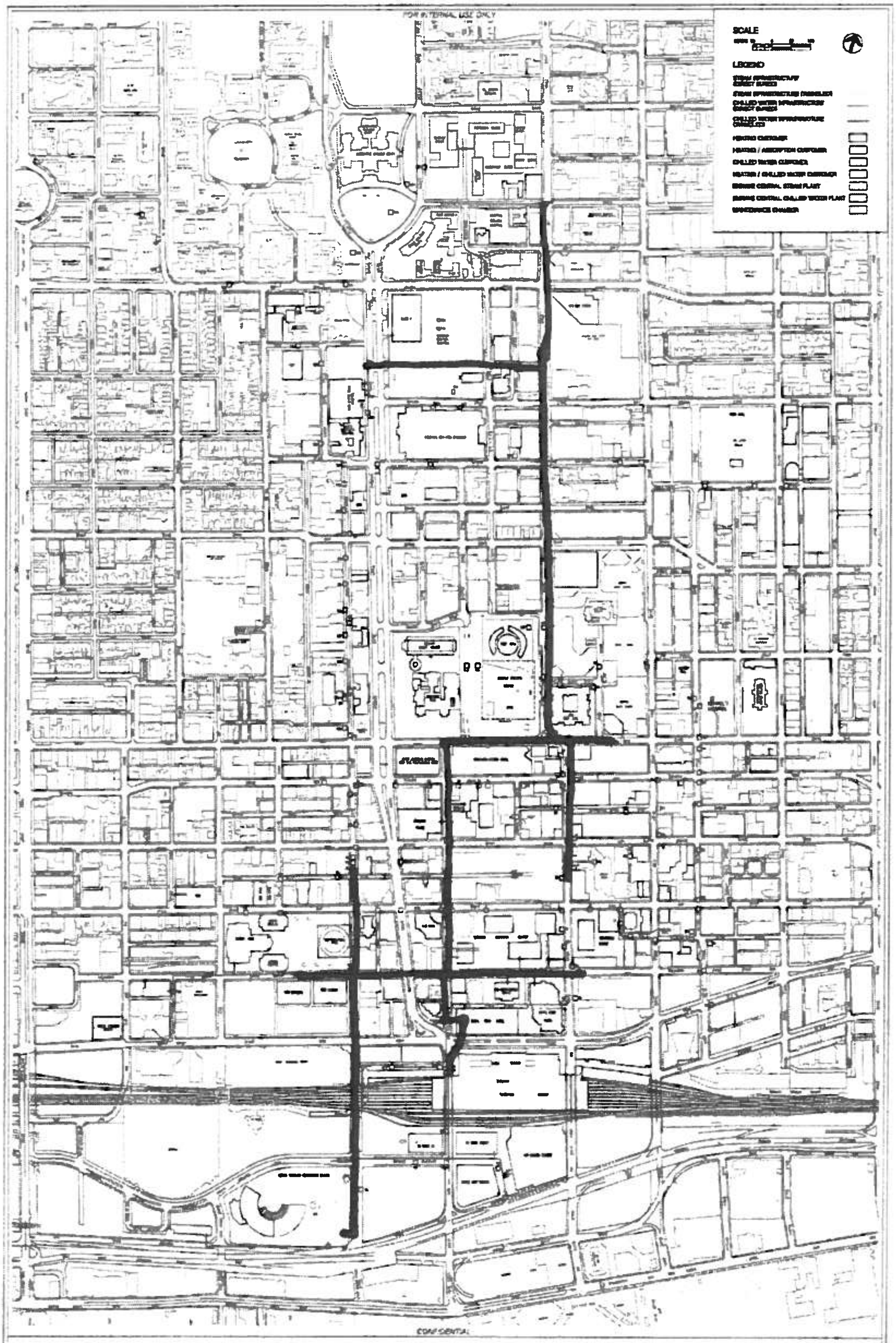
Thanks,

Yianni

-----Original Message-----
From: support@enwave.com [mailto:support@enwave.com]
Sent: Wednesday, December 12, 2012 8:27 AM
To: Yianni Soumalias
Subject:

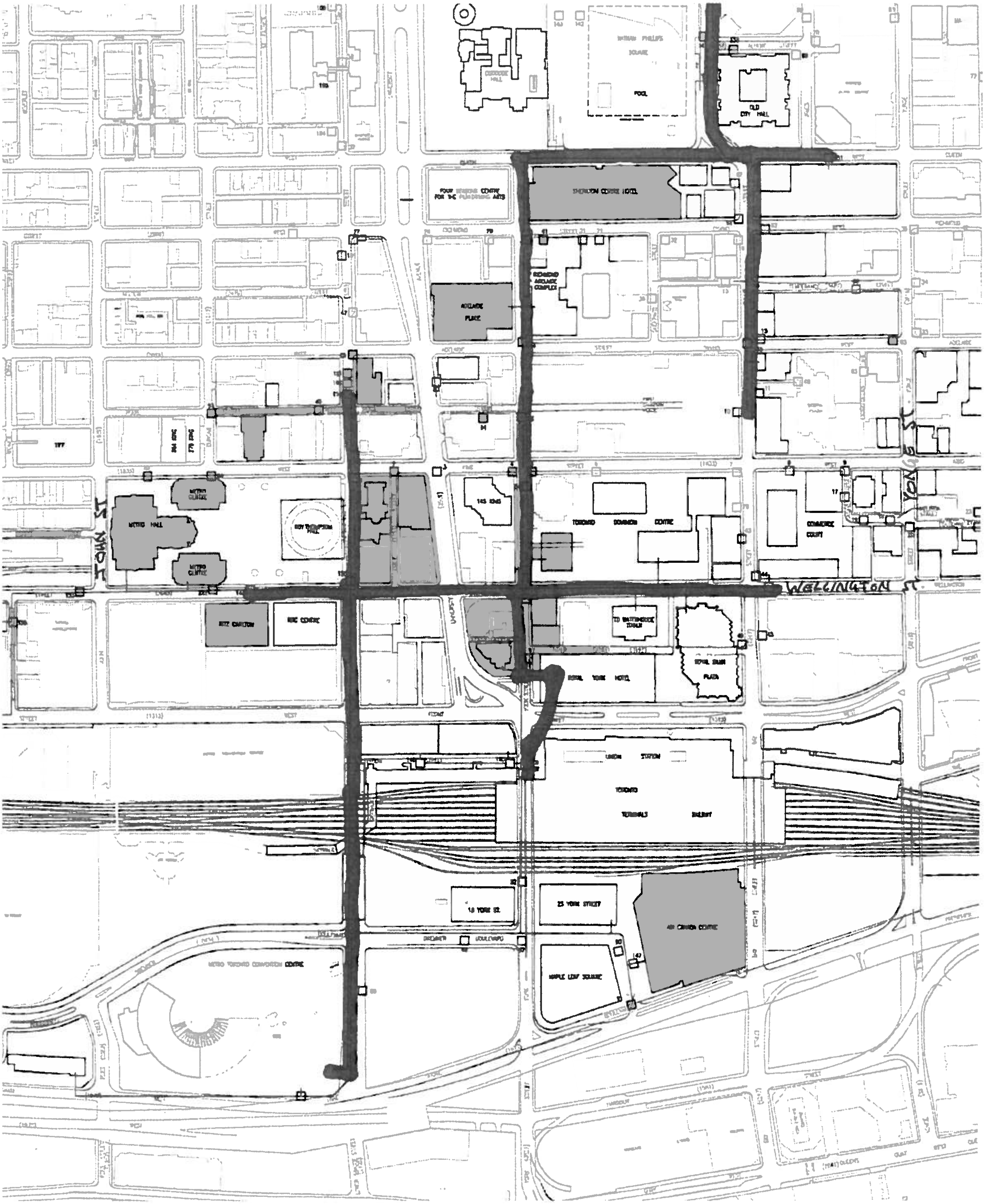
This E-mail was sent from "RNPEF919A" (Aficio MP C5000).

Scan Date: 12.12.2012 08:27:18 (-0500)
Queries to: support@enwave.com



DISTRICT HEATING AND COOLING SYSTEMS
MAY 2012

ENWAVE ENERGY CORPORATION
181 UNIVERSITY AVENUE, SUITE 1710
P.O. BOX 105
TORONTO, ONTARIO, M5H 3M7


NATHAN PHILLIPS SQUARE
OLD CITY HALL
FOUR SEASONS CENTRE FOR THE PERFORMING ARTS
SHERATON CENTRE HOTEL
ADELAIDE PLACE
RICHMOND ADELAIDE COMPLEX
METRO HALL
METRO CENTRE
ROY THOMSON HALL
145 KING
TORONTO DOMINION CENTRE
COMMERCE COURT
JOHN ST
YONGE
WELLINGTON ST
RITZ CARLTON
RBC CENTRE
ROYAL YORK HOTEL
ROYAL BANK PLAZA
UNION STATION
TORONTO TERMINALS RAILWAY
10 YORK ST.
25 YORK STREET
AIR CANADA CENTRE
MAPLE LEAF SQUARE
METRO TORONTO CONVENTION CENTRE

The Bremner Transformer Station vs. Energy Conservation and Distributed Generation

ONTARIO CLEAN AIR ALLIANCE RESEARCH | www.cleanairalliance.org

DECEMBER 18, 2012

As a result of the Ontario Power Authority's failure to aggressively pursue all of Toronto's cost-effective energy conservation and distributed generation opportunities, downtown Toronto's electricity demand may exceed its supply capacity in the future. In response, Toronto Hydro is proposing to build a new $272 million transformer station, near the CN Tower, to supply more electricity to downtown Toronto's office buildings and condos on hot summer days when their air conditioners are running full out.[1] This doesn't make sense since Toronto's electricity needs can be met at a lower cost *and* more securely by a combination of energy conservation and distributed generation (e.g., solar PV and combined heat and power).

Fortunately, Toronto Hydro and the Ontario Power Authority are currently working on a Toronto Regional Electricity Supply Plan which will examine all the options to meet our electricity needs including energy conservation and distributed generation. Therefore, by working together, they now have the opportunity to develop a smart plan to lower our energy bills and move Toronto to a clean, green and reliable energy future.

Lower Cost

Energy conservation and distributed generation are a lower cost option since they avoid the need for:

a) The proposed $272 million Bremner Transformer Station;

b) A $600 million third transmission line to serve downtown Toronto (e.g., the East Toronto Transmission Line)[2]; and

c) $3.2 billion of new nuclear generation capacity.[3]

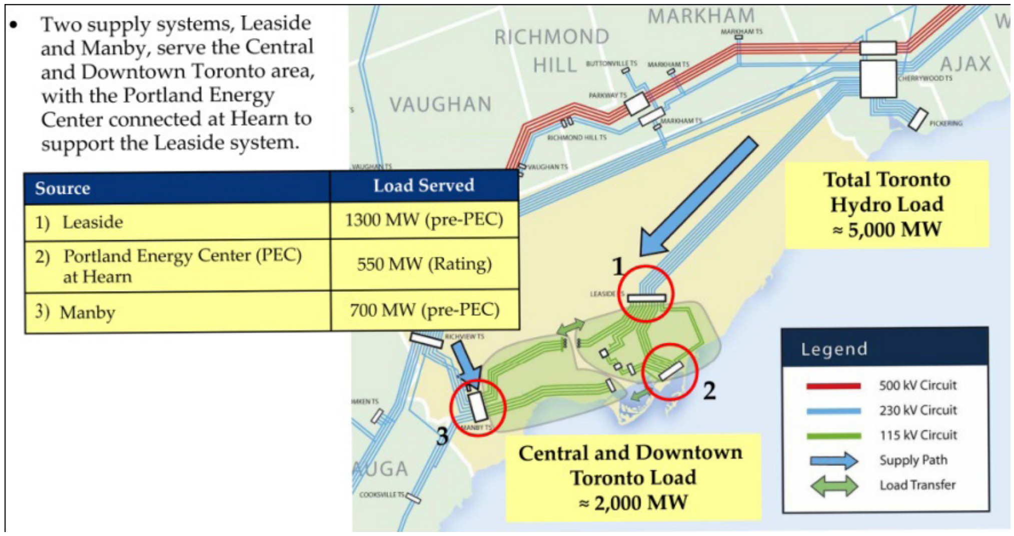
That is, energy conservation and distributed generation can avoid approximately $4 billion of conventional electricity supply-side infrastructure.

More Secure Supply

In addition, unlike the proposed Bremner Transformer Station, energy conservation and distributed generation can also ensure that the lights will stay on in downtown and central Toronto if Hydro One's Leaside Transformer Station unexpectedly goes out of service.

Thanks to the Taylor Irwin Family Fund at the Toronto Community Foundation for their generous financial support.

Figure 1: Downtown Toronto's Major Electricity Supply Sources



Currently, virtually all of downtown and central Toronto's electricity is provided by just three sources:

a) The Portlands Generating Station on the waterfront;

b) Hydro One's transmission lines that bring electricity from east of Toronto to its Leaside Transformer Station; and

c) Hydro One's transmission lines that bring electricity from west of Toronto to its Manby Transformer Station in Etobicoke.

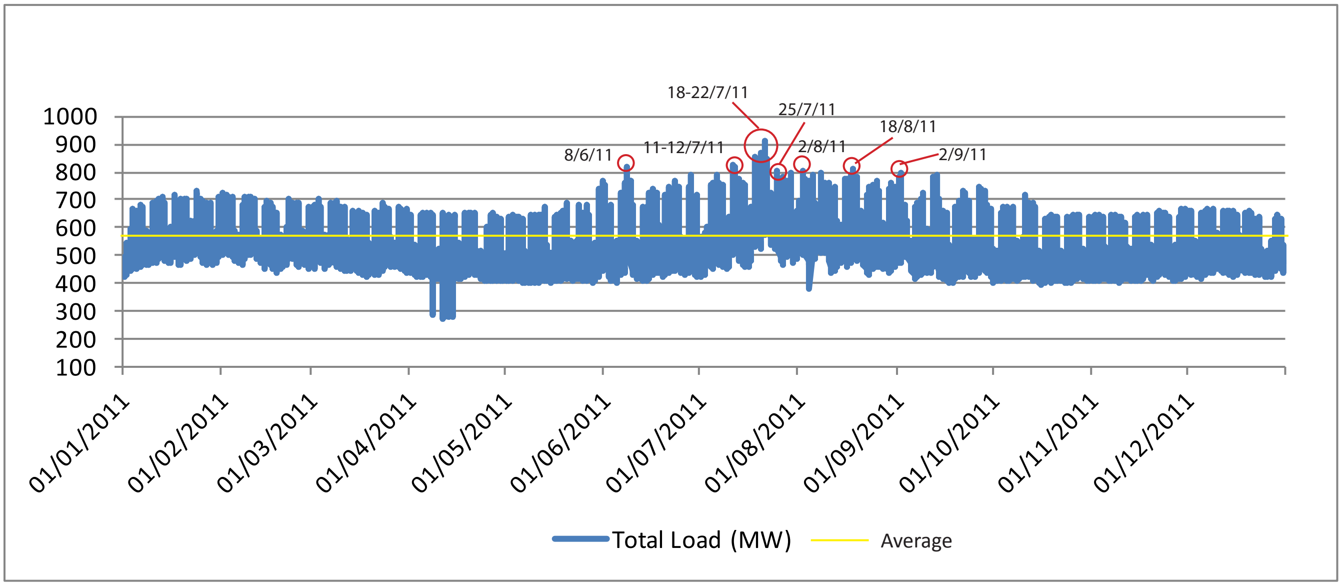
According to the Ontario Power Authority, if the Leaside Transformer Station loses power, downtown and central Toronto would experience a 300 megawatt (MW) power shortage, which would lead to rotating black-outs.[4] By investing in energy conservation and efficiency and by installing small scale solar PV and combined heat and power plants in downtown and central Toronto, we can keep the lights on even if we lose one of our three major electricity supply sources.

At present, Toronto can meet only approximately 13% of its peak day electricity needs from local sources.[5] On the other hand, New York City is required by the New York State Reliability Council to be able to meet 80% of its peak day electricity needs from power plants located within NYC.[6]

Downtown Toronto's Load Profile

The chart on page 3, which plots downtown Toronto's demand for electricity during every hour of 2011, reveals a number of important facts. First, the demand for electricity spikes on a dozen very hot summer days when the downtown office towers' and condos' air-conditioners are running full out. Second, on these days, the peak hourly demands for electricity can be more than 50% higher than downtown Toronto's annual average demand of 564 MW. Third, these summer needle peaks last for only a few hours at a time.

Figure 2: Downtown Toronto's Hourly Electricity Demand in 2011



Toronto Hydro Load Forecast

The summer peak day demand in downtown Toronto was 914 megawatts (MW) in 2011.

According to Toronto Hydro, downtown Toronto's electricity demand on hot summer days will exceed the capacity of its existing transformer stations to deliver electricity from the Hydro One high-voltage transmission grid starting in 2017.

Table 1: Forecast Electricity Demand in Excess of Existing Transformer Station Capacity on Hot, Summer Days in Downtown Toronto[7]

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2 MW	9 MW	20 MW	33 MW	54 MW	71 MW	92 MW	111 MW	134 MW	151 MW

The demand/supply imbalance can be eliminated by Made-in-Toronto energy conservation and distributed generation investments which will reduce the need for electricity from outside of Toronto to power downtown Toronto's air-conditioners.

Energy Conservation Opportunities

Toronto's electricity consumption per person is 56% higher than that of New York City.[8] As a result, there is a huge untapped energy efficiency potential in downtown Toronto's buildings.

The Building Owners and Managers Association (BOMA), the Real Property Association of Canada (REALpac), the Greater Toronto CivicAction Alliance and the City's Better Building Partnership all have programs to encourage and help building owners to reduce their energy consumption.

In addition, Enwave is planning to expand its Deep Lake Water Cooling system which will reduce the need for electricity for cooling.

Toronto Hydro's and the Ontario Power Authority's (OPA) payments to building owners to *reduce* their wasteful electricity consumption are dramatically lower than the OPA's payments to power companies to *produce* electricity. Specifically, their payments to building owners to save electricity can be 1 cent per kWh or less.[9] The OPA should be willing to pay building owners up to the same amount to save a kWh that it pays nuclear power companies to produce a kWh.

Unfortunately, the promotion of energy conservation is **not** a profitable course of action for Toronto Hydro. In fact, the utility is actually encouraged to under invest in conservation. All of the funding for Toronto Hydro's conservation programs is provided by the OPA. And according to the OPA-Toronto Hydro funding agreement, Toronto Hydro can earn a profit bonus of up to $8.5 million by *under spending* its conservation budget even if it fails to achieve its minimum energy conservation targets established by the Ontario Energy Board.[10]

Distributed Generation

Solar PV

Solar photo-voltaic (PV) is the ideal supply option to help meet downtown Toronto's peak day electricity needs since its maximum output occurs on the hot sunny afternoons when the air-conditioners are running full out. According to a report prepared for Toronto Hydro and the Ontario Power Authority, there is the potential for 1,300 MW of solar PV to be installed in downtown and central Toronto.[11]

Combined Heat & Power

Virtually every building in Toronto uses natural gas to provide just one service, namely, heat. It is much more efficient to use these same molecules of natural gas to simultaneously produce heat and electricity. This is what combined heat and power (CHP) plants do. As a result, they can have an overall energy efficiency of 80-90%.

While the University of Toronto and the Senator David Croll Apartments on Bloor Street already have combined heat and power plants, Toronto has a huge untapped CHP potential. In fact, according to a report prepared for Toronto Hydro and the Ontario Power Authority, there is the potential for 1,000 MW of CHP in downtown and central Toronto.[12]

1. CHP plants should be installed at Toronto's downtown hospitals (e.g., Sick Kids, St. Michael's, Toronto Western) to ensure that they will be able to operate at full capacity during a black-out.

2. Enwave's district energy system provides heating for 140 institutional, commercial and government buildings in downtown Toronto. The heat is provided by gas-fired boilers located at its Walton Street, Pearl Street and Queen's Park stations. These steam plants should be converted to CHP to increase their energy efficiency and to increase our electricity supply security.
3. Toronto Community Housing Corporation's gas boilers at Regent Park, St. James Town and Moss Park should be converted to CHP to save money and ensure that the lights will stay on in these communities if there is a black-out.
4. Northland Power's 90 MW CHP project on the Toronto waterfront should proceed. In addition to producing electricity this project would provide steam for Redpath Sugar, the proposed new buildings on the LCBO property, and other Waterfront Toronto developments in the East Bayside.

Short-Circuit Constraints

When the short-circuit upgrades to Hydro One's Leaside, Hearn and Manby Transformer Stations are completed in 2013 & 2014[13], it will be possible to connect up to 490 MW of CHP or 733 MW of solar PV to the Toronto Hydro grid in downtown and central Toronto.[14] In addition, there are many low-cost technical fixes that can be implemented to permit additional CHP and solar PV to be connected to Toronto Hydro's distribution grid.[15]

Back-Up for the Windsor Transformer Station

According to Toronto Hydro, the proposed Bremner Transformer Station is also needed to provide back-up for its Windsor Transformer Station while its obsolete switchgear equipment is replaced. However, the needed back-up can be provided at a much lower cost (approximately $22 million) by installing feeder ties from the Esplanade or Strachan Transformer Stations to Windsor.[16]

The Smart Solution

The smart solution to meet downtown Toronto's electricity needs is to pursue all of our cost-effective energy conservation, renewable energy and combined heat and power options before considering building a new transformer station to facilitate the import of more higher-cost nuclear power. However, this integrated, least-cost solution will require the support of the Ontario Power Authority, which provides the financing for: a) Toronto Hydro's energy conservation programs; and b) all of the province's new electricity supply resources.

Fortunately, Toronto Hydro is currently working with the Ontario Power Authority to develop a Toronto Regional Electricity Supply Plan. The Plan, which will examine all the options to meet our electricity needs, including energy conservation and distributed generation, will be publicly released by April 2013. Therefore, by working together, Toronto Hydro and the Ontario Power Authority have the opportunity to develop a smart plan to lower our energy bills and move Toronto to a clean, green and reliable energy future.

Specifically, Toronto City Council and the Government of Ontario should request Toronto Hydro and the Ontario Power Authority to develop a plan which will ensure that:

1. all the cost-effective, reliable and feasible energy conservation and demand management opportunities in the City of Toronto are implemented;
2. all the cost-effective, reliable and feasible renewable energy opportunities (e.g., deep lake water cooling, geo-thermal, solar thermal and solar PV) in the City of Toronto are implemented;
3. Toronto will not be subject to rolling black-outs if the Leaside Transformer Station unexpectedly goes out of service;
4. all of Toronto's hospitals, emergency facilities and subways will be able to operate at full capacity in the event of a provincial or North American black-out;
5. Enwave's Walton Street, Pearl Street and Queen's Park steam stations are converted to combined heat and power (CHP);
6. Toronto Community Housing Corporation's gas boilers at Regent Park, St. James Town and Moss Park are converted to CHP;
7. Northland Power's CHP and district energy project on the Toronto waterfront proceeds; and
8. the promotion of energy conservation is a profitable course of action for Toronto Hydro.

Endnotes

1 The cost of phases 1 & 2 are $195 million and $77 million respectively. Navigant Consulting, *Business Case Analysis: Downtown Toronto-Electric Supply Evaluation*, Prepared for Toronto Hydro Electric System, (April 2012), pages 21 & 26.

2 Ontario Power Authority, *Ontario's Integrated Power System Plan: Discussion Paper 7: Integrating the Elements – A Preliminary Plan*, (November 15, 2006), page 114.

3 According to the Ontario Power Authority, three hundred megawatts (MW) of energy conservation and/or distributed generation is needed to avoid rolling blackouts in downtown and central Toronto if the Leaside Transformer Station unexpectedly goes out of service. Furthermore, 300 MW of energy conservation and distributed generation in Toronto will avoid the need for 300 MW of new nuclear generation outside of Toronto. According to the result of a 2009 Government of Ontario competitive bidding process, the cost of new nuclear generation is $10.8 million per MW. Ontario Power Authority, *Integrated Power System Plan*, (2007), Exhibit E, Schedule 5, page 21; and Tyler Hamilton, "Nuclear bid rejected for 26 billion reasons", *Toronto Star*, (July 14, 2009).

4 Ontario Power Authority, *Integrated Power System Plan*, (2007), Exhibit E, Schedule 5, page 21.

5 The Portlands Generating Station has a capacity of 550 MW. There are 552 distributed generation facilities in Toronto with a total capacity of 87.6 MW. Toronto's peak day demand in 2011 was 4,919 MW. Anthony Haines, President & CEO, Toronto Hydro Corporation, *Electricity Infrastructure and Economic Development* in Toronto, Power Point Presentation to City of Toronto Economic Development Committee, (October 16, 2012), page 15; and Ontario Energy Board, *2011 Yearbook of Electricity Distributors*, (September 13, 2012), page 66.

6 Email to Jack Gibbons from Paul DeCotis, Director, Energy Analysis, New York State Energy Research and Development Authority, (March 6, 2007).

7 The Navigant forecast of excess demand was expressed in mega volt-amperes (MVa) which we have converted to megawatts (MW) by multiplying by 0.93. Navigant Consulting, *Business Case Analysis*, page 10.

8 New York City's electricity consumption per person in 2011 was 6,557 kWh (54,060 GWh/8,244,910 people). Toronto's electricity consumption per person in 2011 was 10,223 kWh (25,592 GWh/2,503,281 people). Ontario Energy Board, *2011 Yearbook of Electricity Distributors*, (September 13, 2012), page 66; New York Independent System Operator, *Power Trends 2012: State of the Grid*, page 17; and www.nyc.gov/html/dcp/html/census/popcur.shtml.

9 Toronto Hydro's and the OPA's payments to building owners to save electricity are 10 cents per kWh for the first year's electricity savings. If the energy efficiency investment provides savings for ten years then this payment is equal to 1 cent for each kWh of the investment's life-cycle savings. https://www.torontohydro.com/sites/electricsystem/electricityconservation/businessconservation/Pages/RetrofitProgram.aspx

10 Ontario Clean Air Alliance, *An Energy Efficiency Strategy for Ontario's Homes, Buildings and Industries*, (October, 2011), page 30.

11 Navigant Consulting, *Central and Downtown Toronto Distributed Generation: Final Report*, (July 28, 2009), Prepared for Toronto Hydro Electric System and Ontario Power Authority, page 2.

12 Navigant Consulting, *Central and Downtown Toronto Distributed Generation: Final Report*, (July 28, 2009), Prepared for Toronto Hydro Electric System and Ontario Power Authority, page 2.

13 Ontario Energy Board Docket No. EB-2012-0031, Exhibit D1, Tab 3, Schedule 3, Appendix A, page 3.

14 Ontario Energy Board Docket No. EB-2011-0144, Exhibit D1, Tab 12, Schedule 4, Appendix A: Navigant Consulting Ltd., *Toronto Hydro System Connection Capacity and Enabling Options for Distributed Generation*, Presented to Toronto Hydro Electric System, (May, 2011), page 36.

15 *Toronto Hydro System Connection Capacity and Enabling Options for Distributed Generation*, pages 37 – 51.

16 Navigant Consulting, *Business Case Analysis*, pages 19 & 29.

Ontario Clean Air Alliance Research

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November 27, 2012

Mr. Kent Elson
Klippensteins
Barristers & Solicitors
160 John Street, Suite 300
Toronto, ON M5V 2E5
Kent.Elson@klippensteins.ca

Dear Mr. Elson:

Re: Information Request Relating to Ontario Energy Board Matter
EB-2012-0064 – Toronto Hydro 2012-2014 Rates

I am writing in response to your request of November 22, 2012 for a table listing the resulting reductions in demand for each day on which demand was curtailed through the Ontario Power Authority's non-residential demand response programs in 2011 and 2012 in downtown Toronto. Unfortunately, actual impacts for 2012 events are not available at this time. Typically we prepare verified results by August of the following year. As well, the Ontario Power Authority ("OPA") is not able to provide data you requested where there is not sufficient aggregation because of confidentiality obligations in its contracts. There were several days in 2011 where demand response was activated but there was only one participant located in downtown Toronto with available data. Results have therefore not been provided for these days in 2011 - June 6, June 8, July 11 and August 4. It should be noted, however, that the actual verified reductions for these days were well below the maximum average event impact for downtown Toronto for the year (3.46 MW). In addition, the OPA was not able to provide a breakdown of the demand reductions at each of the five downtown Toronto transformer stations (Cecil TS, Esplanade TS, Strachan TS, Terauley TS, and Windsor TS) due to similar confidentiality concerns.

The table below provides the average impact for each Demand Response 3 event in downtown Toronto. Please note that there are no DR1 and DR2 program participants in Toronto Hydro's service territory. As well, it should be noted that the results below do not include the impacts of participants that lacked available interval data. The contracted capacity of these participants, however, is well below 0.5 MW.

Date	Average Event Impact (MW)	Average Contracted MW
31-May-11	1.17	1.17
6-Jun-11	-	-
7-Jun-11	1.24	1.41
8-Jun-11	-	-
11-Jul-11	-	-
21-Jul-11	1.25	1.63
22-Jul-11	3.46	1.63
2-Aug-11	1.94	2.04
4-Aug-11	-	-
21-Nov-11	1.83	1.81
22-Nov-11	1.79	1.81

Sincerely,

Michael Lyle
General Counsel and Vice President
Legal, Aboriginal and Regulatory Affairs
Ontario Power Authority

cc: Jack Gibbons, Consultant for Environmental Defence (by email)
Applicant, Board Secretary, and Intervenors in EB-2012-0064 (by email)

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
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Ministère de l'Énergie

Bureau du ministre

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Ontario

DEC 2 1 2012

MC-2012-3232

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

Demand Response (DR) remains a valuable way for Ontario to respond to supply and demand shifts, while encouraging conservation. The Ontario Power Authority (OPA) and local distribution companies (LDCs) have undertaken DR initiatives in response to previous Ministerial directions.

The government is interested in the extent to which DR can offer additional gains to the electricity system and ratepayers of Ontario. DR provides peak and load shifting benefits and it would be beneficial to know how we can improve on its success. Better aligning DR with local system needs and further exploring innovative DR products and new procurement strategies can help contribute to renewable integration, surplus energy management, and voltage and frequency regulation.

I request that you, in consultation with the Independent Electricity System Operator (IESO), prepare and submit a DR plan for my consideration within three months that reflects these considerations and builds on the achievements to date while being mindful of current and expected supply and demand conditions.

Sincerely,

Chris Bentley
Minister

c. Mr. Paul Murphy, President and CEO, IESO

David S. O'Brien
President and Chief Executive Officer
14 Carlton Street
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toronto hydro corporation

July 13, 2007

Councillor Paula Fletcher
City Hall
100 Queen Street West, Suite C44
Toronto, ON M5H 2N2

Dear Councillor Fletcher,

Further to our conversation yesterday regarding the information released by Toronto Hydro at a meeting on July 10th, I want to state emphatically that neither Toronto Hydro nor Hydro One is pursuing any option such as the so called "Third Line" as the preferred solution to the security of supply issues facing the city. Minister Duncan has made it very clear that the government does not support the Third Line as an option and we support that opinion. The meeting in question was part of our outreach to our stakeholders as we prepare for our 2008 rate application to the Ontario Energy Board. Unfortunately a piece of outdated information was included in the presentation, which gave the impression that Toronto Hydro and Hydro One were pursuing the "Third Line" option. Nothing could be further from the truth. I would like to apologize for this misinformation and as the head of Toronto Hydro Corporation, I take full responsibility for this unfortunate incident.

The material that has been provided to you by Mr. Gibbons has been taken out of context, and it was made very clear by my staff to all in attendance that Toronto Hydro is, first and foremost, committed to seeking demand side management and distributed generation solutions to the supply concerns that all parties recognize must be addressed. This is consistent with public statements from the Minister and Ontario Power Authority. Toronto Hydro will continue to seek solutions to this issue through prudent conservation measures, using the tools that have been made available to us by the provincial government.

I know that you understand that we must find a solution to the supply constraints to Toronto as soon as possible. We will ensure that the process that is put in place to find the answers is open, transparent, includes a significant focus on DSM, and will meet the needs of Toronto. We have serious concerns about the security of our supply in that we do not have enough capacity in the transmission lines feeding Toronto to switch between these lines, should there be a failure of one or both of the lines. Our objective is to finally begin to address the issue and no longer ignore a problem that has been building for the last 20 years. Our intention is to explore all options to find an acceptable solution that provides adequate security for Toronto's electricity supply.

The preferred solution is DSM and other conservation options and we are committed to full public discussion about this. I want to reiterate that we are not pursuing any options other than DSM and other conservation measures. You have my personal commitment that conservation will always be our priority as a first line of defence against the infrastructure issues that we face. We have committed hundreds of millions of dollars to maintain and rebuild our distribution system in Toronto, and we will continue to supplement our capital expenditures by using all options available to us to meet demand growth through conservation.

Toronto Hydro Corporation has taken the lead on so many DSM initiatives. We have much more to do, and we are pushing forward aggressively. Please be assured that we will be looking to fully exploit DSM opportunities in the context of resolving the security of supply issue, and that we will be seeking your assistance in this regard.

Sincerely,

David S. O'Brien
President and Chief Executive Officer

\cb

Cc: The Honourable Dwight Duncan, Minister of Energy
Mayor David Miller
Peter Tabuns, MPP (Toronto-Danforth)
Dr. Jan Carr, Chief Executive Officer, Ontario Power Authority
Jack Gibbons, Chair, Ontario Clean Air Alliance
Laura Formusa, Acting President and CEO, Hydro One Inc.

"Powering Toronto's Electricity Future"

Remarks by Colin Andersen
CEO, Ontario Power Authority

to the

Toronto Board of Trade

October 25, 2012

ACKNOWLEDGMENTS

Thank you, Toronto Board of Trade, for inviting me to speak this morning.

It's a privilege to be here today as the guest of a group, and in the company of people, who do so much to make sure Torontonians live in a world-class city, with a strong economy supported by a clean, modern, reliable electricity system. Thank you for all you do.

It's with a certain amount of relief that I'm here too. On the way up, I stopped to hold the elevator but the doors continued to close. I know it's Halloween, but I'd rather not do a speech like this with a bloody stump for an arm.

And I'm here with a certain amount of embarassment. Looking up at the screens I realize I am wearing the same tie as the one used in the photo to promote the event. Embarassing. I promise I do have more than one tie.

OPENING

My subject today is "Powering Toronto's Electricity Future."

More specifically, I'm going to talk about the broad-based approach I believe is needed to ensure Toronto has the electricity it needs today and for future generations.

But before I do that, I want to talk about some issues that are on a lot of peoples' minds.

PREMIER'S RESIGNATION

Like many people, I was surprised by Premier Dalton McGuinty's resignation, and his calling for a leadership convention that will select a new leader of the Ontario Liberal Party and the next Premier of Ontario.

I was a Deputy Minister in Cabinet Office at the time the government changed and he became Premier. I subsequently ended up serving in a variety of Deputy roles, including as Deputy of Finance through five very interesting budgets (that's how you measure it as Finance Deputy, not in years but in how many budgets you survived).

Very early on, Premier McGuinty put Ontario on the path to phasing out coal while jump-starting a clean energy economy – a noteworthy achievement that will benefit the people of Ontario for years to come.

As the Premier looks forward to the next chapter of his life, I wish him and his family the very best.

GAS PLANTS

It was a very busy summer for us at the OPA. As you may know, we spent most of the summer relocating two gas plants – from Mississauga and Oakville to Lambton and Lennox. And as you may also know, we have spent much of this fall disclosing documents as the Auditor General and a legislative committee examine this government decision.

We support the will of the Legislature. It has an important job to do as do we, in keeping with our legal responsibilities and our own commitment to carrying out the work we do.

OPA-IESO MERGER

So aside from the Premier's moving on, another big topic of conversation, at least until this time a couple weeks ago, is the proposed merger of the Ontario Power Authority with our good friends at the Independent Electricity System Operator. Still is a big topic.

As you may know, in April, the Ontario government unveiled plans to bring together the best of the OPA and IESO into a new, stronger, integrated electricity agency.

But now that the Legislature has been prorogued, Bill 75, the proposed legislation to merge the two agencies, has died on the order paper. It will have to be reintroduced to move forward.

So where does that leave the merger? Good question. It's one I get a lot. We were certainly watching the Bill as it worked its way through the legislative process. And we were doing a lot of work together to get ready.

Now we want to capture the value of that work. Move forward with what we can, where we can.

We certainly learned more about each other, and about ourselves frankly, along the way, so regardless, we will be working better together on the way forward.

And we're going to continue focusing on our day job, as we have all along. And we have a lot of day job – almost two-thirds of Ontario's electricity supply under contract, or 21,000 megawatts, representing an investment of $35 billion in renewing our system with more to come. And that's in addition to the work we do in conservation and planning.

At this point, I would like to publicly thank the employees of both the OPA and IESO for the fine work they have been doing through this period. A lot of twists and turns, but they have been keeping their eye on the ball and getting things done. Very professional, as expected, but not an easy time.

ELECTRICITY'S IMPORTANT

As people in the electricity sector, or who follow the sector, we know how important electricity is for everyone – how cost, reliability, supply mix and smart planning are crucial to business, workers, municipalities, the institutional sector and ordinary people in our everyday lives.

Electricity is so important that even some of Hollywood's biggest hitters get it.

Has anyone heard of JJ Abrams? He produced TV series like Lost, Fringe and Alias? Well, he has a new series called Revolution. It's a post-apocalyptic, dystopian series. I love that word "dystopian" but I haven't been able to use it in a speech until now. It's set in a future world 15 years after electricity goes out and doesn't come back, everything stops working, fear and panic sets in, government collapses, and control falls to local militias.

Suffice it to say – in JJ Abrams' world – a world without electricity is more Breaking Bad than it is Glee.

Not that I'm pitching TV shows, but when you work in a sector where the whole plot of a prime time TV series revolves around life without the commodity you deliver, you know you're relevant.

TORONTO TODAY

But that's why there are people like all of us – people who are dedicated, day in and day out, to keeping the lights on for the people of Ontario.

And here in Toronto, we have a lot to be proud of.

Think about it.

In the last 100 years, Toronto has grown from a turn-of-the-century Victorian city, population 200,000, to a diverse, modern metropolis, population 2.7 million.

Through two world wars, the dawn of the consumer era, the age of space exploration and the arrival of the information age, one constant has been this: The shared commitment of Toronto Hydro and the broader electricity sector to meeting the challenges that come our way. This has been absolutely crucial to helping Toronto achieve its full potential as a Canadian economic engine and a truly world-class city.

That shared commitment is a big reason why today, Toronto has the electricity supply it needs to meet consumer demand. And it's why electricity service is getting better, as this city leads the way on conservation and improving electricity infrastructure.

Let's talk about conservation. In 2011 alone, Toronto Hydro delivered 50 megawatts and over 175 million kilowatt-hours of conservation savings through our joint saveONenergy programs. That's more than any other distribution company in Ontario.

And on the transmission and generation side, the system is being strengthened thanks to $1 billion in recent electricity infrastructure investments that will increase capacity, improve reliability and supply security, and connect distributed and renewable generation within the city:

a. The Portlands Energy Centre, which provides up to 550 megawatts of power – about 25 per cent of central Toronto's needs ...

b. Upgrades to John by Esplanade cables

c. Upgrades to Riverside Junction by Strachan

d. Midtown Reinforcement

e. Leaside and Manby transmission station breaker upgrades and Hearn station rebuild

That is all good news for Toronto's economy and its economic development and job creation climate.

THE FUTURE

But let me be clear. A stable system today is no guarantee of a stable system tomorrow.

The fact is that Downtown Toronto has electricity challenges looming on the horizon. And we will need to address these challenges, together, to make sure the city continues to have the modern, reliable and cost-effective electricity system that is so crucial for jobs, economic growth and prosperity.

Let's consider some of those challenges.

Toronto is getting BIGGER. These next 25 years, the City of Toronto's population is projected to grow to 3.4 million. That's 700,000 – or 25 per cent - more people. The pace of growth for the whole GTA is even greater. Projections call for GTA's population to increase by 2.8 million, or 45 per cent, to reach almost 9.2 million by 2036 (Source: Ont. Ministry of Finance).

Toronto is also getting TALLER and DENSER. You can't miss it. If you looked up on your way here, chances are you saw a lot of tall buildings being built. The last City of Toronto report I saw said the city has 187 high-rise buildings currently under construction. That's more than any other city in North America. It's twice as many as New York City (85), Mexico City (88) and even more than booming Calgary, my hometown. (Source: City of Toronto).

This is not a new trend. Toronto has been getting bigger, taller and denser for some time. Until now, we've managed the growth pretty well. Conservation, new building codes and new buildings being connected to deep lake water cooling have all helped keep growth-related peak electricity demand in check. The recent economic slowdown has also played a role. So has the fact that many of the people who live in the new downtown condo towers work during the day and use less electricity at peak times.

But as intensification intensifies, increased demand will come, and we need to be ready.

There are many options to choose from. Generation, transmission, distribution and conservation are all possibilities. Lots of permutations and combinations. But this much is clear: There are no easy solutions.

Each option has its advantages and disadvantages.

We've made progress on GENERATION. Thanks to progress we've made province-wide and in the Toronto area, we've moved from having to contemplate having diesel generators on rooftops and barges in our harbour. Just this week Bruce Nuclear unit 2 came back into commercial operation.

Here in Toronto, the Portlands Energy Centre is now in service, providing made-in-Toronto electricity supply to help meet Toronto's peak demand. But as we saw in the Portlands, and as we saw more recently in Mississauga and Oakville, getting community buy-in for local generation projects is challenging.

And while distributed generation options like combined heat and power plants show promise, they are not abundant in Toronto. Even still, only 25 per cent of Toronto's electricity needs are met by generation. Not too long ago it was the reverse. Toronto's 25% is a stark contrast to other world-class cities, like NYC, which has a policy objective of having 80% of their electricity needs met by internal generation.

Personally, I'd like to see more supply in the downtown Toronto area.

Historically, Toronto's TRANSMISSION system has performed well. Transmission problems account for a small percentage of the city's power outages – just eight per cent in 2011. The two biggest transmission challenges are 1) the transmission infrastructure is aging and 2) there isn't much space on the existing wires to accommodate growth.

Getting more electricity flowing on those lines would be like asking a twenty-something with a 400-square-foot bachelor apartment to make room for her brother, sister-in-law and their three kids.

DISTRIBUTION challenges are complex and require a sustained long-term focus. Toronto Hydro is doing excellent work sustaining the existing distribution infrastructure. But despite Toronto Hydro's best efforts, Toronto's distribution network is showing signs that renewal is needed.

A 2009 study of power outages found that distribution equipment failures were responsible for 60 per cent of customer minutes lost to power outages.

To their great credit, Hydro One and Toronto Hydro have managed the transmission and distribution challenges well, thanks to their collaboration and their strong asset management processes and skills.

But there remains work to do. Going forward, we need to anticipate the need for replacing aging transmission and distribution system infrastructure. This is expensive and often complex work. Succeeding at this task will be a critical factor in maintaining reliable supply to the city.

One of the ways that we've been able to manage demand growth, and minimize the need for new electricity infrastructure has been CONSERVATION. And as I mentioned earlier on, Toronto Hydro has done a great job – delivering more conservation savings than any other local distribution company.

And here is some good news, because we can always use good news.

Our 2011 Conservation results for the province and individual local distribution companies are in. Despite a slower than expected start, we brought the year in exceeding our 2011 targets overall – and at a program cost to consumers of three cents per kilowatt-hour, our most cost effective year ever.

The programs we have been implementing with local distribution companies like Toronto Hydro are taking hold and momentum continues to build.

But here's the thing. The LDCs have already removed much of the low-hanging conservation fruit. The easiest-to-achieve conservation has been realized.

Don't get me wrong. The electricity sector is going to continue to pursue centrally co-ordinated, locally delivered conservation. It's just going to be more challenging to conserve more.

So where does that leave us?

Like I said, Toronto's system can meet the demand – for now. But clearly, we've got some work to do to make sure the system continues to be clean, reliable and cost-effective.

REGIONAL PLANNING

The question for us now is this:

What's the best, most effective way to tackle these challenges, for the benefit of consumers?

I believe that the essential ingredient will be this: Co-operation.

Toronto Hydro will continue to play the lead role here in Toronto. They have the mandate, the local knowledge and expertise, and the most direct contact with the local consumer.

The reality is that the more the broader sector, local governments, businesses, workers and citizens work together to support Toronto Hydro, the more we tap into that wealth of expertise and goodwill, the better the chances we'll develop a regional plan that identifies all the needs, considers all the options and moves forward with positive solutions that meet local needs.

For the idealists in the room, here is a quote to consider from former U.S. President Bill Clinton: "We all do better when we work together. Our differences do matter, but [what brings us together] matters more."

For the more skeptical (and I won't ask you to identify yourselves), former Canadian Prime Minister and Nobel Peace Prize winner Lester B. Pearson was a little more circumspect. He said: "We must keep on trying to solve problems, one by one, stage by stage, if not on the basis of confidence and cooperation, at least on that of mutual toleration and self-interest."

I think I can safely say that the Ontario Power Authority and Toronto Hydro can mutually tolerate each other. And in fact, it's a lot better than that. Both organizations are filled with people who are ready to work together to tackle Toronto's electricity challenges. And we can extend that to IESO, Hydro One and to all the people in this room. Mutual toleration, self interest and working together can achieve great things.

"Let's co-operate." I know – it's easy to say. But how do we do it?

Here's how: Regional planning.

Now, when it comes to regional planning, different people may use the same terms but can see things different ways.

For example, when the Ontario Energy Board talks about it, they're focused on transmission and distribution infrastructure needs, but taking into account the conservation and generation possibility, and that's where we come in. Just last week the OEB released its Renewed Regulatory Framework and Rosemarie LeClair who is here today has been out on the speech trail like me talking about it.

The Board has indicated that working groups will develop best approaches to the the regional planning process. We at the OPA look forward to taking part in that process.

But what I'm talking about is a more broad-based process that helps the local distributor maintain a clean, modern, reliable electricity system for local consumers. Ours complements and feeds into the OEB process.

It's a process where the Ontario Power Authority, the broader electricity sector and a wide range of stakeholders team up with the local distributors, support the local distributors' development and implementation of integrated solutions that address a local area's electricity needs.

So who's involved and how does regional planning work?

First and foremost, regional planning is a continuous process. It's already been under way here in Toronto now for quite some time. It has fed into the development of our province-wide plans.

And it really kicks into high gear when we drill down to the local level, with a focus on electricity infrastructure requirements at the transmitter and distributor level.

At the outset of the process, a planning team is formed to work together to create a regional plan. Members include the OPA, the IESO, the transmitter and the local distribution companies.

The local distribution companies have direct accountability for results to their customers, while the broader group plays an important support role. They bring all their tools, skills and expertise to bear to make sure the plan succeeds.

- In Toronto, the planning team has been in place for a while now. It includes Toronto Hydro, the OPA, the IESO and Hydro One, all represented here today.

Generally speaking, the regional planning team is responsible for forecasting near, medium and long-term electricity needs. This is done through a series of technical studies and lots and lots of scenarios. We're very good at doing scenarios.

Local distribution companies provide their best projections of electricity demand based on their knowledge of the customer and municipal plans, including conservation projections.

The local distributor is seen as having the best and most up to date intelligence about local growth trends. The LDCs and transmitters also provide information related to their current capital plans, condition of the assets and future plans for refurbishment and/or replacement.

Crucial to this part of the process has been meeting with Metrolinx and city planners to discuss growth plans and discuss common interests like future corridors.

- This process is well under way here and in a number of areas across the province. Here in Toronto, Toronto Hydro recently developed a long-term load forecast that has been updated to account for the ongoing intensification, new developments and long-term projections for electricity demand.

Once short, medium and long-term needs are determined, the planning team looks at all available options – conservation, generation, transmission and distribution – then drafts possible integrated solutions for maintaining a reliable supply of electricity for the region and managing issues unique to the area.

- This is the phase we are at in Toronto's regional planning process.

Municipal and regional governments are then consulted. So Councillor Thompson, get ready. I warned you.

About a month ago, we had a pleasant evening at the Toronto Forum for Global Cities. Pleasant for me. I bent the councillor's ear off I'm afraid. We talked shop. I assure everyone Councillor Thompson is well versed on these matters. In fact, Toronto Hydro just appeared before the City's Economic Development Committee, which Councillor Thompson chair's talking about some of these very things. There's more to come, councillor.

This is followed by consultation with a broader set of stakeholders, including business, industry groups, and residents are invited to have their say on the options going forward through a public consultation process. That input helps shape the local electricity plans and makes sure it meets local needs.

Along the way, the plan supports the regulatory and public information centre work that accompanies an application for project approval/rates application. Once projects are approved by the Ontario Energy Board, they are implemented.

The process doesn't end there. Regional planning is an ongoing process of measuring load, asset performance, reliability and adequacy in the area, identifying need and bringing people together to create and implement solutions.

At the OPA, we believe in regional planning. Why?

- Because it is an **established process.** It is well known and understood by the sector. Contiguous Local Distribution Companies, like the ones in Kitchener-Waterloo-Guelph-Cambridge and elsewhere across Ontario have been at it a long time and we have been working with them on their plans.

  In fact, we took our entire board to meet the Kitchener Waterloo folks last week. We had a really great discussion with them about the work we are doing together on regional plans for the area and got to see firsthand some of their conservation initiatives, thanks to some very dedicated and enthusiastic staff

  We are moving away from province-wide procurements by fuel type. And moving to a more regionalized approach to planning, one that develops more localized solutions, encompassing transmission, distribution, conservation and generation. We are still looking at the short, medium and longer term. And working with transmitters, distributors and the Ontario Energy Board.

- Regional planning promotes **integrated solutions.** It looks at conservation, transmission, distribution, and/or generation options to help meet near, mid and long-term electricity needs, both regionally and provincially. These solutions are developed to provide the best value to end use customers.

- It develops **better plans** by involving multiple stakeholders. It engages local utilities, transmitters, the IESO and key stakeholders early in the analysis and planning assessments. This ensures local input is heard throughout the planning process.

- Regional planning **helps get things done**. The broad engagement it involves promotes wider acceptance of the regional plan and all its elements. This ensures electricity projects get the social licence they need to move forward. The engagement also supports asset holders in getting the regulatory approvals they need.

- And I know the Toronto Board of Trade likes the regional approach too. You have made this point well at the Toronto Regional Summit, and in discussion about advancing regional competitive clusters. Energy is one of them.

Regional planning WORKS BEST WHEN PARTNERS CO-OPERATE. It benefits significantly from the input and involvement of many.

I'd encourage you all to learn more about the role you can play and contributions you can make, to get involved, and help ensure Toronto has the clean, modern, reliable and cost-effective electricity system we need – today and into the future.

SUMMARY

Toronto has a stable, reliable supply of electricity for now. We have the transmission, distribution, generation and conservation we need to keep the lights on and power the local economy.

But challenges loom on the horizon: Continued population growth, intensification, aging electricity infrastructure, and significant hurdles to increasing conservation, generation, transmission and distribution going forward.

These are hurdles that will put Toronto's electricity system to the test, and left unmet, will put at risk the system's ability to meet future demand.

ONE LAST PITCH

One last pitch and then I'll conclude.

Returning to the Halloween theme, Toronto Hydro reminds us to use Energy Star lights for Halloween decorating. Also, be on the lookout out for phantom power in your houses. All that equipment on standby, all those phone chargers left plugged in when they're not charging – they can eat up between 10 and 15 per cent of your power bills. You can save energy and save money by using power bars with timers. And tell your kids too.

CONCLUSION

Failing to plan for Toronto's electricity future will mean planning to fail.

I am confident – however – that we will get the job done.

That working together to develop and implement a regional electricity plan that reflects all our best efforts ...

That balances generation and transmission and distribution and conservation ...

And that keeps its sights on value for consumers ...

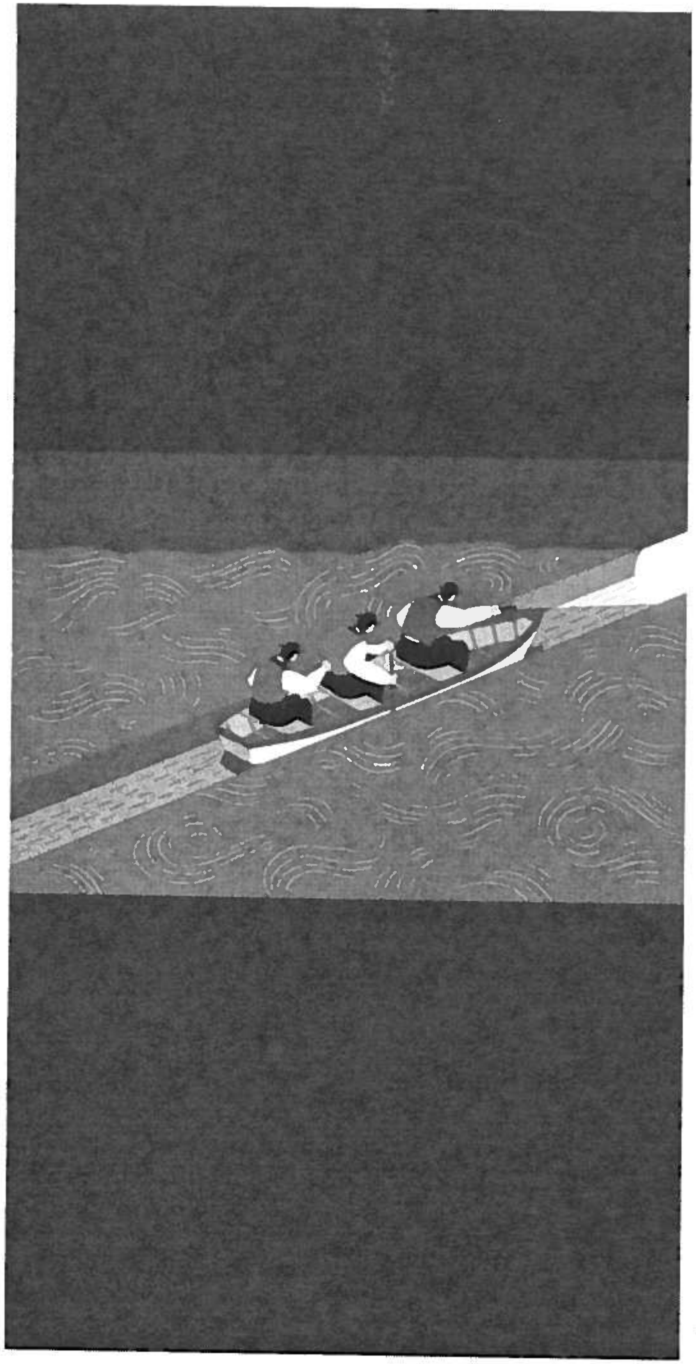
That we will surmount the challenges before us ...

That we will continue to have a clean, modern and reliable electricity system ...

That we will invite investment and power economic development and growth ...

And that we will have a very bright future indeed. Thank you.

Toronto Hydro-Electric System Limited
EB-2009-0139
Exhibit Q1, Tab 4, Schedule 1-3
ORIGINAL
(212 pages)



Central and Downtown Toronto Distributed Generation

Final Report

Prepared for:

toronto hydro electric system

Ontario Power Authority

July 28, 2009

Navigant Consulting, Inc.
1 Adelaide Street East, Suite 2601
Toronto, Ontario M5C 2V9
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NAVIGANT CONSULTING

Estimates of the potential for distributed generation across Central and Downtown Toronto ranges from between 140-550 MW.

- Navigant Consulting estimates the potential market penetration for customer-connected distributed generation in Central and Downtown Toronto ranges from roughly 140 MW in the medium (~5 year) term to more than 550 MW in the long (~10 year) term
- The table below details this expected market penetration by technology and corresponding technical potential across various project sizes.

Technical Potential and Expected Market Penetration (MW)

Project Size	Technical Potential (MW)							
	Diesel Backup w/ SCR	Gas Engine	CHP	Fuel Cell CHP	Multi-Residential CHP	Micro-CHP	Non-Residential PV	Residential PV
100-500 kW	60	60	170	-	84	210	1,000	300
0.5 - 1 MW	40	40	90	-	-			
1-5 MW	60	60	230	150	-			
5-10 MW	20	20	150		-			
Total	180	180	640	150	84	210	1,000	300
Expected Range on Market Penetration (MW)	36-90	12-70	31-224	4-35	5-19	3-84	2-27	1-3

The penetration rate for non-residential and residential PV is based on the feed-in-tariffs as proposed by the government, which provide a payback on the initial investment of ten years or more. Conversely, the penetration rates for the non-PV technologies reflect an assumed payment structure to customers that yields very short (eg, 2 to 4 year) payback period so the expected penetration as a percentage of the technical potential is much higher than for the PV technologies

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The results of this study indicate that DG might be able to serve some of the future electricity supply for Central and Downtown Toronto.

- However, this study is only a first step and further analysis is required to more fully understand how distributed generation can serve the needs of Central and Downtown Toronto and how it can serve the provincial government's policy objectives.
- These next steps for Toronto Hydro and/or the OPA include:
  1. Information gathering with respect to the options and costs for upgrading the short-circuit capabilities of the distribution and transmission system in this area, the effects of Toronto Hydro's and the City of Toronto's aggressive CDM efforts, and an evaluation of the End of Life Asset Replacement plan for the transmission system serving this area.
  2. Further analysis to identify the preferred Local Area Integrated Electrical Service solution that would serve as a long term plan for the local subsystem that meets the unique issues facing Central and Downtown Toronto. This analysis would assess local system impacts and examine the short-term, mid-term and long-term benefits and costs for each option.
  3. Developing an implementation plan for the preferred solution that could include development of additional CDM programs, working with stakeholders to lower barriers to distributed generation (including incentives as appropriate), reinforcing distribution and transmission system facilities as necessary (leveraging Smart Grid initiatives where possible) and phasing of system upgrades to manage short circuit levels.

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Toronto Hydro System Connection Capacity and Enabling Options for Distributed Generation

Presented to

toronto hydro
electric system

Toronto Hydro-Electric System Limited
500 Commissioners Rd.
Toronto, ON M4M 3N7

May 2011

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NAVIGANT

1 Executive Summary

This Navigant study was commissioned by Toronto Hydro-Electric System Limited (THESL) in response to the Ontario Energy Board's ("OEB" or the "Board") request to THESL in its EB-2009-0139 decision. Specifically, the Board stated in its decision:

> *"THESL shall continue its analysis of the incorporation of [Distributed Generation] DG into its Central and Downtown areas. In that regard it shall file a plan concurrent with its filing according to its distribution system planning requirements.*
>
> *The plan will contain an adoption of and justification for the "next steps" listed in the Navigant study and referenced above, or in the alternative, rationale for an "alternative approach" to determining the optimal power system configuration for Central and Downtown Toronto."*

The three "next steps" from the previous Navigant study[1] referred to in the Board decision include:

1. Gathering information with respect to the options and costs for upgrading the short-circuit capabilities of the distribution and transmission system in this area, the effects of Toronto Hydro's and the City of Toronto's aggressive Conservation and Demand Management (CDM) efforts, and an evaluation of the end of Life Asset Replacement plan for the transmission system serving this area.

2. Further analysis to identify the preferred Local Area Integrated Electrical Service solution that would serve as a long-term plan for the local subsystem that meets the unique issues facing Central and Downtown Toronto. This analysis would assess local system impacts and examine the short-term, midterm and long-term benefits and costs for each option.

3. Development of an implementation plan for the preferred solution that could include development of additional CDM programs, working with stakeholders to lower barriers to DG (including incentives as appropriate), reinforcing distribution and transmission system facilities as necessary (leveraging Smart Grid initiatives where possible) and phasing of system upgrades to manage short-circuit levels.

Per the Board's request, THESL has continued its analysis of the incorporation of DG into its distribution system through follow-on analysis undertaken by Navigant that is the subject of this report and THESL's own work in developing its Green Energy Act (GEA) Plan.

[1] *Central and Downtown Toronto Distributed Generation, Final Report*, July 28, 2009, prepared for Toronto Hydro-Electric System Limited and the Ontario Power Authority by Navigant Consulting Ltd.

NAVIGANT

Navigant's analytic approach was broadly consistent with the three "*next steps*" as identified in the previous Navigant report with modifications as appropriate to reflect new information and directions to THESL subsequent to the completion of the previous Navigant report. These key changes relate to:

- The requirement for THESL to prepare a GEA Plan,
- The substantial number of connection requests to THESL under the FIT and microFIT program, and
- Hydro One Network Inc.'s (HONI's) receipt of Board approval for upgrades to Manby and Leaside TS (scheduled for 2012 or 2013) that will increase DG connection capacity in the THESL system served through these stations.

Working closely with THESL engineering staff, Navigant assessed the DG connection capacity across the THESL entire distribution system and identified various enabling options that would address specific local DG connection constraints.

With respect to DG connection capacity on THESL's 13.8kV and 27.6kV distribution system, several feeders and busses were found to have significant DG connection capacity available, whereas some feeders and busses were found to have very limited or no connection capacity. In most areas with limited or no capacity, the current HONI transmission system is the limiting constraint to new DG installations. THESL equipment is the limiting constraint for only a few feeders and busses.

Navigant's specific findings with respect to THESL's DG connection capacity include:

- Currently, new DG in downtown Toronto and the eastern section of the City is limited to 10 MW for PV (and zero for synchronous DG[2]) due to short circuit capacity limits at HONI's Leaside, Hearn and Manby stations, and transmission limits on the 230kV delivery system East to Cherrywood station in Pickering,
- OEB-approved upgrades to the HONI system over the next few years will increase the DG connection capacity on THESL's 13.8kV system to 377 MW for PV or 207 MW for synchronous DG, and
- Without considering the transmission system to which it is connected, THESL's 27.6kV system has connection capacity for up to 833 MW of PV or 693 MW of synchronous DG.

[2] Inverter-based PV generation has different electrical characteristics than synchronous-based generation (such as for a medium-sized CHP installation), particularly with respect to fault current contribution. Given these differences, the available DG connection capacity will depend on the type of generation to be connected. For simplicity Navigant refers to the connection capacity for PV or for synchronous DG, whereas THESL is likely to get connection requests for a combination of generation types and the connection capacity would likely fall between the values given for PV and synchronous DG.

Considering the transmission system and HONI constraints, the connection capacity is reduced to 356 MW for PV or 283 MW of synchronous DG.

Navigant and THESL jointly assessed the viability of the various enabling options as identified by Navigant for potential inclusion in THESL's GEA Plan. As part of this assessment, Navigant and THESL estimated the likely range of costs and unit costs ($ / kW of DG enabled) for such upgrades based on THESL's system characteristics. Since there are several different types of constraints, varying system configurations across THESL's service territory and non-uniform geographic and temporal distribution of DG connection requests, there is no single "silver bullet" or option to address all of THESL's DG connection capacity constraints.

In general, however, where mitigation and upgrades are needed, DG connection capacity can be increased at a unit cost well below the installed cost of DG capacity. For feeders that are constrained, the analysis undertaken by Navigant and THESL indicates that additional DG connection capacity can be installed through a variety of enabling options at an expected cost less than $300/kW of DG enabled with the following caveats:

- Large DG (greater than 10 MW) may require dedicated feeders and station positions that could cost more than $300/kW of DG enabled,
- Local upgrades may still be required to address capacity and voltage constraints, and
- Some enabling options require changes or upgrades to HONI system; notably, some upgrades include replacement of HONI equipment that is 50 or more years old.

THESL's GEA plan will incorporate appropriate enabling options into several local upgrade plans that reflect local system constraints and the best available information on current and forecast DG connection requirements on THESL's stations and feeders. Together, the upgrade plans proposed in THESL's GEA Plan and HONI's local transmission system upgrades will significantly increase THESL's DG connection capacity.

Even with these substantial upgrades, new DG connection applications outside THESL's current forecast may still be subject to constraints on certain feeders or buses. It is expected that many of these constraints can be addressed through the application per THESL's DG requirements and cost recovery policy of the enabling options identified within this report.

Table 3 – DG Capacity by Voltage Level and Technology (THESL System Only)

	PV			Synchronous		
DG Capacity Limit (THESL)	***13.8kV***	***27.6kV***	**TOTAL (MW)**	***13.8kV***	***27.6kV***	**TOTAL (MW)**
Feeder Thermal Limit	5,660	5,460	**11,240**	5,660	5,460	**11,240**
Short Circuit Capacity	1,540	3,290	**4,830**	460	990	**1,450**
Minimum Load	710	1,110	**1,820**	570	890	**1,460**
DG Capacity: Minimum of All Constraints	595	1,031	**1,626**	371	693	**1,065**

As discussed in Section 3.6, the fault current contribution of a synchronous machine is far higher, at five times rated current, than that of an inverter-based device. Accordingly, the distribution system can accommodate less synchronous DG capacity. Also, PV reverse power limits are higher than synchronous DG due to the assumption that reverse power equal to 125 percent of minimum load can be accommodated (PV output during minimum hours of minimum load often is zero).

DG Capacity Limits on HONI System in Isolation under Existing Conditions Case

Table 4 presents DG capacity limits given HONI constraints. Results are presented for PV and synchronous DG. Results indicate the amount of DG capacity that can be installed given HONI constraints is significantly lower, primarily due to short circuit capacity constraints at Leaside, Hearn and Manby. Notably, zero synchronous DG and only 10 MW is available for new DG on the 13.8kV system. In the following section, the impact of HONI station upgrades on total available DG capacity is presented.

Table 4 – Base Case DG Capacity Limits (HONI System)

	PV			Synchronous		
DG Capacity Limit (HONI)	***13.8kV***	***27.6kV***	**TOTAL (MW)**	***13.8kV***	***27.6kV***	**TOTAL (MW)**
TS Short Circuit Capacity	10	1,663	**1,673**	0	499	**499**
Minimum Load	578	601	**1,179**	578	601	**1,179**
Thermal Capacity	669	893	**1,562**	669	893	**1,562**
DG Capacity: Minimum of All Constraints	10	386	**396**	0	310	**310**

4.3 DG Connection Capacity Limits: After Leaside and Manby Upgrades

This section describes how OEB-approved upgrades at Leaside, Hearn and Manby, once completed, will increase DG capacity limits, mostly on 13.8kV circuits in downtown Toronto. Since these upgrades have been approved and under construction (or scheduled for construction), this scenario is deemed to be the "Base Case" for purposes of determining the most likely level of DG that can be installed on THESL's distribution system. These upgrades are scheduled to be completed within the next few years, the time when new DG may be needed to meet provincial RPS targets. Similar to the Existing Conditions Case, the Base Case studies evaluate DG capacity limits under the assumption of 100 percent PV versus 100 Percent synchronous generation.

The additional capacity enabled by the HONI station upgrades occurs solely on the 13.8kV system. Table 5 presents the increase in DG capacity under the assumption the HONI station upgrades are in service. Hence, results that appear in Table 4 for the 27 kV system remain unchanged (Table 3 also is unchanged as DG limits are listed from THESL constraints only). Notably, both PV and synchronous DG capacity limits increase significantly once the station constraints are addressed: up to 1,100 MW of PV and 370 MW of synchronous DG will be enabled upon completion over the next few years. The much higher PV limits are due to the lower short circuit fault contribution for PV compared to synchronous DG.[23]

Table 5 – DG Capacity Following HONI TS Short Circuit Upgrades (HONI System Only)

	PV			Synchronous		
DG Capacity Limit (HONI)	***13.8kV***	***27.6kV***	**TOTAL (MW)**	***13.8kV***	***27.6kV***	**TOTAL (MW)**
TS Short Circuit Capacity	1,248	1,663	**2,992**	374	499	**898**
Minimum Load	578	601	**1,179**	578	601	**1,179**
Thermal Capacity	669	893	**1,562**	669	893	**1,562**
DG Capacity: Minimum of All Constraints	499	386	**884**	278	310	**588**

Total DG Capacity Limits Considering THESL and HONI System

After Leaside, Hearn and Manby upgrades, total system capacity limits will increase to 490 MW of synchronous DG or 733 MW of PV assuming optimal deployment to fill available capacity on each feeder. Table 6 presents these totals by voltage, by technology, and reflect the lowest amount of DG that can be added for each feeder given THESL and HONI constraints, whichever is lowest.

Table 6 – Total Net DG Capacity Limits

	PV			Synchronous		
DG Capacity Limit (HONI & THESL)	***13.8kV***	***27.6kV***	**TOTAL (MW)**	***13.8kV***	***27.6kV***	**TOTAL (MW)**
Net DG Limits - Lower of THESL & HONI Constraints	377	356	**733**	207	283	**490**

[23] If PV fault contribution ratio was reduced from 1.5 to 1 to 1:1, the available capacity for PV would increase to approximately 1,500 MW on the 13.8kV system.

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DG Limits by System Constraint (THESL or HONI)

For the revised base case, which includes HONI station short circuit upgrades, the relative contribution of each of the five HONI or THESL constraints to the aggregate system constraints across all of the THESL feeders evaluated is summarized in Figure 16 and Figure 17. Notably, of the 870 feeders evaluated, THESL and HONI thermal limits did not appear once as a limiting factor, an expected result given the assumption of equal allocation of new DG capacity on all feeders. Further, for PV the greatest constraint is reverse power/minimum load limits at approximately 71 percent; whereas the largest constraint for synchronous DG is HONI short circuit capacity at about 41 percent. Each of these results is expected, as synchronous DG produces much higher fault current than DG. For PV, the primary mitigation option to enable new DG is to address transformer reverse power constraints; options are presented in the following subsection.

Figure 16 – Contribution to Aggregate System Constraints for PV (After HONI Upgrades)

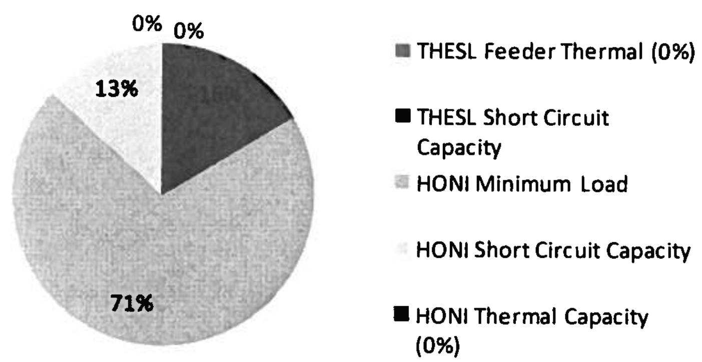
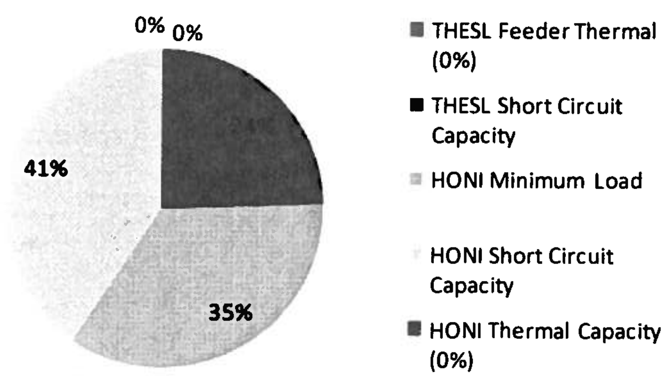


Figure 17 – Contribution to Aggregate System Constraints for Synchronous DG (After HONI Upgrades)



5 Enabling Options to Increase DG Connection Capacity

Candidate solutions to address DG penetration limits were identified for each of the constraints listed in the tables and charts presented in prior sections. These solutions are characterized as "*Enabling Options,*" some of which apply to constraints on the THESL system, some of which apply to the HONI system; and in some instances, may apply both to the THESL and HONI systems.

The primary categories addressed include:

1. Fault Current Mitigation – options to reduce fault current contribution produced by DG. Also includes increasing system fault current limits
2. Minimum Load Limits/Reverse Power Limits – options to mitigate reverse power conditions or to enable reverse power on equipment
3. Thermal Capacity Limits – options to reduce thermal loadings or to avoid overloads
4. Protection Limits and Requirements – upgrades or controls to ensure protections systems or setting are not compromised

Navigant and THESL conducted an exhaustive review of approaches to mitigate factors that limit DG capacity, and identified 17 solutions to allow greater DG penetration. These solutions are characterized as "*Enabling Options*". Enabling options include solutions to address constraints on:

- THESL's 13.8kV and 27.6 kV system;
- HONI stations and lines; and
- DG technologies (PV and Synchronous DG).

As noted in prior sections, the primary factors or constraints limiting the amount of DG that can be installed on THESL's distribution system include:

- Short circuit capacity (HONI and THESL)
- Reverse power limits (on HONI transformers)
- Station thermal capacity limits (HONI and THESL)
- Feeder thermal capacity limits (THESL)

A preferred set of enabling options were screened based on:

- The amount of incremental DG enabled
- Technical and operational performance
- Cost (versus other alternatives)
- Local upgrades will likely be required to mitigate local constraints

Table 7, Table 8 and Table 9 present each of the 17 candidate solutions, with descriptive details, applications and thresholds, and high-level cost estimates (A more detailed description of these options appear in Appendix C). As noted, some of these options apply to HONI, THESL, or both. An explanation of each heading for each column is provided below for each of the four constraint categories listed above. Certain upgrades apply only to the THESL and HONI systems, and are designated as such in the following three tables.

- **Enabling Option** – A description of the option intended to address the constraint
- **Expected Benefits** – A qualitative description of the expected benefits; usually in terms of the additional DG capacity that is enabled. Includes potential disadvantages or trade-offs
- **High Level Cost Estimate** – Estimates of the cost of the solution or option based on industry data, THESL estimates, or Navigant estimates

Table 7 presents six enabling options that may be suitable choices to mitigate short circuit capacity constraints. Each of these options generally is suitable for mitigating fault current contribution for either the THESL or HONI systems.

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Table 7 – Enabling Options: Short Circuit Capacity

Item #	Enabling Option	Expected Benefits	High-level Cost Estimate
1	Current limiting fuses (CLiP) or Fault Fighter Fuse	- Very fast detection and interruption of synchronous DG output - May cause nuisance tripping for local faults	$50-60k per device, including spare fuse
2	In-Line Reactors	- For installation at feeder termination, no momentary or sustained interruptions are need to reduce short circuit currents - Also avoids nuisance tripping for local faults	$100k per installation or $70k each if installed directly at the generator,
3	In-Line Reactors at the TS	- For installation at feeder termination, no momentary or sustained interruptions are need to reduce short circuit currents - Also avoids nuisance tripping for local faults	$500k per installation or $70k each if installed directly at the generator
4	Upgrading equipment short circuit capacity	- Able to accommodate large amounts of DG & improved protection coordination - Extensive planning and construction and may take several years to implement	Highly dependent on location and could range from $260k for low voltage replacements to several million dollars for TS upgrades
5	Install high impedance step-up transformers or generator's	- Lower short circuit currents than standard transformers, but less than other options	10-15% incremental cost above standard transformers
6	Feeder Reconfiguration (e.g., feeder cut and tie)	- Enables greater amount of all types of DG (large and small) - Eliminates short circuit current for stations at risk	Up to $250k if major upgrades are needed. Under $30k where adjacent feeders are close & can be cut over

Similarly, Navigant and THESL identified enabling options that address minimum load or reverse power constraints as potential solutions for increasing DG capacity limits. Table 8 presents five enabling options considered as potential solutions to mitigate minimum load and reverse power constraints, virtually all of which occur at the station level. All of the enabling options listed except Item 10 – Replace TS Transformer, can be used to mitigate THESL and HONI minimum load limits.

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Table 8 – Enabling Options: Minimum Load/Reverse Power

Item #	Enabling Option	Expected Benefits	High-level Cost Estimate
7	Dedicated feeder to station not constrained by minimum load	Enabling greater amounts of large scale DG	$2-4M per feeder
8	Increasing renewable output beyond bus minimum ld condition	Very low cost option for enabling higher amounts of renewable DG	None, other than monitoring feeder loads in conjunction with renewable output
9	Interruptible DG	Enabling greater amounts of large scale DG	$25-50k per DG installation, plus communications systems where applicable
10	Replace TS Transformer	Reducing the minimum load limitations caused by substation transformers	High cost may be mitigated for stations with older transformers or devices near end of life
11	Dedicated substation transformer and feeder unconstrained by minimum load	Enabling greater amounts of large scale DG	$6-8M per transformer and feeder arrangement

Table 9 presents six options for mitigating or addressing constraints or requirements relating to protection and controls.

Table 9 – Enabling Options: Capacity, Protection & Controls

Item #	Enabling Option	Constraint Addressed	Expected Benefits	High-level Cost Estimate
12	Local or mainline equipment replacement	Capacity Limits	Enables greater amounts of large scale DG or DG in aggregate	Up to $25k for local transformation to or $250K for single-phase line or cable upgrade
13	Major substation upgrade	Substation Capacity Constraints	Enables greater amounts of large scale DG or DG in aggregate	Costs range from $250k for single switchgear replacement to over $3M for major substation upgrades
14	Transfer-tripping	Capacity Issues	Enables greater amounts of large scale DG without major system upgrades	Between $50-150k per transfer-trip scheme
15	Real-time monitoring	System Planners and Operations must monitor DG for high amounts of small PV	Enables greater amounts of DG penetration	- For large devices, assume $25k per for data communication and control - For smaller DG, $100 per device to access THESL smart meters
16	Substation Relay Upgrades	Protection	Enables greater penetration of large DG; e.g., synchronous devices	$50k per breaker
17	Transmission Interconnection	Capacity, voltage, protection or other	Eliminates local capacity and short circuit capacity limits. Applicable to large DG (10 – 20 MW each)	Up to $10M

Specific enabling options listed in the above three tables are evaluated in further detail in Section 4 to identify the most likely and cost-effective options. Section 4 also presents an Implementation Plan that enables THESL and DG owners to balance the cost of options versus the additional DG capacity enabled as part of the interconnection application process.

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5.1 Impact of Other Upgrades to the Area Transmission System

The analyses presented herein assume upgrades to Leaside, Hearn and Manby (Stage 2), but exclude other major transmission upgrades or a possible third source of supply to Toronto. If and when completed, any of these other upgrades would likely have a significant impact on the results presented in this report.

Enwave Memo

To: Jack Gibbons
From: Yianni Soumalias
CC: Dennis Fotinos
Date: November 21, 2012

Re: Enwave's Ability to Reduce Toronto Hydro's Power Demand in Downtown Toronto

Jack,

As we have previously discussed Toronto Hydro has undertaken plans to build a new electrical sub-station in downtown Toronto citing the increase in future power demand as the main reason to move forward with the project. Enwave is in the process of developing a two tier plan where we can reduce the demand for power in downtown Toronto and at the same time produce electricity to Toronto Hydro's grid.

Background

Enwave currently owns and operates the world renowned Deep Lake Water Cooling System (DLWC) which supplies chilled water from Lake Ontario to over 50 buildings in Toronto's downtown core.

By connecting a building to Enwave's DLWC system a building can off-set it's electrically load in the summer time by up to 90%.

Enwave also owns and operates 3 steam plants in downtown Toronto that is capable of producing up to 522 MW of thermal energy for its customers. Due to the magnitude of Enwave's thermal production, Enwave is also capable of using its steam to produce electricity which can be connected to Toronto Hydro's electricity grid.

Toronto, Ontario, M5H 3M7
Web: www.enwave.com

Deep Lake Water Cooling Raw Water By-Pass Project

Enwave is currently in the process of expanding its Deep Lake Water Cooling System. Several options were considered and it was determined that a partial raw water by-pass of the Toronto Island Filtration Plant with added water storage would yield the greatest benefit to Enwave and its future customers.

The project is expected to be fully complete by the summer of 2015. When the expansion of Deep Lake Water Cooling is complete, Enwave will be able to add the following capacity to the existing Deep Lake Water Cooling System.

1. Additional flow of 30,000 USGPM from Enwave's Energy Transfer Station
2. Additional renewable Tonnage of 18,125
3. Additional production of 63.7 MW of thermal energy
4. An increase of 43% to Enwave's existing DLWC System

Co-Generation at Enwave's Walton Street Steam Plant

The Walton Street Steam Plant (WSSP) is capable of producing electricity as a byproduct to its main business of steam production.

Electricity can be produced by the installation of high pressure superheated boilers and the use of a back-pressure steam turbine generator exhausting to the existing steam distribution system.

There are other options available which would yield similar results, however after collecting the appropriate data, Enwave determined that installing back pressure steam turbine generators is the best route to pursue for co-generation at WSSP.

This installation would be capable of delivering sustained power of almost 15 MW net and peak power of approximately 17 – 17.4 MW net which will be sold to the Ontario Power Authority via the Toronto Hydro grid.

Enwave is hopeful to begin this project in the near future and is currently exploring the feasibility of co-generation at their other two steam plant locations; Pearl Street Steam Plant and the Queen's Park Steam Plant.

Mayor
DAVID MILLER

February 18, 2010

Honourable Brad Duguid
Minister of Energy and Infrastructure
Hearst Block
4th Floor
900 Bay Street
Toronto, ON M7A 2E1

Re: Clean Cogenerated Energy

Dear Minister Duguid:

It is my understanding that the Ontario Power Authority is considering an appropriate policy and program for purchasing clean cogenerated energy (i.e. generating heat and electric power at the same time from the same energy source) in Ontario. I strongly encourage you to support this initiative, which can provide multiple benefits to the City of Toronto and the Province of Ontario.

According to the July 28, 2009 report by Navigant Consulting for the OPA and Toronto Hydro, steps must be taken to address electricity reliability challenges that will become serious in the 2015 – 2017 timeframe in order to "mitigate against low probability but high impact events." Clean cogenerated energy (along with energy conservation and other distributed energy initiatives) is a more cost-effective and less disruptive way to address electricity reliability than building a third transmission line to supply the City at a cost of approximately $600 million through many City neighbourhoods.

Projects that utilize waste heat and pressure, will be key to reducing our greenhouse gas emissions, an important objective for the City of Toronto and the Province of Ontario. Not only does efficient clean cogenerated energy emit 80 percent less greenhouse gases than coal, it can serve an essential and flexible backstop for the intermittency of renewable energy supply such as solar and wind. Clean cogenerated energy has the additional benefit, when sited at hospitals and extended care facilities, of providing full backup generation capacity, even during a prolonged blackout; a much better air quality option than diesel generation.

Despite the favourable conditions and support for additional clean cogenerated energy within Toronto, the amount of generation that can be readily installed in Toronto is limited by the current short circuit ratings of transformer stations located in Toronto and owned by Hydro One. The Ontario Energy Board previously mandated Toronto Hydro to conduct a study to facilitate the incorporation of up to 300 MW of distributed generation within Toronto. Only 90 MW can presently be installed in Toronto due to limitations caused by short circuit capacity. It is therefore essential that the limitations of the short circuit capacity be addressed and corrected to allow the full potential of clean cogenerated energy to be realized in Toronto.

TORONTO

City Hall • 100 Queen Street West • 2nd Floor • Toronto, Ontario M5H 2N2
Telephone: 416-397-CITY • Fax: 416-696-3687 • E-mail: mayor_miller@toronto.ca

As Canada's largest city, Toronto is well-positioned for clean cogenerated energy, with potential proponents, including hospitals and other institutions, commercial buildings, and industrial facilities throughout downtown/central Toronto and in our many employment areas. A standard offer program, in the form of a feed-in tariff, would permit a number of excellent clean cogenerated projects to proceed in Toronto, when and where the power is needed. Examples include:

- The MARS Discovery District which would like to develop a 20 megawatt (MW) cogeneration and district energy system to meet the needs of the Hospital for Sick Children, Toronto General Hospital, Princess Margaret Hospital, Mt. Sinai Hospital, Toronto Rehabilitation Hospital and the University of Toronto Medical School;

- Sunnybrook Health Sciences Centre would like to install a 5.7 MW cogeneration system to close the gap between its current emergency power supply and its actual peak demand;

- St. Michael's Hospital would like to install a 6 MW cogeneration unit in their proposed new 18 storey tower at Queen and Victoria Street;

- Toronto Community Housing Corporation would like to install a 6 MW cogeneration system as part of their Regent Park redevelopment;

- Waterfront Toronto would like to install a 5 MW cogeneration system in the West Don Lands for the 2015 Pan Am Games;

The City of Toronto recently approved an energy plan, titled "The Power to Live Green: Toronto's Sustainable Energy Strategy", which outlines a range of policies and programs to improve energy efficiency and deploy renewable and distributed energy, including the use of clean cogenerated power. I have every confidence that once the OPA establishes a fair price and a simple process that is accessible for all potential CHP hosts, the market will respond and deliver viable, well-designed projects for the OPA's consideration.

Yours truly,

David Miller

Mayor David Miller
City of Toronto

c Colin Andersen, Chief Executive Officer, Ontario Power Authority
Anthony Haines, President and CEO, Toronto Hydro
Joe Pennachetti, City Manager, Toronto
Richard Butts, Deputy City Manager, Toronto
Bruce Bowes, Chief Corporate Officer, Toronto
Lawson Oates, Director, Toronto Environment Office

From: Philip Jeung [mailto:Philip.Jeung@torontohousing.ca]
Sent: December-03-12 12:22 PM
To: Jack Gibbons
Subject: Re: Draft Bremner fact sheet

Hi Jack,

Thanks for forwarding the draft fact sheet for my review. At present, we have only submitted two applications to OPA for the CHPSOP at Regent Park and Moss Park, but received no approval at this point. To be exact, these proposed CHP or CHeP are not to replace existing gas boilers but to achieve better fuel utilization and efficiency with a view to using the existing boilers as peak boilers once the base thermal loads are satisfied by the proposed CHP generated thermal heat.

Regards,

Philip Jeung
Director, Smart Buildings & Energy Management
729 Petrolia Road,
Toronto, Ontario M3J 2N6
Toronto Community Housing

T 416-981-4373 | F 416-981-4383 | C 416-315-6549

>>> "Jack Gibbons" <jack@cleanairalliance.org> 12/3/2012 10:46 am >>>
Hi Philip,

Please find attached a draft fact sheet re: the Bremner Transformer Station vs. Energy Conservation and Distributed Generation.

Our report recommends installing CHP at Regent Park, St. James Town and Moss Park as alternatives to the proposed Bremner Transformer Station.

Is TCHC still interested in pursuing these options? Did you submit CHPSOP applications to the OPA for all of these locations?

Please let me know if you have any suggestions for improvement.

Thanks for your help.

Jack

Jack Gibbons
Chair, Ontario Clean Air Alliance
160 John St., #300
Toronto M5V 2E5

Tel: 416-260-2080 x 2
Fax: 416-598-9520
Email: jack@cleanairalliance.org

Web sites:
Ontario Clean Air Alliance
Coal Must Go
Ontarios Green Future
HealthPower
Sign Our Petition

WATERFRONToronto

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www.towaterfront.ca

December 18, 2012

Jack Gibbons
Chair
Ontario Clean Air Alliance
160 John St., #300
Toronto, Ontario, M5V 2E5

Dear Mr. Gibbons:

Re: Energy Conservation and Distributed Generation

Thank you for your email regarding concerns over transformer expansions within the City of Toronto. Waterfront Toronto supports energy conservation and distributed generation as important measures to advance progressive approaches for energy. Currently, we have been involved in policy supportive initiatives as well as mandating enabling measures within the waterfront. These include collaboration with others putting forward recommendations to the province to incorporate new thermal energy policies in the Provincial Policy Statement (PPS), as part of the PPS 2005 review earlier this year.

Within the waterfront, we require builders to meet our Minimum Green Building Requirements (MGBR), which include high performance LEED Gold buildings, meeting energy efficiency at a minimum of 40% above MNECB, and over 50% for new projects post 2012. Our latest MGBR also requires an alternate compliance path for renewable energy, to drive building renewable installations to 3% of annual energy cost. This was based on the lack of seeing voluntary renewable installations. In addition, we require buildings to have in-suite metering and data collection to a central system, supported by communication material, so residents can have real-time data for electricity, gas, hot and cold water, understanding and acting towards conservation. This smart building technology will also support our intelligent community high speed broadband infrastructure and portal that will carry applications for residents around energy consumption and monitoring remotely. We are also working with our builder partners to encourage in-suite HVAC units be sized for heat exchangers that accommodate the temperatures of a District Energy system so it will allow for a conversion later, supporting existing building flexibility for future systems.

We trust this is helpful in understanding Waterfront Toronto's activities around energy conservation and community based systems.

Best regards,

John W. Campbell
President and CEO

JWC/lp

AMENDED RESPONSES TO TORONTO HYDRO-ELECTRIC SYSTEM LTD. INTERROGATORIES

Interrogatory No. 2.2 THESL-14

Reference: Environmental Defence Report, Section 3.5

With the addition of 18,125 tons of renewable cooling slated to be operational by 2015, what is the anticipated timeline by which sufficient customers are connected to realize the 18 MW in peak demand savings?

Response:

Enwave advises that: "It is Enwave's intent to have all of Enwave's new customers connected and online by summer 2016." See attached response from Enwave.

Interrogatory No. 2.2 THESL-15

Reference: Environmental Defence Report, Section 3.5

Please provide an estimate of the additional load required to the Enwave DLWC system to enable delivery of the additional 18,125 tons. Is the 18 MW peak demand reduction the net savings?

Response:

Enwave advises that: "It is anticipated that the incremental demand load for Enwave's cooling expansion (18,125 renewable) is 3,625 KW (0.2kw/ton) by 2016." See attached response from Enwave.

Interrogatory No. 2.2 THESL-16

Reference: Environmental Defence Report, Section 3.5

In reference to the possibility of installing back-pressure steam turbine-generators at the Wallton St Steam Plant, is there a potential date when this capacity could be available?

Response:

Enwave advises that: "Additional capacity for a back pressure turbine installation would become available within 2 years of the project's inception. Additional back pressure turbines may also be installed at Enwave's other steam plants at Pearl St, Queen's Park and Ryerson which will realize even greater electricity production." See attached response from Enwave.

January 9, 2012

INTERROGATORIES TO ENVIRONMENTAL DEFENCE

RE: Enwave responses to outlined questions

2.2 THESL-14

Ref: Environmental Defence Report, Section 3.5

It is Enwave's intent to have all of Enwave's new customers connected and online by summer 2016.

2.2 THESL-15

Ref: Environmental Defence Report, Section 3.5

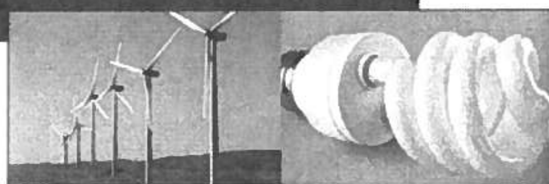
It is anticipated that the incremental demand load for Enwave's cooling expansion (18,125 renewable) is 3,625 KW (0.2kw/ton) by 2016.

2.2 THESL-16

Ref: Environmental Defence Report, Section 3.5

Additional capacity for a back pressure turbine installation would become available within 2 years of the project's inception. Additional back pressure turbines may also be installed at Enwave's other steam plants at Pearl St, Queen's Park and Ryerson which will realize even greater electricity production.

ONTARIO POWER AUTHORITY



November 15, 2006

Ontario's Integrated Power System Plan

Discussion Paper 7: Integrating the Elements— A Preliminary Plan

OPA
Ontario Power Authority

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4. Implementing the Plan

There is one overriding theme on the implementation of the Preliminary Plan. For the plan to be feasible, many actions are required now and in the near term to support not only the immediate and near-term needs, but also the options required in the medium term and opportunities that need to be available in the long term. Thereafter, these actions need to be supported on an ongoing basis.

In its planning, the OPA has been careful to ensure that the various plan elements and resources are viable and that their expected implementation and contribution to the plan is realized. These actions relate, for example, to implementation of CDM, renewable resources, coal replacement, nuclear refurbishment and transmission enhancements. Implementation of the plan will follow its filing with the Ontario Energy Board (OEB) in 2007.

For stakeholders to see the required actions in their proper perspective, the near-term actions are grouped into three categories: actions for implementation in the near term (2007-2010), actions to develop options for medium term (2011-2015) and actions to create opportunities for the long term (2016-2027). This grouping should be viewed as approximate, given that it is not possible to isolate the nature and time period of impact of all actions.

In this paper, we use the term "actions" to capture a variety of tasks and activities, including the initiation of regulatory approvals, initiation of studies, commitment by a proponent to a project or preferred approach, pre-engineering work on a project, and the actual project development. Additionally, some of the identified actions may be taken before the plan is finalized.

4.1 Actions for Implementation in the Near Term

This category includes actions related to the resources to be implemented in the near term (2007-2010). Successful completion of these actions will ensure that the near-term plan elements and resources are implemented as planned.[17]

The full set of actions assigned to this category is summarized in Table 4.1 and Table 4.3 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

[17] In the near-term category, we mean those near-term actions that result in a commitment to a particular course of resorts development, for example a decision to commit to a particular solution for a local-area supply problem, or committing a particular generation or transmission project. Such commitment is not absolute, i.e., it will still be possible not to proceed with the project, but this would not be an expected outcome, and considerable cost may be involved in doing so. There may also be a regulatory requirement to proceed with the project.

Table 4.3 – Actions on Transmission Decisions for the Near Term (2007-2010)

Project #	Project Name	Reasons For Transmission Facilities	Facilities Description	Work Type	Completion Date	Estimated cost ($M)
	Bulk Transmission					
1	Bruce-GTA Transmission Reinforcement	Increased Generation	SVC and shunt capacitors in Southwestern Ontario	Facilities	2009	80
			Upgrade 230 kV circuits from Hanover TS to Orangeville TS	Facilities	2009	10
			Upgrade Bruce area generation rejection facilities	Facilities	2009	10
			Series capacitors on Bruce GS to Longwood TS and Longwood TS to Middleport TS 500 kV circuits	Class EA and Facilities	2010	100
			180 km 500 kV double-circuit line from Bruce to GTA	Ind. EA and Facilities	2011	600
2	GTA East 500kV Reinforcement	Reliability	Full switching of Claireville TS x Cherrywood TS 500 kV circuits	Facilities	2009	60
3	North-South Transmission Reinforcement	Increased Generation	Series capacitors on Essa TS x Hanmer TS 500 kV circuits	Facilities	2010	50
4	Mattagami expansion and Northeast Generation Development	Increased Generation	SVCs at Porcupine TS and Kirkland Lake TS, and shunt capacitors north of Sudbury	Facilities	2010	60
5	Prince Wind and Sault Area Generation Development	Increased Generation	SVC at Mississagi TS and shunt capacitors in Algoma area	Facilities	2010	30
6	Atikokan Off-Coal	Maintain Transfer Capability	Shunt capacitors at Dryden TS and Fort Frances TS	Facilities	2010	7
7	Thunder Bay Off-Coal	Maintain Transfer Capability	Replacement of synchronous condenser with SVC at Lakehead TS	Facilities	2009	15
			Shunt capacitors and combining of buses at Thunder Bay GS	Facilities	2010	5
10	Hydro Quebec Interconnection	Increased Inter-tie Capability	230 kV double-circuit lines from Hawthorne TS to Ottawa and station upgrade at Hawthorne TS	Facilities	2010	130
	Local Area Reliability					
15	Southern Georgian Bay	Area load growth	Rebuild the 115 kV single-circuit line from Essa TS to Stayner TS to 230 kV double-circuit line; upgrade Stayner TS to 230 kV	Facilities	2009	92
16	GTA West	Area load growth	230 kV switching facilities at new Hurontario station	Facilities	2009	42
			230 kV cables from Hurontario SS to J. Yarrow TS	Facilities	2011	30
17	Windsor-Essex	Area load growth	Upgrade 115 kV circuits J3E/J4E	Facilities	2009	20
			Upgrade 115 kV circuits K2Z/K6Z	Facilities	2009	30
			New 230/115 kV autos at Kingsville Junction	Facilities	2012	50
18	Woodstock	Area load growth	13 km 230 kV double-circuit line; new 230 kV station in Woodstock with two 230/115 kV autos	Facilities	2009	65
19	Brant	Area load growth	115 kV double-circuit line and one 230/115 kV auto	Facilities	2009	50
20	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	Area load growth	Low voltage shunt capacitors at Hanlon and Preston	Facilities	2009	5
			Connection of Preston auto to both D7G and D9G	Facilities	2009	3
			230/115 kV autos, one at Campbell TS and one at Preston TS	Facilities	2012	32
21	GTA	Area load growth	New 115 kV line/cables from Leaside TS x Birch Junction	Facilities	2010	25

Source: OPA

4.2 Actions to Develop Options for Medium Term

This category includes actions related to the resources required for implementation in the medium-term (2011-2015), including the development of potential resource options, that need to be taken now.[18]

[18] In the medium-term category we mean those near-term actions that result in an important milestone towards commitment of a demand, supply or transmission resource. It would be possible not to proceed with the project, and this could be done with a moderate penalty. An example would be an environmental assessment approval, which does not commit the applicant to proceed with the associated project.

The full set of near-term actions assigned to this category is summarized in Table 4.4 and Table 4.6 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

Table 4.4 – Actions on Options for CDM and Supply in Medium Term (2011-2015)

Resource Type	Reasons	Action
CDM		
CDM	Increased CDM	Develop additional 1,000 MW by 2015
		Implement CDM programs in residential, commercial and industrial sectors
		Enhance culture of conservation and CDM delivery capability
		Carry out detailed evaluation measurement and verification to confirm CDM savings or reductions achieved
Renewables		
Hydroelectric	Increased generation	Encourage development of projects listed in Table 4.5
		Cooperate with various government ministries (MOE, MNR, MNDM), First Nations, and other hydroelectric proponents in rationalizing processes and policies to facilitate the development of the hydroelectric potential, in particular the undeveloped potential in northern Ontario such as along the Albany river.
		MNR to assess and possibly streamline process for release of undeveloped hydroelectric sites
		Monitor hydroelectric developments on an on-going basis and assess their impacts on the IPSP
		Pursue opportunities for hydroelectric purchases from outside of Ontario
Biomass		Encourage Ontario municipalities to assess feasibility of additional energy from landfill gas capture, wastewater treatment, and anaerobic digestion, including potential to combine additional municipal organic waste in the wastewater treatment process, and potential for co-firing of residual wastewater biosolids
		Encourage Ministry of the Environment to consider a number of possible adjustments to regulations to facilitate smaller biomass generators, particularly regarding disposal of ash and other small volume wastes. It also needs to consider changes that would facilitate the use of food waste in biodigesters.
		Encourage MNR, NRCan, and others to assess pyrolysis and other processes for converting biomass to biofuels, and other bioliquids that can facilitate efficient transportation.
		Encourage work on new protection and design systems for distributed remote generation
Local Area Supply		
Smart Gas Strategy	Increased generation, transmission relief	Initiate process for development of local area generation for in-service 2011-2012
Coal		
Nanticoke, Lambton, Atikokan, Thunder Bay	Coal replacement	Monitor with the IESO system risk profiles on an on-going basis. Inform OPG of any necessary adjustments to the coal replacement plan.
Nuclear Refurbishment		
Nuclear	Increased generation	Assess system and IPSP impacts of refurbishment programs on an on-going basis including future unit refurbishment outage schedules
		OPG to assess Darlington refurbishment feasibility
New Nuclear		
Nuclear	Increased generation	OPG and Bruce Power to continue with environmental assessments seeking approval for new nuclear generation at the Darlington and Bruce sites, respectively, and to keep OPA informed of on-going developments
		OPG and Bruce Power to continue with feasibility studies for new nuclear generation (including consideration of alternative nuclear technologies) at the Darlington and Bruce sites, respectively
		Monitor developments on an on-going basis and assess their impacts on the IPSP

Source: OPA

Table 4.6 – Actions on Options for Transmission in Medium Term (2011-2015)

Project #	Project Name	Reasons For Transmission Facilities	Facilities Description	Work Type	Completion Date	Estimated cost ($M)
	Bulk Transmission					
3	North-South Transmission Reinforcement	Increased Generation	ROW for two new 500 kV lines from Sudbury to GTA	Individual EA	2011	5
7	Thunder Bay Off-Coal	Maintain Transfer Capability	ROW for 22 km 230 kV double-circuit line from Lakehead TS to Birch TS	Class EA	2010	1
8	Toronto Third Supply	Capacity and Security	ROW for 230 kV supply from Parkway TS to Downtown Toronto	Class EA	2010	5
9	GTA East Auto Reinforcement	Maintain Transfer Capability	Site for new 500/230 kV Oshawa Area TS	Class EA	2010	1
11	Barrie South Transmission Reinforcement	Increased Generation	70 km 500 kV single-circuit line from Essa TS to Claireville TS	Individual EA	2012	3
22	Thunder Bay Off-Coal	Maintain Transfer Capability	22 km 230 kV double-circuit line from Lakehead TS to Birch TS and 230/115 kV autos	Facilities	2013	60
23	GTA West Reinforcement	Maintain Transfer Capability	500/230 kV autos at Milton and 230 kV lines	Facilities	2014	200
24	Pleasant Line Upgrade	Increased Transfer Capability	Upgrade Hurontario SS to Pleasant TS 230 kV line section	Facilities	2013	15
25	Nanticoke Off-Coal	Maintain Transfer Capability	Shunts capacitors and SVC at Nanticoke	Facilities	2014	50
26	GTA East Auto Reinforcement	Maintain Transfer Capability	New 500/230 kV Oshawa Area TS with full switching	Facilities	2014	150
27	Barrie South Transmission Reinforcement	Increased Generation	70 km 500kV single-circuit line from Essa TS to Claireville TS	Facilities	2015	170
29	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	Reliability	In-line breakers on Detweiler 230 kV circuits M20D/M21D	Facilities	2014	20
31	Toronto Third Supply	Capacity and Security	230 kV supply from Parkway TS to Downtown Toronto	Facilities	2016	600
	Enabler Connections					
12	Little Jackfish Hydro and East Nipigon Wind Development	Increased Generation	ROW for 185 km 230 kV single-circuit from Alexander SS to Little Jackfish GS	Individual EA	2010	1
13	Parry Sound Wind Development	Increased Generation	ROW for 100 km 230 kV double-circuit line from Parry Sound TS to Byng Inlet	Individual EA	2011	1
14	Goderich Area Wind Development	Increased Generation	Rebuild the 35 km 115 kV line from Goderich TS to Seaforth TS to a 230kV line	Class EA	2011	1
34	Little Jackfish and East Nipigon Wind Development	Increased Generation	185 km 230 kV sngle-circuit from Alexander SS to Little Jackfish GS	Facilities	2013	152
35	Goderich Area Wind Development	Increased Generation	Rebuild the 35 km 115 kV line from Goderich TS to Seaforth TS to a 230 kV double-circuit line and conversion of Goderich TS to 230 kV	Facilities	2014	63
36	Parry Sound Wind Development	Increased Generation	100 km 230 kV double-circuit line from Parry Sound TS to Byng Inlet	Facilities	2015	132

Source: OPA

4.3 Actions to Create Opportunities for Long Term

This category includes actions related to the resources required for implementation in the long term (2016-2027), including the exploration of opportunities showing resource potential.[19]

The full set of actions assigned to this category is summarized in Table 4.7 and Table 4.8 for CDM and supply resources and for transmission, respectively. For the transmission projects, the project numbers in the first column are shown in the maps in Figure 4.1.

[19] In the long-term category we mean those near-term action that represent the first of several milestones towards commitment of a resource. The development of the resource could be terminated at minimal cost. An example would be a study for a project that would not come into service for 10 or more years. It might be in the nature of an insurance project that is within a portfolio of several projects, only one of which may be chosen.

Impact on THESL's Net Income – Bremner Project vs. Increased CDM

Impact on THESL's Net Income of Bremner Transformer Station

Assumptions:

Incremental Rate Base: $272 million[1]

Board-Approved Debt: Equity Ratio: 60:40[2]

Board-Approved Return on Equity: 8.98% After-Tax[3]

Calculation

$272 million x 0.4 x 8.98% = **$9,770,240.00 after-tax net income *per year*** (minus depreciation in subsequent years)

Impact on THESL's Net Income of Exceeding CDM Targets by 50% or More

Assumptions

2014 Net Annual Peak Demand Savings Target: 286.27 MW[4]

2011 – 2014 Net Cumulative Energy Savings Target: 1,303.99 GWh[5]

Performance incentives shall not accrue for performance that exceeds 150% of each CDM Target.[6]

OEB-Approved CDM Performance Incentives:[7]

Range	Range Begins	Range Ends	Incentive per GWh	Incentive per MW
Range 2	100%	Up to 110%	$4,500	$20,250
Range 3	110%	Up to 120%	$7,500	$33,750
Range 4	120%	Up to 130%	$10,500	$47,250
Range 5	130%	Up to 140%	$13,500	$60,750
Range 6	140%	Up to 150%	$18,000	$81,000

Marginal Corporate Tax Rate: 26.4%[8]

Calculations

Toronto Hydro Pre-Tax Performance Incentives For Exceeding its CDM Targets by up to 50%

Range	GWh Incentive	MW Incentive
2 (100% to 110%)	$586,796	$579,696.75
3 (110% to 120%)	$977,993	$966,161.25
4 (120% to 130%)	$1,369,190	$1,352,625.75
5 (130% to 140%)	$1,760,387	$1,739,090.25
6 (140% to 150%)	$2,347,182	$2,318,787
Total	$7,041,548	$6,956,361

Grand Total Maximum *One-Time* Pre-Tax Net Income Increase from CDM Incentives:

$7,041,548 + $6,956,361 = $13,997,909

Grand Total Maximum *One-Time* After-Tax Net Income Increase from CDM Incentives:

$13,997,909 x (1 – 0.264) = **<u>$10,302,461</u>**

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[1] Navigant, *Business Case Analysis*, (April 2012), pages 21 & 26 (Tab 4, Sch. B17, App. 3).
[2] EB-2012-0064, Tab 2, Appendix 1, page 1.
[3] Letter from the Ontario Energy Board Secretary, February 14, 2013, Re: Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013 http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/OEB_Ltr_May1_2013_Cost-of-Capital_update_20130214.pdf
[4] EB-2010-0215/EB-2010-0216, *Decision and Order*, (November 12, 2010), Appendix A.
[5] *Ibid.*
[6] Ontario Energy Board, *Conservation and Demand Management Code For Electricity Distributors*, (September 16, 2010), page 15.
[7] *Ibid.*, Appendix D.
[8] EB-2012-0064, Tab 2, Appendix 1, page 1.

Ontario

ONTARIO ENERGY BOARD

Distribution System Code

Last revised on November 14, 2012
(Originally Issued on July 14, 2000)

Distribution System Code

3.1.4 For residential customers, a distributor shall define a basic connection and recover the cost of the basic connection as part of its revenue requirement. The basic connection for each customer shall include, at a minimum:

(a) supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
(b) up to 30 meters of overhead conductor or an equivalent credit for underground services.

3.1.5 For non-residential customers, a distributor may define a basic connection by rate class and recover the cost of connection either as part of its revenue requirement, or through a basic connection charge to the customer.

3.1.6 All customer classes shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. A distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.2 Expansions

3.2.1 If a distributor must construct new facilities to its main distribution system or increase the capacity of existing distribution system facilities in order to be able to connect a specific customer or group of customers, the distributor shall perform an initial economic evaluation based on estimated costs and forecasted revenues, as described in Appendix B, of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project.

3.2.2 If the distributor's offer was an estimate, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on forecasted revenues, actual costs incurred (including, but not limited to, the costs for the work that was not eligible for alternative bid, and any transfer price paid by the distributor to the customer) and the methodology described in Appendix B.

3.2.3 If the distributor's offer was a firm offer, and if the alternative bid option was chosen and the facilities are transferred to the distributor, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on the amounts used in the firm offer for costs and forecasted revenues, any transfer price paid by the distributor to the customer, and the methodology described in Appendix B.

3.2.4 The capital contribution that a distributor may charge a customer other than a generator or distributor to construct an expansion shall not exceed that customer's share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.5 The capital contribution that a distributor may charge a generator to construct an expansion to connect a generation facility to the distributor's distribution system shall not exceed the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Board. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.5A Notwithstanding section 3.2.5 but subject to section 3.2.5B, a distributor shall not charge a generator to construct an expansion to connect a renewable energy generation facility:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor's licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or
(b) in any other case, for any costs of the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

3.2.5B Where an expansion is undertaken in response to a request for the connection of more than one renewable energy generation facility, a distributor shall not charge any of the requesting generators to construct the expansion:

ONTARIO POWER AUTHORITY

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Toronto, Ontario M5H 1T1

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F 416-967-1947
www.powerauthority.on.ca

November 21, 2012

Mr. Ivano Labricciosa P. Enq., M. Enq., MBA
Vice President, Asset Management
Toronto Hydro Electric System Limited
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Mr. Labricciosa:

This letter is in response to Toronto Hydro-Electric System Limited's ("THESL") request for clarification of the relationship between the scope of the ongoing Toronto Regional Plan and THESL's investment plans as filed in its application for 2012 to 2014 rates (EB-2012-0064).

As part of its evidence in EB-2012-0064, THESL has applied for capital funding in respect of a new station, Bremner TS, to be located within the geographical bounds of the Toronto Regional Plan. The OPA has been aware of THESL's intent to build Bremner TS since before the Toronto Regional Plan was initiated. THESL has indicated that the station is a connection facility intended to deal with reliability and load growth issues in a local service area, and upstream transmission capacity is available.

The Toronto Regional Plan is one of several regional plans across the province being prepared jointly with the Ontario Power Authority (OPA), affected local distribution companies, transmitters, and the IESO. The OPA supports strategic distribution investments that provide flexibility to enable connection of growth in demand, refurbishment of existing assets, and improvements in restoration for both distribution and transmission contingencies. The OPA formulated a view on facilities within a distribution system in its February 2012 submission to the Ontario Energy Board ("OEB") as part of the Renewed Regulatory Framework for Electricity (EB-2011-0043). The OPA specifically stated that:

"The OPA recognizes that distributors and transmitters conduct ongoing connection planning activities that are associated with growth in demand, connecting generators, or addressing reliability issues, and that are more local in nature than the OPA's joint regional planning studies. These planning activities are typically driven by specific customer requests where dedicated connection facilities are required, and where upstream transmission network capacity is available. The expectation is that transmitters will advise the OPA of such planning activities and of their outcomes."

The OPA's assessment is that the location and functionality provided by Bremner TS is consistent with the objectives stated above. At this time, the Toronto Regional Plan assumes that Bremner TS will be available by THESL's proposed in-service date. The OPA will defer to THESL for all aspects of Bremner TS's rationale, the justification of costs, and the evaluation of any potential alternatives.

Please contact me with any further questions.

Sincerely,

Amir Shalaby
Vice President, Power System Planning

cc: Amanda Klein, Toronto Hydro
Fred Cass, Aird & Berlis LLP (Counsel for Toronto Hydro)
Joe Toneguzzo, OPA
Nancy Marconi, OPA

Table 1: Leaside West Capacity Need Dates

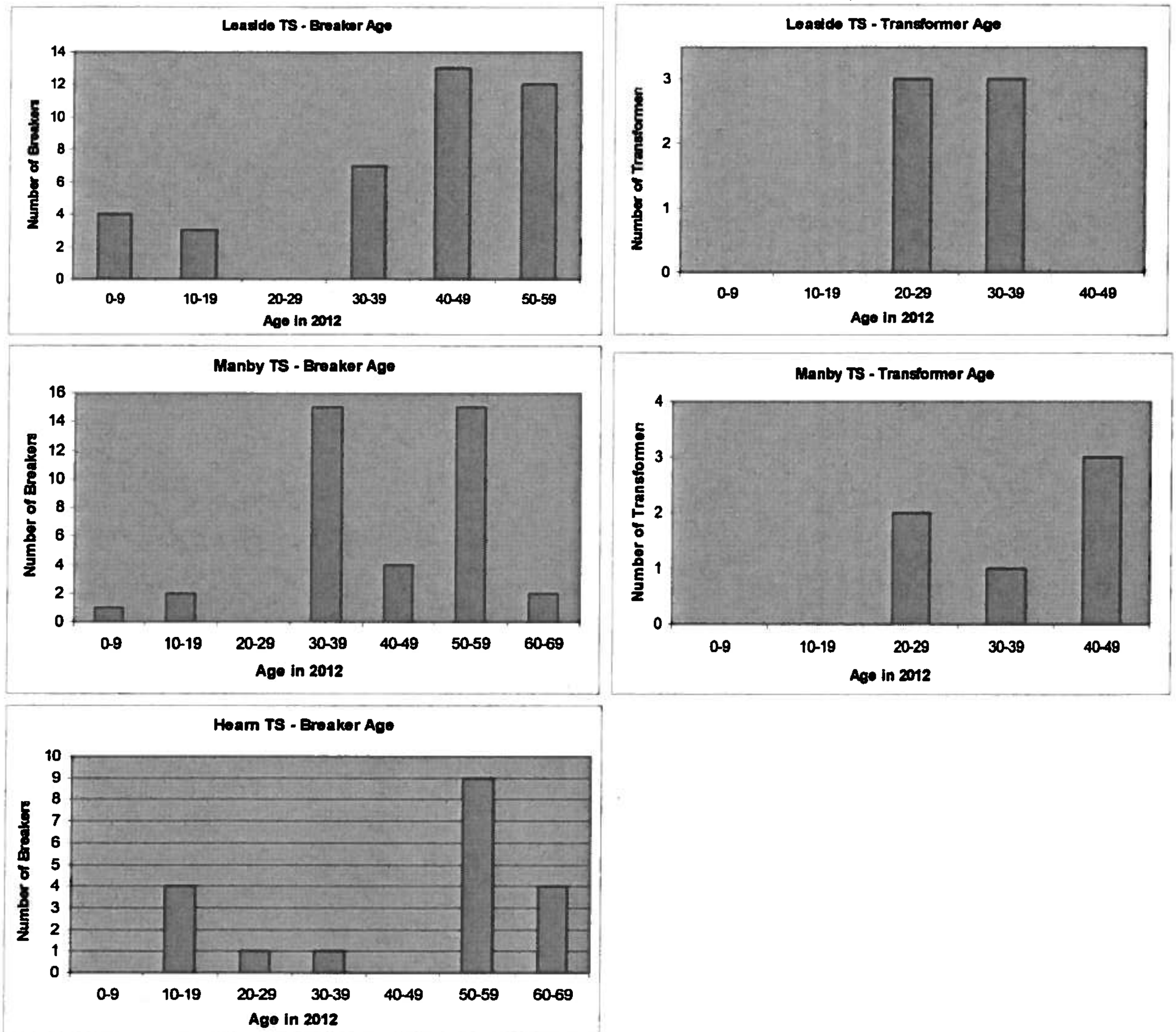
Load Forecast	100% Conservation	67% Conservation	33% Conservation
Base	2027	2020	2015
Base + 0.33%	2020	2016	2013
Base + 0.67%	2016	2013	2012

Source: OPA

4.2 Infrastructure Renewal

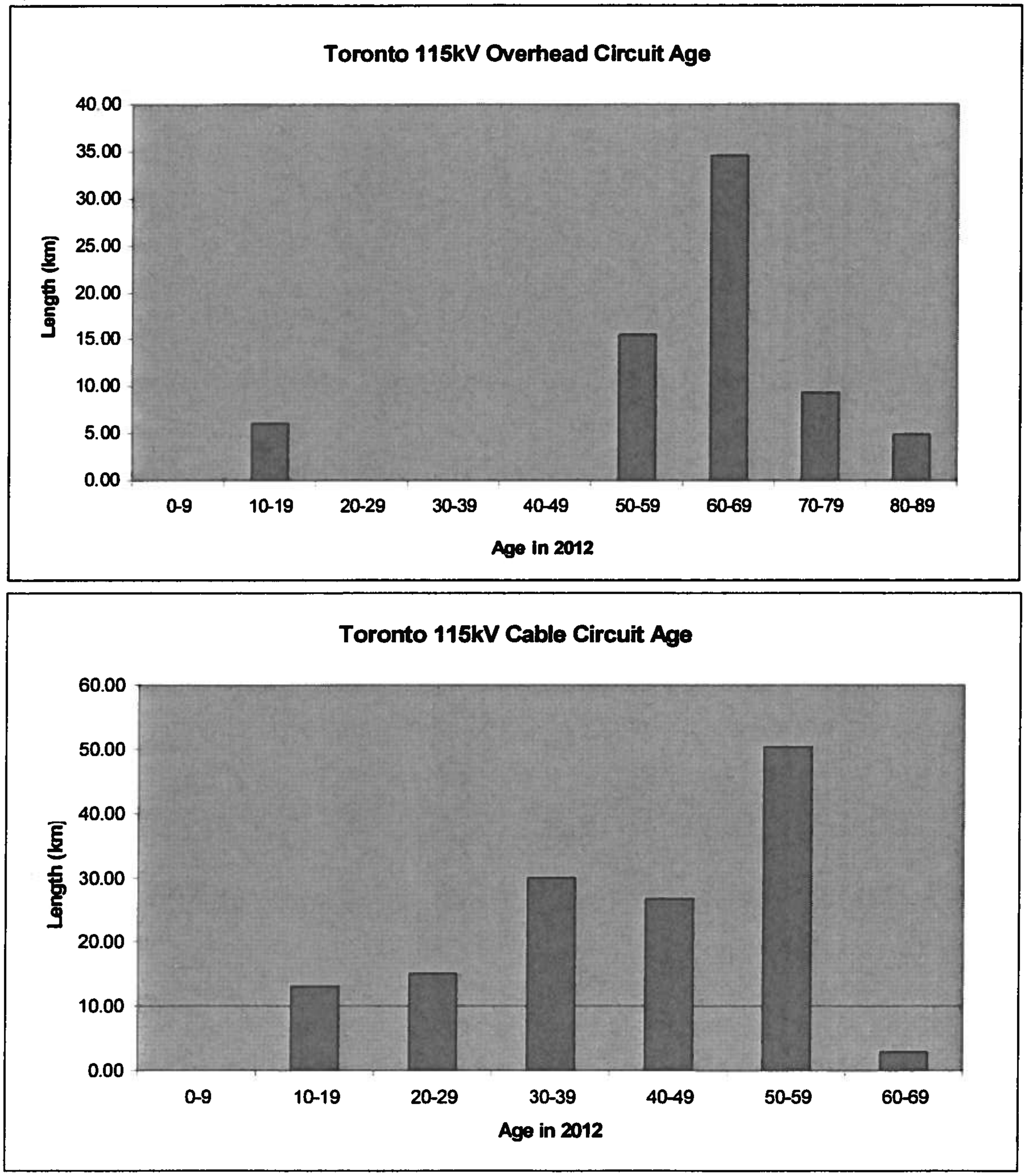
A large number of major facilities in the Downtown Toronto 115 kV system will require replacement or refurbishment over the next five to 10 years. The Hydro One report, "Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115 kV System", included in Attachment 5 to this exhibit, identifies aging facilities in all major asset classes: overhead lines, underground cables, transformers, breakers and other switchgear equipment. Figure 4 shows the age of transformers and breakers at the Manby, Leaside and Hearn transformer stations in 2012. Figure 5 shows the age of overhead lines and cables in the Toronto 115 kV system in 2012.

Figure 4: Manby, Leaside and Hearn 115 kV Station Facilities Age



Source: Hydro One.

Figure 5: Manby and Leaside 115 kV Circuit Age



Source: Hydro One.

By 2012:

- most station facilities will be over 40 years old;
- many underground cables will be over 50 years old; and
- most of the overhead circuits will be over 60 years old.

Loading levels in the Leaside system are very high and near capacity. PEC will provide some near-term relief, but as indicated, capacity issues can occur as early as 2016. While Conservation is expected to offset much of the load growth and keep loading levels below equipment limits, such loading levels will continue to be high over the next 20 years. There is very little buffer in the operating time frame to handle unexpected events beyond normal criteria events.

High loading levels also restrict both the number and duration of outages that can be managed. Outages are limited mainly to off-peak and some shoulder-peak periods. Refurbishment of cables and significant portions of the 115 kV stations will require outages for long durations. At high loading levels and with the number of facilities needing refurbishment over the period 2012 to 2017, Hydro One has indicated in its report that it may not be possible to schedule the necessary work while still providing an uninterrupted supply to customer load. Downtown Toronto customers will be at greater risk of interruptions due to lower supply reliability during extensive equipment outage periods and to higher equipment failure rates if timely refurbishment cannot be done. Figure 1 of Hydro One's report also shows an approximate timeline for a number of cable and line refurbishments or replacements over the next twelve years. Major work on key circuits between Hearn and Leaside, such as C5E/C7E and H1L/H3L, will constrain the output of PEC which may be needed to support the local system when there are outages.

Increased transmission capacity that can provide back up supply when significant facilities are out for long periods will greatly mitigate interruption risks. However, because of the inherent system design and equipment limitations, significant new capacity at Manby and Leaside cannot be effectively provided. There are short circuit limitations at the Manby, Leaside and Hearn transformer stations. As noted earlier, after PEC is connected, there is virtually no remaining short circuit capacity on the Leaside 115 kV system. Not only does this prevent additional generation from being connected to the 115 kV transmission system but also prevents the connection of new transmission facilities. The short circuit limitations prevent both new transformers and new circuits between Leaside and Hearn from being added. The short circuit levels at the Manby station prevent any significant new supply source from being added to the Manby 115 kV system. It also prevents the use of any of the PEC generation to support the Manby West subsystem.

4.3 Vulnerability to High Impact Events

NERC and NPCC standards and planning criteria recognize the loss of a substation, transmission corridor and/or a major load centre as an extreme event. While the design of the power system is not required to withstand such events without interruption of service, planning authorities are required to assess extreme events for potential impact and review what may be feasible measures or procedures to mitigate the impacts. Mitigation measures or procedures may attempt to limit the amount of load that could be lost, though more commonly they focus on reducing the amount and duration of unsupplied load for an extreme event. NERC and NPCC do not provide guidance on what degree of mitigation is appropriate. It is mostly left to individual jurisdictions to assess what levels of risk and what associated impacts for extreme events are deemed acceptable. Most jurisdictions recognize that there are higher levels of impact and therefore have a lower risk tolerance for dense urban areas like Downtown Toronto than they do for other local systems.

4.3.1 Likelihood of High Impact Events

History has shown that extreme events do happen, leading to widespread blackouts and loss of power for prolonged periods ranging from days to weeks. This is evidenced by the number of large scale blackouts in the last ten years (California 1996, Midwest Canada and U.S. 1998, Northeast Ice Storm 1998, Northeast Canada and U.S. 2003, Italy 2003, and European Union 2006). There are also numerous examples of extreme events in major urban centres, with significant impacts to residents and commerce (New York City 1997, 1999, 2006; Chicago 1998; Auckland 1998; San Francisco 1998; Detroit 2000; and Athens 2004).

To illustrate the potential of high impact events that results in the loss of a major supply path to Downtown Toronto, Hydro One conducted an assessment of the risk of losing a key transformer station on each of the two main supply paths. Hydro One submitted to the OPA the report "Qualitative Assessment of Extreme Contingencies at Cherrywood, Leaside, Richview and Manby Transformer Stations". This report reviews a number of scenarios which could lead to the loss of the Manby, Leaside, Richview and Cherrywood transformer stations. The report was provided in confidence to the OPA and has not been filed for security reasons, as it describes how the various risk factors can lead to the loss of these critical stations.

The study looked at fourteen risk factors including explosive failure of major station elements, fire and flooding leading to a loss of protection and control facilities, catastrophic loss of communications, major flooding of cable tunnels and relay room basements, natural disasters, vandalism and terrorism. The likelihoods for 50% and 100% loss of each of the four major stations were qualitatively assessed.

Of the four stations, the Leaside station was identified to be the must vulnerable, for both a 50% and 100% station loss. The frequency for a 50% station loss was once in 45 years and for a 100% station loss was once in 90 years. Sensitivity analysis was performed with Monte Carlo simulations for a range of component failure frequencies. The frequency for a 50% station loss ranges from once in 33 to 55 years. The frequency for a 100% station loss ranges from once in 65 to 110 years.

The study report identified a 100% Manby station loss, both East and West switchyards, as very low probability, with a frequency of once in 400 years. However, for a 50% station loss the probability is much higher, with a frequency of once in 55 years. This is due to the physical separation that exists between the Manby East and West switchyards and greater separation of power equipment in both switchyards. The Leaside station is much more compact with significantly more facilities.

While still low probability, the Hydro One results indicate that the loss of the Leaside station is within a range of probability that should be considered, particularly given the potentially significant adverse consequences (see Section 4.3.2 below). As a comparative reference, the 1998 Ice Storm event has been estimated to have a frequency of once in over 100 years. It should also be noted that there was an incident where the entire supply from the Leaside station was lost, resulting in an 800 MW load loss. The interruption lasted four hours before load was restored. This event occurred in the evening of April 25, 1990. The explosive failure of a potential transformer sprayed oil over adjacent equipment and scattered debris throughout the switchyard. The resulting fires also ignited the building which housed the operating personnel. The station had to be evacuated and the 115 kV facilities had to be de-energized. It was fortunate that the event occurred in the evening period of a shoulder peak day and the impacts were less severe than they could have been. This incident highlights the potential impact arising from a small piece of equipment, such as a potential transformer that is used for metering and monitoring purposes. Much larger equipment such as an oil circuit breaker or a power transformer, which conducts many more times the level of energy, would lead to a much greater impact in the event of an explosive failure at a station such as Leaside.

4.3.2 Economic and Societal Impacts

When extreme events affect dense urban centres, there are significant economic and societal impacts. Damages and lost wages resulting from the August 14^{th} 2003 Northeast Blackout have been estimated at between \$6 billion to \$10 billion[1]. New York City

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[1] ICF Consulting, "The Economic Cost of the Blackout: An issue paper on the Northeastern Blackout, August 14^{th}, 2003"
Anderson Economic Group, "Northeast Blackout Likely to Reduce US Earnings by \$6.4 Billion"
Electricity Consumers Resource Council (ELCON), "The Economic Impacts of the August 2003 Blackout", February 9, 2004

estimated the cost resulting from the event was over $1 billion. The Detroit Regional Chamber of Commerce estimated financial losses of about $220 million[2].

To illustrate the magnitude of the load potentially at risk, the following simplified scenario is presented. An extreme event resulting in a Leaside station loss would result in the isolation of the Leaside system from the rest of the network for potentially several days. For 2010 peak loading conditions, approximately 1,300 MW of load would be lost following the event. In the first four hours following the event, about 480 MW of load can be transferred to the Manby system on an emergency basis. Also during this time the PEC generation could be restarted, assuming that it remained intact following the large electrical disturbance, to provide an additional 500 MW of support. To regulate and respond to load imbalances PEC cannot be at full output on a continuous basis. This leaves about 300 MW of load that would be unsupplied and rotating outages for this load would be required.

This impact would be much higher if PEC is unable to supply a significant portion of the load. Resynchronization of PEC is possible via the H2JK cable circuit; however this is a very weak connection with a cable circuit of limited capability (104 MVA) and requires special switching to isolate the connection from the rest of the Manby West 115 kV system to respect short circuit limitations. Loss of this cable following synchronization would require the PEC generator to operate the islanded Leaside system. PEC has a limited frequency control range of only +/-1.5 Hz. If the island frequency fluctuates too much due to load imbalance, then the generator will disconnect and the load will be lost. Small islands such as these are inherently unstable and with only limited frequency control, the risk of collapsing the island is high.

Figure 6 illustrates what 300 MW and 500 MW of load may look like in the Leaside system and the extent of potential areas that can be affected.

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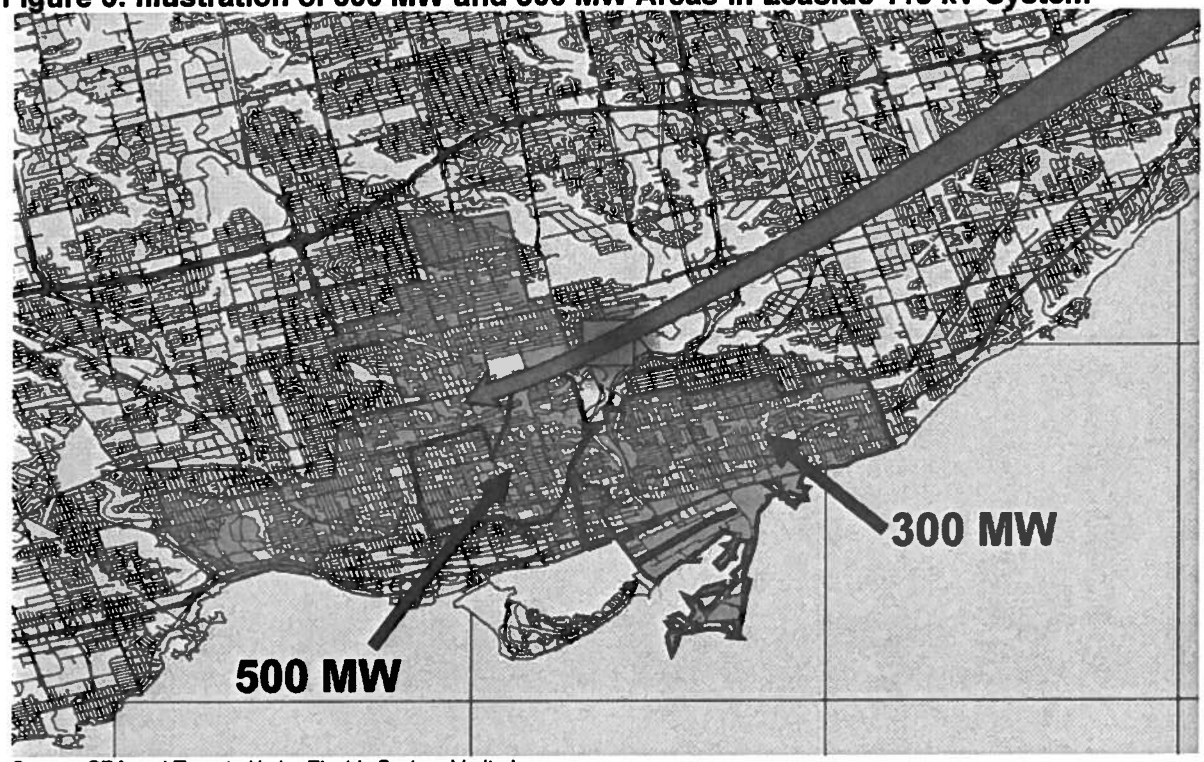
[2] Electricity Consumers Resource Council (ELCON), "The Economic Impacts of the August 2003 Blackout", February 9, 2004.

Figure 6: Illustration of 300 MW and 500 MW Areas in Leaside 115 kV System



Source. OPA and Toronto Hydro Electric System Limited

The 300 MW of unsupplied load remains essentially unchanged even with full conservation levels for Downtown Toronto. The unsupplied load over the 2010 to 2027 period ranges from 260 MW to 335 MW. Higher than forecast loads and/or lower than expected Conservation levels at Leaside would increase the amount of load at risk. It should be noted that with further intensification and increased densities the number of people and businesses affected for the same load level will also increase. A new supply source would ensure that the entire load could be restored within a few hours and would substantially mitigate high impact events affecting the two main supply paths to Downtown Toronto.

4.3.3 Supply Security in Other Major Urban Centres

The concerns about excessive dependence on limited supply points and the need to diversify and reduce the criticality of key facilities is recognized by other jurisdictions with

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0680

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008, May 1, 2009, and May 1, 2010.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

David Balsillie
Member

DECISION

May 15, 2008

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initiative in January 2008 to better understand this issue. In the Board's view it would not be appropriate for the Board to direct a different regulatory treatment for the Applicant than for the sector as a whole by eliminating the provision for a true-up. Moreover, while there is always room for improvement in this area, the Applicant's line losses do not appear to be excessive. The Board does not accept Pollution Probe's proposal and accepts the Company's provision for line losses at 3.1%.

5.3 Distributed Generation

Currently, virtually all of the electricity for Downtown Toronto is supplied through two transmission lines. Concern about ability to supply Downtown Toronto in the future has caused the OPA to consider a third line, at a capital cost of $600 Million.

Pollution Probe noted that neither the Government of Ontario nor Toronto Hydro support a third line. The solution, according to Pollution Probe, is more distributed generation ("DG").

Pollution Probe noted that 300MW of DG would eliminate the supply problem but acknowledged the Applicant's possible limitations as to the size of installation which could be accommodated on the Applicant's distribution system. Pollution Probe therefore proposed that the embedding of thirty 10MW generators within Toronto would be sufficient to avoid the third line.

Pollution Probe also contended that, along with distributed generation, CDM could further reduce the requirement for this additional supply. Pollution Probe compared the budgets for the CDM ($22Million) and Supply-Side Infrastructure ($906Million) programs, inferring a lack of strong commitment to CDM by the Applicant.

The Applicant asserted that the issue of whether or not there should be new transmission supply to Toronto is a transmission issue that should be addressed elsewhere, such as in the IPSP proceeding currently before the Board. It also suggested that issues concerning distributed generation, transmission and distribution cost responsibility and rate design are being reviewed by the Board at this time in other generic proceedings.

The Applicant contended that possible solutions examined include connections for DG and self-generation, but that these must make sense from engineering, economic and regulatory perspectives. For example, DG customers are required to fully fund connections to the network since they do not currently pay distribution or use-of-system charges if they do not take load. This system protects load ratepayers from subsidizing the costs for distributed generators to connect to the Applicant's system.

Board Findings

Leaving aside the question of the need for the third transmission line, which the Board acknowledges is best addressed through other proceedings, including the IPSP application currently before the Board, the Board considers that the Applicant should facilitate connections for DG and self-generation, where they can be implemented practically and economically, both from the perspective of the generator and of the Applicant and its load customers.

With regard to conservation and demand management, it would be premature for the Board to comment on the specific suggestions made by Pollution Probe, as the IPSP proceeding has not yet been completed.

The Board observes that the Applicant's study of distributed generation has not been rigorous. Therefore, the Board directs the Applicant to conduct a study into the capability, costs and benefits of incorporating into the Applicant system, a significant (up to 300MW) component of bi-directional distributed generation in Toronto. In this study, the Applicant should also incorporate the outcomes, as they pertain to distributed generation, of two items which are currently being considered by the Board: 1) enabler lines and their connection costs; and 2) the IPSP. The study should also be responsive to any new policy or regulatory developments in these areas. This study shall be filed as part of the Company's next application dealing with rates beyond the test period dealt with in this proceeding.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2009-0139

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010.

BEFORE: Howard Wetston
Chair & Presiding Member

Gordon Kaiser
Vice Chair & Member

Ken Quesnelle
Member

DECISION

April 9, 2010

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5. DISTRIBUTED GENERATION ISSUES

Background

The Board's Decision on THESL's EB-2007-0680 application of May 15, 2008 made the following finding regarding distributed generation issues:

> The Board observes that the Applicant's study of distributed generation has not been rigorous. Therefore, the Board directs the Applicant to conduct a study into the capability, costs and benefits of incorporating into the Applicant system, a significant (up to 300MW) component of bi-directional distributed generation in Toronto. In this study, the Applicant should also incorporate the outcomes, as they pertain to distributed generation, of two items which are currently being considered by the Board: 1) enabler lines and their connection costs; and 2) the IPSP. The study should also be responsive to any new policy or regulatory developments in these areas. This study shall be filed as part of the Company's next application dealing with rates beyond the test period dealt with in this proceeding.

On August 28, 2009, THESL filed as part of its 2010 application a study by Navigant Consulting Inc. (the "Navigant study") designed to meet this requirement entitled "Distributed Generation in Central and Downtown Toronto". This study was stated as being presented jointly to THESL and the Ontario Power Authority ("OPA").

The Navigant study concludes that distributed generation may be able to serve some future electricity supply for Central and Downtown Toronto, but that further analysis is required to more fully understand how distributed generation could serve the needs of Central and Downtown Toronto and how it could serve the provincial government's policy objectives.

The following "next steps" for THESL and/or the OPA were suggested by the Navigant study:

1. Information gathering with respect to the options and costs for upgrading the short-circuit capabilities of the distribution and transmission system in this area, the effects of Toronto Hydro's and the City of Toronto's aggressive CDM efforts, and an evaluation of the end of Life Asset Replacement plan for the transmission system serving this area.

2. Further analysis to identify the preferred Local Area Integrated Electrical Service solution that would serve as a long-term plan for the local subsystem that meets the unique issues facing Central and Downtown Toronto. This analysis would assess local system impacts and examine the short-term, midterm and long-term benefits and costs for each option.

3. Development of an implementation plan for the preferred solution that could include development of additional CDM programs, working with stakeholders to lower barriers to DG (including incentives as appropriate), reinforcing distribution and transmission system facilities as necessary (leveraging Smart Grid initiatives where possible) and phasing of system upgrades to manage short-circuit levels.

On November 10, 2009, the Board issued Issues List Decision and Procedural Order No. 2 which confirmed Issue 1.1, which was "Has Toronto Hydro responded appropriately to all of the Board's relevant directions from previous proceedings?" as being on the Final Issues List. Pollution Probe had proposed two additional issues be placed on the Final Issues List related to distributed generation and combined heat and power ("CHP") implementation. The Board found that it was unnecessary to place either of these issues on the Issues List on the basis that they were both subsumed under Issue 1.1.

The Settlement Agreement noted that issues related to CHP and distributed generation had not been settled, but that the scope of the unsettled component of Issue 1.1 could be narrowed to "Has Toronto Hydro responded appropriately to all of the Board's relevant directions with respect to distributed generation from previous proceedings?"

THESL submitted that the Navigant study had been diligently completed and satisfied the requirements of the Board's directive. THESL further submitted that it did not "propose" any part of the study as part of its distribution system and that there were no revenue requirement or rate impacts that flowed directly from the study. As such, the study was not being used as evidence to support any increase in THESL's revenue requirement or rates as part of this cost of service rate hearing.

Pollution Probe stated that there were presently four barriers to the installation of small-scale, high efficiency CHP plants in downtown and central Toronto, which are: (1) Ontario's wholesale spot market price for electricity is substantially less than the total cost of building a new power plant, (2) At present, as a result of short circuit constraints at Hydro One's Leaside, Manby and Hearn Transformer Stations only 80 MW of CHP can be installed in downtown and central Toronto, (3) Toronto Hydro's policy of requiring CHP customers to compensate it for 100% of its costs of connecting them to its distribution grid, and (4) Toronto Hydro's distribution system has short circuit issues that impede the installation of more than approximately 200 MW of CHP in downtown and central Toronto.

Pollution Probe submitted that THESL should do three things to deal with constraints on its system related to the facilitation of CHP: (1) Ensure that charges for connecting CHP plants to its distribution grid are identical to its charges for connecting renewable power plants to its distribution grid; (2) Establish a deferral account to permit it to recover its CHP connection costs from all of its customers, and (3) be directed to file within six months, a plan and budget to upgrade its distribution system to permit the installation of at least 300 MW of natural gas-fired CHP in downtown and central Toronto as soon as practically possible.

SEC was the only other party to make a submission in this area, stating that it supported in principle Pollution Probe's position, but believed that the Board should await a policy signal from the provincial government before embarking on major changes relating to support for CHP projects.

In its reply submission, THESL discussed the four barriers to the installation of natural gas-fired CHP asserted by Pollution Probe. It argued that the first two of these barriers, the wholesale electricity price and the apparent lack of an OPA program to provide a higher price to gas-fired CHP generators and the constraint on short-circuit capacity at transmission facilities are both clearly outside THESL's control and do not go to anything in THESL's revenue requirement or rate proposals.

THESL argued that the suggested barrier related to CHP connection policy had already been visited in the course of Pollution Probe's motion for interrogatory responses and in its Decision on that motion, the Board had clearly ruled this issue out of order for this proceeding.

In response to claims regarding the existence of short-circuit constraints on its distribution system which impede the installation of natural gas-fired CHP, THESL submitted that Pollution Probe had not made its case that removing short circuit impediments to allow CHP is an imperative or even preferred to other supply alternatives.

THESL further submitted that any such plan would necessarily be only a fragment of an overall plan, which would not yet be determined and which would likely overtake the fragmentary plan should they be developed in that sequence. Therefore, THESL saw it as unlikely that the fragmentary plan demanded by Pollution Probe could be guiding for any Board decision or action on the part of THESL.

THESL stated that it was quite prepared to contribute significantly to the development of an overall plan in an appropriate, inclusive forum where all affected parties can participate.

Board Findings

The Board finds THESL's response, as reflected in the Navigant study, to be acceptable at this time but incomplete. While informative on some of the challenges associated with the introduction of DG in Central and Downtown Toronto, the study does not identify the actual system costs and benefits related to the incorporation of significant levels of DG.

The study illustrates the potential for uptake of DG in Central and Downtown Toronto from a customer choice perspective based on the current market and policy environment. However, it does not provide sufficient analysis of the system costs and benefits related to the power system alternatives discussed in the Navigant study. The Navigant study noted these limitations, stating that this study "is only the first step and further analysis is required to more fully understand how distributed generation could serve the needs of Central and Downtown Toronto and how it could serve the provincial government's policy objectives."

The Board's concern regarding the lack of a robust plan related to DG arose in the context of a rate application. The Board's direction to THESL was to file the product of its direction in this rate setting proceeding. The Board remains of the view that a cost of service proceeding is the most appropriate forum to review the analysis requested.

It is appropriate to consider the potential system needs associated with the incorporation of DG at the same time as the Board considers the merits of the applicant's spending related to distribution development or sustaining efforts. This is the case irrespective of whether or not THESL is seeking recoveries for spending related to DG. THESL has submitted that a fragmented planning process would not be informative to the Board. The Board agrees. It is important that all planning initiatives that consider distribution system optimization, irrespective of the impetus, be considered in a holistic fashion.

The regulatory framework has evolved since the Board first directed THESL to perform the study. The Board has just recently released its filing requirements for distribution planning related to the GEA. As well, the analysis done to date within the study has provided a new starting point for the evaluation work related to the incorporation of DG going forward. Being cognizant of these factors and in keeping with the need to review all system plans and related studies in a common context, the Board directs THESL as follows: THESL shall continue its analysis of the incorporation of DG into its Central and Downtown areas. In that regard it shall file a plan concurrent with its filing according to its distribution system planning requirements.

The plan will contain an adoption of and justification for the "next steps" listed in the Navigant study and referenced above, or in the alternative, rationale for an "alternative approach" to determining the optimal power system configuration for Central and Downtown Toronto.

The Board leaves it to THESL to determine the most effective way to present the outcomes of these two separate but related planning requirements. A conflation of the exercises may be desirable and is acceptable so long as the outcomes of the two initiatives are identifiable separately.

The Board has not established an expected time-line for the completion of the DG study. However, it expects that the filed plan will contain, at a minimum, a scope of the work associated with the "next steps" or "alternative approach" and a schedule of key milestones within the plan. The Board reiterates and cautions THESL that it considers the analysis of the incorporation of DG to be an important element of its review of THESL's overall infrastructure spending. The absence of such information diminishes the confidence the Board can place on THESL's overall system plans.

With regard to Pollution Probe's interest in this issue, the Board will not direct THESL to take any **specific** action in response to Pollution Probe's submissions. The Board is in agreement with THESL that any such action at the present time would result in a fragmentary plan, rather than the more comprehensive plan which the Board believes is required in the present environment. In this context, the Board considers that the issues raised by Pollution Probe are relevant to the development of such a comprehensive plan. The Board expects that the requirements of both the GEA and those which have been imposed in this Decision will allow for ample consideration of the matters raised by Pollution Probe in future proceedings where this is appropriate.

Appendix 1

EB 2009-0139 & EB 2010-0142

Bremner Transformer Station Narratives and Interrogatories

Contents

Bremner Project Narratives

EB-2009-0139

Stations System Enhancements (Bremner Station)

The purpose of this project is to develop a new substation, Bremner TS, to be located at Bremner Boulevard and Rees Street in downtown Toronto. Electrically, the substation will consist of interface equipment with HONI incoming circuits, two 60/80/100 MVA 115 kV/13.8 kV transformers, 13.8 kV switchgear, protection and control and other ancillary equipment. The project will provide about 72 MVA of new firm capacity. The substation will also include space provisions for future transformers and 13.8 kV switchgear, to provide an additional 216 MVA firm capacity in three future stages (3x72 MVA) as the need arises.

The existing area is supplied by Windsor TS (referred to as John TS by HONI). Windsor TS was built in 1950, and expanded in 1968. Windsor TS has become the largest 13.8 kV substation in Toronto. The 13.8 kV air-blast switchgear, first installed in 1956, needs to be replaced in three stages. The substation is fully occupied with no room for further switchgear. In order to replace the end-of-life switchgear at Windsor TS, the existing customers from the affected equipment need to first be supplied from a new source. In addition, a new source is also needed to reduce the overall loading level at Windsor TS as no spare feeder positions are available. The supply to the existing downtown customers also needs to be diversified to mitigate the effects of high-impact low-probability station events such as fire or flooding. Details are provided at Exhibit D1, Tab 9, Schedule 6.

Secondary Upgrade

During the level III contact voltage inspection work carried out in February 2009, hand well and street lighting pole locations across the city were inspected. Secondary wires were reconnected with standard water proof connectors where needed to standardize the installation. However, there were a number of locations identified during the Level III inspection that require additional follow up work to bring them up to an acceptable operating condition. Those locations include work that is required to reinstall secondary wires between hand wells, fuse installation in street lighting poles and replacement of poles etc. It is essential that the required work be completed to maintain the physical and electrical integrity of the system. Details are provided at Exhibit D1, Tab 9, Schedule 7.

Table 2 below shows THESL's capital costs for 2010, together with the 2008 actual capital costs and the 2009 forecasted capital costs for each category of investment. The table presents operational investments in a similar format as was presented in EB-2007-0680 for consistency and comparative purposes. Additional investment categories have been added to the table which represent emerging requirements new to this filing. This presentation allows THESL to show new categories of investment to satisfy emerging requirements, and to continue to present a view of its investment needs to modernize the distribution plant.

It is clear that the level of sustaining capital investment resulting from the Board's reduction to THESL's proposed 2008 and 2009 program presented in EB-2007-0680 is insufficient. A significant "catch-up" is required and proposed in 2010. Additionally THESL is faced with very significant emerging requirements over and above its infrastructure renewal plans, which comprise more than 25 percent of the test year capital program. THESL has amended its infrastructure renewal plans to reflect the Board's previous decisions in EB-2007-0680, and has incorporated refinements in its asset condition assessment and risk-based modeling to more effectively direct capital investments. Improvements to the long-term planning and work prioritization methods used by THESL are filed at Exhibit C1, Tab 6, Schedules 1 and 2, respectively. THESL's updated 2010-2019 Electrical Distribution Plan is filed at Exhibit D1, Tab 8 Schedule 10, and updated Asset Condition Study is filed at Exhibit Q1, Tab 3, Schedule 1.

EMERGING REQUIREMENTS

STATIONS SYSTEM ENHANCEMENT – BREMNER TS PROJECT

DESCRIPTION

The purpose of this project is to develop a new substation, Bremner TS, to be located at Bremner Boulevard and Rees Street in downtown Toronto. This site is currently owned by Hydro One Networks Inc. ("HONI"). THESL will be the station developer. The project will include site preparation, construction of the substation building, installation of electrical equipment and site landscaping work. Electrically, the substation will consist of interface equipment with HONI incoming circuits, two 60/80/100 MVA 115 kV/13.8 kV-13.8 kV transformers, 13.8 kV switchgear, protection and control and other ancillary equipment. The project will provide about 72 MVA of new firm capacity. The substation will also include space provisions for future transformers and 13.8 kV switchgear, to provide an additional 216 MVA firm capacity in three future stages (3x72 MVA), as the need arises.

JUSTIFICATION

The existing area is supplied by Windsor TS (referred to as John TS by HONI). Windsor TS was built in 1950, and expanded in 1968. Windsor TS has become the largest 13.8 kV substation in Toronto. The 13.8 kV air-blast switchgear, first installed in 1956, needs to be replaced in three stages. The substation is fully occupied with no room for further switchgear. In order to replace the end-of-life switchgear at Windsor TS, the existing customers from the affected equipment need to be supplied from a new source first. In addition, a new source is also needed to reduce the overall loading level at Windsor TS as no spare feeder positions are available. The supply to existing downtown customers also needs to be diversified to mitigate the effects of high-impact low-probability station events such as fire or flooding.

The chosen site of Bremner TS is in relatively close electrical proximity to Windsor TS. The site is also in close proximity to existing THESL duct banks that will permit the linking of the two stations. The site is well-located with respect to the high voltage connection and provisions exist for the interconnection at 115 kV. Its location and the planned design satisfy the objectives of:

- providing a new source of supply to the area's customers,
- permitting the removal from service and the replacement of end-of-life switchgear at Windsor TS,
- providing capacity relief to Windsor TS and to neighbouring stations and
- mitigating the effects of high-impact low probability stations events.

ALTERNATIVES CONSIDERED

Status Quo

THESL will need to continue to have custom-made parts replaced and air-supply systems rebuilt at a significant cost. Even with these actions, however, reliability necessarily will continue to decline, eventually leading to failure. Switchgear failure at Windsor TS will have a high impact on customers in the area, which would include many of the downtown business towers and the financial district. There is no alternate supply to customers should a switchgear fail, and restoration time would be measured in days, possibly weeks. This alternative has been ruled out.

Bus-to-bus Load Transfer within Windsor TS

There is not enough firm capacity available on the bus structure within Windsor TS, to support load transfer to alternate positions because of the high load factor. This alternative is not feasible.

Load Transfer to Existing Adjacent Substations

There are four existing substations adjacent to Windsor TS. None of these adjacent substations has enough firm capacity available, because of high loading. Of the four, two substations (Strachan TS and Esplanade TS) have the space for expansion to provide new capacity. Compared to Bremner TS, these two substations are further away from Windsor TS, and outside of the existing Windsor TS supply area. Installation work for underground cables to pickup Windsor feeders will be required across existing supply areas, and disruption due to construction will be more extensive on city streets. This is not a preferred alternative.

Bremner TS

HONI has acquired the site for Bremner TS, and it is designated for electric substation use. The site is within the existing supply area of Windsor TS. The new Bremner TS has been planned to relieve Windsor TS, and facilitate load transfers in the area to relieve the adjacent substations. There are existing cable ducts installed by THESL along Bremner Blvd. to facilitate feeder egress from Bremner TS. According to current forecasts, Windsor TS and its adjacent substations as a group will require new capacity by 2018. As Bremner TS is already within the supply area of Windsor TS, advancing Bremner TS can provide the capacity required to offload Windsor TS for switchgear replacement. This is the preferred alternative.

BENEFITS

The project will provide capacity required to facilitate the staged replacement of old air-blast switchgear at Windsor TS, reducing the risk of customer outage due to equipment failure at Windsor TS. It also reduces the overall loading level at Windsor TS, thereby diversifying customer supply, and mitigating the impact of high-impact low-probability station events. The project will also provide capacity relief to neighboring stations by enabling distribution load transfers to occur.

Bremner Project Narratives

EB-2010-0142

EMERGING REQUIREMENTS

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