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Joanne.Richardson@HydroOne.com

Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

November 17, 2016

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

Dear Ms. Walli:

EB-2016-0325 – Hydro One Networks Inc.'s Section 92 – West Toronto Transmission Enhancement Project – Application and Evidence

Attached please find two copies of Hydro One Networks Inc.'s ("Hydro One") Application and Evidence in support of an Application pursuant to Section 92 of the Ontario Energy Board Act for an Order or Orders granting leave to upgrade existing transmission line facilities and to expand the existing Runnymede Transformer Station in the city of Toronto.

Hydro One's contacts for service of documents associated with this Application are listed in Exhibit B, Tab 1, Schedule 1.

An electronic copy of the complete application has been filed using the Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Attach

Exhibit List

Exh	Tab	Schedule	Attachment	Contents
A				
	1	1		Exhibit List
B				
	1	1		Application
	1	1	1	Toronto Hydro Letter of Support
	2	1		Project Overview
	2	1	1	Notice Map – Geographic Location
	2	2	2	Schematic Diagram of Proposed Facilities
	3	1		Evidence In Support of Need
	3	1	1	Central Toronto IRRP
	3	1	2	Metro Toronto RIP
	4	1		Classification and Categorization
	5	1		Cost Benefit Analysis and Options
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	7	1		Apportioning Project Costs and Risks
	8	1		Network Reinforcement
	9	1		Transmission Rate Impact
	10	1		Deferral Account

ONTARIO ENERGY BOARD

In the matter of the *Ontario Energy Board Act, 1998*;

And in the matter of an Application by Hydro One Networks Inc. for an Order or Orders granting leave to upgrade existing transmission line facilities and to expand the existing Runnymede Transformer Station ("**West Toronto Transmission Enhancement Project**" or "**WTTE Project**") in the City of Toronto.

APPLICATION

1. The Applicant is Hydro One Networks Inc. ("Hydro One"), a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.
2. Hydro One hereby applies to the Ontario Energy Board ("the Board") pursuant to Section 92 of the *Ontario Energy Board Act, 1998* ("the Act") for an Order or Orders granting leave to upgrade approximately 10 kilometers of transmission line facilities in the City of Toronto and to expand the existing Runnymede Transformer Station ("**TS**"). These facilities are required to increase transformation capacity to accommodate the forecast Toronto Hydro Electric Systems Limited ("**Toronto Hydro**", "**the Customer**", or "**the transmission Customer**") load growth in the West Toronto area. A Toronto Hydro letter of support for the completion of the WTTE Project has been provided as **Exhibit B, Tab 1, Schedule 1, Attachment 1**.
3. The proposed WTTE Project is required to:
    a. Upgrade the 115 kV circuits (K1W/K3W/K11W/K12W) between Manby TS and Wiltshire TS; and

b. Expand the existing 115/27.6 kV Runnymede TS with two 50/83 MVA transformers that will provide an additional 102 MW of transformation capacity.

The proposed in-service date for the WTTE Project is November 30, 2018 assuming a construction commencement date of May 1, 2017. A project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

4. The Project will continue to utilize the existing corridor from Manby TS to Wiltshire TS. As a result, the transmission facilities upgrade will not require any new permanent property rights. Temporary construction rights for access or staging areas may be required for the duration of the construction period of the WTTE Project. Further information on land related matter is found at **Exhibit E, Tab 1, Schedule 1**.

5. The Independent Electricity System Operator's Central Toronto Area Integrated Regional Resource Plan ("**IRRP**") dated April 28, 2015 and the Metro Toronto Regional Infrastructure Plan ("**RIP**") dated January 12, 2016 outline the need for this WTTE Project. Jointly referred to as the **Regional Planning Need Evidence**, these documents are provided as **Exhibit B, Tab 3, Schedule 1, Attachments 1 and 2**.

6. The IESO has also provided a draft System Impact Assessment ("**SIA**") for the proposed Project facilities. The draft SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system. The draft SIA is provided as **Exhibit F, Tab 1, Schedule 1** of Hydro One's prefiled evidence. Hydro One will file the final SIA once available.

7. Hydro One has completed a draft Customer Impact Assessment ("**CIA**") in accordance with Hydro One's connection procedures. The results confirm that there are no adverse results on transmission customers as a result of the WTTE Project. A copy of the draft CIA is provided as **Exhibit G, Tab 1, Schedule 1**. Hydro One will file the final CIA once available.

8. The total cost of the transmission facilities for which Hydro One is seeking approval is approximately $59 million. The details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**. Project economics, as filed in **Exhibit B, Tab 9, Schedule 1**, estimate that the WTTE Project will result in a maximum $0.02/kW decrease in the line connection pool rate and a slight decrease (-0.01%) on the overall average Ontario consumer's electricity bill.

9. The Application is supported by written evidence which includes details of the Applicant's proposal for the transmission line and station work. The written evidence is prefiled and may be amended from time to time prior to the Board's final decision on this Application.

10. Given the information provided in the prefiled evidence, Hydro One submits that the Project is in the public interest. The Project meets the transmission Customer's need and improves the Customer's quality of service and reliability with minimal impact on price.

11. Hydro One is requesting a written hearing for this proceeding. Hydro One requests that a decision on this Application is provided by April 30, 2017 to meet the needs of Toronto Hydro.

12. Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

a) The Applicant:

Ms. Erin Henderson
Sr. Regulatory Coordinator
Hydro One Networks Inc.

Mailing Address:

7th Floor, South Tower
483 Bay Street
Toronto, Ontario
M5G 2P5

Telephone: (416) 345-4479
Fax: (416) 345-5866
Electronic access: regulatory@HydroOne.com

b) The Applicant's counsel:

Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address:

8th Floor, South Tower
483 Bay Street
Toronto, Ontario
M5G 2P5

Telephone: (416) 345-6305
Fax: (416) 345-6972
Electronic access: mengelberg@HydroOne.com

October 28, 2016

John Walewski, P. Eng.
Manager, Network Connections
Hydro One Networks Inc.
483 Bay Street,
North Tower, 13th Floor
Toronto, Ontario
M5G 2P5

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")'s Letter of Support for Hydro One Networks Inc.'s ("HONI") Leave to Construct Application for the West Toronto Transmission Enhancement

---

Toronto Hydro writes to the Ontario Energy Board ("OEB") in support of HONI's Application to expand the existing Runnymede Transformer Station ("TS") site, as well as upgrades to provide the necessary transmission line capabilities between Manby TS and Wiltshire TS.

Toronto Hydro's load forecast indicates that the Runnymede service area will require additional capacity by 2019 in order to supply the growing demand in the west end of Toronto. Specifically, additional transformation capacity will be required to supply the Metrolinx Eglinton Crosstown Light Rail Transit system in 2019. The proposed transit stations from Bathurst Station West to Mount Dennis Station are located in the Runnymede TS service territory. As a result, the proposed expansions and enhancements are required to be in service by November 2018. Without additional capacity, Toronto Hydro may not be able to provide adequate reliability and supply of service to customers in the area.

The Runnymede reinforcement project is expected to address the capacity issues noted above by installing two new 50/83 MVA transformers, along with a new 27.6kV switchgear lineup with 10 feeder breaker positions. In addition, HONI intends to construct new conductors on four sections along transmission circuits to supply the new transformers at Runnymede TS and maintain existing transfer capability between east and west Toronto.

Toronto Hydro has made provisions to fund a capital contribution to HONI for its share of the work detailed above based on the cost allocation principles set out by the OEB in the Transmission System Code. Toronto Hydro's capital contribution was presented as part of the Stations Expansions program (Section E7.9) in the 2015-2019 Distribution System Plan, which was filed with the OEB in Toronto Hydro's 2015-2019 Custom IR Application (EB-2014-0116, Exhibit 2B, Section E7.9).

Overall, Toronto Hydro reiterates its support for HONI's Application to construct the expansion and enhancements noted in this letter, and encourages the OEB to provide HONI direction on this matter as soon as possible in order to ensure that capacity constraints at the Runnymede TS service area can be addressed by 2019.

Regards,

Dino Priore, P.Eng, MBA
Executive Vice President
Chief Engineering & Construction Officer

Project Overview Documents

Hydro One's proposed West Toronto Transmission Enhancement Project ("WTTE Project" or "Project") will contribute to meeting Toronto Hydro's capacity and reliability needs in the west Toronto area, including connecting the Metrolinx Eglinton Crosstown Light Railway Transit system.

The WTTE Project includes the expansion of Hydro One's existing Runnymede TS, located at 95 Woolner Avenue, Toronto. An aerial photo of the proposed site is provided in Figure 1 below.

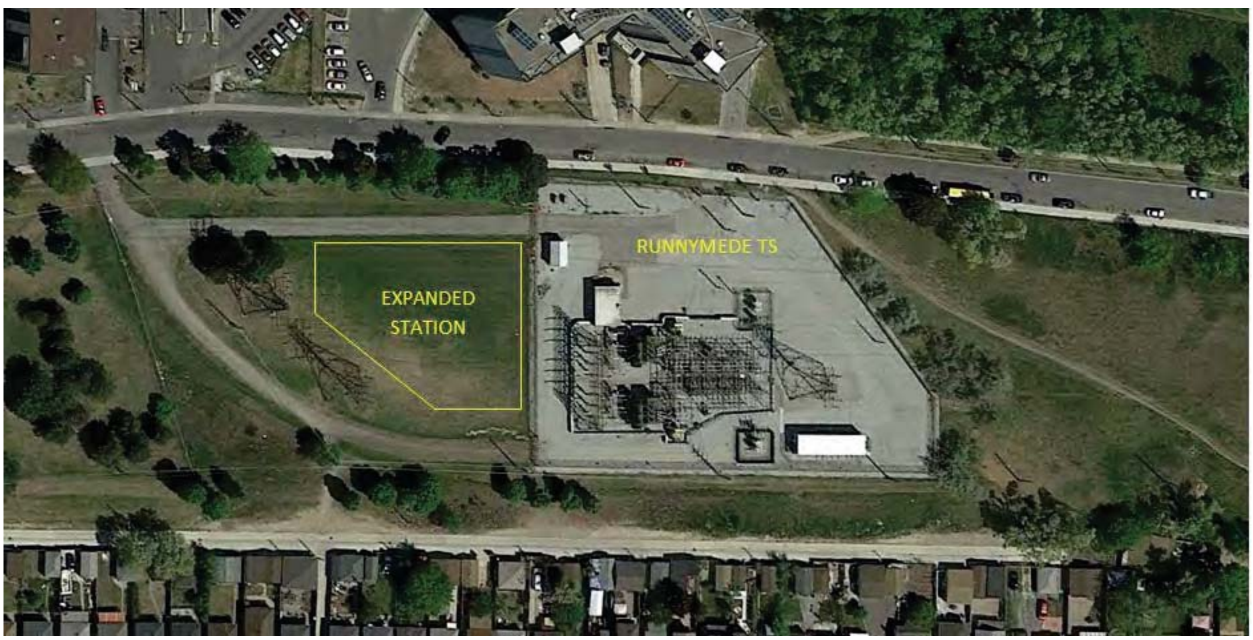


Figure 1: Expansion of Runnymede TS

The WTTE Project also includes the upgrade of four existing 115 kV transmission circuits (K1W, K3W, K11W and K12W) in order to supply the proposed larger Runnymede Transformer Station. Each transmission circuit is approximately 10 kilometers long. The four transmission circuits connect Manby TS and Wiltshire TS terminal stations and currently supply three transformer stations: Runnymede TS, Fairbank TS and Wiltshire TS.

A map indicating the geographic location and a schematic diagram of the proposed facilities are provided as **Attachments 1 and 2** of this Exhibit.

In summary, this application is seeking OEB approval to allow for the following Hydro One transmission facilities to be upgraded or constructed:

- Reconductor the 115 kV K1W, K3W, K11W and K12W transmission circuits, each of which is approximately 10 kilometers long, and runs between Manby TS and Wiltshire TS terminal stations; and
- Build an expansion to the 115 - 27.6 kV Runnymede TS consisting of two new 50/83 MVA transformers.

All of the proposed facilities are subject to section 92 approval.

Attachment 1

Date: Oct 11, 2016
Produced By: Inergi LP, GIS Services
Map16-59_Manby_Wilshire_115kV_Corridor_ExistingFacilities

- Transformer and Switching Stations
- Junction Stations
- 115 kV Existing Transmission Line
- Roads
- Major Highways
- Railway
- Municipal Boundary
- Water

Manby x Wiltshire 115 kV Corridor- Existing Facilities

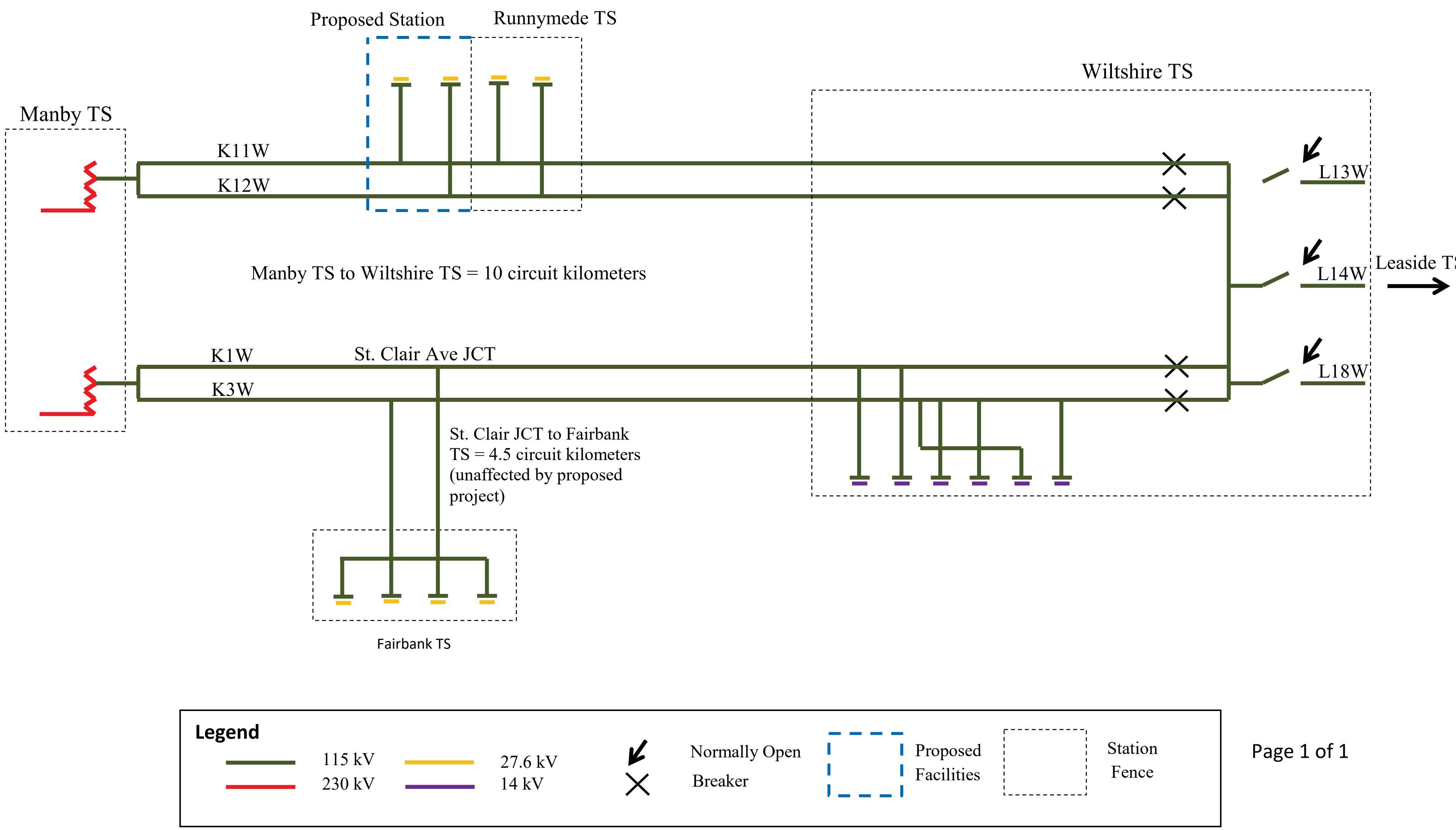
Manby x Wiltshire KxW Circuits § 10 Circuit km

1:50,000

0 1.5 3 km

Schematic Diagram – Existing and Proposed Facilities

Manby TS to Wiltshire TS 115kV Transmission Corridor



Evidence In Support of Need

This Project is part of well-developed regional plans and the bulk of the evidence in support of the need of this Project is embedded within these regional plans. This exhibit provides a summary of those plans.

The proposed project is consistent with the transmission solution recommended in the Independent Electricity System Operator's Central Toronto Area Integrated Regional Resource Plan ("IRRP") dated April 28, 2015 and in the Metro Toronto Regional Infrastructure Plan ("RIP") dated January 12, 2016. The plans are provided as **Attachments 1 and 2** of this exhibit and referred to jointly as the "**Regional Planning Need Evidence**". The Regional Planning Need Evidence identifies near-term supply needs in the West Toronto area. Specifically, the Regional Planning Need Evidence identifies that the existing 115 - 27.6 kV transformation facilities in the area, Runnymede TS and Fairbank TS, have been operating at or near their capacity for the last five years and require capacity relief. There is a need for additional capacity in the area to supply the Metrolinx Eglinton Crosstown Light Railway Transit system and longer term load growth in the West Toronto area. The Regional Planning Need Evidence also outlines a need to maintain the existing load transfer capability between Leaside TS and Manby TS during emergency or outage conditions.

The IRRP expressly documents, that "Conservation is not a technically feasible alternative for providing the capacity relief because there is not sufficient conservation achievable potential within the affected areas to address the capacity relief that is needed and to supply the new customers seeking to connect in the area by 2019"[1]. The IRRP also notes that, "… implementation of [Distributed Generation] is not a technically feasible alternative to address this need because it would require strategically locating a sufficient amount of [Distributed Generation] resources to relieve the specific TSs and feeders. Through recent procurement

[1] Central Toronto Area Integrated Regional Resource Plan – April 28, 2015, Page 61 of 97

efforts and community outreach, the IESO is not aware of any such [Distributed Generation] opportunities in the area that would defer or avoid this need”[2].

The IRRP identified two alternatives to provide the required capacity relief for Runnymede TS and Fairbank TS:

- construction of additional distribution feeders which can be used to permanently transfer load to other stations in the area; or
- expanding Runnymede TS, including upgrading the existing K1W, K3W, K11W and K12W transmission circuits required as a result of the expanded station.

The benefits of each alternative are discussed in **Exhibit B, Tab 5, Schedule 1 and Exhibit B, Tab 6, Schedule 1**.

The transmission alternative is the recommended solution in the IRRP, further recommended in the RIP, and is the proposed work Hydro One is requesting to undertake at this time. This expanded transformer station will increase the power flow requirements on the four 115 kV transmission circuits K1W, K3W, K11W and K12W. As a result, these circuits require upgrading in order to meet capacity needs and reliability of supply to the area while respecting operating limits. The expanded Runnymede Transformer Station and upgrades to the four supplying 115 kV circuits will provide necessary relief to the existing Runnymede and Fairbank Transformer Stations, enabling connection of the Metrolinx Eglinton Crosstown Light Transit system and meeting the long term load supply needs of the West Toronto area.

[2] Ibid, Page 62 of 97

EB-2016-0325
EXHIBIT B, TAB 3, SCHEDULE 1
ATTACHMENT 1

November 17, 2016

CENTRAL TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the Metro Toronto Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Central Toronto Area

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

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

- Independent Electricity System Operator
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Central Toronto Working Group assessed the adequacy of electricity supply to customers in the Central Toronto Area over a 25-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Central Toronto Area; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

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

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List of Abbreviations

Abbreviation	Description
BES	Bulk Electric System
CDM	Conservation and Demand Management
CEMLC	Commercial Energy Management and Load Control
CEP	Community Energy Plan
CHP	Combined Heat and Power
DE	District Energy
DG	Distributed Generation
EM&V	Evaluation, Measurement and Verification
EUE	Expected Unserved Energy
EV	Electric Vehicle
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GFA	Gross Floor Area
GHG	Green House Gas
GTA	Greater Toronto Area
GWh	Gigawatt hour
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan (2007)
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	Long-Term Energy Plan (2013)
LTR	Limited Time Rating
MPAC	Municipal Property Assessment Corporation
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PPWG	Planning Process Working Group
PRA	Probabilistic Reliability Assessment

PSS®E	Power System Simulator for Engineering
PV	Photovoltaic (Solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TGS	Toronto Green Building Standard
THESL	Toronto Hydro-Electric System Limited
TS	Transformer Station
Working Group	Central Toronto Area Working Group

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of Central Toronto. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group (the "Working Group") composed of the IESO, Toronto Hydro-Electric System ("Toronto Hydro" or "THESL") and Hydro One Networks Inc. ("Hydro One" or "HONI").

The Central Toronto Area has been undergoing extensive redevelopment, which has resulted in electricity demand growth that is placing pressure on parts of the electricity system serving the area. The City of Toronto's expectation is that the area will experience substantial continued population and economic growth in the coming decade. Therefore, there is a need for integrated regional electricity planning to ensure that the electricity system can support the pace of development over the long term.

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

The area covered by the Central Toronto IRRP is a sub-region of the "Metro Toronto" region established through the Ontario Energy Board's ("OEB" or "Board") regional planning process. This report contributes to fulfilling the requirements for the Metro Toronto region as required by the IESO's OEB licence. Hydro One completed a Needs Screening for the remainder of Metro Toronto ("Metro Toronto Northern sub-region") in 2014 and found that no regionally coordinated planning was required for the remainder of the region.

This IRRP for Central Toronto identifies and co-ordinates the many different options to meet customer needs in Central Toronto over the next 25 years.[1] Specifically, this IRRP identifies investments for immediate implementation necessary to meet near and medium-term needs. This IRRP also identifies a number of options to meet longer-term needs, but given forecast

[1] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25 year period. The Working Group agreed to assess needs based on the 25 year forecast.

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

This report is organized as follows:

- A summary of the recommended plan for Central Toronto is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Central Toronto Area and study scope is discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions are described in Section 5;
- Near-term and medium-term electricity needs are presented in Section 6;
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7;
- Options for meeting long-term needs are provided in Section 8;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and going forward is provided in Section 9; and
- A conclusion is provided in Section 10;

2. The Integrated Regional Resource Plan

The Central Toronto IRRP addresses the sub-region's electricity needs over the next 25 years, based on the application of the IESO's Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-25+ years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system. For the near term, the IRRP identifies specific investments that need to be immediately implemented or that are already being implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

Near/Medium-Term Needs

- Meeting standards / improving supply security at Manby TS and Leaside TS – **today to 2018**
- Ensuring sufficient capacity to supply near term growth in west Toronto – **2018**
- Ensuring sufficient supply capacity on the 230 kV transmission system between Richview TS and Manby TS – **2018**
- Ensuring sufficient capacity to supply near term growth in downtown Toronto – **2021**

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

The needs and recommended actions for the near/medium-term and long-term plans are summarized below.

2.1 Near- and Medium-Term Plan

The plan to meet Central Toronto's near- and medium-term electricity needs was developed with a view to economically maximizing the use of the existing system while ensuring adequate and reliable supply is in place to meet the growth needs of the region.

The core elements of the near- and medium-term plan include measures to meet the reliability standards and enhance supply security in the area, continuing with implementation of conservation, developing DG, and ensuring that infrastructure options are available to connect new customers and meet demand growth requirements in a timely manner.

Detailed recommendations are provided in Section 7. A summary of the plan's recommended actions is as follows:

1. Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014).
2. Implement Special Protection Systems to address supply security and ensure that the reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS).
3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs.
4. Conduct further work to identify opportunities for distributed generation resources within the Central Toronto Area.
5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021.
6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor.
7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto.
8. Conduct further work to assess options for increasing system resiliency for extreme events.

2.2 Long-Term Plan

Long-Term Needs

• Ensuring sufficient capacity to supply long- term growth in Toronto

In the long term, Central Toronto's electricity system is expected to reach its capacity to supply growth at the two major transformer stations and at key transmission facilities supplying the area as early as the mid-2020s. Uncertainty in the long-term demand forecast, and the opportunity for conservation and DG resources to reduce the area's reliance on the delivery of provincial grid supply via the transmission system, could however defer these needs further into the future. The long-term plans for Central Toronto will be integrated and assessed with plans as a whole for the Metro Toronto Region.

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP.

Detailed recommendations are provided in Section 8. A summary of the recommended actions to support the long-term plan are summarized as follows:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area.
2. Continue to engage with stakeholders and the community to develop community-based solutions.
3. Monitor demand growth, conservation achievement and DG uptake.
4. Initiate the next Regional Planning Cycle early, if needed.

3. Development of the IRRP

3.1 The Regional Planning Process

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

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

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

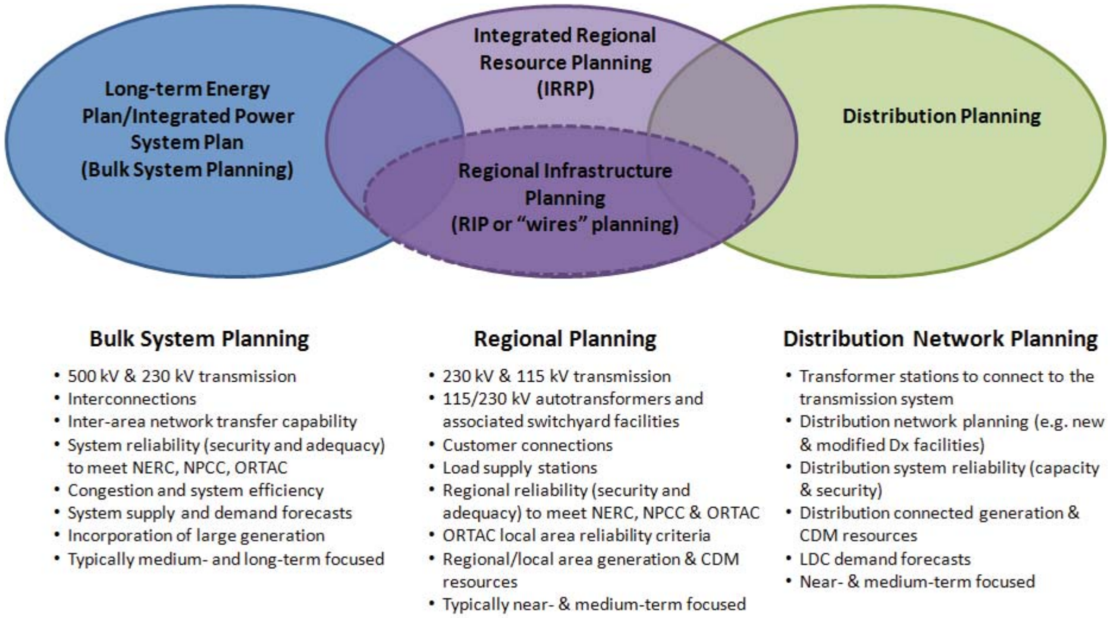
The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are electricity needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment process to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Assessment process – identifying whether an IRRP, RIP, or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and is required to complete the plan within six months. Both RIPs and IRRPs are to be updated at least every five years.

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

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

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

Figure 3-1: Levels of Electricity System Planning



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

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

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

3.2 The IESO's Approach to Integrated Regional Resource Planning

IRRPs assess electricity system needs for a region over a 20-year period, except in cases where the Working Group participants agree on a different planning horizon.[2] The outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

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

In developing an IRRP, the IESO and regional Working Group (see Section 3.3 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities, who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities that are

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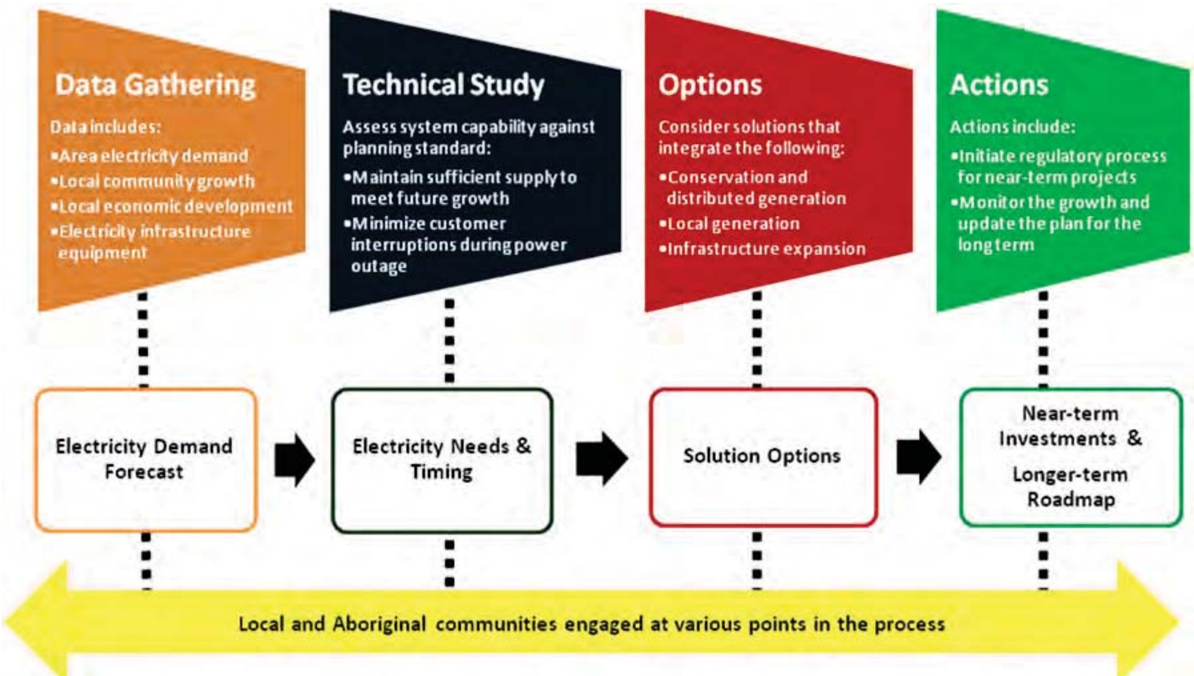
[2] In some cases, such as in this IRRP, the planning assessment was based on a 25-year forecast to account for longer-term growth potential and/or municipal plans. As planning for Central Toronto was initiated in 2011, the forecast period extends to 2036.

responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve development of conservation, local generation, or other solutions, community engagement, or information gathering to support future iterations of the regional planning process in the Region.

Figure 3-2: Steps in the IRRP Process



3.3 Central Toronto Working Group and IRRP Development

The Central Toronto IRRP process was commenced in 2011 by the Ontario Power Authority ("OPA"), in response to the significant rate of growth of new buildings and urban intensification in the downtown core and other areas within the central part of the city. It had been almost five years since the previous planning study for the area was done for the 2007 Integrated Power System Plan. The OPA proposed that a joint integrated planning study be undertaken which led to the establishment of the Working Group which as noted above included representatives of the former OPA, IESO, Toronto Hydro, and Hydro One.

The OPA developed a Terms of Reference that were signed by each of the participating organizations.[3] The Working Group gathered data, identified near term and potential long-term needs in the area, and recommended the near-term plan included in this IRRP. Implementation of elements of the near-term plan began in 2014 with the OPA issuing letters supporting near-term projects so that they could commence immediately in order to be in-service in time to address imminent needs.

This Central Toronto IRRP is therefore a "transitional" IRRP in that it began prior to the development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known. When the Regional Planning process was formalized by the OEB in 2013, the planning approach was adjusted to comply with the elements of the new process. This included the incorporation of formal input from electricity consumer groups in the city, municipal planners, other governments groups interested in electricity planning, industry stakeholders and interested community participants. This IRRP reflects this revised and updated information.

[3] The IRRP Terms of Reference can be found on the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central-Toronto-IRRP-Terms-of-Reference.pdf

4. Background and Study Scope

The City of Toronto ("City"), the largest city in Canada by population and employment, has a very high land-use density of commercial and residential buildings, especially in the central parts of the city. Toronto is the largest electricity demand centre in Canada, at about 5,000 MW of peak summertime electricity demand, 40% of which (about 2,000 MW) is in the central area.[4] Extensive high density residential and commercial urban redevelopment has contributed to steady electricity demand growth in localized pockets, although the overall City of Toronto demand has been steady at around 5,000 MW for the last 10 years. This pace of growth in localized areas is expected to continue for the next several years. In recent years, more tall buildings have been under construction in Toronto than in any other major city in North America.[5]

To set the context for this IRRP, the scope of the IRRP and the existing electricity system serving the area are described in Section 4.1, and a summary of recent investments in the local electricity system is presented in Section 4.2.

4.1 Study Scope

The IRRP study area is shown in green shading in Figure 4-1. The study area is roughly bounded by Highway 401 to the north, Highway 427 and Etobicoke Creek to the west, Victoria Park Avenue to the east and Lake Ontario to the south. Most of this area operates at the 115 kV transmission level, whereas the surrounding Metro Toronto area is served at the 230 kV level. At the distribution level, most of the area operates at 13.8 kV, while the surrounding area is served by distribution at the 27.6 kV level.[6]

The 230 kV corridors supplying the two main 230kV/115kV transformer stations ("TS") in the east and the west are included within the scope of this IRRP. The individual supply stations along the 230 kV corridor in the east were included in the Metro Toronto Northern sub-region Needs Screening assessment completed by Hydro One in 2014.

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[4] The central area includes the downtown central business area.

[5] There are starting to be some signs of a slow-down in the construction of condominium buildings in Toronto, however, at least 55 tall buildings remain under construction, with many more approved by the City of Toronto for construction. Therefore, despite the possibility of a slower pace of growth in the future, electricity system infrastructure will still be required in the near term to supply the growth that is known with more certainty.

[6] Exceptions in the Central Toronto Area include four transformer stations in the study area that supply distribution system voltages at 27.6 kV. These stations include Manby, Leaside, Runnymede, Fairbank, and Horner transformer stations. These stations are shown in Appendix B.

Figure 4-1: Central Toronto IRRP Study Area

1. The study area boundaries, as shown, are the approximate service areas of the transmission and distribution facilities within the scope of the Central Toronto IRRP.
2. The study area also includes the service areas of Manby TS, Leaside TS and Horner TS, which are supplied by 230 kV transmission.

As shown in Figure 4-2, customers in the study area are served by two main electrical sectors, an eastern sector ("Eastern Sector") and a western sector ("Western Sector"). The Eastern Sector is supplied through a major 230 kV/115 kV TS in the Leaside area (Leaside TS) and the Western Sector is supplied through a major station near Islington City Centre – West in Etobicoke (Manby TS). The Portlands Energy Centre (PEC), a 550 MW natural gas fired combined cycle power plant near the downtown core, also feeds into the Eastern Sector. About 70% of the peak electrical demand (1,400 MW) is normally served by the power system facilities in the Eastern Sector and the remaining 30% of the peak electrical demand (600 MW) is normally served by the power system facilities in the Western Sector. The Western Sector is supplied by two independent busses at Manby TS: Manby West which supplies areas of the downtown core, and

Manby East which supplies areas to the northwest of downtown. A detailed diagram of the transmission system supplying the Central Toronto Area is provided in Appendix A. Further information about the electrical system in the study area can be found within a Central Toronto IRRP Discussion Workbook, available on the IESO website.[7]

Figure 4-2: Electrical Supply in Central Toronto by Sub-sector

Horner TS, to the south of Manby TS, is supplied by 230 kV facilities from Manby TS and is therefore inside the Central Toronto IRRP study area.

The transmission system in the study area has the capability of switching electrical demand between the Eastern and Western Sectors. There are switching facilities and cables that allow some of the load to be transferred back and forth between the Manby East and Leaside systems,

[7] The Discussion Workbook is available at: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central%20Toronto%20IRRP%20-%20Discussion%20Workbook.pdf

and between Manby West and Leaside systems, when required to maintain load supply during equipment outages or system emergencies.

In the event of a loss of supply in the Eastern (Leaside) Sector, the generation source at PEC will be initially lost. While PEC does not have black-start capability,[8] there is sufficient flexibility within the transmission system to restore generation at PEC from the West via switching, when emergencies occur in the Eastern Sector. Restarting PEC from the West is estimated to take about 1 hour to complete.[9]

The flexibility and redundancy built into the transmission system has enabled effective restoration of customers within the city under past extreme failure events. This flexibility also enables planned outages for routine maintenance and major refurbishments without materially impacting service to customers.

Transfer capability at the distribution system level is more limited. Some transfer capability is feasible from bus to bus within stations, but there is very little capability to transfer electrical demand between stations in the Central Toronto Area via the 13.8 kV distribution system.[10] This is a result of the legacy design of the distribution system that was originally built in Toronto.

4.2 Recent, Planned and Committed Resources

Since 2006, numerous projects, programs and initiatives in Central Toronto have addressed supply capacity, reliability, and equipment end-of-life. This has produced lasting improvements to the electricity supply situation in the area. These resources include conservation, local and distributed generation, and transmission and distribution investments.

4.2.1 Conservation

Considerable achievements in electricity conservation have been made in the City of Toronto. From 2006 through 2013, about 295 MW of peak demand reduction has been achieved in the

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[8] Black-start is the capability to restore a power station to operation without relying on the external electric power transmission network, which is normally provided from the station's own generators.

[9] This time can vary depending on the sequence of events that had led to the initial isolation of the Leaside bus.

[10] Recent system investments will provide significant enhancements to the transfer capability in Central Toronto once in service. For example, the Midtown Reinforcement project will permit nearly all of the Manby East demand to be supplied via Leaside TS, and Clare R. Copeland TS, currently under construction in downtown Toronto, will eventually have the ability to transfer load to and from the other major stations around it.

city through programs and initiatives delivered by the OPA, Toronto Hydro and other participants, including the City of Toronto. Much of these savings are expected to persist for the next several years, although savings from conservation committed in the past may diminish over time.

The approach to conservation resource procurement that was taken up to 2015, involved designing and delivering conservation programs to customers province-wide. These programs were evaluated through the OPA's evaluation, measurement and verification (EM&V) process to determine both the provincial and LDC-specific impact of each program. The capability to conduct LDC-specific evaluation of savings for the conservation programs evolved with the ramping up of program offerings in the market. Impacts of conservation efforts were reported both at the provincial and LDC-level.

With the transition to more locally designed conservation programs (through the LDCs, for example), it is expected that conservation programs will be tailored to the local customer base, target specific customer groups in local or regional areas of need, and that results will be directly attributable to the local step-down station or bus level.

2006-2014 OPA Conservation Programs

At least 28 conservation programs were offered in the City of Toronto from 2006 to 2014. Eleven of these programs continue to be offered as the province transitions to the new conservation framework and Toronto Hydro's 2015-2020 Conservation Plans are implemented. Moving forward, under the Conservation First Framework, all Ontario LDCs are required to produce a conservation and demand management plan by May 1st, 2015 outlining how they intend to meet their mandated energy savings targets within their allocated conservation budget from 2015 to 2020.

The programs that have been offered to customers in Toronto are listed in Table 4-1. These are mostly province-wide programs delivered by Toronto Hydro or various delivery channel partners. Some initiatives were rolled out as pilots, and learnings from these initiatives were integrated into future programs or program redesign.

Table 4-1: 2006-2014 Conservation Programs in the City of Toronto

Program	Market Sector	Availability
Affordable Housing Pilot	Residential Low Income	2007
Cool & Hot Savings Rebate	Residential	2006-2010
Demand Response 1	Commercial & Institutional, Industrial	2006-2009
Demand Response 2	Commercial & Institutional, Industrial	2009-2010
Demand Response 3	Commercial & Institutional, Industrial	2008-Current
Energy Efficiency Assistance Pilot	Residential Low Income	2007
Every Kilowatt Counts	Residential	2006-2010
Great Refrigerator Roundup	Residential	2006-2010
High Performance New Construction	Commercial & Institutional	2008-Current
Toronto Hydro - Summer Challenge	Residential	2009
Loblaws Demand Response	Commercial & Institutional (Loblaw)	2006-2010
Multi-Family Energy Efficiency Rebates	Residential, Residential Low Income	2009-Current
peaksaver® and ***peaksaver* Plus**®	Residential, Business	2007-Current
Power Savings Blitz	Commercial & Institutional	2008-2010
Social Housing Pilot	Residential Low Income	2007
Summer Savings	Residential	2007
Summer Sweepstakes	Residential	2008
Toronto Hydro Comprehensive	Residential, Commercial & Institutional, Residential Low-Income	2007-2010
Appliance Exchange	Residential	2011-Current
Appliance Retirement	Residential	2011-Current
Residential Coupons (Annual and Event Coupons)	Residential	2011-Current
HVAC Incentives	Residential	2011-Current
Retailer Co-op	Residential	2011-Current
Direct Install Lighting	Commercial & Institutional	2011-Current
Retrofit	Commercial & Institutional	2011-Current
Energy Audit	Commercial & Institutional	2011-Current
Home Assistance Program	Residential	2011-Current
Energy Manager	Industrial	2011-Current

City of Toronto Energy Saving Policies and Programs

In addition to the conservation programs listed in the preceding section, the City of Toronto has developed a number of innovative policies and programs that conserve energy. A summary of these policies and programs is presented in Table 4-2. This summary has been adapted from the City of Toronto Energy & Emissions Inventory and Mapping Report (2013).

Table 4-2: City of Toronto Energy Saving Policies and Programs

Policy	Description	Target Group
City Wide Energy Policies		
Toronto Green Standard (TGS)	The TGS is a two-tiered set of performance measures and guidelines used to achieve sustainable site and building design in new developments. New buildings are required to achieve a minimum energy performance of 25% better than the Model National Energy Code for Buildings/Ontario Building Code within Tier 1, and a voluntary energy performance of 35% energy savings within Tier 2. These minimum and voluntary targets are currently under review and are expected to increase in the future.	New planning applications (including Zoning By-law Amendment, Site Plan Control and Draft Plan of Subdivision) are required to comply with Tier 1 standards. Tier 2 measures are voluntary and applicants who wish to meet them may be eligible for a Development Charge Rebate.
Green Roof By-law	Sets green roof and cool roof coverage requirements for new developments as a way to reduce storm water runoff and building cooling demand.	Applies to new building permit applications for residential, commercial and institutional development made after January 31, 2010 with a minimum gross floor area (GFA) of 2,000 m2
Area Specific Energy Policies		
Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements
Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies
Energy Programs		
Better Building Partnership	Better Building Partnership	Better Building Partnership
Home Energy Load Program	Home Energy Load Program	Home Energy Load Program

Conservation Pilot Initiatives in the City of Toronto

In addition, a number of innovative conservation pilot initiatives have either been completed or are underway in the City of Toronto. The IESO, Toronto Hydro, and the City of Toronto pilot initiatives are summarized in Table 4-3. Opportunities to scale these pilots to programs are being evaluated.

Table 4-3: Conservation Pilot Initiatives in the City of Toronto

Pilot	Description	Savings Opportunity
Pay for Performance (PFP): $/kWh (Loblaws Inc.)	• Pilot initiated in 2014 • Pay for Performance is a financial model in which savings from energy efficiency upgrades receive additional monetary compensation (beyond reduced operating costs) • If energy consumption increases penalties may be applied • Contracts may be offered in targeted areas	• To be evaluated
Municipal financial support through Local Improvement Charges (City of Toronto)	• Pilot initiated in 2014 • Local Improvement Charges (charged and collected by the city) will be used to create a fund, which will be available as a low-interest loan to individuals for investment in energy efficient upgrades • Pilot will include 200 homes and 200 apartment units • The City expects to make the fund available to all Toronto residents by 2015	• Maximum energy efficiency upgrades is expected to be 10% per building/unit
Multi-unit residential building demand response pilot (MURB DR) (Toronto Hydro)	• Pilot initiated in 2013 • Involves the installation of load control devices and programmable communicating thermostats in MURB units and common areas • Energy efficiency retrofits will also be conducted in building common areas	• Involves four condominium facilities for a total of 400 suites; the anticipated savings is 0.3 kW per suite and 77.9 kW per common area (with 100 suites, per building savings is 101 kW (ca. 10% of load) • A total of 20MW of demand reduction may be achieved if full program launch is enabled (ca. 200 buildings)
Local Demand Management Pilot Study (Toronto Hydro)	• Study initiated in fall 2013 • Aim is to assess the estimated demand savings from targeted demand reduction initiatives and to design and run pilots in constrained service areas	• If the initiative achieved 5% in demand savings, infrastructure investments could be offset for several years
Commercial Energy Management and Load Control (CEMLC) pilot (Toronto Hydro)	• Pilot involves the installation of load control devices and programmable communicating thermostats to be activated during peaksaver PLUS activation periods	• Pilot initiated in 2013 for the 50-250 kW commercial sector • Involves 12 facilities (3 in each of the office, retail, hospitality and institutional sectors); the average demand savings per site is expected to be 23.4 kW (280 kW total) • A total of 42 MW of demand reduction may be achieved if full program launch is enabled (1,800 sites)
HVAC load shifting technology pilot (Ice Energy- Ice Bear Energy Storage System)	• Piloted by Toronto Hydro 2010-2011 (supported by the OPA)	• Each unit reduces peak demand by 12 kW

Deep Lake Water Cooling

Downtown Toronto is home to the Deep Lake Water Cooling System that provides air conditioning to commercial, institutional, government and residential buildings by drawing cool lake water and circulating it to buildings to replace the need for electric air conditioning systems. It is estimated that deep lake water reduces electricity usage by 90% compared to conventional cooling systems. The Deep Lake Water Cooling System has been estimated to have reduced the downtown peak demand by as much as 61 MW.

4.2.2 Generation Resources

Since 2008, a number of new generation facilities have been installed in Central Toronto. The Portlands Energy Centre ("PEC") is an example of a large transmission connected generation facility sited within the load centre. Many new small renewable generation facilities have also come into service under the province's Feed-in Tariff program, as well as combined heat and power projects. These facilities are described further below.

Portlands Energy Centre 550 MW Gas-fired Generating Station

Phased in from 2008 to 2009, a major new generation supply resource was placed in-service and connected at the Hearn switching station in the Portlands area. This 550 MW combined cycle generation facility is an important source of generation providing capacity and supply security within the Central Toronto load area. The PEC restored some balance to the supply and demand situation in downtown Toronto, which had become imbalanced when the Hearn generating station was decommissioned in the 1980s.

Renewable Energy Generation

Since 2009, 13.75 MW of new renewable energy generation facilities have been contracted for in Central Toronto under the Feed-in Tariff program. Of these 120 projects, 13 MW are rooftop solar photovoltaic ("PV") projects, and one project is the 750 kW wind turbine installed at Exhibition Place. Another 731 microFIT solar PV projects, totaling approximately 4 MW of capacity, have been contracted for across the City of Toronto, a portion of which are located in the Central Toronto Area.

District Energy

The City of Toronto has identified and studied 27 areas, or "nodes," throughout the city where the density of development provides an opportunity to develop District Energy systems.[11] Of these 27 nodes, 10 were identified as having high potential to be developed, 7 of which are within the Central Toronto Area:

- East Bay Front (Jarvis and Queens Quay)
- Yonge and Dundas
- Yonge and Bloor
- West Don Lands (Eastern and Front)
- Fort York (Bathurst and Lakeshore)
- Etobicoke Civic Complex (West Mall and Civic Center Court)
- Lawrence Phase 2 (Allen and Lawrence)

A 1.6 MW District Energy system is currently under construction at Exhibition Place. Electrical energy generated will help meet local peak electricity demand needs of the area, and thermal energy will be sold to a new hotel under construction on the Exhibition Place grounds.

Other small District Energy systems in the City of Toronto make up a portion of the 21.5 MW of reliable peak electricity demand reduction that represents the full complement of DG resources within the Central Toronto Area.[12]

4.2.3 Transmission and Distribution Facilities

Since 2007, numerous transmission and distribution projects have been started or completed to address supply capability, reliability or equipment end-of-life issues in the Central Toronto Area. These projects include:

- John TS to Esplanade TS underground cables
- Midtown 115 kV transmission reinforcement
- Hearn switching station rebuild
- Breaker upgrades
- Lakeshore 115 kV cable refurbishment
- Clare R. Copeland 115 kV transformer station

[11] Report is available for download at the City of Toronto website: http://www1.toronto.ca/City%20Of%20Toronto/Environment%20and%20Energy/Programs%20for%20Businesses/BBP/PDFs/FINAL-GENIVAR-Report-City-of-Toronto-District-Energy-November-21-13.pdf

[12] 21.5 MW is the capacity of DG resources that can predictably generate during the peak demand period.

Many of these projects stemmed from previous integrated planning studies completed since the mid-1990s, and are discussed in more detail below. Over the last 10 years, investment in Central Toronto's electricity system has been approximately $1.3 billion.

John TS to Esplanade TS Underground Cables

Two new underground cables, 2.2 km in length, from the John TS to Esplanade TS were placed in-service in 2008 by Hydro One. These cables resulted in enhanced reliability and security between the Leaside and Manby systems and addressed the need for increased load transfer capability between the two 115 kV systems. This link was recognized as a common facility required for a future major new transmission supply to Central Toronto. The cables are capable of operation at 230 kV, but are currently being operated at 115 kV.

Midtown 115 kV Transmission Reinforcement

The Midtown transmission project, currently underway, is a multi-stage transmission refurbishment project that is replacing the underground cables between Bayview Junction and Birch Junction in the Leaside TS sector. This joint Hydro One – Toronto Hydro project will add a new 115 kV circuit between Leaside TS and Birch Junction, as well as installing new equipment at Leaside TS and the Bayview, Birch and Bridgman Junctions to provide additional electrical supply capacity to the area. In addition to addressing capacity issues for supplying Bridgman TS and Dufferin TS, the project provides additional capacity to transfer the Wiltshire TS load from the Manby TS sector to the Leaside TS sector under most normal operating conditions. This will provide more flexibility to address loading or equipment issues not only on the Manby TS system but also further upstream in the western parts of the GTA. This line upgrade will also enable nearly all of the electrical demand in the Manby East system to be supplied from Leaside TS under emergency conditions (up to 340 MW).

Hearn Switching Station Rebuild

Hydro One has completed a full rebuild of the Hearn switchyard in the Portlands area to address equipment end-of-life at this important switching station in downtown Toronto. The new Hearn station permits the Hearn 115 kV switchyard to operate as one bus rather than in split bus configuration, resulting in improved overall balancing of electrical demand on the transmission facilities out of Leaside TS.

Breaker Upgrades

Hydro One has replaced the 115 kV circuit breakers at both Leaside TS and Manby TS. These projects have resulted in the removal of fault current limitations that had affected the downtown area. They will also permit the connection of additional DG in the Central Toronto Area. In addition, the new equipment is more reliable and reduces the probability of an unexpected breaker failure contingency affecting supply to customers in the area.

Lakeshore 115 kV Cable Refurbishment

The Lakeshore Renewal Project is the second phase of the Lakeshore sustainment project first undertaken in the 1990s. The current project by Hydro One involves replacement of two 115 kV underground cables connecting Riverside Junction at Windermere Avenue and Lakeshore Boulevard to Strachan TS at Strachan Avenue and Manitoba Drive. Hydro One is installing two new 230 kV cables, but the cables will operate at 115 kV until more power is needed. The existing cables that were originally installed in the late 1950s will be decommissioned once the new cables are in service. The typical lifespan of a cable is 50 to 60 years.

Clare R. Copeland 115 kV Transformer Station (Phase 1)

Toronto Hydro is building the first new step-down transformer station in downtown Toronto in many years. In addition to providing additional supply capacity in the heart of the downtown business district, the Clare R. Copeland TS ("Copeland TS," formerly called Bremner TS) will provide additional flexibility to transfer downtown loads from Manby to Leaside and this additional load-shifting capability can reduce the amount of load at risk of being interrupted in the event of a contingency at Manby TS or John TS.

5. Demand Forecast

This section outlines the demand forecast for Central Toronto. The demand forecast estimates the future peak electricity demand within the area over the planning horizon, including the contribution of conservation and DG to reducing peak electricity demand requirements.

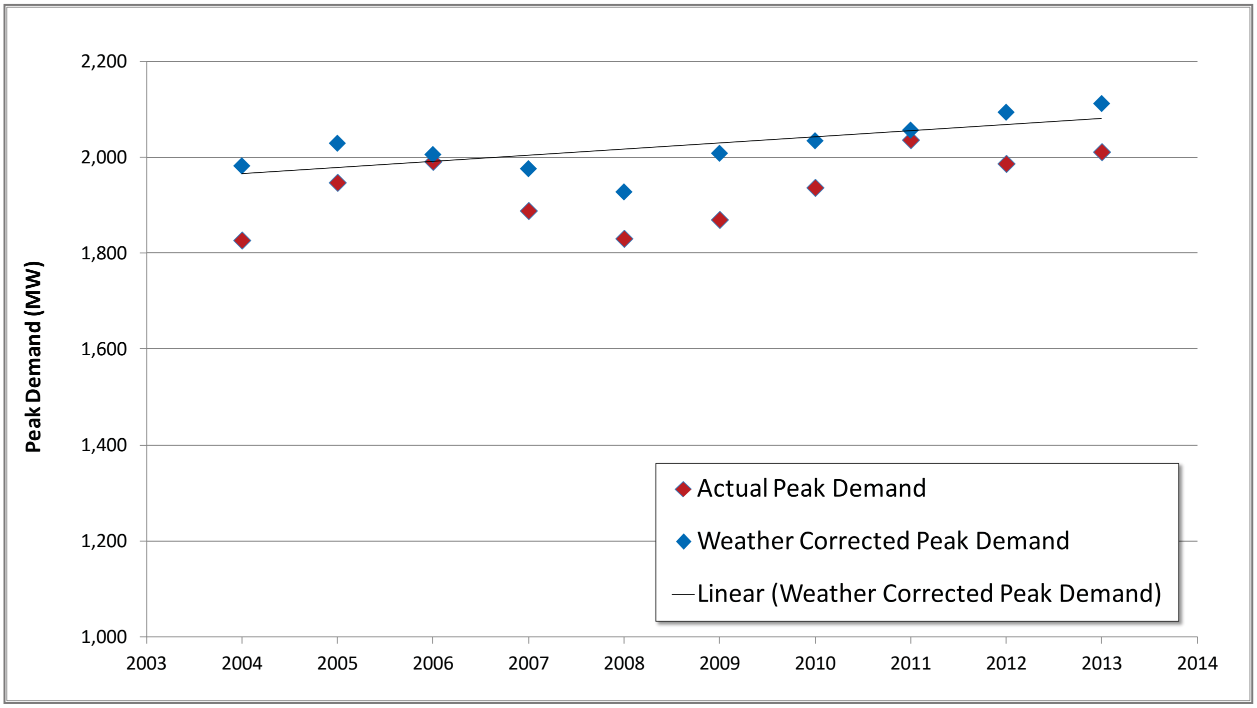
For the purposes of evaluating the adequacy of the electricity system, regional planning is concerned with the regional coincident peak demand. Coincident peak demand is the demand observed at the transformer stations for the hour of the year when overall demand in the study area is at its highest. This represents the moment when equipment is expected to be the most stressed, and resources the most constrained. Within Central Toronto, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during the summer, and is driven primarily by the weather sensitive air conditioning loads of commercial and residential customers. Within the past 10 years, the local peak occurred on the same day as the overall provincial peak in each year but one.

The following sections describe the historical demand trends in the area, followed by a description of the various forecast elements, including the gross forecast, conservation forecasts, and the net forecasts used for determining the electricity service requirements for the plan.

5.1 Historical Demand

Over the past five years, Central Toronto has experienced moderate overall growth in electricity demand. In 2007 and 2008, a decrease in electricity demand in the Central Toronto Area occurred, as conservation programs entered the market and the economy experienced a downturn. Since 2008, the demand in the area has returned to pre-recession levels and has been buoyed by strong growth in new building construction. Historical peak demand has averaged growth of 0.7% per year over the past decade, as shown in Figure 5-1.

Figure 5-1: Historical Electricity Peak Demand for Central Toronto 115 kV System



Within Central Toronto, there have been individual pockets of higher growth, and some areas that have experienced lower growth. In particular, the downtown core, consisting of five transformer stations (Cecil TS, Terauley TS, Esplanade TS, John TS and Strachan TS), has averaged growth of 1.2% per year over the same time period.

Factors that have influenced the historic peak demand from 2006 onwards have been the savings associated with conservation programs, and other initiatives such as the Deep Lake Water Cooling System Project that has been estimated to reduce the downtown peak demand by as much as 61 MW.

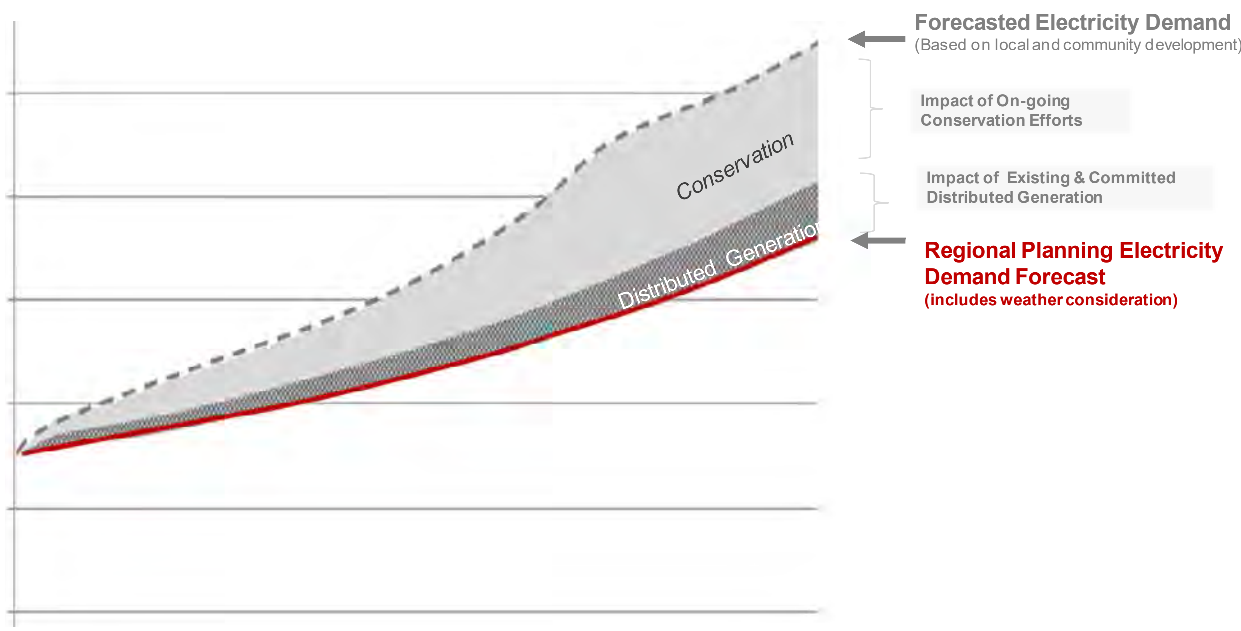
5.2 Demand Forecast Methodology

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

A regional peak demand forecast was developed as illustrated in Figure 5-2. A gross demand forecast, assuming extreme-weather conditions, was provided by Toronto Hydro. The gross demand forecast accounted for the growth projections provided by City of Toronto plans and projections for population, economic development, and intensification through plans for new building and urban development, and considered the impact of existing in-market conservation programs and existing DG. This forecast was then modified to reflect the peak demand impacts of future provincial conservation targets to produce a planning forecast. The planning forecast was then used to assess any growth-related electricity needs in the region.

Using a planning forecast that is net of provincial conservation targets is consistent with the Province's Conservation First policy. However, this planning forecast assumes that the energy targets will be met, and will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by Toronto Hydro, and as necessary, revisiting and adapting the plan if assumptions change.

Figure 5-2: Development of Demand Forecasts



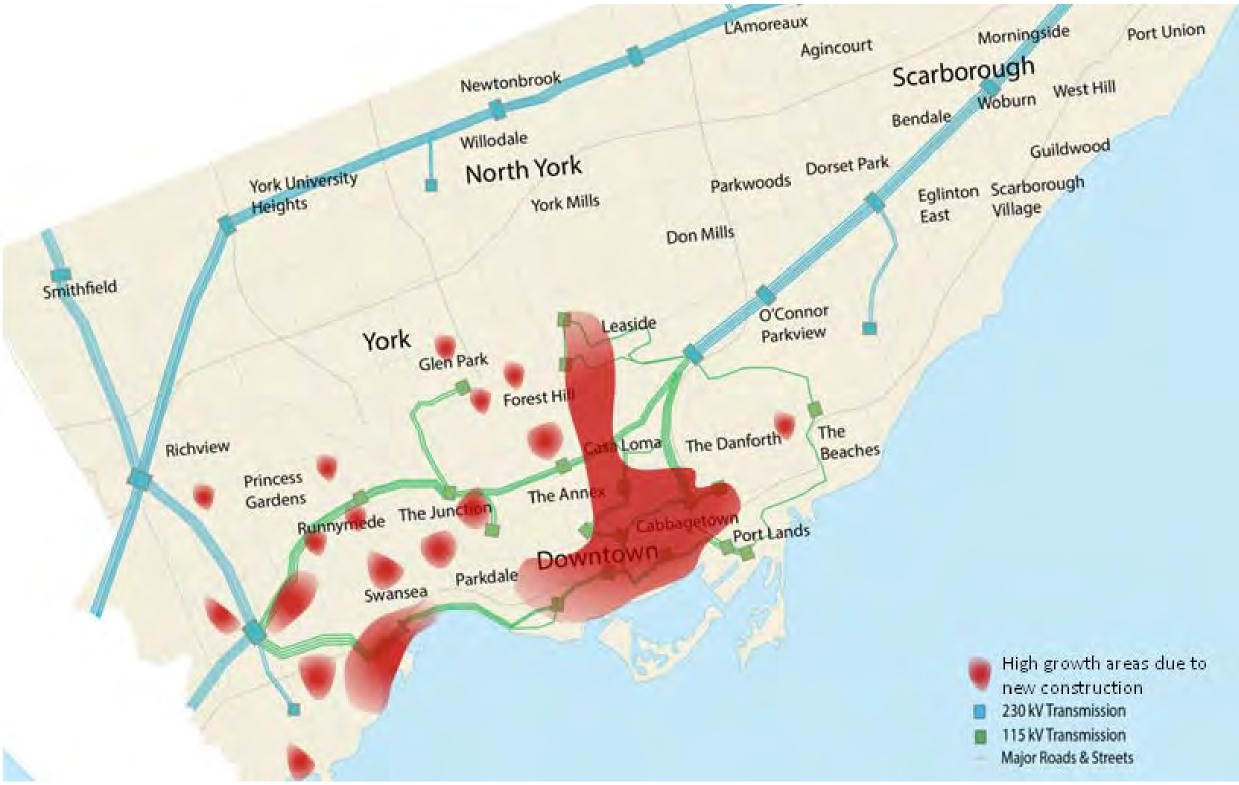
5.3 Gross Demand Forecast

For the purpose of this study, Toronto Hydro commissioned Navigant Consulting Inc. to develop a summer peak demand forecast covering a 25-year planning horizon. The forecast accounts for information on developments expected to contribute to demand growth in the area, including population and employment. The forecast provided by THESL was developed under coincident, extreme-weather assumptions, which accounts for the weather sensitive aspects of electricity demand such as space cooling in the summer months. Further detail about the methodology used to develop Toronto Hydro's gross forecast is provided in Appendix B.[13]

Overall, growth is expected to continue over much of the Central Toronto Area. The majority of growth is expected to be concentrated where significant pockets of new development are occurring, such as the central lakeshore area and the west end of the City. The growth in these areas is primarily due to high rise building development, and is shown in Figure 5-3.

[13] It is noted that Navigant produced separate forecasts termed "gross" and "net." The "gross" forecast excludes all conservation and DG past, present and future, and represents a forecast absent the impact of any conservation measures implemented in Toronto since 2006. This forecast is less useful for the purpose of determining electricity system needs. The "net" forecast includes historical conservation and the current conservation programs that were in-market in 2012 until 2014. After 2014, the THESL "net" forecast does not account for additional conservation programming. The references to THESL's "gross" demand forecast in this document actually refer to the "net" forecast as described in Appendix B.

Figure 5-3: Concentrations of Growth in Central Toronto



Source: City of Toronto

5.4 Conservation Resources Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. Conservation is achieved through a mix of program-related activities, including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results. The conservation savings forecasts for Central Toronto have been applied to the gross peak demand forecast, along with existing DG resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan (LTEP), which outlined a provincial conservation target of 30 TWh of energy savings by 2032. To represent the effect of provincial targets within regional planning, the IESO developed forecast scenarios for peak demand savings based on varying levels of achievement of the provincial savings target. These conservation scenarios were applied to the gross demand forecast to develop estimates of the peak demand impacts in Central Toronto. The conservation estimates are shown in Table 5-1. Additional conservation forecast details are provided in Appendix C.

Table 5-1: Peak Demand Savings Assumed from the 2013 LTEP Conservation Targets in Central Toronto (Megawatts)

Year	2014	2016	2018	2021	2026	2031	2036
High Demand Scenario	305	253	255	241	215	215	238
Low Demand Scenario	305	346	376	411	497	611	641
Median Demand Scenario	305	253	255	284	366	396	423

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG is also anticipated to offset peak demand requirements. The introduction of the *Green Energy Act, 2009* ("GEA"), and the associated development of Ontario's Feed-in Tariff ("FIT") program, has increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, the effects of DG in service at the time were included. Each project's capacity contribution was subtracted from the peak demand at the transformer station to which it was connected. The amount of DG assumed to have a peak demand impact was 21.5 MW.

Future DG uptake was not included in the forecast due to difficulties forecasting the uptake and location. This leaves DG potential as an option for meeting future needs.

Additional details of the demand reductions attributable to DG are provided in Appendix C.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, planning forecast scenarios were produced based on the demand forecast submitted by Toronto Hydro to the Working Group.

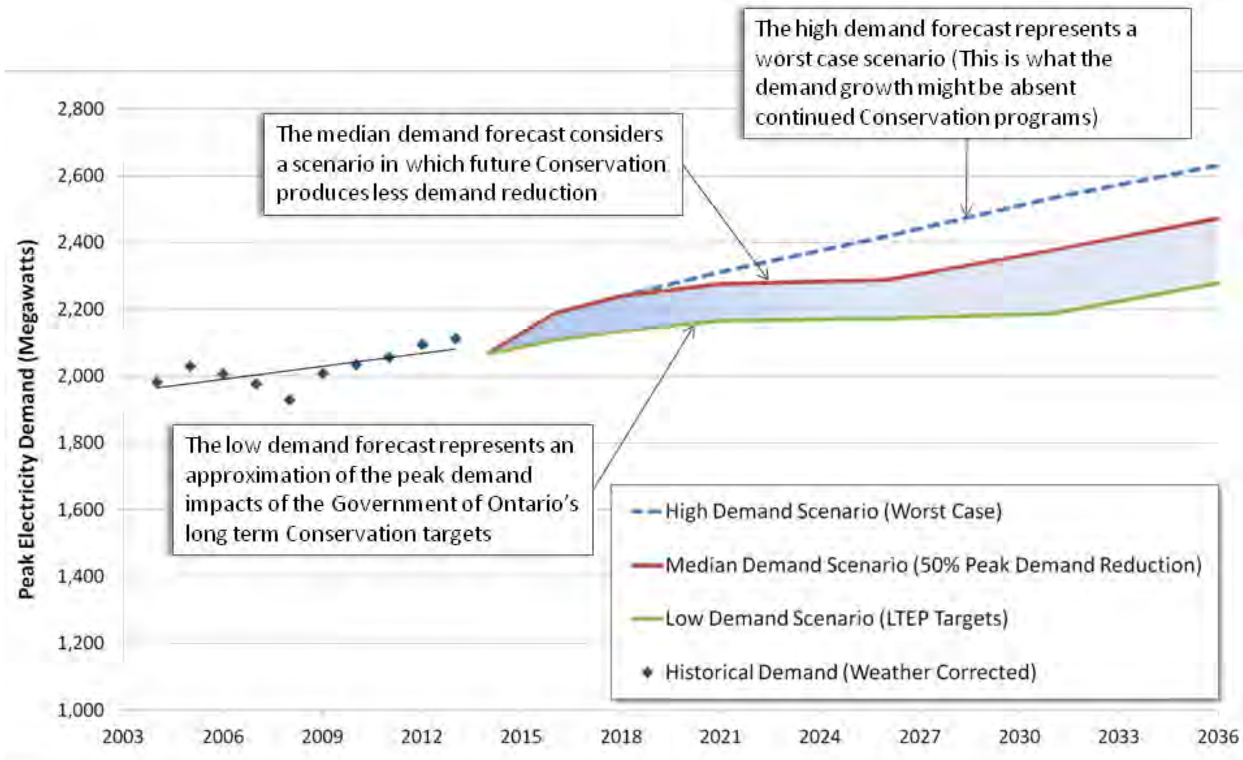
A “high demand” growth scenario was assessed to determine what the system needs would be under a worst-case, in which either conservation does not meet expectations, or new growth and development accelerate in the area. This forecast scenario assumes 238 MW of savings from conservation targets across the Central Toronto Area over the next 25 years. This scenario assumes that all historic and conservation initiatives to the end of 2014 continue to provide persistent savings, but no new conservation after 2015. The average annual growth rate under this scenario is 0.99% per year.

A “low demand” growth scenario was assessed which assumes that 60% of the new demand growth will be met through future conservation programs. The basis for this scenario was the provincial Long-Term Energy Plan targets (“LTEP targets”). This forecast scenario assumes 641 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years. Combined with the effects of DG and existing conservation programs, the low demand scenario forecast assumes that the impact of future conservation programs to meet the long-term targets will reduce the average annual growth rate from 0.99% to 0.38% growth per year.

An additional planning scenario was developed to reflect the uncertainty associated with forecasting electricity demand and the possibility of varying levels of peak demand impact from future conservation. This “median demand” scenario was developed to test the impact on system needs if either future conservation produces less peak demand impact, or new customer growth is higher than forecast. This forecast scenario assumes 423 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years, which considers 50% of the peak demand reduction compared to the low demand scenario. This represents a growth rate of 0.72% growth per year. This growth rate is closest to the historical rate of electricity demand growth in Central Toronto over the last ten years (0.71%).

The three demand scenarios are shown in Figure 5-4 for the 115 kV transmission system in Central Toronto. The raw demand forecast data for the entire study area is provided in Appendix D.

Figure 5-4: Electricity Peak Demand Forecast for Central Toronto (115 kV System)



6. Needs

This study assessed the capability of the existing high voltage power system to provide reliable electrical service over the near-term (0-5 years), medium-term (6-10 years) and longer-term (11-25 years) periods.[14] The assessment accounted for growth in electrical demand within the study area, the reliability standards established for power systems within Ontario, service quality expectations as expressed by customers, and other preferences indicated by the local community through the engagement process. The assessment as noted, also accounted for the implementation of expected conservation, given existing programs that are in the planning phases and targets established by the Province of Ontario.

6.1 Need Assessment Methodology

Provincial planning criteria were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in the Central Toronto are over the forecast period. Electrical system needs were determined through a series of tests as defined in the ORTAC, which establishes the planning criteria and assumptions to be used for assessing the adequacy and security of Ontario's electricity system.[15]

Technical assessments were conducted using industry-standard software-based modeling tools such as Power System Simulator for Engineering ("PSS®E") for conducting deterministic contingency analysis, and using the probabilistic assessment feature within PSS®E to estimate the risk related to certain contingencies that are beyond the stress tests as defined by the criteria in ORTAC. All system tests were performed assuming summertime peak demand conditions under the various demand forecast scenarios described in Section 5.

6.1.1 Ontario Resource Transmission Assessment Criteria

In accordance with the ORTAC, the transmission system must be able to provide continuous supply following defined transmission and generation outage scenarios, and limit the amount of load loss and restoration time following the occurrence of multiple element outages. The

[14] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25-year period. The Working Group agreed to assess needs based on the 25-year forecast.
[15] The ORTAC document can be found on the IESO website:
http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

defined outage scenarios are referred to as "contingencies." These contingency-based tests are deterministic in that they are assessed independent of the probability of their occurrence.

Deterministic assessments are an established electricity industry practice for assessing the power system's ability to supply the demand under various possible states, including:

- all system elements in service (N-0),
- following the loss of any one transmission or generation element (N-1),
- following the loss of any one element while another element is on outage or planned maintenance (N-1-1), and
- In certain cases, following the loss of two elements simultaneously (N-2).[16]

In addition to the deterministic tests, the assessment accounted for the flexibility within ORTAC to rationalize higher (or lower) levels of reliability performance.[17] A probabilistic-based reliability assessment ("PRA") was conducted to test higher-order contingencies beyond those specified in ORTAC. Contingencies involving the loss of up to three independent power system elements (N-3) were tested with consideration of the frequency with which they might be expected to occur and the duration of the outages. The frequency and expected duration of an outage for each element was based on the historic levels of reliability and restoration service within the study area, as reported to the Working Group by Hydro One.

PRA provides an estimation of the amount of energy that is likely to go unsupplied in each year, as expressed by the Expected Unserved Energy ("EUE") metric,[18] giving an indication of "unreliability" related to the system design.

Types of Needs Uncovered in the Assessment

The assessment of the electricity system facilities serving Central Toronto uncovered a number of electricity power system needs. These needs generally fall into the following categories: (1) capacity-based needs relating to providing required infrastructure capacity to supply the peak

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[16] Transmission facilities that provide Local Area supply are tested to N-1, or N-1-1 levels of security, whereas Bulk Power System facilities are tested to N-2 to account for the possible system impacts that could result from double contingencies.

[17] For example, Section 7.4 of ORTAC allows for transmission customers and transmitters to agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. The IRRP Working Group agreed that in the case of Central Toronto, that the assessment be supplemented by reviewing the impact of higher order contingencies on customers in the area.

[18] The EUE metric does not provide an absolute determination of the amount of energy that will not be supplied due to unreliability of the system. Rather, it is an indicator only and should not be interpreted as an accurate representation.

demand; (2) reliability-based needs relating to reducing the impact of supply interruptions; and (3) security-based needs relating to the ability to restore supply after major contingencies or unusual events such as extreme weather. These types of needs are described further below.

- **Capacity** is the ability to supply peak demand under normal conditions (i.e., all equipment in service) or under a contingency condition (e.g., one or more power system elements out of service). This ability includes the electrical and physical attributes of the power system to carry out its role.
- **Reliability**, in the context of interruptions of electricity supply to customers, involves two considerations. The first relates to the frequency of supply interruptions (or how often they occur). The second relates to the duration of supply interruptions, and the ability of the system to enable the restoration of service to customers within a specified period of time.
- **Security** involves ensuring that the power system is designed with enough flexibility to reasonably contain the interruption of electricity supply to customers when extraordinary failures occur, and to enable the restoration of supply to interrupted customers within a reasonable period of time. Security includes the ability of the system to cope during major events such as storms and other extreme weather events. The coincident or overlapping failure of several pieces of equipment, the failure of an entire transmission station, or more than two transmission circuits are considered as extraordinary failure events. Given the rare nature of these events, the cost of ensuring full redundancy is typically not justifiable. However, these rare failure events are given consideration in planning, as the power system should have the capability to limit the number of customers exposed and restore interrupted customers within a reasonable period of time.

As part of the security assessment, the IESO reviewed the system design under major power system failure events. A few of these events have occurred over the last several years and the Working Group agreed that proactively investigating the susceptibility of the local power system to these events should be a key component of this study. Although the occurrence of these types of failure events is statistically rare, they tend to have very high impacts on customers if the system and related operational procedures are not able to restore power to customers within a reasonable time period.

The needs identified through the assessment are summarized in the following sections for the near-term and medium-term periods and in Section 8 for the long term.

6.2 Near-Term and Medium-Term System Needs

The technical assessment of the electricity system serving Central Toronto uncovered a number of system needs to be addressed by actions in the near term and medium term.

The near-term needs (0 to 5 years) and the medium-term needs (6 to 10 years), and the options and recommended actions for addressing these needs are summarized in Table 6-1 and are shown in Figure 6-1. Further details are provided in the following sections. Technical summaries of the assessment results are provided in Appendix E. Long-term needs and options are discussed in Section 8.

Table 6-1: Summary of Near and Medium-Term Needs in Central Toronto

Need	Description	Timing	Map Reference (Figure 6-1)	Section Reference
Supply security	Breaker failure contingency at Manby West and Manby East	Today at Manby West; 2018 at Manby East	1	6.2.2
Supply security	Breaker failure contingency at Leaside TS	Today	2	6.2.3
New transformation capacity	Demand growth in West Toronto is forecast to exceed the limits of Runnymede TS and Fairbank TS	2018	3	6.2.5
New transformation capacity	Demand growth in Southwest Toronto is forecast to exceed the limits of Manby TS and Horner TS	2018	4	6.2.5
Transmission line capacity	Demand growth in Central Toronto is forecast to exceed the limits of the 230 kV Richview TS to Manby TS corridor	2018	5	6.2.6
New transformation capacity	Demand growth in the downtown core is forecast to exceed the limits of Esplanade TS and Copeland TS	2021	6	6.3.2

Figure 6-1: Map Showing Need Locations in Central Toronto

6.2.1 Improving Supply Security for Low Probability Breaker Failures at Manby TS and Leaside TS

The IRRP assessment identified a need to reduce the impact of multiple element contingencies at the two major transformer stations that provide grid supply to the Central Toronto Area. These needs are related to the potential failure of a switching device (e.g., breaker) to perform the intended function of clearing an electrical fault. Such a failure could result in electricity service interruptions to customers in the Central Toronto Area.

6.2.2 Manby TS Needs

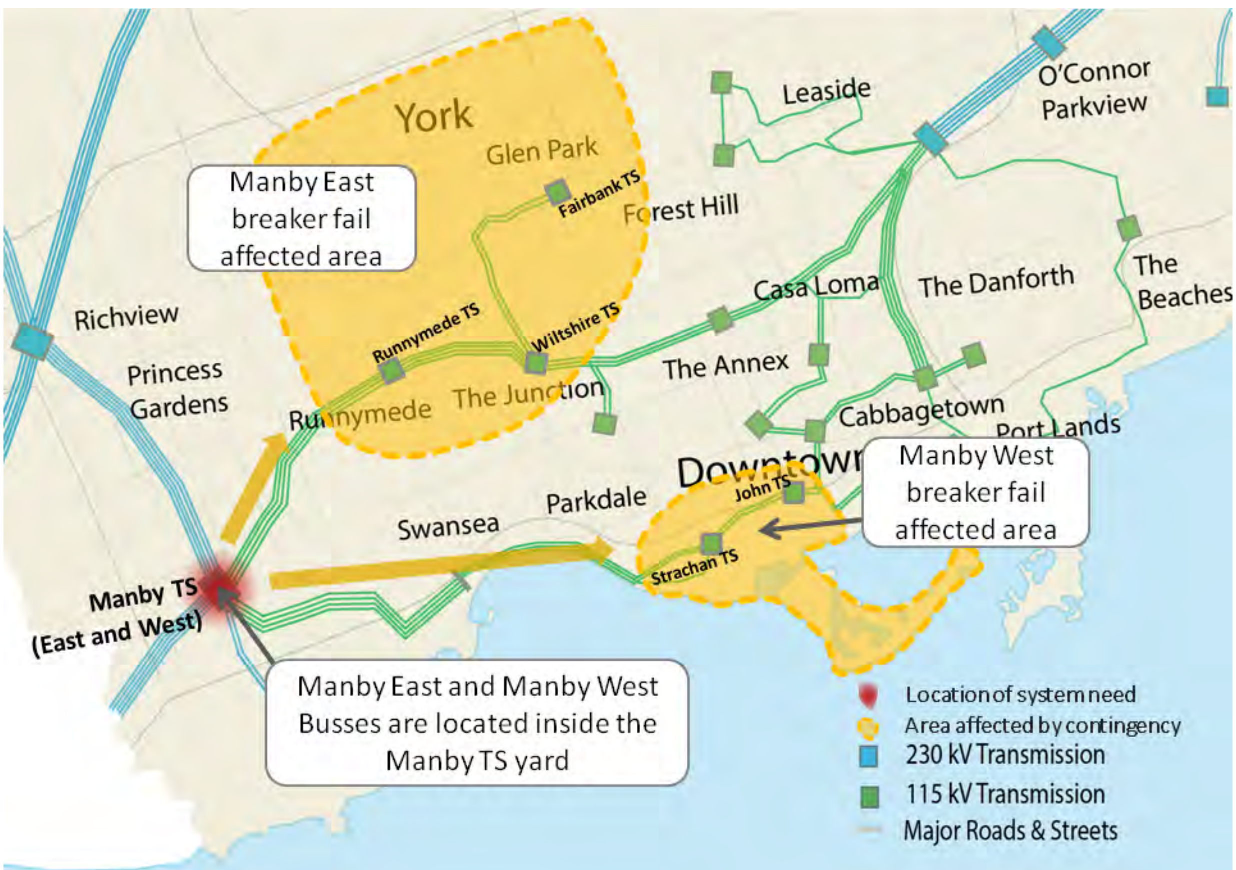
At Manby TS, this need stems from the reliability standards established for interconnected power systems in North America, as defined in the ORTAC. A breaker failure contingency at Manby TS would remove two transformers from service at the same time. The station has two independent delivery points to Central Toronto: a west bus and an east bus, each with three 230/115kV transformers to supply different parts of the Central Toronto Area, as shown in

Figure 6-2.[19] A breaker failure incident at either of these busses will result in only one of the three transformers remaining in service.

In the past, the summer peak station loads have been within the short time emergency rating of the transformer and would thereby still allow the system operator to take necessary action to reduce the transformer load in the event of the contingency. As the demand has increased in Central Toronto, there is a need to take action to ensure that the transformer loading can be reduced, and to minimize the possibility of cascading failures.

The location of the Manby TS and areas affected by the breaker failure are shown in Figure 10. Breaker failure could impact significant customer demand in the affected areas.

Figure 6-2: Manby TS Equipment and Affected Areas



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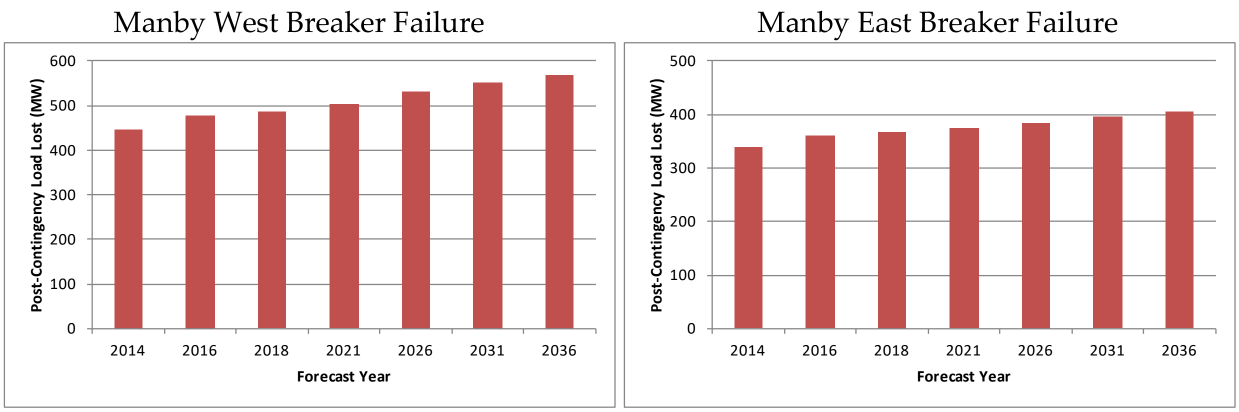
[19] At Manby West, the failure of breaker H1H4 or A1H4 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby West electrical demand. At Manby East, the failure of breaker H2H3 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby East electrical demand.

As stated previously, this need occurs at each of the two independent east and west delivery points at Manby TS, affecting customers both in a large part of the downtown core and in the west Toronto area to the northwest of downtown. The severity of the need is reflected by the amount of load that would be at risk immediately following the breaker failure event. The estimated load at risk at both Manby TS busses is shown in Figure 6-3.

Figure 6-3: Forecast of Customer Load at Risk Following Manby TS Breaker Failure Events



6.2.3 Leaside TS Needs

The need at Leaside TS is considered discretionary because the reliability standards (e.g., ORTAC) do not require action to be taken given system impacts and configuration, but because of the importance of security of supply in the Central Toronto Area and the important role that Leaside plays in backing up the Manby East system, the issue has been flagged in this plan.

A breaker failure contingency at Leaside TS would cause protection systems to activate and consequently remove from service two 115 kV circuits that supply the Bridgman TS to the north of downtown Toronto.[20] This would result in five of six step-down transformers at Bridgman TS being removed from service, leaving only one remaining transformer at Bridgman TS. This remaining transformer is not capable of supplying the full electrical demand of the station.

The location of the Leaside TS and the area affected by the breaker failure are shown in Figure 6-4. This breaker failure would lead to a significant outage to customers in the affected area shown.

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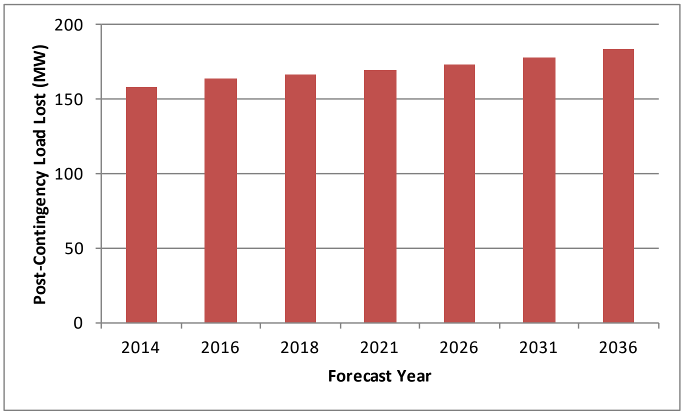
[20] At Leaside TS, the failure of breaker L14L15, which is shared by the 115 kV circuits L14W and L15W supplying Bridgman TS, would remove both circuits from service. The cascading impact of outages at Bridgman TS would affect the supply to the area served by Bridgman TS.

Figure 6-4: Leaside TS Equipment and Affected Areas

In contrast to the breaker events identified at Manby TS which must be addressed to satisfy the reliability standards, mitigating measures should be put in place at Leaside TS as a discretionary measure. These mitigating measures are appropriate given the number of customers potentially affected, the fact that the lines involved are also used to transfer loads from Manby during contingencies, and to improve the supply security in the area. The reliability standards require the testing of breaker failures within the Leaside TS, but since the consequence of the breaker failure do not affect the bulk electric system, the reliability standards do not require that mitigating measures be put in place.

The estimated load at risk immediately following the breaker failure event at Leaside TS is shown in Figure 6-5.

Figure 6-5: Forecast of Customer Load at Risk Following Leaside TS Breaker Failure Event



6.2.4 Capacity Relief to Supply Points in the Manby TS Sector

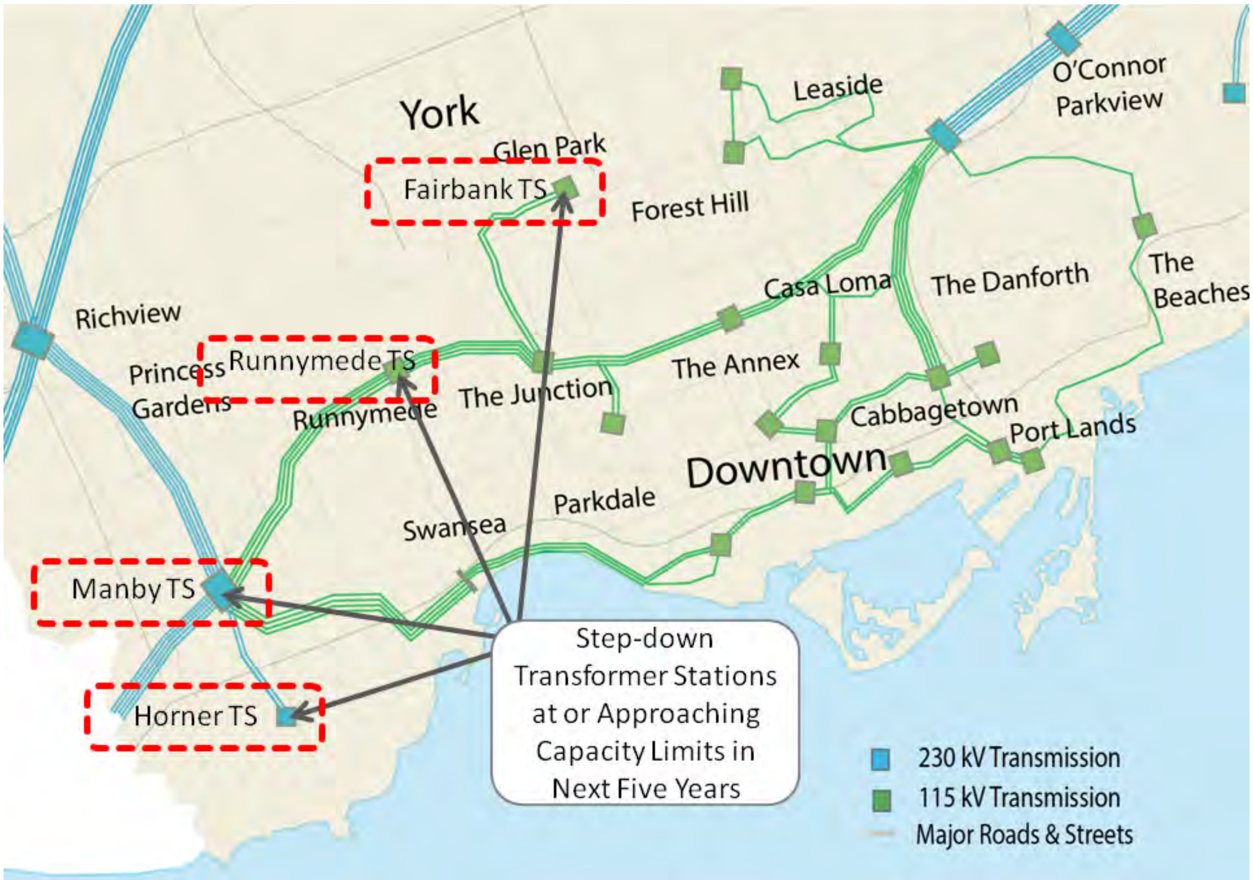
In the near term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the west Toronto area. The capacity need occurs at the step-down transformer stations serving as electricity supply points for distribution customers in the Manby TS sector, and on the 230 kV transmission lines that supply the Manby TS from the provincial grid.

The local TS and line capacity needs are driven by continuing demand growth and by large new customer requests for connection to Toronto Hydro's distribution system. These individual TS and line needs are described separately in the following sub-sections.

6.2.5 Capacity Relief at Step-down Transformer Stations in West Toronto Area

There is a near-term need to provide capacity relief to existing step-down transformer stations serving distribution customers in the western sector. The specific distribution areas and neighbourhoods requiring the capacity relief are shown in Figure 6-6, and include the areas served by Runnymede TS, Fairbank TS, Manby TS, and Horner TS. These transformer stations provide energy transfer points between the high voltage transmission system and the distribution system, and the transmission facilities that provide supply to these stations. Runnymede TS and Fairbank TS are supplied by the 115 kV transmission system connected to the Manby East bus; and Manby TS and Horner TS are supplied by the 230 kV transmission network. The distribution voltage supplied by all four stations operates at 27.6 kV.

Figure 6-6: Station Capacity Needs in Central Toronto in the Near-Term



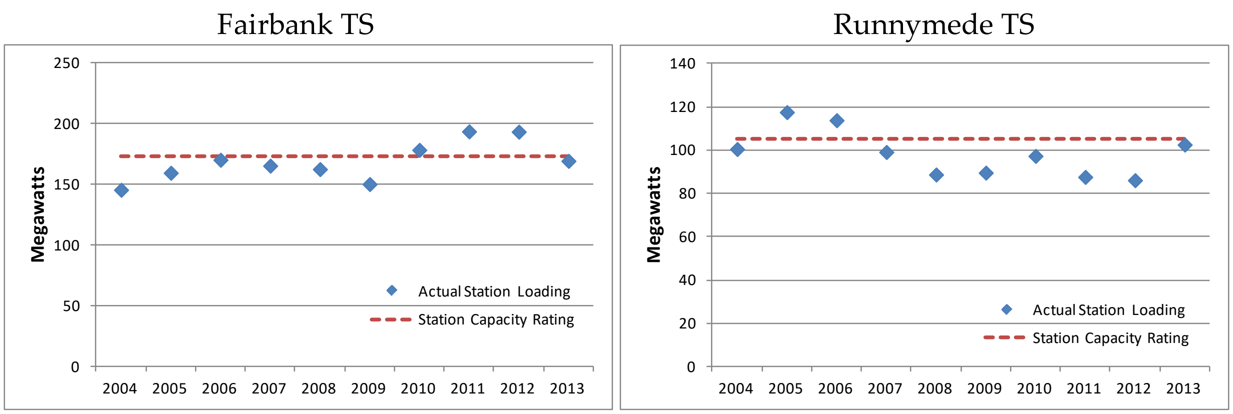
The needs in this area are being driven by the continued strong peak demand growth that has resulted in increasing new load connection request applications received by Toronto Hydro. In addition, other new large loads have signaled their intention to connect to the distribution system, such as the Eglinton Crosstown Light Rapid Transit ("LRT") ("Eglinton LRT") in the Runnymede/Fairbank area which is under construction and planned to be in service by 2019. Based on the geographic separation of the station areas, and the different growth drivers, the need for capacity relief in this area has been separated into two sub-areas: (1) Runnymede TS and Fairbank TS, and (2) Manby TS and Horner TS.

Runnymede TS and Fairbank TS

Both Runnymede TS and Fairbank TS are operating close to the station capacity during the peak demand period. A review of historical loadings at these stations shows that both Runnymede

TS and Fairbank TS have exceeded their 10-day limited time ratings (LTR) in the last 10 years, as shown in Figure 6-7.[21]

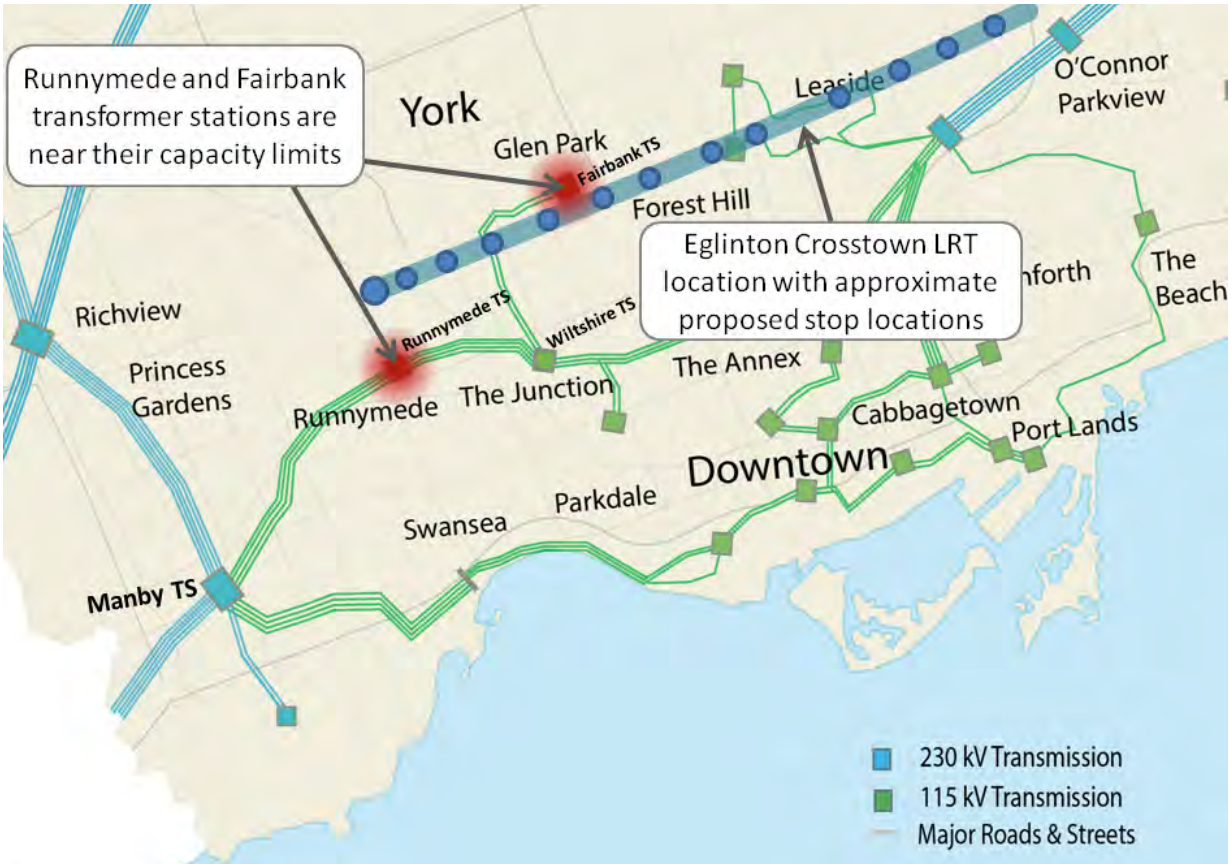
Figure 6-7: Runnymede TS and Fairbank TS Historical Peak Station Loadings



The service area of Runnymede TS and Fairbank TS is experiencing re-development, as well as being host to a portion of the Eglinton LRT project by MetroLinx. The Eglinton LRT project will add approximately 80 MVA (72 MW) of new load within Toronto, with over 20 MVA (18 MW) to be supplied from the west terminus of the line, near Runnymede TS. The location of the Eglinton LRT in relation to Runnymede TS and Fairbank TS is shown in Figure 6-8. As with other areas served by public transit facilities in Toronto, further land development and intensification due to the presence of new mass transit is expected to occur in the future.

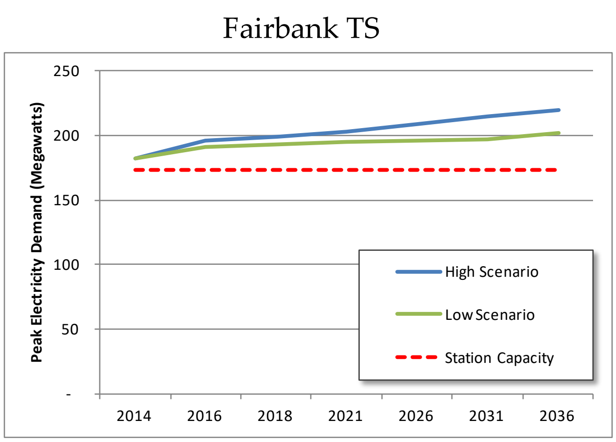
[21] The station capacity ratings were provided to the Working Group by Toronto Hydro and Hydro One.

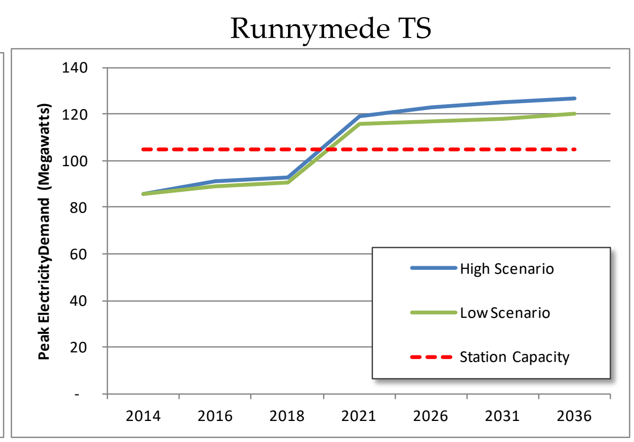
Figure 6-8: Eglinton LRT Project Location in Relation to Supply Points in West Toronto



The demand forecast for Fairbank TS and Runnymede TS is shown in Figure 6-9. Both stations are forecast to require relief. The impact of the Eglinton LRT at the Runnymede TS will exceed the station's capacity to supply the load.

Figure 6-9: Runnymede TS and Fairbank TS Peak Demand Forecast

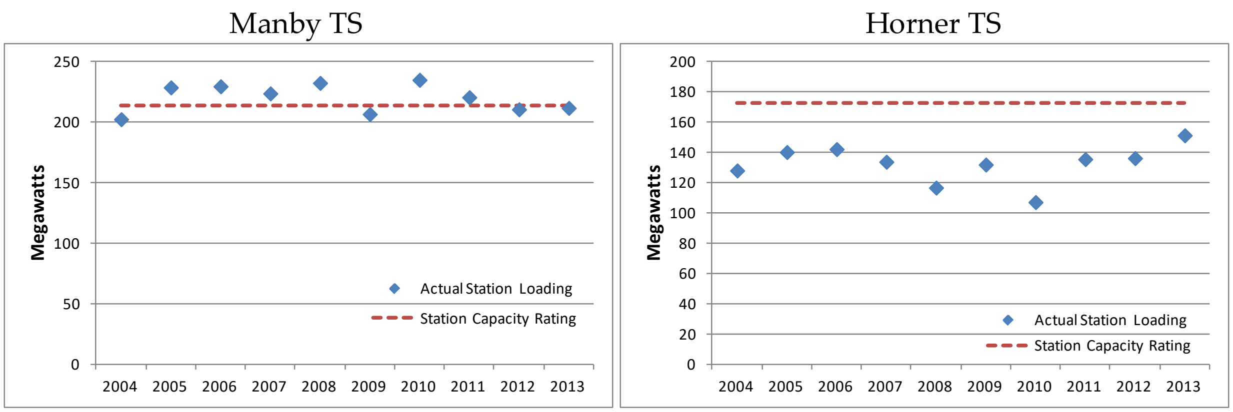




Manby TS and Horner TS

Both Manby TS[22] and Horner TS are operating close to the station capacity during the peak demand period. Manby TS is operating at its LTR and Horner TS was at 88% of its LTR in 2013, as shown in Figure 6-10. Manby TS has exceeded its capacity rating in past few years. Toronto Hydro has implemented several projects to relieve Manby TS in recent years through transfers to Horner TS, exhausting most, if not all, of the economic load transfer ability to Horner TS.

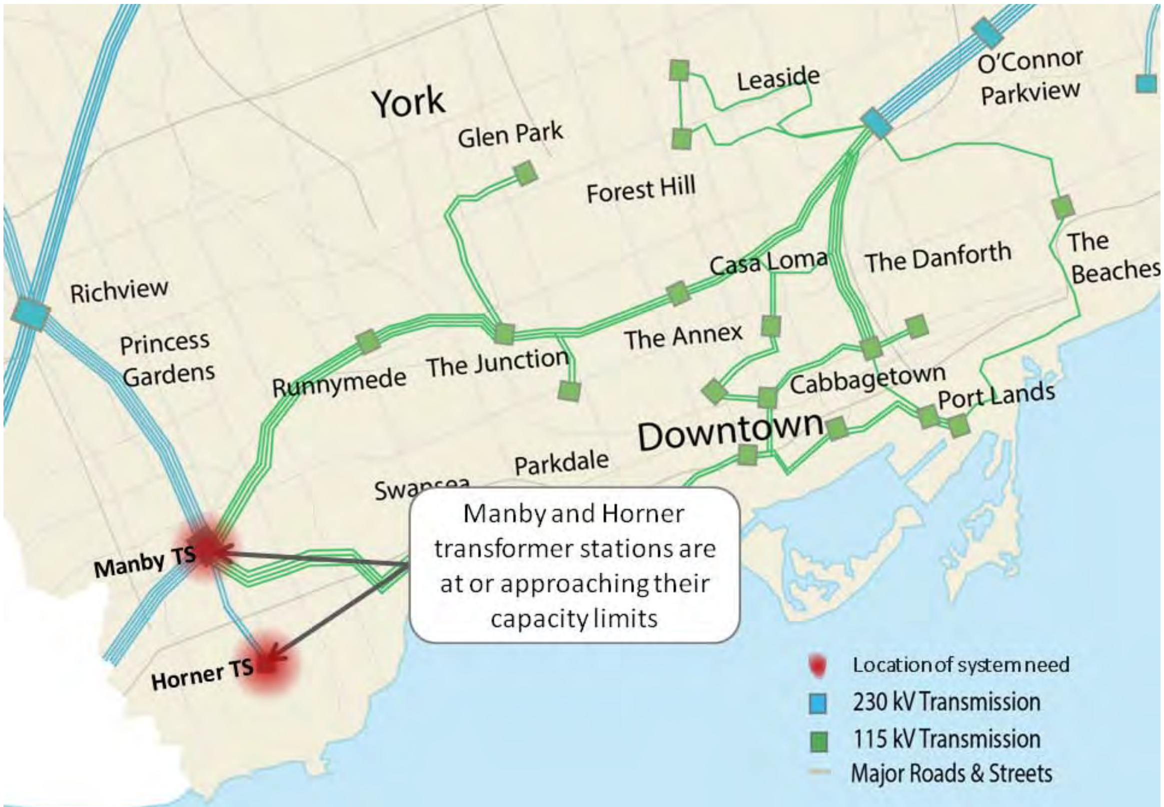
Figure 6-10: Manby TS and Horner TS Historical Peak Station Loadings



A consideration for Manby TS and Horner TS is continuing customer interest in connecting to the stations in this area. The location of Manby TS and Horner TS is shown in Figure 6-11.

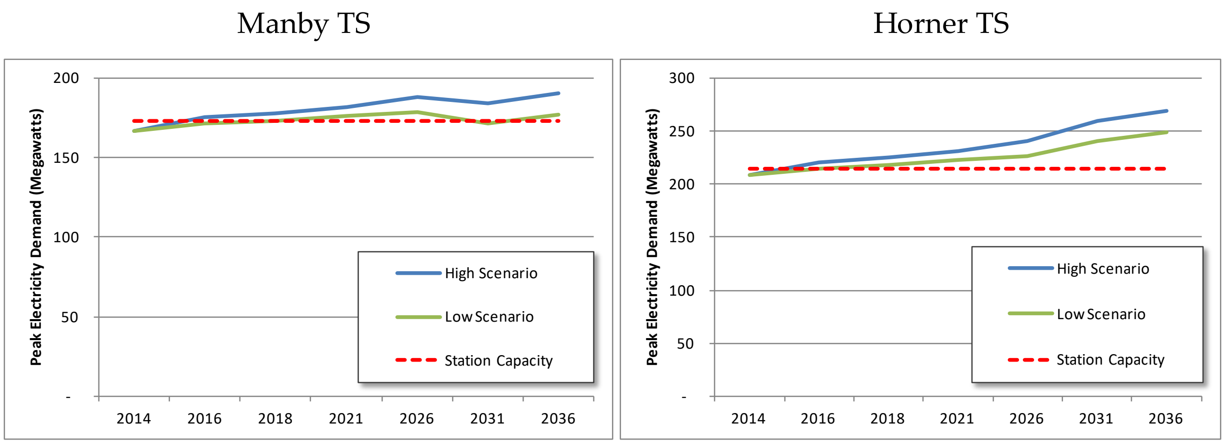
[22] This need refers to the capacity of the Manby TS step-down transformers that supply the local distribution network in the Islington City Centre area (230/27.6 kV), different from the 230/115 kV transformers that supply other parts of the Central Toronto Area via the 115 kV transmission system.

Figure 6-11: Manby TS and Horner TS Supply Points in West Toronto



The demand forecast for Manby TS and Horner TS is shown in Figure 6-12. Capacity relief at both stations is needed in the near-term period.

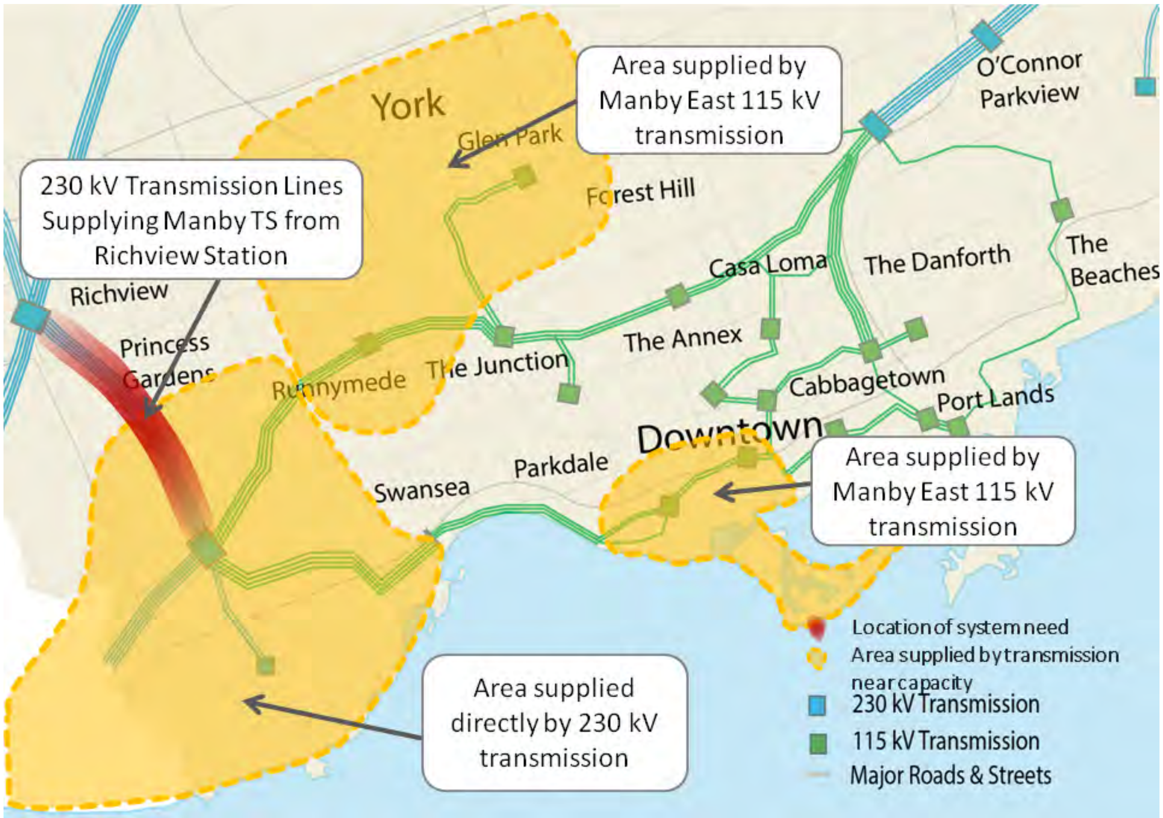
Figure 6-12: Manby TS and Horner TS Peak Demand Forecast



6.2.6 Capacity Relief for Richview x Manby 230 kV Transmission Corridor

At the end of the near-term period, there is a need for additional capacity on the 230 kV transmission lines that supply Manby TS from Richview TS. Richview TS is a major switching station and a main hub of supply from the provincial grid to customers in the western and northwest Greater Toronto Area. The Richview to Manby transmission corridor is the main supply path for a large part of the Central Toronto Area, including downtown Toronto, as well as southern Mississauga and Oakville. Manby TS is supplied by four 230 kV circuits from Richview TS along the corridor shown in red in Figure 6-13. The areas supplied by these transmission facilities are also shown in Figure 6-13 as orange shaded areas.

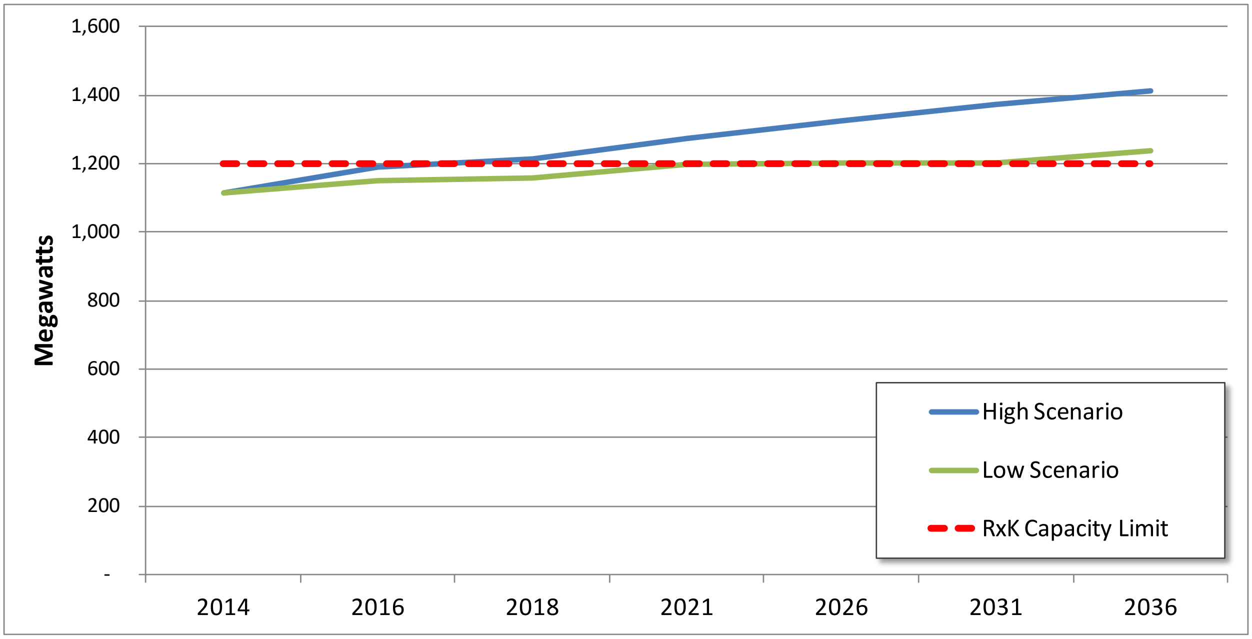
Figure 6-13: Richview – Manby 230 kV Transmission Capacity Needs



Note: The area supplied by Richview – Manby 230 kV transmission includes the Western Sector of the study area and the southern portion of Enersource and Oakville Hydro LDC franchise territory.

In 2014, Hydro One completed work to re-position the 230 kV tap points that supply Horner TS from the Richview – Manby transmission circuits. This project improves the load balancing of Horner TS supply across the Richview – Manby circuits, resulting in better utilization of existing facilities and providing some near-term capacity relief on the Richview – Manby corridor. Other new customers seeking connection to the power system in the Manby TS service area, such as the Eglinton LRT discussed in the previous section, will however add to the need for capacity relief by the end of this decade. The demand forecast for the Richview – Manby transmission corridor is shown in Figure 6-14. The forecast indicates that the capacity of this transmission corridor will be reached between 2018 and 2021, depending on the forecast scenario. Given the lead time for transmission, conservation and DG options, this need is considered urgent.

Figure 6-14: Forecast for Richview – Manby 230 kV Transmission Corridor



The electrical demand for transmission facilities in southern Mississauga and Oakville are excluded from the Richview – Manby ("RxK") corridor forecast and subtracted from the capacity limit shown above. The peak demand in these areas, also supplied via the Richview – Manby corridor is approximately 370 MW.

6.3 Medium-Term Needs

6.3.1 Capacity Relief to Supply Points Serving the Eastern (Leaside TS) Sector

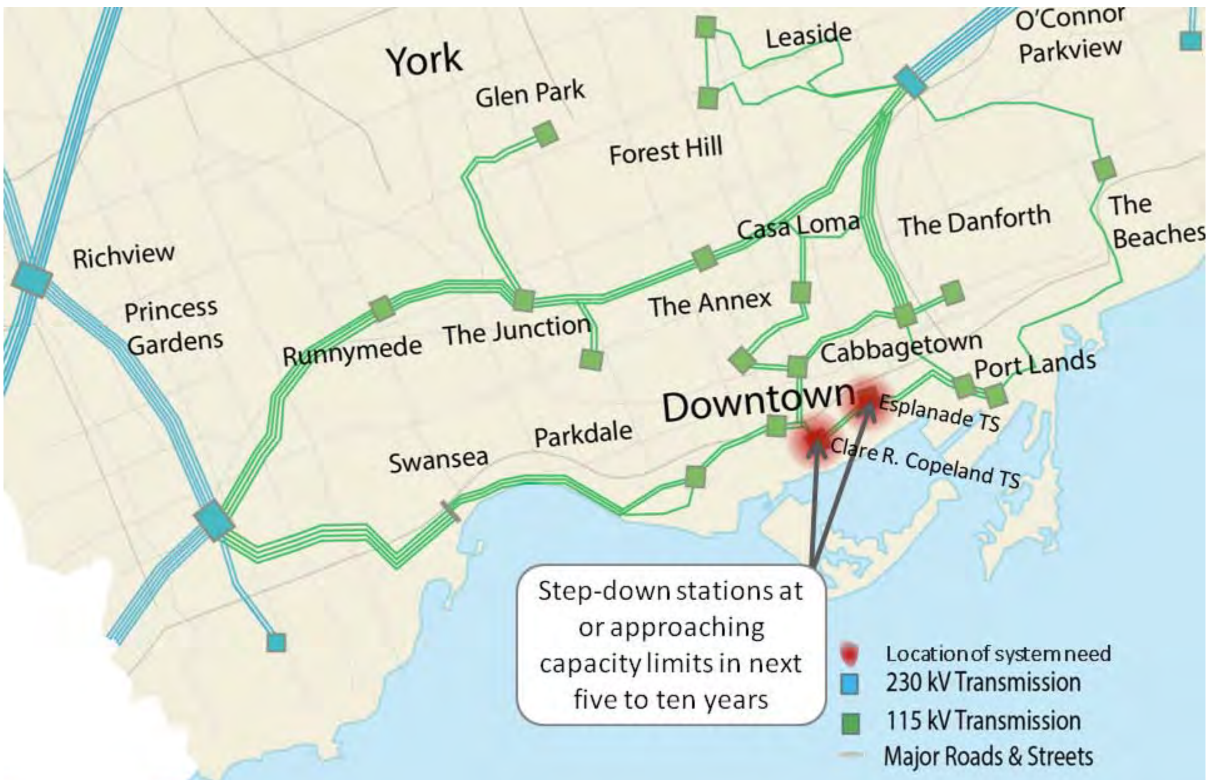
In the medium-term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the downtown Toronto area, at the electricity supply points serving distribution customers in the downtown business district. This need is driven by continuing demand growth and by new customer connection requests.

6.3.2 Capacity Relief at Step-down Transformer Stations in the Downtown Area

There is a medium-term need (as early as 2021) to provide capacity relief to the Esplanade TS and Clare R. Copeland TS ("Copeland TS," phase one of which is currently under construction), which serve customers and supply growth in the downtown core. The stations requiring relief are shown in Figure 6-15.

Copeland TS will be used by Toronto Hydro to enable new customer connections, enable equipment renewal to address end-of-life issues at other downtown stations, and provide capacity relief. Once the first phase of Copeland TS is brought into service in 2016, Toronto Hydro expects that a combination of growth within the area and reconfiguration of adjacent station service areas will fully utilize the capacity by 2021, primarily because the station will pick up the growth from other adjacent, fully utilized downtown transformer stations, and connect new customers in the area.

Figure 6-15: Station Capacity Needs in Downtown Toronto in the Medium-Term



According to the load forecast, approximately 10 MW of relief will be required at Esplanade TS as early as 2016, with the amount of relief increasing to 30 MW by 2026. It is estimated that up to approximately 90 MW of additional customer load will be seeking connection in this area in the next five years. This estimate is based on recent information and is incremental to the load forecast provided for the IRRP. In addition, when Copeland TS is brought into service, the station will accept load from the nearby John TS and other transformer stations in the area, to free capacity to perform refurbishment work at John TS, as well as to provide relief to other downtown stations. Copeland TS is therefore expected to be at capacity very soon after commissioning, and following the reconfiguration of existing station service areas. The need at Esplanade TS indicated in the load forecast will be deferred further into the future.

6.4 Other Observations for Addressing the Quality of Electricity Service

6.4.1 Probabilistic Reliability Assessment of Performance in Central Toronto

Electricity service reliability performance in the Central Toronto study area has typically exceeded reliability standards levels. The IRRP considered options for maintaining these high levels of service in the context of developing the plan. This approach was supported by stakeholder engagement feedback, which indicated that customers in the area expect very high electricity service reliability, including few interruptions and quick restoration of service when interruptions do occur.

To determine whether customers in Toronto should be provided with a higher level of electricity service, a review of utility practice in other jurisdictions containing major metropolitan areas was carried out. The review indicated that many utilities plan to meet higher levels of service reliability in central business areas as compared to outlying areas. About half of the utilities planned to achieve better reliability in central business areas or, in some cases, the capital region of their territory. Not all utilities planned or achieved higher reliability levels in the same manner. For example, some jurisdictions plan redundant transmission infrastructure, some have policies to ensure that greater amounts of generation are located within the load centre, some coordinate transmission and distribution planning more closely to enable one system to better back up the other, and several rely more heavily on special protection systems or operational schemes to provide higher levels of reliability in urban areas, rather than relying on more expensive infrastructure solutions. A summary of the review of planning standards in major metropolitan areas is provided as Appendix F.

A common practice in several jurisdictions is to employ probabilistic assessment tools to assess the reliability risk to customers, and to find solutions – the cost of which may correspond to the potential economic impact of the risk. For the Central Toronto IRRP, a probabilistic reliability assessment was conducted as a means of estimating the risk to customers inherent in the electricity system supplying the area, and to test the resiliency of the electricity system under outage contingency scenarios that are beyond the levels required by the reliability standards (e.g., ORTAC). The PRA took into account the probability of the outages, relying on historical outage statistics of the various classes of equipment, including the frequency and the duration of historical outages.

The PRA results, provided in Appendix E, indicate that the transmission system serving the central part of the city has an inherent design that provides good flexibility for containing the impact of, and recovering from, such events. The design features of the local power system, coupled with the available operator control actions, result in the ability to restore service within a relatively short period of time, considering the magnitude of the types of outages assessed.

Actual experiences from recent major events confirm these findings. Root-cause analyses conducted subsequent to these major events have also incorporated system improvements that further mitigate the risk in the future. Given the low likelihood of occurrence associated with such incidents and the improvements which have been put in place to mitigate the known risks, the Working Group's view is that the cost of added transmission reinforcements to mitigate the residual risk is not justified. This was the case even when the economic impacts of customer outages were taken into account.

The annual monetized risk[23] of outages on the system is in the order of $6 million per year, reflecting the very low probability of multiple coincident transmission element failures. In addition, the risk of customer impact from outages is generally evenly distributed across the 115 kV system, with no one station or transmission service area being disproportionately vulnerable to outages as compared to any other. This finding indicates that there is no single transmission system fix that will substantially enhance supply security for the 115 kV transmission system area.

This PRA found that the greatest risk inherent within the 115 kV transmission system in Central Toronto is related to double transmission element contingencies at the individual step-down transformer station level. The coincident failure of two transformers or their transmission supply lines, on average, result in an annual monetized risk of just under $1 million per year. This indicates that the cost of mitigating solutions should be consistent with this benefit. Higher-order contingencies such as three elements failing at once (e.g., N-3) represent a very low risk to customers due to their very low probability of occurrence.

[23] Using assumptions for the value of customer reliability, the amount of expected unserved energy can be expressed as a monetary value. These assumptions are found in Appendix E.

6.4.2 Assessment of Impact of Extreme Contingencies (Low Probability – High Impact Events)

A number of specific "extreme contingencies" were assessed as part of the needs assessment, such as the loss of key transformer stations supplying the downtown Toronto 115 kV system and the loss of one or more multiple circuit structures (i.e., transmission towers). The contingencies assessed were selected by the Working Group based on a number of known possible scenarios that are beyond the scope of the normal planning criteria and more extreme than would be considered in the PRA discussed in the previous section, but for which an assessment was warranted due to the magnitude of the possible impact on customers.

The reliability standards[24] recognize the loss of a substation, transmission corridor and/or a major load centre as "extreme contingencies." While such extreme contingencies have a very low probability of occurring, the consequences can be high as the resulting interruptions can be widespread and/or take a long time to restore. While the design of the power system is not required to withstand such events without interruption of service, planning authorities assess extreme events for the potential impact and review if measures to mitigate the risk can be justified. Mitigation may include attempting to reduce the likelihood of load being interrupted, or more commonly reducing the extent and/or duration of unsupplied load following an extreme contingency. The ORTAC does not prescribe the degree of mitigation required and it is left to individual jurisdictions to assess the risk of extreme events and to determine if mitigation measures can be justified and incorporated in long-term plans.

The technical summary of the impact of extreme contingencies is not included with this IRRP due to security concerns.

6.4.3 Consideration of Plans for Transmission Infrastructure Renewal

Given the age of many of the transmission facilities in the area, the IRRP study assessed the potential impact on supply reliability of major facilities reaching end of life within the study period. Some facilities in the Central Toronto 115kV system are expected to require replacement or refurbishment over the next several years. The Hydro One report, "Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115kV System," included as Appendix G, identifies aging facilities in all major asset classes: overhead lines, underground cables, transformers, breakers and other switchgear equipment.

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[24] Northeast Power Coordinating Council ("NPCC") criteria, as referenced in the ORTAC.

The refurbishment plans included in Hydro One's report were assessed using the demand forecast for the specific years representing the time periods:

- 1-5 years: 2016 forecast demand was assessed;
- 6-10 years: 2021 forecast demand was assessed; and
- 11-15 years: 2026 forecast demand was assessed.

The high demand forecast scenario was used for this assessment because this scenario represents the worst case loadings on the equipment supplying the area. The robustness of the transmission system, considering the planned outages that outlined in Hydro One's report, was tested by considering a contingency event in addition to the planned outage.

The assessment concluded that, given the process in Ontario for approving and taking equipment outages, it is expected that the local power system will have sufficient flexibility to accommodate the outages required to perform the planned refurbishment work.

The staging of certain refurbishment work, or strategies to keep existing facilities in service while replacement infrastructure is being built, and transferring customer supply to alternate sources, will help to mitigate risk of service interruptions during refurbishment periods.

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

The core elements of the near-term plan must include measures to enhance supply security and ensure that reliability standards continue to be met, and to ensure that sufficient infrastructure capacity is available to supply near-term growth. It is recommended that this be done by continuing with local conservation planning and implementation efforts, and proceeding with certain near-term infrastructure reinforcements to ensure that new customer demand can continue to be connected to the system. Finding opportunities for further DG resource development in the near and medium term is also recommended for improving the supply diversity and supporting system resilience.

This section describes the alternatives considered in developing the near and medium-term plan for Central Toronto and provides details of and rationale to support the recommended plan.

7.1 Alternatives Considered for Meeting Near- and Medium-Term Needs

In developing the near and medium-term plans, the Working Group considered a range of integrated alternatives. These alternatives balanced maximizing the use of the existing infrastructure with costs, and the need for enhancing the capacity, security and reliability of electricity service. A key objective in developing the plan was to ensure that longer-term infrastructure options are kept available and that the plan can adapt to a future in which the demand, resources and technology development are uncertain.

The following sections detail the alternatives that were considered, and comments on their performance in the context of the criteria described above.

7.2 Near-Term Alternatives

7.2.1 Addressing Supply Security Risk at Manby TS and Leaside TS

The supply security risks stemming from the possible breaker failure events at the Manby and Leaside transformer stations are generally recognized as having a low probability of occurring. However, should these events occur there would be significant electricity service interruptions to customers supplied downstream from these facilities. Given the high potential consequence of these events, the number of technically feasible, cost-effective alternatives available for mitigating these risks is limited.

The alternatives that were considered for addressing these needs are discussed below.

Operational Measures (e.g., a Special Protection System, or "SPS")

A SPS can be designed to maintain the electrical demand within the capability of the transmission and distribution equipment that is remaining in service following a critical breaker failure event. These are operational measures that are automated, and do not typically involve major infrastructure upgrades.

The SPS is estimated to require one to two years for design and implementation, with a total cost in the order of $1 million to $3 million.

The use of an SPS is an acceptable solution for satisfying the ORTAC. SPSs are commonly used by utilities worldwide to enhance electricity service security for low probability, high consequence events. The SPS can be implemented quickly and more cost-effectively than other infrastructure based alternatives.

These types of automatic schemes are generally only triggered under very rare circumstances (although they may be "armed" and ready more often). When triggered, customer demand can be reduced in a strategic manner in order to maintain the equipment remaining in service below its emergency ratings and to prevent cascading failures and a wider customer impact. This also enables service to be restored more quickly. Specific customers that are interrupted can be selected based on criticality.

Another benefit of an SPS is that is can be designed and scoped to mitigate the impact of other rare equipment outage events, such as a partial or complete loss of Manby TS or Leaside TS or the loss of two circuits on a multi-circuit tower structure. These additional contingencies were assessed as per the analysis described in Section 6.4.2 and discussed with the Working Group in the context of the SPS alternative.

It is acknowledged that a SPS can introduce operational elements with associated risks that may need to be assessed and managed, such as the risk of failure on activation, inadvertent operation, as well as maintenance and coordination requirements between the transmitter, system operator, and the LDC.

Conservation and Distributed Generation

Conservation and DG are not technically feasible options for addressing these specific needs because there is not enough conservation achievable potential within the affected areas to address the risk within the timeframe required. A summary of each of the needs identified by the assessment, and the amount of conservation achievable potential within the affected areas is provided in Appendix H.

Furthermore, conservation is typically not used to address these types of security risks. However, conservation and DG resources that can be called upon to reduce the demand when needed can help to reduce overall equipment loadings, and thereby reduce the number of hours that a SPS needs to be armed, or to help manage equipment loadings while restoration of service is taking place following the contingency.

Reconfiguration of Station Facilities

An alternative option to address these security risks involves reconfiguring the bus work at the transformer station so that the breaker failure does not automatically remove multiple transmission system elements from service.

The reconfiguration requires significant capital work inside of a major transformer station that would take at least 2 to 3 years to design and implement, and with a cost that is several times more than a SPS.

This option is not precluded by the SPS alternative. It could be implemented coincident with other station refurbishment work as an incremental improvement at a later date, subject to a cost-benefit analysis at the time.

Status Quo

Doing nothing is not an option at Manby TS as this would not satisfy the applicable reliability standards. Doing nothing at Leaside TS would not contravene reliability standards; however, ORTAC Section 7.4 provides guidance for justifying this work based on the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost.

Summary

Given the rare nature of the events discussed in Section 6.2.1, operational measures, such as an SPS, is the only alternative that is technically feasible to implement in the time required, and at a cost that is commensurate with the rarity that it is expected to be needed. The cost of implementing the SPS is estimated to be in the range of $1 million to $3 million, and could be implemented within one or two years.

The use of SPSs to limit the impact of failures of this nature is a common practice of utilities worldwide. These systems can minimize cascading equipment outages that result in the propagation of service interruptions to customers. By way of strategically maintaining electrical demand within equipment ratings, a SPS can reduce the extent of further equipment outages and the amount of customer load impacted. A SPS is especially useful to reduce the risk of rare equipment failures such as a breaker failure. Compared to additional redundant infrastructure, station or line work, a SPS can be implemented more quickly and at a lower cost.

A summary of the attributes of the alternatives considered is shown in Table 7-1.

Table 7-1: Summary of Alternatives for Improving Supply Security Risks

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Operational measures (e.g., SPS)	YES	YES	1-2	1-3	Preferred approach based on least cost and time to implement for improving system resilience for breaker failures
Conservation / DG	NO	N/A	N/A	N/A	Insufficient potential within the area to mitigate the risk for a these low probability events
Reconfiguration of station facilities	YES	YES	2-3	10-30	Costs several times more than a SPS, but a potential medium to longer-term option if done in conjunction with other station refurbishment work
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.2 Addressing Capacity Relief at Runnymede TS and Fairbank TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, and the new Eglinton LRT load will be connecting to the distribution system in the near-term period, there are limited alternatives available that are able to meet the need within the time required. The need for capacity relief in the Runnymede TS and Fairbank TS area is urgent. Only Runnymede TS has the space needed to accommodate new transformation facilities.

The alternatives that were considered for capacity relief in the Runnymede TS and Fairbank TS area are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations and Deferred New Transformation Capacity

This alternative involves building additional distribution feeder capacity by way of 27.6 kV interties between the overloaded stations and adjacent stations to enable permanent load transfers.

This allows for electrical demand to be transferred from Runnymede TS and Fairbank TS to adjacent stations with spare capacity (e.g., Richview TS and Bathurst TS), and to supply the Eglinton LRT using existing feeder positions from the existing stations. Achieving these transfers involves constructing several new 27.6 kV distribution voltage feeders between Runnymede TS and Richview TS, and Fairbank TS and Bathurst TS. The feeder tie routes are expected to be technically challenging due to the distances involved and the number of physical barriers in the area (e.g., highways, bridges, waterways, etc.). The distance from Runnymede TS to Richview TS is approximately 7.5 km, and from Fairbank TS to Bathurst TS is 7 km. These long feeders may have reliability performance and/or voltage quality issues due to their lengths.

The estimated cost of the distribution feeder ties is estimated to be $70 million to transfer loads and to supply the new growth. This alternative is subject to significant cost uncertainty due to the physical barriers in the area and the potential power quality challenges. Within about

10 years, transformation capacity will still be required at an additional cost of about $34 million.[25] Therefore, the total cost of this alternative is approximately $104 million.

Expanding the Existing Runnymede TS to Provide Relief to Fairbank TS and Supply New Customer Demand

This alternative involves installing an additional bus and transformation capacity at Runnymede TS, and upgrading the 115 kV lines between Manby East and Wiltshire TS, as well as building distribution feeder ties between Fairbank TS and Bathurst TS to transfer loads.

There is available space for the expansion at Runnymede TS and therefore, this alternative would not require additional property acquisition.

Increasing the load serving capability of Runnymede TS requires that other system impacts be considered. Runnymede TS is supplied from the 115 kV lines originating at Manby TS (circuits K11W and K12W that run from Manby TS to Wiltshire TS). Installation of new capacity at Runnymede TS would increase the power flow requirements on these 115 kV lines and therefore will require upgrades to the 115 kV lines between Manby TS and Wiltshire TS.

The estimated cost of this alternative is $90 million, which includes $34 million for Runnymede TS expansion, $16 million for upgrades to the 115 kV network, and $40 million for distribution feeders/service for supplying new growth.

Conservation

Conservation is not a technically feasible alternative for providing the capacity relief because there is not sufficient conservation achievable potential within the affected areas to address the capacity relief that is needed and to supply the new customers seeking to connect in the area by 2019.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

[25] This cost is the present value of the cost of expanding the Runnymede TS with additional transformation and bus capacity, and upgrading the 115 kV transmission lines between Manby TS and Wiltshire TS to enable the increased power flow requirements ($50 Million future cost expressed in present day dollars by applying a 4% discount rate).

Distributed Generation

The implementation of DG is not a technically feasible alternative to address this need because it would require strategically locating a sufficient amount of DG resources to relieve the specific TSs and feeders. Through recent procurement efforts and community outreach, the IESO is not aware of any such DG opportunities in the area that would defer or avoid this need.

Status Quo

Doing nothing is not a feasible alternative as it will not permit the connection of the new customer demand or provide relief to the stations already near or at capacity.

Summary

Based on the overall comparison of the costs, benefits and feasibility of the various alternatives, the expansion of the existing Runnymede TS is recommended as the preferred solution to address the need for capacity relief at the existing stations in the area and to supply new growth in the area, including the Eglinton LRT project.

Building distribution feeder ties defers the need date for incremental transformation capacity but carries significant cost due to the complexity of constructing new distribution feeders to transfer the electrical demand over long distances across a number of physical obstacles including major highways and waterways), and power quality concerns. This alternative requires an increase in transformation capacity in the area in about ten years to supply continued growth.

The upgrading of the 115 kV transmission service from Manby TS to Wiltshire TS associated with the Runnymede TS alternative will preserve the flexibility to transfer demand between Leaside TS and Manby TS in the event of system emergencies, and provides long-term capacity to supply demand growth and further expansion in the area.

A summary of the attributes of the alternatives considered is shown in Table 7-2.

Table 7-2: Summary of Alternatives for Providing Capacity Relief at Runnymede and Fairbank TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution load transfers and deferred new transformation	YES	YES	2-3	104	Technical feasibility uncertain due to distance and physical barriers; subject to high degree of cost uncertainty, and will still require additional transformation capacity and transmission upgrades in ten years' time
Expand existing Runnymede TS	YES	YES	2-3	90	Provides service for Metrolinx, relief for existing stations and capacity for future growth; no new sites required
Conservation	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
DG	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.3 Addressing Capacity Relief at Manby TS and Horner TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, there are limited options available that are able to meet the need within the time required. Capacity relief is required at both Manby TS and Horner TS in the near term. There is no available space at Manby TS to accommodate new transformation capacity or high-voltage facilities. Horner TS has space available to accommodate the installation of a new bus and transformation capacity.

The alternatives that were considered for capacity relief at Manby are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations

The distribution alternative involves building additional distribution feeder capacity between Manby TS and Richview TS to permanently transfer loads from Manby TS to Richview TS for relieving Manby TS. This includes constructing several new 27.6 kV feeders that tie existing feeders from the service area of Manby TS to Richview TS.

The estimated cost of this alternative is $77 million. This alternative carries a high level of cost uncertainty due to the distance and number of physical obstacles that require crossing, such as railway corridors, as these types of physical obstacles and barriers can substantially impact the project cost. Furthermore, distribution transfers can result in the demand being supplied by long distribution feeders which may have a reliability impact.

Although this alternative allows for spare capacity at Richview TS to be utilized, it does not provide any additional supply capacity in the area to support additional growth beyond the current near-term forecast.

Expanding the Horner TS and Transferring Load from Manby TS to Horner TS to Provide Relief to Manby TS

This alternative involves installing an additional bus and transformation capacity at Horner TS, as well as building distribution feeder ties between Manby TS and Horner TS to transfer loads.

There is available space for the expansion at Horner TS and this alternative would not require additional property acquisition. In addition, Horner TS is located in a commercial/industrial area with no residential land uses adjacent to the station.

The estimated cost of this alternative is $70 million, which includes $51 million for the Horner TS expansion plus $19 million for distribution transfers.

There are some challenges with respect to the distribution transfers from Manby TS to Horner TS, related to the crossing of Gardiner Expressway. It is expected that Toronto Hydro will address these challenges in the detailed design and routing of the distribution feeders.

This alternative provides additional supply capacity in the area, and will still enable the connection of new customer demand if it does materialize in the medium to longer term.

New Transformer Station near Manby TS and Distribution Feeder Capacity

This alternative involves building a new transformer station near Manby TS, supplied from the 230 kV transmission system, and new distribution feeder capacity to supply new customer growth and provide capacity relief for Manby TS.

Building a new transformer station will require acquisition of new property, and additional costs related to the high voltage connection to the Richview – Manby 230 kV transmission system.

The estimated cost of this alternative is $88 million, which includes $72 million for a new 100 MVA (90 MW) transformer station and $16 million for distribution load transfers to relieve the existing stations in the area.

Conservation Targeted at Customers in the Area to Provide Relief to Manby TS

Conservation is not considered a technically feasible alternative to provide the necessary relief in time to meet the need.

Conservation targeted at this area would take time to ramp up, but the relief is required today, as evidenced by the station exceeding its capacity rating in historical years.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

DG in the Area Supplied by Manby TS

DG is not considered a technically feasible alternative to provide the necessary relief in time to meet the need because the station relief is required today (the station has already exceeded its capacity rating in historical years). The Working Group is not aware of material potential or customer interest in developing DG resources within this area that can meet this need in time.

Status Quo

Doing nothing is not a feasible alternative as it does not provide the necessary relief for Manby TS.

Summary

The least cost alternative to provide capacity relief for Manby TS is to expand the Horner TS by adding a new bus and transformation capacity, and to use distribution feeder ties to transfer demand from Manby TS to Horner TS. This alternative provides additional supply capacity in the area of Horner TS to accommodate future demand growth, while not requiring any additional property. The Horner TS is located in an area that is not adjacent to residential land use and therefore, there is not likely to be local opposition to construction within the station.

A summary of the attributes of the alternatives considered is shown in Table 7-3.

Table 7-3: Summary of Alternatives for Providing Capacity Relief at Manby and Horner TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution feeder ties / load transfers	YES	YES	2-3	77	This alternative is subject to a high degree of cost uncertainty due to the distance and number of physical barriers between the stations in the area
Expand existing Horner TS	YES	YES	2-3	70	Provides relief for existing stations and capacity for future growth; no new sites required
New transformer station	YES	YES	3-5	88	Provides relief for existing stations and capacity for future growth; new site needed with longer implementation time
Conservation	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
DG	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.4 Providing Capacity Relief for the Richview x Manby 230 kV Transmission Corridor

The Richview x Manby 230 kV reinforcement will be needed by between 2018 and 2021, depending on the rate of demand growth in the coming years. Under a low demand scenario, the loading on these transmission lines remains flat at the capacity limit until 2026 (as shown in Figure 6-14).

The alternatives considered for providing the capacity relief are discussed below.

Building Two New Transmission Circuits between Richview TS and Manby TS

This alternative involves replacing a 115 kV double circuit line with a new 230 kV line on the existing transmission right-of-way between Richview TS and Manby TS (a distance of 6.5 km). The new 230 kV circuits can be arranged in two possible configurations:

- Reconfigure two of the existing Richview x Manby TS 230 kV circuits to "supercircuits" which would use existing line terminations at Richview TS and Manby TS and provide the higher capacity, or
- Separately terminate the new 230 kV circuits at both Richview TS and Manby TS to create a total of six 230 kV circuits between these stations. This provides the required higher capacity and increased reliability.

The existing right of way is 100 m wide, and can accommodate the replacement of the 115 kV line with a 230 kV line. The new 230 kV towers would be larger than the existing 115 kV towers. Most of the existing corridor is adjacent to residential land uses.

The estimated cost of this alternative is $19.5 million if the existing circuits are reconfigured as "supercircuits," and $39.5 million if separately terminating the new lines.

Upgrade the Existing Richview x Manby 230 kV Circuits with New Conductors

This alternative involves re-conductoring the existing Richview TS x Manby TS circuits using higher capacity conductors on the existing towers. This will allow the existing infrastructure to carry more power into Manby TS.

The estimated cost of this alternative is $16 million, including the re-conductoring of pairs of circuits at $8 million for each pair.

Since the existing towers can be used with upgraded conductors, this option will result in no visual difference along the transmission right-of way once it is completed.

This alternative does not result in any additional supply reliability to the area.

Installation of 70% Series Compensation

Installation of 70% series compensation at Cooksville TS was reviewed and deemed not technically feasible to meet the need due to the space limitations at Cooksville TS, and the proximity of residential homes to the station which limits the opportunity to expand the station.

The capacitor banks would require 0.6 to 1.5 acres of space which is not present at the station, so additional land would be required.

Conservation

A conservation alternative involves targeting peak demand savings in the areas supplied by Manby TS to reduce peak flows on the existing 230 kV lines. A conservation potential study has validated that sufficient potential exists in the areas supplied by Manby TS to defer the need. The conservation achievable potential for the areas supplied by the Richview x Manby circuits is provided in Appendix H.

Targeted demand response to provide peak demand savings up to 40 MW in the areas supplied by the Richview - Manby 230 kV lines could defer the need by several years, depending on the rate of demand growth in the near-term period and beyond. If the demand grows in line with a low demand scenario, no incremental demand response in addition to the ongoing conservation programs to meet the LTEP targets would be required until the mid-2020s (2026). If demand grows according to a high demand scenario, demand response will be required to curtail the peak demand flows on the Richview x Manby corridor by 2018.

The estimated cost of incremental demand response above the LTEP estimated savings under a low demand forecast scenario is about $7 million, which would result in a deferral of this need to the end of the study period (2036). If demand grows higher than expected, the cost of incremental demand response would be needed sooner, and would cost as much as $8 million to defer the transmission need by five years.

Conservation does not provide the additional security of the infrastructure upgrades.

Distributed Generation

DG can be developed in the areas served by Manby TS to supply part of the demand locally, and reduce the peak flows on the existing transmission lines serving the area. The IESO is aware of proponent interest in developing a district energy facility in downtown Toronto that could provide up to 90 MW of capacity relief for the Richview x Manby transmission corridor.

As an alternative to meet this transmission need, DG in the amount of 40 MW, connected to the Manby TS 115 kV sector (or in parts of southern Mississauga and Oakville also supplied by Richview x Manby transmission), could defer this transmission need until the end of the study period under a low demand forecast scenario. This incremental DG resource capacity would be in addition to the achievement of the LTEP conservation targets.

If the demand grows at a faster rate than expected in the near-term period, DG resources in the amount of 40 MW could defer this transmission need by five years (to 2020). Under this higher growth scenario, additional DG resources would need to be added each year to continue to defer the transmission.

The estimated cost to develop 40 MW of DG resources in Central Toronto is $110 million. There is a high degree of cost uncertainty for DG resources as it depends on the type, size and location of the facilities. It is likely that any such facility would incur higher development costs to meet emissions standards and to integrate the facility into the urban environment.

Smaller DG facilities are generally well accepted by communities. The community acceptance of larger DG facilities in Central Toronto is not known.

Status Quo

Doing nothing is not a feasible alternative as these lines are approaching capacity and action needs to be taken.

Summary

Concurrent with ongoing conservation programming to maintain forecast load levels, it is recommended that a targeted demand response program be implemented in the areas supplied downstream from the Richview x Manby 230 kV facilities, to reduce the loadings on these facilities during peak demand periods. In addition, it is recommended that Hydro One continue detailed design work on the infrastructure alternative to minimize the development lead time required to implement the wires upgrades, in the event that planned conservation and targeted demand response activities do not result in the required capacity relief, or if the demand growths faster than expected.

In addition, opportunities to develop DG resources in the areas supplied by the Richview x Manby 230 kV facilities should be explored. The benefits of siting generation locally, in addition to providing transmission capacity relief, will need to be fully accounted for when making comparisons of cost and technical feasibility to transmission and other alternatives.

Upgrading the existing Richview x Manby corridor will increases the load meeting capability of this 230 kV corridor sufficient to supply the projected load growth in Toronto until beyond the IRRP study period. The detailed engineering design and specification of the transmission option should be completed concurrent to the development of conservation and DG opportunities, so that the infrastructure option is available for implementation with as short as possible of a lead time in the event that it is needed.

A summary of the attributes of the alternatives considered is shown in Table 7-4.

Table 7-4: Summary of Alternatives for Providing Capacity Relief for Richview – Manby 230 kV Corridor

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Two new transmission circuits	YES	YES	5-7	19.5 - 39.5	The lower cost range is in combination with "supercircuiting" the existing circuits, and the higher cost is with new line terminations; this option involves installing larger towers on an existing right-of-way adjacent to homes
Upgrade existing transmission circuits	YES	YES	2-3	16	The feasibility of taking outages to complete this work needs to be determined in a detailed study by Hydro One
Series compensation	NO	N/A	N/A	N/A	Not a feasible alternative
Conservation	YES	YES	1-2	7-8+	Low cost range assumes low demand scenario (provides relief to end of study period), the high cost assumes a median demand scenario (provides five years of capacity relief)
DG	YES	YES	3-5	110	Estimated cost for 40 MW of combined heat and power DG, sufficient to provide relief to the end of the study period under a low demand scenario, and for five years of capacity relief under a median demand scenario
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3 Medium-Term Alternatives

7.3.1 Providing Capacity Relief for Step-down Stations in the Downtown Area

The alternatives that were considered for capacity relief in the Esplanade TS and Copeland TS area are discussed below.

Completing Phase 2 of the Copeland TS

This alternative involves the installation of two additional transformers and load serving busses at Copeland TS, utilizing the space that is being built into phase 1 to accommodate the expansion.

Toronto Hydro's design for Copeland TS phase 2 includes an additional fifth (spare) transformer and a transfer bus to enable the utilization of the spare and station to station ties for additional security for downtown customers.

The bulk of the high voltage switching facilities are being constructed as part of phase 1 of the project.

The estimated cost for the additional transformers and load serving busses is $46 million.

This option does not require any additional property and the station is being built underground. It is not located adjacent to residential land uses.

Expanding the Esplanade TS

This alternative involves constructing a new building next to the existing Esplanade TS and installing two new transformers and load serving busses and high voltage connection facilities.

The estimated cost for this alternative is $48 million.

The Esplanade TS is located adjacent to residential customers and urban parkland.

Conservation

This alternative involves seeking conservation savings targeted at customers in the area to reduce peak demand.

The assessment of achievable conservation potential indicates that there is not technically enough potential in the area to defer or avoid these station needs, nor does conservation add the physical capability to connect new large customers to the distribution system.

The electricity service needs of a number of future developments in the downtown area, such as West Donlands, East Bayfront, lower Yonge Street, and the Portlands area, exceed any conservation savings potential as these developments represent potential large increases in demand that are not be fully reflected in the demand forecast. The total amount of peak demand savings needed includes the 10 MW reflected in the demand forecast, plus up to 90 MW of additional incremental customer demand due to new commercial and high-rise residential development applications. The 90 MW is in addition to the load forecast data as this estimate is based on more recent information regarding development in the downtown area of Toronto.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

Distributed Generation

Given the time required to implement DG resources, DG is not likely to avoid the need for additional station capacity.

Furthermore, DG resources do not add capability to connect new customers to the distribution system (e.g., available feeder positions at the station bus).

DG is therefore not considered a technically feasible option to address this capacity need.

Status Quo

Doing nothing is not a feasible alternative because it does not provide the necessary relief.

Summary

The Copeland TS phase 2 alternative is understood to be the most feasible and economic option because Copeland TS phase 1 is being designed to accommodate the expansion, and it is less costly than the Esplanade TS alternative and is not located adjacent to residential land uses.

Conservation resources, in addition to those being incorporated into Toronto Hydro's 2015-2020 Conservation and Demand Management plan, are not likely to produce sufficient savings in time to meet this need; however, Conservation savings should be pursued on its own merits in downtown Toronto to meet provincial policy goals and to meet conservation targets. In addition, conservation achieved in the downtown core can provide relief for the Richview TS x Manby TS need described in Section 6.2.6.

DG resource development should still be encouraged in the area, but these resources cannot be relied upon to reduce the net demand requirements in the Copeland TS and Esplanade TS area, given the continued growth and high-density development planned to occur in the downtown core and surrounding areas in the coming years.

A summary of the attributes of the alternatives considered is shown in Table 7-5.

Table 7-5: Summary of Alternatives for Providing Capacity Relief for Downtown Transformer Stations

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Copeland TS phase 2	YES	YES	3-5	46	Copeland TS phase 1 is being built with space to accommodate expansion, and is not located next to residential land uses
Expand existing Esplanade TS	YES	YES	3-5	48	Requires expansion of the existing site; cost subject to more uncertainty than Copeland TS
Conservation	NO	N/A	N/A	N/A	Requires demand response targeted within a small area in downtown Toronto; demand from new construction is likely to exceed savings from conservation
DG	NO	N/A	N/A	N/A	DG in sufficient amounts cannot be developed in time to meet the need
Status Quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3.2 Maintaining Reliability/Security Performance Levels Above Standards

Based on the results of the needs assessment and PRA, there are currently not expected to be any cost-effective transmission system options for improving system security in the Central Toronto Area. Transmission and distribution upgrades that have recently been completed, or are in progress, have already introduced additional redundancy and load transfer flexibility to mitigate reliability/security risks. Examples include the John TS to Esplanade TS cable connection, completed in 2008, and the Copeland TS which is under development. These two investments increase the amount of load that can be transferred in the downtown core to alternate supply sources. Other possible actions for maintaining a high level of reliability/security performance in an urban centre such as Central Toronto include:

- Continuing to increase distribution level station intertie capacity to transfer loads in the event of a loss of a transformer station.
    - Toronto Hydro has been systematically increasing the number of distribution station interties in the Central Toronto Area. This program has long-term reliability/security benefits and should continue.
- Developing DG resources for critical customers such as hospitals with the capability to allow these customers to continue operating in the event of power outages.
- Long-term options for additional transmission facilities into downtown Toronto that will provide additional capacity to supply long-term growth, and additional redundant transmission supply sources to the area.

7.3.3 Other Alternatives for Improving System Resiliency for Extreme Contingencies

The assessment of the impact of extreme contingencies indicated that while the existing transmission system supplying the Central Toronto Area is generally resilient in the event of low-probability, high-impact events, there are measures that can be explored to further improve system resilience in the area. Other possible actions to address the risk of extreme contingencies include:

- Special Protection Systems designed to anticipate and enhance the ability of the system operator to quickly respond to extreme contingencies and system emergencies.
- Continued conservation to reduce loadings on equipment and the amount of load that would need to be restored in the event of an extreme contingency.
- DG resources with the ability to provide grid support and operate as islanded micro-grids to continue to supply critical loads such as hospitals and provide critical services during system emergencies.
- Further coordinated study on extreme weather / climate change adaptation options.

7.4 Recommended Near and Medium-Term Plan

In summary, to address the needs expected to occur within the near-term and medium-term period, the IRRP recommends that the following actions be undertaken immediately:

1. **Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014)**

2. Implement Special Protection Systems to address supply security and ensure that reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS)

It is recommended that Hydro One proceed immediately with designing and implementing SPSs that will ensure that facilities at Manby TS satisfy the reliability standards established for the electric power system as demand continues to increase in the area.

It is also recommended that Hydro One review the feasibility of an SPS to enhance supply security in the event of a similar breaker failure contingency at Leaside TS which can affect load supply to Bridgman TS as a discretional security improvement.

- The SPSs will be designed to prevent the failure of breakers: H1H4/A1H4 at Manby West, H2H3 at Manby East, and optionally L14L15 at Leaside TS, from impacting multiple transmission elements that can propagate customer interruptions beyond a minimum level.
- Considering the immediacy of this need, the development of these options was communicated to Hydro One in a hand-off letter in December 2013.[26]
- The December 2013 letter also identified a number of additional observations for consideration in the design of the SPS to enhance the level of electricity service in the area.

3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs

It is recommended that the IESO and Toronto Hydro proceed with planning and implementation of conservation initiatives focused on achieving peak demand savings in the parts of the study area supplied by the Richview – Manby 230 kV transmission facilities that are forecast to approach their capacity limits in the near to medium-term period.

Toronto Hydro's 2015-2020 CDM plan should ensure that the initiatives proposed in the Plan reflect the regional capacity needs identified in this IRRP.

Develop targeted demand response programs designed to reduce electrical demand in the area at peak demand periods. These programs should target small to large scale commercial and

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[26] The letter to Hydro One is available at the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/OPA-Letter-Hydro-One-Toronto.pdf

institutional customers, and multi-unit residential and small residential customers in the Central Toronto Area.

Develop a comprehensive evaluation, measurement and verification program to monitor the progress of the conservation savings and to estimate the impact of conservation in addressing the capacity needs identified in this IRRP.

4. Conduct further work to identify opportunities for DG resources within the Central Toronto Area

The IESO will work with stakeholders and DG proponents within the City of Toronto, Toronto Hydro and Hydro One to identify opportunities for implementation of DG resources, including district energy and combined heat and power projects, in the Central Toronto Area.

Procure cost-effective DG resources taking into account needs for provincial generation capacity, local capacity, reliability, system security benefits, and meeting government policy targets for clean and efficient generation.

The incorporation new DG in the Manby TS and/or Leaside TS supplied areas could be an economic solution to provide provincial, regional, and local benefits, given the additional generation capacity needed in the Province by the end of the decade.

5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021

It is recommended that Toronto Hydro and Hydro One finalize infrastructure options to provide near-term capacity relief in West Toronto for the Runnymede TS, Fairbank TS, Manby TS and Horner TS. This includes Hydro One developing detailed cost and feasibility assessments for upgrades to the 115 kV transmission lines necessary to support the Runnymede TS expansion. Considering the near-term nature of this need, the recommendation to continue with this work was communicated to Toronto Hydro in a letter in April 2014 (Appendix I).

It is also recommended that Toronto Hydro continue with procurement work on the station expansion in downtown Toronto in the medium-term.

The planning, development and procurement work includes:

- Completing the required Connection Impact Assessments and System Impact Assessments,
- Obtaining required regulatory and environmental approvals,
- Identifying detailed station and line work and associated costs to within a range of accuracy suitable for seeking project commitments; and
- Starting the procurement process for long lead time facilities.

6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor

To cover the risk of higher growth or lower conservation peak demand impacts related to Recommendation 3, the IESO and Hydro One will conduct detailed investigations of options for providing capacity relief for the Richview TS to Manby TS 230 kV transmission lines. This recommendation is to ensure that these options can be implemented in a timely manner, if or when the transmission is needed, and to keep the infrastructure lead time as short as possible.

In the event that Conservation and incremental demand response resources do not materialize to the extent necessary to defer the transmission alternative, the reinforcement of the Richview – Manby 230 kV corridor will be needed by about 2020.

7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto

It is recommended that Toronto Hydro continue to investigate opportunities for increasing capability on the distribution system to transfer station loads to adjacent stations using distribution inter-station ties.

The distribution ties should be able to transfer station loads to adjacent stations in the event of rare N-2 transmission contingencies that could impact service from 115 kV-supplied transformer stations. This should be part of a medium to long-term strategy of incrementally increasing distribution tie capability over time, for achieving higher supply resilience in response to risk of interruption of station service.

8. Conduct further work to assess options for increasing system resiliency for extreme events

It is recommended that the IESO, Toronto Hydro and Hydro One coordinate the assessment of options for increasing resiliency in preparation for possible widespread system outages resulting from low probability – high impact events, either caused by catastrophic failure of multiple critical system elements or extreme weather events such as ice storms and flooding.

Options for increasing system resiliency include Special Protection Systems, continued Conservation, and DG resources. It is also recommended that further work on the risk and impact of extreme weather events be conducted to enhance the capability to prepare for, and respond to these types of events.

8. Long-Term Needs and Options

In the long term, there is a need for additional transmission capacity to supply the Central Toronto Area from both Manby TS and Leaside TS. This need will arise when the demand growth exceeds the capability of the 115 kV transmission lines that supply the downtown core from Manby West, and the 230/115 kV transformers at both Manby TS and Leaside TS.

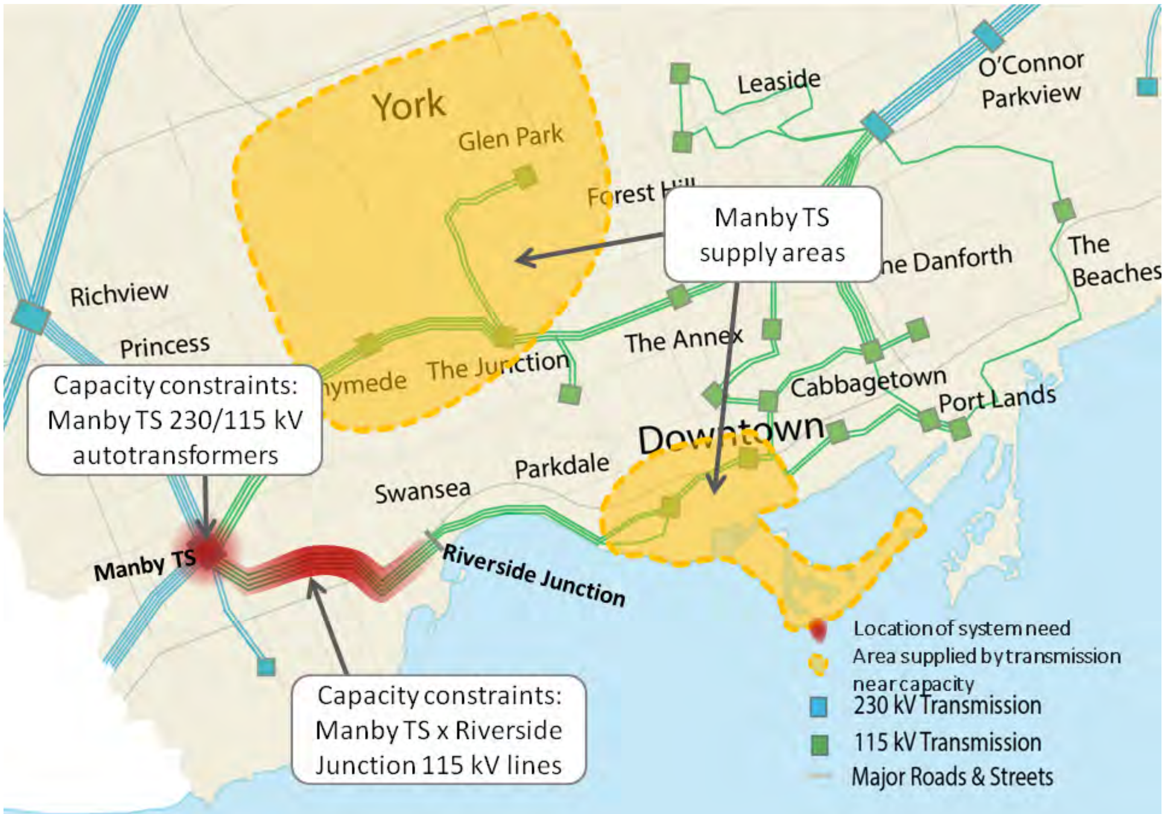
The capacity of the 115 kV transmission lines between Manby TS (Manby West) and the Riverside Junction into the downtown core is forecast to be exceeded as early as 2026 under a high demand scenario. These transmission circuits include the overhead section from Manby TS to Riverside Junction that supply Strachan TS and John TS in the downtown core. The underground section of this transmission corridor, from Riverside Junction to John TS, is being refurbished and upgraded to be capable of operating at 230 kV, although they will continue to operate at 115 kV. Under a forecast scenario that includes the impact of continued planned conservation to reduce electricity demand in the area (e.g., a low demand scenario that assumes achievement of the LTEP conservation targets), the capacity of this section of 115 kV transmission is not expected to be reached until 2031.

In addition to the 115 kV transmission lines, the 230/115 kV transformer capacity at Manby TS is forecast to be reached by 2031 under a high demand scenario. The total capacity shortfall at Manby TS by the end of the study period is forecast to be up to 50 MW. This shortfall is reduced or eliminated considering the achievement of conservation in managing the overall peak electrical demand in the area. Under a low demand scenario that considers the peak demand impact of achieving the LTEP conservation targets, this need is deferred to beyond the study period (after 2036).

A means of addressing this need is could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Manby TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the areas supplied by Manby TS would also reduce the loadings on the Manby TS transformers if the generation could reliably operate during the peak demand period.

The constraints at Manby TS and on the 115 kV transmission described above are shown in Figure 8-1.

Figure 8-1: Forecast Capacity Constraints in the Manby TS Sector in the Long-Term Period



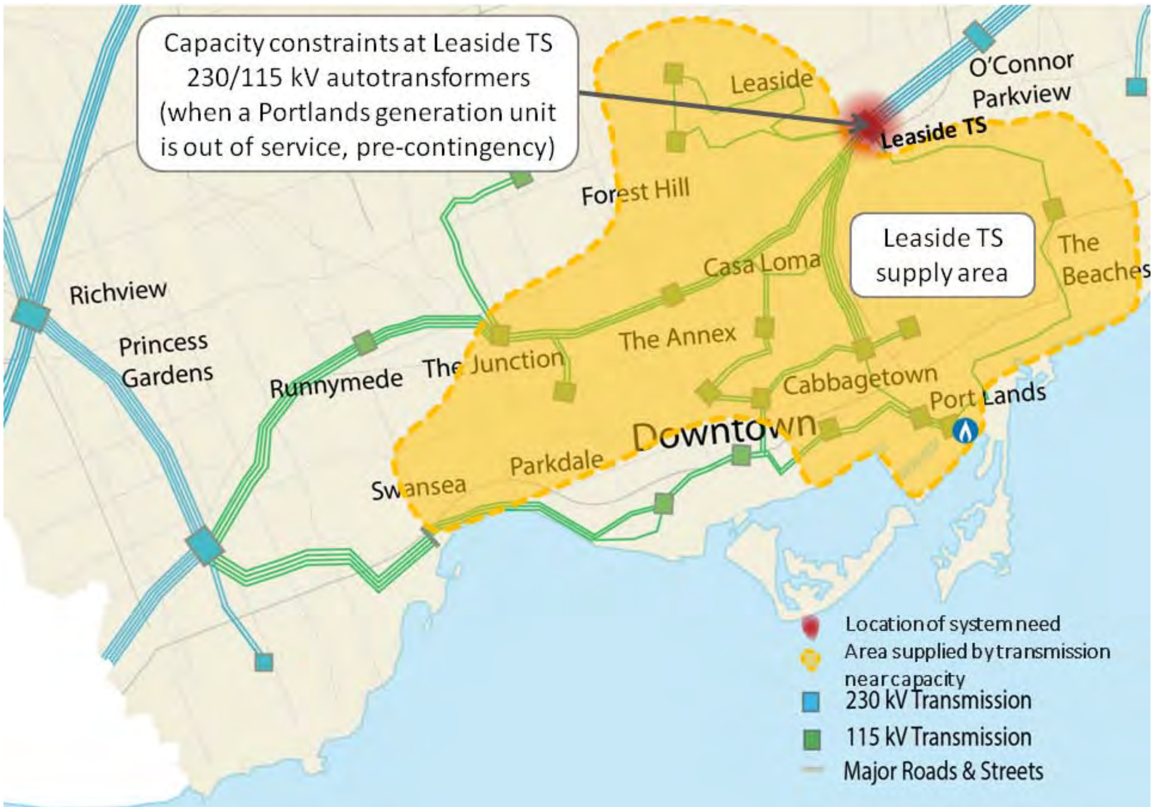
At Leaside TS, the ability to supply long-term load growth is limited by the ratings of 230/115 kV transformers, under a condition when all transmission elements are in service but one unit at PEC is out of service. Under such an N-1 outage at the PEC, both a gas turbine generator and the secondary cycle steam turbine generator will be out of service, and the generation output of the facility drops from 550 MW to 160 MW. This creates a situation, when the demand in the area is high enough (e.g., at peak), in which the Leaside transformers cannot supply the full electrical demand of the area.

This capacity constraint could arise as soon as 2026 under a high demand scenario. The shortfall is forecast to be as high as 200 MW under this scenario. Under a low demand scenario, the shortfall is reduced such that the need is deferred until 2036.

A means of addressing this need could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Leaside TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the area supplied by Leaside TS would also reduce the loadings on the Leaside TS transformers if the generation could reliably operate during the peak demand period.

This constraint at Leaside TS described above is shown in Figure 8-2.

Figure 8-2: Forecast Capacity Constraints at Leaside TS in the Long-Term Period



For each of the needs described above, the capacity constraints could be deferred into the 2030s timeframe if the demand growth in the Central Toronto Area is managed through continued conservation achievement. The total amount of conservation peak demand savings under a low demand growth scenario is in the order of 640 MW of savings (550 MW in the 115 kV transmission service area) over the long-term period.

Given the uncertainty related to the timing of these needs, the approach for developing the long-term electricity plan is different than for the near-term plan. For needs arising in the near term, specific actions, programs or projects are recommended to ensure that the preferred solutions are available in time to meet the needs. For the longer term, potential options are identified, but no specific project commitments are made. There is time to explore and develop optional paths for regional electricity system development for the region. Instead of committing specific projects, the focus is instead on identifying possible approaches for meeting long-term needs as they arise in the future.

The approach for the long term is designed to ensure community values and preferences are identified and given consideration in planning, to maintain flexibility with respect to plans, projects and programs, and avoid committing ratepayers to investments before they are needed. This provides additional time to gauge the success and potential of future conservation programs and initiatives, and to test, pilot and, if appropriate, scale up new and emerging technologies. Long-term plans will also need to coordinate with local energy planning activities. Collectively, these steps will lay a foundation for informed decisions in the future.

Another important consideration in developing long-term plans is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected lead time to bring alternatives into service. To enable fair consideration of all possible alternatives, this latter consideration is driven by the longest lead time among all the possible alternatives. This is usually associated with new major transmission infrastructure, which typically requires five to seven years to bring into service, including conducting development work, seeking regulatory and other approvals, and construction.

Based on the expected timing of the long-term needs in Central Toronto, and the lead times required for infrastructure alternatives, it is expected that, if demand growth turns out higher than is forecast today, decisions on elements of the long-term plan could be required as early as 2019-2020. Current conservation planning targets may result in deferring the timing for these decisions until approximately 2029-2030 (10 years deferral). Additional DG resource integration into the Central Toronto Area could defer this date even further. Therefore, it is recommended that demand growth, impact of conservation, and integration of DG be monitored closely and regularly as part of the implementation of this IRRP. If necessary, the IRRP could be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

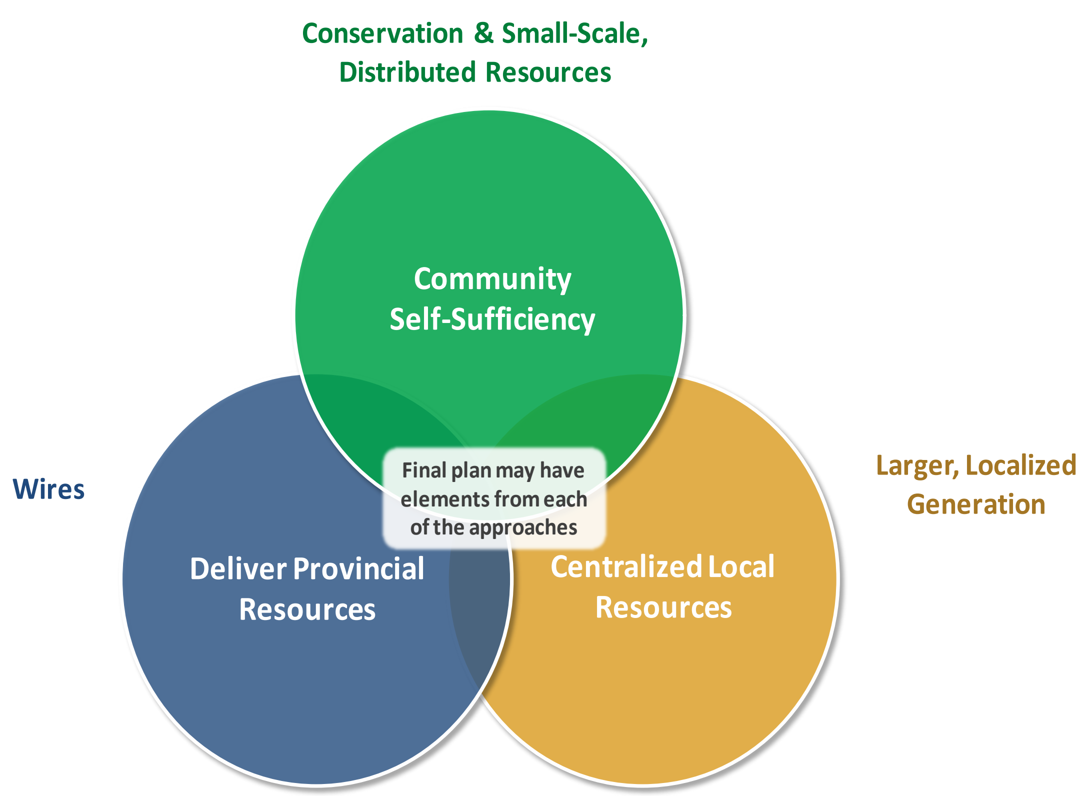
The following sections describe three approaches for meeting the long-term electricity needs of the Region and lay out recommended actions to develop the longer-term plan. It is expected that the regional planning cycle for the Metro Toronto – Central and Northern sub-regions will be aligned for the next planning cycle, and the long-term options for electricity supply will be addressed for the whole Metro Toronto region. Therefore, in the following sections, a City-wide view is presented.

8.1 Approaches to Meeting Long-Term Needs

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

To facilitate discussions about how a community might envision its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (Figure 8-3). Based on regional planning experience across the province over the last ten years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by customers and the community in planning and developing local energy systems.

Figure 8-3: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

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

The intent of this discussion, going forward, is to identify which approach should be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation policies will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. As well, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the preferences of the community are made clear, a plan can be developed around the approach that makes the most sense, which will affect the relative balance of conservation, generation, and wires in the plan. Details of how these three approaches could be developed to meet the specific long-term needs of Central Toronto are provided in the following sections.

8.1.1 Delivering Provincial Resources

Under a "wires" based approach, the long-term forecast under a high growth scenario could necessitate major new transmission development to deliver power from other major provincial grid sources into the area. Options for other major transmission supply points from the north are limited, and thus a new supply source from the provincial grid under Lake Ontario should be considered as an alternative. Some potential long-term supply sources are shown in Figure 8-4.

Standard planning practices give preference to solutions that make use of existing utility corridors. A section of existing corridor in East Toronto, from Warden TS to the 115 kV system near Leaside TS, could provide the opportunity to upgrade the existing facilities along the right-of-way to diversify the transmission supply network in Toronto.

Another possible wires-based solution involves upgrading the 115 kV supply path from Manby TS into Central Toronto to 230 kV supply. Much of this work has already been completed in anticipation of a possible future switchover from 115 kV to 230 kV. For example, the transmission system from Riverside Junction to Strachan TS, and from John TS to Esplanade TS, is capable of operating at 230 kV. A remaining section, from Manby TS to Riverside Junction, if upgraded to 230 kV, would provide an additional 230 kV source of transmission supply into the area. Bypassing Manby TS en-route to downtown (as shown in Figure 8-4) also provides additional supply diversity into the area (effectively making Richview TS a third major supply point). This section of 115 kV line is identified as requiring a capacity upgrade in the long-term period, and so the opportunity exists to rebuild to 230 kV at that time.

Figure 8-4: Potential Transmission Supply Sources to Meet Long-Term Needs

8.1.2 Large, Localized Generation

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

Opportunities for siting large generation within the City of Toronto are extremely limited due to lack of appropriate land space.

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

The cost of the generation would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

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

In Toronto, there is strong community interest in this approach, as evidenced by the municipality taking the lead in identifying and developing energy-based opportunities within the city. Some of these initiatives are described below.

Community Energy Plans

A Community Energy Plan[27] ("CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking Community Energy Plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans that better align energy, infrastructure and land use planning within the community.

The City of Toronto has completed a number of Community Energy Plans and others are in progress. While these plans may, more typically, be conducted at the level of the municipality, the size and character of the City of Toronto has resulted in a number of plans being done across the City. The CEPs completed and underway in the City of Toronto include:

- Etobicoke Centre (completed 2008)
- North York (completed 2010)
- Etobicoke – Mimico (completed 2012)
- Scarborough Centre (completed 2014)
- Downtown – Lower Yonge Precinct (in-progress)
- Etobicoke Centre – Six Points Interchange Reconfiguration (in-progress)
- North York – York University (in-progress)

[27] These plans are sometimes referred to as "Municipal Energy Plans."

Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements and technology solutions that include:

- Advanced fuel cell technologies
- Energy storage technologies
- Demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined Heat and Power and district energy opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model

The Working Group recognizes that there are risks associated with the community self-sufficiency approach, with the most crucial being the ability to successfully meet the electricity demand growth needs with new and unproven load management and storage technologies. Other key challenges include demonstrating consumer value, cost recovery certainty for innovative technologies and the risk of asset stranding, risk/reward incentives and technological obsolescence as a factor for asset replacement.

8.2 Recommended Long-Term Plan

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to support decision-making processes in the future.

To address the needs expected to occur in the long-term period, the IRRP recommends that the following actions be undertaken:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area

It is recommended that a Local Advisory Committee be established to assess the community values and preferences for the different long-term options, including:

- Delivering provincial resources
- Large, localized generation
- Community self-sufficiency

2. Continue to engage with stakeholders and the community to develop community-based solutions

The IESO will continue to engage with the City of Toronto, energy sector stakeholders, and proponents of community-based energy options to seek opportunities to promote testing, pilot projects and, if appropriate, scale up new and emerging technologies, and to coordinate electricity system planning activities with local energy planning activities

3. Monitor demand growth, conservation achievement and DG uptake

It is recommended that the IESO and Toronto Hydro closely and regularly monitor demand growth, impact of conservation, and integration of DG as part of the implementation of this IRRP.

4. Initiate the next Regional Planning Cycle early, if needed

If changes to assumptions for demand, conservation or DG in the community change, then the IRRP should be revisited and revised ahead of the 5-year planning schedule.

9. Community Aboriginal and Stakeholder Engagement Process

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

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

Figure 9-1: Summary of Central Toronto IRRP Community Engagement Process

Creating Transparency:

Creation of Central Toronto IRRP Information Resources

- Dedicated Central Toronto IRRP web page created on IESO (former OPA) website providing background information , IRRP Terms of Reference and list of Working Group members
- Dedicated web page added to Hydro One and Toronto Hydro's websites
- Self-subscription service established for Central Toronto IRRP for subscribers to receive regional specific updates
- Status: Complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Hosted three meetings with more than 15 participants at each session from the City of Toronto in 2013-14
- Information provided to First Nation communities who may have an interest in the planning area with an invitation to meet
- Invited City of Toronto representatives to stakeholder workshops
- Information provide to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Initial Broader Community Outreach

- Discussion workbook developed and tested in **four randomly recruited focus groups** consisting of Toronto Hydro Residential and General Service customers (Three groups between November and December 2013)
- Workbook posted online on September 3, 2014 on IESO, Toronto Hydro and Hydro One websites and promoted in newspaper via advertisements in the Toronto Star, Metroland Community Paper and Metro News
- Stakeholders and community groups engaged through workshops, surveys, webinars, open houses, subscriber lists, bill inserts and traditional and social media channels
- **Four engagement sessions** with General Service and Residential customers in the Central Toronto IRRP study area; between seven and eight stakeholders in each session (September 24 and 25, 2014)
- More than 300 key stakeholders invited to **three workshop sessions** , with between six and 12 participants each
- More than 720 General Service and Residential customers surveyed by phone
- Hosted webinars on September 11 for the public. Webinars were promoted on each Working Group participant's website, via e-blast and through social channels
- Hosted two public open houses in Toronto on September 30 that were promoted through an advertisement in the Toronto Star, Metroland and Metro papers, via social media and e-blasts
- Status: Initial outreach complete

Continued Broader Community Outreach

- Presentations at Municipal Council, First Nation communities & Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee (LAC)
- Targetted engagement to discuss the formation of a LAC
- Formation of LAC to discuss long-term needs and local community engagement plans
- Status: beginning in spring 2015, no time limit

Creating Transparency

To start the dialogue on the Central Toronto IRRP planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide an overview of the regional planning area, information on why the plan was being developed, the plan Terms of Reference, and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was established for the Central Toronto IRRP where stakeholders could subscribe to receive email updates.

Engaging Early and Often:

In 2011, when the Terms of Reference were signed by the four study partners, the Working Group engaged with Toronto Hydro's sole shareholder, the City of Toronto, and presentations were made on three separate occasions engaging more than 15 city staff members from various departments including Economic Development, Environment and Energy Office, Toronto Water, Parks, Forestry and Recreation, and the Toronto Transit Commission. The purpose of the meetings was to raise awareness about electricity planning needs in Central Toronto, and to discuss supply, the load forecast, specific growth centres, major weather events, long-term needs and stakeholder and community engagement. Key input from these discussions focused on achieving municipal targets for energy efficiency and reducing greenhouse gas emissions.

Bringing Communities to the Table

Due to the nature and size of the sub-region being studied, a multifaceted engagement program was developed. There were primarily three elements to developing and implementing the engagement: establishing background material (the workbook), customer engagement (qualitative research) and telephone surveys (quantitative research).

Key findings from the engagement:

- Most customers are familiar with the electricity system and satisfied with their level of service.
    - 84% of telephone survey respondents are satisfied with their current service
    - 58% of online workbook respondents were satisfied with service during major events
- Cost is a key issue - customers want lower electricity prices and better service
    - When asked "what can be done to improve service, paired with increased reliability," the leading answer to the question was to reduce rates. During the

last 12 months, half of Residential and General Service customers experienced an outage of some kind
    - The Focus Groups understood the need to replace aging infrastructure, but suggested that the system look within for savings before asking customers to pay more
- Cutting down the duration of outages is crucial
    - Much of the engagement focused on how reliability issues affected customers day-to-day – examining customer preference between cost and reliability, and frequency and duration
- The three capacity options presented were not well-known to customers
    - General awareness of Conservation, DG and Transmission and Distribution infrastructure is low, with DG least known
    - When asked about electricity generation in Toronto, solar photovoltaics and CHP are the two option respondents felt most appropriate for use in the Central Toronto Area. Bioenergy and emergency generators were seen as less viable options
    - Overall, customers are supportive of energy conservation and concerned about environmental issues
- Customers think that overall, they are getting good value for money
    - Given the difficult choice between increasing rates or reducing reliability, customers have shown that they will, reluctantly, accept paying marginally more for better service

To further continue the dialogue, a Local Advisory Committee (LAC) will be established as an advisory body to the Metro Toronto regional planning team.[28] The purpose of the committee is to establish a forum for members to be informed, and to advise on the regional planning process. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Information on the formation of the LAC is available on the Metro Toronto Region IRRP main webpage.

Strengthened processes for early and sustained engagement with communities and the public were introduced following the 2013 engagement held with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of

[28] It is expected that future iterations of regional plans for Toronto will be addressed at the city-wide level, consistent with the Metro Toronto Regional Planning Area.

recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum" available on the IESO website.

Information on continuing outreach activities can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Central Toronto IRRP or for the Metro Toronto Region.

Copies of the community engagement materials are available on the IESO website, and engagement summary reports are provided in Appendix J.

10. Conclusion

This report documents an IRRP that has been carried out for Central Toronto, a sub-region of the Metro Toronto regional planning region, and fulfils the IESO's OEB licence requirement to conduct regional planning in the Metro Toronto region. The IRRP identifies electricity needs in the Region over the period from 2014 to 2036, recommends a plan to address near-term and medium-term needs, and identifies actions to develop alternatives for the longer term.

Implementation of the near-term plan is already underway, with Toronto Hydro developing conservation plans consistent with the Conservation First policy, and with infrastructure projects being developed by Toronto Hydro and Hydro One.

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

The planning process does not end with the publishing of this IRRP. The community will be engaged in the development of the options for the long term. In addition, the Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area, and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the medium and long term. If demand grows as forecast, it may be necessary to revisit the plan as early as 2018-2019, in order to respect the lead time for development of alternatives. If demand growth slows or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

CENTRAL TORONTO AREA
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

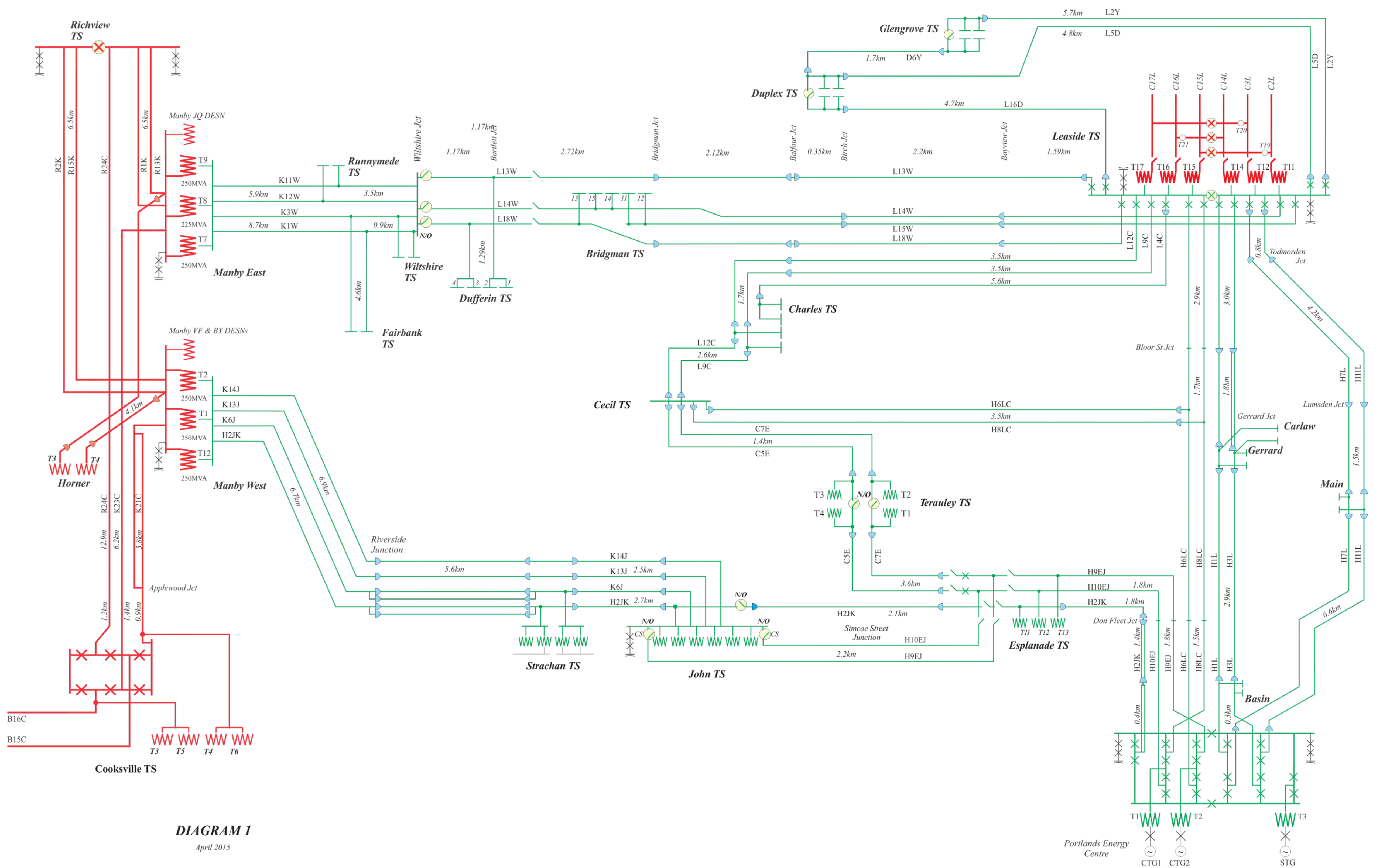
Part of the Metro Toronto Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Metro Toronto – Central IRRP

Appendix A: Single Line Diagram of the Central Toronto Transmission System

Appendix A: Single Line Diagram of the Central Toronto Transmission System



Metro Toronto – Central IRRP

Appendix B: Toronto Hydro Spatial Load Forecast Methodology

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NAVIGANT

Memorandum

To: Angelo Boschetti, Capacity Planning, THESL

From: Glen Wood, Navigant
Peter Steele-Mosey, Navigant

CC: Chun Hung Ngai, Capacity Planning , THESL
Anna Tubina, Rates and Treasury, THESL
Todd Williams, Navigant
Amanda Bond, Navigant

Date: 31 July 2012 (Revised 13 Nov 2012)

Attachment: ***Annual Forecast Peak Demand 30 July 2012 - THESL.xlsx***

Re: **Forecast of THESL System-Wide Gross Peak Demand - 2012 to 2036.**

1. Purpose and Summary of Approach:

The purpose of this memo is to document the methods, data sources, and assumptions used in the development of the forecast of the ***System-Wide Gross Peak Demand Forecast*** for the THESL system. This projection has been completed as the first step in the development of a ***Spatial Peak Demand Forecast*** for the THESL system. While the System-Wide Gross Peak Demand Forecast projects demand for the system as a whole, the Spatial Peak Demand Forecast (SPDF) will project demand for specific areas within THESL's service territory.

This memorandum presents Navigant's projection of peak demand for THESL's total service territory under four different scenarios:

1. "Normal" (i.e., 1-in-2) weather,
2. "Extreme" weather,
3. "Climate Change" scenario, which assumes that "Normal" weather conditions are affected by an average temperatures rise of 2.3 degrees from current "normal" over the next 25 years, and,
4. A "net" demand scenario in which demand reductions as a result of Conservation and Demand Management (CDM) and distributed generation (DG) are subtracted from the extreme weather scenario.

The definitions of "normal" and "extreme" will be discussed in greater detail below.

The memorandum is divided into the following sections:

1. Purpose and Summary of Approach (this section).
2. Data Description:
   - This data includes both:
     a. Historic estimation data (used to estimate the regression model), and,
     b. Forecast input data (not including weather).
3. Econometric modeling:
   a. Regression specification and parameter estimates.
   b. Model diagnostics and validation.
4. Weather scenarios.
5. THESL peak demand forecast.
6. Summary of results.

We have presented the discussion of the data used in the analysis prior to the discussion of the econometric modeling since the outcomes of the regression process are dependent on the data underlying the analysis.

One of the key challenges in projecting future demand for electricity lies in quantifying the future contributions of Conservation and Demand Management (CDM) and Distributed Generation (DG). The level of future demand reduction arising from CDM and DG will be influenced by policy decisions and are therefore subject to uncertainty. After reviewing alternative approaches to addressing these impacts as part of the projection, Navigant recommended and employed an approach in which the effects of CDM were identified and removed from demand during the historic period[1]. This approach allowed the development of a projection of demand as it would have been without the impact of CDM and assuming only current levels of DG. The resulting projection, without the impact of CDM or DG is referred to as the "gross" forecast. The future impacts of CDM and DG can then be treated explicitly over the projection period.

A forecast of gross peak demand was developed for a "normal" weather scenario, an "extreme" weather scenario and a weather scenario in which average and peak temperatures increase as a result of climate change. In addition, a "net" scenario was developed to show the level of peak demand that would be expected under the "extreme" weather scenario if the same level of distributed generation now operating within the THESL system is maintained and CDM programs currently in place continue to operate. This "net" scenario will be referred to as Scenario 1.

[1] Existing DG was assumed to continue operating in the projection period, so no adjustment was made for DG over the historic period.

The project team met with representatives of the IESO and OPA on March 27th to discuss methods for normalizing historic demand for the effects of weather. At that meeting, both the IESO and OPA discussed their forecast methods and the IESO described the processes used for weather normalization. After discussing the objectives of the THESL forecast, the consensus of the group was that the most appropriate weather normalization approach for THESL to follow would be to use the IESO monthly weather normal and extreme scenarios used in their Transmission Planning Analysis.

2. Data Description

The data used in this analysis can neatly be divided into two types: that used to estimate the regression equation (historical data), and that used as an input to the forecast peak demand. Both types are described below.

Historical data

Weather Data

Weather data were obtained from Environment Canada (EC) for Toronto's Pearson International airport (station ID #5097).

The variables considered in the development of this analysis included:

- Temperature (˚C)
- Dew point (˚C)
- Wind speed (km/h)
- Cloud opacity (in tenths)

Missing values were estimated as the simple average of the value observed in the hour before the missing value and the hour after. For cloud opacity, such averages were rounded to the nearest integer.

Population Data

Monthly historical population data for Toronto residents over the age of 15 was provided by the Strategic Growth and Sector Development department of the City of Toronto. This data can be obtained by request through the City of Toronto Economic Indicators webpage[2].

[2] City of Toronto Economic Indicators, http://www.toronto.ca/business_publications/indicators.htm

Employment Data

Employment data for 2002-2010 were obtained from Toronto's annual publication entitled "Profile Toronto, Toronto Employment Surveys" ("the Toronto survey") published by Urban Development Services Policy and Research Division.

The annual figures by sector of the economy were used without change where they were provided. In some cases sectoral figures had to be derived based on percentages of total employment provided in the Toronto survey, and in other cases sectoral figures were derived based on the indicated year-over-year change.

Employment figures are provided for following categories listed below. For the purposes of this analysis, employment figures were aggregated into two sectoral categories as indicated below: "Industrial" employment and "Commercial" employment":

- Manufacturing/Warehouse (Industrial)
- Retail (Commercial)
- Service (Commercial)
- Office (Commercial)
- Institutional (Commercial)
- Other (Commercial)

Demand Data

THESL provided Navigant with hourly demand billing demand data (in kW) from the IESO for its system[3], from May, 2002 to December, 2011.

CDM Data

The data used to remove the impacts of CDM from the historic hourly demand data are described in Navigant's CDM memo, most recently updated on July 23, 2012.

DG Data

DG impacts were not considered as part of the demand modeling, which assumed that existing DG would continue operation during the projection period. Projections of future DG impacts, discussed later in Scenario 1, were provided by THESL.

[3] Hourly billing demand did not include IESO market participants. Market participants represent < 1% of load on THESL system.

Forecast data

Weather Data

As per IESO guidelines[4], and with guidance from the IESO, Navigant created three different types of peak demand weather scenarios for May through September: "Normal" weather, "Normal with climate change" weather (which is simply the "Normal" scenario assuming an average maximum temperature increase of 2.3 ˚C phasing in over thirty years beginning in 2011[5]) and "Extreme" weather. Details of how these scenarios were developed may be found below. For the "normal" and "extreme" weather scenario, the weather input values for a given month's peak demand estimate remain constant across all years of the forecast. Input weather values for a given month's peak demand estimate change gradually for the "normal with climate change" scenario, as noted above.

Population Data

Population projections for the city of Toronto were obtained from the City's "*Flashforward*" publications which describe Toronto's Official Plan. Specifically, projected growth rates from "*Flashforward: Projecting Population and Employment to 2031 in a Mature Urban Area, How Many People Will There be in Toronto?*"[6] were used as the basis for population and employment projections. Population projections are given for every 5th year from 1996-2031.

Understanding that the data in the "*Flashforward*" projection doesn't reflect actual changes in population and employment since its publication, more recent data was obtained from the City for the historic period up to 2011. The growth rates for each 5-year period projected in the "*Flashforward*" document were applied to the actual historic population data. For our dataset, we were able to obtain annual population projections for 2011, 2016, 2021, 2026, and 2031. The base for our population projection was taken as December 2011 based on the monthly series from the City of Toronto, which was used as our starting point for January 2012. In order to derive

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[4] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

[5] Climate Change Research Report (CCRR16) – Current and Projected Future Climatic Conditions for Ecoregions and Select Natural Heritage Areas in Ontario. Ontario Ministry of Natural Resources, 2010. The MNR projection indicates that over the period from 2011-2040, the maximum temperature in warmest month is expected to increase by between 1.8 to 3°C. For the sensitivity analysis we have assumed the mean increase in projected maximum temperatures of 2.3°C.

[6] City of Toronto, *Flashforward: Projecting Population and Employment to 2031 in a Mature Urban Area, How Many People Will There be in Toronto?*, 2001 http://www.toronto.ca/planning/flashforward.htm

monthly population projections from the annual series, the data was linearly interpolated across each year. Note that since the population projection is based on the historical population data, it is consistent in reflecting residents aged 15 years and older.

Forecast Toronto population for December of milestone years is shown in Table 1, below.

Employment Data

Projected employment for the City of Toronto, from the beginning of 2011 to the end of 2037, was obtained from the city of Toronto, in its "*Flashforward*" publications[7]. Select years are published in which projections are given. In cases where no employment projection was provided for a given year, it was estimated by linear interpolation. For years falling after the final year of the City of Toronto's employment forecast, data were extrapolated based on the growth rate observed between the final two years forecast by the City of Toronto.

As with the population data, the City of Toronto forecast was updated to reflect current levels of employment but maintaining the original implicit growth rates. Forecast average levels of employment for milestone years, by sector, is shown in Table 1, below.

[7] City of Toronto, *Flashforward: : Projecting Population and Employment to 2031 in a Mature Urban Area, Where Are We Going to Work?* http://www.toronto.ca/planning/flashforward.htm

Table 1: Projected Population and Employment - Milestone Years

Population and Employment (Thousands)			
Year	Population(1)	Industrial Employment	Commercial Employment
2012	2,179	129	1,185
2013	2,200	128	1,197
2014	2,220	128	1,208
2016	2,262	127	1,231
2018	2,275	128	1,253
2021	2,291	128	1,287
2031	2,352	126	1,400
2036	2,395	125	1,460

(1) for December of given year
Source: City of Toronto, Navigant analysis

3. Econometric Modeling

Forecast data

The basic functional form of the regression equation was determined by the need to adhere to the IESO's established method for developing weather scenarios for long-term forecasts. Which regressors (independent variables) were to be included in the model was determined using a specification search, with competing models ranked by the Schwartz-Bayesian Criterion (SBC) and adjusted R^2. Of the model specifications tested, that with the lowest SBC and highest adjusted R^2 was used[8].

Note that since THESL is summer-peaking and is expected to remain so, only summer months (May through September) were used in the regression. Likewise, since peak demand is not expected to occur on a weekend or holiday[9], all observations on these days are dropped from the sample.

The model estimated by Navigant was:

$$
\begin{aligned}
y_t &= \alpha + \beta_1 Cool\_THI_t + \beta_2 Heat\_THI_t + \beta_3 Cloud_t + \\
&\beta_4 Pop_t + \beta_5 Ind\_Jobs_t + \beta_6 Com\_Jobs_t + \beta_7 \left(Pop_t \times Cool\_THI_t \right) \\
&+ \vec{\gamma}\,\overrightarrow{Day_t} + \vec{\omega}\,\overrightarrow{Month_t} + errors
\end{aligned}
$$

[8] Where the two criteria disagreed as to the relative rank of model specification, priority was given to the SBC.
[9] Peak monthly demand has not occurred on any weekend or holiday previously.

Where:

y_t = THESL's peak observed demand, as it would have been without any CDM impacts (but assuming continued DG operation), day *t*.

$Cool\_THI_t$ = Is the cooling temperature-humidity index (THI) observed on day *t.* THI is calculated in the following manner[10]:

$$THI_s = 17.5 + 0.55 \times DryBulb_s + 0.2 \times Dew_s$$

Where *DryBulb* is the dry bulb temperature (˚C) observed in hour *s* and *Dew* is the dew point temperature (˚C) observed in hour *s*. The daily THI to be used for the analysis is then calculated as the average of: the minimum THI between 7am and noon, the maximum THI between noon and 5pm and minimum THI between 5pm and 10pm (all times EST).

Cool_THI is calculated as the daily THI minus 30 or the number zero, whichever is greater.

Heat_THI = Is calculated as 25 minus the daily THI (see above) or the number zero, whichever is greater.

Cloud = Is the maximum cloud opacity (in tenths) observed on day *t* between 11am and 4pm (EST).

Pop = Is the cumulative change in Toronto's population over the age of 15 since January of 2002 for the month in which day *t* falls.

Ind_Jobs = Is the cumulative change in the number of Toronto's industrial jobs since 2001 for the year in which day *t* falls.

Com_Jobs = Is the cumulative change in the number of Toronto's commercial jobs since 2001 for the year in which day *t* falls.

$\overrightarrow{Day}$ = Is a vector of three dummy variables capturing the impact on peak daily demand if day *t* is a Tuesday, Wednesday or Thursday.[11]

[10] Equations and method for calculating hourly and daily THI and cooling and heating THI were provided by the IESO.

[11] The impact on peak daily demand due to day *t* being a Monday or Tuesday is implicitly captured by the intercept term.

$\overrightarrow{Month}$ = Is a vector of four dummy variables capturing the impact on peak demand if day *t* occurs in June, July, August and September..[12]

The model was estimated in SAS[13] using the PROC REG and PROC MODEL procedures. Parameter estimates, HAC standard errors and p-values are shown in, below. The R-squared of this model is 0.9048 and the adjusted R-squared is 0.9035 indicating a very good fit of the model to the data.

Table 2: Regression Model Parameter Estimates, SEs, t-stats and P-values

Variable	Parameter Estimate	HAC Standard Error	t statistic	P Value
Intercept	3,519.73	28.41510	123.87	<.0001
Cool_THI	158.48	5.57790	28.41	<.0001
Heat_THI	-20.75	5.73750	-3.62	0.0003
Cloud	-9.96	1.54410	-6.45	<.0001
Pop	0.0017	0.00042	3.98	<.0001
Ind_Jobs	0.0080	0.00125	6.39	<.0001
Com_Jobs	0.0018	0.00054	3.35	0.0008
Pop × Cool_THI	0.0002	0.00009	2.47	0.0137
Tue Dummy	33.60	10.07470	3.33	0.0009
Wed Dummy	49.81	11.22920	4.44	<.0001
Thurs Dummy	46.53	10.60340	4.39	<.0001
June Dummy	235.26	16.12160	14.59	<.0001
July Dummy	249.51	18.88670	13.21	<.0001
Aug Dummy	241.34	18.97630	12.72	<.0001
Sept Dummy	187.91	17.37200	10.82	<.0001

Source: Navigant Analysis

Model Diagnostics and Validation

Stationarity

The standard test for stationarity in a data series is the Dickey-Fuller test. Generally, the Dickey-Fuller test for stationarity is conducted by estimating the three equations shown in

[12] The impact on peak daily demand due to day *t* being in May is implicitly captured by the intercept term.
[13] SAS (Statistical Analysis Software) version 9.2 (http://www.sas.com/software/sas9/).

Table 3, below and testing the null hypothesis that gamma is zero (that is, that there exists a unit root).

Table 3: Dickey-Fuller Test Equations

Model	Description	Specification
A	Random walk	$\Delta y_t = \gamma y_{t-1} + \varepsilon_t$
B	Random walk with drift	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \varepsilon_t$
C	Random walk with drift and trend	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \alpha_1 t + \varepsilon_t$

Where "y_t" is the variable which is being tested for stationarity, in this case the peak daily demand experienced by THESL. The three models above were estimated using the PROC ARIMA procedure in SAS and produced the results shown in Table 4, below.

Table 4: Dickey-Fuller Test Statistics

Model	Tau Statistic	Pr < Tau	F Statistic	Pr > F
A	-1.09	0.2488		
B	-10.47	<.0001	54.78	0.001
C	-10.46	<.0001	54.73	0.001

Source: Navigant analysis

Although the null hypothesis of a unit root cannot be rejected for model A, this is clearly not the appropriate model – any plot of changes in peak daily demands will clearly show that this value fluctuates around a non-zero mean due to seasonal shifts, or around a non-zero mean and a deterministic trend (models B and C, respectively). The tau statistics for these two models allow the null hypothesis of a unit root to be rejected, indicating that the data is either mean- or trend- stationary.

Residual Serial Correlation and Heteroskedasticity

Residual serial correlation was tested for using the Durbin-Watson statistic (using the PROC REG procedure). The Durbin-Watson statistic returned was 1.298 meaning the hypothesis that the residuals are serially independent must be rejected – that is, it is highly likely that the residuals are serially correlated. For confirmation, the Breusch-Godfrey/Lagrange Multiplier test for serial correlation was conducted and confirmed the result of the Durbin-Watson test.

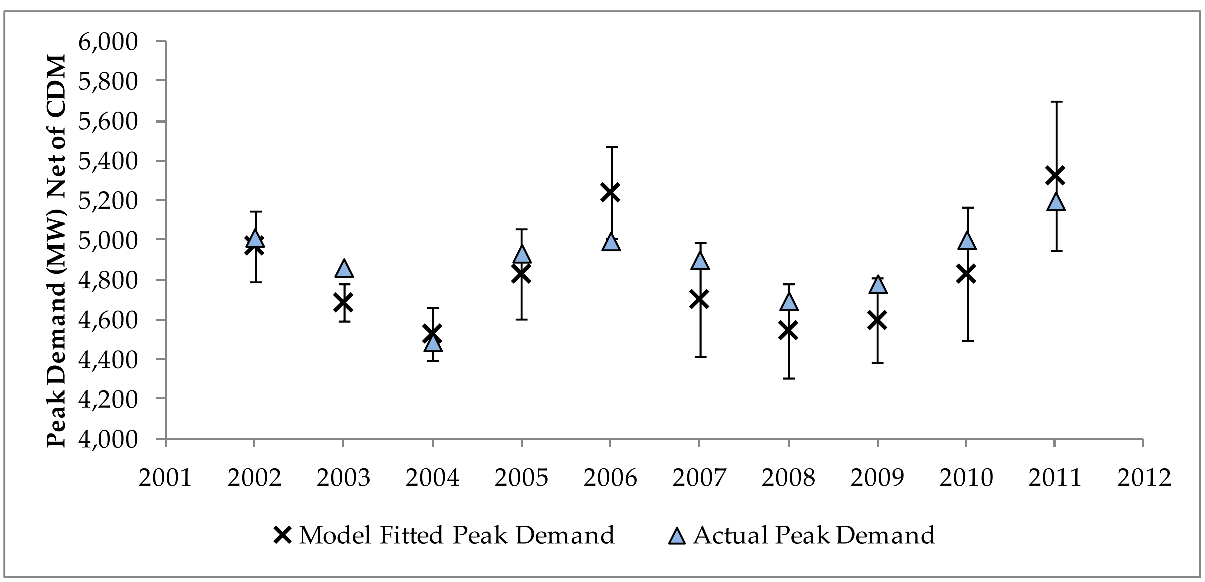
Residual heteroskedasticity was tested using the White test, which delivered the Chi-squared distributed statistic of 125.69, meaning that the null hypothesis that the residuals are homoskedastic must be rejected at the 95% level[14] (p-value of 0.0363) – that is, it is likely that the residuals are heteroskedastic.

Fortunately, neither serial correlation not heteroskedasticity biases the coefficient estimates when no lagged dependent variable is included in the model specification, although both violations of the classic assumptions result in bias of estimates of the coefficient standard errors. This results in inaccurate t-values and may lead to significant estimates being rejected as not significant or vice versa. To correct for this, heteroskedasticity and autocorrelation consistent (HAC) standard errors were estimated using the PROC MODEL procedure. Confidence intervals and statistical testing of parameter estimates was conducted using these standard errors.

Accuracy of Fitted Peak Demands

One of the most important tests of model validity (certainly the most accessible for readers less familiar with econometrics) is simply to compare the model fitted values and the actual historical values. This comparison is made in Table 5, below. For convenience we have used the term "absent CDM" in this memo to refer to demand as it would have been without the impacts of CDM and assuming the continued operation of existing levels of DG.

Table 5: Historic Peak Demand (Absent CDM) vs. Fitted Peak Demand (Absent CDM).



14 Although not at the 99% level of significance.

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

The error bars shown in Table 5 represent the fitted values obtained using the upper and lower 95% confidence intervals for all of the estimated parameters, calculated using (HAC) standard errors.

Note that Navigant's point estimates of historic peak demand (absent CDM) all fall very close to the observed actual historic peak demand, absent the impacts of CDM[15]. In only one case does the historic value fall outside the 95% confidence interval, and even in that case it remains very close to the point estimate. Note too that Navigant's estimates do not always either over-estimate or under-estimate the true impact but fluctuate, sometimes higher and sometimes lower than the true peak demand. The average absolute deviation of Navigant's estimates from the true values shown in Table 11 is less than 3%.

4. Weather Scenarios

Weather scenarios used in the forecast were generated in a manner consistent with the method outlined by the IESO in its "*Methodology to Perform Long Term Assessments*" document[16] and further expanded on in a slide deck presented to both Navigant and THESL in March of 2012.

"Normal" Weather Scenario

Step 1:

Calculate the peak daily demand absent CDM which may be ascribed purely to weather for every day in May, June, July, August and September from 1981 through to the end of 2011. This is done by multiplying the purely weather coefficients by the corresponding variable values on each day and summing them up.

Step 2:

Collect the highest peak demand for each month of each year as calculated in Step 1. This will result in a data set of 155 values, 31 for each of the five months. Each row of this data set will contain the weather observations corresponding to the highest peak daily demand observed in each month of each year.

[15] Note that the relative position of the observations on this chart would not change were CDM to be included – both fitted and actual observations would simply shift downward by the same amount of peak demand attributable to CDM in a given year.

[16] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

Step 3:

Extract the median row for each month. The corresponding weather observations are the weather values that will be used for as the 1-in-2 weather for forecasting the peak demand of each month (i.e., May through September). For each year of the forecast, these values will be used, along with the forecast economic and demographic factors for that year, to estimate the peak monthly demand.

A summary of the temperature and other weather variables drawn from the days used for the "normal" weather scenario is presented in Table 6, below.

Table 6: Summary Statistics From "Normal" Weather Scenario Days, 11am – 5pm EST

Month	Date	Avg. Temperature	Max. Temperature	Avg. Dew Point	Avg. Cloud Opacity
May	22-May-94	26.6	27.8	13.1	0
June	15-Jun-01	28.0	29.1	20.4	0
July	8-Jul-81	30.7	32.0	21.2	4
August	15-Aug-03	30.6	31.0	20.1	5
September	1-Sep-81	24.7	25.6	19.8	9

Source: Environment Canada

"Normal" Weather Scenario with Climate Change

Climate change is already affecting temperatures and hence electricity demand in Ontario: *"Between 1948 and 2008 the average temperature in Ontario has increased by up to 1.4°C"*[17].

The Ontario Ministry of Natural Resources (MNR) has developed projections of the impacts of future climate change for different eco-regions and areas in Ontario based on the outputs from two emission scenarios and using results from four different climate models[18] or GCMs (general circulation models). *"Projections of monthly temperature and precipitation were generated for each year over the period 2011-2100"*[19].

---

17 Province of Ontario, "Climate Ready: Ontario's Adaptation and Strategy and Action Plan – 2011 – 2014", 2011, page 10.

[18] The four models used included: 1) the Canadian GCM, 2) the UK-based Hadley GCM, 3) the Australian-based Commonwealth Scientific and Industrial Research Organization (CSIRO) GCM and 4)the US-based National Center for Atmospheric Research (NCAR).

[19] Climate Change Research Report (CCRR16) – Current and Projected Future Climatic Conditions for Ecoregions and Select Natural Heritage Areas in Ontario, Ontario Ministry of Natural Resources, 2010.

The outputs of these models indicate that the impacts of climate change will become significant over the time period being considered for this forecast. "*For people living in an A2 world, most of southern Ontario will have summers that are 2 to 3°C warmer by mid-century and 4 to 5°C warmer by 2071*"[20].

The results project the impacts of climate change under two different emissions scenarios:

(1) Scenario A2, which "*assumes a higher human population, less-forested land, greater pollution, and higher carbon dioxide (CO2) emissions*", and

(2) Scenario B2 which "a*ssumes an acceleration of energy and resource conservation efforts during the early decades of this century, such that CO2 emissions will decline by mid-century*".

For the purposes of the sensitivity analysis, Navigant has used the conditions projected under Scenario A2 and the change projected for the period from 2011 to 2040 to calculate the potential impact of climate change over the 25-year forecast period. Scenario A2 was selected as being the most conservative in terms of estimating the potential impacts of climate change on the THESL system and as being more representative of the actual trajectory of emissions in the period since the report was issued.

The table below shows the results for six climate variables for the eco-region that includes Toronto (7E). These values were projected by the MNR for each of Ontario's eco-regions under scenario A2. The projections show projected temperature and precipitation impacts over three 30-year future periods compared to average conditions over the period from 1971 to 2000.

Table 7: Projected Change in Climate Variables for Toronto

	1971 200			2011 2040			2041 2070			2071 2100		
Description	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**
Annual Mean temperature (AMT)	7.3	10	8.6	8.5	11.1	9.9	10	12.6	11.5	12.2	14.8	13.7
Maximum Temperature of the Warmest Month	25.8	28.8	27.1	28.8	30.6	29.4	29.9	32	30.7	32.5	34.8	33.3
Min. Temperature in Coldest Month (all minus/ -)	11.2	8	9.1	10.5	7.1	8.7	8.5	5.1	6.5	6.1	2.8	4.2

[20] Climate Change Research Report (CCRR-05) – Climate Change Projections for Ontario: Practical Information for Policymakers and Planners, Ontario Ministry of Natural Resources, 2007,

	1971 200			2011 2040			2041 2070			2071 2100		
Annual Precipitation	776	1012	911	777.5	1022	908	810.3	1067	940	809	1052	933.8
Precipitation in the Warmest Quarter	216	275	249	221	279	251.8	221	278	248.8	204	262	235.5
Precipitation in the Coldest Quarter	154	229	192	160	228	192.5	168	241	202.3	173	252	211.3
Change in Maximum Temperature	**-**	**--**	**-**	***3***	***1.8***	***2.3***	***1.1***	***1.4***	***1.3***	***2.6***	***2.8***	***2.6***

Source: Ontario MNR, CCRR-16 Appendix 1.

The MNR projection indicates that over the period from 2011-2040, the maximum temperature in warmest month is expected to increase by between 1.8 to 3°C. For the sensitivity analysis we have assumed the mean increase in projected maximum temperatures of 2.3°C.

As noted previously, temperature contributes to the peak demand forecast through the value of the THI. Also as noted earlier, the average temperature has been assumed to increase at a constant rate from 2011 to 2040 when it is assumed to be 2.3 degrees Celsius higher than under the "normal" scenario. Therefore, under the normal weather scenario with climate change, in any given year, the THI variable is increased by the number of degrees above normal that temperature is expected to be in that year, times 0.55 as indicated by the equation for calculating THI (see model specification discussion above for more detail).

"Extreme" Weather Scenario

Selection of the extreme weather scenario for each month proceeds in the same manner as selection of the normal weather scenario for steps 1 and 2. For step 3, however, rather than taking the median value within each month, the highest value is selected.

A summary of the temperature and other weather variables drawn from the days used for the "extreme" weather scenario is presented in Table 8, below.

Table 8: Summary Statistics From "Extreme" Weather Scenario Days, 11am – 5pm EST

Month	Date	Avg. Temperature	Max. Temperature	Avg. Dew Point	Avg. Cloud Opacity
May	30-May-06	31.8	32.8	21.3	4
June	19-Jun-95	33.9	35.1	20.0	0
July	21-Jul-11	36.6	37.5	23.9	5
August	1-Aug-06	35.4	36.4	23.4	3
September	10-Sep-83	32.1	33.3	18.9	3

Source: Environment Canada

5. THESL Peak Demand Forecast

Gross Forecast

The System Wide Gross Peak Demand Forecast for 2012 through 2036 is presented in the attached MS Excel spreadsheet. A summary of the forecast peak demand for Toronto Hydro's milestone years is summarized in Table 9 below. For each year, peak monthly demand for May, June, July, August and September was calculated, and the highest of these was selected as the peak summer demand. Given the parameter estimates in Table 2, and the monthly weather scenarios, the peak demand for each July became the peak annual value.

Table 9: System Wide Gross Peak Demand Forecast (MW) for THESL

	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather
2012	4,815	4,830	5,433
2013	4,897	4,921	5,531
2014	4,980	5,012	5,630
2016	5,145	5,195	5,826
2018	5,246	5,314	5,942
2021	5,359	5,454	6,068
2031	5,739	5,932	6,493
2036	5,968	6,218	6,755

Source: THESL demand data, Environment Canada weather data,
City of Toronto population and employment data and Navigant analysis.

Note that the values shown above are for the gross peak demand, as it would occur without the demand reductions resulting from codes and standards put in place in 2006 or later, time-of-use rates, energy efficiency and demand response (both residential and otherwise) CDM programs or distributed generation.

Net Forecast

As described in section 1, Navigant used a method in which the demand reductions attributed to CDM and DG were removed from demand in the historic period in order to project a CDM/DG free "gross" forecast. This approach allows the projected impacts of CDM and DG to be treated explicitly over the forecast period.

Table 10 below shows the system-wide gross peak demand forecast presented above as well as the results for the "net" scenario we have named Scenario 1. This scenario is based on the extreme weather projection, but assumes current levels of DG and current approved CDM programs are continued. It should be noted that Scenario 1 also includes the on-going demand reductions projected to result from "historic" CDM programs operated prior to the forecast period. All of the projections of future CDM and DG impacts were provided to Navigant by THESL.

Table 10: System Wide Gross and Net Demand Forecasts for THESL

	Gross Demand			Net Demand
	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather	**Scenario 1** *Extreme Weather Existing DG Current CDM*
2012	4,815	4,830	5,433	5,047
2013	4,897	4,921	5,531	5,071
2014	4,980	5,012	5,630	5,057
2016	5,145	5,195	5,826	5,344
2018	5,246	5,314	5,942	5,457
2021	5,359	5,454	6,068	5,607
2031	5,739	5,932	6,493	5,832
2036	5,968	6,218	6,755	6,078

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

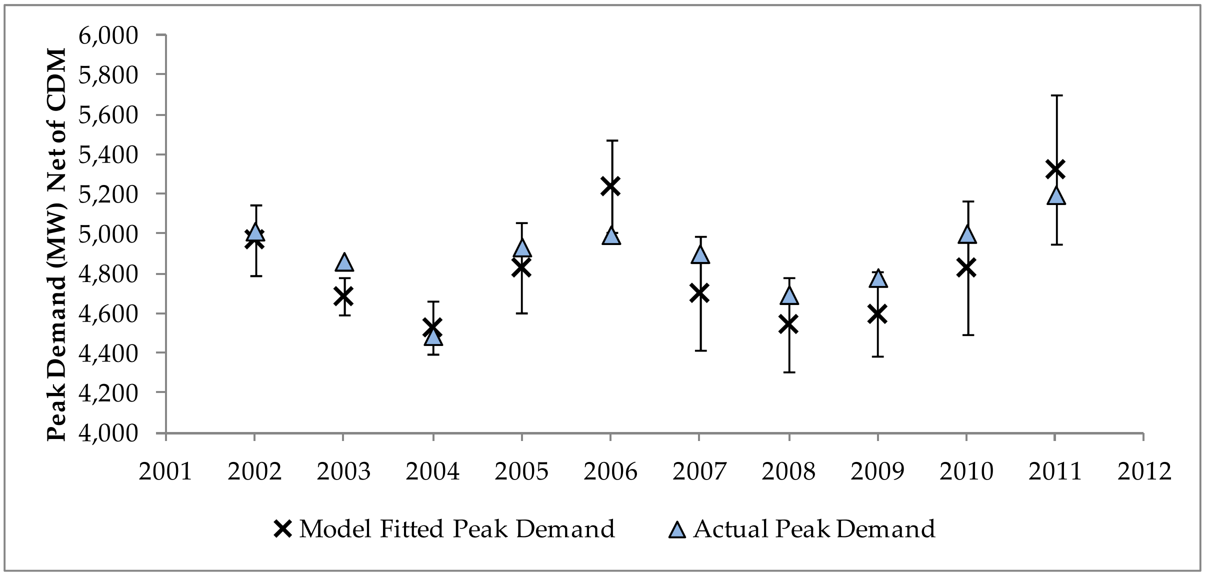
6. Summary of Results

Peak demand absent CDM was forecast based on the historic relationships between daily summer peak demand (absent the impacts of historic CDM) in the THESL system and: weather, levels of employment (in commercial and industrial sectors), population, the day of the week and the month of the year. These estimated relationships were then applied to three types of weather scenarios shown in Table 10. These weather scenarios were generated using the method outlined by the Independent Electricity System Operator (IESO) in its "Methodology to Perform Long Term Assessments" document[21] and through discussion between Navigant analysts and IESO staff.

The principal analytic tool used to generate the estimated forecast is a regression model that estimates the degree to which peak daily demand absent CDM is driven by a variety of economic, meteorological and other factors. This regression model was arrived at after a comparison of a number of possible model specifications and was subjected to a standard battery of statistical diagnostic tests to ensure its validity. These tests are all discussed in the body of this memorandum, below. One of the most important tests of model validity (certainly the most accessible for readers less familiar with econometrics) is simply to compare the model fitted values and the actual historical values. This comparison is made in Table 11, below.

[21] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

Table 11: Historic Peak Demand (Absent CDM) vs. Fitted Peak Demand (Absent CDM).



Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

The error bars shown in Table 11 represent the fitted values obtained using the upper and lower 95% confidence intervals for all of the estimated parameters, calculated using heteroskedasticity and autocorrelation consistent (HAC) standard errors.

Note that Navigant's point estimates of historic peak demand (absent CDM) all fall very close to the observed actual historic peak demand, absent the impacts of CDM[22]. In only one case does the historic value fall outside the 95% confidence interval, and even in that case it remains very close to the point estimate. Note too that Navigant's estimates do not always either over-estimate or under-estimate the true impact but fluctuate, sometimes higher and sometimes lower than the true peak demand. The average absolute deviation of Navigant's estimates from the true values shown in Table 11 is less than 3%.

Again, the resulting projection of "gross" and "net" peak demand for the THESL service territory are shown in the table below.

[22] Note that the relative position of the observations on this chart would not change were CDM to be included – both fitted and actual observations would simply shift downward by the same amount of peak demand attributable to CDM in a given year.

Table 12: System Wide Gross and Net Demand Forecasts for THESL

	Gross Demand			Net Demand
	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather	**Scenario 1** *Extreme Weather Existing DG Current CDM*
2012	4,815	4,830	5,433	5,047
2013	4,897	4,921	5,531	5,071
2014	4,980	5,012	5,630	5,057
2016	5,145	5,195	5,826	5,344
2018	5,246	5,314	5,942	5,457
2021	5,359	5,454	6,068	5,607
2031	5,739	5,932	6,493	5,832
2036	5,968	6,218	6,755	6,078

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

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Appendix C: Conservation and Demand Management and Distributed Generation Forecast

Appendix C: Conservation and Demand Management Forecast

C.1 Toronto Hydro-Electric System Limited ("THESL") Station CDM Forecast

Table C-1: THESL CDM Forecast by Station (MW) – High Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	4.3	4.4	4.1	3.7	3.7	4.1
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	7.4	7.5	7.1	6.3	6.3	7.0
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	10.7	10.8	10.2	9.1	9.1	10.1
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	10.1	10.1	9.6	8.5	8.6	9.5
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	9.3	9.3	8.8	7.9	7.9	8.7
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	9.9	10.0	9.4	8.4	8.4	9.3
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	13.3	13.4	12.7	11.3	11.3	12.5
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	12.7	12.8	12.1	10.8	10.8	12.0
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	24.1	24.2	22.9	20.5	20.5	22.6
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	5.6	5.7	5.4	4.8	4.8	5.3
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	7.9	8.0	7.6	6.7	6.7	7.5
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	11.0	11.1	10.5	9.3	9.3	10.3
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	16.7	16.8	15.9	14.2	14.2	15.7
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	7.2	7.2	6.8	6.1	6.1	6.7
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	15.0	15.1	14.2	12.7	12.7	14.1
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	6.9	6.9	6.5	5.8	5.8	6.5
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	16.1	16.2	15.3	13.7	13.7	15.2
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	43.2	43.5	41.1	36.7	36.7	40.6
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	4.0	4.1	3.8	3.4	3.4	3.8
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	17.8	17.9	16.9	15.1	15.1	16.7
Copeland (Bremner) TS	0	0	0	0	0	0	0	0	0
Total 115 kV Stations	**165**	**201**	**254**	**211**	**212**	**200**	**179**	**179**	**198**
Total 230 kV Stations	**33**	**41**	**51**	**43**	**43**	**41**	**36**	**36**	**40**
Area Total	**199**	**241**	**305**	**253**	**255**	**241**	**215**	**215**	**238**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a high demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

Table C-2: THESL CDM Forecast by Station (MW) – Low Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	6.5	7.1	8.0	10.1	12.9	13.6
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	12.2	13.6	15.4	19.7	24.7	25.6
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	12.7	13.4	13.8	14.4	16.8	18.1
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	15.4	17.1	19.2	24.4	30.7	31.9
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	14.4	16.2	18.6	24.1	30.4	31.9
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	12.7	13.5	14.0	15.6	18.1	19.1
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	16.2	17.1	17.6	19.2	22.3	23.8
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	19.9	22.5	26.0	34.6	45.1	47.3
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	29.0	30.4	31.2	33.4	38.0	40.4
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	7.0	7.5	8.0	11.7	14.6	15.3
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	9.8	10.4	10.8	12.0	14.1	14.9
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	14.8	15.8	16.7	19.1	21.9	23.1
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	21.2	22.5	23.7	26.8	31.7	33.3
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	8.6	9.0	9.2	9.7	11.3	12.3
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	20.2	21.6	23.0	26.7	32.7	34.3
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	8.9	9.4	9.7	10.8	12.5	13.2
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	21.6	23.5	25.6	30.5	37.3	38.9
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	53.8	58.0	62.4	72.0	87.3	92.7
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	5.6	6.0	6.4	7.4	8.8	9.2
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	30.4	35.1	42.3	58.2	76.5	79.3
Copeland (Bremner) TS	-	-	-	5.0	6.7	9.5	17.2	23.4	22.8
Total 115 kV Stations	**165**	**201**	**254**	**290**	**316**	**348**	**425**	**525**	**550**
Total 230 kV Stations	**33**	**41**	**51**	**56**	**60**	**63**	**73**	**86**	**91**
Area Total	**199**	**241**	**305**	**346**	**376**	**411**	**497**	**611**	**641**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a low demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, the assumed peak demand reductions associated with all future planned Conservation, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

Table C-3: THESL CDM Forecast by Station (MW) – Median Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	4.3	4.4	5.1	7.1	7.9	8.5
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	7.4	7.5	9.2	13.5	14.9	15.7
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	10.7	10.8	11.1	12.0	12.7	13.9
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	10.1	10.1	12.0	17.0	18.7	19.8
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	9.3	9.3	11.2	16.4	18.0	19.2
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	9.9	10.0	10.6	12.5	13.2	14.2
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	13.3	13.4	13.9	15.7	16.6	17.9
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	12.7	12.8	15.5	23.3	26.1	27.8
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	24.1	24.2	25.1	27.7	28.9	31.3
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	5.6	5.7	6.0	8.4	9.2	9.7
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	7.9	8.0	8.4	9.6	10.2	11.0
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	11.0	11.1	12.1	14.9	15.5	16.7
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	16.7	16.8	17.9	21.1	22.5	24.1
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	7.2	7.2	7.5	8.1	8.7	9.5
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	15.0	15.1	16.5	20.5	22.3	24.0
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	6.9	6.9	7.4	8.7	9.1	9.8
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	16.1	16.2	17.9	22.6	24.4	25.9
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	43.2	43.5	46.3	54.9	59.0	63.5
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	4.0	4.1	4.5	5.7	6.1	6.5
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	17.8	17.9	23.0	37.3	42.0	44.1
Copeland (Bremner) TS	-	-	-	-	-	2.3	8.8	10.3	10.0
Total 115 kV Stations	**165**	**201**	**254**	**211**	**212**	**237**	**309**	**336**	**358**
Total 230 kV Stations	**33**	**41**	**51**	**43**	**43**	**47**	**56**	**60**	**65**
Area Total	**199**	**241**	**305**	**253**	**255**	**284**	**366**	**396**	**423**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a median demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, half of the assumed peak demand reductions associated with all future planned Conservation, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

C.2 THESL Distributed Generation Forecast by Station

Table C-4: THESL DG Forecast by Station (MW)

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
BRIDGMAN (115KV/13.8KV) TS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CARLAW (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CECIL (115KV/13.8KV) TS	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
CHARLES (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
DUFFERIN (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DUPLEX (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
ESPLANADE (115KV/13.8KV) TS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
FAIRBANK (115KV/27.6KV) TS	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
GERRARD (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
GLENGROVE (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
HORNER (230KV/27.6KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LEASIDE (230KV/27.6 - 13.8KV) TS	-	-	-	-	-	-	-	-	-
MAIN (115KV/13.8KV) TS	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
MANBY (230KV/27.6KV) TS	-	-	-	-	-	-	-	-	-
RUNNYMEDE (115KV/27.6KV) TS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
STRACHAN (115KV/13.8KV) TS	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
TERAULEY (115KV/13.8KV) TS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
WILTSHIRE (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
WINDSOR (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**

Note: Windsor TS is also referred to as “John TS”

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Appendix D: Detailed Load Forecast and Forecast Scenarios

Appendix D: Demand Forecast Scenarios

D.1 High Demand Forecast Scenario

High Demand Scenario (The THESL Station Forecast includes conservation program savings to 2015, codes and standards changes, and persistence of pre-2015 program savings thereafter).

Table D-1: THESL High Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	72	74	77	81	87	92
BRIDGMAN (115KV/13.8KV) TS	155	157	158	164	167	170	173	178	184
CARLAW (115KV/13.8KV) TS	67	67	65	71	74	78	74	82	88
CECIL (115KV/13.8KV) TS	157	157	157	164	166	171	177	185	192
CHARLES (115KV/13.8KV) TS	127	127	127	132	136	139	145	149	157
DUFFERIN (115KV/13.8KV) TS	122	123	122	128	132	133	137	141	145
DUPLEX (115KV/13.8KV) TS	103	103	103	110	113	116	121	128	133
ESPLANADE (115KV/13.8KV) TS	173	174	174	171	177	184	197	210	222
FAIRBANK (115KV/27.6KV) TS	184	184	182	196	199	203	209	215	220
GERRARD (115KV/13.8KV) TS	26	25	25	27	28	30	51	54	56
GLENGROVE (115KV/13.8KV) TS	60	60	59	64	66	68	71	75	77
HORNER (230KV/27.6KV) TS	140	167	167	175	178	182	188	184	190
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	164	168	175	183	191	196
MAIN (115KV/13.8KV) TS	71	71	71	61	63	67	66	74	80
MANBY (230KV/27.6KV) TS	231	207	208	220	225	231	240	260	269
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	91	93	94	97	100	102
STRACHAN (115KV/13.8KV) TS	133	131	129	138	141	146	151	158	162
TERAULEY (115KV/13.8KV) TS	183	178	170	184	190	202	210	223	234
WILTSHIRE (115KV/13.8KV) TS	70	70	70	74	75	77	77	80	82
WINDSOR (115KV/13.8KV) TS	311	314	253	238	244	256	268	281	293
Copeland (Bremner) TS	0	0	63	102	102	102	113	113	113
Total 115 kV Stations	**2080**	**2081**	**2068**	**2187**	**2240**	**2313**	**2418**	**2533**	**2632**
Total 230 kV Stations	**523**	**527**	**528**	**559**	**571**	**588**	**611**	**635**	**655**
Area Total	**2603**	**2608**	**2596**	**2746**	**2811**	**2901**	**3029**	**3168**	**3287**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.

Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.

Windsor TS is also referred to as "John TS"

D.2 Low Demand Forecast Scenario

Low Demand Forecast Scenario (includes conservation savings in the High Demand Scenario, and assumed peak demand savings resulting from the Province's commitment to long-term savings achievement under the Long Term Energy Plan).

Table D-2: THESL Low Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	70	71	73	75	78	83
BRIDGMAN (115KV/13.8KV) TS	155	157	158	159	161	162	160	160	165
CARLAW (115KV/13.8KV) TS	67	67	65	69	71	74	69	74	80
CECIL (115KV/13.8KV) TS	157	157	157	159	159	161	161	163	170
CHARLES (115KV/13.8KV) TS	127	127	127	127	129	129	129	126	134
DUFFERIN (115KV/13.8KV) TS	122	123	122	125	128	128	130	131	135
DUPLEX (115KV/13.8KV) TS	103	103	103	107	109	111	113	117	122
ESPLANADE (115KV/13.8KV) TS	173	174	174	164	167	170	173	176	187
FAIRBANK (115KV/27.6KV) TS	184	184	182	191	193	195	196	197	202
GERRARD (115KV/13.8KV) TS	26	25	25	26	26	27	44	44	46
GLENGROVE (115KV/13.8KV) TS	60	60	59	62	64	65	66	68	70
HORNER (230KV/27.6KV) TS	140	167	167	171	173	176	178	171	177
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	160	162	167	170	174	178
MAIN (115KV/13.8KV) TS	71	71	71	60	61	65	62	69	74
MANBY (230KV/27.6KV) TS	231	207	208	215	218	222	226	240	249
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	89	91	91	92	93	95
STRACHAN (115KV/13.8KV) TS	133	131	129	133	134	136	134	134	138
TERAULEY (115KV/13.8KV) TS	183	178	170	173	175	181	175	172	182
WILTSHIRE (115KV/13.8KV) TS	70	70	70	72	73	74	73	75	77
WINDSOR (115KV/13.8KV) TS	311	314	253	226	227	231	225	220	230
Copeland (Bremner) TS	0	0	63	97	95	93	96	90	90
Total 115 kV Stations	**2080**	**2081**	**2068**	**2108**	**2136**	**2166**	**2172**	**2187**	**2280**
Total 230 kV Stations	**523**	**527**	**528**	**546**	**554**	**565**	**575**	**585**	**604**
Area Total	**2603**	**2608**	**2596**	**2654**	**2690**	**2731**	**2747**	**2772**	**2884**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.
Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.
Windsor TS is also referred to as "John TS"

D.3 Median Demand Forecast Scenario

Median Demand Forecast Scenario (includes conservation savings in the High Demand Scenario, and half of the assumed peak demand savings resulting from the Province's commitment to long-term savings achievement under the Long Term Energy Plan).

Table D-3: THESL Median Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	72	74	76	78	83	88
BRIDGMAN (115KV/13.8KV) TS	155	157	158	164	167	168	166	169	175
CARLAW (115KV/13.8KV) TS	67	67	65	71	74	77	71	78	84
CECIL (115KV/13.8KV) TS	157	157	157	164	166	169	169	175	182
CHARLES (115KV/13.8KV) TS	127	127	127	132	136	137	136	139	147
DUFFERIN (115KV/13.8KV) TS	122	123	122	128	132	132	133	136	140
DUPLEX (115KV/13.8KV) TS	103	103	103	110	113	115	117	123	128
ESPLANADE (115KV/13.8KV) TS	173	174	174	171	177	181	185	195	206
FAIRBANK (115KV/27.6KV) TS	184	184	182	196	199	201	202	207	211
GERRARD (115KV/13.8KV) TS	26	25	25	27	28	29	47	50	52
GLENGROVE (115KV/13.8KV) TS	60	60	59	64	66	67	68	72	73
HORNER (230KV/27.6KV) TS	140	167	167	175	178	180	182	178	184
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	164	168	173	176	183	188
MAIN (115KV/13.8KV) TS	71	71	71	61	63	66	64	71	77
MANBY (230KV/27.6KV) TS	231	207	208	220	225	229	232	250	259
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	91	93	93	94	97	99
STRACHAN (115KV/13.8KV) TS	133	131	129	138	141	143	142	147	151
TERAULEY (115KV/13.8KV) TS	183	178	170	184	190	197	192	201	211
WILTSHIRE (115KV/13.8KV) TS	70	70	70	74	75	76	75	77	79
WINDSOR (115KV/13.8KV) TS	311	314	253	238	244	250	246	254	266
Copeland (Bremner) TS	0	0	63	102	102	100	104	103	103
Total 115 kV Stations	**2080**	**2081**	**2068**	**2187**	**2240**	**2276**	**2288**	**2376**	**2472**
Total 230 kV Stations	**523**	**527**	**528**	**559**	**571**	**582**	**591**	**611**	**630**
Area Total	**2603**	**2608**	**2596**	**2746**	**2811**	**2858**	**2878**	**2987**	**3102**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.
Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.
Windsor TS is also referred to as "John TS"

Metro Toronto – Central IRRP

Appendix E: Technical Results – Deterministic and Probabilistic Assessments

Appendix E: Technical Assessment Results

The following tables present the detailed technical results of the assessments completed for the Central Toronto Integrated Regional Resource Plan.

Electrical system needs were assessed through tests defined in the IESO document Ontario Resource and Transmission Assessment Criteria ("ORTAC"), which establishes the planning criteria and assumptions to be used for assessing the adequacy and security of Ontario's electricity system.

In accordance with the ORTAC, the transmission system must be able to provide continuous supply following defined transmission and generation outage scenarios, as well as limit the amount of load loss and restoration time following the occurrence of multiple element outages. The defined outage scenarios are referred to as "contingencies." These contingency-based tests are deterministic in that they are assessed independent of the probability of their occurrence.

In addition to the ORTAC defined tests, a supplemental Probabilistic Reliability Assessment ("PRA") was conducted to test higher-order contingencies beyond those specified in the ORTAC.

All system tests were performed assuming summertime peak demand conditions under various load forecast scenarios that accounted for City of Toronto growth projections and different levels of achievement of CDM, including efficiency programs, pricing, building codes and efficiency standards.

The assessments were conducted using the software based modeling tool *Power System Simulator for Engineering* ("PSS®E") for deterministic AC contingency analysis. The PRA within PSS®E was used to estimate the risk related to higher-order contingencies up to the simultaneous loss of up to three system elements.

For the contingency-based tests, instances of criteria violations are shaded in Red. Other assessment results which have been highlighted, but that do not represent criteria violations, are shaded in Yellow.

Table E-1: Pre-contingency Conditions: All Transmission Elements In-service and Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby H1H4	Manby T1	N/A	2013	2013	2013	Load Curtailment	105 MW	Manby West 115 kV	118.7% 15-min LTR	*Short-term Emergency ratings ("STE")*	*Operational measures as solution for STE violation*
Manby A1H4	Manby T2	N/A	2013	2013	2013	Load Curtailment	95 MW	Manby West 115 kV	138.7% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
Manby H2H3	Manby T9	N/A	2013	2013	2013	Open Disconnects and restore unfaulted element(s)	N/A	Manby East 115 kV	91.7% 15-min LTR	*Flag Only: Does not violate Criteria*	
R15K	R2K	Richview x Manby	2018	2018	2026	N/A	N/A	N/A		*Long-term Emergency ratings ("LTE")*	
Manby H2H3	Manby T9	N/A	2018	2018	2036	Open Disconnects and restore unfaulted element(s)	N/A	Manby East 115 kV	100.7% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
C16L/C17L	Leaside T15	N/A	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	73.4% 30-min LTR	*Flag Only: Does not violate Criteria*	
H9EJ	H2JK	Don Fleet x Esplanade	2026	2036	Beyond 2036	None	N/A	N/A	97.2% Loading in 2021	*LTE*	*Mitigated through load transfers*
H2JK	K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	99.3% Loading in 2026	*LTE*	
H2JK	K14J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	99.3% Loading in 2026	*LTE*	
H2JK	K6J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.6% Loading in 2026	*LTE*	
K6J	K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.8% Loading in 2026	*LTE*	
K6J	K14J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.8% Loading in 2026	*LTE*	
K6J	H2JK	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.3% Loading in 2026	*LTE*	
Manby T1	Manby T12	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.0% Loading in 2026	*LTE*	
Manby T2	Manby T12	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	96.8% Loading in 2026	*LTE*	
C5E	H9EJ	Hearn x Esplanade	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	92.7% Loading in 2026	*LTE*	
K13J	K14J	Manby x Riverside	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	97.7% Loading in 2031	*LTE*	
K14J	K13J	Manby x Riverside	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	97.7% Loading in 2031	*LTE*	
H10EJ	H2JK	Don Fleet x Esplanade	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	99.6% Loading in 2031	*LTE*	

Table E-2: Pre-contingency Conditions: All Transmission Elements In-service and Steam Turbine Generator Outage at Portlands Energy Centre (@ 160 MW), Dufferin TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
C16L/C17L	Leaside T15	N/A	2013	2013	2013	Load Curtailment	110 MW	Leaside 115 kV	80.6% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	H3L	Gerrard x Basin	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	50.5% 15-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	H1L	Gerrard x Basin	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	53.9% 15-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C2L/C3L	Leaside T14	N/A	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	72.5% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C14L/C15L	Leaside T16	N/A	2018	2018	2018	Load Curtailment Initiated	0 MW	Leaside 115 kV	71.6% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
None	Leaside T15	N/A	2026	2036	Beyond 2036	None	N/A	N/A	98.5 % Loading in 2021	*Continuous equipment ratings*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	Voltage Instability	Leaside 115 kV	2018+	2021	2031	None	N/A	N/A	N/A	*Voltage Criteria*	

Notes:
*Flagged Items are only changes to "All Elements In-service Precontingency and PEC @ 550 MW"
*No Flags beyond pre-contingency violation

Table E-3: Pre-contingency Conditions: All Transmission Elements In-service and Steam Turbine Generator Outage at Portlands Energy Centre (@ 160 MW), Dufferin TS on Manby Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby H2H3	Manby T9	N/A	2013	2013	2013	Load Curtailment	160 MW	Manby East 115 kV	133.5% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
C16L/C17L	Leaside T15	N/A	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	75.3% 30-min LTR	*Flag Only: Does not violate Criteria*	
K12W	K11W	Manby x Runnymede	2016	2016	2016	Load Curtailment Initiated	0 MW	Runnymede TS	81.4% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K11W	K12W	Manby x Runnymede	2016	2016	2016	Load Curtailment Initiated	0 MW	Runnymede TS	81.4% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K11W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.2% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K12W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.2% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K3W	Manby x St. Clair	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.7% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K11W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.1% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K12W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.1% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K1W	Manby x St. Clair	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.7% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
C14L/C15L	Leaside T16	N/A	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	71.2% 30-min LTR	*Flag Only: Does not violate Criteria*	
None	Leaside T15	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	93.2% Loading in 2026	*Continuous ratings*	
C16L/C17L	Voltage Instability	Leaside 115 kV	2026+	2031	Beyond 2036	None	N/A	N/A	N/A	*Voltage Criteria*	

Table E-4: Pre-contingency Conditions: Manby Transformer T1 Out-of-service Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T2	Manby T12	N/A	2013	2013	2013	Load Curtailment	155 MW	Manby West 115 kV	140.5% 15-min LTR	*STE and Load loss*	*Can be mitigated by transferring loads*

Table E-5: Pre-contingency Conditions: Manby Transformer T1 Out-of-service , Portlands Energy Centre In-service (@ 550 MW), Copeland TS and half of Strachan TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T2	Manby T12	N/A	2013	2013	2013	Load Curtailment	105 MW	Manby West 115 kV	125.5% 15-min LTR	*STE*	*Load transfer once Copeland TS in-service*
Manby T2	Manby T12	N/A	2016	2016	2031	Load Curtailment	25 MW	Manby West 115 kV	92.7% 15-min LTR	*Flag Only: Does not violate Criteria*	
Manby T2	Manby T12	N/A	2021	2031	Beyond 2036	Load Curtailment	45 MW	Manby West 115 kV	101.2% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
Manby T2	Manby T12	N/A	2036	Beyond 2036	Beyond 2036	Load Curtailment	90 MW	Manby West 115 kV	141.9% 15-min LTR	*STE*	*Operational measures would satisfy ORTAC beyond study period*

Table E-6: Pre-contingency Conditions: Manby Transformer T1 Out-of-service , Portlands Energy Centre In-service (@ 550 MW), John TS and Copeland TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
H10EJ	H9EJ	Hearn x Esplanade	2013	2013	2013	Load Curtailment	80 MW	John TS	94.6% 15-min LTR	*Flag Only: Does not violate Criteria*	
H10EJ	H9EJ	Hearn x Esplanade	2018	2018	Beyond 2036	Load Curtailment	120 MW	John TS	103.6% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
H10EJ	H9EJ	Hearn x Esplanade	2021	2031	Beyond 2036	Load Curtailment	150 MW	John TS	108.0% 15-min LTR	*STE and Load Loss*	

Table E-7: Pre-contingency Conditions: Leaside Transformer T14 Out-of-service and Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
C16L/C17L	Leaside T15	N/A	2021	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	73.7% 30-min LTR	*Flag Only: Does not violate Criteria*	

Note: This scenario was determined to be far less limiting than considering PEC outages and was not pursued further for establishing needs

Table E-8: Pre-contingency Conditions: Manby Transformer T8 Out-of-service, Portlands Energy Centre In-service (@ 550 MW), Wiltshire TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T9	Manby T7	N/A	2013	2013	2013	Load Curtailment Initiated	0 MW	Manby East 115 kV	73.3% 15-min LTR	*Flag Only: Does not violate Criteria*	
Manby T9	Manby T7	N/A	2036	Beyond 2036	Beyond 2036	Load Curtailment	55 MW	Manby East 115 kV	91.9% 15-min LTR	*Flag Only: Does not violate Criteria*	

Table E-9: Additional Pre-contingency Outage Conditions Assessed with Portlands Energy Centre In-service (@ 550 MW)

Pre-contingency Outage	System Adjustment	Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
					High	Median	Low				1) Loading	2) Violation	3) Mitigation
L14W	Open breaker T11YH*	LxW (new)	L15W	Bayview x Bridgman	2013	2013	2013	None	47 MW	Bridgman (Conf)	83.7% 50-hr LTR	*Flag Only: Requires System Adjustment*	
L14W	Open breaker T11YH*	LxW (new)	L15W	Bayview x Bridgman	2036	Beyond 2036	Beyond 2036	Load Curtailment	55 + 10 MW	Bridgman (Conf)+further L/R	73.3% of 15-min LTR	*Flag Only: Requires System Adjustment + Control Action*	*Could open T12XH as well to drop load automatically following the second contingency*
L13W or L14W	None	L14W or L13W	L15W	Bayview x Bridgman	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Bridgman	92.4% of 15-min LTR	*Flag Only: Requires Control Action*	
L9C or L12C	None	L12C or L9C	L4C	Leaside x Charles	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Bridgman	84.3% 15-min LTR	*Flag Only: Requires Control Action*	
K1W or K3W	None	K11W or K12W	K1W or K3W	Manby x St Clair	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	80.2% 15-min LTR	*Flag Only: Requires Control Action*	
K6J or H2JK	Transfer Bremner to Leaside.	K13J or K14J**	K14J or K13J	Manby x Riverside	2018	2018	Beyond 2036	Load Curtailment Initiated	0 MW	Manby West 115 kV	84.5% 15-min LTR	*Flag Only: Requires System Adjustment + Control Action*	
K6J or H2JK	Transfer Bremner to Leaside.	K13J or K14J**	K14J or K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	Load Curtailment	55 MW	Manby West 115 kV	101.0% 15-min LTR	*STE*	*Below 150 MW Operational measures as solution*

Notes:
*This system adjustment is required to allow load to be lost by configuration post-contingency.
**This scenarios was most limiting for Manby West 1+1 because Strachan is not able to be transferred to Leaside supply. Note - this state is more limited by N-1.

Application of Bulk Electric System Criteria

Table E-10: All Elements In-service Pre-contingency and PEC @ 550 MW

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
H9EJ/H10EJ	H2JK	Don Fleet x Esplanade	2013	2013	2013	Load Curtailment	15 MW	Esplanade TS	55.9% 15-min LTR	*Flag Only: Does not violate criteria*	
Leaside L14L15	Bridgman HL12 HL78 + Bridgman T13	ΔV post-ULTC = 0.11 & 0.13 p.u. (Criteria = 0.05p.u.) + Bridgman T13	2013	2013	2013	Load Curtailment	35 MW	Bridgman TS	121.5% 15-min LTR	*Voltage Criteria, STE*	*Trip Breaker T13XH or T13YH to shed 50% load. Open Breaker Disconnect Switches to restore unfaulted element and restore load*
H6LC/H9EJ	H8LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	66.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
H6LC/H10EJ	H8LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	62.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
H8LC/H10EJ	H6LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	62.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
Cecil L8L12	H6LC	Cecil x Gerrard	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	64.1% 15-min LTR	*Flag Only: Does not violate Criteria*	

Probabilistic Reliability Assessment Results (PRA)

- 65% Load Factor assumed at all busses
- 100 hours per year at peak loading conditions (when system is most at risk to post-contingency load shedding)
- Value of Lost Load (Value of Customer Reliability) assumed at $30 per kWh not supplied
- Probabilistic Input Data:
    - 115 kV circuits:
        - frequency of outages: 0.036 occurrences per km per year
        - average duration of outages: 1760 minutes per occurrence
    - 230 kV circuits:
        - frequency of outages: 0.018 occurrences per km per year
        - average duration of outages: 1275 minutes per occurrence
    - Step Down transformers (115 kV/13.8/27.6 kV):
        - frequency of outages: 0.36 occurrences per year
        - average duration of outages: 3735 minutes per occurrence
    - Autotransformers (230 kV/115 kV):
        - frequency of outages: 0.14 occurrences per year
        - average duration of outages: 3180 minutes per occurrence
- Shedding load is assumed to occur only following the contingency (not in preparation for the contingency)
- Shedding load is the only measure assumed to be available to relieve overloads
- System adjustments are not made to outage states as a mitigation measure
- Load is not restored until (coincident) outages are resolved
- Annualized Transmission Costs for the monetary estimates represent 7% of Capital Investment

PRA Summary Results

System Total Monetized Risk Over The Study Period (All values expressed in $millions)	
Total Capital Risk	83.5
Annual Average	5.85

SUB-SYSTEM BREAKDOWN

Leaside West		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.31**	**0.00**
Capital Risk (M$)	**18.72**	**0.01**
Leaside East		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**0.93**	**0.00**
Capital Risk (M$)	**13.33**	**0.00**
Leaside Radial - Bridgman, Dufferin, Duplex, Glengrove		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**0.91**	**0.00**
Capital Risk (M$)	**12.95**	**0.01**
Manby West		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.06**	**0.40**
Capital Risk (M$)	**15.16**	**5.69**
Manby East		
Buses	**Expected Energy Lost by Configuration**	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.02**	**0.22**
Capital Risk (M$)	**14.54**	**3.11**

PRA Detailed Station-by-Station Results

Leaside West		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, (MWh/a)**	**Expected Energy Lost by Shedding Evaluated At Peak, (MWh/a)**
Charles A1A2	3.67	0
Charels A3A4	3.78	0
Charles A5A6	4.97	0
Charles A7A8	4.02	0
Terauley A12	5.35	0
Terauley A34	4.83	0
Terauley A56	6.13	0.02
Terauley A78	4.6	0
Cecil A12	1.72	0
Cecil A34	1.9	0
Cecil A56	3.08	0
Cecil A78	3.44	0
Esplanade J12	7.28	0.00
Esplanade Q12	7.28	2.21
Esplanade A12	5.15	0.00
Total	67.2	2.23
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.3104	0.000763699
Capital Risk (M$)	**18.72**	**0.01**

Leaside East		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
Basin A56	8.07	0
Basin A78	7.46	0
Carlaw A1A2	7.86	0
Carlaw A4A5	5.65	0
Carlaw A6A7	2.22	0
Gerrard A1A2	6.05	0
Main A1A2	5.98	0
Main A3A4	4.56	0
Total	47.85	0
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	0.933075	0
Capital Risk (M$)	**13.33**	**0.00**

Leaside Radial - Bridgman, Dufferin, Duplex, Glengrove		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
Bridgman A12	5.14	0.01
Bridgman HL12	0.03	0.51
Bridgman HL56	1.77	0
Bridgman HL78	0.01	1.09
Dufferin A12	5.31	0.28
Dufferin A34	3.54	0.1
Dufferin A56	6.35	0.37
Dufferin A78	4.43	0.12
Duplex A1A2	3.37	0
Duplex A3A4	3.01	0
Duplex A5A6	4.19	0
Glengrove 12	2.37	0
Glengrove 34	3.17	0
Glengrove 56	3.79	0
Total	46.48	2.48
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	0.90636	0.000849315
Capital Risk (M$)	**12.95**	**0.01**

Manby West		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
John AB	3.29	166.48
John B1	3.29	164.6
John A1112	1.54	0
John A13	2.07	1.52
John A1516	2.49	164.22
John A1718	2.49	154.56
Strachan A12	9.62	3.16
Strachan A34	7.39	0
Strachan A56	7.83	0.02
Strachan A78	7.83	0.02
Bremner A	4.06	342.38
Bremner B	2.51	166.38
Total	54.41	1163.34
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.060995	0.39840411
Capital Risk (M$)	**15.16**	**5.69**

Manby East		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
WILTSHIR_A12	1.85	0
WILTSHIR_A34	2.02	0
WILTSHIR_A56	2.89	0
Fairbank BQ	16.63	0.41
Fairbank YZ	17.47	635.09
Runnymede	11.34	0.29
Total	52.2	635.79
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.0179	0.217736301
Capital Risk (M$)	**14.54**	**3.11**

Metro Toronto – Central IRRP

Appendix F: Review of Power System Reliability Standards in Major Metropolitan Areas

Appendix F: Review of Power System Reliability Standard for Major Metropolitan Areas

F.1 Introduction and Background

In recognition of the potential high consequences of electricity service interruptions in high density urban areas, the IESO undertook a review of power system planning standards used by utilities in other jurisdictions, to determine if special consideration was given to supply standards in these areas.

The review focused specifically on:

a. whether other jurisdictions apply higher standards in high density urban areas, as compared to the rest of the electricity system, and
b. where higher standards are applied in these urban areas, how is the higher standard achieved?

The purpose of this review was to:

- Identify if planning to achieve higher levels of electricity service reliability is a common utility practice for densely populated urban areas within other jurisdictions, and
- Inform the Central Toronto Integrated Regional Resource Plan ("IRRP") assessments of needs and options.

Early discussions of the Central Toronto IRRP Working Group were focused on determining whether there are reasonable grounds for adopting higher reliability standards for the Central Toronto area. Within the context of a regional planning study, higher reliability standards would require applying power system planning criteria which are more stringent than those typically used in Ontario. Since the Central Toronto area is an economic centre with high density commercial and residential development, government and institutional customers, a review of electricity industry practices used in by utilities in other high density urban areas was considered a prudent course of action in supporting the IRRP analysis.

In Ontario, the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") specifies the specific contingencies to be applied in planning studies for the power system. Sections 2 through 7 of ORTAC provide details on the types of technical studies which must be carried out to assess the adequacy of the grid and to ensure reliability of the electric system.

ORTAC also addresses load security and restoration capability of the system. It should be noted that the power system serving the Central Toronto area is composed of both Bulk Power System facilities (as described in Section 2.7.1 of ORTAC) and Local Area facilities (as described in Section 2.7.2 of ORTAC). In general, Bulk Power needs are determined based on the occurrence of double element contingencies, whereas Local Area needs are typically assessed under single element contingencies. This higher standard for the Bulk Power system is in part related to the greater system-wide consequences and the need to avoid impacts on neighbouring jurisdictions.[1]

The sections that follow present a summary of findings of the review of other jurisdictions, and the resulting considerations for the Central Toronto IRRP assessment.

F.2 Summary of Reliability Planning Standards for Urban Areas

The IESO reviewed several utility industry professional papers and published reliability standards associated with planning practices used by utilities in other regulatory jurisdictions around the world. The focus of this review was to establish the extent to which other utilities plan to higher reliability standards in metropolitan areas. Specific details on planning standards and/or practices for urban areas were not found for many jurisdictions.

Some jurisdictions were found to give explicit consideration to planning for higher reliability in the Central Business Districts ("CBD") than in other parts of their electric power systems. Across the literature, high density urban areas are commonly referred to as the "Central Business District," and they are typically a part of larger metropolitan area. A small number of examples were also found for electricity infrastructure projects that obtained regulatory approval based on the rationale of providing better service to customers in urban areas.

Finding 1: Some jurisdictions conduct planning to meet higher reliability standards in large urban areas; however, the majority of jurisdictions reviewed do not

A survey completed by Cigré[2] entitled Maintenance of Acceptable Reliability in an Uncertain Environment (2007) reported that 36% of respondents indicated that the reliability standards

[1] Due to security concerns, in recent years many jurisdictions have not published specific technical information related to the makeup of their electric power systems.
[2]International Council on Large Electric Systems (Cigré) is an international not for profit association for promoting collaboration with a network of 3,500 electricity experts working to improve electric power systems of today and tomorrow.

were higher for CBDs in urban areas than for the rest of the system. The following table summarizes the responses.

Country	Central Business District (CBD)	Responded that CBD planned to higher reliability than rest of system?
France	Paris	Yes
USA	unspecified	Yes
Japan	Osaka, Kyoto, Tokyo	Yes
Portugal	Lisbon	Yes
Canada	Ottawa	No
Hungary	unspecified	No
Russia	Moscow	No
Northern Ireland	unspecified	No
South Africa	Pretoria	No
Belgium	unspecified	No
Switzerland	unspecified	No

In addition to the nations surveyed for the Cigré report, a small number of other jurisdictions have given consideration to planning for higher levels of reliability service in urban areas. In New York City, for example, Consolidated Edision specifically plans for better reliability in the inner urban areas, such as for transmission load areas in lower Manhattan and surrounding boroughs. This is accomplished by designating the transmission load areas that are planned to a double contingency standard as opposed to a single contingency standard. This practice is intended to reflect the sensitivity and density of customers in these areas.

In Canada, no jurisdictions have been found that plan for higher load security in CBDs than in other areas. An exception to this rule is a project that was developed in downtown Vancouver (Cathedral Square Substation), which was cost justified based on the risk of extended electricity service disruption within the urban area. This project is discussed in the next section.

Additional notes on planning standards applied in other jurisdictions are provided in Table F-1. While some jurisdictions explicitly define higher standards in CBDs, the evidence indicates that this is not a common utility practice.

Finding 2: Jurisdictions that plan for higher reliability in urban areas do not typically rely solely on deterministic reliability criteria; rather, probabilistic assessments are used to compare the economic costs and benefits

Several Australian jurisdictions also plan for better load security in CBDs. This is typically done through a combination of deterministic and probabilistic approaches. In the State of Victoria, this planning practice is based primarily on probabilistic economic analyses. This process is described in greater detail by the Australian Energy Regulator:

> "There are no pre-determined reliability criteria for planning done on an economic basis. In these cases the economic costs and benefits are assessed and an investment only proceeds if the benefits outweigh the costs. Victoria currently uses this approach. The Value of Customer Reliability metric[3] ("VCR") is therefore critical to this planning approach, since the estimated value of a reliability improvement is pitted directly against its cost to determine whether or not an augmentation will be carried out. Victoria is the only jurisdiction undertaking purely economic assessment of transmission investments. Victoria does not rely on deterministic standards for transmission investments that are primarily intended to deliver reliability outcomes. Therefore Victoria has the greatest reliance on an accurate regional estimate of VCR. Arguably it already has existing estimates that meet this criterion (see CRA, 2002 and 2008)."[4]

An example project that was assessed on this probabilistic basis is the Regional Victorian Thermal Capacity Upgrade.[5] The consequence of the "do nothing" scenario was initially calculated by considering the amount of energy which would have to be rejected to meet thermal limits over the course of a year, which was monetized using the VCR metric. This cost increased each year, commensurate with the affected area's demand forecast. A detailed assessment was carried out on all credible options, including a Net Present Value analysis to determine net market benefit under different sensitivity scenarios. The final recommendation included a new and upgraded circuit. The new circuit was approved, and the second upgraded circuit was placed on hold pending further assessment.

[3] $61,960/MWh in 2013-14 $AUS
[4] http://www.aemo.com.au/planning/0400-0032.pdf
[5] http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Regional-Victorian-Thermal-Capacity-Upgrade

In the City of Vancouver, the rationale used to justify the business case for the Cathedral Square substation, which supplies about one-third of downtown Vancouver's load, was based on an economic evaluation of the incremental reliability benefits to affected customers.[6] The original transformer station consisted of two parallel transformers in an underground facility. Studies indicated that following the outage of one transformer, the remaining unit could still supply the area. However the loss of both would interrupt supply until one could be repaired or replaced. Given the age and configuration of this station, the repair/replacement time was estimated at up to 2 years, depending on the type of failure. Since deterministic planning did not require consideration of a contingency this severe, probabilistic planning was applied, given the potential consequences to customers.

Based on the probabilistic analysis, BC Hydro determined it to be cost effective from a societal perspective to invest in a third transformer, thereby reducing the probability of simultaneous loss of all transformers. The British Columbia Utilities Commission approved the expenditure and the probabilistic analysis was integral to the business case submitted to the regulator.

As mentioned earlier, the deterministic standards typically used by BC Hydro were supplemented by using probabilistic planning to support rationale for expansion of the Cathedral Square Substation.

Finding 3: Jurisdictions that plan for higher reliability in urban areas tend to plan transmission and distribution systems in a highly coordinated fashion

In the Cigré study, all of the jurisdictions that planned for higher reliability for CBDs, and several that did not, indicated that the transmission standards for CBDs are coordinated with those for distribution systems to achieve better overall system performance. The responses indicated that coordination of transmission and distribution system development results in better overall system reliability.

Of the countries that indicated CBD standards were higher than for the rest of the system, France explained that planning to an N-2 security standard is specific to Paris, and that in case of loss of supply to any "C-type" substation (225kV/20kV step-down station), while the nearest one is under maintenance, the system has been designed so that the whole load of both substations can be supplied via the distribution network. This level of security is made possible

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

only by distribution ties between step-down stations. The distribution network between transmission stations provides security of supply for any substation from the nearest one. This N-2 security standard is quite specific to Paris. Further, like in most jurisdictions, it is recognized that some load will be lost in the event of multiple element contingencies. In Paris, 40% of the lost load must be restored within 30 minutes after the N-2 incident.

Finding 4: Planning entities rely on a range of options to achieve higher reliability service levels in urban areas

In the Cigré study, 55% of respondents indicated that Special Protection Systems ("SPS") are a part of normal system planning. This indicates that it is generally good utility practice to implement SPSs designed to take corrective action in the event of low probability system contingencies. Schemes of this nature minimize the risk to customers and represent a cost effective alternative to additional infrastructure. SPSs can be implemented quickly and are generally much more cost effective than infrastructure for addressing the impact of contingencies that have a low probability of occurrence.

Other jurisdictions have policies to target location of generation resources in close proximity to, or within, major urban centres. An example is New York City, where an internal generation of 80% of the load is targeted.

Finding 5: It is generally cost prohibitive to achieve load security to ensure full redundancy to withstand a double element contingency without load loss

Where higher standards have been applied, such as N-2 security (e.g., two power system elements out of service simultaneously), the rationale typically employs an economic cost – benefit component. This is accomplished by establishing the incremental cost of investments to achieve better reliability, and comparing these costs to the economic benefit of the change from the status quo. This recognizes that (a) modern power systems planned to N-1 security provide generally high levels of reliability, (b) achieving full N-2 security would come at a very high cost, and (c) 100% reliability is unachievable at any cost. Since the likelihood of N-2 contingencies occurring is low, probabilistic planning methods and value to customer concepts are used to rationalize expenditures which cover these contingencies.

Typical planning studies considering higher reliability levels for specific areas are based on the consideration of a greater number of contingencies than are required to be assessed in other areas served by the utility. Since these additional contingencies (for example, N-2) tend to have a much lower probability of occurring, planning techniques which account for the probability of occurrence (probabilistic methods) are used in addition to the more traditional deterministic studies. The document *TransGrid FINAL REPORT - Review of the MetroGrid Project: Context and Conceptual Design,* (2004) provides a good example of the concept of Cost / Benefit Analysis and network reliability standards within the electric utility industry. The report identifies steps that a prudent operator would have completed in applying a network reliability standard in the Sydney inner metropolitan area. In this report, a prudent operator would have:

- monitored compliance with existing standards;
- assessed the implications (economic and otherwise) of a loss of supply;
- reviewed existing network reliability standards against the above, mindful of international practice;
- if appropriate, recommended and implemented an increase to the standard;
- selected an appropriate option to meet any increase in (or maintain compliance with existing) the standard; and
- put in place a long term plan to maintain reliability and cover any extra contingencies.

F.3 Summary of Assessment Method Used in the Central Toronto IRRP

Based on the above international review of good utility practices for planning large urban areas, the IESO applied the following methodological enhancement for the Central Toronto IRRP. This was developed in consultation with the members of the Working Group, including Toronto Hydro and Hydro One.

1. Assess system performance as per the applicable minimum standards (e.g., ORTAC)
2. Identify where the current system design exceeds the standard, and instances in which the current system performance would degrade given future loadings
3. Review the reasonableness of strict application of the criteria across the study area and make any additional assessments that ensure that all downtown customers are considered equitably, for example, by applying bulk power system standards to certain facilities classified as local area supply
4. Conduct a probabilistic reliability assessment considering up to N-3 element outages and using best available information on outage rates, duration, and value of customer reliability
5. Assess the impact of specifically identified extreme contingencies. These low-probability high-impact events are unlikely to occur, however given that they would result in widespread and / or long-duration outages they have been investigated

including in detail including the time required to restore service given the current operational flexibility within the system.

Table F-1: Transmission Planning Standards in Select Major Metropolitan Areas

Jurisdiction	Planning standard for the urban centre / Central business district	Notes on criteria generally applied in the urban centre
France - Paris	N-2 standard is specific to Paris, and is achieved through coordination with distribution, N-2 is achieved through ability to transfer loads via distribution between substations	N-2 for transmission and distribution together, restoration requirement for 40% of lost load to be resupplied within 30 minutes after the incident
USA – New York City	In addition to the NPCC Regional standards, ConEdison has specified some Manhattan and area transmission load areas (stations, u/g cables) that are planned to a double contingency	N-2 for designated parts of the system which are non-bulk; No additional information regarding use of SPSs or restoration standards; New York City has also had strong policies supporting an 80% supply from in-city generation
Great Britain - London	Demand connection criteria specify the amount of allowable load loss and restoration requirements for an unplanned single element outage or an unplanned outage while an element is out for maintenance; Lower levels of load loss and immediate restoration required for larger demand groups, regardless of the type of demand	Switching / transfers allowable responses, immediate restoration for larger demand groups; criteria allow for higher criteria to be applied subject to an economic assessment
Japan - Osaka, Kyoto, Tokyo	No interruption permitted for N-1. N-2 is taken into consideration for large cities with temporary interruption allowable and resumption of service as soon as possible	SPSs normal part of system planning but must also be backed up to meet the N-2 condition (e.g., backup for protection devices); Allowable interruption time in central part of big cities is set within 30 minutes to 2.5 hours depending on the demand density and demand importance
Canada - Vancouver	Same as in rest of the province	N-1 is the standard applied; investments for higher reliability have been successfully rationalized with economic Cost / Benefit using probabilistic studies
Australia – Sydney	"Modified N-2" standard applied only to the Central Business District; Operator plans to N-2 subject to an economic Cost / Benefit where the benefits must outweigh the costs	N-2 unless the cost of achieving N-2 reliability exceedingly high

Metro Toronto – Central IRRP

Appendix G: Summary of Asset Condition and Sustainment Plans

9 October 2012

Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115kV System

Prepared by:
Transmission System Development

With input from:
Station and Line Sustainment

Hydro One Networks

1. Introduction:

This filing memorandum provides a summary of aging profile of major facilities in the Leaside TS and the Manby TS 115kV system and identifies any planned refurbishment work over the next five years (2013-2017). Asset condition assessment and Information on refurbishment plans was provided by Stations and Line Sustainment Departments.

The previous memorandum on the subject (issued in 2007) had indicated that a significant number of HV circuit breakers and underground cables were approaching end of useful life and required refurbishment. The memorandum also identified 115kV cables requiring replacement. Since then Hydro One has initiated significant capital replacement/refurbishment work in the Toronto Area and most of the previously identified work is expected to be completed by the end of 2014.

2. Facilities Considered:

The following facilities were considered:

1. 230/115V Autotransformers
2. 230kV and 115kV Breakers
3. Switchyard insulators and other bus work
4. 115kV switches
5. 115kV overhead lines
6. 115kV underground cables

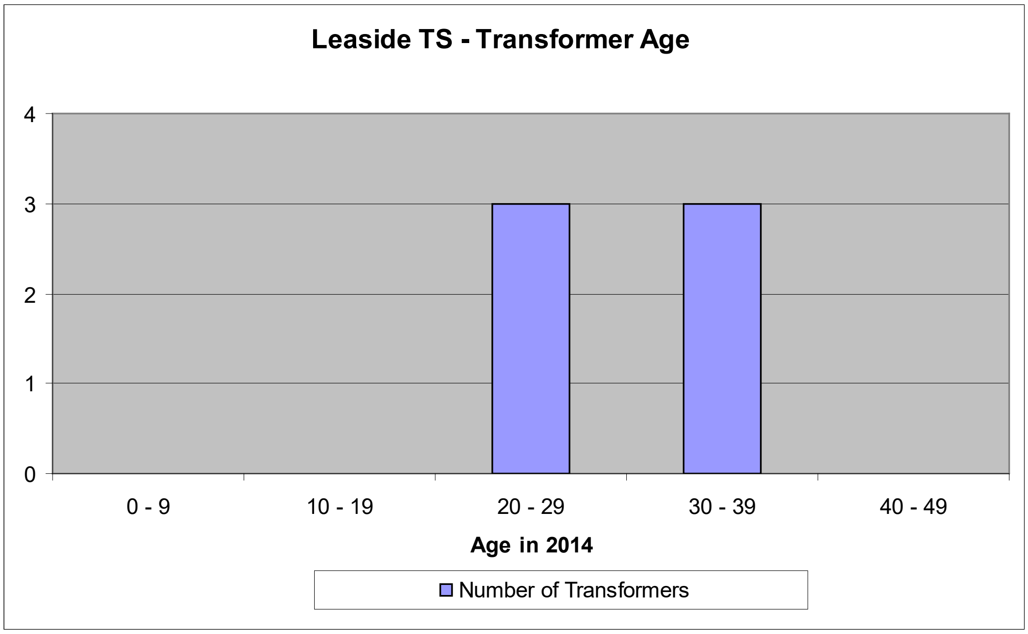
Other facilities such as P&C systems, grounding systems, station civil facilities, station service facilities etc. were not considered since the work can be scheduled without having a critical impact on the system. DESN station transformers and low voltage switchgear were also not covered since the impact is local.

3.0 Stations

3.1 Leaside TS:

<u>Autotransformers</u>:

Leaside TS has six autotransformers with an age distribution as shown in the chart below.

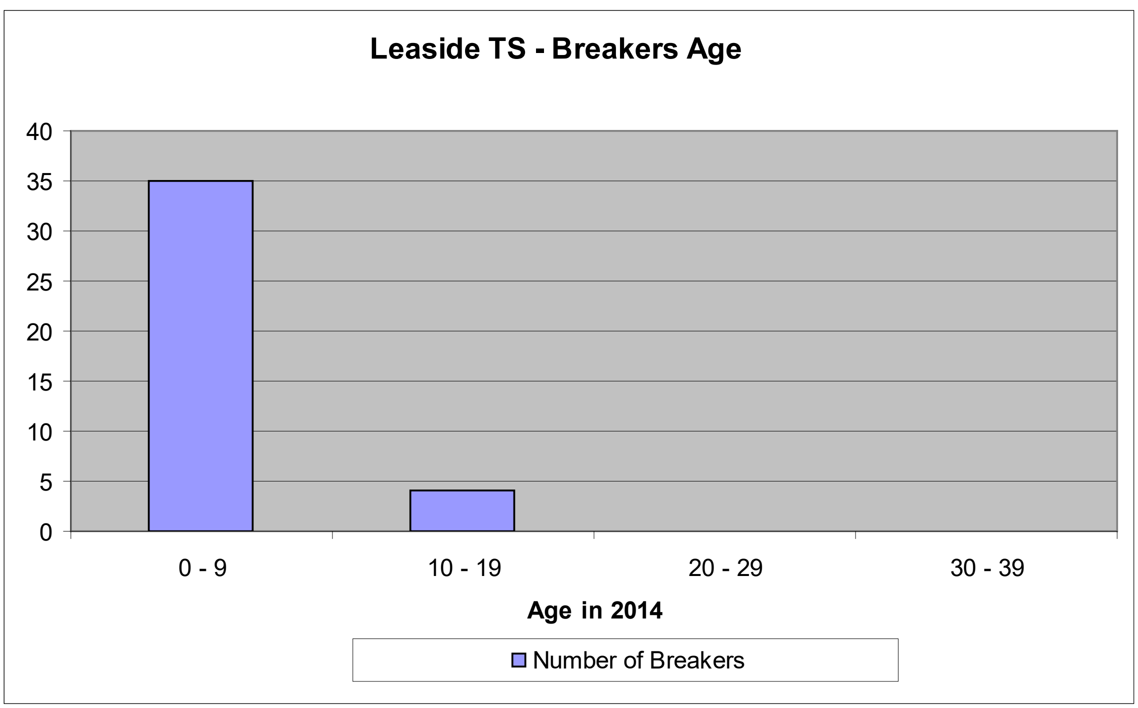


There are no current plans to carry out any major transformer refurbishment work over the next 5 years. However, work may be scheduled beyond that period.

Circuit Breakers – 230 kV and 115kV:

Leaside TS has 3 x 230kV breakers and 36 x 115kV breakers. Eight of the 115kV breakers (used for cap bank switching) and the 230kV breakers have been replaced since 2003. Work is now underway on replacement of all the remaining 115kV breakers by December 2014.

The expected 2014 age profile of Leaside TS breakers is illustrated in the following graph.



Switchyard Insulators, Bus work etc.

The bus work and insulators in the 115kV yard have been reviewed and will be replaced or upgraded as required along with the 115kV breaker upgrade work.

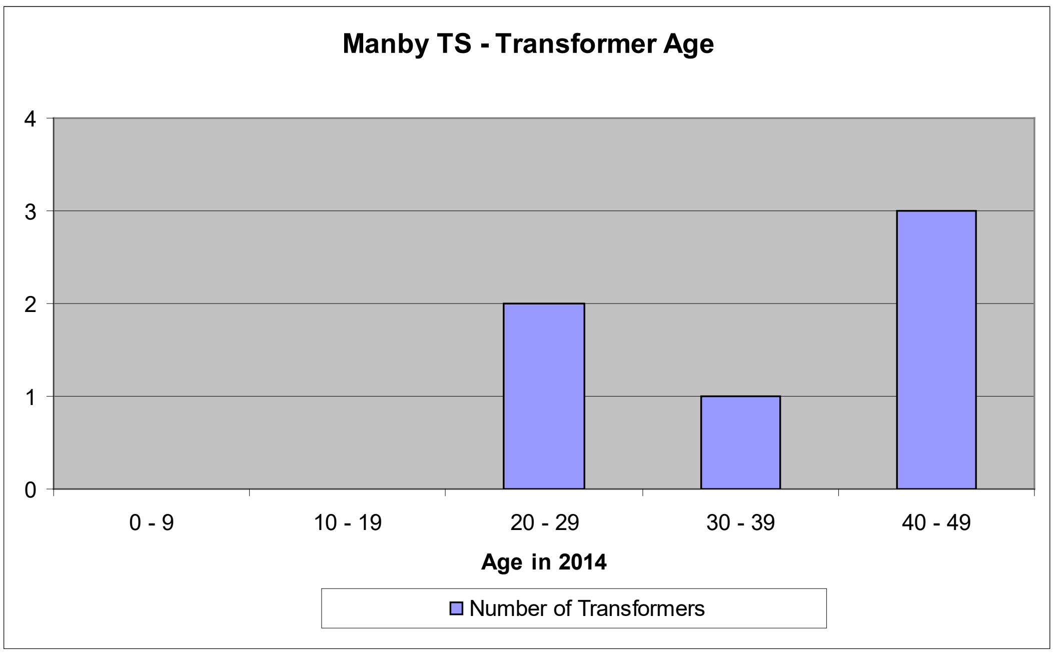
Line and Disconnect Switches – 230kV and 115kV

There are a total of 121 switches at both 230kV and 115kV level, the majority of them over 40 years old. However, the switches are in fair shape and there are no plans to carry out any refurbishment over the next five years.

3.2 Manby TS

Autotransformers:

Manby TS has six autotransformers with an age distribution as shown in the following chart.

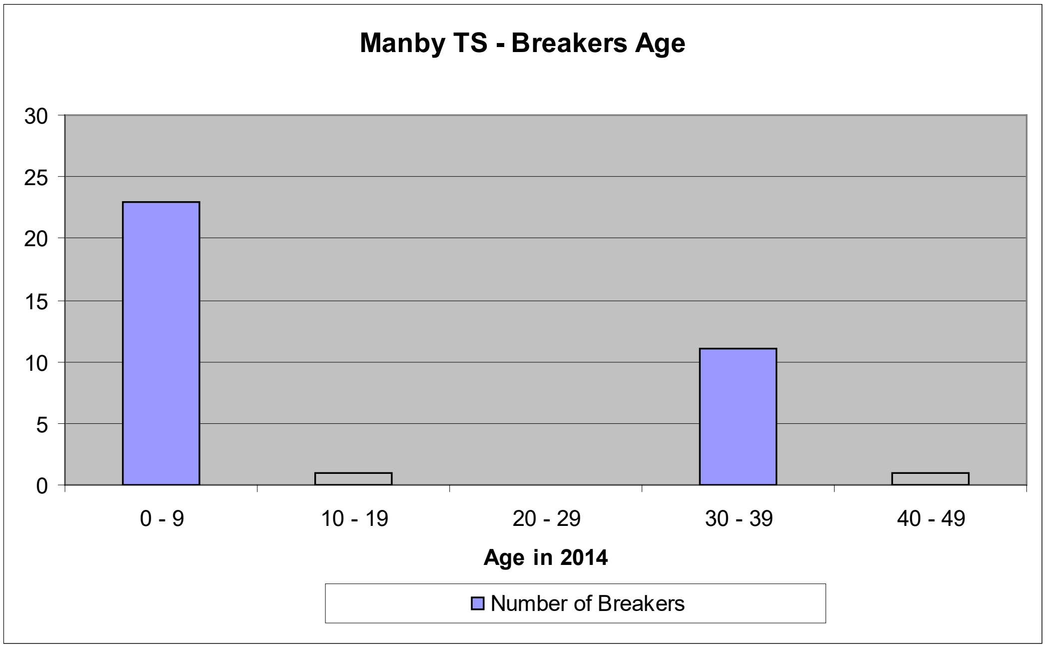


There are no current plans to carry out any major transformer refurbishment work over the next 5 years. However, work may be scheduled beyond that period.

Circuit Breakers – 230 kV and 115kV:

Manby has 18 x 230kV breakers and 18 x 115kV breakers. All except two of the 115kV breakers are oil breakers and these are being replaced under the Manby TS 115kV switchyard upgrade project. The expected date for the Manby breaker replacement work is Dec. 2014.

The expected 2014 age profile of Manby TS breakers is illustrated in the following graph.



Switchyard Insulators, Bus work etc.

There are cap and pin insulators at Manby TS that require replacement. These are being replaced along with the breaker replacement work at the station.

Line and Disconnect Switches – 230kV and 115kV

There are a total of 129 switches at both 230kV and 115kV level, the majority of them over 45 year old. All 115kV switches will be replaced at Manby TS.

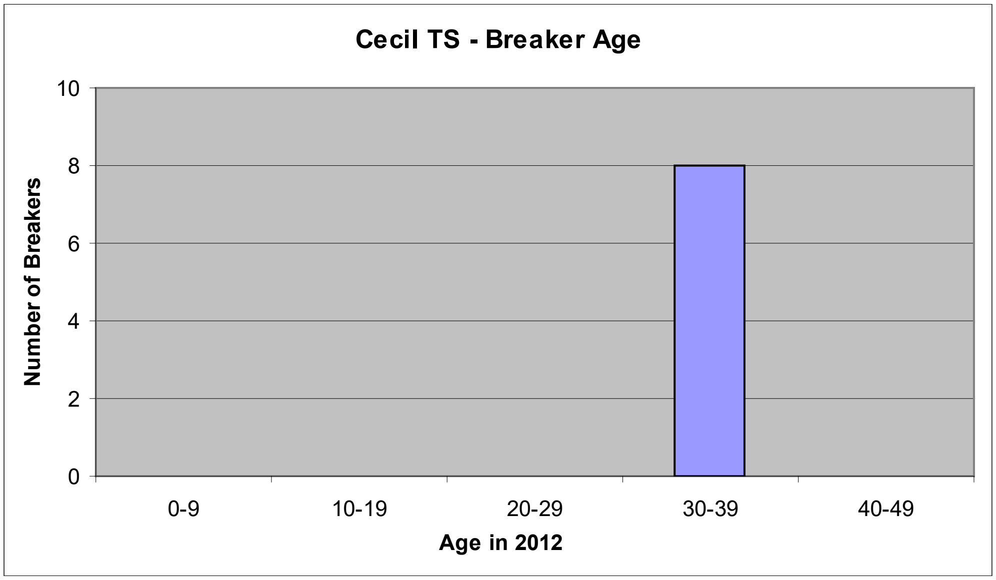
3.3 Hearn TS

Circuit Breakers – 115kV, Line and Disconnect switches, Switchyard Insulators, Bus work etc.

The entire existing 115kV switchyard – including breakers, switches, insulators and bus work - is being replaced with a new GIS indoor switchyard. The expected in-service date is Feb. 2014.

4.0 Cecil TS

Cecil TS is an indoor station and has 8 x 115kV GIS breakers and a 115kV GIS duct ring bus. The age distribution of these breakers is shown in the following graph.



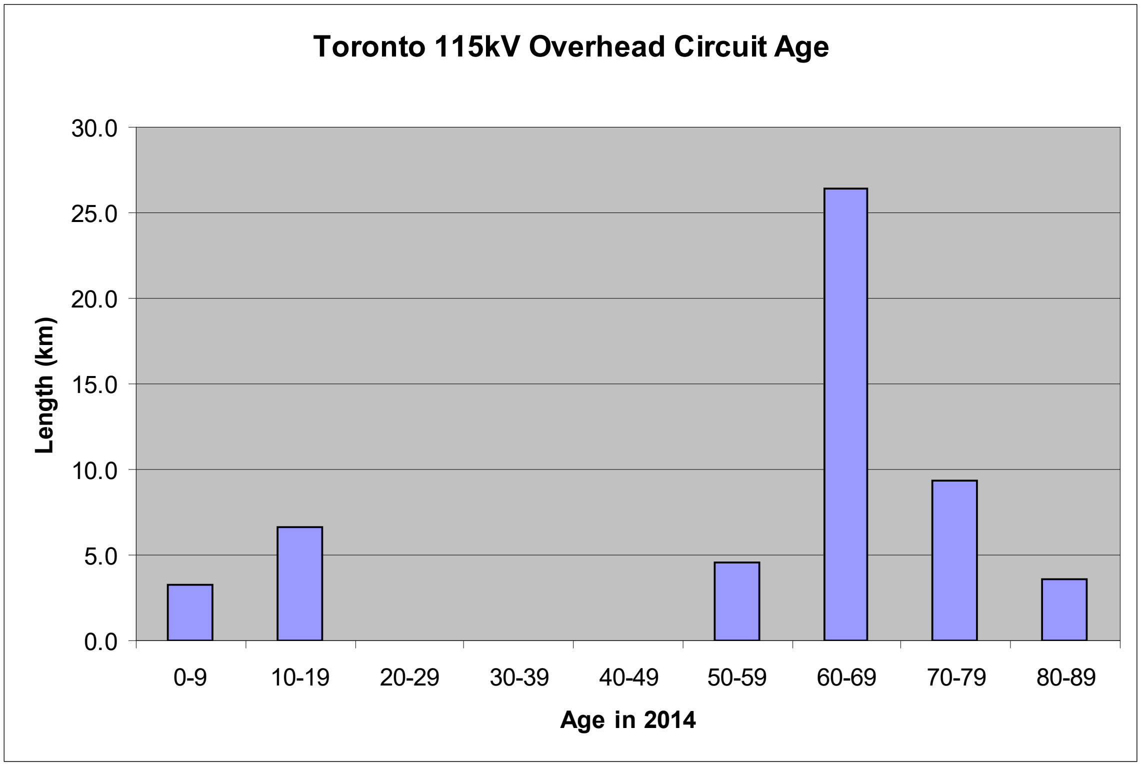
There is no major refurbishment work contemplated at Cecil TS in the next five years.

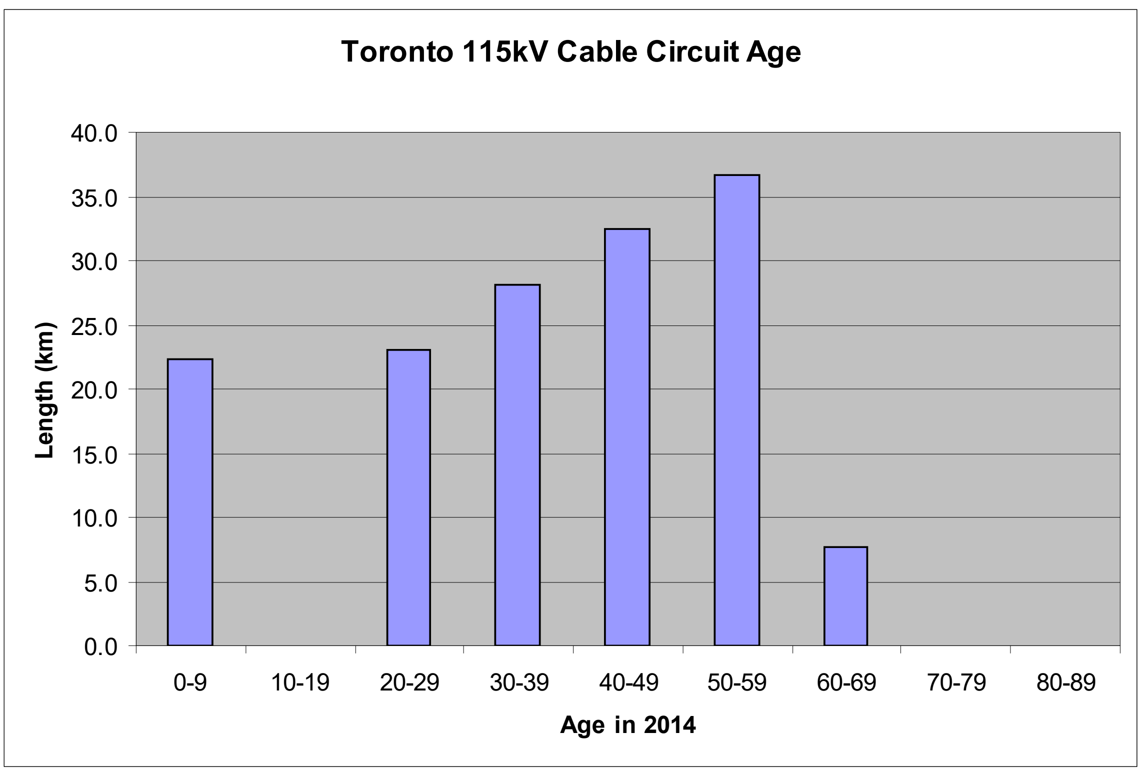
6.0 Leaside TS and Manby TS 115kV Lines

The Leaside TS x Manby TS 115kV network is shown in Figure 1. The overhead lines are over 50 years old except for the overhead section of the circuit H2JK/K6J between Manby TS and Riverside Jct. which was refurbished in 1998 and the Leaside TS x Bayview Jct. section of the line L14W/L15W which is currently being rebuilt to carry a new circuit and to reinforce the Leaside TS x Bridgman TS transmission corridor. Hydro One monitors the conditions of the lines and based on current assessment no overhead transmission line refurbishment work is planned for the next ten years.

The cable network is somewhat newer, but there are some cables circuits over fifty year old. Work is underway on replacing the Leaside TS x Bridgman TS circuit L14W and the Riverside Jct x Strachan TS circuits K6K/H2JK. Both cable replacements are expected to be complete by end 2014.

The age profiles for both overhead and underground circuits are shown in the charts below:





The timeline for the refurbishment of some of the older 115kV cables is also given in Figure 1. This is based on surveys of the cable health carried out over the last several years.

7.0 Conclusions

This filing memorandum summarises the aging profile of the main components of the Toronto area 115kV network and current planned refurbishment work over the next 5 years.

Significant work is currently under way – Hearn TS is being rebuilt and the 115kV oil breakers are being replaced at Leaside and Manby TS. Work is also underway on the Leaside TS x Bridgman TS and the Riverside Jct. x Strachan TS cable circuits.

Hydro One’s challenge for the refurbishment and replacement of the underground and overhead lines over the next 10-20 years will be managing outages to carry out the work while continuing to supply the area load.

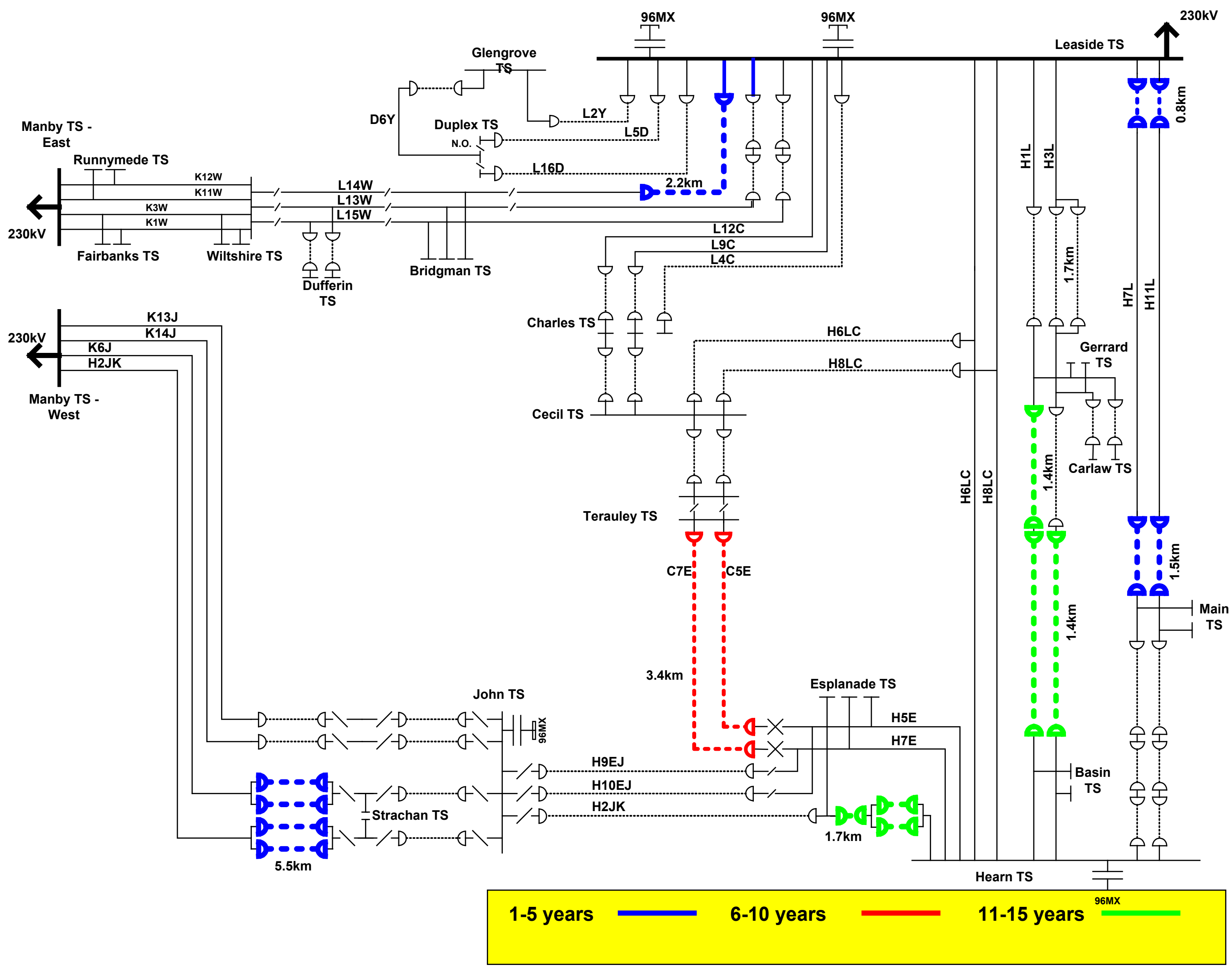


Figure 1. Leaside TS and Manby TS – 115 KV area Transmission Network. Timeline for Refurbishment/Replacement of Overhead lines and Underground Cable

The End

Metro Toronto – Central IRRP

Appendix H: Estimates of Conservation Achievable Potential

Appendix H: Conservation Potential Estimates

The following estimates of conservation potential for Central Toronto are adapted from the analysis and findings presented in the report *Achievable Potential: Estimated Range of Electricity Savings from Energy Efficiency and Energy Management* (ICF Marbek, March 2014).[7]

The conservation Achievable Potential Study estimated energy efficiency electricity savings potential as a function of building and end-use stock, technology electricity intensity, and technology adoption rates. The study included electrical conservation technology measures expected to be available by 2022. Energy efficiency and energy management/customer behaviour measures and district energy were included in the analysis but demand response, lifestyle changes and other customer-based generation resources were excluded.

The study estimated the technical energy savings potential at the provincial level, as well as a range of achievable potential based on different program designs for the Province and each IESO Zone. The varying levels of potential were defined as follows:

- Technical potential: estimated potential savings for all measures that pass an economic screen.
- Upper achievable potential: based on programs with incentives sufficient to reduce customer payback to one year and aggressive support through education, training, marketing.
- Lower achievable potential: based on less aggressive programs with incentives sufficient to reduce customer payback to two years.

Using the estimates of technical potential and range of achievable potential for the Toronto IESO Zone, the energy efficiency savings potential for Central Toronto was estimated by accounting for local building stock and floor space data from the Municipal Property Assessment Corporation (MPAC) and local electricity consumption data from Toronto Hydro.

These steps were followed to develop the conservation potential estimates for Central Toronto.

1. The estimates of technical potential and range of achievable potential for the Toronto IESO Zone were disaggregated by sub-sector (e.g., single family homes, offices, manufacturing, etc). These saving estimates were provided at 5-year intervals from

[7] http://powerauthority.on.ca/news/conservation-achievable-potential-study

which intermediate years were interpolated to develop an annual potential savings forecast.

2. The sub-sector potential savings estimates for the Toronto IESO Zone were then allocated to Central Toronto using the ratio of growth drivers (residential housing stock, commercial floor space, and industrial consumption) for each sub-sector for the technical and two achievable potential levels.

   For example, if the technical potential for large offices in the Toronto IESO zone is 1,000 GWh, the floor space for large offices in the Toronto IESO zone is 5,000 ft sq, and the floorspace for large offices in Central Toronto is 200 ft sq, then the Central Toronto Office Savings Potential = IESO Toronto Zone Office savings x (Toronto Office Floorspace/IESO Toronto Zone office floor space = 1,000 GWh x (200 ft sq/5,000 ft sq) = 40 GWh office technical potential in Central Toronto. This is equivalent to assuming that the sub-sector energy savings intensity (e.g., per unit household or floor space) at the local level is equivalent to that at the Zone level. To allocate the Toronto IESO Zone level savings to Central Toronto, data from the following sources were used. Housing stock data was obtained from Environics, commercial floorspace data was obtained from MPAC, and institutional and industrial consumption was obtained from Toronto Hydro.

3. The energy savings estimates by sub-sector allocated to Central Toronto were then converted to peak demand savings potential using the sub-sector load shapes derived from hourly end use load profiles. Summing up the demand savings across all sub-sectors provided the total savings potential for the Central Toronto area. Note that these savings are reflective of a 2005 base year and are inclusive of persisting savings from existing conservation programs and savings from codes and standards.
4. To develop estimates of the “remaining” program savings potential for comparison to the planned program savings included in the IRRP, the persisting savings from existing conservation programs in the region and from existing codes and standards were subtracted. The existing savings for 2005-2013 were taken from the IESO’s Evaluation, Measurement, and Verification reports which include an estimate of the persistence effect of implemented programs. The Codes and Standards savings were assumed to be the same proportion, by sector, as that assumed in the Provincial study. The savings remaining represent the remaining potential for conservation savings.

Table H-1: Summary of Remaining Conservation Potential and Supply Needs for Central Toronto

Need Area	Supply Need/ Conservation Potential (MW)	2014	2016	2018	2021	2026	2031
Manby TS (West + East)	***Supply Need (MW)***	***90***	***123***	***134***	***158***	***195***	***227***
	Technical Conservation Potential	48	79	113	143	139	130
	Upper Achievable Potential	4	15	36	53	47	49
	Lower Achievable Potential	3	5	15	18	12	13
Leaside TS - Bridgman TS	***Supply Need (MW)***	***13***	***17***	***19***	***21***	***23***	***26***
	Technical Conservation Potential	18	27	35	42	41	38
	Upper Achievable Potential	2	5	9	14	12	12
	Lower Achievable Potential	2	2	4	4	3	3
Richview – Manby 230 kV Corridor	***Supply Need (MW)***	***0***	***15***	***28***	***15***	***9***	***4***
	Technical Conservation Potential	78	123	168	209	203	190
	Upper Achievable Potential	8	23	50	74	64	65
	Lower Achievable Potential	6	8	21	24	16	18
Manby TS (230 - 27.6 kV)	***Supply Need (MW)***	***30***	***30***	***30***	***30***	***30***	***40***
	Technical Conservation Potential	19	26	32	38	37	34
	Upper Achievable Potential	3	5	8	11	9	9
	Lower Achievable Potential	2	2	3	3	2	3
Fairbank TS	***Supply Need (MW)***	***0***	***30***	***30***	***30***	***30***	***30***
	Technical Conservation Potential	15	21	27	32	31	29
	Upper Achievable Potential	2	4	6	10	8	7
	Lower Achievable Potential	1	2	2	3	2	2
Esplanade TS	***Supply Need (MW)***	***0***	***10***	***10***	***10****	***30***	***30***
	Technical Conservation Potential	5	10	16	21	20	19
	Upper Achievable Potential	0	2	6	9	8	9
	Lower Achievable Potential	0	0	3	3	2	2

* Notes: The following forecast new customer demand is not accounted for in the above table (Supply Need)
1. The Eglinton LRT demand is forecast to result in an additional 18 MW of demand in the Fairbank TS service area by 2019, and is in addition to the supply need identified in Table H-1.
2. Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area in the near and medium-term, based on approvals for new buildings and developments.

Metro Toronto – Central IRRP

Appendix I: Letter to Toronto Hydro on Load Stations Planning

ONTARIO POWER AUTHORITY

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April 4, 2014

Mr. Jack Simpson
Director, Generation and Capacity Planning
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario M4M 3N7

RE: Request for Continued Distribution Planning and Development Work for Near Term Infrastructure Projects in Central Toronto

Dear Jack:

This letter is to thank you and your Toronto Hydro team for the support provided to date in progressing the Central Toronto Integrated Regional Resource Planning ("IRRP") and to request your continued support in developing the work scope, cost and timing requirements for the distribution infrastructure options required for meeting the near-term needs identified the by the IRRP Working Group ("Working Group").

The Working Group (consisting of staff from the Ontario Power Authority ("OPA"), Toronto Hydro-Electric System Limited, the Independent Electricity System Operator and Hydro One Networks Inc.) has established that there are certain near term-needs that require action by Toronto Hydro to ensure that distribution infrastructure options are identified and appropriately represented within the study. Of particular concern is the understanding of the lead time that some of these infrastructure options may have as well as their costs, at a planning level of certainty. We understand that some of these options developed by Toronto Hydro may require the coordination and/or participation of Hydro One.

The OPA therefore requests that Toronto Hydro continue with detailed studies and development work for the distribution infrastructure related near-term components of the IRRP as outlined below:

- Develop the distribution infrastructure components of the integrated plan that may be required to meet near-term capacity and/or reliability of the Central Toronto area. These options may be required in the event that planned conservation and demand management (CDM), distributed generation, or other electricity system initiatives are insufficient or are determined to be technically and / or economically infeasible for providing the necessary near-term relief by the Working Group.

- Continue to work with the OPA to ensure that CDM, distributed generation, and other electricity system initiatives are fully and appropraitely accounted for in developing the near-term and longer-term elements of the integrated plan.

In addition to the distribution infrastructure options, alternative or complementary approaches for addressing these near-term needs and issues may include CDM, distributed generation, or other non-wires based electricity system initiatives. These along with recommended solutions will be investigated further by the Working Group through the IRRP process.

Supporting Information for Central and Downtown Toronto Near-Term Projects:

The near-term needs and issues identified by the Working Group which require action by Toronto Hydro are summarized in Attachment 1.

To facilitate the implementation of further planning and development activities, the OPA will provide Toronto Hydro with the following information established by the Working Group:

- Conservation and distributed generation forecasts
- Preliminary assessments of other non-wires based options
- Other relevant information upon request by Toronto Hydro.

I look forward to discussing a timeline for the requested information at our next Working Group meeting.

Thanks again for your support to date and I look forward to continuing to work together and supporting Toronto Hydro on the further development and implementation of solutions.

Best Regards,

Joe Toneguzzo
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

Copied: Central Toronto IRRP Working Group

Attachment 1

Near-Term Needs Requiring Initiation of Planning and Development Work

A. West-Central Toronto Step-down Capacity Relief

Load forecast information provided by Toronto Hydro indicates strong near-term growth pressures in the West-Central Toronto area. This requires the development of distribution infrastructure options for providing step-down station capacity relief. This relief is required to supply growth in demand from existing customers, enable the connection new customers and manage the risk of outages under certain contingencies.

Distribution infrastructure options to address the West-Central Toronto Step-down Capacity relief have not been explored in detail by the Working Group. However, based on preliminary discussions these options should include, as determined appropriate by Toronto Hydro:

- Permanently transferring load from the step-down stations requiring relief to Richview TS or other nearby step-down stations, which are not fully utilized. This may include incorporating feeder-ties between stations where feasible and economic.
- Building an new step-down transformer station to offload the step-down stations requiring relief. This may include incorporating feeder-ties between stations where feasible and economic.
- Providing, where it is feasible and economic to do so, inter-station transfer capability in order to enhance restoration of the West-Central Toronto step-down stations for normal design contingencies as well as extreme contingency events. These stations include, but are not limited to: Manby 230/27.6 kV DESNs, Richview 230/27.6 kV DESNs, Fairbank TS, and Horner TS.

B. Downtown Toronto Step-down Capacity Relief

The load forecast provided by Toronto Hydro indicates that continued strong near-term growth pressure in the downtown Toronto area requires the development of distribution infrastructure options for providing step-down station capacity relief. This relief is required to supply growth in demand from existing customers, enable the connection new customers and manage the risk of outages under certain contingencies.

Distribution infrastructure options to address the downtown Toronto Step-down Capacity relief have not been explored in detail by the Working Group. Based on preliminary discussions within the Working Group these options should include, as determined appropriate by Toronto Hydro:

- Developing Phase II of Copeland TS.
- Expanding Esplanade TS.

- Permenently transferring load to other adjacent step-down stations which are not fully utilized.
- Providing, where it is feasible and economic to do so, inter-station transfer capability in order to enhance restoration and the optimization of station loading.

The information provided should include:

1. A summary of the expected scope of work.
2. The time required to implement specific distribution infrastructure options from the planning phase through to in-service. This should include identifying approval and other requirements such as the need for environmental assessments, the acquisition of property, etc.
3. Planning level capital cost estimates.
4. Rationale for not including options, where Toronto Hydro believes this is not technically feasible.
5. Concerns Toronto Hydro has regarding use of the CDM and/or distributed generation as an interim measure or as alternatives to the distribution infrastructure option.

Depending on the findings from the investigations from 1 and 2 above, it may be possible for CDM, local generation, or other electricity system initiatives to defer the need for wires-based options. This includes the Local Demand Management Pilot Study that Toronto Hydro is conducting with financial support from the OPA's Conservation Fund that is intended to specifically target local areas of high constraint. This determination will be investigated further by the Working Group though the IRRP once the nature, timing and cost of these options are better understood and any concerns expressed by Toronto Hydro are documented.

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END of LETTER

Metro Toronto – Central IRRP

Appendix J: Stakeholder Engagement Summary Reports

Innovative Research Group, Inc.
Toronto • Vancouver

Customer Consultation Report

Central Toronto IRRP

January 2015

Prepared for:

Central Toronto Integrated Regional Resource Plan Study Partners

Customer Consultation Report

Central Toronto IRRP

January 2015

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro-Electric System Limited (THESL), Hydro One Networks Inc. (HONI), the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA).

The conclusions drawn and opinions expressed are those of the authors.

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Contents

Introduction

About this Consultation

INNOVATIVE has been commissioned by the Central Toronto Integrated Regional Resource Plan (IRRP) study partners – made up of Toronto Hydro, Hydro One, the Independent Electricity System Operator, and the former Ontario Power Authority – to help design, collect feedback and document its customer engagement and consultation process as part of the development of the Central Toronto IRRP.

The Central Toronto IRRP is a key element in shaping how energy needs will be met in the Central Toronto for the next 25 years. The outcome of this plan will set the context and basis for the preferred options to meet the growing demand in the region.

In developing the Central Toronto IRRP, the study partners, alongside INNOVATIVE, conducted a comprehensive consultation that obtained input from affected stakeholders to ensure that the preferences of the impacted communities are accounted for. This consultation included a two-way dialogue with stakeholders about regional electricity needs and the related options over the medium and long term. The objectives of this consultation included:

- increasing public understanding of the area's electricity needs and options for the future;
- obtaining feedback on the options developed to address the medium- and long-term needs;
- highlighting the importance of electricity as a driver for economic and community development; and
- explaining and promoting the role of CDM, DG and transmission and distribution solutions in helping meet both current and future needs.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they do not know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking firm positions on issues that are sometimes controversial. Moreover, many customers are simply not aware that public consultations of interest are taking place.

Running a consultation on a complex IRRP has additional challenges – mainly a lack of awareness regarding how the system operates, is funded and the regulatory frameworks. This process is intended to bridge these gaps and educate customers about the electricity system.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of awareness, we built a process built on six key principles:

1. Ensure customers from across Central Toronto have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.

3. Create open voluntary processes to allow anyone who wants to be heard to be heard.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.
6. Test the consultation material ahead of time for clarity of language, appropriateness of questions, ability to respond to questions, and the right balance between comprehensiveness and simplicity.

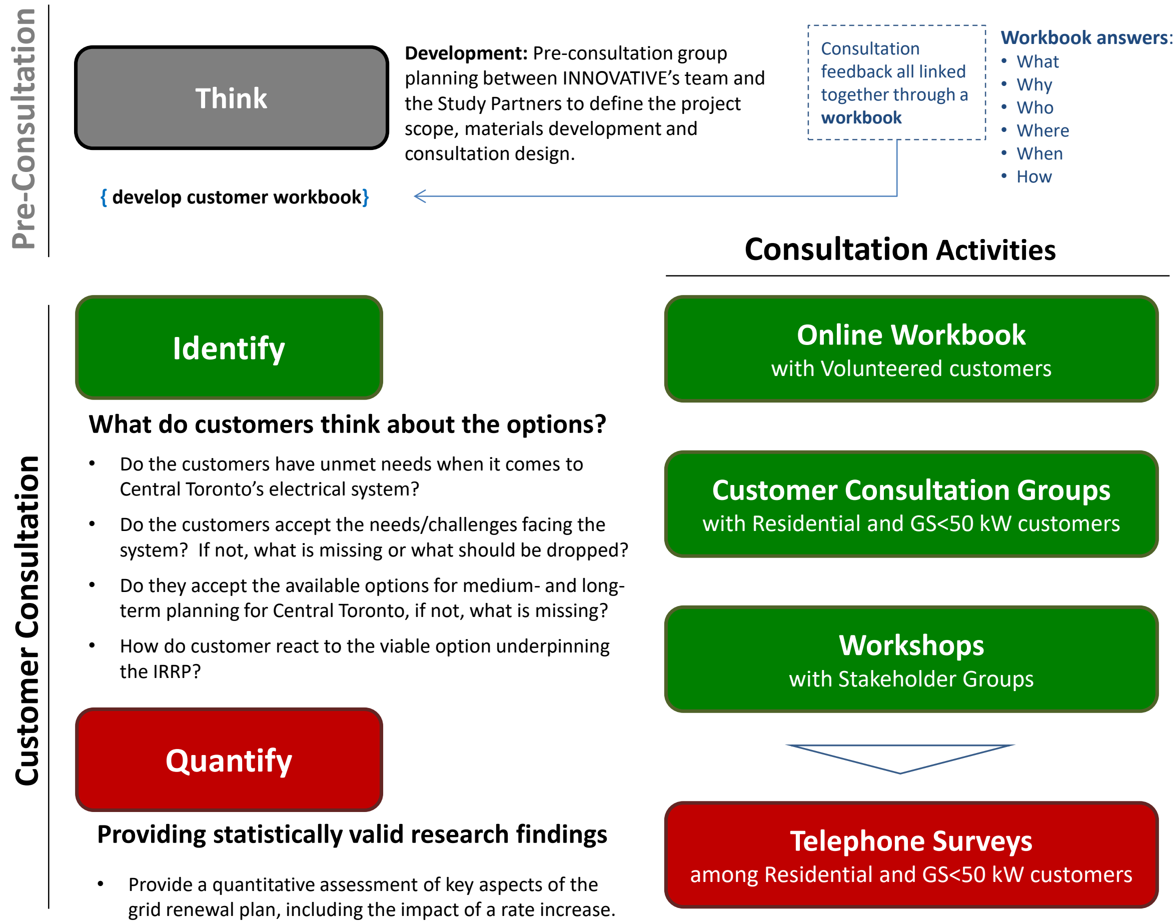
Since this was the first time the IRRP study partners so explicitly engaged customers in the development of their plan, a specific effort was made to collect participant comments on the process itself. While most customers felt this approach to engagement was effective at soliciting their feedback on the Central Toronto IRRP, other ideas on how to improve upon the process were collected throughout the consultation. This is discussed throughout the body of this report.

Customer Consultation Overview

Based on the principles outlined above, INNOVATIVE worked with the Central Toronto IRRP study partners to design a multi-faceted customer engagement program, which included a combination of traditional consultation services, as well as qualitative and quantitative research elements. This comprehensive consultation was designed to engage various rate classes and stakeholder groups and collect feedback on preferences and priorities as they relate to the Central Toronto IRRP.

There were three stages in developing and implementing this consultation:

- **Think**: The first step was developing the core background material and key questions for the workbook. INNOVATIVE and the IRRP study partners worked together to identify potential questions that would allow customers to share their needs and preferences and then to develop a workbook that would provide the information needed to allow customers with different levels of initial knowledge to find answers to those questions.
- **Identify**: The second step in the customer consultation were the qualitative research element. These elements consisted of: a volunteered online workbook that was completed by customers across Central Toronto; customer consultation groups to help identify the needs and preferences of customers as related to the IRRP; and stakeholder workshops to help gauge planning priorities for Central Toronto.
- **Quantify**: The final step included gathering final thoughts on the planning options for Central Toronto through a random recruited telephone surveys of residential and general service customers in the study area. Randomly recruited surveys allow us to draw generalizable conclusions that can be applied to the broader Central Toronto population. The surveys were developed based on the feedback gathered from the subsequent consultation phase of the research.



The consultation encompassed five core elements of customer engagement.

1. **Testing Focus Groups**: Testing groups were used to determine the effectiveness of the workbook. These groups helped determine where improvements could be made to the narrative developed by the IRRP study partners and INNOVATIVE.

2. **Online Workbook**: The online workbook was promoted through both traditional and online media by the four members of the IRRP study partners. This first phase of the consultation was available to all Ontario residents who wanted to participate.

3. **General Service and Residential Consultation Groups:** The general service and residential customer phase of Central Toronto's IRRP multi-faceted customer consultation was used as an engagement tool to educate customers, access customer preferences and priorities, as well as inform subsequent phases of the consultation. The groups were randomly recruited and held in a central location in downtown Toronto. A workbook was used to provide the participants with core information about the Ontario electricity system and the growing demand on Central

Toronto's electricity system. They were provided incentives in recognition of their time commitment.

4. **Stakeholder Workshops**: Key stakeholders were engaged through a series of randomly recruited workshops. More than 300 stakeholders were invited to attend one of the three workshop sessions.
5. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the Central Toronto IRRP. Customer lists for both respondent groups were provided by Toronto Hydro and the sample was randomly-selected by INNOVATIVE.

The consultation was designed so anyone who was interested would have an opportunity to participate in the process through the online workbook. However, in our approach, we distinguished between responses from the opinion research discipline (random recruits and scientific polls) and responses from an "open invitation" consultation discipline.

The small group results are presented as numeric counts to help readers remember that qualitative research only identifies points of view, it does not project the incidence of that point of view in the broader public.

The results from the workbook and random surveys are presented as percentages due to the larger numbers involved.

- Readers are cautioned that the workbook results represent the views of volunteers. The workbook sample is not randomly selected and cannot be generalised to the broader Central Toronto customer-base.
- The telephone surveys are based on random samples so we can reliable project the incidence to the broader population of Central Toronto.
- In some instances, the quantitative total may be greater than 100% due to rounding. This is in keeping with standard research practice.

Workbook Development

As noted earlier, a key challenge in getting public feedback on the Central Toronto IRRP is the lack of awareness concerning Ontario's electricity system. Our challenge was to briefly cover the key issues and to frame meaningful questions around preference as it pertains to electricity needs and options for the future of Central Toronto's electricity system.

The process of developing the consultation workbook began in the fall of 2013 and continued into the spring of 2014. The draft workbook was tested among Toronto Hydro's Central Toronto residential and general service customers in November and December 2013. Based on feedback from testing, the workbook was divided into key sections that explained the IRRP process, the challenges facing Central

Toronto's the electricity system, and how challenges related to capacity, reliability and security could be met in the medium- and long-term.

The final consultation workbook had six distinct chapters:

1. **What is this Consultation about?** This section explains the purpose of the customer engagement and where this consultation fits within the broader scope of electricity planning in Ontario.
2. **Where Does Electricity Come From?** This section explains how electricity is generated, transmitted and distributed to the city of Toronto.
3. **An Overview of the Central Toronto Electricity System Today**: This section provides an overview of Central Toronto's electricity system and how it has grown and changed to meet demand over the past century.
4. **Planning to Meet Customer Expectations**: This section provides a context for the various issues system planners consider when planning for medium- and long-term electricity needs: peak demand, capacity, reliability and security.
5. **Options for Meeting Central Toronto Demands**: This final question provide an overview of potential medium- and long-term planning options for Central Toronto's electricity system.

Although the sophistication of customers varied, the same basic workbook was used in all qualitative engagements – the online workbook, the residential and general service discussion groups and the stakeholder workshops. As the customer went through the consultation workbook – either independently or through a facilitated session – they were prompted with questions related to system reliability, system challenges, and preferences on options for meeting of Central Toronto's demands.

Another key element of the workbook were the questions. In developing the questions, we looked for questions that could work also on telephone without all the information in the workbook.

The workbook began with reliability experience and expectation questions. These questions asked whether the current number and length of outages are acceptable. These questions were followed by an open-ended question about how these outages affected both your business (for general service customers) and you personally (for residential customers). This series of questions then continued to ask the dollar value of any expenses that were incurred as a result of these power outages. Finally, customers were given the opportunity to voice if there was a certain amount of time without power that the costs and consequences of an outage would become more serious. Questions on reliability were then followed with questions related to security (how the electricity performs during major events) and willingness to pay for greater security.

Preference questions were a bit more difficult to design, as we were looking for value choices rather than technical issues. Most customers are not engineers, so additional efforts were required to provide adequate information on conservation and demand management (CDM), distributed generation (DG), and transmission and distribution options. Key topics for preference included:

- Likelihood to participate in various types of CDM programs;
- Preferences on electrical infrastructure build including transmission, distribution and DG; and
- Comparison questions between all the options available to system planners as they plan to meet Central Toronto's electricity needs in the future.

The workbooks can be found in the **Appendix** of this report.

Executive Summary

This section outlines the findings of the two-part customer consultation: both the qualitative research from the online workbook, general service and residential consultation groups, and stakeholder workshops and also the quantitative research from the telephone survey of residential and general service customers in Central Toronto.

Customer Familiarity, Satisfaction and System Reliability

Most Central Toronto customers say they are familiar with the electricity system and satisfied with their current service.

Familiarity: Directional vs. Quantitative

	Directional	Quantitative (Telephone)	
	Online Workbook	**Residential Survey**	**GS Survey**
Familiar	60%	62%	46%
Not Familiar	40%	38%	54%

- About 6-in-10 respondents in both the Online Workbook (60%) and the Telephone Survey (62% Residential) are familiar with the electricity system.

Across all levels of consultation, respondents were quite satisfied with the service they received:

- The participants in the fall 2014 Stakeholder Workshops felt the system works reasonably well, albeit there's always room for improvement.
- In the Telephone Survey, more than 8-in-10 Residential (86%) and GS (82%) are satisfied with their service.
- The Online Workbook satisfaction question focused on service during unusual weather- a bit different, but the results are similarly positive: nearly 6-in-10 (58%) were satisfied with the service during major events.

Cost is the key issue for customers: they want lower rates and better service.

When asked what the electricity system could do to improve service, far-and-away the leading answer was "reduce rates"- 40% of telephone respondents mentioned this in an open-ended question. For many, paying their electricity bill is a financial hardship: about half (46%) of residential and 3-in-4 (77%) general service customers say their electricity bill has a "major impact" on their finances.

The drive to reduce cost is also paired with a preference for increased reliability. In the past twelve months, half of residential and general service customers experienced an outage of some kind, either during a major weather event (50%) or under normal circumstances (51%).

This "more for less" contradiction is something explored through every step of the consultation. The September 2014 focus groups clearly understood the need to replace aging infrastructure, but suggested the system look within for savings and to rein in "waste" before asking customers for a price increase. In the Workbook, those against increased infrastructure spending say primarily “we should use existing infrastructure first”.

Outage length is another major concern. Cutting down the time of outages is crucial.

The problem of outages - particularly the summer flooding and December 2013 ice storm - is top of mind for residential and general service customers. Much of the consultation process focused on how reliability issues affected customers in their day-to-day.

The qualitative consultation in particular examined the impacts of outages, acceptable timelines and frequencies of outages and customer preferences on frequency versus duration.

With this qualitative feedback in mind, the telephone survey examined customer preferences between cost and reliability.

Number of Hours when Cost and Consequence of Outage Becomes More Serious:

Directional vs. Quantitative

	Directional	Quantitative (Telephone)	
	Online Workbook	Residential Survey	GS Survey
<1 hour	9%	19%	62%
1-6 hours	28%	42%	23%
6+ hours	28%	29%	13%
*When food spoilage occurs	19%	--	--
*Any amount of time	11%	--	--

- By more than a six-to-one margin, customers in the telephone poll feel more inconvenienced by the length of outages (77%) than the number (12%).
- According to the Online Workbook, the median customer experienced two outages over the last two years and spent roughly two hours each time without power. When asked an open-ended question on how the outages affected their place of business, most responded with issues of minor inconvenience such as “resetting clocks” and “spoiled food”.
- In the Workbook, three-quarters said that “yes”, there was a certain length of time at which the costs and consequences of an outage became more serious for them. In that small sample the amount of time varied widely, but the telephone survey clarified how fast they wanted power restored: more than 6-in-10 (62%) general service customers say an hour or less outage makes things difficult; a third (32%) say 15 minutes or less is a problem for their organization.

Challenges, Solutions and Customer Preferences for the Future

The three options presented are not well-known to customers.

Throughout the process, customers weighed in on the three capacity solutions: “Conservation and Demand Management”, “Distributed Generation” and “Transmission and Distribution Infrastructure”.

- In the telephone survey, unaided awareness of the three solutions is rather low: about as many customers are familiar as unfamiliar with “Transmission and Distribution Infrastructure” (+10) and “Conservation and Demand Management” (+2).

- “Distributed Generation” is the least known to customers in both the qualitative and quantitative research. Both of the September 2014 focus groups requested more information on this “relative unknown”. And more than 6-in-10 (62%) customers in the Telephone Survey are not familiar with “Distributed Generation”.

Customers in Central Toronto are conflicted when it comes to “Conservation and Demand Management”:

- In the 2014 focus groups, a majority (17/28) of participants choose CDM as their first choice.
- And they are more likely than not to participate in Demand Response Programs that allow managers to cycle off their home equipment (62% likely).
- But in the quantitative telephone survey when asked if they would agree to the option of “Conservation and Demand Management”, customers were split roughly evenly: a third (34%) of customers said they were likely to do so and 4-in-10 (40%) said they would not agree to it.

Overall though, customers are supportive of energy conservation and concerned about environmental issues.

In general terms, customers in both the qualitative and quantitative research appear to embrace the idea of energy conservation.

- A majority in the Workbook claim to participate in conservation activities such as using “LED lightbulbs” or “energy efficient appliances”.
- “Solar” and “combined heat and power” are the two options Online Workbook respondents felt most appropriate for use in the Central Toronto region. Almost all the consulted customers would use solar and combined heat and power “all of the time” or “some of the time”. “Bioenergy” and “using emergency generators” are seen as less viable options, but still received net support.
- Finally, there’s strong concern among customers regarding the environmental effects of the electricity system: 9-in-10 (89%) in the Telephone Survey think “reducing impacts that contribute to climate change” is an important consideration in electricity planning.

When push comes to shove, they will pay more and they think they’re getting good value for money.

In every part of the consultation, from focus group to telephone survey, once the critical issue of aging infrastructure was explained a majority of customers gave their support to increase rates.

- A slight majority (52%) in the Online Workbook supported a potential rate increase to improve the system’s reaction to major events.
- When asked about how much they would be willing to add to their monthly bill for better service, the average customer in the Workbook would be willing to pay about 5% more (median: 3%).
- As for value-for-money, nearly 6-in-10 (58%) residential customers think they are getting a reasonable or good deal on their electricity.

Given the difficult choice between “increased rates” and “reduced reliability”, customers have shown throughout the consultation that they will, rather reluctantly, accept higher rates for better service in Central Toronto.

Online Workbook

Online Workbook
with Volunteered customers

PURPOSE: To inform customers on the details of the Central Toronto IRRP and obtain feedback on the proposed planning options

Summary

This summary underlines key findings from residential and business customer feedback collected through the Online Workbook.

Familiarity, System Reliability and Rates

- Around 6-in-10 (n=49) respondents are generally familiar with Toronto Hydro's electricity distribution system. Of those 49 people, about 32 can explain the details of the system to others.
- A majority of customers think that both the average *number* (n=66 out of 83) and *length* (n=59 out of 83) of outages is acceptable. On average, customers surveyed experienced an average of just under four outages over the last two years (median: two outages) and during these outages, on average they spent a bit over 12 hours (median: two hours) each time without power.
- When asked an open-ended question on how the outages affected their place of business, most responded with issues of minor inconvenience such as "resetting clocks" and "spoiled food". In another follow-up asking customers to estimate their expenses during the outages, 4-in-10 (n=26) did not incur any expenses. The median customer lost about $12.50 from their last power outage.
- While a majority think the current length of outages is acceptable, there's a ceiling to this support. Nearly three-quarters (n=57) felt that "yes", there was a certain length of time at which the costs and consequences of an outage became more serious for them. When those "yes" respondents were asked a follow-up to describe that length of time in detail, timelines varied widely. Specific concerns mentioned include "food spoilage", "home heating and cooling affected" and "access to internet".
- It is important for customers surveyed that the regional electricity system is reliable beyond the bare minimum. About half (n=36) said it is "extremely important" to be reliable beyond the minimum standards and roughly a third (n=27) think it is somewhat important.
- When asked about how much they would be willing to add to their monthly bill for better service, the average customer surveyed would be willing to pay about 5% more (median: 3%). The range of per cent customers would be willing to pay for better service varied widely, from as little as nothing to as high as 25%
- The 11 business respondents who filled out the workbook appear to follow the trends in the larger sample on familiarity, reliability and price.

Security of the Electricity System: Satisfaction and Permission

- The 79 customers surveyed are more satisfied than not with the Central Toronto region's system performance during major events. Forty-six of 79 said they were satisfied with the service during major events and 33 claimed they were dissatisfied with the service.
- That being said, there's always room for improvement and customers appear to understand the need for long-term infrastructure development. A majority (n=41) of customers supported a potential rate increase to improve the system's reaction to major events while 26 of 79 said "no" to the increase. The remaining 12 did not know either way.
- Asking permission for a rate increase could be perceived as more successful when explained in the language of "major events". The average respondent would be willing to pay about 6% more for better service during major events, compared to less than 5% when asked previously about more general infrastructure improvements.
- Again, the eleven business respondents follow a similar trend to the larger sample on satisfaction and permission questions.

Conservation and Long-term Solutions

- About 3-in-4 (n=56) claim to have participated in energy conservation activities. Of the remaining 11 business customers, nine of them state they have participated in conservation.
- Out of the 56 respondents who do participate in conservation activities, 49 explained their actions in a follow-up open-ended question. Some of the conservation activities listed include "LED lightbulbs" (n=17), "*peaksaver* PLUS program" (n=9) and "use of energy efficient appliances" (n=7).
- Most customers (n=48 out of 78) state they would participate in "Demand Response" programs and 29 out of 78 would be "very likely" to participate. The small group of 11 business customers were also net likely to participate in these programs (n=7 to n=4 likely/unlikely).
- Most respondents (n=46) agree that system planners should forge long-term investments in infrastructure to improve reliability and security, compared with about 4-in-10 (n=31) who feel that system planners should manage the issues with the current infrastructure in place.
- In an open-ended follow-up question answered by 53 customers, those against infrastructure investment cited "we should use existing infrastructure" (n=15) as their main reason, followed by "it's more cost-effective" (n=2) and "we should reduce consumption" (n=2). Customers in support of additional infrastructure investment listed "build new infrastructure to improve reliability" (n=12), "plan for the future" (n=11) and "build to improve efficiency" (n=3) as their key reasons for the investment.
- When it comes to electricity generation, "solar" and "combined heat and power" are the two options respondents felt most appropriate for use in the Central Toronto region. Almost all the consulted customers would use solar and combined heat and power "all of the time" (n=45 and n=41, respectively) or "some of the time" (n=28 and 31). 'Bioenergy" (n=28: "all of the time"; n=37: "some of the time) and "using emergency generators" (n=16: "all of the time"; n=41 "some of the time") were seen as less viable options in the region, but still received net support. The small sample of 11 business customers mirrored the results of the larger sample for this and all subsequent questions.

- For demand solutions, customers consulted felt all three possibilities offered –"Conservation and Demand Management", "Transmission and Distribution" and "Distributed Generation"- were appropriate for the problem at hand.
- Customers considered "Conservation and Demand Management" the most appropriate solution ("all the time" n=48; "some of the time": n=20), followed by "Transmission Distribution" (appropriate "all of the time": n=42; "some of the time": n=29) and "Distributed Generation" ("all of the time": n=32; "some of the time": n=39).
- Customers' first choice of demand solutions is "Conservation and Demand Management" (n=31). When asked for their second choice, consulted customers chose "Distributed Generation" (n=35).
- In the open-ended explanations of their first and second choices of electricity solutions, the answers customers gave focused on cost, improved supply, reduced reliance and environmental concerns.

Methodology

About the Online Workbook

In the fall of 2014, the IRRP Study Partners and INNOVATIVE staff started to develop an online customer workbook which would help the IRRP Study Partners to consult and inform customers about a 25-year plan for electricity service.

The Online Workbook was divided into five key sections:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of the Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

The first section informed the respondent about the geography and organizational responsibilities of the IRRP Study Partners, explained why the customer was consulted, and asked for basic demographic information.

The second and third sections were informative only: they explained electricity generation, how electricity is transmitted and distributed in the city of Toronto as well as a brief overview of the current system.

In the next section "Planning to Meet Customer Expectations", the key analysis started. First, the IRRP Study Partners informed customers about each of the key questions to forecast electricity:

- How much electricity will customers likely demand in the future?
- All things being equal, how much electricity can the system supply?
- When things go wrong outside of major events, how reliable is the system?
- And how does the system cope with major storms or disasters?

Respondents then were prompted with questions on system reliability and the perceived financial costs to the customers personally during outages, followed by questions on system security during major events and electricity pricing. Open-ended responses were included (ex: "How did the power outage affect your business?") to provide additional opportunities for customers to give more specific feedback.

(In part because of the small n-sizes of the open-ended responses, the results of these questions should be considered exploratory research and not a definitive quantitative analysis).

The final section of the workbook provided detailed explanations on the three main solutions to capacity concerns (“CDM”, “DG” and “Transmission or Distribution Expansion”) and then asked customers to choose between a variety of options. Again, open-ended responses were included such as “why do you prefer the one view over the other?” to provide additional engagement opportunities for customers.

In total, the Online Workbook contained a total of 23 survey questions and six demographic questions. All responses were anonymous and kept strictly confidential.

This workbook was an opportunity to engage customers and inform them about the IRRP as well as share their feedback. The ultimate goal was to ensure the IRRP accurately reflects the regional customers’ preferences and priorities.

Field Dates:

The Online Workbook was available online to access for Central Toronto residents and businesses for just over six weeks, between September 3, 2014 and October 20, 2014.

Promoting the Online Workbook:

The Online Workbook was promoted by the IRRP Study Partners through traditional print advertising as well as the various organizational web sites and social media accounts of the member organizations, including Facebook and Twitter.

Hosting the Online Workbook:

The Online Workbook was hosted by INNOVATIVE under the URL: *www.centraltorontoplan.ca*.

The IRRP Study Partners and INNOVATIVE designed the workbook to prevent respondents from completing questions multiple times and to save the progress of respondents in case they leave prematurely.

When respondents reached the final webpage, the survey was considered complete and the site was no longer accessible to the internet protocol (IP) address used to complete the Online Workbook. Cookies were used in the design of the Online Workbook ensure that respondents only complete the Online Workbook once. (Cookies are small pieces of data that identify users and prepare customized Web pages for them).

At the same time, the site saved answers if respondents left the Online Workbook part-way through the process. When respondents returned to the Online Workbook, all previously entered answered re-appeared linked to the user’s IP address.

We do not link the information stored in cookies to any personal information submitted on our site.

Respondent feedback data was only ever available to INNOVATIVE staff through a secure data retrieval portal.

Validating Customer Responses:

Respondents were asked to identify themselves as either a residential or business customer of Toronto Hydro and also to provide the postal code that corresponded to either their residence or business. All further questions tagged them with an individual identification number based on this information.

Toronto Hydro provided INNOVATIVE with a list of all valid customer postal codes which were cross-referenced against responses to these questions in this workbook. Invalid postal codes were removed from the final sample.

Sample Characteristics:

The breakdown of Online Workbook responses are as follows:

- 753 unique visitors came to the Online Workbook's landing page.
- 257 unique visitors answered at least one question.
- 71 customers completed the entire Online Workbook by answering all questions.

NOTE: Results contained within this report are based on a limited and non-representative sample of volunteered respondents and should be interpreted as directional research only. Depending on user response error and completes, n-sizes may vary slightly from question to question. Because there was no mechanism in place to force users to answer specific questions, customers sometimes 'cherry-picked' which follow-up they decided to answer. This is reflected in the n-size, particularly on the open-ended questions.

Customer answers for each question were grouped together in tables anonymously and the information provided was used for statistical analysis only.

Out of 257 initial respondents who answered at least one question, 71 completed the entire workbook.

The 60 residential and 11 business customers who completed all questions are the focus of the *Respondent Feedback* section of this report.

As for business respondents, 28 identified as a business customer initially. While the n-size of residential customers experienced a significant drop-off over the course of the survey, the business customers tended to finish what they started. Eleven of the 12 business customers who completed the profiling section of the Online Workbook completed the entire survey from start to finish.

Responses provided by business customers are included in most of the following charts as footnotes because of the small sample size.

Respondent Profile

Figure A1: Residential Customer Profile

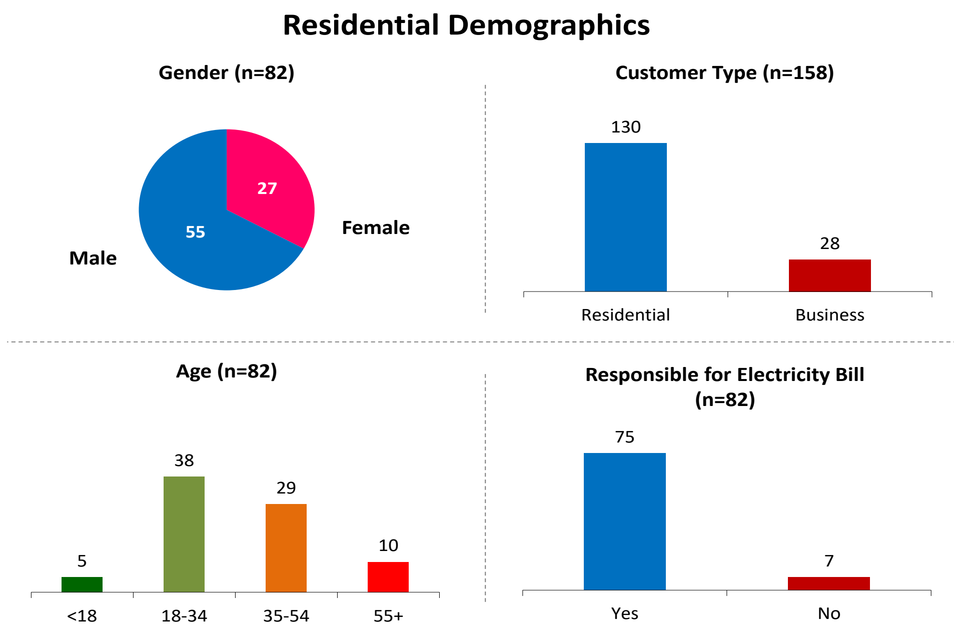


Figure A2: Residential Customer Profile

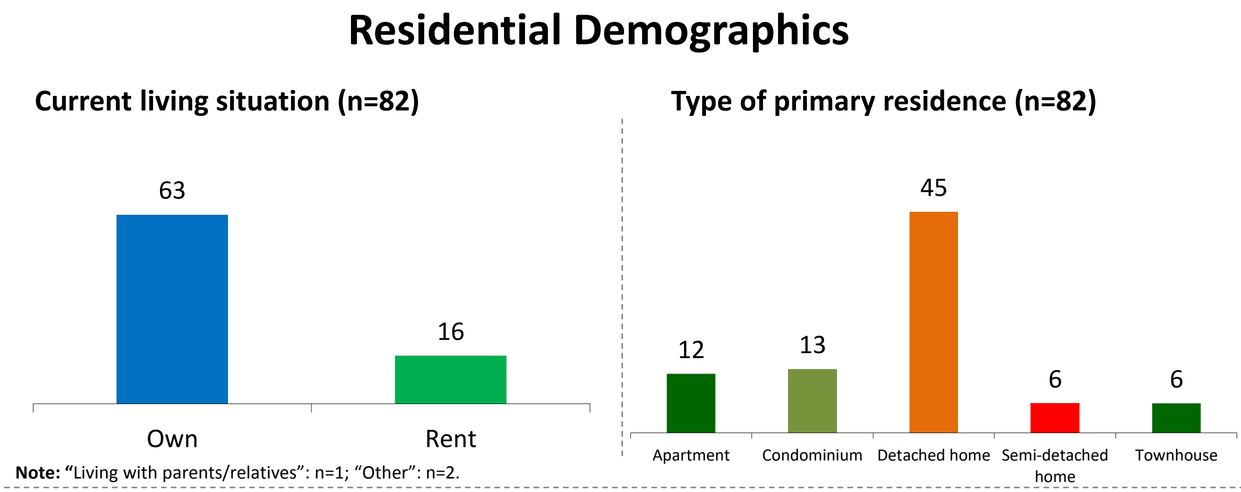
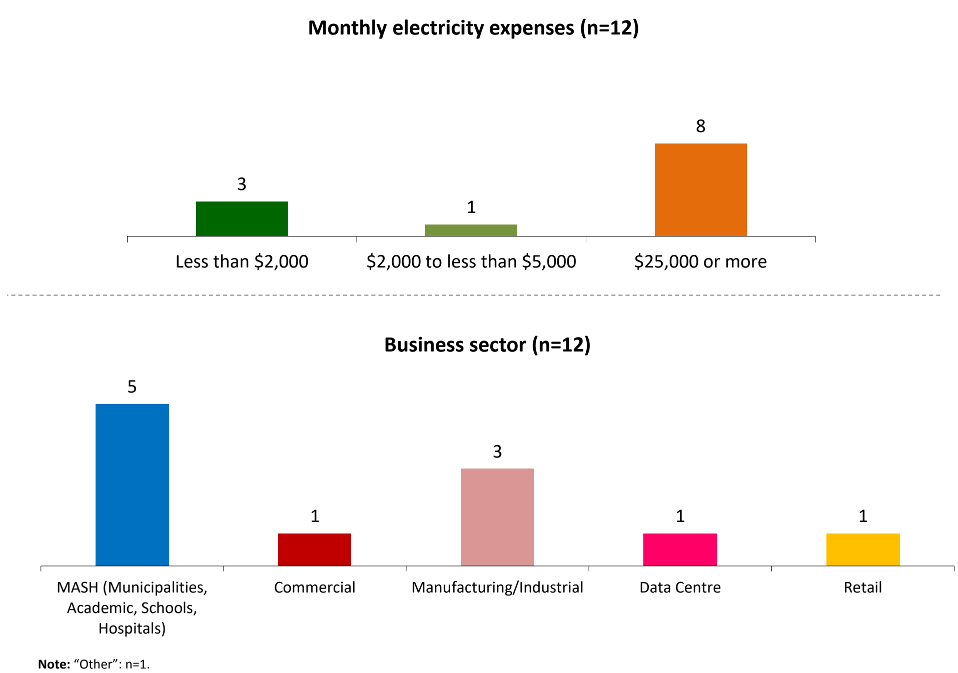
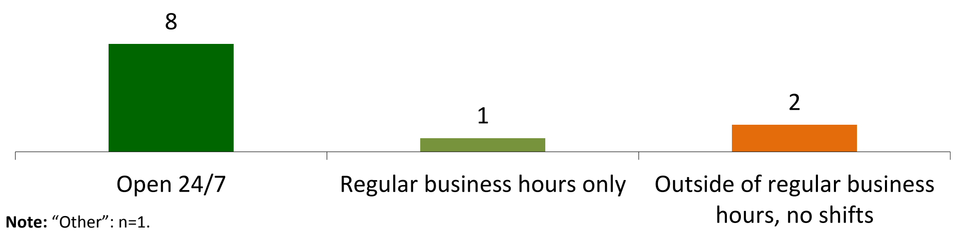


Figure B: Business Customer Profile

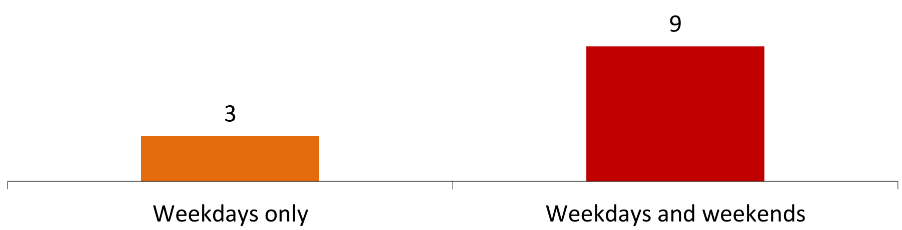


Hours of operation (n=12)



Note: "Other": n=1.

Business sector (n=12)



Respondent Feedback

As mentioned in the previous section, 60 residential and 11 business respondents completed the IRPP's Online Workbook. However, number of completes from question to question vary and are a bit higher at the start.

Familiarity, System Reliability and Price

This first section examines how familiar respondents are with the electricity system, reliability of the electricity system in terms of number, length and overall seriousness of outages and, finally, attitudes on price.

Familiarity with the System

- About 6-in-10 respondents (n=49) state they are "familiar" with Toronto Hydro's electricity distribution system. Of those 49 people, 32 can explain the details of the system to others.

System Reliability: Number, Length and Seriousness of Outages

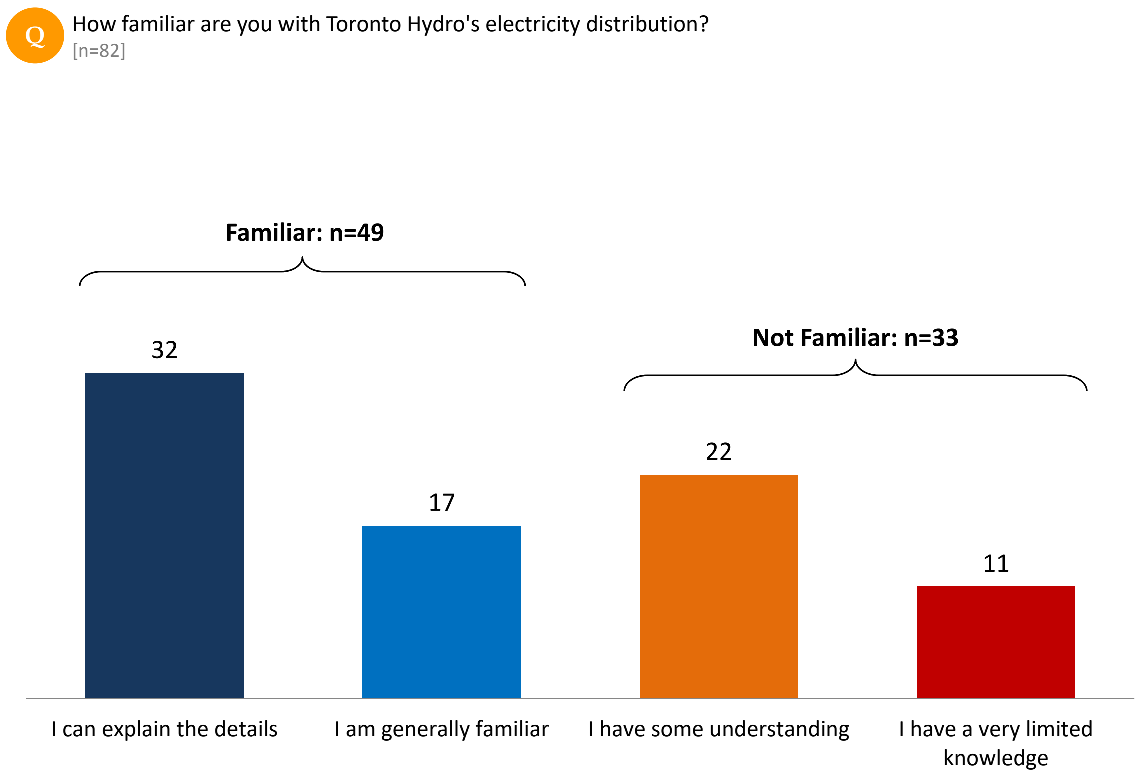
- A strong majority of respondents (n=66 out of n=83) think that the average *number* of outages in Central Toronto is "acceptable". Only 17 out of the 83 respondents on this question consider the number of outages "unacceptable".
- Again, a majority of respondents (n=59 out of n=83) find the average *length* of outages "acceptable" with roughly 3-in-10 (n=24) who find it "unacceptable".
- Sixty-one consulted customers also answered an open-ended question on 'number of outages' and 47 answered the follow-up on 'outage length'. The average *number* of outages for customers was a bit less than four (3.72). But the median or mid-point customer experienced outages much less frequently: two outages over the last two years. This difference can be explained by a few frequent outliers ("20" and "30" outages in the past two years) that skewed the average higher.
- The average outage *length* for customers who experienced one was 12.39 hours; again, the average skewed a bit higher from six possible outliers who experienced an outage of "48 hours or more". The median customer or half-way point in the sample was just two hours; and one in five (n=10) customers experienced an outage of 15 minutes or less.
- When customers were asked an open-ended question on how the outages affected their place of business, 56 people responded. The leading effect was a "minor inconvenience" (n=19) such as resetting clocks, followed by "spoiled food/disrupted holidays" (n=11) and "negatively affected living conditions" (n=11).
- In another open-ended follow-up, 65 customers gave a response estimating the dollar cost of expenses incurred during the power outage. About 4-in-10 (n=26) did not incur any expenses. The median customer experienced a loss of about $12.50 during this time. The average is much higher (almost $100k) due to a $5 million outlier response.
- Nearly three-quarters of respondents (n=57) stated "yes", that there was a certain length of time at which the costs and consequences of an outage became more serious for them.
- When those "yes" respondents were asked a follow-up to describe that length of time in detail, 57 responded. Anywhere from less than 30 minutes (n=5) to 48 hours or more (n=5) were timelines that caused serious consequences to consumers. Specific concerns mentioned include "food spoilage", "home heating and cooling affected" and "access to internet".

- Almost half of respondents (n=36) feel it is "extremely important" for the Central Toronto system to be reliable beyond the minimum standards and roughly a third (n=27) think it is somewhat important.

Reliability and Price

- When asked about how much they would be willing to add to their monthly bill for better service, every single person responded for a total of 83 customers. The average customer surveyed would be willing to pay about 5% more (median: 3%). The range of per cent customers would be willing to pay for better service varied widely, from as little as nothing to as high as 25%

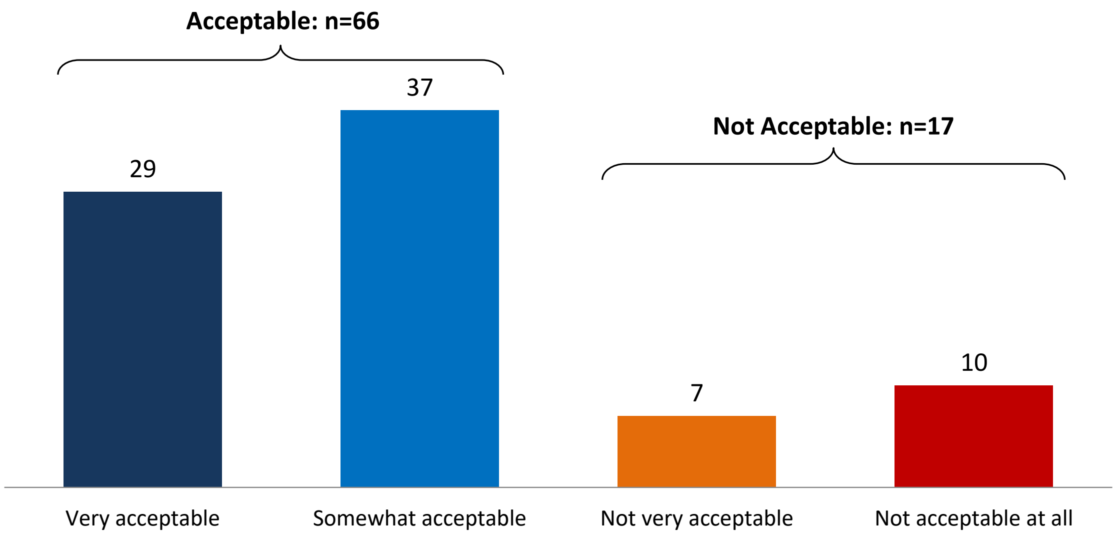
Figure 1: Familiarity with Electricity Distribution System



Roughly 6-in-10 (n=49) respondents are familiar with Toronto Hydro's electricity distribution. Among the 82 people who responded on this question, 32 can explain the details of distribution and 17 say they are generally familiar. About 4-in-10 (n=33) respondents are not familiar. Of these, 22 have some understanding of the system while 11 claim very limited knowledge of Toronto's electricity distribution.

Figure 2: Reliability of System: Number of Outages

Q Do you feel the current average number of electricity outages in the Central Toronto electricity system is acceptable or not acceptable?
[n=83]



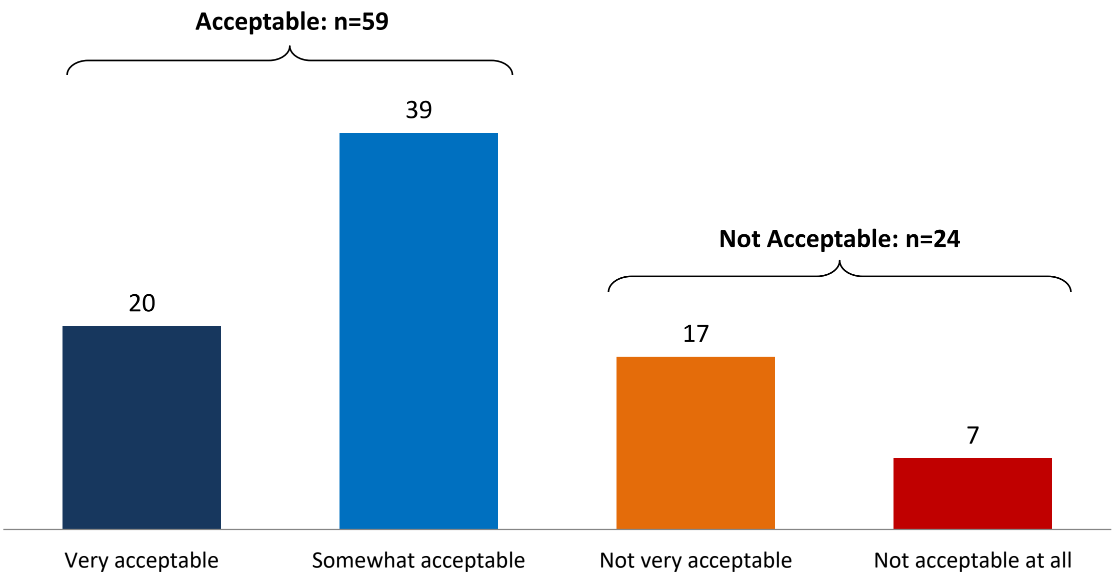
Note: Residential: n=72; Business: n=11. For business: "very acceptable" (4), "somewhat acceptable" (3), "not very acceptable" (1), "not acceptable at all" (3)

A strong majority of respondents (n=66) think that the number of outages in Central Toronto is "acceptable". Of the 83 who responded to this question, 29 stated the average number of outages are "very acceptable" and 37 thought it was "somewhat acceptable". Just 17 of the respondents think the number of outages is "not acceptable" with 10 who think it is "not acceptable at all".

Of the 11 business respondents who answered, four think the current level is "very acceptable", three find it "somewhat acceptable", just one finds it "not very acceptable", and the remaining three find it "not acceptable at all".

Figure 3: Reliability of System: Length of Outages

Q Do you feel the average length of an outage in the Central Toronto electricity system is acceptable or not acceptable?
[n=83]



Note: Residential: n=72; Business: n=11. For business: "very acceptable" (4), "somewhat acceptable" (2), "not very acceptable" (4), "not acceptable at all" (1)

A majority of respondents (n=59) also find the average length of an outage in Central Toronto "acceptable", although agreement is less strong here. Twenty out of the 83 respondents find average outage length "very acceptable" and 39 find it "somewhat acceptable". Roughly 3-in-10 respondents (n=24) find average length of outages in Central Toronto "unacceptable". Seventeen of the 83 think it is "not very acceptable" and the remaining seven believe the average length is "not acceptable at all".

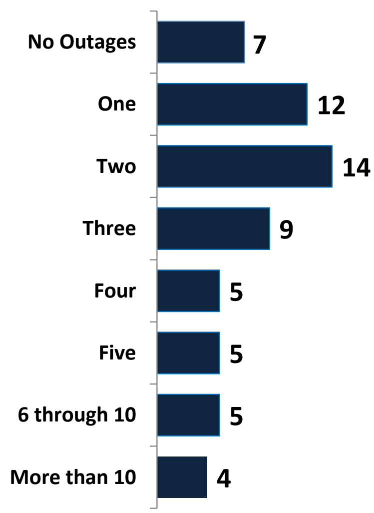
For the 11 business respondents who answered, four think the current level is "very acceptable", two believe it "somewhat acceptable", four find it "not very acceptable", and the remaining person finds it "not acceptable at all".

Figure 4: Open-ended on Number and Length of Outages

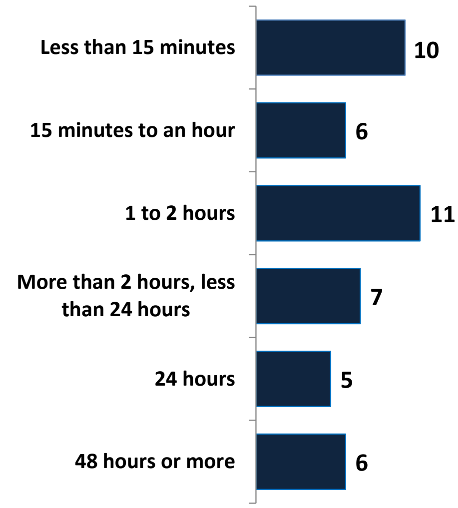
Q How many outages have you experienced over the last two years? [OPEN]
[n=61]

Q [If 1 or more] How long was the power out during your most recent outage? Please describe in hours. [OPEN]
[n=47]

“Number of outages”



“Number of hours without power”



Sixty-one consulted customers also answered an open-ended question on ‘number of outages’ and 47 answered the follow-up on ‘outage length’.

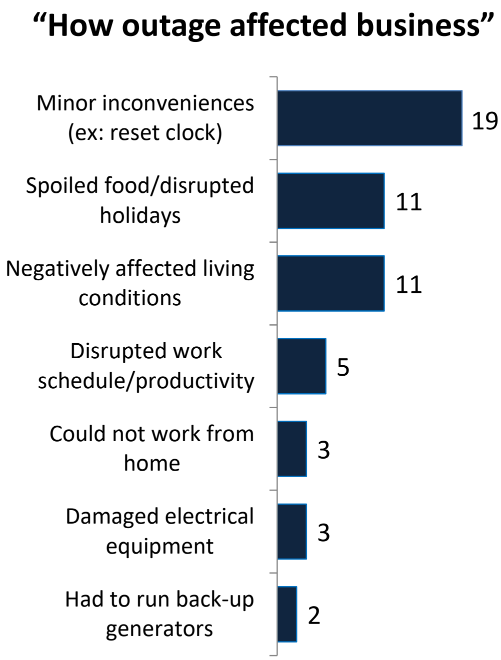
When asked the number of outages they had experienced over the last two years, customer response varied widely from zero to as high as 30 outages. On average, the number of outages among respondents was less than four (3.72). However, because of the wide spread on these numbers (20 and 30 as a possible outlier), it may be more useful to look at the median or mid-way point between all the numbers. The median customer experienced two outages over the last two years.

For those who experienced an outage, they were asked a follow-up question: “how long was the power out during your most recent outage in hours”? Ten of the 47 who responded stated their power was out for “less than 15 minutes”; 6 said “15 minutes to an hour” and 11 said between “one and two hours”. On the higher end, seven customers said “more than two hours but less than 24 hours”, 5 said “24 hours” and the final six suffered outages of “48 hours or more”.

The range on this question varied widely, from just a few moments to a high of 96 hours. Again, because of this wide spread and the outlier of “96 hours” we see a strong difference between the median customer of just two hours and the average customer of 12.39 hours without power.

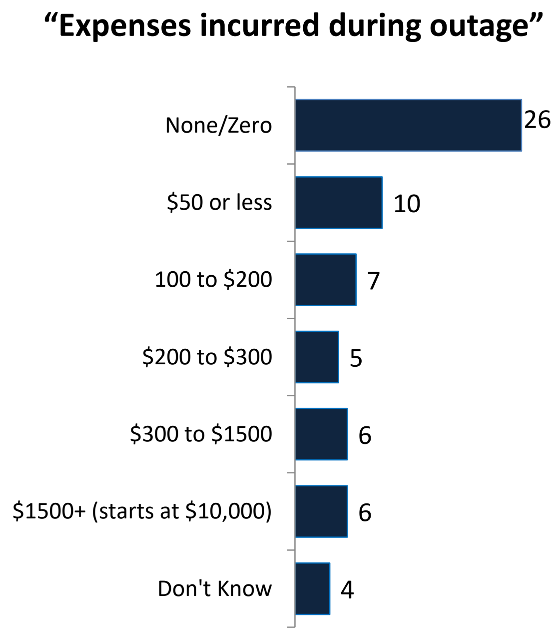
Figure 5: Open-ended on Outages for Business Respondents

Q [If 1 or more] How did the power outage affect your business? [OPEN]
[n=56]



Asked of all respondents. "Other" (n=1) and "No effect" (n=1) not shown.

Q [If 1 or more] Can you estimate the dollar value of any expenses you incurred as a result of the power outage? [OPEN]
[n=65]



"Refused" (n=1).

If customers experienced an outage, they were asked an additional follow-up on how it affected their place of business. Fifty-six customers responded to this open-ended question.

The leading effect for consulted customers was a "minor inconvenience" such as resetting clocks (n=19), followed by "spoiled food/disrupted holidays" (n=11) and "negatively affected living conditions" (n=11). Other effects of the outage on businesses include: "disrupted work schedule/productivity" (n=5), "could not work from home" (n=3", "damaged electrical equipment" (n=3) and "had to run back-up generators" (n=2).

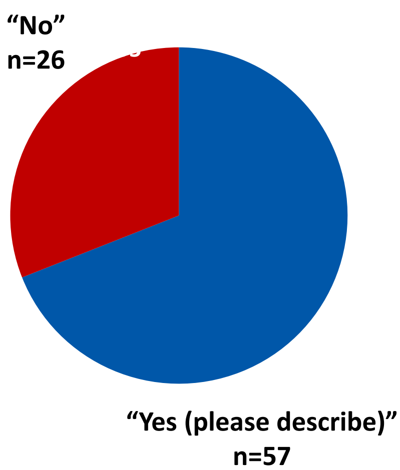
One final follow-up was asked on the dollar estimate of any expenses incurred during the power outage; 65 customers responded.

About 4-in-10 (n=26) did not incur any expenses during the outage and ten customers incurred $50 or less in damages. A smaller number of customers incurred $100 to $200 (n=7), $200 to $300 (n=5) and $300 to $1500 (n=6) in damages during the outages. The six remaining customers experienced $10,000 or more in damages with the highest range of cost up to an estimated $5 million.

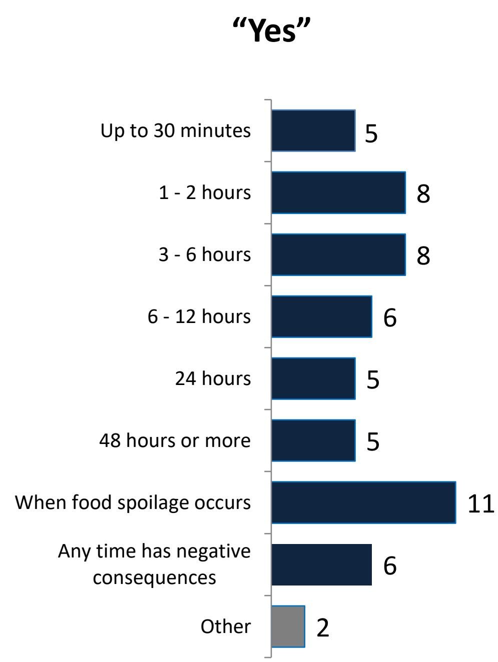
Again, because the range is so high (mostly zero with a $5 million outlier) the average customer loss on this response is going to be much higher than the median or mid-point customer. That being said, the average loss during outages was almost $100,000 ($97,543.88) because of this outlier while the median customer experienced a loss of about the price of dinner at 'Hero Burger': $12.50.

Figure 6: Seriousness of Outage Length

Q Is there a certain length of time at which the costs and consequences of an outage become more serious for you?
[n=83]



Q Yes, please describe [OPEN-ENDED]
[n=57]

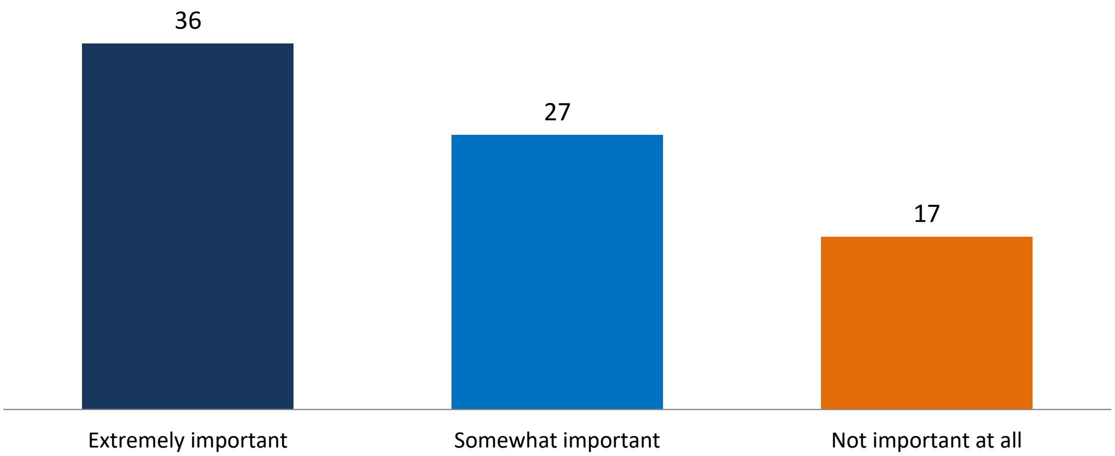


When asked if there was a certain length of time at which the costs and consequences of an outage become more serious, most of the respondents said "Yes" (n=57). Just 26 surveyed said "no", that there was no length of time when the costs and consequences would be serious.

Those that said "yes" were also asked an open-ended follow-up question to describe that length of time and 57 customers responded. A plurality were concerned about food spoilages (n=11 and also mentioned often in multiple time categories). Anywhere from up to 30 minutes (n=5) to 48 hours or more (n=5) were lengths of times that caused serious costs and consequences to consumers. Other concerns mentioned in the open-ended included "home heating and cooling affected", "access to internet" and other specific medical concerns.

Figure 7: Standards for Reliability

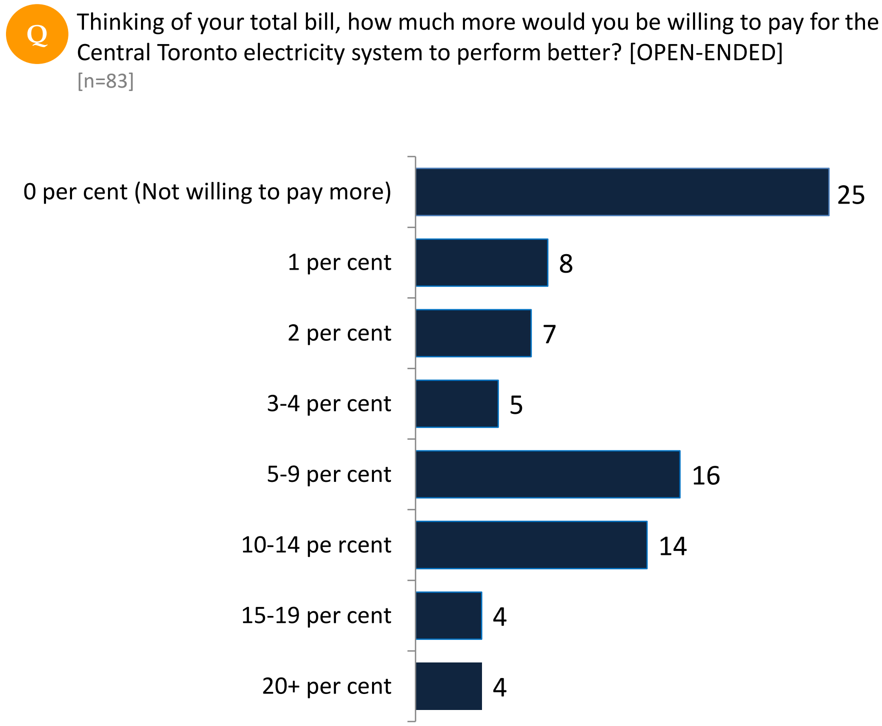
Q How important is it is for the Central Toronto electricity system to be reliable beyond the minimum standard?
[n=81]



Note: "Don't know": n=1. Residential: n=70; Business: n=11.
For business: "extremely important" (9), "somewhat important" (2)

Just under half of respondents (n=36) stated that it is "extremely important" for the Central Toronto electricity system to be reliable beyond the minimum standards. About a third (n=27) think that it is "somewhat important" to be reliable beyond the minimum standard. The remaining 17 people do not think it is important at all to be reliable beyond the minimum.

Figure 8: Reliability and Economic Development



For the open-ended question on billing and how much more they would be willing to pay for better service, every single person still taking the survey responded: a total of 83 customers.

A plurality of customers said they were not willing to pay any more than they currently do (n=25). About a quarter of the customers said they were willing to pay between 1-4% more (1%: n=8; 2%: n=7; 3-4%: n=5). Fifteen customers said they were willing to pay 5-9% more and 14 customers said they would pay between 10-14%. Four customers said they were willing to pay between 15-19% more and the remaining four customers offered to pay 20% or more for better service.

The average customer surveyed would pay roughly 5% (4.89%) more and the median or mid-point customer would pay about 3%. The range of per cent customers would be willing to pay for better service started at nothing and went as high as 25%

Security of the Electricity System: Satisfaction and Permission

This section of the workbook focuses on customer satisfaction with their electricity during major event interruptions and gauges how comfortable customers would be raising rates to address security during major events.

Satisfaction with Service during Major Events

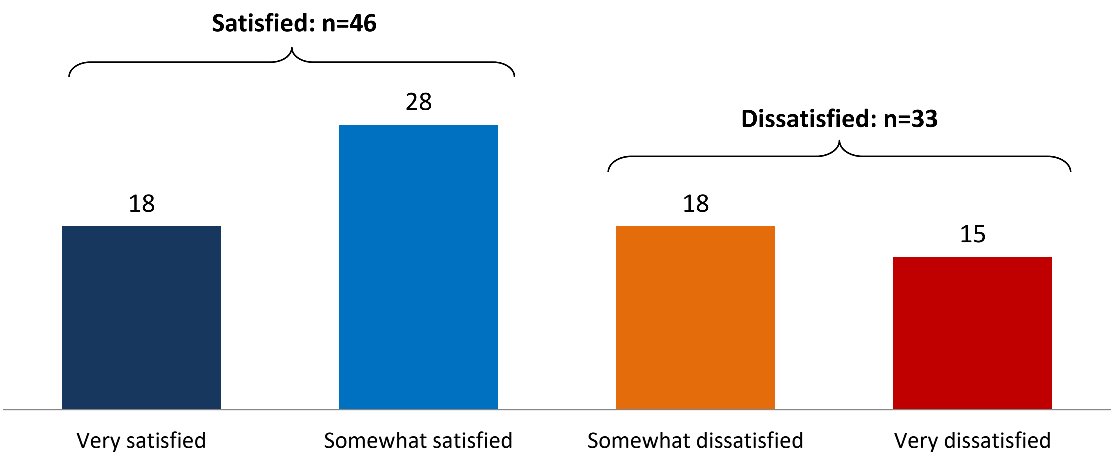
- Satisfaction with electricity system performance during major events is net positive. Forty-six of the 79 who answered the question "how satisfied are you with the way the Central Toronto electricity system has performed during major events" say they are satisfied and 33 of the 79 claim dissatisfaction.
- Of the 11 business customers surveyed, there is a 6-5 split on satisfied/unsatisfied.

Permission for Rate Increase to Address Security

- When asked about a potential rate increase to improve the system during major events, a majority (n=41) of customers supported the idea. Twenty-six of 79 said "no" and the remaining 12 did not know the answer.
- As for the 11 business customers, seven stated "yes", one "no" and the last three did not know how to respond.
- Those who gave permission on a rate increase (n=41) were asked a follow-up: “how much more would they be willing to pay as a percentage of their total bill to improve responses to major events”? (Eleven additional people replied to this despite the “if yes” shown in the question for a total of 52 respondents). The average customer would be willing to pay about 6% more for better service during major events, compared to less than 5% when asked previously about more general infrastructure improvements.

Figure 9: Satisfaction with Service during Major Events

Q From what you have read here and considering your own experience, how satisfied are you with the way the Central Toronto electricity system has performed during major events?
[n=79]



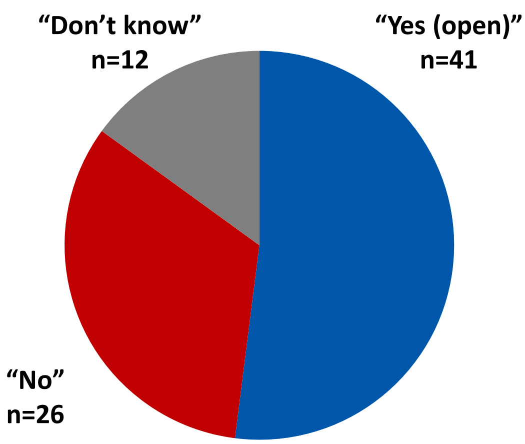
Note: Residential: n=68; Business: n=11. For business: "very satisfied" (4), "somewhat satisfied" (2), "somewhat dissatisfied" (3), "very dissatisfied" (2)

When asked about the performance of the Central Toronto electricity system during major events such as a natural disaster, satisfaction is net positive. Among those surveyed, 46 were satisfied and 33 were dissatisfied with the performance of the electricity system during major events. About one-in-five (n=18) were very satisfied and one-in-three (n=28) respondents were somewhat satisfied. Of those dissatisfied customers, 18 were somewhat dissatisfied and 15 stated they were very dissatisfied.

As for the 11 business respondents who answered, four stated they were "very satisfied", two were "somewhat satisfied", three think it "not very acceptable", and the remaining two people were "very dissatisfied" with the performance during major events.

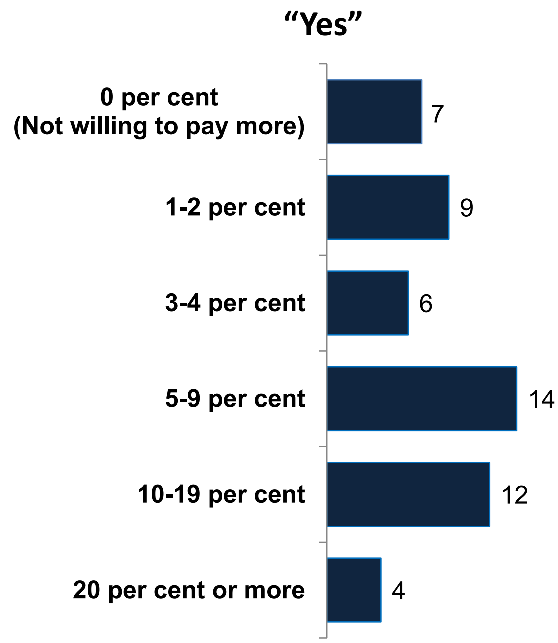
Figure 10: Permission for Rate Increase to Address Security

Q To improve the ability of the Central Toronto electricity system to respond to major events beyond our current standards will require spending more money. Are you willing to pay more on your electricity bill so the Toronto electricity system can improve its ability to respond to major events?
[n=79]



Note: Residential: n=68; Business: n=11. For business: "yes" (7), "no" (1), "don't know" (3)

Q (If Yes) And thinking of a percentage of your bill, how much more would you be willing to pay for the Central Toronto electricity system to improve its ability to respond to major events?
[n=52]



A slight majority of customers (n=41) give permission for a rate increase to improve the system's response to major events. More than a third (n=26) of customers say "no" to a rate increase directed to better service during major events. The remaining 12 people out of 79 just "don't know".

Of the 11 business customers who answered the permission question, seven responded "yes", just one stated "no" and the remaining three did not know the answer.

Those who gave permission (n=41) were asked a follow-up: "how much more would they be willing to pay as a percentage of their total bill to improve responses to major events"? (11 additional people replied to this despite the "if yes" shown in the question for a total of 52 respondents).

With a focus on improving system response to major events, customers were much more willing to pay a higher percentage than the previous, more general question on billing. Just 7 out of 52 respondents were not willing to pay any more, nine were willing to pay 1-2% more and 6 were willing to pay 3-4% more. A plurality of customers (n=14) were willing to pay between 5-9% more and 12 were willing to pay between 10-19% more. The remaining four customers surveyed were willing to pay 20% or more for better service during major events.

The average customer would be willing to pay 6%more for better service during major events, compared to an average of less than 5% more when asked previously about more general improvements. Similarly, the median customer would pay 5% more for better service during major events, compared to just 3%on the previous more general question. Both questions had the same range of responses (0-25%) but the billing question on major events skewed to a slightly higher percentage with less people saying “0%”.

Conservation and Long-term Solutions

This last section examines the customer consultation on long-term solutions, participation in conservation, attitudes on infrastructure investment and also preferences for various demand and generation solutions for regional electricity.

Participation in Energy Conservation

- Roughly three-in-four (n=56) respondents claim they participated in energy conservation activities. Of the 78 respondents left, eleven are business customers. Nine of these 11 business customers say "yes", they have participated in conservation activities.
- Of the 56 respondents who said “yes”, 49 explained their activities in the follow-up questions. Some of the conservation activities listed include “LED light bulbs” (n=17), “*peaksaver* PLUS program” (n=9) and “use of energy efficient appliances” (n=7).
- When asked about “Demand Response” programs, around 6-in-10 (n=48) would participate in them. Of the four categories, a plurality (n=29) of respondents chose “very likely” to participate. Business customers were split about evenly with five “likely” and six “not likely” to participate.

Infrastructure Investment

- Around 6-in-10 (n=46) respondents agree that system planners should look to new long-term investments in infrastructure to improve reliability and security, compared with 4-in-10 (n=31) who feel that system planners should use what they have already first. Slightly more business customers (n=7) than not (n=4) chose the statement on long-term infrastructure investment.
- When customers were asked their reasons for agreeing or disagreeing with the statement supporting infrastructure investment, 53 responded to the follow-up. Those who were against infrastructure investment cited “we should use existing infrastructure” (n=15) as the main reason, followed by “more cost-effective” (n=2) and “should reduce consumption” (n=2). Customers in support of additional infrastructure investment listed “build new infrastructure to improve reliability” (n=12), “plan for the future” (n=11) and “build to improve efficiency” (n=3) as their key reasons for support.

Generation Solutions

- When asked which generation options would be appropriate to Central Toronto "all of the time, some of the time or none of the time", the most popular two options were "solar" and "combined heat and power". Almost all the respondents would use solar and combined heat and power "all of the time (n=45 and n=41, respectively) or "some of the time" (n=28 and 31).
- "Bioenergy" (n=28: "all of the time"; n=37: "some of the time) and "using emergency generators" (n=16: "all of the time"; n=41 "some of the time") were deemed less appropriate generation solutions but still had wide support among those consulted.
- These preferences are largely mirrored in the 11 business customers.

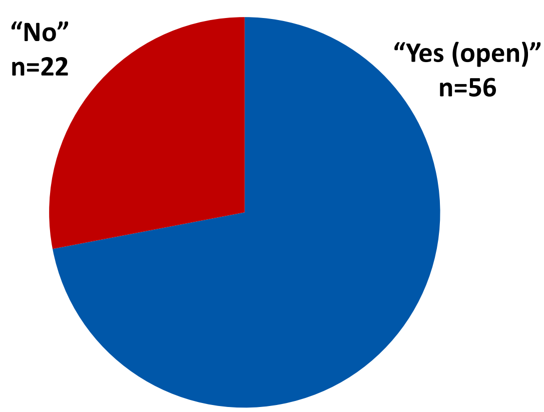
Demand Solutions

- Customers consulted on regional demand solutions felt all three demand solutions were "appropriate" ones. The 11 business customers surveyed also support all three options in similar strength.
- "Conservation and Demand Management" was considered the most "appropriate" demand solution with about two-thirds of customers who think it is a solution that should be used "all the time" (n=48) and a quarter (n=20) who feel it is appropriate "some of the time".
- "Transmission and Distribution" are also considered an "appropriate" demand solution among the 72 surveyed. Roughly 6-in-10 (n=42) think it is appropriate "all of the time" and 4-in-10 (n=29) feel it is appropriate "some of the time".
- The last option "Distributed Generation" also has general support with 32 of 72 customers who feel it is appropriate "all of the time" and 39 who think it should be used "some of the time".
- When asked to rank their first choice of demand solutions, a plurality (n=31) of customers chose "Conservation and Demand Management". Close behind was "Transmission and Distribution" (n=26) and the least popular first choice was "Distributed Generation" (n=15).
- For their second choice of demand solution, "Distributed Generation" (n=35) was the clear winner.
- In the customer explanations of their first and second choices, the main reasons given focused on cost, improved supply, reduced reliance and environmental concerns.

Figure 11: Participation in Energy Conservation

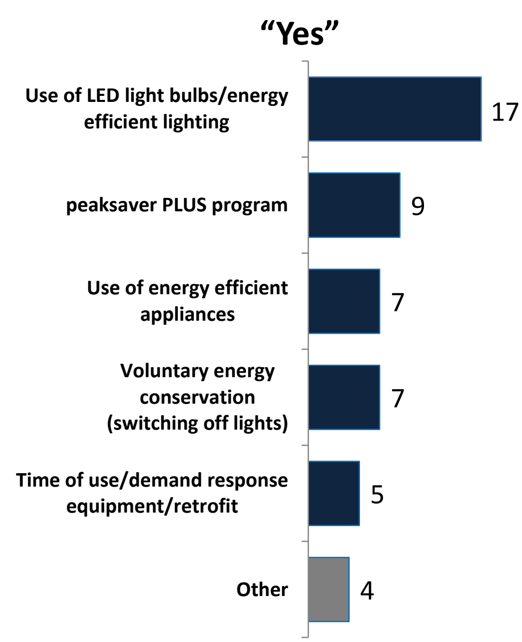
Q For each question, please either check the box for the options that best represents your view or write your response in the space provided.

Have you participated in any conservation activities? [n=78]



Note: Residential: n=67; Business: n=11. For business: "yes" (9), "no" (2)

Q (If Yes) Please describe some of them? [OPEN] [n=49]



About three-quarters (n=56) of customers surveyed have participated in energy conservation activities. The remaining 22 out of 78 respondents say "no", they have not participated in any conservation.

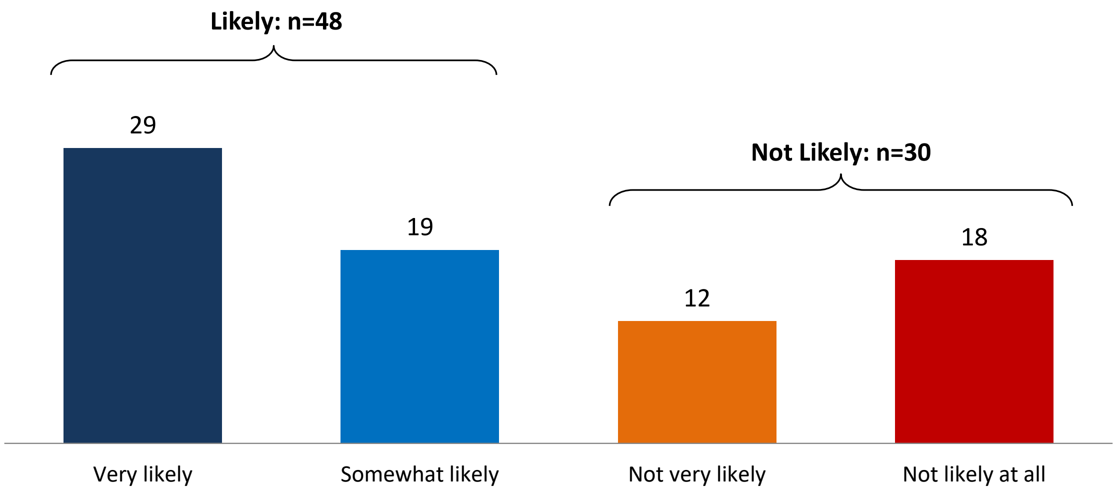
As for the 11 business respondents, nine say "yes", they have participated in conservation activities and the remaining two state the opposite.

Of the 56 respondents who say "yes", they do participate, 49 respondents chose to fill out the next questions describing those activities:

- About 3-in-10 (n=17) respondents cited "use of LED lightbulbs/energy efficient lighting" as their conservation activity.
- The "*peaksaver* PLUS program" (n=9) was the second leading conservation activity for customers.
- Other conservation activities mentioned include "use of energy efficient appliances" (n=7), "voluntary energy conservation" such as switching unused lights off more (n=7) and "time of use/demand response equipment retrofit" (n=5).

Figure 12: Likely Participation in Demand Response Programs

Q For CDM to provide an alternative to DG or transmission/distribution, it must provide an acceptable level of certainty as compared to DG or transmission. **How likely is it that you will participate in Demand Response programs that will allow electricity system managers to cycle equipment you are using?** For residences, this would involve automated devices that turn off your pool heater and air conditioner for short periods at time of peak demand. For commercial or industrial users, this would be an agreement to shut down specific agreed upon equipment on request.
[n=78]



Note: Residential: n=67; Business: n=11. For business: "very likely" (3), "somewhat likely" (2), "not very likely" (1), "not likely at all" (5)

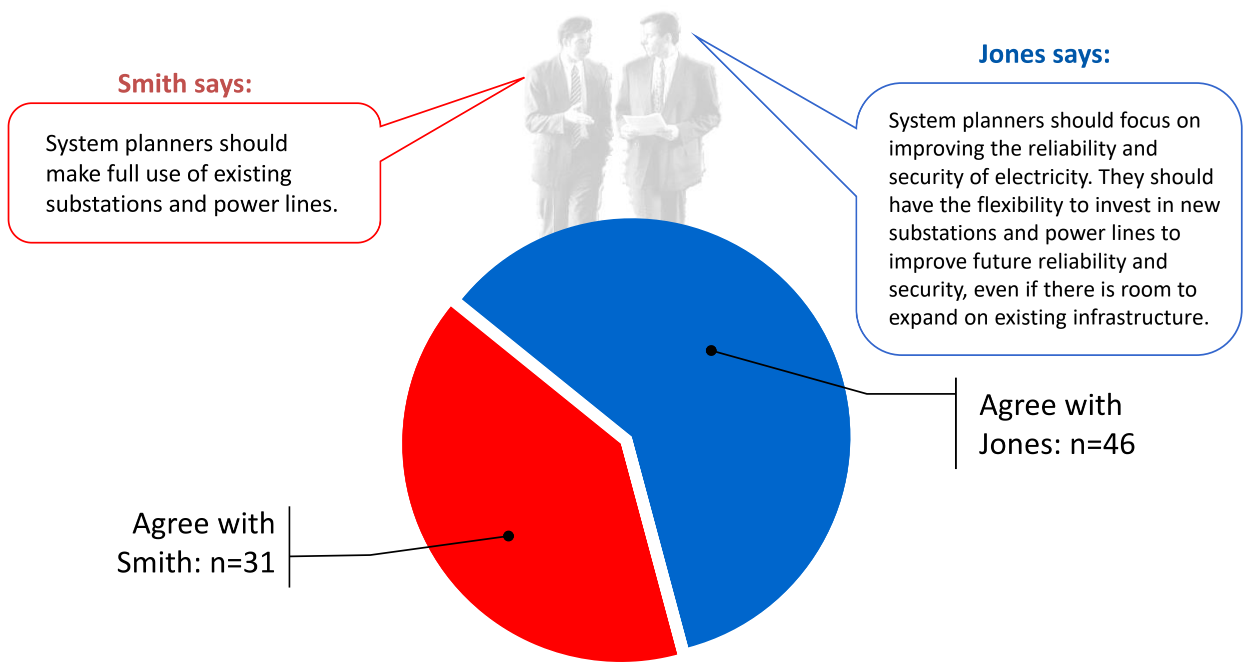
Roughly 6-in-10 (n=48) of the respondents would participate in "Demand Response" programs that would cycle equipment. Of those, 29 out of the 78 are "very likely" to participate and 19 are "somewhat likely" to do so. Roughly 4-in-10 respondents (n=30) are not likely to participate in these programs, with 12 "not very likely" and the remaining 18 "not likely at all" to participate in this type of response.

The 11 business customers responded as follows: three "very likely", two "somewhat likely", one person "not very likely" and five business customers "not likely at all".

Figure 13a: Investments in Infrastructure

Q For each question, please either check the box for the options that best represents your view or write your response in the space provided.

Sometimes planners have tough choices to make when it comes to balancing the need for capacity, reliability, and security. Below you will see two choices. Please indicate which choice you would make and why? [n=77]



Note: Residential: n=66; Business: n=11. For business: "Smith" (4), "Jones" (7).

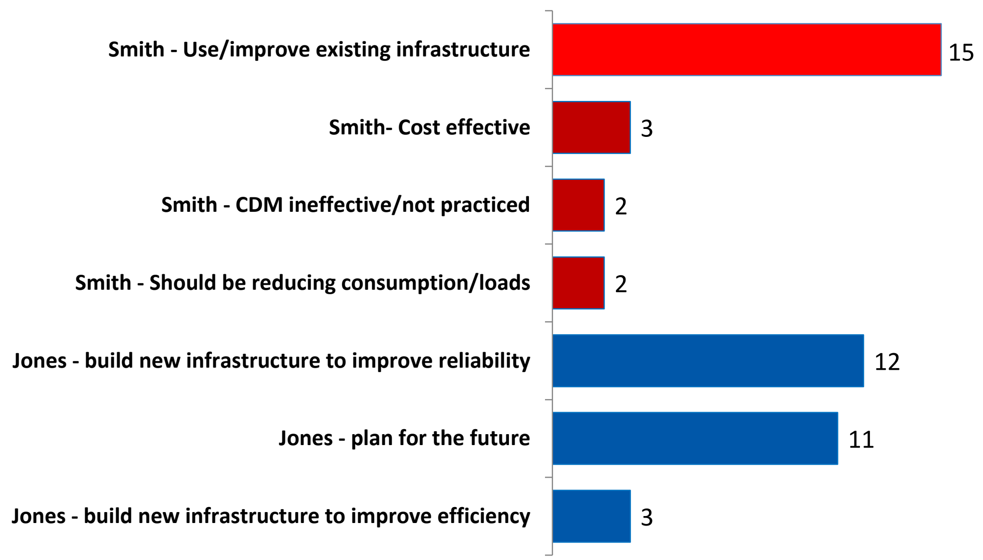
The next question asked respondents to choose between two strong opinions on balancing the need for capacity, reliability and security. One side argues that "system planners should make full use of existing substations and power lines" while the other states that "system planners should focus on improving the reliability and security of electricity…and invest in new substations and power lines to improve future reliability and security, even if there is room to expand on existing infrastructure".

About 4-in-10 (n=31) agree with the first opinion, that system planners should use what they have first. Around 6-in-10 (n=46) agreed with the second option, that system planners should look to new investments in infrastructure to improve future reliability and security.

Of the 11 business respondents, slightly more agree with the second statement on increased infrastructure investment (n=7) than the first statement that system planners should use what they have (n=4).

Figure 13b: Open-ended Response to Investments in Infrastructure

Q Sometimes planners have tough choices to make when it comes to balancing the need for capacity, reliability, and security…Why do you prefer the one view over the other? [OPEN-ENDED]
[n=53]



Note: "Other" [n=4], "Don't know" [n=1]

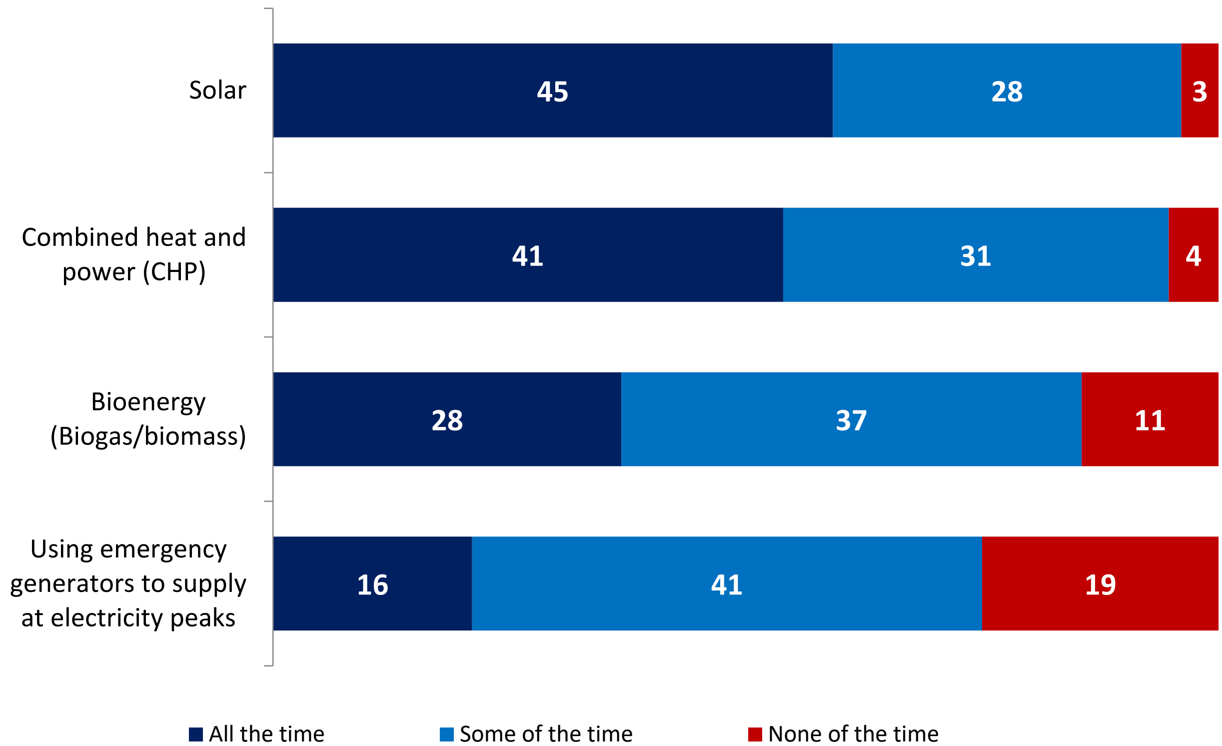
Respondents were then asked an open-ended question on why they preferred one of these arguments to the other- 53 customers answered.

For those that supported "Smith", the argument against infrastructure investment, the number one reason given is that "we should use/improve existing infrastructure" (n=15). Other reasons include "more cost-effective" (n=3), "CDM ineffective/not practiced" (n=2) and "should be reducing consumption/loads" (n=2).

And of those that supported new infrastructure investment or "Jones'" argument, 12 stated "build new infrastructure to improve reliability" (n=12), 11 said to "plan for the future" and the final three respondents stated we should "build new infrastructure to improve efficiency".

Figure 14: Generation Solutions for Central Toronto Area

Q For each of the following types of generation, please tell us what type of generation is appropriate in the Central Toronto area all of time, some of the time or none of the time:
[n=76 for all four questions]



Notes: Residential: n=65; Business: n=11. For business- "Solar" ("all the time": 8; "some of the time": 3), "Combined heat and power" ("all the time": 9; "some of the time": 2), "bioenergy" ("all the time": 7; "some of the time": 1; "none of the time": 3), "generators" ("all the time": 5; "some of the time": 4; "none of the time": 2)

Customers were then asked which of the following four different generation solutions are appropriate in the region "all of the time", "some of the time" or "none of the time": "solar", "combined heat and power (CHP)", "bioenergy" and "using emergency generators to supply at electricity peaks".

Solar proved the most popular option among the 76 remaining respondents with about six-in-ten (n=45) preferring to use this source "all of the time". Twenty-eight of the 76 customers would use it "some of the time" and the remaining three people would not use it at all.

A majority of customers (n=41) also would use combined heat and power 100% of the time. About 4-in-10 (n=31) customers would use this generation solution "some of the time" and just four people would not use it at any time.

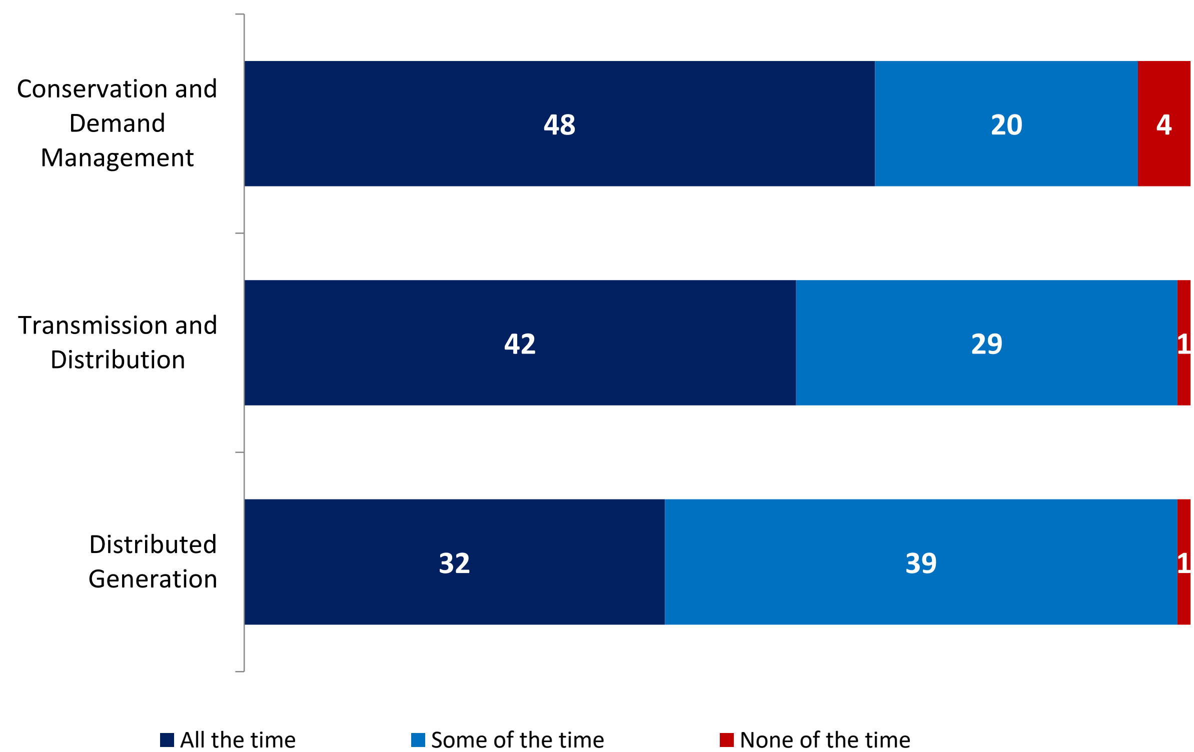
More than a third (n=28) of customers would prefer to use bioenergy at all times and just under half (n=37) would use this solution "some of the time". The remaining 11 people state they would use bioenergy "none of the time".

The least popular generation solution among customers is “emergency generator use at electricity peaks”. Of every five respondents, one of them (n=16) would prefer this option “all the time” and more than half (n=41) think it is appropriate “some of the time”. The remaining quarter (n=19) of customers think it is never appropriate to use.

Of the 11 business respondents, all of them support “solar” (n=8: “all of the time”; n=3: “some of the time”) and “combined heat and power” (n=9: “all of the time”; n=2: “some of the time”). The two remaining options, “bioenergy” (n=7: “all the time”; n=1: “some of the time”: n=3: “none of the time”) and “generators” (n=5: “all the time”; n=4: “some of the time”; n=2: “none of the time”) are less popular among business customers.

Figure 15: Demand Solutions for Central Toronto Area

Q For each of the following types of demand solutions, please tell me if you feel that solution is appropriate in the Central Toronto area all of time, some of the time or none of the time.
[n=72 for all four questions]



Notes: Residential: n=61; Business: n=11. For business- “Conservation and Demand” (“all the time”: 10; “some of the time”: 1), “Transmission and Distribution” (“all the time”: 9; “some of the time”: 2), “Distributed Generation” (“all the time”: 7; “some of the time”: 4)

When consulted about demand solutions for the region, customers proved widely supportive of all three options.

“Conservation and Demand Management” was considered the most “appropriate” demand solution with about two-thirds of customers who think it is a solution that should be used “all the time” (n=48). About a quarter (n=20) of respondents would use this solution “some of the time” and the remaining four people do not think it is an appropriate solution at any time.

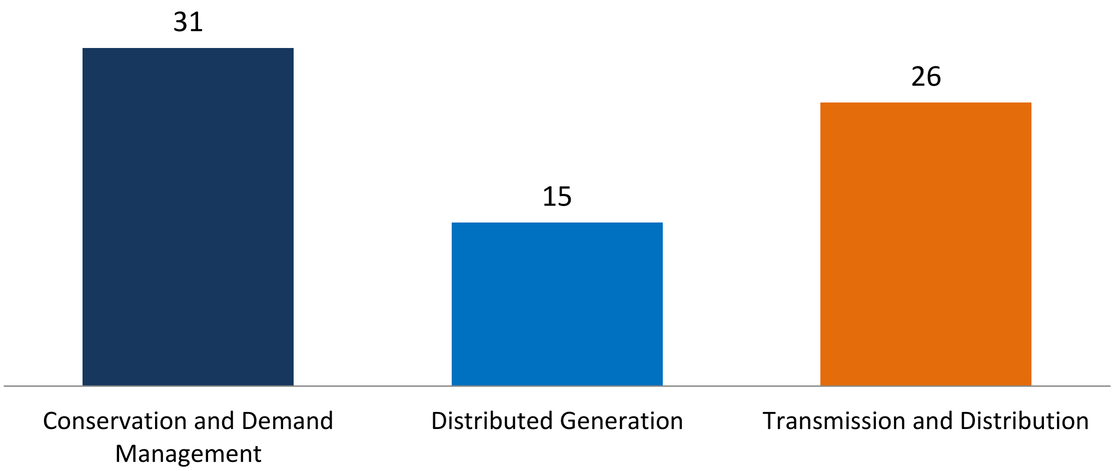
“Transmission and Distribution” also has wide support as an “appropriate” demand solution among the 72 customers surveyed. About 6-in-10 (n=42) of the respondents think it is an appropriate solution “all of the time”, around 4-in-10 (n=29) feel it should be used “some of the time” and just one person would not support “transmission and distribution” at any point in time.

The final option, “Distributed Generation”, has the least amount of support among customers, but is still considered largely an appropriate solution. Thirty-two of the 72 customers consulted feel it is appropriate “all of the time”, 39 think it should be used “some of the time” and again just one person does not think distributed generation is appropriate for any situation.

All 11 business customers surveyed support all three options in similar strength to the full sample. (“Conservation and Demand”: n=10 “all the time” and n=1 “some of the time”; “Transmission and Distribution”: n=9 “all of the time” and n=2 “some of the time; and “Distributed Generation”: n=7 “all of the time” and n=4 “some of the time”).

Figure 16a: First Choice of Demand Solution

Q Which of these solutions would be your first choice to deal with growing neighbourhood demands?
[n=72]



Notes: Residential: n=61; Business: n=11. For business- "Conservation and Demand": n=6; "Distributed Generation": n=3; "Transmission and Distribution": n=2

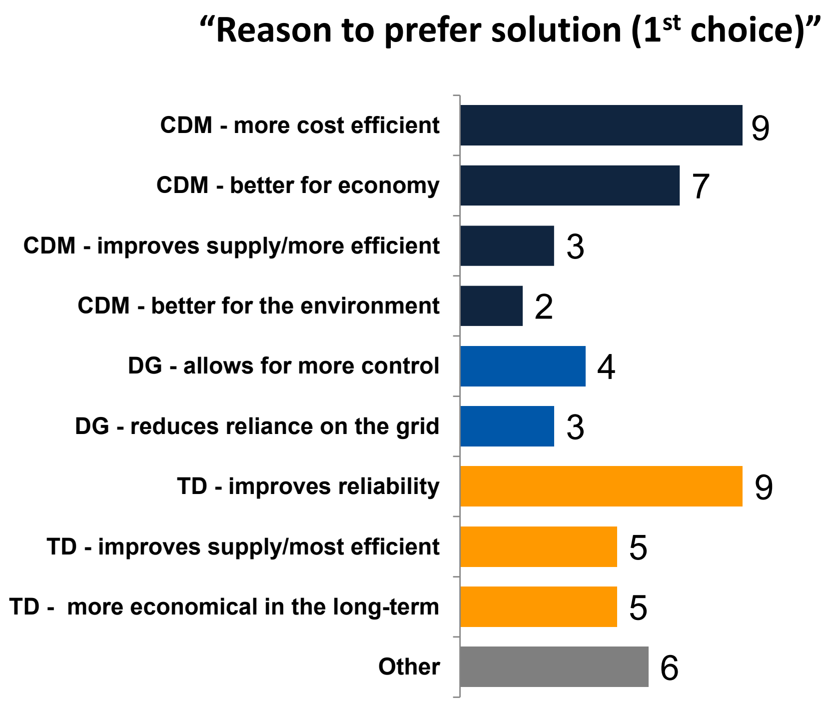
The final part of the workbook asked customers to rank their first and second choice of demand solutions and then to explain their reasoning behind it in two open-ended questions.

Just over 4-in-10 (n=31) of the remaining respondents chose "Conservation and Demand Management" as their first choice. "Transmission and Distribution" is right behind with 26 of the 72 customers picking it as their first choice. The remaining 15 felt "Distributed Generation" was their preferred solution.

Of the 11 business customers, six chose "Conservation and Demand" as their first preference, three picked "Distributed Generation" and the final two chose "Transmission and Distribution".

Figure 16b: Explanation of First Choice

Q And why do you prefer that solution over the remaining options? [OPEN-ENDED]
[n=55]



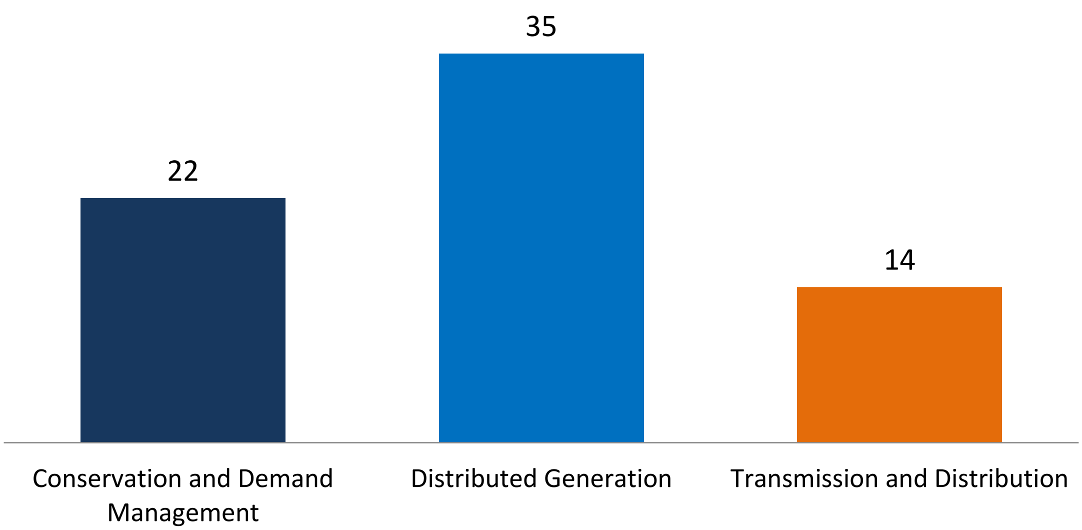
Notes: "Don't know" (n=3) not shown.

When asked to explain why they chose that particular solution over the remaining options, fifty-five customers responded as follows:

- Of those who picked "Conservation and Demand Management" as their first choice, nine cite "more cost efficiency", seven say "better for the economy", three say "improves supply" and the remaining two argue it is "better for the environment".
- The seven that chose "Distributed Generation" and responded to this question were split between "allows more control" (n=4) and "reduces reliance on the grid" (n=3).
- Finally, those that picked "Transmission and Distribution" and answered listed "improves reliability" (n=9), "improves supply" (n=5) and "more economical in the long-term" (n=5) as their reasons for support.

Figure 17a: Second Choice of Demand Solution

Q Which of these solutions would be your second choice to deal with growing neighbourhood demands?
[n=71]

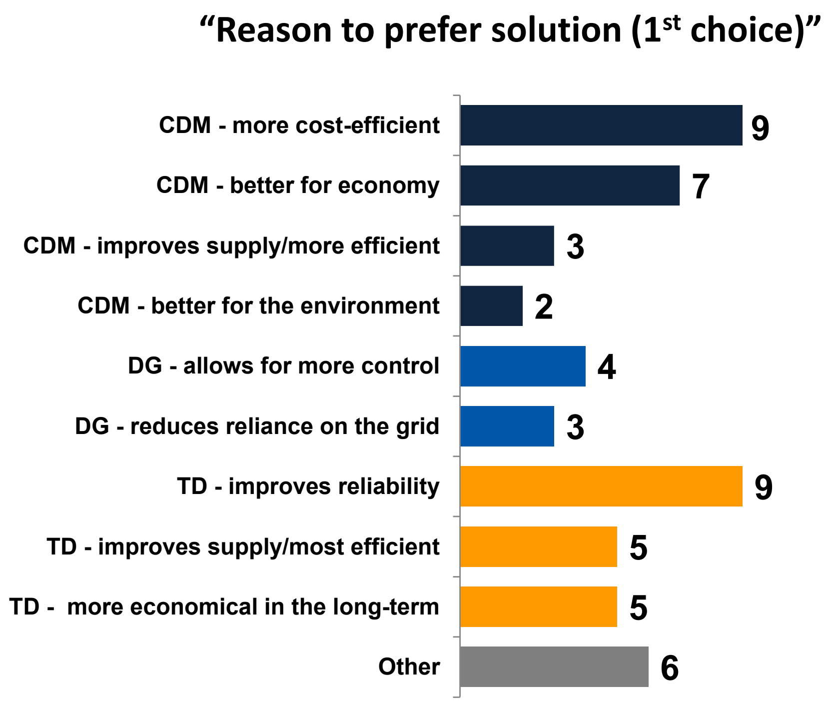


Notes: Residential: n=60; Business: n=11. For business- "Conservation and Demand": n=7; "Distributed Generation": n=3; "Transmission and Distribution": n=1

The clear second choice to deal with growing demand is "Distributed Generation": about half (n=35) of customers picked this option. Twenty-two of the remaining 71 respondents felt that "Conservation and Demand Management" was their second choice and the remaining 14 customers picked "Transmission and Distribution" as their second choice to deal with growing demand.

Figure 17b: Explanation of Second Choice

Q And why do you prefer that solution over the remaining options? [OPEN-ENDED]
[n=55]



Notes: "Don't know" (n=3) not shown.

In the last follow-up question of the survey, 54 customers explained their second choice solution as follows:

- Those who picked "Conservation and Demand Management" as their second choice cite "more cost-efficient" (n=7) and "need to reduce consumption" (n=3) as their main arguments.
- Of the plurality who picked "Distributed Generation" as their second choice, reasons included: "improving local generation" (n=7), "reduces reliance on the grid (n=6), "more control" (n=6) and "better for the environment" (n=4).
- And those that picked the third and final category "Transmission and Distribution" explained their reasoning as "better use of infrastructure" (n=4), "more economical in the long-term" (n=2) and, again, "better for the environment" (n=2).

Customer Consultation Groups

Customer Consultation Groups
with Residential and General Service customers

PURPOSE: To gain qualitative input on planning options for Central Toronto from residential and GS < 50 kW customers and to obtain feedback into survey design

Summary

The following summary highlights key findings from the general service and residential Consultation sessions held in downtown Toronto on September 24th and 25th, 2014. Each night included one group of general service under 50 kW customers and one group of residential customers.

System Reliability: Customer Experience and Expectations

Most participants in the consultation groups have experienced an average of zero to four power service interruptions at their businesses and homes in the past 12 months. The duration of the service interruption lasted from a few minutes to, in some cases, many hours. Most general service and residential customers reported minor losses of productivity and a general inconvenience within their respected businesses and households due to outages.

Due to the relatively low number of outages, 24 of 29 participants found the current number of outages to be either very or somewhat acceptable.

That being said, many participants in both general service and residential groups felt that outside of extreme weather, there should be no system outages at all. For most customers, in both classes the key concern with outages was in the duration, and effective, accessible communications about the expected length of outages.

Improving Reliability Standards in Central Toronto

Twenty-five out of 29 participants believed it was either very or extremely important that the Central Toronto electricity system be reliable beyond the minimum standard.

Both general service and residential participants pointed to critical services like hospitals and subways to support the need for increased reliability standards in Central Toronto.

Despite acknowledging a need for increased standards, participants in both groups pointed to large-scale developments like condominiums to assume the bulk of the financial obligation of these investments. General service participants believed it was these large businesses that require increased reliability, and therefore they should be the ones to pay for it.

When setting goals for the system, residential users cared about both the frequency and the duration of the outages and requested less of both. The general service users stated that depending on the type of business, both the frequency and duration of outages can have major consequences.

Generally, participants in both groups understood the need for further investments; however, they were reluctant to see substantial increases on their bills. They have heard many stories of waste and mismanagement and expect the system will look hard for savings before asking consumers for more resources.

Planning for Extreme Events

Generally, when it came to extreme events, participants in both groups understood the rarity of these events; however, the uncertainty of future weather trends made them, for the most part, more willing to pay more.

Several participants in both groups pointed to the distribution system as a primary concern during extreme events. Both general service and residential customers requested proactivity when dealing with falling trees that cause system disruptions.

A few of the participants thought that instead of investing more in planning for extreme events, they could pay for generation themselves in the form of gas powered generators.

Several small business owners suggested that they don't have the capital to deal with the negative impacts of extreme events, such as flooding and loss of business during outages.

Customer Preferred Solutions

Seventeen out of 28 participants would select CDM as their first choice solution for dealing with growing neighbourhood demands.

That being said, many participants in both groups saw CDM as a community building tool rather than a peak demand solution.

A few participants saw Transmission and Distribution as the best "long-term" solution to meet the growing demand in Toronto. Generally they seem to see "wires" as a more tangible and reliable source of supply, compared to other sources.

Many participants saw DG as a relative unknown. Participants in both groups pointed to the need for more information and further technological advancement before selecting DG as a permanent, long-term solution for meeting growing neighbourhood demands.

Methodology

About the General Service and Residential Customer Consultation

The consultation sessions were held in Toronto on September 24th and 25th, 2014. A total of 29 general service and residential customers participated in these consultation sessions.

September 24, 2014

General Service under 50 kW Rate Class	7 participants
Residential Rate Class	8 participants

September 25, 2014

General Service under 50 kW Rate Class	6 participants
Residential Rate Class	8 participants

Recruiting Consultation Participants:

General service customers in the under 50 kW rate class were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General service customers qualified for the consultation if they managed or oversaw their business' electricity bill. This was to ensure that they were at least somewhat knowledgeable of their electricity costs and that they could have an informed discussion on Central Toronto's IRRP.

Customer recruitment lists were randomly generated and provided to INNOVATIVE by Toronto Hydro.

An incentive of $100 was provided to all general service participants and $80 to residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotations.

Consultation Session Structure:

The consultation sessions were structured around the themes contained in the workbook, which was developed by INNOVATIVE and the Central Toronto IRRP study partners.

The workbook themes consisted of the following:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of the Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

The penultimate version of the workbook was tested with the public to ensure that it provided the key information they felt they needed; as well as to test the accessibility of the language, and the effectiveness of the illustrations.

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why they are seeking feedback from general service and residential customers.

After explaining the purpose of the consultation, hardcopy workbooks were distributed to act as a session guide for participants to record their answers to the question contained within.

Participants read through the workbook section-by-section and the moderator facilitated discussion based on each individual section.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what they meant for them or their businesses.

Hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately two hours. Participants commented that they felt the sessions were informative. In several groups, some participants continued to discuss the topic after the formal session was completed.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section summarizes the feedback from general service and residential customers.

General Service under 50kW Rate Class

System Reliability: Customer Experience and Expectation

Most general service customers had experienced an outage within the last 12 months. How and at what point the outage affected their business varied between customers.

In reference to when an outage would start to affect their business, one participant said, *"Because I'm downtown, I like to have a well-lit area and my security would go, and night is when things get weird downtown. So, after dark, that would be when I really start worrying".*

One participant, whose company operates 24-hours a day, explained the consequences of an outage, saying, *"For us, it's extremely detrimental for any period of time".* Any loss of productivity for a small business that operates 24/7 can be extremely costly.

For many general service customers, the time of day of outages greatly affects the severity of the impact. For instance, one participant who operated a catering company, said outages in the morning are costly; while a participant who ran a restaurant said the same about evenings. Additionally, a participant in the laundromat business said the after-work rush would be the most impactful time of day for an outage.

The bottom line for businesses is that an outage at any time can impact a wide variety of functions and minimizing both the number and length of outages is key to avoiding significant losses.

Improving Reliability Standards in Central Toronto

Many general service participants alluded to the need for increased reliability in critical areas. One participant said, *"Some critical areas, like hospitals that need to be running if it's life threatening. Also the banking system".*

While most participants in this group felt the need for increased reliability standards in Central Toronto, they were, for the most part, not interested in paying for it.

Many participants pointed to increasing bills without increasing reliability. One participant said, *"We've experienced probably the highest increase in rates in North America. No ifs, ands or buts. When I first started heating with electricity it was an effective way to go and now I'm stuck with it. Over the years they just keep bumping it. What are you going to do? There is no alternative".*

Again, while the need for increased reliability was felt by many in these groups, small business owners did not feel that the onus should be put on them. One participant said, *"The tax base in this city is increasing and do we see our taxes going down? The tax base is going up and our rates are going up, where's the money going? Put a surcharge on the heavy, the ones that need reliability the most.* ***You want to ride your elevator in a power outage, pay for it****"*.

Many general service participants agreed that certain high-use customers should be paying more to improve the reliability standards in Toronto. One participant said, *"I think in terms of the sustainability of the city, and the long-term plan, they definitely need a higher standard. People shouldn't be paying equal amounts. I think large developers [should be paying more]".*

Many general service customers found that the additional money needed to improve Toronto's reliability should be found from within. One participant said, *"I get really bent out of shape over the salaries that the people at Hydro are making",* another said, *"They seem to be getting more money, the salary packages are ridiculous".*

The general feeling amongst this group was to "**look first to yourself for more money".**

Planning for Extreme Events

Most general service customers were generally satisfied with the way the system has performed during major events - primarily the ice storm and flooding.

For a few participants, being prepared for major events was more important than an overall increase in reliability. One participant said, *"Major events were more important to me than normal reliability"*. This concern appears to be related to the extended duration of the major outage events.

While most participants understood that these events were infrequent, they still expressed interest in improved planning for extreme events. When it came to paying for it, however, one participant said, *"I think they should do more because systems are changing and the reality, but I think how we spend that is a whole other question".*

While most participants wanted increased planning for major events, only 3 out of 13 general service customers would be willing to pay more for these system increases.

A few participants believed that while a backup plan was important during extreme events, it was not necessary to harden the whole system. One participant said, *"They need a few more generators scattered around the city, because it's not going to happen every year, or twice a year, maybe every ten years. But, in the case that it happens, it's life threatening, they need to have – as a government – a backup plan, not the hydro system by itself".*

Many small business owners stressed the fact that while investing in extreme events was important; their businesses were already struggling to keep up with rising bills as they are. With regards to paying more for increased extreme event planning, one small business owner said, *"So, when we hear hydro's going up 40%, we're freaking, because that means we're either going to have to cut staff, cut our teachers, we're going to have to work expanding our schedules, figuring out new ways to bring in that income that is going to go out to another big corporate entity".*

For the few participants that were willing to spend more to increase preparedness for extreme events, they generally believed it was a long-term investment in infrastructure that will be permanent, unlike other temporary fixes.

Customer Preferred Solutions

Ten out of 13 general service participants were either somewhat or very likely to participate in Demand Response programs. Additionally, 9 out of the same 13 selected CDM as their first choice in dealing with growing neighbourhood demand.

Many participants were attracted to CDM because they considered it to be a community building and involvement tool. Related to this, one participant said, *"You've got to deal with it on the community level and the trouble with the way Toronto Hydro has approached this thing is they are too busy shoving programs down our throat and not busy enough getting people to organize within their community".*

Additionally, many general service participants thought that CDM would be the best solution for reducing bills. One participant said, *"It makes sense to be able to do something that you can see* *immediate benefit, you feel like you actually have some impact, and the impact is the lowering of your bills".*

A few participants saw the best solution as a combination of CDM and Transmission & Distribution. One participant thoughtfully expressed her ideal combination, saying, *"What makes most sense to me is first CDM to control the problem right now while we start at the same time doing Transmission and Distribution, because that's a long-term fix. The city is going to continue to grow, so why procrastinate the fact that it needs to be done. Let's start right now with the areas that are more critical. DG doesn't take care of the heat of the area. Throwing money to the garbage unless it's placed near critical areas like hospitals".*

Residential Rate Class

System Reliability: Customer Experience and Expectation

Most residential customers had experienced an outage within the last 12 months. How and at what effect it had on them varied on the length and time of year the outage occurred.

Most participants noted minor inconveniences during shorter outages; including having to reset clocks, inability to communicate via internet or phone, and having to purchase candles to provide light.

However, participants who had experienced more prolonged outages reported more severe personal impacts. For instance, one participant said, *"My husband has health problems and so it's very important that we can be in contact with services and I just find that totally unacceptable".*

A few other residential customers were concerned with caring for the elderly and vulnerable during prolonged outages. One participant purchased a generator in case of an outage because they lived with an elderly person who utilized an electrically powered bed.

Additionally, a few residential participants noted that prolonged outages during the winter caused major property damage, such as flooding caused by frozen pipes. One participant said, *"A water pipe froze and when the power came back, the pipe burst. It cost $10,000".*

Several participants also noted that they work from home, and outages can seriously affect their productivity and cost them the ability to communicate with customers and clients.

Despite the personal impact of both short and prolonged outages, 12 of 16 residential customers found the number of outages to be either very or somewhat acceptable.

However, when it came to the length of these outages, only 9 of 16 agreed that they were either very or somewhat acceptable.

Improving Reliability Standards in Central Toronto

A few participants agreed that overall, some areas have excellent reliability, while others don't. "*Why should we pay the same amount if the system is not delivering the same amount?"*

While most residential customers agree that a higher standard is needed in Central Toronto, they were generally unhappy with the idea of paying more. One participant said, *"['I'd] prefer to have a better standard but can't afford to pay for it".*

While most participants were unwilling to pay additionally for improved reliability standards, a few said that they would, should reliability be significantly increased. One participant said, *"I would pay double if the system performed 100%".*

Despite the agreement of most participants that a higher standard was necessary, a few residential customers in the second group were generally satisfied with the current standard. One participant said, *"I don't think the change in my bill is going to make a difference".*

Planning for Extreme Events

Most participants in these groups found that more should be done to plan for the possibility of more extreme events.

However, a few participants found that this should occur gradually, and that more should be done to anticipate the unknown and strengthen the system where needed. One participant said, *"There should be a slow progression to get it to a better standard".*

Most participants feel that money from the current rates should be used to make these improvements to the system. They hear a lot about waste and mismanagement and do not believe a strong effort has been made to find savings. Again, most participants agreed that more should be invested; however, they were reluctant to pay more on their bills.

A few participants also said that instead of investing in the whole system, in order to combat these extreme events, residential customers could invest in their own self-generation.

Customer Preferred Solutions

Four out of 8 Residential customers in the first group selected Transmission and Distribution as their number one choice for dealing with increasing neighbourhood demand. Many of these participants believed it to be the most permanent solution that will help meet the growing demands. In the second group, however, zero participants selected this option at their first choice.

With regards to Transmission and Distribution solutions, one residential participant said, *"Because it seemed that the growth in demand was permanent, not temporary and because we don't have any information on how much more effective these other alternatives will become as technology advances and so if the growth is permanent it needs and increase in infrastructure and it seems as if the other two were temporary fixes to peak demand rather than a permanent, reliable increase to capacity and infrastructure".*

Eight out of a total of 15 residential customers selected CDM as their first choice; however, they believed it was important to combine several solutions to meet the demand.

A few participants noted that while conservation is a great tool, *“demand will exceed what we conserve”.*

Questionnaire Results

The following tables are the tabulations of participant feedback to questions in the hardcopy workbooks that were returned at the end of each consultation session.

Responses to *open-ended* questions were coded to generate frequency charts. Examples of transcribed responses are provided for each code.

Missing values are recorded beneath each table to indicate the number of participants who left a particular question unanswered.

1. Do you feel the current average number of electricity outages in the Central Toronto electricity system is acceptable or not acceptable?

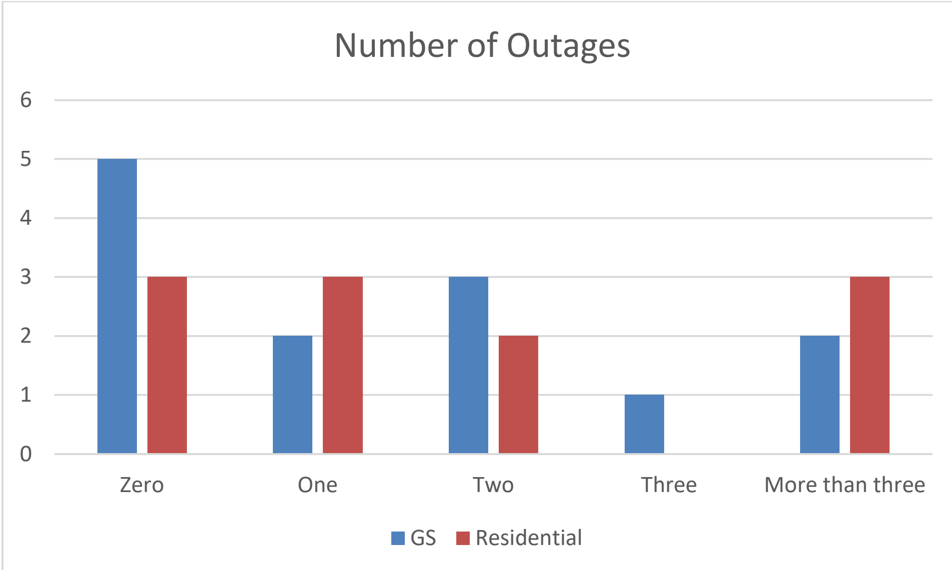
Response	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	3	2	5	3	2	5	**10**
Somewhat acceptable	4	4	8	2	4	6	**14**
Not very Acceptable	0	1	1	1	1	2	**3**
Not acceptable at all	0	1	1	0	1	1	**2**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

2. Do you feel the average length of an outage in the Central Toronto electricity system is acceptable or not acceptable?

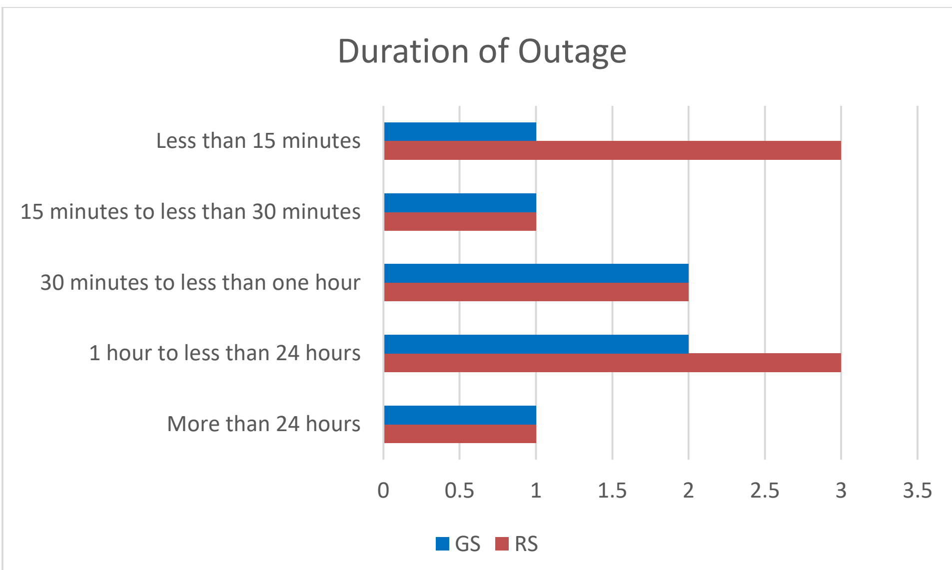
Response	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	2	1	3	3	2	5	**8**
Somewhat acceptable	4	2	6	1	4	5	**11**
Not very acceptable	0	4	4	2	1	3	**7**
Not acceptable at all	0	1	1	0	1	1	**2**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**

MV=1 MV=1

3. How many outages have you experienced over the past 12 months?



4. How long was the power out during your most recent outage? Please describe in hours (e.g. = .25 hours, 2 days = 48 hours)

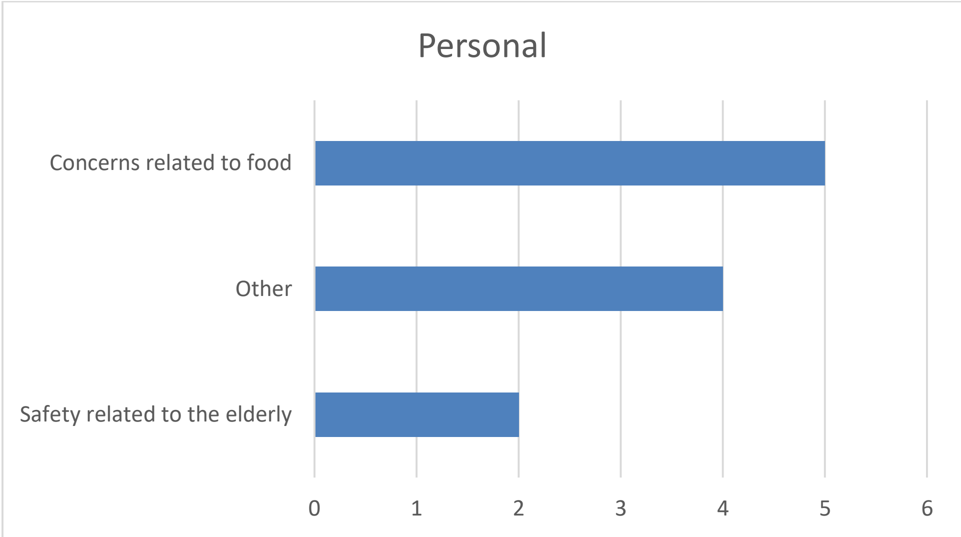


5. (IF 1 OR MORE OUTAGE)

Residential Customer

How did the power outage affect you personally?

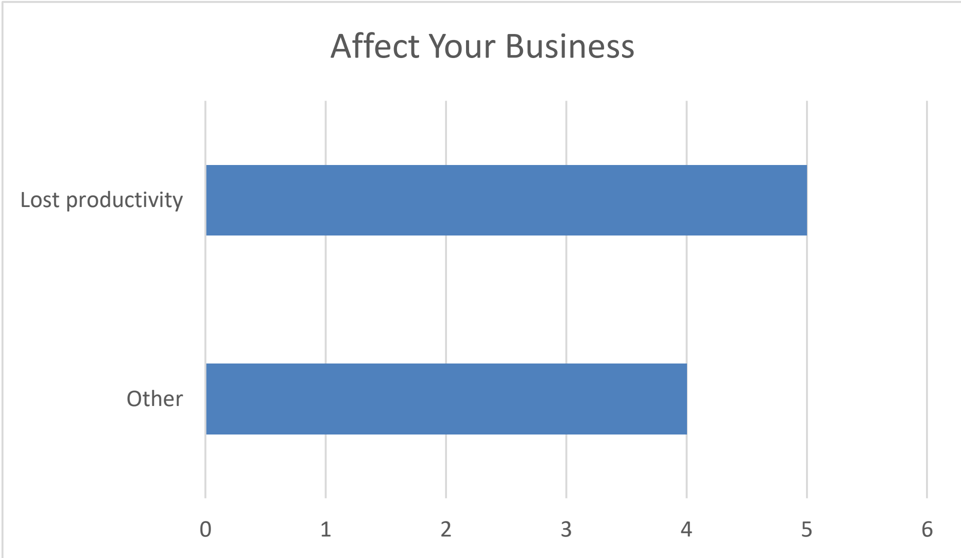
> **Concerns related to food:** *I was uncertain if food in refrigerator was affected… should it be thrown out?*
>
> **Safety related to the elderly:** *I have elderly parents and keeping them safety was an issue*
>
> **Other:** *I believe the power did go out on me one evening but it was my bed time hours so I didn't care. I was fine*



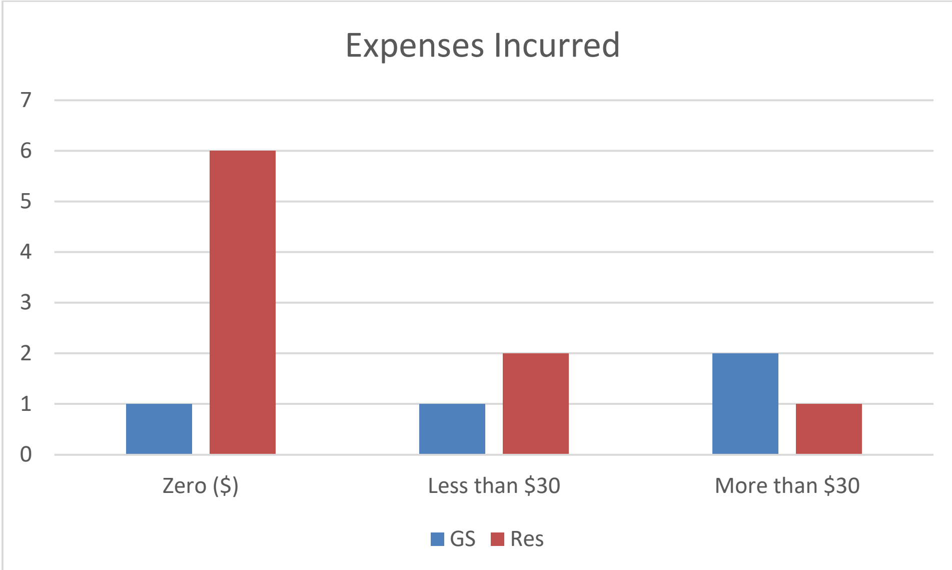
Business Customer

How did the power outage affect your business?

> **Lost productivity:** *Studio was unable to operate, no sales electronically could be made and heat issues.*
> **Other:** *Minor inconvenience*



6. (IF 1 OR MORE OUTAGE) Can you estimate the dollar value of any expenses you incurred as a result of the power outage?

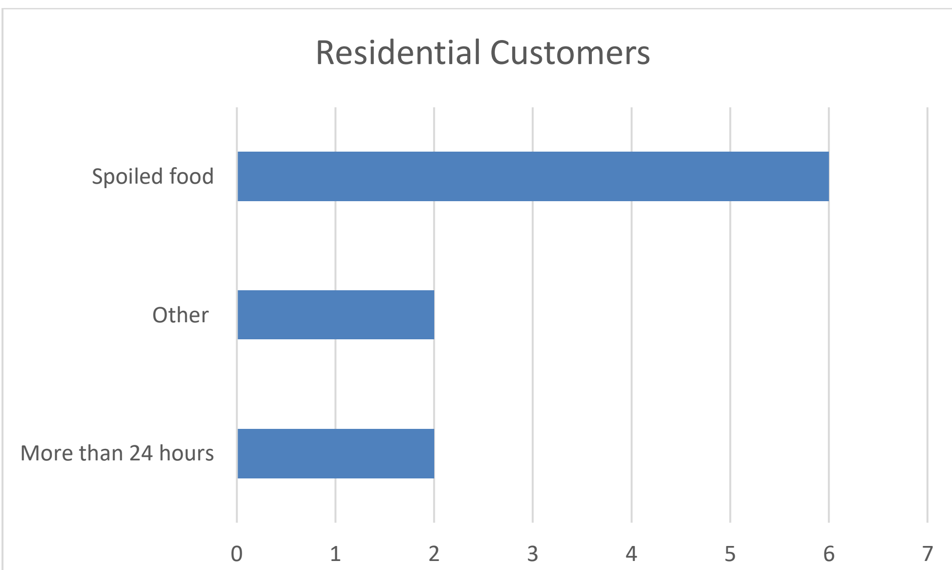


7. Is there a certain length of time at which the costs and consequences of an outage become more serious? [Yes (Please describe)

Spoiled Food: *I would consider a delay that impacted the food in my fridge to be problematic and costly*

More than 24 hours: *Particularly if it is beyond 24 hour period. The December blackout created MAJOR problems throughout my home*

Other: *2 hrs or more would cost me more*



Business responses varied, some comments included:

Winter time is very crucial if we have power outage

More than one day causes significant communication difficulties. Communication by phone only is problematic.

Electric heating system down during cold temperatures would be major inconvenience

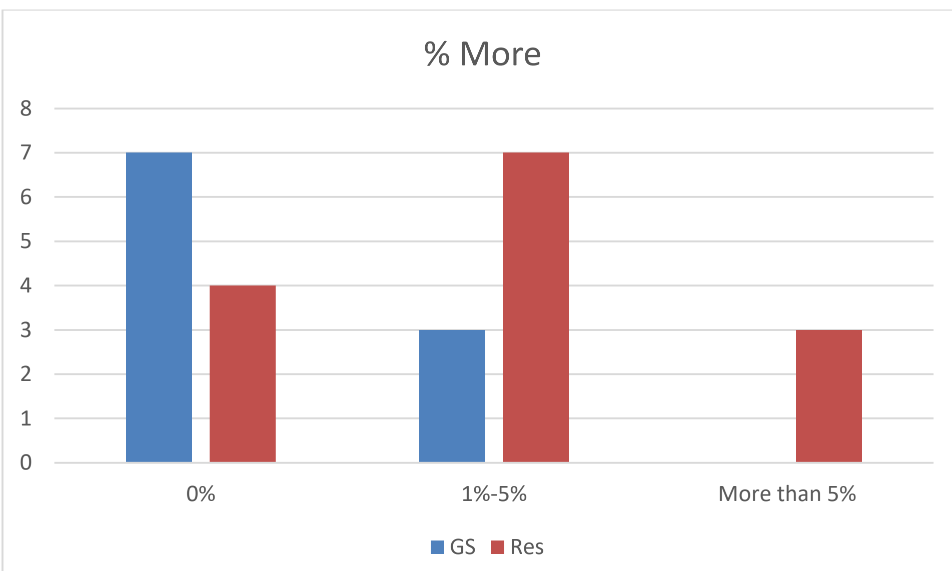
When an outage goes over 15 min at peak time

Food in freezers would be lost & the cost would be astronomical also fridges

8. How important is it that the Central Toronto electricity system be reliable beyond the minimum standard?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Extremely important	3	6	9	5	1	6	**15**
Very important	2	2	4	0	6	6	**10**
Somewhat important	0	0	0	1	0	1	**1**
Not very important	1	0	1	0	0	0	**1**
Not important at all	0	0	0	0	0	0	**0**
Don't know	1	0	1	0	1	1	**2**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

9. Thinking of your total bill, how much more would you be willing to pay for the Central Toronto electricity system to perform better?



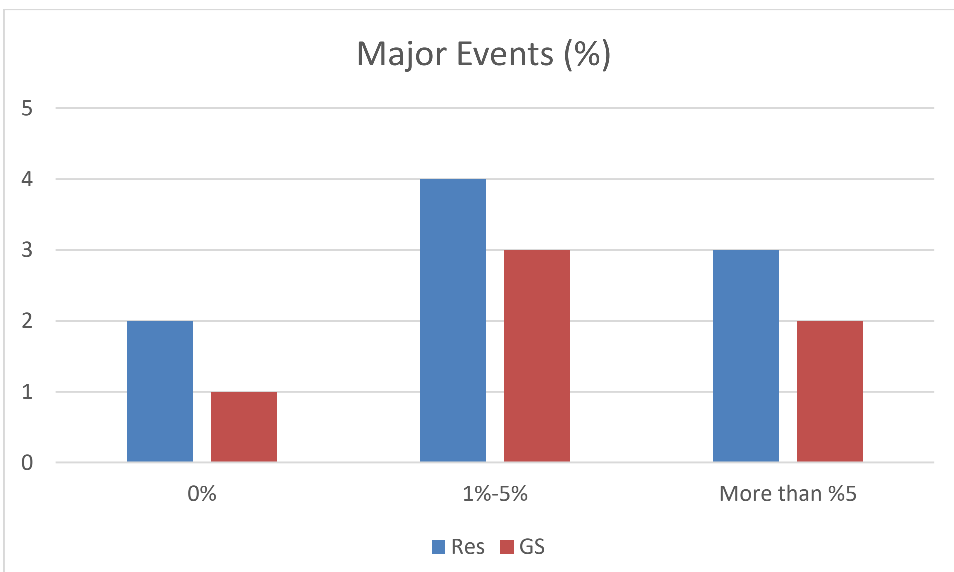
10. From what you have read here and considering your own experience, how satisfied are you with the way the Central Toronto electricity system has performed during major events?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Very satisfied	1	0	1	3	2	5	**6**
Somewhat satisfied	4	5	9	0	5	5	**14**
Somewhat dissatisfied	1	2	3	2	0	2	**5**
Very dissatisfied	0	1	1	0	0	0	**1**
Don't know	1	0	1	1	1	2	**3**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

11. To improve the ability of the Central Toronto electricity system to respond to major events beyond our current standards will require spending more money. Are you willing to pay more on your electricity bill so the Central Toronto electricity system can improve its ability to respond to major events?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Yes	1	3	4	2	3	5	**9**
No	3	3	6	3	3	6	**12**
Don't know	3	2	5	1	2	3	**8**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

11. IF YES: And thinking of a percentage of your bill, how much more would you be willing to pay for the Central Toronto electricity system to improve its ability to respond to major events?



12. Have you ever participated in any conservation activities?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Yes	6	6	12	6	5	11	**23**
No	1	1	2	0	2	2	**4**
Total	**7**	**7**	**14**	**6**	**7**	**13**	**27**

MV=1 MV=1 MV=2

12. Have you participated in any conservation activities? If so, please describe some of them?

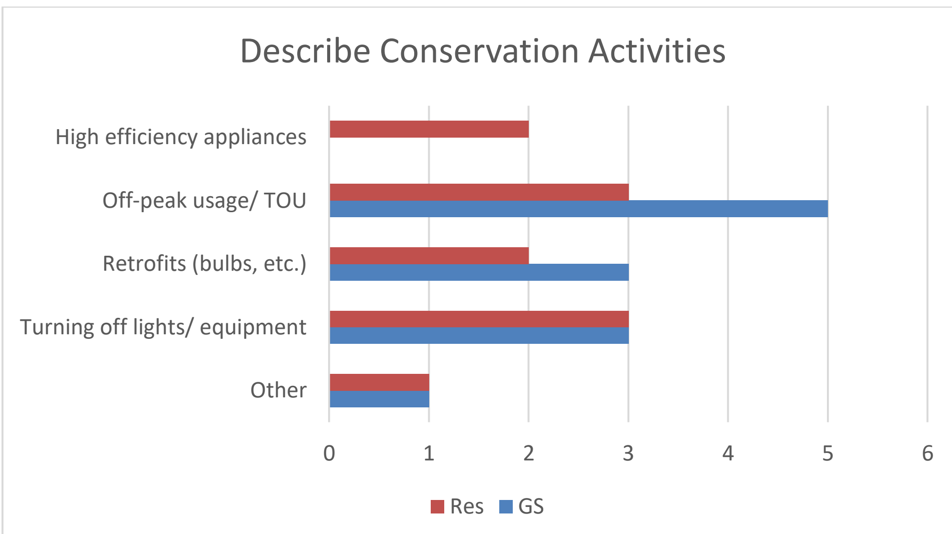
High efficiency appliances: *energy efficient equipment*

Off-peak usage/TOU: *Use washer, dryer, dishwasher off peak time, having energy saving lights and appliances*

Retrofits: *Home energy and added basement insulation, new furnace; caulking around window frames; do laundry in evening/ weekends*

Turning off lights: *Turning lights, appliances off whenever possible*

Other: *Urban agriculture, greenpeace, environmental justice campaigns*



13. For CDM to provide an alternative to DG or transmission/distribution, it must provide an acceptable level of certainty as compared to DG or transmission. How likely is it that you will participate in Demand Response programs that will allow electricity system managers to cycle equipment you are using? For residences, this would involve automated devices that turn off your pool heater and air conditioner for short periods at time of peak demand. For commercial or industrial users, this would be an agreement to shut down specific equipment on request.

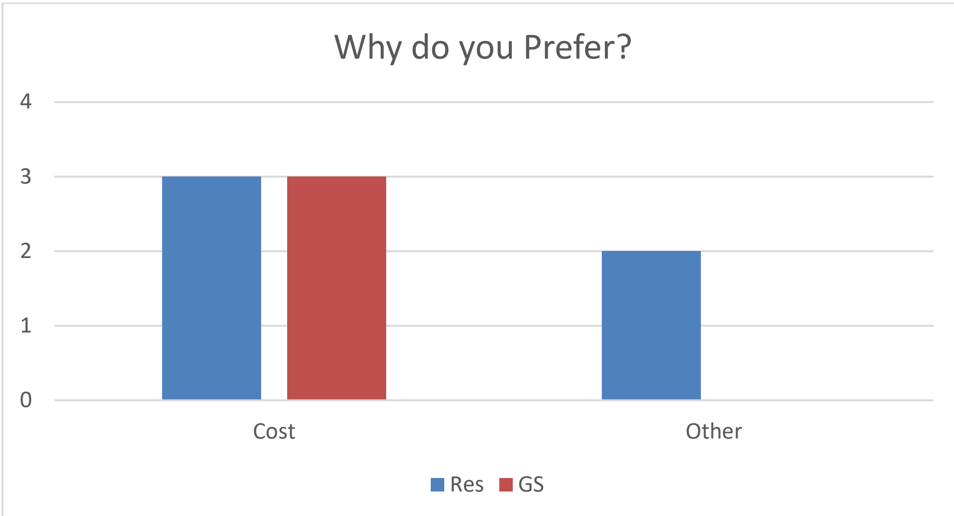
Response	GS	RS	Total	GS	RS	Total	Sum Total
Very likely	4	0	4	4	3	7	**11**
Somewhat likely	2	3	5	0	2	2	**7**
Not very likely	0	3	3	1	1	2	**5**
Not at all likely	1	2	3	1	1	2	**5**
Total	**7**	**8**	**15**	**6**	**7**	**13**	**28**

MV=1 MV=1

14. (System planners should make full use of existing substations and power lines) **Why do you prefer the one view over the other?**

Cost: money, cost to my bill hydro bill is sky rocketing

Other: The existing substations are not fully utilized and have the capacity to supply enough power. The planners need to focus on the efficiency and full utilization of existing system

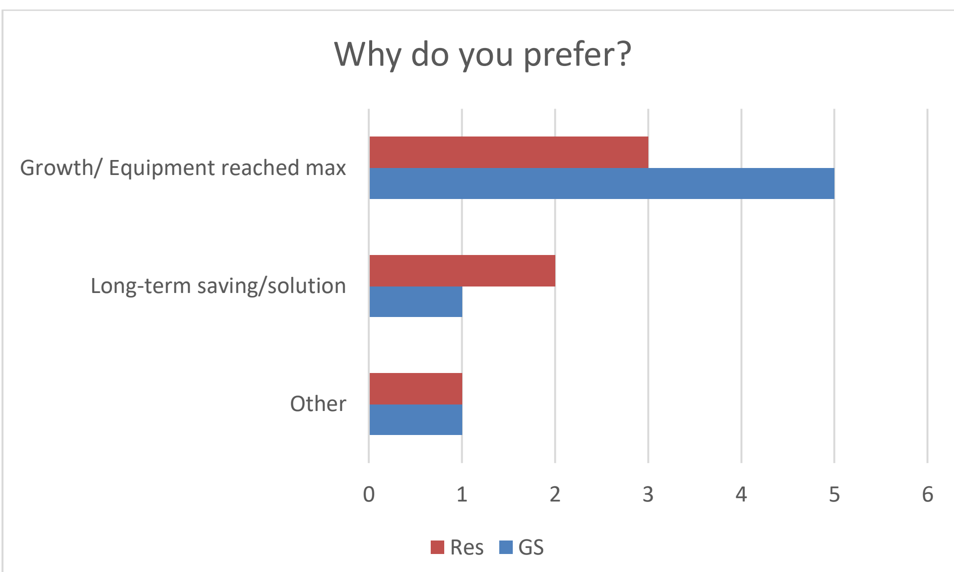


System planners should focus on improving the reliability and security of electricity. They should have the flexibility to invest in new substations and power lines to improve future reliability and security, even if there is room to expand on existing infrastructure.

Growth: *City is growing & power must keep up with the future. Newer, more efficient technologies will be available & improve: capacity, reliability & security*

Long-term saving: *I would think that this points to long term saving cost*

Other: *Because the government needs to be proactive and enhance the electrical system on an ongoing basis to avoid a total crash and a huge expense all at once*



For each of the following types of generation, please tell us what type of generation is appropriate in the Central Toronto area all of the time, some of the time or none of the time.

15. Solar

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	5	5	10	4	4	8	**18**
Some of the time	0	2	2	2	4	6	**8**
None of the time	1	0	1	0	0	0	**1**
Total	**6**	**7**	**13**	**6**	**8**	**14**	**27**

MV=1 MV=1 MV=2

16. Bioenergy (Biogas/biomass)

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	1	1	2	2	0	2	**4**
Some of the time	4	4	8	3	7	10	**18**
None of the time	1	2	3	1	1	2	**5**
Total	**6**	**7**	**13**	**6**	**8**	**14**	**27**

MV=1 MV=1 MV=2

17. Combined heat and power (CHP)

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	2	1	3	2	1	3	**6**
Some of the time	3	6	9	4	7	11	**20**
None of the time	0	0	0	0	0	0	**0**
Total	**5**	**7**	**12**	**6**	**8**	**14**	**26**

MV=2 MV=1 MV=3

18. Using emergency generators to supply at electricity peaks

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	1	1	2	1	6	7	**9**
Some of the time	3	5	8	4	1	5	**13**
None of the time	1	1	2	1	1	2	**4**
Total	**5**	**7**	**12**	**6**	**8**	**14**	**26**

MV=2 MV=1 MV=3

For each of the following types of demand solutions, please tell me if you feel that solution is appropriate in the Central Toronto area all of the time, some of the time or none of the time

19. Conservation and Demand Management

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	5	5	10	5	7	12	**22**
Some of the time	1	3	4	1	1	2	**6**
None of the time	1	0	1	0	0	0	**1**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

20. Distributed Generation

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	3	1	4	1	5	6	**10**
Some of the time	2	7	9	5	3	8	**17**
None of the time	1	0	1	0	0	0	**1**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**
	MV=1						MV=1

21. Transmission and Distribution

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	3	2	5	2	3	5	**10**
Some of the time	3	6	9	4	4	8	**17**
None of the time	0	0	0	0	1	1	**1**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**
	MV=1						MV=1

22. Which of these solutions would be your first choice to deal with growing neighbourhood demands?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Conservation and Demand Management	4	2	6	5	6	11	**17**
Distributed Generation	1	2	3	1	1	2	**5**
Transmission and Distribution	2	4	6	0	0	0	**6**
Total	**7**	**8**	**15**	**6**	**7**	**13**	**28**
					MV=1		MV=1

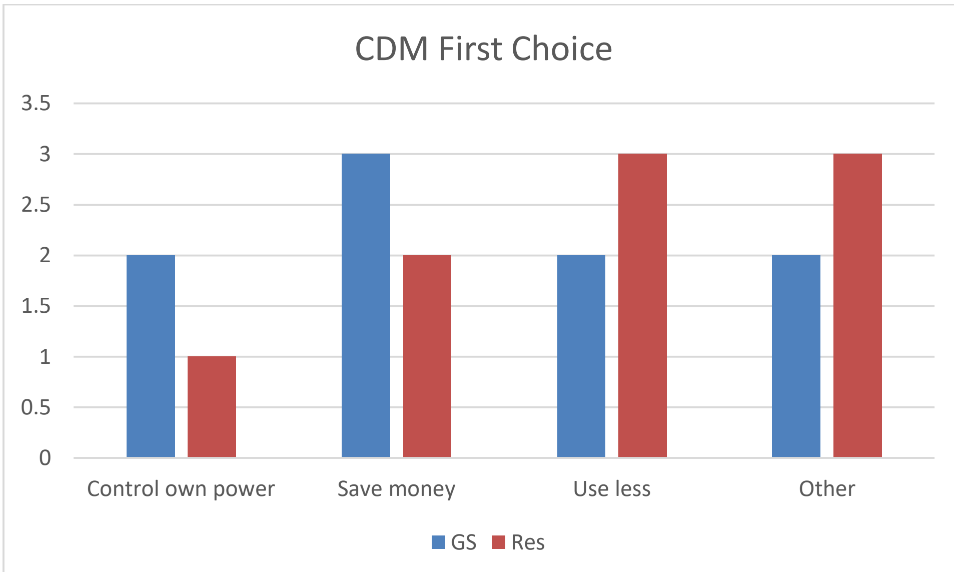
23. And why do you prefer that solution over the remaining options? **(Conservation and Demand Management)**

Control own power: *It allows us to become personally responsible for the amount of energy we use and if used in tandem with the current system would save the public and businesses alike, money.*

Save money: *it does not have a cost for me*

Use less: *we must conserve and use less*

Other: *CDM more long-term*



23. And why do you prefer that solution over the remaining options? **(Distributed Generation)**

Only two residential and one business customer selected **Distributed Generation** as their first choice, their responses included:

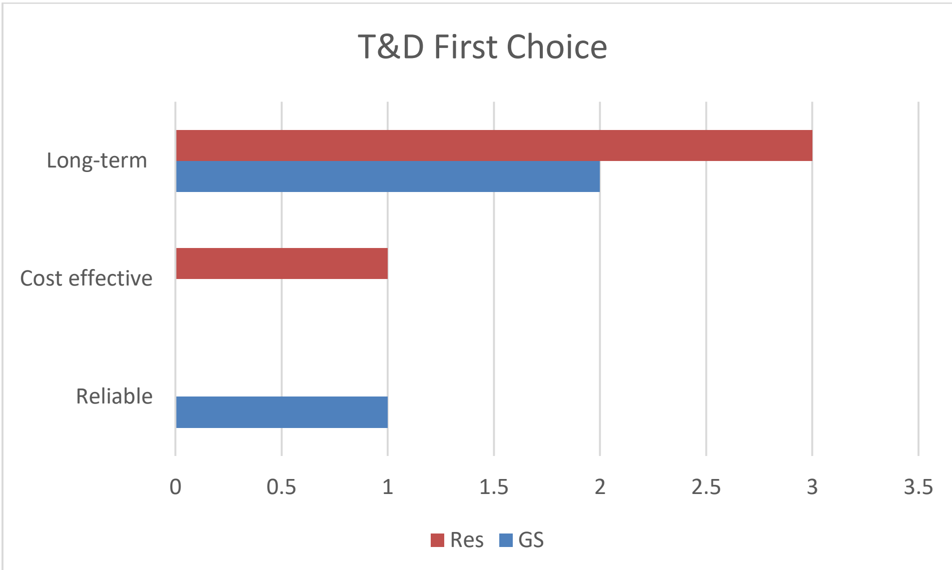
I believe this solution has less unknown and better control
This can be a permanent solution
Sets up in two to five years. Uses renewables

23. And why do you prefer that solution over the remaining options? **(Transmission and Distribution)**

Long-term: *#1 permanent solutions*

Cost effective: *It is cost effective in it does not require maintenance and other costs*

Reliable: *I think it's more reliable than CDM and more efficient (cost) than DG*



24. Which of these solutions would be your second choice to deal with growing neighbourhood demands?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Conservation and Demand Management	0	2	2	1	0	1	**3**
Distributed Generation	3	4	7	2	3	5	**12**
Transmission and Distribution	3	1	4	3	3	6	**10**
Total	**6**	**7**	**13**	**6**	**6**	**12**	**25**
	MV=1	MV=1			MV=2		MV=4

25. And why do you prefer that solution over the remaining options? **(Conservation and Demand Management) (Second Choice)**

Conservation and Demand Management was selected by only two respondents (1 GS & 1 Res) as a second choice, their answers are as follows:

DG is tougher in urban areas. Windmills need space and solar isn't a consistent and continuous form of power

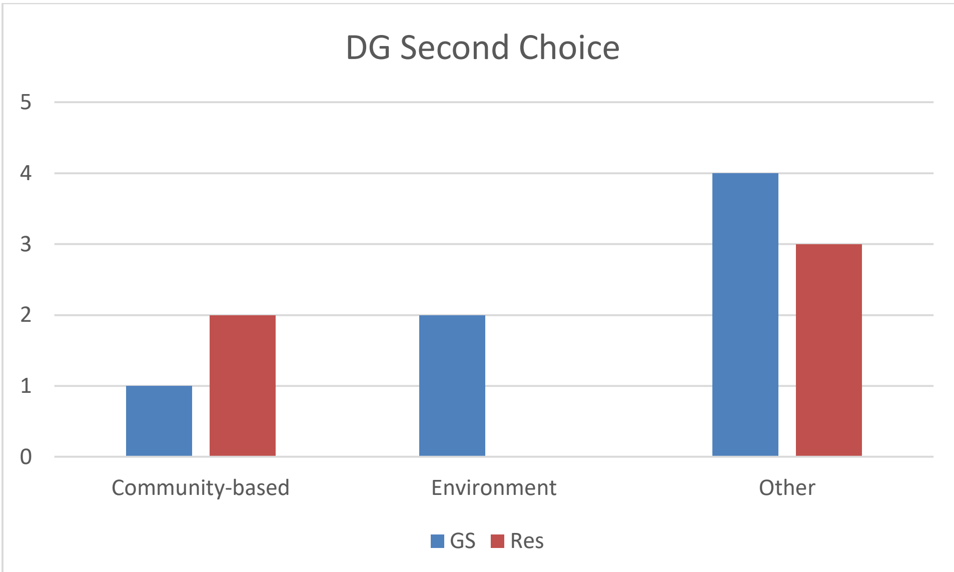
Cost effective. Off sets peak demands

25. And why do you prefer that solution over the remaining options? **(Distributed Generation) (Second Choice)**

Community-based: *It allows for the energy source to be located close to the communities it serves and can be used hand in hand with Conservation and Demand Management.*

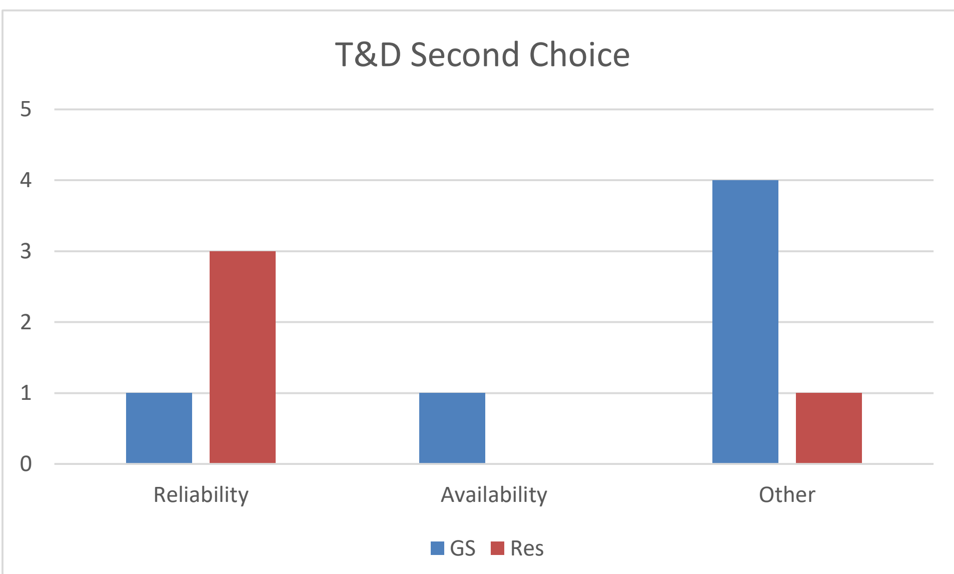
Environment: *Best environmental impact. Conservation implies a failure of delivery and capacity*

Other: *Conservation is well intentioned but not practical*



25. And why do you prefer that solution over the remaining options? **(Transmission and Distribution) (Second Choice)**

Reliability: *seems most reliable and easiest to maintain*
Availability: *Greater availability when needed*
Other: *It is important to be prepared for unforeseen events*



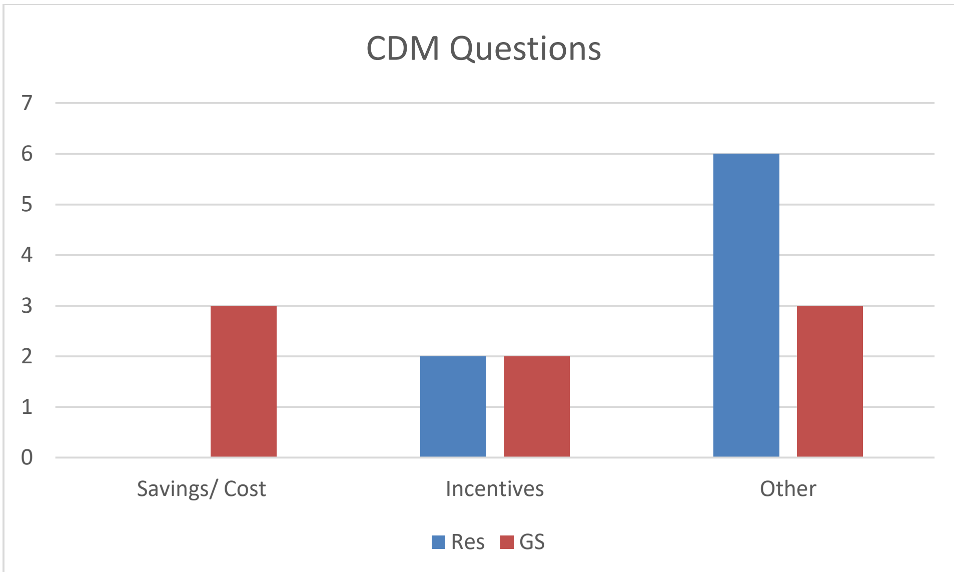
What, if any, questions would you want to have answered before deciding whether the following are appropriate for Central Toronto?

26. Conservation and Demand Management

Savings/cost: Need for new infrastructure. What cost to us?

Incentives: *How can this option be encourages and controlled. What incentives for me to buy in to this approach*

Other: *How will technological advances make this an improvingly desirable choice?*

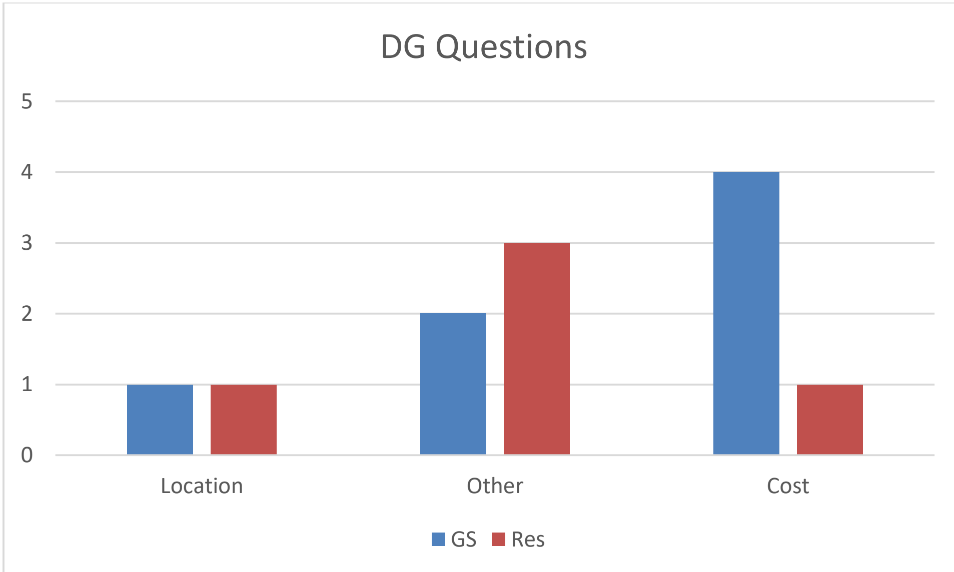


27. Distributed Generation

Location: *how much and where they would they be located? What type of energy what repercussions?*

Cost: *If the costs distributed generation are so high what would be the incentive?*

Other: *What would we do in an emergency situation?*



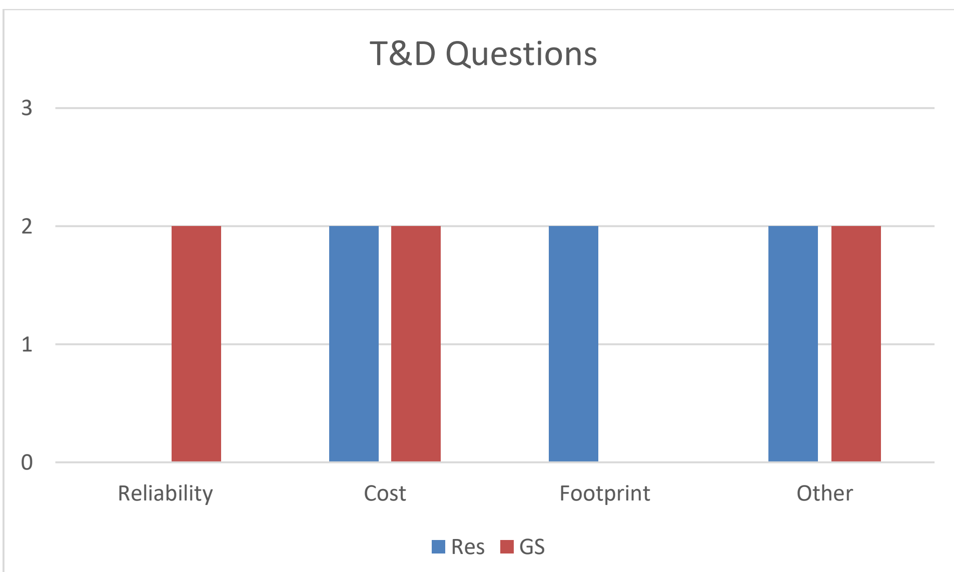
28. Transmission and Distribution

Reliability: *Reliability. All in all no more cost to the small businesses or home owners. We pay enough.*

Cost: *What is the cost per KwH?*

Footprint: *How large would the footprint be and how close to where I will it be built*

Other: *How can we make sure that transmission and distribution are fully utilized?*



Stakeholder Workshops 1

Workshop Presentations and Discussion Groups
with Stakeholder groups

PURPOSE: To gain qualitative input on planning options for Central Toronto from stakeholder groups and to obtain feedback into survey design

Summary

The following summary highlights key findings from the stakeholder workshop sessions held in the Toronto area on September 18, September 22 and October 20 2014.

System Reliability: Customer Experience and Expectation

- Most participants in the workshop groups felt that the electricity system works reasonably well but that there is room for improvement in system reliability.
- The first two groups were specifically concerned with the reliability of essential services, including; hospitals, water treatment facilities and public transportation.
- Several participants were also concerned with industry leaving downtown because of the increasing lack of system reliability.
- There is concern from most business and industry participants about potential rate impacts and a strong reluctance to increase reliability standards without a clear demonstration of the benefits.

Planning at a Higher Standard

- Many participants in the first two groups believe that Toronto requires planning at a higher standard than the rest of Ontario.
- The first two groups pointed to financial institutions, hospitals and vulnerable people as reasons for justifying this higher standard.
- That being said, some participants prefaced that the burden of these higher standards should not be placed solely on the ratepayers. They feel the need for higher standards is based on social needs that should be supported by government through taxes.

Planning for Extreme Events

- Generally, participants were leery of committing to funding improvements to reduce the impact of major events because of the uncertainty regarding future frequency.
- Additionally, several participants pointed to other growing pressures as more potentially damaging to existing system reliability.

Peak Demand

- The second group featured an interesting discussion regarding peak demand. Several participants agreed that a new definition was needed for peak demand.
- Additionally, some participants supported adopting the term “super peaking” in reference to these spikes, but suggested addressing the peak in a broader sense.

Community Involvement

- The two first groups placed an emphasis on the need for more granular community involvement in the planning process.
- Many participants agreed that community planning can be used to address specific, local stresses on the system.
- Additionally, many participants believed that the analysis provided in community plans would help leverage the success of this plan.

How Could the Consultation Process be Improved?

- Generally, participants found this consultation process to be useful.
- Some participants felt further community involvement could be beneficial to creating local solutions to growth pressures.
- Many participants had questions regarding the format of this consultation process, particularly regarding the role of the City of Toronto and local community organizations.
- Because these groups were quite knowledgeable of the system, participants frequently requested additional data and cost projections related to proposed projects.

Methodology

About the Stakeholder Workshop Consultation

Stakeholders were consulted on Central Toronto’s IRRP during three, two to three hour workshop sessions. Planners from the Ontario Power Authority and Toronto Hydro presented material and fielded questions while INNOVATIVE facilitated discussions and kept notes. No recordings were made so only a limited number of direct quotes are included and comments are not directly attributed to specific participants.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Recruiting Workshop Participants:

The four organizations compiled a list of more than 300 broad-reaching stakeholders, and each was invited to provide their input on the Central Toronto IRRP. Stakeholders were encouraged to either attend one of the workshops or open houses, participate in a webinar or submit their feedback in writing.

Workshop Session Structure:

The consultation sessions were structure around the themes contained in the workbook, which was developed by INNOVATIVE and the Central Toronto IRRP Study Partners.

The workbook themes included the following:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

All workshop participants were provided hard copies of the workbook at the time of the session.

Following a brief introduction explaining the purpose of the workshop, the OPA and Toronto Hydro provided a presentation of the key areas and objectives of the IRRP.

Following each section of the presentation, the facilitator led participants in a discussion, allowing time for clarification of aspects of the slideshow.

Each workshop session ran for between two and three hours.

The following stakeholders were involved in the 3 workshop sessions.

September 18, 2014	September 22, 2014	October 20, 2014
Sunnybrook Health Sciences Centre	City of Toronto	Redpath Sugar Ltd.
Toronto Clean Air Alliance	Toronto Blue Jays	Retail Council of Canada
Greenpeace Canada	Ryerson University	Toronto Region Board of Trade
Northland Power	Electricity Distributors Association (EDA)	Accenture
City of Toronto	Siemens Canada	Beechgrove Country Foods Inc.
	Weston Food	AGE Power Consultant

Participant Feedback

The following section highlights specific feedback from the three workshops.

Stakeholder Workshop Session

System Reliability: Customer Experience and Expectation

Most participants in the workshop groups did not believe that the current level of reliability is adequate.

When asked about reliability, one participant said, *it's not at all where it should be.*

In the third group, participants were less concerned with the amount of outages, rather the time it takes to restore power while the first two groups expressed similar levels of concern about frequency and duration.

Most participants in the groups noted that it was not acceptable to see outages occur at hospitals, subways, water treatment facilities or high-rise buildings.

One participant with experience in one of these key facilities noted it experienced 20-25 interruptions per year. While they were mainly short outages, they can create many risks, depending on the facility involved.

Many participants wanted to know what was being done about outages occurring at the "key facilities". One participant in the first workshop suggested that these facilities should be equipped with combined heat and power to maintain reliability.

A participant in the third workshop felt that residential and localized generation is a good way to help address reliability questions. The panel noted in some cases emergency generators can quickly run out of fuel, and that some of them may not have planned for extended outages.

Participants expressed concern over the issue of vulnerable people being stuck in high-rises because of a lack of system reliability.

Several participants agreed that system reliability in Toronto is effecting where businesses choose to build industrial facilities. One participant voiced that, *industry is moving out of downtown Toronto because of the urban pressures to the* system.

Additionally, some participants from the second group noted that for the cost needed to improve reliability, they could build their own plants onsite.

One business participant said that cost is most important and reliability is second. It was said that these were the two variable drivers that members in that participant's organization mentioned most often. These same members thought the day-to-day reliability was "pretty good", however they need to be able to recover more quickly.

When it came to reliability, a participant in the first group said *"the average consumer doesn't know how to quantify reliability, you have to build support around hospitals, subways and water treatment plants".*

Several participants in the second session noted that existing standards are significantly lower than emerging reliability standards. *"You cannot plan knowing what you know, meeting current standards is not relevant. Are we meeting the standards that will exist in five years?"*

One participant in the second session voiced a concern that reliability standards might be being met in theory, but not *"politically and in communities".*

One participant in the third workshop asked whether the IRRP study partners were coordinating with the city to push demand to other parts of GTA. The partners responded that they work closely, but have a legislated responsibly to connect whomever makes a request.

Planning for a Higher Standard

Most participants said that Toronto requires a higher standard than the rest of Ontario. That being said, a few participants noted that Toronto taxpayers should not have to pay significantly more than the rest of the province for these increased standards.

In addition to these key facilities, many participants noted that a higher standard was necessary because of the high number of disadvantaged and vulnerable people in the city. One participant said, *"These individuals cannot be stranded on the 75th floor during an outage. We have an economic, moral and ethical obligation to be more reliable."*

One participant said that the complexity of the downtown system must already put Central Toronto at a higher standard. In response, the study partners said that there is more redundancy downtown and that it experienced 1/3 the number of outages as the rest of the city. During the 2013 Manby Station flooding, it was fully re-supplied in two hours which was six hours quicker than the standard.

Another participant commented that Toronto does need a higher standard because *"individual customers are being replaced by condos the size of small towns on one city block".*

It was said that planners have to look at this need for higher reliability on an intersection scale, because new development is leading to severe increases in heat.

A participant then raised the issue of "increased performance metrics". *"Downtown Toronto needs a plan and (its development) should include The Building Owners and Managers Association (BOMA)".*

In the first two groups, participants encouraged "transformative thinking" to address a higher standard of reliability in Toronto. One participant in the first group said that "*the IESO standards are not good enough".*

In order to provide this higher standard, one participant advocated that *"all key facilities should be equipped with combined heat and power generation"*

The third group in particular focused on the question of benchmarks and standards compared to other comparable cities.

When asked about standards used in other major cities, the study partners said that it is often difficult to find these standards. Not everyone measures reliability the same way and standards vary in different cities.

The panel continued to say that core North American standards are set primarily in the US. They noted that Ontario has taken these standards and made them more specific and moved standards to local areas.

One participant said that the challenge that exists is that there is nothing with which to compare current standard in Toronto. The panel said that while there are limited standards for comparison, there are some statistics available and that Central Toronto does "stack up well" to other major cities. They also noted that there are certain redundancy standards that are common amongst big cities. The panel indicated that while comparisons are difficult, downtown Toronto does well compared to cities such as Chicago and Boston that share similar circumstances.

While there was general support for a higher standard, one participant said that standards should not be raised just for bragging rights. One participant noted that for developers, it is still a matter of how cost effective it is to get power to buildings. There needs to be a balance between reliability and how much it costs.

Planning for Extreme Events

While many participants agreed that the general, day-to-day reliability of the system was good, most suggested improvements need to be made when the system does fail during extreme weather events and other outages.

Some participants asked how climate change was being factored into current forecast projections. In response, it was said that the IESO criteria requires forecast scenarios to account for extreme weather.

Not all participants agreed. One industry participant said that they didn't expect more system redundancy for extreme weather events. This participant said that they understood these events happen, and that we should learn from them.

Another participant said *"we don't know if these things will happen again, we just have to live with them".*

Participants expressed concern about the investments that may be needed to meet these changing standards. Several participants pointed to a possible increase in customer bills to plan for these extreme events that might not occur for another 50 years.

Participants in the first two groups commented that extreme weather is not the only concerning stress being placed on the system.

In response to this comment, a participant from the City of Toronto commented that the city had tabled a report on the probability of similar weather occurrences. *"More frequent severe storms are predicted and should be accounted for in reliability planning".* Some participants agreed, one noted that *"rising temperatures and heatwaves are also a concerning trend".*

Several participants asked what kind of steps had been taken to plan for these events following the recent ice storm and flooding.

A participant in the first session asked whether "undergrounding" the whole system would make it more reliable and help mitigate the damage of such events. A response was provided that it was not *"straightforward"*, and that *"flooding can be a long-term issue for an underground system. Also, freeze/thaw effect on underground pipes and underground is not always possible, especially in urban areas".*

As a response to these participants concerns, it was said that, *"Toronto is on the leading edge for understanding extreme weather. The long-term part of the plan is working on these concerns, in fact, funding has been received from the Federal government. Specifics related to probability and type of extreme weather are being researched now. Findings from these studies will be made public when completed".*

In the third workshop, several participants agreed that while they did not believe that investments for these extreme weather events were necessary, there was a general concern regarding the prompt restoration of the system during these periods. They were not looking to avoid outages from major event but to take steps to improve restoration times.

During that discussion, a participant from a small business group said that many of his members were devastated by the response time during extreme weather events. Because the frequency of these events seems to be increasing, it is a critical issue for his small business members.

In response to these concerns, a member of the study group said that the OPA and Toronto Hydro are involved in detailed risk assessments. They have been awarded funding from Natural Resources Canada and these results are expected in spring 2015.

Planning for Growth and Development

Many participants inquired as how to the IRRP accounted and planned for growth in Central Toronto. There was a general concern that larger projects would put a significant strain on the existing system.

One participant asked how long it would take to build new capacity to handle the electrification of GO. The study group responded that they do not expect it will affect downtown much. GO lines stretch a long distance, and can be connected at various spots. Also, the 10 years proposed for this project falls within the time needed to get the necessary approval.

Additionally, a participant asked about whether the Waterfront Toronto development plans were being accounted for in this plan. The study group said that, in terms of demand, they look at the City of Toronto when deciding local demand. However, it is difficult to make concrete demand decisions when the projects have not yet received funding.

In addition to this, the panel said that transmission needs are tied to station capacities and not to other developments that are further out.

Peak Demand

The second group featured an interesting discussion regarding how to define "peak demand".

"*Super peaking"* is a term used to refer to these drastic spikes in demand, however, several participants argued that peaks should be looked at in a broader sense, addressing the peak in total. *"Other jurisdictions are having the same difficulties defining peak and this is an opportunity for thought leadership".*

In response to this, it was said that it has to be looked at from a reliability perspective. *"Transmission and distribution is limited by physics. The heat has to be taken away when stressed (i.e. summer periods). Ambient temperature is cooler in the offseason, and equipment can be run harder".*

One participant then said, *"Peak represents a demand for cooling. Peaks are going to go above 500kW, why not look into heat water cooling".*

Looking at demand, one participant questioned the ratio of peaking kW compared to means and asked *"Should the system as a whole be hardened for 100 hours?"*

In response to "super peaks", a response was given that smaller peaks don't put the system at risk. The heat can be dealt with more easily in the winter. Additionally, "critical peak pricing" is currently being looked at in addition to 'TOU' pricing that already exists.

Community & Local Involvement

Several participants in the first two sessions stressed the importance of Community Planning and Community Energy Plans. It was said that these plans *"Can provide a deep analysis of the given area and this information can be leveraged in the IRRP".*

In addition to this, a few participants felt that CDM would be enhanced through local engagement with a better understanding of where it is needed within the community.

A participant in the first group emphasized the importance of building a relationship with local groups (like the participant's), so they can know where to prioritize next community-based energy projects.

A member of a community group then continued to say, *"We are looking forward to working with Toronto Hydro, the OPA, etc. Their organization has three objectives; conservation, resilience and power generation/growth".*

In the first two sessions, there was an emphasis placed on the value of involving the City of Toronto in the process.

Specifically in the first group, a participant from the City said, *"The City can provide a human and economic element. There is great value having the City involved in this plan.*

It was also said that the municipalities are doing their own energy planning and risk assessments, including vulnerable populations.

One participant also met with the Toronto Industry Network (TIN), who said they were concerned with the cost of electricity in Toronto compared to other regions. The message that they are hearing is that they must lower costs to attract new industries.

Best Options Moving Forward

Participants were generally in agreement that the planners were looking at the right solutions for meeting demand. Despite agreement, participants offered suggestions on where they believe further emphasis should be placed. Some of these suggestions are included below.

One participant in the first group expressed concern at the conservation assumptions in the base case and sought a much more aggressive approach in the final plan. This position was strongly supported by a second participant and appeared to be supported by several other participants.

One participant asked why Toronto Hydro was not considering more underground wires solutions. The panel said that they were looking at return for investment. Ice storms still affect the underground systems and tree trimming is far more cost effective. Additionally, the study group noted that underground distribution lines would be more difficult to maintain.

A business participant felt that the system has already caught up on the capacity side, but asked what was being done on the distribution side of the system. *How do developers get connected to the load centres?* In response to this, the study group noted that the $1.3B investment did not include the distribution portion of the system. The study group noted that there is also work being done to re-distribute load.

Some participants expressed concerns regarding emissions from DG. The study group said this is a challenge, noting that for existing installations retrofitting can be an expensive challenge.

Another participant noted that one set of standards applied to facilities such as existing water boilers and that if they were converted to combined heat and power, a tougher set of rules may apply that will act as a disincentive to conversion.

One participant said that transmission and distribution solutions are the best, because the other two options (CDM and DG) are less controllable. This participant continued on to say that history indicates we can't count on CDM.

A participant from a business group said that CDM plans are municipally based, and the integration of them is crucial to get businesses on board. The participant indicated that businesses are concerned about the paperwork, timelines and standards of having inconsistent CDM plans across Ontario. The participant noted that smaller utilities don't have the same resources to facilitate the development and integration of CDM.

Some participants indicated that business would be open to CDM if incentives were great enough, but it is difficult for them to shift during times of peak demand.

Again, with regards to CDM, a participant said that they need a far more aggressive approach if they want businesses to get on board.

For developers, one participant said that it's all about transmission and distribution. These solutions are needed to meet demand that is constantly growing.

Request for Expression of Interest (RFEI)

Participants in all three groups were asked what they thought of RFEI's for DG customer driven solutions.

While many had an initially positive reaction, some participants were skeptical because they had been frustrated by these requests in the past. *"We're frustrated because we work hard on these submissions and then nothing ever happens. We are developing CHP and then having to walk away".*

Many participants found the economic costs of these past proposals to be too high.

Despite that concern, most participants appear to believe that there will be overwhelming support for any request **if it is shown that this time is for real.**

When asked about the accuracy of these proposals, participants in both groups said it was previously too high. One participant echoed the opinion of several others, saying, *"RFEI's get concepts, not prices. Ask for an accuracy of ±25%. This can be done in as little as a month. If you ask for less than that, costs too much money to produce".*

Many participants in both groups, noted that prior requests had not been clear. Projects should be framed more clearly, including the nature of project, geography and constraints. This is also helpful in terms of community DG planning.

Generally, the majority of participants expressed interest, however, the proposal process must overcome a credibility challenge to garner trust from those providing submissions.

How could the Consultation Process be Improved?

Most participants in this group found this consultation to be a positive experience.

One participant said that it was critical to keep this dialogue open. Generally, this participant thought that the reliability was there, it was just about the distribution side because it takes a long time to connect a new building.

Several participants agreed that it was important to get this information to more businesses and make sure that it's easily accessible.

Many participants said that they should seek feedback from businesses using groups like the Canadian Chamber of Commerce. It was also suggested that this sort of information be brought directly to these businesses.

A participant representing developers said that the most effective way to reach them for consultation was through consultants.

Some participants in the first two groups were unclear as to the role of communities and the City of Toronto.

Some participants were also looking for more clarity regarding timelines of the plan. There were questions asking when a final plan would be submitted.

Some participants in the first two groups felt that the process would be improved with increased community engagement.

Overall, most participants found the presentation and information provided to be useful and welcomed the opportunity to engage directly with planners.

Customer Telephone Surveys 1

Telephone Surveys
among Residential and GS customers

PURPOSE: To obtain statistically significant quantitative customer feedback on the planning options presented and assess reaction to customer opinions obtained from the previous research phases

Summary

The following summary highlights the key findings from two telephone surveys of 621 Toronto Hydro residential customers and 101 general service customers:

Respondents familiar, satisfied with their electricity system

- More than 6-in-10 (62%) residential customers say they are familiar with the system and nearly 9-in-10 (86%) are satisfied with their current service. General service customers are a bit less familiar (46%), but still quite satisfied (82%).

Cost is a key issue for respondents, "number of outages" a distant second

- When asked how the electricity system could improve their service, 4-in-10 say "reduce rates" (40%). Just 1-in-10 (10%) say "number of outages", the next specific improvement mentioned.

Interruptions a common thread among Residential and GS

- Half (50%) of residential and GS customers experienced power service interruptions during the major weather events of 2013. And half (51%) of residential customers experienced outages in the last 12 months during normal weather.

"Length of outage", *not* "number" a key concern for Residential customers

- Customers are far more inconvenienced by the length of outages (77%) than the number (12%). Also, they think the government should prioritize fixing length over number of outages (67% vs. 28%).
- On average, outages for residential respondents are not frequent- nearly 6-in-10 (57%) only experienced one or two in the last year. But they tended to be long. Just 15% experienced an outage of an hour or less and more than 2-in-10 (22%) experienced outages for 24 hours or longer.
- That being said, general service customers are much more concerned about short outages: three-quarters (74%) experienced one or two outages at their place of business and nearly 3-in-10 (28%) said those outages were less than an hour. More than 6-in-10 (62%) GS customers say an hour or less outage makes things difficult. And a third (32%) say that outages of 15 minutes or less are a difficulty.

Reliability a concern…but they don’t want to pay more for it

- When asked to choose between the current levels of reliability and holding Toronto to a higher reliability standard even if it means paying more, staying the course wins out by 21-points (55% to 34%).

“Climate change contribution”, “emissions impacting” health key concerns

- Customers’ greatest environmental concerns are how the electricity system contributes to climate change (+35) and also how those emissions directly impact their health (+28).

Majority think they’re getting good value for money, divided on bill impact

- Nearly 6-in-10 (58%) residential customers think they are getting either a reasonable or good deal on their electricity. And about the same amount (Residential: 57%) think they get good value for money on their electricity.
- Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances (46% major impact vs. 50% no impact).
- General service customers feel a much greater impact (77%) major impact) and are less likely to think they are getting good value for money (46% vs. 52%).

Low Awareness and Interest in Distributed Generation

- Respondents are the least familiar with “Distributed Generation” (net -27 vs. +10 “Transmission and Distribution Infrastructure” and +2 “Conservation and Demand Management).
- “Distributed Generation” is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% “Transmission and Distribution Infrastructure”).

Most important considerations “time”, “rates” and “climate change”

- When asked to rate seven considerations relating to capacity, residential customers focus the most on “reducing the time it takes to restore power” (+91), “reducing the impact on electricity rates” (+81), and “reducing impacts that contribute to climate change” (net +80).

Methodology

About the Survey

From December 15, 2014 to January 15, 2015, a total of 622 Toronto Hydro residential customers residing in Central Toronto were surveyed by telephone. As for the second sample of general service customers in Central Toronto, a total of 101 were survey by telephone from December 16, 2014 to January 16, 2015. Note: no customer calls were made between December 24, 2014 and January 2, 2015. The list of residential and general service customers were provided by Toronto Hydro.

The survey followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customers' level of annual electricity consumption). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In this survey, residential and general service customers were divided into four strata based on their electricity consumption in 2013 to ensure that the sample had a mix of customers from low, medium-low, medium-high, and high electricity usage households. The sample, randomly selected from a client provided list, was weighted to ensure each stratum accounts for 25% of the total sample. In both surveys, the sample was weighted down to its "target sample".

Residential Sample

Quartile	Customer Distribution	Target Sample	Actual Sample	Difference
Low Consumption	25%	125	151	+26
Medium-Low	25%	125	147	+22
Medium-High	25%	125	128	+3
High Consumption	25%	125	196	+71
TOTAL	**100%**	**500**	**622**	**+122**

General Service Sample

Quartile	Customer Distribution	Target Sample	Actual Sample	Difference
Low Consumption	25%	25	23	-2
Medium-Low	25%	25	31	+6
Medium-High	25%	25	25	0
High Consumption	25%	25	22	-3
TOTAL	**100%**	**100**	**101**	**+1**

The residential sample is considered accurate to within ±3.9 percentage points, 19 times out of 20. The general service sample is considered accurate to within ±9.7 percentage points, 19 times out of 20. The margin of error will be larger within each quartile of the sample.

Field: Sample and Logistics

For the purposes of executing this survey, Toronto Hydro provided INNOVATIVE with a confidential contact list containing residential customers and general service customers in Central Toronto. The research team built this contact list by randomly selecting records from customer its database.

The contact list included only customers with landline contact information on file and who had been a customer of Toronto Hydro since at least December 31st, 2012. The information contained in the contact list included customer name, home telephone number, home address, service area, and total annual usage between January 1st and December 31st, 2013.

Only one customer per household or organization was eligible to complete the survey. Survey respondents were screened to certify that only the resident primarily responsible for paying their Toronto Hydro electricity bill or, in the case of general service, the person responsible for paying the organizational electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household or organization to answer questions about their electricity bill.

Before retiring any randomly selected telephone number from the contact list, 12 attempts to reach a potential customer, for each unique telephone number, were initially made, or until an interviewer received a refusal. Each number was called twice a day for the first four days and once a day for the final four. Each night, a new sample was released from the contact list to replace completed or retired calls.

All fieldwork was conducted using INNOVATIVE's CATI system.

Respondent Feedback

The following sections will outline key issues such as respondent satisfaction, system reliability, environment, cost and value of electricity and finally the solutions proposed to deal with capacity issues moving forward.

General Satisfaction with the Electricity System

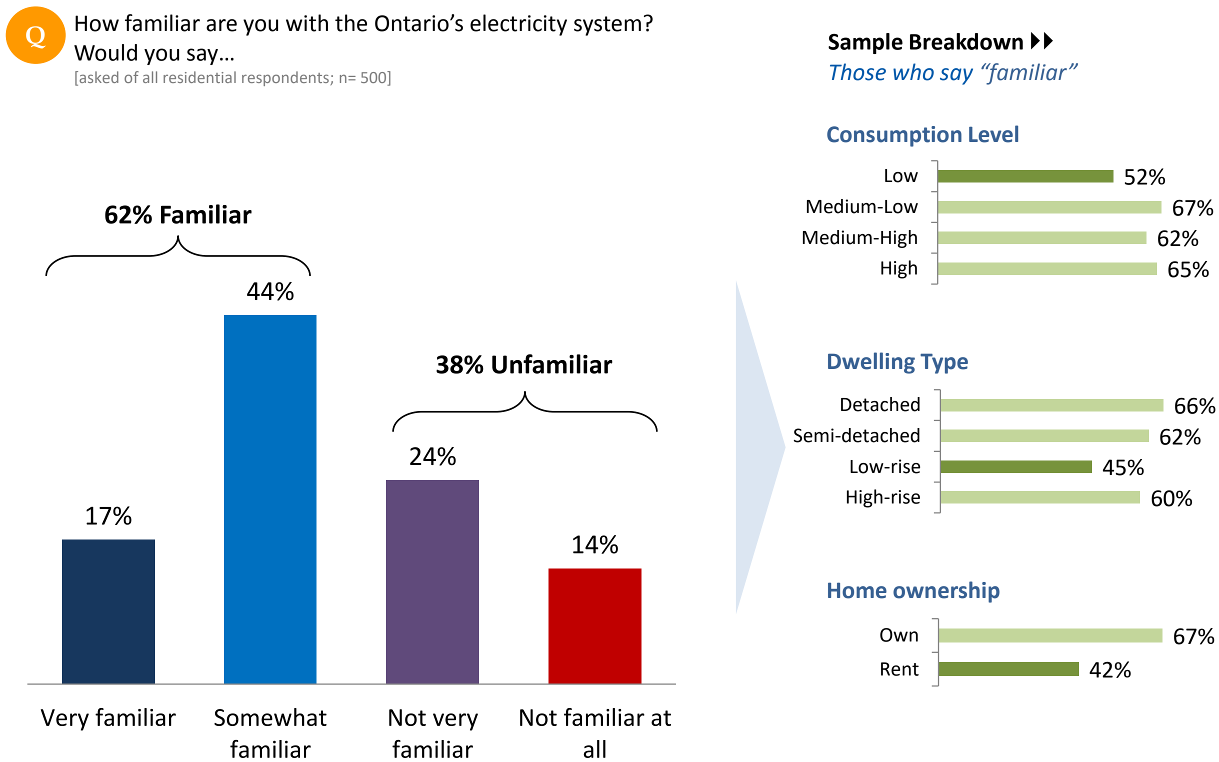
Respondents familiar, satisfied with their electricity system

- More than 6-in-10 (62%) residential customers say they are familiar with the system and nearly 9-in-10 (86%) are satisfied with their current service. General service customers are a bit less familiar (46%), but still quite satisfied (82%).
- Low-consumption users are the least familiar with the system.

Cost is a key issue for respondents, "number of outages" a distant second

- When asked how the electricity system could improve their service, four-in-10 of residential and general service say "reduce rates" (40%). Just 1-in-10 (10%) say "number of outages", the next specific improvement mentioned.
- About a quarter of residential (23%) and a third of general service respondents (33%) can't think of a way the system could be improved ("none" or "satisfied").

Figure 1RS: Familiarity with Ontario Electricity System

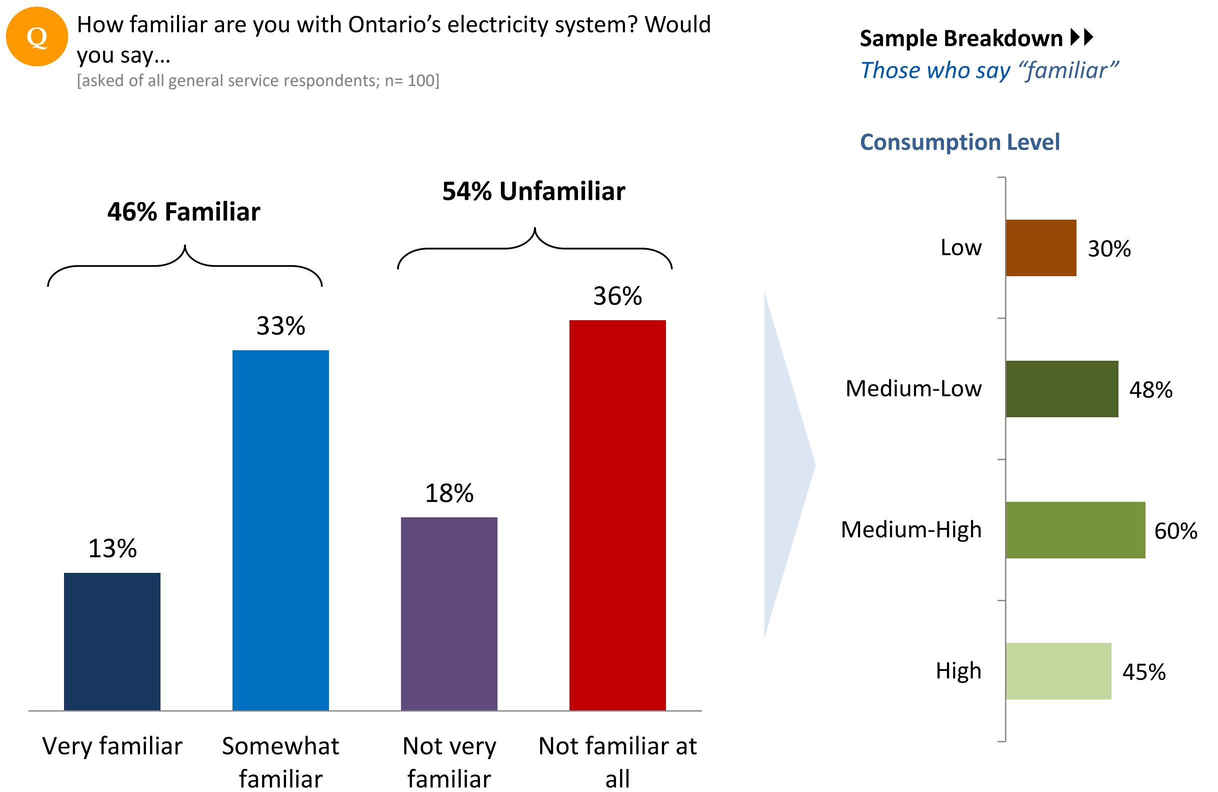


Residential customers are, for the most part, familiar with the Ontario electricity system. More than 6-in-10 (62%) say they are familiar with it and less than 4-in-10 say they are unfamiliar (38%).

- Low consumption users (52%), residents living in low-rise dwellings (45%) and renters (42%) are the least familiar with the Ontario electricity system.

Figure 1GS: Familiarity with Ontario Electricity System

How familiar are you with Ontario's electricity system? Would you say…
[asked of all general service respondents; n= 100]



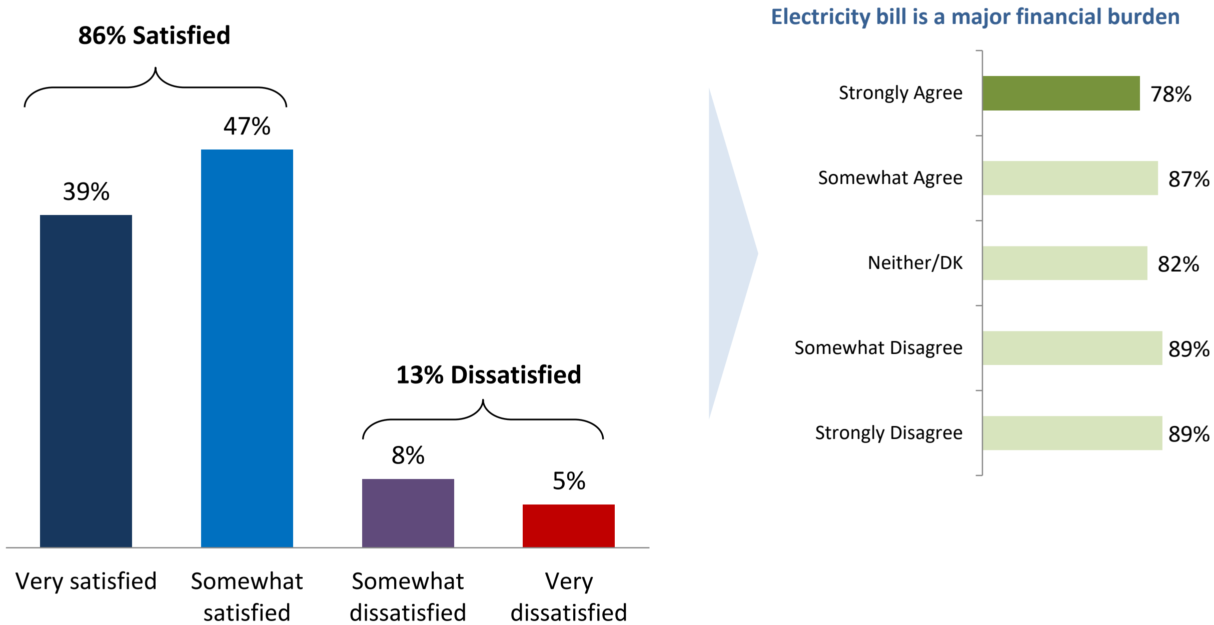
A large majority of general service customers are familiar (46%) with the Ontario electricity system and just over half are unfamiliar (54%).

- Again, low consumption users (30%) are the least familiar with the system.

Figure 2RS: Satisfaction with Ontario Electricity System

Q Generally speaking, how satisfied are you with the job the electricity system does in providing you with electricity? Would you say …
[asked of all residential respondents; n= 500]

Sample Breakdown
Those who say "satisfied"

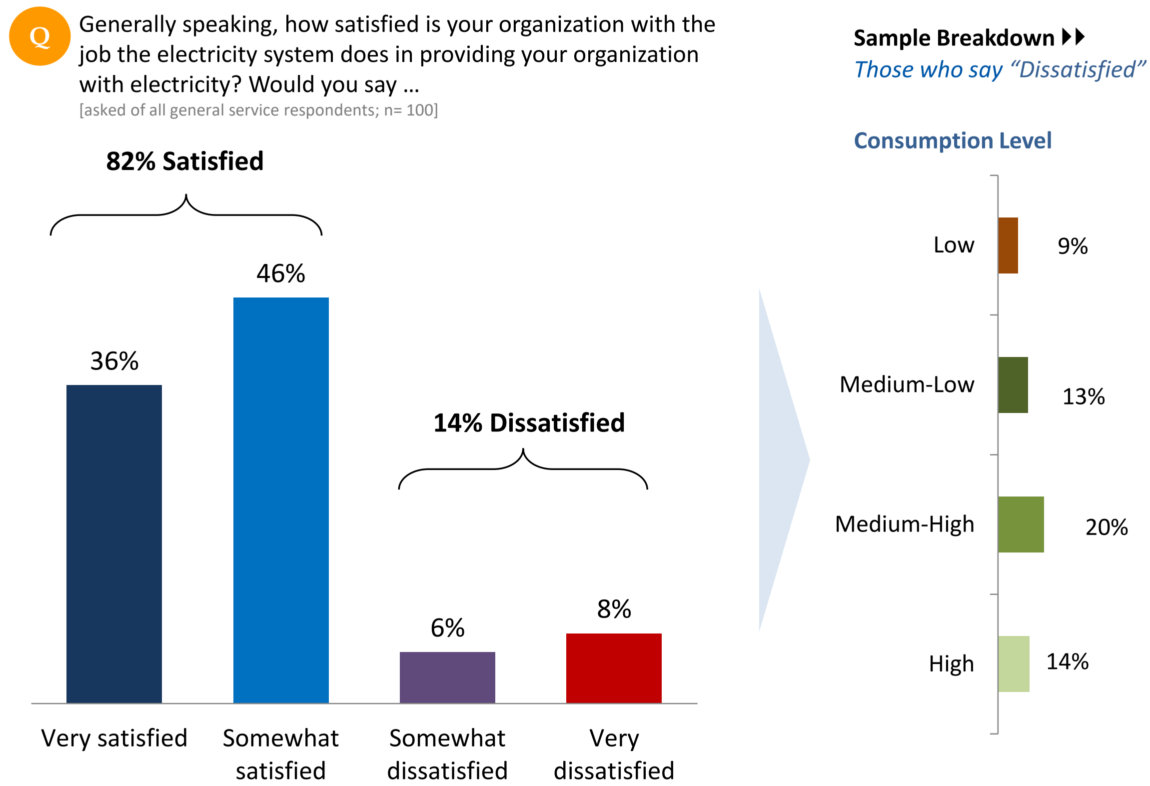


Note: 'Don't know' (<1%) not shown

Almost nine out of every 10 (86%) residential customers are satisfied with the electricity system. Just 13% say they are dissatisfied with how the system provides them with electricity.

- Those who "strongly agree" that the electricity bill is a major financial burden are a bit less satisfied (78% satisfied).

Figure 2GS: Satisfaction with Ontario Electricity System

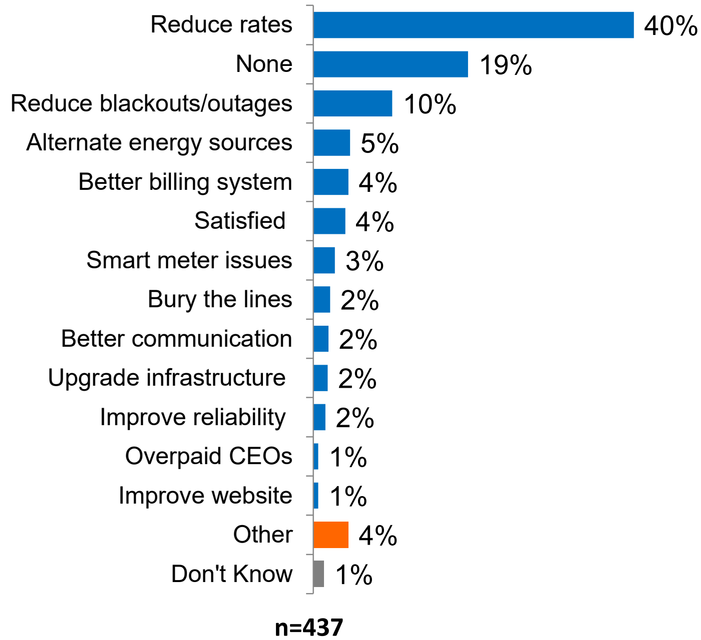


Note: 'Don't know'/'Refused' (4%) not shown

For the 101 general service customers who responded, the satisfaction numbers are similar: more than 8-in-10 (82%) are satisfied with the system and only 14% say they are dissatisfied.

Figure 3RS: Open-ended on How to Improve Service

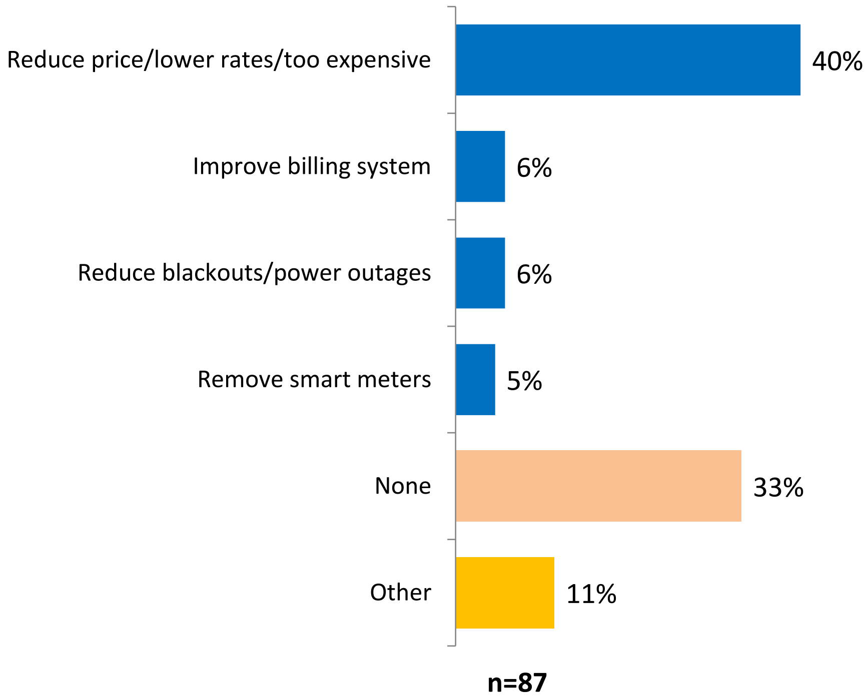
Q Is there anything in particular the electricity system can do to improve their service to you?



When asked how the electricity system could improve their service, 4-in-10 say “reduce rates” (40%). About a quarter say “none” or “satisfied” (23%)-they can’t think of anything that the system could do to improve their service. Other mentions include “reduce blackouts/outages” (10%), “alternate energy sources” (5%), “better billing system” (4%), “smart meter issues” (3%), “bury the lines” (2%), “better communication” (2%), “upgrade infrastructure” (2%), “improve reliability” (2%), “reduce pay for CEOs” (1%) and “improve the website” (1%).

Figure 3GS: Open-ended on How to Improve Service

Q Is there anything in particular the electricity system can do to improve its service to your organization?



Of the 87 general service customers who responded, 40% think “reduced rates” is the number one way to improve service. Other reasons include “improved billing system” (6%), “reduced blackouts and power outages” (6%) and “removing smart meters” (5%). A third (33%) of those 87 customers can’t think of any way to improve the electricity system.

System Reliability

This next section examines customer experiences during power service interruptions as well as their overall preferences concerning system reliability.

Interruptions are a common thread among Residential and GS

- Half (50%) of residential and GS customers experienced power service interruptions during the major weather events of 2013.
- And half (51%) of residential customers experienced outages in the last 12 months during normal weather.

Length of outage, *not* number a key concern for Residential customers

- Customers are far more inconvenienced by the length of outages (77%) than the number (12%). Also, they think the government should prioritize fixing length over number of outages (67% vs. 28%).
- On average, outages for residential respondents are not frequent- nearly 6-in-10 (57%) only experienced one or two in the last year. But they tended to be long. Just 15% experienced an outage of an hour or less and more than 2-in-10 (22%) experienced outages for 24 hours or longer.
- That being said, general service customers are much more concerned about short outages: three-quarters (74%) experienced one or two outages at their place of business and nearly 3-in-10 (28%) said those outages were less than an hour. More than 6-in-10 (62%) say an hour or less outage makes things difficult. And a third (32%) say that outages of 15 minutes or less are a difficulty.

But…they don't want to pay more for it

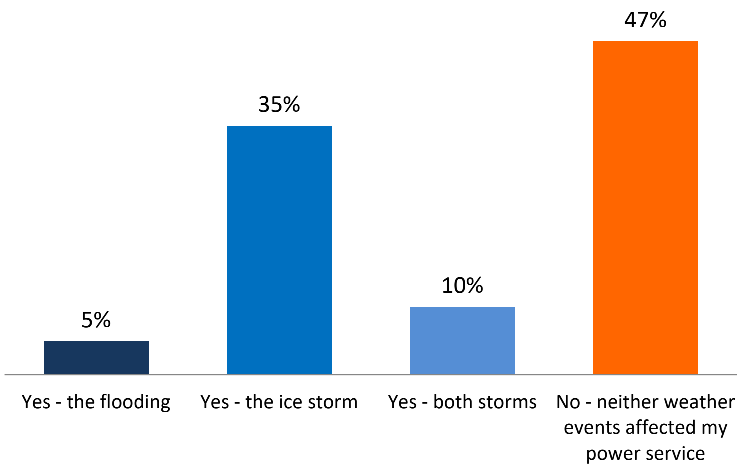
- When asked to choose between the current levels of reliability and holding Toronto to a higher reliability standard even if it means paying more, staying the course wins out by 21-points (55% to 34%).

Figure 4RS: Power Service Interruptions

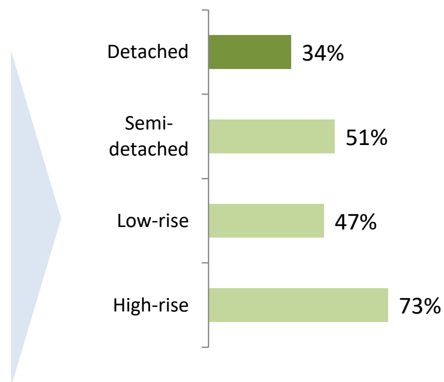
In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Q Did either of these major weather events cause a power outage at your home?
[asked of all residential respondents; n=500]

Sample Breakdown ▸▸
Those who say "no"



Dwelling Type



Note: 'Don't know' (3%) not shown

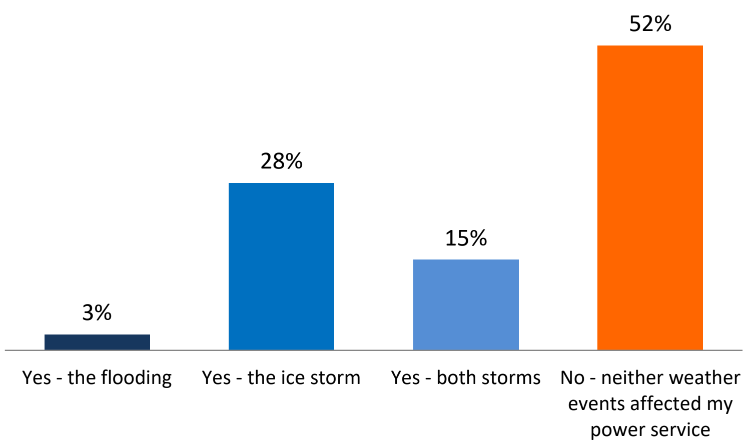
Half (50%) of residential customers experienced power service interruptions during the major weather events of 2013. More than a third (35%) lost power during the storm, 5% during the flooding and 10% during both. Just under half (47%) did not experience any interruption in power during these extreme weather events.

- Detached dwellings were the hardest hit during the flooding and ice storm of 2013: just a third (34%) say they did not experience an outage, compared to three-quarters (73%) of high-rise residents who had no interruptions.

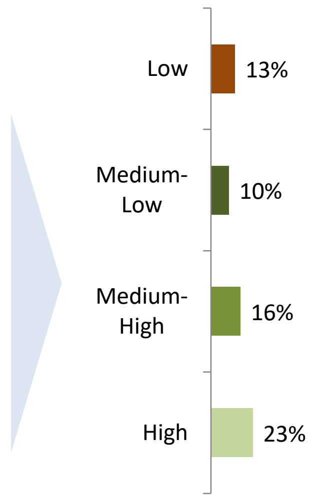
Figure 4GS: Power Service Interruptions

In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Q Did either of these major weather events cause a power outage at your organization?
[asked of all general service respondents; n=100]



Sample Breakdown ▸▸
Those who say "both storms"



Note: 'Don't know'/'Refused' (2%) not shown

Roughly the same level of interruptions occurred for general service customers: around half (52%) did not experience any outage during the July 2013 flooding and December ice storm.

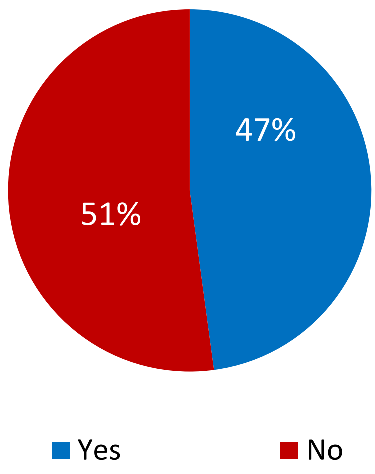
Figure 5RS: Other Power Outages

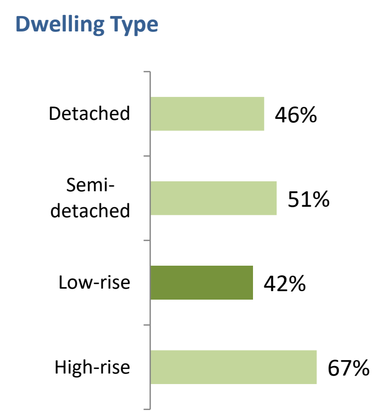
Q <u>Not</u> including power outages caused by these major weather events, did you have any other power outages in the **last 12 months**?

[asked of all residential respondents; n =500]

Sample Breakdown

Those who say "no"





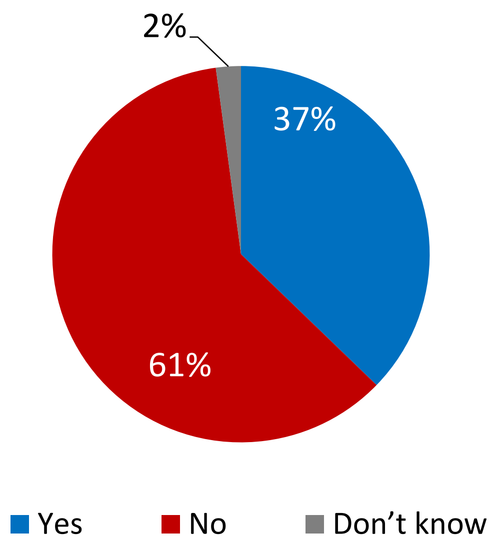
Note: 'Don't know' (3%) not shown

Not including these major weather events, nearly half (47%) of residential respondents experienced a power outage in the last 12 months.

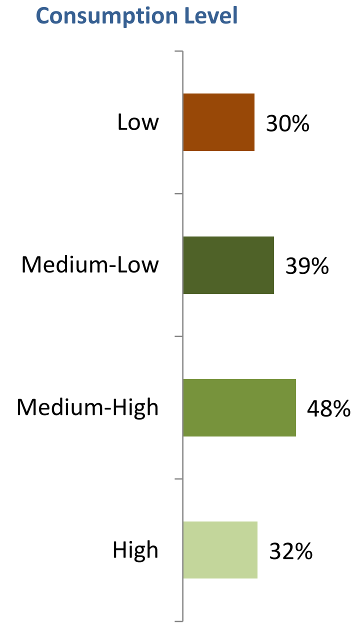
- High-rise residential customers had the least number of power interruptions during normal weather: 67% say they did not experience any in the last 12 months.

Figure 5GS: Other Power Outages

Q Not including power outages caused by these major weather events, did your organization have any other power outages in the **last 12 months**?
[asked of all general service respondents; n =100]



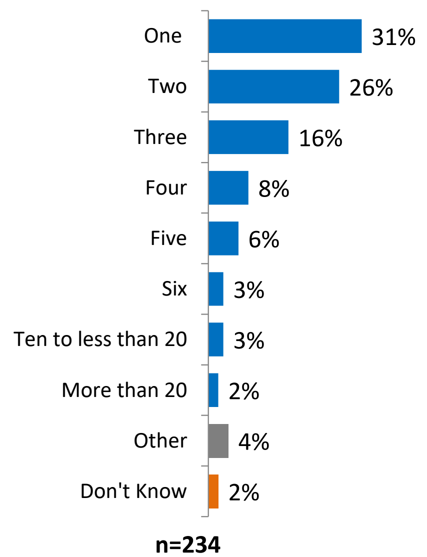
Sample Breakdown ▶▶
Those who say "yes"



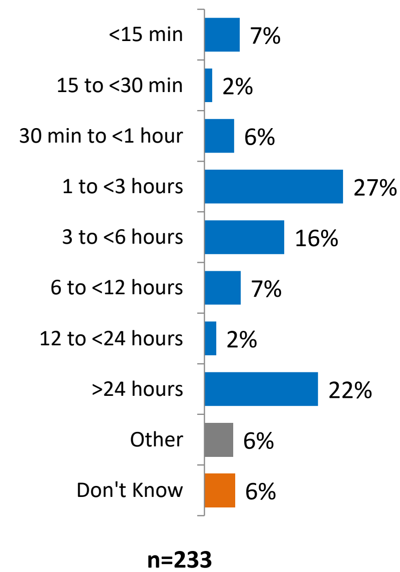
About 4-in-10 (37%) general service customers have experienced an outage in the last 12 months, not including major events.

Figure 6RS: Open-ended on Number and Length of Outages

Q [IF YES] How many outages did you experience over the past 12 months, NOT including those caused by extreme weather events?
[asked only of respondents who answered 'yes' to previous question]



Q [IF YES] And what was the longest period of time you were without power?
[asked only of respondents who answered 'yes' to previous question]



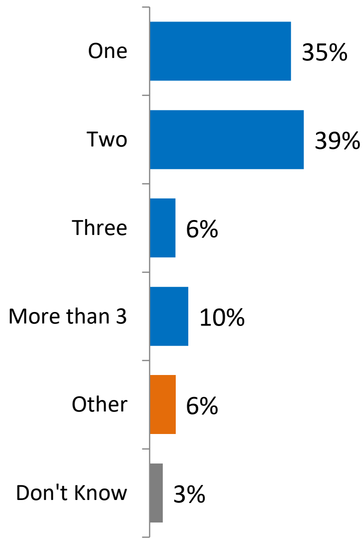
Residential respondents were asked two follow-up open-ended questions: if they had experienced outages, "how many in the past 12 months?" and also what the longest period of time was they went without power.

Nearly 6-in-10 (57%) Residential customers experienced one (31%) or two (26%) outages. About a quarter experienced three (16%) or four (8%) and 15% experienced five or more.

Most outages for residential respondents were on the longer side. Just 15% experience an outage of an hour or less. More than a quarter (27%) experienced an outage lasting one to three hours and another quarter (25%) experienced outages from three to 24 hours. More than 2-in-10 (22%) experienced outages longer than 24 hours.

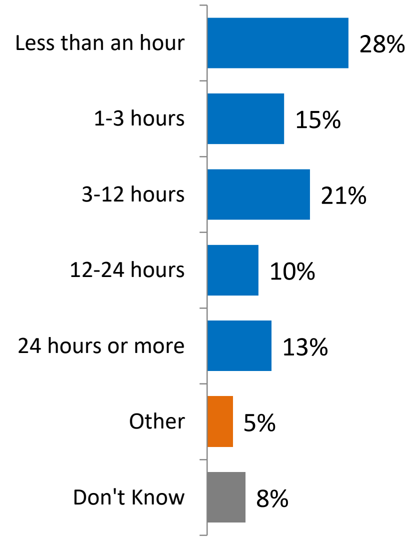
Figure 6GS: Open-ended on Number and Length of Outages

Q [IF YES] How many outages did your organization experience over the past 12 months, NOT including those caused by extreme weather events?
[asked only of respondents who answered 'yes' to previous question]



n=39

Q [IF YES] And what was the longest period of time your organization was without power?
[asked only of respondents who answered 'yes' to previous question]



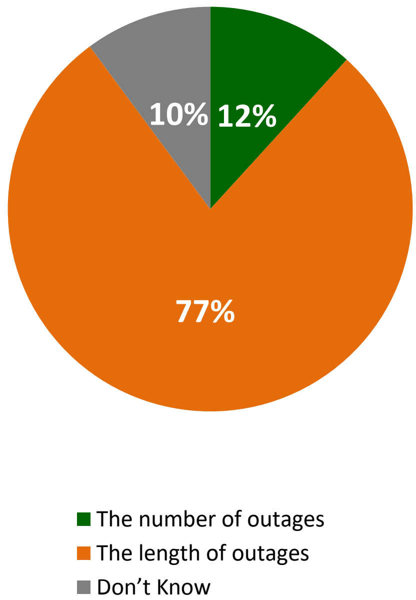
n=39

The 39 general service customers who experienced outages showed a similar breakdown. Roughly three-in-four (74%) experienced one (35%) or two (39%) breakdowns and 16% experienced three or more.

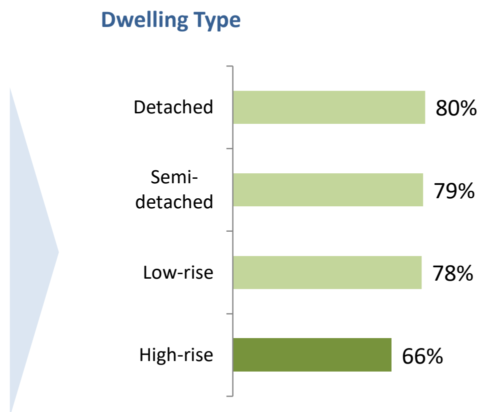
Just less than 3-in-10 (28%) general service respondents suffered outages of less than an hour and 15% lost power for 1-3 hours at their place of business. 2-in-10 (21%) experienced outages up to 12 hours long and about a quarter (23%) experienced 12 hour outages or longer.

Figure 7RS: Number vs. Length of Outages

Q When you do lose power, what causes you more difficulty:
[asked of all residential respondents; n = 500]



Sample Breakdown ▶▶
Those who say "length of outages"



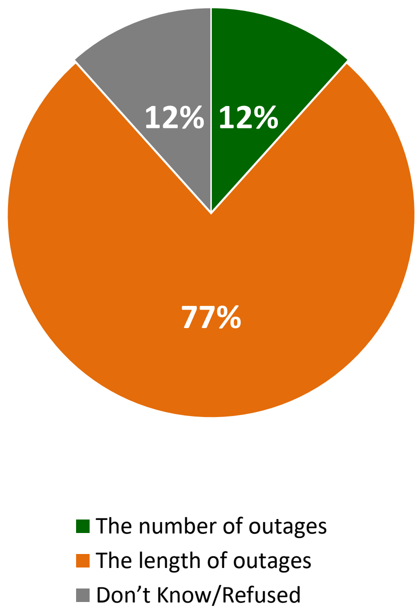
Note: 'Refused' (2%) not shown

When asked which causes them more difficulty, "number of outages" or "length", residential customers say the latter (77%) by a wide margin. Just 12% say the number of outages causes them more difficulty.

- High-rise (66%) residential customers are less likely to say "length of outages" than those living in low-rise, semi-detached or detached dwellings (78-80%).

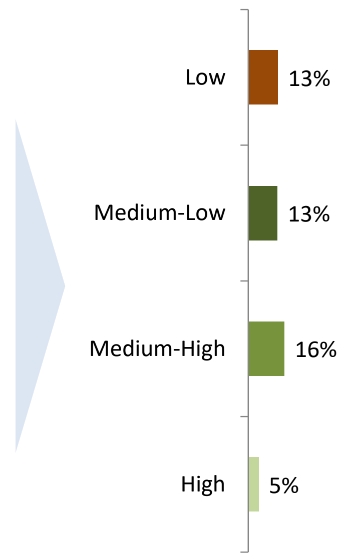
Figure 7GS: Number vs. Length of Outages

Q When your organization does lose power, what causes your organization more difficulty:
[asked of all GS respondents; n =100]



Sample Breakdown ▸▸
Those who say "number of outages"

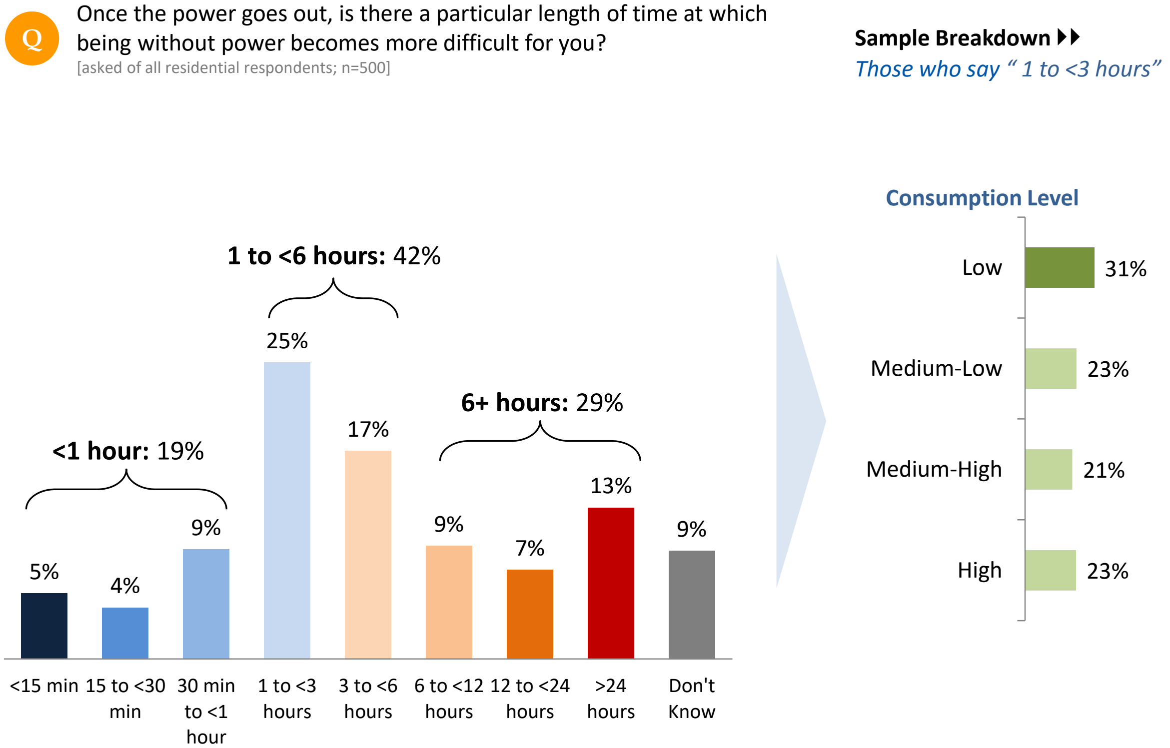
Consumption Level



General service customers also find the length of outages (77%) more difficult than the number of them (12%) by a 65-point margin.

Figure 8RS: Length of Outage Time and Difficulty

Q Once the power goes out, is there a particular length of time at which being without power becomes more difficult for you?
[asked of all residential respondents; n=500]



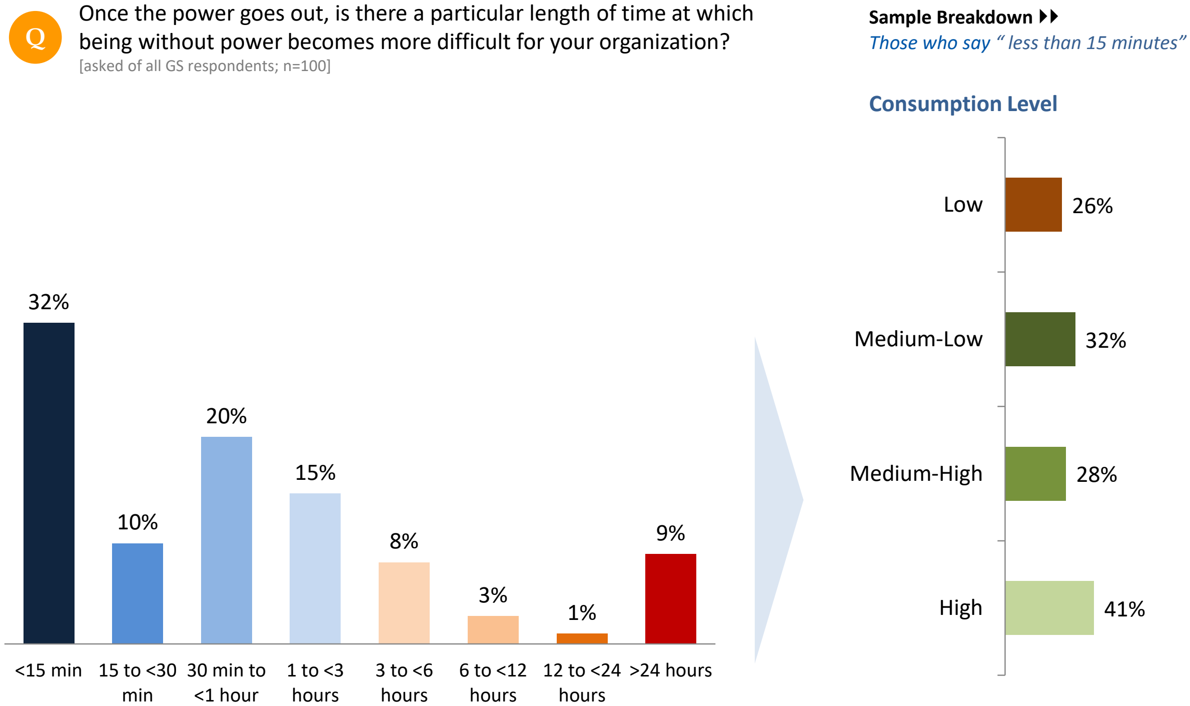
Note: 'Refused' (1%) not shown

When asked if there is a particular length of time at which being without power becomes more difficult, two-in-ten (19%) residential customers say just "an hour or less". More than four-in-ten say between "one and six hours" starts making their life more difficult and three-in-ten say it only becomes difficult at six or more hours without power.

- Low-consumption residential consumers are more likely to say that even short outages make their lives more difficult (low: 31%; medium-low to high: 21-23%).

Figure 8GS: Length of Outage Time and Difficulty

Q Once the power goes out, is there a particular length of time at which being without power becomes more difficult for your organization?
[asked of all GS respondents; n=100]



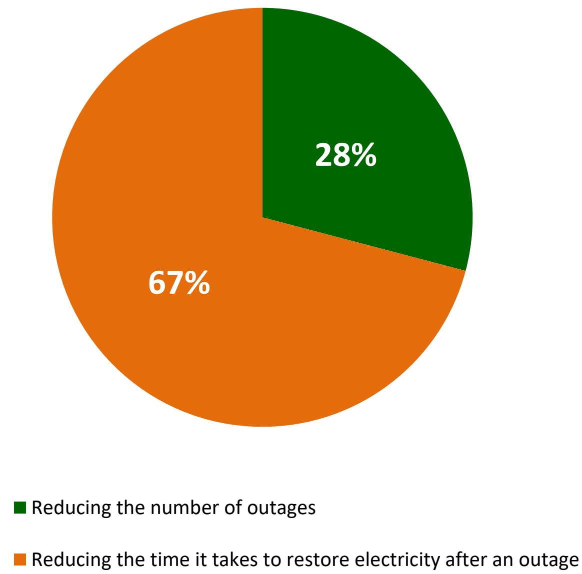
Note: 'Don't know'/'Refused' (2%) not shown

General service customers say that even a five-minute outage is a considerable problem for their organization. More than 6-in-10 (62%) say an outage of an hour or less starts making things more difficult for their organization. Of those, a third (32%) say a power outage of less than 15 minutes makes it more difficult.

- High-consumption GS customers are more likely to say that less-than-15-minute outages are a difficulty for them (41% vs. 26% low-consumption).

Figure 9RS: Priorities during Power Service Interruptions

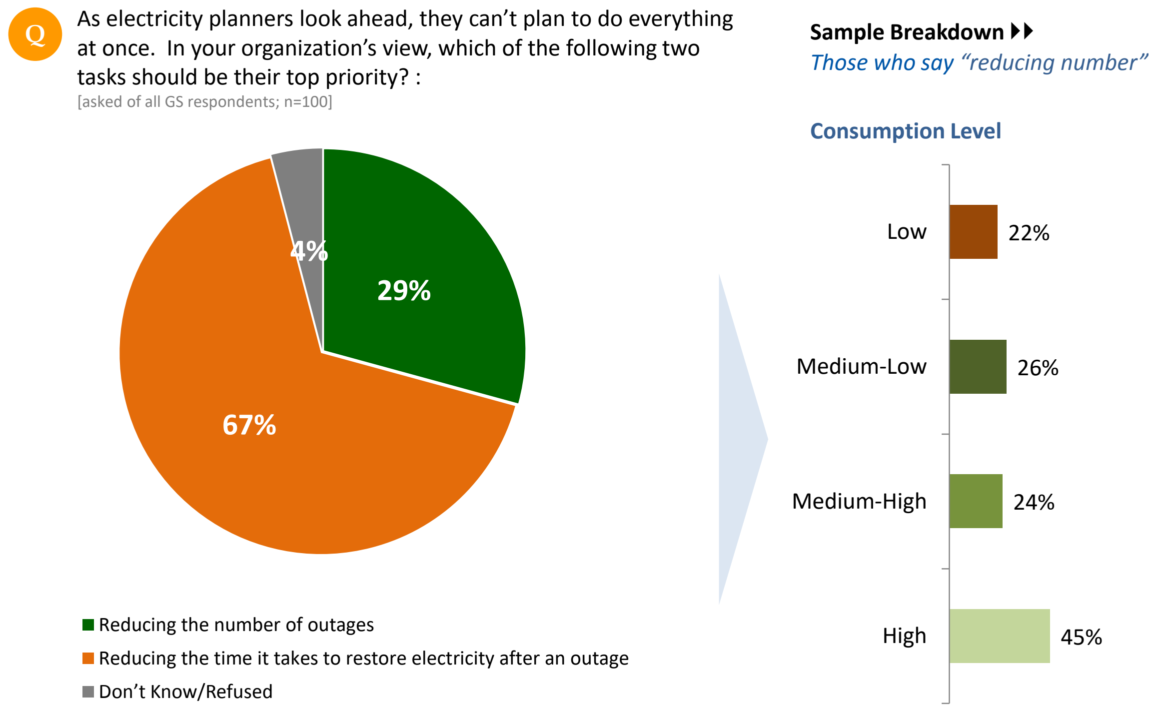
Q As electricity planners look ahead, they can't plan to do everything at once. In your view, which of the following two tasks should be their top priority? :
[asked of all respondents; n =500]



Note: 'Don't know'/'Refused' (5%) not shown

When asked to prioritize between "reducing the number of outages" (28%) and "reducing the time it takes to restore power" (67%), residential customers chose "reducing the time" by more than a two-to-one margin.

Figure 9GS: Priorities during Power Service Interruptions

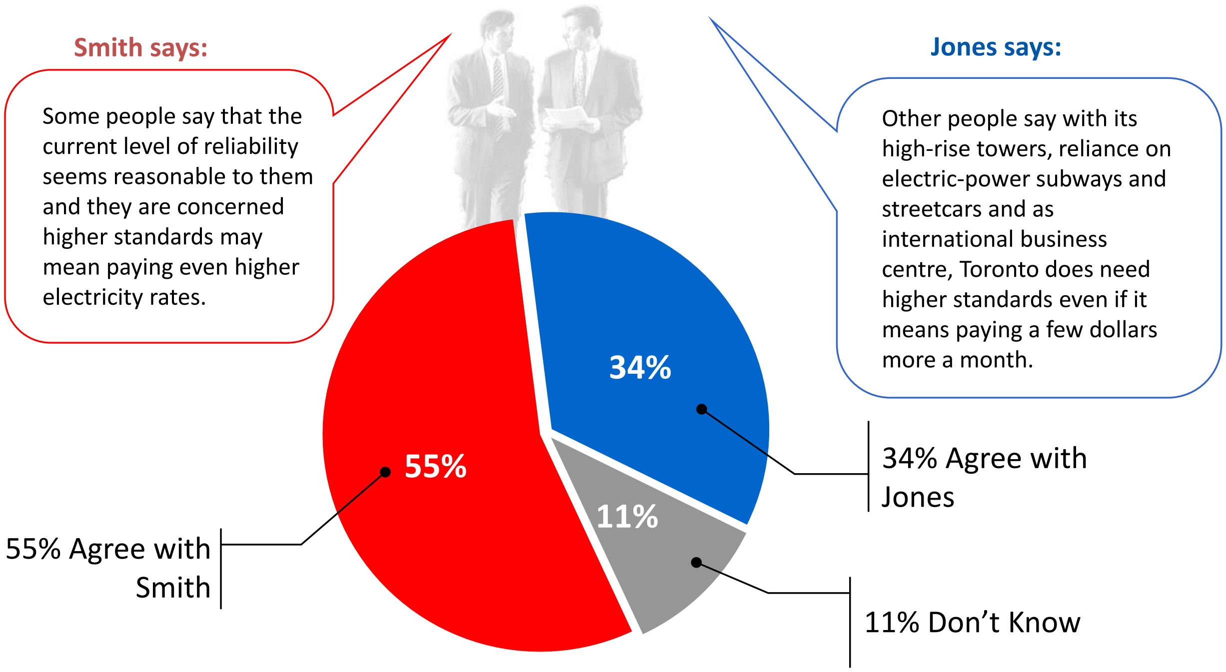


General service customers also prefer electricity planners reduce outage time over "reducing the number of outages", again by more than a two-to-one margin (67% to 29%).

- High-consumption GS respondents (45%) are more likely to want the number of outages reduced than those with lower consumption levels (22-26%).

Figure 10RS: Smith and Jones on Reliability

Q There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your own:
[asked of all residential respondents; n=500]



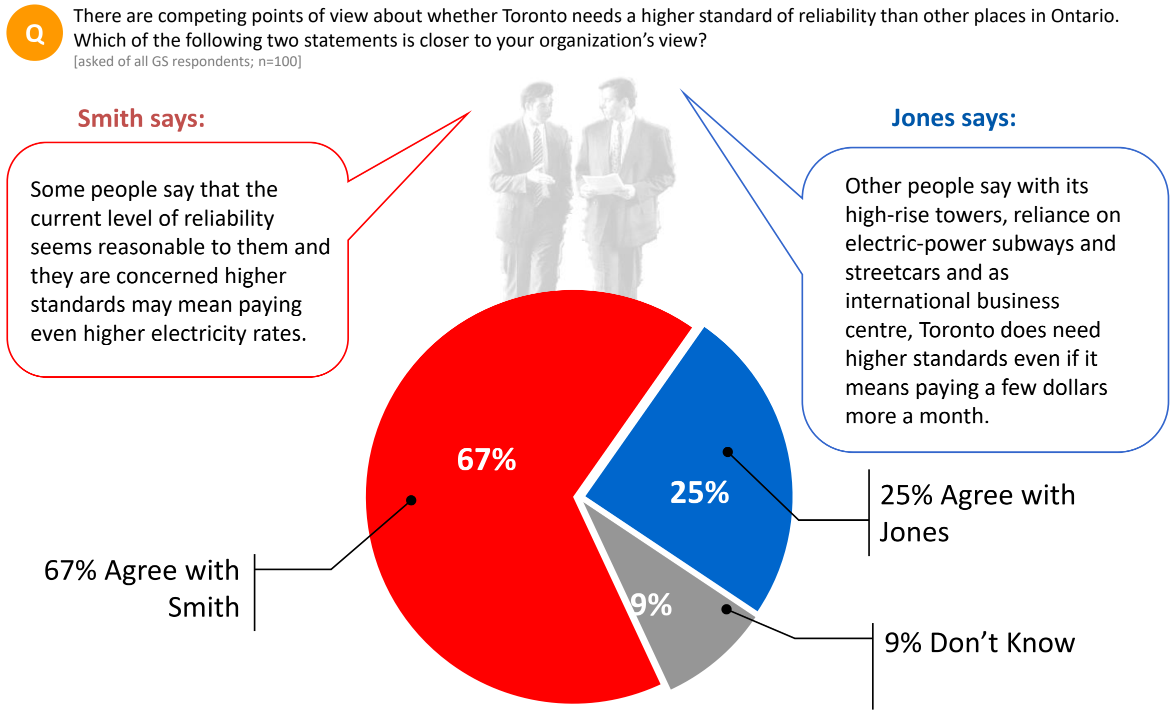
Note: Statements randomized ("some" vs. "other" will switch).

The final question on system reliability asks residential customers to choose between two competing viewpoints: that the "current level of reliability is reasonable" and higher standards would mean higher rates; or that Toronto, because of its current infrastructure needs, should be held to a higher standard even if it means paying more per month.

A majority (55%) of residential customers agree that the current level of reliability is reasonable and they are concerned that higher standards means paying even higher rates. Just a third (34%) support the opposing statement: Toronto needs to be held to a higher reliability standard even if it means paying more on their monthly bills.

- Those residential customers who consume the most power are also the most likely to support paying more for a "higher standard" of reliability (39% high-consumption vs. 32% low-consumption).

Figure 10GS: Smith and Jones on Reliability



Note: Statements randomized ("some" vs. "other" will switch).

When asked the same question, general service customers agree that the "current level of reliability seems reasonable" and are worried about higher rates. Just a quarter (25%) think Toronto needs to be held to a higher standard of reliability "even if it means paying a few dollars more a month".

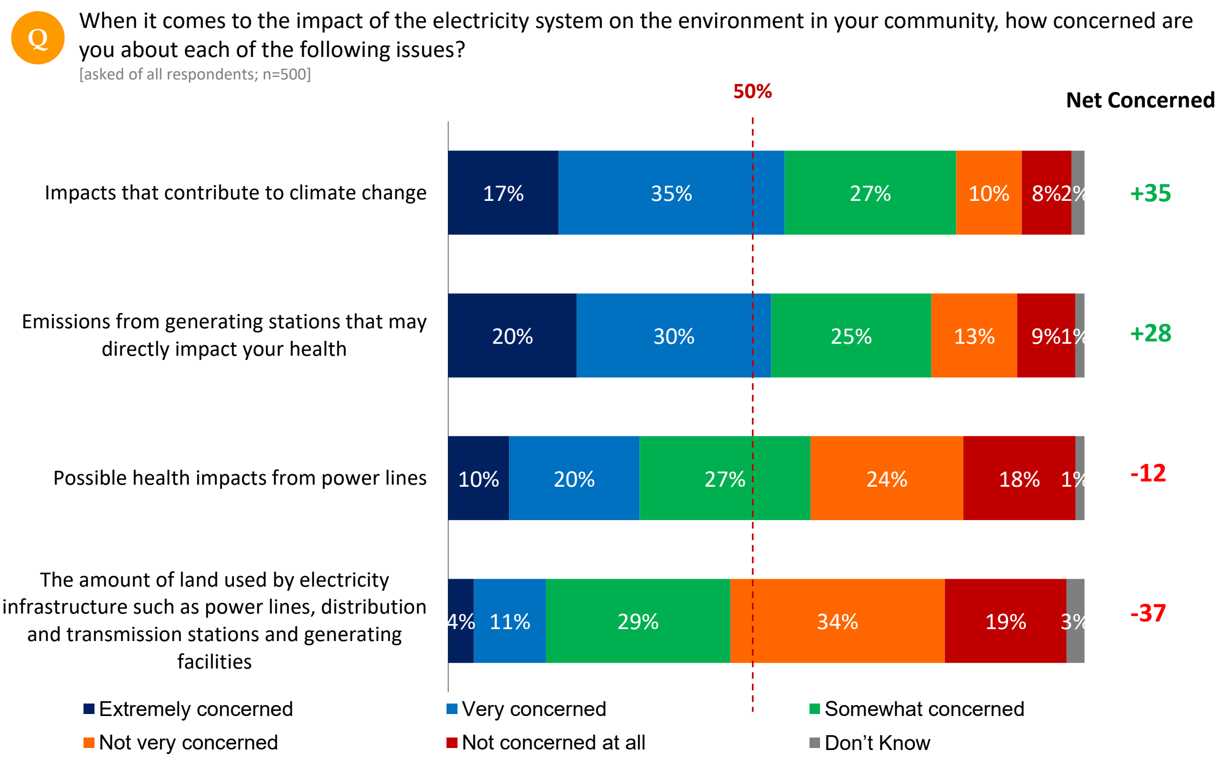
Environment

Respondents were then asked a battery of questions to gauge their environment concerns about the Ontario electricity system.

"Climate change contribution", "emissions impacting" health key concerns

- Customers' greatest environmental concerns are how their electricity system contributes to climate change (+35) and also how those emissions directly impact their health (+28).
- They are not particularly concerned with "health impacts from power lines" (-12) or "the amount of land used by electricity infrastructure" (-37).

Figure 11RS: Environmental Concern Battery



Note: 'Refused' (<1%) not shown

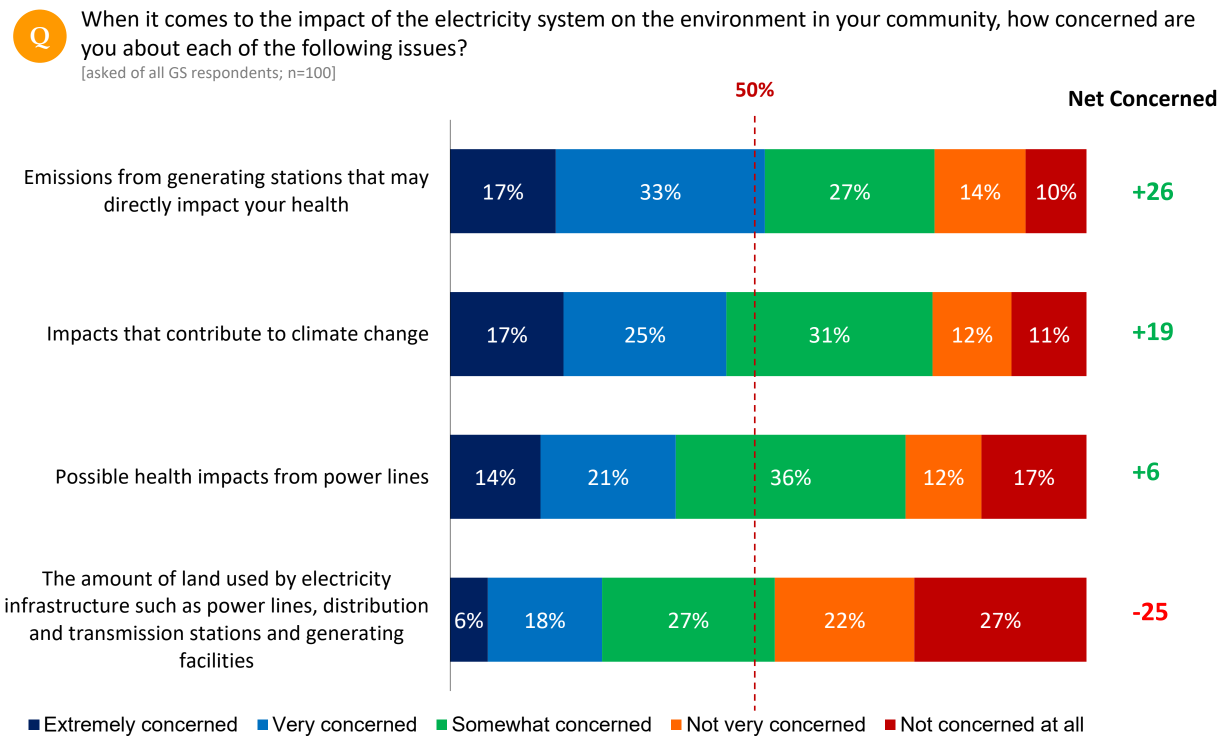
Of the four concerns polled, the one most concerning to residential customers is how Ontario electricity contributes to climate change (net +35). Over half (52%) are concerned about the electricity system impacting climate change, while less than 2-in-10 (18%) are not concerned about this issue.

Another main issue of concern for these respondents are "emissions from generating stations" that may personally affect their health (net +28%). 1-in-2 residential customers is concerned about this issue, compared to just over 2-in-10 (22%) who feel the opposite.

Overall, residential customers are much less concerned about "the possible health impacts from power lines" (net -12) and "the amount of land used by electricity infrastructure" (-37). Just three-in-ten (30%) are concerned about the former and less than 2-in-10 (15%) are concerned about the latter.

- Low-consumption users are the most concerned about the electricity system's impact on climate change (64% vs. 43% high-consumption).

Figure 11GS: Environmental Concern Battery

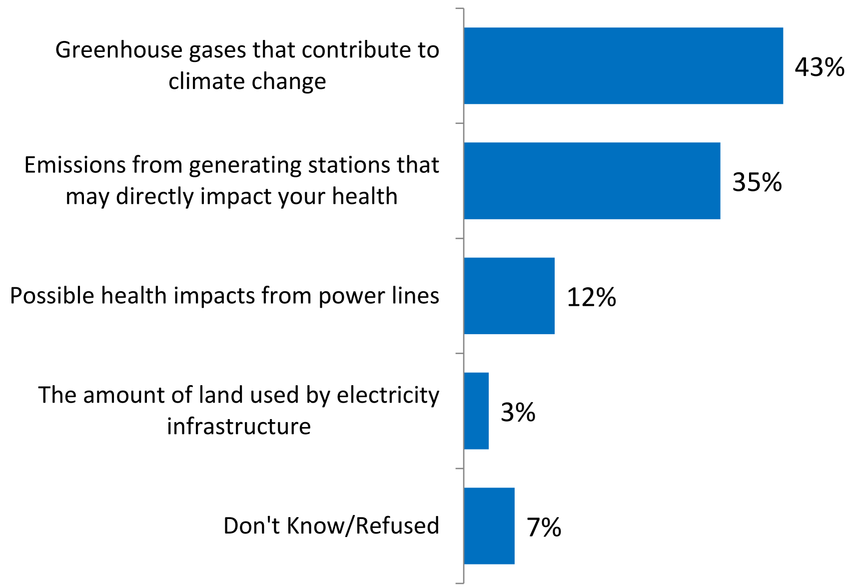


Note: 'Refused'/'Don't know' not shown

Turning to general service customers, net positive concerns for them are "emissions impacting health" (+26) and the "system contributing to climate change" (net +19) as well. GS customers are also less concerned about the "possible health impacts from power lines" (+6) or "the amount of land used by electricity infrastructure" (-25).

Figure 12RS: Greatest Environmental Concern

Q And which of these environmental issues is of the greatest concern to you?
[asked all respondents; n=500]

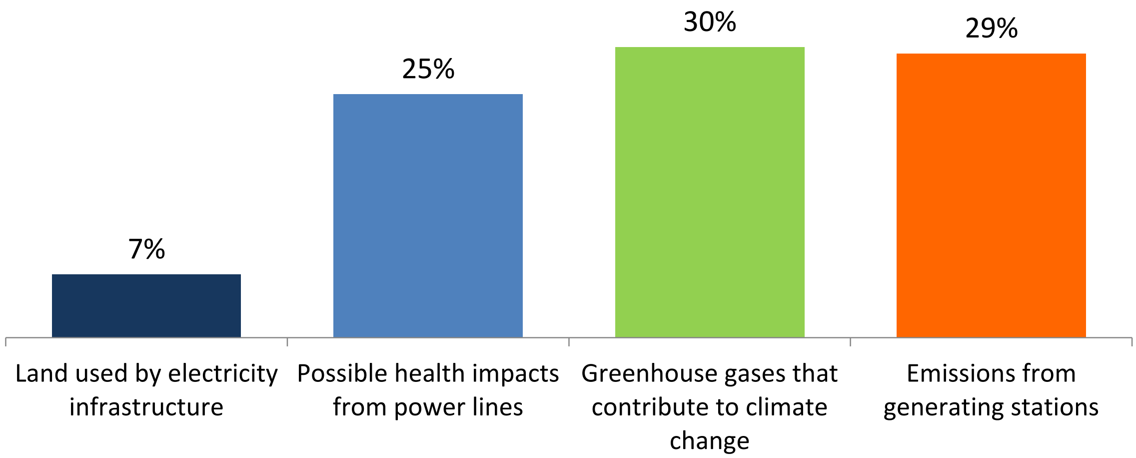


When asked which of the four electricity system issues concerns them the most, residential customers still choose "contributing to climate change" (43%) with "emissions possibly impacting their health" a close second (35%). Just over 1-in-10 (12%) voice "the possible health impacts from power lines" as their top concern and almost no one considers "the amount of land used by electricity infrastructure" (3%) their top environmental concern.

- In this question as well, low-consumption users are the most likely to consider the electricity system's effect on climate change their key important environmental concern (55% vs. 38% high-consumption).
- On climate change and the electricity system, smaller households (single: 46%; two: 50%) and renters (52%) are more concerned than larger households (31-39%) and owners (62%), respectively.

Figure 12GS: Greatest Environmental Concern

Q And which of these environmental issues is of the greatest concern to your organization?
[asked of all GS respondents; n=100]



Note: 'Don't know'/'Refused' (9%) not shown

General service respondents feel about equally concerned with "health impact from power lines" (25%), "climate change" (30%), and "emissions from generating stations" (29%). Very few (7%) care about the amount of land used by electricity infrastructure.

Cost and Value of Electricity

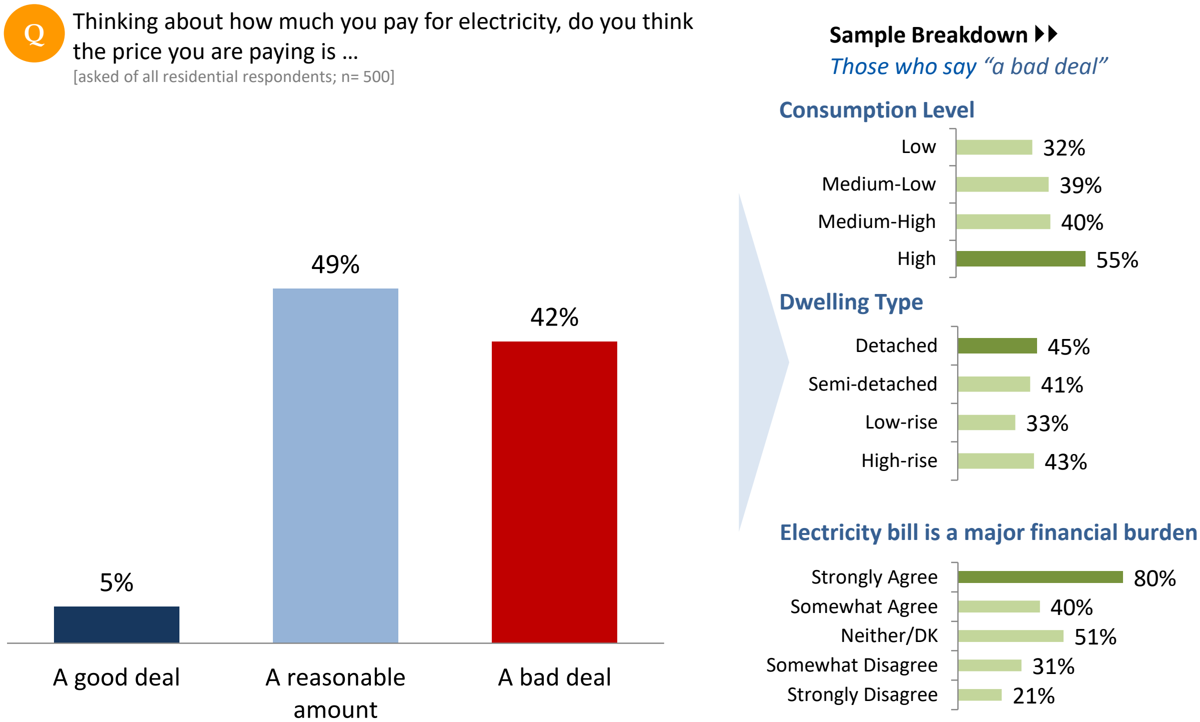
This short section examines how the cost of electricity affects the every-day lives of residential and general service customers and also whether they feel they are getting value for money on their electricity.

Majority think they're getting good value for money, divided on bill impact

- Nearly 6-in-10 (58%) residential customers think they are getting either a reasonable or good deal on their electricity. And about the same amount (Residential: 57%) think they get good value for money on their electricity.
- Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances (46% major impact vs. 50% no impact).
- General service customers feel a much greater impact (77%) major impact) and are less likely to think they are getting good value for money (46% vs. 52%).
- High-consumption users are also the most impacted financially by their electricity bills (91%).

Figure 13RS: Price Paid for Electricity

Q Thinking about how much you pay for electricity, do you think the price you are paying is …
[asked of all residential respondents; n= 500]

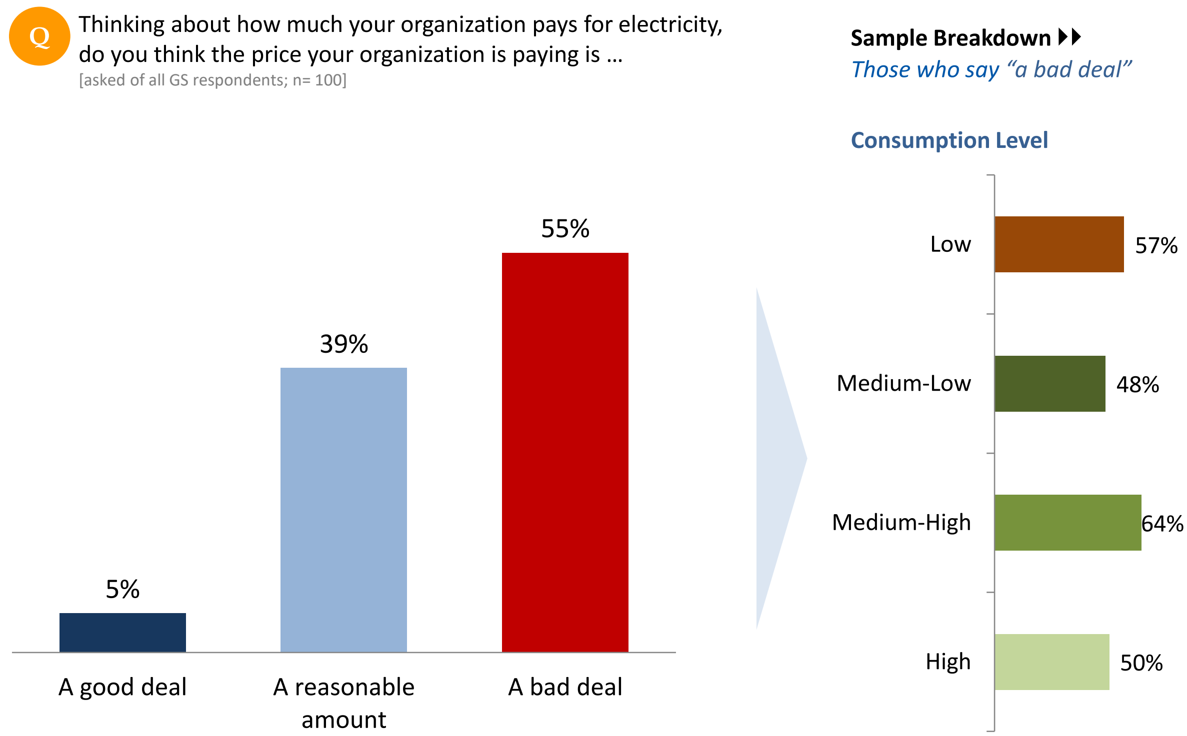


Note: 'Don't know' (4%) not shown

Turning to cost, more than 4-in-10 (42%) residential customers think they have a bad deal on their electricity. About half (49%) think they pay "a reasonable amount" and only 5% think the price they pay for electricity is "a good deal".

- High-consumption customers (55%) are more likely than lower-consumption residents (32-40%) to say they are getting a bad deal on electricity.
- Those residents who "strongly agree" (80%) that their bill is a major financial burden are by far the most likely to feel their electricity price is "a bad deal".

Figure 13GS: Price Paid for Electricity



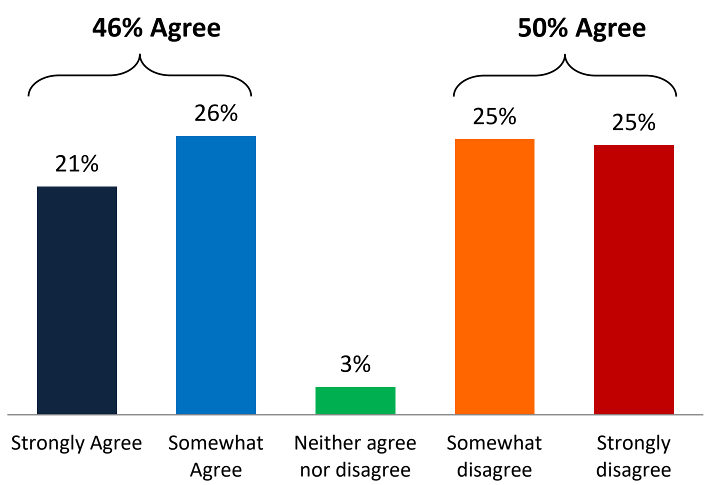
Note: 'Don't know'/'Refused' (1%) not shown

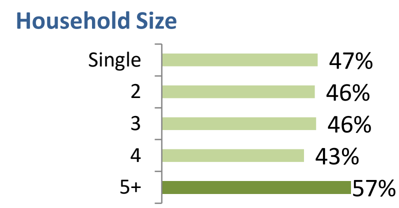
A majority (55%) of GS respondents think they are getting a bad deal on electricity. 4-in-10 (39%) say they pay a reasonable amount and only 5% think they are getting a good deal.

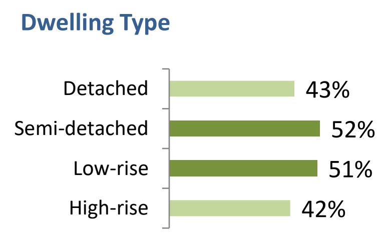
Figure 14RSa: Financial Impact of Electricity Bill

Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.
[asked of all residential respondents; n=500]

Sample Breakdown ▸▸
Those who say "agree"





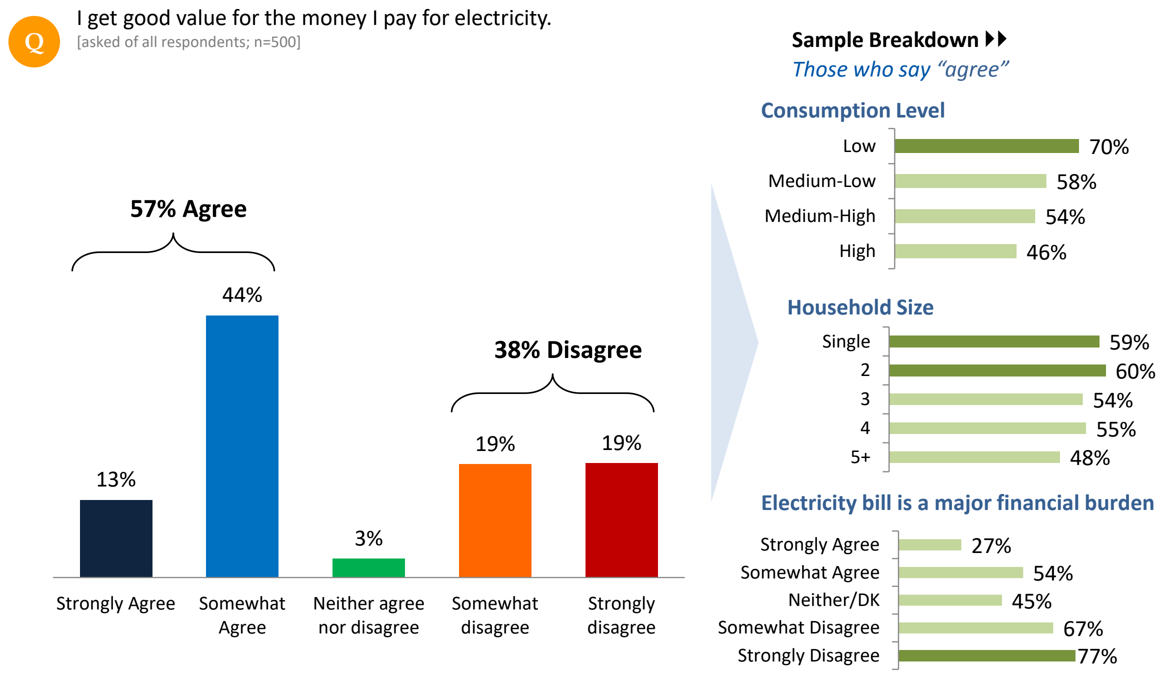


Note:'Don't Know'/'Refused' (1%) not shown

Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances. Just under half (46%) feel that their bill has a major impact on their finances while half (50%) feel otherwise with roughly the same intensity (21% vs. 25% strongly agree/disagree).

- Larger households (5+ people: 57%) are more likely than smaller ones (43-47%) to feel the financial impact of their electricity bill.

Figure 14RSb: Financial Impact of Electricity Bill



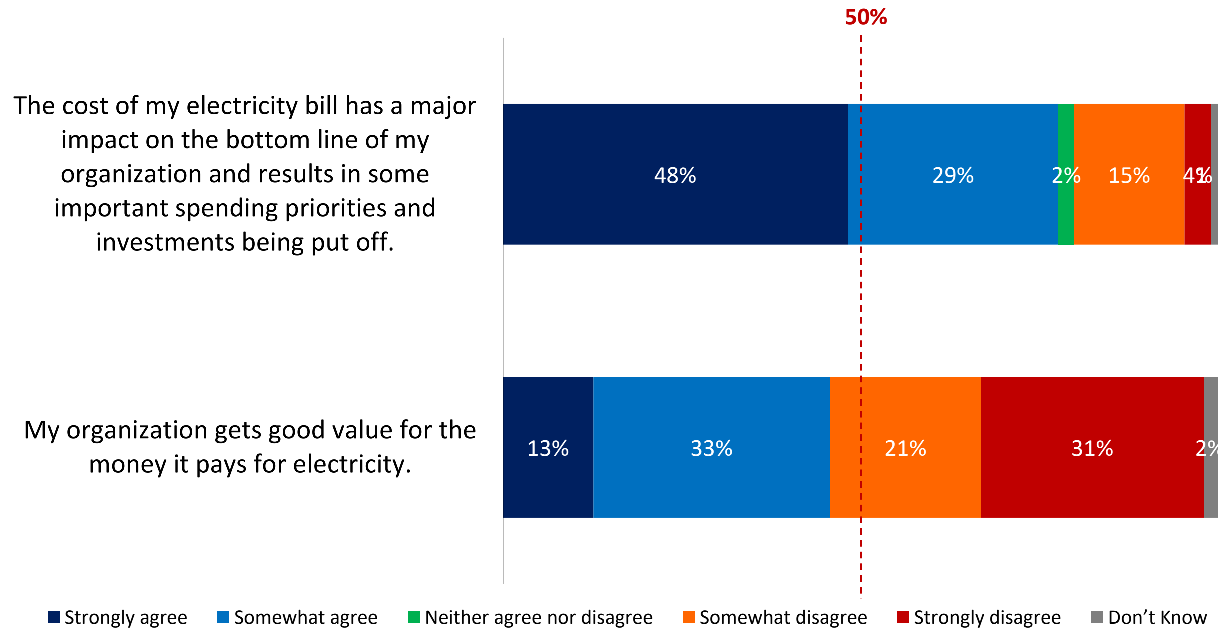
Note: 'Don't Know'/'Refused' (2%) not shown

A majority (57%) of residential customers feel they get good value for money on their electricity. Less than 4-in-10 (38%) say the opposite.

- Low-consumption users (70% vs. 46-58%), single and two-person households (59-60% vs. 48-54%), and those who feel strongly that their electricity bill is not a major financial burden (77% vs. 27-67%) are the most likely to think that they get good value for money on their electricity.

Figure 14GS: Financial Impact of Electricity Bill

Q Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.[asked of all GS respondents; n=100]



Cost Statements: AGREE	Low	Medium -low	Medium -high	High
The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	70%	74%	76%	91%
I get good value for the money they pay for electricity.	39%	48%	40%	55%

On the question of cost, a strong majority of general service customers (77%) agree with great intensity that the cost of their bill has an impact on the organization's bottom line. Just 2-in-10 (19%) feel their bill cost does not have a major impact.

GS customers lean a bit negative on the statement "my organization gets good value for the money it pays for electricity". Less than half (46%) feel their organization gets good value, while just over half (52%) think otherwise.

- High-consumption users (91%) are the most likely to say the cost of their bill has a major impact on their finances.

Goals and Criteria

The final section of the survey outlines the three solutions to deal with capacity issues: "Conservation and Demand Management", "Distributed Generation" and "Transmission and Distribution Infrastructure". Customers are then asked to rank these solutions as well as the considerations that are most important to them when choosing one of these three options.

Low Awareness, Interest in Distributed Generation

- Respondents are the least familiar with "Distributed Generation" (net -27 vs. +10 "Transmission and Distribution Infrastructure" and +2 "Conservation and Demand Management").
- "Distributed Generation" is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% "Transmission and Distribution Infrastructure").

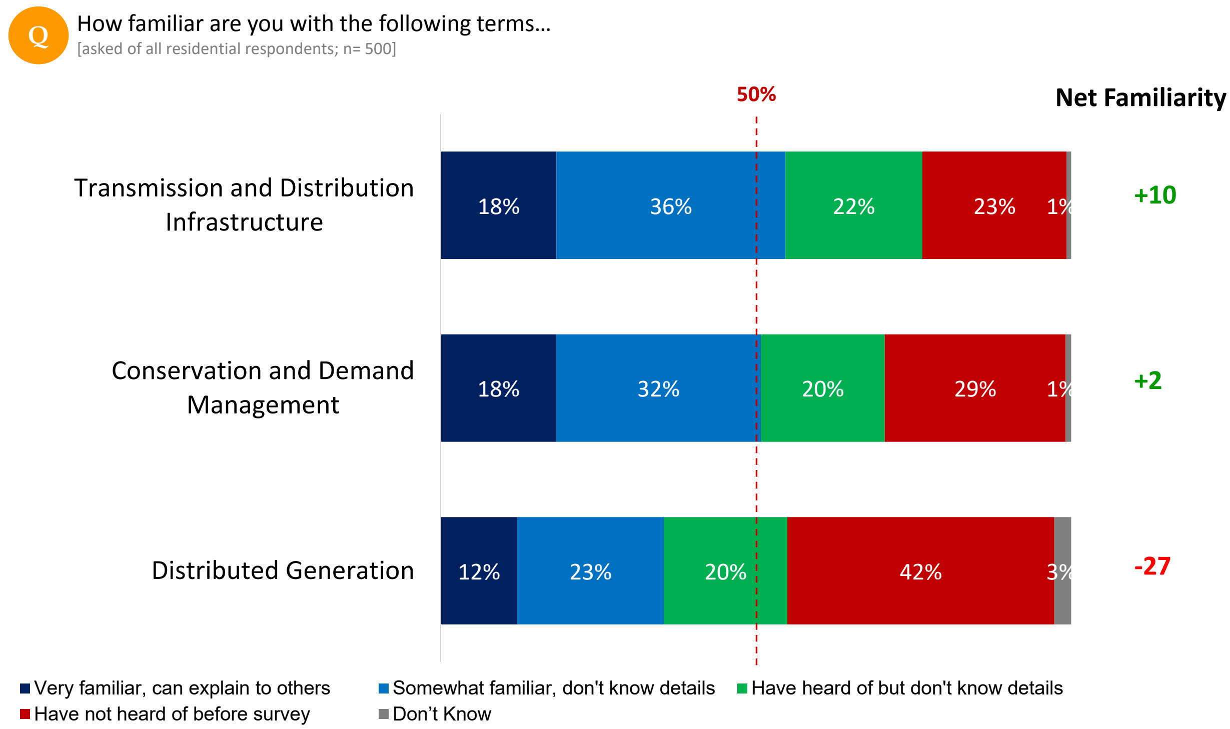
Low Awareness and Interest in Distributed Generation

- Respondents are the least familiar with "Distributed Generation" (net -27 vs. +10 "Transmission and Distribution Infrastructure" and +2 "Conservation and Demand Management").
- "Distributed Generation" is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% "Transmission and Distribution Infrastructure").

Most important considerations "time", "rates" and "climate change"

- When asked to rate seven considerations relating to capacity, residential customers focus the most on "reducing the time it takes to restore power" (+91), "reducing the impact on electricity rates" (+81), and "reducing impacts that contribute to climate change" (net +80).

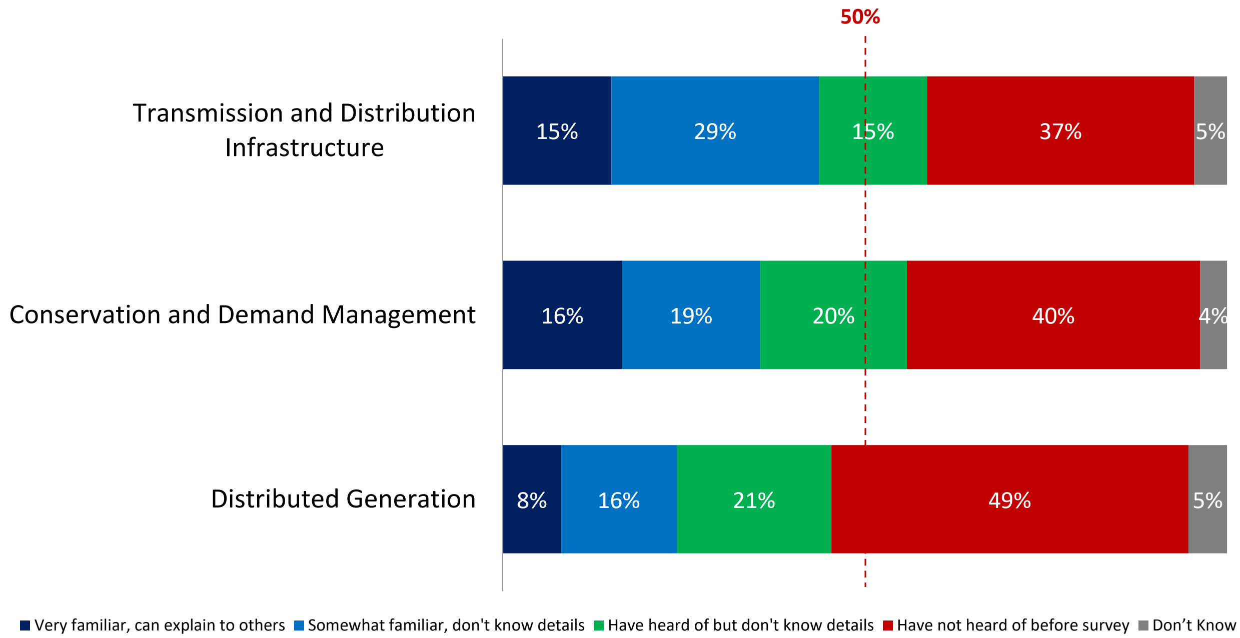
Figure 15RS: Familiarity with Solutions



A majority of residential customers are familiar with the solutions "Transmission and Distribution Infrastructure" (net +10) and "Conservation and Demand Management" (+2). A smaller minority are familiar with "Distributed Generation" (net -27).

Figure 15GS: Familiarity with Solutions

Q How familiar are you with the following terms?
[asked of all GS respondents; n= 100]



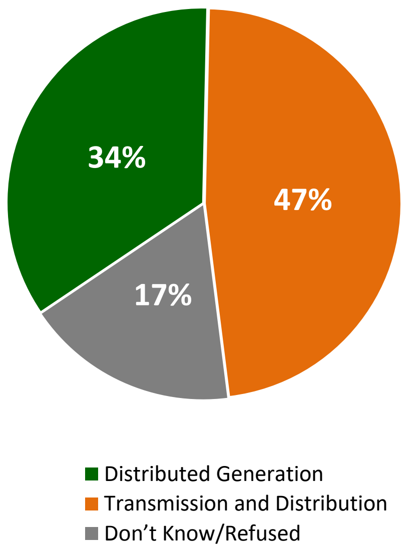
Solutions: FAMILIAR	Low	Medium-low	Medium-high	High
Transmission and Distribution Infrastructure	61%	42%	40%	32%
Conservation and Demand Management	39%	48%	32%	23%
Distributed Generation	35%	23%	16%	23%

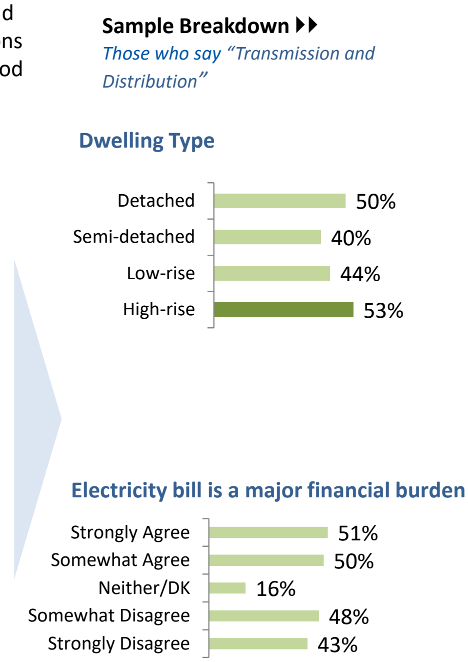
As for general service respondents, a majority are unfamiliar with all three options ("Transmission and Distribution Infrastructure": net -8; "Conservation and Demand Management": -25; "Distributed Generation" -47).

Taking into account the small sample size (n=100), low-consumption general service customers appear a bit more familiar with "Transmission and Distribution Infrastructure" (61%) and "Distributed Generation" (35%) than higher-consumption customers ("Transmission and Distribution Infrastructure": 32-42%; "Distributed Generation": 16-23%).

Figure 16RS: Second Choice Solution

Q Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your second choice to deal with growing neighbourhood demands?
[asked of all residential respondents; n =500]





Note: 'Refused' (2%) not shown

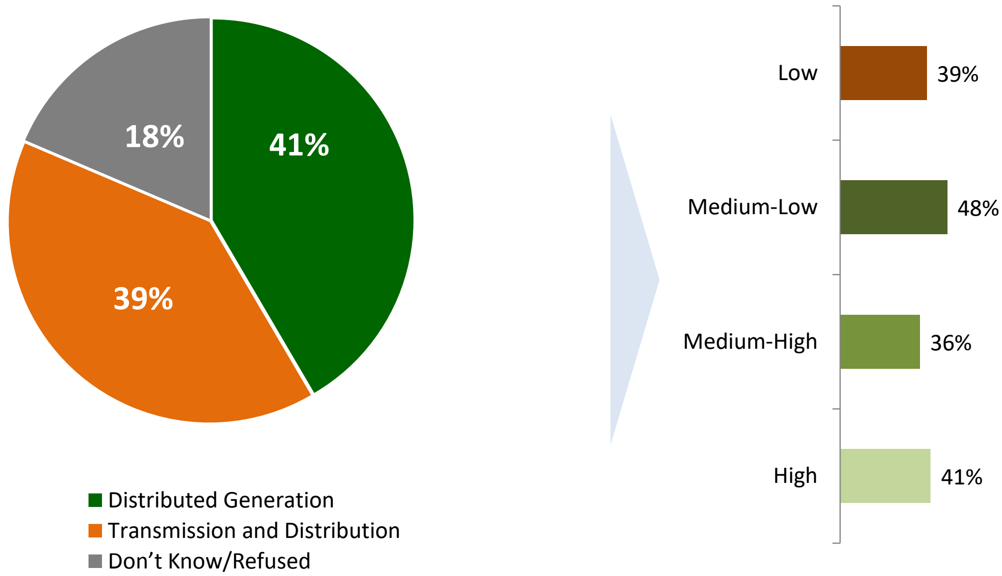
After a brief preamble explaining the three possible solutions and explaining policy requires a look at "Conservation and Demand Management" first, the survey asks respondents to choose their preferred second option. Of the two remaining, nearly half (47%) choose "Transmission and Distribution" and a third (34%) pick "Distributed Generation". Almost 2-in-10 (17%) do not know their second choice.

Figure 16GS: Second Choice Solution

Q Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your organization's second choice to deal with growing neighbourhood demands?
[asked of all GS respondents; n =100]

Sample Breakdown ▸▸
Those who say "Distributed Generation"

Consumption Level



Note: 'Don't know'/'Refused' (1%) not shown

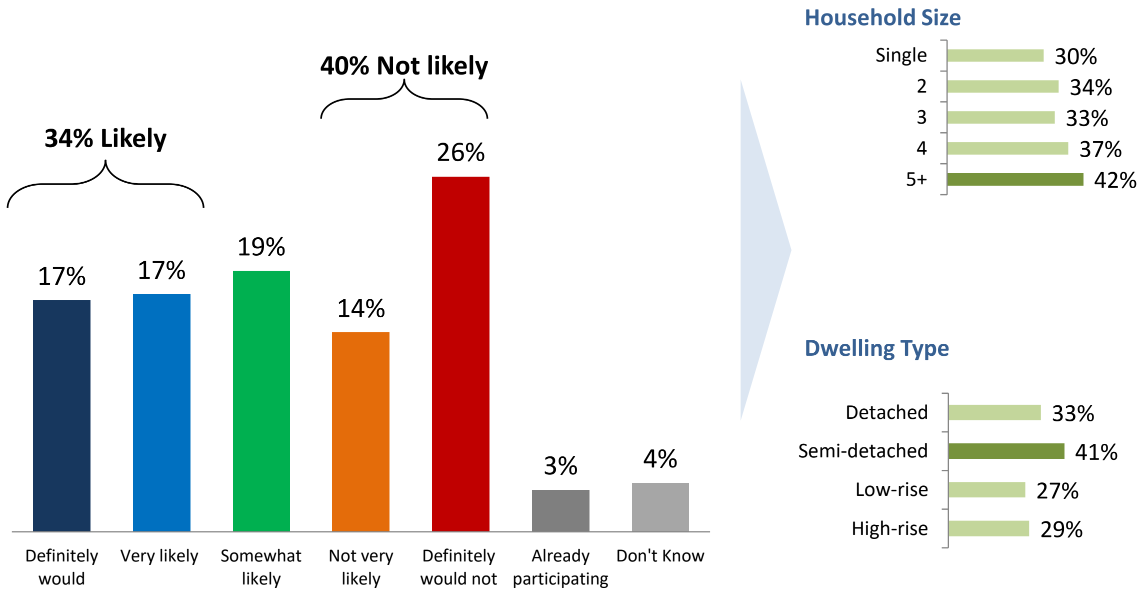
General service respondents are more evenly divided on the remaining two options: roughly 4-in-10 say either 'Transmission and Distribution" (39%) or "Distributed Generation" (41%). Again, about 2-in-10 (18%) are not sure on their second choice.

Figure 17RS: Likelihood to Install Controls

Q How likely is it that you will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed?

[asked of all residential respondents; n= 500]

Sample Breakdown ▶▶
Those who say "likely"



Residential customers are divided on whether or not they would install automated controls for conservation. About a third (34%) say they are likely to do so, but 4-in-10 (40%) say they would not install controls in their home that would allow managers to turn home equipment off remotely.

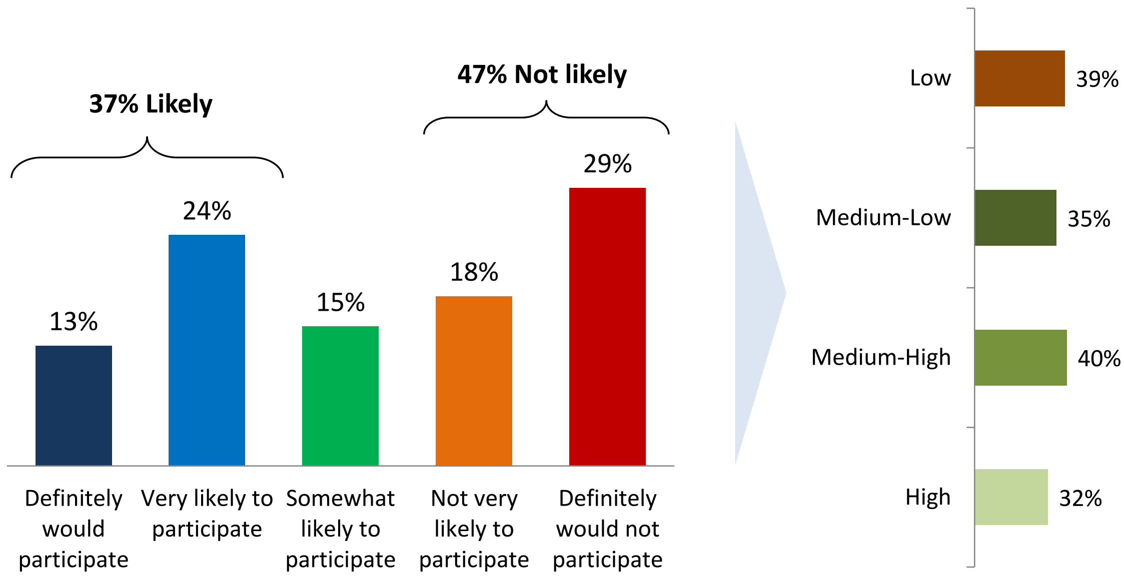
- Larger households (42% 5+ vs. 30% single) are the most likely to allow remote controls installed to automate equipment such as air conditioners.

Figure 17GS: Likelihood to Install Controls

Q How likely is it that your organization will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed?
[asked of all GS respondents; n= 100]

Sample Breakdown ▶▶
Those who say "likely"

Consumption Level

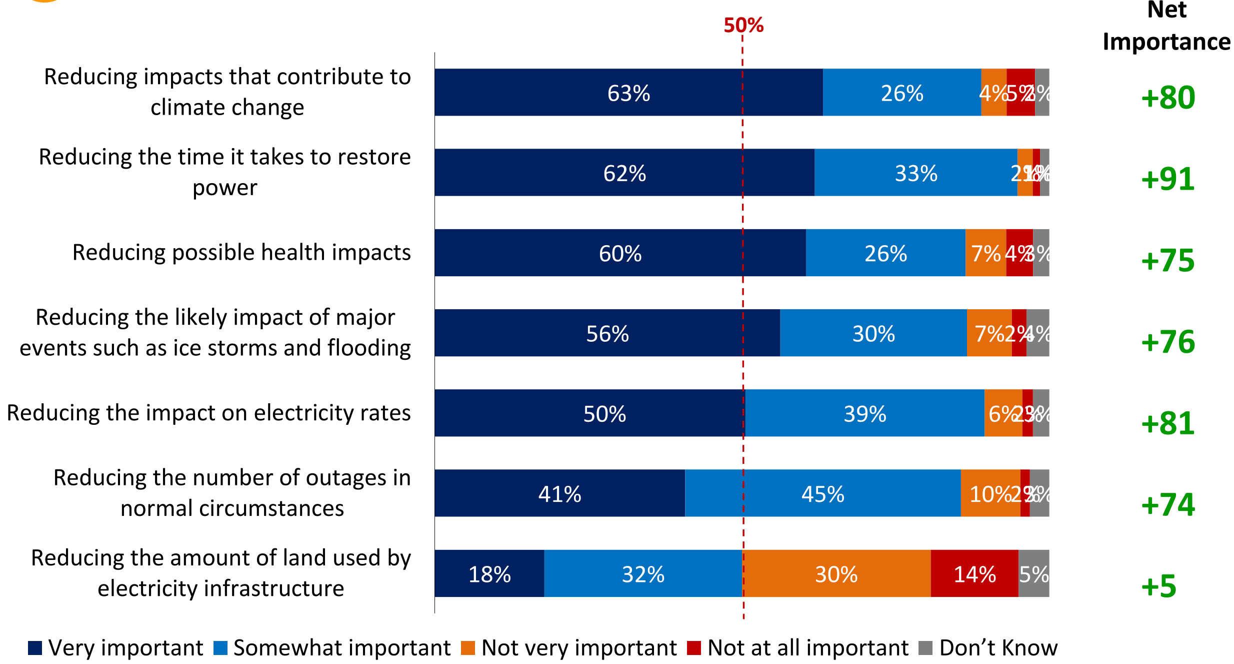


Note: 'Don't know'/'Refused' (2%) not shown

General service customers are a bit less likely to allow remote control activation in their place of business. Less than 4-in-10 (37%) say they are likely to agree to install automated controls, while almost half (47%) say they would not participate in such a program.

Figure 18RS: Consideration of Choice Battery

Q How important are each of the following considerations as planners chose between these three options?
[asked of all residential respondents; n= 500]



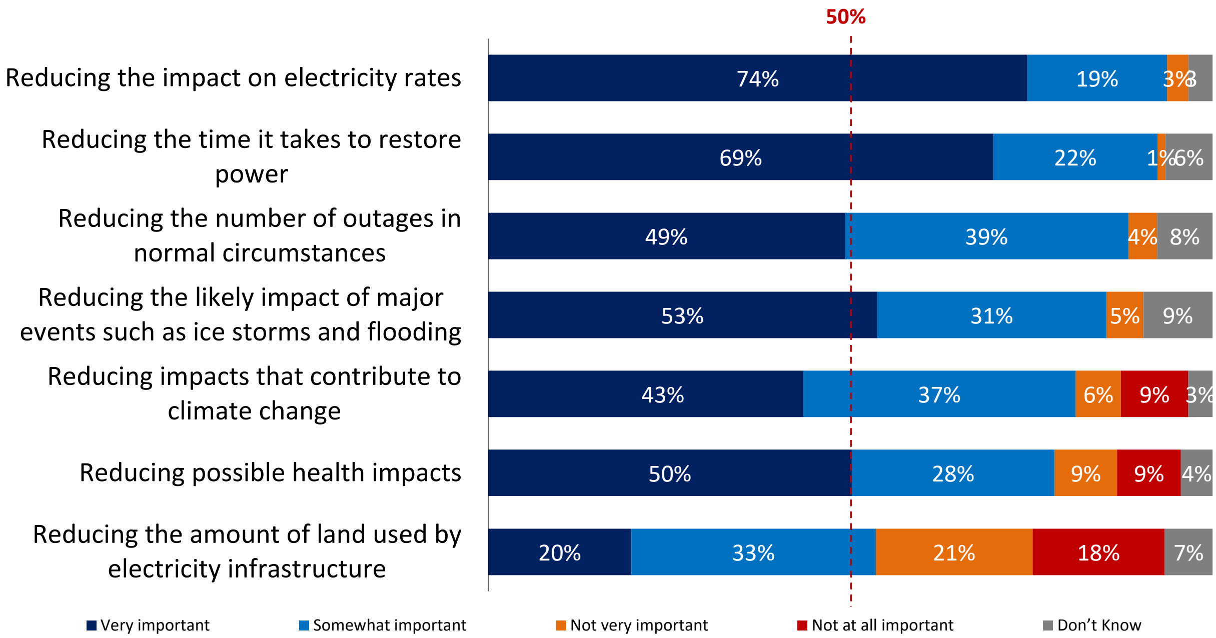
Residential customers were then asked to rate seven different considerations relating to capacity issues. Six of these options are of a high importance to customers when choosing between the three options: "reducing impacts that contribute to climate change" (net +80); "reducing the time it takes to restore power" (+91), "reducing possible health impacts" (+75), "reducing the likely impact of major events" (+76); "reducing the impact on electricity rates" (+81); and "reducing the number of outages in normal circumstances" (+74). All six of these considerations have high intensity of importance for customers (41-63%: "very important").

The least important consideration for residential customers is "reducing the amount of land used" (+5).

- High-consumption residential customers see "reducing the likely impact of major events such as ice storms and flooding" as less important than lower-consumption customers (69% vs. 74-81%). They are also a bit less worried about "reducing the impacts that contribute to climate change" than low-consumption customers (76% vs. 87% low-consumption).

Figure 18GS: Consideration of Choice Battery

Q How important are each of the following considerations as planners chose between these three options?
[asked of all GS respondents; n= 100]

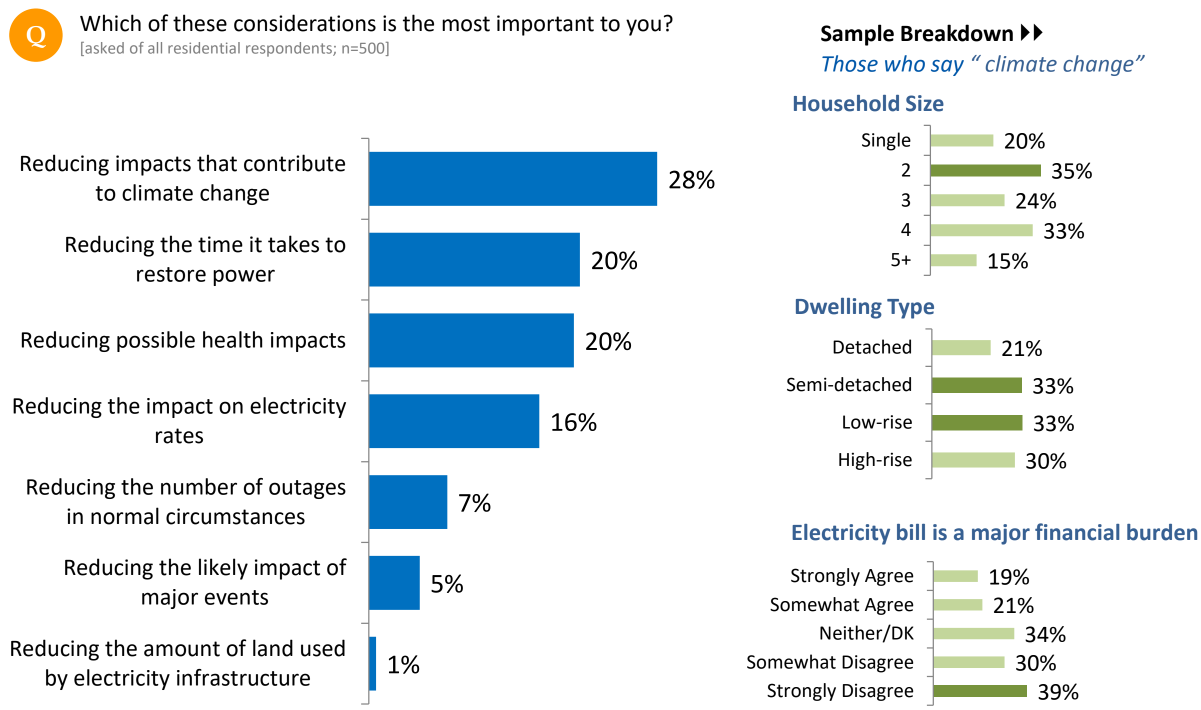


Q How important are each of the following considerations as planners chose between these three options?
[asked of all GS respondents; n= 100]

Considerations: IMPORTANT	Low	Medium-low	Medium-high	High
Reducing the number of outages in normal circumstances	83%	97%	84%	86%
Reducing the time it takes to restore power	83%	100%	92%	91%
Reducing the likely impact of major events such as ice storms and flooding	78%	90%	92%	77%
Reducing the amount of land used by electricity infrastructure	48%	61%	48%	55%
Reducing possible health impacts	70%	87%	80%	73%
Reducing impacts that contribute to climate change	78%	77%	88%	77%
Reducing the impact on electricity rates	83%	97%	96%	95%

General service customers see the same six considerations as important for deciding between the three options. For them, “reducing the impact on electricity rates” (+90 net) and reducing the time (+90) and number of outages (+84) are the top concerns. Climate change (+65) is a bit lower in the list, but still a key concern.

Figure 19RS: Importance of Considerations for Choice



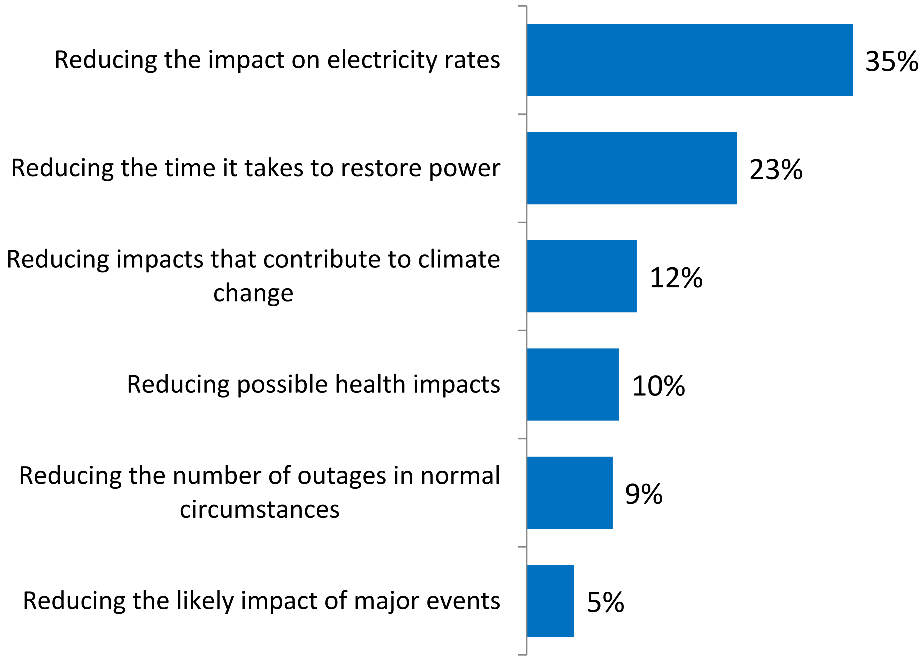
Note: 'Don't know' (3%) not shown

When asked to pick the most important consideration from the list of seven, a large minority of residential customers say "climate change" (28%). About one-in-five say "reducing the time it takes to restore power" or "reducing possible health impacts" (20%). Less important considerations include reducing "the impact on rates" (16%), "number of outages" (7%), "likely impact of major events" (5%) and "the amount of land used by electricity infrastructure" (1%).

- Those who do not feel their bill is a major burden are most likely to say "climate change" is their most important consideration (30-39% disagree "major burden" vs. 19-21%).

Figure 19GS: Importance of Considerations for Choice

Q Which of these considerations is the most important to your organization?
[asked of all GS respondents; n=100]



Note: 'Don't know'/'Refused' (6%) not shown

A large minority of general service respondents considers "reducing the impact on electricity rates" (35%) the most important for their organization. About a quarter mention "reducing the time it takes to restore power" 23% as their leading consideration.

Survey Instruments

Residential Survey Instrument

Section A: Introduction

INTRO

Hello, my name is ________________ and I'm calling from **Innovative Research Group,** a national public opinion research firm. We have been commissioned by **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One** to help them better understand the needs and preferences of customers like you as they prepare plans to meet your future electricity needs.

A2. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1 [**continue**]
No – NOT PRIMARY BILL PAYER	2 [**go to TRANSFER-1**]
No – BAD TIME	3 **ARRANGE CALLBACK**
No – HARD REFUSAL	4 [**Terminate**]

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A3. Have I reached you at your home phone number?

INTERVIEWER NOTE; IF "NO" ASK: May I speak to someone who does live there?

Yes - SPEAKING, CONTINUE	1 [**continue**]
YES - TRANSFERRED – **(GO BACK TO INTRODUCTION)**	2 [**back to INTRO**]
No - NOT AVAILABLE – **(ARRANGE CALLBACK)**	3 [**ARRANGE CALLBACK]**
Refused – LOG **(THANK AND TERMINATE)**	9 [**Terminate**]

A4. Are you the person primarily responsible for paying the electricity bill in your household?

Yes	1 [**skip to A4**]
No	2 [**go to TRANSFER-1**]
Don't know (**DNR**)	98 [**Terminate**]

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

Yes	1 [**BACK TO *INTRO***]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2 [**ARRANGE CALLBACK]**
No – HARD REFUSAL	3 [**Terminate**]
Don't know (**DNR**)	98 [**Terminate**]

A5. Can you confirm that your household receives an electricity bill from **Toronto Hydro**?

Yes	1 [**continue**]
No	2 [**Terminate**]
Don't know (**DNR**)	98 [**Terminate**]

GENDER	Note gender by observation:
Male	1
Female	2

Section B: General Satisfaction

B6. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

How familiar are you with Ontario's electricity system? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Generally speaking, how satisfied are you with the job the electricity system does in providing you with electricity? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B8. Is there anything in particular the electricity system can do to improve its service to you? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

ROTATE SECTIONS C, D AND E – TRACK ROTATION

Section C: System Reliability

These questions are about priming the respondent to think about their experience with system reliability and to separate views about adverse weather from failing equipment.

C9. In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "**major events**" in the electricity sector. These major weather events caused power outages across Toronto.

Did either of these major weather events cause a power outage at your home?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

[Ask all respondents]

C10. Not including power outages caused by these extreme weather events, did you have any other power outages in the **last 12 months**?

Yes	1
No	2 **SKIP TO C13**
Don't know (**DNR**)	98 **SKIP TO C13**
Refused (**DNR**)	99 **SKIP TO C13**

C11. How many outages did you experience over the past 12 months, NOT including those caused by extreme weather events?

C12. And what was the longest period of time you were without power?

[**Ask all respondents**]

C13. When you do lose power, what causes you more difficulty: [**READ LIST**]

The number of outages	1
The length of the outages	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

This provides an independent measure planners can consider when assessing what periods of time should be used when setting standards.

C14. Once the power goes out, is there a particular length of time at which being without power becomes more difficult for you? **[DO NOT READ LIST, select category accordingly]** (NOTE: If respondent says depends, please ask "Thinking about a typical day, is there a particular length of time at which being without power becomes more difficult for you?")

Less than 15 minutes 1
15 to less than 30 minutes 2
[ask to specify if less than *15 minutes*, if response is "less than 30 minutes"]
30 minutes to less than 1 hour 3
1 hour to less than 3 hours 4
3 hours to less than 6 hours 5
6 hours to less than 12 hours 6
12 to less than 24 hours 7
More than 24 hours 8
Don't know (**DNR**) 98

Refused (**DNR**) 99

Second take on restoration vs outage priorities.

C15. As electricity planners look ahead, they can't plan to do everything at once. In your view, which of the following two tasks should be their top priority? (RANDOMIZE STATEMENTS)

Reducing the number of outages	1
Reducing the time it takes to restore electricity after an outage	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C16. There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your own.
(ROTATE AND USE APPROPRIATE FIRST WORD IN EACH CASE)

1 Some/Other people say that the current level of reliability seems reasonable to them and they are concerned higher standards may mean paying even higher electricity rates.

2 Other/Some people say with its high-rise towers, reliance on electric-power subways and streetcars and as international business centre, Toronto does need higher standards even if it means paying a few dollars more a month.

98 Don't Know

Section D: Environment

When it comes to the impact of the electricity system on the environment in your community, how concerned are you about each of the following issues. **(RANDOMIZE STATEMENTS)**

[READ LIST]

Extremely concerned	1
Very concerned	2
Somewhat concerned	3
Not very concerned	4
Not concerned at all	5
Don't know (**DNR**)	98
Refused (**DNR)**	99

D17. The amount of land used by electricity infrastructure such as power lines, distribution and transmission stations and generating facilities.

D18. Possible health impacts from power lines

D19. Impacts that contribute to climate change

D20. Emissions from generating stations that may directly impact your health

END BATTERY

D21. And which of these environmental issues is of the greatest concern to you? **(READ LIST AND RANDOMIZE STATEMENTS)**

The amount of land used by electricity infrastructure	1
Possible health impacts from power lines	2
Greenhouse gases that contribute to climate change	3
Emissions from generating stations that may directly impact your health	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

Section E: Cost

E22. Thinking about how much you pay for electricity, do you think the price you are paying is … **[READ LIST]**?

A good deal	1
A reasonable amount	2
A bad deal	3
Don't know	98

Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.

01 Strongly agree

02 Somewhat agree

03 Neither agree nor disagree **(DNR)**

04 Somewhat disagree

05 Strongly disagree

98 Don't know (**DNR**)

99 Refused (**DNR**)

E23. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

E24. I get good value for the money they pay for electricity.

END BATTERY

Section F: Goals and Criteria

How familiar are you with the following terms? [READ LIST]

Very familiar and can explain the details to others	1
Somewhat familiar, but don't know the details	2
Have heard of, but don't know any details	3
Have not heard of before this survey	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

ROTATE F24-F26

F25. Conservation and Demand Management

F26. Distributed Generation

F27. Transmission and Distribution Infrastructure

END BATTERY

This preamble will help less informed respondents 'catch-up' with more informed people.

F28**.** **READ PREAMBLE:** There are three main solutions to deal with capacity issues.
RANDOMIZE OPTIONS

1. For this plan, Conservation and Demand Management involves consumers giving electricity system managers the ability to turn equipment such as air conditioners off for short periods of time when electricity demand peaks.
2. Distributed Generation involves small-scale power generation located in your local community where electricity is consumed.
3. Transmission and Distribution primarily involves transmission and distribution stations as well as underground and overhead wires that bring electricity from more distant generating plants to your local area.

F29. Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your second choice to deal with growing neighbourhood demands? (**ROTATE AND READ LIST**)

Distributed Generation	1
Transmission and Distribution	2
Don't know (**DNR)**	98
Refused (**DNR**)	99

F30. For ***conservation and demand management*** to provide an alternative to ***distributed generation*** or ***transmission and distribution***, it must provide a similar level of certainty as the other options. For residences, this would involve voluntary agreements to install automated controls that allow electricity system managers to turn equipment such as pool heaters and air conditioners off for short periods of time during periods of peak demand.

How likely is it that you will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed? [READ LIST]

Definitely would participate	1
Very likely to participate	2
Somewhat likely to participate	3
Not very likely to participate	4
Definitely would NOT participate	5
Already participate (**DNR**)	6
Don't know (**DNR**)	98
Refused (**DNR**)	99

How important are each of the following considerations as planners chose between these three options? [RANDOMIZE F30-F36] [READ LIST]

Very important	1
Somewhat important	2
Not very important	3
Not at all important	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

F31. Reducing the number of outages in normal circumstances

F32. Reducing the time it takes to restore power

F33. Reducing the likely impact of major events such as ice storms and flooding

F34. Reducing the amount of land used by electricity infrastructure.

F35. Reducing possible health impacts

F36. Reducing impacts that contribute to climate change

F37. Reducing the impact on electricity rates

END BATTERY

F38. Which of these considerations is the most important to you? [**READ LIST**]

Reducing the number of outages in normal circumstances	1
Reducing the time it takes to restore power	2
Reducing the likely impact of major events	3
Reducing the amount of land used by electricity infrastructure.	4
Reducing possible health impacts	5
Reducing impacts that contribute to climate change	6
Reducing the impact on electricity rates	7
Don’t know (**DNR**	98
Refused (**DNR**)	99

Section G: Demographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G39. In which year were you born? [**Enter YEAR**]

INTERVIEWER NOTE: if REFUSE; ask "AGE".

AGE: Can you tell me what age category do you fall into? [**READ LIST**]

Less than 18	0
18-25	1
25-34	2
35-44	3
45-54	4
55-64	5
65 years or older	6
Refused (**DNR**)	99

G40. Do you own or rent your home?

Own	1
Rent	2
Refused (**DNR**)	99

G41. How would you describe your primary residence? Would you say you live in … [**READ LIST**]

A fully-detached home;	1
A semi-detached home;	2
An apartment or condo building **less than 5 stories**; or	3
An apartment or condo building **5 stories or higher**?	4
Refused (**DNR**)	99

G42. Counting yourself, how many people live in your household?

1 person	1 **SKIP TO END**
Enter number of people	2---7
8 or more	8
Refused (**DNR**)	99 **SKIP TO END**

Ask only if H42 = 2 thru 8

G43. And how many of them are under 18?

None	0
Enter number of children	1---7
8 or more	8
Refused (**DNR**)	99

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

General Service Survey Instrument

Section A: Introduction

INTRO

INTRO. Hello, my name is ________________ and I'm calling from **Innovative Research Group** on behalf of **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One.**

Can I please speak to the person who is in-charge of managing the electricity bill at [**organization name**] located in Toronto?

1) Yes, speaking <**contact on the line**>	[**skip to A1]**
2) Yes <**transferred to contact**>	[**skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record call-back time]**
5) Maybe <**may I ask who is calling?**>	[**skip to GATE]**

NEW. And … can I have their …
First Name ______________
Last Name ______________
Title/Position ____________
Phone Number ___________

ASK to be transferred …

- **if transferred → go to A1**
- **if not transferred → Thank & Add to Callback List**

GATE. I'm calling from **Innovative Research Group**, on behalf of **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One**

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a regional electricity customer consultation.

1) Yes <**transferred to contact**>	**[skip to A1]**

2) No <**not available**>	"When is a good time to callback?	**[record call-back time and GO to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:
Innovative Research Group is a national public opinion research firm. We have been commissioned by **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One** to help them better understand the needs and preferences of customers like you as they prepare plans to meet the future electricity needs of Central Toronto.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	4	[**Terminate**]

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Just to confirm, does your organization receive an electricity bill from Toronto Hydro?

YES	1	**[continue]**
NO	2	**[Terminate]**
DK (volunteered)	98	**[Terminate]**

A3. As part of your job, are you in-charge of <u>managing</u> or <u>overseeing</u> your organization's electricity bill?

Yes	1	[**Continue to A4]**
No	2	[**go to TRANSFER-1**]
DK	3	[**go to TRANSFER-1**]

TRANSFER-1
Can I speak with the person who manages your organization's electricity bill?

Yes	1	[**BACK TO** *<u>INTRO</u>*]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

Which of the following best describes the sector in which your organization operates?

MASH (Municipalities, Academic, Schools, Hospitals	1
Multi-residential	2
Commercial	3
Manufacturing/Industrial	4
Data Centre	5
Hospitality	6
Restaurant/Tavern	7
Retail	8
Warehouse	9
Other	88
Don’t know (**DNR**)	98
Refused (**DNR**)	99

GENDER	Note gender by observation:
Male	1
Female	2

Section B: General Satisfaction

We need to prime respondents to start thinking about electricity and the part of the system that Toronto Hydro operates.

B5. PREAMBLE-1 To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

How familiar are you with Ontario's electricity system? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B6. Generally speaking, how satisfied are your organization with the job the electricity system does in providing your organization with electricity? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Is there anything in particular the electricity system can do to improve its service to your organization? [OPEN]

Don't know (**DNR**)	98
Refused (**DNR**)	99

ROTATE SECTIONS C, D AND E – TRACK ROTATION

Section C: System Reliability

These questions are about priming the respondent to think about their experience with system reliability and to separate views about adverse weather from failing equipment.

C8. In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Did either of these major weather events cause a power outage at your organization?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

[Ask all respondents]

C9. Not including power outages caused by these extreme weather events, did your organization have any other power outages in the last 12 months?

Yes	1	
No	2	**SKIP TO C13**
Don't know (**DNR**)	98	**SKIP TO C13**
Refused (**DNR**)	99	**SKIP TO C13**

C10. How many outages did your organization experience over the past 12 months, NOT including those caused by extreme weather events?

C11. And what was the longest period of time your organization were without power?

[**Ask all respondents**]

C12. When your organization does lose power, what causes your organization more difficulty: [READ LIST]

The number of outages	1
The length of the outages	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

This provides an independent measure planners can consider when assessing what periods of time should be used when setting standards.

C13. Once the power goes out, is there a particular length of time at which being without power becomes more difficult for your organization? [DO NOT READ LIST, select category accordingly] (NOTE: If respondent says depends, please ask "Thinking about a typical day, is there a particular length of time at which being without power becomes more difficult for you?")

Less than 15 minutes	1
15 to less than 30 minutes	2
[ask to specify if less than *15 minutes*, if response is "less than 30 minutes"]	
30 minutes to less than 1 hour	3
1 hour to less than 3 hours	4
3 hours to less than 6 hours	5
6 hours to less than 12 hours	6
12 to less than 24 hours	7
More than 24 hours	8
Don't know (**DNR**)	98
Refused (**DNR**)	99

Second take on restoration vs outage priorities.

C14. As electricity planners look ahead, they can't plan to do everything at once. In your organization's view, which of the following two tasks should be their top priority? (RANDOMIZE STATEMENTS)

Reducing the number of outages	1
Reducing the time it takes to restore electricity after an outage	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C15. There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your organization's view?
(ROTATE AND USE APPROPRIATE FIRST WORD IN EACH CASE)

1 Some/Other people say that the current level of reliability seems reasonable to them and they are concerned higher standards may mean paying even higher electricity rates.

2 Other/Some people say with its high-rise towers, reliance on electric-power subways and streetcars and as international business centre, Toronto does need higher standards even if it means paying a few dollars more a month.

98 Don't Know

Section D: Environment

When it comes to the impact of the electricity system on the environment in your community, how concerned are your organization about each of the following issues. **(RANDOMIZE STATEMENTS)**

[READ LIST]

Extremely concerned	1
Very concerned	2
Somewhat concerned	3
Not very concerned	4
Not concerned at all	5
Don't know (**DNR**)	98
Refused **(DNR)**	99

D16. The amount of land used by electricity infrastructure such as power lines, distribution and transmission stations and generating facilities.

D17. Possible health impacts from power lines

D18. Impacts that contribute to climate change

D19. Emissions from generating stations that may directly impact your health

END BATTERY

D20. And which of these environmental issues is of the greatest concern to your organization? (READ LIST AND RANDOMIZE STATEMENTS)

The amount of land used by electricity infrastructure	1
Possible health impacts from power lines	2
Greenhouse gases that contribute to climate change	3
Emissions from generating stations that may directly impact your health	4
Don't know (DNR)	98
Refused (DNR)	99

Section E: Cost

E21. Thinking about how much your organization pays for electricity, do you think the price your organization is paying is … [READ LIST AND ROTATE OPTION 1 & 3]?

A good deal 1
A reasonable amount 2
A bad deal 3
Don't know 98

Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.

01 Strongly agree
02 Somewhat agree
03 Neither agree nor disagree **(DNR)**
04 Somewhat disagree
05 Strongly disagree
98 Don't know (**DNR**)
99 Refused (**DNR**)

E22. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

E23. My organization gets good value for the money it pays for electricity.

END BATTERY

Section F: Goals and Criteria

How familiar are you with the following terms? [READ LIST]

Very familiar and can explain the details to others	1
Somewhat familiar, but don't know the details	2
Have heard of, but don't know any details	3
Have not heard of before this survey	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

ROTATE F24-F26

F24. Conservation and Demand Management

F25. Distributed Generation

F26. Transmission and Distribution Infrastructure

END BATTERY

This preamble will help less informed respondents 'catch-up' with more informed people.

F27. READ PREAMBLE: There are three main solutions to deal with capacity issues. For this plan… RANDOMIZE OPTIONS

1. Conservation and Demand Management involves consumers giving electricity system managers the ability to turn equipment such as air conditioners off for short periods of time when electricity demand peaks.
2. Distributed Generation involves small-scale power generation located in your local community where electricity is consumed.
3. Transmission and Distribution primarily involves transmission and distribution stations as well as underground and overhead wires that bring electricity from more distant generating plants to your local area.

F28. **Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your organization's second choice to deal with growing neighbourhood demands? (ROTATE AND READ LIST)**

Distributed Generation	1
Transmission and Distribution	2
Don't know (**DNR)**	98
Refused (**DNR**)	99

F29. **For conservation and demand management to provide an alternative to distributed generation or transmission and distribution, it must provide a similar level of certainty as the other options. For businesses, this would involve voluntary agreements to install automated controls that allow electricity system managers to turn equipment such as air conditioners off for short periods of time during periods of peak demand.**

How likely is it that your organization will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed? [READ LIST]

Definitely would participate	1
Very likely to participate	2
Somewhat likely to participate	3
Not very likely to participate	4
Definitely would NOT participate	5
Already participate (**DNR**)	6
Don't know (**DNR**)	98
Not applicable **(DNR)**	96
Refused (**DNR**)	99

How important are each of the following considerations as planners chose between these three options? [RANDOMIZE F30-F36] [READ LIST]

Very important	1
Somewhat important	2
Not very important	3
Not at all important	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

F30. Reducing the number of outages in normal circumstances

F31. Reducing the time it takes to restore power

F32. Reducing the likely impact of major events such as ice storms and flooding

F33. Reducing the amount of land used by electricity infrastructure.

F34. Reducing possible health impacts

F35. Reducing impacts that contribute to climate change

F36. Reducing the impact on electricity rates

END BATTERY

F37. Which of these considerations is the most important to your organization? [READ LIST]

Reducing the number of outages in normal circumstances	1
Reducing the time it takes to restore power	2
Reducing the likely impact of major events	3
Reducing the amount of land used by electricity infrastructure.	4
Reducing possible health impacts	5
Reducing impacts that contribute to climate change	6
Reducing the impact on electricity rates	7
Don’t know (**DNR**	98
Refused (**DNR**)	99

Section G: Firmographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G38. Which of the following best describes the hours of operation of your business? Would you say … [READ LIST]

We are open 24/7	1
We operate several shifts each day, but are not open 24/7	2
We operate during regular business hours only	3
We operate outside of regular business hours, but do not have shifts	4
Other (please specify): ____________________________	88

G39. And, which of the following best describes when your business operates through the week? Would you say … [READ LIST]

We operate on weekdays only	1
We operate on weekdays and weekends	2
Other (please specify): ____________________________	88

G40. Finally, how many people are employed at your place of work? [###]
[Interviewer prompt if respondent is struggling to come up with an employee count: "… an approximation is fine"]

G41. And are those all full-time employees?

01	Yes
02	No → And how many are full-time employees? [###]
98	Don't know (**DNR**)
99	Refused (**DNR**)

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Workbook Appendices:

Central Toronto Integrated Regional Resource Plan

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Enersource Hydro Mississauga
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
PowerStream Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE METRO TORONTO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator ("IESO"), PowerStream Inc., Toronto Hydro-Electric System ("THESL"), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

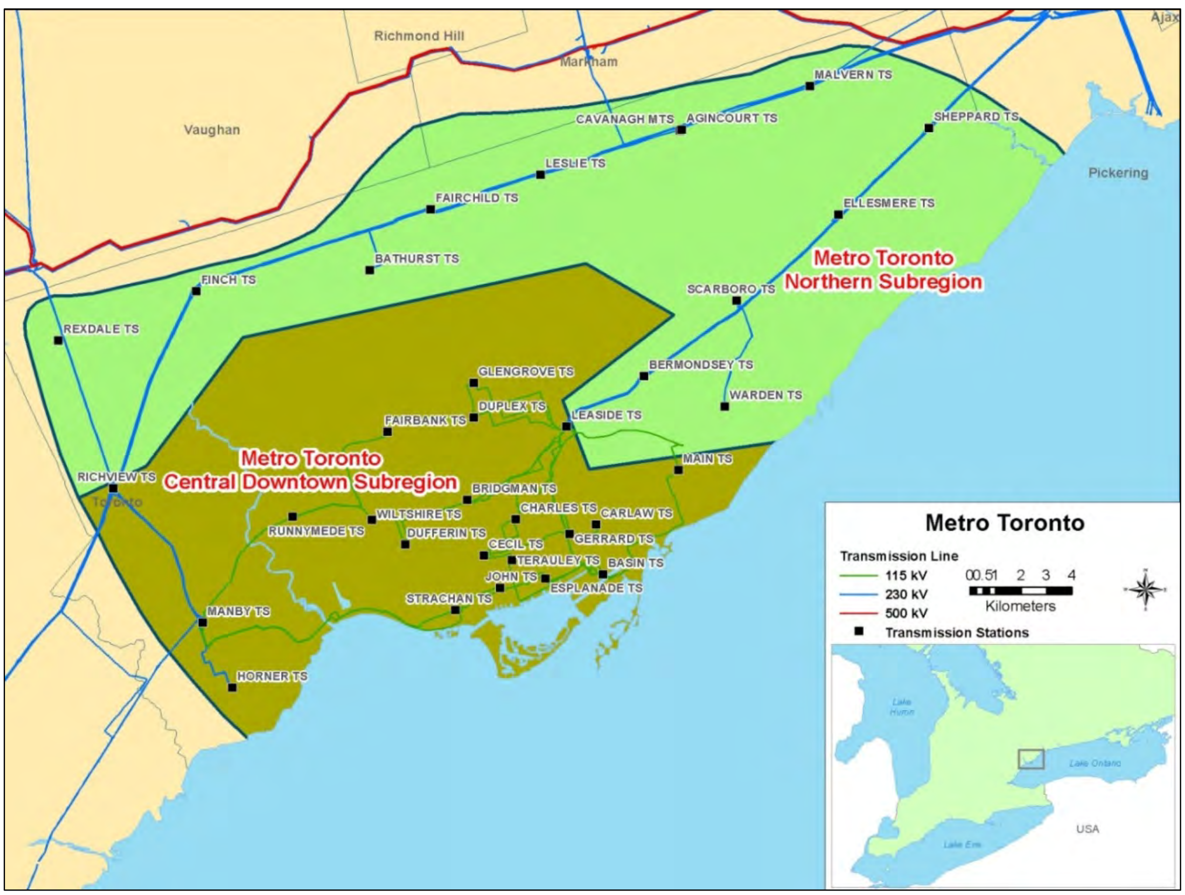

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

This RIP report examines the needs in the Metro Toronto Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

---

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

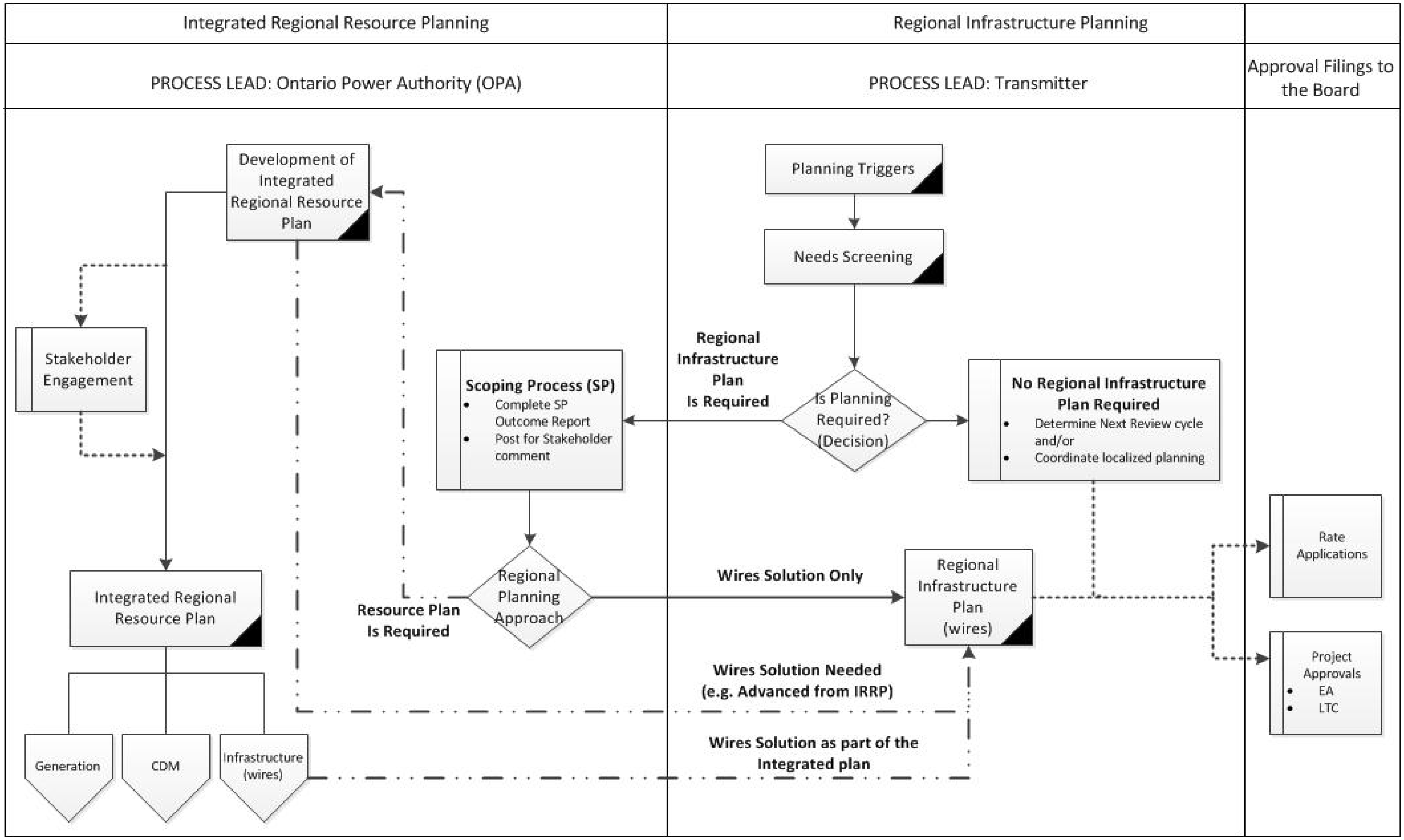

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

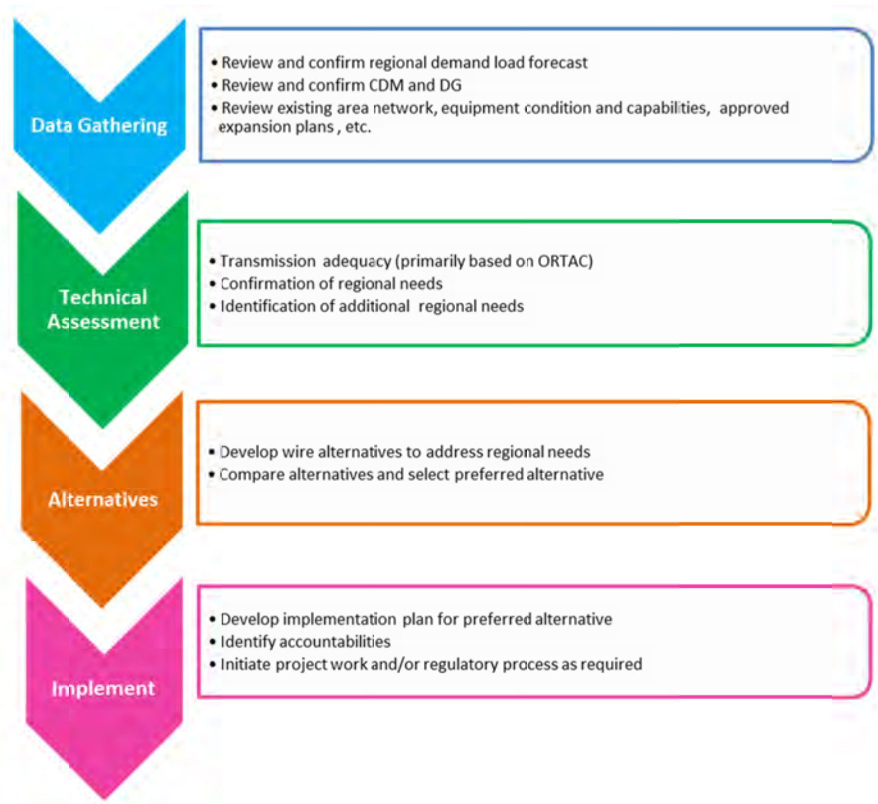

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

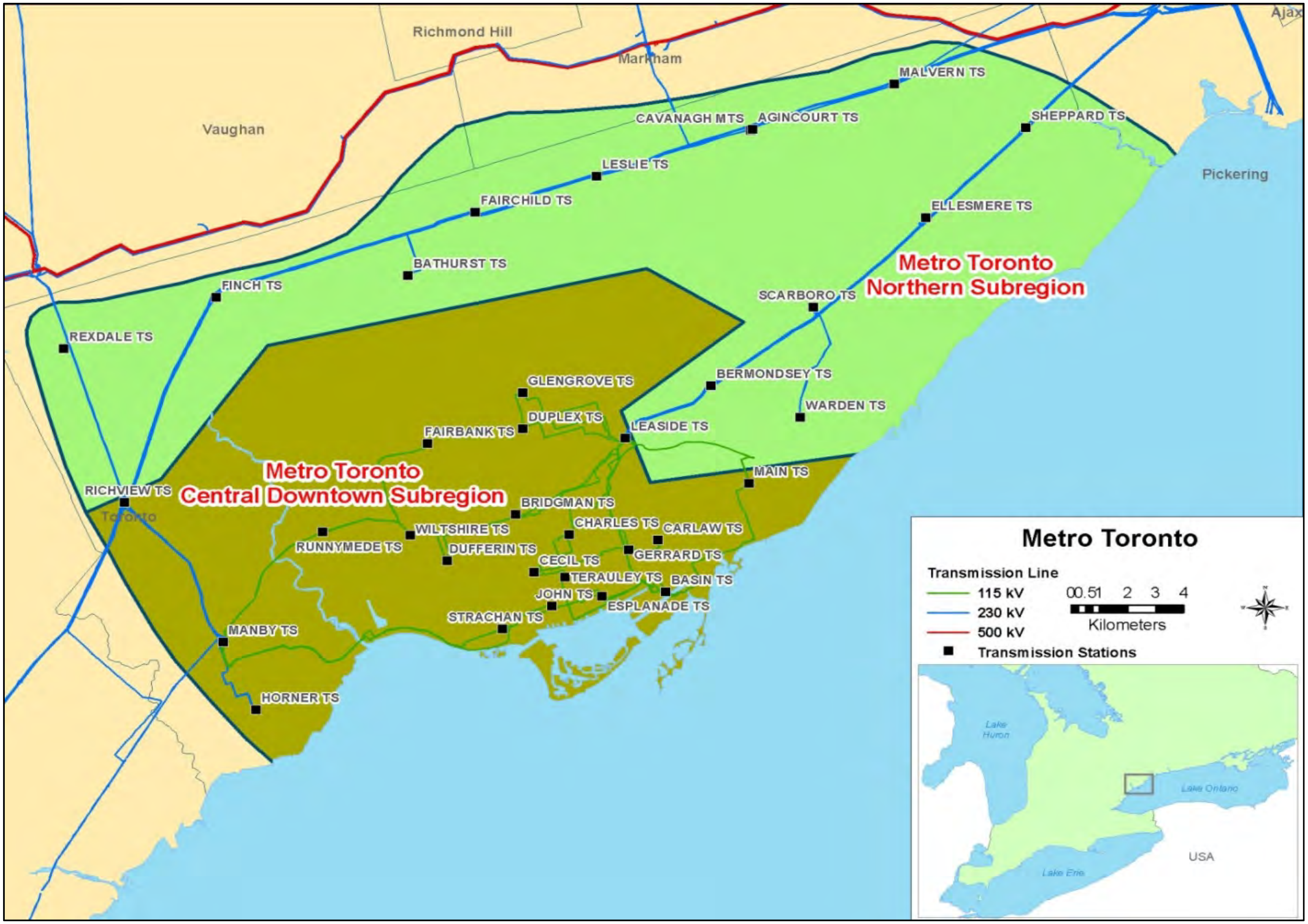

Figure 3-1 Metro Toronto Region – Supply Areas

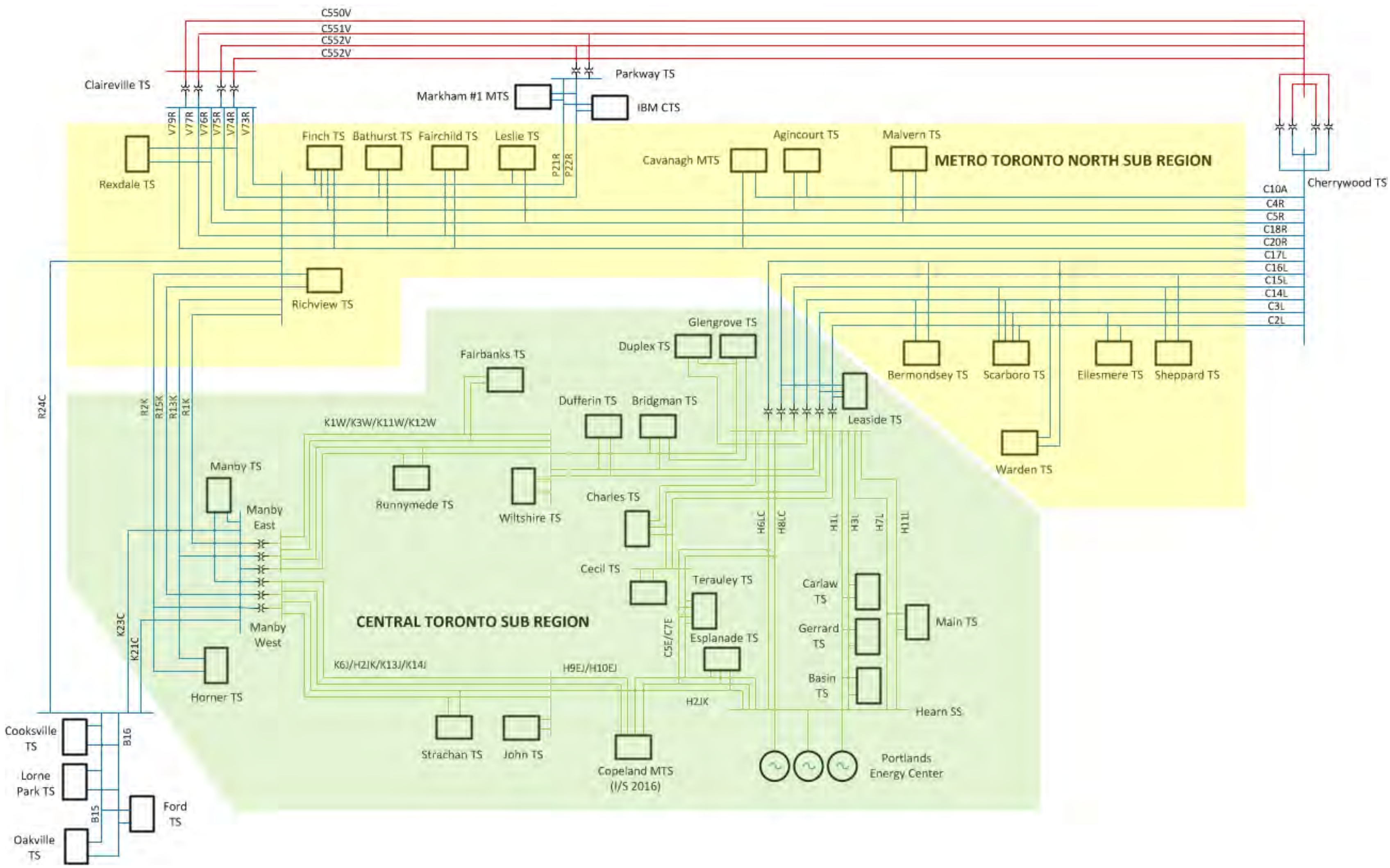

Figure 3-2 Metro Toronto Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.

- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.

- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

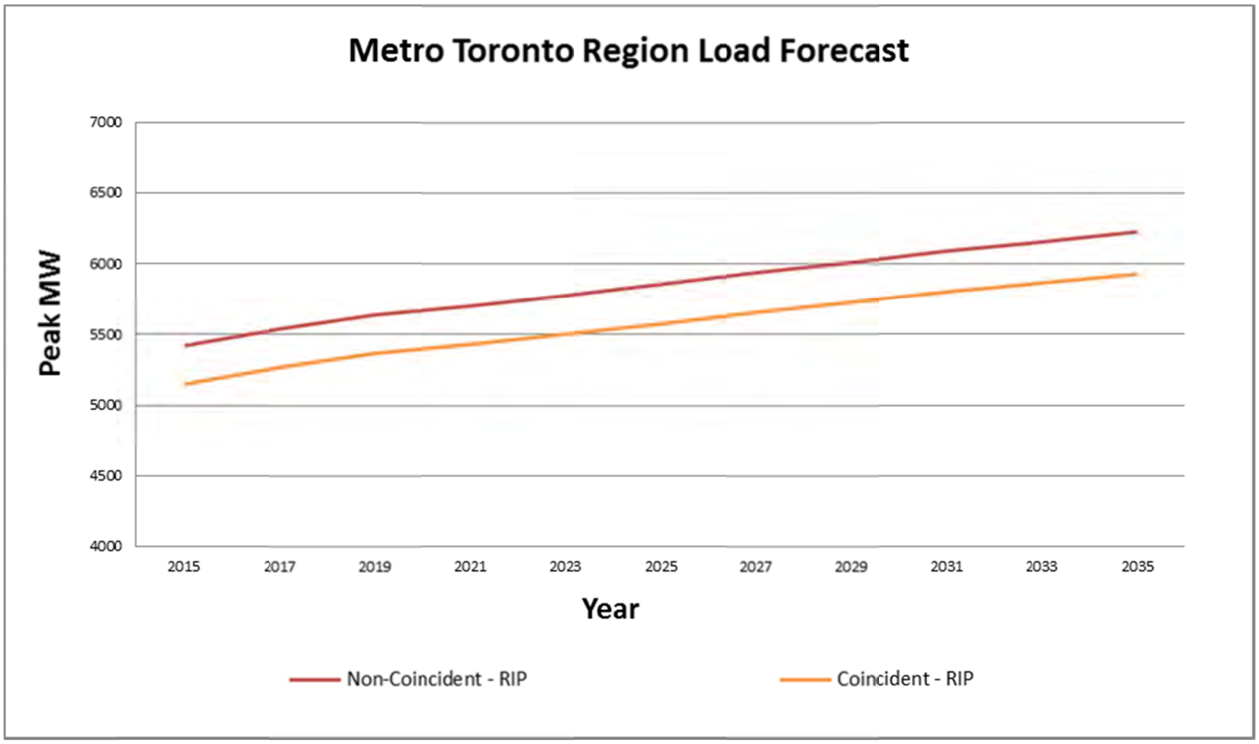

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

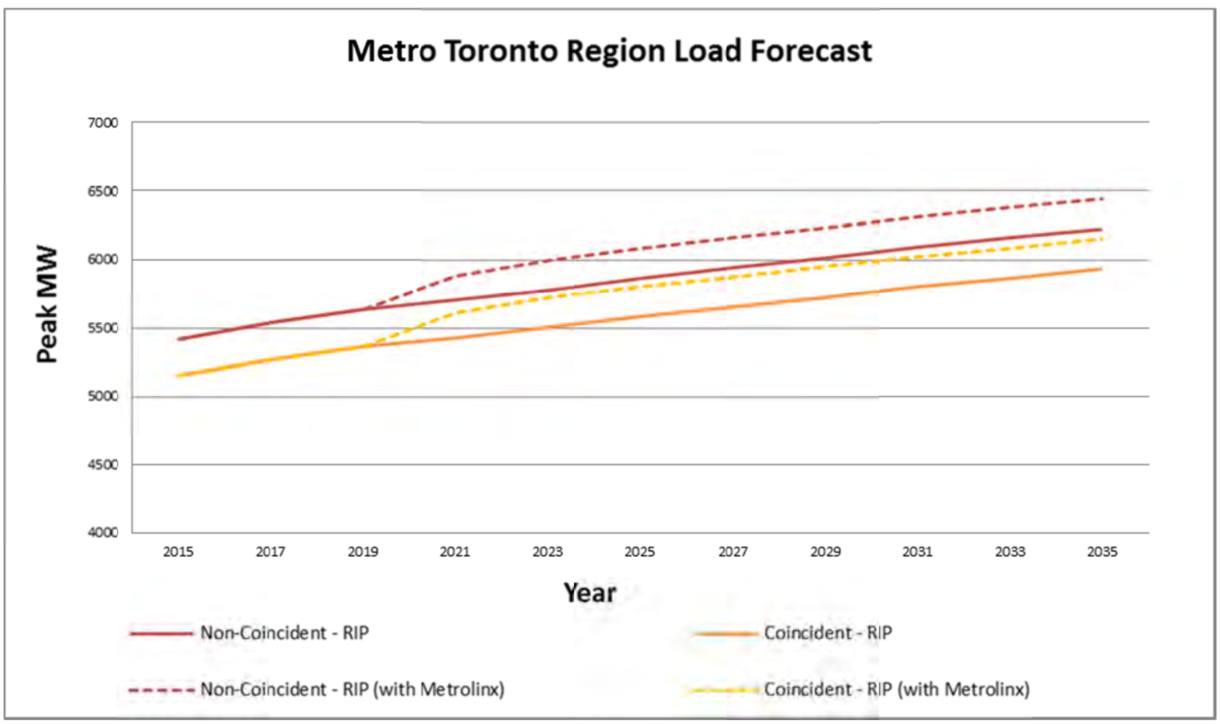

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC(1) Area)	2020+(2)
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

(1) JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.
(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.
(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.
(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit (“LRT”) project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

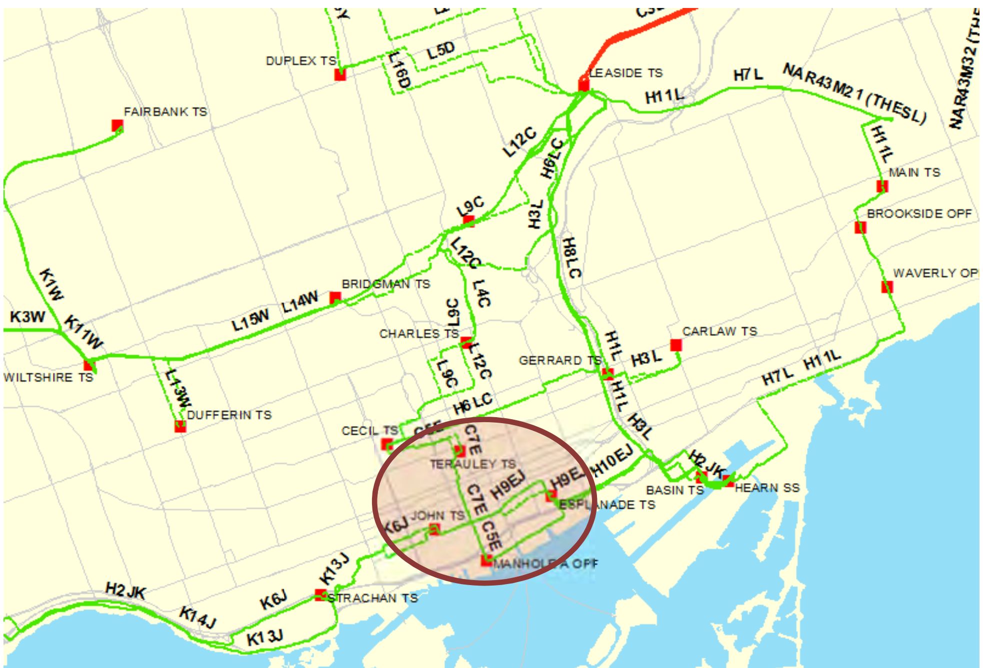

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

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[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	**Runnymede**	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	**Manby230**	**Horner**	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	**Runnymede**	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	**Manby230**	**Horner**	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Project Classification and Categorization

Project Classification

Per the Board's filing guidelines, rate regulated projects are classified into three groups based on their purpose.

- Development projects are those which
  - (i) provide an adequate supply capacity and/or maintain an acceptable or prescribed level of customer or system reliability for load growth or for meeting increased stresses on the system; or
  - (ii) enhance system efficiency such as minimizing congestion on the transmission system and reducing system losses.
- Connection projects are those which provide connection of a load or generation customer or group of customers to the transmission system.
- Sustainment projects are those which maintain the performance of the transmission network at its current standard or replace end-of-life facilities on a "like for like" basis.

Based on the above criteria, the WTTE Project is predominantly a Connection project with a Development component.

Expansion of Runnymede TS is driven by the current need to relieve loading levels at the existing Runnymede and Fairbank Transformer Stations. Both of these stations have been operating at or near capacity over the last five years. Relief of these stations enables Toronto Hydro to connect the Metrolinx Eglinton Crosstown Light Railway system and meet longer term supply needs in the west Toronto Area. The station expansion is therefore exclusively a Connection component of the WTTE project.

Upgrading the existing 115 kV circuits (K1W, K3W, K11W, and K12W) is required to supply the expanded Runnymede TS – this is the Connection component of the line upgrade. This line work also comprises a development component as the upgrade maintains reliability of transmission supply to the west Toronto area.

Project Categorization

The Board's filing guidelines require that projects be categorized to distinguish between a project that is a "must-do", which is beyond the control of the applicant ("non-discretionary"), from a project that is at the discretion of the applicant ("discretionary"). Non-discretionary projects may be triggered or determined by such things as:

a) mandatory requirement to satisfy obligations specified by regulatory organizations including NPCC/NERC or by the Independent Electricity System Operator (IESO);
b) a need to connect new load (of a distributor or large user) or new generation connection;
c) a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
d) projects identified in a provincial government approved plan;
e) projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
f) a need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Based upon the above criteria, the WTTE Project is considered non-discretionary. The Project is being undertaken at the request of the customer and it will:

- enable near and long term connection of new load by Toronto Hydro, most immediately for Toronto Hydro to connect the Metrolinx Eglinton Crosstown Light Railway system; and

- mitigate the risk of overloading the existing Runnymede and Fairbank Transformer Stations, which have been operating at or near capacity for the last five years; and

Categorization and Classification

		Project Need	
		Non-discretionary	Discretionary
Project Class	Connection	**X**	

Cost Benefit Analysis and Options

The Regional Planning Need Evidence (**Exhibit B, Tab 3, Schedule 1, Attachments 1 and 2**) identifies an immediate need for capacity relief at Runnymede TS and Fairbank TS. In order to meet the immediate need of the customer, only two alternatives were considered feasible. Furthermore, as documented in the Regional Planning Need Evidence, achievable conservation potential is insufficient to provide the required capacity relief at Runnymede TS and Fairbank TS. The IRRP also notes that there is no known opportunity for implementation of distributed generation to defer or avoid the need for capacity relief.

Hydro One considered the following alternatives to meet the near-term supply needs in the West Toronto area as well as the longer term load growth:

1. Construct additional distribution feeders to permanently transfer load from Runnymede and Fairbank stations to nearby transformer stations; or
2. Expand the Runnymede TS, including an upgrade of the existing K1W, K2W, K11W and K12W transmission circuits.

Both of these options were evaluated in the IRRP and RIP.

<u>Alternative 1 – Distribution Feeders Alternative – Estimated to Cost $70M</u>

Construction of additional distribution feeders would have to be undertaken by Toronto Hydro to transfer load from Fairbank TS and Runnymede TS to other stations in the area, such as Richview TS and Bathurst TS. The feeders would be 27.6 kV, which is the distribution voltage of all feeders supplied by Runnymede TS and Fairbank TS. The distance between Runnymede TS and Richview TS is 7.5 kilometers and the distance between Fairbank TS and Bathurst TS is 7 kilometers. The estimated cost of proceeding with this distribution alternative is $70 million[1]. This option was rejected because the length of the feeders would result in greater potential for reliability and power quality issues. Further, installation of additional distribution feeders would defer, rather than eliminate, the need for investment in transmission facilities by approximately 10 years, at which time transmission facilities would still be required.

The IRRP estimates the cost of constructing additional distribution feeders to be $70 million with significant degree of uncertainty.

Alternative 2 – West Toronto Transmission Enhancement Project – $59.3 million

The second alternative, known as the West Toronto Transmission Enhancement (WTTE) Project, is to expand the existing Runnymede TS, providing additional transformation capacity and relieving the existing Runnymede and Fairbank Transformer Stations. This alternative includes increasing the capacity of the four existing 115 kV transmission circuits (K1W, K3W, K11W and K12W) to meet forecast increased customer demand. Upgrading these circuits will avoid any deterioration of reliability of transmission supply to the area. The existing Runnymede TS site, owned by Hydro One, has the space required to accommodate the proposed expansion. Hydro One has completed a detailed connection cost estimate for implementing this alternative and provided this to Toronto Hydro. The estimated cost of constructing the Runnymede TS expansion is $30 million and the estimated cost of performing the necessary upgrades to the four 115 kV (K1W, K3W, K11W and K12W)

A detailed Hydro One cost connection estimates the total cost of this Project to be $59.3 million.

[1] The estimate is as per the IRRP (Page 60 of 97) and is subject to a significant degree of uncertainly due to the number of physical barriers, such as highways, bridges and waterways in the area.

transmission circuits is estimated to be $29.3 million. The total cost of implementing this alternative is estimated to be $59.3 million.

Analysis and Recommendation

Consistent with the recommendations of the Regional Planning Need Evidence, Alternative 2, or the Hydro One proposed WTTE Project, is the preferred alternative for the following reasons:

- Alternative 2 is more cost effective than constructing additional distribution feeders by an estimated $10 million. The estimated cost of additional distribution feeders ($70 million) exceeds the estimated cost of installing additional transmission capacity ($59.3 million).
- Alternative 2 meets the long term supply needs of the area which would not be met by Alternative 1. Alternative 1 will only defer the need for transmission investment leading to additional expenditures in the future.
- Proceeding with the WTTE Project also mitigates real estate risk as the WTTE Project does not require the acquisition of additional property.

Hydro One submits that Alternative 2, to construct an expanded Runnymede Transformer Station and upgrade four 115 kV circuits, will provide necessary relief to the existing Runnymede and Fairbank Transformer Stations, enabling connection of the Metrolinx Eglinton Crosstown Light Transit system and satisfy the long term need for capacity to supply future load growth in the area.

A table summarizing the comparison of the two viable alternatives is provided below.

Comparison Criterion	**Expand Runnymede TS**	**Construct Additional Distribution Feeders**
Cost	$59.3 million	$70 million
Uncertainty of estimated cost	Low	High
Meets long term supply needs	Yes	No
Implementation risks	Low	High
Makes use of existing rights of way and real estate	Yes	No

Qualitative Benefits of the Project

The WTTE Project encompasses two significant qualitative benefits over the alternative that cannot be specifically quantified at this point in time.

Avoiding Real Estate Acquisition Costs

Expanding the existing Runnymede TS site and upgrading existing transmission circuits uses existing station land owned and maintained by Hydro One or for which Hydro One already has easement rights. No new permanent real estate rights will be required for the Project as described in **Exhibit E, Tab 1, Schedule 1**. The Project is therefore expected to have minimal disruption to land owners, residents, infrastructure in the area and the environment.

Improving Refurbishment Plans

Existing west Toronto area transformation facilities, including Fairbank TS and Runnymede TS, are of early 1960s vintage. As the need to refurbish the area's transformation facilities arises, the expanded Runnymede TS may provide additional flexibility in planning outages in order to execute refurbishment work.

Apportioning Project Costs & Risks

The estimated capital cost of the WTTE, including overheads and capitalized interest is shown below:

Table 1: Cost of Line Work

	Estimated Cost ($000's)
Materials	5,222
Labour	8,261
Equipment Rental & Contractor Costs	6,802
Sundry	534
Contingencies	3,823
Overhead [1]	3,697
Allowance for Funds Used During Construction [2]	931
Total Line Work	**$29,269**

[1] Overhead costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[2] Capitalized interest (or AFUDC) is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and carrying forward closing balance from the preceding month.

Table 2: Cost of Station Work

	Estimated Cost ***($000's)***
Materials	9,598
Labour	9,194
Equipment Rental & Contractor Costs	2,147
Sundry	455
Contingencies	3,818
Overhead[1]	3,771
Allowance for Funds Used During Construction[2]	986
Total Station Work	**$29,969**

The cost of the line and station work provided above allows for the schedule of approval, design and construction activities provided in **Exhibit B, Tab 11, Schedule 1**.

1.0 RISKS AND CONTINGENCIES

As with most projects, there is some risk associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks.

Based on past experience, the estimate for this project work includes allowances in the contingencies to cover the following potential risks:

- Delays in obtaining required approvals including Environmental Certificate of Approval, Environmental Screen Out/Class EA, and Section 92
- Outage availability risk[3];
- Material delivery delay due to procurement or vendor issues;

[3] Summer and Winter outages may not be available since the circuit may be operating at full capacity.

- There are 4 TTC parking lots in the area, but to accommodate commuter needs, they must remain at least partly operational during the term of the Project. To mitigate the duration of any parking lot disturbance, overtime may be required;
- The project may be elevated to a higher level of environmental assessment (full Class EA) due to public concerns, including First Nations and Metis, which could result in a delay of up to six months;
- If community concerns emerge regarding Runnymede TS expansion and disruptions to parks and gardens may require mitigation landscaping and related investment after construction.

Cost contingencies that have not been included, due to the unlikelihood or uncertainty of occurrence, include:

- Labour disputes;
- Safety or environmental incidents;
- Significant changes in costs of materials since the estimate preparation;
- Any other unforeseen and potentially significant event/occurrence.

2.0 COSTS OF COMPARABLE PROJECTS

The OEB Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 4, requires the Applicant to provide information about a cost comparable project constructed by the Applicant. For station cost comparisons, Table 2 below shows the cost, construction and technical comparisons of the Runnymede expansion to the recently constructed Barwick TS in Northwestern Ontario. Table 3 compares the reconductoring component of the WTTE Project to the D1A/D3A refurbishment project completed in 2013.

For the purpose of context, Barwick TS is a 115/44KV DESN (Dual Element Spot Network) station with two (2) feeders, one (1) capacitor bank, and PCT in a box relay building, which was completed and placed in-serviced in August of 2014. The station is very similar to the Runnymede TS with the exceptions that Barwick TS has a 44 kV low voltage yard, has significantly fewer feeder positions than Runnymede TS, and does not have any significant duct bank installation. This Project was chosen as a good "apples-to-apples" comparison to the Runnymede expansion Project because of its similar construction conditions and design. Key project information on the two projects is provided in Table 2 below. The main drivers of the variance in costs between the two are the greater number of feeders at the Runnymede expansion and the timing between the two project in-service dates, as the Runnymede expansion will be placed into service four years after Barwick TS.

Table 2: Costs of Comparable Station Projects

Project	**Barwick TS New Station Build (actual)**	**Runnymede TS Station Expansion (Estimate)**
Technical	115/44kV DESN Including 2x Transformers, 2x feeders, 1x cap bank, and PCT in a box	115/27.6kV DESN Including 2x Transformers, 10x feeders, 1x cap bank, and PCT in a box
Length (km)	N/A	N/A
Project Surroundings	Mostly rural	Mostly urban residential
Environmental Issues	None	None
In-Service Date	2014-08	2018-11
Total Project Cost	$22,102k	$29,969k
Less: Non-Comparable Costs		
8 Additional Feeder Positions		$6.400k[4]
Add: Non-Comparable Costs		
Escalation Adjustment (2%/year)	$1,822k	
Total Comparable Project Costs	$23,924k	$23,569k

With regards to the comparable lines project, the D1A/D3A Line Refurbishment was a line refurbishment project from structure 1 at Decew Falls SS to structure 16 at St. Johns Valley Junction. The D1A/D3A Line Refurbishment included like-for-like conductor replacement along with insulators and hardware. That project went in-service in December of 2013. The main driver of the variance in comparable costs between the two Projects is timing – the WTTE Project will go in-service approximately 5 years after the selected comparable. Additionally, the WTTE Project involves structural reinforcement work which was not required in the D1A/D3A Line Refurbishment.

[4] Rough estimate of $800k per feeder position.

Table 3: Costs of Comparable Line Projects

Project	**D1A/D3A Line Refurbishment Project (actual)**	**WTTE Project (Estimate)**
Technical	Double circuit 115kV refurbishment, like for like, 4.25km	Reconductor approximately 10 km of four 115Kv single circuits mainly on single tower, shield wire replacement and significant structural reinforcement to 70 towers
Length (circuit km)	8.5km	40km
Project Surroundings	Rural	Mostly urban residential
Environmental Issues	None	None
In-Service Date	December, 2013	November 30, 2018
Total Project Cost	$4,850k	$29,269k
Add: Non-Comparable Costs		
Escalation Adjustment (2%/year)	$505k	
Total Comparable Project Costs	$5,535k	$29,269k
Total Cost/Circuit km	$630k	$731k

Connection Projects Requiring Network Reinforcement

The WTTE Project will not require reinforcement of network facilities as defined by the Transmission System Code.

Transmission Rate Impact Assessment

1.0 ECONOMIC FEASIBILITY

The proposed WTTE Project comprises both line and transformation assets and will contribute to meeting Toronto Hydro's capacity and reliability needs in the west Toronto area, including the Metrolinx Eglinton Crosstown Light Railway Transit system. The WTTE Project includes the construction of an expanded transformer station at Hydro One's Runnymede TS, as well as the upgrade of four existing 115 kV transmission circuits, K1W, K3W, K11W and K12W, to supply the expanded transformer station. Each transmission circuit is approximately 10 kilometers long. The transformer station costs will be included in the Transformation Connection pool, whereas the costs for the upgraded circuits will be included in the Line Connection pool for cost classification purposes. All costs will be 100% customer funded as the requirementfor the Project is driven entirely by Toronto Hydro's capacity and reliability needs. Hydro One is requiring the customer to pay the required capital contribution consistent with the economic evaluation requirements of Section 6.5.2 of the *Transmission System Code*.

A 25-year illustrative discounted cash flow analysis of the line work is provided in Table 1 below. The results show that based on the estimated initial cost of $29.3[1] million, plus assumed ongoing operating and maintenance costs and net of incremental revenue, the capacity enhancement project will have a negative net present value of $28.1 million. This amount will be fully recovered from the customer via capital contribution.

[1] Initial costs of $29.3 million include $25.9 million of up front capital costs plus $3.4 million cost of removals

A 25-year illustrative discounted cash flow analysis of the station work is provided in Table 2 below. The results show that based on the estimated initial cost of $30[2] million, plus assumed ongoing operating and maintenance costs and net of incremental revenue, the capacity enhancement project will have a negative net present value of $33.8 million. This amount will be recovered directly from the customer via capital contribution.

2.0 COST RESPONSIBILITY

Line Pool

The capital contribution assigned to the customer is $28.1 million. This amount, together with the incremental revenues, covers the initial and ongoing costs associated with the re-conductoring the four existing 115 kV circuits, K1W, K3W, K11W and K12W, between Manby TS and Wiltshire TS terminal stations. This work is being done to enable the Customer to meet load demand in the West Toronto area without deteriorating reliability of supply, and as such, the cost of this work, net of forecast incremental rate revenues, has been assigned to the customer for cost responsibility purposes. The table below indicates the cost responsibility for the elements of work to be done on the project.

Transformation Pool

The capital contribution assigned to the customer is $33.8 million. This amount, together with the incremental revenues, covers the initial and ongoing costs for the expansion of the Runnymede Transformer Station consisting of two 83 MVA transformers and ten 27.6 kV feeder breakers. The additional transformation capacity is being installed to enable the customer to meet load demand in the West Toronto area,

[2] Initial costs of $30 million include $29.8 million of up front capital costs plus $0.13 million cost of removals

and as such, the cost of this work, net of forecast incremental rate revenues, has been assigned to the customer for cost responsibility purposes. The table below indicates the cost responsibility for the elements of work to be done on the project.

Cost Responsibility *in $ million, excluding HST*	Cost of Work (per B-7-1)	Cost Responsibility		Capital Contribution
		Customer	Pool	
Transmission Line Facilities	29.3	28.1	1.2	28.1
Station Facilities	30.0	33.8	-3.8	33.8[3]
Total	59.3	61.9	-2.6	61.9

[3] Capital contribution exceeds the capital cost of the Project as it includes recovery of OM&A

3.0 RATE IMPACT ASSESSMENT

The analysis of the Line and Transformation Connection pools rate impacts has been carried out on the basis of Hydro One's transmission revenue requirement for the year 2016, and the most recently approved Ontario Transmission Rate Schedules. Both the Line Connection pool and Transformation Connection pool revenue requirements would be affected by the expanded station and the upgrade to four existing circuits based on the project cost allocation to these pools.

Line Connection Pool

Based on the project's initial cost of $29.3 million and the associated line pool incremental cash flows, there will be a change in the line pool revenue requirement once the project's impacts are reflected in the transmission rate base at the projected in-service date. Over a 25-year time horizon, the line pool rate will fall by $0.02/kw/month, from the current rate of $0.87/kW/month to $0.85kW/month. The maximum revenue decrease related to the proposed line connection facilities will be $0.07 million in the year 2025. This will result in a maximum line connection facilities rate impact of negative 1.15% in 2026. The detailed analysis illustrating the calculation of the incremental line connection pool revenue shortfall and rate impact is provided in Table 3 below.

Transformation Connection Pool

Based on the project's initial cost of $30 million and the associated Transformation Connection pool incremental cash flows, there will be no change in the Transformation pool revenue requirement once the project's impacts are reflected in the transmission rate base at the projected in-service date of November 2018. Over a 25-year time horizon, the Transformation pool rate will remain the same at $2.02/kW/month. The detailed analysis illustrating the calculation of the incremental transmission revenue shortfall and rate impact is provided in Table 3 below.

<u>Impact on Typical Residential Customer</u>

Based on the load forecast, initial capital costs and ongoing maintenance costs, the required customer capital contribution will cause the Line Connection rate to change resulting in a negative, or favourable, bill impact to end-use customers. There will be no impact on the Transformation Connection rate. The table below shows this result for a typical residential customer who is under the Regulated Price Plan (RPP).

A. Typical monthly bill (Residential R1 in a high density zone at 1,000 kWh per month with winter commodity prices.)	$188.28 per month
B. Transmission component of monthly bill	$11.86 per month
C. Line Connection Pool share of Transmission component	$1.48 per month
D. Transformation Connection Pool share of Transmission component	$3.43 per month
E. Impact on Line Connection Pool Provincial Uniform Rates	-1.15%
F. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
G. Decrease in Transmission costs for typical monthly bill (C x E)	-$0.02 per month or -$0.2 per year
H. Net decrease on typical residential customer bill (G / A)	-0.01%

Note: Values rounded to two significant digits.

1 ***Table 1 – DCF Analysis, Line Pool, page 1***

Date: 24-Oct-16
Project #

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name: Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description:
Customer: Toronto Hydro

Month / Year	Cumulative PV @ 5.78%	In-Service Date Nov-30 **2018** 0	<------- Nov-30 **2019** 1	Nov-30 **2020** 2	Nov-30 **2021** 3	Nov-30 **2022** 4	Project year ended - annualized from In-Service Date Nov-30 **2023** 5	Nov-30 **2024** 6	--------> Nov-30 **2025** 7	Nov-30 **2026** 8	Nov-30 **2027** 9	Nov-30 **2028** 10	Nov-30 **2029** 11	Nov-30 **2030** 12
Revenue & Expense Forecast														
Load Forecast (MW)			3.0	5.8	7.4	9.6	11.1	13.3	14.8	15.6	16.3	17.1	17.8	19.2
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			3.0	5.8	7.4	9.6	11.1	13.3	14.8	15.6	16.3	17.1	17.8	19.2
Tariff Applied ($/kW/Month)			0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $M			0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Removal Costs - $M		(3.4)												
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M			(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		(3.4)	(0.1)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Income Taxes		0.9	0.3	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2
Operating Cash Flow (after taxes) - $M		(2.5)	0.2	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
PV Operating Cash Flow (after taxes) - $M (A)	**1.9**	**(2.5)**	**0.2**	**0.5**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC		(21.2)												
- Overheads		(3.7)												
- AFUDC		(0.9)												
Total upfront capital expenditures		**(25.9)**												
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures		0.0												
Total capital expenditures - $M		**(25.9)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M		**0.1**												
PV Working Capital - $M		**0.0**												
PV Capital (after taxes) - $M (B)	**(25.7)**	**(25.7)**												
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(23.8)**	**(28.2)**	**(28.0)**	**(27.6)**	**(27.2)**	**(26.8)**	**(26.5)**	**(26.2)**	**(25.9)**	**(25.7)**	**(25.5)**	**(25.3)**	**(25.1)**	**(25.0)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.78%**

		Before Cont $M		**After Cont** $M	**Impact** $M
PV Incremental Revenue		2.2		2.2	
PV OM&A Costs		(3.4)		(3.4)	
PV Municipal Tax		(1.5)		(1.5)	
PV Income Taxes		0.7		0.7	(0.0)
PV CCA Tax Shield		4.0		(0.3)	(4.3)
PV Capital - Upfront	(25.9)		(25.9)		
Add: PV Capital Contribution	**0.0**	(25.9)	**28.1**	2.3	28.1
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(23.8)		(0.0)	23.8
Profitability Index*		**0.1**		**(1.0)**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date: 30-Nov-18

Payback Year: 2043

No. of years required for payback: 25

2

Table 1 – DCF Analysis, Line Pool, page 2

Date:	24-Oct-16
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

Facility Name:	Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description:	
Customer:	Toronto Hydro

<------- Project year ended - annualized from In-Service Date -------->

Month	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30
Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	20.0	20.8	21.5	22.2	23.0	23.7	25.1	25.9	26.7	27.4	28.1	28.9	30.3
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	20.0	20.8	21.5	22.2	23.0	23.7	25.1	25.9	26.7	27.4	28.1	28.9	30.3
Tariff Applied ($/kW/Month)	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $M	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Removal Costs - $M													
On-going OM&A Costs - $M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Income Taxes	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV Operating Cash Flow (after taxes) - $M (A)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(24.8)**	**(24.7)**	**(24.6)**	**(24.5)**	**(24.4)**	**(24.3)**	**(24.2)**	**(24.1)**	**(24.1)**	**(24.0)**	**(23.9)**	**(23.9)**	**(23.8)**

Table 2 – DCF Analysis, Transformation Pool, page 1

Date:	24-Oct-16
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description:	
Customer:	Toronto Hydro

			In-Service Date	<-------		Project year ended - annualized from In-Service Date			-------->					
		Month	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30
		Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)				3.0	5.8	7.4	9.6	11.1	13.3	14.8	15.6	16.3	17.1	17.8	19.2
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				3.0	5.8	7.4	9.6	11.1	13.3	14.8	15.6	16.3	17.1	17.8	19.2
Tariff Applied ($/kW/Month)				2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $M				0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5
Removal Costs - $M			(0.1)												
On-going OM&A Costs - $M			0.0	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
Municipal Tax - $M				(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M			(0.1)	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)	(0.5)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)
Income Taxes			0.0	0.4	0.7	0.6	0.6	0.5	0.6	0.5	0.5	0.4	0.4	0.4	0.3
Operating Cash Flow (after taxes) - $M			(0.1)	0.0	0.4	0.4	0.4	0.3	0.1	0.1	0.1	0.1	0.0	0.0	0.0
		Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	**1.1**	**(0.1)**	**0.0**	**0.3**	**0.3**	**0.3**	**0.3**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC			(25.1)												
- Overheads			(3.8)												
- AFUDC			(1.0)												
Total upfront capital expenditures			**(29.8)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(29.8)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M			**0.1**												
PV Working Capital - $M			**0.0**												
PV Capital (after taxes) - $M	**(B)**	**(29.7)**	**(29.7)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(28.6)**	**(29.8)**	**(29.8)**	**(29.4)**	**(29.1)**	**(28.8)**	**(28.5)**	**(28.5)**	**(28.4)**	**(28.4)**	**(28.3)**	**(28.3)**	**(28.3)**	**(28.3)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.78%**

		Before Cont $M		After Cont $M	Impact $M
PV Incremental Revenue		5.2		5.2	
PV OM&A Costs		(8.1)		(8.1)	
PV Municipal Tax		(1.7)		(1.7)	
PV Income Taxes		1.2		1.2	(0.0)
PV CCA Tax Shield		4.6		(0.6)	(5.2)
PV Capital - Upfront	(29.8)		(29.8)		
Add: PV **Capital Contribution**	**0.0**	(29.8)	**33.8**	3.9	33.8
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		**(28.6)**		**0.0**	**28.6**
Profitability Index*		**0.0**		**(1.0)**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	30-Nov-18
Payback Year:	2043
No. of years required for payback:	25

Table 2 – DCF Analysis, Transformation Pool, page 2

Date:	24-Oct-16
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

Facility Name:	Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description:	
Customer:	Toronto Hydro

<------- Project year ended - annualized from In-Service Date -------->

Month	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30	Nov-30
Year	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast													
Load Forecast (MW)	20.0	20.8	21.5	22.2	23.0	23.7	25.1	25.9	26.7	27.4	28.1	28.9	30.3
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	20.0	20.8	21.5	22.2	23.0	23.7	25.1	25.9	26.7	27.4	28.1	28.9	30.3
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $M	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Removal Costs - $M													
On-going OM&A Costs - $M	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
Municipal Tax - $M	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
Income Taxes	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Operating Cash Flow (after taxes) - $M	0.0	0.0	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
PV Operating Cash Flow (after taxes) - $M (A)	**0.0**	**0.0**	**0.0**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
Capital Expenditures - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(28.3)**	**(28.3)**	**(28.3)**	**(28.3)**	**(28.3)**	**(28.4)**	**(28.4)**	**(28.5)**	**(28.5)**	**(28.5)**	**(28.5)**	**(28.6)**	**(28.6)**

Table 3 – Revenue Requirement and Line Pool Rate Impact, page 1

Revenue Requirement and Line Pool Rate Impact **(After Capital Contribution)**

		Project YE											
Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits		30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Calculation of Incremental Revenue Requirement ($000)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Nov-18												
Capital Cost	25,869												
Less: Capital Contribution Required	(28,132)												
Net Project Capital Cost	(2,263)												
Average Rate Base		(1,109)	(2,195)	(2,150)	(2,105)	(2,059)	(2,014)	(1,969)	(1,924)	(1,878)	(1,833)	(1,788)	(1,742)
Incremental OM&A Costs		0	0	0	0	0	0	0	0	0	0	0	0
Grants in Lieu of Municipal tax		108	108	108	108	108	108	108	108	108	108	108	108
Depreciation		(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)
Interest and Return on Rate Base		(72)	(143)	(140)	(138)	(135)	(132)	(129)	(126)	(123)	(120)	(117)	(114)
Income Tax Provision		2	17	13	9	5	2	(1)	(4)	(6)	(8)	(10)	(12)
REVENUE REQUIREMENT PRE-TAX		**(8)**	**(63)**	**(65)**	**(66)**	**(66)**	**(67)**	**(67)**	**(66)**	**(66)**	**(65)**	**(64)**	**(63)**
Incremental Revenue		31	61	77	100	116	138	154	163	170	178	186	201
SUFFICIENCY/(DEFICIENCY)		**39**	**124**	**142**	**166**	**182**	**205**	**221**	**229**	**236**	**243**	**250**	**264**
	Base Year												
Line Pool Revenue Requirement including sufficiency/(deficiency)	212,407	212,399	212,344	212,343	212,342	212,341	212,341	212,341	212,341	212,341	212,342	212,343	212,344
Line MW	245,299	245,335	245,369	245,388	245,414	245,433	245,459	245,477	245,487	245,495	245,504	245,513	245,530
Line Pool Rate ($/kw/month)	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.86	0.86	0.86	0.86	0.86
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
RATE IMPACT relative to base year		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**

Assumptions

Incremental OM&A		N.A.
Grants in Lieu of Municipal tax	0.42%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.53%	Includes OEB-approved ROE of 9.18599047619048%, 1.65357476190476% on ST debt, and 4.98859485989344% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2016 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets

Table 3 – Revenue Requirement and Line Pool Rate Impact, page 2

Revenue Requirement and Line Pool Rate Impact **(After Capital Contribution)**

Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits		30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov
		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Calculation of Incremental Revenue Requirement ($000)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	30-Nov-18													
Capital Cost	25,869													
Less: Capital Contribution Required	(28,132)													
Net Project Capital Cost	(2,263)													
Average Rate Base		(1,697)	(1,652)	(1,607)	(1,561)	(1,516)	(1,471)	(1,426)	(1,380)	(1,335)	(1,290)	(1,245)	(1,199)	(1,154)
Incremental OM&A Costs		0	0	0	0	0	0	0	0	0	0	0	0	0
Grants in Lieu of Municipal tax		108	108	108	108	108	108	108	108	108	108	108	108	108
Depreciation		(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)	(45)
Interest and Return on Rate Base		(111)	(108)	(105)	(102)	(99)	(96)	(93)	(90)	(87)	(84)	(81)	(78)	(75)
Income Tax Provision		(14)	(15)	(16)	(18)	(18)	(19)	(20)	(21)	(21)	(22)	(22)	(22)	(22)
REVENUE REQUIREMENT PRE-TAX		**(62)**	**(60)**	**(58)**	**(57)**	**(55)**	**(52)**	**(50)**	**(48)**	**(45)**	**(43)**	**(40)**	**(38)**	**(35)**
Incremental Revenue		209	217	224	232	240	248	262	271	278	286	294	301	316
SUFFICIENCY/(DEFICIENCY)		**271**	**277**	**283**	**289**	**294**	**300**	**312**	**318**	**324**	**329**	**334**	**339**	**351**
	Base Year													
Line Pool Revenue Requirement including sufficiency/(deficiency)	212,407	212,346	212,347	212,349	212,351	212,353	212,355	212,357	212,359	212,362	212,364	212,367	212,370	212,372
Line MW	245,299	245,540	245,549	245,557	245,566	245,575	245,584	245,601	245,611	245,619	245,628	245,637	245,646	245,663
Line Pool Rate ($/kw/month)	0.87	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Increase/(Decrease) in Line Pool Rate ($/kw/month), relative to base year		-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
RATE IMPACT relative to base year		**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**	**-1.15%**

Table 3 – Revenue Requirement and Transformation Pool Rate Impact, page 1

Revenue Requirement and Transformation Pool Rate Impact **(After Capital Contribution)**

Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits		Project YE 30-Nov 2019	30-Nov 2020	30-Nov 2021	30-Nov 2022	30-Nov 2023	30-Nov 2024	30-Nov 2025	30-Nov 2026	30-Nov 2027	30-Nov 2028	30-Nov 2029	30-Nov 2030
Calculation of Incremental Revenue Requirement ($000)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	30-Nov-18												
Capital Cost	29,839												
Less: Capital Contribution Required	(33,773)												
Net Project Capital Cost	(3,933)												
Average Rate Base		(1,927)	(3,815)	(3,737)	(3,658)	(3,579)	(3,501)	(3,422)	(3,343)	(3,265)	(3,186)	(3,107)	(3,029)
Incremental OM&A Costs		329	329	329	329	329	658	658	658	658	658	658	658
Grants in Lieu of Municipal tax		125	125	125	125	125	125	125	125	125	125	125	125
Depreciation		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Interest and Return on Rate Base		(126)	(249)	(244)	(239)	(234)	(229)	(224)	(218)	(213)	(208)	(203)	(198)
Income Tax Provision		3	30	22	15	9	3	(2)	(7)	(11)	(15)	(18)	(21)
REVENUE REQUIREMENT PRE-TAX		**252**	**156**	**153**	**152**	**150**	**479**	**479**	**479**	**480**	**481**	**483**	**485**
Incremental Revenue		72	141	180	232	269	321	359	378	396	414	432	466
SUFFICIENCY/(DEFICIENCY)		**(180)**	**(15)**	**26**	**80**	**119**	**(157)**	**(120)**	**(101)**	**(84)**	**(68)**	**(51)**	**(19)**
	Base Year												
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	422,219	422,471	422,375	422,372	422,370	422,369	422,697	422,697	422,698	422,699	422,700	422,702	422,704
Transformation MW	209,136	209,172	209,206	209,225	209,251	209,270	209,296	209,314	209,324	209,332	209,341	209,350	209,367
Transformation Pool Rate ($/kw/month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Assumptions

Incremental OM&A		Years 1 to 5 $329 k each year; Years 6 to 15 $658 k each year; Years 16 to 25 $822.5 k each year.
Grants in Lieu of Municipal tax	0.42%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.53%	Includes OEB-approved ROE of 9.18599047619048%, 1.65357476190476% on ST debt, and 4.98859485989344% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2016 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets

Table 3 – Revenue Requirement and Transformation Pool Rate Impact, page 2

Revenue Requirement and Transformation Pool Rate Impact **(After Capital Contribution)**

Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits		30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov	30-Nov
		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Calculation of Incremental Revenue Requirement ($000)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	30-Nov-18													
Capital Cost	29,839													
Less: Capital Contribution Required	(33,773)													
Net Project Capital Cost	(3,933)													
Average Rate Base		(2,950)	(2,871)	(2,793)	(2,714)	(2,635)	(2,557)	(2,478)	(2,399)	(2,321)	(2,242)	(2,163)	(2,085)	(2,006)
Incremental OM&A Costs		658	658	658	823	823	823	823	823	823	823	823	823	823
Grants in Lieu of Municipal tax		125	125	125	125	125	125	125	125	125	125	125	125	125
Depreciation		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Interest and Return on Rate Base		(193)	(188)	(182)	(177)	(172)	(167)	(162)	(157)	(152)	(147)	(141)	(136)	(131)
Income Tax Provision		(24)	(26)	(29)	(30)	(32)	(34)	(35)	(36)	(37)	(38)	(38)	(39)	(39)
REVENUE REQUIREMENT PRE-TAX		**488**	**490**	**493**	**661**	**664**	**668**	**672**	**676**	**680**	**685**	**689**	**694**	**699**
Incremental Revenue		485	503	521	539	557	575	609	628	646	664	682	700	734
SUFFICIENCY/(DEFICIENCY)		**(2)**	**13**	**28**	**(122)**	**(108)**	**(93)**	**(63)**	**(48)**	**(34)**	**(21)**	**(7)**	**6**	**36**
	Base Year													
Transformation Pool Revenue Requirement including sufficiency/(deficiency)	422,219	422,706	422,709	422,712	422,880	422,883	422,887	422,891	422,895	422,899	422,903	422,908	422,913	422,917
Transformation MW	209,136	209,377	209,386	209,394	209,403	209,412	209,421	209,438	209,448	209,456	209,465	209,474	209,483	209,500
Transformation Pool Rate ($/kw/month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Increase/(Decrease) in Transformation Pool Rate ($/kw/month), relative to base year		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE IMPACT relative to base year		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Table 4 – DCF Assumptions

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2016 Parameters and Assumptions

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Transformation	**2.02**
Line	**0.87**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.42%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2016	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2016	**11.50%**	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2016	**8%**	Current rate
Decision Support defined costs (1)	2016	**0%**	
Decision Support defined costs (2)	2016	**0%**	
Decision Support defined costs (3)	2016	**0%**	
After-tax Discount rate:		**5.78%**	Based on OEB-approved ROE of 9.19% on common equity and 1.65% on short-term debt, 4.99% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

Other Assumptions:

Estimated Incremental OM&A: Project specific ($ k):

Dual Transformer Station	**$329**	each year for years 1 - 5
	$658	each year for years 6 - 15
	$823	each year for years 16 - 25

Deferral Account Requests

There are no new deferral account requests being made as part of this Application.

Project Schedule

TASK	START	FINISH
Submit Section 92		November 2016
Projected Section 92 Approval	November 2016	May 2017
Prepare and Sign CCRA	October 2016	December 2016
STATIONS		
Order Station Power Transformers	September 2016	September 2016
Detailed Engineering	May 2016	June 2017
Tender and Award Other Major Station Equipment	September 2016	November 2016
Receive Major Station Equipment	March 2017	October 2017
Construction	May 2017	September 2018
Commissioning	May 2018	November 2018
LINES		
Property Rights Acquisition	N/A	N/A
Detailed Engineering	August 2016	April 2017
Tender & Award Structural Steel	January 2017	March 2017
Receive Structural Steel	September 2017	October 2017
Construction	May 2017	August 2018
In Service		**30 November 2018**

Descriptions of the Physical Design

1.0 LINE FACILITIES

Proposed Line Facilities

Hydro One is proposing to increase the transmission capacity of the 115kV circuits K1W, K3W, K11W and K12W between Manby TS and Wiltshire TS in Toronto. K1W/K3W and K11W/K12W are each strung on two 2-circuit 115kV towers from Manby TS to Structure 4. From Structure 4 to Wiltshire TS all circuits are strung on 4-circuit 115kV towers, with the exception at Runnymede TS and St. Clair JCT. Currently all Manby x Wiltshire (KxW) circuits are strung with 605kcmil Aluminum Conductor Steel Reinforced (54/7) and have a continuous ampacity limit of 680A. However, due to future load growth in Western Toronto it is necessary to increase the ampacity of all four circuits. A map indicating the geographic location of the Project that also provides structure numbers along the route is provided as **Exhibit E, Tab 1, Schedule 1, Attachment 1**. A schematic diagram of the proposed facilities is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 2**.

Hydro One is seeking OEB leave to construct approval for the following upgrade work on existing transmission facilities:

- Upgrade approximately 10km of the four transmission circuits K1W, K3W, K11W and K12W between Manby TS and Wiltshire TS with High Temperature Low Sag conductor 1433.6kcmil Aluminum Conductor Steel Supported High Strength-285 (39/19), which will meet the continuous and short term emergency ampacity requirement of 1,800A and 2,400A, respectively
- Replace 11/32" Copperweld shieldwire with 7#7Alumoweld shieldwire from Structure 6 to Runnymede TS to Wiltshire TS
- Replace existing insulators and associated hardware on the K1W, K3W, K11W and K12W circuits

- Structural reinforcement on the towers
- Replace four wood pole structures with four G4L steel pole structures (two poles at two separate locations)
- Install two G4L steel pole structures between one span
- Replace two severely corroded towers with one BPD structure at Wiltshire TS
- Adjust line protections due to change in conductor type.

Details of the Proposed Line Facilities

As documented previously, the total route length of the proposed upgrade to the four 115kV circuits K1W, K3W, K11W and K12W from Manby TS to Wiltshire TS is approximately 10km and passes through the City of Toronto.

The four KxW 115kV circuits are primarily strung on 115kV 4-circuit Kipling-St. Clair Type Towers. This tower type was first used in 1950 and was originally designed for use with 605kcmil ACSR (54/7) with a maximum tension of 26.7kN (6,000lbs). With the proposed 1433.6kcmil ACSS HS-285 (39/19) conductor, which is heavier and larger in diameter than 605kcmil ACSR (54/19), the design tensions are much higher than the original design tensions. Significant structural reinforcement is required to the 115kV 4-circuit Kipling-St. Clair Type Semi-Anchor towers because of the higher tensions whereas only minor reinforcement is required to the 115kV 4-circuit Kipling-St. Clair Type Suspension towers. Reinforcement includes replacing old undersized diagonal with new ones which was deemed necessary based on structural analysis. This reinforcement will not alter the overall look or geometry of the towers.

The proposed transmission project will require the upgrade of the existing circuits K1W, K3W, K11W and K12W with High Temperature Low Sag conductor 1433.6kcmil ACSS HS-285 (39/19). This new conductor will satisfy the continuous and short term emergency ampacity requirements of 1,800A and 2,400A respectively.

Manby TS to Runnymede TS

K1W/K3W and K11W/K12W are strung on separate 2-circuit 115kV towers to Structure 4. From Structure 4 to Runnymede TS all circuits are strung on 115kV 4-circuit Kipling-St. Clair Type towers, however between Structures 11 and 12 two wood pole structures were added approximately 20 years ago to fix a pre-existing clearance issue. The two wood poles will be replaced with two G4L steel towers. With the addition of the proposed conductor, structural reinforcement is required on the 115kV 4-circuit Kipling-St. Clair Semi Anchor towers. Minor reinforcement is required on all other tower types.

Runnymede TS to St. Clair JCT

From Runnymede TS to St. Clair JCT all circuits are strung on 115kV 4-circuit Kipling-St. Clair Type towers, however between Structures 34 and 35 two wood pole structures were added to fix a pre-existing clearance issue approximately 20 years ago. With the addition of the proposed conductor, structural reinforcement is required on the 115kV 4-circuit Kipling-St. Clair Semi Anchor towers. Minor reinforcement is required on all other tower types. The two G4L steel poles will be installed between Structures 28 and 29 for clearance requirements. The two wood poles between Structures 34 and 35 will be replaced with two G4L steel towers.

St. Clair JCT to Wiltshire TS

From St. Clair JCT to Wiltshire TS all circuits are strung on 115kV 4-circuit Kipling-St. Clair Type towers. With the addition of the proposed conductor, structural reinforcement is required on the 115kV 4-cicuit Kipling-St. Clair Semi Anchor towers. Minor reinforcement is required on all other tower types. Two existing steel towers at Wiltshire TS require replacement due to severe corrosion, and will be replaced by one BPD structure.

Illustrations of the transmission towers along this corridor are provided and referenced in this Exhibit are provided as **Attachments 1 and 2** of this Exhibit.

2.0 STATION FACILITIES

Proposed Station Facilities

Runnymede TS is an existing Hydro One transformer station currently consisting of two (2) power transformers, eight (8) distribution feeders, two (2) capacitor banks, two (2) relay buildings. This investment includes expanding the transformer station on the same property – i.e., the expanded station will be built on Hydro One owned property adjacent to the existing station. The station expansion will consist of the following major assets for which Hydro One is seeking leave to construct approval:

- Two (2) 50/66.7/83.3, 110-28 KV MVA Power Transformers
- Fourteen (14) 28kV SF6 Circuit Breakers
- Two (2) 115kV Disconnect Switches
- One (1) modular PCT building
- One (1) 21.6 MVAR Capacitor Bank

Details of the Proposed Station Facilities

There are several Hydro One standard structures being installed inside of Runnymede TS for the expanded station. Please refer to the attached station layout provided as **Attachment 3** of this exhibit for more details on the structures being used. Standard structural drawings can be made available for each structure indicated on the layout.

Further station details, including conductor type, ratings are as follows:

a) HV Switchyard (115 KV)

- 1000 KCMIL CU
- 5” AL Rigid Pipe

b) MV Switchyard (28 KV)

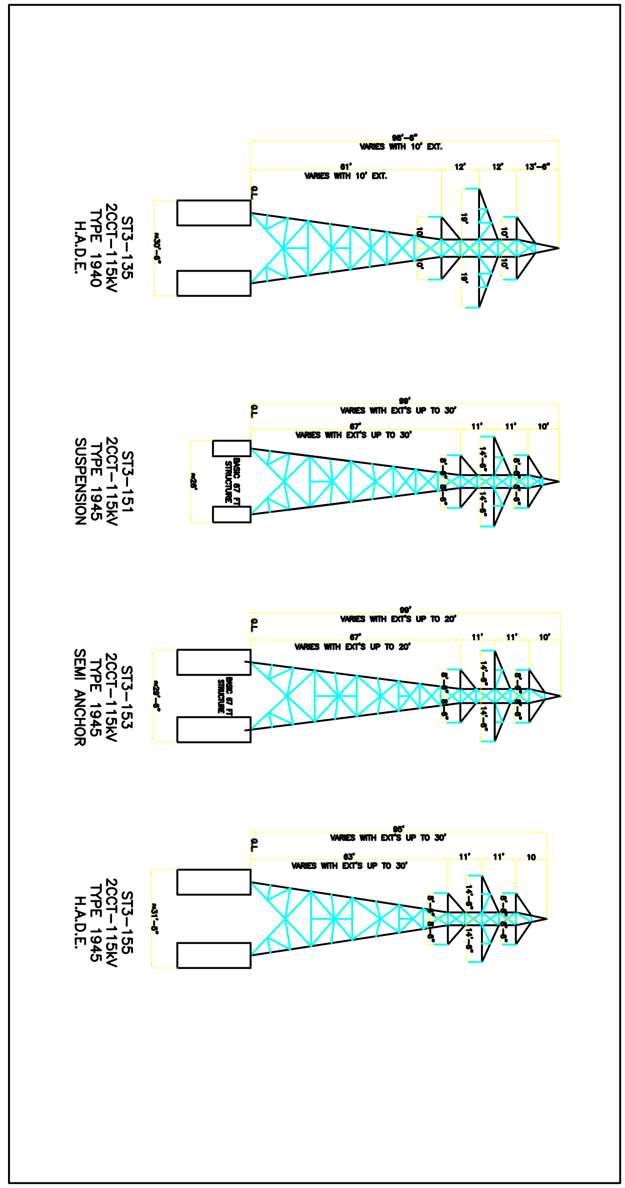
- 3X1000 KCMIL CU (Main Bus Connection)
- 2X500 KCMIL CU (Feeder Breaker Connection)
- 5” AL Rigid Pipe (Main Bus)
- 2.5” AL Rigid Pipe (Feeder Connection)
- Underground Feeder Cables to be provided by Toronto Hydro.

No High Voltage Power cables are being installed in Runnymede TS as part of this Project but Hydro One will be installing the following cables inside the transformer station:

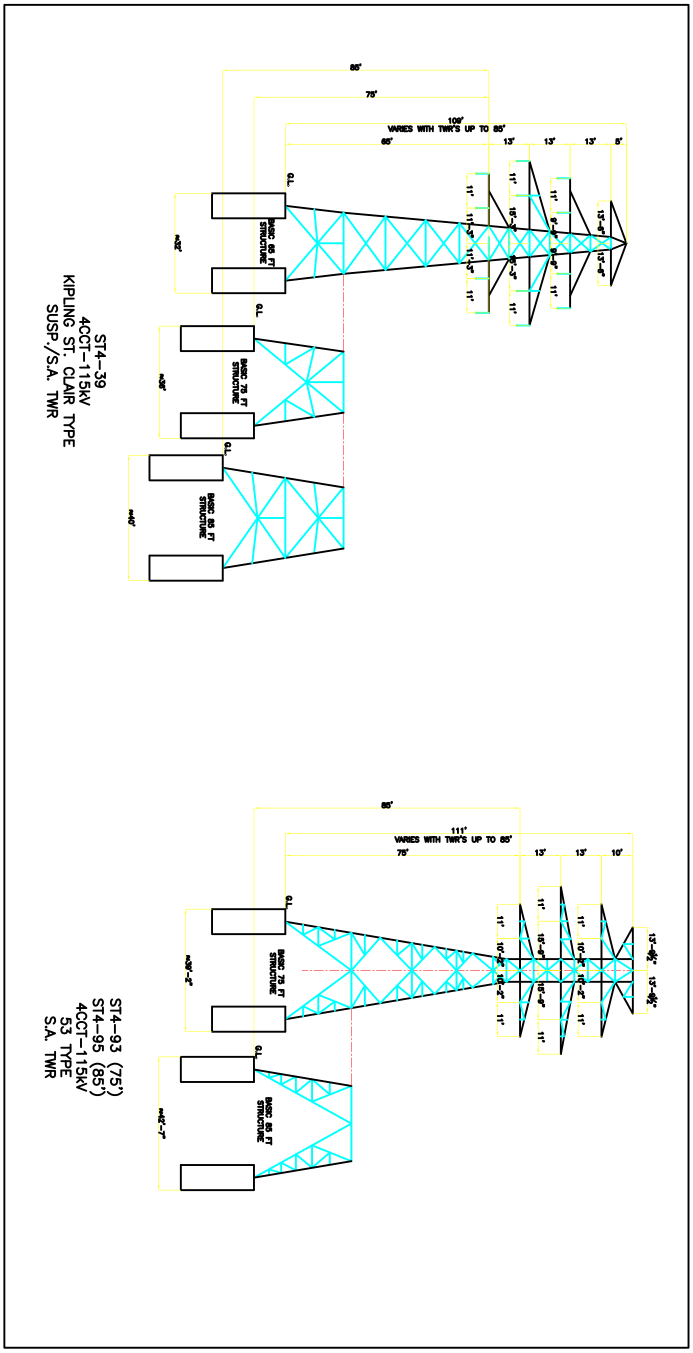
- 27.6kV XLPE Cables from the secondary bushings of the new power transformer to the MV switchyard (2X2000KCMIL/phase).
- 27.6kV Feeder Cables (to be provided by Toronto Hydro)
- 27.6kV XLPE Cables from the MV switchyard to the capacitor bank (1X500KCMIL/phase).
- 120/208V AC Station Service Power Cables (Multiple Sizes)
- 125V DC Power Cables (Multiple Sizes)
- Metallic Control Cables
- Multi-mode Fiber Optic Cables

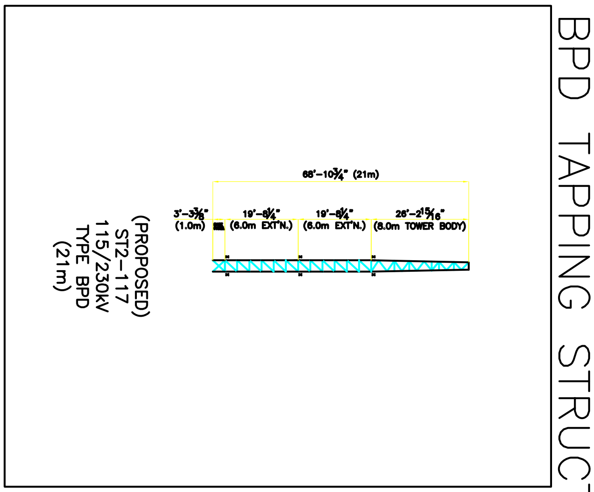
November 17, 2016

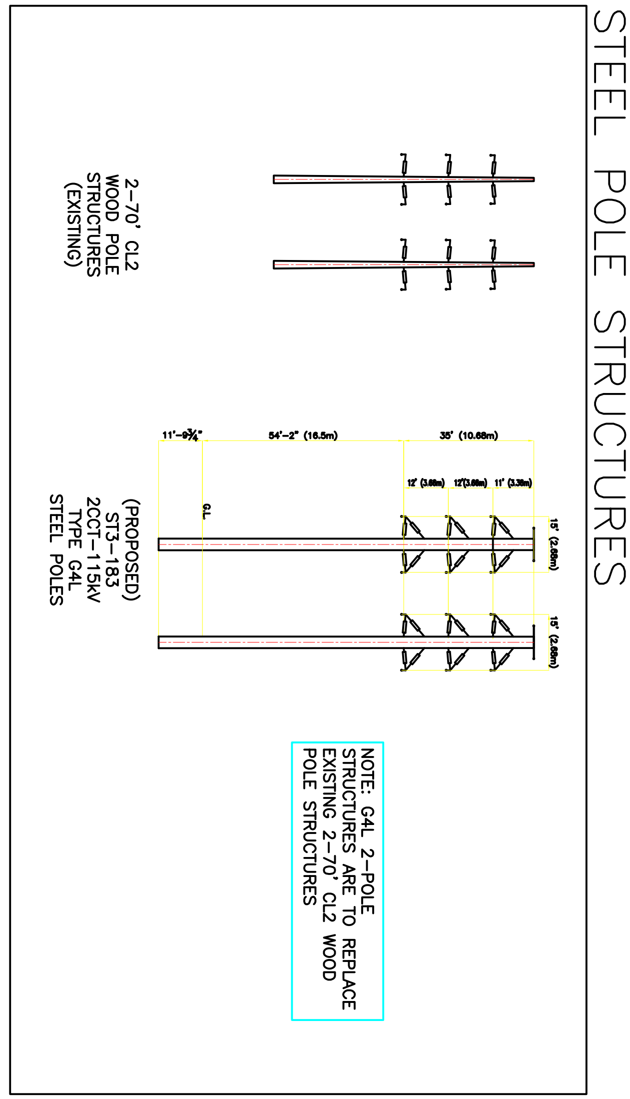
2—CCT STRUCTURES



4—CCT STRUCTURE

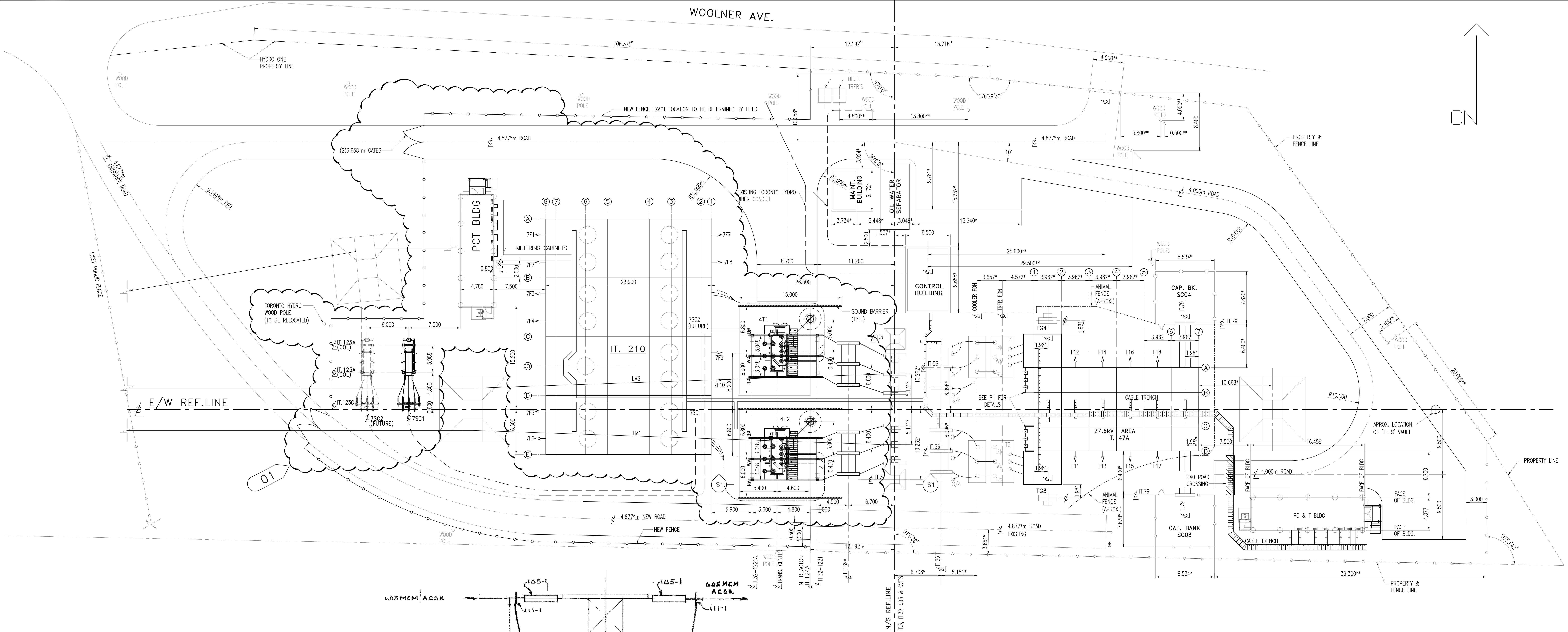


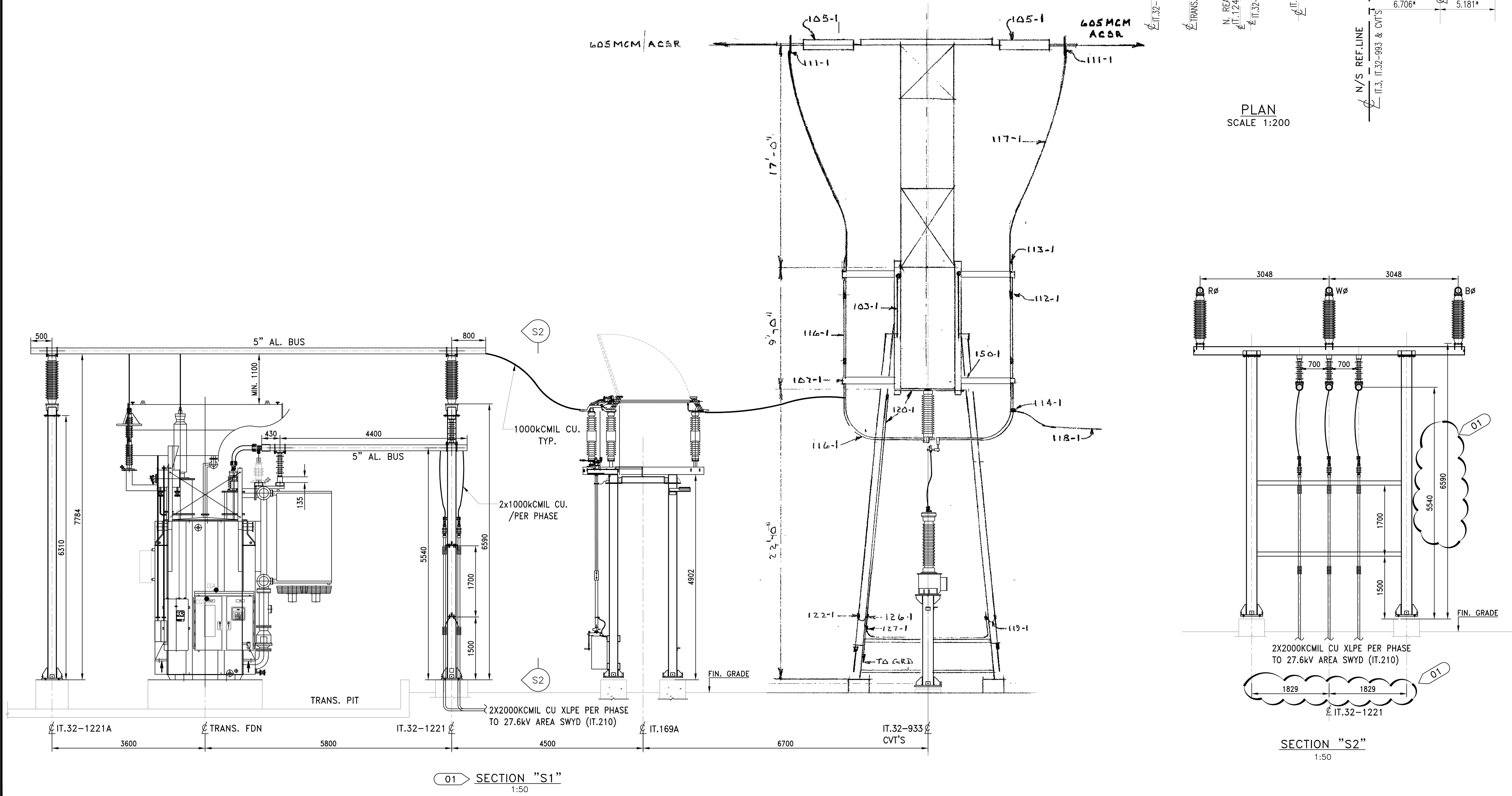

BPD TAPPING STRUCTURE
(PROPOSED)
ST2-117
115/230kV
TYPE BPD
(21m)


STEEL POLE STRUCTURES
2-70' CL2
WOOD POLE
STRUCTURES
(EXISTING)
(PROPOSED)
ST3-183
2CCT-115kV
TYPE G4L
STEEL POLES
NOTE: G4L 2-POLE
STRUCTURES ARE TO REPLACE
EXISTING 2-70' CL2 WOOD
POLE STRUCTURES

Attachment 3

NT11-DOS-50000-0002





NOTES:

1. ALL DIMENSIONS ARE IN METRES.
2. DIMENSIONS ARE NOMINAL AND BEAR NO TOLERANCE UNLESS SPECIFIED.
3. DIMENSIONS IDENTIFIED * ARE SOFT CONVERTED AND ROUNDED TO THE NEAREST MILLIMETER.
4. DIMENSIONS IDENTIFIED ** ARE FIELD MEASURED.

REFERENCE DRAWINGS:

STAGE DEVELOPMENT DIAGRAM STAGE ONE, TWO & ULTIMATE --------------------------DWG. 414325ES

BASIC STEEL RECORD-------------DWG. 414326ES

STEEL BILL OF MATERIAL-----------DWG. 16826ES SHT.1 TO 3

TELECOMMUNICATION CABLE SYSTEM ELECTRICAL ARRANGEMENT----------DWG. NT11-DOS-60290-0001

STEEL LIST FOR STAGE THREE--------NT11-25000-0002

BASIC LAYOUT STAGE THREE DIAGRAM---NT11-50000-0003

FOR REFERENCE ONLY

rev. no.	date	revision particulars	dwn	ckd	des	app
01	SEP 06 2016	NW# 50136682 ADDED CAP. BANK 7SC1 & 7SC2(FUTURE), REVENUE METERING CABINETS REVISED LOCATIONS OF 4T1,4T2 & ASSOC., HV SW, HV BUS SUPP. IT. 32-1221, 1221A; 27.6kV IT.210; PCT BLDG; FENCE LAYOUT & STATION GATES.	JL	TL	EC	XS

Hydro One Networks Inc.
Engineering Services

contract no. | subconsultant

property name: TORONTO RUNNYMEDE TS | property no.: NT11

title: BASIC LAYOUT STAGE RECORD STAGE THREE

appropriation request no. | network no.: 50136682

ref. engineering standard | ref. model/standard dwg. no. | rev. no.

drawn by: J. LIN | checked by: T. LIU | designed by: E. CAI

scale: AS SHOWN | design approved by: X. SHEN | date yyyy/mm/dd: 2016/05/25

drawing no.: NT11-DOS-50000-0002 | sheet no. | rev. no.: 01

CLASS NO. 10

A0 (841 x 1189)

TITLE BLOCK REV 11 - MAY 2014

Maps

A map indicating the geographic location of the Project is provided as **Exhibit B, Tab 2, Schedule 1, Attachment 1**.

This Project proposes to reinforce an existing transmission line and expand an existing transformer station. The current right of way for all existing transmission line facilities along the route will be maintained and the Runnymede TS expansion will be completed on existing Hydro One owned land. Further details on land matters are available at **Exhibit E, Tab 1, Schedule 1**.

Operational Details

The WTTE Project includes the replacement of the existing 115 kV K1W, K3W, K11W and K12W transmission circuits with new conductors of higher thermal capability. No portion of the circuits will be relocated or reconfigured, and as a result, there will be no change to the operation of the circuits. The control stations will remain Manby TS and Wiltshire TS, which are connected by the four transmission circuits and are the terminal stations for the circuits.

Toronto Hydro will be the only customer supplied by the Runnymede TS expansion. The new transformers at Runnymede TS will be revenue metered on the 27.6 kV side, as is the case with the existing transformers which also exclusively supply Toronto Hydro.

Land Matters

As referenced in the Application, the WTTE Project will involve conductor reinforcement on the existing 115 kV overhead transmission corridor between the Manby TS and Wiltshire TS, a distance of approximately 10 kilometers. In addition, Hydro One is proposing to expand the existing Runnymede TS which is located approximately half way between the Manby TS to Wiltshire TS transmission corridor. All facility improvements at Runnymede TS will remain within current Hydro One property boundaries.

The existing corridor from Manby TS to Wiltshire TS is a combination of:

- Provincially owned lands held by the Ministry of Infrastructure, and managed jointly by Infrastructure Ontario and Hydro One ("Bill 58 Lands")[1];
- Hydro One owned lands (Manby TS, RunnymedeTS and Wiltshire TS);
- Municipal road allowances; and
- Railway crossings.

The location of the existing statutory easement rights properties along the Manby to Wiltshire corridor are shown on the maps at Attachment 1. The work on this section of the existing corridor will impact approximately 22 provincially-owned properties and three Hydro One owned properties. The transmission line also crosses three railway corridors, two of which are owned by Canadian Pacific Railway Company and one owned by Metrolinx. The transmission line also crosses 17 road allowances owned by

[1] Bill 58 Lands consist of transmission corridor lands formerly owned by Hydro One in fee simple and transferred, as of December 31, 2002, to the Province of Ontario (the "Province") pursuant to the *Electricity Act, 1998*. The legislation transferred the transmission corridor lands owned in fee simple to the Province, however all fixtures and structures on the transmission corridor lands were not part of the transfer and all fixture and structures on these lands remain Hydro One's. Hydro One has a statutory easement to use Bill 58 Lands to operate its transmission or distribution systems and it also has the primacy of use to use Bill 58 Lands for transmission and distribution purposes.

the City of Toronto, and the Humber River, owned by the Metropolitan Toronto and Region Conservation Authority ("**TRCA**").

The current route of the existing transmission facilities crosses several distribution lines owned and operated by Toronto Hydro. These lines are primarily located on road allowances. From Scarlett Road to Runnymede TS, a Toronto Hydro distribution line is located on the Bill 58 corridor running parallel to the Hydro One transmission line. The proposed transmission facility upgrade is not expected to have any impact on any of the existing Toronto Hydro distribution facilities.

The proposed transmission facility upgrade is not expected to have any impact on the rights of any adjacent properties.

Required Land Easements

The transmission facilities upgrade will not require any new permanent property rights. The width of the existing provincially owned transmission corridor lands varies throughout the route however, ranging from 100 to 280 feet wide. The right-of-way width will not be altered for the proposed work. All easement lands on the corridor are provincially-owned and held under title to the Ministry of Infrastructure. Hydro One enjoys statutory rights on these easements.

Temporary rights for construction purposes will be required at specific locations along the corridor. These rights may be required when crossing or paralleling existing or planned utilities (e.g., pipelines, power lines) or other planned infrastructure (e.g., highways), and when building construction access roads and working pads. Temporary access agreements with landowners will be required.

No early access to land is expected due to the absence of any permanent property right acquisition.

Land Acquisition Process

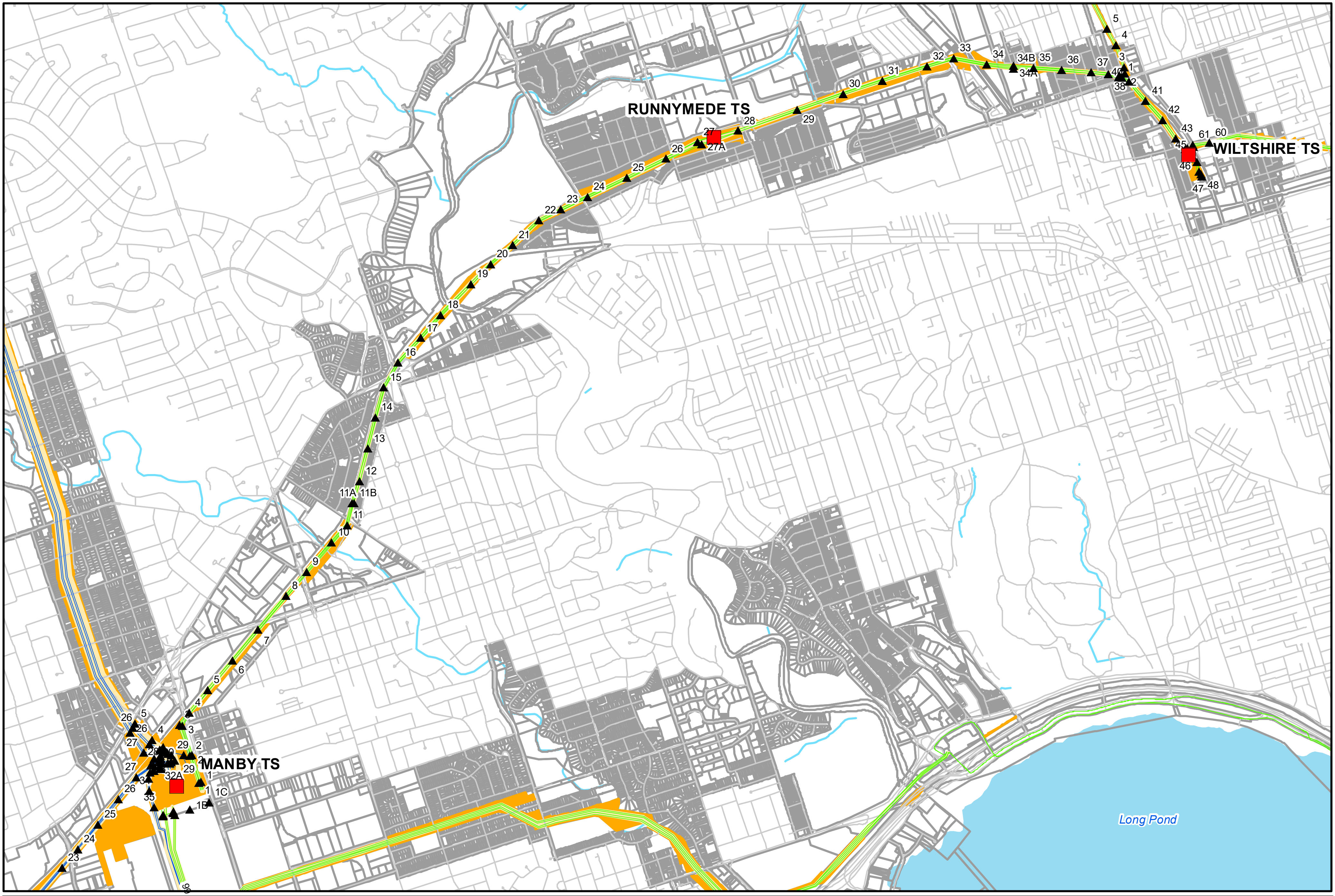
Hydro One will be using its existing land rights along the corridor from Manby TS to Wiltshire TS. The location of the transmission line route and all associated equipment is not expected to be altered from the planned work.

Hydro One enjoys existing land rights on properties owned by the following parties on the Manby TS to Wiltshire TS corridor:

- Her Majesty the Queen in right of Ontario as represented by the Minister of Infrastructure;
- Canadian Pacific Railway Company;
- Metrolinx;
- City of Toronto (Road allowances);and
- Toronto Region Conservation Authority (Humber River).

Temporary working rights will be required but are not expected to be significant. These temporary rights will be used mainly for gaining access to the transmission corridor to carry out the construction of the transmission facilities upgrade. These requirements will be determined and confirmed at the engineering design stage.

Copies of Off-Corridor Temporary Access and Temporary Access Road, Construction License Agreement for construction staging, and a Damage Claim Agreement and Release Form which will be used as the basis for compensation related to construction impacts such as crop or property damage, are included at the end of this schedule as **Attachments 2 through 4**.



hydro one

inergi

Produced By: Inergi LP, GIS Services
Date: November 1, 2016
Map16-64 Manby Wiltshire TS

Transmission Lines

Voltage

115 kV

230 kV

500 kV

Transformer Stations

Towers

Roads

ROW

Hydro One Land Rights

Parcels

Manby TS to Wiltshire TS: Real Estate Rights

0 0.5 1 km

1:32,000

Temporary Access and Temporary Access Road

THIS AGREEMENT made in duplicate the ___________day of _______________20XX

Between:

INSERT NAME OF OWNER

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as, ***INSERT LEGAL DESCRIPTION*** (the "Lands").

WHEREAS HONI in connection with its **[Insert Project Name]** Project (the "Project") desires the right to enter onto the Lands in order to construct temporary access roads on, over and upon the Lands in order to access the construction site associated with the "Project.

WHEREAS the Grantor is agreeable in allowing HONI to enter onto the Lands for the purpose of constructing temporary access roads on, over and upon the Lands, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of ***INSERT CONSIDERATION*** to be paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted in yellow as shown in Schedule "A" attached hereto (the "Access Lands"), the rights privileges, and easements as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Access Lands for the purpose of access to the construction site associated with the Project, subject to payment of compensation for damages to any crops caused thereby;

(b) to construct, use and maintain upon the Access Lands, a temporary road to the construction site associated with the Project, together with such gates, bridges and drainage works as may be necessary for HONI's purposes (collectively, the "Works"), all of which Works shall be removed by HONI upon completion of the construction associated with the Project.; and

(c) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. The term of this Agreement and the permission granted herein shall be XXXX from the date written above (the "Term"). HONI may, in its sole discretion, and upon 60 days notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated between the parties.

3. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Access Lands and/or Lands resulting from HONI's use of the Access Lands and the permission granted herein; and, shall restore the Access Lands to its original condition so far as possible and practicable.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Access Lands shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

5. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Access Lands or of its activities on or in connection with the Access Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

6. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
5th Floor
483 Bay Street South Tower
Toronto, Ontario M5G 2P5

Attention:
Fax:

TO GRANTOR:

7. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

8. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

9. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

SIGNED, SEALED & DELIVERED In the presence of:	**OWNER:**
______________________ Witness	______________________
______________________ Witness	______________________

HYDRO ONE
HST #

HYDRO ONE NETWORKS INC.

By: ______________________

Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

TEMPORARY CONSTRUCTION LICENCE

THIS AGREEMENT made in duplicate the X day of X 20XX

BETWEEN:

HYDRO ONE NETWORKS INC.	(hereinafter called the "HONI") OF THE FIRST PART
and	
XXXXX	(hereinafter called the "Owner") OF THE SECOND PART

WHEREAS:

(a) The Owner is the registered owner of lands legally described as ***INSERT LEGAL DESCRIPTION*** (the "Lands").

(b) HONI will be constructing new electrical transmission facilities in the area highlighted in yellow on a portion of the Lands more particularly shown on Schedule "A" attached hereto (the "Project") and requires a portion of the Lands as a temporary construction area.

(c) The Owner is agreeable in allowing HONI to enter onto the Lands and using a portion of the Lands for the purposes of a temporary construction area, which area is more particularly shown in red on Schedule "A" attached hereto in order to facilitate construction work on HONI's adjacent transmission corridor.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT IN CONSIDERATION of the sum of Five Dollars ($5.00) now paid by each party to the other and the respective covenants and agreements of the parties hereinafter contained (the receipt and sufficiency of which are hereby acknowledged by the parties hereto), the parties hereto agree as follows:

1. The Owner hereby grants to HONI the right to enter upon a portion of the Lands highlighted in red, being XX acres, for the purpose of a temporary construction area (the "Licenced Area").

2. HONI will pay the Owner the amount of ***INSERT CONSIDERATION*** for the rights granted herein (the "Licence Fee").

3. HONI agrees that it shall take all reasonable care in its construction practices. HONI agrees that it shall erect such barriers and take such other appropriate safety precautions (i.e. gating system), as may be reasonably required to effectively prevent death or injuries to persons or the Owner's property during the Term of this Agreement.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Licenced Area shall be at the sole risk of HONI and the Owner shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Owner.

5. HONI agrees that it shall indemnify and save harmless the Owner from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Lands or of its activities on or in connection with the Licenced Area arising out of the permission granted herein except to the extent any of such Costs arise out of the negligence or willful misconduct of the Owner.

6. This Agreement and the permission granted herein shall be for a XXXXX term commencing from XXXXX until XXXXX (the "Term").

7. This Agreement and the permission granted herein may be renewed by HONI on a month to month basis up to an additional one year term, upon the same terms and conditions contained herein, including the Licence Fee, which amount shall be pro-rated to a monthly amount if applicable, save and except any further right to renewal. In the event HONI desires to renew this Licence, it shall provide notice in writing to the Owner of its desire to renew the Licence, at least thirty (30) days prior to the end of the Term, or any renewal thereof.

8. Upon the expiry of this Licence, HONI shall remove all equipment and debris from the Licenced Area and shall restore the Licenced Areas to as close as is practicable to its original condition immediately prior to HONI's occupancy at HONI's sole cost and expense.

9. Any notice to be given to the Owner shall be in writing and shall be delivered by pre-paid registered post or by facsimile, at the address noted below:

   in the case of the Owner, to:

   Attention:
   Fax No.:

   in the case of the HONI, to:

   Attention:
   Fax No.:

   Such notice shall be deemed to have been given, in, writing or delivered, on the date of delivery, and, where given by registered post, on the third business day following the posting thereof, and if sent by facsimile, the date of delivery shall be deemed to be the date of transmission if transmission occurs prior to 4:00 p.m. (Toronto time) on a business day and on the business day next following the date of transmission in any other case. It is understood that in the event of a threatened or actual postal disruption in the postal service in the postal area through which such notice must be sent, notice must be given in writing by delivery or by facsimile, in which case notice shall be deemed to have been given as set out above. “Business day” shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

10. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

11. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

12. Any amendments, modification or supplement to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have executed this Agreement by the hands of their duly authorized signing officers in that regard.

Per: ______________________________

Name:

Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per: ______________________________

Name:

Title:

I have authority to bind the Corporation

SCHEDULE "A"

Damage Claim

THIS MEMORANDUM OF AGREEMENT dated the day of 20XX

Between:

herein called the "Claimant"

-and-

Hydro One Networks Inc.

herein called "HONI"

Witnesseth:

The Claimant agrees to accept ………………………………………………………………($) in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by HONI during the construction, completion, operation or maintenance of the works of HONI constructed on Lot(s) ………………………………….. , Concession(s) ……………………………….. or according to Registered Plan No. ………………… in the …………………………………………………… of ……………………………………………… of which property the Claimant is the ………………………………… and which damages may be approximately summarized and itemized as:

WITNESS

Name:

Address:

CLAIMANT

Name:

Address:

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST#

Per:

Name:
Title:

I have authority to bind the Corporation

RELEASE AND WAIVER

FULL AND FINAL RELEASE

IN CONSIDERATION of the payment or of the promise of payment to the undersigned of the aggregate sum of [INSERT SETTLEMENT AMOUNT] ($), the receipt and sufficiency of which is hereby acknowledged, I/We, the undersigned, on behalf of myself/ourselves, my/our heirs, executors, administrators, successors and assigns (hereinafter the "Releasors"), hereby release and forever discharge HYDRO ONE NETWORKS INC., its officers, directors, employees, servants and agents and its parent, affiliates, subsidiaries, successors and assigns (hereinafter the "Releasees") from any and all actions, causes of action, claims and demands of every kind including damages, costs, interest and loss or injury of every nature and kind, howsoever arising, which the Releasors now have, may have had or may hereafter have arising from or in any way related to [INSERT DESCRIPTION OF THE DAMAGE CAUSED] on lands owned by [INSERT PROPERTY OWNER NAME] and specifically including all damages, loss and injury not now known or anticipated but which may arise or develop in the future, including all of the effects and consequences thereof.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to make any claim or take any proceedings against any other person or corporation who might claim contribution or indemnity under the provisions of the *Negligence Act* and the amendments thereto from the persons or corporations discharged by this release.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to disclose, publish or communicate by any means, directly or indirectly, the terms, conditions and details of this settlement to or with any persons other than immediate family and legal counsel.

AND THE RELEASORS hereby confirm and acknowledge that the Releasors have sought or declined to seek independent legal advice before signing this Release, that the terms of this Release are fully understood, and that the said amounts and benefits are being accepted voluntarily, and not under duress, and in full and final compromise, adjustment and settlement of all claims against the Releasees.

IT IS UNDERSTOOD AND AGREED that the said payment or promise of payment is deemed to be no admission whatsoever of liability on the part of the Releasees.

AND IT IS UNDERSTOOD AND AGREED that this Release may be executed in separate counterparts (and may be transmitted by facsimile) each of which shall be deemed to be an original and that such counterparts shall together constitute one and the same instrument, notwithstanding the date of actual execution.

IN WITNESS WHEREOF, the Releasors have hereunto set their respective hands this .... day of ...., 20XX.

SIGNED, SEALED & DELIVERED In the presence of:	
Witness	Name
SIGNED, SEALED & DELIVERED In the presence of:	
Witness	Name

System Impact Assessment

Please refer to Attachment 1 for the Draft System Impact Assessment prepared by the Independent Electricity System Operator.

November 17, 2016

REPORT

Connecting Today.
Powering Tomorrow.

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Draft Report

CAA ID: **2016-571**

Project: **Add new 2nd DESN at Runnymede TS and uprate 115 kV circuits K1W, K3W, K11W, and K12W**

Applicant: **Hydro One Networks Inc.**

Connections & Registration Department
Independent Electricity System Operator

Document Name	System Impact Assessment Report
Issue	0.1
Reason for Issue	Draft Report
Effective Date	November 9, 2016

System Impact Assessment Report

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and project loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional project studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

List of Figures

List of Tables

Executive Summary

Conditional Approval for Connection

Hydro One Networks Inc. (the “connection applicant”) has proposed to add a new second Dual Element Spot Network (DESN) switchyard at the existing Runnymede Transformer Station (TS), and uprate the existing 115 kV circuits K1W, K3W, K11W and K12W (the “project”). The project is required in anticipation of increased load demand.

This new DESN switchyard will supply existing loads transferred from existing T3/T4 DESN at Runnymede TS and Fairbank TS, and new load from Eglinton Crosstown Light Railway Transit (“LRT”) line project. The overall load at Runnymede TS is expected to increase by about 50%.

Runnymede TS is connected to K11W and K12W between Manby East TS and Wiltshire TS in the Toronto zone of the IESO-controlled grid. The new DESN switchyard will consist of two 115/28 kV, 50/66.6/83.3 MVA load transformers T1 and T2 as shown in Figure 1 in section 1.

K1W, K3W, K11W and K12W will be uprated as per the ratings detailed in section 3.2.1.

The planned in-service date for the project is May 2018.

This assessment concludes that the proposed project is expected to have no material adverse impact on the reliability of the integrated power system. Therefore, the IESO recommends that a Notification of Conditional Approval for Connection be issued for Runnymede TS subject to the implementation of the requirements outlined in this report.

Findings

We have analyzed the impact of the project on the system reliability of the IESO-controlled grid, and based on our study results, we have identified that:

(1) The proposed connection arrangement and equipment for the new DESN switchyard are acceptable to the IESO.

(2) As currently assessed, the project does not fall within the North American Electric Reliability Corporation’s (NERC) definition of the Bulk Electric System (BES) or the Northeast Power Coordinating Council’s (NPCC) definition of the Bulk Power System (BPS). As such, the project does not have to meet NERC or NPCC requirements and is only required to meet obligations and requirements under the IESO’s Market Rules.

(3) There will be a post-contingency thermal overloading issue on the remaining Manby East autotransformer when two Manby East autotransformers are out of service beyond year 2016. To address this thermal overloading issue, Hydro One Networks Inc. is planning to install a Remedial Action Scheme (RAS) named Manby Autotransformer Overload Protection Scheme (CAA ID 2016-EX863) that automatically rejects load following the loss of two Manby East autotransformers.

(4) Except for the thermal overloading issue detailed in Finding #3, the Manby East 115 kV system will meet the IESO load security criteria after the incorporation of the project.

(5) The voltage performance of the Manby East 115 kV system with the incorporation of project is expected to be acceptable under both pre-contingency and post-contingency operating conditions.

(6) Based on the project scope and data provided by the connection applicant, no additional reactive power compensation is required at new DESN switchyard.

(7) Following the loss of the E (or D) 115 kV bus during an outage of the D (or E) 115 kV bus at Manby TS, up to 375 MW of load in the Manby East 115 kV system would be lost. The connection applicant was not able to confirm that the load excess of 150 MW can be restored within 4 hours and all the load can be restored within 8 hours. The new increased load at Runnymede TS, resulting from the incorporation of the project, aggravates load restoration capabilities. It is recommended that this issue be reviewed in the next Integrated Regional Resource Plan (IRRP) for Central Toronto Region.

IESO's Requirements for Connection

Transmitter/Connection Applicant Requirements

Since the connection applicant is also the associated "transmitter" for the project, this section identifies the connection requirements for both.

Project Specific Requirements: The following *specific* requirements are applicable for the incorporation of the project.

(1) The connection applicant must submit to the IESO any protection modification not considered in this System Impact Assessment (SIA) at least six (6) months before any modification is to be implemented on the existing protection systems. The IESO will assess any modification and if it results in adverse impact on the reliability of the integrated power system, the connection applicant will be required to develop mitigation solutions.

(2) The connection applicant must implement the Manby Autotransformer Overload Protection Scheme (CAA ID 2016-EX863) as soon as possible and prior to the in-service date of this project.

(3) The connection applicant is required to ensure that the new the Manby Autotransformer Overload Protection Scheme will reject all or some load at the new DESN switchyard.

General Requirements: The connection applicant shall satisfy all applicable requirements specified in the Market Rules and the Transmission System Code (TSC). Some of the general requirements that are applicable to this project are presented in detail in section 2 of this report.

– End of Section –

1. Project Description

Runnymede TS is a connection applicant owned load facility supplied by two 115 kV transmission circuits K11W and K12W between Manby East TS and Wiltshire TS in the Toronto zone of IESO-controlled grid. The existing station consists of a single Dual Element Spot Network (DESN) with two 115/28 kV, 58/93 MVA transformers T3 and T4.

The connection applicant plans to add a new second DESN switchyard at the current point of connection of Runnymede TS. The new DESN will consist of two 115/28 kV, 50/66.6/83.3 MVA transformers T1 and T2. A new 115 kV motorized disconnect switch will be installed between the HV side of each transformer and each circuit.

This new DESN switchyard will supply existing loads transferred from existing T3/T4 DESN at Runnymede TS and Fairbank TS, and new load from Eglinton Crosstown Light Railway Transit ("LRT") line project. The overall load at Runndymede TS is expected to increase by about 50%.

The layout design of the new DESN switchyard has provisions for the installation of two future capacitors.

To accommodate the anticipated, increased load demand, K1W, K3W, K11W and K12W will also be uprated by replacing the existing conductors with new ones. The re-conductored circuits will be rated as per the ratings detailed in section 3.2.1.

The proposed in-service date of the project is May 2018.

The single line diagram of Runnymede TS with the addition of the new DESN is shown in Figure 1.

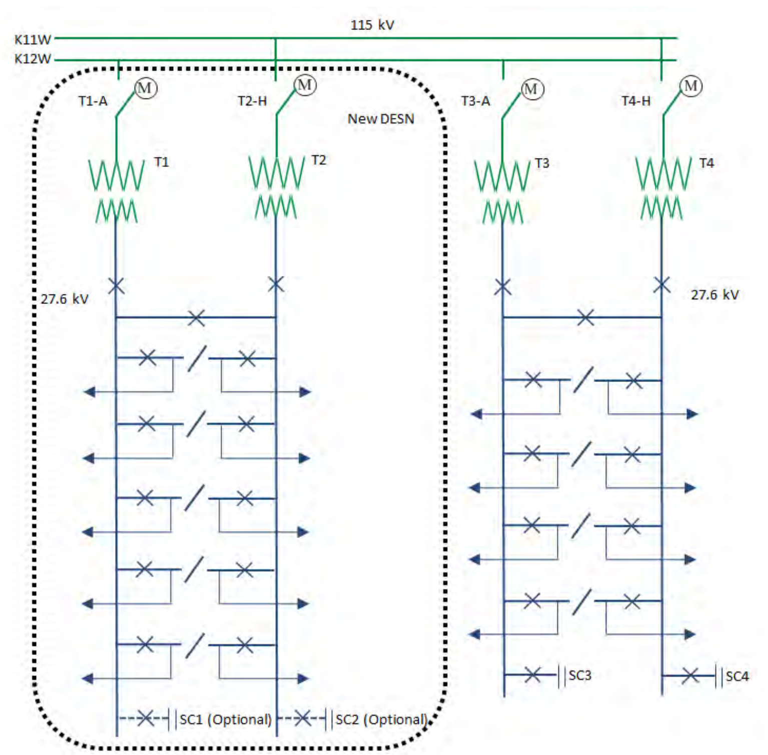


Figure 1: Runnymede TS single line diagram

– End of Section –

2. General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules and the Transmission System Code (TSC). The following sections highlight some of the general requirements that are applicable to the project.

2.1 Project Changes

The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.

2.2 Reliability Standards

As currently assessed, the project does not fall within the North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) or the Northeast Power Coordinating Council's (NPCC) definition of the Bulk Power System (BPS). As such, the project does not have to meet NERC or NPCC requirements and is only required to meet obligations and requirements under the IESO's Market Rules.

The BPS and BES classifications of this project will be re-evaluated by the IESO as the power system evolves. Should a classification change, the connection applicant would need to satisfy all applicable requirements in the appropriate set of reliability standards.

2.3 Power Factor

As per Appendix 4.3 of the Market Rules, the connection applicant must have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project.

2.4 Voltage Levels

The connection applicant must ensure that the project's equipment must meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

2.5 Fault Levels

As per the TSC, the connection applicant shall ensure the project's 115 kV connection equipment is designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to maximum fault level specified in the TSC. Appendix 2 of the TSC establishes the maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground symmetrical fault levels are 50 kA.

2.6 Protection Systems

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

As currently assessed by the IESO, Runnymede TS with the project incorporated will not be on the current Bulk Power System list, is not considered essential to the power system and therefore does not require redundant protection systems in accordance with section 8.2.1a of the TSC. In the future, as the electrical system evolves, this facility may be placed on the BPS list, or designated as essential by either the IESO or by the transmitter. In that case these redundant protections systems would have to satisfy all requirements of the TSC, and in particular, they could not use common components, common battery banks or common secondary CT or PT windings.

The connection applicant is required to have adequate provision in the design of protections and controls at the project to allow for future installation of Special Protection Scheme (SPS) equipment. Should a future SPS be installed or an existing SPS be expanded to improve the transfer capability in the area or to accommodate transmission reinforcement projects, the project may be required to participate in the SPS system and to install the necessary protection and control facilities to affect the required actions. These SPS facilities must comply with the NPCC Reliability Reference Directory #7 for Type 1 SPS. In particular, if the SPS is designed to have ‘A’ and ‘B’ protection at a single location for redundancy, they must be on different non-adjacent vertical mounting assemblies or enclosures. Two independent trip coils are required on the breakers selected for L/R.

The protection systems associated with the project must only trip the appropriate equipment required to isolate the fault. After the incorporation of the project, if an improper trip of the 115 kV circuits K11W and K12W occur due to events within the project, the project may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The project shall have the capability to ride through routine switching events and design criteria contingencies in the grid that do not disconnect the project by configuration. Standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times are to be assumed.

2.7 Voltage Reduction Facilities

As per Appendix 4.3 of the Market Rules, the connection applicant must install and maintain facilities and equipment to provide voltage reduction capability at load facilities directly connected to the IESO-controlled grid with an aggregated rating of 20 MVA or more and with the capability to regulate distribution voltage under load. Voltage reduction capability represents the capability of reducing demand by lowering the customer voltage by 3% and 5% within five minutes of receipt of the direction from the IESO. This is required to achieve load reduction during periods when supply resources are limited. The voltage reduction capability can be achieved by installing under-load tap changers (ULTC) at the project.

2.8 Under Frequency Load Shedding Facilities

The connection applicant has an aggregate peak load at all its owned facilities, including the project, that is greater than 25 MW. Thus, the connection applicant is required to participate in the Under-Frequency Load Shedding (UFLS) program according to section 5.6 of the Market Manual Part 7.4.

As an alternative to installing UFLS facilities and selecting load for under-frequency tripping at the proposed project, the connection applicant has indicated that the UFLS requirements associated with the incorporation of the project will be met by reviewing and, if necessary, modifying its selections at existing UFLS scheme(s).

The IESO recommends that the connection applicant have adequate provision in the design of its project to allow for future installation of UFLS facilities should the UFLS requirements change in the future, requiring the project to participate in the UFLS program.

The connection applicant must select 35% of aggregate peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to section 10.4 of Chapter 5 of the Market Rules.

As the connection applicant has a peak load of 100 MW or greater at all its owned facilities, the UFLS relay connected loads shall be set to achieve the amounts to be shed stated in the following table:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
1	59.5	0.3	7 – 9	7 – 9
2	59.3	0.3	7 – 9	15 – 17
3	59.1	0.3	7 – 9	23 – 25
4	58.9	0.3	7 - 9	32 - 34
Anti-Stall	59.5	10.0	3 – 4	35 - 37

Capacitor banks connected to the same facility bus as the load should be shed by UFLS relay at 59.5 Hz with a time delay of 3 seconds and should be coordinated in conjunction with the relevant transmitter, if applicable.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

2.9 Connection Equipment Design

The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated.

2.10 IESO Telemetry Data

In accordance with Section 7.5 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.17 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.22, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO Market Registration process.

The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market Rules. As part of the IESO Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

2.11 IESO Market Registration Process

The connection applicant must initiate and complete the IESO Market Registration process in a timely manner, at least eight months before energization to the IESO-controlled grid and prior to the commencement of any project related outages, in order to obtain IESO final approval.

The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

If the submitted data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

2.12 Revenue Metering

If revenue metering equipment is being installed as part of the project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

2.13 Restoration Participant

The connection applicant is currently a restoration participant. The connection applicant is required to update its restoration participant attachment to include details regarding its proposed project. For more details please refer to the Market Manual 7.8. Details regarding restoration participant requirements will be finalized at the IESO Market Registration process.

As currently assessed by the IESO, the project is not classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout. Key Facility and Basic Minimum Power System are terms defined in the NPCC Glossary of Terms.

2.14 Load Restoration

The Ontario Resource and Transmission Assessment (ORTAC) states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:

a. All load must be restored within approximately 8 hours.

b. When the amount of load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately 4 hours.

c. When the amount of load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within a target of 30 minutes.

2.15 Project Status

As per Market Manual 2.10, the connection application will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO. The project status report form can be found on the IESO Web site at http://www.ieso.ca/imoweb/pubs/caa/caa_f1399_StatusReport.doc . Failure to comply with project status requirements listed in Market Manual 2.10 will result in the project being withdrawn.

The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Market Manual 2.10. A committed project is a project that has demonstrated to the IESO a high probability of being placed into service.

– End of Section –

3. Data Verification

3.1 Connection Arrangement

The connection arrangement of the project, as shown in Figure 1, will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 Equipment Data

3.2.1 Re-conductored 115 kV circuits K1W, K3W, K11W and K12W

Voltage	115 kV
Length	9.5 km
Conductor size (kcmil)	1433
Conductor type	ACSS
Positive Sequence Impedance	R= 0.0019103 pu, X = 0.02399569 pu, B = 0.00491641 pu
Zero Sequence Impedance	R = 0.018217 pu, X = 0.073838 pu, B = 0.001611 pu
Summer Thermal Ratings (Continuous, LTE*, STE**)	1150 A, 1530 A, 1730A
Winter Thermal Ratings (Continuous, LTE*, STE**)	1410 A, 1710 A, 2500 A

* long-term emergency
** short-term emergency

3.2.2 New 115 kV Disconnect Switches

Identifier	T1-A, T2-H
Maximum continuous rated voltage	127 kV
Continuous current rating	800 A
Rated symmetrical short circuit capability	40 kA

3.2.1 115 kV Step-down Transformer

Identifier	T1, T2
Thermal ratings	50/66.6/83.3 MVA (ONAN/ONAF/OFAF)
Rated voltage	115 kV/28 kV
Under-load tap changer (ULTC)	132 kV (max tap), 108 kV (min tap) in 32 steps on HV winding
Transformer configuration	HV: wye (Solid ground) LV: zigzag (grounded via a 1.5 ohm neutral reactor)
Summer 10 day LTE rating	112 MVA
Impedance	+j12.28% based on 50 MVA

– End of Section –

4. Fault Level Assessment

As the LV windings of the new transformers T1 and T2 will be configured zigzag and there is no major synchronous motor load to be supplied by Runnymede TS, the project will not change the fault levels in its surrounding area for both 3-phase and L-G faults. Thus, short circuits studies will not be conducted.

As there will be no fault interrupting equipment to be installed at the HV side of the project, fault level results are not needed in this report to assess new fault interrupting equipment.

– End of Section –

5. Impact on System Reliability

The technical studies focused on identifying the impact of the increased load at Runnymede TS on the reliability of the IESO-controlled grid. It includes primarily a thermal loading assessment of transmission lines, and a voltage assessment of local buses, and a load restoration assessment of local loads.

5.1 Local Transmission System

Figure 2 provides an overview of the Central Toronto Region, which supplies the central and downtown portions of the City of Toronto. The eastern sector of the Central Toronto Region is supplied by Leaside TS; this area is referred to the Leaside 115 kV system. The western sector of the Central Toronto Region is supplied by two independent West and East 115 kV switchyards at Manby TS. The East 115 kV switchyard at Manby TS supplies loads at Runnymede TS, Fairbank TS and Wiltshire TS via 115 kV circuits K1W, K3W, K11W and K12W; this area is known as the Manby East 115 kV system. The West 115 kV switchyard supplies loads at Strachan TS, John TS and Copeland TS (future); this area is known as Manby West 115 kV system.

Portlands Energy Centre (PEC) CGS, which is a 550 MW natural gas fired combined cycle power plant, can provide generation to the eastern sector.

The Central Toronto Region is summer peaking.

The Manby East 115 kV system does not fall within NPCC's definition of the BPS or NERC's definition of the BES. However, the 230 kV/115 kV autotransformers at Manby East 115 kV switchyard are classified as BPS and BES.

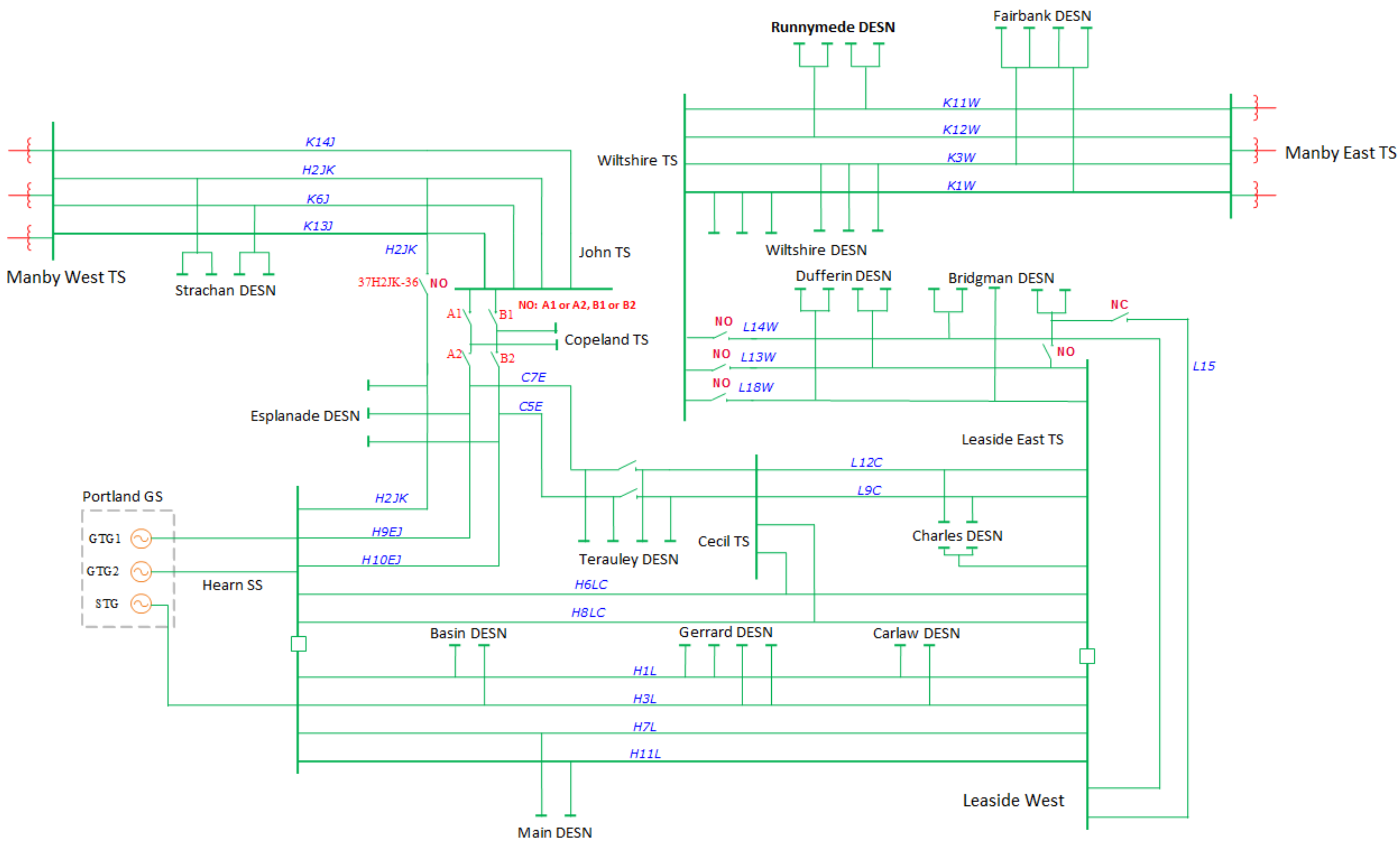


Figure 2: 115 kV Transmission in Central Toronto Region

5.2 Assumptions

In this assessment, a 2018 summer base case was used with the following assumptions:

(1) **Transmission facilities**: All existing and committed major transmission facilities with 2018 in-service dates or earlier were assumed in-service. Specifically, the committed transmission facility includes:

- Manby Autotransformer Overload Protection Scheme (CAA ID 2016-EX863).
- Copeland TS (CAA ID 2012-481)

(2) **Generation facilities:** All existing and committed major generation facilities with 2018 in-service dates or earlier were assumed in-service.

(3) **Protection schemes:** The connection applicant confirmed that the existing line protections and associated settings for the 115 kV circuits K1W, K3W, K11W, and K12W will not change due to re-conductored circuits.

(4) **Load Forecast:** Table 1 shows the coincident extreme weather summer peak load forecast provided by the connection applicant for load facilities in the Central Toronto Region. The load forecast is consistent with the load forecast used in the Metro Toronto Regional Infrastructure Plan (RIP) report, taking into account the load transfers from the existing T3/T4 DESN switchyard at Runnymede TS and Fairbank TS to the new DESN switchyard.

Table 1: Area load forecast

Area	Major load Station	Peak forecast load (MW)									
		2016	2017	2018	2019	2020	2021	2023	2025	2027	2028
Manby West 115 kV	Copeland	0	86	102	102	102	102	106	111	113	113
	John	266	179	179	182	185	188	191	195	199	200.5
	Strachan	133	135	138	139	141	143	145	146	149	150.5
	Total	**399**	**400**	**419**	**423**	**428**	**433**	**442**	**452**	**461**	**464**
Leaside 115 kV	Terauley	191	196	201	205	209	213	217	220	224	227
	Esplanade	170	172	173	176	178	180	185	190	195	197.5
	Cecil	154	156	158	159	161	162	165	167	170	171.5
	Charles	152	155	157	159	160	161	164	166	169	170
	Dufferin	142	144	147	147	148	148	150	152	153	154
	Gerrard	45	46	47	48	49	50	62	77	87	88
	Glengrove	53	55	56	57	57	58	59	60	61	61.5
	Main	59	58	57	58	59	60	60	60	61	62.5
	Bridgman	173	175	177	179	180	181	182	183	185	186
	Carlaw	63	65	67	68	69	70	69	68	68	69.5
	Basin	55	58	61	62	63	63	65	66	68	69
	Duplex	105	107	109	110	111	112	114	116	118	119.5
	Total	**1362**	**1387**	**1410**	**1428**	**1444**	**1458**	**1492**	**1525**	**1559**	**1576**
Manby East 115 kV	Fairbank	156	156	119	118	121	122	124	126	128	129
	Runnymede – existing T3/T4 DESN	95	96	74	75	76	77	78	80	81	82
	Runnymede - new DESN	0	0	78	79	79	80	81	82	83	84
	Wiltshire	57	63	80	75	76	76	77	78	79	80

	Total	**308**	**315**	**351**	**347**	**352**	**355**	**360**	**366**	**371**	**375**

(5) **Load power factor at Runnymede TS:** Based on information provided by the connection applicant, the load power factor at the existing T3/T4 DESN and new DESN switchyards at Runnymede TS was assumed 0.95 at the LV side of the transformers. Existing capacitors SC3 and SC4 were assumed out of service.

(6) **Base case:** The base case was modified to study year 2028. A peak load base case with the following assumptions was used for thermal and voltage assessments:

- The Ontario demand was assumed 25,561 MW. The Toronto zone demand was assumed 11,026 MW based on the extreme weather summer peak load forecast available to the IESO for the year 2028 (as of April 21, 2016);
- Loads in the Central Toronto Region were set to levels as per Table 1 for year 2028;
- A 0.9 lagging power factor was assumed at the high voltage buses of stations in the studied area;
- All units at PEC CGS were in-service;
- Shunt capacitors at Manby TS, John TS , Hearn SS, and Leaside TS were in-service;
- 115 kV buses were operated closed at Hearn SS;
- The project is connected to the Manby East 115 kV system under normal system conditions.

5.3 Power Factor Analysis

Appendix 4.3 of the Market Rules requires connected wholesale customers and distributers connected to the IESO-controlled grid to have the capability to maintain a power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined metering point of the facility.

Table 2 shows that the calculated power factor on the high voltage side of the transformers meets the Market Rules requirement. As such, based on the load power factor data provided by the connection applicant, no additional reactive power compensation is required at the project.

Table 2: Power Factor Analysis at Runnymede TS

LV Side of the Transformers			HV Side of the Transformers		
P Total (MW)	Q Total (MX)	Assumed Power Factor	P Total (MW)	Q Total (MX)	Calculated Power Factor
166	54.56	0.95	166.5	73.7	0.914

5.3 Load Security

A thermal loading assessment and a load tripped by configuration assessment were completed to evaluate load security. The ORTAC specifies the following criteria for load security:

Criterion I: With all the transmission facilities in-service, equipment loading must be within continuous ratings.

Criterion II: With one element out of service, equipment loading must be within applicable long-term ratings and not more than 150 MW of load may be interrupted by configuration.

Criterion III: With two elements out of service, equipment loading must be within applicable short-term emergency ratings. The equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-time ratings. Planned load curtailment or load rejection exceeding 150 MW is permissible only to account for local generation outages. Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment.

Thermal ratings of the monitored circuits and transformers are listed in Table 3 and Table 4, respectively. These circuit ratings were provided by the connection applicant and were calculated for the summer weather conditions with ambient temperature of 35°C and wind speed of 4 km/h. The ratings for K1W, K3W, K11W and K12W incorporate the re-conductored circuits. The continuous ratings for the conductors were calculated at the lower of the sag temperature or 93°C operating temperature. The LTE ratings for the conductors were calculated at the lower of the sag temperature or 127°C operating temperature. The STE ratings were calculated at the sag temperature with 100% continuous pre-load.

Table 3: Circuit section summer thermal ratings

Circuit	Section		Continuous	LTE Rating	STE Rating
	From	To	Amps	Amps	Amps
K1W	Manby East TS	St. Clair Ave JCT	1150	1530	1730
K1W	St. Clair Ave JCT	Wiltshire TS	1150	1530	1730
K3W	Manby East TS	St. Clair Ave JCT	1150	1530	1730
K3W	St. Clair Ave JCT	Wiltshire TS	1150	1530	1730
K11W	Manby East TS	Runnymede TS	1150	1530	1730
K11W	Runnymede TS	Wiltshire TS	1150	1530	1730
K12W	Manby East TS	Runnymede TS	1150	1530	1730
K12W	Runnymede TS	Wiltshire TS	1150	1530	1730
L13W	Leaside TS	Balfour JCT	985	1690	2249
L13W	Balfour JCT	Bridgman JCT	800	1950	3900
L13W	Bridgman JCT	Dufferin JCT	680	890	1120
L13W	Dufferin JCT	Wiltshire TS	680	890	970
L14W	Leaside TS	Bayview JCT	1130	1500	1810
L14W	Bayview JCT	Birch JCT	1200	1320	1500
L14W	Birch JCT	Bridgman JCT	910	1190	1370
L14W	Bridgman JCT	Wiltshire TS	680	890	1120
L15	Leaside TS	Bayview JCT	810	1070	1390
L15	Bayview JCT	Balfour JCT	670	1360	2990
L15	Balfour JCT	Bridgman JCT	800	1950	3900
L18W	Leaside TS	Leaside TS	1350	2700	5400
L18W	Leaside TS	BayviewJCT	1130	1500	1810
L18W	Bayview JCT	Birch JCT	1200	1375	1500
L18W	Birch JCT	Bridgman JCT	910	1190	1370
L18W	Bridgman JCT	Barlette JCT	750	980	1260
L18W	Bartlett JCT	Wiltshire TS	750	980	1260

Table 4: Transformer thermal ratings

Transformer	Continuous	LTE 10 DAY	STE 15 MIN
	MVA	MVA	MVA
Manby East T7	250	282.6	386.3
Manby East T8	250	348.6	430.8
Manby East T9	250	307.8	386.3
Leaside West T11	250	350.3	465.8
Leaside West T12	250	372.2	465

Transformer	Continuous	LTE 10 DAY	STE 15 MIN
	MVA	MVA	MVA
Leaside West T14	250	308.9	465.8
Leaside East T15	250	372	464.6
Leaside East T16	250	308.9	465.8
Leaside East T17	250	371.7	464.4

Table 5 summarizes a list of study scenarios considered for the thermal assessment. Each scenario is defined by the studied system, the initial condition and the contingency simulated.

Table 5: List of study scenarios for thermal assessment

Studied System	Initial Condition	Contingency
Normal System Conditions - Manby East 115 kV system	All In-Service	K1W
		K11W
		Manby East T8
	K1W outage	K11W
	Manby East T8 outage	Manby East T7 (results in loss Manby T5 and Manby SC22) or T9

Under equipment outages or system contingencies within the eastern sector of Central Toronto Region, some load at Dufferin TS and Bridgman TS can be transferred to the Manby East 115 kV system. This scenario was not studied in this SIA as the new load transfer capability is expected to be higher after K1W, K3W, K11W and K12W are re-conductored even with the consideration of the new load at Runnymede TS.

Except for the thermal issue following the loss of two Manby East autotransformers as described in section 5.3.1, the Manby East 115 kV system will meet load security criteria with the project incorporated.

5.3.1 Thermal Loading Assessment

All elements in-service

Table 6 and Table 7 show the thermal analysis results for the monitored circuits and autotransformers, respectively, after the incorporation of the project. With all elements in-service, the flows on all monitored line sections and autotransformers are within their continuous ratings. The post-contingency flows on all monitored elements are within their LTE ratings.

Table 6: Circuit thermal loading for all elements in-service

Circuit	From Bus	To Bus	Cont. (A)	LTE (A)	All I/S		Loss of K1W		Loss of K11W	
					Loading (A)	%Cont.	Loading (A)	%LTE	Loading (A)	%LTE
K1W	Manby East TS	St. Clair Ave JCT	1150	1530	427	37.1	0	0	574.6	37.6
K1W	St. Clair Ave JCT	Wiltshire TS	1150	1530	83.8	7.3	0	0	227	14.8
K3W	Manby East TS	St. Clair Ave JCT	1150	1530	427.9	37.2	624.2	40.8	577	37.7
K3W	St. Clair Ave JCT	Wiltshire TS	1150	1530	84.3	7.3	132.1	8.6	229.3	15
K11W	Manby East TS	Runnymede TS	1150	1530	559	48.6	718.4	47	0	0
K11W	Runnymede TS	Wiltshire TS	1150	1530	128.3	11.2	285.6	18.7	0	0
K12W	Manby East TS	Runnymede TS	1150	1530	559.6	48.7	719	47	899.8	58.8

Circuit	From Bus	To Bus	Cont. (A)	LTE (A)	All I/S		Loss of K1W		Loss of K11W	
					Loading (A)	%Cont.	Loading (A)	%LTE	Loading (A)	%LTE
K12W	Runnymede TS	Wiltshire TS	1150	1530	127.2	11.1	284.5	18.6	38.5	2.5

Table 7: Transformer thermal loading for all elements in-service

Transformer	Cont. (MVA)	LTE (MVA)	All I/S		Loss of Manby East T8	
			Loading (MVA)	%Cont.	Loading (MVA)	%LTE
Manby East T7	250	282.6	141.1	56.5	218	77.1
Manby East T8	250	348.6	146.7	58.7	0	0
Manby East T9	250	307.8	141.6	56.7	218.7	71.1

One element out of service pre-contingency

With K1W out of service, Table 8 show that both the pre-contingency and post-contingency flows on all monitored line sections and autotransformers are within their LTE ratings after the incorporation of the project.

Table 8: Circuit thermal loading for K1W outage

Circuit	From Bus	To Bus	LTE (A)	STE (A)	K1W o/s		Loss of K11W		
					Loading (A)	%LTE	Loading (A)	%LTE	%STE
K1W	Manby East TS	St. Clair Ave JCT	1530	1730	0	0	0	0	0
K1W	St. Clair Ave JCT	Wiltshire TS	1530	1730	0	0	0	0	0
K3W	Manby East TS	St. Clair Ave JCT	1530	1730	622.1	40.7	933.3	61	53.9
K3W	St. Clair Ave JCT	Wiltshire TS	1530	1730	129	8.4	173.6	11.3	10
K11W	Manby East TS	Runnymede TS	1530	1730	716.5	46.8	0	0	0
K11W	Runnymede TS	Wiltshire TS	1530	1730	284	18.6	0	0	0
K12W	Manby East TS	Runnymede TS	1530	1730	717.1	46.9	1224.7	80	70.8
K12W	Runnymede TS	Wiltshire TS	1530	1730	283	18.5	281.3	18.4	16.3

Table 9 shows the thermal loading of the monitored autotransformers for Manby East T8 outage after the incorporate of the project. Following the loss of Manby East T7 or Manby East T9, the loading on the remaining autotransformer, i.e. Manby East T9 or Manby East T7, exceeds their STE ratings. This thermal overloading issue is to be addressed by Manby Autotransformer Overload Protection Scheme Project (CAA ID 2016-EX863).

Table 9: Transformer thermal loading for Manby East T8 outage for year 2028

Transformer	LTE (MVA)	STE (MVA)	Manby East T8 o/s		Loss of Manby East T7			Loss of Manby East T9		
			Loading (MVA)	%LTE	Loading (MVA)	%LTE	%STE	Loading (MVA)	%LTE	%STE
Manby East T7	282.6	386.3	217.8	77.1	0	0	0	464.4	164.3	120.2
Manby East T8	348.6	430.8	0	0	0	0	0	0	0	0
Manby East T9	307.8	386.3	218.6	71	467.9	152	121.1	0	0	0

5.3.2 Load Tripped by Configuration Assessment

As per criterion II and III for load security, the maximum load interrupted by configuration should not exceed 150 MW and 600 MW for the loss of one element and two elements respectively.

To assess these criteria after the incorporation of the project, the total amount of load tripped by configuration for the loss of one or two element involving the project was examined.

For single contingencies, the loss of either K11W or K12W would result in no load interruption.

With the loss of both K11W and K12W (for example, K11W outage followed by K12W contingency), a maximum of 166 MW of load would be interrupted based on the load forecast for 2028. With an outage of the 115 kV D bus and the loss of the 115 kV E bus at Manby TS, a maximum of 375 MW of load would be interrupted based on the load forecast for 2028. Under these two worst-case scenarios of loss of two elements, the interrupted load would not exceed 600 MW.

5.4 Voltage Assessment

For the voltage assessment, the ORTAC states that the following criteria shall be satisfied:

- The pre-contingency voltage on 115 kV buses must not be less than 113 kV, and on 230 kV buses must not be less than 220 kV;
- The post-contingency voltage on 115 kV buses must not be less than 108 kV, and on 230 kV buses must not be less than 207 kV;
- The voltage change following a contingency must not exceed 10% pre-ULTC and 10% post-ULTC on both 115 kV and 230 kV buses.

Table 10 summarizes a list of study scenarios considered for the voltage assessment. Each scenario is defined by the system connection, the outage condition and the contingency simulated.

Table 10: List of studied scenarios for voltage assessment

Studied System	Initial Condition	Contingency
Normal System Conditions - Manby East 115 kV system	All In-Service	K1W
		K11W
		Manby East T7 (results in loss Manby T5 and Manby SC22)
	K1W outage	K3W
		K11W
	Manby East T8 outage	Manby East T7 (results in loss Manby T5 and Manby SC22)

All elements in-service

The pre-contingency and post-contingency voltage results for all elements in-service pre-contingency are shown in Table 11. Simulation results show that the voltage levels are within the criteria under both pre- and post-contingency conditions, and post-contingency voltage changes are within acceptable ranges with the connection of the project.

Table 11: Voltage assessment results for all elements in-service

Bus Name	Pre-Cont.	Loss of K1W				Loss of K11W				Loss of Manby East T7			
		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
	kV	kV	%	kV	%	kV	%	kV	%	kV	%	kV	%
Manby East 115 kV	122.5	121.8	-0.6	121.7	-0.6	121.8	-0.6	121.8	-0.6	118	-3.7	118.2	-3.5
Runnymede 115 kV K11W	121.5	120.4	-0.9	120.3	-1	-	-	-	-	116.9	-3.8	117.2	-3.6
Runnymede 115 kV K12W	121.5	120.4	-0.9	120.3	-1	120	-1.3	120	-1.2	116.9	-3.8	117.2	-3.6

Fairbank 115 kV K1W	120.5	-	-	-	-	119.3	-1	119.3	-1	115.9	-3.8	116.1	-3.6
Fairbank 115 kV K3W	120.5	118	-2.1	117.8	-2.2	119.3	-1	119.3	-1	115.9	-3.8	116.1	-3.6
Wiltshire 115 kV	121.3	120	-1.1	119.9	-1.2	120	-1	120.1	-1	116.7	-3.8	117	-3.6

One element out of service pre-contingency

Table 12 and Table 13 show the pre- and post-contingency voltage results with one element out of service pre-contingency. Simulation results show that voltage levels are within the criteria under both pre- and post-contingency conditions, and post-contingency voltage changes are within acceptable ranges with the connection of the project.

Table 12: Voltage assessment results for K1W outage

Bus Name	K1W o/s								
	Pre-Cont.	Loss of K3W				Loss of K11W			
		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
	kV	kV	%	kV	%	kV	%	kV	%
Manby East 115 kV	121.8	125.8	3.2	125.8	3.3	120.9	-0.7	121	-0.7
Runnymede 115 kV K11W	120.4	125.0	3.9	125.0	3.9	-	-	-	-
Runnymede 115 kV K12W	120.4	125.0	3.9	125.0	3.9	118.3	-1.8	118.3	-1.7
Fairbank 115 kV K1W	120.5	-	-	-	-	-	-	-	-
Fairbank 115 kV K3W	117.9	-	-	-	-	115.9	-1.7	115.9	-1.7
Wiltshire 115 kV	120	125.0	4.2	125.0	4.2	117.9	-1.8	117.9	-1.7

Table 13: Voltage assessment results for Manby East T8 outage

Bus Name	Manby East T8 o/s				
	Pre-Cont.	Loss of Manby East T7			
		Pre-ULTC		Post-ULTC	
	kV	kV	%	kV	%
Manby East 115 kV	120.6	111.1	-7.9	111.4	-7.6
Runnymede 115 kV K11W	119.6	109.9	-8.1	110.3	-7.8
Runnymede 115 kV K12W	119.6	109.9	-8.1	110.3	-7.8
Fairbank 115 kV K1W	118.6	108.8	-8.2	109.2	-7.9
Fairbank 115 kV K3W	118.6	108.8	-8.2	109.2	-8.0
Wiltshire 115 kV	119.4	109.7	-8.1	110.1	-7.8

5.5 Load Restoration Assessment

The ORTAC states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:

a) All load must be restored within approximately 8 hours.
b) When the amount of load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately 4 hours.
c) When the amount of load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within a target of 30 minutes.

As previously detailed in section 5.3.2, all loads at Runnymede TS, Fairbank TS and Wiltshire TS (375 MW for year 2028) are lost following the loss of the E (or D) 115 kV bus during an outage of the D (or E) 115 kV bus at Manby TS. To restore the amount of load in excess of 250 MW within a target of 30 minutes, 125 MW at these stations would need to be transferred to the Leaside 115 kV system. Thermal loading and voltage assessments were performed for the Leaside 115 kV system to determine if it could accommodate the required load transfer for load restoration.

To accommodate the load transfer, equipment loading in the Leaside 115 kV system must be within applicable LTEs pre-contingency with the load transfer of 125 MW. Following the loss of one element in the Leaside 115 kV system, equipment loading must be within applicable STEs.

Table 14 show the simulation results with 125 MW load transfer from the Manby East 115 kV system to the Leaside 115 kV system. The loading of all monitored line sections is within their LTE ratings pre-contingency. The worst-case single contingency, loss of 115 kV circuit L18W, was simulated. Following the loss of L18W, the post-contingency loading is within their STE ratings on all monitored circuits.

Table 14: Circuit thermal loading in the Leaside 115 kV system with 125 MW of load transfer

Circuit	From Bus	To Bus	LTE (A)	STE (A)	Pre-Contingency		Loss of L18W		
					Loading (A)	%LTE	Loading (A)	%LTE	%STE
K1W	Manby East TS	St. Clair Ave JCT	1530	1730	0	0	0	0	0
K1W	St. Clair Ave JCT	Wiltshire TS	1530	1730	1.2	0.1	1.2	0.1	0.1
K3W	Manby East TS	St. Clair Ave JCT	1530	1730	0	0	0	0	0
K3W	St. Clair Ave JCT	Wiltshire TS	1530	1730	1.2	0.1	1.2	0.1	0.1
K11W	Manby East TS	Runnymede TS	1530	1730	0	0	0	0	0
K11W	Runnymede TS	Wiltshire TS	1530	1730	325.1	21.3	329.9	21.6	19.1
K12W	Manby East TS	Runnymede TS	1530	1730	0	0	0	0	0
K12W	Runnymede TS	Wiltshire TS	1530	1730	326.3	21.3	331.1	21.6	19.1
L13W	Leaside TS	Balfour JCT	1690	2249	600.6	35.5	979.8	58	43.6
L13W	Balfour JCT	Bridgman JCT	1950	3900	634.4	32.5	1023.1	52.5	26.2
L13W	Bridgman JCT	Dufferin JCT	890	1120	634.4	71.3	1023.1	115	91.3
L13W	Dufferin JCT	Wiltshire TS	890	970	222.1	25	135.8	15.3	14
L14W	Leaside TS	Bayview JCT	1500	1810	813.1	54.2	1016.8	67.8	56.2
L14W	Bayview JCT	Birch JCT	1320	1500	813.3	61.6	1017	77	67.8
L14W	Birch JCT	Bridgman JCT	1190	1370	828.3	69.6	1033.9	86.9	75.5
L14W	Bridgman JCT	Wiltshire TS	890	1120	431.7	48.5	525.4	59	46.9
L15	Leaside TS	Bayview JCT	1070	1390	432.3	40.4	546.7	51.1	39.3
L15	Bayview JCT	Balfour JCT	1360	2990	441	32.4	553.5	40.7	18.5
L15	Balfour JCT	Bridgman JCT	1950	3900	452.9	23.2	568.8	29.2	14.6
L18W	Leaside TS	Leaside TS	2700	5400	582.4	21.6	0	0	0
L18W	Leaside TS	BayviewJCT	1500	1810	583.1	38.9	0	0	0
L18W	Bayview JCT	Birch JCT	1375	1500	583.2	42.4	0	0	0
L18W	Birch JCT	Bridgman JCT	1190	1370	591.8	49.7	0	0	0
L18W	Bridgman JCT	Barlette JCT	980	1260	406.1	41.4	0	0	0
L18W	Bartlett JCT	Wiltshire TS	980	1260	19.9	2	0	0	0

Table 15 shows the pre-contingency pre- and post-contingency voltage results with the 125 MW load transfer from Manby East 115 kV system to the Leaside 115 kV system. Simulation results show that voltage levels are within the criteria under both pre- and post-contingency conditions, and post-contingency voltage changes are within acceptable ranges with the load transfer.

Table 15: Voltage assessment results in the Leaside 115 kV system with 125 MW of load transfer

Bus Name	Pre-Cont.	Loss of L18W			
		Pre-ULTC		Post-ULTC	
	kV	kV	%	kV	%
Runnymede 115 kV K11W	120.1	118.6	-1.3	118.5	-1.3
Runnymede 115 kV K12W	120.1	118.6	-1.3	118.5	-1.3
Fairbank 115 kV K1W	120.4	118.9	-1.2	118.8	-1.3
Fairbank 115 kV K3W	120.4	118.9	-1.2	118.8	-1.3
Wiltshire 115 kV	120.4	118.9	-1.2	118.8	-1.3
Dufferin 115 kV L13W	120.4	118.7	-1.4	118.6	-1.5
Dufferin 115 kV L18W	120.3	-	-	-	-
Bridgman 115 kV L14W	121.1	119.9	-1.0	119.9	-1.0
Bridgman 115 kV L15	122	121.1	-0.7	121.1	-0.7
Bridgman 115 kV L18W	121	-	-	-	-
Leaside 115 kV EJ Bus	122.5	121.8	-0.6	121.8	-0.6
Leaside 115 kV KP Bus	122	121.7	-0.3	121.6	-0.3

With a load transfer to the 115 kV Leaside system, it is expected that 125 MW (the load excess of 250 MW) can be restored with 30 minutes, meeting the load restoration criterion (c). However, the connection applicant was not able to confirm that the load excess of 150 MW can be restored within 4 hours and all the load can be restored within 8 hours. The new increased load at Runnymede TS, resulting from the incorporation of the project, aggravates load restoration capabilities. It is recommended that this issue be reviewed in the next Integrated Regional Resource Plan (IRRP) for Central Toronto Region.

– End of Document –

Customer Impact Assessment

Please refer to Attachment 1 for the Draft Customer Impact Assessment prepared by Hydro One.

483 Bay Street
Toronto, Ontario
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CUSTOMER IMPACT ASSESSMENT

RUNNYMEDE TS – STATION EXPANSION AND 115 KV CIRCUIT UPGRADES

Plan/Project # : **AR 23616**

Revision: **DRAFT**

Date: **November 14, 2016**

Issued by: **Network Connection and Development**
Hydro One Networks Inc.

Prepared by:

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DISCLAIMER

This Customer Impact Assessment was prepared based on preliminary information available about the proposed *Runnymede TS: Station Expansion and 115 kV circuit upgrades,* consisting of construction of 2 x 50/66.6/83.3 MVA (115-28kV) transformers (T1 and T2) and an upgrade to 9.5km of circuits K11W, K12W, K1W and K3W from Manby TS to Wiltshire TS. This report is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have, including those needed for the review of the connection and for any possible application for Leave to Construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. The fault levels computed as part of this Customer Impact Assessment are meant to assess current conditions in the study horizon and are not intended to be for the purposes of sizing equipment or making other project design decisions. Many other factors beyond the existing fault levels go into project design decisions.

Hydro One Networks Inc. shall not be liable, whether in contract, tort or any other theory of liability, to any person who uses the results of the Customer Impact Assessment under any circumstances whatsoever for any damages arising out of such use unless such liability is created under some other contractual obligation between Hydro One Networks Inc. and such person.

EXECUTIVE SUMMARY

Hydro One is planning to increase reinforcement of the supply to Manby East 115kV area to address the load forecast in the area as a result of the future Metrolinx Eglinton Light Railway Transit system, and future load growth in the western Toronto area, as identified in the Metro Regional Infrastructure Plan dated January 2016. This plan is intended to ensure compliance with IESO's Ontario Resource and Transmission Assessment Criteria. This Customer Impact Assessment (CIA) is concerned with the potential impact of this plan on the area customers.

The plan consists of:

- Construction of a second DESN station at Runnymede TS with 2x 50/66.6/83.3MVA (115-28kV) transformers
- Upgrading 9.5km of 115kV overhead transmission lines for circuits K11W, K12W, K1W and K3W.

An assessment of the reliability of the transmission facilities in the area has been carried out and documented in an IESO System Impact Assessment (SIA) Draft Report of the proposed transmission reinforcement, "Add new 2nd DESN at Runnymede TS and uprate 115kV circuits K1W, K3W, K11W and K12W", CAA ID 2016-571, November 9, 2016. The SIA concluded that the proposed project is expected to have no material adverse impact on the reliability of the integrated power system.

The following potential impacts on existing customers in the area are reviewed is this CIA:

- Short circuit impact to customers
- Voltage impact to customers
- Reliability impact

The findings of this CIA are as follows:

1. The proposed plan has no significant impact on Short-Circuit Levels in the area since there is no source of generation contribution as a result of this project. Hence additional short-circuit contribution due to this project is minor and insignificant.

2. The proposed plan has no adverse voltage impact in the vicinity of proposed project.

3. The proposed plan has no adverse impact on supply reliability in the vicinity of the proposed project.

4. Thermal loading analysis was completed in the SIA and no issues were identified.

CUSTOMER IMPACT ASSESSMENT
RUNNYMEDE TS: STATION EXPANSION AND 115 KV CIRCUIT UPGRADES

1.0 INTRODUCTION

1.1 Background

Runnymede TS, located in Toronto consists of a single DESN with two 58/93 MVA, 115kV-28kV transformers. Runnymede Transformer Station was placed in service in 1962 and has been operating at, or near its capacity limit of 105 MW for the last five years. Runnymede TS exclusively supplies Toronto Hydro Electric System Limited (the "Customer"). The load forecast for the area includes future Metrolinx Eglinton Light Railway Transit system (i.e. the "Eglinton Crosstown Light Rail Transit (EC-LRT)) and future load growth in the western Toronto area, as identified in the Metro Regional Infrastructure Plan dated January 2016. As such, the customer requires the installation of a second DESN at Runnymede TS – the new DESN would consist of two 50/83 MVA transformers in order to add capacity for the customer to be able to supply additional load.

This Customer Impact Assessment (**CIA**) examines the impact of the recommended plan which consists of:

- **Runnymede DESN Station Expansion**
  An expansion to the original station at Runnymede, adding a second DESN with 2 x 50/66.6/83.3MVA (115-28kV) transformers (T1 and T2) supplied by the 115kV K12W and K11W Manby x Wiltshire circuits. The new DESN will include ten 28 kV feeder breakers to supply the Customer's feeders, and some loads will be transferred to the new DESN from existing Runnymede DESN (BY bus) and from Fairbank TS. A 21.6 MVAR capacitor bank will also be installed at the station.

- **Upgrade of 115kV supply circuits**
  Based on the configuration of the K1W, K3W, K11W and K12W circuits between Manby TS and Wiltshire TS, all four circuits supply Runnymede TS (and Fairbank TS). Installing the new DESN at Runnymede TS will require upgrading 9.5km from Manby TS to Wiltshire TS on all four of these circuits.

A schematic diagram of the existing and proposed facilities is shown in Appendix A. A system overview in the vicinity of Runnymede TS is shown in Appendix B.

As part of the Connection Assessment and Approval (**CAA**) process, the IESO has carried out System Impact Assessment (**SIA**) of the proposed transmission reinforcement and has documented the findings in the draft SIA report CAA ID 2016-571, "Add new 2nd DESN at Runnymede TS and uprate 115kV circuits K1W, K3W, K11W, and K12W", dated November 9, 2016. Immediate and subsequent to receiving IESO's SIA, Hydro One has carried out this CIA to assess the impact that the proposed transmission connection and upgrade may have on facilities owned by load and generation customers (if any) in the vicinity of the Runnymede TS. This is in accordance with the requirements of the Ontario Energy Board Transmission System Code.

1.2 Customer List

Table 1 lists all transmission customers in the Manby East 115kV area.

Table 1: Transmission Customers in Area

No.	*Station*	*Supply Circuits*	*Connected Customer*
1	Runnymede TS	115kV K11W, K12W	Toronto Hydro-Electrical System Limited (THESL)
2	Fairbank TS	115kV K1W, K3W	Toronto Hydro-Electrical System Limited (THESL)
3	Wiltshire TS	115kV K1W, K3W, K11W, K12W	Toronto Hydro-Electrical System Limited (THESL)

2.0 CUSTOMER IMPACT ASSESSMENT SCOPE

The purpose of this CIA is to assess the potential impacts of the proposed new transmission facilities on the existing connected load in the Manby East 115kV area. This is in accordance with the requirements of the Ontario Energy Board Transmission System Code.

A review of the following potential impacts on existing customers is conducted in this CIA:
- Short circuit impact to customers
- Voltage impact to customers
- Supply reliability impact to customers

An assessment of the thermal loading of conductors and transformers in the area was conducted in the SIA for this project. No thermal loading issues due to this project were identified.

Some of the main assumptions used to perform the analysis are stated below:

- The 2016 summer peak base case is used to perform this study
- The simulated loads at Runnymede TS, Fairbank TS and Wiltshire TS were taken from the 2028 peak load forecast in the Metro Toronto Regional Infrastructure Plan (RIP) report dated January 2016.
- The model for this project included 2 new transformers, 1 new capacitor bank, circuit upgrades and new load distribution.

3.0 SHORT-CIRCUIT STUDY ANALYSIS

The proposed transmission reinforcement has no significant impact on Short-Circuit Levels in the area and continues to meet the fault level requirements set in the Transmission System Code.

Short circuit levels in the area are provided in Appendix C.

4.0 VOLTAGE PERFORMANCE ANALYSIS

The post contingency voltages at the customer delivery points for Runnymede, Fairbank and Wiltshire TS were simulated before transformer under load tap-changer (Before ULTC) operation and after transformer under load tap-changer (After ULTC) operation.

The following contingencies were simulated:

Studied System	Initial Condition	Contingency
Normal System Conditions - Manby East 115 kV system	All In-Service	K1W
		K11W
		Manby East T8
	K1W outage	K11W

The voltages and percentage changes can be found in Appendix D and fall within the acceptable limits as specified in section 4 of Ontario Resource and Transmission Assessment Criteria (ORTAC).

5.0 SUPPLY RELIABILITY IMPACT

Given the existing load in the supply area (Runnymede TS and Fairbank TS) is close to the station load capacities, the addition of a second DESN at Runnymede TS will alleviate concerns of thermal overloading at the existing transformers. With the upgrade of the K1W, K3W, K11W and K12W circuits, these circuits will continue to provide backup supply to Dufferin TS and/or Bridgman TS loads under Leaside area outage conditions. The supply reliability from Manby TS to Fairbank, Runnymede and Wiltshire TS will not be affected by this project.

6.0 CONCLUSIONS AND RECOMMENDATIONS

This CIA report describes the impact of the proposed new DESN at Runnymede TS and K11W, K12W, K1W and K3W circuit upgrades on the customers in the Manby East 115kV area.

The proposed transmission project has no material adverse impact on short-circuit levels, voltage performance and supply reliability to existing customers in the area. The thermal limits as reported in the SIA document shows that the thermal limits in the area remains within the Planning Criteria for all the scenarios studied.

Appendix A

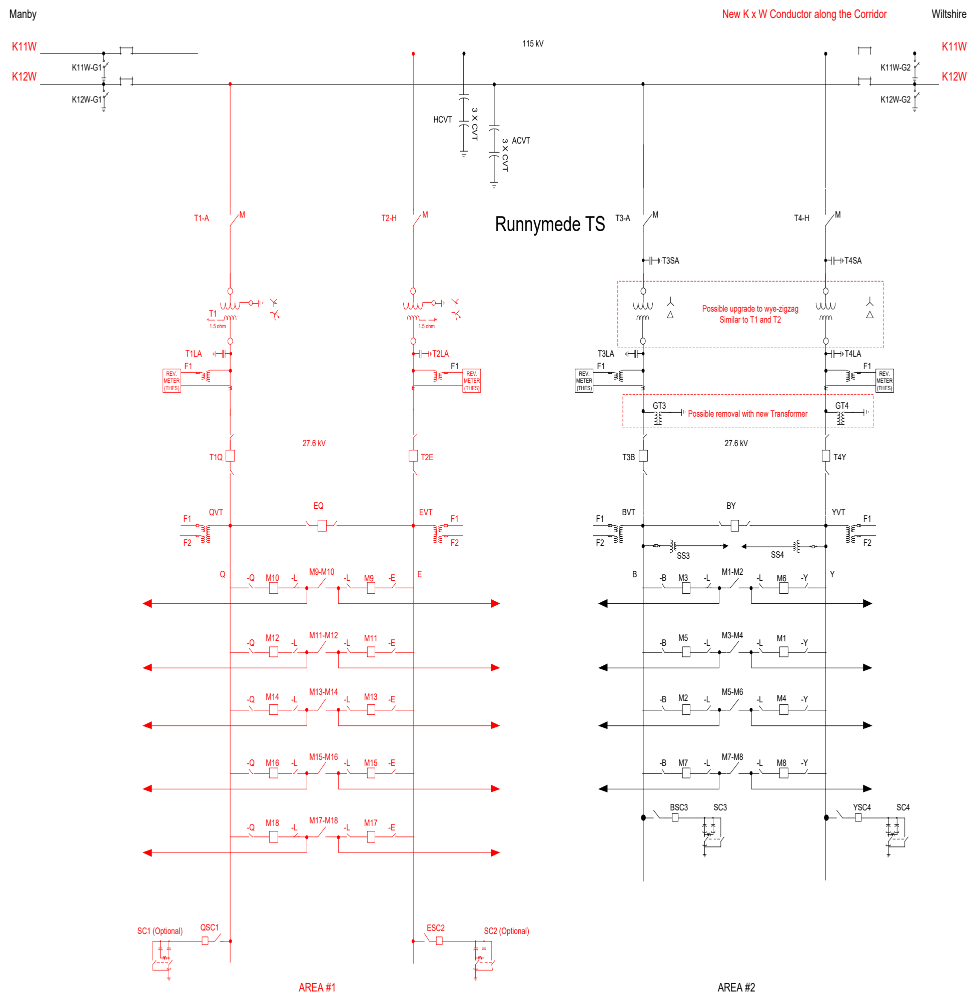

Figure 1: Runnymede TS Configuration with Proposed Area #1 and Existing Area #2

Appendix B

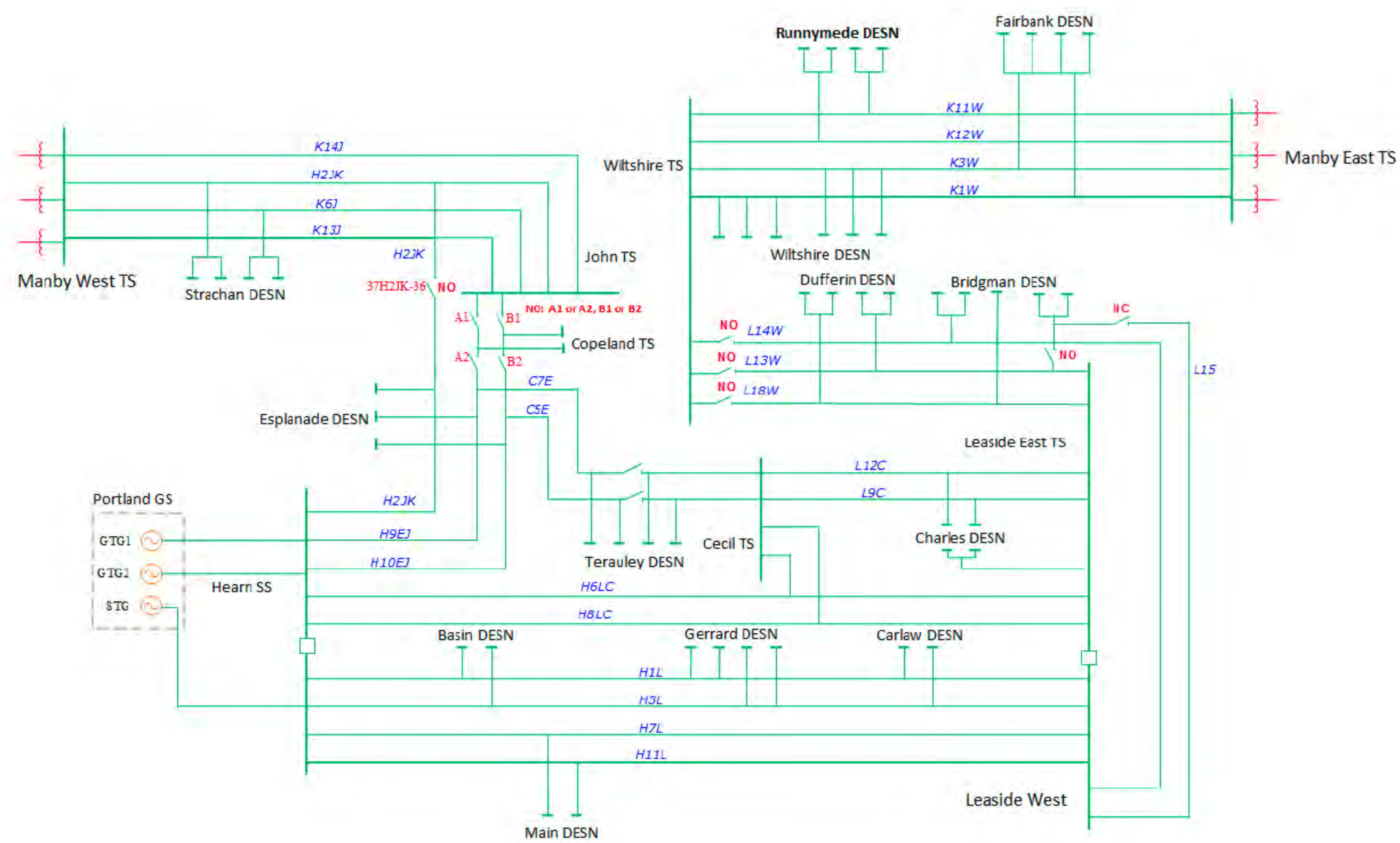

Figure 2: 115kV Transmission System Overview around Runnymede TS

Appendix C

C.1 Short Circuit levels in the Manby Area before and after project

		Three Phase Fault (kA)				Line to Ground (kA)			
		Before project		After Project		Before project		After Project	
Bus Name	Max kV	Symm	Asymm	Symm	Asymm	Symm	Asymm	Symm	Asymm
RUNYMK11	127	17.66	18.992	19.411	23.427	14.658	15.454	16.306	18.351
RUNYMK12	127	17.658	18.992	19.409	23.428	14.634	15.443	16.267	18.342
RUNNYMED	29	13.623	14.037	13.775	14.709	10.689	11.344	10.752	11.577
RUNNYMEQ	29	N/A	N/A	14.682	16.417	N/A	N/A	10.899	13.315
FBANKK1W	127	12.392	13.065	13.098	14.194	8.273	8.599	8.653	9.123
FBANKK3W	127	12.425	13.098	13.126	14.222	8.283	8.611	8.66	9.133
FBANK YZ	29	13.873	13.889	14.057	14.448	10.508	11.386	10.578	11.71
FBANK BQ	29	13.878	13.912	14.063	14.481	10.858	11.774	10.933	12.124
MANBYEQZ	29	11.708	12.213	11.708	12.213	9.691	11.25	9.691	11.25
MANBY E	250	45.463	51.913	45.463	51.913	41.812	48.577	41.888	48.697
MANBY E	127	27.41	35.408	27.41	35.408	32.425	42.77	32.527	42.939
WILTSH13	127	19.223	20.832	20.749	25.171	13.9	15.059	14.83	17.357
WILTSA56	14.2	15.375	15.743	15.495	16.204	9.488	10.775	9.518	10.981
WILTSA34	14.2	15.753	16.667	15.892	17.485	9.625	11.552	9.66	11.846
WILT1112	14.2	15.829	16.724	15.97	17.536	9.64	11.562	9.675	11.855

Appendix D

D.1 Loss of K1W

Bus	Base (kV)	Loss of K1W Before ULTC (kV)	Change (%)	After ULTC (kV)	Change (%)
Runnymede 27.6kV (EQ)	27.6	27.5	-0.4%	27.5	-0.4%
Runnymede 27.6kV (BY)	28.1	28	-0.4%	28	-0.4%
Fairbank 27.6kV (ZY)	28.4	29.3	3.2%	28.7	1.1%
Fairbank 27.6kV (BQ)	28.9	29.8	3.1%	28.8	-0.3%
Manby East 115kV (DE)	125.2	124.9	-0.2%	124.8	-0.3%
Wiltshire 13.8kV (A5/A6)	14.1	14.1	0.0%	14	-0.7%
Wiltshire 13.8kV (A3/A4)	13.7	13.7	0.0%	13.7	0.0%
Wiltshire 13.8kV (A11/A12)	13.7	13.7	0.0%	13.7	0.0%

D.2 Loss of K11W

Bus	Base (kV)	Loss of K11W Before ULTC (kV)	Change (%)	After ULTC (kV)	Change (%)
Runnymede 27.6kV (EQ)	27.6	26.2	-5.1%	27.3	-1.1%
Runnymede 27.6kV (BY)	28.1	26.6	-5.3%	28.1	0.0%
Fairbank 27.6kV (ZY)	28.4	28.2	-0.7%	28.7	1.1%
Fairbank 27.6kV (BQ)	28.9	28.7	-0.7%	28.7	-0.7%
Manby East 115kV (DE)	125.2	124.5	-0.6%	124.6	-0.5%
Wiltshire 13.8kV (A5/A6)	14.1	14	-0.7%	13.9	-1.4%
Wiltshire 13.8kV (A3/A4)	13.7	13.6	-0.7%	13.7	0.0%
Wiltshire 13.8kV (A11/A12)	13.7	13.6	-0.7%	13.7	0.0%

D.3 Loss of Manby East TS T8

		Loss of Manby East T8			
Bus	Base (kV)	Before ULTC (kV)	Change (%)	After ULTC (kV)	Change (%)
Runnymede 27.6kV (EQ)	27.6	27.6	0.0%	27.6	0.0%
Runnymede 27.6kV (BY)	28.1	28	-0.4%	28	-0.4%
Fairbank 27.6kV (ZY)	28.4	28.4	0.0%	28.4	0.0%
Fairbank 27.6kV (BQ)	28.9	28.8	-0.3%	28.8	-0.3%
Manby East 115kV (DE)	125.2	125	-0.2%	125	-0.2%
Wiltshire 13.8kV (A5/A6)	14.1	14.1	0.0%	14.1	0.0%
Wiltshire 13.8kV (A3/A4)	13.7	13.7	0.0%	13.7	0.0%
Wiltshire 13.8kV (A11/A12)	13.7	13.7	0.0%	13.7	0.0%

D.4 Initial condition with K1W outage followed by the loss of K11W

		K1W outage plus loss of K11W			
Bus	Base with K1W out (kV)	Before ULTC (kV)	Change (%)	After ULTC (kV)	Change (%)
Runnymede 27.6kV (EQ)	27.5	26.5	-3.6%	27.5	0.0%
Runnymede 27.6kV (BY)	28	26	-7.1%	27.3	-2.5%
Fairbank 27.6kV (ZY)	28.7	28.5	-0.7%	28.6	-0.3%
Fairbank 27.6kV (BQ)	28.8	28.6	-0.7%	28.7	-0.3%
Manby East 115kV (DE)	124.8	124.2	-0.5%	124.4	-0.3%
Wiltshire 13.8kV (A5/A6)	14	13.9	-0.7%	14	0.0%
Wiltshire 13.8kV (A3/A4)	13.7	13.6	-0.7%	13.6	-0.7%
Wiltshire 13.8kV (A11/A12)	13.7	13.6	-0.7%	13.6	-0.7%