# 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

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

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.

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.

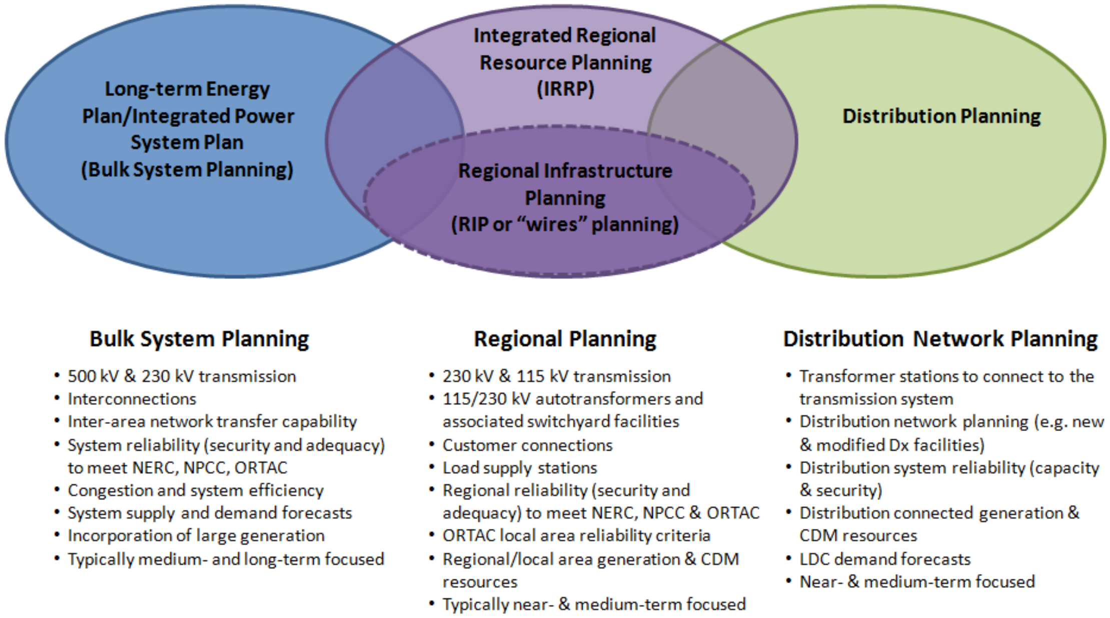
The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are electricity needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment process to determine whether a comprehensive 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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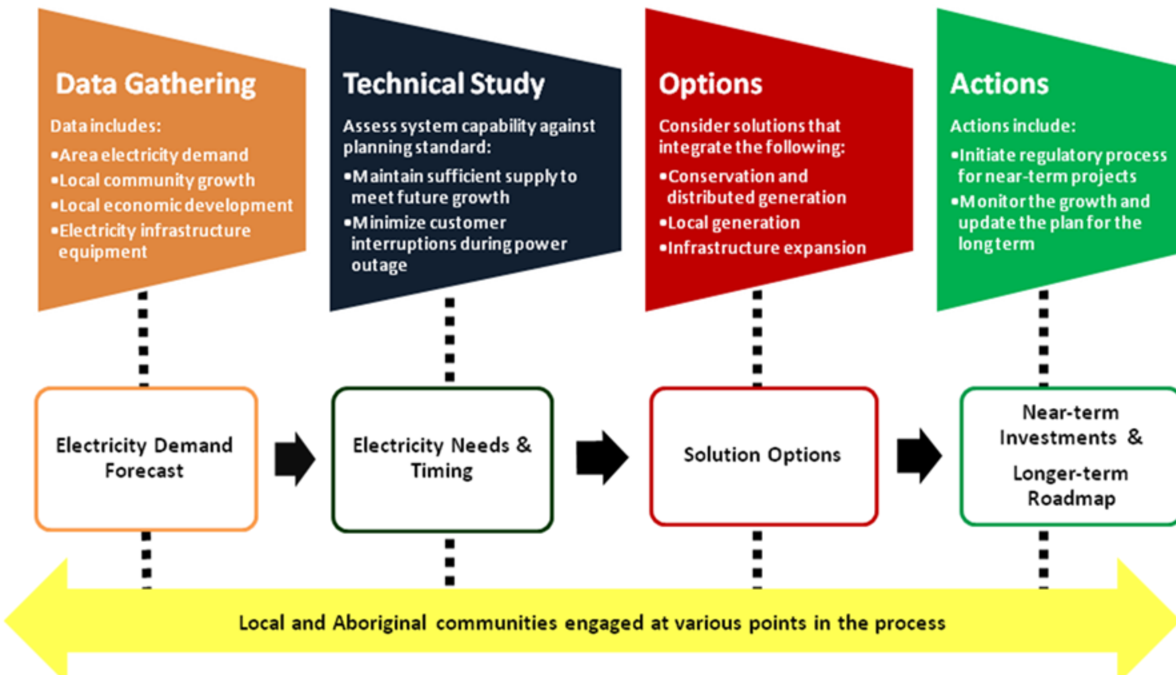
[2] In some cases, such as in this IRRP, the planning assessment was based on a 25-year forecast to account for longer-term growth potential and/or municipal plans. As planning for Central Toronto was initiated in 2011, the forecast period extends to 2036.

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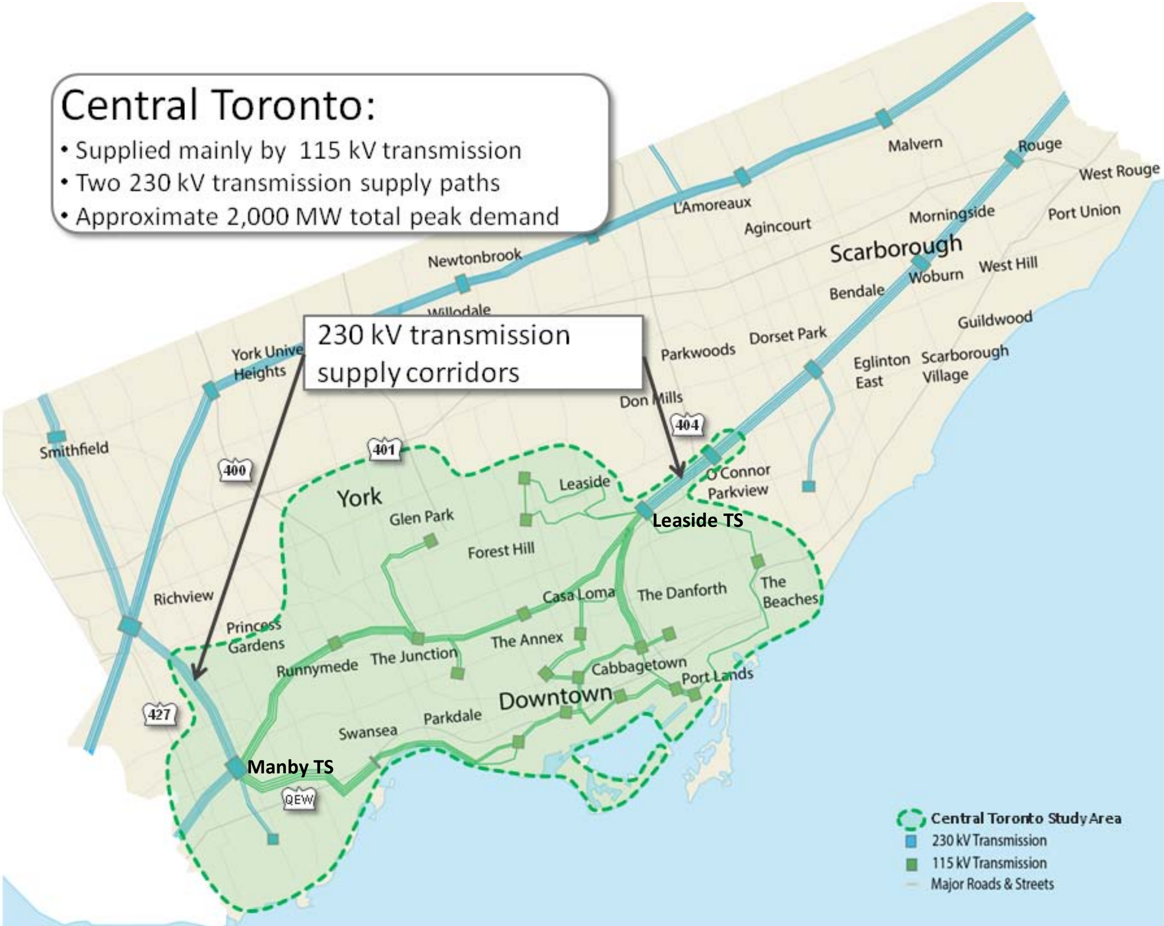
[4] The central area includes the downtown central business area.

[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**

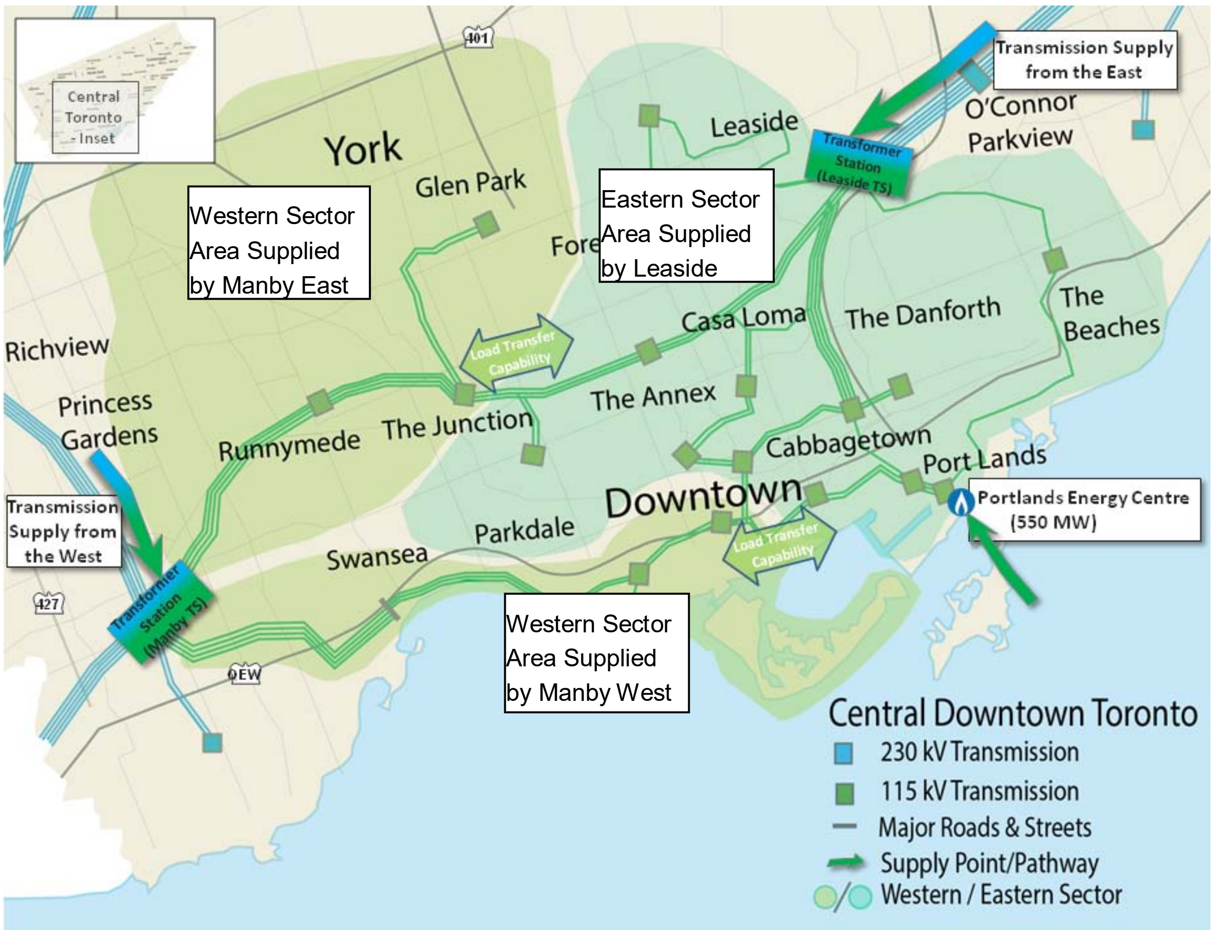



**1.** The study area boundaries, as shown, are the approximate service areas of the transmission and distribution facilities within the scope of the Central Toronto IRRP.
**2.** The study area also includes the service areas of Manby TS, Leaside TS and Horner TS, which are supplied by 230 kV transmission.

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.<br><br>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<br>• Pay for Performance is a financial model in which savings from energy efficiency upgrades receive additional monetary compensation (beyond reduced operating costs)<br>• If energy consumption increases penalties may be applied<br>• Contracts may be offered in targeted areas | • To be evaluated |
| Municipal financial support through Local Improvement Charges (City of Toronto) | • Pilot initiated in 2014<br>• 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<br>• Pilot will include 200 homes and 200 apartment units<br>• 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<br>• Involves the installation of load control devices and programmable communicating thermostats in MURB units and common areas<br>• 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)<br>• 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<br>• 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<br>• 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)<br>• 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.

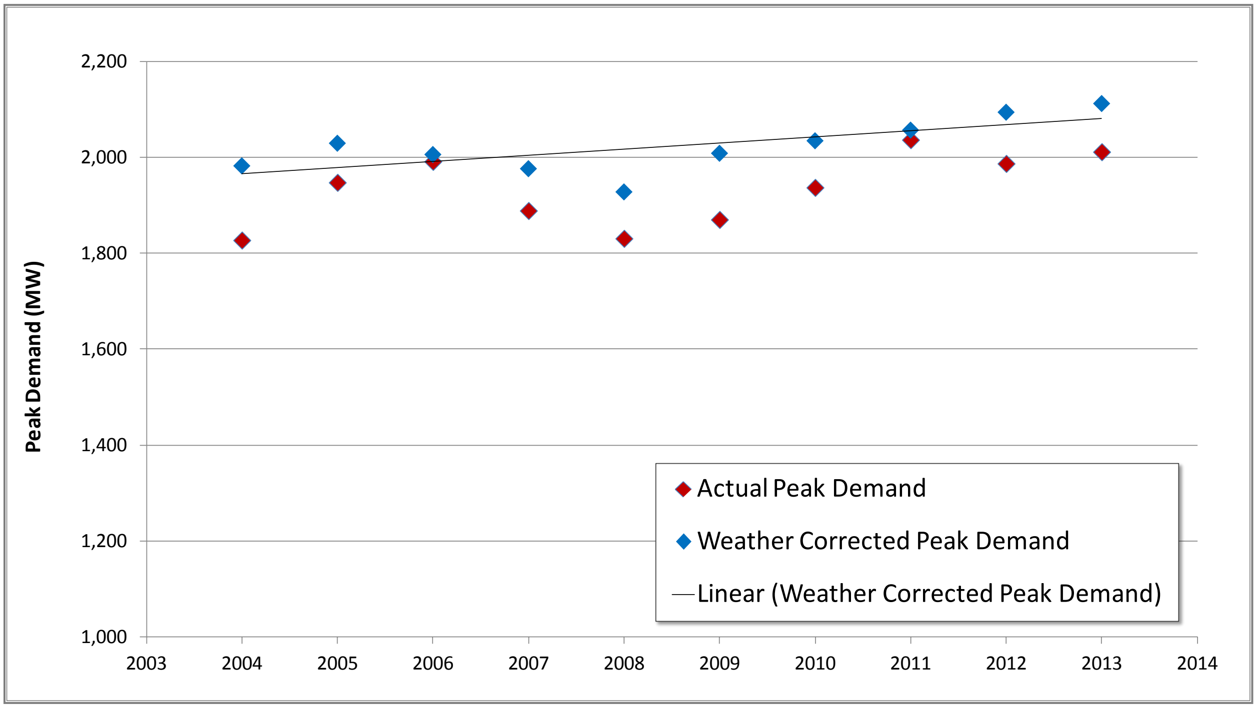
For the purposes of evaluating the adequacy of the electricity system, regional planning is concerned with the regional coincident peak demand. Coincident peak demand is the demand observed at the transformer stations for the hour of the year when overall demand in the study area is at its highest. This 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.

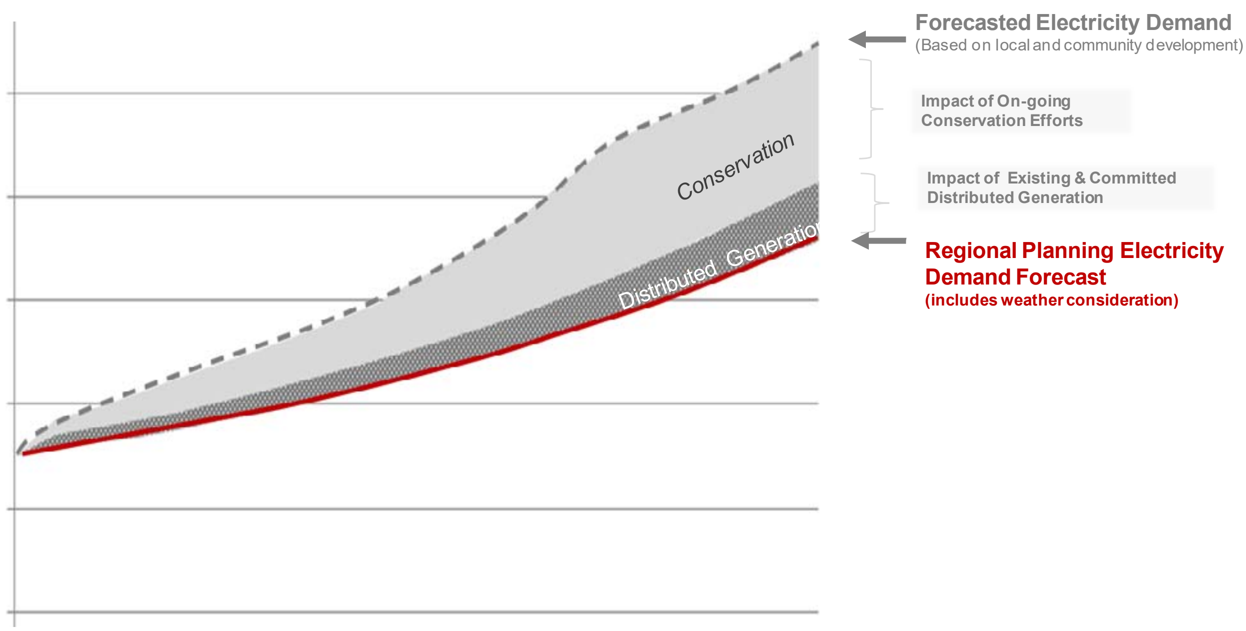
## 5.2 Demand Forecast Methodology

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**



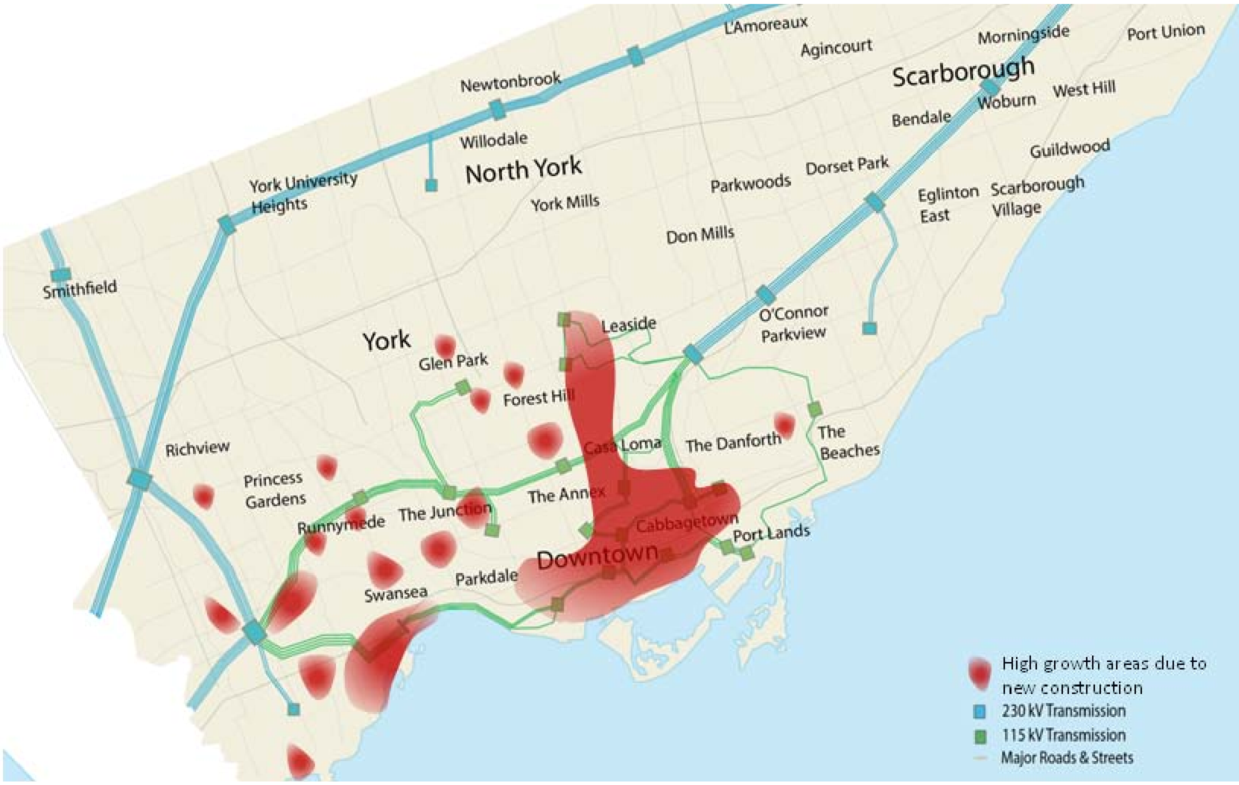
## 5.3 Gross Demand Forecast

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.

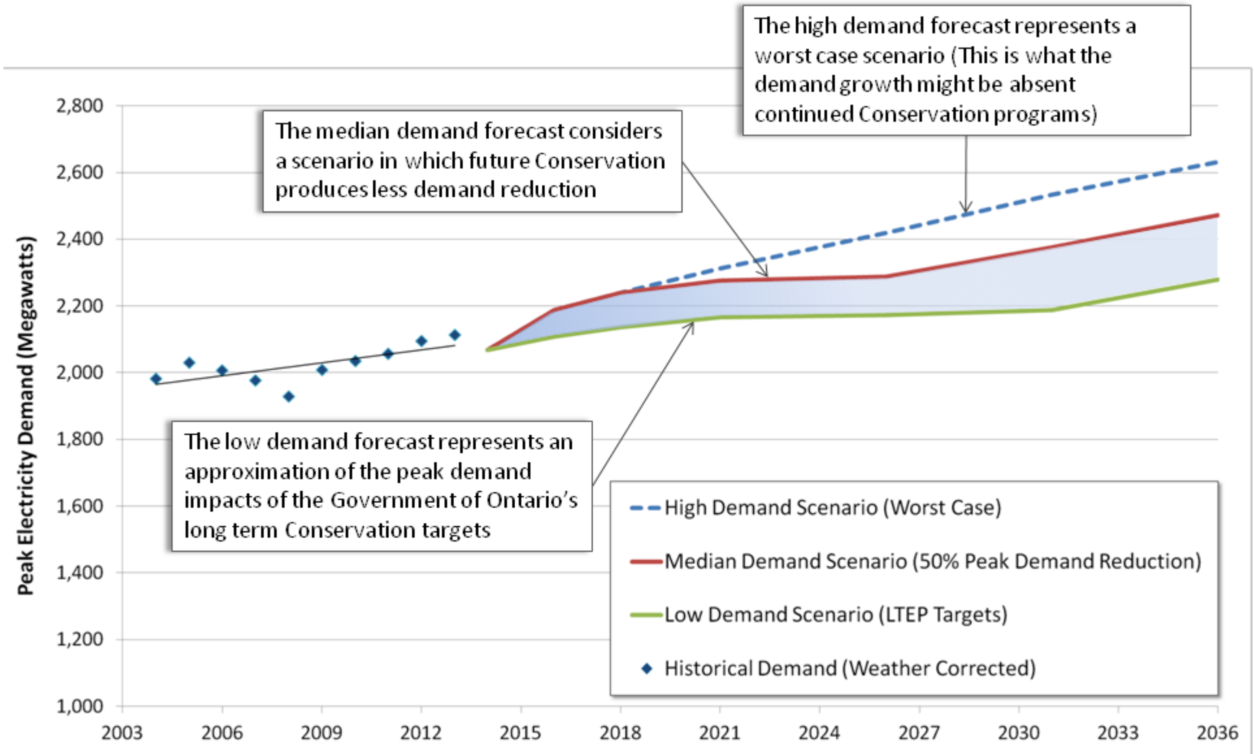
A “high demand” growth scenario was assessed to determine what the system needs would be under a worst-case, in which either conservation does not meet expectations, or new growth and development accelerate in the area. This forecast scenario assumes 238 MW of savings from conservation targets across 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

[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

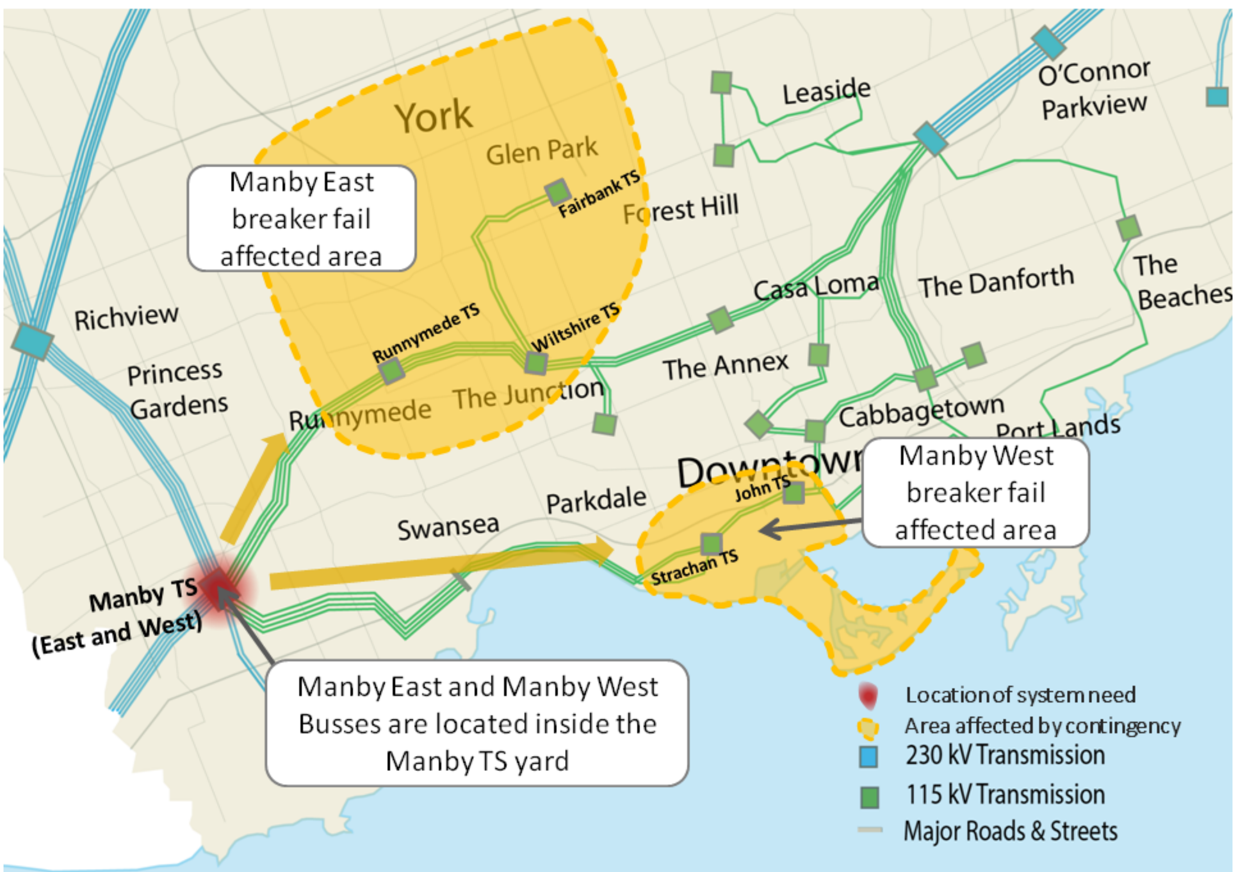
At Manby TS, this need stems from the reliability standards established for interconnected power systems in North America, as defined in the ORTAC. A breaker failure contingency at Manby TS would remove two transformers from service at the same time. The station has two independent delivery points to 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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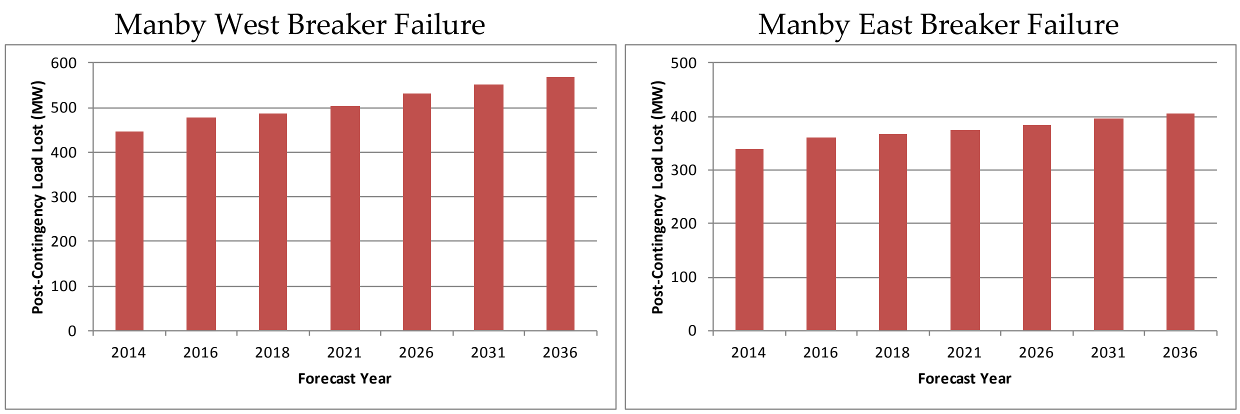
[19] At Manby West, the failure of breaker H1H4 or A1H4 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby West electrical demand. At Manby East, the failure of breaker H2H3 would activate breaker failure protection at the station resulting 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

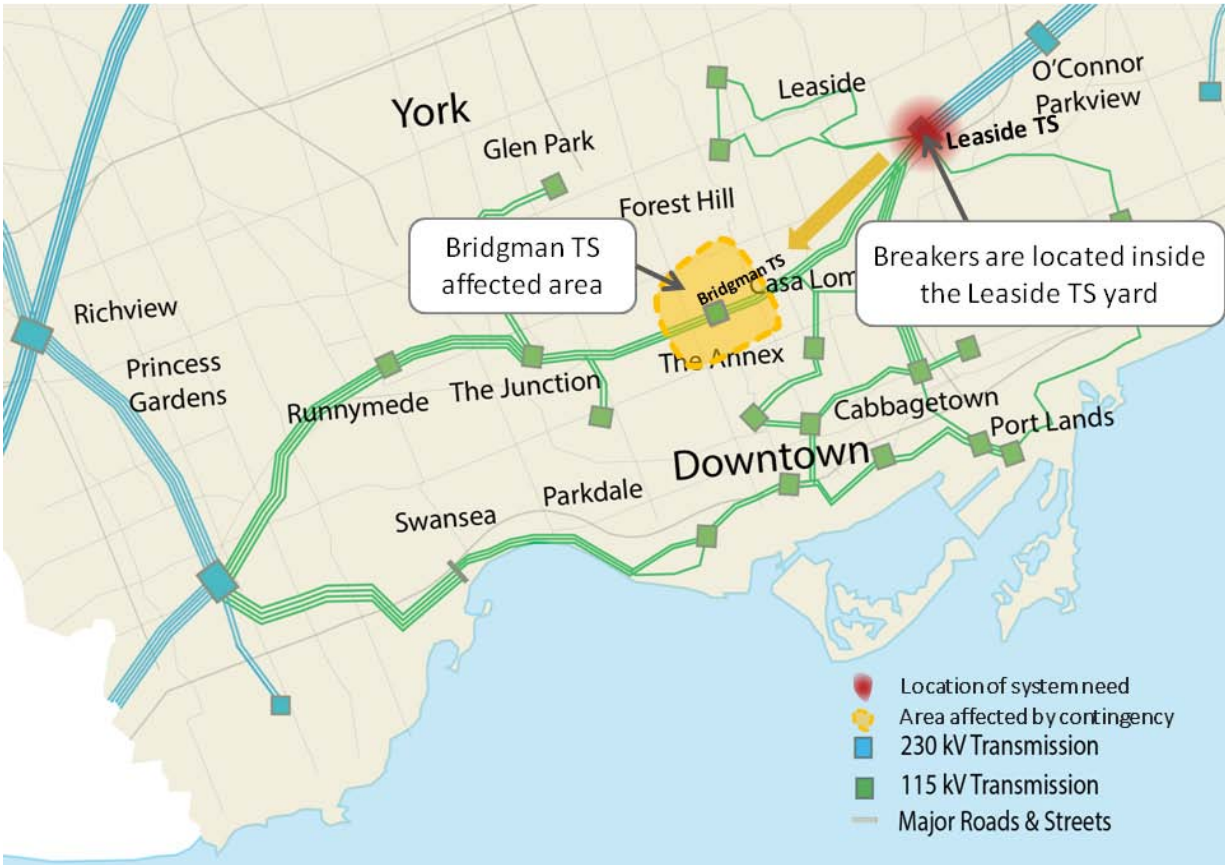
The need at Leaside TS is considered discretionary because the reliability standards (e.g., ORTAC) do not require action to be taken given system impacts and configuration, but because of the importance of security of supply in the Central Toronto Area and the important role that Leaside plays in backing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

[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.

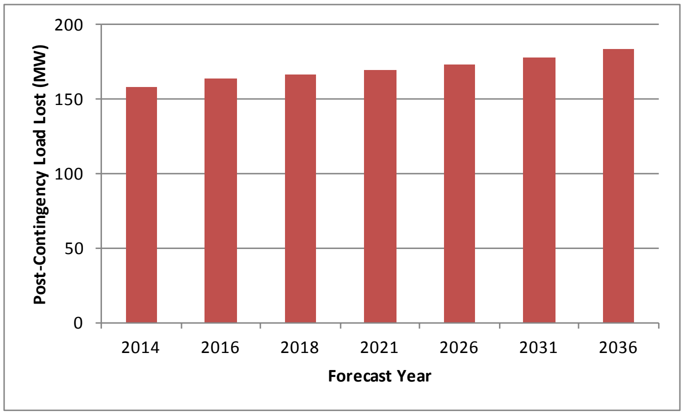
**Figure 6-4: Leaside TS Equipment and Affected Areas**




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

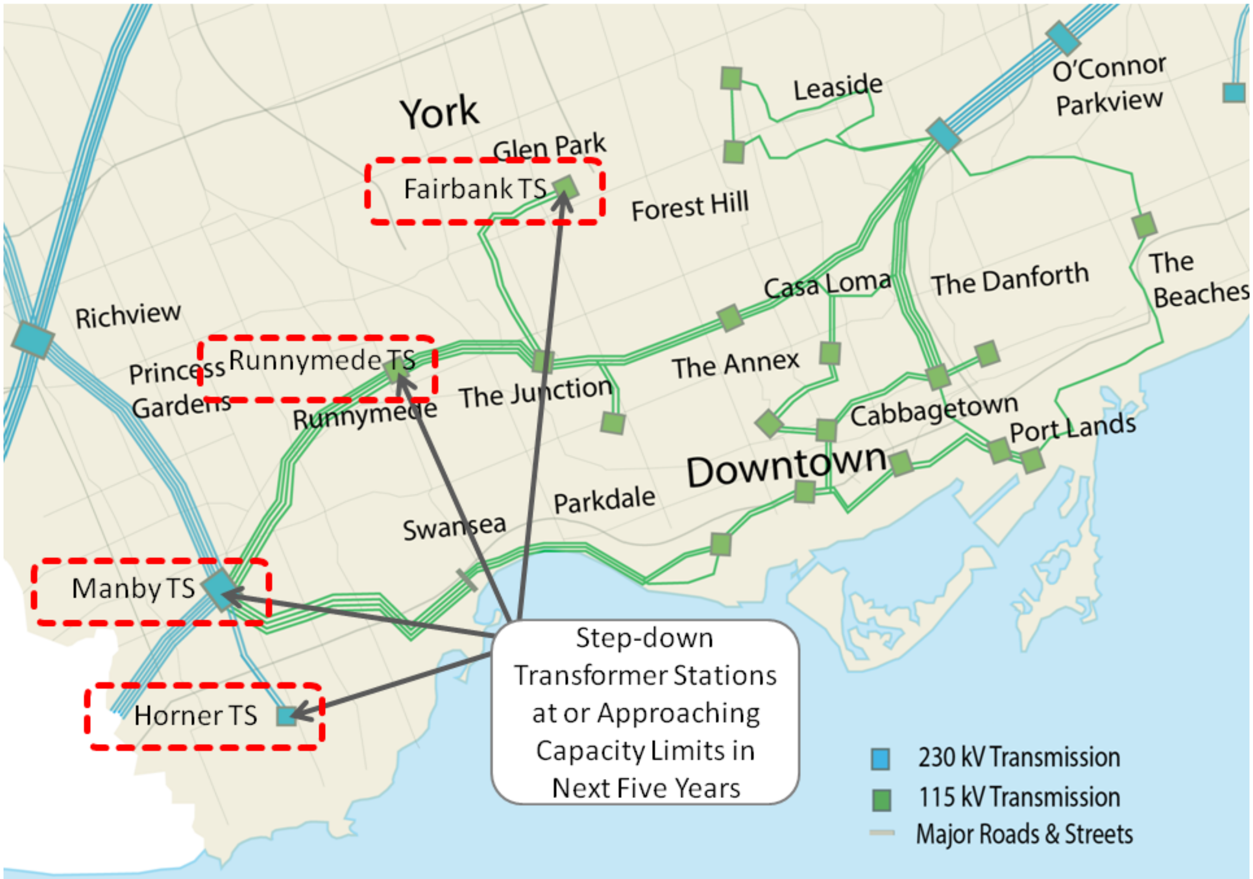
In the near term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the west Toronto area. The capacity need occurs at the step-down transformer stations serving as electricity supply points for distribution customers in the Manby TS sector, and on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



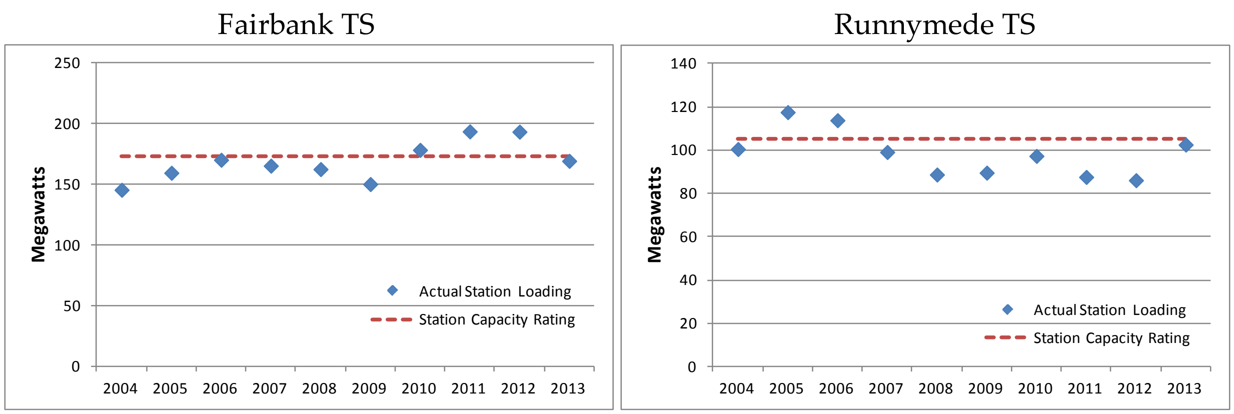

The needs in this area are being driven by the continued strong peak demand growth that has resulted in increasing new load connection request applications received by Toronto Hydro. In addition, other new large loads have signaled their intention to connect to the distribution system, such as the Eglinton 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]

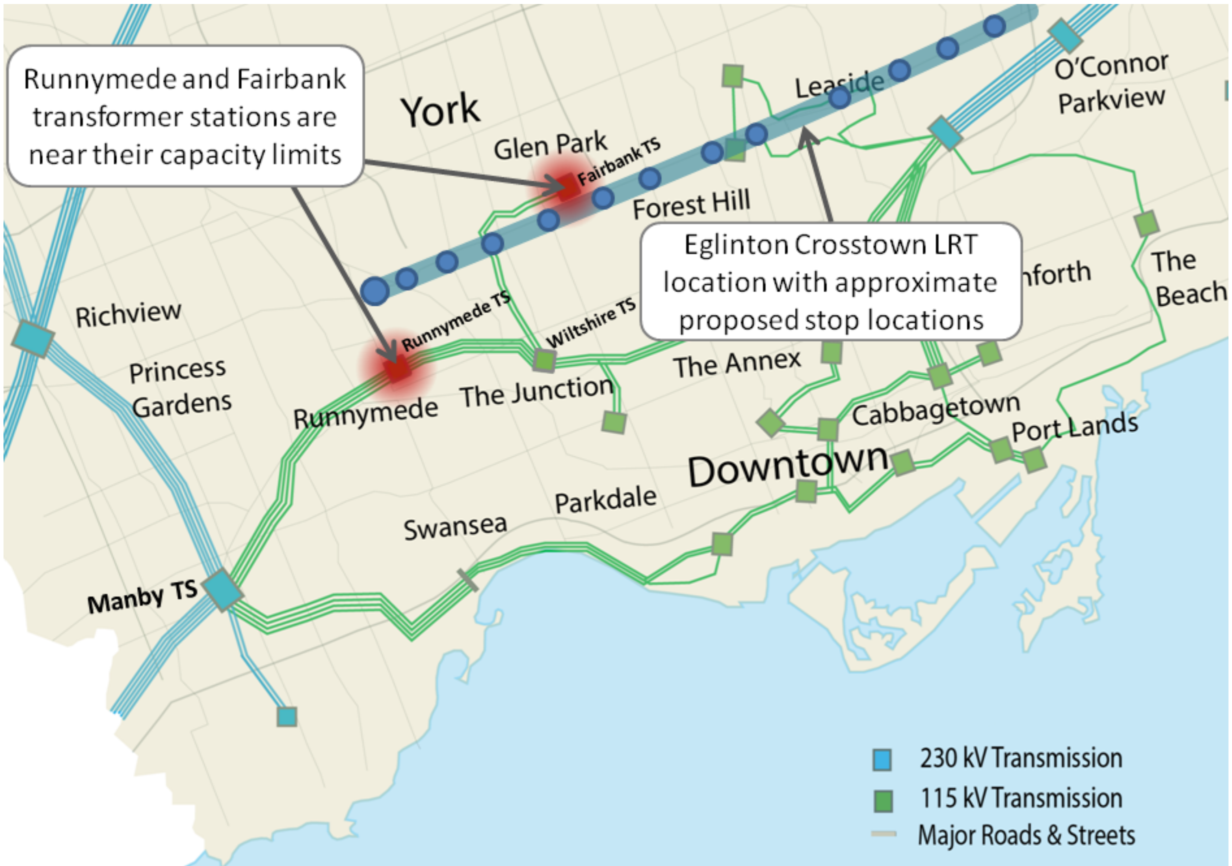
### Figure 6-7: Runnymede TS and Fairbank TS Historical Peak Station Loadings




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.

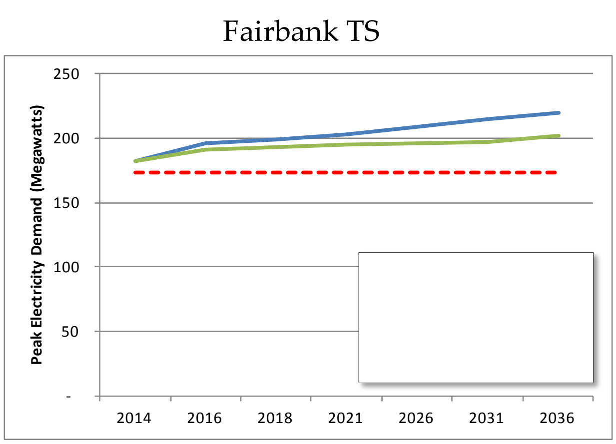
[21] The station capacity ratings were provided to the Working Group by Toronto Hydro and Hydro One.

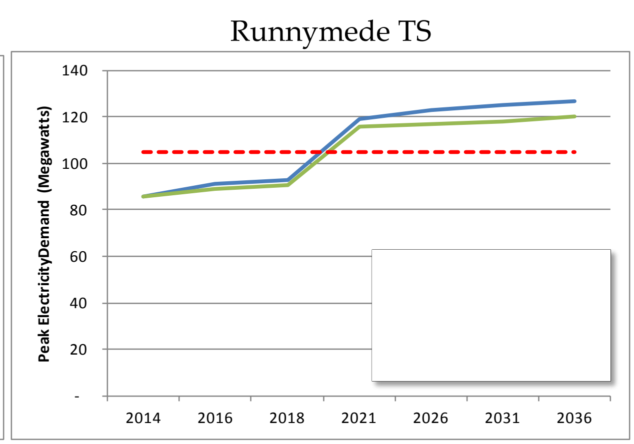
**Figure 6-8: Eglinton LRT Project Location in Relation to Supply Points in West Toronto**




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**

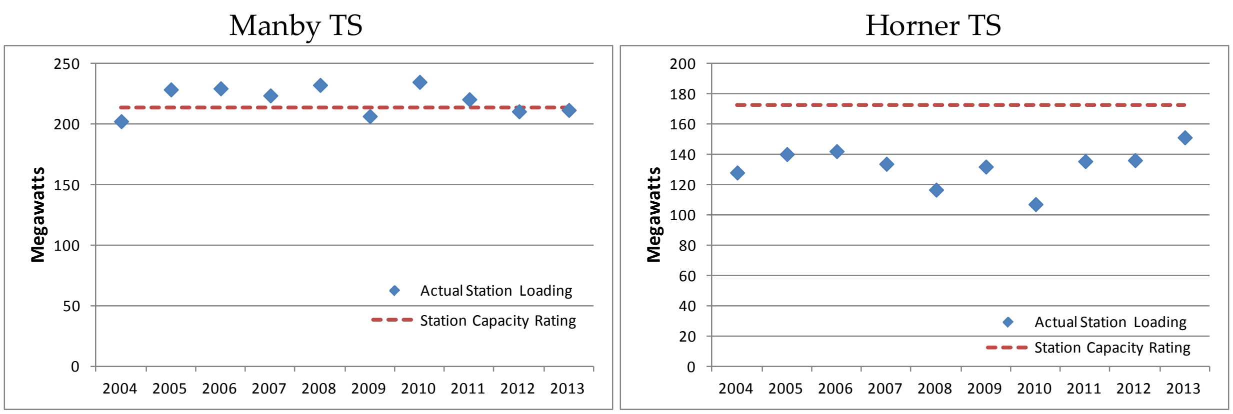


## Manby TS and Horner TS

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.

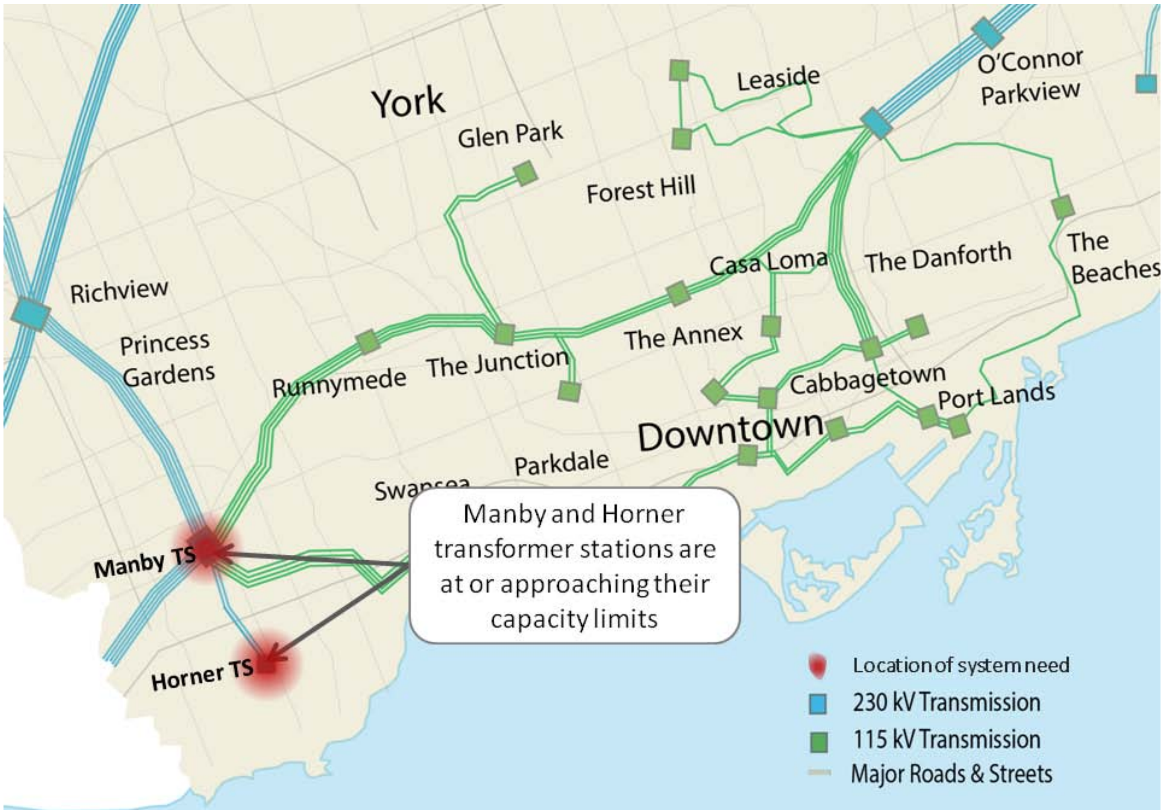
**Figure 6-10: Manby TS and Horner TS Historical Peak Station Loadings**




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.

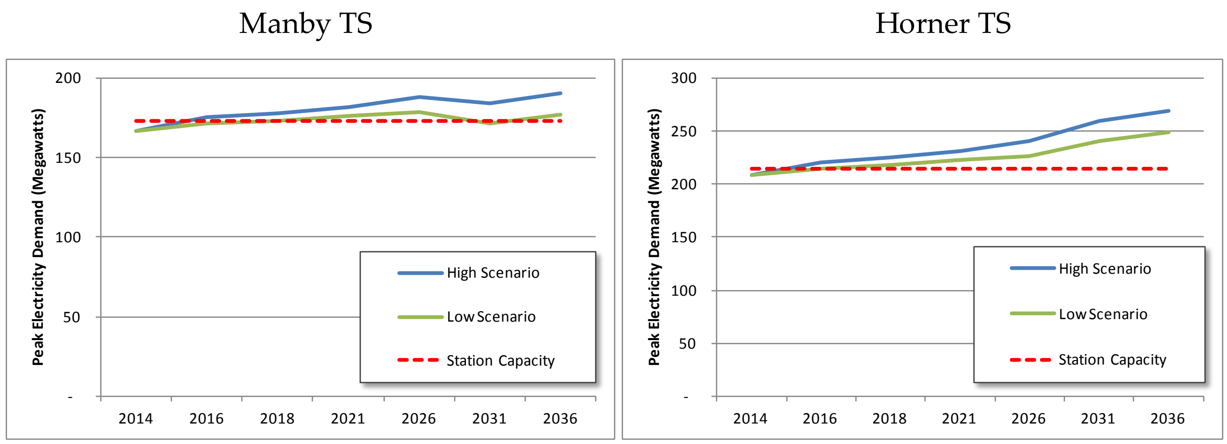
[22] This need refers to the capacity of the Manby TS step-down transformers that supply the local distribution network in the Islington City Centre area (230/27.6 kV), different from the 230/115 kV transformers that supply other parts of the Central Toronto Area via the 115 kV transmission system.

**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.

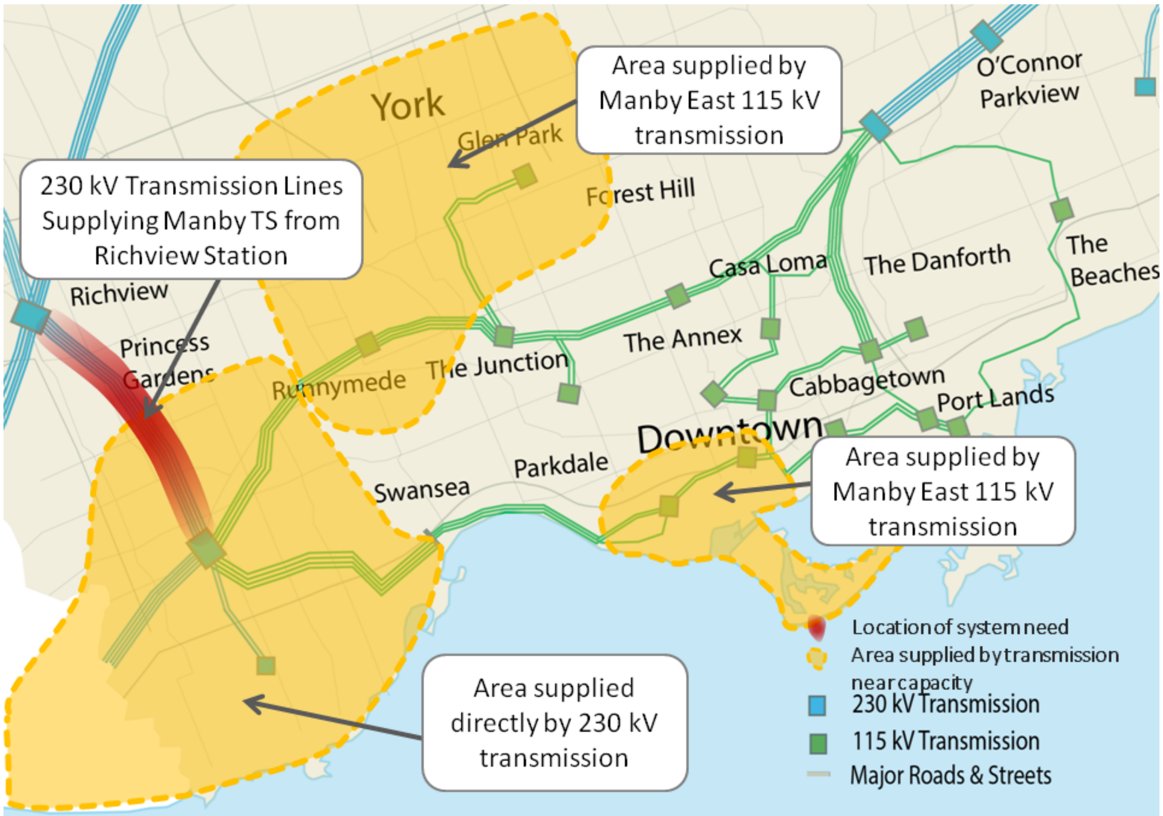
**Figure 6-12: Manby TS and Horner TS Peak Demand Forecast**




## 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.

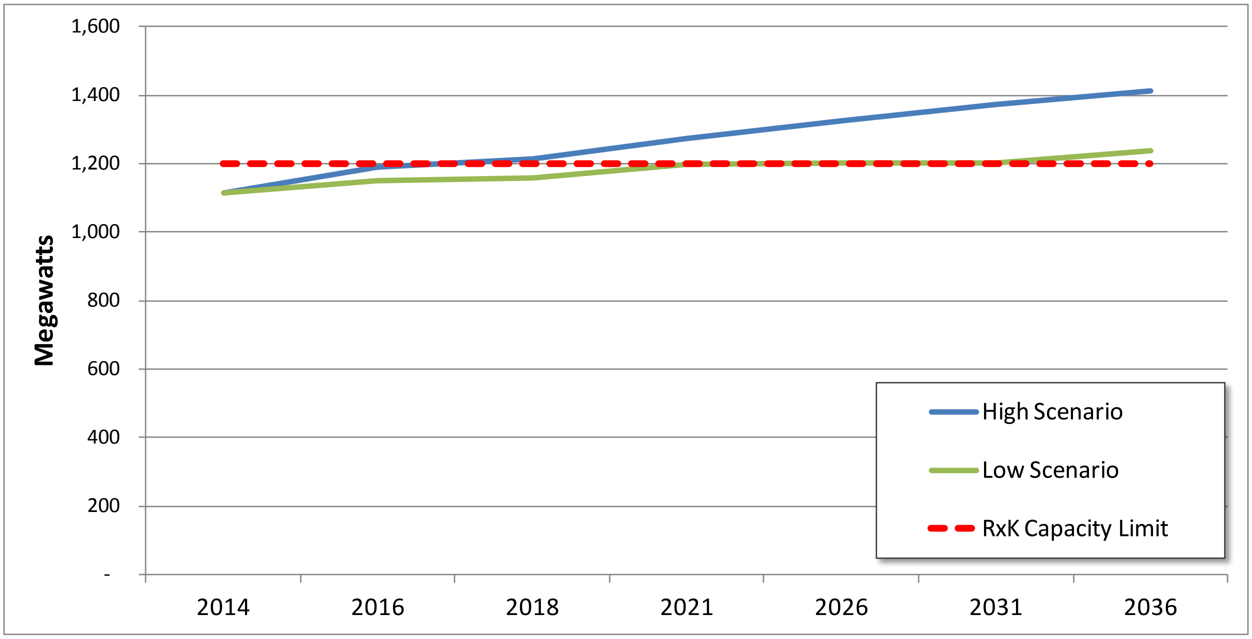
**Figure 6-13: Richview – Manby 230 kV Transmission Capacity Needs**




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

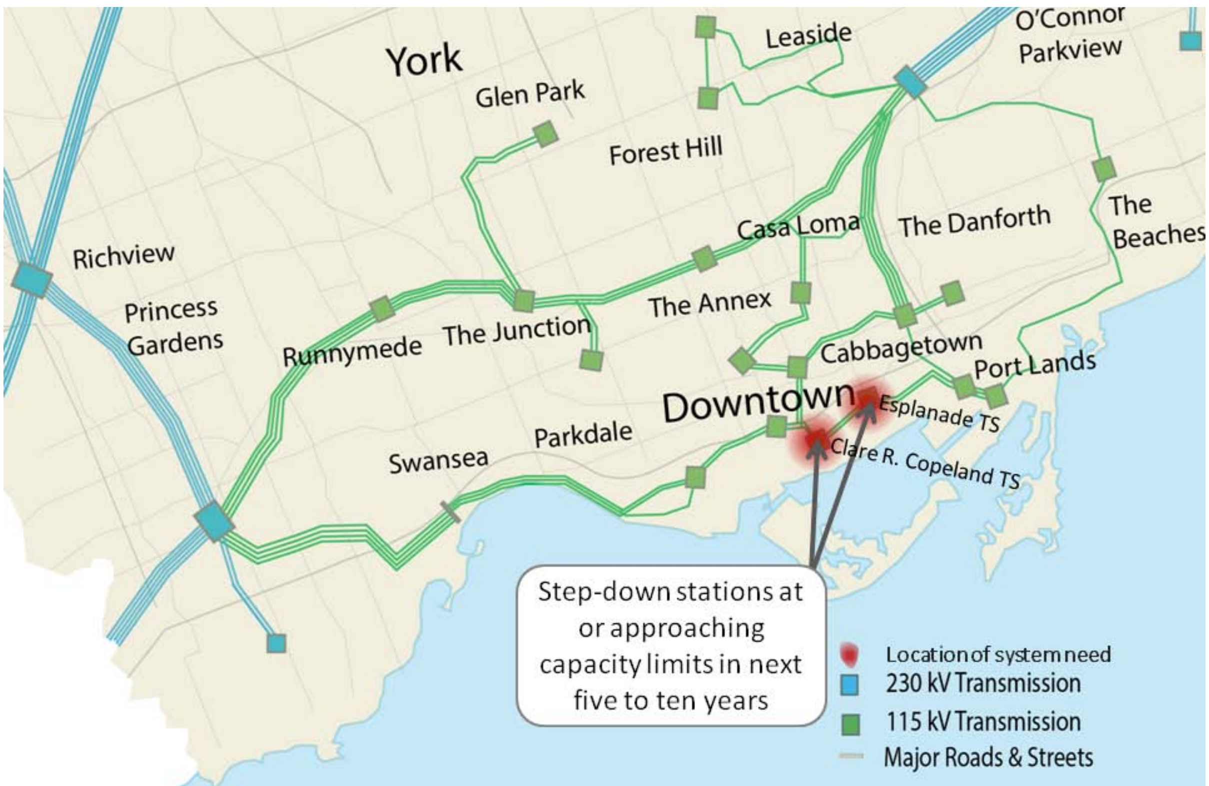
In the medium-term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the downtown Toronto area, at the electricity supply points serving distribution customers in the downtown business district. This need is driven by continuing demand growth and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

[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.

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[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.

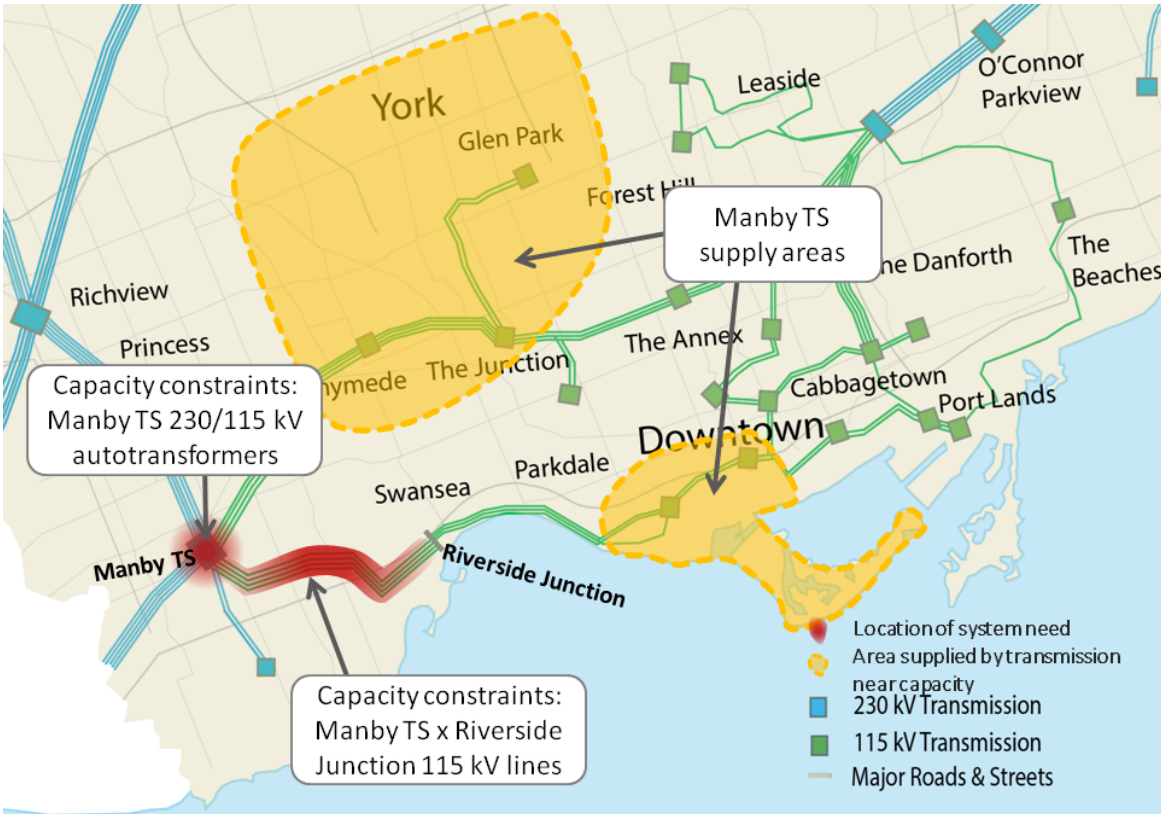
The capacity of the 115 kV transmission lines between Manby TS (Manby West) and the Riverside Junction into the downtown core is forecast to be exceeded as early as 2026 under a high demand scenario. These transmission circuits include the overhead section from Manby TS to Riverside Junction that supply 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**



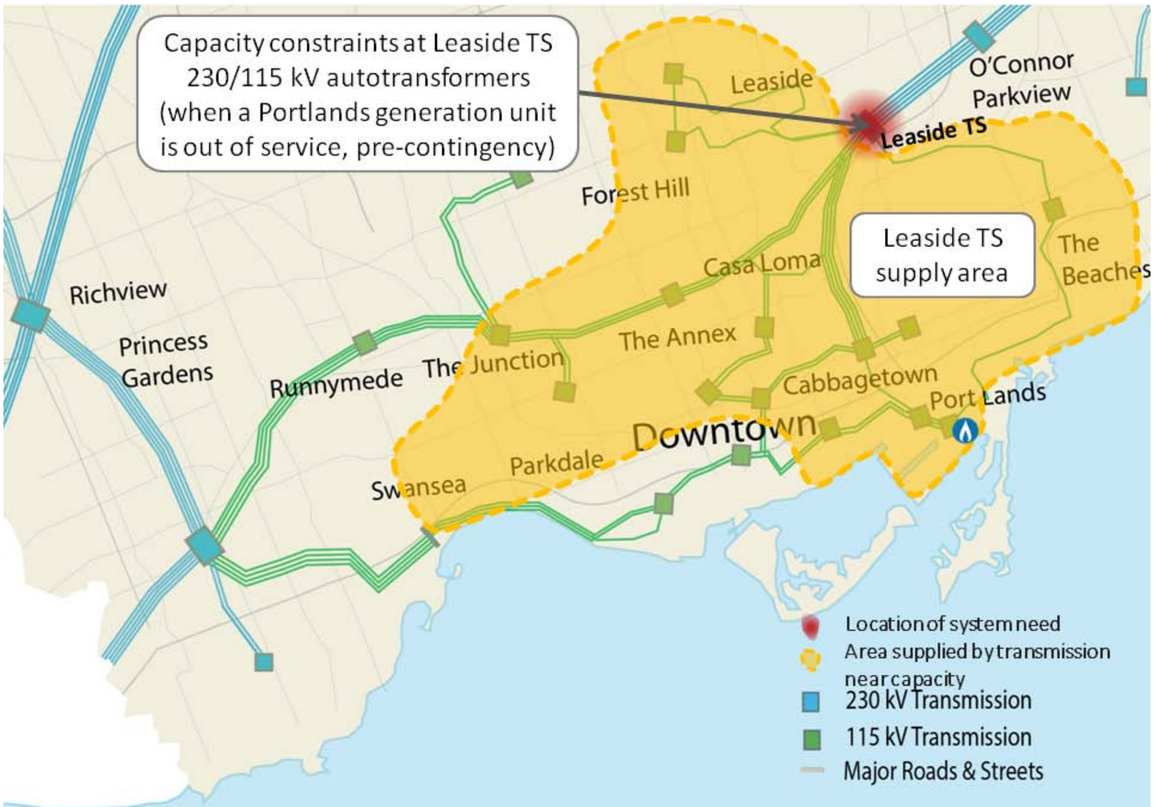

At Leaside TS, the ability to supply long-term load growth is limited by the ratings of 230/115 kV transformers, under a condition when all transmission elements are in service but one unit at PEC is out of service. Under such an N-1 outage at the PEC, both a gas turbine generator and the secondary cycle 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.

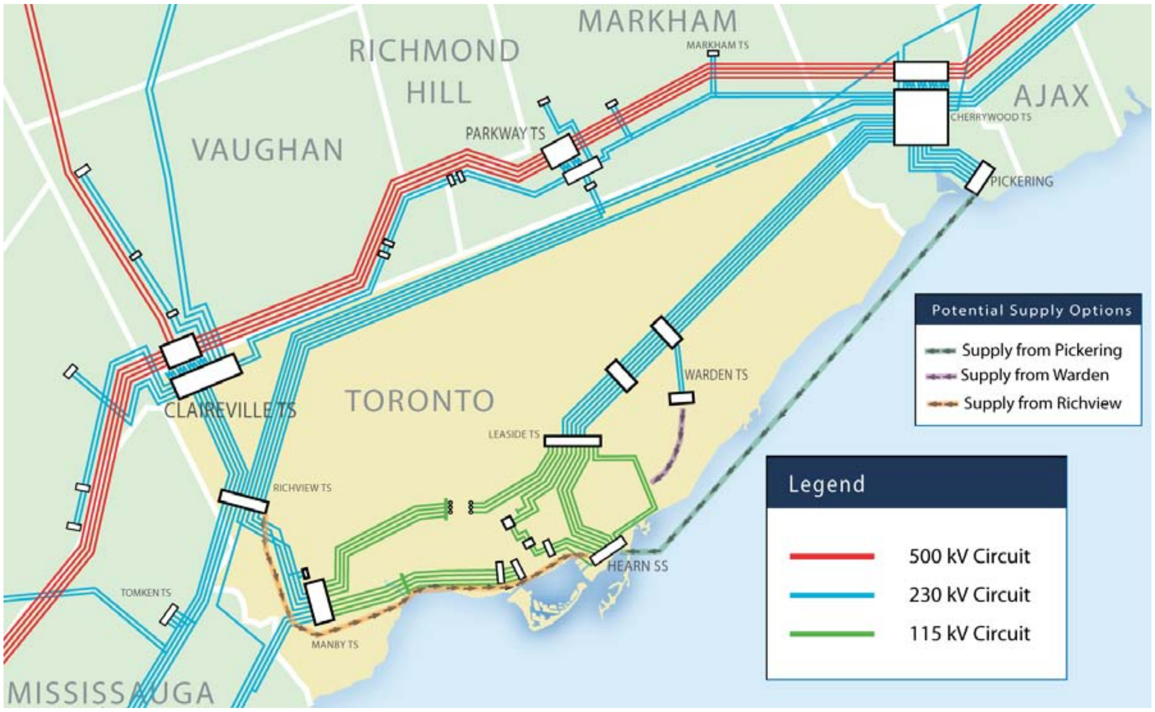
### 8.1.1 Delivering Provincial Resources

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)

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[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<br>• Dedicated web page added to Hydro One and Toronto Hydro's websites<br>• Self-subscription service established for Central Toronto IRRP for subscribers to receive regional specific updates<br>• 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<br>• Information provided to First Nation communities who may have an interest in the planning area with an invitation to meet<br>• Invited City of Toronto representatives to stakeholder workshops<br>• Information provide to Métis Nation of Ontario<br>• 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)<br>• 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<br>• Stakeholders and community groups engaged through workshops, surveys, webinars, open houses, subscriber lists, bill inserts and traditional and social media channels<br>• **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)<br>• More than 300 key stakeholders invited to **three workshop sessions** , with between six and 12 participants each<br>• More than 720 General Service and Residential customers surveyed by phone<br>• 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<br>• 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<br>• Status: Initial outreach complete |
| **Continued Broader Community Outreach** | • Presentations at Municipal Council, First Nation communities & Métis Nation of Ontario as requested<br>• Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee (LAC)<br>• Targetted engagement to discuss the formation of a LAC<br>• Formation of LAC to discuss long-term needs and local community engagement plans<br>• 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

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[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.