Independent Electricity Market Operator

10-Year Outlook:

An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario

from January 2004 to December 2013

Independent
Electricity
Market Operator

Executive Summary

The Independent Electricity Market Operator (IMO) publishes an annual assessment of the security and adequacy of the Ontario electricity system over the next 10 years. This report represents the IMO assessment for the 10-year period from 2004 to 2013. This assessment is based on the IMO's forecast of electricity demand, information provided by Ontario generators on the supply available and the latest information on the configuration and capability of the transmission system.

This report highlights the need for additional supply in Ontario and the need for transmission reinforcements to increase supply to downtown Toronto and to meet rapidly growing electricity demands in the Greater Toronto Area. The report also addresses other needs related to the transmission system.

Electricity Supply Outlook

As was noted in the previous 10-Year Outlook, additional Ontario electricity supply and demand response is required to maintain adequacy throughout the decade and reduce Ontario's dependency for supply from other jurisdictions. New generators and nuclear generators returning from long term outages will improve the reliability of the Ontario power system. Since the last outlook, TransAlta has begun operating a 500 MW cogeneration facility at Sarnia.

To date, the IMO has received proposals for 26 generating facilities totaling more than 8,700 MW of additional supply. However, construction has only begun on four of the proposed units, including Bruce Power units 3 and 4, which are scheduled to begin producing electricity in April and June of this year. In addition, publicly announced delays in the return to service of the Pickering A units have occurred since the previous 10-Year Outlook. For any projects that have not begun construction, there is insufficient basis for assuming the participant is committed to completing the facility. For that reason the IMO does not include these projects in the supply assumptions for this report. Since the majority of the proposed generation facilities are gas-fired, the IMO continues to investigate the impacts and potential concerns associated with natural gas becoming an increasing part of the generation fuel mix in Ontario and throughout northeastern North America.

If new generators currently under construction and nuclear generators returning from long-term outages are placed in service on schedule, and if additional generators are not retired or taken out of service on a long-term basis beyond those that have currently been identified to the IMO, the need date for additional generation could be pushed off toward the end of the decade. However, if the generation additions do not take place, or if additional generation is taken out of service, the need date could be advanced significantly.

Additional supply can be achieved in a variety of ways, including constructing new generation sources, improving existing generation, and reducing demand through conservation, changing consumption patterns and the use of new, more efficient technologies.

The increasing age of Ontario generation is emerging as a potential issue toward the end of and beyond the study period as much of the existing generation infrastructure reaches or exceeds its nominal life. All scenarios examined in the 10-Year Outlook assume that the Lakeview Thermal

Generating Station (TGS) will cease generating electricity at the end of April 2005 as a result of regulatory requirements. Up to 20 percent of the existing resource base can be expected to be retired from service or require substantial refurbishment over the next 10 years with another 20 percent in the subsequent 5 years. New environmental regulations, particularly with respect to air emissions could also drive the need for replacement of existing supply with cleaner alternatives. Given the long lead times required for some supply and demand options, consideration of how up to 40 percent of Ontario's generation will be replaced needs to begin now.

Supply to Greater Toronto Area

In the last outlook we identified the need for additional supply to maintain the reliability of the Toronto area. Several proposals for generation projects and transmission reinforcement submitted to the IMO will help address this need.

Proposed Generation Projects

The IMO has assessed proposals for two generation projects located in downtown Toronto – the Portlands Energy Center project (550 MW) proposed by Ontario Power Generation and Trans Canada Pipelines, and the Portlands project (180 MW) proposed by Toronto Hydro and Boralex. These projects, if implemented, will provide much-needed sources of supply for downtown Toronto. They will complement, but not replace, the need for the required transmission reinforcements described below.

Required Transmission Reinforcement

Significant transmission reinforcement is required in the Greater Toronto Area (GTA) in order to maintain an acceptable level of supply reliability over the Outlook period. The need for transmission reinforcement is due to forecast load growth both in downtown Toronto and in the municipalities north, west and southwest of Toronto, as well as the removal from service of Lakeview TGS in 2005.

Hydro One has proposed two alternative transmission projects to address the need for supply to downtown Toronto – a Direct Current (DC) Option and an Alternating Current (AC) Option. The DC option would see the construction of a High Voltage DC link across Lake Ontario from Niagara to Toronto whereas the AC option would consist of 230 kV transmission reinforcement from the west side of Toronto.

Both options have been assessed by the IMO as part of the Connection Assessment and Approval process, and while the IMO has a preference for the DC option, both options are acceptable to the IMO from a system reliability perspective. The IMO requires that either the DC Option (Hearn SS to John TS section) or the AC Option (phase 1) be placed in-service before the summer of 2006.

The high rate of load growth in the municipalities of Newmarket, Aurora, Markham, Richmond Hill, Vaughan, Mississauga, Brampton, Milton and Oakville located to the north, west and southwest of Toronto has created an early need to increase the supply capability to these areas. In order to maintain reliability of supply to municipalities north and west of Toronto, the IMO requires that the necessary transmission reinforcements be placed in-service as soon as possible beginning no later than April 2005.

Lakeview TGS is required to cease operation as a coal-fired generating station on April 30, 2005. A number of transmission infrastructure additions as well as additional reactive supply capability will be required before the shutdown takes place, in order to maintain an acceptable level of system reliability in the GTA.

Transmission Outlook Outside of the GTA

Transmission adequacy studies show that the Detweiler operating area, encompassing Kitchener-Waterloo, Cambridge and Guelph in Southwestern Ontario, is susceptible to supply interruptions for double circuit line contingencies. Based on summer conditions from 2002, thermal overloads on the autotransformers in this area are also possible. Respecting minimum voltage levels is a third concern. In combination, these are indicative of the need for transmission reinforcements in this area.

Transmission adequacy studies also show that the Windsor operating area may be susceptible to potential supply reliability problems under certain conditions. Based on current operating experience, the secure operation of this area relies on the operation of Special Protection Systems for single element contingencies with all elements in-service under peak load conditions. This reliance indicates that there is a need for transmission reinforcements in this area.

Ontario Demand Forecast

Under the Median economic growth scenario, energy consumption is forecast to grow from about 154 terawatt-hours (TWh) in 2004 to about 169 TWh in 2013. This represents an average annual growth rate of energy of 1.0%.

Normal weather peak demands are expected to increase from just over 24,000 MW in 2004 to 26,800 MW (summer of 2013) and 25,600 MW (winter of 2013). Under the Extreme weather scenario, winter peak demand will reach about 27,400 MW while the summer peak will exceed the 29,500 MW level.

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Caution and Disclaimer

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1.0 Introduction

This report presents a 10-year forecast and assessment of the adequacy of the generation and transmission facilities in Ontario. Its primary purpose is to provide information to market participants for long-term planning and investment decisions.

This report incorporates information received from market participants between December 2002 and February 2003. It supercedes the previous 10-Year Outlook published by the IMO on April 3, 2002.

The focus of this Outlook is to provide insight into potential investment opportunities, including the need for new or modified IMO-controlled grid facilities to maintain the reliability of the system, and to assist the IMO-administered markets to operate efficiently. A period of ten years spans the lead-time to install most new generation and transmission facilities. The assessment of generation adequacy is based upon ensuring that sufficient resources are available to meet the forecast demand plus required reserves. Ontario generation that is available to operate is assumed to supply Ontario demand. The assessment of transmission adequacy is based upon ensuring that sufficient transmission capability is available to transmit power to forecast loads in a secure manner.

The contents of this Outlook document focus on the assessment of resource and transmission adequacy. Other supporting information, forecasts and assessments are contained in separate documents. These documents will be updated as required.

- The document titled "Ontario Demand Forecast from January 2004 to December 2013" (IMO_REP_0098) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReport/10Year_ODF_2004jan.pdf) describes in detail the forecast of electricity demand for Ontario used in this Outlook. The document provides the details regarding peak and energy demand forecasts for Ontario and parts thereof. It also contains information regarding variations in demand due to weather, economic growth and calendar day types.
- The document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReports/Methodology_RTAA_2003apr.pdf) contains information regarding the methodology used to perform the demand forecasts, and resource and transmission adequacy assessments in this Outlook.
- The document titled "Ontario Transmission System" (IMO_REP_0045) (found on the IMO web site at www.theimo.com/imoweb/pubs/marketReports/OntTxSystem_2003apr.pdf) provides specific details on the transmission system, including the major internal transmission interfaces and interconnections with neighbouring jurisdictions.

Readers are invited to provide comments on this report or to give suggestions as to the content of future reports. To do so, please call the IMO Help Centre at 905-403-6900 or 1-888-448-7777 or send an email to forecasts.assessments@theIMO.com.

1.1 Changes from the Previous 10-Year Outlook

Changes to Forecast Demands

Compared to the previous 10-year forecast the most significant methodological change has been the transition to an hourly peak from the previously reported 20-minute peak value. Historically, the hourly peak is 80 to 100 MW lower than the 20-minute peak. In addition to this methodological change, the model has been re-estimated based on actual data through to the end of October 2002.

The economic assumptions that underpin the forecast have been updated to reflect the most recent outlook for the Ontario economy. This represents a fairly significant change since the previous 10-Year Outlook. The previous Outlook was produced shortly after the events of September 11, 2001. At that time, the outlook for the U.S. and Canadian economies was for minimal growth. Although the U.S. economy has held to the expectations at that time, the Canadian economy has shown a remarkable resilience in the face of the war on terrorism, the stock market meltdown and the U.S. economic slump. Presently, the outlook for the Canadian economy continues to be quite optimistic in comparison with the other developed nations of the world. Therefore, the economic outlook is significantly better than in the previous 10-year forecast. However, better than expected economic performance in 2002 also meant higher than expected Ontario electricity demand. This causes the starting point for this forecast to be significantly higher than the previous forecast. The weather corrected energy demand for 2002 was 151.4 TWh as opposed to the forecast of 148.7 TWh.

The median growth scenario has energy demand growing at an annual rate of growth of 1.1% versus 0.9% in the previous 10-Year Outlook (for the common 2003-2012 time frame). This higher growth rate is the product of generally improved economic expectations. In terms of levels, the forecast is higher in 2012 than the previous forecast (168 TWh vs. 164 TWh). This is due to the combination of a higher growth rate and higher starting point.

Higher overall economic growth means that peak demand will grow faster than in the previous forecast. For the common time frame of 2003-2012 the updated forecast has summer peak demand averaging annual growth of 1.3% (versus 1.1%) and winter peak demand averaging growth of 0.8% (versus 0.6%). Relative to the overall energy demand growth of 1.1%, cooling load is growing faster than the overall energy demand, while heating load is growing slower.

The continued growth of cooling load means that the system will be summer peaking in 2005 under Normal weather, and is currently summer peaking under the Extreme weather scenario.

Changes to Resources

The amount of existing installed generation resources has been updated from the previous 10-Year Outlook to include all generators that are registered to participate in the IMO-administered markets. The latest generation resource additions and upgrades, and the latest capacity ratings are also included. The list does not include generators that are not registered to participate in the IMO-administered markets.

The amount of planned outages assumed to take place over the seasonal peak demand periods has been changed to approximately 900 MW, from 800 MW over the winter peak demand and 1,300 MW over the summer peak demand periods considered in the previous 10-Year Outlook.

In past 10-Year Outlooks, 300 MW of price-responsive demand was assumed to be available for the purposes of resource adequacy assessments under all scenarios. In this Outlook, 300 MW of price-responsive demand was assumed to be available only under the Intermediate and Planned Resource Scenarios. No price-responsive demand was assumed to be available under the Existing Resource Scenario.

Changes to Transmission Outlook

Compared to the previous 10-Year Outlook, the zonal supply reliability assessment, the "Snapshot" congestion assessment and the Multi-Area Reliability Simulation (MARS) congestion assessment were not performed for this Outlook. The previous congestion assessments were replaced by the sole use of the Multi-Area Production Simulation (MAPS) program to perform congestion assessment.

The transmission adequacy assessment was also expanded to consider different transmission network scenarios under different resource scenarios and demand scenarios. The different transmission network scenarios incorporate variations of planned transmission projects in the Connection Assessment and Approval (CAA) queue and additional transmission reinforcements. Additional reinforcements are IMO suggested reinforcements, which have not yet been submitted by a proponent to the CAA queue.

In past 10-Year Outlooks, some assessments were performed under winter peak conditions. In this Outlook, transmission adequacy assessments pertaining to supply availability, contingency-based supply reliability and steady state voltage level adequacy were performed only under summer peak conditions. Summer peak conditions are forecasted to be higher than winter peak conditions and will stress the IMO-controlled grid to a greater extent.

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2.0 Resources

This section describes the generation resources that are forecast to be in service throughout the ten-year study period, taking into account existing generation and generation resource additions and retirements, based on information available to the IMO.

2.1 Existing Generation Resources Included in the Study

The existing installed generation included in the study is summarized in Table 2.1. It includes nuclear, coal, oil, gas, hydroelectric, wood and waste-fuelled generation which adds to a total installed capacity of 30,500 MW. The new TransAlta – Sarnia Cogeneration Project is now included in the existing generation resources.

The capacity of installed generation resources in Table 2.1 does not include Bruce A nuclear units, which are currently being prepared for reactivation. Bruce A units, together with other additions to generating capacity identified to the IMO, were progressively added to the installed resources, under the Intermediate and Planned Resource Scenarios, as described in Section 2.3.

The Pickering A nuclear units were included in the list of existing installed generation resources, but were modeled initially as out-of-service. Various numbers of Pickering A units were assumed to return to service under the resource scenarios described in Section 2.3.

Table 2.1 Existing Installed Generation Resources

Resource Type	Total, MW	# of Stations
Nuclear	10,836	4*
Coal	7,546	5
Oil/Gas	4,416	24
Hydroelectric	7,636	59
Miscellaneous (wind, waste, etc.)	66	2
Total	30,500	94

* The number of operating nuclear stations will increase to five with the operation of the first Bruce A unit.

2.2 Potential New Generation Resources

Table 2.2 summarizes the new generation projects in the IMO's Connection Assessment and Approval (CAA) process. Generator owners or operators have provided the information regarding the status of their projects and the in-service/restart dates listed in Table 2.2. Although approximately 8,800 MW of generation additions have been submitted to the IMO and remain in the IMO queue, the continued deferral of many of these projects, year over year, has prompted the IMO to develop resource scenarios which only consider those generation additions that are under construction.

Table 2.2 Potential Generation Resource Additions in Ontario

Proponent/Project Name	Zone	Fuel Type	Capacity MW	Connection Applicant's Estimated I/S Date	Under Construction**
Bruce Power Inc. - Bruce A G4	Bruce	Nuclear	770	2003 - Q2*	Yes
Bruce Power Inc. - Bruce A G3	Bruce	Nuclear	770	2003 - Q2*	Yes
Superior Wind Energy Inc.	Southwest	Wind	100	2003 - Q3	No
AGSTAR Power Inc.	West	Gas	88	2003 - Q4	No
AGSTAR Power Inc.	West	Gas	538	2004 - Q1	No
Superior Wind Energy Inc.	Northeast	Wind	100	2004 - Q1	No
ATCO Power Ltd.	West	Gas	578	2004 - Q2	Yes
Enron Canada Corp.	West	Gas	505	2004 - Q2	No
Imperial Oil Ltd.	West	Gas	98	2004 - Q2	Yes
Northern Cross Energy	Southwest	Wind	50	2004 - Q2	No
Port Albert Wind Farms	Southwest	Wind	50	2004 - Q2	No
Ontario Power Generation Inc. - Lac Seul	Northwest	Hydroelectric	14	2004 - Q3	No
Superior Wind Energy Inc.	Northeast	Wind	200	2004 - Q3	No
Superior Wind Energy Inc.	Southwest	Wind	100	2004 - Q3	No
Superior Wind Energy Inc.	Southwest	Wind	200	2004 - Q3	No
Superior Wind Energy Inc.	West	Wind	200	2004 - Q3	No
Toronto Hydro ES Inc.	Toronto	Gas	180	2004 - Q3	No
Northland Power Inc. - Kirkland	Northeast	Gas	48	2004 - Q4	No
REpower Wind Corp.	Northeast	Wind	57	2004 - Q4	No
AES Kingston Inc.	West	Gas	530	2005 - Q2	No
Northland Power Inc. - Thorold	Niagara	Gas	273	2005 - Q2	No
Superior Wind Energy Inc.	Northwest	Wind	200	2005 - Q2	No
Calpine Canada Power Holdings	West	Gas	870	2005 - Q3	No
Ontario Power Generation Inc. - Hearn	Toronto	Gas	550	2005 - Q4	No
Sithe Canadian Holdings Inc. - Goreway	Toronto	Gas	932	2006 - Q2	No
Sithe Canadian Holdings Inc. - Southdown	Toronto	Gas	763	2007 - Q2	No
Total			8764		

* Estimated restart date.
** For projects not under construction, the IMO assumes no commitment on the part of the market participant to complete the project.

Since the majority of the proposed generation facilities are gas-fired, the IMO continues to investigate the impacts and potential concerns associated with natural gas becoming an increasing part of the generation fuel mix in Ontario and throughout northeastern North America.

Details regarding the IMO's Connection Assessment and Approval process and the status of all projects in the queue, including copies of available Preliminary Assessment (PA) and System Impact Assessment (SIA) Reports, can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

2.3 Summary of Generation Resource Scenarios

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of supply resources that will be available for operation. Three different scenarios were assumed in this Outlook regarding the level of installed resources: an Existing Resource Scenario, an Intermediate Resource Scenario, and a Planned Resource Scenario.

Tables 2.3 and 2.4 show the three generation resource scenarios, at the time of the winter and summer peak demands. These scenarios have been developed starting from the existing installed generation resources shown in Table 2.1.

The **Existing Resource Scenario** assumes that:

- existing Ontario resources, listed in Table 2.1, will be in-service for the entire duration of the study period, with the exception of the Pickering A and Lakeview units;
- Lakeview units will be out of service beginning April 2005; and
- no additional generation in Ontario will be placed in service during the Outlook period, including new generation projects and nuclear generation returning to service;

The **Intermediate Resource Scenario** is identical to the Existing Resource Scenario, with the following additions:

- it includes the additional generation resources listed in Table 2.2, for which the connection applicant has indicated that construction is in progress or has been completed. These resource additions were assumed to be complete on the dates provided by market participants;
- it includes one Pickering A nuclear unit which was assumed to restart by the end of the second quarter of 2003, as indicated by the generator owner;
- it includes 300 MW of price-responsive demand; and
- Bruce A Unit 3 has been assumed to retire within this ten-year forecast based on the information received from Bruce Power. This is a conservative assumption, which will be reviewed as part of the market participant's normal business planning process and will depend on the material condition of the unit and market conditions.

The **Planned Resource Scenario** is identical to the Intermediate Resource Scenario, with the exception that the remaining three Pickering A nuclear units were assumed to restart at one-year time intervals after the first one, as indicated by the generator owner.

Table 2.3 Summary of Installed Generation Resource Scenarios Assumed in the Study (at Winter Peak)

Line	Description \ Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	Existing Installed Resources as of February 2003	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500
2	Installed Resources Increment Under Existing Resource Scenario	0	0	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148
3	Installed Resources Increment Under Intermediate Resource Scenario	1,540	2,216	1,068	1,068	1,068	298	298	298	298	298
4	Installed Resources Increment Under Planned Resource Scenario	1,540	2,216	1,068	1,068	1,068	298	298	298	298	298
5	Existing Resource Scenario	30,500	30,500	29,352	29,352	29,352	29,352	29,352	29,352	29,352	29,352
6	Intermediate Resource Scenario	32,040	32,716	31,568	31,568	31,568	30,798	30,798	30,798	30,798	30,798
7	Planned Resource Scenario	32,040	32,716	31,568	31,568	31,568	30,798	30,798	30,798	30,798	30,798

Table 2.4 Summary of Installed Generation Resource Scenarios Assumed in the Study (at Summer Peak)

Line	Description \ Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1	Existing Installed Resources as of February 2003	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500	30,500
2	Installed Resources Increment Under Existing Resource Scenario	0	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148	-1,148
3	Installed Resources Increment Under Intermediate Resource Scenario	2,216	1,068	1,068	1,068	1,068	298	298	298	298	298
4	Installed Resources Increment Under Planned Resource Scenario	2,216	1,068	1,068	1,068	1,068	298	298	298	298	298
5	Existing Resource Scenario	30,500	29,352	29,352	29,352	29,352	29,352	29,352	29,352	29,352	29,352
6	Intermediate Resource Scenario	32,716	31,568	31,568	31,568	31,568	30,798	30,798	30,798	30,798	30,798
7	Planned Resource Scenario	32,716	31,568	31,568	31,568	31,568	30,798	30,798	30,798	30,798	30,798

Notes to Tables 2.3 and 2.4:

1. Existing Installed Resources as of February 2003: Represent the total capacity of the existing installed generation resources in Ontario as described in section 2.1. This value includes all the generation registered in the Ontario electricity market, except Bruce A.

2. Installed Resources Increment Under Existing/Intermediate/Planned Resource Scenario: Represents the installed resources increments to the existing resources, at the winter/summer peaks, as described under the 'Existing/Intermediate/Planned Resource Scenario' paragraph above.
The Installed Resources Increments (lines 3 and 4) do not change under the Intermediate and Planned Resource scenarios since the Pickering A units are assumed to be part of the installed resources under both scenarios. Although not indicated in this table, only one Pickering A unit is available for use under the Intermediate Resource Scenario, while all Pickering A units are available for use under the Planned Resource Scenario, making the two resource scenarios quite different from a resource availability perspective.

3. Existing Resource Scenario: Is the sum of 'Existing Installed Resources as of February 2003' (line 1) and 'Installed Resources Increment Under Existing Resource Scenario' (line 2).

4. Intermediate Resource Scenario: Is the sum of 'Existing Installed Resources as of February 2003' (line 1) and 'Installed Resources Increment Under Intermediate Resource Scenario' (line 3).

5. Planned Resource Scenario: Is the sum of 'Existing Installed Resources as of February 2003' (line 1) and 'Installed Resources Increment Under Planned Resource Scenario' (line 4).

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3.0 Resource Adequacy Assessment

This section provides an assessment of the adequacy of the resources described in Section 2 to meet the forecast demand. Capacity analyses were performed using the Load and Capacity program (L&C), and the Multi-Area Reliability Simulation program (MARS). The methodology and tools used to carry out these analyses are described in detail in the document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044). The resource availability scenarios are described in Section 3.1, results of the L&C and MARS runs are described in Section 3.2, and other considerations and influencing factors are briefly discussed in Section 3.3. Conclusions are provided in Section 5, and detailed result tables can be found in Appendix A.

3.1 Supply/Demand Modeling Approach

The resource availability scenarios used in the capacity and energy production capability analyses were created using the installed generation resources derived under the three resource scenarios in Section 2.3. For each resource scenario, generator deratings, planned and long-term generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity were combined with installed generation resources.

For 2004 only, specific generator outage plans have been used. For the period from 2005 through 2013, explicit generator outage plans were unavailable. For these years it was necessary to model a hypothetical outage plan to reflect known cyclic outages (such as nuclear station containment outages) and planned outage factors supplied by generator participants. This is referred to as a "generic" outage plan to reflect the fact the majority of assumptions were modeled repetitively for nine of the ten years studied. In the generic outage plan, approximately 900 MW of generating capacity was considered to be on planned outage over the seasonal peak periods. However, should outage duration grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate more outages during peak periods. If reserve margins increase through addition of generation resources connected to the IMO-controlled grid, the ability for the IMO to approve outages scheduled during peak periods will improve. The IMO considers explicit dates of scheduled outages in the 18-Month Outlooks.

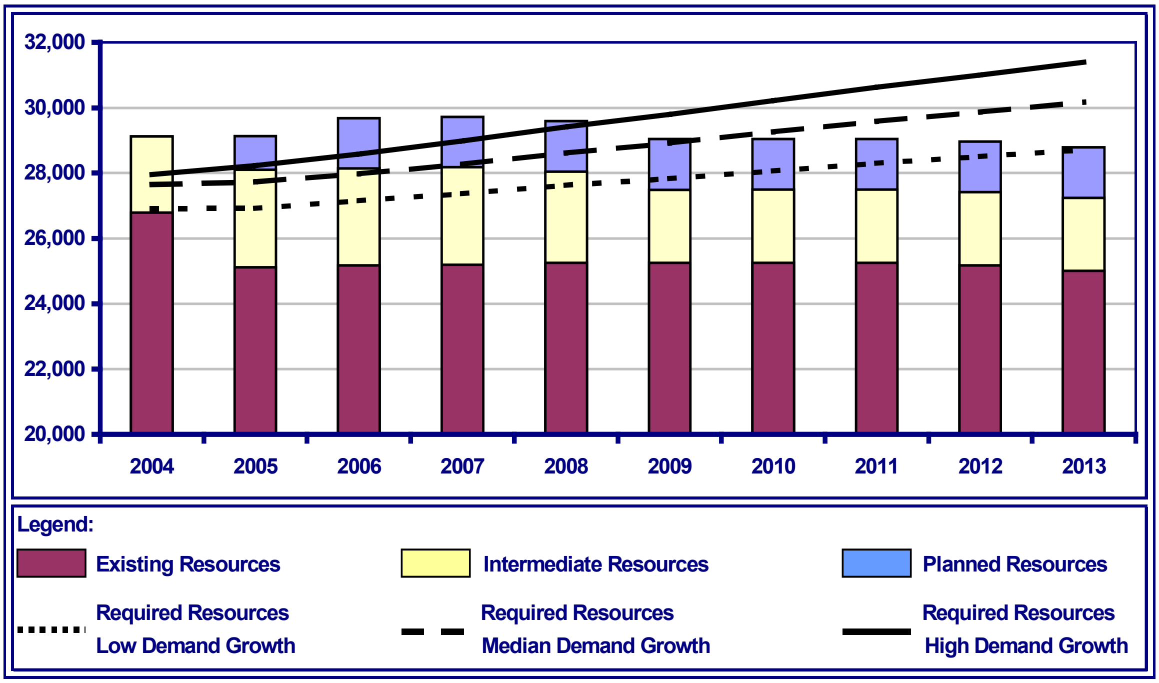
The forecast demand scenarios used to perform the adequacy assessment are the low, median and high demand growth scenarios, under normal weather conditions. Comprehensive analyses were carried out for all combinations of the three demand growth scenarios and the three resource scenarios.

3.2 L&C and MARS Results

L&C calculations were performed for the three resource scenarios described in Section 2.3, and reserve margins were calculated for the winter and summer peak of each year in the study period, for each demand scenario. The need for additional resources is indicated by negative reserve margins. Graphical results of the L&C program calculations, for the annual peaks, are shown in Figure 3.1. Tables A1 to A18 in Appendix A provide more technical details.

The MARS calculations were performed in two steps. In the first step, the same resources as in the L&C calculations were modeled in MARS. In the second step, additional supply was modeled in any scenario for which the annual Loss of Load Expectation (LOLE) was computed to be greater than 0.1 days/year. The second step was repeated, with increasing amounts of additional supply, until all annual LOLE values became less or equal to 0.1 days/year.

Figure 3.1 Resource Adequacy Outlook – Annual Peak



3.2.1 Resource Adequacy under the Existing Resource Scenario

L&C and MARS results under the Existing Resource Scenario clearly demonstrate an immediate and increasing need for additional resources in Ontario, in order to meet the 0.1 days/year LOLE target in each year of the study period. Even under the low demand growth scenario, reserve deficiencies are forecast to exist throughout the entire study period, approaching the current Ontario coincident import capability of 4,000 MW in 2013. Any events that would decrease supply availability or increase demand, such as extreme weather, higher than expected generator forced outages, and lower than forecast hydroelectric resources, would result in the inability to supply the Ontario demand, especially in the later years of the study period.

If Ontario experiences median or high demand growth over the ten-year period, the dependency on external resources is even greater. Without expansion of the current Ontario coincident import capability, reserve deficiencies of over 4,000 MW could not be made up by supply from outside Ontario even if it were available.

A combination of generation additions and demand response is required to reduce the risk of insufficient supply below 0.1 days/year level and eliminate the dependency on external resources during peak demand periods. The necessary amount of additional resources is expected to be about 6,400 MW over the Outlook period.

3.2.2 Resource Adequacy under the Intermediate Resource Scenario

Under the Intermediate Resource Scenario, L&C and MARS results indicate some delay in the need-dates for additional resources, when compared to the Existing Resource Scenario. Under the low demand growth scenario, reserve margins are forecast to become negative in 2009, and additional resources, up to approximately 1,500 MW in 2013, will most likely be required to maintain risk levels below the 0.1 days/year target. Under the median demand growth scenario, resource additions are expected to become necessary starting in 2007, increasing to about 2,900 MW in 2013. Should Ontario experience high demand growth, additional resources are forecast to be required as early as 2005.

To avoid dependency on external supply, about 4,100 MW of additional resources would have to come from some combination of demand response and additional generation, during the Outlook period.

3.2.3 Resource Adequacy under the Planned Resource Scenario

Under the Planned Resource Scenario, L&C and MARS simulation results indicate significant delay in the need-dates for additional resources, compared to the Existing Resource Scenario. Under the low demand growth scenario, reserve margins are forecast to remain positive throughout the entire study period. The amount of occasional imports that may be required to maintain risk levels below the 0.1 days/year target is not significant. Under the median demand growth scenario, resource additions are expected to become necessary by 2010, increasing to about 1,300 MW in 2013. Should Ontario experience high demand growth, additional resources are forecast to be required before 2009, increasing to approximately 2,500 MW in 2013.

In order to avoid dependency on external generation, the amounts of additional resources mentioned above would have to come from demand response combined with more generation additions than assumed under this resource scenario.

3.3 Other Considerations and Influencing Factors

There are many factors that could cause the long-term supply-demand balance to change from the assumptions used in the analysis above, and endless combinations of these factors can be postulated. On the supply side, almost all of the factors would tend to reduce the available generation from that used in the adequacy analysis. Tables A19 to A24 in Appendix A indicate the reserve margins that would result if the available generation resources are lower by 1,000 MW and 2,000 MW, respectively, than the forecast amount under the Existing Resource Scenario. They are intended as a starting point for other combinations one might consider.

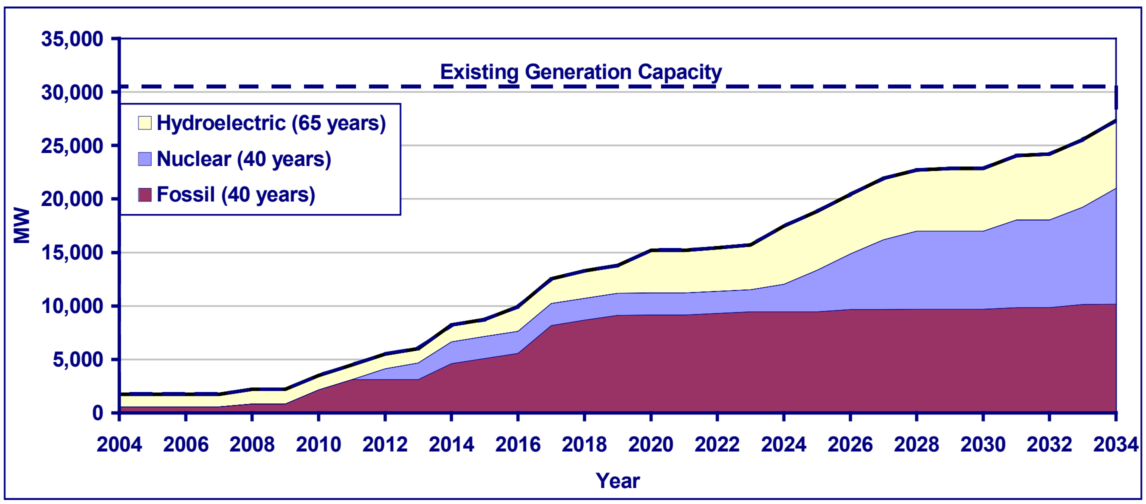
3.3.1 Demand Growth

Higher demand growth than assumed under the high demand growth scenario, would create an earlier and larger need for additional resources or demand response. Lower demand growth than assumed under the low demand growth scenario above, would delay and lower the need for additional resources.

3.3.2 Aging Generators

The increasing age of the fleet of Ontario generators is a consideration, which could lead to additional retirements or the need for major refurbishment. Age can also contribute to higher incapability factors than assumed under the three resource scenarios studied in this Outlook. Higher incapability factors are the result of longer planned and/or forced outages. Major refurbishment plans would result in longer planned outages, with increased pressure on the peak demand periods, but with predictable short-term effect on the supply availability and an improvement of long-term reliability. The lack of major refurbishment plans and timely maintenance would increase the forced outage rates of the generators, with unpredictable negative effects on reliability of Ontario generation resources. Figure 3.2 illustrates the cumulative amount of Ontario generating capacity which will exceed the indicated nominal service life over the next 30 years and which will potentially need major refurbishment or require replacement.

Figure 3.2 Capacity Exceeding Nominal Service Life



From the chart above, it is evident that more resource additions than those identified in the three earlier resource scenarios may be necessary to replace aging facilities.

3.3.3 Environmental Regulations

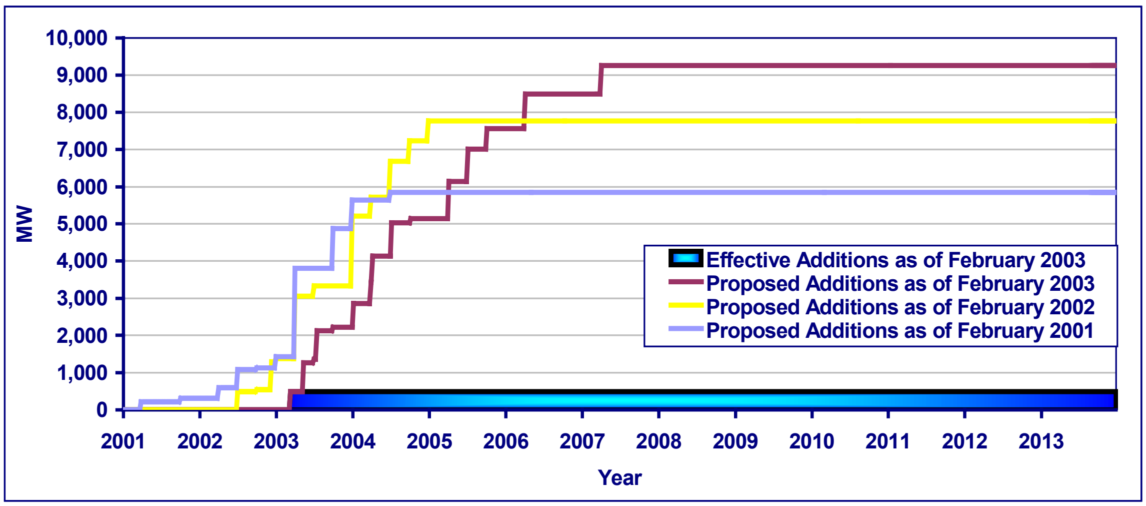
Environmental considerations may also result in either additional retirements over those already identified to the IMO or lower utilization factors for some generating units. Lakeview generating units are already expected to retire by April 2005 as a result of the government regulation requiring the plant to cease burning coal. A recent report[1] issued by the government of Ontario recommends the retirement of Atikokan and Thunder Bay generating units by July 1, 2005. These considerations further emphasize the need for additional generation or demand reduction in Ontario to replace coal-burning generating units. Even if these units are not retired over the next ten years, fossil fuel emission limits can be expected to influence installation of emission abatement measures, conversion to other fuels, or lower utilization rates.

[1] Select Committee on Alternative Fuel Sources - Final Report, 3rd Session, 37th Parliament, 51 Elizabeth II

3.3.4 Generation Additions

The amount of generation additions that will materialize over the next few years is critical for the long-term resource adequacy of Ontario. Figure 3.3 depicts the evolution of the proposed new generation additions over the last three years, as reflected by the CAA queue. While the amount of proposed new generation has constantly increased, the in-service dates for most projects have been delayed over the years. The only new generation project completed to date is the TransAlta - Sarnia Cogeneration Project. Two Bruce A generating units, expected to restart before the summer of 2003, as well as the ATCO – Brighton Beach and Imperial Oil projects identified to the IMO as being under construction, have been included under the various resource scenarios. Even if the planned additions, along with the restart of Pickering A units, are completed as scheduled, a further 2,500 MW of all generation projects submitted to the IMO for Connection Assessment and Approval (CAA) may need to materialize (or be offset by demand response) in the last years of the study period, especially under the high demand growth scenario, to maintain reserve levels at the reliability standard and avoid dependency on external resources.

Figure 3.3 Evolution of Proposed New Generation Additions



3.3.5 Capacity Sustainability

Experience over the summer of 2002 has also shown that even when sufficient capacity is available, its use can be limited because of a lack of energy. An example of this occurs when peaking hydroelectric generation is operated extensively early within a period of time, in response to market demands and, as a result, has insufficient water available in storage reservoirs to support required levels of operation later within that period. An exceptionally dry season can have the same effect. About 25 percent of the capacity within Ontario is hydroelectric with much of it subject to this risk.

- End of Section -

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4.0 Transmission Adequacy Assessment

4.1 Introduction

The transmission adequacy assessment provides information to market participants, connection applicants and other stakeholders to assist in planning a reliable transmission system. If applicable, the assessment also identifies the potential need for IMO-controlled grid investments or other actions by market participants to maintain reliability of the IMO-controlled grid and to permit the IMO-administered markets to function efficiently.

Figure 4.1 provides a simplified depiction of Ontario's major internal transfer interfaces and Ontario's points of interconnection with neighbouring control areas. The internal interfaces are also used to define the boundaries of internal zones, called transmission zones. This simplified depiction is used to assist in understanding the analytical evaluations of the Ontario transmission system.

The following assessments and summaries are presented in Sections 4.4 to 4.13, one section for each transmission zone of Ontario, starting with the Toronto zone in Section 4.4.

- A supply availability assessment of adequacy is performed by examining the impact of specific contingencies on the ability of transmission facilities to supply certain 230 kV and 115 kV loads. Specifically, load pockets greater than 500 MW and load pockets between 250 MW and 500 MW are studied.
- A contingency-based supply reliability assessment is performed by examining the impact of specific contingencies on the ability of the 500 kV and 230 kV autotransformers and transmission circuits to supply loads without exceeding equipment thermal overload capabilities. This assessment is referred to as the "contingency assessment" throughout this section.
- The steady state voltage level adequacy of the 500 kV, 230 kV and 115 kV transmission networks of the IMO-controlled grid is examined.
- As required, a summary of current and emerging transmission constraints is also included.

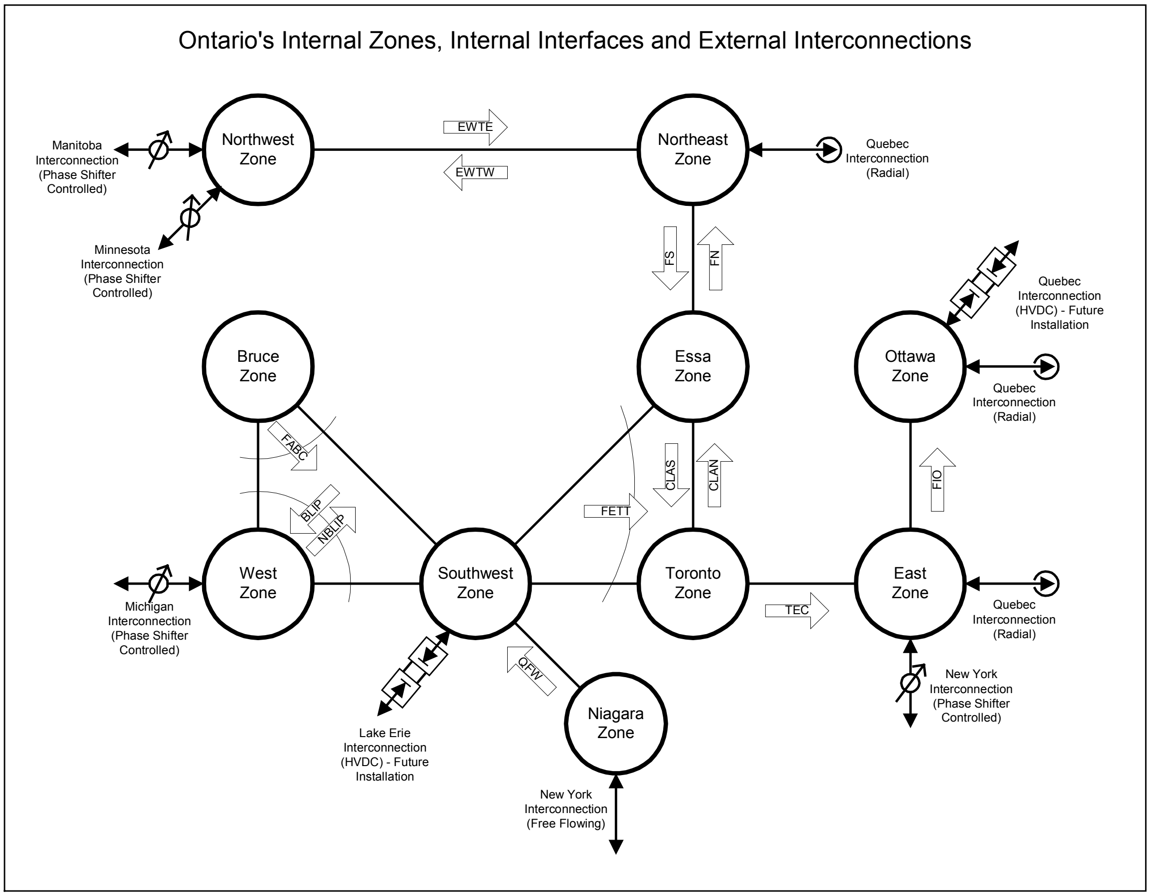
In these sections where appropriate, additional summaries are provided related to projects in the Connection Assessment and Approval (CAA) queue. Complete details on these projects can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

Section 4.14 identifies transmission interfaces that have the potential to regularly become congested and thus reduce market efficiency. Section 4.15 lists the various new transmission projects in Ontario. Conclusions are provided in Section 5.0.

The methodology used to assess the transmission adequacy is described in the IMO document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044).

Section 4.0 does not exhaustively assess all areas of the IMO-controlled grid. It is possible that other deficiencies in the IMO-controlled grid may exist or emerge. The IMO continuously monitors, assesses and reports the adequacy of the IMO-controlled grid. If additional concerns are identified they will be managed through existing IMO processes.

Figure 4.1 Ontario's Zones, Interfaces and Interconnections



4.2 Summary of Transmission Network Scenarios Used

In assessing future transmission adequacy, it is necessary to make a number of assumptions regarding the network configurations that will be available for operation. Generally, two different scenarios were assumed in this Outlook regarding the transmission network: an Existing Transmission Network Scenario and a Planned Transmission Network Scenario.

Under the **Existing Transmission Network Scenario** the transmission network studied consists of the existing transmission network as of November 2002 plus all the Ontario-Michigan phase shifters assumed installed and regulating.

Under the **Planned Transmission Network Scenario** the transmission network scenario studied consists of the Existing Transmission Network Scenario plus planned transmission facility additions in the Connection Assessment and Approval (CAA) queue. The planned transmission facilities include reactive additions at Birch and Wawa Transformer Stations (TSs), 230/115 kV autotransformer additions at Hawthorne and Kent TSs, High Voltage Direct Current (HVDC) additions across Lake Erie and with Quebec, and upgrades to the Queenston Flow West (QFW) interface. Depending on the year of study, the Planned Transmission Network Scenario is further modified to include some additional transmission reinforcements as described later in this Section.

The years 2004, 2007 and 2013 are used for the transmission adequacy assessments because they capture key points in the 10 year period where the demand, generation and transmission conditions are likely to stress the Ontario Electricity system.

The Existing Transmission Network Scenario only is used in the assessments for 2004.

For the 2007 assessments, the Existing and Planned Transmission Network Scenarios are used. In addition to these two scenarios, a third transmission network scenario is also studied where the Planned Transmission Network Scenario is modified to include additional transmission reinforcements in the West and Toronto zones. In the Toronto zone, reinforcements are defined to address supply reliability and the retirement of Lakeview Thermal Generating Station (TGS) in the Greater Toronto Area (GTA). The transmission reinforcements include a new Parkway TS, 500/230 kV autotransformers at the Milton Switching Station (SS), the decoupling of Cherrywood 500 kV autotransformers, and transmission circuits between Trafalgar and Oakville TSs and between Meadowvale TS and north Mississauga. In the West zone, upgrades to increase the thermal ratings of the Keith-Essex 115 kV circuits are modeled to address supply reliability in the Windsor area.

For the 2013 assessments, the Planned Transmission Network Scenario with the transmission reinforcements noted above is further modified to include the Greater Toronto Area (GTA) third supply proposal from the CAA queue. The GTA third supply plan has two distinct Options. To evaluate each Option, two different transmission network scenarios for the Toronto zone are considered. In the first Toronto zone network scenario, the GTA third supply Alternating Current (AC) Option is studied assuming the addition of two 500/230 kV autotransformers at Claireville TS and 230 kV busbar splits at Claireville TS. The AC Option (phase 1 and 2) includes a new 230 kV TS at Railway Lands, the addition of three new 230 kV circuits from Manby West TS to John TS, and the reconfiguration of John and Esplanade TSs to 230 kV. In the second Toronto zone network scenario, the GTA third supply Direct Current (DC) Option is used. The DC Option (phase 1 and 2) includes two DC links between the Beck 2 Generating Station in the Niagara zone and Hearn SS in the Toronto zone, with an additional DC link from Hearn SS to John TS.

4.3 Summary of Assumptions Used

Transmission adequacy is assessed using various resources and demand scenarios combined with the transmission network scenarios described in Section 4.2. For the supply availability, contingency and steady state voltage adequacy assessments involving load flow studies, summer peak conditions under the High Growth, Extreme Weather Demand Scenario are studied. For congestion assessment, using the MAPS software program, the Median Growth, Normal Weather Demand Scenario is used. These demand scenarios are described in the IMO document titled "Ontario Demand Forecast from January 2004 to December 2013" (IMO_REP_098).

In addition to the demand considerations for the transmission adequacy assessments involving load flow studies, the Existing and Planned Resource Scenarios (ERS and PRS, respectively) are studied in combination with the transmission network scenarios described in Section 4.2. These resource scenarios are described in Section 2.3 of this Outlook. In 2004 with the ERS, the load flow study does not converge without the addition of unplanned reactive sources in the Toronto zone. Since unplanned reactive resources are required in the Toronto zone before the retirement of Lakeview TGS, the ERS is not studied in 2007 and 2013. The PRS has sufficient resources to meet the summer peak demand in 2004 and 2007 but not 2013. In 2013, part of the demand is satisfied by imports from the Quebec HVDC interconnection and New York.

For the congestion assessment, the Existing and Planned Resource Scenarios are only studied in combination with the existing transmission network scenario as defined above. The ERS is not studied in 2013 because of its very low probability of occurring at that time.

Other assumptions used in the assessments are detailed in the following paragraphs.

The power factor for consumers is assumed to be 0.9 at the defined meter point consistent with the minimum market rule requirement, except for the contingency assessment of transmission circuits noted below.

Load values from the demand scenarios have been uniformly scaled by zone. This assumption may skew load distribution in the future because it does not distinguish between high and low growth pockets within zones. Some element overloads that depend strongly on the scaling assumptions (e.g. 230/115 kV autotransformers) may not materialize. Typical operating values have been used for future equipment where forecasted values are unavailable.

For the supply availability assessment, the assessment focuses on load pockets of 250 MW or greater and determines if a supply interruption occurs for a permanently faulted double circuit line. Supply is deemed inadequate for any interruption of load pockets greater than 500 MW, and for interruption of load pockets between 250 and 500 MW where there is no means for sectionalizing transmission to restore half the load within 30 minutes of the contingency.

For the contingency assessment of transmission circuits, post-contingency flows on circuits are examined for single element and double element contingencies. For single element contingencies, a circuit is noted as a potential concern if the flow exceeds its continuous ratings. For double element contingencies, a circuit is noted as a potential concern if the flow exceeds its 15-Minute Limited Time Rating (LTR). The assumption of a 0.9 power factor at the defined meter point has not been used in this analysis. A load power factor of 0.9 is used instead.

For the contingency assessment of autotransformers, the impact of a transformer contingency on specific 500/ 230 kV and 230/115 kV transformation points of the IMO-controlled grid is examined. Upon loss of an autotransformer within a transformation point, the remaining autotransformers at the transformation point should continue to supply the required load. For those 230 kV autotransformers that feed radial loads, adequacy is determined by comparing total station or group load with the sum of 10-Day LTRs with one autotransformer out of service. For 500 kV and those 230 kV autotransformers that do not feed radial loads, outage distribution factors based on the Existing Transmission Network Scenario are used to determine the post-contingency flow on the remaining autotransformers. The resulting post-contingency flow on each autotransformer is then compared to its 10-Day LTR to determine if there is a potential concern. Finally, a similar assessment based on double element contingencies is conducted to determine if the post-contingency loading on an autotransformer exceeds its 15-Minute LTR.

4.4 Toronto Zone

4.4.1 Greater Toronto Area (GTA) Transmission Reinforcement

Significant transmission reinforcement has been identified for the Greater Toronto Area (GTA) in order to maintain an acceptable level of supply reliability over the Outlook period 2004 to 2013. The need for transmission reinforcement is due to forecast load growth in downtown Toronto and in the municipalities north, west and southwest of Toronto, as well as the removal from service of Lakeview Thermal Generating Station (TGS) when it ceases to burn coal in 2005.

Supply to Municipalities within the GTA - excluding the Downtown Area

The high rate of load growth in the municipalities of Newmarket, Aurora, Markham, Richmond Hill, Vaughan, Mississauga, Brampton, Milton and Oakville located to the north, west and southwest of Toronto has created an early need to increase the supply capability to these areas. The specific transmission additions or modifications that are required are described below.

Supply to the Newmarket, Aurora, Markham, Richmond Hill and Vaughan Areas

Since many of the loads in these areas are supplied radially via 230 kV double circuit lines, it is proposed that a new 230 kV Switching Station (SS) be established at Parkway Junction.

As shown in Appendix C, Diagram 1, the 230 kV circuits to Richmond Hill Transformer Station (TS) No. 2 would be extended to the new Parkway SS, and the radial circuits to Buttonville TS would be extended to Armitage TS, which supplies the Newmarket/Aurora area. This would provide each of the major load centres with an alternative supply source and thereby maintain the supply reliability for these loads.

Supply to the Northern Mississauga, Brampton, Milton and Town of Halton Hills Areas

A similar situation exists for the loads in the above areas; to maintain supply reliability it is proposed to establish a new 230 kV Switching Station (Hurontario SS) on the right-of-way of the existing 230 kV double circuit line to Pleasant TS and Jim Yarrow TS. The radial circuits to Bramalea TS and to Meadowvale TS would also be extended to terminate at the new SS. Extending the 230 kV circuits from Bramalea TS to the new SS would also allow for the future development of a new TS to supply northern Mississauga. The proposed arrangement is shown in Appendix C, Diagram 2.

Supply to the Southern Mississauga and Southern Oakville Areas

The supply to southern Mississauga and southern Oakville is presently provided by a radial double circuit line that is tapped on to the Richview TS to Lakeview SS circuits. To maintain the supply reliability to these substantial loads it is proposed that the radial line be extended and terminated at Trafalgar TS as shown in Appendix C, Diagram 3.

230 kV Transmission Reinforcement

Diagram 4 in Appendix C shows that by establishing both Parkway TS and Hurontario TS, as well as completing the proposed extension of the existing 230 kV transmission lines, an outer 230 kV ring would be established around the GTA to supply the increasing load through those areas.

It should also be noted that this transmission development would be fully compatible with the Sithe generation projects at Goreway and Southdown should a decision be made to proceed with either or both projects.

- In order to maintain the reliability of the supply to the municipalities in north, west and southwest areas of the GTA, the IMO requires that either the transmission reinforcement as described above, or an acceptable equivalent, be placed in-service as soon as possible and no later than 2005.

Impact of the Shutdown of Lakeview TGS

Lakeview TGS is required to cease operation as a coal-fired generating station by April 30, 2005. At that time, the approximately 1,200 MW supply deficit in the western half of the GTA would need to be met either through the development of a comparable amount of new generation capacity or through increased transmission supply into the area.

During the summer peak demand periods of 2002, with Lakeview TGS operating at full output, the 500/230 kV autotransformers at Cherrywood TS, Claireville TS and Trafalgar TS were all loaded to their nameplate ratings, leaving no capacity to accommodate increased transfers. Consequently, to accommodate the increased supply from the 500 kV system that will be necessary to compensate for the lost output from Lakeview TGS, additional 500/230 kV autotransformers will need to be installed.

Studies have shown that a predominant proportion of the additional imports would be expected to appear on the autotransformers at Claireville TS (50%) and Trafalgar TS (35%). However, since installing additional autotransformers at Claireville TS would be expected to trigger a need to operate with the 230 kV busbar split in order to respect the fault interrupting capability of the existing breakers at that TS, that location has been avoided. It is therefore proposed that two 500/230 kV autotransformers should be installed at the new Parkway TS and a further two 500/230 kV autotransformers should be installed either at Milton TS or at Trafalgar TS.

The two autotransformers at Parkway TS, together with the 230 kV transmission reinforcement identified for improving the supply reliability to the loads in the northeastern portion of the GTA would allow some of the loads that are presently supplied from Claireville TS to be supplied from Parkway TS.

Similarly, installing two autotransformers at Milton TS (or at Trafalgar TS), together with the 230 kV transmission reinforcement previously identified for maintaining the supply reliability to the loads in the northwestern portion of the GTA, would allow some of the loads that are presently supplied from Claireville TS to be transferred to Milton TS (or Trafalgar TS).

Transferring some of these existing loads would then leave adequate autotransformer capacity available at Claireville TS to accommodate the increased transfers required to compensate for the loss of the generation capacity at Lakeview TGS.

Diagram 5 in Appendix C shows the proposed arrangement of the new autotransformers at Parkway TS and Milton TS.

This Diagram also shows the proposed retermination of the paired 500/230 kV autotransformers at Cherrywood TS to increase the transfer capability through that station by eliminating the requirement to respect the simultaneous loss of two autotransformers.

Reactive Power Compensation

When all four generating units are operating at Lakeview TGS they are able to provide approximately 600 MVAr of reactive support to the western area of the GTA. When these generating units are retired, the increased transfers through the transmission system to compensate for the approximately 1,200 MW loss of output will result in a reactive power deficit in the area totaling approximately 1,000 MVAr.

Hydro One has recently submitted a proposal to install either two static VAr compensators (SVCs), each rated at 60 MVAr, or two shunt capacitor banks, each rated at 200 MVAr. These are to be installed either at Lakeview SS or in the immediate area, and while they would be beneficial, there will still be a substantial reactive power deficit when Lakeview TGS is retired. It should also be noted that while additional shunt capacitive devices would help maintain acceptable voltage levels, the area will need 'dynamic' compensation from generators, synchronous condensers and/or SVCs to manage the risk of area voltage collapse.

- The IMO therefore invites market participants to submit proposals by no later than **June 30, 2003** for the installation of additional reactive power sources within the western half of the GTA.
- To maintain the reliability of the supply to the Toronto area, the IMO requires that the additional 500/230 kV autotransformers as described above, together with any associated changes to the transmission system, be placed in-service no later than the shutdown date for Lakeview TGS.

Impact of Pickering A Units on Reactive Power Compensation

The 2004 study with the Planned Resource Scenario showed that five Pickering units were sufficient to provide the voltage control requirements for the eastern part of the GTA.

Cherrywood TS

In the last 10-Year Outlook, the IMO raised concerns regarding the reduced transfer capability through Cherrywood TS due to a requirement to respect the simultaneous loss of either of the paired groups of 500/230 kV autotransformers at that station. The IMO recommended that measures should be implemented so that each autotransformer would be individually terminated on to the 500 kV busbar.

Hydro One Networks Inc. has recently submitted an application seeking approval to proceed with the work involved for modifying the terminations for the four autotransformers at Cherrywood TS. This work is scheduled to be completed in Q2-2004.

Supply to Downtown Toronto

Concerns regarding the continued reliability of the supply to downtown Toronto, due to thermal limitations on the existing transmission facilities in the Leaside sector, and a need for an additional (third) supply to downtown Toronto were described in the IMO's previous 10-Year assessment dated April 3, 2002.

Based on Toronto Hydro's most recent load forecast, additional supply capability for downtown Toronto will be required before the summer of 2008. However, recognizing the uncertainty inherent in such a forecast, and the vital need to maintain supply reliability in this area, the IMO considers it prudent to ensure that additional supply capability is available beginning in the summer of 2006. This additional supply capability can take the form of some combination of additional transmission capability, new generation and increased demand response.

Additional Transmission Capability

Hydro One Networks Inc. responded to the IMO's concern regarding supply to downtown Toronto with a proposal to establish a third supply to the downtown Toronto area. Two distinct options have been proposed for establishing this new supply:

1. 230 kV Alternating Current (AC) Option

    This option involves a new 230 kV connection from the existing transmission system in the Manby area and the conversion of some of the existing transformer stations to 230 kV operation so that they can be supplied from the new connection. This would also make capacity available to supply the new loads that are expected to emerge as the Railway Lands and Port Lands are developed.

    The transfer of some of the existing loads to the new 230 kV supply would reduce the present loading on the facilities in both the Manby and Leaside sectors, providing scope within the rating of the existing transmission facilities to cater for future load growth in both of these sectors.

    This project would be developed in two phases and the proposed arrangement for the 230 kV AC Option is shown in Appendix C, Diagram 6.

2. Direct Current (DC) Option

    This option involves a new DC connection from Beck 2 GS in the Niagara zone to connect to Hearn SS (Leaside sector) and John TS (Manby sector).

    By providing direct injections into the remote portion of both the Leaside and Manby sectors, the DC connection would also reduce the loading on the existing facilities in the two sectors, providing scope for future load growth.

    This project would be developed in two phases and the proposed arrangement for the DC Option is shown in Appendix C, Diagram 7.

Both Options have been assessed by the IMO through the Connection Assessment and Approval (CAA) process, and both Options are acceptable to the IMO from a system reliability perspective.

However, the 230 kV AC Option, since it involves the transfer of load from the Leaside sector to the Manby sector, would require the installation of two additional 500/230 kV autotransformers at Claireville TS and two new 230 kV circuits between Richview TS and Manby TS to accommodate the increased flows. Furthermore, the installation of the two additional autotransformers would be expected to trigger a requirement for operating the 230 kV busbar at Claireville TS split. This would also require retermination of a number of the existing 230 kV circuits. The proposed transmission reinforcement is shown in Appendix C, Diagram 8.

No comparable reinforcement of the transmission system would be required for the DC Option.

Since the DC Option would require relatively minor system upgrades (including the rebuilding of the Hearn 115 kV switchyard) and since it would also result in reduced transfers across the QFW interface, this Option is preferred by the IMO.

In addition, the IMO considers that significant system benefits would be obtained by staging the development and undertaking that part of the DC Option involving the DC connection between Hearn SS and John TS, as soon as possible.

- If the DC Option is selected for development, the DC connection between Hearn SS and John TS should be completed as soon as possible but no later than the summer of 2006. This may allow a deferral in the completion of the remainder of Phase 1 (the underwater connection to Beck GS) of the Project. However, further assessment will be required and this could be influenced by OPG's plans for developing the Portlands Energy Centre Project.
- Should the AC Option be selected for development, then Phase 1 (two new 230 kV circuits and the associated TSs), together with the associated system reinforcement shown in Appendix C, Diagram 8, will need to be placed in-service before the summer of 2006.

Portlands Energy Centre Project

For the Portlands Energy Centre project, the IMO has completed its assessment of an alternative connection arrangement that has been shown to avoid the requirement to rebuild the entire 115 kV switchyard at Leaside TS. The complexity of undertaking this work while maintaining the supply to the Leaside sector was expected to seriously delay the target in-service date of the project.

To incorporate the new generating facility, two of the existing 115 kV breakers at Hearn SS would need to be replaced with breakers having a higher fault rating. In addition, temporary neutral reactors would need to be installed to coincide with the return to service of the Pickering A generating units.

Since the Hearn 115 kV switchyard would need to be rebuilt should the DC Option be selected for the third Supply to Downtown Toronto, the IMO supports the advancement of this work rather than undertaking the required replacement of the two breakers. This would also have the added benefit of allowing the Portlands Energy Centre Project to be terminated permanently into the new switchyard.

Although the alternative connection arrangement for the incorporation of the new generating facility is acceptable to the IMO, approval has only been given on the assumption that the third Supply to Downtown Toronto will proceed on schedule. With increasing load growth within the Downtown area, particularly at both Esplanade TS and Terauley TS, the ability of the new generation capacity to back off the flows on the critical cabled circuits into Terauley TS will diminish. It is therefore imperative that the third Supply still be developed to provide an additional supply injection into the Leaside sector via Hearn SS.

4.4.2 Load flow Study Results and Existing and/or Emerging Constraints

Using the High Growth, Extreme Weather Demand Scenario, the supply availability assessment indicates that to the north and west of downtown Toronto there are several load pockets greater than 500 MW that could be interrupted by a double circuit line contingency. In the 2007 and 2013 studies, the Planned Transmission Network Scenario with the transmission reinforcements for the Greater Toronto Area (GTA) remedies some of these situations. By 2013, load growth causes a load pocket in the east part of the Toronto zone west of the Transfer East Cherrywood (TEC) interface to increase beyond 250 MW. A double circuit line contingency will result in loss of this entire load pocket with no facilities available to restore at least half the load within 30 minutes.

For each selected year of study, a Cherrywood-Leaside 230 kV circuit and a Cherrywood-Richview 230 kV circuit may become thermally overloaded above their 15-Minute rating for several double element contingencies which are not currently respected by the IMO. In the 2004 studies, the Cherrywood-Leaside circuit also becomes thermally overloaded upon loss of Cherrywood 500 kV autotransformers T14 and T17, which is considered a single contingency since the autotransformers are connected as a pair. In the 2007 and 2013 studies with the Planned Transmission Network and transmission reinforcements for the GTA, the re-termination of the 500 kV autotransformers as single connections eliminates this possible overload condition on the Cherrywood-Leaside circuit. Hydro One Networks has recently submitted a proposal under the Connection Assessment and Approval (CAA) process to re-terminate the Cherrywood autotransformers as single connections.

In 2004 with the Existing Transmission Network Scenario and in 2007 with the Existing and Planned Transmission Network Scenarios, the contingency assessment of 500 kV autotransformers did not show any potential concerns with the 10-Day LTR transfer capability following the loss of an autotransformer. However, at both the Claireville and Cherrywood 500 kV transformation points, the post-contingency flows exceed the continuous ratings of the remaining autotransformers. Based on summer peak conditions from 2002, pre-contingency flows on the Claireville autotransformers exceeded their continuous ratings. In 2007 and 2013, when the Planned Transmission Network Scenario is studied with the postulated transmission reinforcements for the GTA, pre-contingency flows reduce significantly at Cherrywood and Claireville. No potential concerns are observed for the 230 kV autotransformer assessments. Result tables can be found in Appendix B.

For the 2004 and 2007 studies with Existing Transmission Network Scenario, the steady state 230 kV voltage level at Manby is below the minimum requirements to ensure secure operation under summer peak conditions. In the 2007 study with the Planned Transmission Network Scenario and no transmission reinforcements for the GTA, the voltage levels do not change when compared to the 2007 study with the Existing Transmission Network Scenario. In the 2007 study with GTA transmission reinforcements, all voltage levels are above minimum requirements. For the 2013 studies, the voltage levels at Cherrywood (500 kV and 230 kV), Richview (230 kV), Manby (230 kV and 115 kV) and Leaside (115 kV) stations are below minimum requirements under summer peak conditions. This suggests that additional reactive resources may be required even with the third supply DC or AC enhancements and reactive power of 1,000 MVAr at Lakeview SS.

4.5 Southwest Zone

4.5.1 Load flow Study Results and Existing and/or Emerging Constraints

For each selected year of study, the supply availability assessment shows that the Detweiler operating area, encompassing Kitchener-Waterloo, Cambridge and Guelph, is susceptible to supply interruptions for double circuit line contingencies, independent of the transmission network scenario considered. Under the High Growth, Extreme Weather Demand Scenario, the loads in this area range from 250 MW to 500 MW. Since the loads are approaching 500 MW, which is considered unacceptable under these circumstances, transmission reinforcements to provide sectionalizing capability to the supply points in this area may not be sufficient. If the load level exceeds the 500 MW level, new transmission facilities may be required.

The contingency assessment of transmission circuits in the Southwest zone did not reveal any potential concerns under the study scenarios. However, a transmitter-submitted study to the IMO identified existing high line loading of 115 kV circuits D7G and D9G that can cause reliability issues for the Kitchener and Guelph areas supplied by these circuits. Specifically, thermal overloads on circuit D7G can potentially occur under peak conditions for a contingency involving the loss of circuit D9G.

The 230 kV autotransformer contingency assessment reveals that the post-contingency loading on the Burlington 230/115 kV transformation point may be a potential concern following the loss of an autotransformer under summer peak conditions. The 10-Day Limited Time Rating (LTR) transfer capability of the remaining autotransformers is exceeded, regardless of the transmission network scenario studied, for each year of study. For this assessment, based on single autotransformer contingencies, the post-contingency loadings also exceed the 15-Minute LTR transfer capability for each year of study. Result tables can be found in Appendix B.

Although not reflected in the study results, possibly due to the load scaling and power factor assumptions, the Detweiler 230/115 kV transformation point is also a potential concern based on summer peak loading conditions from 2002. The 2002 loadings suggest that on loss of a particular autotransformer, the post-contingency flows would have been very near the continuous transfer capability of the remaining autotransformers at Detweiler.

For the 500 kV transformation points in the Southwest zone, no thermal overloads occur at Middleport or Trafalgar following the loss of an autotransformer under summer peak conditions. However, in the 2007 study with the Existing Transmission Scenario, the post-contingency flow at Trafalgar is near but below the 10-Day Limited Time Rating (LTR) of the remaining autotransformer. Pre-contingency loadings of the Trafalgar autotransformers reduce significantly when the transmission reinforcements for the Greater Toronto Area (GTA) are added to Planned Transmission Network Scenario for the 2007 studies. For the 2013 studies, the pre-contingency loadings at Trafalgar do not materially change from 2007 with the incorporation of either of the GTA third supply options. Result tables can be found in Appendix B.

Respecting minimum required voltage levels under summer peak conditions is also a potential concern when the minimum market rule requirement of a 0.9 power factor is assumed at the defined meter point. Specifically, the 500 kV voltage levels at Milton and the 230 kV voltages at Detweiler are below minimum levels for each selected year of study, independent of the transmission network scenario considered. Depending on the transmission network scenario and the year studied, 230 kV voltage levels below minimum requirements also occur at Middleport, Orangeville and Trafalgar Transformer Stations. The 115 kV voltage levels at Seaforth, Detweiler, Beach and Burlington are also lower than typical operating levels for the various studies. In some cases, the Beach and Burlington 115 kV voltage levels are below the minimum requirement of 113 kV.

The existence of a load rejection scheme at Stayner Transformer Station is indicative of a known supply deficiency to that area. This scheme is armed during cold weather conditions during the winter as much of the load in the area is related to the ski industry. As winter peak conditions were not explicitly studied for this Outlook, no potential concerns have been identified for this area. However, this situation requires monitoring to ensure that the customers in this area can continue to be supplied reliably.

4.5.2 Lake Erie HVDC Interconnection Project

There is a proposal by Hydro One and TransEnergie US to construct a 990 MW High Voltage Direct Current (HVDC) interconnection, which would connect at the Nanticoke Thermal Generating Station (TGS) and cross Lake Erie. The proponents of this project have indicated an in-service date that is not expected to be earlier than the second quarter of 2006.

The addition of the proposed interconnection would have no adverse impact on the transfer capability and performance of the Ontario transmission system. However, fault levels at Nanticoke TGS would increase. As a result, the fault interrupting capability of certain Nanticoke 230 kV breakers would be exceeded. If this project is constructed, mitigating measures will be required to reduce fault levels at Nanticoke.

4.5.3 Caledonia Transformer Station Project

Hydro One Networks Inc. has received approval to install two new 230/115 kV autotransformers with rated installed transformation of 75/125 MVA each, at Caledonia Transformer Station (TS) and to modify the system connectivity in the area to facilitate the supply of Norfolk TS from the new autotransformers. The target in-service date for the facility is May 1, 2004.

The proposed transmission modification will result in the removal of the Norfolk TS load from the Allanburg 115 kV load pocket and re-supply of this load directly from the Nanticoke TGS to Middleport TS 230 kV circuits. The assessment concluded that the proposed development would:

- Provide some relief to the loading on the Allanburg autotransformers,
- Contribute to congestion on the Queenston Flow West (QFW) interface,
- Result in an improvement of the 115 kV level voltage at Norfolk TS,
- Result in an improvement in the reliability of supply for Norfolk TS.

4.5.4 Burlington Area Transmission Project

As part of the Connection Assessment and Approval (CAA) for the new Dundas Transformer Station (TS) #2, an examination of the Burlington 115 kV system was performed. A number of concerns appeared with respect to the capability of the present transmission facilities to continue providing reliable load supply beyond 2004. The assessment concluded that the maximum power transfer capability of Burlington 230/115 kV transformation facilities could be exceeded and 115 kV voltages could be lower then required for summer peak load conditions.

The CAA assessment revealed the following findings:

- With all transmission elements in service the power flows are expected to be within the continuous thermal capability of the respective elements.
- By 2003 or 2004, with one autotransformer out of service, the peak Burlington area load could exceed the Burlington TS transformation capability.

- For a contingency associated with one Burlington 230/115 kV autotransformer, the post-contingency power flow over at least one of the remaining autotransformers could exceed its 10-Day Limited Time Rating (LTR).
- For a contingency involving autotransformer T6 or T9 and assuming that bus-tie breaker H1H2 does not operate, both autotransformers will be temporarily lost by configuration and the flows on the remaining two autotransformers exceed their 15-Minute LTRs.
- For a contingency involving autotransformer T4 or T12 and assuming that bus-tie breaker A1A2 does not operate, both autotransformers will be temporarily lost by configuration and the flows on the remaining two autotransformers exceed their 15-Minute LTRs.
- A contingency involving the 115 kV double circuit line B12 and B13 will result in post contingency loading of the remaining circuits to about 96% of their emergency ratings.
- Pre-contingency voltages at Burlington 115 kV bus could be as low as 118 kV and, at Brant TS and Cedar TS could potentially be lower than 113 kV.

It is recommended that Hydro One Networks initiate a study to identify options for addressing IMO's concerns with respect to near-future limitation of the Burlington 230/115 kV transformation capability.

Hydro One Networks has recently submitted a proposal under the CAA process to add a 125 MVAr, 115 kV capacitor bank at Burlington TS. This capacitor bank will provide additional voltage support and will also reduce the MVAr loading through the Burlington autotransformers.

4.5.5 Detweiler Autotransformer Replacement Project

Hydro One Networks has recently submitted an application to replace the Detweiler T3 autotransformer, one of the 230/115 kV autotransformers at Detweiler. The T3 is the lowest rated autotransformer at this location and its replacement will help to alleviate potential loading concerns at this transformation point under peak conditions.

4.6 West Zone

4.6.1 Load flow Study Results and Existing and/or Emerging Constraints

Transmission adequacy assessments relating to contingency assessment of 500 kV autotransformers did not show any potential concerns.

Under the High Growth, Extreme Weather Demand Scenario during summer peak conditions, the supply availability assessment shows a load pocket consisting of between 250 MW and 500 MW, located east of Scott TS and west of Buchanan TS, that would experience a supply interruption as a result of a double circuit line contingency. However, since one of these supply circuits is equipped with sectionalizing devices, it should be possible to restore at least half the load within 30 minutes. This potential for a supply interruption was identified for each study year regardless of the transmission network scenario studied.

The contingency assessment of transmission circuits did not indicate any potential concerns except for the Windsor area 115 kV circuits J3E and J4E. In the 2004 study under the Planned

Resource Scenario (PRS), the pre-contingency flow on 115 kV circuit J4E exceeds its continuous rating. In the 2007 and 2013 studies with the PRS and the upgrades to increase the thermal ratings of J3E and J4E, the pre-contingency flow on J4E did not exceed its continuous rating. However, in the same 2007 and 2013 studies, upon the loss of one these circuits, the post-contingency flow on the remaining companion circuit did exceed its continuous rating. Normally, as is required in the real-time operation of the Windsor operating area, the thermal overloading of this circuit would be protected by the operation of the Windsor Area Overload Protection System.

As detailed in Appendix B, Table B2, the contingency assessment of 230 kV autotransformers suggests that there may be potential concerns at the Buchanan and Scott Transformer Stations under summer peak conditions. At Scott, for the loss of autotransformer T6, loading on the remaining autotransformer, T5, will exceed its 10-Day Limited Time Rating (LTR) for each study year and each associated transmission network scenario. At Buchanan, the 230/115 kV transformation point may also become thermally overloaded for the loss of an autotransformer. This potential overload is observed for all study years and corresponding transmission network scenarios. However, a comparison of the Buchanan study loadings to actual 2002 summer peak loadings shows that the actual loadings were significantly lower. This discrepancy may be attributed to the study assumptions on load distribution and power factor.

In 2013 with all generating facilities in the Windsor area in-service, a double circuit line contingency involving 230 kV circuits C22J and C24Z will result in a post-contingency flow on Keith autotransformer, T11, exceeding its 15-Minute LTR.

The load flow studies show that the 500 kV steady state voltage levels are above minimum requirements. The 230 kV voltage levels at Buchanan TS in the 2013 studies are below minimum requirements. The 115 kV voltage levels at Lauzon TS in the 2013 studies are below the minimum requirements of 113 kV.

The ability of the existing transmission facilities to supply the Windsor area is a concern to the IMO for several reasons. The addition, in the 1990s, of non-utility generation to the 115 kV system near Windsor has helped stabilize voltage levels and alleviate equipment loading. This generation has been incorporated without the need for special protection systems. However, the incorporation of any new generation to this area will rely heavily upon special protection systems even for single element contingencies. A transmission system that relies on Special Protection Systems for single element contingencies with all elements in-service needs to be expanded with additional transmission facilities.

To coincide with the scheduled in-service date for the new ATCO - Brighton Beach generating facility, Hydro One is replacing the existing Windsor Area Overload Protection System with a new connectivity-based facility to initiate both generation rejection and splitting of the Windsor area 115kV transmission system.

While this will provide greater flexibility in the operation of the Windsor area transmission system, the IMO has some additional concerns regarding the ability of the existing transmission facilities in the Windsor area to provide a reliable supply under contingency conditions.

In particular, for contingencies involving either of the 115 kV circuits J3E or J4E, between Keith TS and Essex TS, the splitting of the 115 kV busbar at Essex TS is designed to transfer the major portion of the load supplied from the local 115 kV system on to Lauzon TS, to avoid thermally overloading the companion circuit. Once the new ATCO - Brighton Beach generation project comes into service in Q2-2004 it will provide an additional power injection into the 115 kV busbar at Keith TS, enhancing the ability to supply a greater proportion of the local 115 kV area load.

With this enhanced supply capability, the need to split the 115 kV system in response to 115 kV contingencies could be avoided if the thermal rating of the Keith-Essex 115 kV circuits were higher. Alternatively, if the 115 kV system still needed to be split, then with the rating of these circuits increased, it could be done in such a manner that the greater portion of the local 115 kV load continued to be supplied from Keith TS. This would also require the reconfiguration of some of the circuit terminations at Essex TS.

Although the temporary near-term reduction in load that is expected to occur in Windsor as a result of some recent auto sector announcements may allow the upgrading of the Keith-Essex 115 kV circuits and that of the 115 kV busbar at Essex TS to be deferred, this work will eventually need to be completed to accommodate any future load growth within the Windsor area. However, the IMO has concerns about undertaking this work after the ATCO - Brighton Beach project has been placed in-service. The outages that are expected to be required for reconductoring the Keith-Essex 115 kV circuits could seriously impact the operation of the new generating facility.

The IMO therefore recommends that Hydro One attempt to complete this work before the ATCO - Brighton Beach generation project is scheduled to be in-service. While the advantages of an early in-service of the Keith-Essex 115 kV circuit upgrades are recognized, Hydro One has indicated that the thermal upgrades will not be completed before the ATCO - Brighton Beach in-service date, since the need to undertake this work has only been recently identified by the IMO and in view of the lead time required for this type of project.

While the upgrading of 115 kV circuits J3E and J4E would allow more of the Windsor area load to be supplied from Keith TS when the ATCO - Brighton Beach generation project is in-service, the existing autotransformers at Keith TS would limit this capability when ATCO - Brighton Beach is not dispatched. This would require either the replacement of the existing autotransformers with higher rated units or the operation of ATCO - Brighton Beach during peak load conditions.

In addition to enhancing the transfer capability between Keith and Essex, the IMO also suggests that the transmitter consider transferring some of the existing load in the Kingsville/Leamington area on to a new supply point, and/or increasing the transfer capability of the 230 kV transmission facilities into Lauzon TS together with an increase in the capacity of autotransformers at that location. Increasing the Lauzon transfer capability could involve a new 230 kV connection between Keith TS and Lauzon TS, together with an associated new 230/115 kV autotransformer at Lauzon.

Hydro One has proposed the transfer of the Tilbury area load away from Lauzon through the addition of new autotransformer facilities at Kent. Such a transfer would provide limited relief to the Kingsville area and thereby, allow local voltages to be maintained above the minimum market rule requirements.

The 230 kV transmission corridor between Lambton TGS and Chatham TS is a significant bottleneck both to imports and to internal generation within the Scott operating area. Without imports from Michigan, control actions must be in place under hot windless conditions to avoid 230 kV circuit L28C from exceeding its continuous rating for the loss of circuit L29C. The only effective control action is to limit generation in the Scott operating area. Increasing the transfer capability between Lambton and Chatham would alleviate this bottleneck. Replacing the 115 kV circuit N5K with a new 230 kV or 500 kV circuit between Lambton and Chatham is an option that would increase the transfer capability.

The transmitter studies submitted to the IMO regarding the addition of a Longwood-Lambton 500 kV circuit and 70 percent series compensation of 500 kV circuit N582L do not indicate significantly changed flows in western Ontario for the resource scenarios considered in this Outlook. These modifications would be more valuable if the generation-load balance in the West zone changes significantly. For example, if most of the generation projects currently in the Connection Assessment and Approval (CAA) queue were to materialize, congestion in the West zone would likely occur. The proposed transmission projects would reinforce the network in western Ontario and alleviate that congestion.

4.6.2 Imperial Oil Generation Project

Imperial Oil is proceeding with the installation of a 112MVA gas-turbine-generating unit at its complex in Sarnia. This is scheduled to be placed in-service in Q2-2004.

This facility is intended to displace existing load at the Imperial Oil complex and will not normally deliver surplus output to the IMO-controlled grid. However, to cater for situations where there is an inadvertent loss of load while deliveries are being made to the system, the existing Sarnia-Scott G/R Scheme is to be enhanced. The Scheme will then have the capability of initiating rejection of the new generating unit should a contingency occur involving either of the 230kV circuits to Sarnia-Scott Transformer Station.

4.7 Ottawa Zone

4.7.1 Load flow Study Results and Existing and/or Emerging Constraints

Transmission adequacy assessments relating to supply availability and contingency assessment of autotransformers did not show any potential concerns.

With a minimum market rule requirement of 0.9 power factor at the defined meter point, the 500 kV voltage levels in the load flow studies for the study years are lower than typical operating levels but above the minimum market rule requirement of 490 kV. The 230 kV and 115 kV voltage levels are adequate.

As detailed in Section 4.7.3, the installation of a new 230/115 kV autotransformer and new 115 kV circuits at Hawthorne will help to reinforce the supply to the city of Ottawa. The planned reinforcement leaves some problems unresolved. Only the Bilberry Creek portion of load on 115 kV circuit H9A can be readily transferred to another Ontario supply. The rest of the H9A load could be supplied only if a supply from Quebec is available. If 115 kV circuit H2A is removed from service, there is not enough thermal capability on H9A to accommodate the Bilberry Creek load that could be transferred.

The lack of thermal capability on H9A is also confirmed in the contingency assessment of transmission circuits for the Ottawa zone. For each study year, 115 kV circuit H9A becomes thermally overloaded on loss of 115 kV circuit H2AR. The transmitter should consider upgrading the thermal rating of this circuit.

4.7.2 Quebec HVDC interconnection Project

Hydro One Networks plans to build a 1,250 MW High Voltage Direct Current (HVDC) interconnection with Quebec. Two 230 kV circuits are required for this project, each approximately 35 kilometers long, connecting from the Hawthorne Transformer Station (TS) in Ottawa, running through Gamble Junction and then crossing over the Ottawa River to Outaouais Substation in Quebec. The proponent has indicated a probable in-service date of the third quarter of 2005. The Ontario Energy Board has given Hydro One Networks a Leave-to-Construct approval for this project.

New facilities will be added at Hawthorne TS to accommodate the new circuits and the expected increase in power flow through the station. The new facilities will also include two new shunt capacitors rated at 200 MVAr each.

At the Outaouais Substation, Hydro Quebec will install two single pole 625 MW HVDC converters. New transmission circuits will also be built by Hydro Quebec to improve the security of supply to the Outaouais Area.

The proposed facilities will have no adverse impact on the adequacy or the performance of the Ontario transmission system. In fact, the proposed facilities should improve the reliability of the Ottawa transmission zone during import conditions as it provides greater supply diversity. The Flow Into Ottawa (FIO) transfer limit is expected to increase from 1,900 MW to 3,000 MW.

The HVDC interconnection can affect the transfer capability of the Ontario – New York St. Lawrence interconnection during conditions of simultaneous maximum imports/exports. Under these conditions, the Ontario – New York St. Lawrence interconnection may become thermally overloaded for the loss of the HVDC interconnection. Currently, the transfer limit on the Ontario – New York St. Lawrence interconnection is based on the loss of one of the companion 230 kV circuits, L33P or L34P. With the addition of the HVDC interconnection, the transfer capability limit of this interface will have to be based on the loss of the HVDC interconnection. If under certain scenarios, the import or the export to New York becomes limited due to the HVDC transaction with Quebec, then the transfer on the HVDC interconnection may have to be restricted. It is estimated that without mitigating measures, the HVDC interconnection could restrict the flow at the New York St. Lawrence interconnection by up to 100 MW. It is expected that any operating restrictions required to remove transfer limitations on L33P and L34P will not have a material effect on the utilization of this interconnection. If full utilization of the Ontario – Quebec interconnection is desired, then the transmitter could consider the addition of the loss of the HVDC interconnection to the Saunders generation rejection scheme.

The L33P and L34P phase shifters reach their maximum phase shift angle when there is large imbalance between the load and generation within the combined East and Ottawa zones. At their maximum phase shift angles, L33P and L34P phase shifters have their lowest thermal ratings. If the Quebec HVDC interconnection is operated to make this imbalance larger, then these phase shifters will be more limiting than in the past.

4.7.3 Ottawa Area Transmission Reinforcement Project

The IMO has recently approved a Hydro One Networks Inc. plan to reinforce the Ottawa Area transmission system. The proposal includes:

- Installing a new 250 MVA, 230/115kV autotransformer at Hawthorne Transformer Station (TS) together with the required switching equipment,
- Building a 115 kV double circuit line from Hawthorne to Blackburn Junction (Jct.)and stringing a second 115 kV circuit from Blackburn Jct. to Riverdale Jct. on the existing double circuit 115 kV tower which presently supports 115 kV circuit H2AR,
- Adding three new breakers on the 115 kV Hawthorne switchyard to connect the new transformer and the two new 115 kV circuits,
- Opening H2AR at Blackburn Jct. and connecting the Russell TS end to the new 115 kV RH1 circuit,
- Opening 115 kV circuit A3RM tap to Russell TS at Riverdale Jct. and connecting the tap to Russell TS to the new 115 kV RH2 circuit, and
- Opening H2AR east of Russell TS and connecting the Russell TS end to 115 kV circuit K1R at Riverdale Jct. and the other end to the new RH2 circuit.

The expected in-service date of this project is May 31, 2004.

The proposed reconfiguration of the 115 kV lines will result in the new double circuit line from Hawthorne TS supplying Russell TS load and the existing 115 kV circuit H2AR becoming a dedicated supply for the loads east of Ottawa.

The general conclusion of this assessment is that the proposed plan will result in a significant improvement to the reliability of Ottawa area load supply and will not have a negative impact on the overall system reliability.

4.8 Northeast Zone

4.8.1 Load flow Study Results and Existing and/or Emerging Constraints

Under the High Growth, Extreme Weather Demand Scenario, there are no growth related concerns with respect to transmission adequacy as it pertains to supply availability, contingency of autotransformers and steady state voltage adequacy.

Presently, double element contingencies that result in thermal overloads on transmission circuits in the Northeast zone are not recognized. Consequently, overloads due to double element contingencies are not evaluated in this Outlook. However, in general, double element contingencies on the Northeast 230 kV system result in overloads on the 115 kV Northeast system.

The loss of a single 500 kV circuit (P502X) leaves most of the Northeast with only one 115 kV connection to the rest of the Ontario transmission system. To secure the operation of this zone, a

Special Protection System (SPS) enforces a load-generation balance following the loss of P502X. In practice, generation rejection is armed most days and load rejection is armed most nights. Given that the operation of the Northeast zone relies so heavily upon an SPS for a single element contingency, the existing transmission infrastructure provides a relatively lower level of reliability. Reliability could be improved with transmission reinforcements on the 115 kV system between Ansonville and Dymond. The SPS is complicated and generation rejection at many different sites has to be very well coordinated. As a result, the SPS has not always been able to produce the desired outcome.

A contingency involving 500 kV circuits P502X or D501P without generation rejection would cause many 115 kV thermal overloads. As this is a well-known problem, a single element contingency involving one of these circuits is also not evaluated in the thermal overload assessment of transmission circuits. The thermal overload assessment of the remaining contingencies in the Northeast zone did not reveal any potential concerns.

4.8.2 Wawa Transformer Station Reactive Compensation Project

Hydro One Networks Inc. has proposed to upgrade the reactive compensation facilities at Wawa Transformer Station by replacing the existing four oil-filled shunt reactors with two new 40 MVAr air core units and by installing shunt capacitors with a total reactive capability of 80 MVAr.

The CAA assessment concluded the following:

- The proposed replacement of the exiting shunt reactors and the installation of two new 39.6 MVAr shunt capacitors do not have an adverse impact in the reliability of the IMO-controlled grid and meet the Market Rule requirements for sudden voltage variations. Any switching associated with the new shunt reactor or one new shunt capacitor bank of 39.6 MVAr will result in abrupt voltage changes that are less than 4%. In most cases switching on the new 39.6 MVAr shunt capacitor resulted in a change in voltage of up to 6 kV.
- An increase of about 30 MW in power transfer capability of the East-West interface could be achieved under certain system conditions. However, any expansion of the East-West interface limits requires coordination with Manitoba and Minnesota to avoid adversely affecting their operations. Detailed operating studies will be initiated by the IMO to establish the new system security limits and system operating instructions for the incorporation of the proposed facilities.

4.9 Northwest Zone

4.9.1 Load flow Study Results and Existing and/or Emerging Constraints

Under the High Growth, Extreme Weather Demand Scenario, load growth in the Northwest zone is forecast to be very small during the study period.

The transmission adequacy assessments pertaining to supply availability, autotransformer and transmission circuit contingency, and steady state voltage adequacy did not show any potential concerns.

The Northwest transmission system comprises only one 1,000 km double circuit 230 kV line with a 115 kV underlay. Only one generating station, Atikokan, is directly connected to the 230 kV system. To accommodate any significant change in load or generation the transmission system in this zone will need to be expanded.

Like the Northeast zone, but to a lesser extent, the use of Special Protection Systems is also required for the operation of this zone. Even at a relatively large station like Rabbit Lake TS a relatively small new load was required to participate in a load rejection scheme in order to avoid adversely affecting nearby consumers.

Several customers in this zone have already indicated that the existing Market Rules regarding minimum voltage will not meet their requirements. Some customers lack the under load tap changing (ULTC) transformers that would allow them to compensate for transmission system voltages. Higher than minimum voltages can be maintained at an additional cost by constraining the output of specific generation or other rotating reactive resources.

Near Thunder Bay, voltage levels are maintained using the Thunder Bay generating and condensing units. If neither generating unit is on line, arrangements can be made to ensure the condensing unit is dispatched to support voltages but at an additional cost. During times when the need for the condenser is greatest it may not be available because it requires the Thunder Bay G2 unit to start.

For contingencies involving the Lakehead-Marathon 230 kV circuits, post-contingency overloads can occur on the parallel Lakehead-Alexander-Marathon 115 kV circuits. During times when these overloads may occur on the 115 kV circuits, control actions are implemented to constrain generation off in the Northwest zone in order to reduce the west to east transfers on these circuits.

In the late 1990s, a contingency in the MAPP region resulted in the collapse of the Northwest system. The Ontario Northwest system design and operation has also been reviewed. Ontario is working towards improvements that will reduce the exposure of the MAPP system to design criteria contingencies in Ontario.

4.9.2 Birch Transformer Station Shunt Capacitor Project

The IMO has approved the installation of a 115 kV, 80 MVAr shunt capacitor at Port Arthur Birch Transformer Station (TS), a project proposed by Hydro One Networks Inc.

The assessment concluded that the addition of the 80 MVAr shunt capacitor at Birch TS will result in an improvement of the 115 kV voltage profile near Thunder Bay and increased load supply reliability under conditions of peak load.

4.10 Niagara Zone

4.10.1 Load flow Study Results and Existing and/or Emerging Constraints

No potential concerns are observed for the transmission adequacy assessments pertaining to supply availability, autotransformer and transmission circuit contingency, and steady state voltage adequacy.

The Queenston Flow West (QFW) interface has been limiting under hot windless conditions. Without expanding the thermal capability of QFW, adding generation in the Niagara zone does not increase generation availability as the import capability from New York is correspondingly reduced.

The generation and transmission required to reliably supply the 25 Hz load is out of proportion compared to the 60 Hz system. The 25 Hz generation capacity significantly exceeds the 25 Hz demand by approximately 10 to 1. Due to the limited transfer capability of the Beck 60/25 Hz frequency changer, a significant amount of 25 Hz generation is congested off. In addition, the 25 Hz load at Gage Transformer Station requires two Beck units to be available following a Beck frequency changer contingency to regulate frequency. A more efficient use of resources would have the 25 Hz generation and transmission converted to 60 Hz operation with the installation of frequency changers where required.

4.10.2 Allanburg 115 kV Local Area Projects

During 2002 the IMO assessed two load supply transformer projects that are being proposed for connection to the 115 kV Allanburg area transmission system. They include Winona TS and Niagara-on-the-Lake TS #1. The new transformer stations will relieve some of the existing station overloading problems and meet future load growth in the area.

The results of these assessments indicate that the power flows into the Allanburg 115 kV pocket and over the internal 115 kV transmission interfaces are closely dependent on generation in the Allanburg pocket, composed of Decew Falls GS and Beck #1 GS.

Under peak load conditions and certain internal generation patterns, the IMO has identified the following concerns:

- The existing 115 kV circuits between Decew Falls GS and Beck #1 GS, D10S. D9HS, Q11S and Q12S could become loaded over their 15-Minute Limited Time Rating for a contingency associated with a section of the companion circuit,
- The overloading of Allanburg T1 could occur in pre-contingency situations for high power flows on Q30M to Middleport, or after a contingency associated with the double circuit 230 kV line Q30M and Q32A or Beck #1 E-bus.

The assessment also reveals that the voltage decline at Crowland TS could exceed 10% for the loss of the double circuit 230 kV line Q26A and Q28A.

The planned transfer by 2004 of Norfolk TS, about 85 MW of load, to Caledonia TS and the capping of the Beasmville TS and Vineland DS loads to the stations' capabilities appear to relieve the loading on the Allanburg autotransformers for the next six to seven years. As the load continues to grow however, it may be necessary that additional transmission solutions be sought by the transmitter to address concerns related to Allanburg TS, especially the rating of T1 autotransformer.

4.11 East Zone

4.11.1 Load flow Study Results and Existing and/or Emerging Constraints

For the study years, no potential concerns are observed in the transmission adequacy assessments for supply availability and contingency of autotransformers and transmission circuits.

The 500 kV steady state voltage level at Lennox is adequate throughout the study years under summer peak conditions and a 0.9 power factor at the defined meter point. Generally, the 230 kV and 115 kV voltage levels are also adequate in the East zone. However, the 230 kV and 115 kV voltage levels at Dobbin are consistently low throughout the study years. In the 2007 study with the Planned Transmission Network Scenario and no transmission reinforcements for the Greater Toronto Area, the 115 kV voltage level at Dobbin is below the minimum requirement. In the 2013 studies, the 115 kV voltage level at Dobbin is also below the minimum requirement. This voltage could be improved by providing additional 230 kV supply points to Dobbin. Tapping the 230 kV circuits from Cherrywood TS that by-pass Dobbin is an option.

The frequent use of load rejection schemes at Dobbin, Sidney, Port Hope and Frontenac Transformer Stations to respect single element contingencies with all elements in-service, suggests that transmission reinforcements at or near these stations are required.

4.12 Essa Zone

4.12.1 Load flow Study Results and Existing and/or Emerging Constraints

Under the High Growth, Extreme Weather Demand Scenario, the supply availability assessment indicates that consumers to the east of Essa and west of Minden could be subject to interruptions outside the study criteria. For the 2004 and 2007 studies, a load level between 250 and 500 MW is interrupted by a double circuit line contingency with no means of sectionalizing at least half the load back to service within 30 minutes of the event. For the 2013 studies, these consumers would also experience a supply interruption with the same contingency. However, load growth in the demand scenario pushes the load level for this pocket beyond the 500 MW which is considered to be unacceptable under these circumstances.

The contingency assessment of transmission circuits reveals an Essa-Barrie 115 kV circuit could become thermally overloaded on loss of its companion circuit under summer peak conditions for the selected years of study.

In addition, under summer peak conditions, the Essa 230 kV T1 autotransformer becomes thermally overloaded above its 10-Day Limited Time Rating (LTR) transfer capability for loss of Essa 230 kV T2 and vice versa. In 2013, the post-contingency loading on Essa T1 also exceeds its 15-Minute LTR following the loss of T2. The potential thermal overload concerns occur for each year of study. The contingency assessment of 500 kV autotransformers did not reveal any potential concerns. Result tables can be found in Appendix B.

The load flow studies with a 0.9 power factor at the defined meter point did indicate the 500 kV voltage levels at Essa were lower than typical operating levels but at or higher than the minimum requirement of 490 kV. No potential concerns are observed for the 115 kV or 230 kV voltage levels. These voltage levels are noted under summer peak conditions.

4.13 Bruce Zone

4.13.1 Load flow Study Results and Existing and/or Emerging Constraints

The transmission adequacy assessments did not reveal any potential concerns for this zone.

4.14 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. If additional generation is added to appropriate points on the system in future years, the level of system flows on constrained interfaces would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby, creating or aggravating congestion. In these instances the incorporation of additional transmission capacity on the interface might be necessary to alleviate this problem.

With the opening of the Ontario Electricity Market, an additional level of uncertainty is added because bid and offer prices will predominately determine the dispatch of generation. The behaviour of Ontario market participants can only be predicted based on experiences in other markets until sufficient local bid/offer experience is observed and analyzed. This makes it very difficult to forecast congestion on the Ontario transmission system with any degree of accuracy.

4.14.1 MAPS Congestion Assessment

The MAPS software program was used to assess the potential duration and range of transmission congestion on Ontario's major internal interfaces, under an economic generator dispatch pattern based on forecast operational costs and an interconnected pool system. With an economic dispatch of generation and respecting transmission constraints, the program may even dispatch resources external to Ontario to supply demand in Ontario, if it is more economic to do so, before dispatching internal resources within Ontario. Further details on the MAPS software program are identified in the IMO document titled "Methodology to Perform Long Term Assessments" (IMO_REP_0044). Details on Ontario's major internal interfaces and associated limits can be found in the IMO document titled "Ontario Transmission System" (IMO_REP_0045).

The program allows for a projection of expected hours of congestion on an interface when the flow on that interface is constrained by a limit. To access the potential range, in MW, of the transmission congestion on the same interface, the program was re-run with the limit on the interface removed. The resulting maximum flow on the interface was compared with the interface limit to identify the potential range of congestion.

Table 4.14.1 summarizes the potential hours at the identified interface limit and the potential range of congestion based on the Existing Resource Scenario and Planned Resource Scenario studies. For the years and conditions studied in this assessment, congestion is likely to occur on the East-West Transfer East (EWTE), Queenston Flow West (QFW) and Negative Buchanan Longwood Input (NBLIP) interfaces. Since the QFW interface limit changes depending on winter and summer conditions, separate winter and summer results are provided.

The assessment shows the EWTE interface frequently constrains off lower cost generation in the Northwest zone that would otherwise flow to load points in South Ontario. The QFW and NBLIP interfaces also constrain off generation to load points west and east of the QFW and NBLIP interfaces, respectively. However, the potential range of congestion on these interfaces is higher than indicated in the studies for a number of reasons. During circuit outage conditions or under extreme weather, congestion can be aggravated above the levels modeled by the IMO. Congestion also occurs on the QFW and NBLIP interfaces during periods of high demand or tight supply, when imports from New York, over the Niagara interconnection, and from Michigan are required.

Table 4.14.1 Potential Congestion on Major Interfaces

Hours	2004	2007	2013
EWTE	430 to 2000	1010 to 2460	1005 or more
QFW summer	up to 365	up to 605	920 or more
QFW winter	up to 120	up to 410	n/a
NBLIP	up to 100	up to 295	n/a

MW	2004	2007	2013
EWTE	up to 250	up to 435	335 or more
QFW summer	up to 610	up to 330	545 or more
QFW winter	up to 625	up to 660	n/a
NBLIP	up to 605	up to 790	n/a

4.15 Potential New Transmission Facilities

Table 4.15 summarizes the new transmission projects in the IMO's Connection Assessment and Approval (CAA) process. Transmitters have provided the information regarding the status of their projects and the in-service dates listed in Table 4.2.

Table 4.15 Potential New Transmission Facilities in Ontario

Niagara Zone	Projected I/S Date
Reinforcement of QFW interface.	2006-Q2

Northeast Zone	Projected I/S Date
Attawapiskat: Additional loads and transmission.	2006-Q4
Reinforcement of GLP transmission system.	2008

Ottawa Zone	Projected I/S Date
Hawthorne TS: Interconnection to Quebec.	2005-Q3

Southwest Zone	Projected I/S Date
Caledonia TS: Add two new 75/125 MVA 230/115 kV autotransformers and re-supply Norfolk TS off these new autotransformers.	2004-Q2
Nanticoke TGS: Interconnection to USA.	2006-Q2

Toronto Zone	Projected I/S Date
Cecil TS: Increase station capacity.	2004-Q2
Cherrywood TS: Reterminate 500 kV autotransformers as single connections.	2004-Q2
Leaside TS: Install 125 Mvar capacitor bank.	2004-Q2
Lakeview TS: Install two 50 MVAr static var compensators or two 200 MVAr shunt capacitors.	2005-Q2
New 3rd supply into downtown Toronto.	Stage 1: 2008-Q2 Stage 2: 2010-Q2

West Zone	Projected I/S Date
Keith TS: Install new/upgrade existing facilities for incorporation of the ATCO Project.	2004-Q1
Windsor Area: Enhance Windsor Area Overload Protection Scheme.	2004-Q2

Details regarding the IMO's Connection Assessment and Approval process and the status of all projects in the queue, including reports, can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

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5.0 Overall Observations, Findings and Conclusions

- If new generators currently under construction and nuclear generators returning from long term outages are placed in service on schedule, and if additional generators are not retired or taken out of service on a long-term basis beyond those that have currently been identified to the IMO, the need date for additional generation could be pushed off toward the end of the decade. However, if the generation additions do not take place, or if additional generation is taken out of service, the need date could be advanced significantly.
- Based on existing generation facilities, Ontario is expected to require about 6,400 MW of additional resources over the Outlook period, in order to meet the NPCC reliability standard, and reduce the dependency on external resources during peak demand periods.
- As a competitive alternative to new and existing generation, the IMO believes market participants should vigorously pursue demand management options. Demand management is most frequently viewed from one or more of three perspectives: the first being price-responsive demand (dispatchable or self-scheduled) which reacts to market price signals; the second being demand curtailment; and the third being energy conservation. Each of these options can have a role to play in the demand and supply balance of the Province. Energy conservation can be implemented individually or collectively, at any time, not only in response to price but for other reasons such as environmental concerns. Demand curtailment relies on a broader-based decision process integrated with appropriate deployment technology; introduction of new measures requires some lead-time for development of the necessary infrastructure. Price-responsive demand requires not only the technical infrastructure for conveying price signals and implementing dispatch but also an appropriately structured market. To fully harvest the fruits of this latter demand option at the individual consumer level will require technological advances as well as full retail access tomarket prices.
- The increasing age of Ontario generation is emerging as a potential issue toward the end of and beyond the study period as much of the existing generation infrastructure reaches or exceeds its nominal life. All scenarios examined in the 10-Year Outlook assume that the Lakeview Thermal Generating Station (TGS) will cease generating electricity at the end of April 2005 as a result of regulatory requirements. Up to 20 percent of the existing resource base can be expected to be retired from service or require substantial refurbishment over the next 10 years with another 20 percent in the subsequent 5 years. New environmental regulations, particularly with respect to air emissions could also drive the need for replacement of existing supply with cleaner alternatives.
- Should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate more outages over peak periods. Should reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve.
- The requirement for significant transmission reinforcement has been identified for the Greater Toronto Area (GTA) in order to maintain an acceptable level of supply reliability over the

Outlook period 2004 to 2013. The need for transmission reinforcement is due to forecast load growth in downtown Toronto and surrounding areas, as well as the removal from service of Lakeview TGS when it ceases to burn coal in 2005. The IMO has identified the following requirements:

- Transmission reinforcement is required in order to maintain the reliability of supply to the municipalities in the northeastern, northwestern and southwestern areas of the GTA. This includes two new switching stations – Parkway and Hurontario. This tranmission reinforcement is required to be placed in-service as soon as possible beginning no later than **2005**.
- Either the DC Option (Hearn SS to John TS section) or the AC Option (phase 1) for a third supply to downtown Toronto is required to be placed in-service before the summer of 2006 in order to maintain reliability of supply to the downtown Toronto area. Both Options are acceptable to the IMO from a system reliability perspective. However, the DC Option is preferred by the IMO since relatively few system upgrades are required.
- Additional 500/230 kV autotransformers are required to be installed at a new Parkway SS/TS and either Milton SS or Trafalgar TS, together with associated changes to the transmission system, no later than the shut-down date for Lakeview TGS.
- Significant amounts of additional reactive power sources are required within the western half of the GTA no later than the shut-down date for Lakeview TGS. The IMO invites market participants to submit proposals by no later than **June 30, 2003**.

- Transmission adequacy studies show that the Detweiler operating area, encompassing Kitchener-Waterloo, Cambridge and Guelph in Southwestern Ontario, is susceptible to supply interruptions for double circuit line contingencies. Based on summer conditions from 2002, thermal overloads on the autotransformers in this area are also possible. Respecting minimum voltage levels is a third concern. In combination, these are indicative of the need for transmission reinforcements in this area.
- Several other load pockets of 250 MW or greater in the Toronto, Southwest, West and Essa zones are susceptible to a supply interruption following double circuit line contingencies. This suggests that transmission reinforcements are needed in these areas.
- Studies also show that the Windsor operating area may be susceptible to potential supply reliability problems under certain conditions. Based on current operating experience, the secure operation of this area relies on the operation of Special Protection Systems for single element contingencies with all elements in-service under peak load conditions. These items indicate that there is a need for transmission reinforcements in this area.
- As early as summer 2003, it is estimated that the peak load at Burlington TS could reach its transformation capability. In addition, for certain recognized contingencies, the post-contingency power flows will exceed the rating of the Burlington 230/115 kV autotransformers. The IMO recommends that Hydro One Networks initiate a study to identify options for addressing these concerns.
- Potential thermal overload concerns have been identified following certain contingencies for several transformation points, and on a number of circuits in the Toronto, West, Ottawa, and Essa zones. In addition the potential for voltage levels to be below minimum requirements

has also been identified, particularly at the Milton Switching Station (500 kV) and at Detweiler TS (230 kV).

- Post-contingency overloads can also occur on the parallel Lakehead-Alexander-Marathon 115 kV circuits. During times when these overloads may occur, it is necessary to limit generation in the Northwest zone in order to reduce the west to east transfers on these circuits. Transmission reinforcements in this area would decrease congestion.
- At Niagara, the 25 Hz generation capacity significantly exceeds the 25 Hz demand. Due to the limited transfer capability of the Beck 60/25 Hz frequency changer, a significant amount of 25 Hz generationcannot be used. A more efficient use of resources would be achieved if the 25 Hz generation and transmission were converted to 60 Hz operation with the installation of frequency changers where required.
- The 230 kV transmission corridor between Lambton and Chatham can be a significant bottleneck to the dispatch of generation in the West zone. Under hot windless conditions, 230 kV circuit L28C can be over its continuous rating for the loss of 230 kV circuit L29C without any imports from Michigan. Presently, the only effective control actions are to reduce generation at Lambton TGS and near Scott TS. Replacing the 115 kV circuit N5K with a new 230 kV or 500 kV circuit between Lambton and Chatham is an option that would increase the transfer capability.
- Existing congestion is likely to continue on the East-West Transfer East (EWTE) transmission interface. To allow higher volume transactions with Manitoba and Minnesota and minimize limitations on generation in the Northwest zone, transmission enhancements on the EWTE interface are needed near Wawa or Marathon TSs. The Wawa reactors/capacitors proposed by Hydro One will marginally increase the EWTE interface limit under certain system conditions.
- Congestion on the Queenston Flow West (QFW) interface may also occur when imports from New York over the Niagara interconnection are required to supply demand. The proposed Queenston Flow West (QFW) interface reinforcements by Hydro One will increase the thermal capability of the interface and will help alleviate congestion on the interface under certain system conditions. The proposed third supply DC option to downtown Toronto would also help relieve the QFW interface.
- Congestion on the Negative Bruce Longwood Input (NBLIP) interface may occur when imports from Michigan and generation from within the West zone are required to supply demand to points east of the West zone.

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Appendix A – Resource Adequacy Assessment Details

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1.0 Resource Adequacy Assessment Tables

The following tables provide numeric results of the resource adequacy assessment. They support Figure 3.1 in Section 3.2 and the statements made in Section 3.2 and 3.3. Orange (darker for black and white display/print) cell shading in the 'Reserve Margins' column means the forecast supply deficiency exceeds the current Ontario coincident import capability of 4,000 MW.

Table A1 Reserve Margins Under Low Demand Growth, Summer Peak, Existing Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,234	11-Jul-04	27,172	26,919	3,938	3,685	16.9	15.9	253
2005	23,556	17-Jul-05	25,119	26,786	1,563	3,230	6.6	13.7	-1,667
2006	23,863	16-Jul-06	25,178	27,091	1,315	3,228	5.5	13.5	-1,913
2007	24,109	15-Jul-07	25,192	27,337	1,083	3,228	4.5	13.4	-2,145
2008	24,357	13-Jul-08	25,255	27,585	898	3,228	3.7	13.3	-2,330
2009	24,596	12-Jul-09	25,255	27,824	659	3,228	2.7	13.1	-2,569
2010	24,822	18-Jul-10	25,257	28,050	435	3,228	1.8	13.0	-2,793
2011	25,045	17-Jul-11	25,259	28,289	214	3,244	0.9	13.0	-3,030
2012	25,248	15-Jul-12	25,179	28,494	-69	3,246	-0.3	12.9	-3,315
2013	25,439	14-Jul-13	25,008	28,703	-431	3,264	-1.7	12.8	-3,695

Table A2 Reserve Margins Under Low Demand Growth, Winter Peak, Existing Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,367	11-Jan-04	26,783	26,787	3,416	3,420	14.6	14.6	-4
2005	23,453	16-Jan-05	26,322	26,873	2,869	3,420	12.2	14.6	-551
2006	23,625	15-Jan-06	25,375	27,045	1,750	3,420	7.4	14.5	-1,670
2007	23,736	14-Jan-07	25,610	27,156	1,874	3,420	7.9	14.4	-1,546
2008	23,869	13-Jan-08	25,610	27,289	1,741	3,420	7.3	14.3	-1,679
2009	24,011	11-Jan-09	25,607	27,431	1,596	3,420	6.6	14.2	-1,824
2010	24,011	17-Jan-10	25,610	27,431	1,599	3,420	6.7	14.2	-1,821
2011	24,106	16-Jan-11	25,610	27,526	1,504	3,420	6.2	14.2	-1,916
2012	24,185	15-Jan-12	25,524	27,605	1,339	3,420	5.5	14.1	-2,081
2013	24,268	13-Jan-13	25,346	27,688	1,078	3,420	4.4	14.1	-2,342

Table A3 Reserve Margins Under Median Demand Growth, Summer Peak, Existing Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,014	11-Jul-04	27,172	27,699	3,158	3,685	13.2	15.3	-527
2005	24,360	17-Jul-05	25,131	27,640	771	3,280	3.2	13.5	-2,509
2006	24,689	16-Jul-06	25,191	27,917	502	3,228	2.0	13.1	-2,726
2007	25,005	15-Jul-07	25,205	28,233	200	3,228	0.8	12.9	-3,028
2008	25,326	13-Jul-08	25,270	28,569	-56	3,243	-0.2	12.8	-3,299
2009	25,641	12-Jul-09	25,270	28,910	-371	3,269	-1.4	12.7	-3,640
2010	25,945	18-Jul-10	25,273	29,240	-672	3,295	-2.6	12.7	-3,967
2011	26,247	17-Jul-11	25,276	29,562	-971	3,315	-3.7	12.6	-4,286
2012	26,530	15-Jul-12	25,197	29,858	-1,333	3,328	-5.0	12.5	-4,661
2013	26,803	14-Jul-13	25,027	30,156	-1,776	3,353	-6.6	12.5	-5,129

Table A4 Reserve Margins Under Median Demand Growth, Winter Peak, Existing Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,112	11-Jan-04	26,783	27,532	2,671	3,420	11.1	14.2	-749
2005	24,233	16-Jan-05	26,322	27,653	2,089	3,420	8.6	14.1	-1,331
2006	24,422	15-Jan-06	25,375	27,842	953	3,420	3.9	14.0	-2,467
2007	24,603	14-Jan-07	25,610	28,023	1,007	3,420	4.1	13.9	-2,413
2008	24,808	13-Jan-08	25,610	28,228	802	3,420	3.2	13.8	-2,618
2009	25,024	11-Jan-09	25,607	28,444	583	3,420	2.3	13.7	-2,837
2010	25,101	17-Jan-10	25,610	28,521	509	3,420	2.0	13.6	-2,911
2011	25,273	16-Jan-11	25,610	28,693	337	3,420	1.3	13.5	-3,083
2012	25,431	15-Jan-12	25,524	28,851	93	3,420	0.4	13.4	-3,327
2013	25,595	13-Jan-13	25,346	29,015	-249	3,420	-1.0	13.4	-3,669

Table A5 Reserve Margins Under High Demand Growth, Summer Peak, Existing Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,369	11-Jul-04	27,172	28,054	2,803	3,685	11.5	15.1	-882
2005	24,845	17-Jul-05	25,139	28,152	294	3,307	1.2	13.3	-3,013
2006	25,275	16-Jul-06	25,200	28,513	-75	3,238	-0.3	12.8	-3,313
2007	25,672	15-Jul-07	25,215	28,931	-457	3,259	-1.8	12.7	-3,716
2008	26,072	13-Jul-08	25,281	29,365	-791	3,293	-3.0	12.6	-4,084
2009	26,466	12-Jul-09	25,283	29,787	-1,183	3,321	-4.5	12.5	-4,504
2010	26,850	18-Jul-10	25,287	30,202	-1,563	3,352	-5.8	12.5	-4,915
2011	27,230	17-Jul-11	25,291	30,616	-1,939	3,386	-7.1	12.4	-5,325
2012	27,590	15-Jul-12	25,212	30,995	-2,378	3,405	-8.6	12.3	-5,783
2013	27,935	14-Jul-13	25,043	31,378	-2,892	3,443	-10.4	12.3	-6,335

Table A6 Reserve Margins Under High Demand Growth, Winter Peak, Existing Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,420	11-Jan-04	26,783	27,840	2,363	3,420	9.7	14.0	-1,057
2005	24,690	16-Jan-05	26,322	28,110	1,632	3,420	6.6	13.9	-1,788
2006	24,977	15-Jan-06	25,375	28,397	398	3,420	1.6	13.7	-3,022
2007	25,240	14-Jan-07	25,610	28,659	370	3,419	1.5	13.5	-3,049
2008	25,523	13-Jan-08	25,610	28,943	87	3,420	0.3	13.4	-3,333
2009	25,818	11-Jan-09	25,607	29,237	-211	3,419	-0.8	13.2	-3,630
2010	25,973	17-Jan-10	25,610	29,392	-363	3,419	-1.4	13.2	-3,782
2011	26,223	16-Jan-11	25,610	29,643	-613	3,420	-2.3	13.0	-4,033
2012	26,459	15-Jan-12	25,524	29,879	-935	3,420	-3.5	12.9	-4,355
2013	26,695	13-Jan-13	25,346	30,115	-1,349	3,420	-5.1	12.8	-4,769

Table A7 Reserve Margins Under Low Demand Growth, Summer Peak, Intermediate Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,234	11-Jul-04	30,105	27,109	6,871	3,875	29.6	16.7	2,996
2005	23,556	17-Jul-05	28,100	26,871	4,544	3,315	19.3	14.1	1,229
2006	23,863	16-Jul-06	28,138	27,091	4,275	3,228	17.9	13.5	1,047
2007	24,109	15-Jul-07	28,173	27,337	4,064	3,228	16.9	13.4	836
2008	24,357	13-Jul-08	28,043	27,585	3,686	3,228	15.1	13.3	458
2009	24,596	12-Jul-09	27,491	27,824	2,895	3,228	11.8	13.1	-333
2010	24,822	18-Jul-10	27,493	28,056	2,671	3,234	10.8	13.0	-563
2011	25,045	17-Jul-11	27,495	28,299	2,450	3,254	9.8	13.0	-804
2012	25,248	15-Jul-12	27,415	28,505	2,167	3,257	8.6	12.9	-1,090
2013	25,439	14-Jul-13	27,244	28,714	1,805	3,275	7.1	12.9	-1,470

Table A8 Reserve Margins Under Low Demand Growth, Winter Peak, Intermediate Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,367	11-Jan-04	29,112	26,900	5,745	3,533	24.6	15.1	2,212
2005	23,453	16-Jan-05	29,323	26,944	5,870	3,491	25.0	14.9	2,379
2006	23,625	15-Jan-06	28,320	27,045	4,695	3,420	19.9	14.5	1,275
2007	23,736	14-Jan-07	28,611	27,156	4,875	3,420	20.5	14.4	1,455
2008	23,869	13-Jan-08	28,349	27,289	4,480	3,420	18.8	14.3	1,060
2009	24,011	11-Jan-09	27,853	27,431	3,842	3,420	16.0	14.2	422
2010	24,011	17-Jan-10	27,856	27,431	3,845	3,420	16.0	14.2	425
2011	24,106	16-Jan-11	27,856	27,526	3,750	3,420	15.6	14.2	330
2012	24,185	15-Jan-12	27,770	27,605	3,585	3,420	14.8	14.1	165
2013	24,268	13-Jan-13	27,592	27,688	3,324	3,420	13.7	14.1	-96

Table A9 Reserve Margins Under Median Demand Growth, Summer Peak, Intermediate Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,014	11-Jul-04	30,105	27,889	6,091	3,875	25.4	16.1	2,216
2005	24,360	17-Jul-05	28,112	27,709	3,752	3,349	15.4	13.7	403
2006	24,689	16-Jul-06	28,150	27,959	3,461	3,270	14.0	13.2	191
2007	25,005	15-Jul-07	28,186	28,264	3,181	3,259	12.7	13.0	-78
2008	25,326	13-Jul-08	28,057	28,611	2,731	3,285	10.8	13.0	-554
2009	25,641	12-Jul-09	27,506	28,921	1,865	3,280	7.3	12.8	-1,415
2010	25,945	18-Jul-10	27,509	29,252	1,564	3,307	6.0	12.7	-1,743
2011	26,247	17-Jul-11	27,512	29,576	1,265	3,329	4.8	12.7	-2,064
2012	26,530	15-Jul-12	27,433	29,871	903	3,341	3.4	12.6	-2,438
2013	26,803	14-Jul-13	27,263	30,169	460	3,366	1.7	12.6	-2,906

Table A10 Reserve Margins Under Median Demand Growth, Winter Peak, Intermediate Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,112	11-Jan-04	29,112	27,645	5,000	3,533	20.7	14.7	1,467
2005	24,233	16-Jan-05	29,323	27,723	5,090	3,490	21.0	14.4	1,600
2006	24,422	15-Jan-06	28,320	27,842	3,898	3,420	16.0	14.0	478
2007	24,603	14-Jan-07	28,611	28,023	4,008	3,420	16.3	13.9	588
2008	24,808	13-Jan-08	28,349	28,228	3,541	3,420	14.3	13.8	121
2009	25,024	11-Jan-09	27,853	28,444	2,829	3,420	11.3	13.7	-591
2010	25,101	17-Jan-10	27,856	28,521	2,755	3,420	11.0	13.6	-665
2011	25,273	16-Jan-11	27,856	28,693	2,583	3,420	10.2	13.5	-837
2012	25,431	15-Jan-12	27,770	28,851	2,339	3,420	9.2	13.4	-1,081
2013	25,595	13-Jan-13	27,592	29,015	1,997	3,420	7.8	13.4	-1,423

Table A11 Reserve Margins Under High Demand Growth, Summer Peak, Intermediate Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,369	11-Jul-04	30,105	28,244	5,736	3,875	23.5	15.9	1,861
2005	24,845	17-Jul-05	28,120	28,224	3,275	3,379	13.2	13.6	-104
2006	25,275	16-Jul-06	28,160	28,581	2,885	3,306	11.4	13.1	-421
2007	25,672	15-Jul-07	28,196	28,974	2,524	3,302	9.8	12.9	-778
2008	26,072	13-Jul-08	28,068	29,409	1,996	3,337	7.7	12.8	-1,341
2009	26,466	12-Jul-09	27,519	29,800	1,053	3,334	4.0	12.6	-2,281
2010	26,850	18-Jul-10	27,523	30,215	673	3,365	2.5	12.5	-2,692
2011	27,230	17-Jul-11	27,527	30,628	297	3,398	1.1	12.5	-3,101
2012	27,590	15-Jul-12	27,448	31,006	-142	3,416	-0.5	12.4	-3,558
2013	27,935	14-Jul-13	27,279	31,387	-656	3,452	-2.3	12.4	-4,108

Table A12 Reserve Margins Under High Demand Growth, Winter Peak, Intermediate Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,420	11-Jan-04	29,112	27,953	4,692	3,533	19.2	14.5	1,159
2005	24,690	16-Jan-05	29,323	28,182	4,633	3,492	18.8	14.1	1,141
2006	24,977	15-Jan-06	28,320	28,397	3,343	3,420	13.4	13.7	-77
2007	25,240	14-Jan-07	28,611	28,659	3,371	3,419	13.4	13.5	-48
2008	25,523	13-Jan-08	28,349	28,943	2,826	3,420	11.1	13.4	-594
2009	25,818	11-Jan-09	27,853	29,237	2,035	3,419	7.9	13.2	-1,384
2010	25,973	17-Jan-10	27,856	29,392	1,883	3,419	7.2	13.2	-1,536
2011	26,223	16-Jan-11	27,856	29,643	1,633	3,420	6.2	13.0	-1,787
2012	26,459	15-Jan-12	27,770	29,879	1,311	3,420	5.0	12.9	-2,109
2013	26,695	13-Jan-13	27,592	30,115	897	3,420	3.4	12.8	-2,523

Table A13 Reserve Margins Under Low Demand Growth, Summer Peak, Planned Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,234	11-Jul-04	30,620	27,140	7,386	3,906	31.8	16.8	3,480
2005	23,556	17-Jul-05	29,130	26,917	5,574	3,361	23.7	14.3	2,213
2006	23,863	16-Jul-06	29,683	27,149	5,820	3,286	24.4	13.8	2,534
2007	24,109	15-Jul-07	29,718	27,370	5,609	3,261	23.3	13.5	2,348
2008	24,357	13-Jul-08	29,588	27,625	5,231	3,268	21.5	13.4	1,963
2009	24,596	12-Jul-09	29,036	27,824	4,440	3,228	18.1	13.1	1,212
2010	24,822	18-Jul-10	29,038	28,050	4,216	3,228	17.0	13.0	988
2011	25,045	17-Jul-11	29,040	28,283	3,995	3,238	16.0	12.9	757
2012	25,248	15-Jul-12	28,960	28,489	3,712	3,241	14.7	12.8	471
2013	25,439	14-Jul-13	28,789	28,698	3,350	3,259	13.2	12.8	91

Table A14 Reserve Margins Under Low Demand Growth, Winter Peak, Planned Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	23,367	11-Jan-04	29,112	26,900	5,745	3,533	24.6	15.1	2,212
2005	23,453	16-Jan-05	29,838	26,970	6,385	3,517	27.2	15.0	2,868
2006	23,625	15-Jan-06	29,350	27,045	5,725	3,420	24.2	14.5	2,305
2007	23,736	14-Jan-07	30,156	27,156	6,420	3,420	27.0	14.4	3,000
2008	23,869	13-Jan-08	29,894	27,289	6,025	3,420	25.2	14.3	2,605
2009	24,011	11-Jan-09	29,398	27,431	5,387	3,420	22.4	14.2	1,967
2010	24,011	17-Jan-10	29,401	27,431	5,390	3,420	22.4	14.2	1,970
2011	24,106	16-Jan-11	29,401	27,526	5,295	3,420	22.0	14.2	1,875
2012	24,185	15-Jan-12	29,315	27,605	5,130	3,420	21.2	14.1	1,710
2013	24,268	13-Jan-13	29,137	27,688	4,869	3,420	20.1	14.1	1,449

Table A15 Reserve Margins Under Median Demand Growth, Summer Peak, Planned Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,014	11-Jul-04	30,620	27,920	6,606	3,906	27.5	16.3	2,700
2005	24,360	17-Jul-05	29,142	27,720	4,782	3,360	19.6	13.8	1,422
2006	24,689	16-Jul-06	29,695	27,974	5,006	3,285	20.3	13.3	1,721
2007	25,005	15-Jul-07	29,731	28,261	4,726	3,256	18.9	13.0	1,470
2008	25,326	13-Jul-08	29,602	28,595	4,276	3,269	16.9	12.9	1,007
2009	25,641	12-Jul-09	29,051	28,905	3,410	3,264	13.3	12.7	146
2010	25,945	18-Jul-10	29,054	29,236	3,109	3,291	12.0	12.7	-182
2011	26,247	17-Jul-11	29,057	29,559	2,810	3,312	10.7	12.6	-502
2012	26,530	15-Jul-12	28,978	29,854	2,448	3,324	9.2	12.5	-876
2013	26,803	14-Jul-13	28,808	30,151	2,005	3,348	7.5	12.5	-1,343

Table A16 Reserve Margins Under Median Demand Growth, Winter Peak, Planned Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,112	11-Jan-04	29,112	27,645	5,000	3,533	20.7	14.7	1,467
2005	24,233	16-Jan-05	29,838	27,749	5,605	3,516	23.1	14.5	2,089
2006	24,422	15-Jan-06	29,350	27,842	4,928	3,420	20.2	14.0	1,508
2007	24,603	14-Jan-07	30,156	28,023	5,553	3,420	22.6	13.9	2,133
2008	24,808	13-Jan-08	29,894	28,228	5,086	3,420	20.5	13.8	1,666
2009	25,024	11-Jan-09	29,398	28,444	4,374	3,420	17.5	13.7	954
2010	25,101	17-Jan-10	29,401	28,521	4,300	3,420	17.1	13.6	880
2011	25,273	16-Jan-11	29,401	28,693	4,128	3,420	16.3	13.5	708
2012	25,431	15-Jan-12	29,315	28,851	3,884	3,420	15.3	13.4	464
2013	25,595	13-Jan-13	29,137	29,015	3,542	3,420	13.8	13.4	122

Table A17 Reserve Margins Under High Demand Growth, Summer Peak, Planned Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,369	11-Jul-04	30,620	28,275	6,251	3,906	25.7	16.0	2,345
2005	24,845	17-Jul-05	29,150	28,213	4,305	3,368	17.3	13.6	937
2006	25,275	16-Jul-06	29,705	28,565	4,430	3,290	17.5	13.0	1,140
2007	25,672	15-Jul-07	29,741	28,958	4,069	3,286	15.8	12.8	783
2008	26,072	13-Jul-08	29,613	29,393	3,541	3,321	13.6	12.7	220
2009	26,466	12-Jul-09	29,064	29,783	2,598	3,317	9.8	12.5	-719
2010	26,850	18-Jul-10	29,068	30,198	2,218	3,348	8.3	12.5	-1,130
2011	27,230	17-Jul-11	29,072	30,611	1,842	3,381	6.8	12.4	-1,539
2012	27,590	15-Jul-12	28,993	30,987	1,403	3,397	5.1	12.3	-1,994
2013	27,935	14-Jul-13	28,824	31,367	889	3,432	3.2	12.3	-2,543

Table A18 Reserve Margins Under High Demand Growth, Winter Peak, Planned Resource Scenario

Year	Winter Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2004	24,420	11-Jan-04	29,112	27,953	4,692	3,533	19.2	14.5	1,159
2005	24,690	16-Jan-05	29,838	28,208	5,148	3,518	20.9	14.2	1,630
2006	24,977	15-Jan-06	29,350	28,397	4,373	3,420	17.5	13.7	953
2007	25,240	14-Jan-07	30,156	28,659	4,916	3,419	19.5	13.5	1,497
2008	25,523	13-Jan-08	29,894	28,943	4,371	3,420	17.1	13.4	951
2009	25,818	11-Jan-09	29,398	29,237	3,580	3,419	13.9	13.2	161
2010	25,973	17-Jan-10	29,401	29,392	3,428	3,419	13.2	13.2	9
2011	26,223	16-Jan-11	29,401	29,643	3,178	3,420	12.1	13.0	-242
2012	26,459	15-Jan-12	29,315	29,879	2,856	3,420	10.8	12.9	-564
2013	26,695	13-Jan-13	29,137	30,115	2,442	3,420	9.1	12.8	-978

Table A19 Change in Reserve Margins from Existing Resource Scenario, Low Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-1,747	-747	253	2,996	3,480
2005	-3,667	-2,667	-1,667	1,229	2,213
2006	-3,913	-2,913	-1,913	1,047	2,534
2007	-4,145	-3,145	-2,145	836	2,348
2008	-4,330	-3,330	-2,330	458	1,963
2009	-4,569	-3,569	-2,569	-333	1,212
2010	-4,793	-3,793	-2,793	-563	988
2011	-5,030	-4,030	-3,030	-804	757
2012	-5,315	-4,315	-3,315	-1,090	471
2013	-5,695	-4,695	-3,695	-1,470	91

Table A20 Change in Reserve Margins from Existing Resource Scenario, Low Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-2,004	-1,004	-4	2,212	2,212
2005	-2,551	-1,551	-551	2,379	2,868
2006	-3,670	-2,670	-1,670	1,275	2,305
2007	-3,546	-2,546	-1,546	1,455	3,000
2008	-3,679	-2,679	-1,679	1,060	2,605
2009	-3,824	-2,824	-1,824	422	1,967
2010	-3,821	-2,821	-1,821	425	1,970
2011	-3,916	-2,916	-1,916	330	1,875
2012	-4,081	-3,081	-2,081	165	1,710
2013	-4,342	-3,342	-2,342	-96	1,449

Table A21 Change in Reserve Margins from Existing Resource Scenario, Median Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-2,527	-1,527	-527	2,216	2,700
2005	-4,509	-3,509	-2,509	403	1,422
2006	-4,726	-3,726	-2,726	191	1,721
2007	-5,028	-4,028	-3,028	-78	1,470
2008	-5,299	-4,299	-3,299	-554	1,007
2009	-5,640	-4,640	-3,640	-1,415	146
2010	-5,967	-4,967	-3,967	-1,743	-182
2011	-6,286	-5,286	-4,286	-2,064	-502
2012	-6,661	-5,661	-4,661	-2,438	-876
2013	-7,129	-6,129	-5,129	-2,906	-1,343

Table A22 Change in Reserve Margins from Existing Resource Scenario, Median Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-2,749	-1,749	-749	1,467	1,467
2005	-3,331	-2,331	-1,331	1,600	2,089
2006	-4,467	-3,467	-2,467	478	1,508
2007	-4,413	-3,413	-2,413	588	2,133
2008	-4,618	-3,618	-2,618	121	1,666
2009	-4,837	-3,837	-2,837	-591	954
2010	-4,911	-3,911	-2,911	-665	880
2011	-5,083	-4,083	-3,083	-837	708
2012	-5,327	-4,327	-3,327	-1,081	464
2013	-5,669	-4,669	-3,669	-1,423	122

Table A23 Change in Reserve Margins from Existing Resource Scenario, High Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-2,882	-1,882	-882	1,861	2,345
2005	-5,013	-4,013	-3,013	-104	937
2006	-5,313	-4,313	-3,313	-421	1,140
2007	-5,716	-4,716	-3,716	-778	783
2008	-6,084	-5,084	-4,084	-1,341	220
2009	-6,504	-5,504	-4,504	-2,281	-719
2010	-6,915	-5,915	-4,915	-2,692	-1,130
2011	-7,325	-6,325	-5,325	-3,101	-1,539
2012	-7,783	-6,783	-5,783	-3,558	-1,994
2013	-8,335	-7,335	-6,335	-4,108	-2,543

Table A24 Change in Reserve Margins from Existing Resource Scenario, High Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Existing Resource Scenario -2000 MW	Existing Resource Scenario -1000 MW	Existing Resource Scenario	Intermediate Resource Scenario	Planned Resource Scenario
2004	-3,057	-2,057	-1,057	1,159	1,159
2005	-3,788	-2,788	-1,788	1,141	1,630
2006	-5,022	-4,022	-3,022	-77	953
2007	-5,049	-4,049	-3,049	-48	1,497
2008	-5,333	-4,333	-3,333	-594	951
2009	-5,630	-4,630	-3,630	-1,384	161
2010	-5,782	-4,782	-3,782	-1,536	9
2011	-6,033	-5,033	-4,033	-1,787	-242
2012	-6,355	-5,355	-4,355	-2,109	-564
2013	-6,769	-5,769	-4,769	-2,523	-978

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Appendix B – Autotransformer Contingency-Based Supply Reliability Assessment Details

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1.0 Autotransformer Contingency-Based Supply Reliability Assessment Tables

The following tables provide the results of the contingency-based supply reliability assessment for autotransformers using a 10 day Limited Time Rating for single element contingencies and 15-Minute Limited Time Rating for double element contingencies. A 'blank' entry indicates no potential concerns. These tables support statements made in Sections 4.4 to 4.13.

Table B1 Contingency-Based Supply Reliability - 500/230 kV Transformation Points

500/230 kV Transformation Point	Transmission Zone	Planned Resource Scenario		
		2004	2007	2013
Bruce T25,T27,T28	Bruce	No potential concerns identified.		
Lennox T51,T52	East			
Essa T3,T4	Essa			
Hamner T6,T7,T8,T9	Northeast			
Porcupine T7,T8	Northeast			
Hawthorne T2,T3	Ottawa			
Nanticoke T11,T12	Southwest			
Middleport T3,T6	Southwest			
Trafalgar T14,T15	Southwest			
Cherrywood T14,T15, T16,T17	Toronto			
Claireville T13,T14, T15,T16	Toronto			
Longwood T3,T4,T5,T6	West			

Table B2 Contingency-Based Supply Reliability - Specific 230/115 kV Transformation Points

230/115 kV Transformation Point	Transmission Zone	Planned Resource Scenario		
		2004	2007	2013
Dobbin T1,T2,T5	East			
Essa T1,T2	Essa	Potential concern	Potential concern	Potential concern
Allanburg T1,T2,T3,T4	Niagara			
Hawthorne T4,T5,T6,T9	Ottawa			
Merivale T11,T12	Ottawa			
Beach T1,T7,T8	Southwest			
Burlington T4,T6,T9, T12	Southwest	Potential concern	Potential concern	Potential concern
Detweiller T2,T3,T4	Southwest	Potential concern	Potential concern	Potential concern
Seaforth T5,T6	Southwest			
Leaside T11,T12,T14, T15,T16,T17	Toronto			
Manby East T7,T8,T9	Toronto			
Manby West T1,T2,T12	Toronto			
Buchanan T2,T3,T4	West	Potential concern	Potential concern	Potential concern
Keith T11,T12 * Lauzon T1,T2	West			
Kent T1	West			
Scott T5,T6	West	Potential concern	Potential concern	Potential concern

Note: * Keith and Lauzon autotransformers are grouped as a single point.

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Appendix C - Proposed Transmission Reinforcement Diagrams for the Greater Toronto Area (GTA)

List of Diagrams

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Diagram 1 - To Maintain Supply Reliability to the Newmarket/Aurora, Markham, Richmond Hill & Vaughan Areas

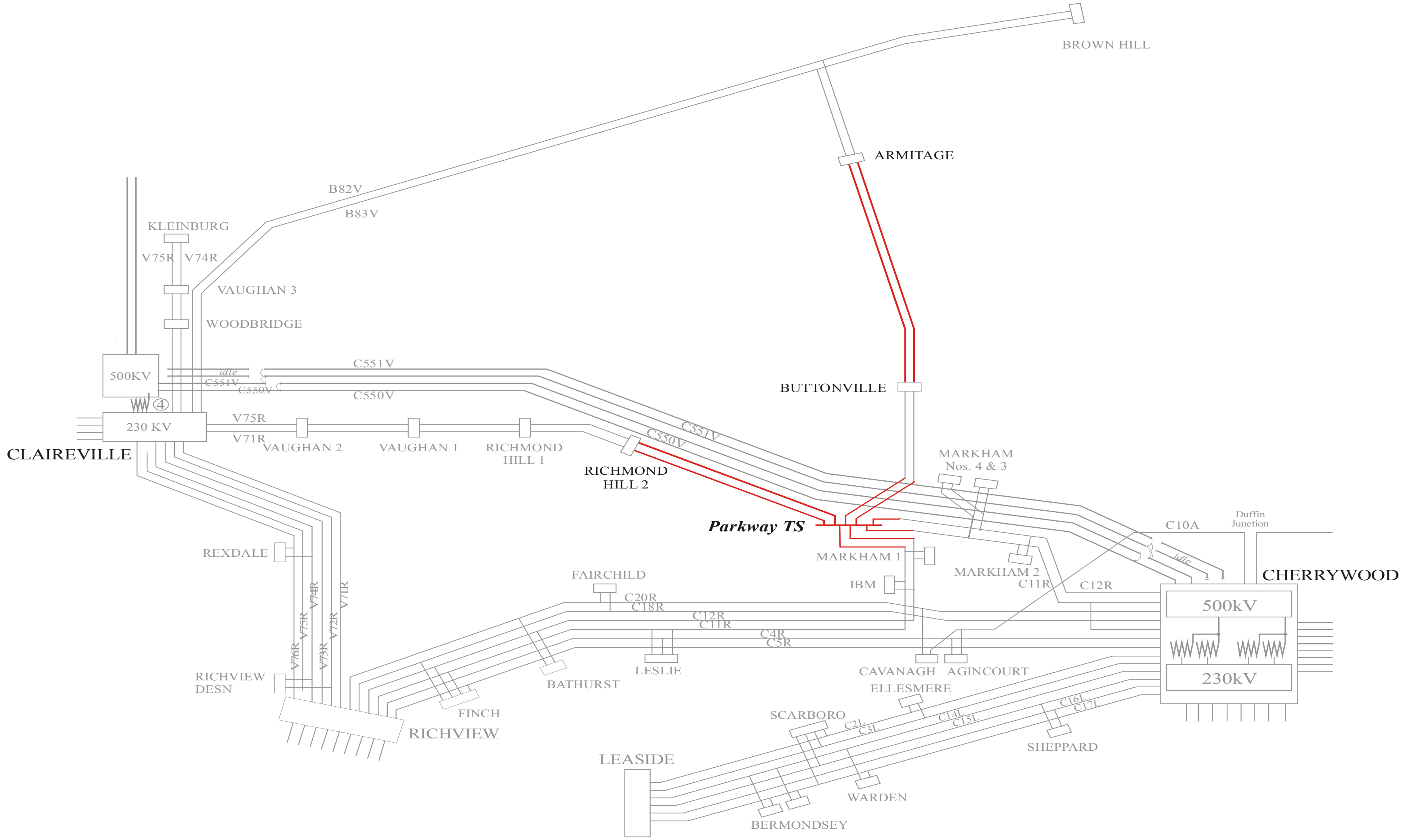


Diagram 2 - To Maintain Supply Reliability to the Milton, Northern Mississauga & Brampton Areas

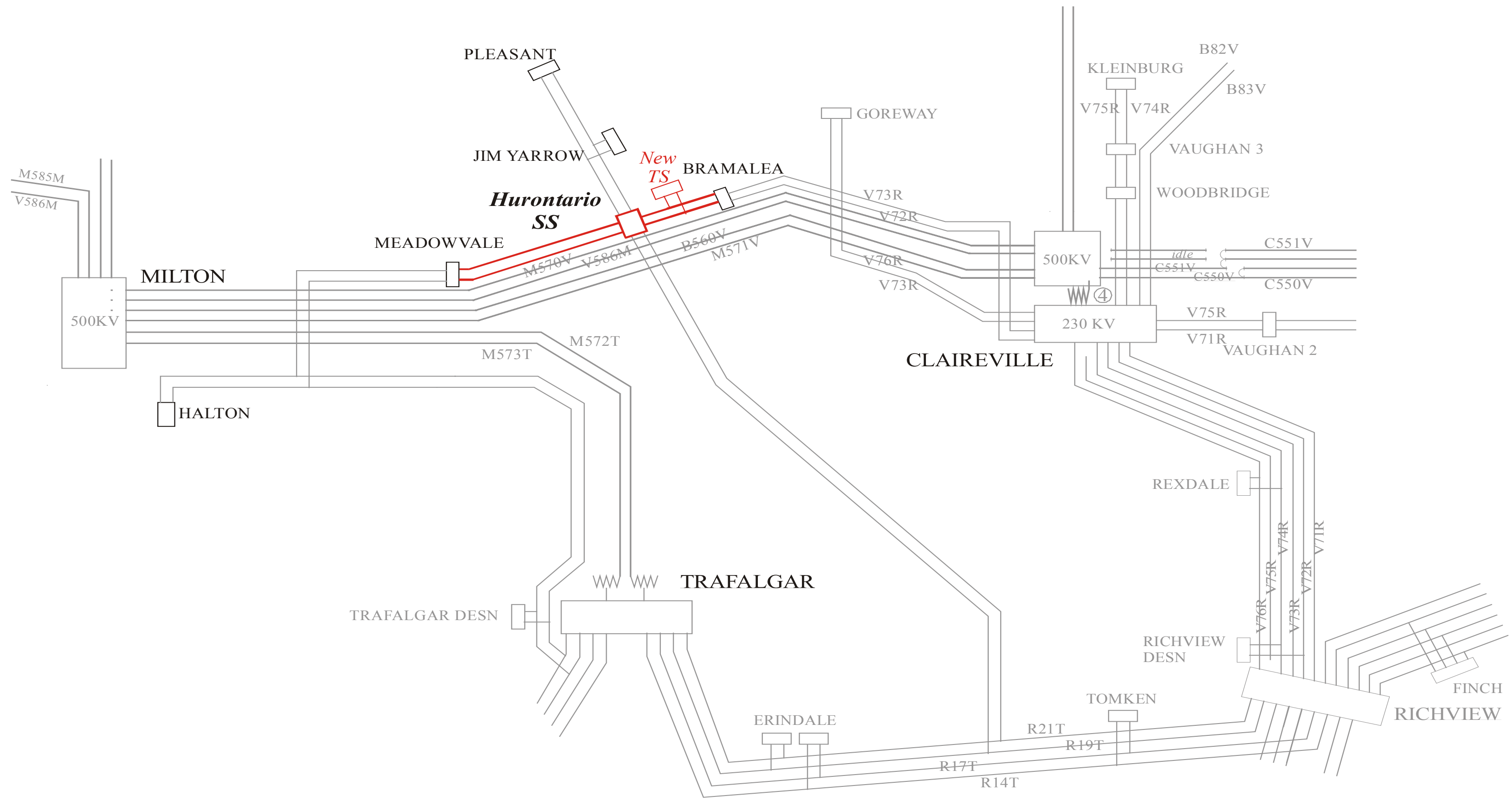


Diagram 3 - To Maintain Supply Reliability to the Southern Mississauga & Southern Oakville Areas

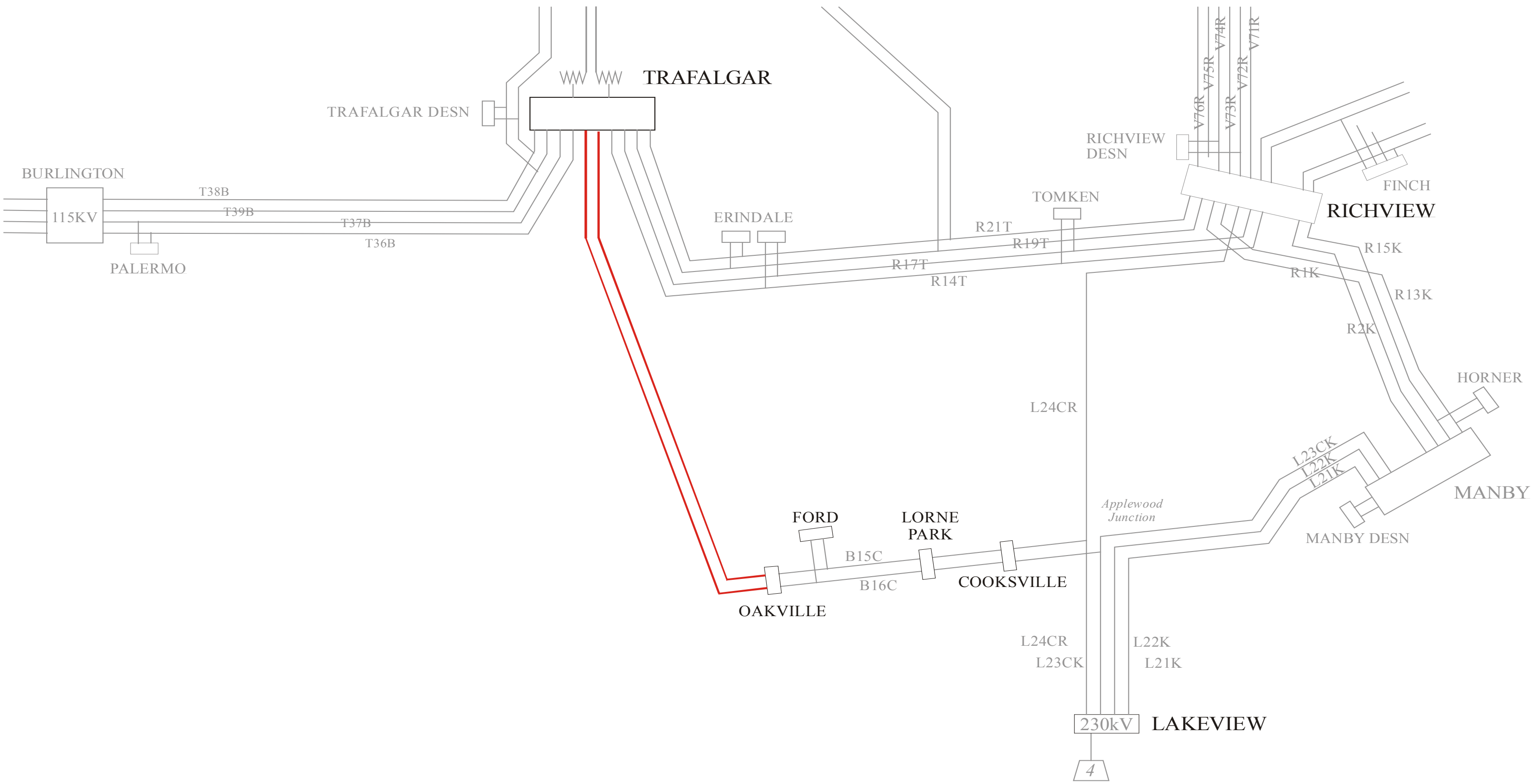


Diagram 4 - To Maintain Supply Reliability to the Greater Toronto Area

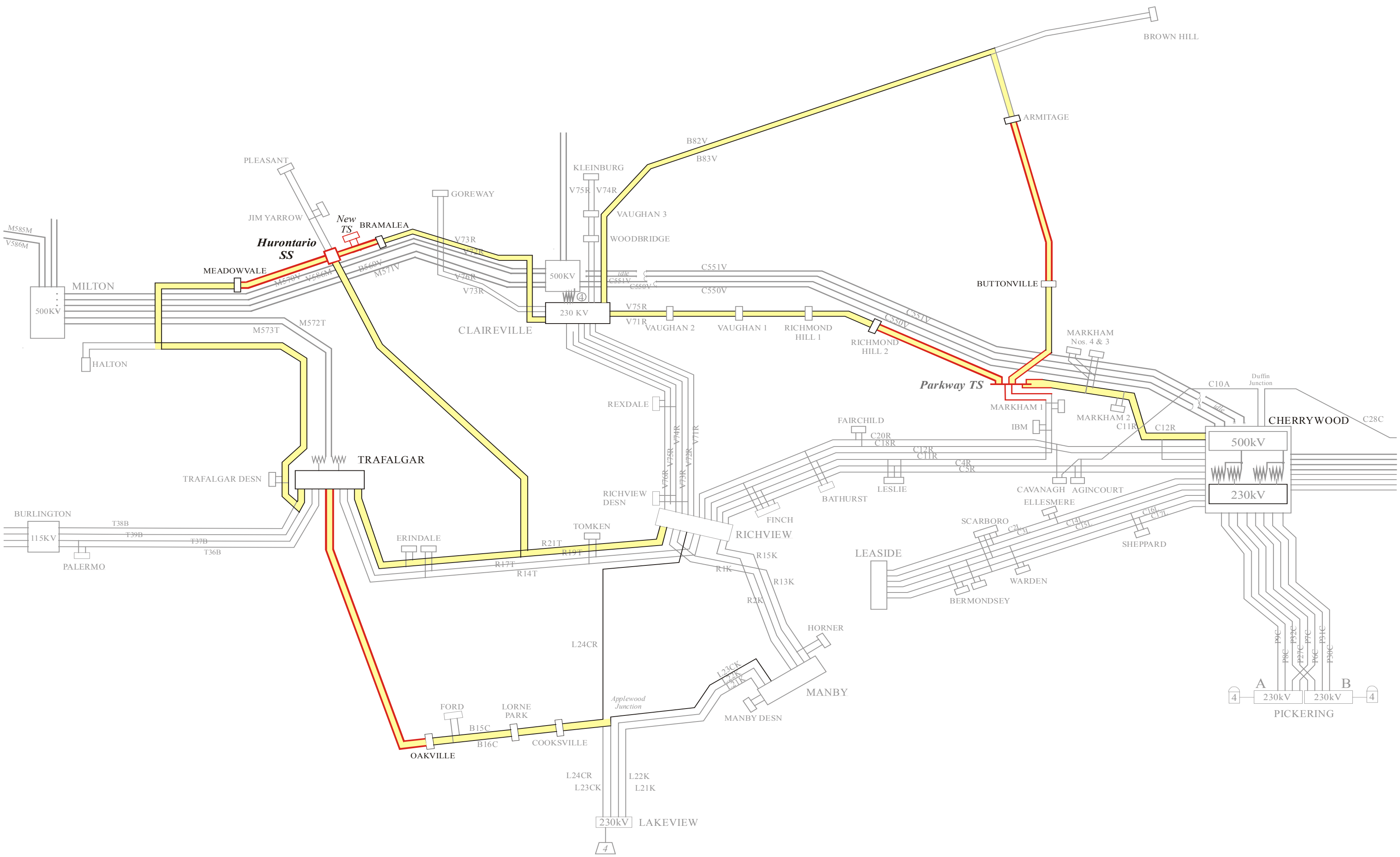


Diagram 5 - To Manage Transfers When Lakeview TGS Retires

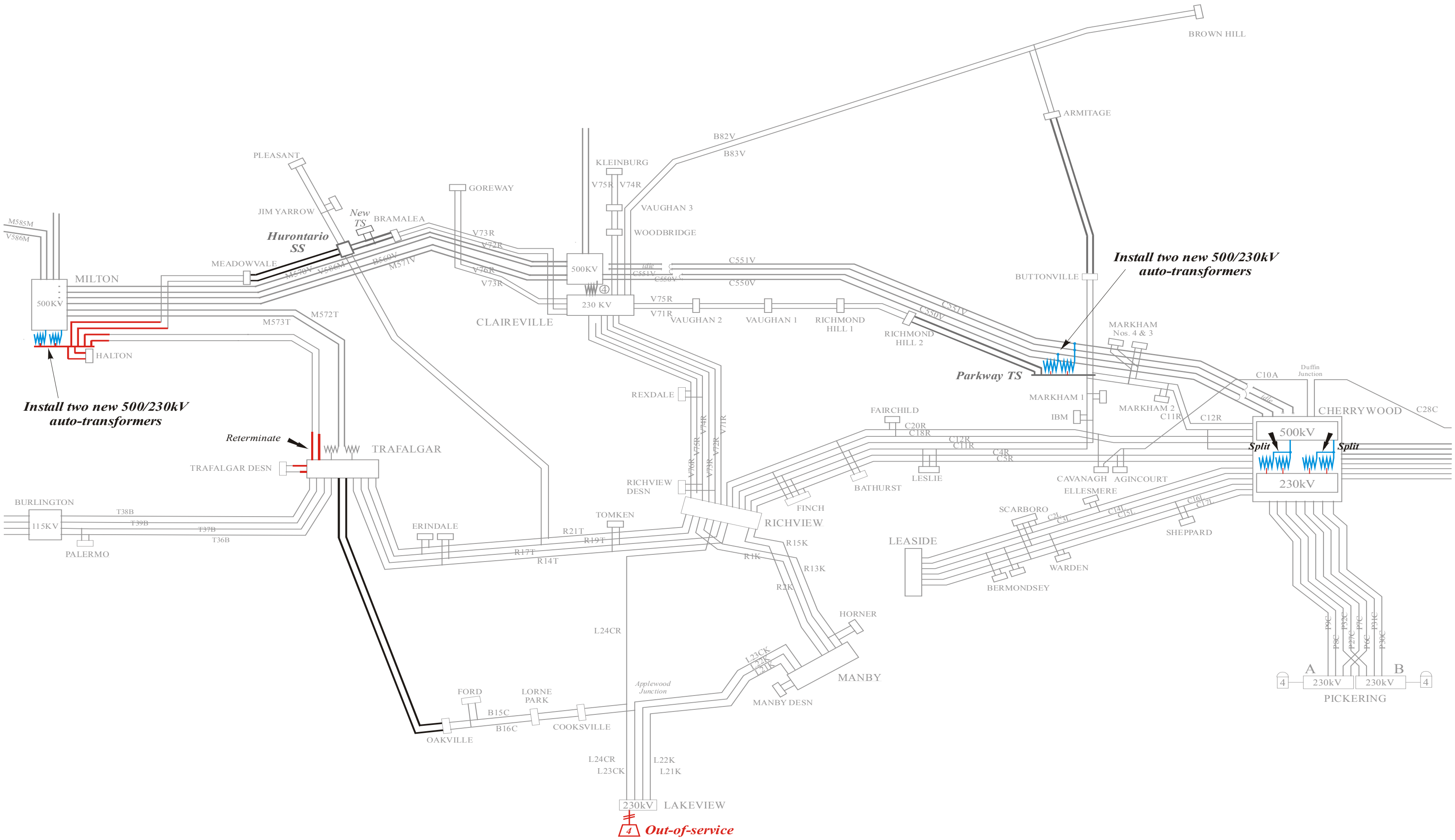


Diagram 6 - Proposed Third Supply for Downtown Toronto: Proposed 230 kV AC Option

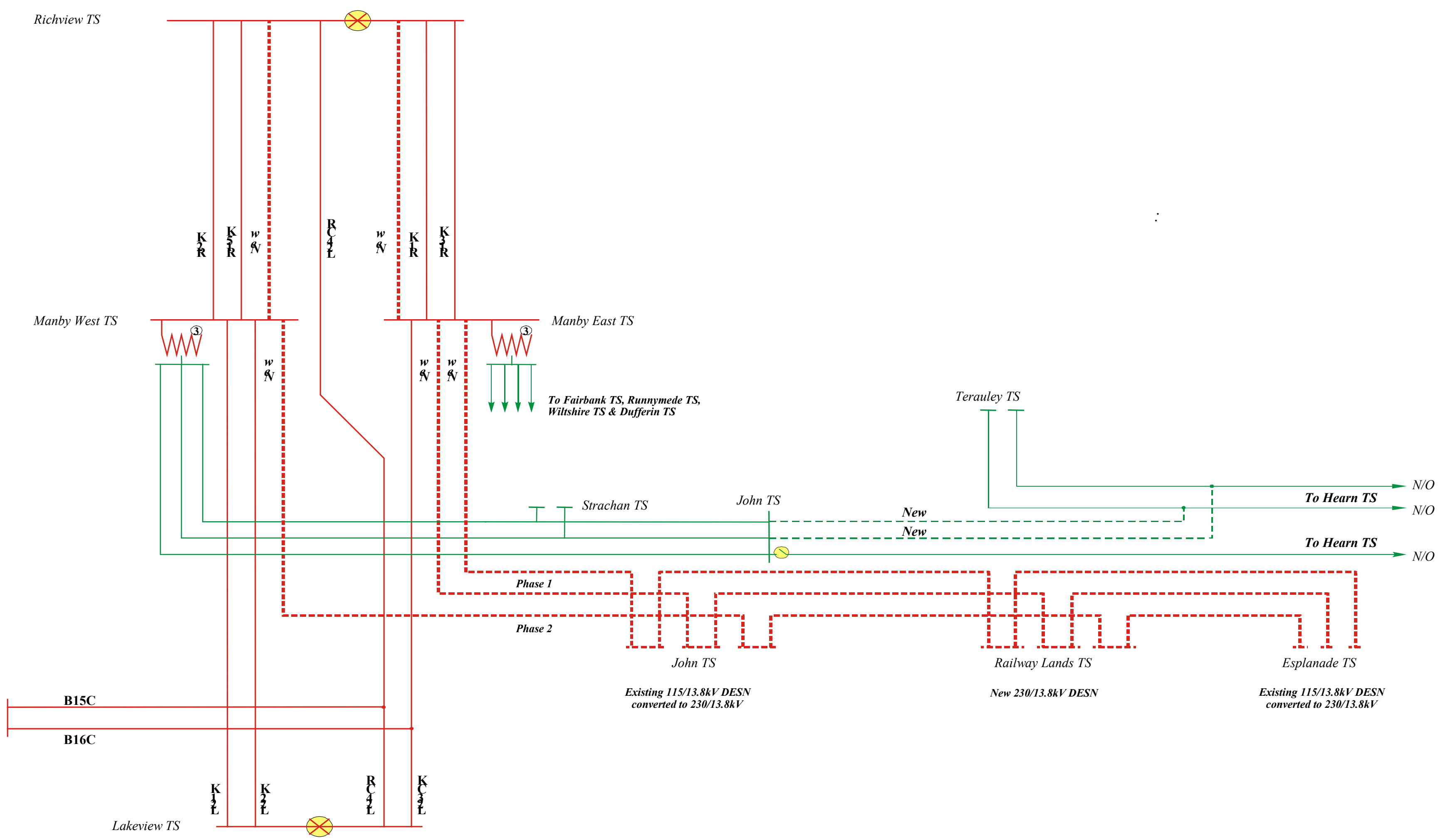


Diagram 7 - Proposed Third Supply for Downtown Toronto: Proposed DC Option

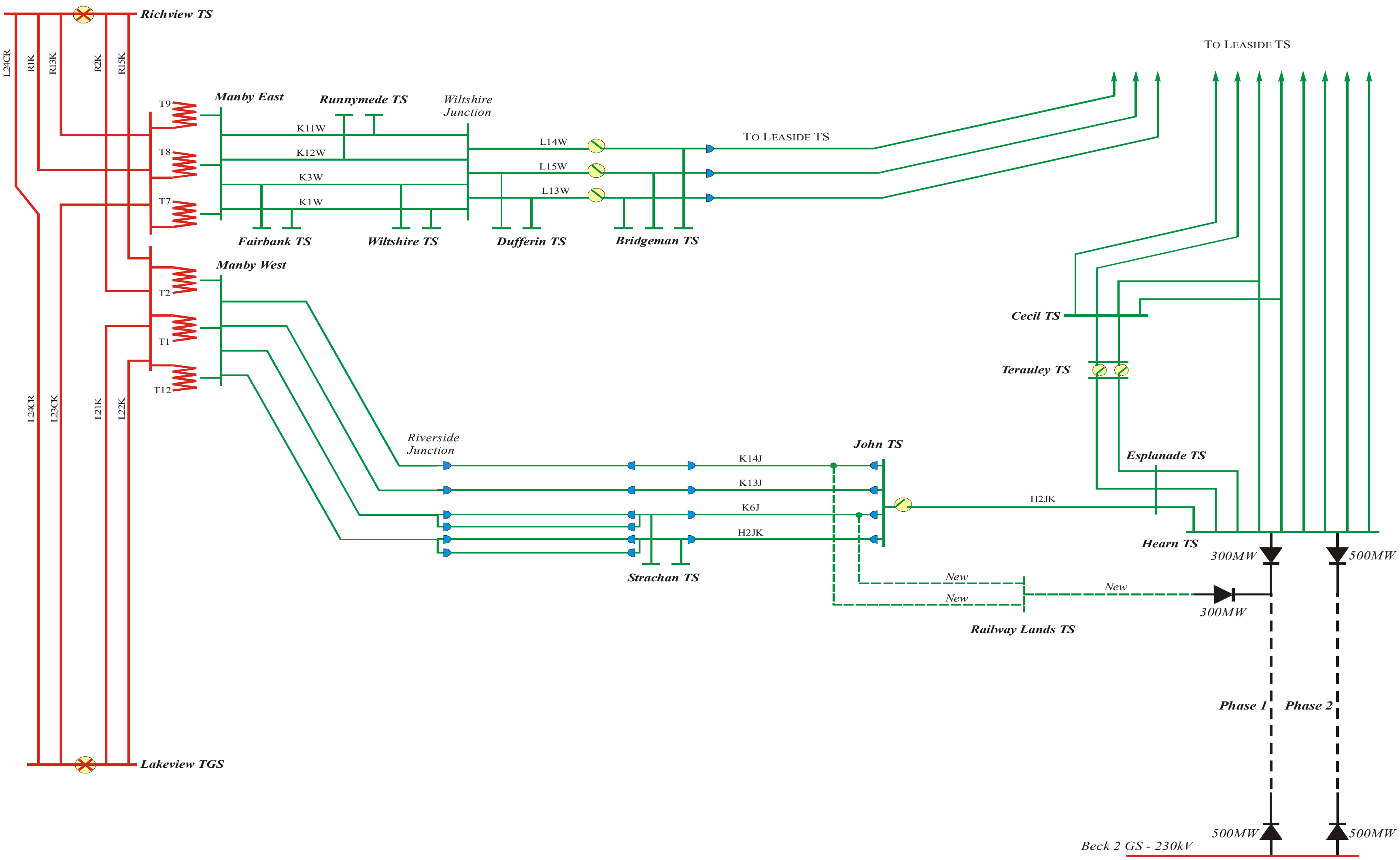
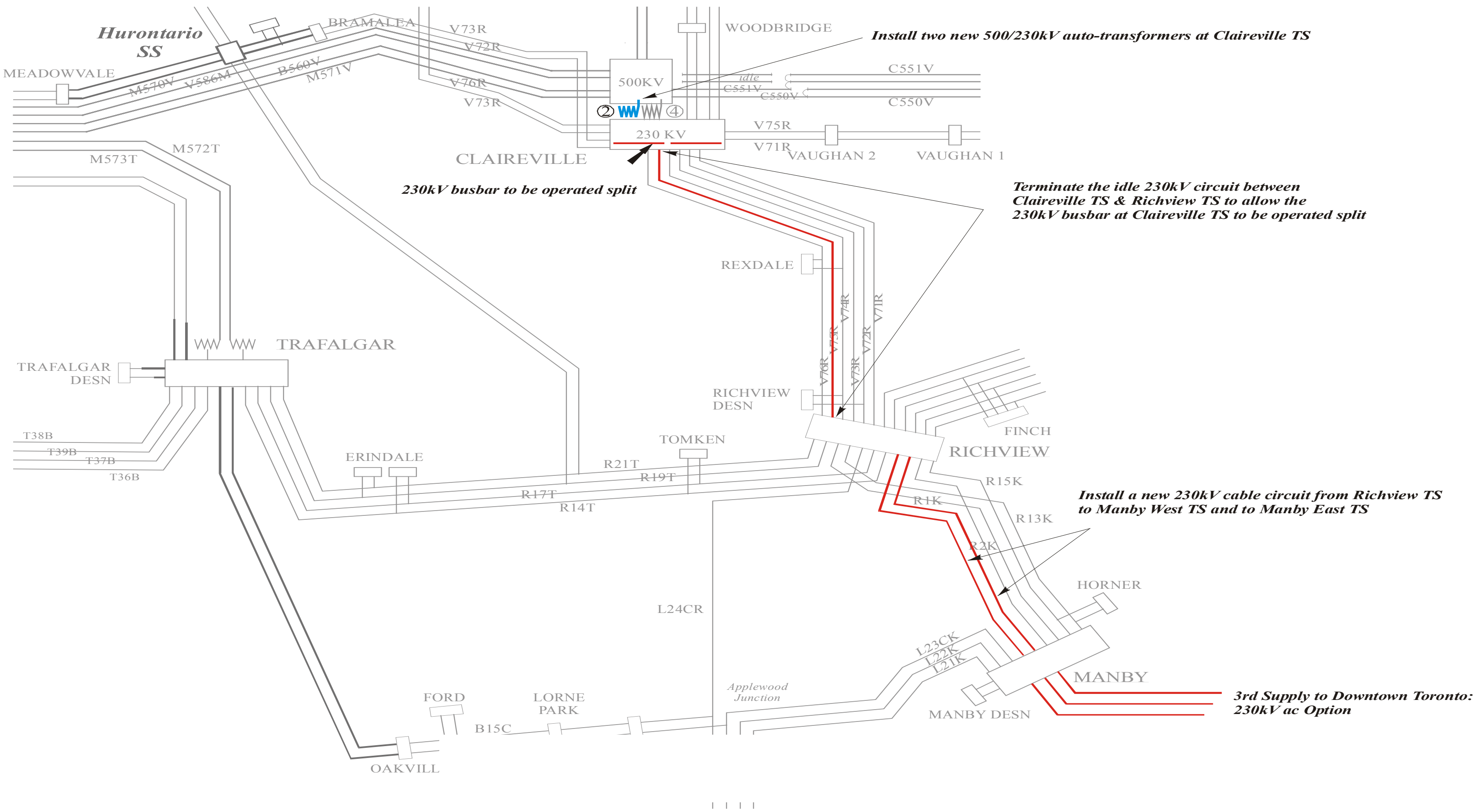


Diagram 8 - Proposed System Reinforcement for the 230 kV AC Option for Providing a Third Supply for Downtown Toronto



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