OEB, OPA and IESO Planning Summary Document

Lake Superior Link

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Overview

This supporting document provides a summary of the need for the East-West Tie Expansion Project (the Project) as identified by the Ontario Energy Board (OEB), Ontario Power Authority (OPA) and Independent Electricity System Operator (IESO). These summaries demonstrate that the need for the Project has been defined by planning processes undertaken by other provincial planning and governing authorities (i.e. OPA, IESO and OEB).

The following OEB, OPA and IESO planning documents listed below are summarized in chronological order to provide an understanding of the need and planning history of the Project from 2010 to 2018:

1. November, 2010, Ontario's Long Term Energy Plan;
2. August 26, 2010, OEB Framework for Transmission Project Development Plans;
3. March 29 2011, Minister of Energy Letter to the OEB;
4. April 25, 2011, OEB Letter to OPA;
5. June 30, 2011, OPA Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion;
6. August 18, 2011, OPA An assessment of the westward transfer capability of various options for reinforcing the east-west tie;
7. August 22, 2011, OEB Registration letter to all licensed electricity transmitters for the East-West Tie Line;
8. December 20, 2011, Information Package letter OEB Letter to all registered electricity transmitters for the East-West Tie Line;
9. April 24, 2012, OEB Proceeding to designate a transmitter to carry out development work for the EWT line;
10. August 7, 2013, OEB East-West Tie Line Designation Decision and Order;
11. October 8, 2013, OPA Updated Assessment of the Rationale for the East-West Tie Expansion;
12. December 2, 2013, Ontario's Long Term Energy Plan;
13. December 15, 2015, IESO Assessment of the Rationale for the East-West Tie Expansion Third Update Report;
14. March 10, 2016, MoE Minister Letter to OEB Order in Council Letter;
15. August 4, 2017, MoE Minister Letter to IESO for an updated needs assessment;
16. December 1, 2017, IESO Updated Assessment of the Need for the East-West Tie Expansion;
17. 2017 Ontario's Long Term Energy Plan; and
18. June 29, 2018, IESO Addendum to the 2017 Updated Assessment of the Need for the East-West Tie Expansion.

November, 2010, Ontario's Long-Term Energy Plan

On November 23, 2010 the Ministry of Energy published the 2010 Long-Term Energy Plan (LTEP) as a follow up to the 2007 Integrated Power System Plan. Due to changes in demographics, economic trends, technological advancements, and the growth of the renewable energy sector, Ontario's plan for energy production was in need of an update. The underlying goal of the 2010 LTEP was to ensure Ontario was capable of meeting its electricity needs while also maintaining a modern, clean and reliable system that would provide energy to Ontario homes and businesses well into the future. This goal was to be achieved by setting out targets for each of the following 7 categories:

- Demand
- Supply
- Conservation
- Reliable transmission/modern distribution
- Aboriginal communities
- Energy in Ontario's economy- capital investments
- Electricity prices

The most relevant to this needs assessment is the reliable transmission/modern distribution category, which speaks in depth about the need to modernize the process of energy transmission and guarantee reliability. With the growth of clean energy resource development, reliable transmission and modern delivery is crucial in supporting Ontario's evolving supply mix.

The 2010 LTEP notes the following in terms of transmission, modern distribution, future needs and the plan:

Transmission

Due to population growth and changes to the energy supply mix, improvements to Ontario's aging transmission system is needed to address the growing and evolving needs of the province. The government of Ontario has already taken steps towards developing and updating existing infrastructure with more than $7 billion invested in transmission and distribution systems since 2003. This investment is double what was invested in the last decade (1996-2003) for infrastructure improvements. Since 2003, reliability has also improved significantly because of new generation, transmission upgrades, reduced load growth and successful conservation programs.

Modern Distribution

Due to the importance of the distribution system to the reliability of Ontario's electricity system, efforts are being made to enable optimal performance. The government has been moving towards a Smart Grid system as it replaces old infrastructure and integrates more renewable energy sources. A Smart Grid system is a more intelligent grid infrastructure that allows for the maximization of existing infrastructure, while modernizing the grid and laying the foundations for smart homes.

Future Needs

To ensure the future reliability of energy transmission and distribution in Ontario, the Ontario government, as well as various agencies, is moving forward on transmission projects that will modernize and improve the existing energy infrastructure in all areas of the province. This commitment to new infrastructure and improvements to existing infrastructure will balance environmental concerns, community needs and the cost to Ontario ratepayers.

The Plan

In 2009, the government of Ontario approached Hydro One to plan and develop a series of new transmission and distribution projects. The OPA provided advice to the government regarding these development projects. Based on this advice, the government has decided to move forward with cost-effective priority transmission projects. Only projects deemed capable of meeting current and future demands; can accommodate renewable projects; serve new load; and support reliability have been chosen as priority projects. The government of Ontario has invested $2 billion to proceed with 5 priority projects, which are to be completed in the next seven years. The identified priority projects, which were consistent with the transmission planning advice received from the OPA, were:

1. Series compensation in Southwestern Ontario - upgrade needed to add renewables grid;
2. Rewiring west of London - upgrade needed to add renewables to the grid;
3. West of London - new line needed to add renewables to the grid;
4. East-West Tie - new line needed to maintain system reliability, allow more renewables and accommodate electricity requirements of new mineral processing projects; and
5. Line to Pickle Lake - new line needed to serve industry needs and to help future remote community connection.

In terms of the East-West Tie expansion, the target completion date was 2016-2017 and the OEB was to carry out a designation process to select a transmitter. The purpose of the designation process was to ensure the selection of the most qualified and cost effective transmitter.

August 26, 2010, OEB Framework for Transmission Project Development Plans

As a result of the passage of the Green Energy and Green Economy Act (GEA) in 2009, the interest in connecting renewable energy generation to distribution and transmission systems has grown substantially. Unfortunately, the existing transmission facilities in Ontario were incapable of consistently accommodating more generation. This issue prompted the release of the OEB Framework for Transmission Project Development Plans, which focuses on enabling transmission project development plans to increase capacity for renewable energy production. On August 26, 2010 the Ontario Energy Board (OEB) released a document that set out a framework for developing new transmission investments in Ontario. The OEB believed that the policy would:

- enable transmitters to develop projects in a timely manner;
- bring additional resources for project development through the support of new entrants to transmission in Ontario; and
- be beneficial to ratepayers as economic efficiency would result from the creation of competition in Ontario’s transmission market.

The main objective of the OEB in developing this framework is to facilitate timely and effective development of transmission systems. In order to fulfill this objective, the OEB has identified 3 principles to abide by: economic efficiency; regulatory predictability; and administrative efficiency. This framework for policy change is consistent with global patterns, in particular those identified in the United States and the United Kingdom.

Licensing

An important aspect of the OEA Act is the licensing of owners and operators of transmission systems in Ontario. According to Section 57 of the OEB Act, various activities, including owning and operating a transmission system, are prohibited without being licensed by the OEB. In order to accommodate this, OEB staff proposed entrant transmitters who wish to participate in the designation process be licensed by the Ontario Energy Board. To be licensed, transmitters must meet minimum requirements in terms of financial and technical capabilities. The licensing process would also determine whether an entrant transmitter is qualified and committed to doing business in Ontario. Although some stakeholders considered the process time consuming, expensive and onerous, the Board considered it reasonable and necessary in evaluating new entrant transmitters. The Board has 3 general policies on transmission licensing and they are as follows:

- *"Transmitters will need a transmission license from the Board to participate in the designation process*
- *Existing transmitters that are already licensed by the Board will participate in the designation process under their existing licence.*
- *New entrant transmitters will need to apply for, and obtain, a transmission licence before being able to participate in the designation process."*

Hearing to Designate a Transmitter

According to the staff Discussion Paper, one of the objectives of the OPA is to conduct independent planning for electricity generation; demand management; conservation and transmission; and developing integrated power system plans (IPSPs) every three years. They also intend to assess transmission investments that they deem required and financially justified to connect Feed-in Tariff (FIT) applications that cannot be supported by existing capacity. The assessment process is required to be completed every 6 months and is referred to as the Economic Connection Test (ECT). In the ECT, the staff Discussion Paper anticipates the identification of four project types: capacity enhancements, network reinforcements, enabler facilities and network expansions. Upon receiving the results of an ECT from the OPA, the Board will begin a process to designate a transmitter for two of the four project types: enabler facilities and network expansions. If an IPSP has recently been released, its transmission recommendations can also be used for the designation process. However, waiting for an approved IPSP every 3 years would be inconsistent with the Board's statutory objective of facilitating timely expansion of the transmission system.

In order to designate a transmitter, the Board will issue a Notice of a Hearing that acts as an invitation to all licensed transmitters to submit their plans for the development project before a specified deadline. Designation is dependent on decision criteria predetermined by the Board, which are: organization; technical capability; financial capacity; schedule; costs; landowner and other consultations; and other factors that are dependent on the individual circumstances of the project. These criteria are set out to ensure that a transmitter is capable of successfully undertaking the project to its completion.

After designation, the transmitter is assured of recovery of the budgeted amount for the planning stage of the project development. The transmitter is then required to meet conditions given in the order of designation, such as performance milestones and reporting requirements on progress and expenditures. A primary performance milestone is the Leave to Construct application that is granted and required by the OEB in order to construct, expand or reinforce any transmission line, with some exceptions based on the scope of the project.

March 29, 2011, Minister of Energy Letter to the OEB

On March 29, 2011 the former Minister of Energy, Brad Duguid, issued a letter to Cynthia Chaplin, the Chair of the OEB. The purpose of this letter was to request that the Board select a transmitter to develop the East-West Tie expansion project through the undertaking of a designation process. The Board's Policy Framework for Transmission Project Development Plans, 2010, is also discussed as being suitable to apply to this development project as it meets the requires of encouraging time efficiency; introduction of new entrants to transmission in Ontario; and brings additional resources for project development. The letter goes on to state the importance of choosing the most qualified and cost-effective candidate in order to promote these same values in the transmission of electricity. The body of the letter in its entirety is as follows:

> *"Ontario's Long-Term Energy Plan, published November 23, 2010, identified five priority transmission projects based on the advice of the Ontario Power Authority (OPA). Among the five priority projects is the East-West Tie, identified by the OPA primarily to meet the need of maintaining long-term system reliability in Northwest Ontario. Consistent with the intents identified in the Long-Term Energy Plan, I am writing to express the Government's interest that the Ontario Energy Board ("the Board") undertakes a designation process to select the most qualified and cost-effective transmission company to develop the East-West Tie.*
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> *The Board's Policy Framework for Transmission Project Development Plans is well suited to apply to the East-West Tie project. Such an approach would allow transmitters to move ahead on development work in a timely manner, encourage new entrants to transmission in Ontario and bring additional resources for project development. It will also support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.*
>
> *A designation process for the East-West Tie also promotes the Board's electricity objectives of protecting the interests of consumers with respect to prices and of promoting cost-effectiveness in the transmission of electricity. In respect of those particular ends, and given the location and value of the East-West Tie in ensuring reliability and maintaining efficiency of the system, I would expect that the weighting of decision criteria in the Board's designation process takes into account the significance of aboriginal participation to the delivery of the transmission project, as well as a proponent's ability to carry out the procedural aspects of Crown consultation.*
>
> *As the Board has noted in its framework, the starting point for transmission project development planning should be an informed, effective plan from the Province's transmission planner, the OPA. As such, it would be prudent for the Board to request further analysis for the East-West Tie from the OPA to support initiation of designation process."*

April 25, 2011, OEB Letter to OPA

On April 25, 2011 following the letter from the Minister of Energy addressed to the OEB, the OEB issued a letter to the OPA requesting further analysis of the East-West Tie Expansion Project. In this letter the OEB requested that the OPA undertake a preliminary assessment on the need for the expansion of the East-West Tie. This more detailed assessment would act as a follow up to the 2010 LTEP and would assist in determining whether the designation process was justified in accordance with the objectives of the board's policy. The body of the OEB letter in its entirety is as follows:

> *"The Minister suggests that the designation process outlined on the Board's August 26, 2010 policy report could be used to select the most qualified and cost-effective transmission company to develop the East-West Tie line. The Board agrees and is prepared to proceed with a designation process if project planning is justified. In developing the designation policy, the Board recognized the role of the OPA as the transmission planner for the province and identified an informed, effective plan from the OPA as the trigger for starting a process.*
>
> *The Board understands that the OPA provided information to the Minister for the Long-Term Energy Plan supporting the need for an East-West Tie line in order to maintain long-term system reliability in Northwest Ontario. The Board, therefore, requests a report from the OPA regarding the preliminary assessment of the need for the East-West Tie line. The assessment should be sufficiently robust to allow the Board to determine whether the designation process should be initiated in accordance with the Board's designation policy. Final assessment of need and therefore approval to construct a line will still require a hearing before the Board for leave to construct a transmission line.*
>
> *The Board expects that the OPA's report would provide information on system reliability in relation to the East-West Tie line. More specifically, the report should include technical information as:*
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> - *the line connection points to the existing system;*
> - *any specific routing requirements besides the connection points;*
> - *the required carrying capacity of the line;*
> - *any technical requirements to address the system need identified above;and*
> - *any available information regarding benefits of the project to ratepayers.*
>
> *A report from the OPA by the end of June 2011 is required in order for the Board to decide whether undertaking a designation process for the East-West Tie line is justified at this time in accordance with the objectives of the Board's policy. Earlier receipt of the OPA's report would allow the Board to move ahead expeditiously.*
>
> *If the Board decides to proceed with a designation process, the Board expects the OPA will participate by providing additional information related to project requirements and need."*

June 30, 2011, OPA Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion

In response to the request by the OEB for a detailed preliminary assessment of the need for the East-West Tie Expansion Project, the OPA released a report on June 30, 2011. The report, titled "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion", provided a more robust analysis of the background and rationale for the East-West Tie Expansion, as well as recommendations on the scope and timing. The report is divided into 6 sections:

- Background on the Northwest Area
- Northwest Conservation and Demand
- Supplying Northwest Demand
- Planning Considerations and Context for the East-West Tie Expansion
- The OPA's Recommendation
- Project Implementation

The Northwest

The Northwestern region of Ontario, which makes up 60% of the land area in the province, consists of the districts of Kenora, Rainy River and Thunder Bay. It comprises the area north of Lake Superior, from Wawa in the east to Manitoba in the west. Thunder Bay is home to 50% of the population, while the remaining 50% are sparsely located in rural and remote communities across the region.

Northwest Conservation and Demand

The demand for electricity in the Northwest is winter peaking with relatively less pronounced peaks than Southern Ontario. The primarily resource based industrial load in the Northwest is the predominant consumer of energy. Additionally, there tends to be sizable fluctuations in demand for energy, as the resource based industry (e.g., forestry and mining) is vulnerable to fluctuations in the economy. Historically, the annual energy requirements between 1985 and 2005 were consistent. However, since 2005 there has been a significant decline in energy demand. This is largely due to the decline in the pulp and paper industry. The following scenarios were considered by the OPA when evaluating future trends in the Northwest's electrical demands:

- *"The pulp and paper sector demand in the Northwest has declined and the extent and pace of its recovery will have a large influence on the regions electricity demand.*
- *The mining industry is consistently growing. There are operations north of Thunder Bay and requests have been made for additional supply for gold mines located in the Red Lake and Pickle Lake area. Several inquiries have also been made regarding the development of new mines or resuming operation at old mines. This will largely impact the growth in demand for electricity*
- *The Ring of Fire, located around 300 km northeast of Thunder Bay, has potential to become a significant area for development of mines. This is due to the findings of high quality rare earth metal ores, including chromite. Around 20 -25 Mw would potentially be needed for each active mine*

- *The OPA is developing a plan to connect remote communities beyond Pickle Lake. 24 MW of load could be added to the Northwest demand by 2020 due to this"*

The extent of the development for each of these scenarios was still unknown. In order to account for the uncertainty, the OPA considered two scenarios to forecast electrical demand.

Supplying Northwest Demand

Due to the lack of interconnectivity with neighbouring areas, the Northwest is more reliant on internal resources to supply demand. The internal resources system is mainly comprised of hydroelectric and coal-fired generation. Combined, these account for 90% of the region's internal resource capacity.

Hydroelectric generation accounts for over half of the installed generation capacity. However, due to variability of the generation capacity and energy output, the Northwest's hydroelectric generation cannot be relied on to supply a fixed amount of demand each year. This variability is caused by fluctuations in hydraulic conditions as well as the inability to store water from year to year. Coal-fired generation is expected to make up for these fluctuations. There are two coal-fired generating stations that supply approximately one third of the generation capacity in the Northwest. The remaining energy supply comes from gas-fired and biomass generation as well as external resources.

The resource mix in the Northwest is changing as government policies are implemented regarding coal-fired generation and renewable energy. As per the OPA, the most significant changes and effects on the Northwest system are as follows:

- *"The Thunder Bay and Atikokan coal-fired generation stations are to cease coal-fired operation by the end of 2014 in accordance with Ontario Regulation 496/07.*
- *The OPA has been directed to contract for the conversion of the Atikokan plant to run using biomass fuel. Though it will still have capacity of about 200 MW, its forecast fuel availability will limit energy production to 140 GWh per year.*
- *The government has stated that both currently operating Thunder Bay coal-fired units are to be converted to use natural gas by 2014. Under gas-fired operation, the Thunder Bay plant will be capable of providing the same capacity as it does today. However, higher fuel costs under natural gas operation will make it better suited to peaking operation.*
- *Approximately 200 MW of new renewable resources have been contracted in the Northwest. These new resources consist primarily of wind and solar resources, but also include some hydroelectric and biomass generation. The load-meeting capability of these resources will be considered to determine their contribution to meeting Northwest demand.*
- *Demand response resources in the Northwest are expected to total approximately 90 MW."*

With only three interconnections to the neighbouring area, the external resources available to supply the Northwest's demand are limited. The current East-West Tie is capable of importing 350 MW into and 325 MW out of the Northwest and is relied upon to supply a large amount of the demand in low water years or periods of high demand. The remaining two interconnections, the Manitoba system and the Minnesota system, are capable of supplying some of the demand for the Northwest. The Manitoba system is capable of transmitting 330 MW in and 262 MW out of the Northwest and the Minnesota system is capable of supplying 90 MW in and 140 MW out. However, both systems are unable to supply the full potential of MW because of the limitation of the combined import capability of 570 MW under normal operating conditions.

As mentioned above, the East-West Tie's nominal capacity westbound transfer is 350 MW. Key considerations to be kept in mind regarding the capacity of the westbound transfer include:

- *"The nominal westbound limit of 350 MW is based on operating the system to respect the outage of one of the two circuits on the East-West Tie, which share a common tower line. Elsewhere in Ontario the bulk electricity system is operated to respect the loss of both circuits on a common tower line, a practice which complies with current IESO reliability criteria and NERC2 system design standards. Consequently, the nominal westbound limit of 350 MW for the East-West Tie does not conform to current reliability standards. Operating to respect the loss of both East- West Tie circuits would reduce its transfer capability from 350 MW to 175 MW. Loss of the East- West Tie while it is transferring 350 MW could lead to the interruption of load in the Northwest.*
- *Today, the IESO respects the double-circuit contingency limits (175 MW) on the East-West Tie when an electrical storm is detected over the Northwest, as the likelihood of losing both circuits is more likely during such events.*
- *Since 2006, there have been over 60 forced outages along the East-West Tie, averaging about 12 outages per year. Over a quarter of these outage events have been double-circuit outages in which both East-West Tie circuits were forced out of service."*

In general, the IESO's reliability criteria, which must be consistent with the Northeast Power Coordinating Council (NPCC) criteria and the North American Electric Reliability Corporation (NERC) criteria, will serve as a base to which the updated transmission line will be planned around. The existing East-West Tie transmission line was not designed in accordance with these standards because of the terrain and distance that the line has to traverse. In order to maintain its compliance with these reliability standards, the existing transfer capability of the current East-West Tie must be reduced to 175 MW.

Planning Considerations and Context for the East-West Tie Expansion

Three major investment decisions have been made in the last fifty years because of the Northwest's increasing demand. These were the construction of the existing East-West Tie, the Thunder Bay Generation Station and the Atikokan Generation Station. In addition to the significant increase in demand for energy in the Northwest, the need for the expansion is also based on the need for reliability and a cost-effective alternative. The OPA examined 2 alternatives to gauge the need for this Project. One alternative examined internal generation, and in the other the East-West Tie transmission line was expanded. In its comparison based on cost-effectiveness, flexibility, and ability to remove barriers to renewable generation development, the OPA found that the expansion of the existing transmission line would be the preferred alternative, with a net benefit ranging from $20 million to $80 million. It is important to note that this figure does not include any monetary cost of emissions.

After carrying out the preliminary assessment of long-term supply needs of the Northwest and the two alternatives, the OPA recommended that development work on the East-West Tie expansion should be initiated. The OPA identified the next step in the implementation process as the selection of a transmitter to carry out development. The development work entails project design, specification and costing; routing and siting; initiation of necessary approval processes; and consultation and communications. This development work only represents 2 to 5 percent of the project cost and would provide the necessary information to make a decision on whether or not to proceed with the project.

In addition, the OPA also specified that in the interest of cost-effectiveness a double-circuit 230 kV transmission line would be preferred but other options could be proposed if they are within the project scope criteria. The project criteria were outlined in the report and are as follows:

- *"The new line is to connect to both Wawa TS in the Northeast and Lakehead TS in the Thunder Bay area- a distance of approximately 400 km- and into include all station termination facilities.*
- *The new line is to be switched at Marathon TS, which is an existing station between Wawa TS and Lakehead TS. The existing E-W Tie is switched at this station.*
- *The new line in conjunction with the existing tie is to provide total eastbound and westbound capabilities on the order of 650 MW, while respecting all NERC, NPCC, IESO reliability standards.*
- *The project should also include any reactive facilities that are to be identified in a pending IESO study. It is anticipated that this study will be available prior to the commencement of any designation process.*
- *The target in-service date of the new line and associated reactive facilities is currently estimated to be 2017, based on typical transmission project lead times.*
- *The new line should be designed to have a lifetime of at least 50 years."*

August 18, 2011, OPA An Assessment of the Westward Transfer Capability of Various Options for Reinforcing the East-West Tie

The new East-West Tie Line and the existing line, will be capable of providing total eastbound and westbound capabilities in the order of 650 MW, while respecting all NERC, NPCC, and IESO reliability standards. To assess the best option to efficiently meet all standards, the OPA undertook and released a feasibility study titled "*An Assessment of the Westward Transfer Capability of Various Options for Reinforcing the East-West Tie*". The goal of the expansion of the East-West Tie is to achieve a transfer capability of 650 MW westward, while continuously respecting double-circuit contingencies. The feasibility study provided an analysis of two options to meet this goal, which were:

- *Option 1- With a new 230 kV double-circuit line installed between Wawa TS and Lakehead TS, as proposed by the OPA*
- *Option 2- With a new 230 kV high-capacity, single circuit line installed between the same terminal stations.*

After considering and testing various criteria, the study concluded that a double-circuit line reinforcement of the East-West Tie would be ideal as it offers a higher level of security, from a planning perspective.

August 22, 2011, OEB Registration Letter to all Licensed Electricity Transmitters for the East-West Tie Line

Following the preliminary assessment and feasibility study undertaken by the OPA, the OEB deemed the designation process justifiable.

On August 22, 2011 the OEB issued a letter inviting all licensed electricity transmitters, all applicants and potential applicants for an electricity transmitter licence, and all interested parties to express their interest in planning the East-West Tie Expansion Project. In this letter the OEB clarified that each application is required to meet the project requirements outlined in the OPA's Report, but is also not required to use the preferred option given by the OPA as their solution. A significant section of the letter is as follows:

> *"The OPA is responsible for independent transmission planning in Ontario and has advised the Board that there is a need to proceed with development work on the East-West Tie. The Board has received the OPA's preliminary assessment of need as a basis for a designation process. The Board expects the final determination of need to be made as part of a future application for leave to construct, not through the designation process.*
>
> *The OPA Report defines a specific solution as its preferred option but acknowledges that it may be possible for other solutions to meet the requirements for the line as described in the project scope criteria of the OPA Report. The Board will call the OPA's solution, with additional requirements from the IESO Feasibility Study, the "Reference Option." Transmitters may propose alternative solutions that meet the requirements. A transmitter proposing a solution different from the Reference Option will bear the onus of proving that the alternative is the equivalent, in term of performance, reliability, cost, etc., of the Reference Option. This would include a feasibility study prepared by the IESO or prepared by the transmitter to the IESO's requirements."*

December 20, 2011, Information Package OEB Letter to all Registered Electricity Transmitters for the East-West Tie Line

Following the letter addressed to all potential transmitters, the OEB issued a letter addressed specifically to the electricity transmitters that registered for the East-West Tie Line expansion. This letter was issued on December 20, 2011 and provided more information on the following:

- The Designation Process - the designation process is a hearing of the Board, the sole purpose of which is to "*identify a licensed transmitter who will be entitled to recover its prudently incurred development costs of a specific transmission project*." The costs are slated to begin when the transmitter is designated and end when an application for a Leave to Construct is submitted. Only the designated transmitter would be able to recover its costs of becoming designated.
- The East-West Tie Line Project - the letter specifies the scope of the project for the purposes of designation. In addition to this, it also provides information on the Minimum

Technical Requirements that outlines the requirements for one possible solution for expanding the East-West Tie Line.

- Planning Meetings to Discuss Further Action – the letter specifies a date for a meeting at the Board's office where filing of plans and the process for the evaluation of plans would be discussed.

April 24, 2012, OEB Proceeding to Designate a Transmitter to Carry Out Development Work for the EWT Line

In order to designate a transmitter, the OEB (the Board) adopted a two-phase process. In Phase 1, the Board established specifics for proceeding including: decision criteria, filing requirements, obligations and consequences arising on designation, the hearing process for Phase 2 and the schedule for the filing of applications for designation. While in Phase 2, registered transmitters are given the opportunity to submit their applications so the Board could make a decision. In the OEB report released on April 24, 2012, the Board's staff submitted a list of issues regarding Phase 1 that were each addressed and discussed in depth. The primary purpose of this report was not only to address the issue list approved by the Board, but also to elicit submissions from other parties on the issues identified during Phase 1.

August 7, 2013, OEB East-West Tie Line Designation Decision and Order

The OEB issued a report in August of 2013 that stated the designation decision and order for the East-West Tie Expansion Project. There were 7 transmitters that registered their interest in seeking the designation in response to the letter released on August 22, 2011 by the OEB. The OEB issued a "Notice of Proceeding" to designate a transmitter to carry out development work and also accepted 24 parties as interveners in this proceeding.

Following the release of the OEB April 2012 report, six complete applications were received by the OEB for designation. These applications were assessed in the Phase 2 stage of the Decision and Order using the discussed methodology and ranking system for each decision criteria. This was as follows:

- Organization;
- First Nation and Métis participation;
- Technical capability;
- Financial capacity;
- Proposed design;
- Schedule; development and construction phases;
- Cost; development, construction, operation and maintenance phases;
- Landowner, municipal, and community consultation; and
- First Nations and Métis consultation.

The transmitter that ranked the highest overall was Upper Canada Transmission, Inc. (operating as NextBridge) and as such was selected as the designated transmitter to complete the development work for the East-West Tie Expansion Project.

October 8, 2013, OPA Updated Assessment of the Rationale for the East-West Tie Expansion

Following the OPA's June 2011 report, the OEB requested an update on the assessment of the rationale for the East-West Tie Expansion, which was completed and released on October 8, 2013. One major change that occurred between these reports was the change in available resources to supply the Northwest with electricity due to the suspension of the conversion of the Thunder Bay Generating Station from coal-fired to natural-gas fired.

The need for additional electricity supply was also updated in this report, with the elimination of coal-fired power generation planned and the forecasted expansion of the mining sector. Using a probabilistic analysis approach, the OPA conducted a reliability assessment of the Northwest's electricity capacity. The capacity shortfall was estimated to begin in 2015 and expected to increase substantially in the coming years. This was largely due to the continuous forecasted growth of load for the Northwest due to increased activity in the mining sector.

In order to meet this load two alternatives were considered: the expansion of the East-West Tie or no expansion of the East-West Tie (installation of gas-fired generation instead). The primary update assessed in this report was the cost-effectiveness of the two alternatives. After making various educated assumptions, it was estimated that under the reference scenario the net benefit for the expansion of the East-West Tie would be just over $300 million compared to the alternative of no expansion. This outlined the clear cost benefit of building the East-West Tie expansion, which would help substantially in supplying energy and preventing the forecasted capacity shortfalls.

December 2, 2013, Ontario's Long Term Energy Plan

On December 2, 2013, the Ministry of Energy published a Long-Term Energy Plan (LTEP), titled "*Achieving Balance*", to serve as an update for the 2010 LTEP. The report stated that Ontario was in a strong supply situation and that there was time to carefully consider how to address future energy needs. The LTEP took a pragmatic approach and was centralized around 5 principles: cost-effectiveness, reliability, clean energy, community engagement and an emphasis on conservation and demand management before building new power generation. The key elements of the 2013 LTEP were:

- Conservation First;
- Annual reporting;
- Nuclear;
- Renewable energy;
- Natural gas/combined heat and power;
- Clean imports;
- Rate mitigation and efficiencies;
- Enhanced regional planning;
- Transmission enhancements;
- Aboriginal engagement;
- Energy innovation; and
- Oil and gas.

In 2013, coal accounted for less than 3% of Ontario's energy generation and Ontario was projected to be coal free in 2014. This was a significant improvement from the 25% of Ontario's electricity supply that it provided a decade ago. The report identified that the energy makeup has been moving towards renewable energy and also creating a more efficient means of transmission. In the LTEP, five key transmission projects were noted:

- East- West Tie development;
- Northwest bulk transmission line;
- New line to Pickle Lake;
- Improvements on line from Dryden to Red Lake; and
- Remote connections.

In terms of the need for the East-West Tie development project, the LTEP mentioned the recent spotlight on Northwestern Ontario with regards to electricity planning. It also stated that while provincial demand was generally flat, demand in Northwestern Ontario was projected to increase in the near future due to an increase in mining activity. In 2010, the expansion of the East-West Tie was made a priority project and work on the development of the line commenced as a means to satisfy the growing energy demand of the Northwest. Efforts were focused on engineering work, seeking necessary approvals such as the Environmental Assessment, and engagement with First Nation and Métis communities. The East-West Tie expansion was expected to be finished in 2018 and was expected to create hundreds of jobs for the duration of development and construction. The 2013 LTEP also anticipated that the new East-West Tie Line would not only provide a rejuvenated source of supply to the Northwest but would also ensure that remote communities in the Northwest have the power that they require.

December 15, 2015, IESO Assessment of the Rationale for the East-West Tie Expansion Third Update Report

On December 15, 2015, the IESO released the third update of the Assessment of the Rationale for the East-West Tie Expansion. This report was submitted to the OEB to confirm the rationale for the East-West Tie (E-W Tie) based on information and updated study results available at the time.

There were a number of updates in this report, such as updated transformer station costs; the refined transmission system limits; the identification of a potential opportunity to defer costs through twinning; and refined resource assumptions.

The transformer station costs in this report had been updated from the previous report to $150 million, a $50 million dollar increase, reflecting a more detailed design than what was previously available. In order to defer some of these costs, the IESO presented a potential strategy called twinning, which is the process of creating two "super circuits", one carried by the existing E-W Tie line structures and the other one on a new line. This would potentially allow for approximately $100 million of the station facility costs to be deferred. In addition to this, the IESO refined its studies of transmission system limits and interface capabilities to allow for analysis of the most up-to-date supply and demand information available.

In terms of refining resource assumptions, the IESO analyzed updated market trends; updated analysis of internal and external resource use; as well as using new data available (e.g., energy and demand data from 2014) in order to create more educated estimates for their assumptions. With these refined assumptions, the IESO concluded that the net economic benefit of building the E-W Tie Expansion would be $1.1 billion under the reference scenario compared to not building the expansion. In order to accommodate for sensitivities, the IESO tested the net economic benefit for low and high demand scenarios, these ranged from a break even outcome for low demand forecast to $1.7 billion for high demand growth.

The IESO also stated that in addition to economic benefits and meeting reliability requirements, building the expansion would also be beneficial in terms of system flexibility, removal of a barrier to resource development, reduced congestion payments, reduced losses and improved operational flexibility. Therefore, the IESO continued to recommend the E-W Tie Expansion as a preferred alternative in order to maintain a long-term, reliable and cost-effective supply of electricity to Northwestern Ontario.

March 10, 2016, MoE Minister Letter to OEB Order-in-Council Letter

On March 10, 2016, the former Minister of Energy, Bob Chiarelli, addressed a letter to the Chair and CEO of the OEB, Rosemarie Leclair. In his letter, the Minister reiterated the significance of the East-West Tie Expansion Project by noting it was identified as a priority project in the 2013 Long Term Energy Plan and referred to it as "*a cornerstone of this government's policy to support expansion of transmission infrastructure in northwestern Ontario*". In addition to this the Minister stated, that the Government of Ontario issued an Order-in-Council declaring that the construction of the Project was needed as a priority project, which took effect on March 4, 2016. The Order-in-Council was attached in the letter and stated the following:

> *"WHEREAS Ontario considers it necessary to expand Ontario's transmission system in order to maintain a reliable and cost-effective supply of electricity in the Province's Northwest, increase operational flexibility, reduce congestion payments and remove a barrier to resource development in the region;*
>
> *AND WHEREAS Ontario considers the expansion or reinforcement of the electricity transmission network in the area between Wawa and Thunder Bay composed of the high voltage circuits connecting Wawa TS with Lakehead TS (the "East-West Tie Line Project"), with an in service date of 2020, to be a priority;*
>
> *AND WHEREAS the Lieutenant Governor in Council may make an order under section 96.1 of the Ontario Energy Board Act, 1998 (the "Act") declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project;*
>
> *AND WHEREAS an order under section 96.1 of the Act requires the Ontario Energy Board, in considering an application under section 92 of the Act in respect of the electricity transmission line specified in the order, to accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96 of the Act;*
>
> *NOW THEREFORE it is hereby declared pursuant to section 96.1 of the Act that the construction of the East-West Tie Line Project is needed as a priority project, and*

that the present order shall take effect on the day that section 96.1 of the Act comes into force."

August 4, 2017, MoE Minister Letter to IESO for an Updated Needs Assessment

On August 4, 2017, the former Minister of Energy, Glenn Thibeault, issued a letter to the Independent Electricity System Operator (IESO) requesting that an updated needs assessment on the East-West Tie Expansion Project be provided. The request for additional assessment was prompted by the updated cost estimates provided by NextBridge in their Leave to Construct application in 2017. The cost estimates submitted to the OEB were significantly higher than the previous estimates provided by NextBridge, and the IESO's estimate in their December 2015 needs assessment. Based in part on the cost estimates submitted by NextBridge and the indication by the IESO that the Project was the lowest cost alternative in 2015, the Government of Ontario passed an Order-in-Council on March 4, 2016 under the *OEB Act* to make it a priority project. However, with the updated cost estimate submitted by NextBridge in 2017, the Government deemed another need assessment, updated with the latest costs and system needs, to be necessary. The IESO was asked to provide an updated need assessment to the Ministry of Energy by December 1, 2017.

December 1, 2017, IESO Updated Assessment of the Need for the East-West Tie Expansion

In response to the letter received from the Minister of Energy, Glenn Thibeault, on August 4, 2017, requesting an updated needs assessment, the IESO released an updated need assessment report for the East-West Tie Expansion on December 1, 2017. This report served as the fourth update to the original June 2011 report titled "*Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion*". This report was requested by the Minister of Energy due to increased costs provided by Nextbridge in its Leave to Construct (LTC) application. The report's focus was on the updated NextBridge project costs and an updated demand and supply outlook for the Northwest.

In terms of updated costs, the NextBridge LTC application estimated the project cost to be $777 million, which was significantly higher than the initial planning estimate of $500 million. According to NextBridge, this cost increase can be attributed to unbudgeted costs as well as unforeseeable factors such as the delay of the in-service date to 2020 requested by the IESO to undergo optimization of equipment and design. After conducting this optimization and additional needs assessment, the IESO's recommendation for design would be the initial stage that enables 450 MW of transfer capability, which would include a cost of $147 million in transformer station upgrades; followed by the second stage of implementing the full 650 MW transfer capability, which would include a cost of an additional $60 million in transformer station upgrades. Therefore, the estimated project cost would be $924 million for the initial stage, followed by an additional $60 million for stage 2, which would yield a total estimated project cost of $984 million.

In terms of updating the demand and supply outlook for the East-West Tie Expansion, there were a variety of contributing factors. The cancellation of the TransCanada Energy East Pipeline Project on October 5, 2017 had a large impact, as it eliminated around 110 MW of peak demand from the outlook. This cancellation, in conjunction with the continuous decline in historical demand, has worked to significantly decrease the magnitude of the demand outlook. Historical demand has also been declining (evident in 2015 and 2016 demand data) as a result of population decline, conservation, distributed generation and the continuous decline of the pulp and paper industry.

Community input was added to this report as the IESO continued to consult with stakeholders on the current market outlook for electricity demand and associated demand impacts. Furthermore, the IESO hosted a planning forum in Thunder Bay in October 2017 where stakeholders voiced their support for the project and provided suggestions. Some provided recommendations for alternatives and others commented that flexibility to accommodate demand uncertainty should be in the chosen solution to decrease the impediment to additional developments.

In the assessment of the demand outlook, the IESO considered 3 potential outlook scenarios in order to accommodate for uncertainties due to industrial fluctuations. The outlooks are described in the report as follows:

- *"**Reference demand outlook -** In this outlook, mining sector demand includes proposed mines that have passed significant development milestones. Mining loads are assumed to persist for the expected lifetime of the proposed developments. This outlook assumes modest growth in the forestry sector in the short term and assumes stabilization of the pulp and paper sector.*
- ***High demand outlook –** This outlook considers the impact of stronger and faster development in the mining sector, which could potentially be driven by factors such as increased commodity prices. This outlook also reflects modest growth in the forestry sector and the stabilization of the pulp and paper sector.*
- ***Low demand outlook –** This outlook describes a more restrained outlook in the mining sector and continuing decline in the pulp and paper sector."*

In addition to this, the IESO also considered two alternatives, which are the East-West Tie Expansion and no East-West Tie Expansion (gas-fired generation alternative). The details, as described in the report, are below:

> *"1) No E-W Tie Expansion - In this option, all of the identified capacity and energy needs are met through the addition of new natural gas-fired simple cycle gas turbine ("SCGT") generation in the Northwest, with the size of units and the timing of installation defined to meet the needs as they arise during the planning period. Under the Reference demand outlook, a total of 500 MW of generation is added. As in the previous update, it was assumed that, due to the difficulty and cost associated with obtaining firm gas service in the Northwest, all new-build natural gas-fired generation utilizes on-site reserve fuel.*
>
> *2) E-W Tie Expansion - In this option, the E-W Tie Expansion project provides a foundation for meeting the Northwest needs, with additional generation installed to meet any incremental supply requirements. In this update, a staged implementation of the E-W Tie Expansion was adopted, with the interim 450 MW E-W Tie stage and the final stage, to provide the full 650 MW transfer capability, added as required to meet the capacity needs throughout the study period. Under the 1 Reference demand outlook only the interim stage of the E-W Tie Expansion is required."*

Other options were considered under the No East-West Tie Expansion alternative, such as utilizing biomass resources; building new non-emitting generation, including storage and firm imports from Manitoba; or wind power generation. These options were all deemed uneconomical as investments in transmission to connect the resources, as well as the development in resource production, would be necessary. Usage of Manitoba imports was also considered as a way to deal with the demand for energy but this option had constraints because of current transmission capacity being only 150-200 MW.

After assessing the 3 potential demand outlooks as well as the alternative solutions using various updated assumptions, the case for building the East-West Tie Expansion continued to be substantial. The net present cost of the Reference demand outlook was $200 million lower than the no East-West Tie Expansion alternative, while the High demand outlook and the Low demand outlook ranged from $500 million lower to $100 million lower.

The IESO's updated assessment of the Northwest's capacity needs continues to support the expansion of the East-West Tie as the preferred solution under a range of system conditions. It also continues to recommend the in-service date of 2020 and will continue to support the line's implementation and monitoring of electricity supply and demand in the Northwest until the in-service date.

2017 Ontario's Long Term Energy Plan

The 2017 Long Term Energy Plan (LTEP) titled "Delivering Fairness and Choice" is a continuation and builds on the previous work done through prior LTEPs. After having phased out coal-fired energy and making significant steps towards building a clean and reliable energy system, this LTEP is focused on helping Ontarians. Its main goal is to manage electricity systems in a cost-effective way in order to provide fair and equitably distributed energy costs. The key elements discussed in this LTEP are:

- Ensuring affordable and accessible energy;
- Ensuring a flexible energy system;
- Innovating to meet the future;
- Improving value and performance for consumers;
- Strengthening our commitment to energy conservation and efficiency;
- Responding to the challenge of climate change;
- Supporting First Nation and Métis capacity and leadership; and
- Supporting regional solutions and infrastructure.

In Chapter 2: Ensuring a Flexible Energy System, the need for a flexible energy system that can meet any possible future outlooks is mentioned as a priority. It also states that the aim of this LTEP is to maximize the use of Ontario's existing energy assets as a way to eliminate unnecessary costs for electricity consumers. In order to do this, the government will direct the IESO to formalize and institute a process that would allow the future province-wide bulk system to be integrated efficiently. The IESO demand outlook, as of 2017, indicates that there would be no need for any major expansion projects other than the ones already planned or in progress. The East-West Tie Transmission Line is one of the planned projects mentioned in this report. The passage mentioning the Project is as follows:

> *"The East-West Tie Line would provide a long-term, reliable supply of electricity to meet the growth in demand and changes to the supply mix in Northwest Ontario. As the project has moved through development, estimates on its total cost have*

increased. This is a concern, as Ontario is focused on making the electricity system more cost-effective. The government will review all options to protect ratepayers as the project continues to be developed."

June 29, 2018, IESO Addendum to the 2017 Updated Assessment of the Need for the East-West Tie Expansion

This addendum, released on June 29, 2018 by the IESO, was published in response to a June 14, 2018 request from the OEB to assess the impacts of a delay to the in-service date of the East-West Tie expansion. It addresses the potential reliability impacts of delaying the in-service date beyond 2020 and the potential costs of managing the capacity gap for each year until 2024. According to the IESO, the capacity need of the Northwest can be met on an interim basis prior to 2020 by using the Northwest Special Protection Scheme, which allows for load rejection of 150 MW, and other interim measures. However, past 2020, the projected capacity requirement continues to increase incrementally, resulting in the greater capacity gaps. This puts the entire system at a higher risk and decreases its reliability to meet the transmission capacity requirements in the near future. The incremental capacity gap would need to be addressed through the use of interim measures. Interim measures suggested include: demand response, firm imports from Manitoba, and contract extensions with existing resources. This is not an ideal scenario, as each interim measure comes with its own cost and risks. Further details, as outlined in the report, are provided below:

- *"The 2018 demand response auction cleared 30 MW of demand response in the summer and winter in the Northwest for approximately $80/kW-year. However, the product's availability limits its contribution to meeting the capacity need in the Northwest and the extent to which additional demand response can be acquired in the Northwest on a cost effective basis is unknown*

- *The cost of firm import capability from Manitoba is uncertain; it would not be known until the time of negotiation and the price could be increased by the short commitment period and reduced competition due to the small size of the Northwest market. Currently, the firm import capability from Manitoba is also limited to between 150 – 200 MW3. To inform a decision with respect to acquiring firm imports, the cost of acquiring firm imports, the cost of a firm capacity import from Manitoba would be compared to the 1 cost of acquiring new local generating capacity. The lifetime levelized cost of new local generating capacity in Northern Ontario is approximately $180/kW-year.*

- *There are resources within the Northwest with contracts currently set to expire throughout the 2020-2024 period. Extending contracts for select facilities could be considered as an interim measure. While the contract terms for these facilities are not public, the capacity cost would be compared to the cost of acquiring new local generating capacity. However, there could be a mismatch between how long the IESO would need the facility to run to meet the need and the facility owner's required commitment period for re-acquiring the facility, which could contribute to additional costs."*

Using these considerations, the IESO considers it reasonable to estimate a capacity cost of addressing a delayed in-service date of the E-W Tie Expansion. To estimate this cost, the lifetime levelized cost of new local generating capacity in Northern Ontario was used. A sensitivity range was also necessary in accommodating for uncertainties and so, on the low end of the sensitivity range, the recent cost of winter demand response resources in the Northwest was used, while on the high end, 25% of uncertainty range was added to the levelized cost mentioned above. The overall projected cost estimation ranged from a $16 million in 2020 to $44 million in 2024. With sensitivities factored in, the projected cost range ranged from $7 million - $20 million in 2020 to $19 million – $55 million in 2024.

According to the IESO, if the in-service date extends beyond the end of 2022 the risk of not being able to manage the capacity gap through interim measures significantly increases the need for more capacity. As the capacity shortfall grows, the implementation of more than one interim measures will be needed since there are certain constraints on each measure. As an example of this, the capacity need can be met through imports from Manitoba for a short while but when the shortfall extends beyond its capacity additional measures such as demand response or contract extensions would need to be implemented. This results in more costs and uncertainties, especially if contract extensions are required.

The IESO states clearly that if the in-service date goes beyond 2022 it will take necessary measures to acquire additional capacity. However, it would expectedly come at a higher cost because of the urgency, along with the uncertainty of costs for short term contracts; the small market; and the potential that resources are limited or insufficient to provide short term capacity. New resources or capital investment in retired facilities would also likely be required to support the interim measures. These measures would ultimately result in the increase in average cost of energy.

Congestion in the existing East-West Tie is also contributing to the increase in average cost of energy since much of the low-cost energy from hydro facilities is bottled in the Northwest. This results in Southern Ontario dispatching higher priced and higher emitting resources to meet Ontario's energy needs.

The IESO continues to recommend the in-service date of 2020 for the Expansion of the East-West Tie, based on applicable planning and reliability criteria. Interim measures may potentially be relied on until 2024; however, each comes with additional costs and risks, which leads to increased uncertainty. Therefore, the IESO does not support delaying the in-service date beyond the end of 2022 as costs will become unacceptable.

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Ontario's Long-Term Energy Plan

Building Our Clean Energy Future

Ontario

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foreword

Maintaining a clean, modern and reliable electricity system for all Ontarians is this government's number one energy priority. Ontario families, businesses and the economy rely on the efficiency, dependability and environmental sustainability of electric power. We have to keep the lights on in Ontario homes, schools, hospitals and businesses and power everything from the coffee-maker to the CT scanner. We also need a clean system that won't threaten the health of current and future generations.

Ontarians deserve balanced, responsible long-term energy planning for electricity to ensure that Ontario has clean air, reliable energy and a strong economy for our children and grandchildren. This report represents an update to the McGuinty government's long-term energy plan and outlines how we are helping families and businesses with increasing electricity costs.

Prior to 2003, Ontario's electricity system was weakening and unreliable. Our reliance on coal meant that our electricity sources were polluting and dirty. Between 1995 and 2003, the electricity system lost 1,800 megawatts (MW) of power — the equivalent of Niagara Falls running dry. A brief deregulated pricing experiment in 2002 resulted in sharply increased prices, prompting the government of the time to freeze consumer prices. Energy infrastructure was crumbling, a shortage of supply caused risks of brownouts.

Worst of all, Ontario relied heavily on five air-polluting coal plants. This wasn't just polluting our air, it was polluting our lungs. Doctors, nurses and researchers stated categorically that coal generation was having an impact on health increasing the incidence of various respiratory illnesses. A 2005 study prepared for the government found that the average annual health-related damages due to coal could top $3 billion. For the sake of our well-being, and our children's well-being, we had to put a stop to coal.

Over the past seven years, the McGuinty government has made tremendous progress after inheriting a system with reduced supply and little planning for the future. Today, our system is cleaner, more modern, more reliable and we plan ahead.

The McGuinty government has made electricity cleaner: we are on track to eliminate coal by 2014, the single largest climate change initiative in North America in that timeframe. We have already reduced the use of coal by 70 per cent. Last year our greenhouse gas emissions from the electricity sector reached the lowest they have been in 45 years. In 2009, more than 80 per cent of our generation came from emissions-free sources like wind, water, solar, biogas and nuclear.

Conservation efforts have been working — many Ontario families and businesses are becoming very active energy conservers. Through various programs, Ontarians have conserved more than 1,700 MW of electricity since 2005 — the equivalent of more than half a million homes being taken off the grid.

Today we have enough electricity to power our homes, businesses, schools and hospitals. Our government has increased Ontario's energy capacity by adding over 20 per cent (more than 8,000 MW) of new supply to the system – enough to power two million homes. Investments in Ontario are transforming the electricity system and have helped to make Ontario a leading jurisdiction in North America for renewable and reliable energy. And since 2007, we've used a formal 20-year planning process to help us forecast and meet the province's electricity needs.

Ontario's electricity system is more reliable. Investments in new generation and upgrades to 5,000 kilometres of our transmission and distribution lines — about the width of Canada from coast to coast — have ensured that our electricity system is able to manage peak and sudden swings in demand and supply availability.

We are moving toward a modern, smart electricity system that will help consumers have greater control over their energy usage — even when they're not at home. A smart grid can isolate outages allowing for faster or even automated repair. This will improve overall reliability for all electricity consumers and make it easier for consumers to produce their own power.

As part of the Open Ontario plan, the McGuinty government is moving Ontario from dirty coal dependency to a clean, modern and reliable energy economy that creates jobs. Energy is one of the engines of our economy and employs more than 95,000 Ontarians. Recent investments to modernize the system are helping to create and support jobs and opportunities for people and communities across the province. Ontario's landmark Green Energy and Green Economy Act, 2009 is projected over three years to support over 50,000 direct and indirect jobs in smart grid and transmission and distribution upgrades, renewable energy and conservation.

We've accomplished a great deal in the past seven years, but there is more to do. Ontario has sufficient electricity supply — but we will require more clean power for the future. As Ontario's energy infrastructure ages, we will need to rebuild or create another 15,000 MW of generating capacity over the next 20 years. We will also need to continue to upgrade and update transmission and distribution lines.

While we are proud of our collective efforts so far, we must continue to develop cleaner forms of electricity and foster a conservation-oriented culture. We need to have a balanced low-carbon supply mix to meet energy needs cleanly and reliably — Ontario will be ready for when North America moves to greenhouse gas regulation. We also need to maximize the electricity assets we have and ensure that those assets continue to provide clean, reliable supply.

The necessary, unavoidable investments that Ontario has been making in our electricity system are paid by ratepayers. The cost to bring our system back up to date and build a clean energy economy is having an impact on household and business bills.

We are all paying for previous decades of neglect. In Ontario, in order to have clean air, reliable generation and modernized transmission, residential prices over the next 20 years are expected to increase by about 3.5 per cent per year.

Increases to electricity bills are not easy for Ontario families and businesses. Even though Ontarians are committed to clean air, every increase takes a bite out of take-home income, and that is difficult for families during lean times. To help with rising costs, the McGuinty government has created a number of tax credits for families and seniors to help manage electricity increases. But we need to do more.

In this Plan, and the government's 2010 Economic Outlook and Fiscal Review we have taken steps to ensure that we help families and businesses with electricity costs while investment in clean energy continues. On November 18, 2010, the McGuinty government introduced the Ontario Clean Energy Benefit.

If passed, the Ontario Clean Energy Benefit will give Ontario families, farms and small businesses a 10 per cent benefit on their bills for five years. That would be 10 per cent off your electricity bill every month, effective January 1, 2011.

The proposed Clean Energy Benefit will help families, hard-working small business owners and Ontario farms. The McGuinty government is doing this to help those who are feeling the pinch of the rising cost of living and especially, rising electricity prices. Every little bit helps during lean economic times.

This balanced and responsible Plan sets out Ontario's expected electricity needs and the most efficient ways to meet them.

The Honourable Brad Duguid
Minister of Energy

overview

Ontario Electricity 1906-2003

On October 11, 1910, when Adam Beck lit up a Kitchener street sign that read "For the People," the town went wild, and the electrification of Ontario began. It was the first major project of the Hydro-Electric Power Commission of Ontario, created in 1906 as the world's first publicly owned electric utility. Beck, a municipal and provincial politician, believed that it was essential to the province's economic development that electricity be available to every Ontarian.

The Queenston-Chippawa power station at Niagara (renamed Sir Adam Beck I in 1950) helped Ontario meet the growing demand for electricity during the postwar economic boom. But despite continued expansion, it had become increasingly clear that hydropower alone would not be able to keep up with the province's demand.

As a result, Ontario began to diversify its supply mix in the 1950s, adding new sources of power, including six coal-fired generating stations built near areas where demand was highest. Between the early 1970s and the early 1990s, nuclear power was also added at three generating facilities. In the meantime, in 1974, the Hydro-Electric Power Commission was recognized as a crown corporation and renamed Ontario Hydro.

This trio of electricity sources — hydro, coal and nuclear — would support Ontario's economic prosperity into the 1990s. By then, much of the province's electricity infrastructure was aging and in need of replacement or refurbishment. The system had become unreliable, and there was widespread concern about whether supply would be able to meet projected demand.

Between 1996 and 2003, Ontario's generation capacity fell by six per cent — the equivalent of Niagara Falls running dry, while electricity demand grew by 8.5 per cent. Investments to build new supply and the upkeep of lines were modest. Investments in upgrades to transmission and distribution were less than half of current levels. There were no provincially funded conservation programs.

In 1998, Ontario passed legislation that authorized the establishment of a market in electricity. In April 1999, Ontario Hydro was re-organized into five successor entities. The move to break up Ontario Hydro and partially privatize the electricity system saddled Ontario with a stranded debt of over $20 billion.

A brief market-deregulation scheme saw electricity prices spike an average of over 30 per cent in just seven months. The government of the day was forced to cap prices for residential and small business owners — an unsustainable policy. The cap just masked the underlying problem of rising cost pressures in an electricity system in need of renewal and additional supply.

Ontario was also heavily reliant on coal-fired generation. About 25 per cent of electricity generation came from polluting coal-fired plants. In addition, Ontario imported coal power from neighbouring American states. Ontario, a province with ample power resources, had become a net importer of power.

Ontario Electricity Accomplishments 2003-2010

After taking office in 2003, the Ontario government faced a number of challenges including: a shortfall in supply, a system reliant on dirty coal-fired generation, a lack of conservation programs, an unsustainable pricing regime and little long-term planning.

The shortfall in supply was restored with investments of over $10 billion to keep the lights on in the province's homes and businesses. Since 2003, about 8,400 megawatts (MW) of new cleaner power have come on line — over 20 per cent of current capacity. That's enough electricity to power cities the size of Ottawa and Toronto. Ontario completed the return to service of Pickering A Unit 1 and enabled hydro and other renewable projects. The province also invested $7 billion to improve some 5,000 kilometres of transmission and distribution lines — the equivalent of the distance between Toronto and Whitehorse, Yukon.

Ontario's power has become cleaner by shutting down coal-fired generation and investing in renewables. In 2005, the government permanently shut-down the Lakeview coal-fired plant in Mississauga — the equivalent of taking 500,000 cars off the road. The province is on track to phase out coal-fired electricity by 2014, the largest climate change initiative of its kind in North America.

Currently, Ontario is Canada's solar and wind power leader, and home to the four largest operating wind and solar farms in the country. The province is developing a smart electricity grid that will help integrate the thousands of megawatts of new renewable power from these projects and others.

Public conservation programs were reintroduced to Ontario in 2005 to encourage and provide incentives for families, businesses and industry to consume less energy. Conservation is now a cornerstone of long-term electricity planning, recognizing that all Ontarians — for generations to come — will benefit from cleaner air and a lower carbon footprint.

In 2004, the government introduced a stable pricing regime that better reflected the true cost of electricity in Ontario. As a result, in 2005 the Ontario Energy Board (OEB) released a Regulated Price Plan, which brought predictability to electricity prices for residential and small business consumers. The OEB updates rates and adjusts prices every six months to reflect the costs of supply for that period.

Ontario has also taken steps to lower the stranded debt left by the previous government. Since 2003, Ontario has decreased the stranded debt by $5.7 billion.

In 2004, the government established the Ontario Power Authority (OPA) as the province's long-term energy planner. That set into motion a planning process that would ensure that Ontario's energy infrastructure would continue to be modernized. In 2007, the OPA prepared a 20-year energy plan (formally known as the Integrated Power System Plan or IPSP). The 2007 Plan focused on creating a sustainable energy supply, targeted to improving current natural gas and renewable assets at a sustainable and realistic cost. The government has made significant progress on the items outlined in the 2007 Plan.

2007 Plan Goal/ Target	Accomplishments
Ensure adequate supply	Invested over $10-billion to bring about 8,400 MW of new supply online — enough capacity to meet the annual requirements of 2 million households.
Double the amount of renewable supply (to 15,700 MW by 2025)	More than 1,500 MW of clean, renewable energy online since 2003, enough power for more than 400,000 homes.
Reduce demand by 6,300 MW by 2025.	More than 1,700 MW of conservation (reduction in demand) since 2005, equivalent to more than 500,000 homes being taken off the grid.
Replace coal in the earliest practical time frame	Phasing out coal-fired generation by 2014 Four units closed in 2010, ahead of schedule.
Strengthen the transmission system	Over $7 billion in investments since 2003 — upgrades to more than 5,000 kilometres of wires Moved forward on transmission projects to enable additional renewables; import potential; and refurbished nuclear generation
Ensure stable energy prices for Ontarians	The Regulated Price Plan introduced in 2005 has provided predictability Electricity prices have increased on average by about 4.5 percent per year over the past seven years Introduced energy tax credits to help residential and small business consumers with electricity costs

In 2009, the government introduced the groundbreaking Green Energy and Green Economy Act, 2009 (GEA). The GEA is sparking growth in clean and renewable sources of energy such as wind, solar, hydro, and bioenergy. A series of conservation measures in the GEA are providing incentives to lower energy use. In its first three years, the GEA will help create 50,000 clean energy jobs across the province. A clean-energy manufacturing base has been growing in the province and creating jobs for Ontarians.

Ontario's Energy Future 2010-2030

The priorities that the government sets and the investments the government makes today are laying the groundwork for an Ontario of tomorrow that will feature a modern, clean and globally competitive economy; healthy, vibrant and liveable communities; and an exceptional quality of life for all Ontarians. The government has a responsibility to ensure a clean, modern and reliable system for the health and well-being of Ontario families and businesses.

By 2030, Ontario's population is expected to rise about 28 per cent — a gain of almost 3.7 million people. Ontario's population will become more urbanized with population growth taking place in primarily urban areas. The Greater Toronto Area (GTA) population will increase by almost 38 per cent over the same period.

The overall composition of the economy will evolve as high-tech and service industries grow and manufacturers change how they do business to keep pace with technological advances and global competition. The output of large industrial customers, which accounts for about 20 per cent of electricity demand, is expected to grow moderately.

Getting around will be easier for all Ontarians. Improved regional and local transit systems that form integrated transportation networks will make it easy to travel, both within and between urban centres. There will be more electric cars on the road — Ontario's goal is that by 2020, about one in every 20 vehicles on the road will be electric.

All of this means that Ontario needs a more modern energy system and a diverse supply mix. Clean, reliable energy is the fuel that will power Ontario's future economic prosperity. Ontario must take steps today to ensure that the right kind of energy will continue to be there for us tomorrow.

Ontario is building a culture of conservation and as a result, it is expected that the province's demand for energy will grow only moderately over the next 20 years. Increased demand in the long term will be due to the rising population, industrial growth and increased use of electrical appliances and vehicles.

The Smart House of the Future

A smarter electricity grid will enable Smart Houses in the future by using technologies that have built-in intelligence. With Smart Grid infrastructure, homes will be able to use power when it is least expensive, charge electric vehicles, generate their own power via solar panels or other generation – and all of this can be controlled by the owner online, or by smart phone.

The Plan

Since the 2007 Plan, developments in technology, trends in demographics, changes in the economy and the advancements of the renewable energy sector (the success of the Feed-in-Tariff program) mean that Ontario needs an updated plan. This updated long-term energy plan will help to ensure that Ontario can meet the needs of an evolving economy and shifting electricity demands, while providing affordable electricity.

Currently, Ontario's electricity system has a capacity of approximately 35,000 MW of power. The OPA forecasts that more than 15,000 MW will need to be renewed, replaced or added by 2030. Because of capacity brought online in recent years, Ontario has some flexibility moving forward. The challenge is in choosing the right mix of generation sources and the necessary level of investment to modernize Ontario's energy infrastructure to meet future needs.

Through initiatives already underway, the province will be able to reliably meet electricity demand through 2015. Ontario needs to plan now for improving the power supply capacity to meet the province's electricity needs beyond 2015. Ontario must plan in advance because:

- Insufficient investment between 1995 and 2003 left an aging supply network and little new generation
- Additional clean generation will be needed to ensure a coal-free supply mix after 2014
- Nuclear generators will need to go offline while they are being modernized
- The population is projected to grow.

To meet these needs Ontario will need a diverse supply mix. Each type of generation has a role in meeting overall system needs. Ontario requires the right combination of assets to ensure a balanced supply mix that is reliable, modern, clean and cost-effective. Ontario will also, first and foremost, make the best use of its existing assets to upgrade, expand or convert facilities.

As part of a reliable network, the system needs both small and large generators. Nuclear power will continue to reliably supply about 50 per cent of the province's electricity needs. It does not emit air pollutants or emissions during production. Hydroelectric power is expanding to include increased capacity from the Niagara Tunnel project and the Lower Mattagami project — producing clean energy by tapping into a renewable and free fuel source. Natural gas-fired plants have the flexibility to respond when demand is high — acting as peak source or cushion for the electricity system. Natural gas is the cleanest of the fossil fuels, emitting less than half of the carbon dioxide emitted by coal.

Ontario is also planning for future energy generation that will focus on efficient, localized generation from smaller, cleaner sources of electricity rather than exclusively from large, centralized power plants transmitting power over long distances. This strategy is known as "distributed generation". Distributed generation also opens up opportunities for smaller power producers, allowing individuals, Aboriginal communities and small co-operatives or partnerships to become generators.

Renewable energy—wind, solar, hydro, and bioenergy — is an important part of the supply mix. Once the initial investment is made in equipment and infrastructure, fuel cost and greenhouse gas emissions are zero or very low. Renewable energy makes it possible to generate electricity in urban and rural areas where it was not feasible before.

In developing this report, the government heard from over 2,500 Ontarians (individuals, energy organizations, community representatives, and First Nation and Métis leaders and groups). Their views have helped to inform this report. In addition, the Ontario Power Authority (OPA), Hydro One, Ontario Power Generation (OPG), the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) contributed information and advice.

Ontario's Long-Term Energy Plan will help guide the province as it continues to build a clean, modern, and reliable electricity system for Ontario families now and well into the future. It will ensure Ontario continues to be a North American leader for clean energy jobs and technology and becomes coal-free by 2014. Key features of the plan include:

- Demand will grow moderately (about 15 per cent) between 2010 and 2030.
- Ontario will be coal-free by 2014. Eliminating coal-fired generation from Ontario's supply mix will account for the majority of the government's greenhouse gas reduction target by 2014. Two units at the Thunder Bay coal plant will be converted to gas and Atikokan will be converted to biomass. Two additional units at Nanticoke will be shut down in 2011.
- The government is committed to clean, reliable nuclear power remaining at approximately 50 per cent of the province's electricity supply. To do so, units at the Darlington and Bruce sites will need to be modernized and the province will need two new nuclear units at Darlington. Investing in refurbishment and extending the life of the Pickering B station until 2020 will provide good value for Ontarians.
- Ontario will continue to grow its hydroelectric capacity with a target of 9,000 MW. This will be achieved through new facilities and through significant investments to maximize the use of Ontario's existing facilities.
- Ontario's target for clean, renewable energy from wind, solar and bioenergy is 10,700 MW by 2018 (excluding hydroelectric) – accommodated through transmission expansion and maximizing the use of the existing system. Ontario will continue to grow the clean energy economy through the continuation of FIT and microFIT programs.
- Natural gas generation for peak needs will be of value where it can address local and system reliability issues. Natural gas will support the increase in renewable sources over time and supplement the modernization of nuclear generators.
- Combined Heat and Power is an energy-efficient source of power and the OPA will develop a standard offer program for projects under 20 MW.
- Ontario will proceed with five priority transmission projects needed immediately for reliability, renewable energy growth, and changing demand. Future Plans will identify more projects as they are needed.
- Ontario is a leader in conservation and the government will continue to increase and broaden its targets to 7,100 MW and reduce overall demand by 28 terawatt-hours (TWh) by 2030.
- Over the next 20 years, estimated capital investments totalling $87 billion will help ensure that Ontario has a clean, modern and reliable electricity system.
- Measures outlined in this Plan will help create and sustain jobs and investments in Ontario's growing clean energy economy.
- Residential bills are expected to rise by 3.5 per cent per year over the next 20 years. Industrial prices are expected to rise by 2.7 per cent per year over the next 20 years.
- The government is proposing an Ontario Clean Energy Benefit to give Ontario families, farms and small businesses a 10 per cent benefit on their electricity bills for five years.

This plan will help ensure that Ontario is able to meet its electricity needs until 2030 and build a modern, clean, reliable system that will provide energy to Ontario homes and businesses for generations to come.

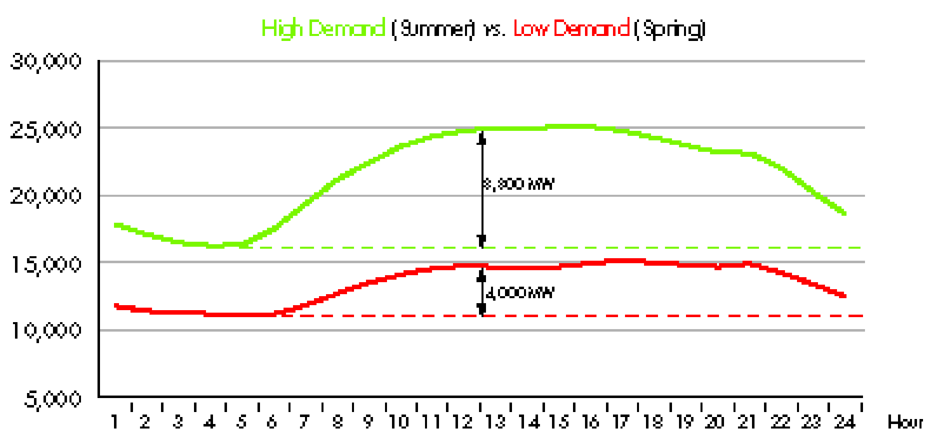
1 demand – an updated forecast

Electricity demand in Ontario has declined since reaching a peak in 2005. For the next 10 years, demand is expected to recover from the recent recession and then stay relatively flat as conservation efforts and an evolving economy change Ontario's energy needs.

A forecast of the demand for electricity establishes the context for long-term planning — it predicts the amount of electricity Ontario will need.

System planning requires a complex forecast of the total amount of electricity that will be used over the course of a year, as well as the amount required to meet peak demand. The next step is to match these requirements with available generation and transmission capacity. Demand fluctuates with the time of day, weather, time of year and the structure of the economy. Ontario's demand can fluctuate between 11,000 MW on an early Sunday morning in spring to 25,000 MW on a hot Thursday afternoon in summer.

FIGURE 1: ONTARIO ELECTRICITY DEMAND COMPARISON



Unlike other forms of energy, electricity cannot be easily stored. Ontario's electricity system must be able to produce and move enough electricity to meet the changing demand for it instantaneously — all day and all night, every day and every night.

Ontario is part of an interconnected grid consisting of thousands of generators linked by tens of thousands of kilometres of transmission lines, crossing international, provincial and regional borders. The interconnected nature of the grid, supported by mandatory reliability standards, helps to ensure a stable power supply even when major components fail or when demand exceeds what can be met with domestic resources. Trade in electricity takes place over this interconnected system — for instance, between Ontario, Quebec and the U.S. — on a daily basis. In 2003, Ontario was a net importer and much of this imported supply came from U.S. coal power, which increased prices and reduced Ontario's air quality. Ontario is now a net exporter of electricity.

Accomplishments

Ontario families and businesses have participated in conserving energy through various government conservation programs and shifting the demand away from peak hours.

- Ontario's conservation initiatives have been successful. Since 2005, Ontarians have saved enough energy to meet the combined electricity demand of Mississauga and Windsor.
- peaksaver®, a residential and small business electricity demand reduction program that temporarily powers down central air conditioning systems, has conserved enough to power a community the size of Thunder Bay.

Future Needs

Demand is recovering slowly in 2010 after the global economic recession. Future demand will depend on a number of factors including: the speed of Ontario's economic recovery, population and household growth, greater use of electronics in appliances and home entertainment systems, the pace of the recovery of large, energy-intensive industry and the composition of the economy (e.g. a shift to more high-tech and service jobs). Demand will also be impacted by the success of conservation efforts, as well as the potential electrification of public transit and the number of electric vehicles on the road. Weather can also have a pronounced effect.

To account for generation maintenance, extreme weather or significant changes in the amount of electricity the province needs, it is important to have electricity capacity in reserve.

The Plan

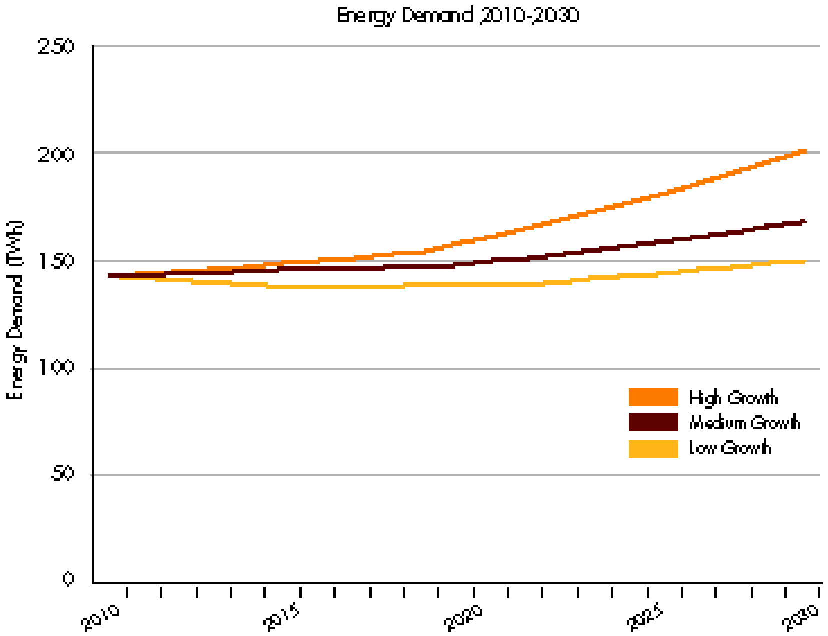
Based on OPA analysis, this Plan outlines three potential scenarios (net of conservation) for electricity demand:

1. Low growth (yellow) assumes that Ontario's manufacturing and industrial sectors continue to grow modestly in accordance with the current trend. Some of the recent decline in consumption is due to conservation, some to restructuring in the various industrial sectors, and some due to the recession. This forecast assumes a lower rate of population growth than in the other two scenarios. It further assumes that only 13 per cent of people use electricity for heating and that small appliance use accounts for 30 per cent of growth.

2. Medium growth (brown) represents moderate growth in the industrial sector and in population. This scenario assumes continued growth in the residential, commercial and transportation sectors. This forecast assumes that there is a consistent move towards high-tech and service industries and somewhat higher provincial population growth than the low growth scenario. This scenario is consistent with the current government goal for electric vehicles: five per cent by 2020.

3. High growth (orange), or aggressive electrification, assumes that there is a significant increase in electric transportation — both public and private. It assumes that there is aggressive North American greenhouse gas regulation, faster population growth than the low growth scenario, significant industrial change and that by 2030 about 12 per cent of vehicles on the road are electric.

FIGURE 2: RANGE OF ENERGY DEMAND FORECAST



The three scenarios do not differ significantly until 2018, allowing time to adjust as the Long-Term Energy Plan will be updated every three years. For planning purposes, the government is using the medium growth line to predict future electricity needs. The medium growth scenario balances the expected growth in residential and commercial sectors, with modest, post-recession growth in the industrial sector. The addition of 1.1 million households and the expected increase in the use of entertainment electronics, and small appliances will increase residential electricity demand. The addition of 132 million square metres of commercial space and the associated use of air-conditioning, lighting and ventilation will increase electricity demand in the commercial sector.

Based on the medium growth scenario, Ontario's demand will grow moderately (15 per cent) between 2010 and 2030, based on the projected increase in population and conservation as well as shifts in industrial and commercial needs. As a result, for planning purposes, the system should be prepared to provide 146 TWh of generation in 2015 rising to 165 TWh in 2030.

Ontario is also planning to create sufficient flexibility in the system to accommodate the higher growth scenario.

2 supply

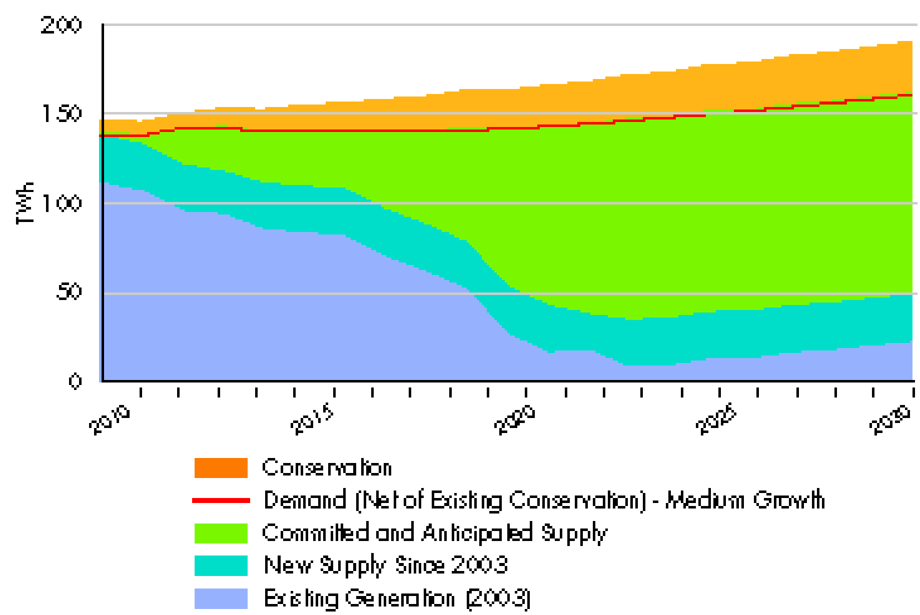
With a long-term demand forecast in place, Ontario must determine the most effective way to meet that demand so that there is no gap in supply. Ontario needs a balanced, cost-effective supply mix that supports the economy, is modern, can adapt to future changes and provides clean, reliable electricity to Ontario families and businesses for generations to come.

A clean, reliable energy system relies on a balance of resources. Good system planning includes a sustainable supply mix that meets the demands of the public. It also means continually looking for efficiencies and emphasizing the best use of current resources. Ontario's supply mix includes:

- Conservation: As the best and first resource, it reduces consumption and therefore demand on the system. By avoiding the need to build new generation, all consumers benefit through cost savings.
- Baseload power: Generation sources, such as nuclear and hydro stations, designed to continuously operate (Niagara Falls, for example). Baseload power is the foundation of a stable, secure supply mix.
- Variable or intermittent power: Generation sources that produce power only during certain times such as wind and solar projects. These are important contributors to a cleaner supply mix.
- Intermediate and peak power: Generation sources designed to ramp up and down as demand changes throughout the day such as natural gas and hydro generation with some storage capability. These function as a cushion to the system to ensure reliability when demand is highest.

This supply mix balances reliability, cost and environmental performance.

FIGURE 3: FORECAST SUPPLY AND DEMAND (2010-2030)

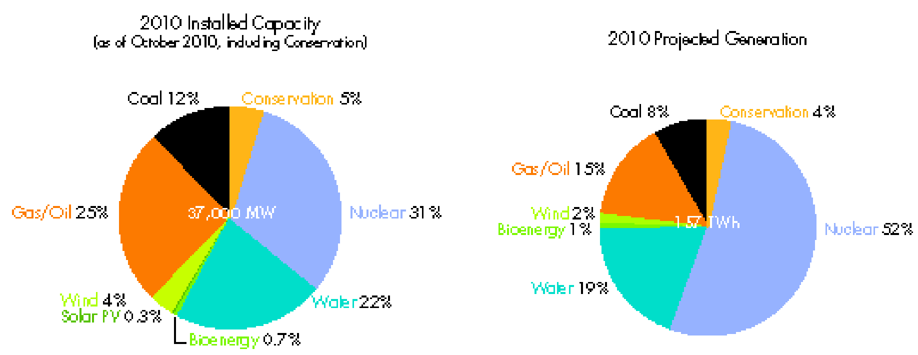


Energy Storage can help to balance the electricity grid by storing off-peak generation and using it during peak hours. This helps to reliably incorporate more renewable generation into the grid. Energy storage is an important part of the move to a Smart Grid. Ontario will continue to investigate the potential for new storage technologies. There are a number of issues that impact the development of energy storage:

- The capital costs for large-scale electricity storage are high largely due to high engineering and construction costs.
- Research is underway on flywheel storage, plug-in vehicle storage, various forms of thermal storage as well as other storage options.
- There are growing opportunities for small storage projects, particularly as battery technology improves.
- Ontario has a pumped storage facility in the Sir Adam Beck Pumping Generating Station at Niagara Falls. OPG is currently studying the possible expansion of the reservoir to allow for further storage at the station.

The capacity of the system is necessarily larger than what is actually generated. It is critical to have more capacity than generation to be able to manage normal equipment maintenance and shutdowns, unprecedented peak demands or an unexpected shutdown of an electricity generator. Generation, or the amount of electricity Ontario produces, is measured in terawatt hours (TWh or billion kWh). The capacity of the system, or what it is able to generate, is measured in megawatts (MW).

FIGURE 4:
CONTRAST BETWEEN GENERATION AND INSTALLED CAPACITY



Selecting a supply mix and investment in supply is a matter of choices and trade-offs. A variety of power supply sources — some designed for baseload requirements, some designed for meeting peak requirements — is superior to relying heavily on only one source. For this long-term plan the government has considered environmental, economic, health, social and cost implications to come up with the best possible supply mix.

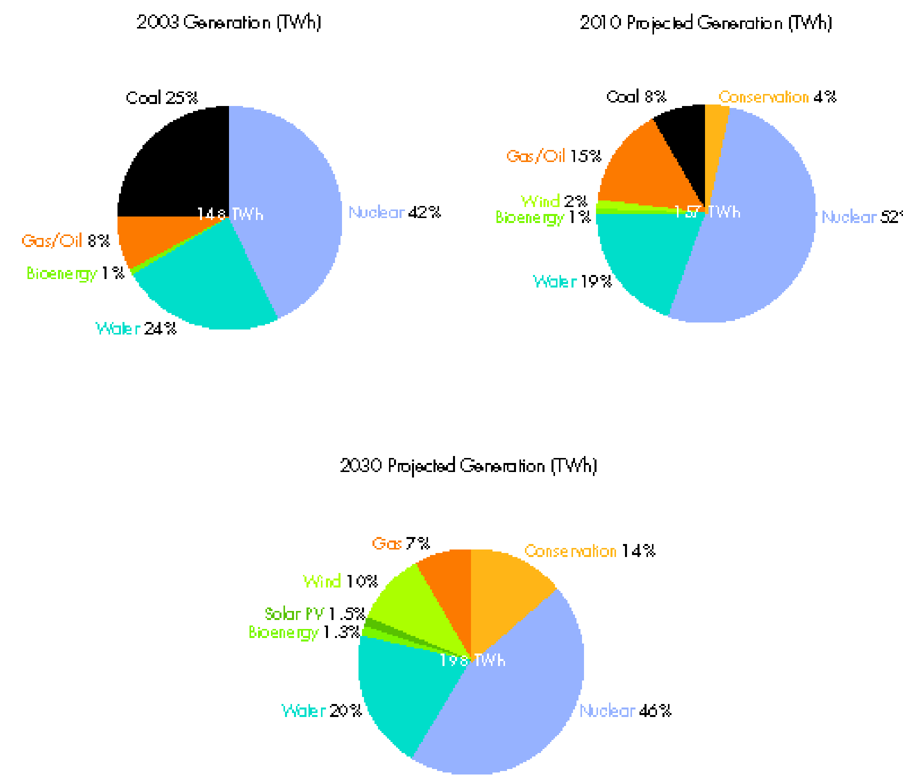
This improved supply mix will be cleaner, sustainable, modern and reliable. It phases out coal-fired generation at a faster pace, it modernizes Ontario's nuclear fleet, it includes more renewables, it maximizes hydroelectric power over the near term, and it advances Ontario's conservation goals.

By 2030, Ontario will have completely eliminated coal as a generation source and will have also increased wind, solar and bioenergy from less than one per cent of generation capacity in 2003 to almost 13 per cent. To ensure reliability, the strategic use of natural gas will be required to complement renewable generation. Nuclear will continue to supply about 50 per cent of Ontario's electricity needs.

The following chapter will include a review of the various components of Ontario's electricity supply:

- Coal
- Nuclear
- Renewables: Hydroelectric
- Renewables: Wind, Solar and Bioenergy
- Natural gas
- Combined Heat and Power (CHP)

FIGURE 5: BUILDING A CLEANER ELECTRICITY SYSTEM



Coal Free

The Ontario government is committed to improving the health of Ontarians and fighting climate change. Coal-fired plants have been the single largest source of greenhouse gas emissions in the province and among the largest emitters of smog-causing pollutants. Ontario's reliance on coal-fired generation shot up 127 per cent from 1995-2003, significantly polluting the province's air. During that period Ontario also relied on importing coal-fired power from the United States. An Ontario study found the health and environmental costs of coal at $3 billion annually ("Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation," April 2005).

Since 2003, the government has reduced the use of dirty coal-fired plants by 70 per cent. Eliminating coal-fired electricity generation will account for the majority of Ontario's greenhouse gas reduction target by 2014 — the equivalent of taking 7 million cars off the road.

In addition, Ontario Power Generation (OPG) is required to meet strict government-mandated greenhouse gas emission targets, including ensuring that between 2011 and 2014 annual emissions are two-thirds lower than 2003 levels.

Ontario is the only jurisdiction in North America that is phasing out coal-fired generation. The government has committed to eliminating coal-fired generation by 2014 and is introducing clean and reliable sources of energy in its place. Until then, coal and natural gas plants will continue to provide power in peak-demand periods to maintain the reliability of the system.

Accomplishments

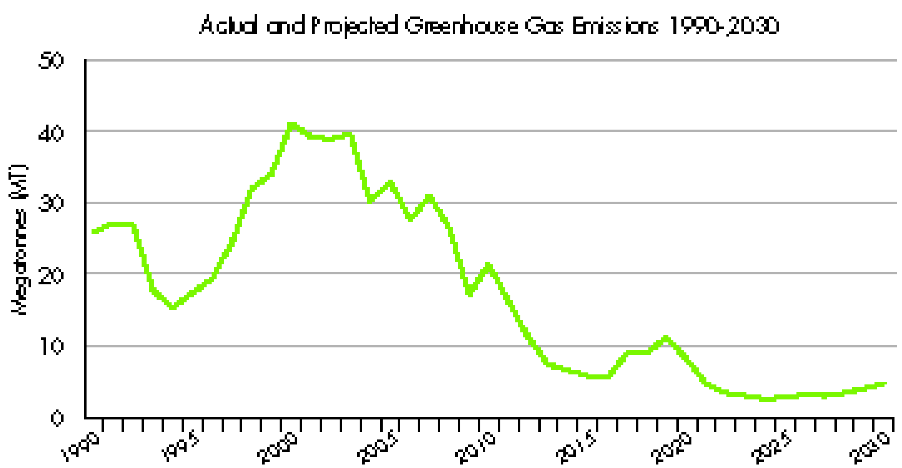
The government of Ontario has shut down eight coal units since 2003 (3,000 MW) and will close the remaining units by 2014 or earlier.

- Lakeview (Mississauga) – four units closed April, 2005
- Nanticoke – two units closed October, 2010
- Lambton – two units closed October, 2010

After the closure of four coal units on October 1, 2010, coal-fired generation makes up only 13 per cent of Ontario's electricity capacity.

Ontario's electricity sector emissions will decrease dramatically to only five megatonnes post-2020 as a result of becoming coal-free. Between 2015 and 2019, extensive nuclear refurbishments will take place and Ontario will rely on its natural gas-fired stations to maintain reliable electricity supply.

FIGURE 6:
REDUCING EMISSIONS IN ONTARIO'S ELECTRICITY SECTOR



The Plan

Coal-fired plants will cease to burn coal in 2014. Ontario will shut down two additional units at Nanticoke Generating Station before the end of 2011.

The government recognizes the potential benefits of continuing to use Ontario's existing electricity-generating assets and sites. Coal-fired plants could be converted to use alternative fuels, such as natural gas. Similar to coal, biomass and/or natural gas can provide electricity on demand for peak periods.

In line with the Growth Plan for Northern Ontario and future needs of the Ring of Fire, the province is replacing coal at Atikokan and Thunder Bay and re-powering these facilities with cleaner fuel sources.

Converting the Atikokan Generating Station to biomass by 2013 will create up to 200 construction jobs and help protect jobs at the plant. It will also support jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. The project is expected to take up to three years to complete. Once converted, the plant is expected to generate 150 million kilowatt-hours of renewable power, enough to power 15,000 homes each year.

At the Thunder Bay Generating Station, two units will be converted to natural gas in a similar timeframe. The Thunder Bay plant is needed not only for local supply to the city of Thunder Bay, but for system reliability in northwestern Ontario, particularly during periods of low hydroelectric generation and until the proposed enhancement to the East-West tie enters operation. The government will work with suppliers on the planning process to convert the Thunder Bay units.

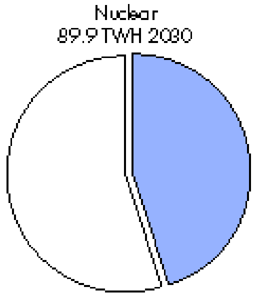
Ontario will continue to explore accelerating the closure of the remaining six units (four at Nanticoke and two at Lambton), taking into consideration the impact of the closures on system reliability.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering. The government expects in 2012 to have an update on the progress of extending the life of these units. At this time, Ontario will consider the possible conversion of some of the units at Nanticoke and Lambton to natural gas, if necessary for system reliability. Due to the lead times involved, planning and approval work for the natural gas pipeline infrastructure required to Nanticoke will begin soon.

Ontario will continue to explore opportunities for co-firing of biomass with natural gas for any units converted to natural gas. Decisions on other biomass opportunities will have to carefully take into account the ability to bring in fuel supply and the cost of conversion.

Nuclear – New/Modernized

Nuclear power is a reliable, safe supplier of the province's baseload generation needs — accounting for about 36 per cent of the province's installed electricity capacity. Nuclear operates 24 hours a day, seven days a week and it produces about 50 per cent of the electricity generated in Ontario. Nuclear power does not produce any primary air pollution or release greenhouse gases into the atmosphere.



Nuclear power plants are able to operate steadily, providing a plentiful, consistent supply of energy for decades at stable prices. In addition, the fuel cost for a nuclear power plant is a small portion of its total costs, so nuclear power is generally not impacted by fuel price escalation or fluctuations.

- Ontario has used nuclear power for more than 40 years.
- In 2009, more than half of the province's electricity came from nuclear energy.
- Ontario's nuclear power stations and waste storage facilities have an excellent safety record. OPG won the Zeroquest Platinum (Sustainability) Award from the Infrastructure Health and Safety Association (IHSA) in June 2010.
- Over 70,000 jobs in Canada are directly or indirectly related to the nuclear power industry.

Accomplishments

A number of nuclear power producing units have been modernized and returned to service since 2003 including:

- Pickering A Unit 1, in November 2005, providing 515 MW (or about 6 per cent of new supply)
- Bruce Unit 3, in March 2004, providing 770 MW (or about 9 per cent of new supply)
- Bruce Unit 4, in November 2003, providing 770 MW (or about 9 per cent of new supply)

Future Needs

Nuclear power is crucial to providing reliable electricity to the province. Units at Bruce B and Darlington are expected to reach the end of their service lives over the next decade. To extend the life of these units, each would have to be shut down for about three years while being modernized.

At the time of the 2007 Plan, there was a need for new nuclear planning to begin immediately. Since then, demand has declined and renewable generation has become a bigger contributor to the system. Investment in renewables, the reduction in demand and the availability of natural gas have all reduced the immediate need for new nuclear. However, to preserve the long-term reliability of the system, particularly for baseload generation, additional investment in nuclear generation will be required.

Ontario will continue to rely on nuclear power – at its current level of contribution to the supply. Nuclear generation is ideally suited for providing baseload generation because of its unique economic and operating characteristics. Nuclear plant operational design and economics depend on the plants being able to operate steadily throughout the year. A generation mix of 50 per cent nuclear combined with baseload hydroelectric generation is sufficient to meet most of Ontario's baseload requirements.

If nuclear capacity beyond this were added, the hours in the year in which nuclear capability exceeded Ontario demand could substantially increase. Under such surplus conditions, some nuclear units might need to be shut down or operate differently than intended. This could lead to significant system and operating challenges and so therefore, generating too much nuclear is undesirable.

The Plan

Over the first 10 to 15 years of this Plan, 10,000 MW of existing nuclear capacity will be refurbished. Investment should focus first and foremost on the improvement of existing assets so that those facilities can continue to provide reliable, affordable electricity. A coordinated refurbishment schedule was agreed to in 2009 by a working group including OPG, Bruce Power, the OPA and the Ministry of Energy. This schedule will be regularly reviewed and updated to reflect current information on resources and plant performance and conditions.

The government is committed to continuing to use nuclear for about 50 per cent of Ontario's energy supply — a capacity of 12,000 MW will produce that amount of energy. The remaining nuclear capacity of 10,000 MW at Darlington and Bruce will need to be refurbished and modernized.

The remainder of the nuclear capacity that Ontario will need for its projected demand (about 2,000 MW) will be made up of new nuclear at Darlington.

The construction of new nuclear infrastructure requires a significant lead time (approximately 8 to 10 years to commercial operation) and while new nuclear supply will be needed in Ontario, it must be provided at a fair price to ratepayers. Both refurbishment and new build will have significant positive impacts on local economies – and considerable employment opportunities.

In February 2008, the government of Ontario launched a process to procure two new units at the Darlington site. Atomic Energy of Canada Limited (AECL) was one of three vendors who met the February 2009 bid submission deadline. AECL emerged as the only compliant bidder in the process; however the AECL bid price exceeded the province's target. Ontario then sought to finalize a deal with the company to procure the units at an acceptable price.

During the discussions between the Ontario government and the federal government, the federal government announced its intention to sell AECL in May 2009. The news cast a great deal of uncertainty over Ontario's procurement process. The position of uncertainty that the federal government placed AECL in, together with a much higher than anticipated price, made it very difficult for Ontario to finalize a procurement that was in the best interest of ratepayers. As a result, Ontario suspended the RFP process in June 2009.

The Province continued to engage AECL, as the only compliant bidder, in discussions with the hope that a deal could still be finalized. The talks did not lead to any demonstrable progress. Consequently, the Premier of Ontario wrote to the Prime Minister requesting that the process to sell AECL be halted. It was Ontario's position that both levels of government should try to complete the procurement with AECL before the company was sold so that Ontario's need for significant nuclear refurbishment and new nuclear generation could be met while simultaneously protecting jobs and preserving the industry in Canada. This proposal was not pursued by the federal government and their process is continuing without a deal with Ontario being completed.

It is anticipated that the federal government will identify a preferred vendor by the end of this year. Ontario is expecting that the federal government will restructure AECL in a manner that will allow Ontario to be able to complete a deal with the new owner at a price that is in the best interest of ratepayers.

The decrease in demand together with the new supply added in recent years, means that Ontario is well-positioned to examine a number of options for negotiating new nuclear production at the right time and at a cost-effective price.

In the meantime, OPG is continuing with two initiatives that were underway prior to the suspension of the new build procurement process: the environmental assessment and obtaining a site preparation licence at Darlington. It is essential that the province stay ready to construct new nuclear plants as part of the government's ongoing commitment to modernize Ontario's nuclear fleet.

OPG will invest $300 million to ensure the continued safe and reliable performance of its Pickering B station for approximately 10 years, to 2020. Following this, OPG will begin the longer term decommissioning process and will work with the community of Pickering and the advisory committee to explore future opportunities for the site.

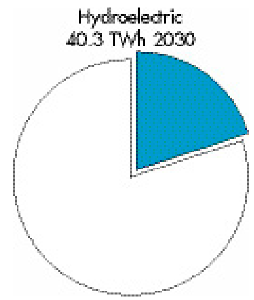
A 2010 report by the Canadian Manufacturers and Exporters estimates the employment and economic benefits from refurbishing and operating the Bruce and Darlington reactors will be substantial: almost 25,000 jobs and annual economic activity of $5 billion.

In developing a new-build procurement and modernization strategy Ontario will:

- Secure an acceptably priced contract for construction of nuclear new build under specified timeframes.
- Pursue project terms that are in the best interest of ratepayers.
- Retain the maximum number of high-quality, high-paying nuclear industry jobs in the province while providing opportunities for long-term growth of the nuclear industry.

Renewables: Hydroelectric

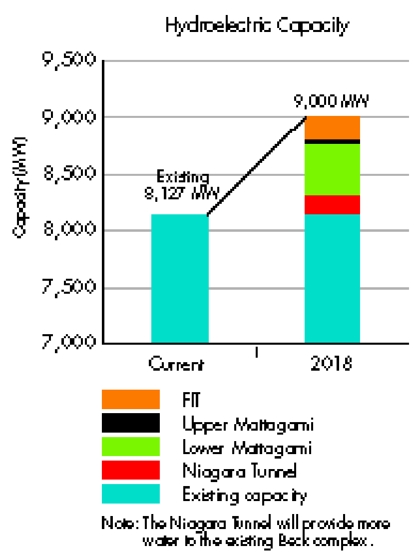
Ontario has been generating renewable power from water — hydroelectric power — for over 100 years. Hydroelectric power is clean, renewable, cost-effective and helps to contribute to clean air quality. Hydro currently makes up the vast bulk — about 90 per cent — of Ontario's total renewable energy supply, representing 8,127 MW of capacity. It is a reliable source of electricity that can continue to provide clean energy for generations to come.



Accomplishments

The 2007 Plan projected a total of 7,708 MW of hydroelectric capacity by 2010. The government has exceeded this goal. Ontario has also launched significant hydroelectric projects — the first major investments in 40 years. Since October 2003, 317 MW of new hydro projects have been brought online.

FIGURE 8: HYDROELECTRIC CAPACITY



Some of the larger completed and ongoing hydro projects to meet Ontario's future needs include:

- Niagara Tunnel project, which will increase the amount of water available for power generation at the Sir Adam Beck Generating Station
- The Lower Mattagami project expansion – the largest hydroelectric project undertaken in Ontario in 40 years. This project will add about 440 MW of clean electricity generating capacity to Ontario's energy grid, while providing $2.6 billion of investment in the North
- Healey Falls, a 15.7 MW facility near Campbellford, east of Peterborough
- Lac Seul Generating Station, a 12.5 MW facility near Ear Falls
- Trent Rapid Hydroelectric Station, an 8 MW facility near Peterborough
- Sandy Falls, a 5.5 MW facility on the Mattagami River, near Timmins.

Future need

More hydroelectric power will be added to Ontario's electricity system in the next eight years than over the previous 40 years. Unlike Quebec, Ontario does not have the geography to support massive reliance on hydroelectric power. (Quebec has almost four times the hydro capacity of Ontario.) New hydroelectric generation will continue to be an important part of a clean, reliable system over the next 20 years. The government is also reviewing how crown land is made available for waterpower projects, particularly for smaller Feed-InTariff (FIT) Program projects.

The Plan

Ontario will continue to develop the province's hydroelectric potential and is planning for 9,000 MW of hydroelectric capacity by 2018.

Once the Niagara Tunnel expansion is complete, it will provide enough electricity to power 160,000 homes. When the capacity expansion at Lower Mattagami is complete, the project will provide enough electricity to power over 300,000 homes. These projects will help to maximize Ontario's existing hydro projects.

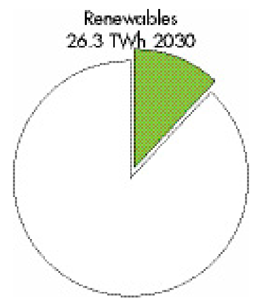
Existing hydro is the cheapest form of generation in Ontario and in many cases, it can help to meet peak power demand. There are a number of projects that are currently under consideration, such as:

- Two hydroelectric generating stations on the Little Jackfish River (north of Lake Nipigon) that could add 100 MW of capacity
- New Post Creek, a 25 MW project in the development stage
- Mattagami Lake Dam, a 3-6 MW development at Kenogamissi Falls on the Mattagami River.

Ontario will plan for future hydroelectric development where it is cost-effective to build. This will mean FIT-level hydro projects (less than 50 MW) will also be considered.

New hydro projects complement other renewable initiatives and help to eliminate coal by 2014. Some additional projects will be considered, but large-scale projects, usually in remote locations, are not economically feasible at this time due to high capital and construction costs. Transmission, engineering and environmental factors are also challenges. However, due the importance of hydroelectric generation, Ontario will continue to study Northern hydro options over the period of the Plan.

Renewables: Wind, Solar and Bio-energy



Ontario has become a North American leader in producing energy from sources that are continually renewed by nature such as wind, sun and bioenergy. Renewables do not produce harmful emissions, which contribute to smog, pollution and climate change. Increasing Ontario's renewable energy supply helps reduce the province's reliance on fossil fuels. Greater investments and reliance on renewable energy help to ensure that Ontario has a clean and reliable electricity system for generations to come.

Accomplishments

Ontario is now Canada's leading province for wind and solar capacity and home to the country's four largest wind and solar farms. The world's largest photovoltaic solar farm is in Sarnia (Enbridge's 80 MW Sarnia Solar) and Canada's largest wind farm is near Shelburne (the 199.5 MW Melancthon EcoPower Centre). In 2003, Ontario had 10 wind turbines; today, the Province has more than 700.

Since October 2003, the government has signed more than 16,000 renewable energy supply contracts from wind, water, solar and bio-energy sources. This includes almost 2,400 MW of small and large renewable power projects under North America's first comprehensive Feed-in Tariff (FIT) Program, introduced in 2009. These FIT contracts represent a private sector investment of $9 billion and are projected to create approximately 20,000 direct and indirect clean energy jobs.

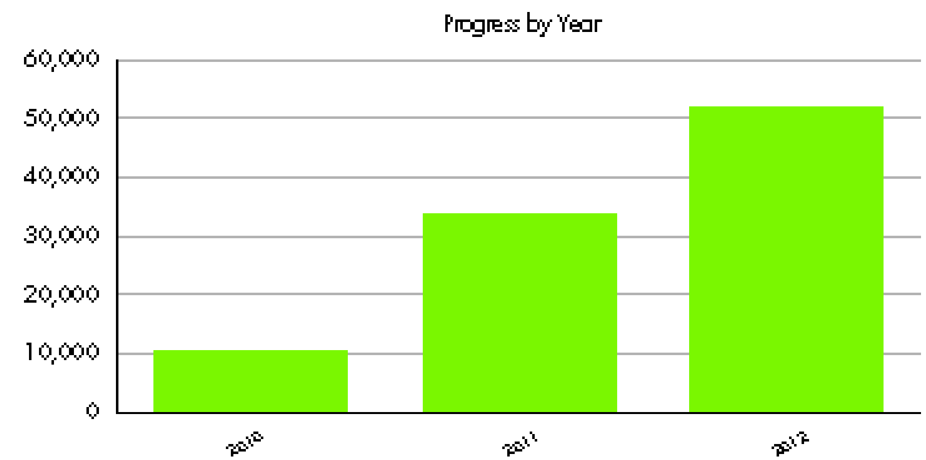
The success of the FIT Program has also attracted the notice of global investors, including a consortium of companies led by Samsung C&T Corporation, laying the foundation for Ontario to become a global clean energy production and manufacturing hub.

> Ontario's Feed-in Tariff (FIT) Program combines stable, attractive prices and long-term contracts for energy generated using renewable resources.
>
> Homeowners, business owners and developers may apply to the FIT Program if they use one or more forms of renewable energy, including wind, waterpower, solar photovoltaic (PV) power and bioenergy.
>
> The Program is the first comprehensive FIT program in North America. It was launched through the Green Energy and Green Economy Act, 2009.
>
> Over 1,000 FIT contracts are currently in place for clean energy projects.

Some 51 community projects will provide renewable electricity supply to the grid through the Ontario FIT program. From these projects, more than 200MW of clean electricity will be generated by communities engaging in, solar, wind and bio-energy projects across Ontario.

Thousands of Ontarians are also participating in the microFIT Program. Homeowners, farmers or small business owners, are able to develop a very small or "micro" renewable electricity generation project (10 kilowatts or less in size) on their properties. Under the microFIT program, they are paid a guaranteed price for all the electricity they produce for 20 years.

FIGURE 9: PROGRESS ON 50,000 PROJECTED GREEN ENERGY ACT JOBS



Major Private-Sector Renewable Investments in Ontario

The $7-billion Green Energy Investment Agreement with Samsung C&T Corporation and Korea Electric Power Corporation (Consortium), is the single largest investment in renewable energy in provincial history. It will:

- Build 2,500 MW of wind and solar power.
- Deliver an estimated 110 million megawatt-hours of emissions-free electricity over the 25-year lifetime of the project — enough to supply every Ontario home for nearly three years.
- Create more than 16,000 new clean energy jobs to supply, build, install and operate the renewable generation projects.
- Lay the groundwork with major partners to attract four manufacturing plants.

Out of the 16,000 new clean energy jobs, this investment is expected to create or sustain 1,440 manufacturing and related jobs, building wind and solar technology for use in Ontario and export across North America.

As part of the Green Energy Investment Agreement, Samsung and Siemens have announced plans to build Ontario's first wind turbine blade manufacturing plant, which will create up to 900 direct and indirect jobs. The Consortium will negotiate with manufacturing partners to locate three other plants in Ontario for wind turbine towers, solar inverters and solar module assembly.

Under the agreement, three of the four manufacturing facilities are scheduled to be ready in 2013, while the fourth is scheduled to be in operation by the end of 2015. The Consortium also intends to use Ontario-made steel and other Ontario content in its renewable energy projects for items such as wind turbine towers.

More than 20 companies have publicly announced plans to participate in Ontario's clean energy economy, in the last year. These companies are currently operating or plan to set up solar and wind manufacturing facilities in Ontario in the following categories: solar PV modules, mounting systems, inverters, wind turbine blades and wind turbine towers. Some recent examples include:

- Heliene Inc., producing modules in Sault Ste. Marie;
- Canadian Solar, will manufacture modules in Guelph;
- Photowatt, producing modules in Cambridge;
- Samco, an auto parts manufacturer now also producing solar mounting systems in Scarborough;
- Schletter, producing solar mounting systems in Windsor;
- Sustainable Energy Technologies partnering with Melitron to produce inverters in Guelph;
- Satcon, producing inverters in Burlington;
- Siemens will be producing wind turbine blades; and,
- DMI Industries is producing wind turbine towers in Fort Erie.

Future Needs

Ontario will continue to be a leader in renewable energy development and generation. The growth of the renewable energy sector will be influenced by electricity demand, the ability of the system to accommodate additions to the grid, continued innovation in the renewable technology sector and global demand for renewable energy production. Expansions and upgrades to the transmission and distribution system will be necessary to increase the capacity for renewable energy in Ontario.

As more and more of Ontario's electricity comes from renewable energy sources and research and innovation of Smart Grid technologies continues, there will be increased opportunities for renewable energy projects, both large and small to be established in Ontario.

There will also be greater opportunity for employment in this field. Renewable energy projects require skilled labour, such as engineers as well as construction and maintenance labour across the province. As renewable energy projects are established, the need for skilled and general labour will continue to provide jobs for thousands of Ontarians over the next decade. Innovation in new technology also contributes high skilled jobs and economic opportunities for Ontario.

> Biomass is dispatchable and can be used as a peaking resource. This attribute allows it to complement increased wind and solar generation. The conversion of Atikokan Generating Station to run on biomass will contribute to long-term system reliability, especially during low water conditions in the region. The conversion from coal to biomass at Atikokan by 2013 will create up to 200 construction jobs and help protect jobs at the plant. It will also support jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. Ontario will continue to monitor the conversion of Atikokan and consider future potential of biomass generation.

The Plan

Ontario will continue to develop its renewable energy potential over the next decade. Based on the medium growth electricity demand outlook, a forecast of 10,700 MW of renewable capacity (wind, solar, and bioenergy) as part the supply mix by 2018 is anticipated. This forecast is based on planned transmission expansion, overall demand for electricity and the ability to integrate renewables into the system. This target will be equivalent to meeting the annual electricity requirements of two million homes.

The province's renewable energy capacity target will be met with the development of renewable energy projects from wind, solar, biogas, landfill gas and biomass projects across Ontario.

Future rounds of FIT projects will be connected to the Bruce to Milton transmission line and the priority transmission projects identified as part of this Long-Term Energy Plan. This will enable 4,000 MW of new renewable energy projects to be connected.

In the near term, the OPA will be releasing information regarding the status of all FIT applications not offered contracts as of June 4, 2010. These applications will be subject to the first Economic Connection Test (ECT) under the FIT program. The ECT process, to be conducted on a regular basis and in alignment with major planning or system development milestones, will help to determine whether the costs of grid upgrades to allow a FIT project to connect to the grid are economically viable.

For the period after 2018, depending on changes in demand, Ontario will look for opportunities to increase the development of renewable energy projects and expand renewable energy capacity in the Province. Ontario will review the electricity demand outlook in the next Long-Term Energy Plan to explore whether a higher renewables capacity forecast is required.

FIT contract prices were set following extensive consultations and are designed to ensure a reasonable rate of return for investors while providing good value for clean, renewable energy for Ontario ratepayers.

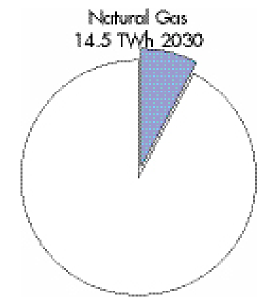
As part of the scheduled two-year review of the FIT Program in 2011, the FIT price of renewables in Ontario will be re-examined. Successful and sustainable FIT programs in a number of international jurisdictions (such as Germany, France and Denmark) have decreased price incentives. Advances in technology and economies of scale reduce the cost of production. A new price schedule will be carefully developed to achieve a balance between the interests of ratepayer and the encouragement of investment in new clean energy in Ontario.

The response to the microFIT and FIT programs has been a tremendous. Thousands of Ontarians are participating in the program to feed clean energy into the grid.

Given the popularity of Ontario's growing clean energy economy, applications to the microFIT and Capacity Allocation Exempt (CAE FIT) program are outpacing needed upgrades to the grid. To continue to ensure the growth of small clean energy projects, Ontario will continue to invest in upgrades to the transmission and distribution systems to accommodate renewable supply.

In areas where there are technical challenges, the OPA, Hydro One and Local Distribution Companies will continue to work with proponents that have already applied to the CAE FIT or microFIT program.

Natural Gas



Natural gas plants have the flexibility to respond well to changes in demand, making them an important cushion for Ontario's electricity system — particularly for peak periods.

Natural gas produces electricity either by burning to directly power a gas turbine or by producing steam to drive a steam turbine. A combined cycle gas plant combines these two technologies. Natural gas can supplement baseload power supply and, because it responds quickly to increases in demand, it can also complement the intermittent nature of wind and solar electricity generation.

Natural gas is much cleaner than coal. Some air emissions — particularly mercury and sulphur dioxide — are totally eliminated when natural gas replaces coal. Carbon dioxide emissions are reduced by between 40 and 60 per cent. Currently, Ontario's electricity generation capacity from natural gas is over 9,500 MW.

By replacing coal with natural gas and renewable energy sources, Ontario has greatly reduced greenhouse gas emissions from its electricity supply mix. This policy has prepared Ontario for the possibility of greenhouse gas regulation in the North American market.

Accomplishments

The Ontario government and the OPA have launched a number of clean natural gas and cogeneration projects since 2003 to help with local reliability and peak demand.

The 2007 Plan projected that some 12,000 MW of natural gas would be needed by 2015. Since then, changes in demand and supply — including about 8,400 MW of new, cleaner power across the system and successful conservation efforts — means that less capacity will be required.

Future Needs

In 2009, about 10 per cent of Ontario's electricity generation came from natural gas. In the coming years, the government anticipates that it will be necessary to maintain the amount of natural gas supply at its current level in the supply mix.

The Plan

Natural gas will continue to play a strategic role in Ontario's supply mix as it helps to:

- Support the intermittent supply from renewables like wind and solar
- Meet local and system reliability requirements
- Ensure adequate capacity is available as nuclear plants are being modernized

The 2007 Plan outlined a forecast need for an additional three gas plants in the Province, including one in the Kitchener-Waterloo-Cambridge and one in the southwest GTA.

Because of changes in demand along with the addition of approximately 8,400 MW of new supply since 2003, the outlook has changed and two of the three plants — including the proposed plant in Oakville — are no longer required. However, a transmission solution to maintain reliable supply in the southwest GTA will be required.

As indicated in 2007 Plan, the procurement of a peaking natural gas-fired plant in the Kitchener-Waterloo-Cambridge area is still necessary. In that region, demand is growing at more than twice the provincial rate.

Ontario is taking advantage of its existing assets with the conversion of two coal-fired units in Thunder Bay to natural gas. (See page 21 on Coal.)

Over the next few years, non-utility generation contracts, which were entered into between the private sector and the former Ontario Hydro in the early 1990s, will begin to expire. Many of these are natural gas-fired. These non-utility generators — or NUGs as they are known — have been part of Ontario's overall supply mix for 20 years. They can contribute up to 1,550 MW of clean power to the system. The contracts with NUGs are currently held by the Ontario Electricity Financial Corporation, an agency of the Ministry of Finance.

As non-utility generator contracts expire, the IESO and the OPA will determine if the generation is still required to help ensure reliability. The government will direct the OPA to design contracts that will encourage NUGs to operate during periods when it would most benefit the electricity system. The OPA will be authorized to enter into new contracts where this generation is needed and will negotiate to get the best value for consumers.

CHP (Combined Heat and Power/Cogeneration)

Combined Heat and Power is the simultaneous production of electricity and heat using a single fuel such as natural gas. The heat produced from the electricity generation process is captured and used to produce steam or hot water that can then be used for industrial and commercial heating or cooling purposes, such as district energy systems.

CHP can make more efficient use of fuel and therefore reduce greenhouse gas emissions. CHP overall efficiency can exceed 80 per cent — which means that 80 per cent of the energy can be captured as electricity or usable heat.

Accomplishments

Currently, the total industrial CHP capacity in Ontario is estimated to be about 2,000 MW, or about 6 per cent of Ontario's installed generation capacity.

In October 2006, the OPA awarded seven contracts with a total capacity of 414 MW — enough to provide the power for 400,000 Ontario homes. Much of this new capacity (395 MW) will be coming from industrial projects. These facilities are in communities across the province including: Windsor, Kingsville, London, Oshawa, Markham, Sault Ste. Marie and Thorold.

Algoma Energy Cogeneration Facility

The 63 MW Algoma Energy Cogeneration Facility is located in Sault Ste. Marie, Ontario. The facility uses the by-product fuels from cokemaking and ironmaking (blast furnace and coke oven gas) to generate electricity and steam used for steel manufacturing operations.

The facility reduces Essar Steel Algoma's reliance on the provincial power grid by 50 per cent on average, freeing up this capacity for the rest of the province. This cogeneration facility helps to reduce Essar Steel Algoma's nitrous oxide emissions by 15 per cent (approximately 400 metric tonnes a year).

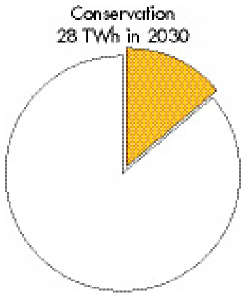
The Plan

Ontario will target a total of 1,000 MW of CHP. It will be procured through the OPA and will include existing contracts, individual negotiations for large projects and a new standard offer program for smaller projects in key strategic locations.

The government will encourage new local CHP generation projects, where price, size and location make sense. The government will work with the OPA to develop options for small, targeted programs. Over the next 20 years, Ontario will see more community-scale CHP projects. The OPA will create a new standard offer program for CHP projects under 20 MW in specific locations.

The OPA will continue to negotiate larger CHP projects on an individual basis. For example, the OPA and St. Marys Paper Corporation recently signed a 10-year contract for the company to generate clean electricity at a new 30 MW biomass-fuelled plant to be built next to St. Marys existing mill in Sault Ste. Marie. The plan is expected to reach commercial operation by early 2014 and will support 550 direct and indirect jobs.

3 conservation



Conservation is Ontario's most environmentally friendly and cost-effective resource. Conservation initiatives save money and reduce greenhouse gas emissions. Reducing consumption reduces bills for consumers and reduces demand on the system, avoiding the need to build new generation. For every dollar that is invested in conservation, two to three dollars of net savings are realized over the life of the investment. Conservation can also create local jobs in energy audits and energy services.

Accomplishments

From 1995 to 2003, there were no provincial conservation programs — it was not a priority. Since 2003, Ontario has had goals for conservation and as a result, this province has become a North American leader. The goal to reduce peak demand by 6,300 MW by 2025 was included in the 2007 Plan. Ontario is on target to meet this goal.

Ontario's A+ 2009 National Energy Efficiency Report Card from the Canadian Energy Efficiency Alliance

The province raised its grade from a "C-" in 2004 to an A+ in 2009 with its strong commitment to energy efficiency and conservation as cornerstones of its energy plan. In addition to the Green Energy and Green Economy Act, 2009, the report lauds Ontario's energy conservation programs, improved energy efficiency in building codes and product standards, as well as other initiatives supporting energy efficiency.

To improve the quality of the province's air and the efficiency of the system, Ontario invested about $1.7 billion in conservation programs from 2006 to 2010. This will save ratepayers $3.8 billion in avoided costs.

Conservation programs also give customers the tools to help them manage costs, and balance demand in peak periods in winter and summer. Conservation programs also create jobs in the clean energy sector.

Ontario has helped to create a culture of conservation since 2003 by:

- Updating Ontario's building code to make energy efficiency a core purpose.
- Delivering the Home Energy Savings Program which has helped over 393,000 homeowners with energy audits and helped nearly 250,000 homeowners with energy savings and retrofits. Despite the federal government's early withdrawal from funding this conservation program in March 2010, Ontario will continue to support the Home Energy Savings Program until March 31, 2011. This program helped save annual greenhouse gas emissions equivalent to taking over 83,000 cars off the road.
- Initiating the OPA's Great Refrigerator Round Up which has removed more than 230,000 old appliances since 2007. It will result in lifetime savings of more than one million megawatt hours over the life of the program.
- Providing $550 million over two years for energy retrofits in schools.
- Launching the Ontario Solar Thermal Heating Initiative for solar water and air heating projects for institutional, commercial or industrial organizations. The program continues until March 31, 2011. Almost 600 projects have been launched or completed to date.
- Moving forward with Smart Meters and Time of Use billing to encourage consumers to shift electricity consumption away from peak periods of demand; Avoided system expenditures help keep costs down for Ontarians.
- Reducing electricity consumption in government buildings through initiatives such as deep lake water cooling — a reliable, efficient and sustainable way to cool buildings while reducing demand on the grid.

Over the past five years, Ontario's conservation programs have generated over 1,700 MW of peak demand savings — the equivalent of over 500,000 homes being taken off the grid. Local Distribution Companies have been partners in helping Ontario achieve its conservation targets.

Conservation efforts are measured by looking at the results of conservation programs. The impacts of the global economic recession are not counted as part of conservation efforts, although they did result in a significant reduction in electricity demand. The recession also affected the level of participation in conservation programs which, although successful, are not expected to allow Ontario to meets its 2010 interim target. Confirmation of this will occur late in 2011, after program results undergo rigorous verification by independent third-parties. Had the global recession not had a significant impact on Ontario's economy, 2010 conservation achievements would have been significantly higher.

The Plan

Working together to reduce electricity use at peak times makes sound economic and environmental sense. Providing consumers with the benefit of up-to-date and accurate electricity consumption readings is also critical to the creation of a culture of conservation. The government is committed to moving forward with implementation of a Time-of-Use pricing structure that balances benefits for both the consumer and the electricity system as a whole.

To help families, Ontario will move the off-peak period for electricity users to 7 p.m. which will provide customers with an additional two hours in the lowest cost period. This change will be in effect for the May 2011 Regulated Price Plan update.

Time-of-Use

"On average, most farmers will pay slightly less on time-of-use billing than they currently pay. Advantages for farmers will be modest with a savings in the range of one to five per cent. However, the advantages for the power supply system will be substantial…"

- Don McCabe, Ontario Federation of Agriculture

Ontario is already a North American leader in conservation (the province conserved over 1,700 MW since 2005). The government's target is 7,100 MW and 28 TWh by 2030. This would mean the equivalent of taking 2.4 million homes off the grid. This level of conservation will reduce Ontario's greenhouse gas emissions by up to 11 megatonnes annually by 2030. These targets are among the most aggressive in North America.

As part of the Green Energy and Green Economy Act, 2009, Local Distribution Companies (LDCs) will become a more recognizable "face of conservation" and have been assigned conservation targets which they must meet as a condition of their licence. LDCs will meet their targets through a combination of province-wide and local conservation programs.

Ontario proposes to provide support for homeowners to have energy audits to become better informed of the opportunities to improve the energy efficiency of their homes.

Conservation targets

Date	2015	2020	2025	2030
Capacity	4,550 MW	5,840 MW	6,700 MW	7,100 MW
Generation	13 TWh	21 TWh	25 TWh	28 TWh

These targets will be met through a combination of programs and initiatives:

- Innovative energy efficiency programs for residential, commercial and industrial sectors
- Next-generation building code updates and standards for appliances and products
- Demand response programs to help reduce peak demand
- Time-Of-Use rates

The government anticipates that the commercial sector will contribute 50 per cent of the conservation target; residential sector will contribute 30 per cent; and industrial sector 20 per cent.

Over the next 20 years, Ontario's conservation targets and initiatives are projected to save about $27 billion in ratepayer costs on the basis of a $12 billion investment. Conservation will also do more than that by helping to ensure that Ontario's air is cleaner and the electricity sector reduces its impact on the environment.

Ontario will continue to provide broad support for achieving these targets through policy initiatives such as bringing forward a proposed regulation to require the broader public sector (municipalities, universities, schools and hospitals) to develop energy conservation plans.

In early 2011, together with LDCs, Ontario will launch a number of new programs, which will allow the province to meet its conservation targets over the next few years and make up for the slower period between 2009 and 2010. The programs will target all sectors, be better coordinated and have greater customer focus than previous programs.

Ontario is designing, implementing and funding a province-wide electricity conservation and demand management program for low-income residential consumers . Ontario is also developing a low-income energy program comprised of natural gas conservation, customer service standards and emergency financial assistance.

These new conservation programs, together with programs for very large industrial customers, will require an investment of about $3 billion over the next five years. The results will be significant: an avoided lifetime supply cost of $10 billion and a net benefit to Ontario ratepayers of about $7 billion over the life of the conservation measures.

4 reliable transmission/ modern distribution

Reliable transmission and modern delivery is the backbone of Ontario's electricity system. It is crucial for supporting Ontario's evolving supply mix, including the closing of coal-fired plants by 2014 and the further expansion of Ontario's clean energy resources. Reliable, safe transmission brings electricity from large generators to Ontario's largest industries and local distribution companies who in turn, deliver to homes and businesses. A modern distribution system, utilizing new technology, allows for greater customer control, incorporates renewable energy, enhances reliability, and supports new technology like electric vehicles.

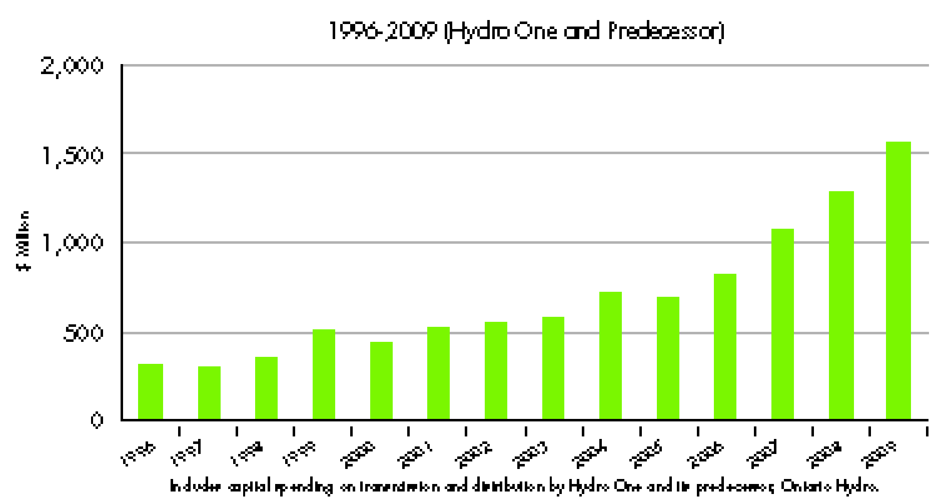
Transmission

Ontario must take the transmission system that's been built over the past century and continue to renew and update it to meet Ontario's growing population, evolving supply mix, and enable more distributed generation.

The Ontario government has taken early and decisive steps to enhance existing electricity infrastructure. It is important to ensure that Ontario can efficiently upgrade the grid to carry additional renewable generation to homes, businesses and industries.

Since 2003, Hydro One has invested more than $7 billion in its transmission and distribution systems. The average annual investment has been double what it was from 1996-2003.

FIGURE 10: GRID INVESTMENTS



Some of Ontario's recent investments include:

- The launch of the Bruce to Milton transmission expansion project — the largest electricity transmission investment in Ontario in the last 20 years, which will connect refurbished nuclear units and additional renewable energy to the grid.
- Ongoing work to reinforce the power transfer capability between northern and southern Ontario including additional 750 MW of planned clean northern generation (Lower Mattagami and some northern FIT Program projects).
- The new Ontario-Québec Interconnection Project (2010), which increased access to 1,250 MW of hydroelectric power and enhanced system reliability in eastern Ontario.
- Additional transmission projects that will facilitate the retirement of coal-fired generation, including transmission reinforcement in the Sarnia area, the installation of new transformers in the northern GTA, and voltage support facilities in the Niagara, London and Kitchener areas. These projects represent an investment of over $400 million.
- Over 15 per cent of transformer stations across Ontario have received overhauls in the past five years, amounting to a total investment of $850 million.
- Installation of almost 4.3 million smart meters across the province, which are already helping with outage management and remote meter reading and reducing the number of estimates for consumers.
- Early investments in Smart Grid infrastructure and technologies, including pilots and demonstration projects. These projects will help Ontario move toward a Smart Grid system that can integrate energy monitors, home automation systems, in-home renewable generation and electric cars.
- Hydro One's $125-million Grid Control Centre opened in 2004 and uses some of the most sophisticated technology in the world to efficiently manage the bulk of Ontario's electricity network.

Reliability has also been improved since 2003 due to a combination of new generation, transmission upgrades, reduced load growth and successful conservation programs. For example, Toronto's reliability was enhanced with the installation of two new underground cables between downtown transfer stations and will be further assisted by reinforcement and upgrade projects worth about $360 million. Annual capital investments by Ontario's Local Distribution Companies, including Hydro One, have averaged $1.1 billion between 2004 and 2009, maintaining reliable and high quality power for Ontario's electricity customers. These investments have made the operation of the system more cost-effective, which will have an impact on Ontarians' bills over the long term.

Modern Distribution

Local distribution systems are an important link in how electricity moves from generators to homes and businesses. In 2003, Ontario's distribution systems often relied on older technology. The government's move towards a Smart Grid was driven by the need to replace aging infrastructure, introduce customer control, incorporate more renewable energy and accommodate new adaptive technology such as electric vehicle charging. Over time, LDCs will have to replace old mechanical infrastructure with newer automated infrastructure that meets Ontario's future needs.

A modern distribution system must be able to accommodate new energy supply from a variety of sources and deliver it reliably to consumers. It must take advantage of Smart Grid technologies to enable efficient and cost-effective delivery of electricity, helping customers to better manage their electricity use, and integrate more renewable energy.

Building a Smart Grid that can coordinate the production of power from large numbers of small power producers and allow utilities to more efficiently manage their grid infrastructure is another essential element of Ontario's clean energy future. Other jurisdictions (Australia, Great Britain and California) are moving toward a smarter grid, but Ontario is leading the way in many areas. By leveraging existing communications technology, a Smart Grid will enable the two-way power flow of electricity across the grid. The Smart Grid will help incorporate distributed generation. It will also improve grid automation with real-time information that will help save energy, reduce the cost of supply over time and increase reliability.

A Smart Grid is a more intelligent grid infrastructure, incorporating communications technology and automation to:

- Maximize existing infrastructure
  - Rather than building out more traditional grid infrastructure (poles, wires, etc), a Smart Grid will use Information Technology solutions to improve and automate distribution.
- Modernize the grid
  - The current distribution system in some places is decades old. A modernized grid is critical for improving reliability, home automation and adapting to evolving transportation needs.
- Lay the foundation for Smart Homes
  - A Smart Grid will put in place the intelligent infrastructure required to support applications for home automation, conservation and smart charging for electric vehicles.

The Green Energy and Green Economy Act, 2009 identified three main areas of focus for Ontario's Smart Grid:

- Helping consumers become active participants in conservation.
- Connecting new and renewable sources of energy to the overall system (consumers and businesses produce energy that can be connected to the local system) to help address power demands.

- Creating a flexible, adaptive grid that can accommodate the use of emerging, innovative energy-saving technologies and control systems.

Smart meters provide a foundation for the Smart Grid and provide customers with timely and accurate information about their electricity use. Smart meters also provide utilities with automatic notification of outages, save on in-person meter-reading costs and enable Time-of-Use pricing.

Smart meters also help avoid system costs that in turn save money for ratepayers: Hydro Ottawa saved $200,000 in meter reading in 2008 and Toronto Hydro estimates that smart meters will cut meter-reading costs by $2.5 million by 2010.

Future Needs

The Ontario government, working with its agencies, will move forward responsibly on a number of new and modernizing transmission projects as well as on improving and maintaining the province's existing infrastructure across all regions in Ontario. These improvements will also balance environmental concerns and the cost to ratepayers. In addition to evaluating the province's need for transmission to integrate renewables, meet provincial demand growth and ensure reliable service, system planning will address community needs. For example, a transmission solution to maintain reliable supply in the southwest GTA will be required.

The Plan

In 2009, the government asked Hydro One to start planning and developing a series of new transmission and distribution projects. Since that time, there have been a number of developments, such as the substantial interest in the Green Energy and Green Economy Act, 2009 to develop renewable energy projects.

Based on the advice of the OPA, the government will prudently move forward with cost-effective priority transmission projects that meet current and future demand and also:

- Accommodate renewable projects;
- Serve new load; and
- Support reliability.

Ontario will proceed first with an investment of approximately $2 billion in five priority projects to be completed in the next seven years, which will ensure a growing mix of renewable sources can be reliably transmitted across the province. These priority projects together with the Bruce to Milton line, in addition to various other station and circuit upgrades, will enable approximately 4,000 MW of additional renewable energy.

FIGURE 11: TRANSMISSION INVESTMENTS: COMPLETE, UNDERWAY AND PROPOSED

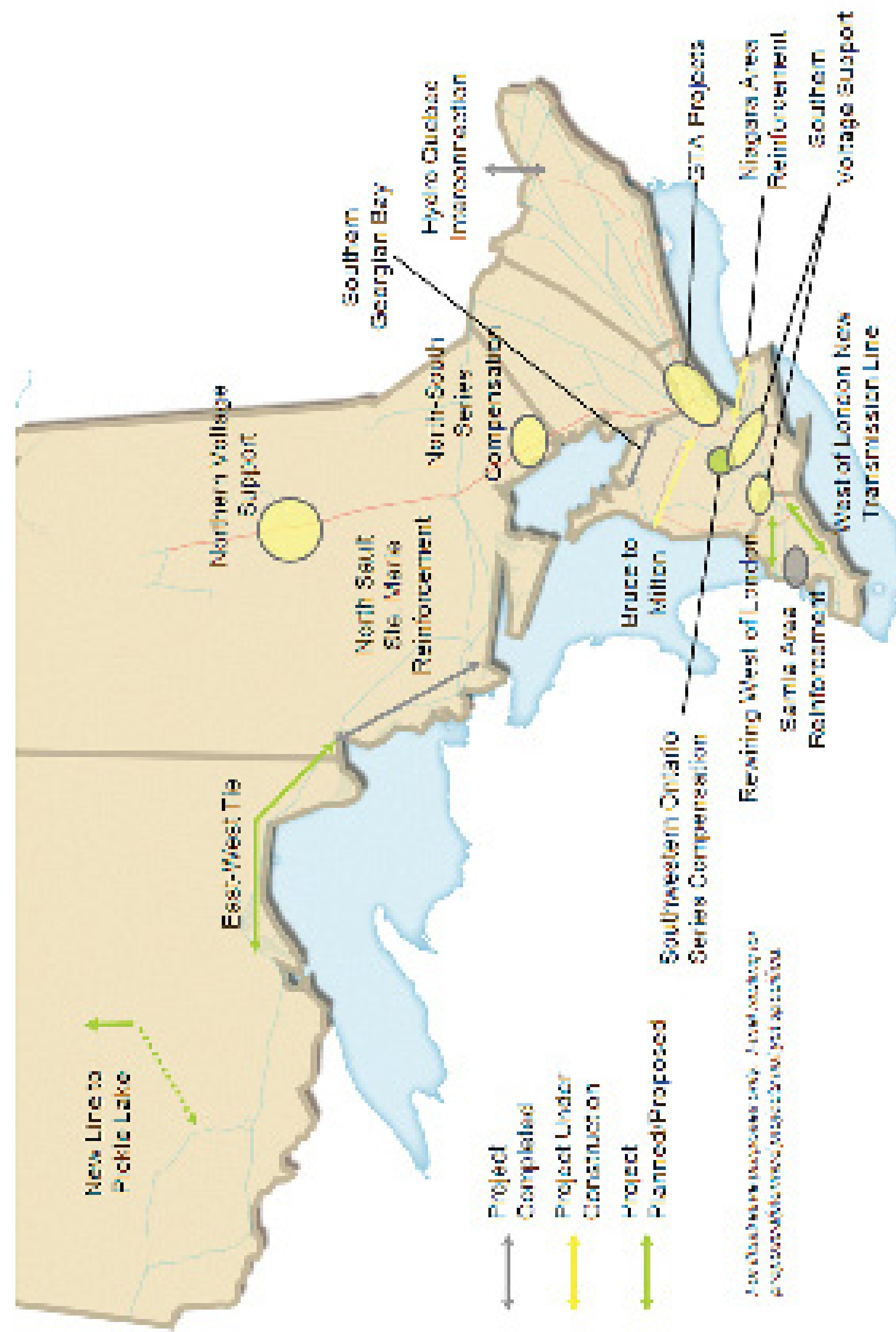


FIGURE 12: PRIORITY TRANSMISSION PROJECTS

Project	Type	Need	Target Completion Date
Series compensation in Southwestern Ontario	Upgrade	Add renewables to grid	2014
Rewiring west of London	Upgrade	Add renewables to grid	2014
West of London	New Line	Add renewables to grid	2017
East-West Tie	New Line	Maintain system reliability, allow more renewables, accommodate electricity requirements of new mineral processing projects.	2016-17
Line to Pickle Lake	New line	Serve industry needs and help future remote community connection	Pending consultation

Given the nature of the transmission upgrades in southwestern Ontario, including series compensation, rewiring and a new line west of London, the government intends to direct Hydro One to carry out these projects immediately.

The East-West tie will be submitted to the OEB to carry out a designation process to select the most qualified and cost-effective transmission company to develop the line.

To ensure successful and timely implementation of the line to Pickle Lake, the government will work with its agencies and the multiple parties involved, including the Federal government, local industries, and First Nation communities that stand to benefit from the project to establish an implementation schedule and a proponent for the line.

Transmission planning will also continue at the regional level, using an approach that considers conservation, demand management, distributed generation and transmission. Regional plans will assess needs based on a region's unique resource mixes and community priorities. Load growth and system reliability are also factors in determining system planning and transmission solutions. Ontario will continue to plan and study additional transmission projects as demand and changes to supply require.

To build a modern system, the government will issue a set of Smart Grid principles and objectives to the Ontario Energy Board. These will provide guidance to LDCs in modernizing their distribution systems and enable the smart home of the future. LDCs will develop smart grid plans and ensure that these are coordinated across the Province. The government will also establish a Smart Grid Fund in 2011 which will provide assistance to Smart Grid companies with a strong Ontario presence. This will lead to new economic development opportunities and bolster Ontario's position as a leader in the Smart Grid.

5 aboriginal communities

Accomplishments

The Ontario government is committed to encouraging opportunities for Aboriginal participation in the energy sector and has launched several initiatives to support participation by First Nation and Métis communities in energy projects, including:

- The Aboriginal Energy Partnerships Program
- The FIT Program: 17 aboriginal-led or partnered projects have secured contract offers
- The $250-million Aboriginal Loan Guarantee Program

Ontario also has a significant partnership at the $2.6 billion Lower Mattagami hydroelectric project, which will see Moose Cree First Nation have up to a 25 per cent equity position with OPG.

Future Needs

First Nation and Métis communities have diverse energy needs and interests. Ontario will work to ensure there is a wide range of options for Aboriginal participation in Ontario's energy future.

Conservation

Conservation priorities and the applicability of programs will vary between First Nation and Métis communities. Community education and youth engagement are also critical for conservation success. Ontario will launch programs to support participation in conservation initiatives, including Aboriginal Community Energy Plans and targeted conservation programs.

Renewable Energy

Future opportunities for First Nation and Métis communities include:

- Partnerships with private developers on confirmed FIT projects under development,
- Development of smaller renewable microFIT projects, like small wind or solar, to build community capacity in energy and generate income.

Existing Green Energy and Green Economy Act, 2009 support programs will be adjusted to ensure that aboriginal communities can take advantage of these opportunities. Aboriginal participation levels will also be reviewed during the regular FIT program review to determine whether adjustments are needed to the rules and incentives.

Transmission

Where new transmission lines are proposed, Ontario is committed to meeting its duty to consult First Nation and Métis communities in respect of their aboriginal and treaty rights and accommodate where those rights have the potential to be adversely impacted. Ontario also recognizes that Aboriginal communities have an interest in economic benefits from future transmission projects crossing through their traditional territories and that the nature of this interest may vary between communities.

There are a number of ways in which First Nation and Métis communities could participate in transmission projects. Where a new transmission line crosses the traditional territories of aboriginal communities, Ontario will expect opportunities be explored to:

- Provide job training and skills upgrading to encourage employment on the transmission project development and construction.
- Further Aboriginal employment on the project.
- Enable Aboriginal participation in the procurement of supplies and contractor services.

Ontario will encourage transmission companies to enter into partnerships with aboriginal communities, where commercially feasible and where those communities have expressed interest. The government will also work with the OPA to adjust the Aboriginal Energy Partnerships Program — currently focussed on renewable energy projects — to provide capacity funding for aboriginal communities that are discussing partnerships on future transmission projects.

The Plan

Ontario recognizes that successful participation by First Nation and Métis communities will be important to advance many key energy projects identified under a Long-Term Energy Plan. The path forward needs to be informed by regular dialogue with First Nation and Métis leadership through distinct processes. Working with First Nation and Métis leadership, Ontario will look for opportunities to promote on-going discussion of these issues.

Ontario's remote First Nation communities currently rely on diesel generation for their electricity supply — but diesel fuel is expensive, difficult to transport, and poses environmental and health risks. According to analysis done so far, transmission connection would be less expensive over the long term than continued diesel use for many remote communities.

New transmission supply to Pickle Lake is a crucial first step to enable the connection of remote communities in northwestern Ontario. A new transmission line to Pickle Lake — one of this plan's five priority projects — will help to service the new mining load and help to enable future connections north of Pickle Lake. Subject to cost contributions from benefiting parties, Ontario will focus on supplying Pickle Lake from the Ignace/Dryden area immediately. A line to serve the Nipigon area specifically will continue to be considered as the need for it evolves.

As part of this project, the government will also ask the OPA to develop a plan for remote community connections beyond Pickle Lake, including consideration of the relevant cost contributions from benefiting parties, including the federal government. This plan may also consider the possibility of onsite generation such as small wind and water to reduce communities' diesel use.

6 energy in Ontario's economy — capital investments

Energy has a significant impact on Ontario's economy. Ontario businesses rely on electricity to produce goods and services and it is essential to our quality of life.

- Ontario's electricity sector is a $15 billion annual industry.
- Energy accounts for eight per cent of Canada's GDP.
- Some 95,000 Ontarians are currently directly and indirectly employed in the energy sector.
- More than $10 billion has been invested in Ontario in new clean energy projects that are online or under construction.
- Ontario has attracted more than $16 billion in private sector investments in the energy sector in the past year.

Ontario's progress in modernizing and upgrading electricity has not only benefited electricity users, it has strengthened the economy by attracting investment and creating jobs. Large infrastructure projects typically have high GDP and employment impacts, and this is also true of the ongoing and planned investments in Ontario's electricity sector.

Hydroelectric investment

Waterpower has been helping to fuel Ontario's economic growth for more than 100 years and is the backbone of renewable supply.

Ontario hydroelectric producers spend $250 million annually in operating and maintenance costs and in the past decade alone have made additional capital investments of $400 million to bring new waterpower online. Today, Ontario's hydroelectric producers directly employ more than 1,600 people and support an additional 2,000 jobs.

Hydroelectric has an even greater impact in Ontario's north, where it accounts for more than 80 per cent of the electricity generated. Twenty-four of 65 generating stations run by OPG are located in Ontario's north, representing close to 2,000 MW.

Many older hydroelectric facilities date to Ontario's early industrial mining and forestry activities and some of these sites are being rebuilt at higher capacity. Recent substantial investments are playing an important economic role in the north. The Lower Mattagami River Hydroelectric Project, Ontario's largest hydroelectric project in 40 years, will bring a $2.6-billion investment into northeastern Ontario and create up to 800 construction jobs.

In southwestern Ontario, work is underway on the Niagara Tunnel project, the single biggest construction project for the Niagara region since the Beck 2 Generating Station was built 55 years ago. The project means that region will benefit from over 230 construction jobs.

Wind, Solar and Bio-Energy investment

Ontario is creating a new sector for investment and is becoming a global destination of choice for clean energy developers and suppliers. Ontario's Green Energy and Green Economy Act, 2009 has laid the foundation for economic opportunities throughout the province. In the coming years, over 20,000 people will be employed in renewable energy and development activities including manufacturing triggered by North America's most comprehensive FIT program.

Ontario has already attracted more than $16 billion of private sector investment and over 20 companies have announced plans to set up or expand operations in Ontario. This activity will create or support indirect jobs in areas such as finance, consulting and other manufacturing, service, and development industries.

Many communities that were hard-hit during the recent economic downturn are reaping benefits of Ontario's growing clean energy economy. According to the Windsor Essex Economic Development Commission, of the 6,000 new jobs created in Windsor in the past 10 months, five to 10 per cent are tied to renewable energy.

The Green Energy and Green Economy Act, 2009 has already attracted the single-largest investment in renewable energy in provincial history. The Consortium, led by Samsung C&T Corporation, is investing $7 billion to create 2,500 MW of new wind and solar power in Ontario. The investment will lead to more than 16,000 new clean energy jobs to build, install and operate the renewable generation projects and associated manufacturing. The consortium is also working with major partners to secure four manufacturing plants in the province. This will lead to the creation of 1,440 manufacturing and related jobs to build wind and solar technology for use in Ontario and export across North America.

Plans for the first of the four plants have already been announced. Samsung and Siemens have said they intend to build Ontario's first wind turbine blade manufacturing plant, creating up to 900 direct and indirect jobs. The supply-chain of Ontario's new clean energy economy is providing benefits to other sectors of the economy. For example, the Consortium intends to use Ontario steel in its projects, subject to necessary quality standards.

The clean energy sector is also providing new opportunities to people in rural Ontario. Farmers are leasing portions of their land for wind turbines, allowing them to generate income while continuing to farm. For example, in Port Alma, local farmers and landowners are leasing their land to the 44-turbine Kruger Energy wind power project, which produces enough clean electricity to power 30,000 households.

Province-wide, farmers and agri-food businesses received a total of $11.2 million to develop and build generating systems that produce clean energy, reduce electricity costs and contribute to local economies through OMAFRA's Biogas Systems Financial Assistance Program, which ran from September 2008 to March 2010.

> "Building a clean energy economy is not an issue that splits left from right. It's about past and future. People of all political stripes who are entrusted in building a modern economy can – and do – look ahead."
>
> - Rick Smith, founding partner of Blue Green Canada

Modernization of nuclear fleet

The nuclear sector has contributed a great deal to Ontario's economy over the past forty years. According to the Canadian Nuclear Association, the sector supports over 70,000 jobs across Canada and injects some $6 billion into the national economy every year. The Organization of CANDU Industries estimates that its 165 members employ over 30,000 people, many of them here in Ontario. Its members supply goods and services for nuclear reactors in domestic and export markets.

Plans to upgrade and refurbish Ontario's nuclear plants are expected to create and support thousands of jobs and inject billions of dollars into this sector over the next decade. A report by the Canadian Manufactures and Exporters estimates that the refurbishment and operation of the Bruce and Darlington units will create or sustain 25,000 jobs and provide $5 billion in annual economic activity.

The design and construction of two new nuclear units at Darlington will employ up to 3,500 people and support many thousands more indirect jobs. Ongoing operation at the plant will require a further 1,400 tradespeople, nuclear operators, and engineering and technical support staff for the duration of the plant's life.

Transmission upgrades

Thousands of Ontarians are employed in the province's electricity transmission sector and billions of dollars in planned upgrades to and expansion of the system are expected to support and create thousands more jobs in the future.

Fully owned by the Province of Ontario, Hydro One is the province's largest electricity transmission and distribution company. It owns 97 per cent of the transmission facilities in the province and employs approximately 5,400 workers, many of them highly skilled technicians, in communities throughout Ontario.

This Plan includes a commitment to develop five priority transmission projects. Employment on the five priority projects alone will peak at over 5,000 in 2013. This new transmission capacity will enable further generation development, including many new private-sector renewable projects.

The rollout of new transmission projects will also allow communities, including Aboriginal communities, to develop more small-scale renewable generation and, in certain cases, reduce their dependence on polluting forms of electricity generation.

Coal plant conversion

Converting Ontario's existing coal-fired generating stations to new fuels will create new constructions jobs and support clean energy jobs in operations and maintenance.

For example, the Atikokan biomass conversion project will create up to 200 construction jobs and help protect jobs at the plant. It will also support an estimated 20 to 25 jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. The project will provide engineering and construction jobs during the conversion as well as ongoing employment in the forestry and transportation sectors to keep the station supplied with fuel. Natural gas conversion at Thunder Bay will provide additional jobs in pipeline construction and ongoing operations.

Conservation

Conservation programs contribute to local and regional jobs, creating employment and new business opportunities in a number of areas, including technology and product development, manufacturing, distribution, marketing, sales, installation and maintenance. For example, Ontario's $3-billion investment in conservation programs over the next five years is expected to create or sustain about 5,000 jobs annually.

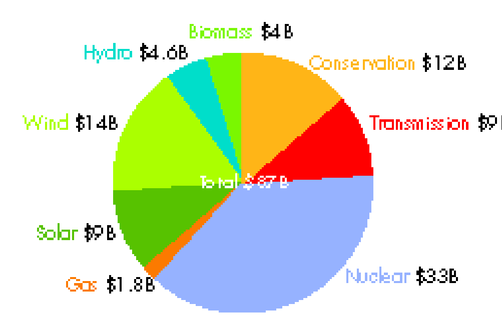
Capital Investments

Ontario's electricity sector is a $15-billion annual industry. Investments in the electricity system are helping to clean Ontario's air, improve the reliability of the energy supply and create jobs and economic opportunities in communities across the province. Since 2003, over $10 billion has been invested to bring new supply on line, and over $7 billion has been spent to strengthen the transmission system. Ontario has also attracted more than $16 billion in private sector investment through the FIT program.

Investments over the past seven years to build new cleaner generation and modernize electricity infrastructure has increased significantly to make up for years of underinvestment. Needed capital investments in Ontario's energy system over the next 20 years will be significant, and are in line with the government's efforts to upgrade and replace aging infrastructure. For example, the ReNew Ontario Infrastructure plan invested $30 billion over four years in capital projects across the province.

This Plan outlines essential capital expenditures to continue building a clean and modern electricity system and to keep the lights on for Ontario families and businesses. The total capital cost in 2010 dollars is estimated to be $87 billion over the life of the Plan. This accounts for new and refurbished energy supply, transmission and distribution infrastructure and conservation investments. This Plan provides more investments over the 2007 Plan due to increased investments in renewables, updated capital cost assumptions, and more certainty on the costs of nuclear refurbishments and new build. These cost estimates will be further refined by the OPA in the coming months and then submitted to the OEB.

FIGURE 13: ESTIMATED CAPITAL COST OF LONG-TERM ENERGY PLAN: 2010 TO 2030 ($ BILLIONS)



The capital investments outlined are through both the private and public sector, and the majority will be paid for by electricity consumers spread over many years, depending on the cost recovery mechanism. (For example, electricity generators typically recover their investment over 20 years, whereas transmission investments may take up to 40 years to be fully repaid). This ensures that the annual costs to consumers, as reflected on electricity bills are spread over a longer period of time.

Conservation expenditures in this Plan include direct program costs and additional capital expenditures driven by higher appliance energy efficiency standards and higher building code efficiency standards.

Overall, renewables account for one third of total expenditures, nuclear just over one third, and natural gas, conservation and transmission the remainder. The breakdown is reflective of the Plan's objective to deliver a balanced and diverse supply mix that is cost effective, clean and helps create clean energy jobs.

7 electricity prices

Over the past 20 years, the price of water, fuel oil and cable TV have outpaced the price of electricity. Over the next 20 years, Ontario can expect stable prices that also reflect the true cost of electricity. The government will need to take a balanced and prudent approach to investment and pricing that ensures that Ontario's children and grandchildren have a clean, reliable system.

Ontarians now pay the true cost of electricity to ensure that essential investments are made in clean energy and modern transmission. About 40 per cent of Ontario's electricity generation is subject to price regulation, contributing significantly to predictable prices for Ontario consumers. Regulated Price Plan (RPP) rates (adjusted every six months) ensure pricing reflects the true cost of generating electricity. This helps to provide stable and predictable electricity prices for consumers.

Accomplishments

In 2003, the electricity system was in significant decline but Ontario families and businesses have invested in the creation of cleaner sources and the restoration of reliability. The cost of energy has increased in order to provide cleaner, more reliable energy for generations to come.

The government has also taken several steps to keep the cost of electricity down for Ontario families and businesses. Actions taken to prudently manage expenditures total over $1 billion, including:

- Freezing the compensation structures of all non-bargained public sector employees for two years – which include the five energy agencies.
- Limiting travel costs and other expenses for public sector workers.
- Requesting that Hydro One and Ontario Power Generation revise down their 2010 rate applications to find savings and efficiencies.
- The IESO has reduced costs by $23 million over the past seven years.
- For 2011, the OPA has reduced its overall operating budget by 4.1 per cent.
- Hydro One will reduce operations costs by $170 million in 2010 and 2011. Information technology upgrades will save $235 million over the next four years.
- OPG is reducing operations costs by more than $600M over the next four years.

Ontario has taken steps to lower the hydro debt left by the previous government. In 1999, the restructuring of Ontario Hydro and the attempt to sell-off Hydro left electricity consumers with a debt of $20.9 billion. Since 2003, Ontario has decreased that stranded debt by $5.7 billion. Payments toward the debt are made through Payments in Lieu of Taxes, dedicated income from government energy enterprises, and by ratepayers through the Debt Retirement Charge.

The government has also launched a number of initiatives to help Ontario families and businesses manage electricity bill increases. Some of these include:

- The Northern Ontario Energy Credit, a new, permanent annual credit to help families and individuals in the North who face high energy costs. The yearly credit of up to $130 for a single person and up to $200 for a family would be available to over half of all northern Ontario households.
- Ontario Energy and Property Tax Credit, starting with the 2010 tax year, to low-income Ontarians who own or rent a home would receive up to $900 in tax relief, with seniors able to claim up to $1,025 in tax relief to help with both their energy costs and property tax. Overall, the proposed Ontario Energy and Property Tax Credit would provide a total of about $1.3 billion annually to 2.8 million Ontarians.

Energy Consumer Protection Act, 2010:

On January 1, 2011, new rules will take effect under the Energy Consumer Protection Act, 2010 that will help protect electricity and natural gas consumers by putting an end to unfair practices by energy retailers. The rules will ensure that consumers receive accurate price disclosure from all energy retailers before they sign contracts, helping to protect Ontario families and seniors.

Ontario is helping low-income Ontarians with their energy costs through a province-wide strategy to help consumers better manage their energy consumption and costs, including:

- Establishing a new emergency energy financial assistance fund.
- Implementing enhanced customer service rules that will assist all customers, particularly low-income Ontarians.

Ontario is also developing a comprehensive electricity conservation program for low-income households in coordination with the natural gas utilities. Through the conservation measures, customers will be better able to manage their energy bills.

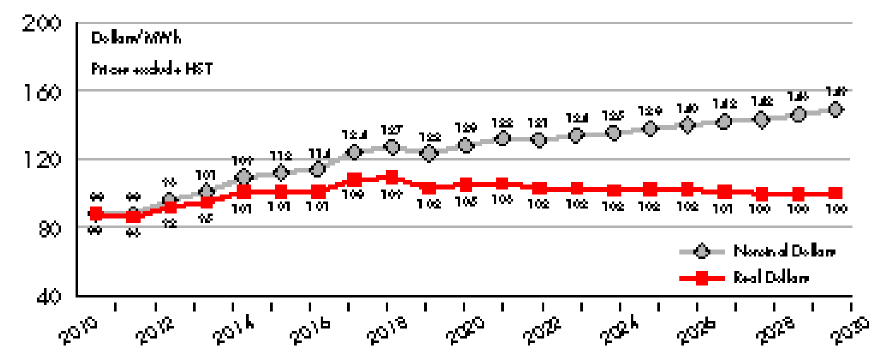
The Plan

Industrial Users

Due to investments to make the electricity system cleaner and more reliable for industry, the government projects that the industrial rate will increase by about 2.7 per cent annually over the next 20 years. The Ontario government has introduced initiatives to enhance the efficiency and competitiveness of large industrial consumers as well as protect jobs and local economies. These include:

- The Industrial Conservation Initiative will help the province's largest industrial and manufacturers to conserve energy, save on costs and increase their competitiveness. By changing the Global Adjustment Mechanism, large industrial users can shift their usage off peak times and save on electricity costs.
- The OPA's Industrial Accelerator Program has been launched to assist transmission-connected industrial electricity users to fast-track capital investment in major energy-efficiency projects.
- The Northern Industrial Energy Rate Program provides electricity price rebates for qualifying northern industrial consumers who commit to an energy efficiency and sustainability plan. On average, the program reduces prices by about 25 per cent for large facilities.

FIGURE 14: INDUSTRIAL PRICE PROJECTIONS (2010-2030)



Helping Ontario Small Businesses and Families

In order to ensure that Ontario has a clean, modern system that increases renewables, ensures reliability and creates jobs, continued investments in the electricity system are essential.

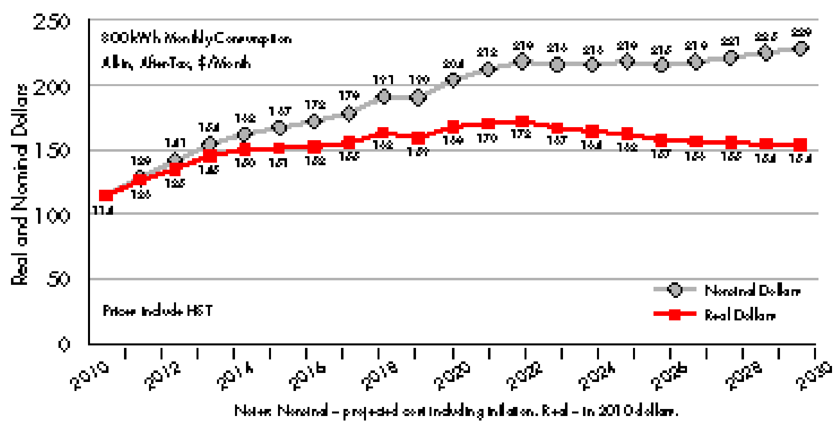
Based on the significant investments in clean, modern energy outlined in this plan, the government projects, based on current forecasts, that electricity prices will increase. Over the next 20 years, prices for Ontario families and small businesses will be relatively predictable. The consumer rate will increase by about 3.5 per cent annually over the length of the long-term plan.

Over the next five years, however, residential electricity prices are expected to rise by about 7.9 per cent annually (or 46 per cent over five years). This increase will help pay for critical improvements to the electricity capacity in nuclear and gas, transmission and distribution (accounting for about 44 per cent of the price increase) and investment in new, clean renewable energy generation (56 per cent of the increase).

Continued investments in transmission, conservation and supply are needed for a system that provides more efficient and reliable electricity to consumers whenever they need it and does not pollute Ontario's air or negatively affect the health of citizens and future generations.

After five years, Ontario will have largely completed the transition to a cleaner more reliable system due to the replacement of coal-fired generation and new renewable generation under the GEA. Once these investments have been made, price increases are expected to level off. The investments that the entire province is making in the future of electricity will help to ensure that Ontario never finds itself in the dire straits it was in just seven years ago.

FIGURE 15: RESIDENTIAL PRICE PROJECTIONS (2010-2030)



However, in the next five years, the government recognizes that the increases will have an impact on Ontario families and businesses.

The government's 2010 Ontario Economic Outlook and Fiscal Review took action to help Ontarians who are feeling the pinch of rising costs and electricity prices. The Ontario government proposed direct relief through a new Ontario Clean Energy Benefit (OCEB).

For eligible consumers, the proposed OCEB would provide a benefit equal to 10 per cent of the total cost of electricity on their bills including tax, effective January 1, 2011. Due to the length of time required to amend bills, the price adjustments would appear on electricity bills no later than May 2011, and would be retroactive to January 1, 2011.

Every little bit of assistance helps during lean times. The proposed OCEB together with the Northern Ontario Energy Credit and the Ontario Energy and Property Tax Credit will all help mitigate electricity costs for families.

Eligible consumers would include residential, farm, small business and other small users. The proposed OCEB would help over four million residential consumers and over 400,000 small businesses, farms and other consumers with the transition to an even more reliable and cleaner system.

Benefits for Eligible Consumers

Customer Monthly Consumption	Current Estimated Monthly Bill	Estimated Bill after Ontario Clean Energy Benefit	Monthly Benefit* (10%)	Yearly Benefit (10 %)
Typical Residential 800kWh	$128	$115.20	$12.80	$153.60
Small Business 10,000kWh	$1,430	$1,287	$143	$1,716
Farm 12,000kWh	$1,710	$1,539	$171	$2,052
*Typical 2011 monthly benefit for a consumer. Benefit amount will vary based on actual price, consumption and location				

Providing the 10 per cent OCEB to Ontarians is a responsible way of helping Ontario families and businesses through the transition to a cleaner electricity system. The OCEB would help residential and small business consumers over the next five years as the grid is modernized. The government has introduced legislation to implement the proposed OCEB.

Working together to reduce electricity use at peak times makes sound economic and environmental sense. Providing consumers with the benefit of up-to-date and accurate electricity consumption readings is also critical to the creation of a culture of conservation. The government is committed to moving forward with implementation of a Time-of-Use pricing structure that balances benefits for both the consumer and the electricity system as a whole.

To help families, Ontario will move the off-peak period for electricity users to 7 p.m. which will provide customers with an additional two hours in the lowest cost period. This change will be in effect for the May 2011 Regulated Price Plan update.

This plan has outlined a new clean, modern and reliable electricity system for the people of Ontario. Instead of a system that was polluting, unreliable and in decline with unstable pricing, Ontarians will have a North American-leading clean energy system that keeps the lights on for generations to come, creates jobs for Ontario families and ensures that the air they breathe is cleaner.

FIGURE 16: SAMPLE BILL

Your Electricity Bill

Service Address: Customer name
Address
City, Ontario

Monthly Statement		
Account Number 000 000 000 000 0000 0	Statement Date	June 30, 2011
Meter Number 0000000		
Electricity Used This Billing Period		
Metered usage in kilowatt-hours = 800 kWh		
Your Electricity Charges		
Electricity		
	On-Peak: 153.60 kWh @ 9.900¢	$15.21
	Mid-Peak: 216.40 kWh @ 8.100¢	$17.69
	Off-Peak: 428.00 kWh @ 5.100¢	$21.83
Delivery		$46.90
Regulatory		$6.04
Debt Retirement Charge		$5.60
Your Total Electricity Charges		$113.27
HST	Federal $5.67 Provincial $9.06	$14.73
	Subtotal	$128.00
Adjustments		
	Ontario Clean Energy Benefit (-10%)	-$12.80 CR
Total Amount		**$115.20**

Sample bill for illustrative purposes only. Other adjustments may apply.

Appendix One:
who does what

Ontario Power Generation: Generates 60 per cent of Ontario's electricity.

Hydro One: Operates 97 per cent of Ontario's transmission network.

Independent Electricity System Operator: Ensures reliability, forecasts short-term demand and supply, monitors supply, and manages the Ontario wholesale market.

Ontario Power Authority: Responsible for system planning (generation, transmission, demand and conservation), contracts for new generation and conservation, and manages contracts for about 40 per cent of Ontario's generation.

Ontario Energy Board: Independent, quasi-judicial regulator of Ontario's energy sector

Licensed Transmission System Operators: Transmit electricity (There are five; Hydro One Networks is the largest).

Local Distribution Companies: More than 80, mostly owned by municipalities, deliver electricity and serve customers in a given area.

Electricity Retailers: Seventy-seven private-sector companies that sell contracts to businesses and consumers

Privately-owned generators: Facilities that produce energy (Bruce Power, wind and solar energy companies)

Appendix Two:

consultations and next steps

Ontario's Long-Term Energy Plan was informed by public and stakeholder consultations as well as advice from the OPA. In addition to issuing this plan, the government is posting a proposed supply mix Directive on the Environmental Registry for a 45 day public comment period. Following this posting, the directive will be finalized and sent to the OPA. The OPA will consult publicly during the development the Integrated Power System Plan (IPSP) and submit the plan to the OEB. The OEB will conduct a review of the IPSP including public hearings. The final IPSP will constitute the detailed long-term energy plan for the next 20 years. It will be updated every three years as required by regulation.

Public and Stakeholder and Online Consultations
September 21st – November 18, 2010
More than 40 stakeholder sessions and over 2,500 online response

↓

Ontario's Long-Term Energy Plan
November 23, 2010

↓

45-Day Posting on Environmental Registry of Proposed Supply Mix Directive
www.ebr.gov.on.ca
November 23, 2010-January 7, 2011

↓

OPA prepares detailed IPSP, holds consultations and submits it to the OEB
Mid-2011

↓

OEB Review
2011-2012

Appendix Three:

installed capacity (MW)

Installed Capacity	2003	2010 (Projected)	2030 (Projected)
Nuclear	10,061	11,446	12,000
Renewables – Hydroelectric	7,880	8,127	9,000
Renewables – Wind, Solar, Bioenergy	155	1,657	10,700
Gas	4,364	9,424	9,200
Coal	7,546	4,484	0
Conservation	0	1,837	7,100
Total	30,006	36,975	48,000

glossary – of energy terms

Baseload Power: Generation sources designed to operate more or less continuously through the day and night and across the seasons of the year. Nuclear and generally large hydro generating stations are examples of generators that operate as baseload generation.

Biomass: Energy resources derived from organic matter, including wood, agricultural waste and other living cell material that can be burned to produce heat energy or electricity.

Demand Response (DR): Programs designed to reduce the amount of electricity drawn by customers from the grid, in response to changes in the price of electricity during the day, incentive payments and/or other mechanisms. In Ontario, both the OPA and the IESO run demand response programs.

Dispatchable Generation: Sources of electricity such as natural gas that can be dispatched at the request of power grid operators; that is, output can be increased or decreased as demand or availability of other supply sources changes.

Distribution: A distribution system carries electricity from the transmission system and delivers it to consumers. Typically, the network would include medium-voltage power lines, substations and pole-mounted transformers, low-voltage distribution wiring and electricity meters

Feed-in Tariff (FIT): A guaranteed rate program that provides stable prices through long-term contracts for energy generated using renewable resources

Greenhouse Gas (GHG): Gases that contribute to the capture of heat in the Earth's atmosphere. Carbon dioxide is the most prominent GHG, in addition to natural sources it is released into the Earth's atmosphere as a result of the burning of fossil fuels such as coal, oil or natural gas. Widely acknowledged as contributing to climate change.

Intermittent Power Generation: Sources of electricity that produce power only during certain times such as wind and solar generators whose output depends on wind speed and solar intensity.

Kilowatt (kW): A standard quantity of power in a residential-size electricity system, equal to 1,000 watts (W). Ten 100-watt light bulbs operated together consume one kW of power.

Kilowatt-hour (kWh): A standard unit of electrical energy in a residential-size system. One kWh (1,000 watt-hours) is the amount of electrical energy produced or consumed by a one-kilowatt unit during one hour. Ten 100-watt light bulbs, operated together for one hour, consume one kWh of energy.

Load or Demand Management: Measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period.

Local Distribution Company (LDC): An entity that owns a distribution system for the local delivery of energy (gas or electricity) to consumers.

Megawatt (MW): A unit of power equal to 1,000 kilowatts (kW) or one million watts (W).

Megawatt-hour (MWh): A measure of the energy produced by a generating station over time: a one MW generator, operating for 24 hours, generates 24 MWh of energy (as does a 24 MW generator, operating for one hour).

MicroFIT: Ontario residents are able to develop a very small or "micro" renewable electricity generation project (10 kilowatts or less in size) on their properties. Under the microFIT Program, they are paid a guaranteed price for all the electricity they produce for at least 20 years.

Peaking Capacity: Generating capacity typically used only to meet the peak demand (highest demand) for electricity during the day; typically provided by hydro, coal or natural gas generators.

Peak Demand: Peak demand, peak load or on-peak are terms describing a period in which electricity is expected to be provided for a sustained period at a significantly higher than average supply level.

Photovoltaic: A technology for converting solar energy into electrical energy (typically by way of photovoltaic cells or panels comprising a number of cells).

Regulated Price Plan (RPP): Rates (adjusted every six months) to ensure electricity pricing reflect the true cost of generating electricity. They provide stable and predictable electricity prices for consumers.

Smart Grid: A Smart Grid delivers electricity from suppliers to consumers using digital technology with two-way communications to control appliances at consumers' homes to save energy, reduce costs and increase reliability and transparency.

Supply Mix: The different types of fuel that are used to produce electricity in a particular jurisdiction. Normally the mix is expressed in terms of the proportion of each type within the overall amount of energy produced.

Terawatt-hour (TWh): A unit of power equal to a billion kilowatt-hours. Ontario's annual electricity consumption is around 140 TWh.

Transmission: The movement or transfer of electricity over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other, separate electric transmission systems. Transmission of electricity is done at high voltages (50kV or higher in Ontario); the energy is transformed to lower voltages for distribution over local distribution systems.

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Ontario Energy Board

EB-2010-0059

Board Policy:

Framework for Transmission Project Development Plans

August 26, 2010

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1 Introduction

1.1 Purpose

This document sets out the policy of the Ontario Energy Board for a framework for new transmission investment in Ontario, in particular with regard to transmission project development planning. The policy describes how project development planning will work in conjunction with existing Board processes for licensed transmitters.

This policy is the end result of a consultation on facilitation of the timely and cost effective development of major transmission facilities that may be required to connect renewable generation in Ontario. The goal is the implementation of a process that provides, among other things, greater regulatory predictability in relation to cost recovery for development work. The Board believes that this policy will:

- allow transmitters to move ahead on development work in a timely manner;
- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

This introduction includes a background of the issue and history of the consultation. Section 2 of this paper describes principles and goals that the Board used to evaluate staff's proposal and the stakeholder comments in order to devise the final policy. Section 3 outlines the licensing process for transmitters intending to participate in the Board designation process. Section 4 outlines the process to be followed in designating a transmitter to undertake development work on enabler facilities and network expansions including: the method for identification of eligible projects; the trigger for the process; the decision criteria for designation and the filing requirements intended to solicit the information; and the implications of approval of a plan.

The Filing Requirements for Transmission Project Development Planning are published under separate cover on the Board's website[1].

[1] http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms

1.2 Background

As a consequence of the passage of the *Green Energy and Green Economy Act, 2009* ("GEA"), there has been enormous interest in connecting renewable generation to both distribution and transmission systems. However, the ability of existing or approved transmission facilities in Ontario to accommodate more generation is limited. Based in part on the number of applications for contracts under the Feed-in Tariff ("FIT") program, the Board understands that significant investment in transmission infrastructure will be required to accommodate current FIT applicants as well as any future renewable generation projects.

Advance knowledge of the location and timing of new infrastructure should allow developers to site prospective generation projects along anticipated transmission corridors in order to reduce overall connection costs. Developers should be able to anticipate development of the system and plan its construction schedule to coincide with economic connection.

Board staff met with licensed transmitters to discuss how the transmission planning process might work. Transmitters have indicated the need for a clear process, including an articulation of the overall transmission planning, approval and rate recovery framework.

On April 19, 2010, the Board released a staff Discussion Paper[2] for comment by stakeholders. Board staff's proposals built on earlier work by the Board with respect to transmission connection cost responsibility and in particular on the process that the Board has developed for "enabler" transmission facilities. Staff's proposals focused specifically on development work for projects identified by the Ontario Power Authority ("OPA") as it assesses transmission investments associated with the connection of generation under the FIT program.

The Board received 27 comments[3] on staff's proposals from entities representing a variety of stakeholder groups: current Ontario transmitters and those who would be new to Ontario; generator groups; ratepayer groups; special interest groups; one distributor; the IESO and the OPA.

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[2] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2010-0059/Staff_paper_Tx_Project_Dev_20100419.pdf

[3] Complete text of stakeholder comments is available at the Board's website at: http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Transmission+Project+Development+Planning/Transmission+Project+Development+Planning

2 Board Principles

The Board's goal in developing a policy for transmission project development planning is to facilitate the timely development of the transmission system to accommodate renewable generation.

In developing this policy, the Board is guided by its objectives in relation to the electricity sector under the *Ontario Energy Board Act, 1998* (the "OEB Act"). Of particular relevance in this instance are the objectives of protecting the interests of consumers with respect to price, quality and reliability of electricity supply and facilitating economic efficiency in the development of the transmission system including the maintenance of a financially viable electricity industry. Also important in this instance is the new objective of the Board to promote the use of energy from renewable generation sources.

The Board has previously identified the principles it uses in fulfilling its objectives in transmission policy[4]: economic efficiency; regulatory predictability; and administrative efficiency. The Board has reviewed the staff proposal and the stakeholder comments with the goal of fulfilling its objectives and promoting these principles.

Within the context of transmission investment policy, economic efficiency can be understood to mean achieving the expansion of the transmission system in a cost effective and timely manner to accommodate the connection of renewable energy sources. The Board believes that economic efficiency will be best pursued by introducing competition in transmission service to the extent possible within the current regulatory and market system.

Regulatory predictability allows proponents to understand how and on what basis regulatory decisions are likely to be made. The Board achieves this through policy statements and guidance to the industry and through transparent processes leading to consistency in the determinations it makes and the orders that it issues. Transmission planning is an ongoing procedure. The Board intends to put in place a transmission investment policy and project development planning process that is robust enough to provide consistency of process through many cycles of planning.

Administrative efficiency relates to the level of effort required from the perspective of proponents and other interested parties for effective participation in processes. In

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[4] Most recently in the Staff Discussion Paper: Generation Connections for Transmission Connection Cost Responsibility Review (EB-2008-0003) available at: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0003/Staff_Discussion_Paper_20080708.pdf

devising this process, the Board has sought to avoid duplication and unnecessary effort for transmitters, Board staff and other stakeholders.

Taken together, regulatory predictability and administrative efficiency should facilitate investment, planning and decision-making by transmission proponents and should help them to manage business risks.

These aims are consistent with broader movements in energy regulation around the world. In particular, the United Kingdom and the United States are both currently consulting on policy changes along similar lines.

Ofgem in the U.K. is proposing[5] to evolve its regulatory framework to the RIIO model: Revenue set to deliver strong Incentives, Innovation and Outputs. Ofgem acknowledges that changes are needed to "meet the demands of moving to a low carbon economy…whilst maintaining safe, secure and reliable energy supplies"[6]. Ofgem's new proposed framework to deliver long-term value for money for network services includes involving third parties in design, build, operation and ownership of large, separable enhancement projects. Third party participation is to be considered where long-term benefits, especially for new technologies, new delivery solutions and new financing arrangements, are expected to exceed long-term costs. Ofgem would be responsible for any competitive process.

FERC in the U.S. released a Notice of Proposed Rulemaking on June 17, 2010.

> "With respect to transmission planning, the proposed rule would (1) provide that local regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighbouring transmission planning regions with respect to interregional facilities ; and (3) remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[7]

[5] "Regulating energy networks for the future: RPI-X@20 Recommendations" available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=RPI-X@Recommendations.pdf&refer=Networks/rpix20/ConsultDocs
[6] Ibid: Executive Summary.
[7] The Notice of Proposed Rulemaking: Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities (Docket No. RM10-23-000) by the Federal Energy Regulatory Commission, pg 1. available at: http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf .

The Board sees this proposal to improve interstate planning and align it with state and federal policy drivers (particularly clean energy requirements) and to level the playing field between incumbent and nonincumbent transmitters to be analogous to its own goals for transmission in Ontario.

3 Licensing

Section 57 of the OEB Act prohibits persons from undertaking various activities in the electricity industry in Ontario, including owning or operating a transmission system, unless they are licensed to do so by the Board.

In the Discussion Paper, Board staff proposed that new entrant transmitters who want to participate in the designation process should be licensed by the Board as transmitters. Board staff stated that the licensing process could be used to ensure that a new entrant transmitter meets certain minimum requirements in relation to both financial and technical capability, and that this would provide comfort that the new entrant transmitter is both qualified and committed to doing business in Ontario should it be designated.

Many stakeholders, including the existing transmitters and most of the new entrant transmitters, agreed with Board staff's proposal. Others suggested that the licensing process was a barrier to entry by being onerous, time-consuming or expensive and suggested a separate, rigorous pre-qualification stage before any designation process. Some stakeholders noted that certain provisions of the transmitter licence, such as the Affiliates Relationship Code or the legislative provisions pertaining to the planning requirement or smart grid development, were too burdensome on a prospective basis. The IESO suggested that new entrants could have a more general form of licence.

The Board considers it reasonable to require that new entrant transmitters be licensed in order to participate in the designation process. The licensing process will allow the Board to evaluate the financial viability and technical capabilities of the new entrant transmitters. The Board would need to evaluate these items regardless of whether it was done in a licensing process or another type of pre-qualification process. The Board's licensing process is neither unduly onerous nor time consuming.

Licence applications to the Board are usually handled through a written process and may involve interrogatories from Board staff to clarify information. Other parties may intervene in the application. Licences are generally issued within 90 days of a complete application being received by the Board. An application form and sample licence is available on the Board's website[8].

The Board notes that some of the requirements in the transmission licence may not apply unless a transmitter has assets in Ontario. If a new entrant transmitter feels that there are particular requirements that should not apply to them, it may raise those issues as part of its application process.

Existing transmitters that are already licensed by the Board can participate in the designation process under their existing licence. No additional requirements or actions are needed.

Board Policy on Transmission Licensing

Transmitters will need a transmission licence from the Board to participate in the designation process.

Existing transmitters that are already licensed by the Board will participate in the designation process under their existing licence.

New entrant transmitters will need to apply for, and obtain, a transmission licence before being able to participate in the designation process.

4 Hearing to Designate a Transmitter

4.1 Identification of Facilities Requiring Designation

The staff Discussion Paper noted that one of the legislated objectives of the OPA is to conduct independent planning for electricity generation, demand management, conservation and transmission and to develop integrated power system plans[9] (the "IPSP"). By regulation, an IPSP is to be filed with the Board every three years. The Board's role is to review and either approve the IPSP or to refer it back to the OPA for further consideration.

In addition, the OPA intends to assess transmission investments that in its view are required and economically justified to connect the FIT applications whose projects

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[8] http://www.oeb.gov.on.ca/OEB/Industry/Licences/Apply+for+a+Licence/Apply+for+a+Licence+-+Electricity+Transmission

[9] *The Electricity Act, 1998* section 25.2(1)(b)

cannot be accommodated by existing transmission capacity i.e. those in the FIT production line and FIT reserve. The OPA's assessment process is known as the Economic Connection Test ("ECT") and is expected to be completed every six months.

Further, the Board is aware that on May 7, 2010[10], the Minister of Energy and Infrastructure (as it was then known) asked the OPA to provide an updated transmission plan considering the sequencing necessary to meet the needs of the FIT program and the Korean Consortium.

The staff Discussion Paper proposed to use the results of the ECT as the inputs for a Board initiated process whereby interested transmitters would be designated to develop the enabler facilities and network expansions identified in the ECT. Staff proposed that the results of the ECT be accepted without prejudice and that a final determination of need for each project be deferred until the leave to construct hearing.

While most stakeholders accepted the ECT as a starting point, one ratepayer group noted that development funds would be spent by transmitters and recovered from ratepayers for projects that were subsequently found to be unnecessary or uneconomical. It argued that no approval should be given for any costs to be recovered from ratepayers until the economic feasibility of the projects could be fully tested, including the value of the energy being enabled. Some stakeholders suggested that the ECT must be fully tested in the designation process and others insisted that the only valid starting point is an IPSP.

The need for transmission projects may emerge in a number of different ways. New transmission is meant to achieve several purposes: increasing supply to new and existing load customers; facilitating interconnections; ensuring security, reliability and robustness of the system; and facilitating connection of FIT, non-FIT renewable, and non-renewable generation. The Board recognizes that, to the extent that the OPA's various planning tools and reports address differing combinations of these purposes, there is a hierarchy to the reports. An IPSP that considers all uses for transmission and all inputs from economic planning is preferable as a base for provincial transmission planning. However, an approved IPSP is not expected before the later half of 2011. The Board believes that waiting for an approved IPSP would be inconsistent with its statutory objective to promote timely expansion of the transmission system to facilitate connection of renewable generation. And while the hearing to approve an IPSP will be a thorough and comprehensive process, the evidence is not

[10] The letter from the Minister can be found at: http://www.powerauthority.on.ca/Storage/118/16599_MEI_Directive_to_update_H1_09_instruction_May_7_10.pdf

expected to be detailed enough over the three year planning cycle to allow final determination of need for any particular transmission project.

The Board agrees that the starting point for transmission project development planning should be an informed, effective plan from the province's transmission planner, the OPA. The Board believes that the ECT fits that description and is, therefore also a valid starting point for the process. Since the staff Discussion Paper was issued, the OPA has made progress in developing the process and substance of the ECT such as the announcement that the objective is 5% congestion of the system and an economic threshold of $500 of anticipated project cost per kW of new generation enabled[11].

The designation process is intended to be a preliminary stage in an increasingly disciplined process. The ECT is expected to provide a preliminary analysis of need sufficient for approving funding of preliminary development budgets. As budgetary and technical information becomes available, the Board will test need and prudence with increasing vigor. The Board considers that ensuring recovery of development costs before a final determination of need will advance the development of projects compared to the current process. In this way, it will promote the timely expansion of the transmission system and the use of energy from renewable sources.

While the ECT is focused on two of the many purposes of transmission, designation is simply the beginning of the development process and the Board expects the selected transmitter to consult with the OPA and IESO regarding the purposes of the project in order to bring a full justification of need to a leave to construct hearing. Therefore testing of the more detailed information developed after designation will take place in the next stage of the process, likely a leave to construct hearing.

One stakeholder objected to the enabler screening criteria described in clause 3A of the Transmission System Code being replaced by the ECT. The Board sees no conflict as the OPA has used the requirement of the Transmission System Code (the "TSC") in defining and scoping enabler facilities within the ECT. The Board notes that the staff Discussion Paper clarified that the proposal dealt specifically with enablers identified by the OPA through the ECT but the process could also apply to enabler facilities identified in the other two ways set out in the TSC. i.e. a renewable resource cluster is identified in an IPSP or the enabler facility and associated renewable resource cluster is the subject of a direction by the Minister to the OPA. The Board agrees.

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[11] A presentation by the OPA on the ECT can be found here: http://fit.powerauthority.on.ca/Page.asp?PageID=122&ContentID=10630&SiteNodeID=1137&BL_ExpandID=272

A few stakeholders commented that the Board's proposed approach presumes the approval of the IPSP in relation to transmission and, as such, the approach pre-empts the due process of an IPSP proceeding and aboriginal consultation and accommodation requirements. The same argument was made in the consultation on transmission connection cost responsibility, in which the Board stated that:

> "The Board is not, through this process, determining whether [transmission] facilities will be identified in an IPSP, nor what those facilities might be nor when or on what conditions the Board might approval the IPSP once it has been re-filed with the Board. Any aboriginal consultation and accommodation requirements associated with the IPSP and/or with the siting and construction of any [transmission] facilities remain unaffected by the Board's proposals…"[12]

The Board maintains the view set out above and reiterates that the OPA remains responsible for independent transmission planning in Ontario. The Board's mandate is restricted to those review and approval authorities given in the legislation. Further, the Board notes that legislation grants to the Minister of Energy the authority to direct the OPA to implement procedures for consulting aboriginal peoples (among others) in relation to the planning and development of transmission systems and to establish measures to facilitate the participation of aboriginal peoples in the development of renewable generation facilities and transmission systems.

Board policy on project identification

When the Board receives the results of an ECT from the OPA, it will begin a process on its own motion to designate a transmitter to undertake development work on any incremental enabler facilities or network expansions identified. If a recently approved IPSP is available, its transmission recommendations may be used for the designation process.

4.2 Notice and Invitation to File a Plan

Under section 70 (2.1) of the OEB Act, every transmitter's license is deemed to have as a condition that the licensee is required to prepare plans, in the manner and at the times required by the Board regarding expansion or reinforcement of the system to accommodate the connection of renewable generation. Plans may also be required for the development of the smart grid in relation to the licensee's system.

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[12] Notice of Revised Proposal to Amend a Code dated April 15, 2009: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0003/Notice_REVISED_Proposed_Amendments_TCCRR_20090415b.pdf

In order to promote the connection of renewable generation, the Board will use the planning provision to ensure that needed transmission projects are being actively developed. As existing transmitters undertake capital planning as part of their normal business operations and the Board already has the authority to require transmitters to build projects for reliability purposes, the Board does not, at this time, anticipate requiring general “Green Energy Plans” under this section. There may be a future requirement for smart grid plans, either specifically or as part of cost of service rate filings.

The staff Discussion Paper anticipated that the ECT would identify four types of projects.

1. Capacity enhancements;
2. Network reinforcement;
3. Enabler facilities; and
4. Network expansions.

Staff proposed that the Board give Notice of a Hearing (a “Notice”) on its own motion to designate a transmitter to develop projects of types 3 and 4. Staff proposed that the incumbent transmitter be directed and other licensed transmitters be invited to file plans in three months from the date of the Notice.

Several of the transmission companies pointed out that clarification was required with respect to the definition of network expansions, specifically if new lines in existing or widened transmission corridors were expansions or reinforcements. One transmitter noted that new entrants might harm the existing relationships between incumbent transmitters and landowners along corridors.

The Board notes that transmission corridors typically have multiple uses and therefore multiple companies have landowner agreements. The rights of way for most transmission corridors belong to the provincial government through the Ontario Realty Corporation[13] and should not be considered a part of existing infrastructure or a transmission asset. The Board believes that introducing competition in transmission development will improve economic efficiency and lead to better outcomes for the consumer. It is, therefore, in the public interest to keep the definition of network

[13] Pursuant to Part IX.1 of the *Electricity Act, 1998*, ownership of corridor land was transferred from Hydro One Inc. (and its subsidiaries) to Her Majesty in right of Ontario in 2002.

expansion as broad as possible and to classify new lines on existing or widened corridors as expansions subject to designation.

Several stakeholders requested clarification as to whether all transmitters who file a plan and/or the designated transmitter will be permitted to recover the costs of preparing plans. In addition some stakeholders commented that the ability of the incumbent transmitter to recover the cost of preparing the plan as directed by the Board could provide an unfair advantage for the incumbent.

The Board agrees and, similar to the situation regarding corridors above, the Board sees benefit in keeping the process as open and unbiased[14] as possible. Also the Board does not consider it appropriate for consumers to fund a transmitter's efforts to expand its commercial business through preparation of a plan seeking designation.

Therefore, when the Board receives an ECT report from the OPA and issues Notice of a designation hearing, the Board will invite all licensed transmitters to submit plans in the form mandated by the filing requirements. The incumbent transmitter is not obligated to file a plan at this point. Only the transmitter that is successful in being designated will be able recover the costs of preparing a plan. This is comparable to the more usual business model in which proponents prepare proposals or bids at their own cost and own risk. In this way, the Board seeks to ensure that all transmitters will be on equal footing when submitting plans and ratepayers will not pay for multiple plan preparation.

If there are no plans filed for a particular project, the Board will direct the incumbent to file a plan. The incumbent will then be able to recover the costs of plan preparation.

The staff Discussion Paper asked for comment on the period of time between a Notice and the filing deadline for plans. The paper gave examples of the Ofgem and Texas PUC contracting processes that allowed three months for an apparently similar stage of information. Some stakeholders questioned the comparison of plan preparation with either the Qualification to Tender for Ofgem or the statement of intent for Texas PUC. While many stakeholders felt that three months was an appropriate period for some projects depending on the level of detail expected in plans, some stated that larger or more complex projects would require more time to prepare adequately.

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[14] The Notice of Proposed Rulemaking: Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities (Docket No. RM10-23-000) by the Federal Energy Regulatory Commission states that neither incumbent nor nonincumbent transmission facility developers should…receive different treatment in a regional transmission planning process. http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf .

The Board agrees. Therefore, the Notice will specify a deadline for filing of plans: the default period will be three months but will be as long as six months for some projects at the Board's discretion.

Some stakeholders also felt that the knowledge advantage of the incumbent transmitter with respect to the technical configuration of connections points created an unfair advantage and suggested that the Board create rules regarding the timing and information that must be provided to proponents. The TSC primarily references requirements for the incumbent transmitter to provide connection information to customers (loads); the IESO; and neighbouring transmitters and primarily for the purposes of connection impact assessments, system operations or third party design. The Board agrees that the incumbent could frustrate other transmitters by delay in providing technical information on the relevant potential connection points and thus gain a competitive advantage. The Board therefore intends to begin a process to amend the TSC in order to provide specific instruction to incumbent transmitters on the level and timing of information to be provided. Comment on these issues will be received in the Notice and Comment process for those TSC amendments.

Board policy on notice and invitation to file

Definitions

Enabler facilities (subject to designation and plan approval process): As defined in Board's Transmission System Code, these are transmitter-owned connection facilities designed to connect clusters of renewable resources to the existing network; and

Network expansions (subject to designation and plan approval process): Transmission work undertaken to expand the transmission network, in particular the major bulk transmission system, through construction of new network facilities. For clarity, this includes greenfield projects and new lines in existing or expanded transmission corridors.

When the Board receives an ECT report from the OPA, it will issue a Notice of a hearing to designate development of any enabler facilities and network expansions identified in the ECT report. In the Notice, the Board will invite all licensed transmitters to submit plans in the form mandated by the filing requirements. Only the transmitter that is successful in being designated will be able recover its costs of preparing a plan.

If no plans are submitted for a particular project, the Board will require the incumbent transmitter to file a plan.

The Notice will specify a deadline for filing of plans. The period will be at least three months but may be as long as six months for larger or more complex projects.

4.3 Decision Criteria

In the Discussion Paper, Board staff had suggested project decision criteria that built on the general threshold of licensing to look at specific project related issues: organization and experience; technical capability; schedule; costs; financing; and landowner and other consultations. Staff asked for comments on the proposed criteria and prospective weightings for each one.

Many stakeholders commented that the criteria were appropriate. A few stakeholders suggested that organization, technical capability and financial capacity should be threshold (pass/fail) criteria and that cost, schedule and consultation should be evaluated. Most stakeholders suggested that the Board should balance the criteria at their discretion on a case by case basis. Others suggested that cost or consultation should be the most important.

The Board agrees that it would be irresponsible to risk the ratepayers' money with an entity (either a single transmitter or an identified consortium) that does not have the ability to see a project through to completion and that the criteria of organization, technical capability and financial capacity are crucial. However, the Board's process is not the same as a procurement process. The Board's hearing process does not lend itself to threshold tests nor is the Board convinced that it will be possible to examine those three criteria without substantial reference to the evidence regarding cost, scheduling, and consultation plans for the project.

The decision criteria and filing requirements are in regard to a specific project and are all critical to the successful construction of the project. However, the Board acknowledges that depending on the size, complexity and location of a particular line, some criteria will be relatively more important than the others. Therefore, the criteria will be weighted by the Board, based on the evidence in the proceeding, taking into account the individual circumstances of the project.

In fact, a few stakeholders suggested that socio-economic benefits (local employment or First Nation ownership) or environmental sustainability interests should be included as specific criteria. The IESO suggested that by focusing only on the rate-regulated model of transmission, the Board was excluding other models such as merchant generation.

The Board notes that, while the environmental assessment is a separate process, the criteria listed were meant to emphasize the Board's priorities, not to be exclusive. The filing requirements include an allowance for "any other information that [the applicant] considers relevant to its plan." It is here that a transmitter could include information on local employment, community partnerships, innovative models, etc. Where projects were otherwise equivalent or close in the other factors, this information could prove decisive. In particular, financial models that do not put the risk on ratepayers or increase rates would be of interest to the Board, although it is hard to see how these might arise in the context of FIT-associated transmission.

Board policy regarding decision criteria

Organization; technical capability; financial capacity; schedule; costs; landowner and other consultations; and other factors will be weighted by the Board, based on the evidence in the proceeding, taking into account the individual circumstances of the project.

4.4 Filing Requirements

Stakeholders were generally supportive of the filing requirements proposed by Board staff. Some suggested that they should be high level as befits the level of information available before development of a project begins. Others suggested that they should be as specific as possible to avoid ambiguity and wasted effort by the transmitters.

Where specific suggestions were made regarding the Filing Requirements, the Board has generally incorporated them. The general question regarding major risks and mitigation strategies has been bolstered by specific inquiries regarding permitting and consultations. The Board acknowledges that major projects may be in a very preliminary stage of plan development and has allowed transmitters to identify alternatives with a method for subsequent selection.

In addition, the Board has removed a question that implied that transmitters must undertake consultation as part of plan preparation.

The Filing Requirements published as G-2010-0059[15] are adopted by the Board as the manner required for transmitters filing plans seeking designation for a project identified in a Notice by the Board. The Board considers them appropriate until it has gained more experience with the practice of transmission plans and the amount of information available.

The Board reminds prospective participants in the process that filing requirements are the starting point for the public record and additional information may be required as the hearing progresses.

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[15] Available on the Board's website at: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms

In fact, the Board emphasizes that the designation hearing is an open, public process. Information that the transmitter considers to be commercially sensitive should be identified as such and confidentiality requested according to the Board's "Practice Direction on Confidential Filings"[16]. The Board will then make a determination of the degree of confidentiality to be provided to balance the competing interests of private intellectual property and commercially sensitive information with the public interest in a transparent process. Potential solutions include redacted evidence, *in camera* proceedings, and undertakings by counsel to maintain confidentiality.

4.5 Implications of Plan Approval

The staff Discussion Paper recommended that the budgeted development costs of the designated transmitter be determined to be recoverable in a future rate proceeding. Most stakeholders supported the recovery of budgeted development costs for the designated transmitter provided that normal Board practices apply, including material overages being at risk until subsequently approved. Some stakeholders requested greater clarity as to what costs are considered "development costs".

The Board accepts the premise that designation should carry with it the assurance of recovery of the budgeted amount for project development. When subsequent analysis by the OPA suggests that a project has ceased to be needed or economically viable (e.g. FIT applications have dropped out of the reserve such that the project falls below the economic threshold), the transmitter is entitled to amounts expended and reasonable wind-up costs. Threshold materiality for amounts beyond the approved budget could be established in the order and would likely be in relation to the total budget.

From the Board's perspective, the objective of the development phase is to bring a project to the point where there is sufficient information for the transmitter to submit a leave to construct application. Therefore development costs begin when a transmitter is designated and end when a leave to construct application is submitted. The Board expects, therefore, the development budget to include route planning, engineering, site/environmental reports and some (but not all) consultation.

Where a leave to construct is not required for a designated project[17], the end point is when costs begin to be capitalized against the project.

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[16] Available on the Board's website at: http://www.oeb.gov.on.ca/documents/practice_direction-confidentiality_161106.pdf

[17] Ontario Regulation 161/99 clause 6.2 lists situations where Subsection 92(1) of the OEB Act does not apply. http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_990161_e.htm

In recent rate cases, Hydro One Networks Inc. (EB-2009-0416)) and Great Lakes Power Transmission LP ("GLPT") (EB-2009-0409) received approval of deferral accounts for IPSP and other long term projects' preliminary planning costs and GEA related planning expenses, respectively.

In its Decision and Order in each case, the Board stated that each company "is cautioned that this approval does not provide any assurance, either explicit or implicit, that the amounts recorded in the account will be recovered from ratepayers. No finding of prudence is being made at this time….A full test of prudence will be undertaken when [the company] applies for disposition of the account[s]."

The staff Discussion Paper also suggested that the Board's order for designation might have conditions such as milestones or reporting requirements. The purpose of establishing the designation process is to promote timely expansion of the transmission system for connection of renewable generation by ensuring that identified projects are being developed. If a designated transmitter is failing to make progress on developing the project and is not making progress toward bringing a leave to construct application, the Board needs the ability to rescind the designation both to limit the exposure of the ratepayer and to allow a different transmitter to be designated. Therefore, the Board order of designation will have conditions such as performance milestones (in particular, a deadline for application for leave to construct) and reporting requirements on progress and spending that, if not met, will result in the designation being rescinded and will put further expenditures at risk. Designated transmitters who are having trouble meeting the milestones for any reason, but intend to carry through with the work may apply to the Board for an amended schedule.

In the Discussion Paper, Board staff asked for comments on the potential of two transmitters being designated to develop the same project. Some stakeholders did not feel that it would ever be appropriate to allow ratepayers to fund development of two projects when only one will need to be constructed. Others felt that there may be extra-ordinary conditions where it might be justified.

The Board agrees with stakeholders that designation of two transmitters should be an exceptional circumstance where the Board is persuaded that:

- Two proposed projects to meet the same need cannot be directly compared since they are so significantly different
    - o as to route, or
    - o as to technology to be employed; or
- The amount saved on construction cost could be more than the cost added by the funding of a second development project.

The staff Discussion Paper also noted limitations on the Board's ability to guarantee a transmitter the ability to construct and operate a particular project. Many stakeholders expressed concern over this issue and looked for further assurance that the successful transmitter would be able to construct and operate the facilities.

The designation process of the Board is not a procurement process where the end result is a contract. Neither the Board, the OPA, nor the IESO has statutory authority to procure transmission. Under normal circumstances, the Board would expect that the transmitter who is designated would construct and operate the facilities. There are two instances where this might not be the case.

One circumstance is where the designated transmitter makes arrangements to assign the project to another transmitter. A project designation, particularly once a leave to construct has been issued, could have commercial value. The Board would not preclude this option but would have to grant permission to assign the project and be assured that there was no adverse ratepayer impact of the transaction and that the assignee was also licensed and equally qualified to undertake the work.

The other possibility is that another transmitter brings a leave to construct application for a different project that meets the same need in a better way. The Board cannot prevent any person from submitting an application for any matter under its jurisdiction. However, the undesignated transmitter would have undertaken development at its own cost which would not be recoverable from ratepayers. The transmitter would also need to adequately explain why it had not taken part in the designation process. Once a leave to construct is granted, the Board would not grant another transmitter approval for duplicative facilities.

Board Policy regarding implications of plan approval

The transmitter designated for a particular project will be assured of recovery of the budgeted amount for project development. Material overages will be at risk until a future prudence review. Threshold materiality for amounts beyond the approved budget could be established in the designation order and would likely be in relation to the total budget. When subsequent analysis by the OPA suggests that the project has ceased to be needed or is no longer economically viable, the transmitter will be entitled to appropriate wind-up costs.

The Board order of designation will have conditions such as performance milestones based on the project schedules (in particular, a deadline for application for leave to construct) and reporting requirements on progress and spending that, if not met, will result in the designation being rescinded and will put further expenditures at risk.

Under exceptional circumstances, the Board may designate two transmitters to proceed to the development phase where the Board is persuaded that:

- Two proposed projects to meet the same need cannot be directly compared since they are so significantly different
  - as to route, or
  - as to technology to be employed; or
- The amount saved on construction cost could be more than the cost added by the funding of a second development project.

Final project selection will take place after application for leave to construct.

5 Hearing for Leave to Construct

Section 92 of the OEB Act prohibits any person from constructing, expanding or reinforcing a transmission line without an order of the Board granting leave. Clause 92(2) and Ontario Regulation 161/99 provide exceptions to this requirement including relocation or reconstruction of a line without new land requirements; lines that are less than 2 km in length; and interconnections between two adjacent transmission systems. Section 96 specifies the issues that the Board may consider in finding that proposed work is in the public interest. The GEA amended the OEB Act to include as one of those issues the use of energy from renewable resources, where applicable and in a manner consistent with the policies of the Government of Ontario.

A designated transmitter is ensured recovery of development costs with the objective of submitting a leave to construct application. The requirements of a leave to construct application are described in the Board's existing Filing Requirements for Transmission and Distribution Applications[18].

The staff Discussion Paper included an illustrative flow chart of the Board's processes. One stakeholder stated that it did not show the Environmental Assessment approval process. Stakeholders should note that it does not include any stages of a project that are not under the Board's jurisdiction, such as the System Impact Assessment from the IESO that must be filed as part of the leave to construct application or the Connection Impact Assessment that must be completed by any transmitter to which the new project will connect.

The flow chart has been updated to show the Board's policy.

[18] http://www.oeb.gov.on.ca/documents/minfilingrequirements_report_141106.pdf

The following is an illustrative flow chart of the OEB designation and transmission project plan approval process, and where it fits with leave to construct and rate proceedings. For convenience, the chart shows the recovery of cost flowing from a cost of service rate hearing. However, a rate rider could be approved at other points in the process.

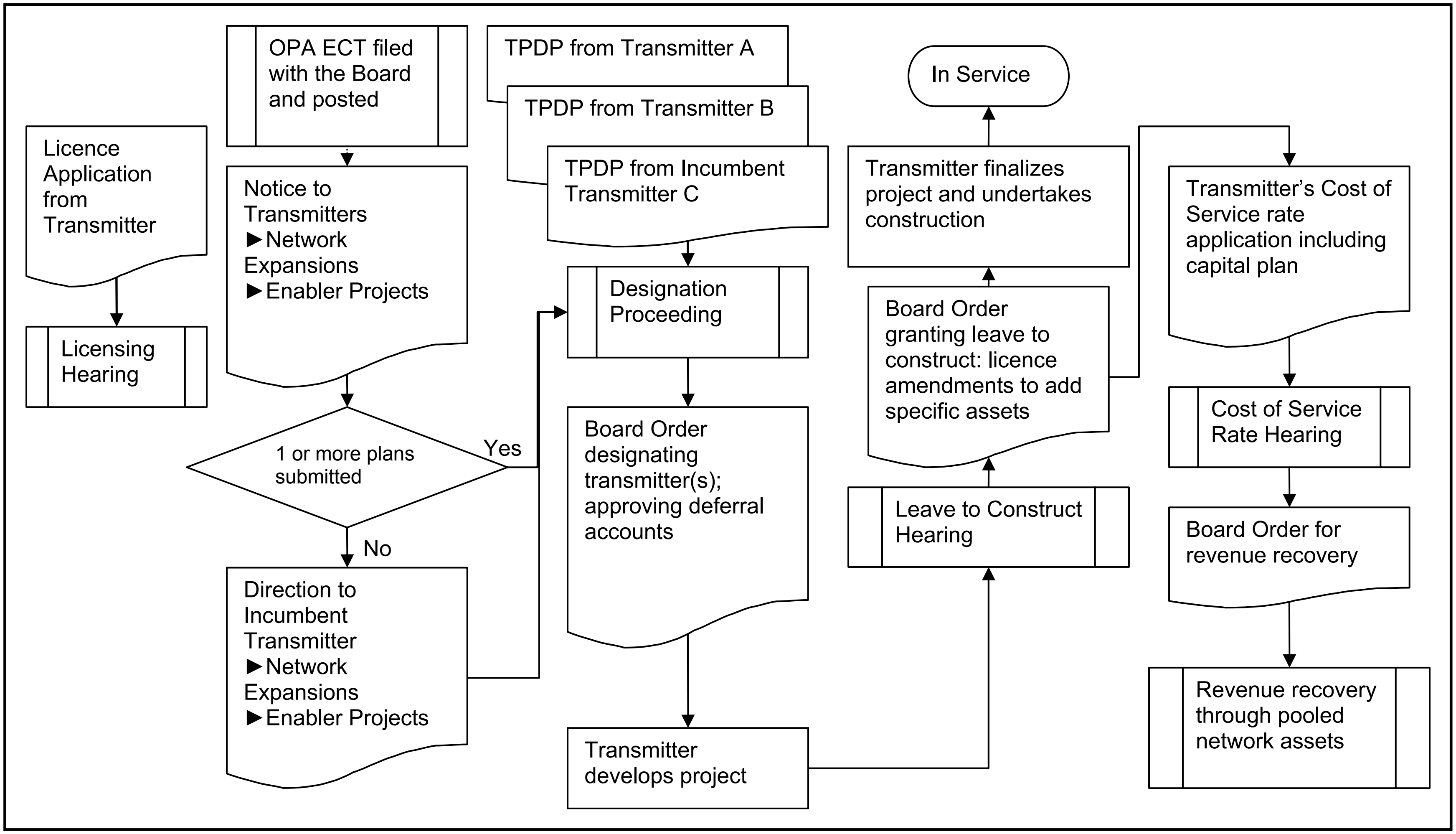

Figure 1: OEB Process for Transmitter Designation and Transmission Project Development Plan Approval

The ECT focuses on transmission needed to accommodate FIT applications and the projects of the Korean Consortium. As mentioned above, transmission serves other needs as well. The Board expects that during the development phase, the designated transmitter will consult with the OPA and the IESO regarding capacity, configuration and final routing that would support those other needs.

The Board expects that the OPA will support transmitters in preparing evidence of need for a transmission project.

There are two types of projects that could be identified in the ECT that would not be subject to designation: capacity enhancements and network reinforcements. As these types of projects are work on the incumbent transmitter's system, the incumbent will undertake them directly. It is highly likely that network reinforcements will require a leave to construct. The incumbent transmitter should develop these projects and prepare a leave to construct under the assurance that reasonable development costs will be recoverable from ratepayers at a future proceeding by reference to the ECT results. The Board expects that the OPA will support proof of need at this time.

6 Hearing for Rate Recovery

In the staff Discussion Paper, Board staff suggested that development costs by both incumbents and new entrants could be recovered through the Uniform Transmission Rates of Ontario (the "UTR"). Several stakeholders requested clarification of the workings of the Uniform Transmission Rate.

Section 78.(1) of the OEB Act prohibits a transmitter from charging for transmission of electricity except in accordance with an order of the Board. The UTR is a Board ordered schedule of tariffs charged to all transmission customers. There are 5 currently licensed transmitters that are rate regulated. Each one has a periodic hearing to determine its cost of service revenue requirement. After each Hydro One Networks Inc. hearing,[19] these revenue requirements are summed to determine the total transmission revenue requirement in Ontario. This revenue requirement is then spread over the total transmission service in the province to determine appropriate postage stamp transmission rates. The IESO is tasked with charging out this rate, collecting it from transmission customers and then paying it out to the transmitters. The payments to

[19] The most recent proceeding to set and allocate the Uniform Transmission Rate resulted in an Order released January 21, 2010 (EB-2008-0272). It is expected that the current Hydro One Networks Inc. case (EB-2010-0002), will result in a revised UTR.

transmitters are according to an allocation that has been predetermined by the Board based on each transmitter's percentage of the total transmission revenue requirement.

If a designated transmitter had development costs but did not construct the facilities[20], those costs could be converted into a regulatory asset for rate recovery. The regulatory asset would create a revenue requirement that would be added to the total provincial transmission revenue requirement and included in the calculation of the UTR. Then, the IESO would bill all transmission customers, collect the revenues and remit the appropriate amount to the designated transmitter.

Construction budgets would be part of the capital budget for a transmitter's cost of service rate hearing. Alternative mechanisms as set out in the "Report of the Board: The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario" (EB-2009-0152)[21] could be requested.

Some network reinforcement and many capacity enhancement projects (not subject to designation) may not require a leave to construct. The incumbent transmitter should proceed to develop the projects and include them in the capital budget for the appropriate cost of service application. The project's inclusion in an ECT is sufficient support for recovery of reasonable development costs. Approval of construction budgets is subject to a determination of need for the capital budget. The Board expects that the OPA will support proof of need at that time.

[20] E.g. the facilities were ultimately determined to be not necessary.
[21] Available on the Board's website at http://www.oeb.gov.on.ca/OEB/_Documents/EB-2009-0152/Board_Report_Infrastructure_Investment_20100115.pdf

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MAR 3 1 2011

CHAIR
ONTARIO ENERGY BOARD

Ontario

MAR 2 9 2011

MC-2011-1537

Ms Cynthia Chaplin
Chair
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Chaplin:

Ontario's Long-Term Energy Plan, published November 23, 2010, identified five priority transmission projects based on the advice of the Ontario Power Authority (OPA). Among the five priority projects is the East-West Tie, identified by the OPA primarily to meet the need of maintaining long-term system reliability in Northwest Ontario.

Consistent with the intents identified in the Long-Term Energy Plan, I am writing to express the Government's interest that the Ontario Energy Board ("the Board") undertakes a designation process to select the most qualified and cost-effective transmission company to develop the East-West Tie.

The Board's Policy Framework for Transmission Project Development Plans is well suited to apply to the East-West Tie project. Such an approach would allow transmitters to move ahead on development work in a timely manner, encourage new entrants to transmission in Ontario and bring additional resources for project development. It will also support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

A designation process for the East-West Tie also promotes the Board's electricity objectives of protecting the interests of consumers with respect to prices and of promoting cost-effectiveness in the transmission of electricity. In respect of those particular ends, and given the location and value of the East-West Tie in ensuring reliability and maintaining efficiency and flexibility of the system, I would expect that the weighting of decision criteria in the Board's designation process takes into account the significance of aboriginal participation to the delivery of the transmission project, as well as a proponent's ability to carry out the procedural aspects of Crown consultation.

.../cont'd

As the Board has noted in its framework, the starting point for transmission project development planning should be an informed, effective plan from the province's transmission planner, the OPA. As such, it would be prudent for the Board to request further analysis for the East-West Tie from the OPA to support initiation of a designation process.

Sincerely,

Brad Duguid
Minister

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Rosemarie T. Leclair
Chair & CEO

Rosemarie T. Leclair
Président et Directrice Générale

Ontario

BY E-MAIL

April 25, 2011

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

Dear Mr. Andersen:

The Board has received a letter from the Minister of Energy dated March 29, 2011 expressing an interest in having the Ontario Energy Board undertake a designation process to select the most qualified and cost-effective transmission company to develop the East-West tie line.

The Board released a policy on August 26, 2010, for transmission project development planning to accommodate the connection of renewable energy generation facilities. The policy describes a process to designate a licensed transmitter to undertake development work on any transmission network expansions or enabler lines identified by the Ontario Power Authority (the "OPA") as necessary to connect renewable generation. The designation process is intended to allow transmitters to move ahead on development work in a timely manner; to encourage new entrants to transmission in Ontario bringing additional resources for development work; and to support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

The Minister suggests that the designation process outlined in the Board's August 26 2010 policy report could be used to select the most qualified and cost-effective transmission company to develop the East-West tie line. The Board agrees and is prepared to proceed with a designation process if project planning is justified. In developing the designation policy, the Board recognized the role of the OPA as the transmission planner for the province and identified an informed, effective plan from the OPA as the trigger for starting a process.

The Board understands that the OPA provided information to the Minister for the Long-Term Energy Plan supporting the need for an East-West tie line in order to maintain long-term system reliability in Northwest Ontario. The Board, therefore, requests a report from the OPA regarding the preliminary assessment of the need for an East-West tie line. The assessment should be sufficiently robust to allow the Board to determine whether the designation process should be initiated in accordance with the Board's designation policy. Final assessment of need and therefore approval to construct a line will still require a hearing before the Board for leave to construct a transmission line.

The Board expects that the OPA's report would provide information on system reliability in relation to the East-West tie line. More specifically, the report should include such technical information as:

- the line connection points to the existing system;
- any specific routing requirements besides the connection points;
- the required carrying capacity of the line;
- any technical requirements to address the system need identified above; and
- any available information regarding benefits of the project to ratepayers.

A report from the OPA by the end of June 2011 is required in order for the Board to decide whether undertaking a designation process for the East-West tie line is justified at this time in accordance with the objectives of the Board's policy. Earlier receipt of the OPA's report would allow the Board to move ahead expeditiously.

If the Board decides to proceed with a designation process, the Board expects the OPA will participate during the planning process and the designation proceeding by providing additional information related to project requirements and need.

Yours truly,

ORIGINAL SIGNED BY

Rosemarie T. Leclair
Chair and CEO

Enclosure

cc: The Honourable Brad Duguid, Minister of Energy

Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion

June 30, 2011

ONTARIO POWER AUTHORITY

Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion

1.0 INTRODUCTION

In a letter to the Ontario Power Authority ("OPA") dated April 25, 2011, the Ontario Energy Board ("OEB") wrote that it "is prepared to proceed with a designation process if project planning is justified" for the proposed expansion of the East-West Tie ("E-W Tie") between Northeast and Northwest Ontario. In that regard, the OEB requested a report from the OPA documenting the preliminary assessment of the need for a new E-W Tie line. The assessment should be "sufficiently robust to allow the Board to determine whether the designation process should be initiated".

Further, the OEB also asked that the following information be included in the report:

- The line connection points to the existing system;
- Any specific routing requirements besides the connection points;
- The required carrying capacity of the line;
- Any technical requirements to address the system need identified above; and
- Any available information regarding benefits of the project to ratepayers.

This report responds to the OEB's request and provides further information on the background and rationale for the expanded E-W Tie, as well as the OPA's recommendations on its scope and timing. The report presents a preliminary assessment of need for a new E-W Tie line and provides planning justification to support the implementation of the OEB's transmitter designation process. The OPA will update this assessment as required for future proceedings, such as a Leave to Construct application undertaken by a selected transmitter.

This report is organized into the following sections:

- Section 2 provides background on the Northwest area;
- Section 3 describes the Northwest's electricity conservation and demand;
- Section 4 describes the Northwest's internal and external supply resources;

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- Section 5 discusses planning considerations for the Northwest and context for the E-W Tie expansion project;

- Section 6 provides the OPA's recommendation; and

- Section 7 provides the project scope information requested by the OEB and outlines the major milestones in the implementation of the E-W Tie project.

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2.0 THE NORTHWEST

Northwestern Ontario (“the Northwest”) consists of the districts of Kenora, Rainy River and Thunder Bay, which is roughly the area north of Lake Superior stretching from the Wawa area in the east to the Manitoba border in the west (see Figure 1). The area accounts for approximately 60% of the land area in the province and approximately 2% of Ontario’s total population. Approximately half of the population in the Northwest resides in the city of Thunder Bay and the remaining population resides in rural and remote communities across the region.

Figure 1: Map of Northwest Ontario

SOURCE: OPA

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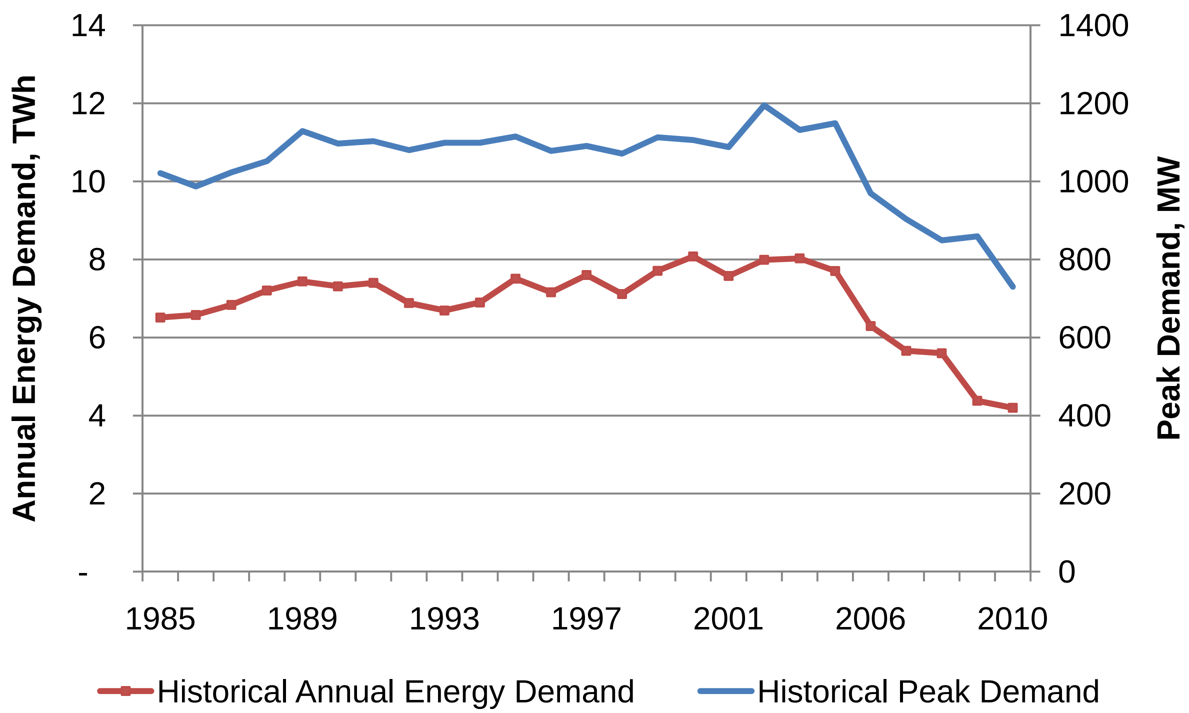
3.0 NORTHWEST CONSERVATION AND DEMAND

The electric system in the Northwest is winter-peaking. Its demand exhibits a relatively flat daily load profile that has less pronounced peaks than occur in Southern Ontario. This is due to the predominance of large industrial loads in the Northwest, which tend to operate on a continuous basis, as well as relatively minor cooling loads compared to Southern Ontario. The concentration of industrial demand in the Northwest also leads to sizable swings in annual energy demand as industries respond to economic changes. This section describes the Northwest's historical and forecast demand.

3.1 Historical Northwest Demand

Between 1985 and 2005, Northwest annual energy requirements and peak demand have been in the range of 6.5 to 8 TWh and 950 to 1,150 MW, respectively. Since 2005, there has been a significant decline in Northwest demand, due primarily to a downturn in the pulp and paper industry. Northwest annual energy and peak demand declined by 45% (from 7.7 to 4.2 TWh) and 35% (from 1,150 MW to 730 MW) respectively, between 2005 and 2010.

Figure 2: Historical Northwest Peak and Energy Demand



SOURCE: IESO

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3.2 Northwest Demand Scenarios

The Northwest's future electricity demand is expected to continue to be driven largely by industrial activities in the area. Key considerations are listed below.

- The pulp and paper sector demand in the Northwest has declined over recent years. In 2010, the sector's electrical demand was approximately 30% of 2005 levels. The extent and pace of recovery of the sector will influence the region's electricity demand.

- The mining industry is growing in the Northwest. Mining operations have resumed at the Lac Des Iles palladium mine north of Thunder Bay and requests have been made for additional supply for gold mines in the Red Lake and Pickle Lake areas. There have also been several inquiries related to the development of new mines or resuming operation at old mines in the area. Together, these developments will contribute to electricity demand growth in the area.

- There is the potential to develop an area situated about 300 km northeast of Thunder Bay, known as the Ring of Fire, which has been found to contain high quality rare earth metal ores, including chromite. Each active mine in the Ring of Fire could have a demand of approximately 20 to 25 MW.

- In addition, the OPA is developing a plan to connect remote communities beyond Pickle Lake. This could add approximately 24 MW of load in the Northwest by 2020.

The extent to which these developments will materialize is still uncertain. To manage this uncertainty, the OPA is considering two demand scenarios. The annual energy demand in each scenario is shown in Figure 3 and the peak demand in each scenario is shown in Figure 4. Scenario A illustrates a future in which the pulp and paper industry experiences a partial recovery by 2020, and mining and related industries increase their demand in the Northwest. Scenario B incorporates a similar recovery in the pulp and paper industry, but assumes less mining expansion than Scenario A. These scenarios both include forecast conservation savings, except demand response, which is included as a supply resource in Section 4.1. These savings total approximately 0.5 TWh in 2031.

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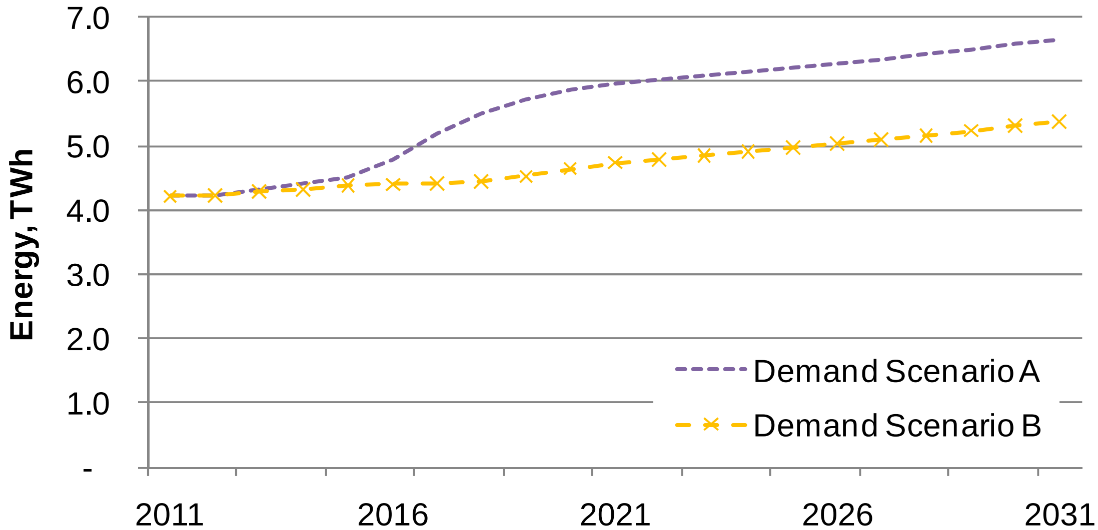
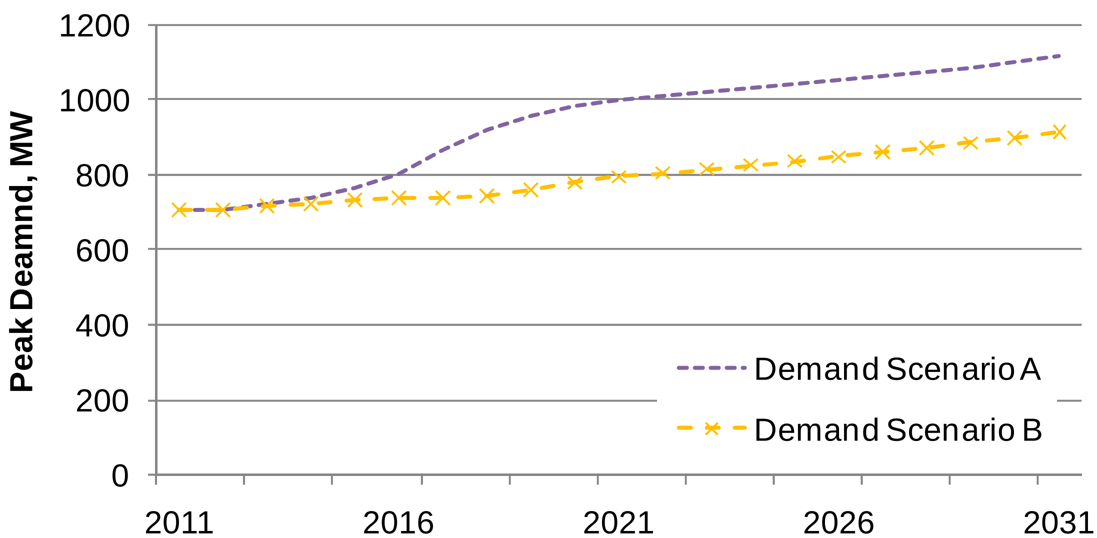
Figure 3: Northwest Energy Demand Scenarios



SOURCE: OPA

Figure 4: Northwest Peak Demand Scenarios



SOURCE: OPA

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4.0 SUPPLYING NORTHWEST DEMAND

The Northwest is much more reliant on internal resources to supply demand than any other area in Ontario. This is due to the limited capability of the Northwest's interconnections with neighbouring areas, which only allow a part of the Northwest's demand to be supplied by external resources. The Northwest's internal and external supply resources are discussed in Sections 4.1 and 4.2, respectively, including the ways in which these resources are expected to change over time. The expected contribution of these resources to meeting Northwest demand in 2020 is described in Section 4.3.

4.1 The Northwest's Internal Resources

Today, the Northwest system's internal resources consist mainly of hydroelectric and coal-fired generation, which together account for over 90% of the area's internal resource capacity (see Figure 5 below).

4.1.1 Current (2010) Internal Resources

Hydroelectric Generation

Hydroelectric generation accounts for just over half of the existing installed generation capacity in the Northwest (see Figure 5). Most of the hydroelectric facilities in the Northwest are run-of-river plants which have limited storage capability. The inability to store water from year to year, combined with variations in hydraulic conditions, result in large annual variations in energy production. Between 1985 and 2008, hydroelectric production in the Northwest ranged between 2.5 TWh and 5 TWh per year, averaging approximately 4 TWh per year.

Due to varying availability of hydroelectric generation capacity and energy output, it is not possible to rely on the Northwest's hydroelectric generation to supply a fixed amount of demand every year. Other resources are required to meet Northwest demand in low-water years, as illustrated in Figure 6. This figure shows the types of resources used to meet Northwest demand in 2003 and 2005. These years were chosen as they had similar levels of demand, while 2003 was a low-water year and 2005 was a median-water year. As the figure shows, coal and external resources were relied upon to replace lower hydroelectric output in the low-water year. This illustrates the historical role of coal and external resources as "swing" resources to complement variable hydroelectric output in the Northwest.

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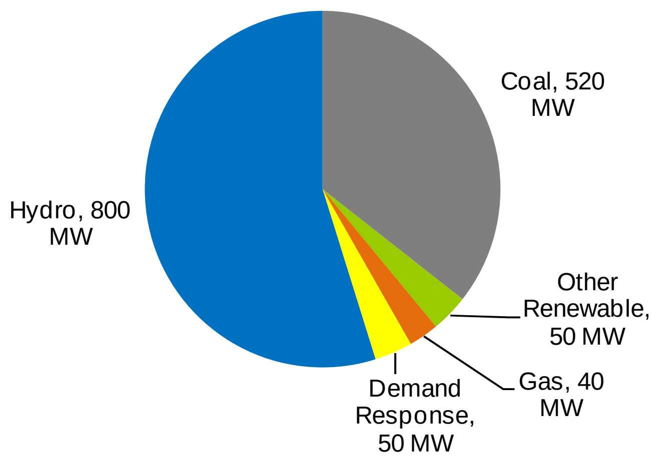
Figure 5: Northwest Internal Resources by Type in 2010 (installed capacity)



Note: capacities have been rounded to the nearest 10 MW.

SOURCE: OPA

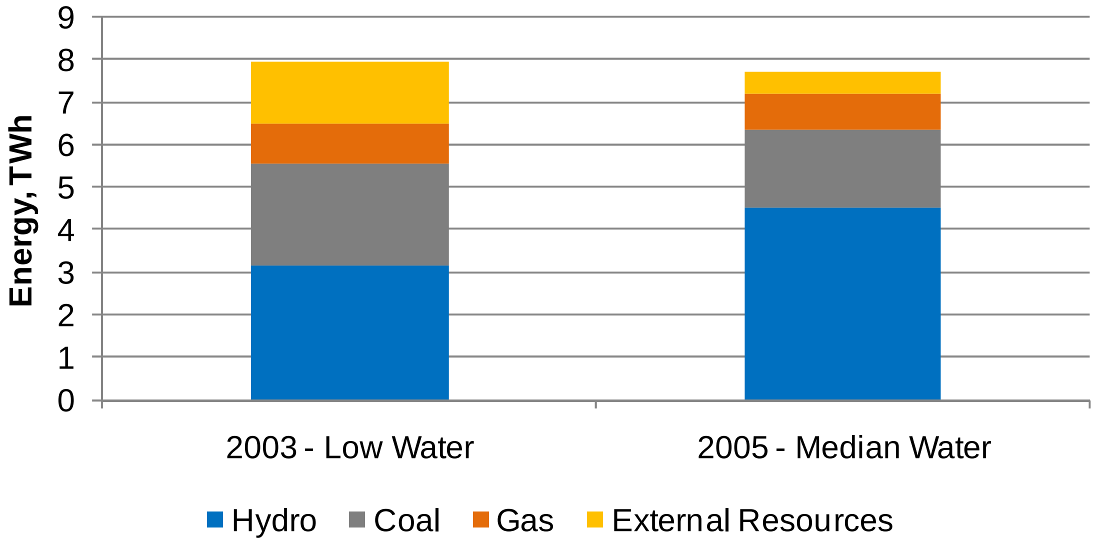
Coal-fired Generation

The Northwest's two coal-fired generating stations, Thunder Bay and Atikokan, currently provide about 500 MW or one third of the generation capacity in the Northwest system. These plants serve as both base and peaking resources and historically have provided up to 3 TWh of generation in the Northwest. The operational flexibility of the coal-fired plants also allows them to complement the output of hydroelectric facilities in the area during low-water years.

Gas and Biomass Generation in the Northwest

At present, gas-fired and biomass generation account for a small portion of the Northwest supply mix. Two natural-gas fired stations near Nipigon and Fort Frances have, until recently, supplied approximately 150 MW of capacity and between 0.5 TWh and 1 TWh of energy per year. As of 2010, the Fort Frances facility had been converted to biomass operation and its installed capacity was reduced by approximately 50 MW.

Figure 6: Comparison of Resources Used to Supply Northwest Demand (Historical)



SOURCE: OPA

4.1.2 Changes to Northwest Internal Resources

In the Northwest, the resource mix is changing as government policies related to coal-fired generation and renewable energy are implemented. The most significant changes and the corresponding effects on the Northwest system are listed below.

- The Thunder Bay and Atikokan coal-fired generation stations are to cease coal-fired operation by the end of 2014 in accordance with Ontario Regulation 496/07.
- The OPA has been directed to contract for the conversion of the Atikokan plant to run using biomass fuel. Though it will still have a capacity of about 200 MW, its forecast fuel availability will limit energy production to 140 GWh per year.
- The government has stated that both currently operating Thunder Bay coal-fired units are to be converted to use natural gas by 2014. Under gas-fired operation, the Thunder Bay plant will be capable of providing the same capacity as it does today. However, higher fuel costs under natural gas operation will make it better suited to peaking operation.
- Approximately 200 MW of new renewable resources have been contracted in the Northwest through the RESOP, RES and FIT Programs. These new resources consist primarily of wind and solar resources, but also include some hydroelectric and biomass

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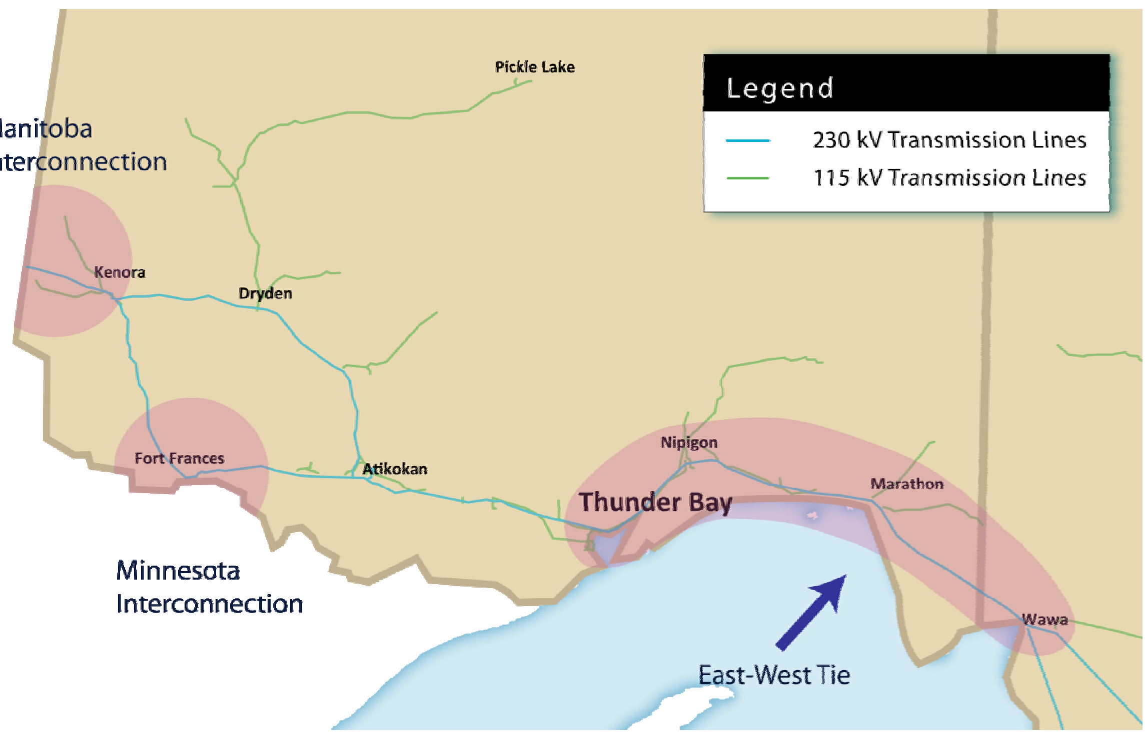
generation. The load-meeting capability of these resources will be considered to determine their contribution to meeting Northwest demand.

- Demand response resources in the Northwest are expected to total approximately 90 MW.

Over the next five years, these changes to the Northwest generation mix will increase the area's internal installed capacity. However, there will be less energy available from these internal resources than has historically been the case. Furthermore, the only internal generation resource that will be capable of providing flexible energy output will be the converted Thunder Bay plant, which will have higher unit energy costs than it currently does.

4.2 Supplying the Northwest Using External Resources

Figure 7: Combined Import Capability is up to 570 MW into the Northwest



SOURCE: OPA

The ability to supply Northwest demand using external resources is limited by the capability of the interconnections with neighboring areas. Figure 7 above shows the Northwest transmission system and its three interconnections with neighbouring areas: (1) the rest of the Ontario system via the E-W Tie at Marathon, (2) the Manitoba system via an interconnection at Kenora,

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and (3) the Minnesota system via an interconnection at Fort Frances. The current use of these interconnections is described in Section 4.2.1 below.

The capability of the three interconnections between the Northwest and neighbouring areas is shown in Table 1 below. It should be noted that these interconnections cannot all be fully utilized at the same time. They are limited to a combined import capability of 570 MW under normal operating conditions, but this can only be achieved if there is sufficient reserve generation on standby in the Northwest system.

Table 1: Capability of Interconnections between the Northwest and Neighbouring Areas

Interconnection	Capability to Transmit (MW)	
	Into Northwest	Out of Northwest
East-West Tie	350	325
Manitoba Interconnection	330	262
Minnesota Interconnection	90	140
Total Simultaneous Capability with Sufficient Standby Generation	Up to 570	Up to 490

SOURCE: IESO

4.2.1 Historical Use of External Resources to Supply Northwest Demand

The Manitoba and Minnesota interconnections provide opportunities for economic power transactions between Ontario and these jurisdictions. However, as there are currently no firm import arrangements in place, these interconnections cannot be relied upon for planning purposes to meet the Northwest's supply needs. Some reinforcement of the Northwest transmission system would be required to accommodate significant firm imports from these jurisdictions. While these two interconnections cannot be used to plan firm capacity and energy to supply the Northwest, they are crucial to the security and robustness of the Northwest power system operationally, because they provide the only connection between the Northwest system and the rest of the North American grid when the E-W Tie is out of service.

The existing E-W Tie is a 400 km double-circuit 230 kV transmission line connecting Wawa TS and Lakehead TS. The E-W Tie, being part of the Ontario system, is an important source of firm supply to the Northwest. It has been relied upon heavily to supply Northwest demand in low-water years or during periods of high demand (see Figure 6).

While the nominal capacity of the existing E-W Tie's westbound transfer is currently 350 MW, there are a number of important considerations regarding this capability listed below.

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- The nominal westbound limit of 350 MW is based on operating the system to respect the outage of one of the two circuits on the E-W Tie, which share a common tower line. Elsewhere in Ontario the bulk electricity system is operated to respect the loss of both circuits on a common tower line, a practice which complies with current IESO reliability criteria and NERC system design standards. Consequently, the nominal westbound limit of 350 MW for the E-W Tie does not conform to current reliability standards. Operating to respect the loss of both E-W Tie circuits would reduce its transfer capability from 350 MW to 175 MW. Loss of the E-W Tie while it is transferring 350 MW could lead to the interruption of load in the Northwest.

- Today, the IESO respects the double-circuit contingency limit (175 MW) on the E-W Tie when an electrical storm is detected over the Northwest, as the likelihood of losing both circuits is more likely during such events.

- Since 2006, there have been over 60 forced outages along the E-W Tie, averaging about 12 outages per year. Over a quarter of these outage events have been double-circuit outages in which both E-W Tie circuits were forced out of service.

The E-W Tie plays a critical role in maintaining a reliable supply to the Northwest. Accordingly, the points above are important considerations that must be factored into determining an appropriate planning limit for the E-W Tie in Northwest supply assessments.

4.2.2 Planning to Current Reliability Standards

In general, the transmission system in Ontario is to be planned in accordance with the IESO's reliability criteria, which must comply with NPCC and NERC criteria. This was reinforced in a memorandum of understanding between the OEB and NERC dated October 25, 2006. IESO and NERC/NPCC reliability criteria all require that planners respect contingencies involving multiple elements, including the outage of a double-circuit line.

The existing E-W Tie has not been designed to consider this level of reliability due to the terrain and distance that the line has to traverse. However, any planned future developments in the Northwest will need to meet current reliability standards. Compliance with these standards will require that the transfer capability of the existing E-W Tie be reduced to 175 MW.

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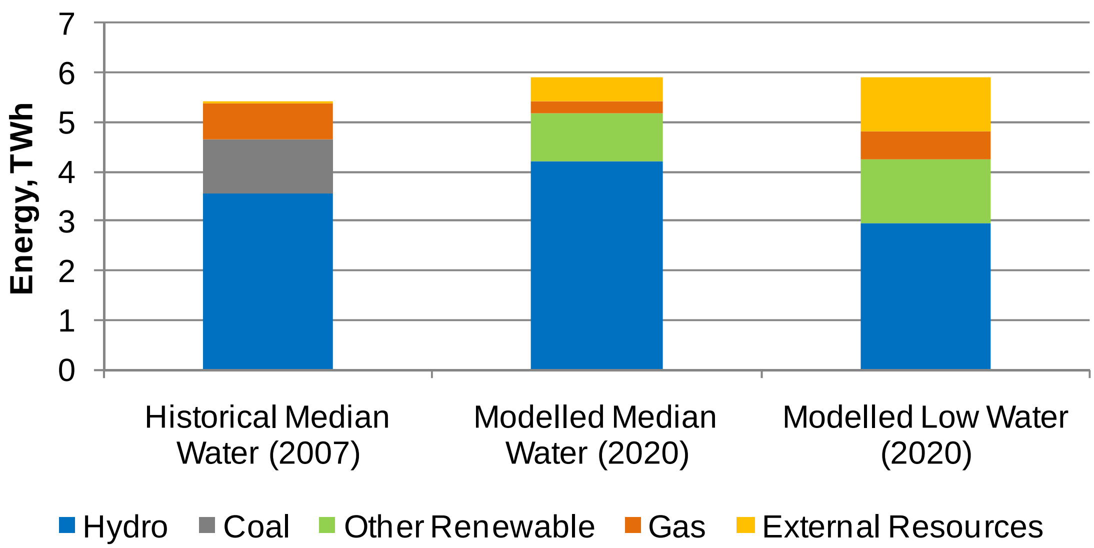
4.3 Expected Contribution of Northwest Resources in 2020 with the Existing E-W Tie

As noted in the sections above, many changes to the Northwest power system will occur over the next five years. The future impact of these changes has been simulated using UPLAN, an energy simulation tool, assuming the existing E-W Tie capability is 175 MW to respect NERC/NPCC criteria.

Figure 8: Gas and External Resources Make Up the Shortfall in Low-Water Years



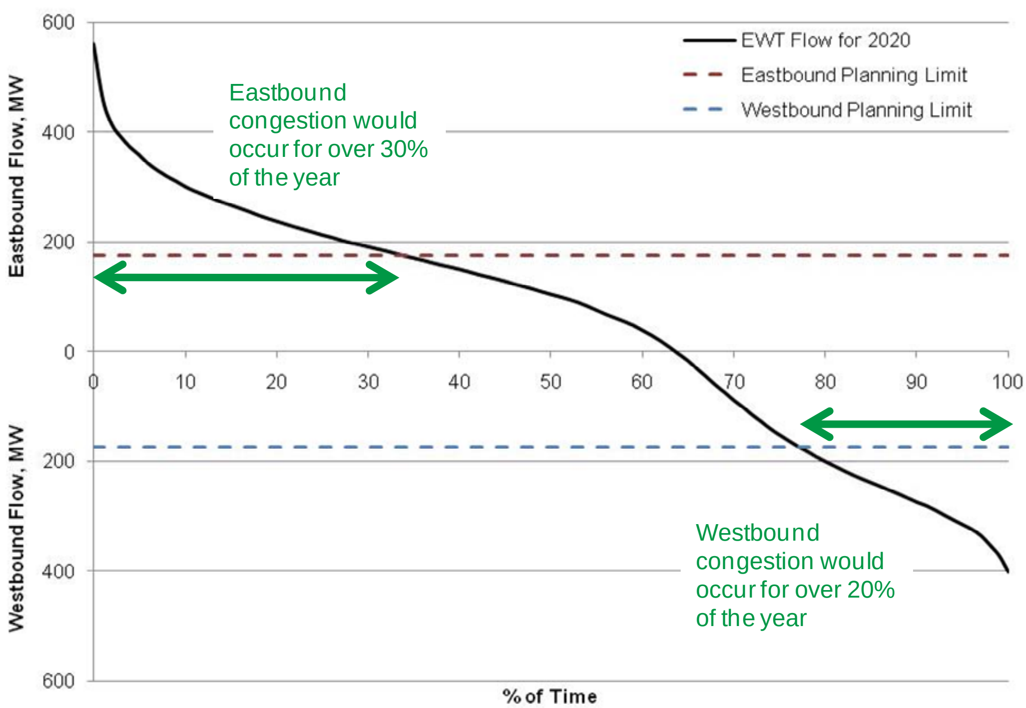
SOURCE: OPA

Figure 8 shows the types of resources expected to supply Northwest demand in 2020, under both median-water and low-water conditions. These are compared to the resources used to meet Northwest demand in 2007. The annual Northwest energy demand in 2007 is similar to the forecast demand for the area in 2020. Figure 8 shows that under median-water conditions, external resources and new renewable resources will be sufficient to provide most of the energy that had been previously supplied by coal-fired generation. There will still be a need, however, to dispatch the Thunder Bay plant uneconomically to meet Northwest demand. In a low-water year, the reduced output from the hydroelectric plants must be replaced to meet Northwest demand, and the contribution of the Thunder Bay plant is much higher than under median-water conditions. Almost all of the output from Thunder Bay in the low-water simulation is associated with uneconomic dispatch of the plant.

The OPA also simulated congestion on the E-W Tie in 2020 as part of its assessment. Figure 9 shows an illustrative duration curve for the unconstrained flow on the existing E-W Tie in 2020 under median-water conditions, expressed as a percentage of time. The duration curve represents the flow on the E-W Tie assuming no transmission constraints, and shows that the E-W Tie would be relied upon approximately one-third of the time to supply the Northwest. This is represented by the westbound flow into the Northwest through the E-W Tie. The remainder of the time, the E-W Tie would supply energy to the rest of the Ontario system under unconstrained conditions (which is represented by eastbound flow).

Both eastbound and westbound flows would have to be curtailed by operators in order to respect the 175 MW transfer limits. Figure 9 shows the impact of the 175 MW eastbound and westbound transfer limits on the operation of the existing E-W Tie. Under this simulation, there would be congestion for over 50% of the time: approximately 20% of the time for westbound flow, and 30% of the time for eastbound flow. When there is westbound congestion, generation within the Northwest needs to be dispatched uneconomically to supply the area's demand. When there is eastbound congestion, Northwest generation needs to be constrained off to respect the E-W Tie's transfer limit.

Figure 9: Unconstrained E-W Tie Flow and Planning Limits



SOURCE: OPA

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5.0 PLANNING CONSIDERATIONS AND CONTEXT FOR THE EAST-WEST TIE EXPANSION

In the last fifty years, increasing Northwest demand led to three major investment decisions: the construction of the current E-W Tie, the Thunder Bay Generation Station and the Atikokan Generation Station. The need for enhancing supply to the area is not driven by increased demand or near term adequacy, but is primarily to maintain reliable, cost effective supply over the long term in the Northwest reflecting the changes to the region's supply mix, including the phase-out of generation from coal. While the capacity of the Atikokan and Thunder Bay plants will be maintained following conversion, the economics, availability and flexibility of the plants will be altered.

In general, there are two basic alternatives for supplying the Northwest following the conversion of the Atikokan and Thunder Bay plants: (1) using internal generation within the Northwest, and (2) using external resources transferred via the E-W Tie. The OPA has compared these two alternatives in terms of their cost-effectiveness, flexibility, ability to remove barriers to renewable generation development, and other benefits in the subsections below.

5.1 Cost-Effectiveness Comparison

Expanding the E-W Tie would increase both the eastbound and westbound transfer capability of this transmission interface. Increased westbound transfer capability would allow the Northwest to be supplied by available lower-cost energy from the rest of Ontario. In the same way, increasing the eastbound transfer capability could allow congested energy in the Northwest to be transferred to the rest of Ontario displacing less economic generation. Increased eastbound transfer capability would also increase the availability of Northwest generation capacity to meet reliability needs in other parts of the province, and therefore delay the future potential need for new capacity in the rest of Ontario.

For these reasons, expanding the E-W Tie, as compared to operating the converted Thunder Bay plant uneconomically and eventually building new generation in the Northwest, holds the potential for reducing the cost of electricity to ratepayers. To conduct a comparative assessment of these two alternatives, it is necessary to evaluate the capital investment required to expand the E-W Tie against the available savings from utilizing lower-cost energy supply and from deferring the need for new generation capacity.

A cost-benefit analysis comparing the 50-year net present value between the existing and expanded E-W Tie was conducted for the two demand scenarios described in Section 3.2. The difference in system costs between the two alternatives was compared to the capital cost of

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expanding the E-W Tie to determine which alternative would be more cost-effective. The system costs consist of the energy and emissions costs to supply demand in the Northwest and the rest of Ontario, and the capital and fixed OM&A cost of additional generation capacity required to preserve system reliability in the Northwest and Ontario as a whole. A range of input assumptions were used for both demand scenarios to account for the potential volatility in natural gas prices, carbon prices and E-W Tie expansion cost. The following assumptions were used in the net-present value analysis.

- For the purposes of modeling, the expanded E-W Tie was assumed to come into service by the end of 2017 and would have a life of 50 years. A base capital cost of $600 million was used for planning purposes.[1] A range of capital costs was also considered.
- The existing E-W Tie has westbound and eastbound capabilities of 175 MW. The expanded E-W Tie has total westbound and eastbound capabilities of 650 MW.
- New capacity needs in the Northwest and the rest of Ontario are added as required to satisfy adequacy criteria. System generation capacity needs for reliability purposes were estimated assuming dependable water (i.e., “low-water”) conditions in the Northwest.
- Median-water hydroelectric energy output was used for energy simulation purposes. Consideration of low-water years would improve the cost-effectiveness of the E-W Tie.
- Natural gas forecast real (2010 $ Cdn) prices are assumed to be $6.8/MMBtu throughout the study. A range of real natural gas prices between $4/MMBtu and $12/MMBTu was considered.
- A base assumption of $0/T for CO_2 emissions prices was used. Real CO_2 emission prices up to $160/T in 2030 were also considered.
- The heat rate of the converted Thunder Bay generating station is assumed to be 10.5 MMBtu/MWh and its CO_2 emissions rate is assumed to be 0.54 T/MWh, compared to CCGT rates assumed at 7.3 MMBtu/MWh and 0.31 T/MWh.
- Future costs were present-valued at 2010 using a 4% real discount rate.

[1] A capital cost of $600 million was identified in the OPA’s presentation *IPSP 2011 Stakeholder Consultation: Transmission Planning* (May 31, 2011) and in the OPA’s *Response to the Minister’s Request for an Updated Transmission Expansion Plan* (November 8, 2010).

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The results of the OPA's comparative analysis are that, even before any monetary cost of emissions is considered, the expanded E-W Tie provides a net benefit ranging from approximately $20M to $80M when considering the two Northwest demand scenarios under mid-range assumptions for the factors listed above. If the full range of assumptions is also considered, the E-W Tie provides a net benefit as high as approximately $345M and as low as a net cost of about $130M. Overall, this cost-effectiveness analysis shows that the E-W Tie creates a net benefit under the majority of assumptions considered.

In a letter to the OEB dated March 29, 2011, the Minister of Energy stated his expectation that the weighting of decision criteria in the Board's designation process take into account the significance of Aboriginal participation to the delivery of the transmission project, as well as a proponent's ability to carry out the procedural aspects of Crown consultation. The OPA has discussed the E-W Tie with First Nation and Métis communities through consultation sessions, including those related to the Integrated Power System Plan. The interests raised by First Nation and Métis communities through these sessions have been linked to the cost of the project and the importance of beginning consultation early in the project development phase. The OPA heard that it is important to consider potential project costs that may relate to Aboriginal participation in the transmission project and any accommodation of Aboriginal or treaty rights. The Ministry of Energy has identified 14 First Nations and 4 Métis communities that may have interests affected by the proposed E-W Tie.

5.2 System Flexibility with an Expanded E-W Tie

Without an expanded E-W Tie, it would be necessary to closely match internal generation to demand to meet the Northwest's future requirements. Given the inherent uncertainties in forecasting the largely industrial-driven demand in the Northwest, this exposes the system to the risk of under-investment in generation, resulting in resource shortfalls, or over-investment in generation, leading to underutilized assets.

An expanded E-W Tie provides greater system flexibility. By allowing external resources to supply incremental load growth, and by providing a means to transfer excess generation to the rest of Ontario, an expanded E-W Tie reduces the impact of over- or under-investment in generation. Below are some examples of the flexibility afforded by an expanded E-W Tie.

- In low-water years, internal generation would not need to be run uneconomically to meet demand.

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- In high-water years, excess generation could be transferred to meet demand elsewhere in the province.
- In the event of significantly higher demand than forecast, additional generation capacity investment could be avoided or deferred.
- Under a lower than forecast demand scenario, excess generation could be utilized in the rest of the province.

These potential flexibility benefits are in addition to those considered in the cost-effectiveness analysis presented in Section 5.1.

5.3 Remove Barriers to Renewable Generation Development in the Northwest

Currently, the development of new renewable generation in the Northwest is constrained by the ability to transfer power out of the Northwest toward Southern Ontario. An expanded E-W Tie would remove the largest barrier to renewable generation development in the Northwest, which is the limited capability of the existing E-W Tie to transfer surplus power out of the Northwest. While other transmission congestion currently limits additional flow from new generation in the Northwest, increased demand and/or changes in the operation of generation in the Northeast, combined with the expansion of the E-W Tie, would provide opportunities for further resource development in the Northwest.

5.4 Other Benefits

In addition to providing cost-effective, reliable supply to the Northwest, the E-W Tie expansion is expected to provide additional benefits. These benefits are summarized in Table 2.

Table 2: Summary of Other Benefits of an Expanded E-W Tie

Benefit	Description
Reduced Congestion Payments	Once in service, an expanded E-W Tie is expected to reduce congestion in the Northwest system by approximately 40%. Market congestion payments (CMSC) in the Northwest have averaged $40M per year over the last 9 years since market opening. Under the current market structure, an expanded E-W Tie could create savings of roughly $15M per year through congestion payment reduction. As this payment is borne by Ontario ratepayers, any reduction in CMSC payments would be a benefit to them. This benefit is not included in the cost-effectiveness analysis presented in Section 5.1.

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Reduced Losses	With the addition of a new double-circuit line, the electrical resistance between the Northwest and the rest of Ontario would be reduced by half, and therefore transmission line losses would be reduced for all levels of flow across the E-W Tie. The monetary benefit of this loss reduction is captured in the cost-effectiveness analysis presented in Section 5.1.
Improved Operational Flexibility in the Northwest	A double-circuit contingency resulting in the loss of the existing E-W Tie would cause the Northwest system to become electrically separated from the rest of Ontario and to rely solely on the interconnections with Manitoba and Minnesota to maintain system integrity. By providing an additional transmission connection between the Northwest and Northeast systems, the expanded E-W Tie would greatly reduce the risk of system separation due to double-circuit contingencies, and would allow the Northwest system to be operated without relying on special protection schemes and operational procedures during high risk weather conditions.

SOURCE: OPA

6.0 THE OPA'S RECOMMENDATION

The OPA has carried out a preliminary assessment of the long-term supply needs of the Northwest and the two basic alternatives that address this need: internal generation and an expanded E-W Tie. Based on this assessment, the OPA finds that expansion of the E-W Tie is the preferred alternative based on economic, flexibility, technical, operational and other considerations. The OPA therefore recommends that development work be initiated on this project. Proceeding with this project after development work has been completed will depend on many factors, including the capital cost of the E-W Tie and the extent of the developments in the Northwest described in Section 3.2.

In accordance with the Minister of Energy's March 29, 2011 letter to the OEB, the next step in the implementation process would be the selection of a transmitter to carry out development work. Development work includes but is not limited to: project design, specification and costing; routing and siting; preparation of necessary approvals; and consultation and communications. In most cases, development work represents a small fraction of the project cost – typically 2 to 5 percent. The OPA believes this cost is justified in order to maintain the viability of this option. The development work for the E-W Tie project will provide the necessary information to guide a final decision on whether to proceed with the project through the OEB Leave to Construct process.

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7.0 PROJECT IMPLEMENTATION

7.1 Project scope

The OPA has assumed that the proposed expanded E-W Tie would be a new double-circuit 230 kV overhead transmission line. This is based on the knowledge that a 500 kV line or a high-voltage direct-current line would be more costly than a 230 kV line, while providing a similar benefit. A single-circuit 230 kV line would likely have a similar cost to a double-circuit 230 kV line, but would have reduced operability during planned and forced outages. Therefore, the OPA believes that the double-circuit 230 kV line is preferred, but other options could be proposed to the extent that they meet the other project scope criteria outlined below.

- The new line is to connect to both Wawa TS in the Northeast and Lakehead TS in the Thunder Bay area - a distance of approximately 400 km - and is to include all station termination facilities.

- The new line is to be switched at Marathon TS, which is an existing station between Wawa TS and Lakehead TS. The existing E-W Tie is switched at this station.

- The new line in conjunction with the existing tie is to provide total eastbound and westbound capabilities on the order of 650 MW, while respecting all NERC, NPCC and IESO reliability standards.

- The project should also include any reactive facilities that are to be identified in a pending IESO study. It is anticipated that this study will be available prior to the commencement of any designation process.

- The target in-service date of the new line and associated reactive facilities is currently estimated to be 2017, based on typical transmission project lead times.

- The new line should be designed to have a lifetime of at least 50 years.

7.2 Key project milestones

- June 2011 – OPA submits E-W Tie report to OEB

- TBD – OEB Designation Process

- TBD – Submission of Environmental Assessment ToR

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- TBD – Submission of Leave to Construct Application
- 2017 – Target in-service date for new line

It is expected that a designated transmitter would carry out all required technical, environmental, regulatory and any other approvals needed to bring the new E-W Tie line into service. The OPA will provide support to a designated transmitter during the project's implementation process.

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Feasibility Study

Power to Ontario.
On Demand.

An assessment of the westward transfer capability of various options for reinforcing the East-West Tie

1.0

A study to review the requirements for reinforcing the East-West Tie to provide a westward transfer capability of approximately 650MW

FINAL VERSION *18th August 2011*

FEASIBILITY STUDY:

TO ASSESS THE TRANSFER CAPABILITY OF VARIOUS OPTIONS FOR REINFORCING THE EAST-WEST TIE

EXECUTIVE SUMMARY

Feasibility Study: To assess the transfer capability of various options for reinforcing the East-West Tie

EXECUTIVE SUMMARY

1. Introduction

The OPA, in their report on the *Long-Term Electricity Outlook for the North-West*, has identified scope for additional load growth in the North-West and, from their assessment of the long-term supply needs for the area, *"finds that expansion of the E-W tie is the preferred alternative based on economic, flexibility, technical, operational and other considerations."*

"The OPA has assumed that the proposed expanded East-West Tie would be a new double-circuit 230kV overhead transmission line. The new line is to connect both Wawa TS and Lakehead TS.....and is to be switched at Marathon TS."

"The new line in conjunction with the existing tie is to provide total eastbound and westbound capabilities of the order of 650MW, while respecting all NERC, NPCC and IESO reliability standards."

Following the issue of FERC Order No. 743 on 18th November 2010, directing NERC to revise the definition of the Bulk Electric System (BES), it is expected that the 230kV transmission facilities west of Sudbury will be designated as BES.

This will require the East-West Tie to be designed to meet:

- the *Transmission System Planning Performance Requirements* specified in *NERC Standard TPL-001-2, &*
- the requirements for the *Design & Operation of the Bulk Power System* specified in *NPCC Directory No. 1*

This will mean that double-circuit contingencies will need to be respected at all times, rather than during high-risk periods when electrical storms are in the area, as is currently the practice.

It should be noted that although the standards specify other contingency conditions that must also be examined, including single-circuit contingencies with either a failure of their relay protection, or the failure of one of the breakers to operate, these conditions have been assumed to be less onerous for the system than double-circuit contingencies. However, to limit the adverse effects of breaker failure conditions, good station design will be critical.

Feasibility Study

This report summarises the results of analysis performed on two options for reinforcing the East-West Tie to achieve a transfer capability of approximately **650MW** westwards, measured at Wawa TS, while respecting double-circuit contingencies at all times:

Option 1 With a new 230kV double-circuit line installed between Wawa TS and Lakehead TS, as proposed by the OPA, and

Option 2 With a new 230kV high-capacity, single-circuit line installed between the same terminal stations.

East-West Tie

The present 'storm limit' on the East-West Tie, between Wawa TS and Mackenzie TS, under which double-circuit contingencies are respected, restricts transfers to approximately 175MW. As noted by the OPA in their report, should it become necessary to apply this limit at all times, it would severely affect the ability to supply the forecast load in the North-West, especially during periods of low rainfall when the output of the 780MW of hydroelectric facilities in the area would be restricted.

Sudbury Flow West Interface

The requirement to respect the loss of *'any two adjacent (vertically or horizontally) circuits on a common structure'* (NERC Standard TPL-001-2) would similarly have a significant effect on the transfer capability of the Sudbury Flow West Interface (SFW).
Following the loss of the 230kV double-circuit line between Algoma TS and Mississagi TS, all of the transfer across the SFW Interface would then appear on the 206km single-circuit 230kV line between Hanmer TS and Mississagi TS. The subsequent increase in the reactive losses would severely depress the voltages at Mississagi TS and Wawa TS; effectively limiting the maximum transfer across this Interface to approximately **350MW**.

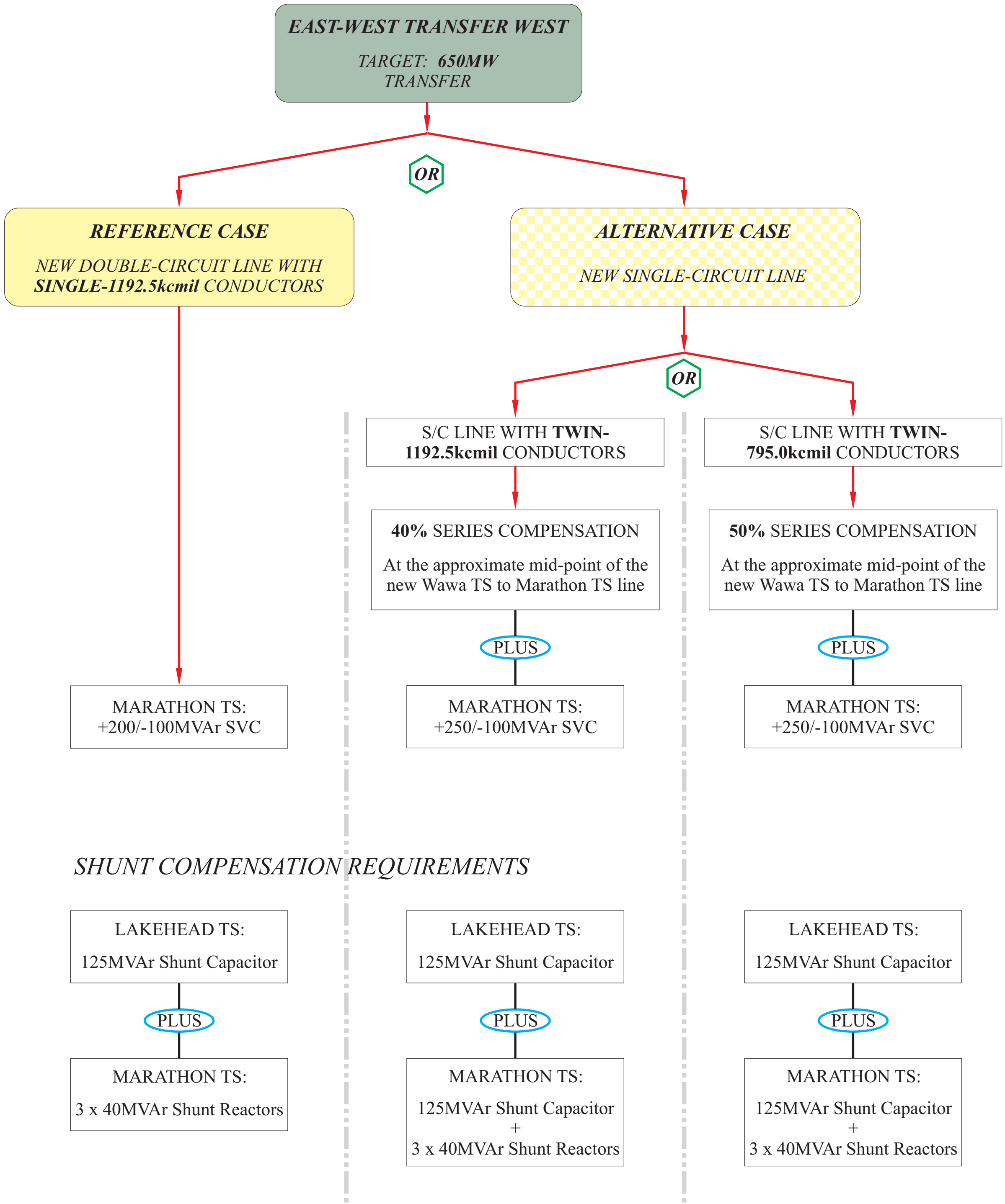
Transmission System between Mississagi TS & Wawa TS

The transmission system between Mississagi TS & Wawa TS consists of the facilities shown in the following Table:

Hydro One			*Circuits*	*Generation Connected*
Mississagi TS	to Wawa TS	230kV double-circuit line:	P25W & P26W	Aubrey Falls G1 & G2
Great Lakes Power				
Mississagi TS	to Third Line TS	Two 230kV circuits that occupy common structures for 11 spans	P21G & P22G	Wells G1 & G2
Third Line TS	to MacKay TS	230kV single-circuit line	K24G	-
MacKay TS	to Wawa TS	230kV single-circuit line	W23K	-

With the East-West Tie reinforced with a new double-circuit line between Wawa TS and Lakehead TS, double-circuit contingencies involving either the existing Hydro One owned line between Mississagi TS and Wawa TS, or the GLP owned line between Mississagi TS and Third Line, would restrict westward transfers across the East-West Tie Interface to a maximum of approximately **500MW**.

In their assessment, the OPA has identified a maximum transfer requirement across the East-West Tie of approximately *400MW* during the initial period of operation following its reinforcement. The 500MW E-W Tie Transfer West limit, for contingencies on that portion of the system between Mississagi TS and Wawa TS, would therefore be more than adequate for the expected transfers during this period.



SUMMARY OF THE REINFORCEMENT OPTIONS ***FIGURE 1***

SVC Static VAr Compensator

Reference Case for the Feasibility Study

The *Reference Case* that was used for this study assumed the construction of a new 230kV double-circuit line between Wawa TS and Lakehead TS, as proposed by the OPA, with intermediate terminations into Marathon TS. To minimise transmission losses, the new line was assumed to be equipped with single-1192.5kcmil conductors.

The following interface transfers were also assumed for the *Reference Case*, and these were achieved through adjustments to the load and generation patterns that were modelled:

- approximately **650MW** westwards, across the East-West Tie Interface, and
- approximately **350MW** across the Sudbury Flow West Interface

This report summarises the results of the analysis performed on the *Reference Case* and it also provides an assessment of an *Alternative Case* for reinforcing the East-West Tie based on the construction of a high-capacity, single-circuit 230kV line.

2. Conclusions

Figure 1 provides a summary of those facilities, identified through the analysis, which would be required to achieve the target transfer of **650MW** westwards across the East-West Tie, measured at Wawa TS, for both the *Reference Case* and the *Alternative Case,* with a coincident transfer of **350MW** across the Sudbury Flow West Interface.

2.1 Requirements for the Reference Case: With reinforcement consisting of a new 230kV double-circuit line equipped with single-1192.5kcmil conductors

For the *Reference Case*, an additional shunt capacitor bank with a nominal rating of 125MVAr (at 250kV) would be required at Lakehead TS to limit the pre-contingency reactive output from the two SVCs (Static VAr Compensators) at Lakehead TS.

Following a double-circuit contingency involving the new 230kV double-circuit line between Wawa TS and Marathon TS, all of the transfer on the East-West Tie would appear on the existing double-circuit line. To supply the immediate increase in the post-contingency reactive losses, a fast-acting source of reactive compensation would be required at Marathon TS. Further dynamic reactive compensation would also be needed to ensure that the IESO's criterion for voltage stability could be satisfied. This criterion requires the planned post-contingency transfer across the critical transmission Interface to have a margin of at least 5% from the transfer at which voltage instability is detected.

To supply both the increased post-contingency reactive losses and achieve a voltage stability limit that could accommodate a transfer of 650MW westwards across the East-West Tie, an SVC, or an equivalent source of dynamic reactive compensation, with a rating of **200MVAr,** would be required at Marathon TS.

The analysis also showed that the installation of the 200MVAr SVC, or its equivalent, at Marathon TS would be sufficient to respond to contingencies involving the new double-circuit line on the adjacent section of the East-West Tie between Marathon TS and Lakehead TS.

115kV Circuits T1M, A1B & A5A between Marathon TS and Alexander TS

Following a double-circuit contingency involving either the existing 230kV line between Marathon TS and Lakehead TS or the proposed new line, overloading of the parallel 115kV single-circuit connection between Marathon TS and Alexander TS would occur. To accommodate these increased transfers, the maximum continuous operating temperature for circuits T1M, A1B & A5A, that together form the parallel connection, would need to be increased to at least 93^{o}C to provide a continuous rating of approximately 620A.

Double-circuit Contingencies involving the section of the EW Tie between Lakehead TS & Mackenzie TS

To avoid overloading circuit B6M, which provides a parallel 115kV connection from Birch TS to Moose Lake TS, it was assumed that this circuit would be cross-tripped immediately following a double-circuit contingency involving circuits A21L & A22L between Lakehead TS and Mackenzie TS.

With the 230kV circuits A21L & A22L out-of-service, and with the 115kV circuit B6M cross-tripped, all of the load to the west of Mackenzie TS would then be isolated on to the Manitoba and Minnesota Interconnections.

To accommodate the immediate post-contingency reductions in both the transfers on the East-West Tie and in the associated reactive losses, while also maintaining voltages within acceptable limits, a reactive absorption capability of at least 100MVAr would be required at Marathon TS. This would be in addition to the absorption capability already assumed to be available from the two SVCs at Lakehead TS.

Reactive Compensation requirement for the lightly-loaded case

To maintain the pre-contingency voltages within the 250kV threshold and to limit the 'continuous' reactive absorption by the SVC at Marathon TS to a maximum of approximately 50MVAr , three 40MVAr shunt reactors would need to be installed at Marathon TS to augment the absorption capabilities of the SVCs at Lakehead TS and Marathon TS:

- Lakehead TS — a total of -80MVAr from both the existing SVC and the SVC that has been proposed to replace the existing synchronous condenser
- Marathon TS — -100MVAr as proposed to limit the post-contingency 'transient' voltages following the separation of the system west of Mackenzie TS in response to a contingency involving the 230kV line between Lakehead TS and Mackenzie TS

Restricting the maximum 'continuous' absorption by the SVC at Marathon TS to around 50MVAr was found necessary to ensure that the local voltages could be maintained below the 250kV threshold in the event of a contingency involving the SVC.

2.2 Requirements for the Alternative Case: With reinforcement consisting of a new 230kV single-circuit line

For the *Alternative Case*, the higher impedance of the new 230kV single-circuit line would result in an unbalanced flow distribution between the two lines, resulting in increased reactive losses. To compensate for these increased pre-contingency losses, a 125MVAr capacitor bank would be required at both Lakehead TS and Marathon TS.

For this Case, the loss of the existing double-circuit line would represent the more-critical contingency since all of the post-contingency transfer would then appear on the new single-circuit line.

With only the single-circuit line remaining in-service post-contingency, the reactive losses would be substantially higher than those arising from the *Reference Case*. To compensate for these increased post-contingency losses, the amount of dynamic reactive compensation available at Marathon TS would also need to increase.

For the version of the *Alternative Case* with twin-1192.5kcmil conductors, 'dynamic' compensation rated at 350MVAr would be required at Marathon TS to address the immediate post-contingency reactive requirements for a transfer of 650MW westwards across the East-West Tie.

However, a 350MVAr SVC would not be sufficient to provide a voltage stability limit that would satisfy the 5% margin required under the IESO's criteria. Since the voltage decline at Wawa TS would be the critical factor, further increases in the rating of the Marathon SVC would be far less effective than installing a second SVC at Wawa TS. Rather than pursuing this, the study concentrated on the benefits of installing series compensation on the new line.

Series Compensation on the new single-circuit line

The analysis for the *Reference Case* showed that a 200MVAr SVC would be required at Marathon TS to support the post-contingency flows through the existing double-circuit line following a contingency involving the new double-circuit line. For the *Alternative Case*, since a contingency involving the new single-circuit line would also leave only the existing double-circuit line in-service over the faulted section, an SVC rated at 200MVAr was considered to represent the *minimum* reactive requirement for achieving a transfer capability of 650MW with the *Alternative Case*.

The effect of installing different levels of series compensation on the section of the new single-circuit line between **Wawa TS and Marathon TS**, with the object of limiting the size of the SVC that would be required at Marathon TS to approximately **200MVAr**, was examined.

With the new single-circuit line equipped with either:

- ***twin-1192.5kcmil** conductors & with **40%** series compensation installed on the Wawa to Marathon section OR*
- ***twin-795.0kcmil** conductors & with **50%** series compensation installed on the Wawa to Marathon section*

For both versions of the *Alternative Case,* a **200MVAr** SVC at Marathon TS would be sufficient to provide a voltage stability limit with the necessary 5% margin to accommodate the post-contingency transfers following the loss of the existing double-circuit line between Wawa TS and Marathon TS.

For the loss of the existing double-circuit line on the adjacent section of the East-West Tie between Marathon TS and Lakehead TS, the SVCs at Lakehead TS would reach their maximum output, leaving insufficient reactive support available to allow for margin. To ensure that the requirement for a 5% margin could be satisfied, the rating of the SVC at Marathon TS would need to be increased to **250MVAr**.

115kV Circuits T1M, A1B & A5A between Marathon TS and Alexander TS

Following a double-circuit contingency involving the existing line between Marathon TS and Lakehead TS, the higher impedance of the new high-capacity, single-circuit line that would remain in-service over this section would result in higher transfers over the parallel 115kV connection than were recorded for the *Reference Case*. To accommodate this higher flow, the maximum continuous operating temperature for the circuits T1M, A1B & A5A that form this parallel connection would need to be increased to at least 105°C to provide a long-term emergency rating of approximately 690A.

Double-circuit Contingencies involving the section of the East-West Tie between Lakehead TS and Mackenzie TS

For the Alternative Case, separation of that part of the system west of Mackenzie TS on to the Manitoba and Minnesota Interconnections and the subsequent reductions in the transfers on the East-West Tie, would require not only the full reactive absorption capability of the SVCs at Marathon TS and Lakehead TS, but also the cross-tripping of the new shunt capacitor bank at Marathon TS to ensure that voltages remained below the 250kV threshold.

Relative Merits of a new High-Capacity Single-Circuit line versus a new Double-Circuit line

One-plus-One Contingency

The NERC, NPCC & IESO criteria all refer to a requirement to respect a second single-element contingency after experiencing an initial single-element contingency or outage, with control actions being taken between the two events to adjust the flows.

With the East-West Tie reinforced with a new single-circuit line, it would therefore be necessary, immediately following a contingency or outage involving this new line, to re-prepare the system for the loss of one of the circuits on the remaining double-circuit line.

Since the loss of the new single-circuit line would leave only the existing double-circuit in-service over the affected section, the transfer capability of the East-West Tie would therefore be reduced to the present limit for a *single-circuit contingency* of 350MW.
Since the targeted transfer capability of the reinforced East-West Tie is 650MW, a reduction to 350MW following the loss of the new single-circuit line would therefore require either additional generating resources totalling at least 300MW to be dispatched, or if there were the capability to arm load rejection of up to 150MW in response to the second contingency, then this would allow a corresponding lesser amount of generation to be dispatched.

Increasing the transfers via the Interconnections with Manitoba and Minnesota would also allow the amount of generation capacity that would need to be dispatched to be reduced.

All of these control actions would comply with the IESO's criteria.

Reinforcing the East-West Tie with a new double-circuit line would require no similar actions following the loss of either of the double-circuit lines (a simultaneous One-plus-One contingency) or the loss of one circuit of one of the lines followed by the loss of one of the circuits of the companion line.

For the One-plus-One contingency condition, the installation of a new double-circuit line to reinforce the East-West Tie would therefore represent the superior option.

2.3 Transmission System Losses: For the two reinforcement options

The transmission losses recorded for each of the reinforcement options that were assessed have been summarised in the following Table:

Summary of Transmission Losses on the East-West Tie								
Diagram	*East-West Transfer West*	*Marathon to Wawa Section*			*Lakehead to Marathon Section*			*Total Losses for both Sections*
			Circuit losses	*Total Losses*		*Circuit losses*	*Total Losses*	
Reference Case: With double-circuit lines equipped with single-1192.5kcmil conductors								
5.	652.0MW	New line	8.6MW	20.6MW	New line	8.4MW	19.8MW	*40.4MW*
		Existing:	12.0MW		Existing:	11.4MW		
Alternative Case with: New single-circuit lines equipped with twin-1192.5kcmil conductors								
14.	664.2MW	New line	6.0MW	23.6MW	New line	5.6MW	21.4MW	*45.0MW*
		Existing:	17.6MW		Existing:	15.8MW		
Alternative Case with: New single-circuit lines equipped with twin-1192.5kcmil conductors & with 40% series compensation of the new Wawa x Marathon line								
18.	662.0MW	New line	10.0MW	20.8MW	New line	5.7MW	21.5MW	*42.3MW*
		Existing:	10.8MW		Existing:	15.8MW		
Alternative Case with: New single-circuit lines equipped with twin-795.0kcmil conductors & with 50% series compensation of the new Wawa x Marathon line								
28.	670.6MW	New line	17.9MW	27.5MW	New line	8.4MW	24.8MW	*52.3MW*
		Existing:	9.6MW		Existing:	16.4MW		

These results show the following:

- For the Reference Case (Diagram 5), the installation of the 1192.5kcmil conductors on the new double-circuit line would reduce the losses by approximately 6.4MW. (A reduction of approximately 27%)

  [3.4MW on the Wawa to Marathon section plus 3.0MW on the Marathon to Lakehead section.]

- For the Alternative Case with no series compensation installed on the new line (Diagram 14), the unbalanced flow distribution would increase the losses on the existing line by 10.0MW (~ 43%). The results also show that because of the much lower losses on the new line there would be little benefit from equipping it with a larger conductor.

- Installing series compensation on the new line of the Alternative Case would improve the flow distribution between the two lines, reducing the losses on the existing line.

  In Diagram 18, with 40% series compensation installed on the new line equipped with 1192.5kcmil conductors, the total losses for the two lines on the *Wawa to Marathon section* would be similar to those for the Reference Case.

  In Diagram 28, with 50% series compensation installed on the new line equipped with 795.0kcmil conductors, the total losses for the two lines on the *Wawa to Marathon section* would be approximately 7MW higher than those for the Reference Case. Although the higher level of compensation would contribute to these increased losses, the primary cause would be the smaller conductor size.

Series Compensation and Conductor Size: Effect on Transmission Losses

Although the primary objective of installing series compensation on the new single-circuit line for the *Alternative Case* was to achieve a reduction in the post-contingency reactive losses on the new line and to reduce the size of the SVC required at Marathon TS, the improved flow distribution that would occur between the two lines would be an added benefit.

Since the proportion of the East-West Tie transfer that would appear on the new line will depend on the level of compensation installed, this would present an opportunity to minimise the transmission losses through the selection of an appropriate conductor size in conjunction with the preferred level of series compensation.

3. Replacement SVC at Lakehead TS: Recommendation

In this study it was assumed that the replacement SVC for the existing synchronous condenser at Lakehead TS would be rated the same as the existing SVC; namely +60/-40MVAr.

The analysis has indicated that should the East-West Tie be reinforced and its transfer capability increased, that the Lakehead area would benefit from a higher rated unit.

It is therefore recommended that when a decision is made to replace the existing synchronous condenser that consideration should be given to acquiring an SVC with rating of at least ± 100MVAr.

4. Station Layout Diagrams

A second report detailing the proposed connection arrangements for the new facilities at Mississagi TS, Wawa TS, Marathon TS and Lakehead TS, paying particular attention to reducing any adverse effects from breaker-failure conditions, will be issued by end-September 2011.

FEASIBILITY STUDY:

TO ASSESS THE TRANSFER CAPABILITY OF VARIOUS OPTIONS FOR REINFORCING THE EAST-WEST TIE

STUDY REPORT

STUDY REPORT

This report summarises the results of analysis performed on different options for reinforcing the East-West Tie to achieve a transfer capability of approximately **650MW** westwards, measured at Wawa TS.

5. *Reinforcement Options that were examined*

i. The *Reference Case*, with the East-West Tie reinforced with a new 230kV double-circuit line, equipped with 1192.5kcmil conductors, installed between Wawa TS and Lakehead TS, with terminations into Marathon TS

ii. An *Alternative Case* with the reinforcement of the East-West Tie provided through the installation of a new single-circuit 230kV line between Wawa TS and Lakehead TS, with terminations into Marathon TS.

Two options were considered for the conductors to be installed on the proposed single-circuit line:

- Twin-795.0kcmil 26/7 conductors (two conductors per phase, separated by spacers), to give thermal ratings approximately the same as those provided by the existing double-circuit line.
- Twin-1192.5kcmil 54/19 conductors to provide similar thermal ratings to those proposed for the new double-circuit line.

Each of these cases will require different amounts of post-contingency reactive support to satisfy the IESO's voltage-stability requirements. Additional studies were also conducted to identify facilities that would permit the IESO's criteria to be met while minimising or eliminating the need for additional reactive compensation.

Assumed thermal ratings for the new line

Thermal Ratings for the new line *(assumed sheltered)*			*(MVA ratings at 240kV)*			
For an ambient temperature of 30^oC & a wind speed of 0-4km/hr			*Continuous at 93^oC*		*Long-term Emergency at 127^oC*	
1.	*Reference Case* For each circuit of the new double-circuit line	*equipped with* ***single-*** *1192.5kcmil 54/19 conductors*	1120A	466MVA	1440A	599MVA
2.	*Alternative Case* For the new circuit of the single-circuit line	*equipped with* ***twin-*** *795.0kcmil 26/7 conductors*	1750A	727MVA	2240A	931MVA
3.		*equipped with* ***twin-*** *1192.5kcmil 54/19 conductors*	2230A	927MVA	2880A	1197MVA

6. *Generation Assumptions*

North-West

For this study, the output from the existing hydroelectric facilities was set at 334MW, which would represent approximately 43% of the peak output of 780MW from these facilities. This would be similar to the expected output from the hydroelectric facilities during a dry year.

A further contribution of 56MW was also assumed to be available from the existing gas-fired facilities in the area, giving a total output of **390MW** from the generation facilities in the North-West.
The Atikokan and Thunder Bay facilities were assumed to be out-of-service, and the output from the wind-turbine facilities was assumed to be zero.

North-east

The output from the hydroelectric facilities owned by Great Lakes Power (GLP), within the area between Algoma TS and Wawa TS, was set at 560MW. This would represent approximately 70% of their peak output of 804MW.

The existing thermal generation in the area was assumed to contribute a further 142MW, primarily from the Lake Superior Power and the Algoma Steel facilities.

The total generation assumed for the GLP area was therefore **702MW**. For the entire north-east, of which the GLP area is part, the total generation output was assumed to be **1372MW**.

7. Load Assumptions

For this study, a peak load of 950MW was assumed for the North-West, which would give a peak demand of approximately1040MW once the transmission losses of approximately 90MW have been factored in. This demand would therefore correspond reasonably closely with the demand forecast contained in the OPA's report of 30th June 2011 entitled:

Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion

The base load for the North-West that had been modelled in the load flow case used for this study totalled approximately 675MW. To achieve the required load of 950MW, 215MW of new load was added in the Thunder Bay area, with a further 60MW of new load distributed throughout the Red Lake/Crow River/Musselwhite area.

To avoid possible overloading of the existing 115kV transmission facilities from Dryden TS as a result of adding the new loads in the Red Lake/Crow River/Musselwhite area, a new 115kV connection was assumed to be available between Valora Junction and Musselwhite SS.

8. Target Transfers on the East-West Tie and on the Sudbury Flow West Interface

With the output from the local generation facilities in the North-West set at 390MW, and with the total load in this area adjusted to 950MW, then after accounting for the estimated 90MW of transmission losses on the system west of Wawa TS, this would result in the targeted transfer of approximately **650MW** being required across the East-West Tie Interface.

For the area between Algoma TS and Wawa TS, the loads included in the model totalled approximately 370MW, while the transmission losses over this part of the system were shown to total approximately 30MW.

Analysis had also shown that the existing transmission facilities between Sudbury (Hanmer TS and Martindale TS) and Mississagi TS would be capable of supporting a maximum transfer of approximately **350MW**, following a double-circuit contingency involving the existing line between Algoma TS and Mississagi TS.

With a maximum transfer of **350MW** across the Sudbury Flow West Interface and with a total demand of approximately 400MW in the area between Algoma TS and Wawa TS, the output from the generating facilities in this area, all of it owned by GLP, had to be set at approximately 700MW to achieve the targeted transfer of **650MW** across the East-West Tie**.**

9. Planning Criteria

On 18th November 2010 FERC issued Order 743 and directed NERC to revise the definition of Bulk Electric System so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system.

In response, NERC initiated Project 2010-17 SDT and proposed the following continent-wide definition of the Bulk Electric System:

Bulk Electric System:

All Transmission and Generation Elements and Facilities operated at voltages of 100kV or higher necessary to support bulk power system reliability. Elements and Facilities operated at voltages of 100kV or higher, including Radial Transmission systems, may be excluded and Elements and Facilities operated at voltages less than 100kV may be included if approved through the BES definition exemption process.

Should those 230kV transmission facilities west of Sudbury be designated as part of the Bulk Electric System, then the Standards that would need to be respected would be the following:

i. NERC Standard TPL-001-2 **Transmission System Planning Performance Requirements**

[This Standard scheduled to be submitted for regulatory approval during Q3 of 2011]

Extract from Table 1. Transmission System Standards - Normal and Emergency Conditions

Category	*Initial Condition*	*Event*	*Fault Type*	*Interruption of firm transmission service allowed*	*Non-consequential load loss*
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments: 1. Transmission Circuit 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: Any two adjacent (vertically or horizontally) circuits on a common structure	SLG	Yes	Yes

ii. ***NPCC Directory No. 1*** dated 15th December 2009, which states:

5.4 Transmission Design Criteria

The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of the **ten-minute reserve** and where available, phase angle regulator control and HVdc control.

5.4.1 Stability Assessment

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing.** For each of the **contingencies** stated below that involves a fault, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **"system B" protection group**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**.

iii. The IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)

From Section 2.7.1: ***The Bulk Power System Contingency Criteria***

In accordance with *NPCC* criteria A-02, the bulk power system portion of the *IESO-controlled grid* shall be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in this section. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that generation and power flows are adjusted between *outages* by the use of *ten-minute operating reserve* and where available, phase angle regulator control and HVdc control.

Stability of the bulk power system shall be maintained during and following the most severe of the contingencies stated below, with due regard to reclosing. The following contingencies are evaluated for the bulk power system portion of the *IESO-controlled grid*:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.

b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent circuits of a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition is an acceptable risk and therefore can be excluded.

The analysis covered by this report therefore concentrated on the effects of double-circuit contingencies involving the following line sections:

i.	between Algoma TS and Mississagi TS	Circuits A23P & A24P	
ii.	between Wawa TS and Marathon TS	Circuits W21M & W22M,	or the new double-circuit line
iii.	between Marathon TS and Lakehead TS	Circuits M23L & M24L,	or the new double-circuit line
iv.	between Lakehead TS and Mackenzie TS.	Circuits A21L & A22L	

Analysis also examined the effect of double-circuit contingencies involving the line section between Mississagi TS and Wawa TS (circuits P25W & P26W) and the section of circuits P21G & P22G near GLP's Third Line Substation that uses double-circuit line construction, to provide an indication of the transfer capability of this portion of the system.

Both of these contingency conditions would result in the loss of generation capacity; for a P25W + P26W contingency - the loss of both Aubrey Falls units; and for a P21G + P22G contingency - the loss of both Wells units.

From Section 4.5.1 **_Power - Voltage (P-V) Curves_**

With the loads modelled as constant MVA loads, the transfer across the critical interface is to be increased in small increments (usually 1% of the interface transfer), recording the power flow and busbar voltages until the knee-point of the P-V Curve is reached or the case does not solve.

For voltage stability, the interface transfer corresponding to the knee-point when multiplied by 0.95 (representing the required 5% margin) must be greater than the interface transfer recorded in the post-contingency study.

10. Transfers to Manitoba & Minnesota

For this study, pre-contingency transfers of approximately 0MW were assumed on the Interconnections with both Manitoba and Minnesota.

Operation of the Phase-Shifters

The current modes of operation for the phase-shifters on the Manitoba and Minnesota Interconnections are described below. For the purpose of this study it has been assumed that, following the reinforcement of the East-West Tie, the present modes of operation will continue.

Phase-shifters on the Manitoba Interconnections

Once a difference of more than 25.6MW from the scheduled transfer is detected across this Interconnection, the operation of the phase-shifters is initiated. Tap-changer operation will then continue until either the difference between the actual and the scheduled transfer is reduced below the 25.6MW threshold or until four tap-changer operations have been completed. Once four tap-changer operations have occurred within a two minute period, the controller is automatically switched to the manual mode.

Phase-shifters on the Minnesota Interconnection

For transfers across this Interconnection that increase by more than 55MW in 10 seconds, the two, series-connected phase-shifters will move a combined total of four taps before automatically switching to the manual mode.

For transfers that are greater than 10MW and less than 55MW, tap-changer operation will continue until the difference between the actual and the scheduled transfer is less than 10MW.

11. Contingency Conditions Examined

Sudbury Flow West Interface

- To establish the appropriate transfer level to use for the Sudbury Flow West Interface:

  A double-circuit contingency involving circuits A23P & A24P between Algoma TS and Mississagi TS

  This contingency would leave only circuit X74P between Hanmer TS and Mississagi TS to supply all of the system west of Mississagi TS

East West Tie Interface

- *For the Wawa - Marathon Section*

  i. For the *Reference Case* with a new double-circuit 230kV line, equipped with 1192.5kcmil conductors, installed between Wawa TS & Marathon TS

     A double-circuit contingency involving the *new* line would leave the existing line, with its lower-rated 795kcmil conductors, to carry the entire transfer on the East-West Tie.

  ii. For the *Alternative Case* with a new single-circuit 230kV line installed between Wawa TS & Marathon TS

     A double-circuit contingency involving the *existing* line would leave the new single-circuit line to carry the entire transfer on the East-West Tie.

- *For the Marathon - Lakehead Section*

  Depending on whether the reinforcement of the East-West Tie were to consist of either a new single- or a double-circuit line, the same contingency conditions that were identified for the previous section would also apply to this section.

  It should also be noted that for this section, there is a parallel, single-circuit 115kV connection, formed by circuits T1M, A1B & A5A between Marathon TS & Alexander TS. Since a portion of the post-contingency transfer would appear on this line, it could result in overloading.

- *For the Lakehead - Mackenzie Section*

  Since there are no plans to reinforce this section, a double-circuit contingency involving circuits A21L & A22L would require that the parallel 115kV circuit B6M be cross-tripped to avoid it being overloaded. Alternatively, this circuit could be operated normally-open.

  The net result of this contingency would be the separation of the system, with that part of the system west of Mackenzie TS remaining connected to the Manitoba & Minnesota systems via their respective Interconnections.

  Separation of this area from the East-West Tie and the transfer of its supply on to the Manitoba & Minnesota systems would therefore unload the connections between Hanmer TS and Lakehead TS, resulting in increased voltages.

12. Study Results

- For each of the reinforcement options, pre-contingency load-flows were performed and the results summarised in load-flow diagrams.

- For each contingency condition, two individual load-flows were performed for the following conditions and the results also summarised in separate load-flow diagrams:

  i. for the situation *prior to* the adjustment of the phase-shifters on the Manitoba & Minnesota Interconnects, and

  ii. for the situation *after* the phase-shifters had been adjusted.

  PV-analysis (Power versus Voltage) was then performed on the post-contingency case *after* the phase-shifter adjustments had been completed. The intent of this analysis was to confirm that the reactive resources available would be sufficient to provide the 5% margin on the critical transfer as required by the IESO's criteria.

Comments have only been provided on a selection of these studies.

However, the following commentary, for the initial study on the Reference Case, has been prepared to assist in the interpretation of these results.

12.1 Reference Case Commentary

With a new double-circuit 230kV line equipped with single-1192.5kcmil conductors

Diagram 5: Pre-contingency Load-Flow

For this case, the principal transfers and outputs from the SVCs were as follows:

Sudbury Flow West		353.1MW
East-West Transfer West		652.0MW
Manitoba Transfer	(positive into Ontario)	3.4MW
Minnesota Transfer	(positive into Ontario)	2.2MW
Marathon SVC	+ 200/- 100MVAr	13.6MVAr
Lakehead SVCs	+ 120/- 80MVAr	-53.4MVAr
NW Transmission Losses		83MW
NE Transmission Losses		70MW

Diagram 6: Post-contingency Load-Flow *prior to* the adjustment of the Manitoba & Minnesota phase-shifters
For a double-circuit contingency involving the Wawa to Marathon section of the new line

				Change compared to Diagram 5
Sudbury Flow West		321.1MW	Δ	- 32.0MW
East-West Transfer West		622.8MW	Δ	- 29.2MW
Manitoba Transfer	(positive into Ontario)	31.8MW	Δ	+ 28.4MW
Minnesota Transfer	(positive into Ontario)	20.6MW	Δ	+ 18.4MW
Marathon SVC	+ 200/- 100MVAr	152.5MVAr	Δ	+ 138.9MVAr
Lakehead SVCs	+ 120/- 80MVAr	-61.4MVAr	Δ	- 8.0MVAr
NW Transmission Losses		109MW	Δ	+ 26MW
NE Transmission Losses		58MW	Δ	- 12MW

Following the contingency, the transfers on the SFW & EW Tie-W Interfaces were reduced by 32MW and 29MW, respectively while the combined import via the Interconnections to Manitoba and Minnesota increased by approximately 47MW. The difference is due primarily to the increased losses on the system in the North-West

In response to the increased reactive losses on the existing line following the loss of the new line between Wawa TS and Marathon TS, the output from the SVC at Marathon is shown to increase by 139MVAr.

Diagram 7: Post-contingency Load-Flow *after* the adjustment of the Manitoba & Minnesota phase-shifters
For a double-circuit contingency involving the Wawa to Marathon section of the new line

				Change compared to Diagram 5
Sudbury Flow West		373.0MW	Δ	+ 19.9MW
East-West Transfer West		668.6MW	Δ	+ 16.6MW
Manitoba Transfer	(positive into Ontario)	18.0MW	Δ	+ 14.6MW
Minnesota Transfer	(positive into Ontario)	2.5MW	Δ	+ 0.3MW
Marathon SVC	+ 200/- 100MVAr	200.0MVAr	Δ	+ 186.4MVAr
Lakehead SVCs	+ 120/- 80MVAr	-31.2MVAr	Δ	+ 22.2MVAr
NW Transmission Losses		123MW	Δ	+ 40MW
NE Transmission Losses		66MW	Δ	- 4MW

Following the adjustment of the phase-shifters, the combined transfer from Manitoba and Minnesota would be reduced to 15MW, resulting in increased transfers over the SFW and E-W Tie-W Interfaces to supply the increased transmission losses in the North-West.

The increased transfer across the East-West Tie is shown to result in a further increase in the reactive losses on the remaining two circuits between Wawa TS and Marathon TS, causing the output of SVC at Marathon TS to reach its maximum of 200MVAr.

The combined reactive output from the two Wells units is shown as 19.5MVAr (leaving approximately 84MVAr of their capability remaining) while the combined reactive output from the two Aubrey Falls units is 20.6MVAr (leaving 45MVAr available).

Diagram 8: Results from the PV-analysis on the post-contingency case *after* phase-shifter action

A contingency involving the new double-circuit line between Wawa TS and Marathon TS would have a direct effect on the ability to transfer power westwards across the East-West Tie Interface. This study therefore examined the effect on the busbar voltages in the immediate area of increasing the transfers across this Interface. The purpose of this analysis was to confirm that adequate reactive resources would be available to provide a margin of at least 5% on the transfer that was recorded across the East-West Tie Interface in the post-contingency study.

From **Diagram 7**, the post-contingency transfer across the EW-W Interface was **668.6MW**.

The PV-analysis plots in **Diagram 8** start at this transfer level and show the effect of increasing the flow across the EW-W Interface until the load-flow fails to converge. This is shown to occur at an EW-W Transfer of **722MW**, when the voltages at Wawa TS and Marathon TS experienced excessive declines.

The final plot on **Diagram 8** shows the reactive capability remaining available from the monitored resources.

Since the SVC at Marathon TS was shown to have reached its maximum output of 200MVAr in **Diagram 7** it would no longer be able to contribute reactive support. Although the units at Wells GS are shown to provide some reactive support in response to the declining voltage at Mississagi TS, the decline at that location is not sufficient for these units to reach their maximum output. Similarly, for the units at Aubrey Falls GS. However, the greatest reactive contribution is shown to be provided by the SVCs at Lakehead TS and, from the upper plot on **Diagram 8**, they are shown to be successful in maintaining the voltage on the 230kV busbar at Lakehead TS at its set point of 243kV while they still have reactive capacity available.

Once the two SVCs at Lakehead reach their maximum combined output of 120MVAr, the load-flow fails to converge (since the output from these SVCs is shown as - 31.2MVAr in **Diagram 7**, they would therefore have 151.2MVAr remaining available for voltage support at the start of the PV-analysis.)

When the SVCs at Lakehead TS are no longer capable of maintaining the voltage at that busbar at its set point, the voltages at Wawa TS and Marathon TS will collapse, resulting in the load-flow failing to converge.

Applying a 5% margin on the limiting transfer of *722MW* at which the PV-analysis terminated would give a *voltage stability limit* of **686MW**. Since this would exceed the post-contingency transfer of 668.6MW, it would satisfy the IESO's voltage stability criterion.

The installation of a 200MVAr SVC at Marathon TS would therefore be sufficient to support the post-contingency transfer across the East-West Tie Interface of 668MW, or the equivalent pre-contingency transfer of 652MW.

In practice, this 'dynamic' reactive support could be provided by fast, mechanically-switched shunt devices with individual ratings selected to ensure that the IESO's criterion that the maximum incremental voltage change in response to their switching should be no greater than 4%, is respected. [Section 4.3.2 of ORTAC]

12.2 Summary of the results from the studies on the Sudbury Flow West Interface

To establish an appropriate value for the transfer across the Sudbury Flow West Interface to be included in the load flow model used for the analysis of the options for reinforcing the East-West Tie, an initial series of studies were completed. These studies examined the transfer capability of the existing transmission facilities between Sudbury and Mississagi TS, following the loss of the double-circuit line between Algoma TS and Mississagi TS. The results have been summarised in **Table 1**.

For these studies the proposed *Reference Case* reinforcement, involving a new 230kV double-circuit line between Wawa TS and Lakehead TS, via Marathon TS, was included in the model.

To achieve the targeted transfer of 650MW across the East-West Tie, a shunt capacitor rated at 125MVAr (at 250kV) was included at Lakehead TS on the 230kV busbar. For this analysis, no additional reactive support was included at Marathon TS.

The PV-analysis showed that with the two SVCs at Lakehead TS in-service, together with all four units at Wells GS and Aubrey Falls GS available to provide post-contingency reactive support, the voltage stability limit for the Sudbury Flow West Interface, after allowing for the required 5% margin, would be approximately 360MW.

For the transfers across Sudbury Flow West Interface, **350MW** was therefore adopted as the reference value in all of the subsequent analysis.

12.3 Summary of the results from the studies on the Reference Case

The results from the series of studies on the *Reference Case* with a new 230kV double-circuit line between Wawa TS and Lakehead TS, via Marathon TS, have been summarised in **Table 2**.

For contingencies involving the new double-circuit line between Wawa TS and Marathon TS, the PV-analysis shows that an SVC at Marathon TS with a rating of + 200MVAr would provide voltage stability limit that would be more than adequate to accommodate the targeted transfer of 650MW westwards across the East-West Tie.

However, for contingencies involving the new double-circuit line between Marathon TS and Lakehead TS, a 200MVAr SVC at Marathon would result in a voltage stability limit that would be marginally lower than the post-contingency transfer. This would mean that either a higher rated SVC would need to be installed at Marathon TS or that the replacement SVC for the existing synchronous condenser at Lakehead TS should have a higher rating than the +60/-40MVAr rating of the existing SVC.

For contingencies involving the existing double-circuit line between Lakehead TS and Mackenzie TS, that would require cross-tripping of the parallel 115kV circuit B6M and result in the separation of the system west of Mackenzie TS, the SVC at Marathon TS would need to have a reactive absorption capability of at least 100MVAr to ensure that voltages remain within the 250kV threshold.

In all of these studies the post-contingency flows on the remaining circuits were within their respective long-term emergency ratings except for those on the 115kV circuit T1M, between Marathon TS and Terrace Bay TS. Since the maximum conductor operating temperature of this circuit is only 70^{o}C, its rating is limited to just 96MVA. In **Diagram 8**, the post-contingency flow on this circuit is shown to be approximately 93MVA, but once the phase-shifters are adjusted this would increase to approximately 100MVA, as shown in **Diagram 9**.

TABLE 1:	***SFW Transfer***	***Study Results for the Reference Case***	***With a new double-circuit line**, equipped with single-1192.5kcmil conductors*		
Diag.	*E-W Tie Transfer Westwards:* **650MW**		*Sudbury Flow West (SFW) Transfer:* **350MW**	*EW Transfer W*	*SFW Transfer*
1.	Pre-contingency		*With a new 230kV double-circuit line between Wawa TS and Lakehead TS*	651MW	353MW
2.	D/C Contingency: Algoma x Mississagi circuits	No PS action	Manitoba: 38MW Minnesota: 25MW Lakehead SVCs: -80MVAr	580MW	273MW
3.		With PS action	Manitoba: 33MW Minnesota 2MW Lakehead SVCs: -45MVAr	615MW	312MW
4.		PV-analysis:	*Voltage Stability Limit for SFW Transfers:* *361MW*		

TABLE 2:	***EW Tie Transfer West***	***Study Results for the Reference Case***	***With a new double-circuit line**, equipped with single-1192.5kcmil conductors*	
Diag.	*E-W Tie Transfer Westwards:* **650MW**		*Sudbury Flow West (SFW) Transfer:* **350MW**	*EW Transfer W*
5.	Pre-contingency		*With a +200/-100MVAr SVC at Marathon TS*	652MW
6.	D/C Contingency: New Wawa x Marathon circuits	No PS action	Manitoba: 32MW Minnesota: 21MW Marathon SVC: 153MVAr Lakehead SVCs: -61MVAr	623MW
7.		With PS action	Manitoba: 18MW Minnesota: 3MW Mississagi SVC: **200MVAr** Marathon SVC: -31MVAr	669MW
8.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* *686MW*	
9.	D/C Contingency: New Marathon x Lakehead circuits	No PS action	Manitoba: 31MW Minnesota: 21MW Marathon SVC: 89MVAr Lakehead SVCs: 77MVA	624MW
10.		With PS action	Manitoba: 15MW Minnesota: 2MW Marathon SVC: 143MVAr Lakehead SVCs: 116MVAr	**673MW**
11.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* ***671MW***	
12.	D/C Contingency: Mackenzie x Lakehead circuits	No PS action	Manitoba: 119MW Minnesota: 75MW Marathon SVC: -100MVAr Lakehead SVCs: -69MVA	434MW
13.		With PS action	Manitoba: 130MW Minnesota: 64MW Marathon SVC: -100MVAr Lakehead SVCs: -69MVA	434MW

Notes on the Tables

PS	Phase-Shifters on the Interconnections to Manitoba and Michigan
PV-analysis	Power versus Voltage studies to confirm that the required 5% margin can be achieved on the post-contingency case
D/C Contingency	Double-circuit contingency involving adjacent circuits on a common line structure
S/C Contingency	Single-circuit contingency

As part of the project to reinforce the East-West Tie it is therefore recommended that the maximum operating temperature of circuits T1M, A1B & A5A that form the connection between Marathon TS and Alexandra SS be increased to at least 93^{O}C. This would provide a continuous rating for this connection of approximately 130MVA.

12.4 Summary of the results from the studies on the Alternative Case

The results from the series of studies on the *Alternative Case* with a new 230kV single-circuit line between Wawa TS and Lakehead TS, via Marathon TS, have been summarised in **Table 3**.

Following a double-circuit contingency involving the existing East-West Tie line, the higher reactance of the remaining single-circuit line would result in substantially higher reactive losses than would occur for the *Reference Case* that would leave a double-circuit line in-service. This would require greater amounts of reactive compensation to be installed to maintain an acceptable post-contingency voltage performance.

With the East-West Tie reinforced with a new single-circuit line equipped with twin-1192.5kcmil conductors, a 125MVAr (at 250kV) shunt capacitor would need to be installed at Marathon TS, in addition to a similarly rated bank at Lakehead TS, to compensate for the increased reactive losses.

The PV-analysis on the post-contingency case for the loss of the existing double-circuit line between Wawa TS and Marathon TS showed that an SVC at Marathon TS, rated at 350MVAr would be insufficient to achieve a voltage stability limit that would be high enough to accommodate the post-contingency transfer.

Series Compensation

Although the size of the SVC at Marathon TS could be increased, or a second SVC installed at Wawa TS to achieve the required voltage stability limit, this would not address the cause of the high reactive losses which arise as a result of the higher reactance of the single-circuit line.

Installing series compensation on the new line to reduce its effective reactance would reduce the reactive losses and hence the requirement for additional reactive compensation at Marathon TS.

Alternative Case with twin-1192.5kcmil conductors

The results from the studies for the *Alternative Case* with a new single-circuit line equipped with twin-1192.5kcmil conductors and with **40%** series compensation installed on the **Wawa TS to Marathon TS** section are summarised in **Diagrams 18 to 27** inclusive.

These show that, with 40% series compensation installed on the Wawa TS to Marathon TS section of the new line:

- for the loss of the existing double-circuit line between Wawa TS and Marathon TS, a 200MVAr SVC at Marathon TS, would be sufficient to provide a post-contingency voltage stability limit that would satisfy the IESO's criteria.

- for the loss of the existing double-circuit line between Marathon TS and Lakehead TS, the size of the SVC at Marathon TS would need to be increased to 250MVAr, to provide a post-contingency voltage stability limit that would satisfy the IESO's criteria.

TABLE 3: ***EW Tie Transfer West***		***Study Results for the Alternative Case*** ***With a new single-circuit, high-capacity line***		
Diag.	*E-W Tie Transfer Westwards:* **650MW** *Sudbury Flow West (SFW) Transfer:* **350MW**			
With a new single-circuit line, equipped with twin-1192.5kcmil conductors				*EW Transfer W*
14.	Pre-contingency		*With a **350MVAr** SVC at Marathon TS*	664MW
15.	D/C Contingency: Existing Wawa x Marathon circuits	No PS action	Manitoba: 45MW Minnesota: 28MW Marathon SVC: 128MVAr Lakehead SVCs: -60MVAr	589MW
16.		With PS action	Manitoba: 40MW Minnesota: 0MW Marathon SVC: 233MVAr Lakehead SVCs: -42MVAr	**636MW**
17.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers with a 350MVAr SVC at Marathon TS:* ***630MW***	
18.	Pre-contingency		*With a **200MVAr** SVC at Marathon TS & **40% series compensation** on the new Wawa x Marathon line*	662MW
19.	D/C Contingency: Existing Wawa x Marathon circuits	No PS action	Manitoba: 22MW Minnesota: 14MW Marathon SVC: 68MVAr Lakehead SVCs: -38MVAr	632MW
20.		With PS action	Manitoba: 2MW Minnesota: 1MW Marathon SVC: 123MVAr Lakehead SVCs: -16MVAr	676MW
21.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* *716MW*	
22.	D/C Contingency: Existing Marathon x Lakehead circuits	No PS action	Manitoba: 38MW Minnesota: 25MW Marathon SVC: 63MVAr Lakehead SVCs: 96MVAr	607MW
23.		With PS action	Manitoba: 27MW Minnesota: 0MW Marathon SVC: 142MVAr Lakehead SVCs: 120MVAr	**657MW**
24.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers with a 200MVAr SVC at Marathon TS:* ***646MW***	
25.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers with a **250MVAr** SVC at Marathon TS:* ***662MW***	
26.	D/C Contingency: Mackenzie x Lakehead circuits.	No PS action	Manitoba: 120MW Minnesota: 75MW Marathon SVC: -95MVAr Lakehead SVCs: -28MVA	433MW
27.		With PS action	Manitoba: 131MW Minnesota: 64MW Marathon SVC: -95MVAr Lakehead SVCs: -28MVA	433MW
With a new single-circuit line, equipped with twin-795.0kcmil conductors				*EW Transfer W*
28.	Pre-contingency		*With a **200MVAr** SVC at Marathon TS & **50% series compensation** on the new Wawa x Marathon line*	671MW
29.	D/C Contingency: Existing Wawa x Marathon circuits	No PS action	Manitoba: 22MW Minnesota: 15MW Marathon SVC: 93MVAr Lakehead SVCs: -26MVAr	656MW
30.		With PS action	Manitoba: 4MW Minnesota: 3MW Marathon SVC: 146MVAr Lakehead SVCs: -3MVAr	700MW
31.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* *735MW*	
32.	D/C Contingency: Existing Marathon x Lakehead circuits	No PS action	Manitoba: 45MW Minnesota: 29MW Marathon SVC: 70MVAr Lakehead SVCs: 120MVAr	616MW
33.		With PS action	Manitoba: 40MW Minnesota: 1MW Marathon SVC: 164MVAr Lakehead SVCs: 120MVAr	**667MW**
34.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers with a 200MVAr SVC at Marathon TS:* ***649MW***	
35.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers with a **250MVAr** SVC at Marathon TS:* ***665MW***	

Alternatively, as indicated by the bottom plot on **Diagram 25**, where the SVCs at Lakehead are shown to have exhausted their reactive capability before the transfer margin is applied, the availability of *additional* reactive capability at Lakehead TS would avoid the need to increase the rating of the SVC at Marathon TS to 250MVAr to achieve the required voltage stability limit.

- for the loss of the existing double-circuit line between Mackenzie TS and Lakehead TS which would unload the East-West Tie following the isolation of the loads west of Mackenzie TS on to the Manitoba and Minnesota Interconnections, the new 125MVAr shunt capacitor bank at Marathon TS would need to be cross-tripped. This would be in addition to having a 100MVAr absorption capability from the SVC at Marathon TS to ensure that the post-contingency voltages are maintained below the 250kV threshold.

Alternative Case with twin-795.0kcmil conductors

The results from the studies for the *Alternative Case,* with a new single-circuit line equipped with twin-795.0kcmil conductors and with the level of series compensation installed on the **Wawa TS to Marathon TS** section increased to **50%**, are summarised in **Diagrams 28 to 35** inclusive.

These show that with the new line equipped with the smaller conductors but with the level of series compensation on the Wawa TS to Marathon TS section increased to **50%,** there would be no change in the rating required for the SVC at Marathon TS for the following double-circuit contingencies:

- for a contingency involving circuits W21M & W22M, from Wawa to Marathon: an SVC rated at **200MVAr**
- for a contingency involving circuits M21L & M22L, from Marathon to Lakehead: an SVC rated at **250MVAr**

As before, the analysis indicates that if the reactive capability of the SVCs at Lakehead TS were to be increased (by installing a higher rated SVC to replace the existing synchronous condenser) it would result in a lower rated SVC being required at Marathon TS to respond to contingencies involving the existing line between Marathon TS and Lakehead TS.

12.5 115kV Circuits T1M, A1B and A5A

In **Diagram 33**, in which the results for a contingency involving the existing double-circuit line between Marathon TS and Lakehead TS have been summarised, a post-contingency flow of 136MW is shown on circuit T1M. This would require the maximum conductor operating temperature of this circuit, as well as that for circuits A1B & A5A, to be increased from their present values (70^{o}C for T1M; 84^{o}C for A5A; and 66^{o}C for A5A) to at least 105^{o}C to provide a long-term emergency rating that could accommodate this transfer.

> Should a new single-circuit line be installed to reinforce the East-West Tie, then it is recommended that the maximum operating temperature of circuits T1M, A1B & A5A that form the connection between Marathon TS and Alexandra SS be increased to at least 105^{o}C. This would provide a long-term emergency rating for this connection of approximately 144MVA.

13. Transmission Losses

Table 4 summarises the losses on the principal 230kV circuits for the various transmission reinforcement options that were assessed.

TABLE 4	***Summary of Transmission Losses on the East-West Tie***							
	East-West Transfer West	*Marathon to Wawa Section*			*Lakehead to Marathon Section*			*Total Losses for both Sections*
			Circuit Losses	*Total Losses*		*Circuit Losses*	*Total Losses*	
Reference Case: With double-circuit lines equipped with single-1192.5kcmil conductors								
Diagram 5.	652.0MW	New line	8.6MW	20.6MW	New line	8.4MW	19.8MW	40.4MW
		Existing: W21M & W22M	12.0MW		Existing: M23L & M24L	11.4MW		
Case with: New single-circuit lines equipped with twin-1192.5kcmil conductors								
Diagram 14.	664.2MW	New line	6.0MW	23.6MW	New line	5.6MW	21.4MW	45.0MW
		Existing: W21M & W22M	17.6MW		Existing: M23L & M24L	15.8MW		
*Case with: New single-circuit lines equipped with twin-1192.5kcmil conductors with **40%** series compensation of the new Wawa to Marathon line*								
Diagram 18.	662.0MW	New line	10.0MW	20.8MW	New line	5.7MW	21.5MW	42.3MW
		Existing: W21M & W22M	10.8MW		Existing: M23L & M24L	15.8MW		
*Case with: New single-circuit lines equipped with twin-795.0kcmil conductors with **50%** series compensation of the new Wawa to Marathon line*								
Diagram 28.	670.6MW	New line	17.9MW	27.5MW	New line	8.4MW	24.8MW	52.3MW
		Existing: W21M & W22M	9.6MW		Existing: M23L & M24L	16.4MW		

Table 5 shows the corresponding flow distribution between the new and the existing circuits for each of the transmission reinforcement options.

TABLE 5	***Flow Distribution for each of the Transmission Reinforcement Options***			*Combined Flows* Wawa x Marathon Section	*Combined Flows* Marathon x Lakehead Section
Reinforcement Option					
Reference Case	New double-circuit line with single-1192.5kcmil conductors	Diagram 5	New	325MW	276MW
			Existing	327MW	273MW
				Compensated Section	*Uncompensated Section*
Alternative Case	New single-circuit line with twin-1192.5kcmil conductors	Diagram 14	New	270MW *41%*	225MW *41%*
			Existing	394MW *59%*	325MW *59%*
	New single-circuit line with twin-1192.5kcmil conductors *plus* 40% series compensation on the WxM section	Diagram 18	New	353MW *53%*	226MW *41%*
			Existing	309MW *47%*	325MW *59%*
	New single-circuit line with twin-795.0kcmil conductors *plus* 50% series compensation on the WxM section	Diagram 28	New	375MW *56%*	219MW *40%*
			Existing	296MW *44%*	333MW *60%*

Table 5 shows that for the *Reference Case*, the flow distribution between the two lines is reasonably balanced even though the new line has been assumed to be equipped with larger conductors.

For the *Alternative Case* with no series compensation installed on the new single-circuit line, approximately 40% of the flow is distributed on the new line and 60% on the existing line. Although the size of the conductor installed on the new line is shown to have an effect on the flow distribution between the two lines, it is relatively small (~ 1%).

The effect that the installation of series compensation would have on the flow distribution between the two lines is summarised below:

	Effect on the flow distribution of installing Series Compensation on the new line			
Conductors on new line	Twin-1192.5kcmil Conductors		Twin-795.0kcmil Conductors	
	Uncompensated	With **40%** Series Compensation	Uncompensated	With **50%** Series Compensation
New Line	41%	53%	40%	56%
Existing Line	59%	47%	60%	44%

The transmission losses that have been summarised in **Table 4** show the following:

- For the *Reference Case* (**Diagram 5**), since the flow distribution between the new and the existing line are virtually the same, the difference in the losses of approximately 6.4MW (a reduction of approximately 27%) would represent the reduction that would result from using the larger conductor on the new line.

  [3.4MW on the Wawa to Marathon section plus 3.0MW on the Marathon to Lakehead section.]

- For the *Alternative Case* with no series compensation installed on the new line (**Diagram 14**), the unbalanced flow distribution would increase the losses on the existing line by 10.0MW (~ 43%). The results also show that because of the much lower losses on the new line there would be little benefit from equipping it with a larger conductor.
- Installing series compensation on the Wawa TS to Marathon TS section of the new line of the *Alternative Case* would increase the flow over this section of the new line, resulting in reduced losses on the existing line.

  In **Diagram 18**, for the case with the new line equipped with 1192.5kcmil conductors, installing 40% series compensation would result in combined losses for the two lines on the Wawa to Marathon section, which would be similar to those for the Reference Case.

  In **Diagram 28**, for the case with the new line equipped with 795.0kcmil conductors, increasing the level of series compensation to 50% would result in a higher proportion of the flow over the Wawa to Marathon section appearing on the new line. The combined losses on the two lines over this section are shown to be approximately 7MW higher than those for either the *Reference Case* or the version of the *Alternative Case* with the larger 1192.5kcmil conductors.

14. Reactive Compensation requirements for the lightly loaded case

To represent a typical 'lightly loaded case', the load in the North-West was reduced to 428MW and the generation was adjusted to 460MW. Since the transmission losses for the North-West totalled approximately 22MW, this was intended to result in a transfer across the East-West Tie Interface of approximately 0MW.

Diagrams 36 & 38 show the results of the studies with the same load and generation patterns but with the East-West Tie reinforced with a new double-circuit line and a new single-circuit line, respectively.

For both studies, the shunt compensation remained the same, with the following reactors assumed to be in-service:

- Wawa TS Two 36MVAr tertiary-connected reactors (existing)
- Marathon TS Two 40MVAr tertiary-connected reactors (NEW)
- Mackenzie TS One 40MVAr tertiary-connected reactor (existing)

In addition, the following reactive absorption capabilities were assumed to be available:

- At Marathon a new 230kV-connected SVC with an absorption capability of 100MVAr
- At Lakehead TS, it was assumed that the existing synchronous condenser would be replaced with an SVC having the same +60/-40MVAr rating as the existing SVC.

For the two studies, the reactive absorption by these dynamic resources was as follows:

Reactive Absorption for the lightly-loaded case		
	Diagram 36 *With a new double-circuit line*	*Diagram 38* *With a new single-circuit line*
Marathon SVC	- 97.2MVAr	- 67.0MVAr
Lakehead SVCs (combined contribution)	- 67.0MVAr	- 60.8MVAr

TABLE 6:	EW Tie Transfer West	Study Results for the light-load condition with transfers of ~ 0MW on the EW Tie	
Diag.	*E-W Tie Transfer Westwards:* Approximately **0MW**	*Sudbury Flow West (SFW) Transfer:* Approximately **0MW**	*EW Transfer W*
With a new double-circuit line, equipped with single-1192.5kcmil conductors With a +200/-100MVAr SVC & two 40MVAr reactors at Marathon			
36.	Pre-contingency	*Marathon SVC: -97.2MVAr Lakehead SVCs: -76MVAr Lakehead: 242kV Marathon: 241kV Wawa: 245kV*	-6.4MW
37.	*Post-contingency: SVC tripped*	*Marathon SVC: 0MVAr Lakehead SVCs: -80MVAr Lakehead: 250kV Marathon: 255kV Wawa: 254kV*	-7.2MW
With a new single-circuit line, equipped with twin-1192.5kcmil conductors & with 40% series compensation of the Wawa to Marathon section With a +200/-100MVAr SVC & two 40MVAr reactors at Marathon			
38.	Pre-contingency	*Marathon SVC: -67.0MVAr Lakehead SVCs: -61MVAr Lakehead: 242kV Marathon: 241kV Wawa: 245kV*	-6.3MW
39.	*Post-contingency: SVC tripped*	*Marathon SVC: 0MVAr Lakehead SVCs: -80MVAr Lakehead: 245kV Marathon: 249kV Wawa: 250kV*	-6.6MW

TABLE 7:	EW Tie Transfer West		Study Results for Contingencies on the 230kV system between Mississagi TS and Wawa TS	
Diag.	*E-W Tie Transfer Westwards:* **500MW**		*Sudbury Flow West (SFW) Transfer:* **350MW**	*EW Transfer W*
With a new double-circuit line, equipped with single-1192.5kcmil conductor With a +200/-100MVAr SVC & two 40MVAr reactors at Marathon			*With a single generating unit in-service at Wells GS and Aubrey Falls GS*	
40.	Pre-contingency		*With a **200MVAr** SVC at Marathon TS & with one unit in-service at Wells GS & one at Aubrey GS*	520MW
41.	D/C Contingency: Existing Mississagi to Wawa circuits *P25W + P26W*	No PS action	Manitoba: 44MW Minnesota: 28MW Marathon SVC: -25MVAr Lakehead SVCs: -3MVAr	427MW
42.		With PS action	Manitoba: 42MW Minnesota: -3MW Marathon SVC: 16MVAr Lakehead SVCs: 9MVAr	**465MW**
43.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* ***500MW***	
44.	D/C Contingency: Existing Mississagi to Third Line circuits *P21G + P22G*	No PS action	Manitoba: 28MW Minnesota: 18MW Marathon SVC: -15MVAr Lakehead SVCs: 6MVAr	456MW
45.		With PS action	Manitoba: 22MW Minnesota: -3MW Marathon SVC: 19MVAr Lakehead SVCs: 18MVAr	***488MW***
46.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* ***562MW***	
47.	S/C Contingency: Existing Wawa to MacKay circuit *W23K*	No PS action	Manitoba: 10MW Minnesota: 7MW Marathon SVC: -14MVAr Lakehead SVCs: 19MVAr	490MW
48.		With PS action	Manitoba: -3MW Minnesota: -3MW Marathon SVC: 12MVAr Lakehead SVCs: 31MVAr	**517MW**
49.		PV-analysis:	*Voltage Stability Limit for EW Tie-W Transfers:* ***569MW***	

Studies were performed to examine the effect on the local voltages of tripping the SVC at Marathon TS at these levels of reactive absorption.

The results are summarised in **Diagrams 37 & 39** for the *Reference* and *Alternative Case*, respectively.

For the Reference Case, with the Marathon SVC absorbing 97MVAr pre-contingency, the loss of the SVC would result in voltages of 255kV at Marathon TS and 254kV at Wawa TS, which would exceed the permitted maximum of 250kV.

For the Alternative Case, with the Marathon SVC absorbing 67MVAr pre-contingency, the voltages at Wawa TS and Marathon TS would increase to 249.7kV and 249.1kV, respectively, in response to the loss of the SVC. The voltage at Marathon would therefore be only marginally within the 250kV limit.

The results from these studies, which are summarised in **Table 6,** show the following:

- A minimum of *three* new 40MVAr shunt reactors would need to be installed at Marathon TS regardless of whether the proposed reinforcement consists of a new 230kV double-circuit line or a new 230kV single-circuit line.

  Installation of the third reactor would be required to limit the reactive absorption by the SVC at Marathon TS to less than about 50MVAr so that in the event that the SVC should trip, the voltages would remain within the agreed 250kV threshold.

- Although the SVC proposed for Marathon TS would not be permitted to operate continuously at an absorption level in excess of 50MVAr because of the consequences of it tripping when loaded above this level, it would still need to have a 'dynamic' capability of at least -100MVAr.

  This requirement was identified in Section 12.3 to ensure that the post-contingency voltages would remain below the 250kV threshold following the loss of the double-circuit line between Lakehead TS and Mackenzie TS and the subsequent separation of that part of the system west of Mackenzie TS on to the Interconnections.

- The rating of the replacement SVC for the existing synchronous condenser at Lakehead TS would need to be at least the same as the existing unit so that the combined absorption capability of the two units would be at least 80MVAr to ensure that the Lakehead voltage would remain within acceptable limits.

15. Transfer Capability of the Existing Transmission Facilities between Mississagi TS and Wawa TS

Although the enhanced East-West Tie is required to have a transfer capability of at least **650MW** westwards, the OPA's assessment of the Long-Term Electricity Outlook for the North-West has identified a maximum transfer requirement during the initial period of operation of the enhanced facility, of approximately 400MW westwards.

Studies were conducted to confirm that the transfer capability of the existing transmission facilities between Mississagi TS and Wawa TS, while respecting the loss of either of the double-circuit lines in this part of the system, would be sufficient to support a transfer of at least 400MW westwards across the East-West Tie.

The results are summarised in **Table 7** and also in **Diagrams 40 to 49**, inclusive.

For these studies, the East-West Tie was assumed to be reinforced with a new double-circuit line as proposed under the *Reference Case.* A +200/-100MVAr SVC was also assumed to be installed at Marathon TS, in addition to three 40MVAr reactors, of which only two were required to be in-service for these studies.

Only a single generating unit was assumed to be in-service, pre-contingency, at Wells GS and at Aubrey Falls GS, for the following reasons:

- to limit the amount of post-contingency reactive support that could be provided from these facilities, and
- to increase the post-contingency transfer across the East-West Tie Interface.

  A contingency involving circuits P25W & P26W would result in the operational units at Aubrey Falls being isolated, while a contingency involving circuits P21G & P22G would similarly result in the isolation of the operational units at Wells GS. In response to the resulting resource deficiency from the loss of these units, there would be a significant increase in the transfers on the Manitoba and Minnesota Interconnections. Although these increased transfers would be reduced through automatic adjustments to the phase-shifters on the Interconnections, they would not be reduced to zero, particularly on the Manitoba Interconnection which allows only four tap-changer operations before locking out.

  With two units automatically isolated at either Wells GS or Aubrey Falls, the combined post-contingency transfers via the Manitoba and Minnesota Interconnections would be substantially higher following the adjustment of the phase-shifters.

  Since any *increase* in the post-contingency transfers across the Interconnections would result in a corresponding *decrease* in the transfer across the East-West Tie, the studies therefore examined the loss of only a single unit at either Wells GS or Aubrey Falls GS to minimise the reduction in the latter transfer.

In addition to examining the double-circuit contingencies involving circuits P25W & P26W; and P21G & P22G, the effect of a single-circuit contingency involving circuit W23K between Wawa TS and MacKay TS was also examined. For this contingency, since there would be no associated loss of generation capacity, the post-contingency transfer across the East-West Tie Interface would not be similarly affected.

For all three contingencies, the analysis showed that, with the new double-circuit line between Wawa TS and Lakehead and the addition of a 200MVAr SVC at Marathon, the existing transmission facilities between Mississagi TS and Wawa TS would be able to support a westward transfer of approximately **500MW** across the East-West Tie.

16. Reinforcement of the East-West Tie with a new 230kV single-circuit line rather than a double-circuit line

All of the criteria produced by NERC, NPCC & the IESO refer to a requirement to respect a second single-element contingency after experiencing an initial single-element contingency or outage, with control actions taken between the two events to adjust the flows.

The IESO's planning criteria require any control actions to re-prepare the system for a subsequent contingency be implemented within the 30 minute period following an initial contingency.

The IESO's criteria for determining the adequacy of any plans to reinforce the transmission system also limit the maximum loss to two elements, either simultaneously or with one loss following another.

With the East-West Tie reinforced with a single-circuit line, the criteria require that, following the loss of the new single-circuit line, control actions be implemented to prepare the system for the loss of one of the circuits on the remaining double-circuit line.

Following the loss of the new single-circuit line, the system configuration for the section affected by the fault would revert to the present arrangement, for which the transfer capability is approximately 350MW, when respecting the loss of only a single circuit.

Since the targeted transfer capability of the reinforced East-West Tie is 650MW, a reduction to 350MW following the loss of the new single-circuit line would therefore require, as a control action, either the dispatch of additional generating resources totalling at least 300MW, or a lesser amount if there were also the capability to arm load rejection of up to 150MW in response to the second contingency. An increase in the transfers via the Interconnections with Manitoba and Minnesota would also allow the amount of generation capacity that would need to be dispatched to be reduced.

Reinforcing the East-West Tie with a new double-circuit line would therefore offer a higher level of security since, from the planning perspective, the initial loss of the two elements of the double-circuit line would provide acceptable performance, in accordance with the prevailing standards, while requiring no control actions to be taken following the initial loss of either of the double-circuit lines.

17. Replacement SVC at Lakehead TS: Recommendation

In this study it has been assumed that the replacement SVC for the existing synchronous condenser at Lakehead TS would be rated the same as the existing SVC; namely +60/-40MVAr.

The analysis has indicated that should the East-West Tie be reinforced and its transfer capability increased, that the Lakehead area would benefit from a higher rated unit.

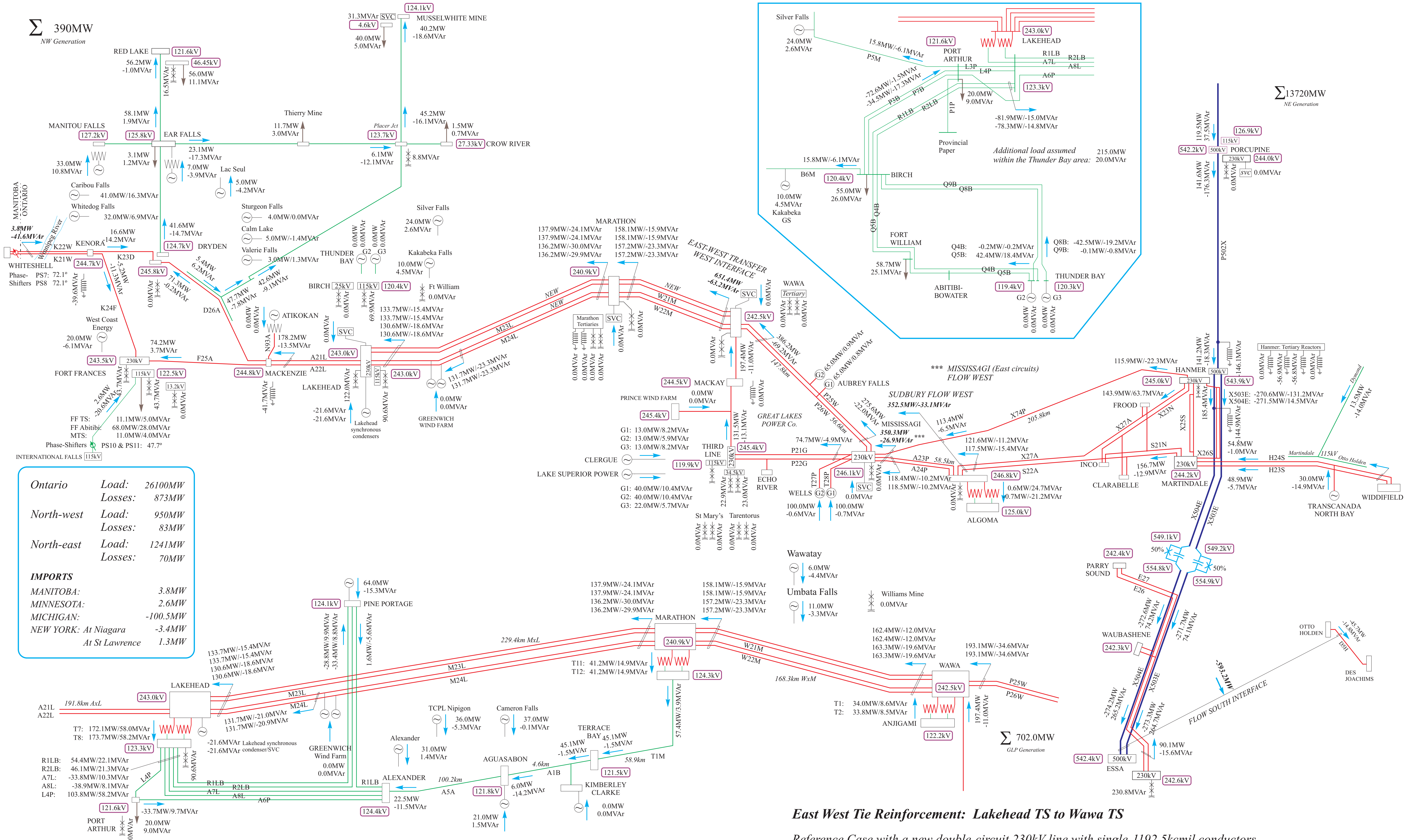
It is therefore recommended that when a decision is made to replace the existing synchronous condenser that consideration should be given to acquiring an SVC with rating of at least ± 100MVAr.

APPENDIX A Line Ratings										
230kV Line Ratings				*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 240kV*						
Circuit	*Conductor (Limiting Section)*		*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
X74P Hanmer TS to Mississagi TS										
Hanmer TS to Mississagi TS	1192.5kcmil	54/19	127^{o}C	1120A	465MVA	1440A	598MVA	1650A	686MVA	*Pre-load of 1120A*
S22A: Martindale TS to Algoma TS 150.1km *(Martindale - Clarabelle 11.9km + Clarabelle - Algoma 138.1km)*										
Martindale-Clarabelle Jct	1924kcmil	69/19	127^{o}C	1500A	623MVA	1940A	806MVA	2400A	997MVA	*Pre-load of 1500A*
Clarabelle Jct to Algoma TS	1924kcmil	69/19	127^{o}C	1500A	623MVA	1940A	806MVA	2400A	997MVA	*Pre-load of 1500A*
	1307.4kcmil	28/19	127^{o}C	1160A	482MVA	1500A	623MVA	1800A	748MVA	*Pre-load of 1160A*
X27A: Hanmer TS to Algoma TS 155.6km										
Hanmer TS to Junction Point	1843.2kcmil	72/7	93^{o}C/116^{o}C	1420A	590MVA	1720A	715MVA	1990A	827MVA	*Pre-load of 1420A*
Junction Point to Algoma	1307.4kcmil	28/19	127^{o}C	1160A	482MVA	1500A	623MVA	1800A	748MVA	*Pre-load of 1160A*
A23P & A24P: Mississagi TS to Algoma TS 58.5km										
Mississagi to Algoma	795kcmil	26/7	150^{o}C	880A	366MVA	1120A	466MVA	1430A	594MVA	*Pre-load of 880A*
P25W & P26W: Mississagi TS to Wawa TS 204.4km *(Mississagi - Aubrey Falls 56.6km + Aubrey Falls - Wawa 147.8km)*										
Mississagi TS to Aubrey Falls Jct	795kcmil	26/7	110^{o}C	880A	366MVA	1010A	420MVA	1070A	445MVA	*Pre-load of 880A*
Aubrey Falls Jct to Wawa TS	795kcmil	26/7	93^{o}C	880A	366MVA	880A	366MVA	880A	366MVA	*Pre-load of 880A*
W21M & W22M: Wawa TS to Marathon TS 168.3km										
W21M	795kcmil	26/7	93^{o}C	880A	366MVA	880A	366MVA	880A	366MVA	*Pre-load of 880A*
W22M			111^{o}C	880A	366MVA	1020A	424MVA	1080A	449MVA	*Pre-load of 880A*

***230kV Line Ratings** (Continued)*				*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 240kV*					
Circuit	*Conductor (Limiting Section)*		*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
M23L & M24L: Marathon TS to Lakehead TS			***229.4km***							
M23L M24L	795kcmil	26/7	95^{o}C	880A	366MVA	890A	370MVA	900A	374MVA	*Pre-load of 880A*

Ratings for Proposed 230kV Lines			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 240kV*						
Conductor		*Sag Temp*	*Continuous at 93^{o}C*		*Long-Term 'Emergency' at 127^{o}C*		*15-min LTR at 150^{o}C Temperature*		
*Double-circuit line with **single**-1192.5kcmil*	54/19	127^{o}C	1120A	465MVA	1440A	598MVA	1650A	686MVA	*Pre-load of 1120A*
*Single-circuit line with **twin**-1192.5kcmil*	54/19	127^{o}C	2230A	927MVA	2880A	1197MVA	3310A	1376MVA	*Pre-load of 2230A*
*Single-circuit line with **twin**-795.0kcmil*	26/7	127^{o}C	1750A	727MVA	2240A	931MVA	2480A	1031MVA	*Pre-load of 1750A*

115kV Line Ratings				*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*		*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
T1M: Marathon TS to Terrace Bay SS										
Marathon TS to Terrace Bay	477.0kcmil	26/7	70^{o}C	460A	96MVA	460A	96MVA	460A	96MVA	*Pre-load of 460A*
A1B: Terrace Bay SS to Aguasabon SS										
Terrace Bay SS to Aguasabon	477.0kcmil	26/7	84^{o}C	570A	119MVA	570A	119MVA	570A	119MVA	*Pre-load of 570A*
A5A: Aguasabon SS to Alexandra SS										
Aguasabon SS to Alexandra SS	477.0kcmil	26/7	66^{o}C	430A	90MVA	430A	90MVA	430A	90MVA	*Pre-load of 570A*

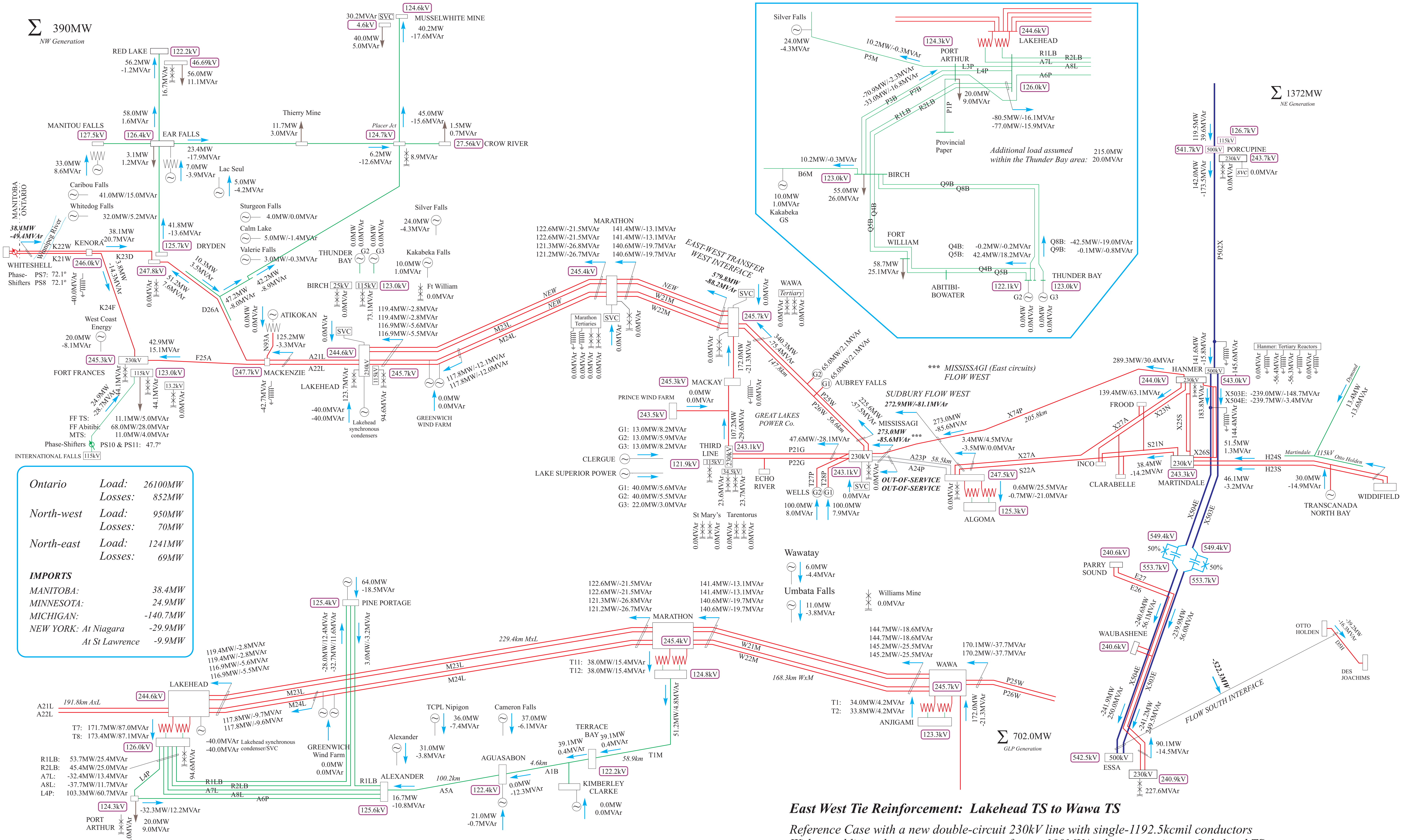


East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With no additional reactive support apart from a 100MVAr shunt capacitor at Lakehead TS

DIAGRAM 1

11th August 2011



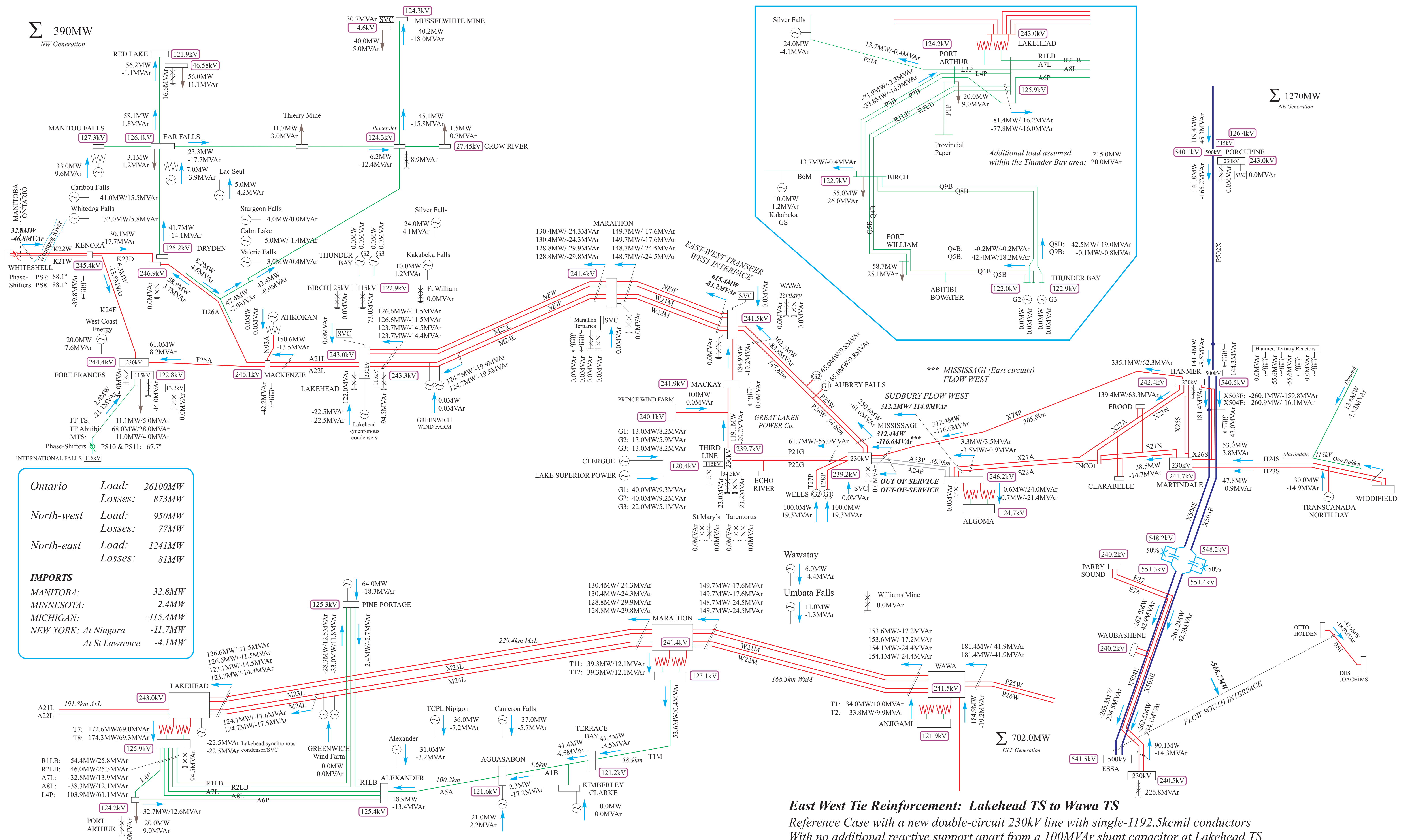
East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With no additional reactive support apart from a 100MVAr shunt capacitor at Lakehead TS

Contingency: 230kV double-circuit A23P + A24P - Algoma TS to Mississagi TS
Prior to Phase-Shifter action

DIAGRAM 2

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

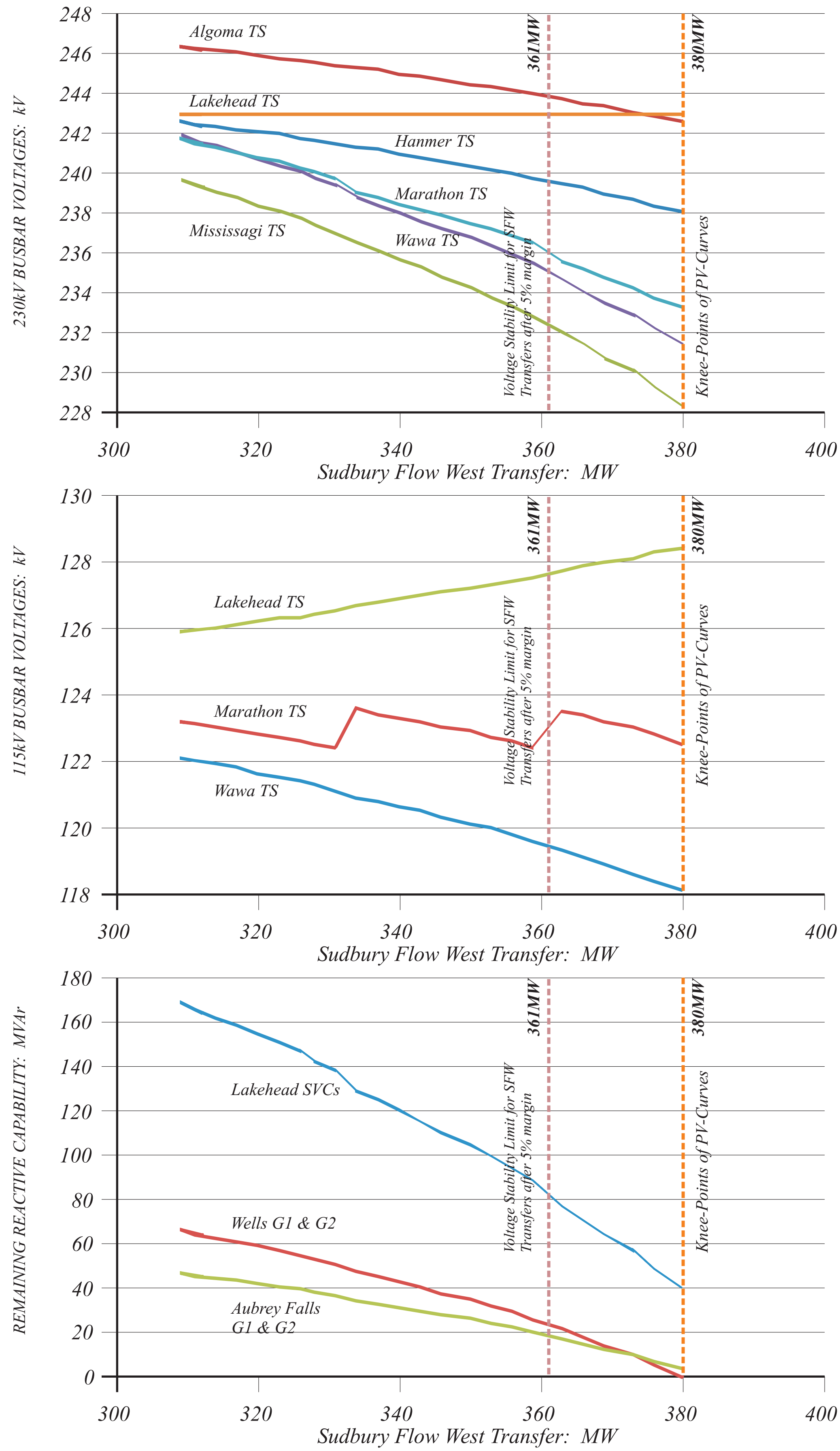
With no additional reactive support apart from a 100MVAr shunt capacitor at Lakehead TS

Contingency: 230kV double-circuit A23P + A24P - Algoma TS to Missisagi TS

After Phase-Shifter action

DIAGRAM 3

11th August 2011



PV-analysis
No additional SVCs

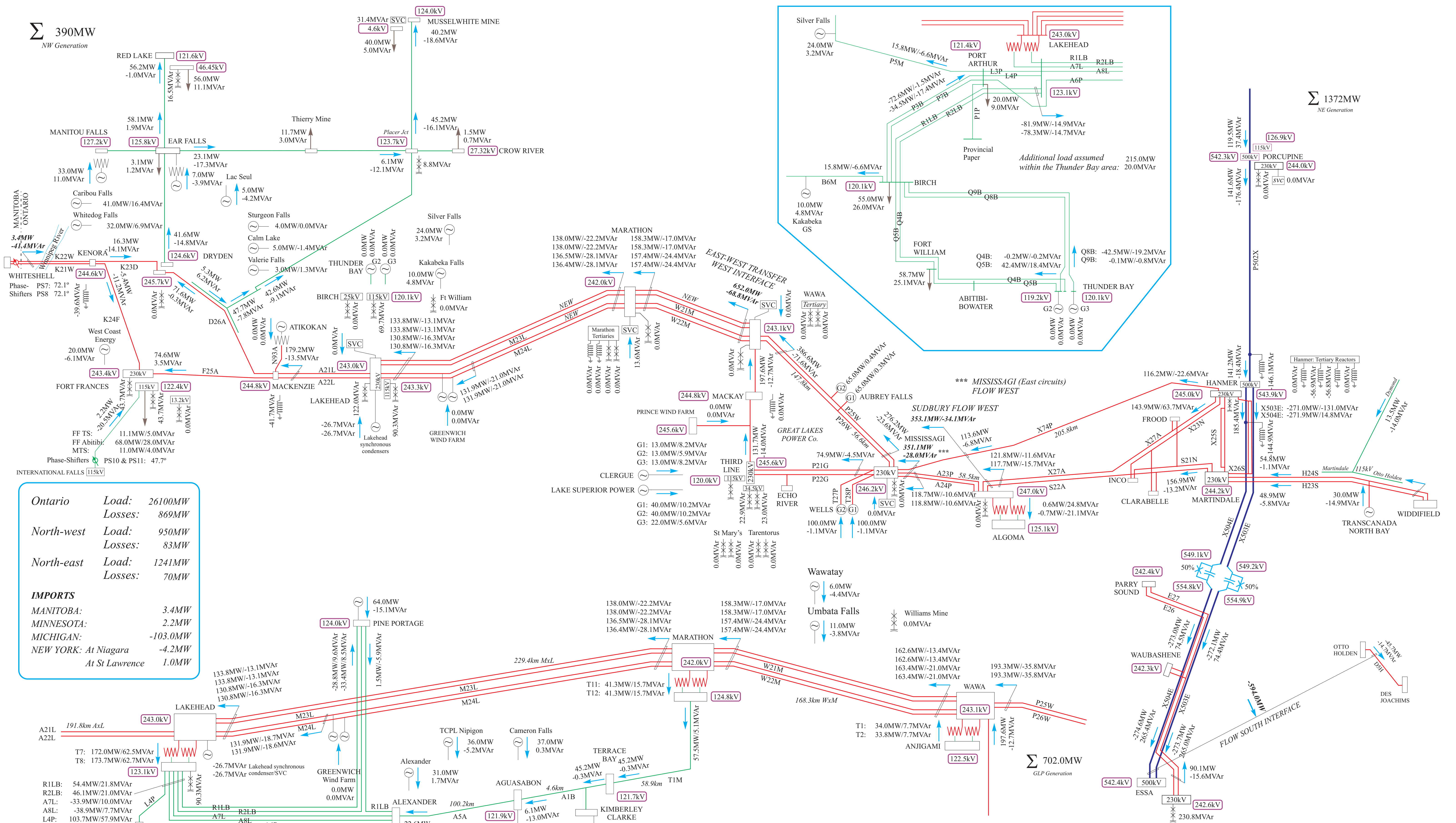
East West Tie Reinforcement: Lakehead TS to Wawa TS

Case with a new double-circuit 230kV line with 1192.5kcmil conductors

Contingency: 230kV double-circuit A23P & A24P
After Phase-Shifter action

DIAGRAM 4

26th July 2011

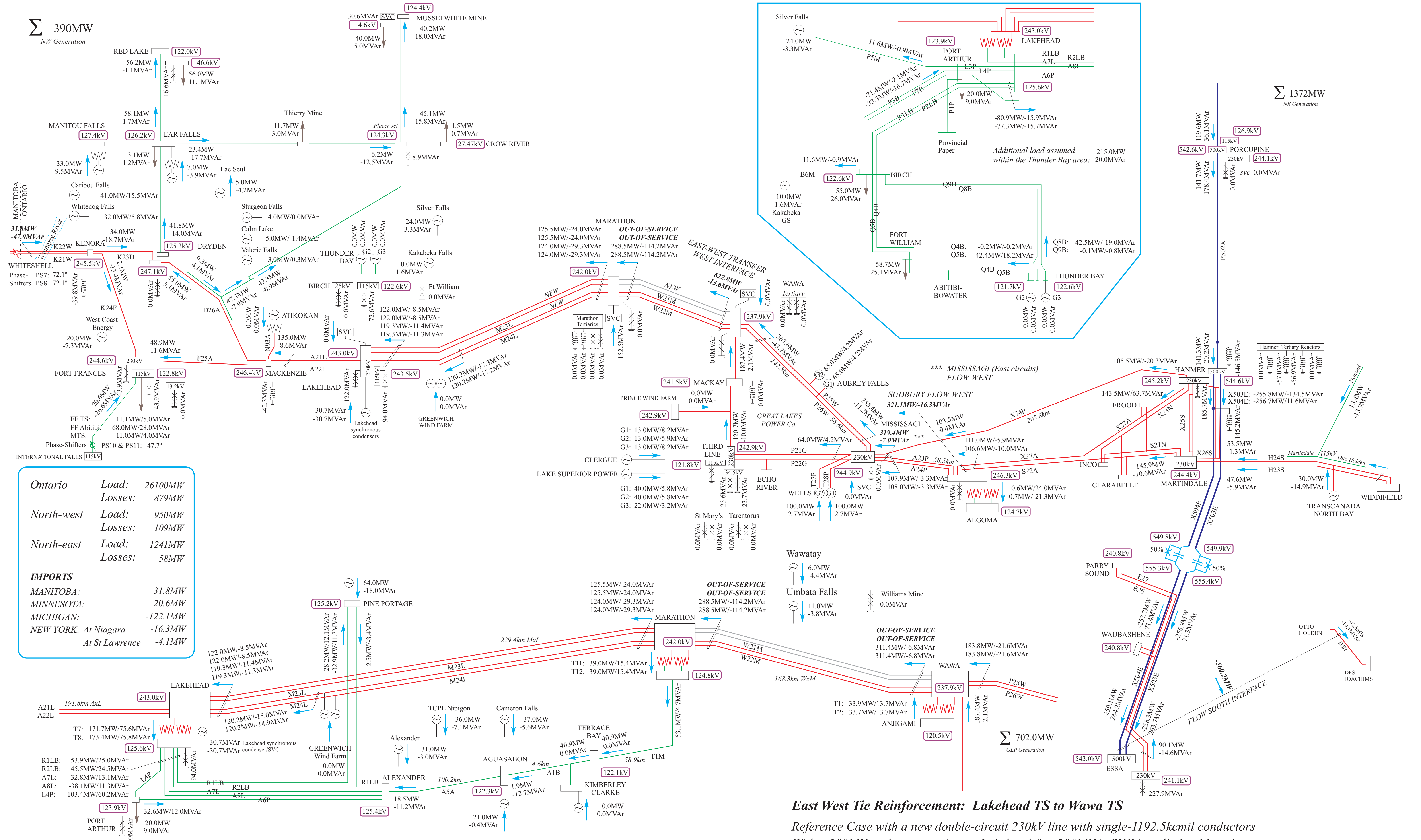


East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

DIAGRAM 5

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

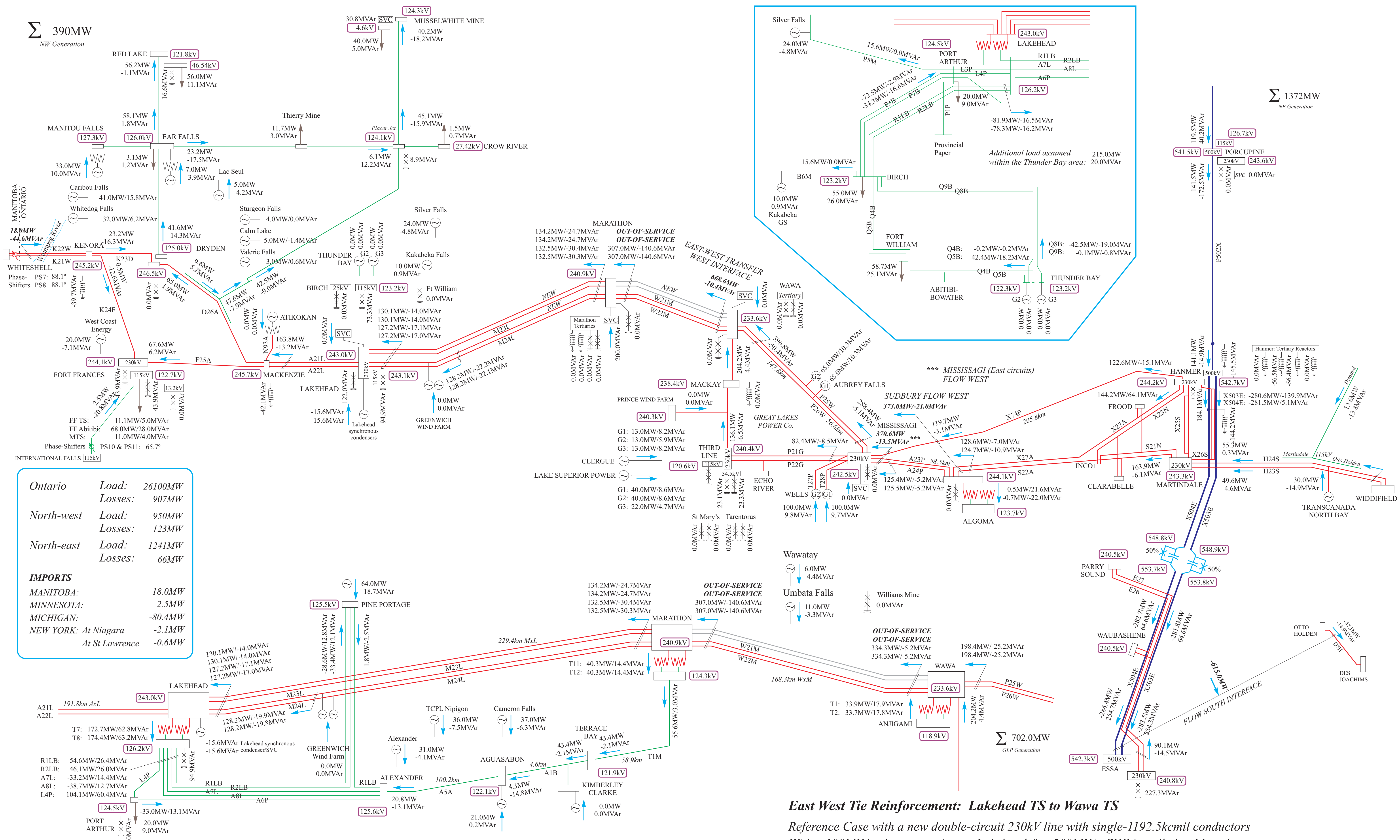
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

Contingency: 230kV double-circuit involving the new Wawa TS to Marathon TS line

Prior to Phase-Shifter action

DIAGRAM 6

11th August 2011

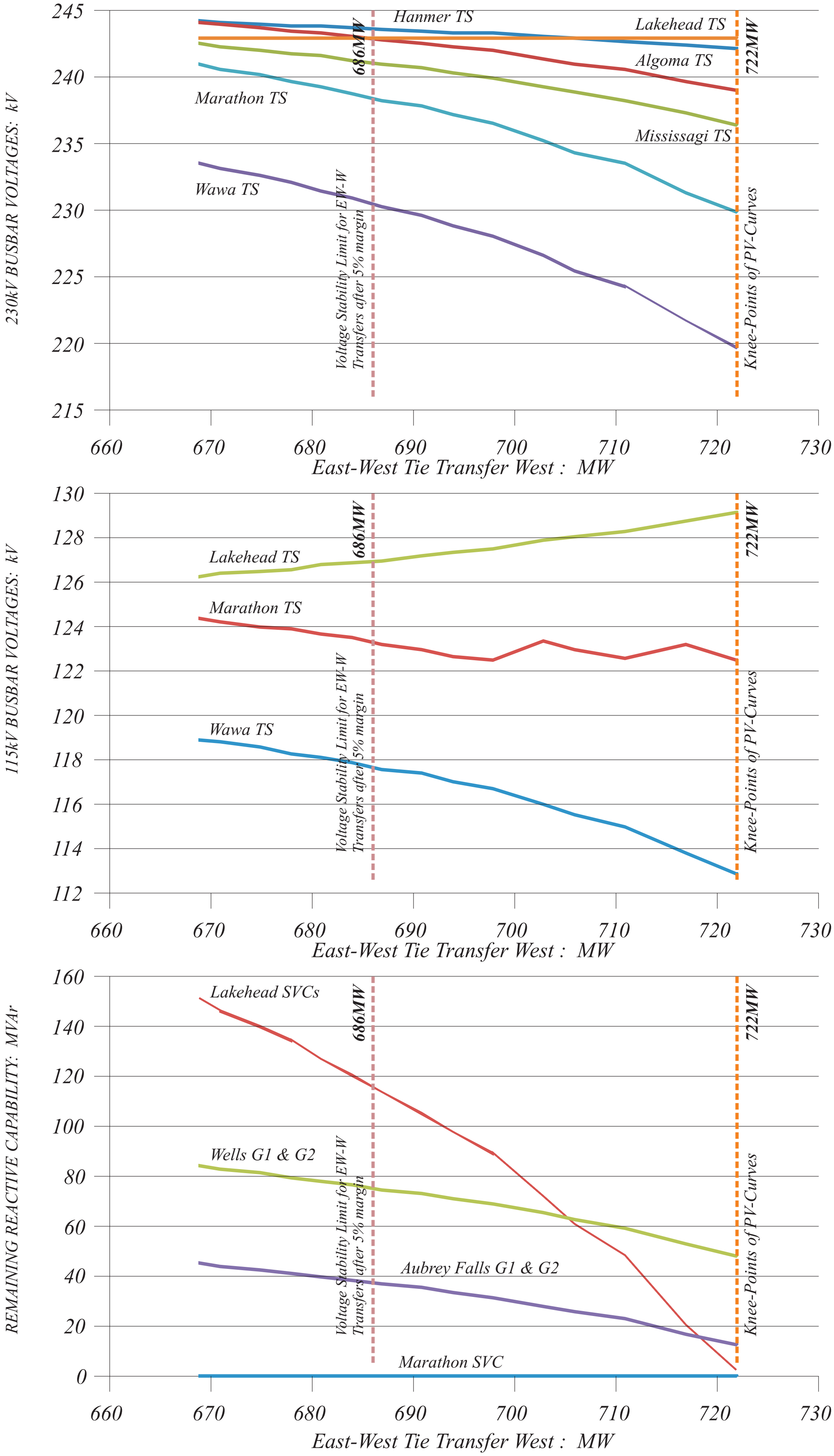


East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon
Contingency: 230kV double-circuit involving the new Wawa TS to Marathon TS line
After Phase-Shifter action

DIAGRAM 7

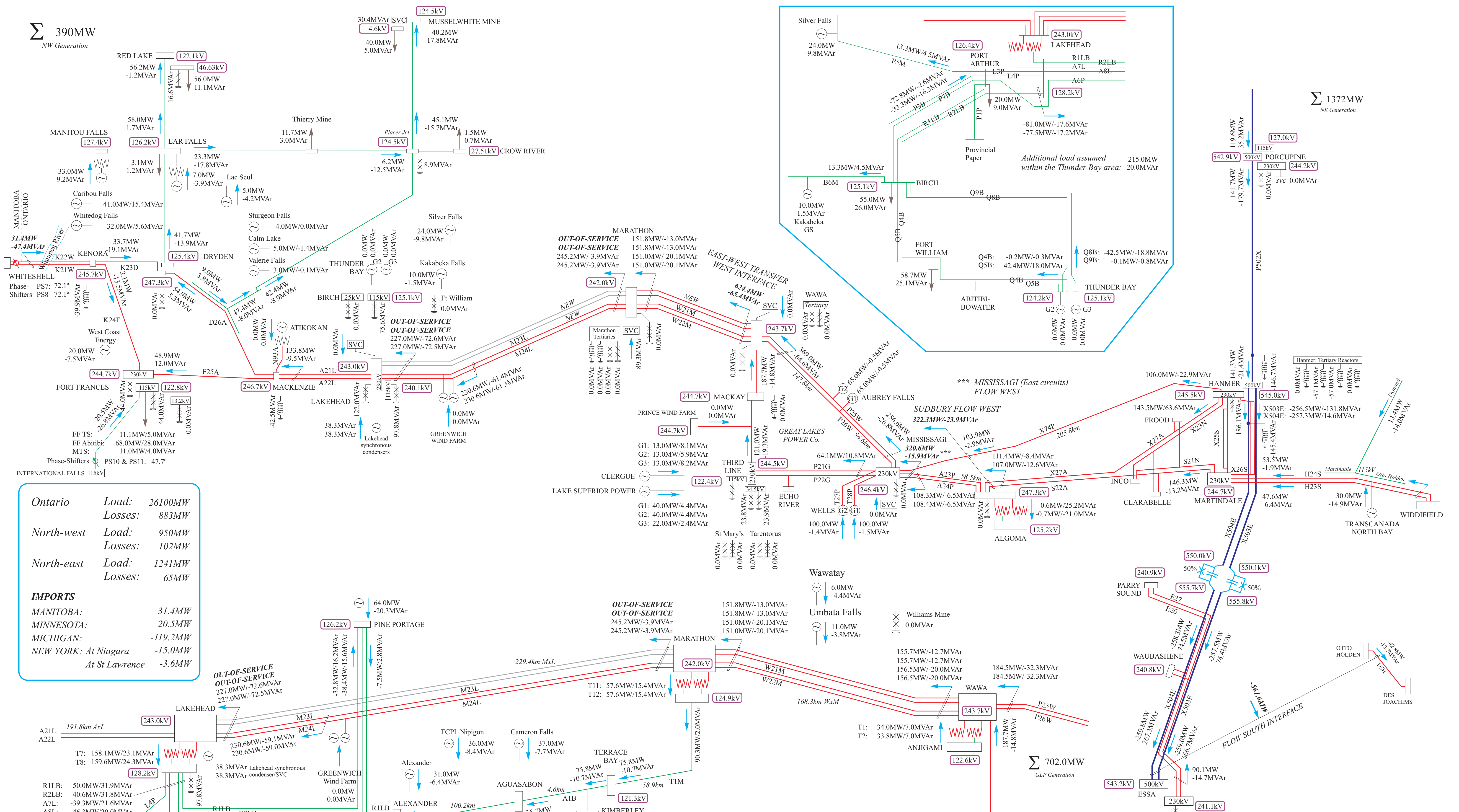
11th August 2011



PV-analysis
Marathon 200MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
Contingency: new 230kV double-circuit Wawa TS to Marathon TS
After Phase-Shifter action

DIAGRAM 8
30th July 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

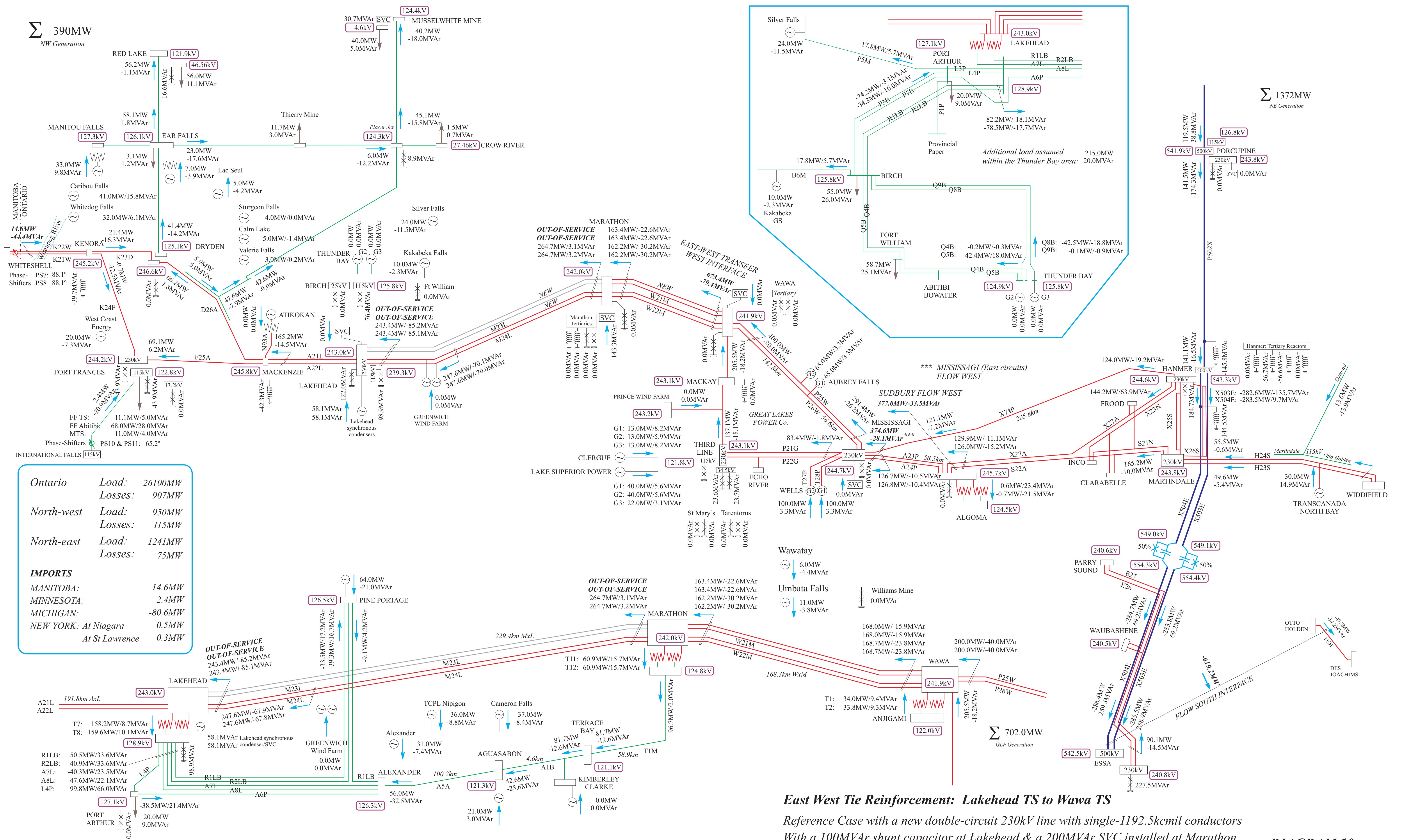
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

Contingency: 230kV double-circuit involving the new Marathon TS to Lakehead TS line

Prior to Phase-Shifter action

DIAGRAM 9

11th August 2011



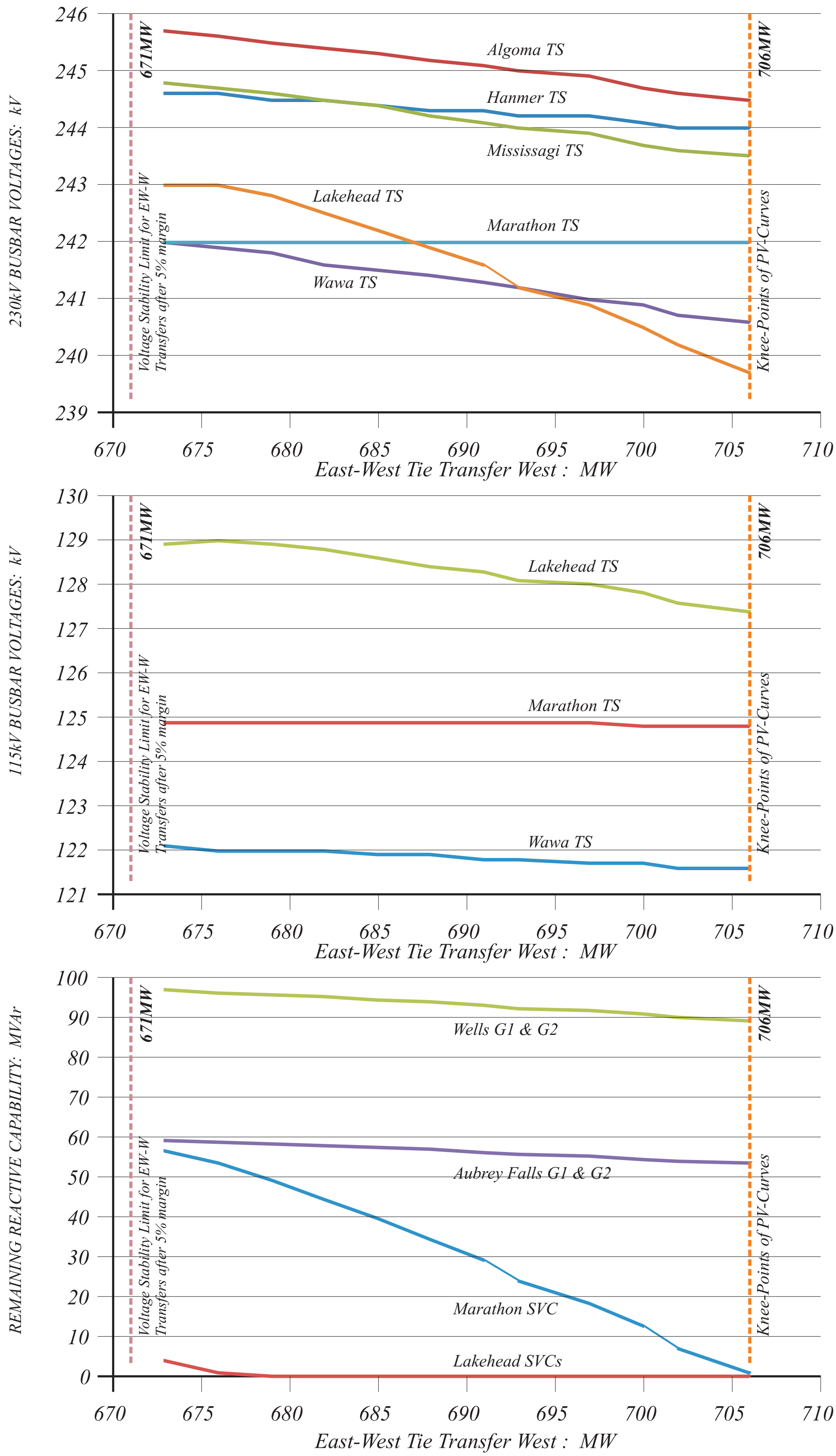
East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

Contingency: 230kV double-circuit involving the new Marathon TS to Lakehead TS line

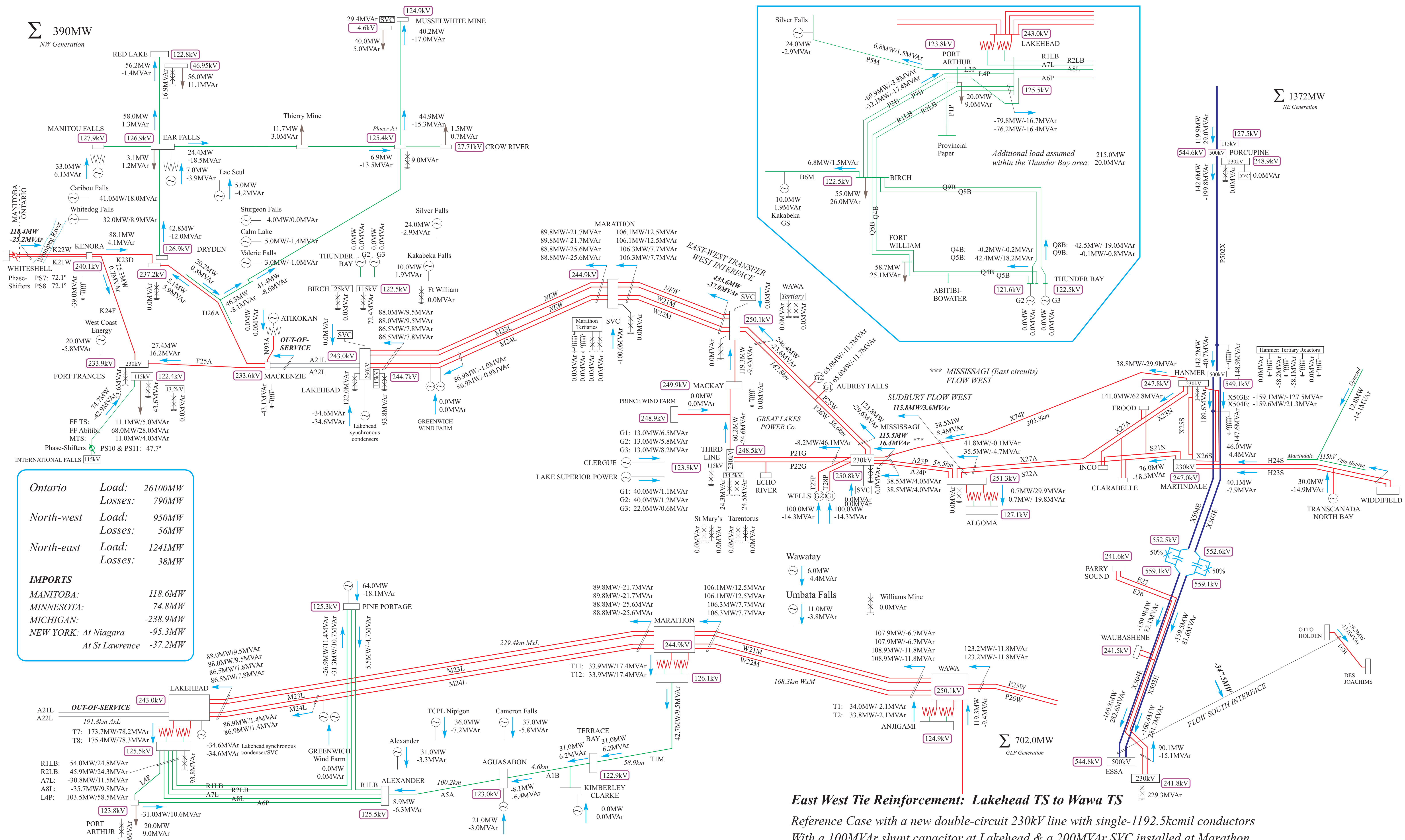
After Phase-Shifter action



PV-analysis
Marathon 200MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
Contingency: new 230kV double-circuit Marathon TS to Lakehead TS
After Phase-Shifter action

DIAGRAM 11
26th July 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

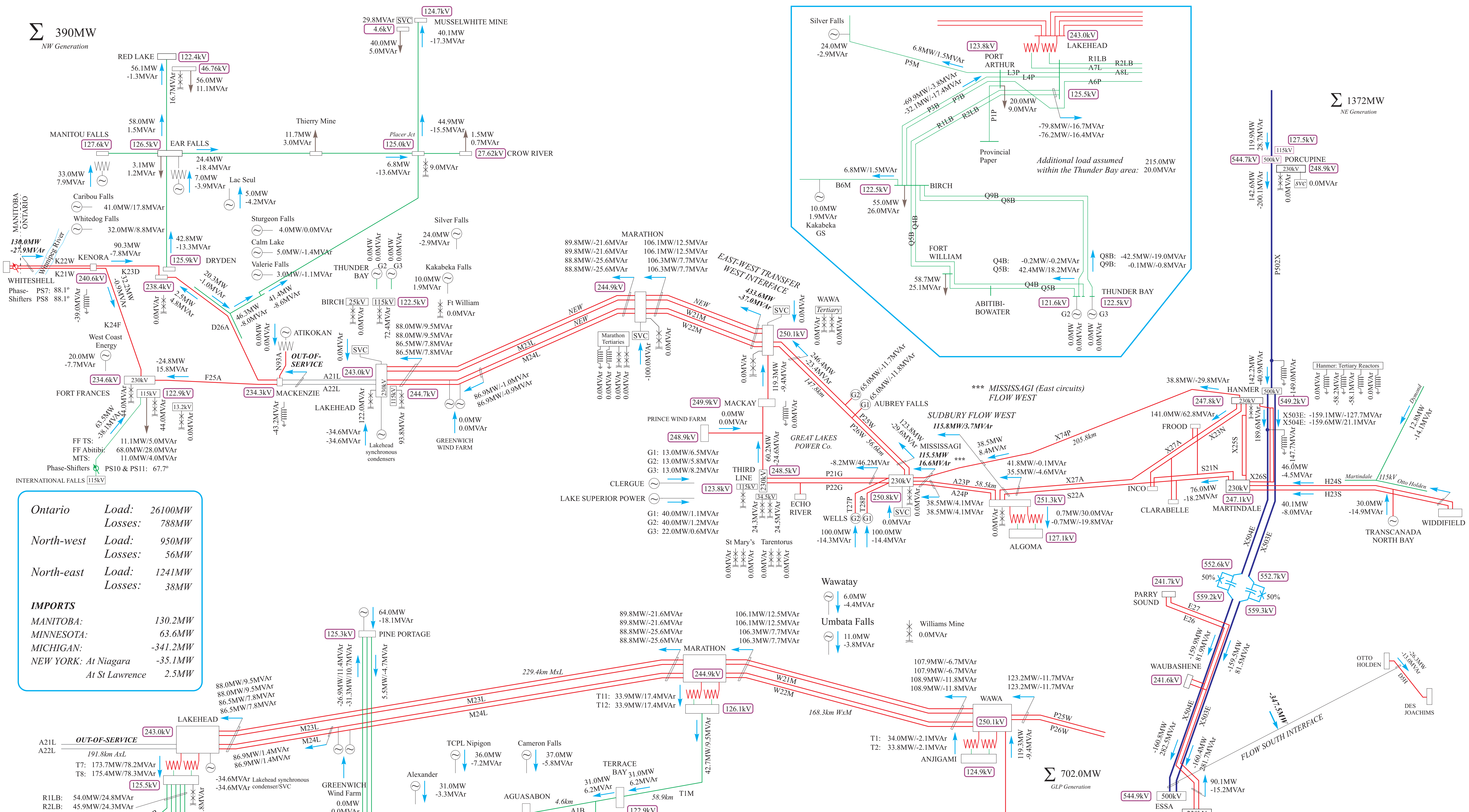
Contingency: 230kV double-circuit A21L + A22L Lakehead TS to Mackenzie TS

115kV Circuit B6M - Moose Lake TS to Birch TS cross-tripped

Prior to Phase-Shifter action

DIAGRAM 12

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

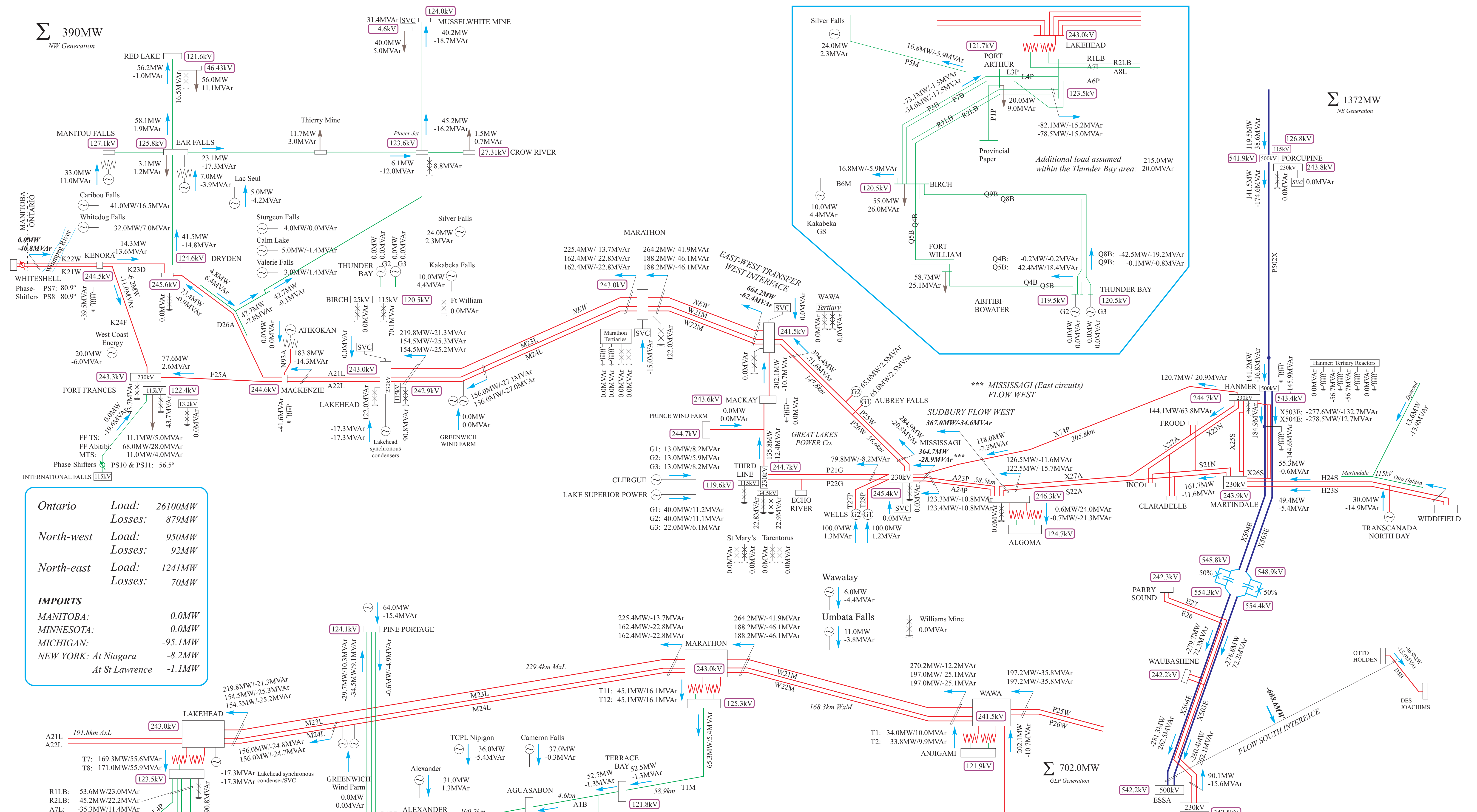
Contingency: 230kV double-circuit A21L + A22L Lakehead TS to Mackenzie TS

115kV Circuit B6M - Moose Lake TS to Birch TS cross-tripped

After Phase-Shifter action

DIAGRAM 13

11th August 2011

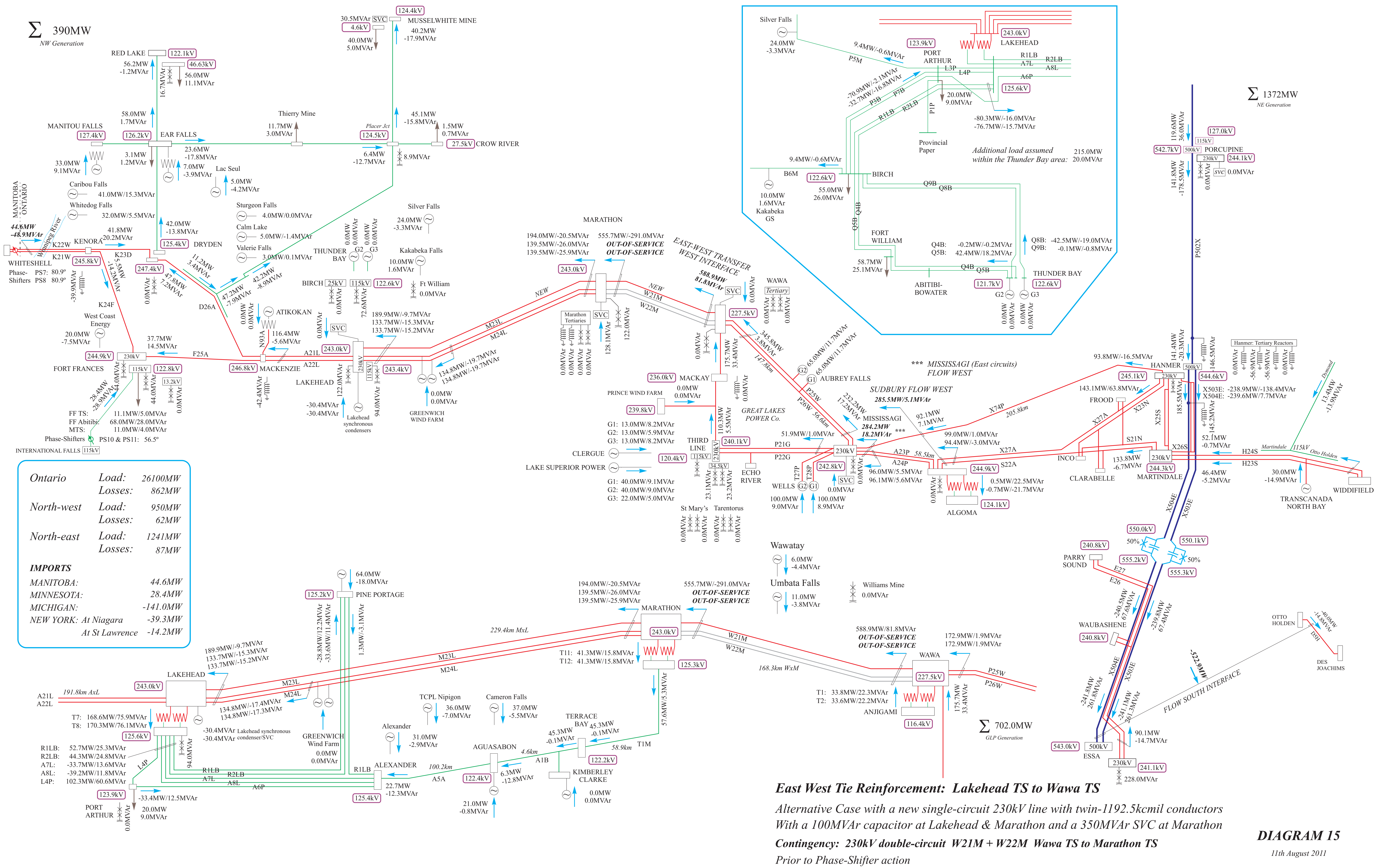


East West Tie Reinforcement: Lakehead TS to Wawa TS

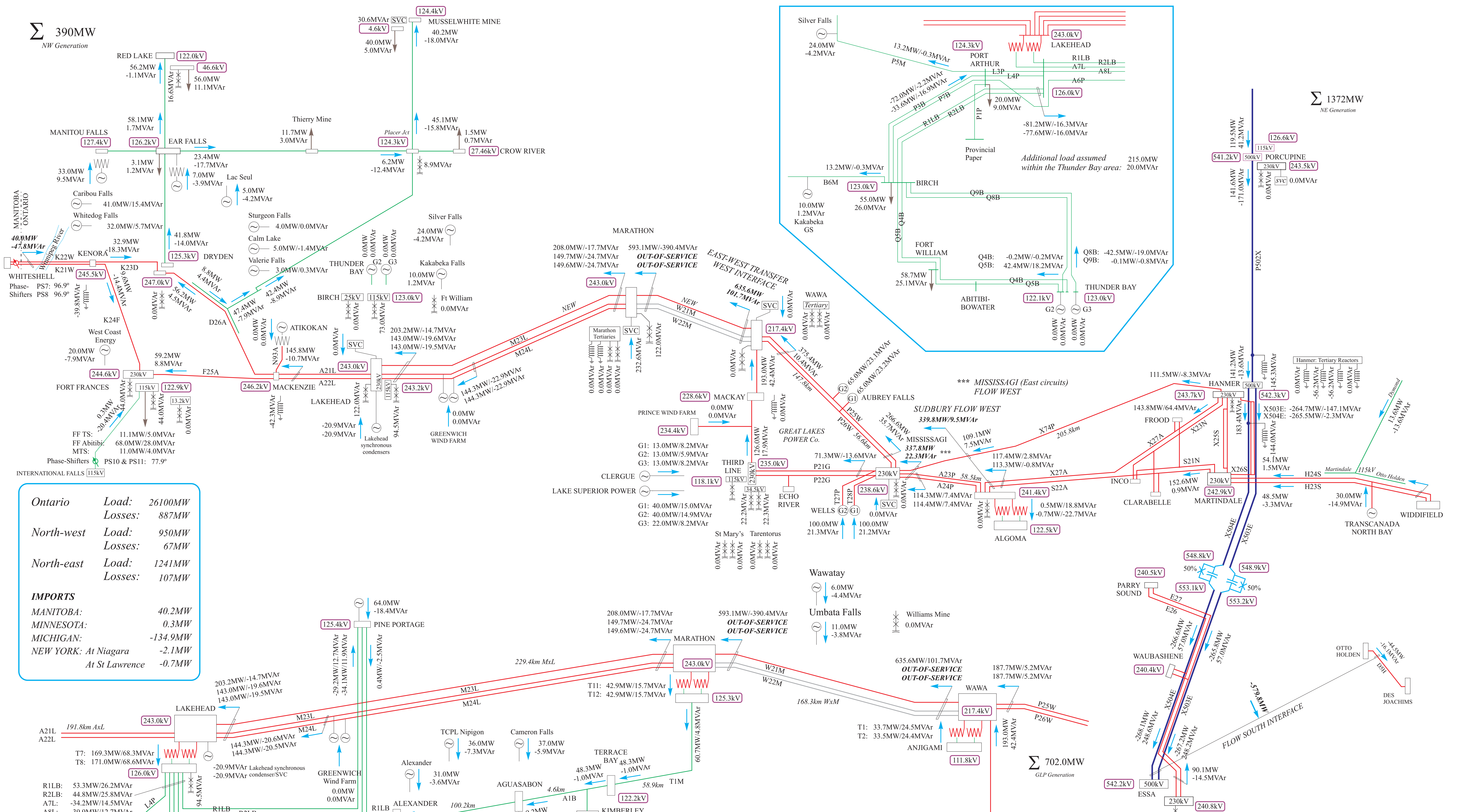
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon and a 350MVAr SVC at Marathon

DIAGRAM 14

11th August 2011



Σ 390MW
NW Generation
Σ 1372MW
NE Generation
Σ 702.0MW
GLP Generation
RED LAKE
EAR FALLS
MANITOU FALLS
Caribou Falls
Whitedog Falls
Thierry Mine
MUSSELWHITE MINE
Placer Jct
CROW RIVER
Lac Seul
Sturgeon Falls
Calm Lake
Valerie Falls
Silver Falls
Kakabeka Falls
Ft William
THUNDER BAY
BIRCH
KENORA
DRYDEN
WHITESHELL
MANITOBA
ONTARIO
Winnipeg River
Phase-Shifters PS7: 80.9° PS8 80.9°
West Coast Energy
FORT FRANCES
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 56.5°
INTERNATIONAL FALLS
ATIKOKAN
MACKENZIE
LAKEHEAD
Lakehead synchronous condensers
GREENWICH WIND FARM
MARATHON
OUT-OF-SERVICE
OUT-OF-SERVICE
Marathon Tertiaries
EAST-WEST TRANSFER WEST INTERFACE
588.9MW 81.8MVAr
WAWA
Tertiary
AUBREY FALLS
MACKAY
PRINCE WIND FARM
GREAT LAKES POWER Co.
THIRD LINE
CLERGUE
LAKE SUPERIOR POWER
ECHO RIVER
WELLS
St Mary's
Tarentorus
MISSISSAGI
*** MISSISSAGI (East circuits) FLOW WEST
SUDBURY FLOW WEST 285.5MW/5.1MVAr
ALGOMA
INCO
CLARABELLE
FROOD
MARTINDALE
HANMER
Hanmer: Tertiary Reactors
PORCUPINE
TRANSCANADA NORTH BAY
WIDDIFIELD
Otto Holden
Martindale
Dymond
PARRY SOUND
WAUBASHENE
ESSA
OTTO HOLDEN
DES JOACHIMS
FLOW SOUTH INTERFACE
Silver Falls
LAKEHEAD
PORT ARTHUR
Provincial Paper
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
Kakabeka GS
FORT WILLIAM
ABITIBI-BOWATER
THUNDER BAY
Ontario Load: 26100MW
Losses: 862MW
North-west Load: 950MW
Losses: 62MW
North-east Load: 1241MW
Losses: 87MW
IMPORTS
MANITOBA: 44.6MW
MINNESOTA: 28.4MW
MICHIGAN: -141.0MW
NEW YORK: At Niagara -39.3MW
At St Lawrence -14.2MW
PINE PORTAGE
Wawatay
Umbata Falls
Williams Mine
TCPL Nipigon
Cameron Falls
Alexander
ALEXANDER
AGUASABON
TERRACE BAY
KIMBERLEY CLARKE
ANJIGAMI
Wind Farm
229.4km MxL
191.8km AxL
168.3km WxM
100.2km
T11: 41.3MW/15.8MVAr
T12: 41.3MW/15.8MVAr
T1: 33.8MW/22.3MVAr
T2: 33.6MW/22.2MVAr
T7: 168.6MW/75.9MVAr
T8: 170.3MW/76.1MVAr
R1LB: 52.7MW/25.3MVAr
R2LB: 44.3MW/24.8MVAr
A7L: -33.7MW/13.6MVAr
A8L: -39.2MW/11.8MVAr
L4P: 102.3MW/60.6MVAr
East West Tie Reinforcement: Lakehead TS to Wawa TS
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon and a 350MVAr SVC at Marathon
Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS
Prior to Phase-Shifter action
DIAGRAM 15
11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors

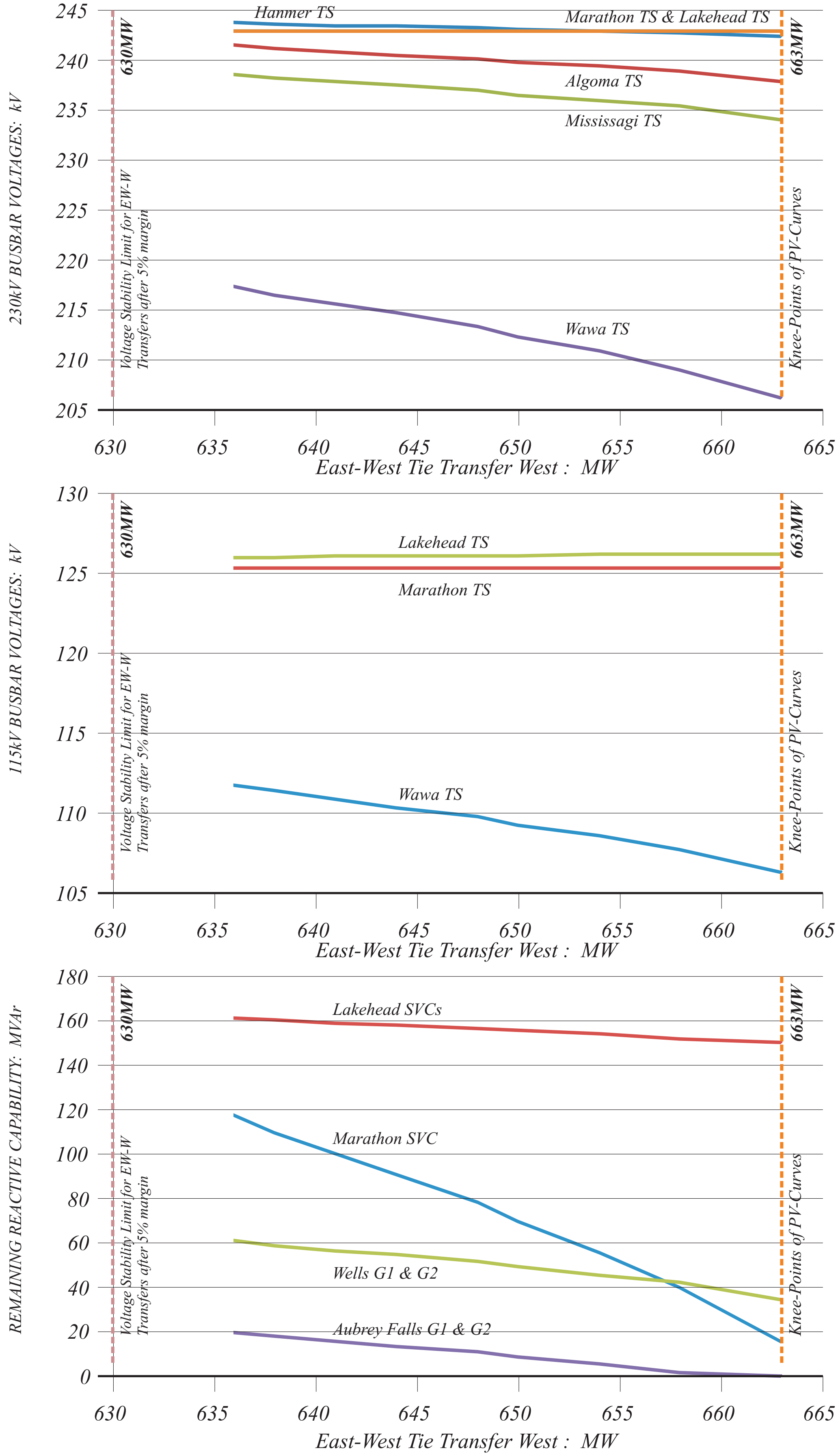
With a 100MVAr capacitor at Lakehead & Marathon and a 350MVAr SVC at Marathon

Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS

After Phase-Shifter action

DIAGRAM 16

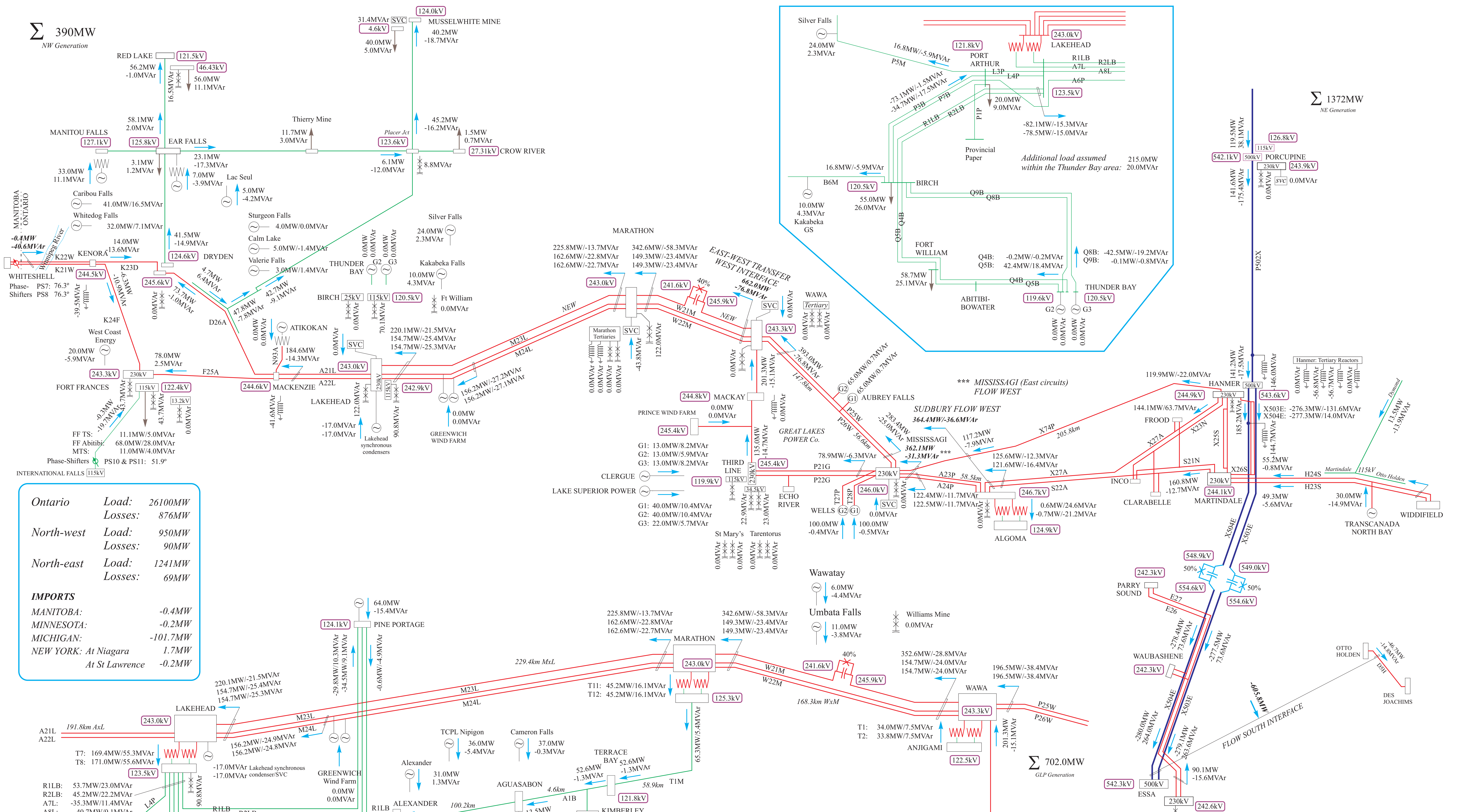
11th August 2011



PV-analysis
Marathon
350MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
Contingency: new 230kV double-circuit Wawa TS to Marathon TS
After Phase-Shifter action

DIAGRAM 17
28th July 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

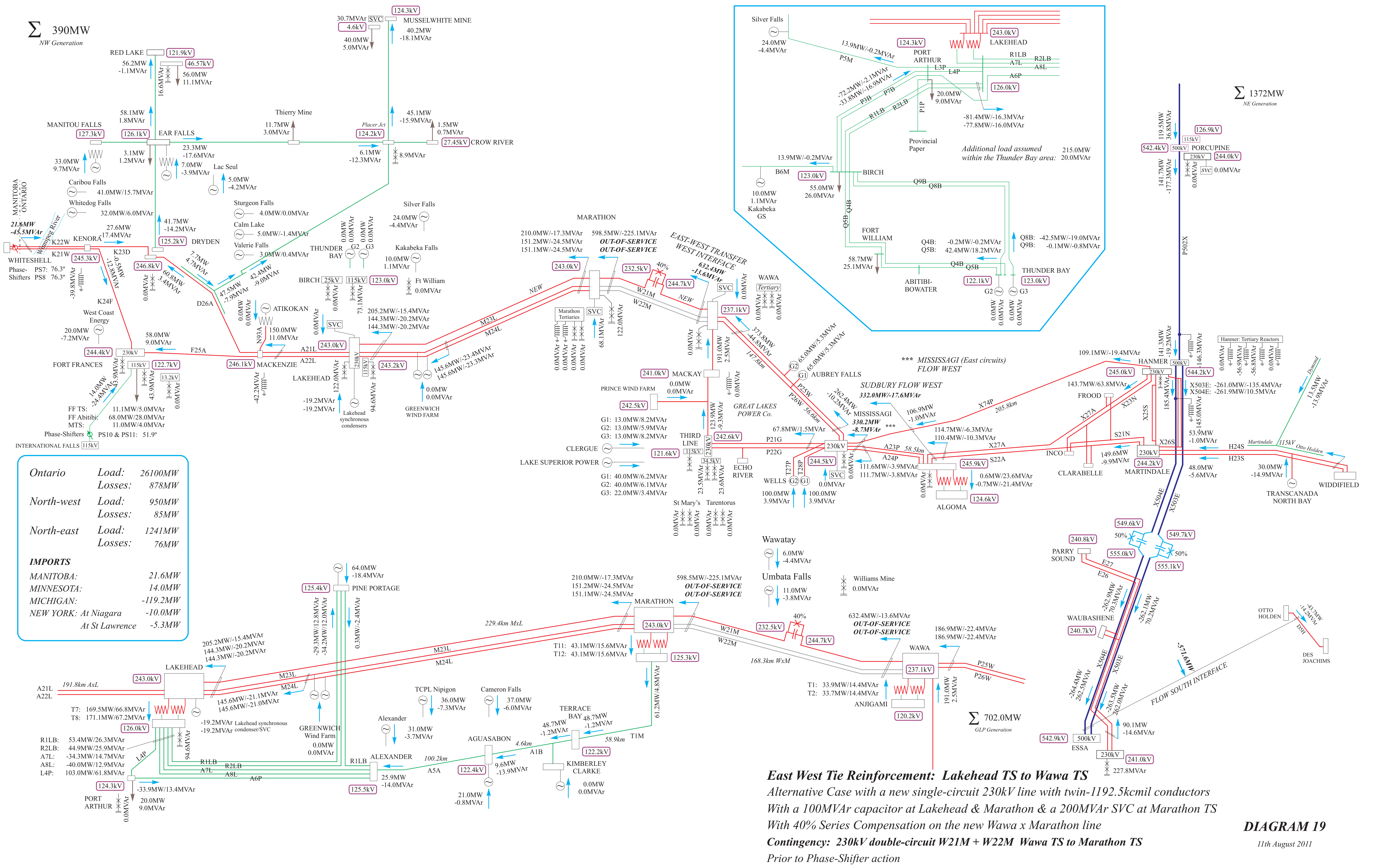
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors

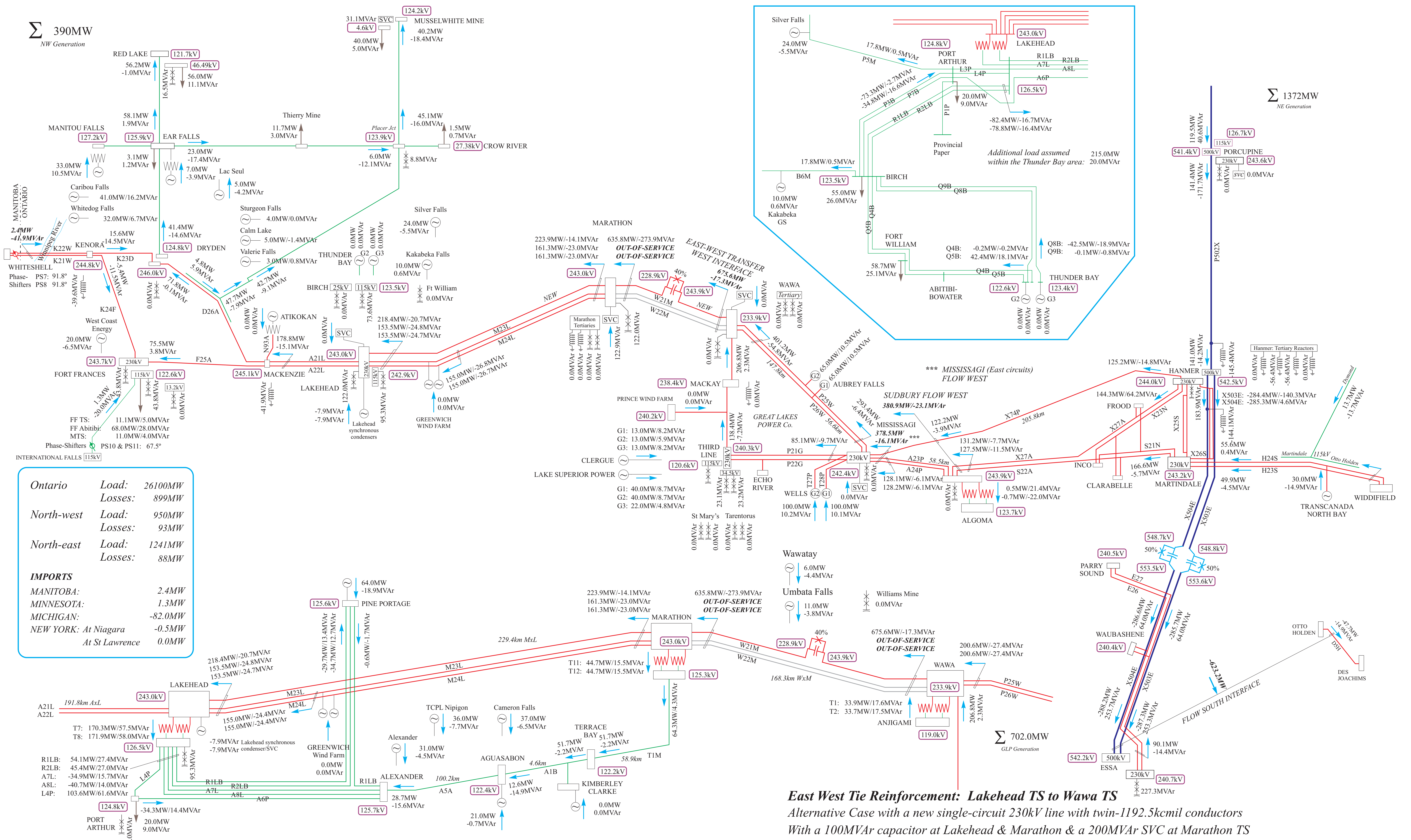
With a 100MVAr capacitor at Lakehead & Marathon and a 350MVAr SVC at Marathon

With 40% Series Compensation on the new Wawa x Marathon line

DIAGRAM 18

11th August 2011


Σ 390MW
NW Generation
Σ 1372MW
NE Generation
Σ 702.0MW
GLP Generation
Ontario Load: 26100MW
Losses: 878MW
North-west Load: 950MW
Losses: 85MW
North-east Load: 1241MW
Losses: 76MW
IMPORTS
MANITOBA: 21.6MW
MINNESOTA: 14.0MW
MICHIGAN: -119.2MW
NEW YORK: At Niagara -10.0MW
At St Lawrence -5.3MW
EAST-WEST TRANSFER
WEST INTERFACE
632.4MW
-13.6MVAr
SUDBURY FLOW WEST
332.0MW/-17.6MVAr
*** MISSISSAGI (East circuits)
FLOW WEST
FLOW SOUTH INTERFACE
-571.6MW
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
East West Tie Reinforcement: Lakehead TS to Wawa TS
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS
With 40% Series Compensation on the new Wawa x Marathon line
Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS
Prior to Phase-Shifter action
DIAGRAM 19
11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

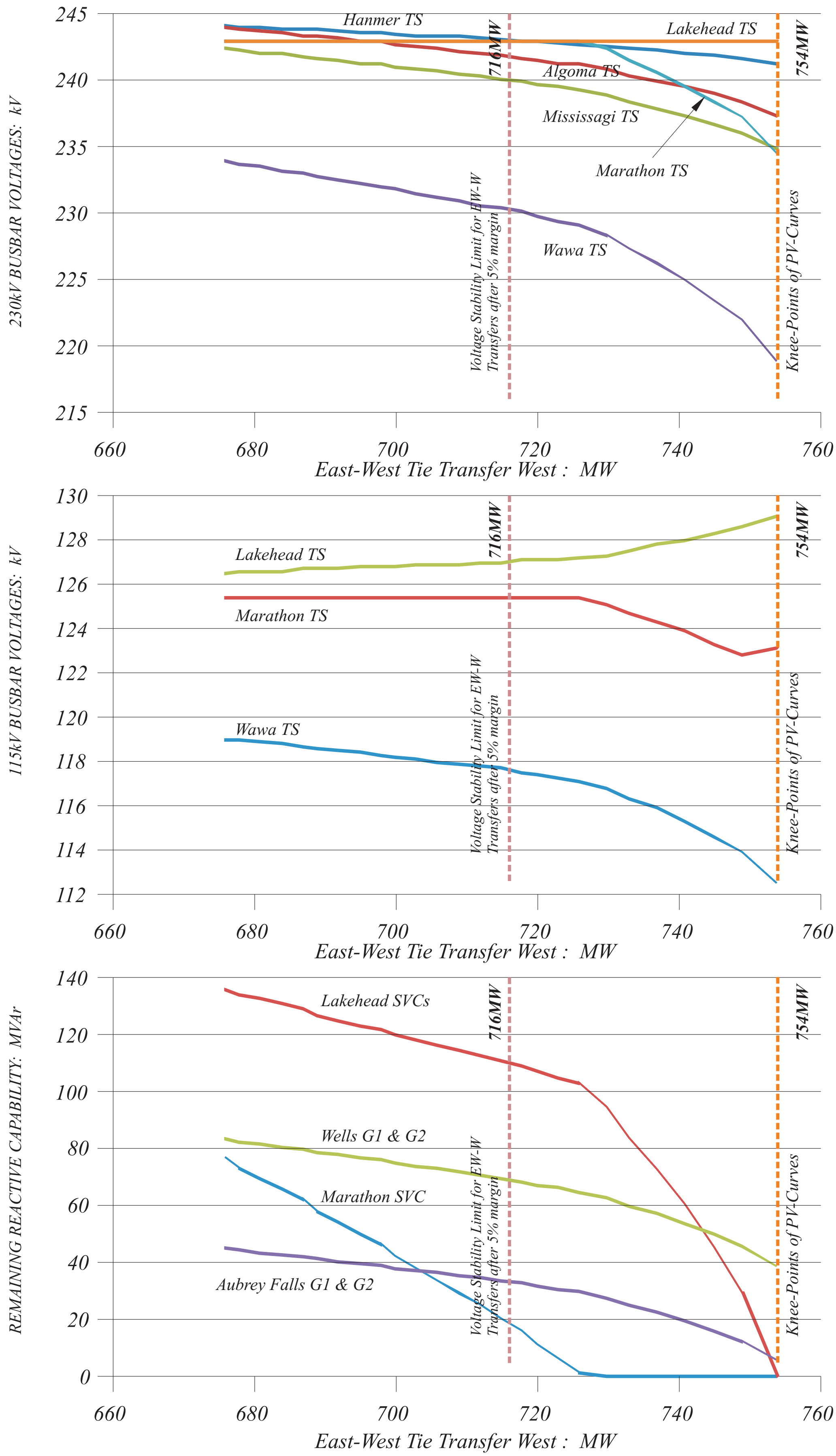
With 40% Series Compensation on the new Wawa x Marathon line

Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS

After Phase-Shifter action

DIAGRAM 20

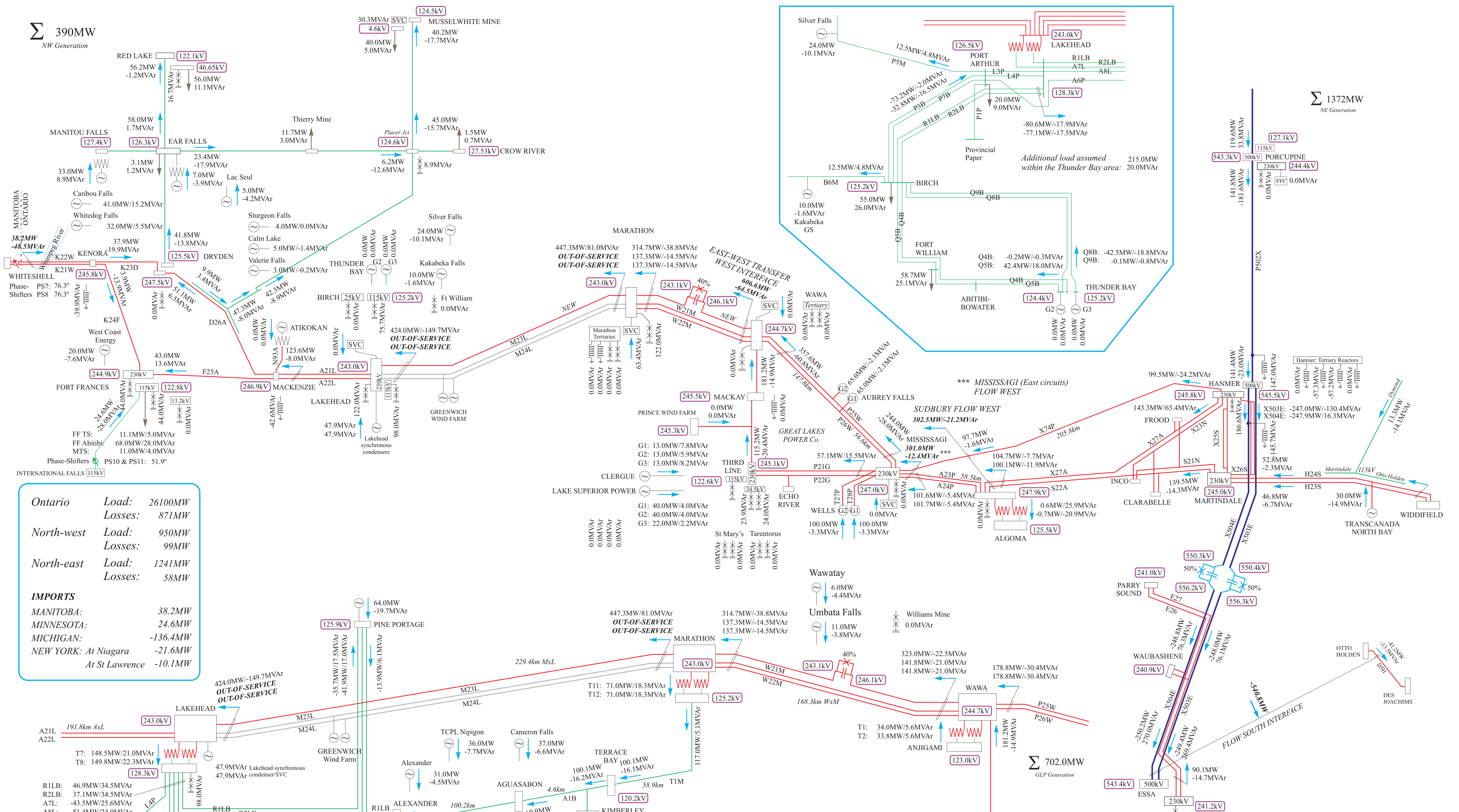
11th August 2011



PV-analysis
Marathon 200MVAr SVC + series caps on new WxM line

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
Contingency: existing 230kV double-circuit Wawa TS to Marathon TS
After Phase-Shifter action

DIAGRAM 21
28th July 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

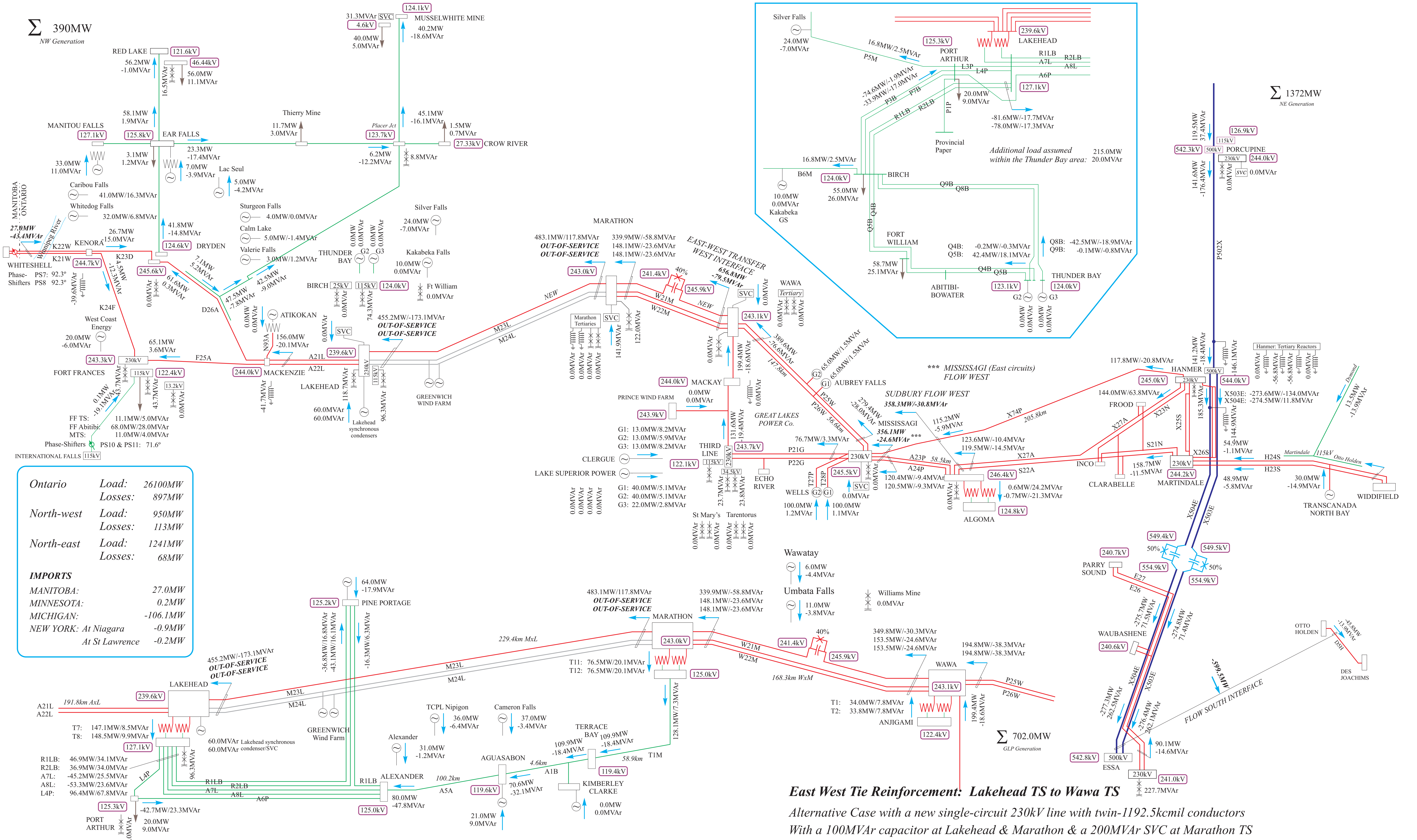
With 40% Series Compensation on the new Wawa x Marathon line

Contingency: 230kV double-circuit M23L + M24L Marathon TS to Lakehead TS

Prior to Phase-Shifter action

DIAGRAM 22

11th August 2011

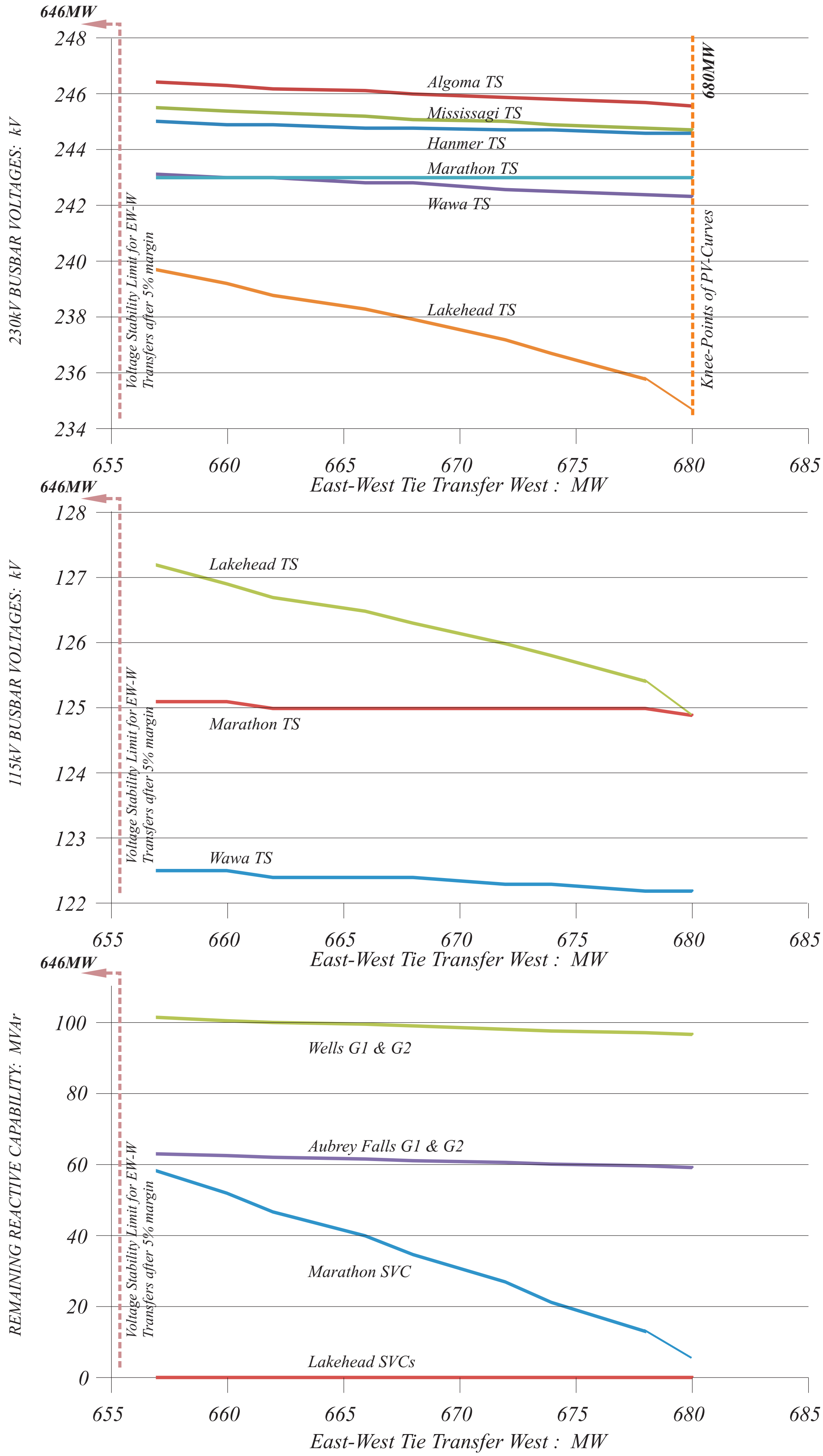


East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS
With 40% Series Compensation on the new Wawa x Marathon line
Contingency: 230kV double-circuit M23L + M24L Marathon TS to Lakehead TS
After Phase-Shifter action

DIAGRAM 23

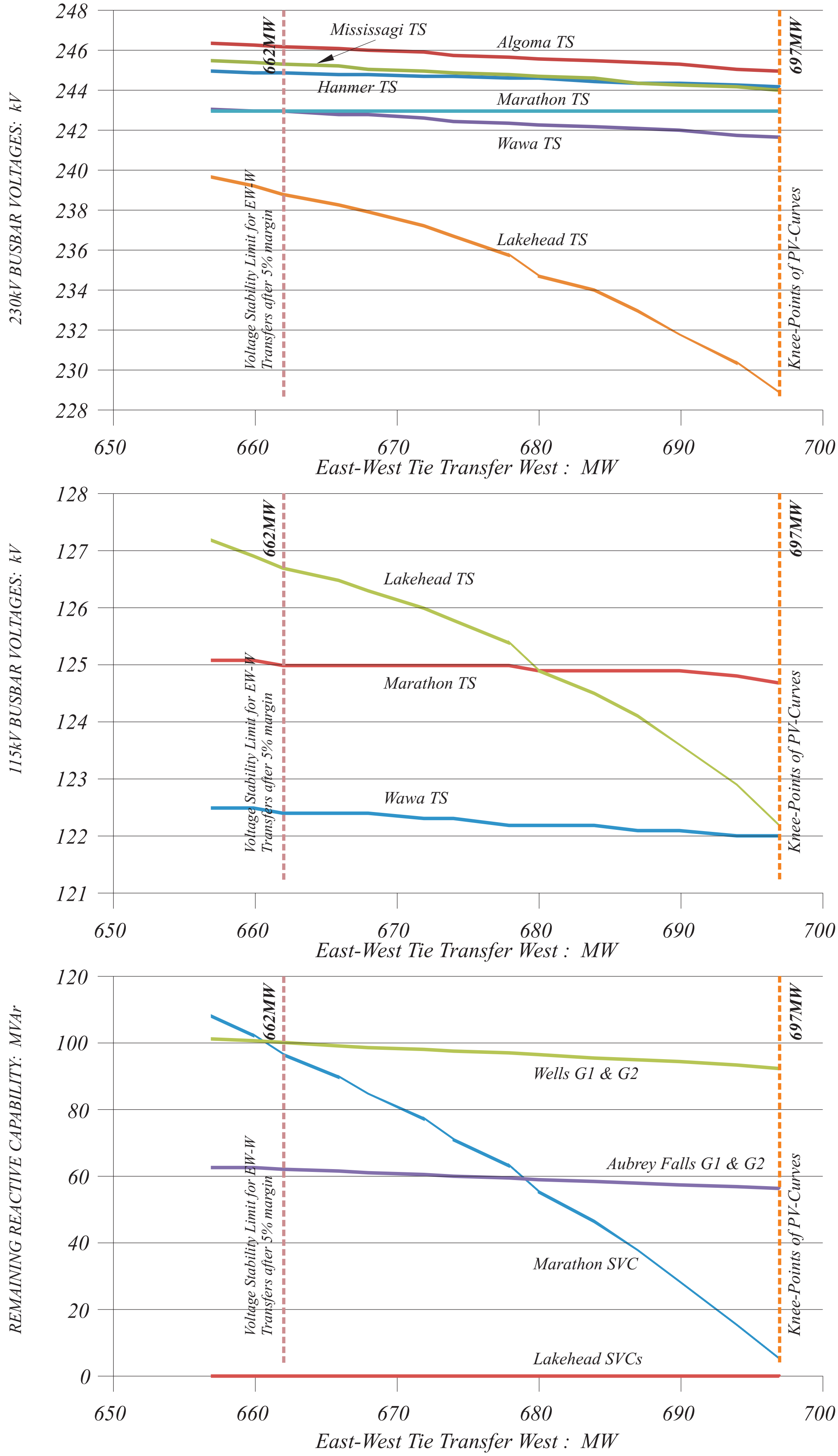
11th August 2011



PV-analysis
Marathon 200MVAr SVC + series caps on new WxM line

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
Contingency: existing 230kV double-circuit Marathon TS to Lakehead TS
After Phase-Shifter action

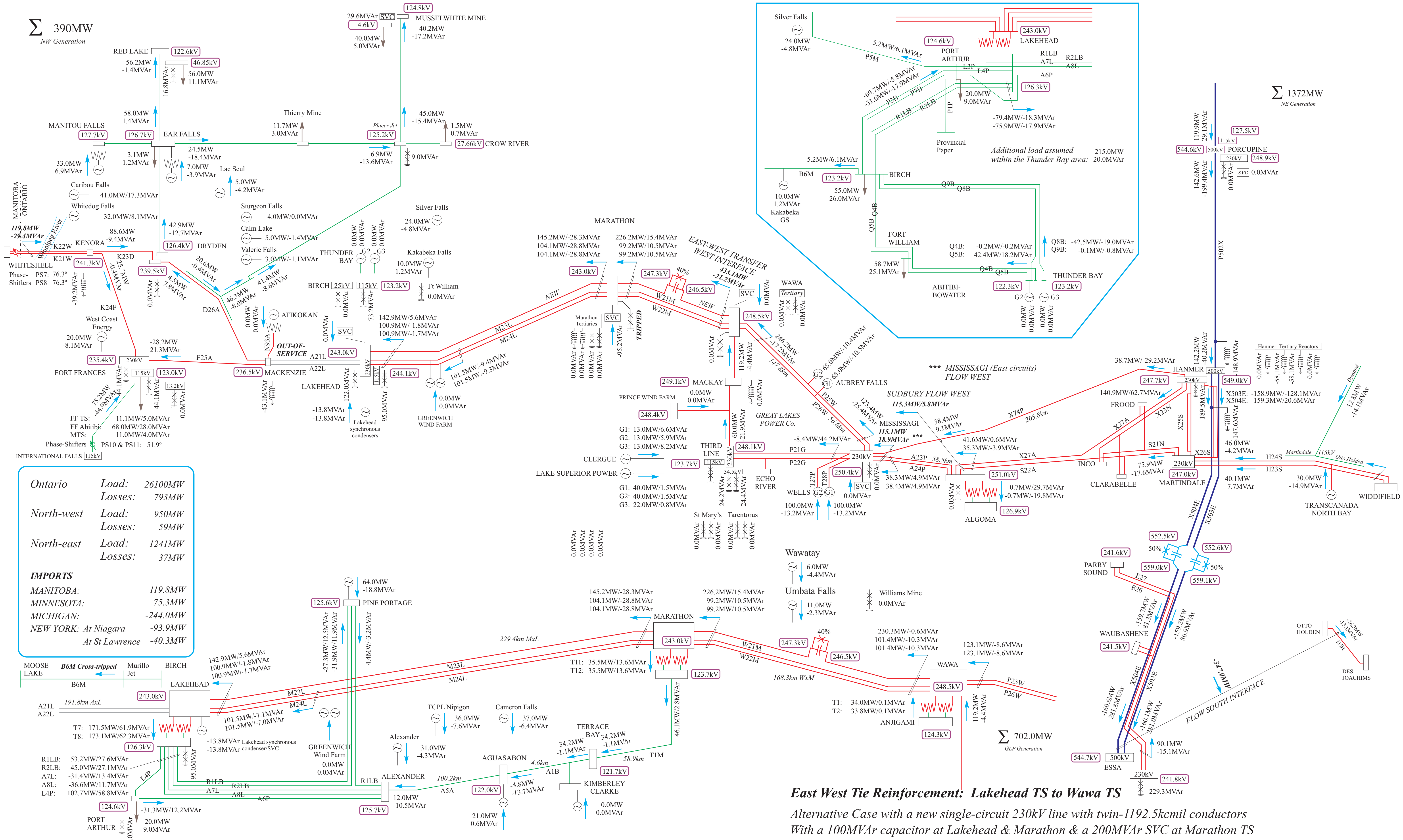
DIAGRAM 24
29th July 2011



PV-analysis
Marathon ***250MVAr***
SVC + series caps
on new WxM line

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
Contingency: existing 230kV double-circuit Marathon TS to Lakehead TS
After Phase-Shifter action

DIAGRAM 25
29th July 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

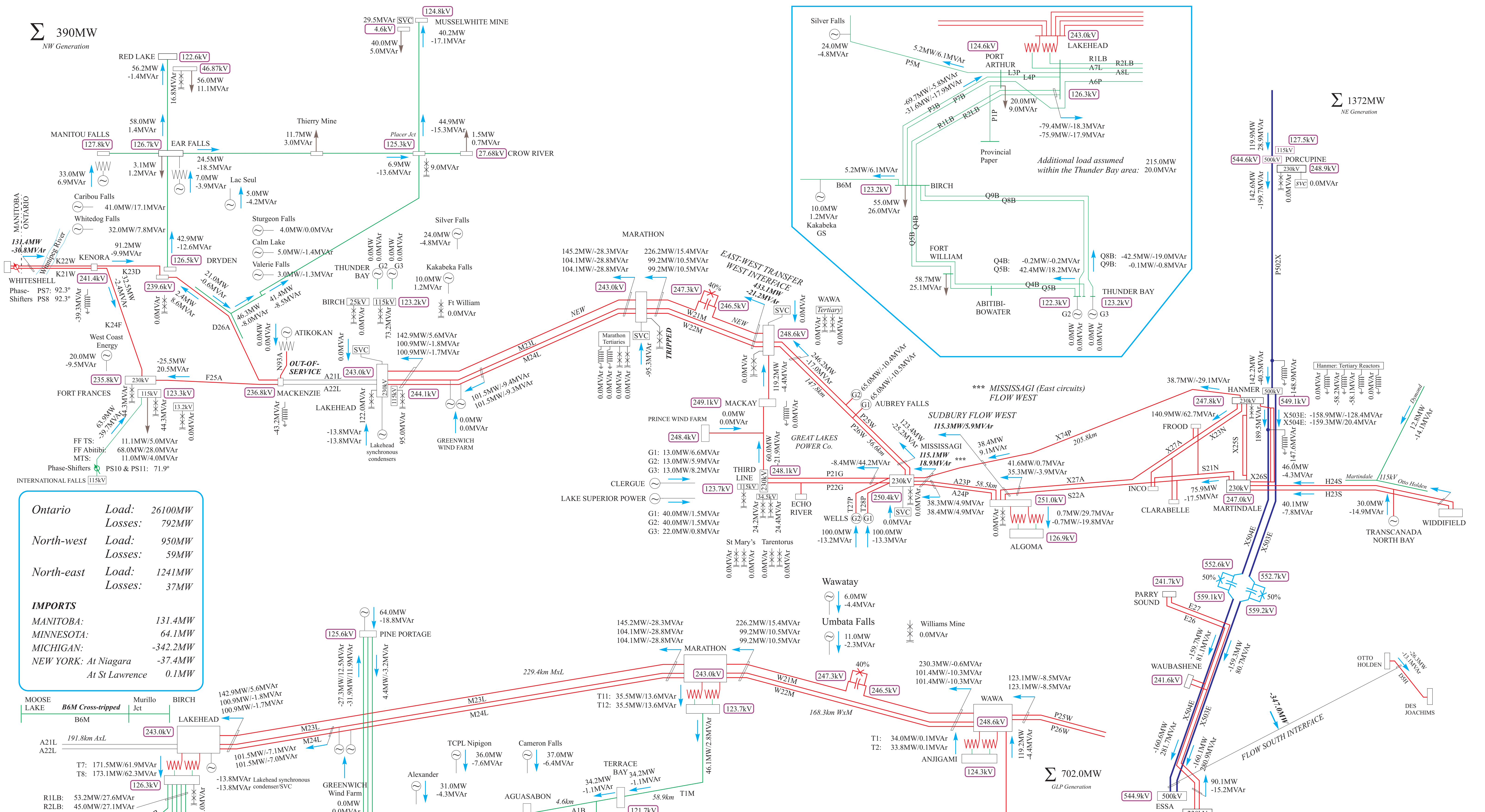
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS
With 40% Series Compensation on the new Wawa x Marathon line

DIAGRAM 26

Contingency: 230kV double-circuit A21L + A22L Lakehead TS to Mackenzie TS

Marathon capacitor tripped & Prior to Phase-Shifter action

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

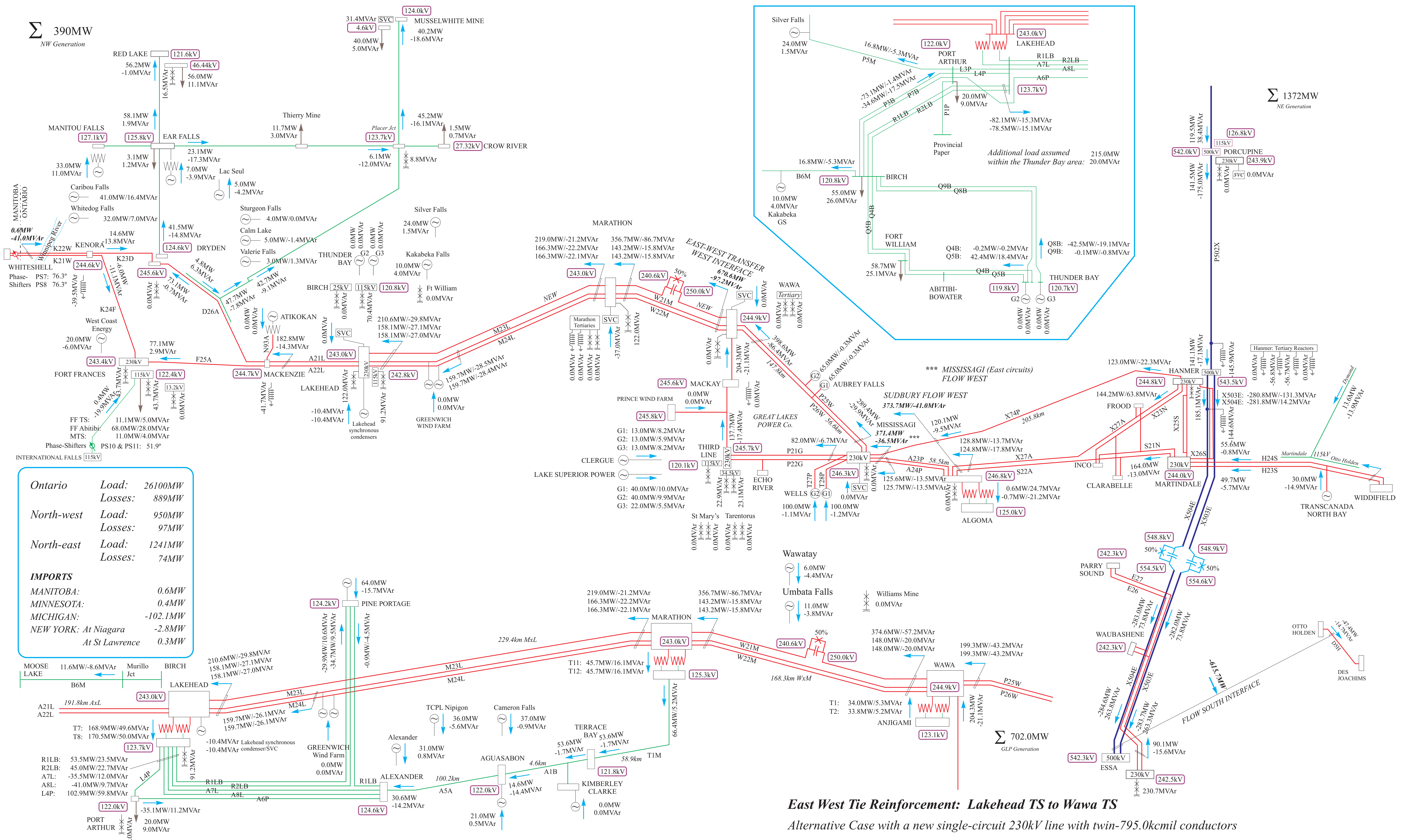
Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS
With 40% Series Compensation on the new Wawa x Marathon line

DIAGRAM 27

11th August 2011

Contingency: 230kV double-circuit A21L + A22L Lakehead TS to Mackenzie TS

Marathon capacitor tripped & After Phase-Shifter action



East West Tie Reinforcement: Lakehead TS to Wawa TS

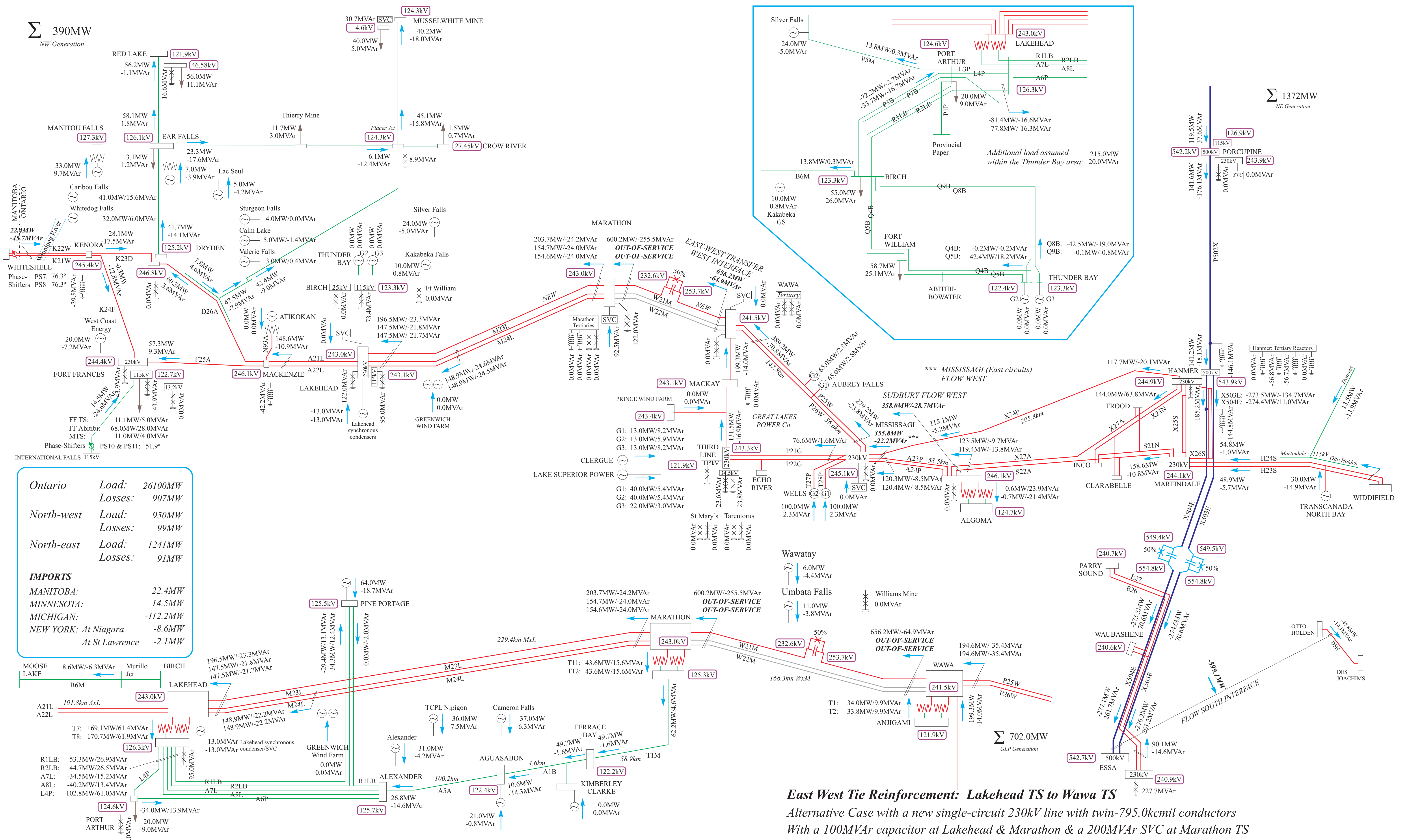
Alternative Case with a new single-circuit 230kV line with twin-795.0kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

With 50% Series Compensation on the new Wawa x Marathon line

DIAGRAM 28

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-795.0kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

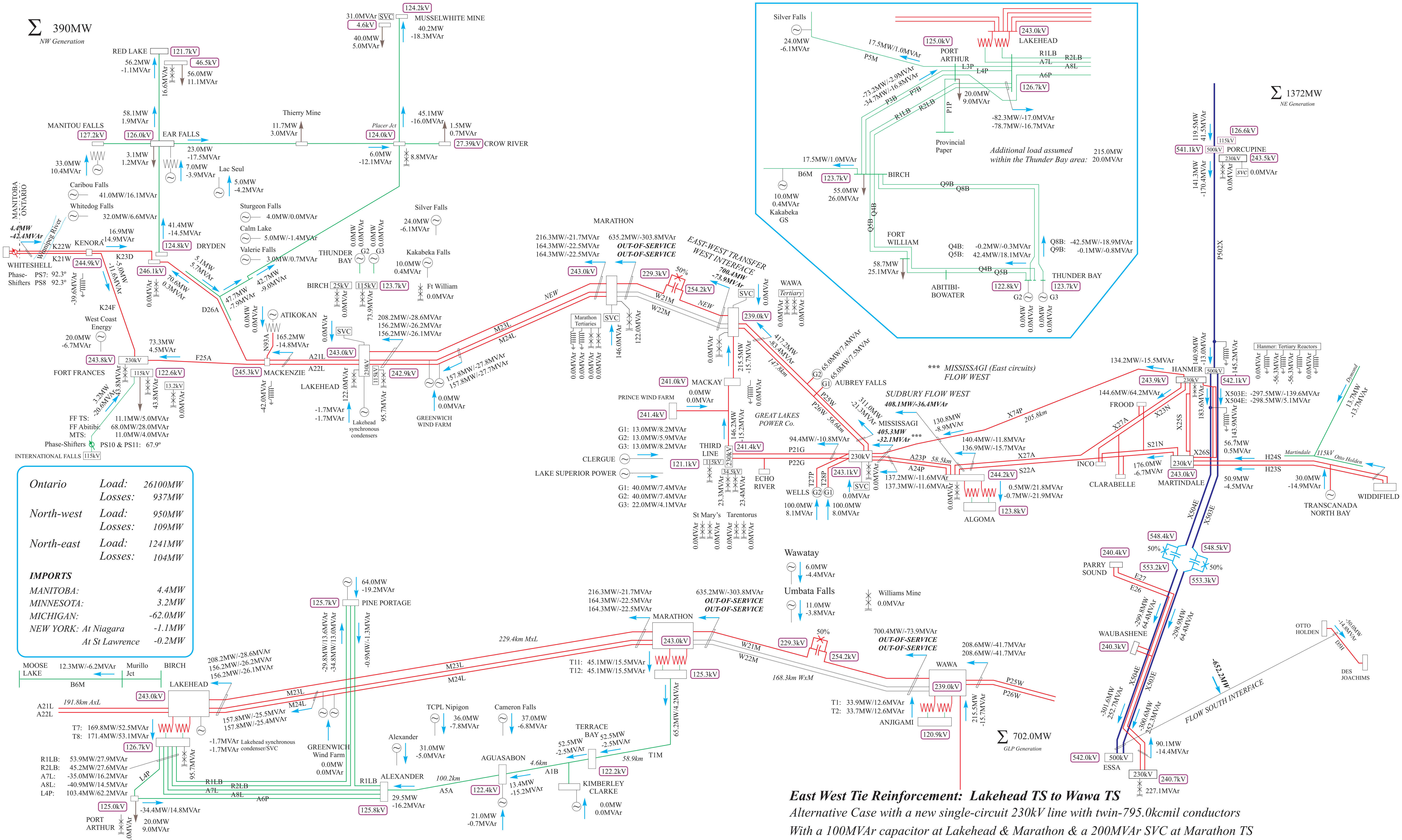
With 50% Series Compensation on the new Wawa x Marathon line

Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS

Prior to Phase-Shifter action

DIAGRAM 29

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-795.0kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

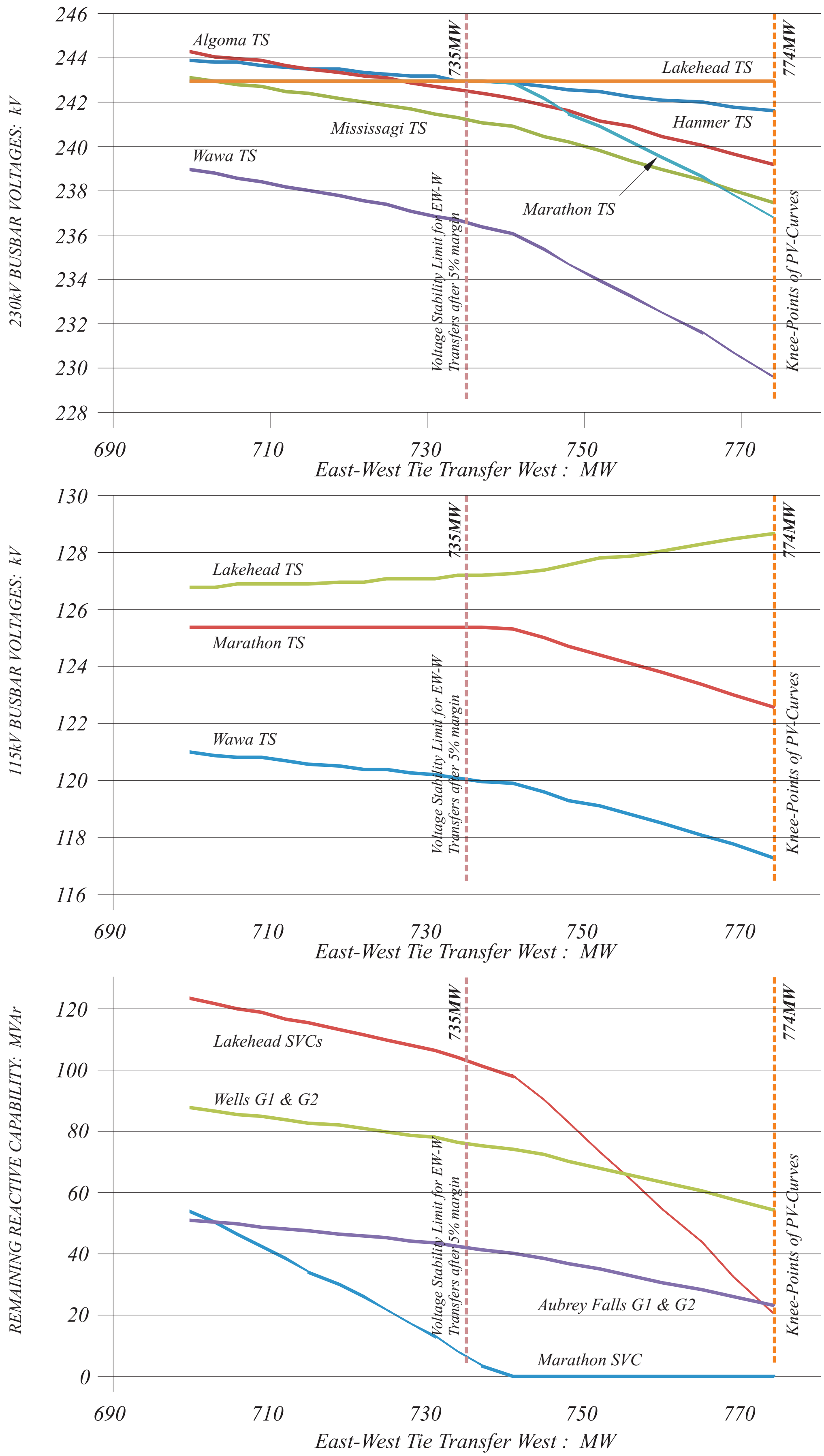
With 50% Series Compensation on the new Wawa x Marathon line

Contingency: 230kV double-circuit W21M + W22M Wawa TS to Marathon TS

After Phase-Shifter action

DIAGRAM 30

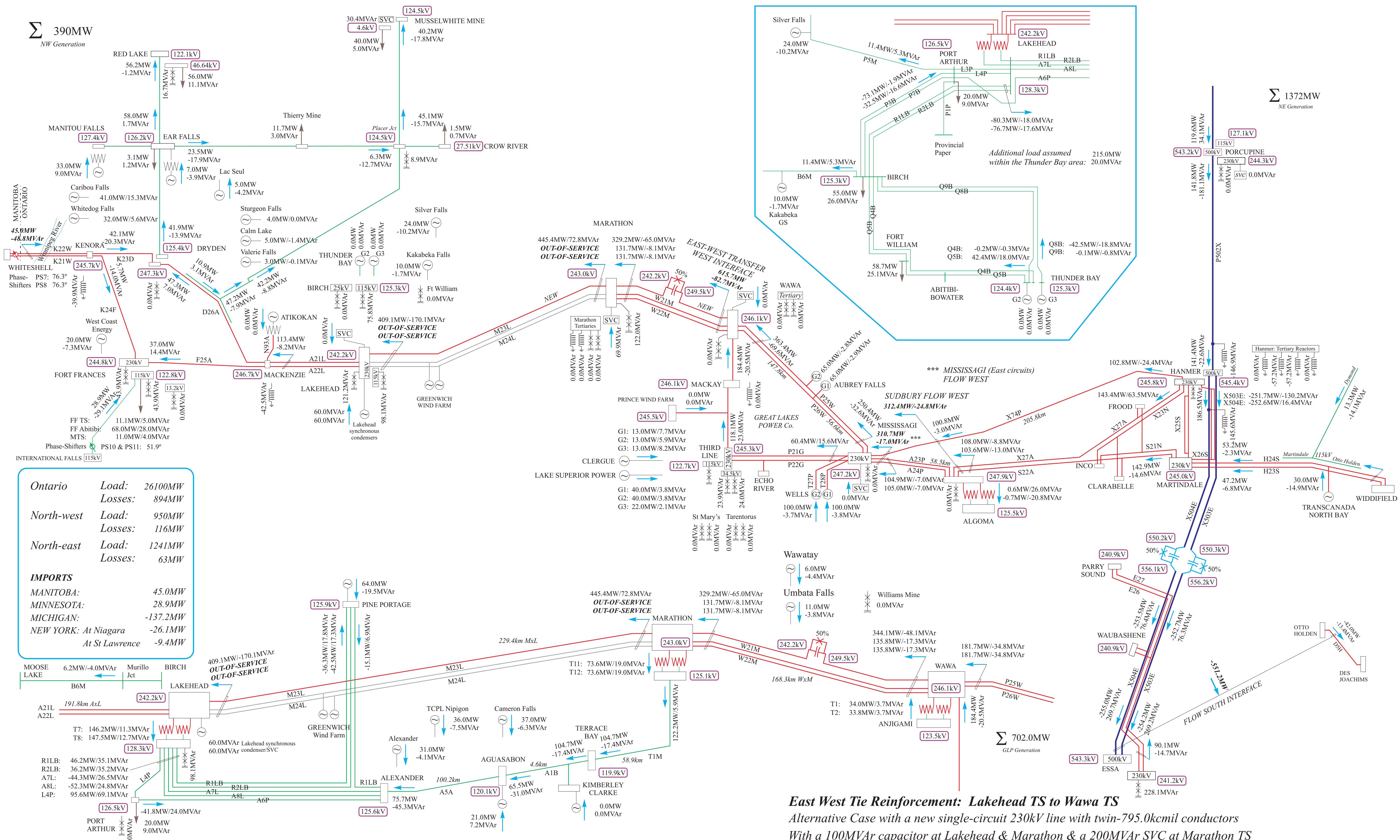
11th August 2011



PV-analysis
Marathon 200MVAr SVC + series caps on new WxM line

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
Contingency: existing 230kV double-circuit Wawa TS to Marathon TS
After Phase-Shifter action

DIAGRAM 31
1st August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-795.0kcmil conductors

With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS

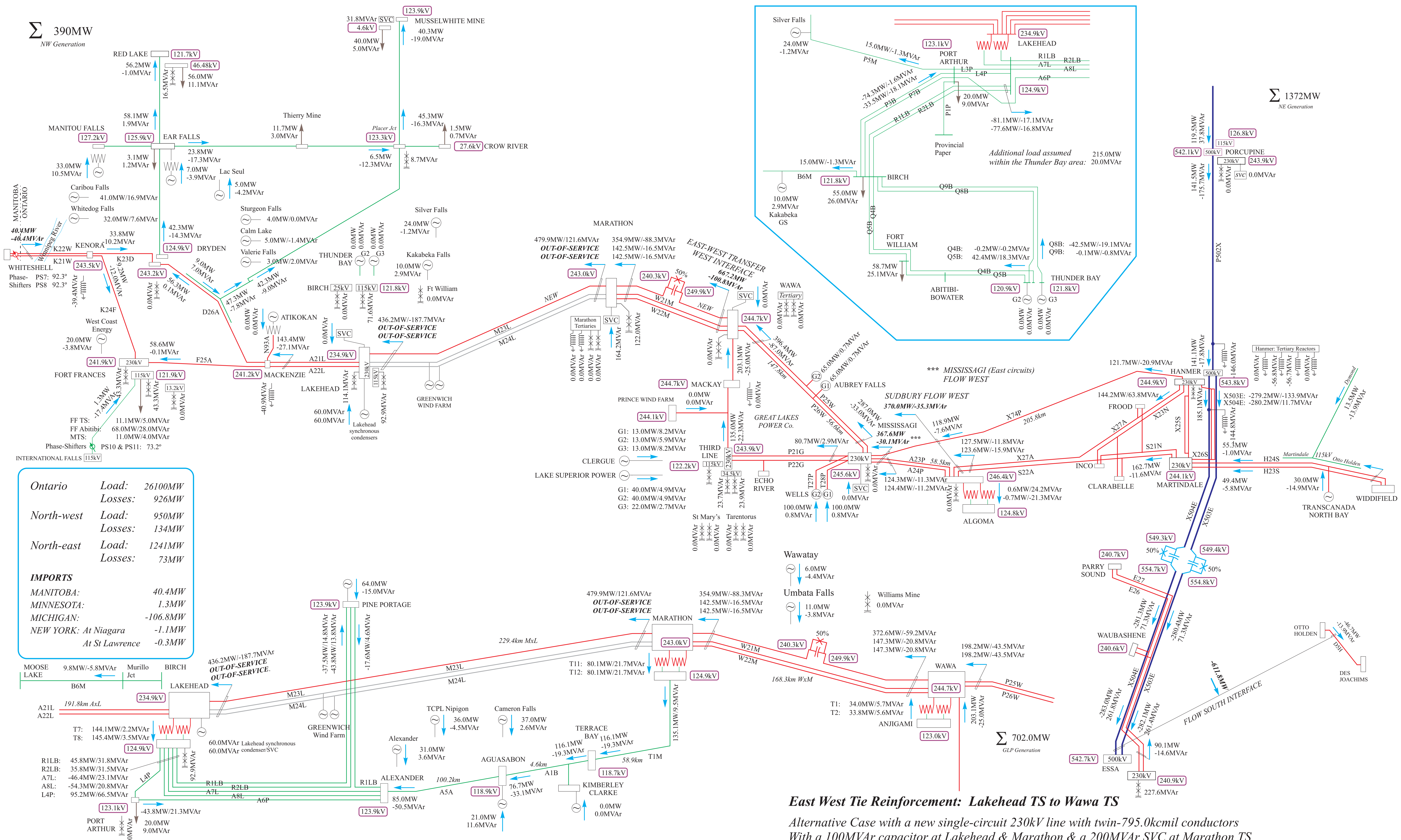
With 50% Series Compensation on the new Wawa x Marathon line

Contingency: 230kV double-circuit M23L + M24L Marathon TS to Lakehead TS

Prior to Phase-Shifter action

DIAGRAM 32

11th August 2011

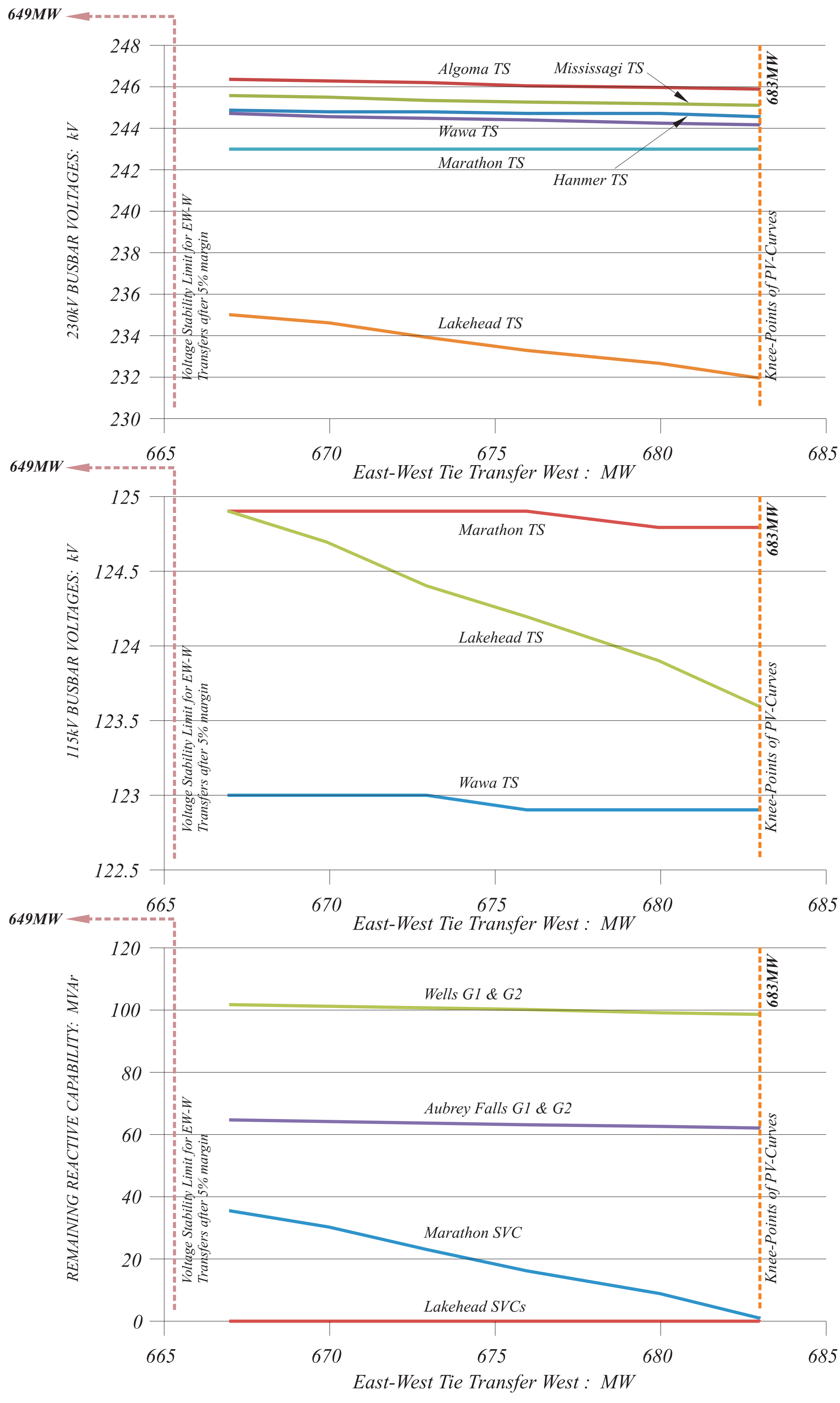


East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-795.0kcmil conductors
With a 100MVAr capacitor at Lakehead & Marathon & a 200MVAr SVC at Marathon TS
With 50% Series Compensation on the new Wawa x Marathon line
Contingency: 230kV double-circuit M23L + M24L Marathon TS to Lakehead TS
After Phase-Shifter action

DIAGRAM 33

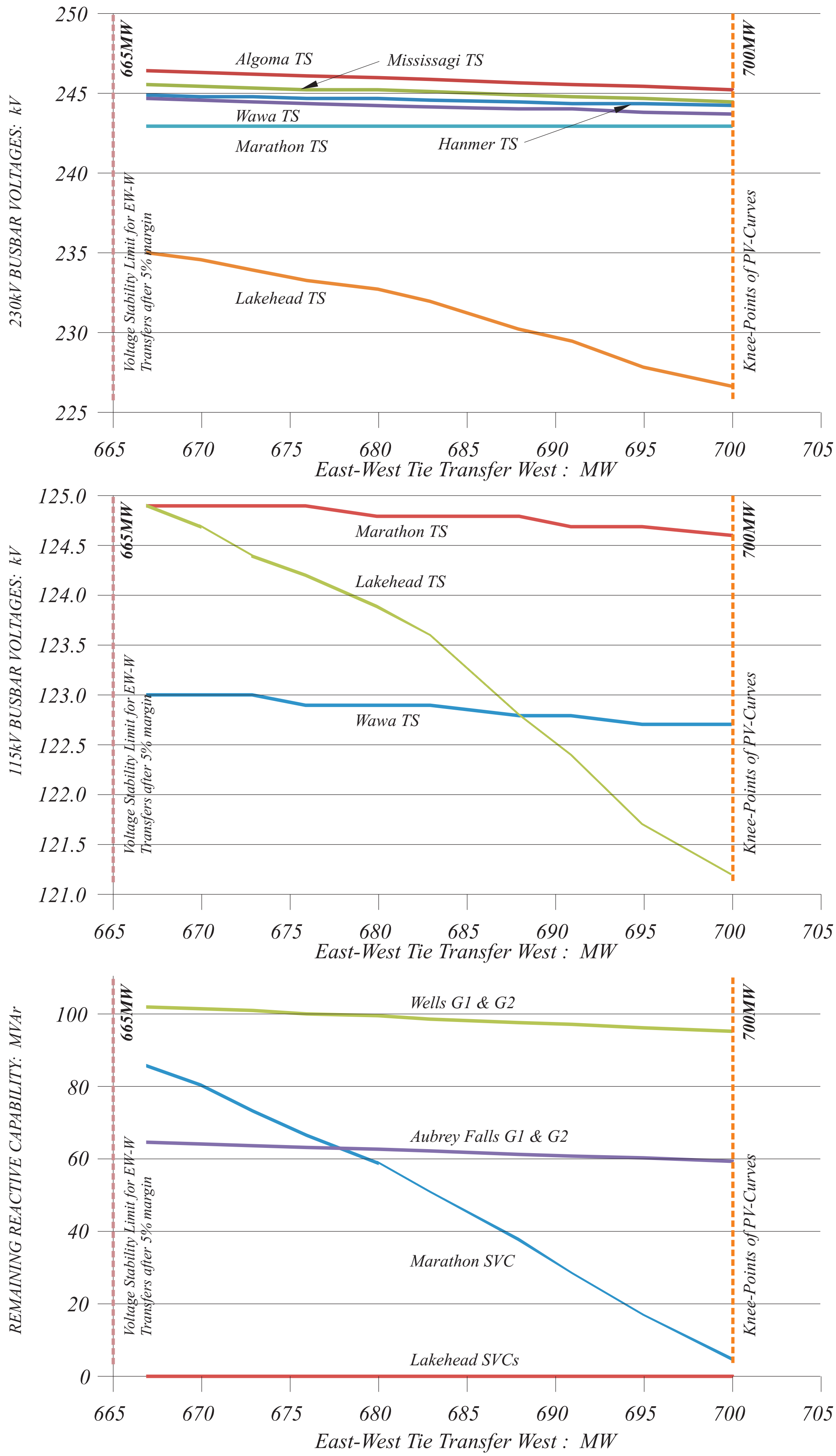
11th August 2011



PV-analysis
Marathon 200MVAr SVC + 50% series caps on new WxM line

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-795.0kcmil conductors
Contingency: existing 230kV double-circuit Marathon TS to Lakehead TS
After Phase-Shifter action

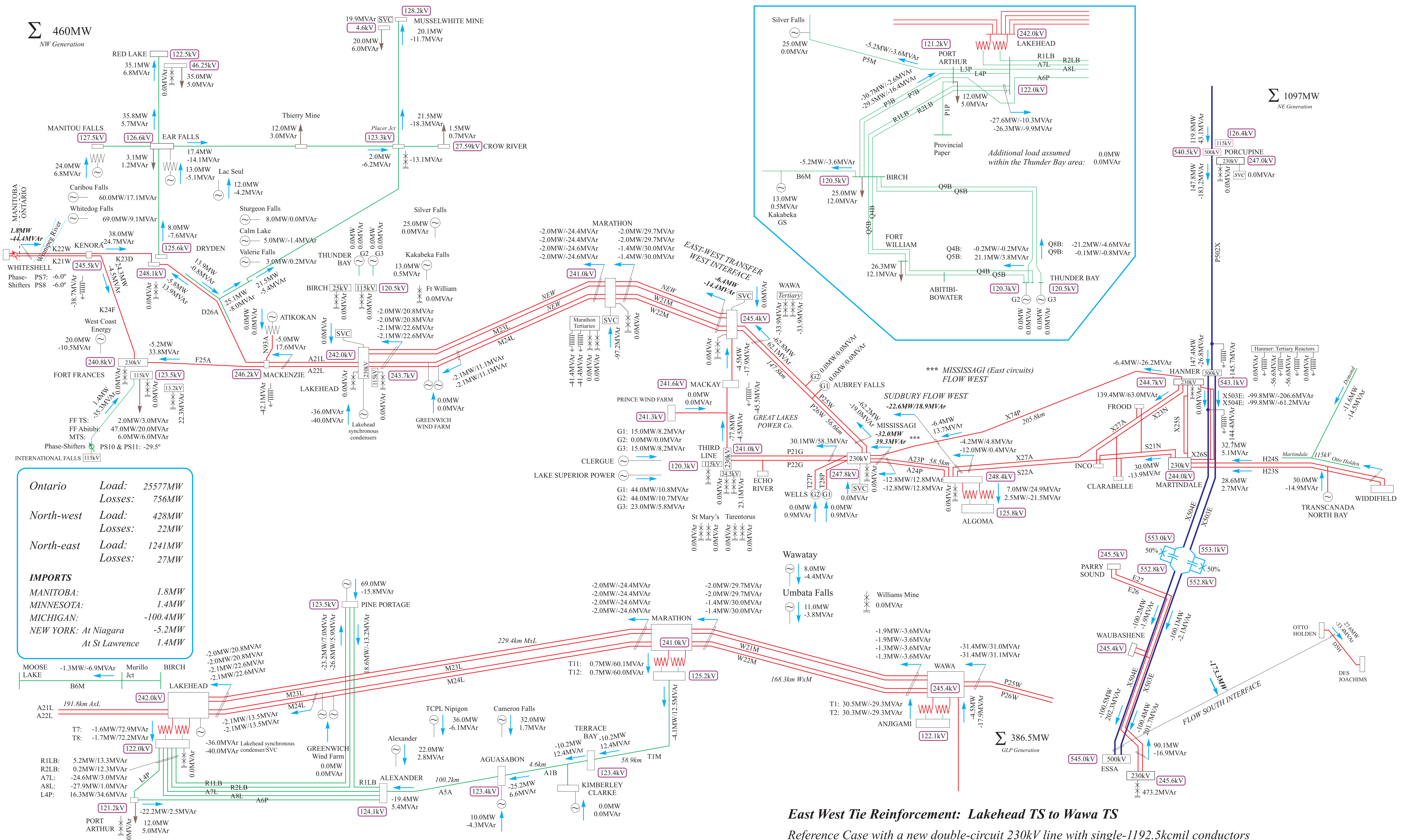
DIAGRAM 34
1st August 2011



PV-analysis
*Marathon **250MVAr** SVC + 50% series caps on new WxM line*

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new single-circuit 230kV line with twin-795.0kcmil conductors
Contingency: existing 230kV double-circuit Marathon TS to Lakehead TS
After Phase-Shifter action

DIAGRAM 35
1st August 2011

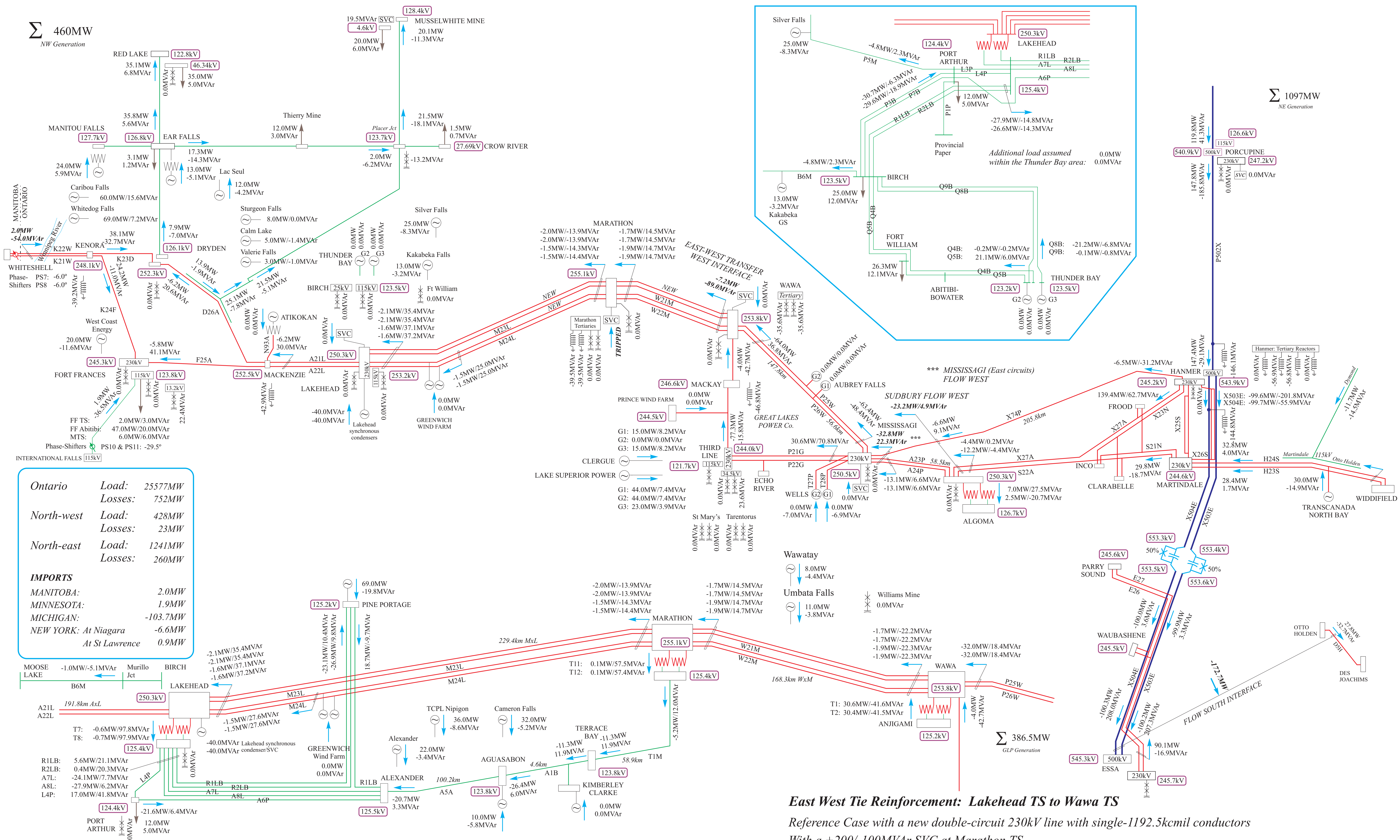


East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a +200/-100MVAr SVC at Marathon TS
Condition with reduced loads & transfers of approximately 0MW on the East-West Tie

DIAGRAM 36

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors

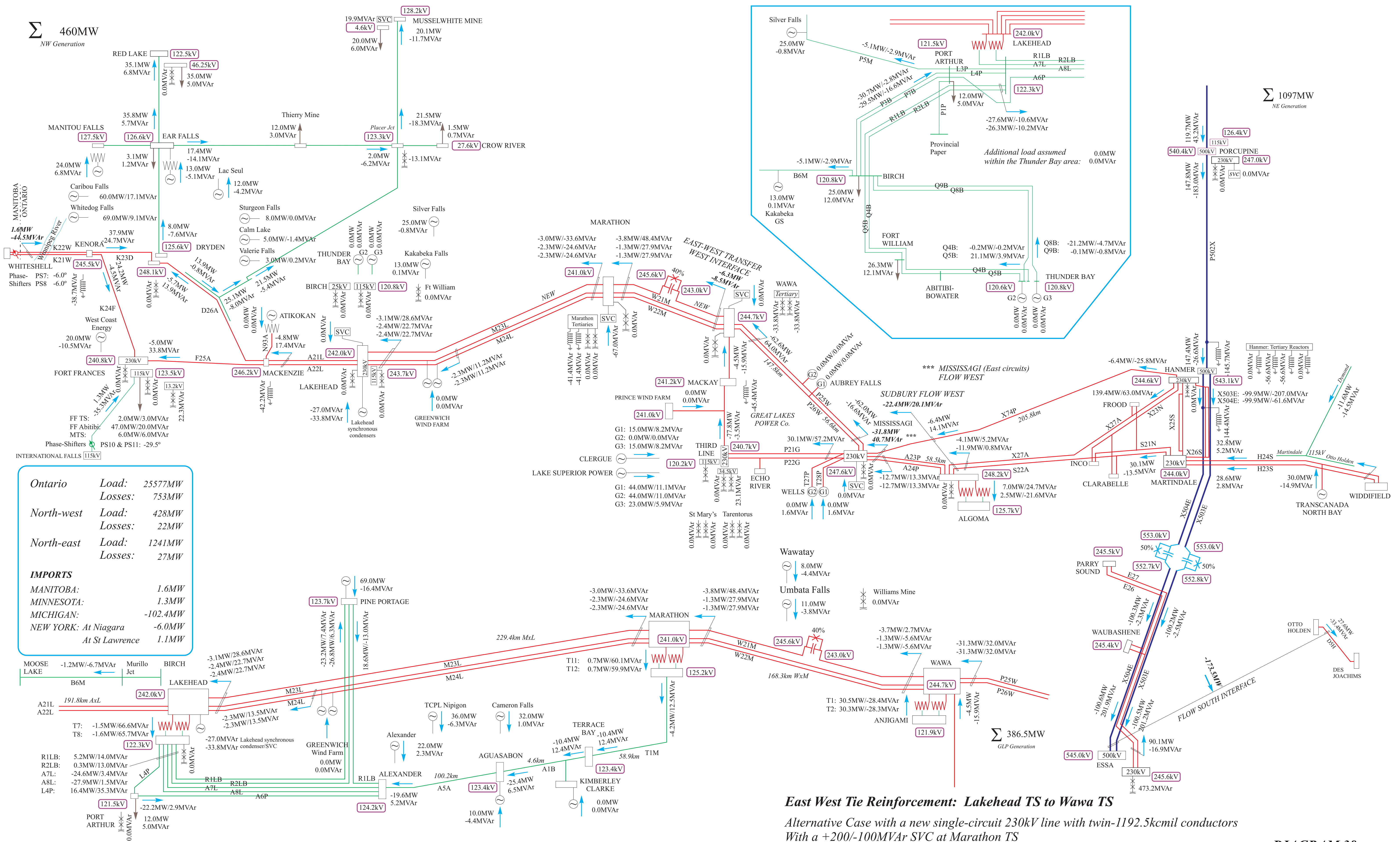
With a +200/-100MVAr SVC at Marathon TS

Condition with reduced loads & transfers of approximately 0MW on the East-West Tie

Contingency: Marathon SVC tripped

DIAGRAM 37

11th August 2011

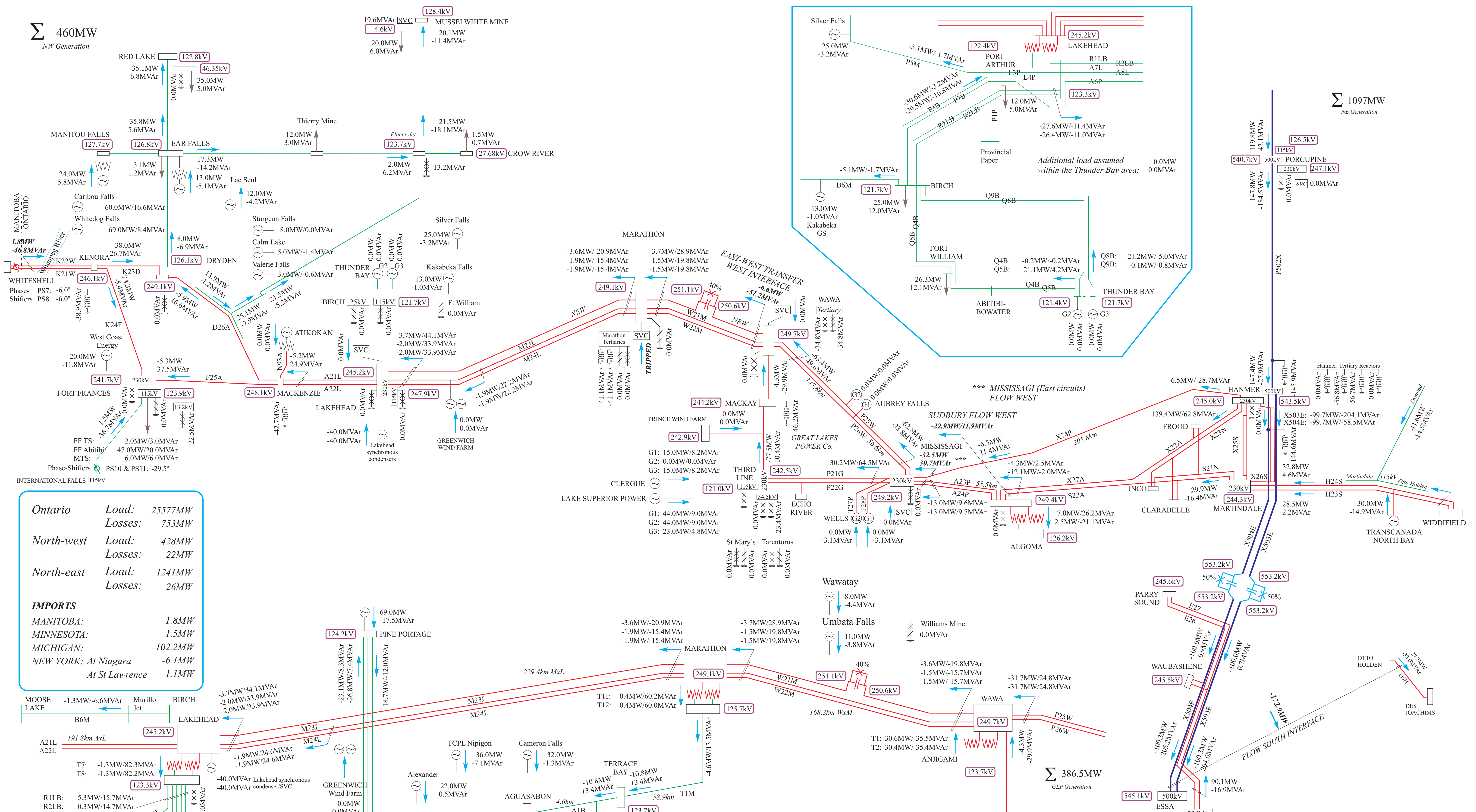


East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a +200/-100MVAr SVC at Marathon TS
With 40% series compensation at the mid-point of the new Wawa TS to Marathon TS line
Condition with reduced loads & transfers of approximately 0MW on the East-West Tie

DIAGRAM 38

11th August 2011



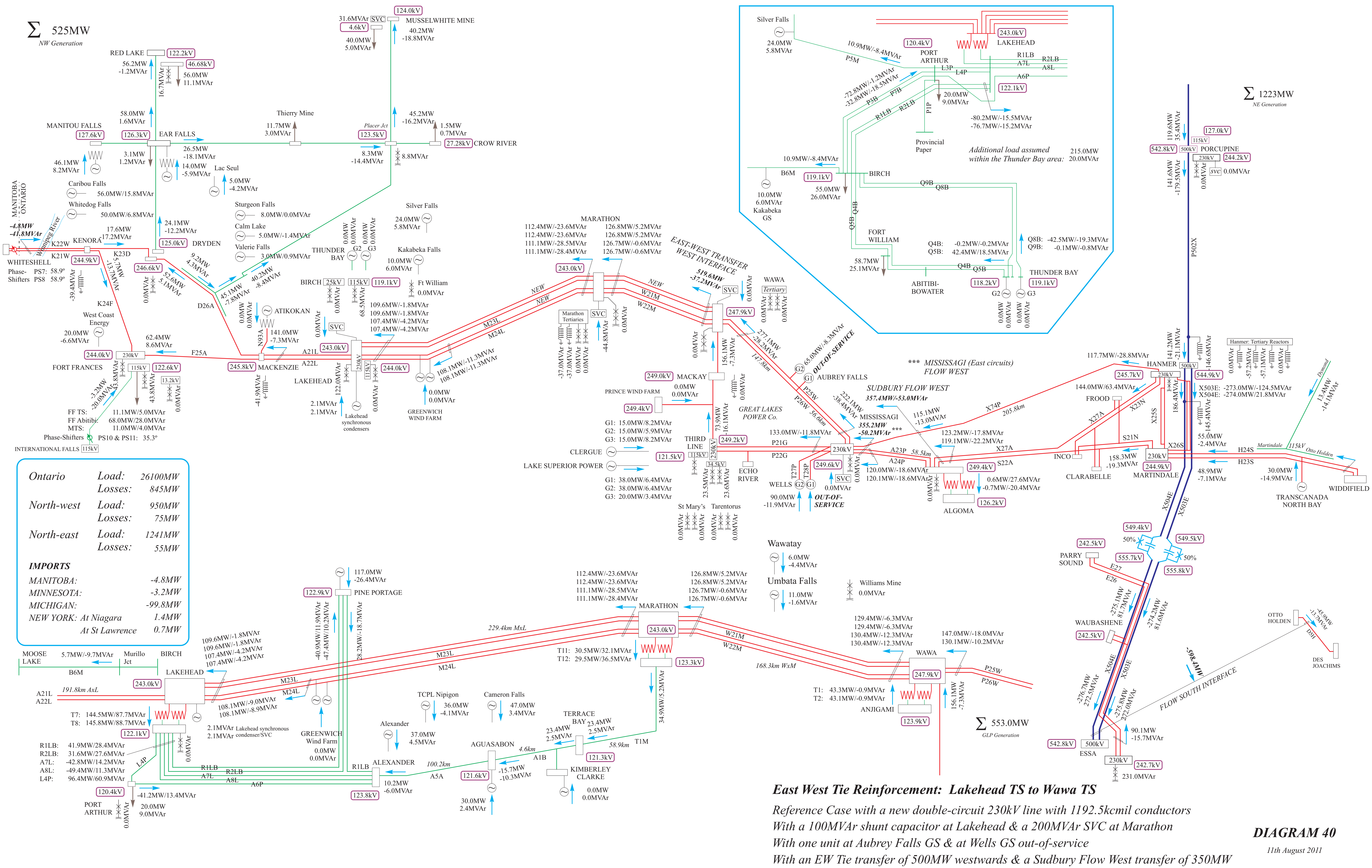
East West Tie Reinforcement: Lakehead TS to Wawa TS

Alternative Case with a new single-circuit 230kV line with twin-1192.5kcmil conductors
With a +200/-100MVAr SVC at Marathon TS
With 40% series compensation at the mid-point of the new Wawa TS to Marathon TS line
Condition with reduced loads & transfers of approximately 0MW on the East-West Tie

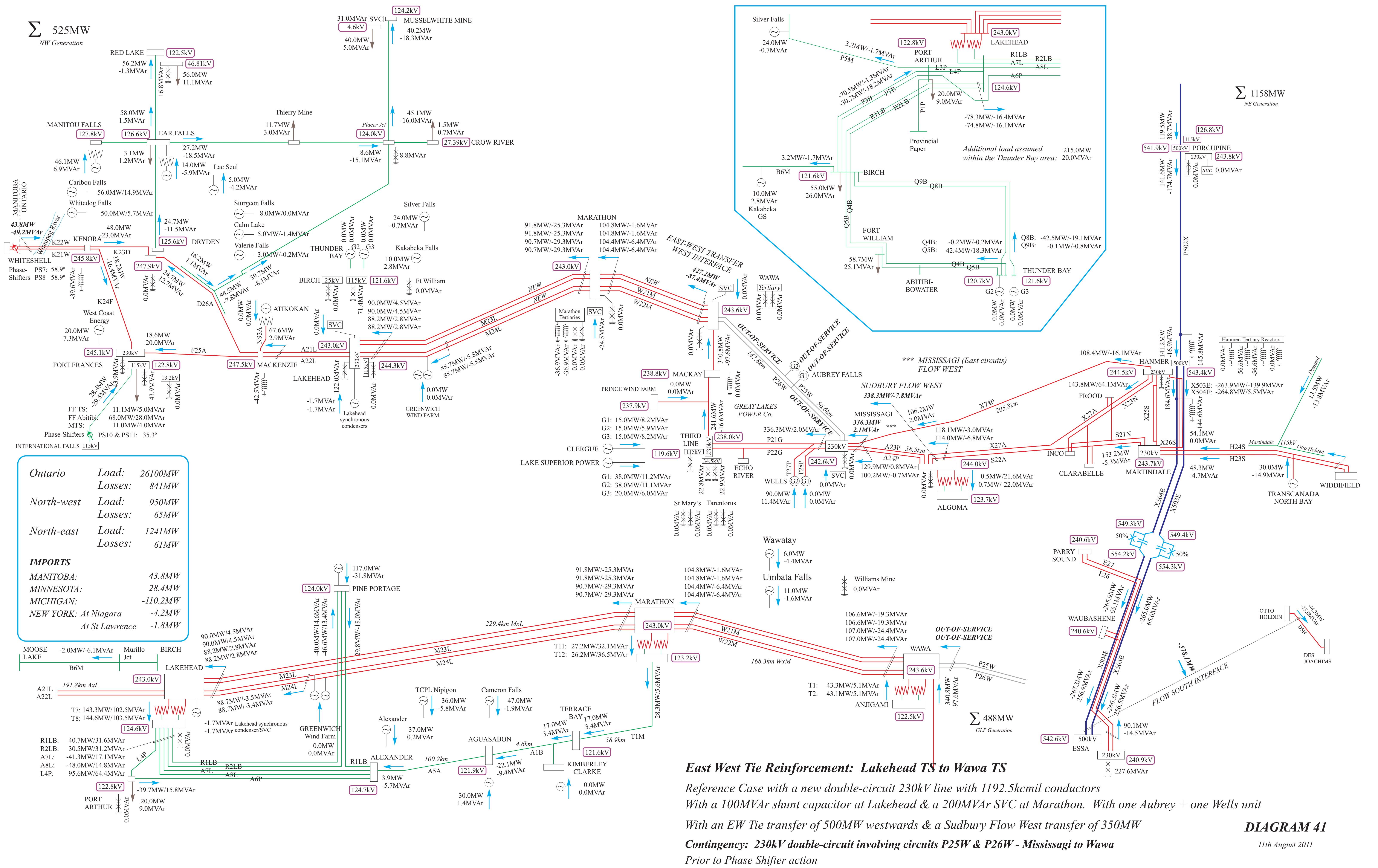
Contingency: Marathon SVC tripped

DIAGRAM 39

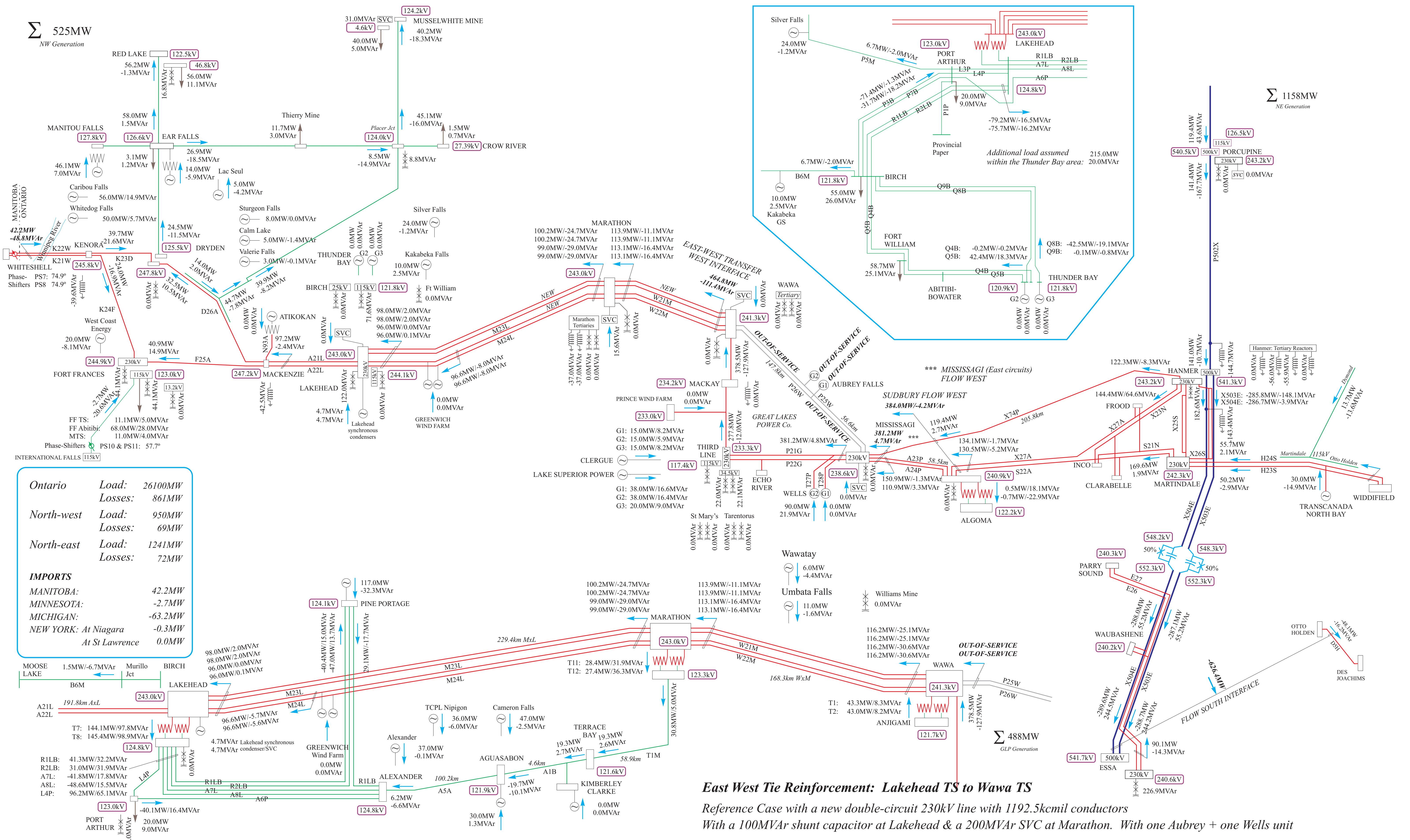
11th August 2011



Σ 525MW
NW Generation
Σ 1223MW
NE Generation
Σ 553.0MW
GLP Generation
Ontario Load: 26100MW Losses: 845MW
North-west Load: 950MW Losses: 75MW
North-east Load: 1241MW Losses: 55MW
IMPORTS
MANITOBA: -4.8MW
MINNESOTA: -3.2MW
MICHIGAN: -99.8MW
NEW YORK: At Niagara 1.4MW
At St Lawrence 0.7MW
MANITOBA
ONTARIO
WHITESHELL
KENORA
DRYDEN
RED LAKE
EAR FALLS
MANITOU FALLS
Caribou Falls
Whitedog Falls
Lac Seul
Thierry Mine
Placer Jct
MUSSELWHITE MINE
CROW RIVER
Sturgeon Falls
Calm Lake
Valerie Falls
Silver Falls
Kakabeka Falls
Ft William
THUNDER BAY
BIRCH
ATIKOKAN
MACKENZIE
FORT FRANCES
West Coast Energy
INTERNATIONAL FALLS
LAKEHEAD
Lakehead synchronous condensers
GREENWICH WIND FARM
MARATHON
Marathon Tertiaries
EAST-WEST TRANSFER WEST INTERFACE
519.6MW -37.2MVAr
WAWA
MACKAY
PRINCE WIND FARM
GREAT LAKES POWER Co.
AUBREY FALLS
OUT-OF-SERVICE
MISSISSAGI
*** MISSISSAGI (East circuits) FLOW WEST
SUDBURY FLOW WEST 357.4MW/-53.0MVAr
THIRD LINE
CLERGUE
LAKE SUPERIOR POWER
ECHO RIVER
WELLS
St Mary's
Tarentorus
ALGOMA
HANMER
Hanmer: Tertiary Reactors
PORCUPINE
FROOD
INCO
CLARABELLE
MARTINDALE
TRANSCANADA NORTH BAY
WIDDIFIELD
Otto Holden
PARRY SOUND
WAUBASHENE
ESSA
OTTO HOLDEN
DES JOACHIMS
FLOW SOUTH INTERFACE
-598.4MW
PORT ARTHUR
Provincial Paper
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
Kakabeka GS
FORT WILLIAM
ABITIBI-BOWATER
PINE PORTAGE
MOOSE LAKE
Murillo Jct
TCPL Nipigon
Cameron Falls
Alexander
ALEXANDER
AGUASABON
TERRACE BAY
KIMBERLEY CLARKE
ANJIGAMI
Wawatay
Umbata Falls
Williams Mine
East West Tie Reinforcement: Lakehead TS to Wawa TS
Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon
With one unit at Aubrey Falls GS & at Wells GS out-of-service
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW
DIAGRAM 40
11th August 2011



Σ 525MW
NW Generation
Σ 1158MW
NE Generation
Σ 488MW
GLP Generation
RED LAKE
EAR FALLS
MANITOU FALLS
Thierry Mine
MUSSELWHITE MINE
Placer Jct
CROW RIVER
Lac Seul
Caribou Falls
Whitedog Falls
MANITOBA
ONTARIO
Winnipeg River
KENORA
WHITESHELL
Phase-Shifters PS7: 58.9° PS8 58.9°
DRYDEN
Sturgeon Falls
Calm Lake
Valerie Falls
Silver Falls
Kakabeka Falls
Ft William
THUNDER BAY
BIRCH
West Coast Energy
FORT FRANCES
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 35.3°
INTERNATIONAL FALLS
ATIKOKAN
MACKENZIE
LAKEHEAD
Lakehead synchronous condensers
GREENWICH WIND FARM
MARATHON
Marathon Tertiaries
EAST-WEST TRANSFER
WEST INTERFACE
427.2MW
-87.4MVAr
WAWA
OUT-OF-SERVICE
AUBREY FALLS
MACKAY
PRINCE WIND FARM
GREAT LAKES POWER Co.
THIRD LINE
CLERGUE
LAKE SUPERIOR POWER
ECHO RIVER
WELLS
St Mary's
Tarentorus
MISSISSAGI
*** MISSISSAGI (East circuits) FLOW WEST
SUDBURY FLOW WEST
338.3MW/-7.8MVAr
ALGOMA
INCO
CLARABELLE
FROOD
HANMER
Hanmer: Tertiary Reactors
MARTINDALE
PORCUPINE
TRANSCANADA NORTH BAY
WIDDIFIELD
Otto Holden
Martindale
Dymond
PARRY SOUND
WAUBASHENE
ESSA
OTTO HOLDEN
DES JOACHIMS
FLOW SOUTH INTERFACE
Silver Falls
PORT ARTHUR
LAKEHEAD
Provincial Paper
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
Kakabeka GS
FORT WILLIAM
ABITIBI-BOWATER
THUNDER BAY
Ontario Load: 26100MW Losses: 841MW
North-west Load: 950MW Losses: 65MW
North-east Load: 1241MW Losses: 61MW
IMPORTS
MANITOBA: 43.8MW
MINNESOTA: 28.4MW
MICHIGAN: -110.2MW
NEW YORK: At Niagara -4.2MW
At St Lawrence -1.8MW
PINE PORTAGE
MOOSE LAKE
Murillo Jct
BIRCH
LAKEHEAD
GREENWICH Wind Farm
TCPL Nipigon
Cameron Falls
Alexander
ALEXANDER
AGUASABON
TERRACE BAY
KIMBERLEY CLARKE
MARATHON
WAWA
ANJIGAMI
Wawatay
Umbata Falls
Williams Mine
229.4km MxL
168.3km WxM
191.8km AxL
East West Tie Reinforcement: Lakehead TS to Wawa TS
Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW
Contingency: 230kV double-circuit involving circuits P25W & P26W - Mississagi to Wawa
Prior to Phase Shifter action
DIAGRAM 41
11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit

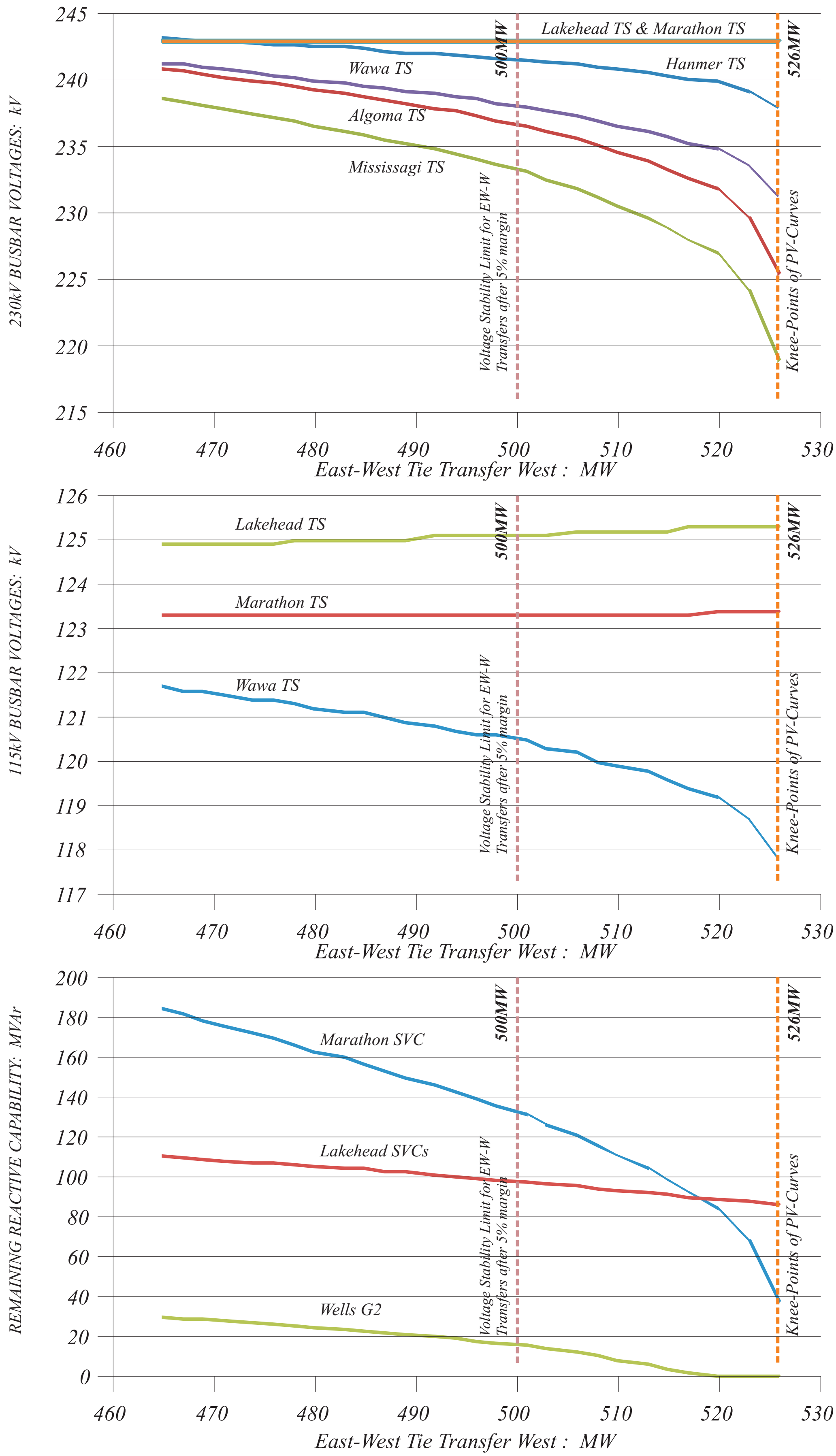
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW

Contingency: 230kV double-circuit involving circuits P25W & P26W - Mississagi to Wawa

After Phase Shifter action

DIAGRAM 42

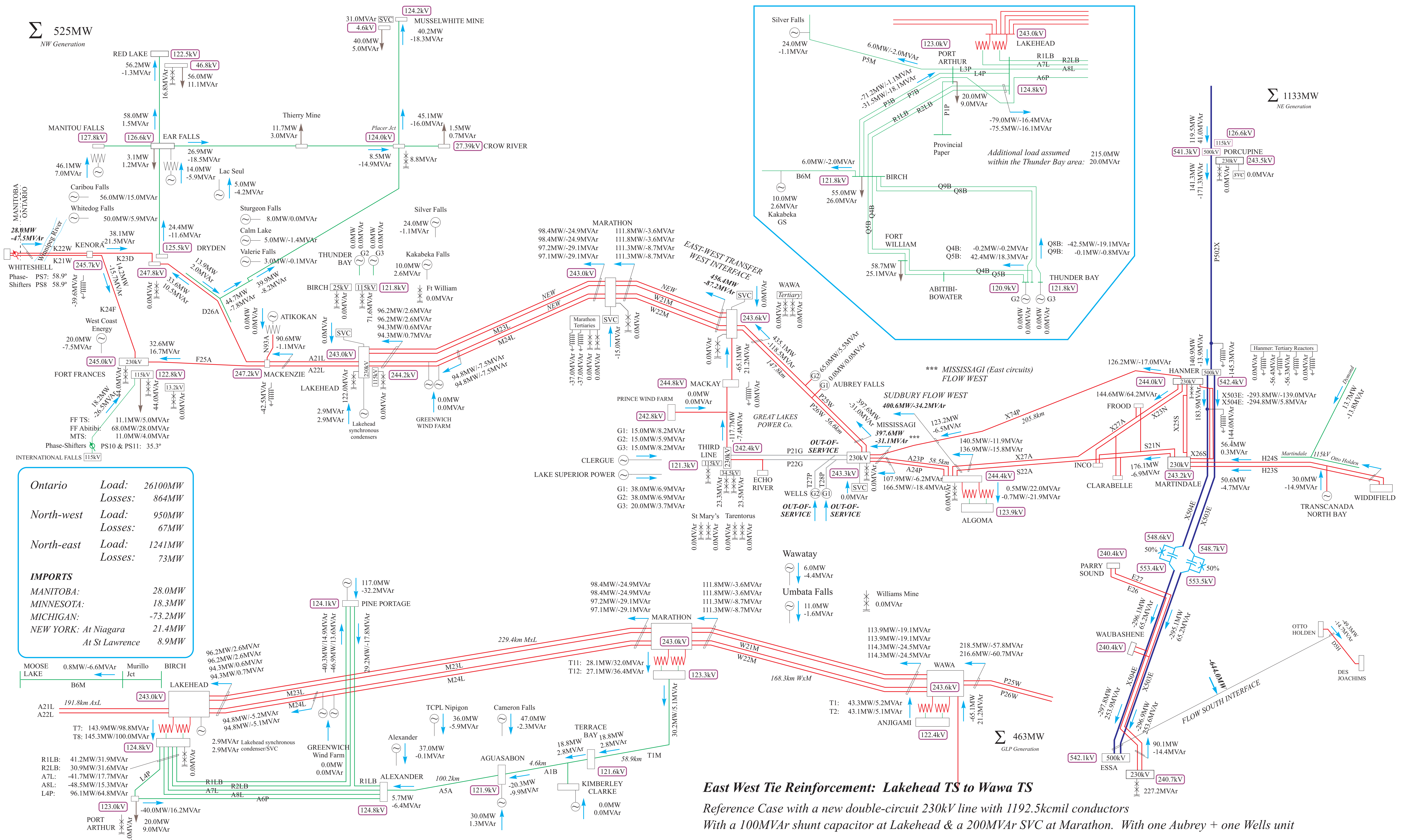
11th August 2011



PV-analysis
Marathon
200MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
Contingency: 230kV double-circuit P25W + P26W Mississagi TS to Wawa TS
After Phase-Shifter action

DIAGRAM 43
7th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit

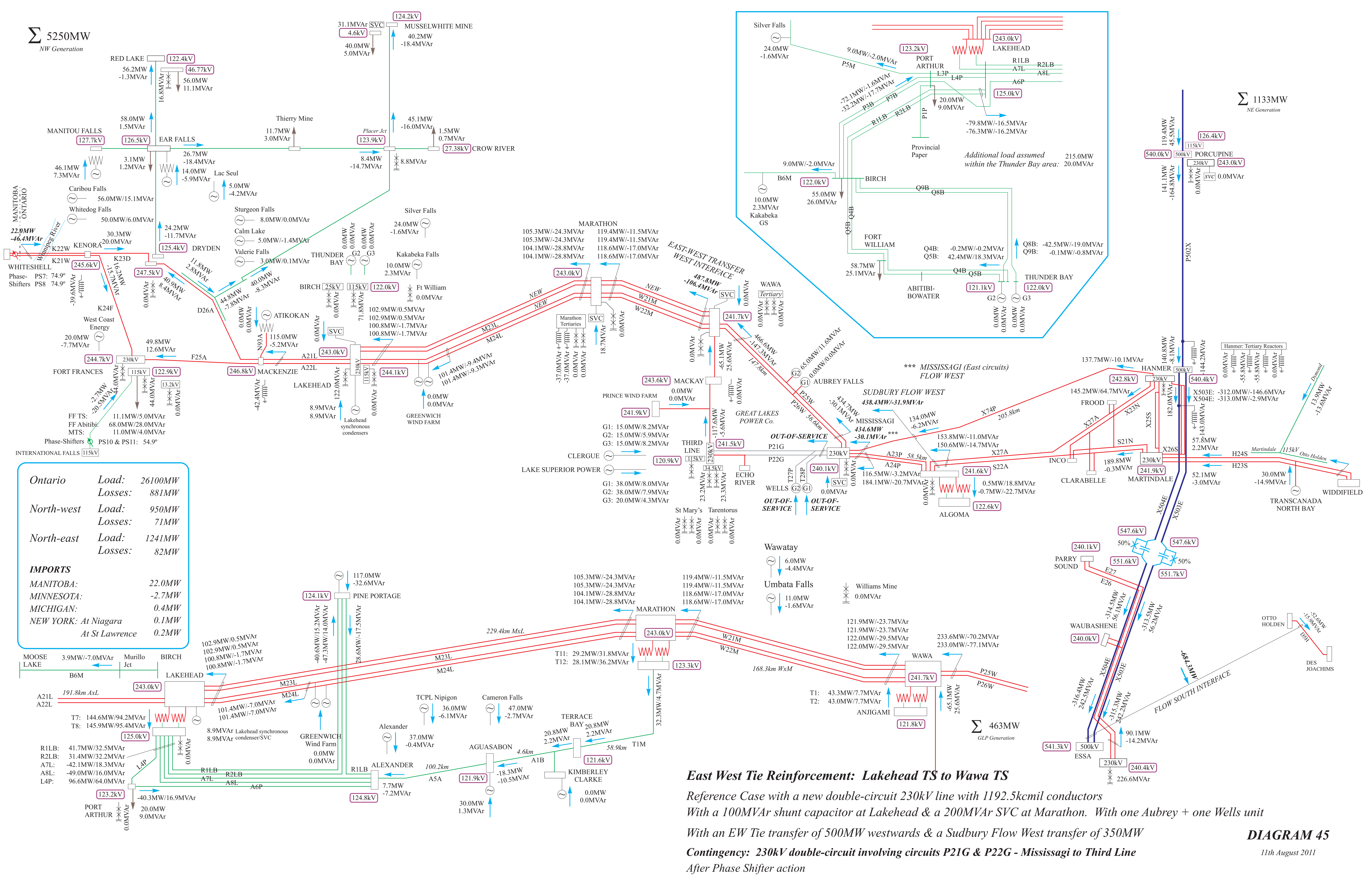
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW

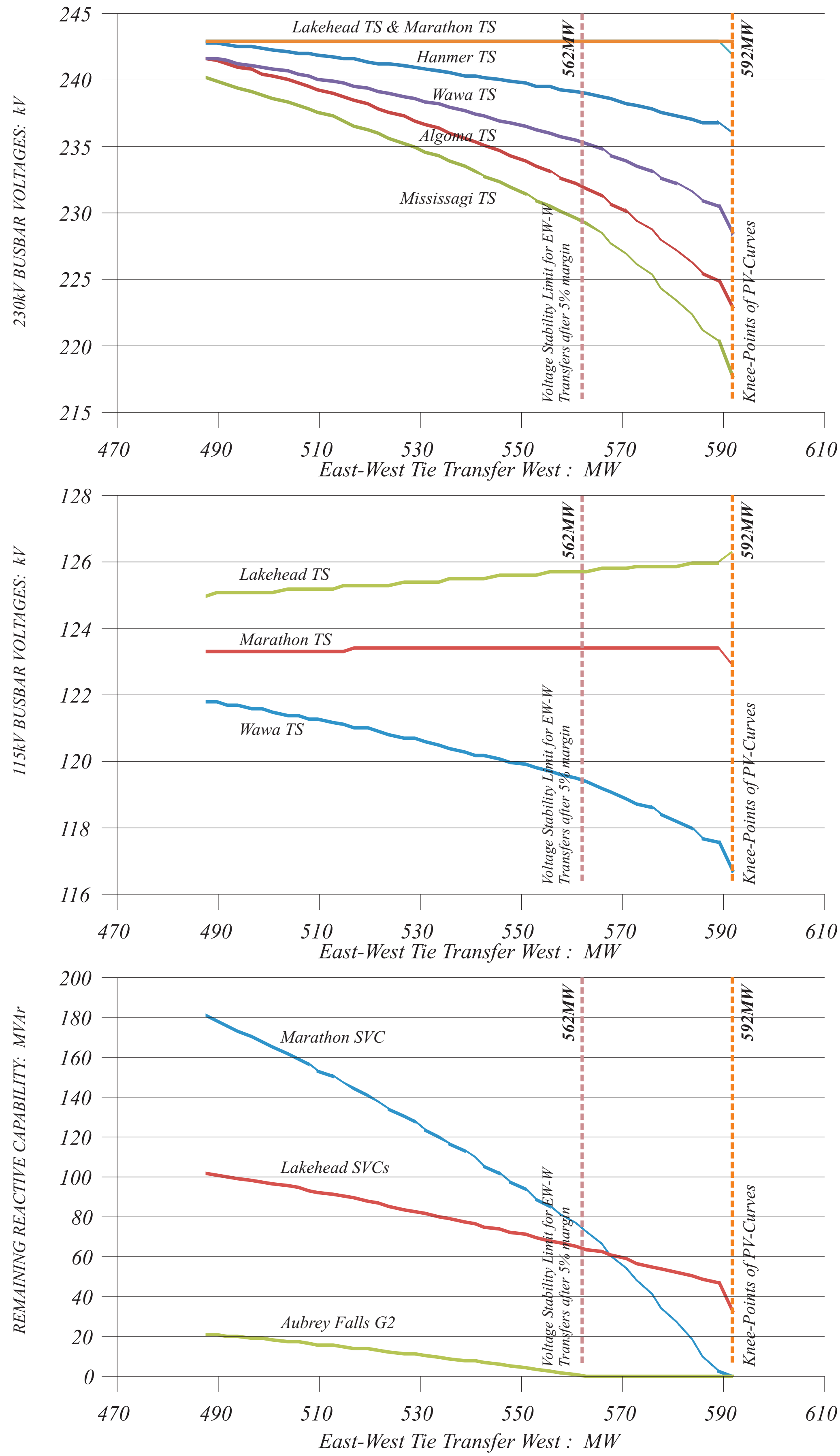
Contingency: 230kV double-circuit involving circuits P21G & P22G - Mississagi to Third Line

Prior to Phase Shifter action

DIAGRAM 44

11th August 2011

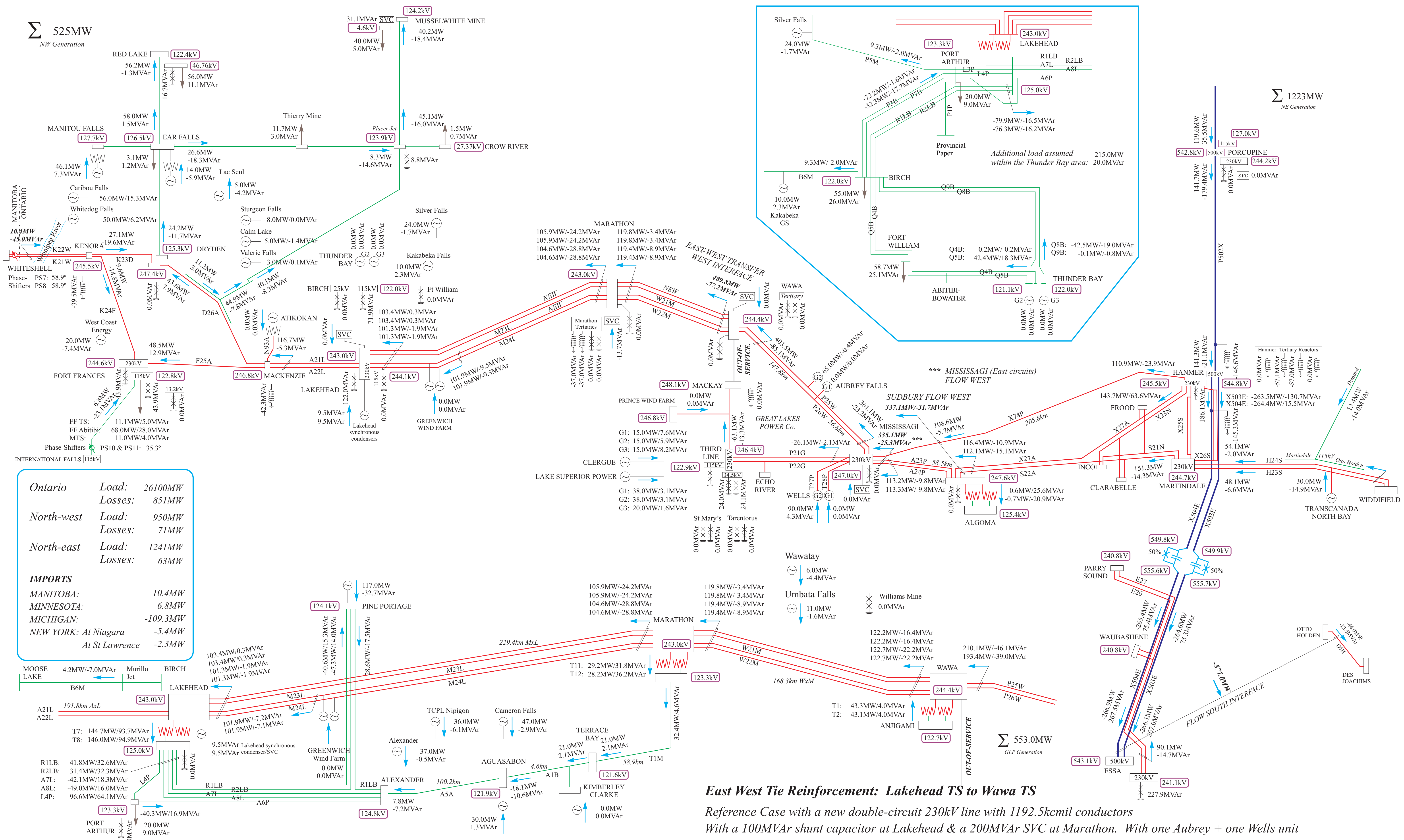

∑ 5250MW
NW Generation
∑ 1133MW
NE Generation
∑ 463MW
GLP Generation
Ontario Load: 26100MW
Losses: 881MW
North-west Load: 950MW
Losses: 71MW
North-east Load: 1241MW
Losses: 82MW
IMPORTS
MANITOBA: 22.0MW
MINNESOTA: -2.7MW
MICHIGAN: 0.4MW
NEW YORK: At Niagara 0.1MW
At St Lawrence 0.2MW
EAST-WEST TRANSFER
WEST INTERFACE
487.8MW
-106.4MVAr
SUDBURY FLOW WEST
438.4MW/-31.9MVAr
*** MISSISSAGI (East circuits)
FLOW WEST
FLOW SOUTH INTERFACE
-684.3MW
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
RED LAKE
EAR FALLS
MANITOU FALLS
CROW RIVER
MUSSELWHITE MINE
DRYDEN
KENORA
WHITESHELL
FORT FRANCES
MACKENZIE
ATIKOKAN
LAKEHEAD
MARATHON
WAWA
MACKAY
AUBREY FALLS
MISSISSAGI
THIRD LINE
ALGOMA
HANMER
PORCUPINE
ESSA
PARRY SOUND
WAUBASHENE
PINE PORTAGE
ALEXANDER
AGUASABON
TERRACE BAY
KIMBERLEY CLARKE
ANJIGAMI
PORT ARTHUR
BIRCH
THUNDER BAY
East West Tie Reinforcement: Lakehead TS to Wawa TS
Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW
Contingency: 230kV double-circuit involving circuits P21G & P22G - Mississagi to Third Line
After Phase Shifter action
DIAGRAM 45
11th August 2011



PV-analysis
Marathon
200MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
Contingency: existing 230kV double-circuit P21G + P22G Mississagi to Third Line
After Phase-Shifter action

DIAGRAM 46
7th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit

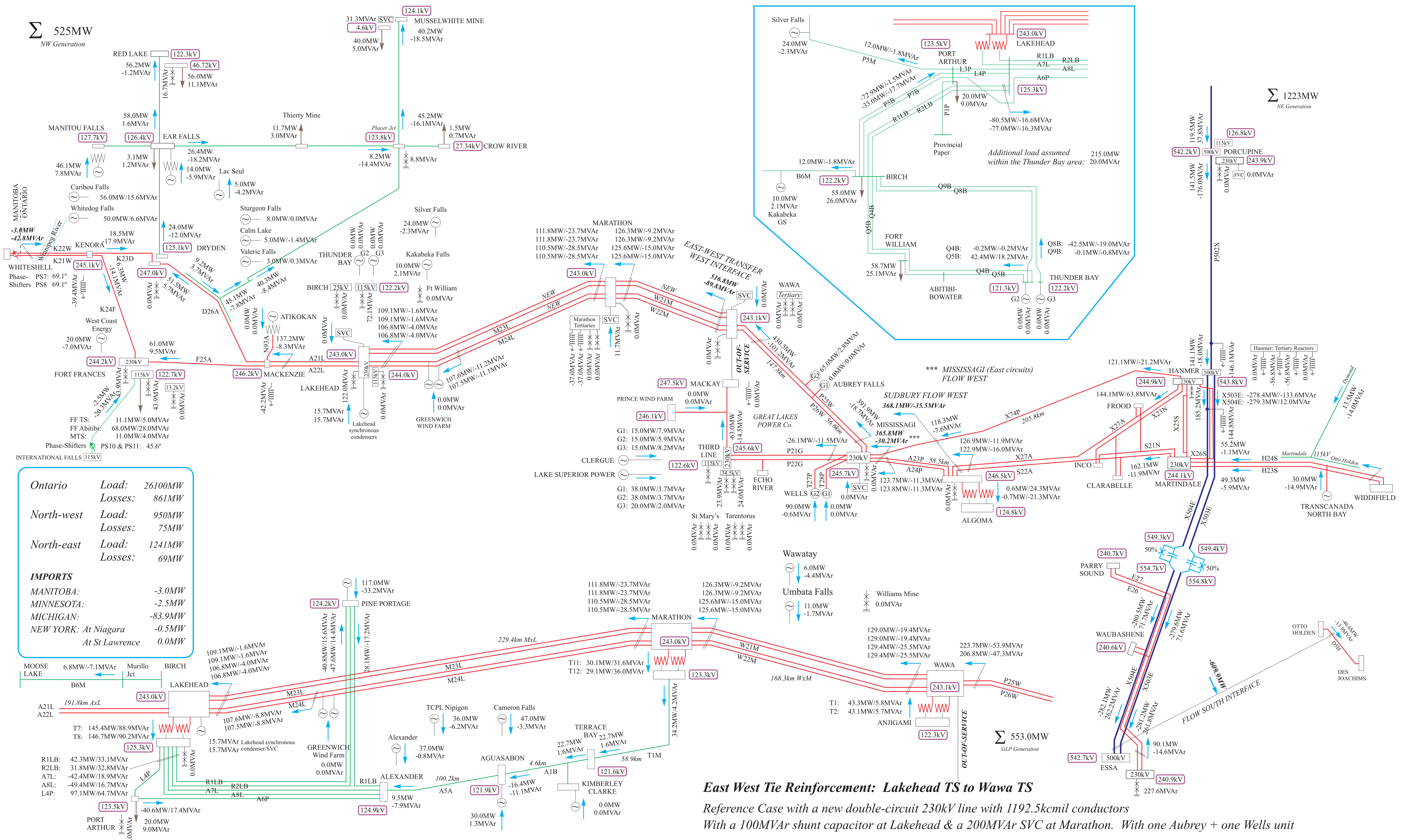
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW

DIAGRAM 47

Contingency: 230kV single-circuit involving circuit W23K - Wawa to MacKay

Prior to Phase Shifter action

11th August 2011



East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with 1192.5kcmil conductors

With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC at Marathon. With one Aubrey + one Wells unit

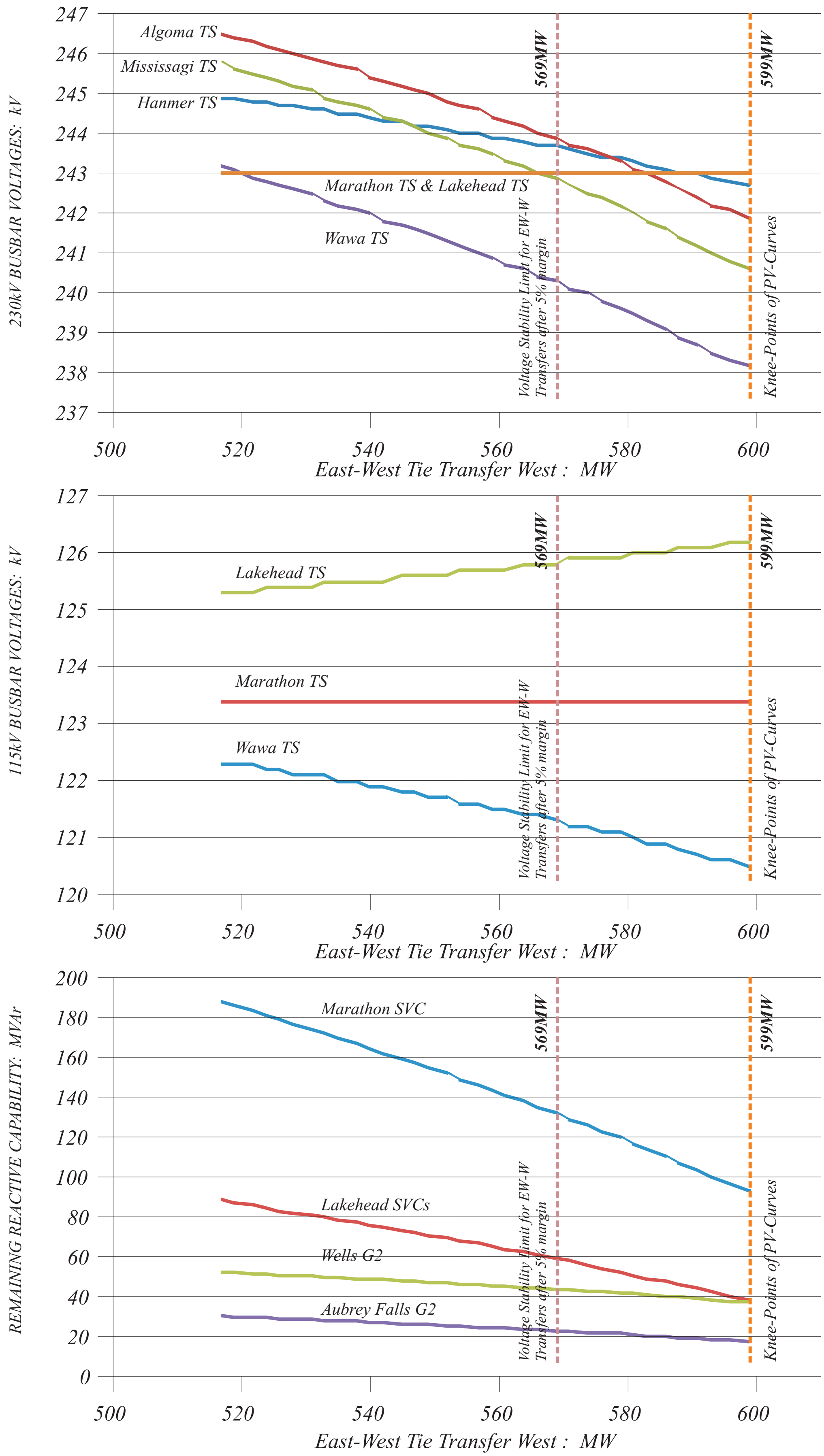
With an EW Tie transfer of 500MW westwards & a Sudbury Flow West transfer of 350MW

Contingency: 230kV single-circuit involving circuit W23K - Wawa to MacKay

After Phase Shifter action

DIAGRAM 48

11th August 2011



PV-analysis
Marathon
200MVAr SVC

East West Tie Reinforcement: Lakehead TS to Wawa TS
Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
Contingency: 230kV single-circuit K23G Wawa TS to MacKay TS
After Phase-Shifter action

DIAGRAM 49
7th August 2011

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BY E-MAIL AND WEB POSTING

August 22, 2011

To: All Licensed Electricity Transmitters
All Applicants and Potential Applicants for an Electricity Transmitter Licence
All Interested Parties

Re: Board File Number: EB-2011-0140
Electricity Transmission Infrastructure: The East-West Tie Line

---

The Government of Ontario and the Ontario Power Authority (the "OPA") have identified five priority transmission projects for the province. One of the priority projects is a major new piece of transmission infrastructure to increase transfer capacity between the transmission system in the northwest and the rest of Ontario, namely an East-West tie line (the "E-W Tie").

On August 26, 2010, the Ontario Energy Board (the "Board") issued its policy entitled "Framework for Transmission Project Development Plans". In a letter to the Board Chair, dated March 29, 2011, the Minister of Energy suggested that the designation process outlined in the Board's policy framework could be used to select the most qualified and cost-effective transmission company to develop the E-W Tie. Consequently, by letter to the OPA Chief Executive Officer dated April 25, 2011, the Board Chair requested a report from the OPA regarding its preliminary assessment of the need for an E-W Tie.

On June 30, 2011, the Board received from the OPA its "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion" (the "OPA Report"). The OPA report is available on the Board's website at http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/East-West+Transmission+Tie+Line

On August 19, 2011, the Board received a Feasibility Study by the Independent Electricity System Operator (the "IESO") in relation to the E-W Tie, which is also available on the Board's webpage.

The OPA is responsible for independent transmission planning in Ontario and has advised the Board that there is a need to proceed with development work on the E-W Tie. The Board has received the OPA's preliminary assessment of need as a basis for a designation process. The Board expects the final determination of need to be made as part of a future application for leave to construct, not through the designation process.

The Board finds it advisable to invite licensed transmitters and those who have applied for a transmission licence (collectively "transmitters") to indicate their interest in filing a plan for the development of the E-W Tie. Parties who file a transmitter licence application before the deadline for registering interest below may also register and participate.

The OPA Report defines a specific solution as its preferred option but acknowledges that it may be possible for other solutions to meet the requirements for the line as described in the project scope criteria of the OPA Report. The Board will call the OPA's solution, with the additional requirements from the IESO Feasibility Study, the "Reference Option". Transmitters may propose alternative solutions that meet the requirements. A transmitter proposing a solution different from the Reference Option will bear the onus of proving that the alternative is the equivalent, in terms of performance, reliability, cost, etc., of the Reference Option. This would include a feasibility study prepared by the IESO or prepared by the transmitter to the IESO's requirements.

Registration Required

Transmitters who may be interested in filing a plan for the E-W Tie must register with the Board Secretary at BoardSec@OntarioEnergyBoard.ca by **4:45 pm on September 21, 2011** quoting file number **EB-2011-0140**, identifying the transmitter and a person to act as contact for the transmitter including name, telephone number and e-mail address.

Registration is required from any transmitter that intends to file a plan. Failure to register may disqualify a transmitter from participation in the designation process.

Further details on the project and the process will be made available in the coming weeks. Please contact the Market Operations hotline at 416-440-7604 or by e-mail at market.operations@OntarioEnergyBoard.ca with any questions. The Ontario Energy Board's toll-free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

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Ontario

BY E-MAIL

December 20, 2011

To: All Electricity Transmitters Registered for the East-West Tie Line

Re: Board File Number: EB-2011-0140
Information Package on the East-West Tie Line

Thank you for registering your interest in the designation process for the East-West Tie Line. This letter sets out additional information and announces an informational meeting for registered transmitters.

The Designation Process

As described in the Ontario Energy Board's policy *Framework for Transmission Project Development Plans* a designation process is a hearing of the Board, convened to identify a licensed transmitter who will be entitled to recover its prudently incurred development costs for a specific transmission project. Development costs begin when a transmitter is designated and end when a leave to construct application is submitted. The designated transmitter will also be able to recover its cost of becoming designated. Unsuccessful applicants will not.

As the Board stated in its policy, "the designation process of the Board is not a procurement process where the end result is a contract." This transmitter designation process is not a tender call nor does it commit the Board in any way to designate a transmitter to undertake development work.

The East-West Tie Line Project

Attached to this letter are two packages of information intended to define the project that is the subject of this designation process. Attachment 1 is a description of the scope of the East-West Tie Line for the purposes of designation. Attachment 2 is a document of Minimum Technical Requirements for the Reference Option of the East-West Tie Line that provides minimum requirements for one possible solution for expanding the East-West Tie. These requirements should be used in costing any potential application for designation.

Planning Meeting and Next Steps

Board staff will convene a meeting at the Board's offices on the 25th floor of 2300 Yonge Street on Tuesday, January 10, 2012 at 9:30 am, to discuss with the registered transmitters the filing of plans and the process for the evaluation of plans. This meeting is for registered transmitters. Other stakeholders will have other opportunities to participate in the process.

In order to attend this first meeting, you must respond with your company's name, and the name, email and telephone number of each representative attending from your company, to East-West.Tie.Line@OntarioEnergyBoard.ca. This is to ensure that the meeting facilities are adequate for the attendees expected.

Information on the Board's website

Documents related to this process are available for public inspection on the Board's website[1] and at the office of the Board during normal business hours.

Contact

Please contact Laurie Reid at 416-440-7623 or by e-mail at East-West.Tie.Line@OntarioEnergyBoard.ca with any questions. The Ontario Energy Board's toll-free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachments: Project Definition for Designation for the East-West Tie Line
Minimum Technical Requirements for the Reference Option of the East-West Tie Line

[1] http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/East-West+Transmission+Tie+Line

Attachment 1: Project Definition for Designation for the East-West Tie Line

The East-West Tie Expansion

The OPA has conducted a preliminary assessment of the supply needs of Northwest Ontario (the "OPA Report[1]") and has concluded that expansion of the East-West Tie is the preferred alternative for ensuring adequate supply.

The project, as defined by the Ontario Power Authority, is for new transmission facilities between Northeast and Northwest Ontario (see Figure 1) that, in conjunction with the existing tie[2], will provide total eastbound and westbound capabilities on the order of 650 MW[3], while respecting all North American Electric Reliability Corporation, North East Power Coordinating Council and Independent Electricity System Operator reliability standards. The East-West Tie expansion should be designed to have a lifetime of at least 50 years[4]. The East-West Tie expansion target in-service date is 2017[5].

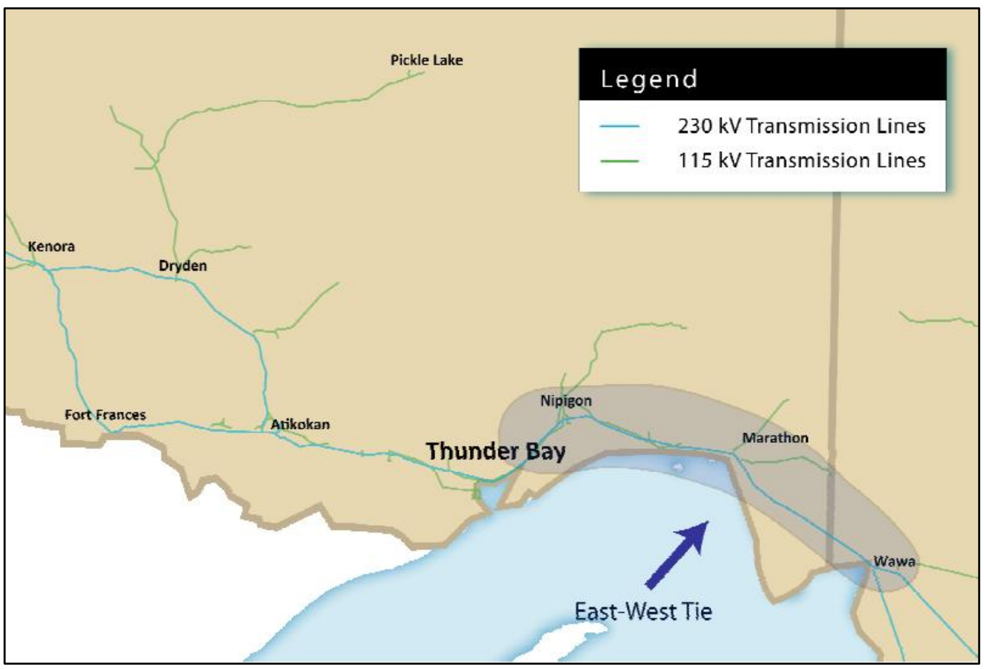

Figure 1: Existing transmission in the Northwest – Northeast corridor.

A complete East-West Tie expansion will include three parts:

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[1] "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion", Ontario Power Authority, June 30, 2011.
[2] The existing connection between Lakehead TS and Wawa TS consists of a 230kV double circuit line with each circuit having ratings of 365 MVA continuous (at 93ºC) and and 465 MVA limited-time emergency (at 27ºC).
[3] The OPA Report, p. 20.
[4] The OPA Report, p, 20.
[5] The OPA Report, p. 20.

1. The line consisting of conductors, structures and protection systems running from point to point (the "East-West Tie Line");
2. Upgrades to existing transformer stations to supply reactive facilities that are dependent on the specifications for the East-West Tie Line, such as have been identified by the IESO in its Feasibility Study; and
3. Interconnection of the line to the existing system at existing transformer stations including line disconnect switches.

In order to focus the designation process, the Board will limit the scope of applications to the East-West Tie Line as defined above. Therefore the definition of the East-West Tie Line for the purposes of designation is:

- A new line that, in conjunction with the existing line, will provide total eastbound and westbound capabilities in the East-West corridor on the order of 650 MW[6], while respecting all North American Electric Reliability Corporation, North East Power Coordinating Council and Independent Electricity System Operator reliability standards.
- The East-West Tie Line should be designed to have a lifetime of at least 50 years[7].
- The East-West Tie Line target in-service date is 2017[8].
- The East-West Tie Line is to be considered 2 segments: one running from Wawa TS to Marathon TS and one running from Marathon TS to Lakehead TS.
- The demarcation points of each segment of the East-West Tie Line are the first transmission line structures outside the fence of the Wawa TS, Marathon TS and Lakehead TS, but within 250 metres of that fence.
- The East-West Tie Line segments will dead-end on the structures that are the demarcation points with a mid-span opener for non-compensated lines.
- If the proposal involves series compensated AC line or DC lines, the East-West Tie Line will include the protection system, associated communications, and line isolation breaker(s).
- The project definition for the purposes of designation assumes that the East-West Tie Line between the demarcation points will be owned and operated by the designated transmitter.

The Reference Option

The OPA Report identifies a specific solution[9] as its preferred option but acknowledges that other options could be proposed provided they meet the other project scope criteria. The IESO has studied the feasibility of the OPA's preferred option, which it called the reference case, and an alternative case. The Board considers the OPA's preferred solution together with the IESO's reference case as the "Reference Option". The Reference Option is one possible, specific solution for the East-West Tie Line.

The Reference Option can be summarized as follows:

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[6] The OPA Report, p. 20.
[7] The OPA Report, p, 20.
[8] The OPA Report, p. 20.
[9] The OPA Report, p. 20.

- The East-West Tie Line will be a new double-circuit 230 kV overhead transmission line[10] with a continuous capacity of approximately 465 MVA and an emergency capacity of approximately 600 MVA (per circuit)[11];
- The East-West Tie Line will be switched at Marathon TS[12].

The Board, with the help of a consultant, has developed a document detailing the minimum technical requirements for the Reference Option that forms part of this information package. It will also be available on the Board's website. Applicants should develop proposals with costs that reflect these minimum technical requirements. Any planned deviations from them must be documented and the onus will be on the transmitter proposing the deviation to prove equivalency.

Alternative Solutions for the Defined Project

The Board welcomes technical innovation in the solution for the East-West Tie Line. Transmitters may propose alternatives to the Reference Option that meet the need as contained in the Project Description section above. A transmitter proposing an alternative to the Reference Option will bear the onus of proving that the alternative solution is the equivalent or superior to the Reference Option and the Board's minimum technical requirements in terms of performance, reliability, cost, etc. This analysis must include a feasibility study prepared by the IESO or prepared by the transmitter to the IESO's requirements.

A transmitter choosing to submit an alternative to the Reference Option should contact Mike Falvo at the IESO at (905)855-6209 or mike.falvo@ieso.ca as soon as possible regarding scheduling and process for feasibility studies.

After Designation

For clarity, the designated transmitter, once selected, will be responsible for preparing a leave to construct application for a complete, functional East-West Tie. To this end, the designated transmitter must liaise with the OPA regarding the need for the project, with the IESO for a system impact assessment, and with Hydro One Networks Inc. regarding connection of the demarcation points to the existing system.

In addition, the designated transmitter will be expected to carry out the procedural aspects of the Crown's duty to consult with affected aboriginal peoples.

The designated transmitter will be required to ensure compliance with the requirements of provincial legislation and of agencies other than the Board.

Please note that the Board has no statutory authority to procure transmission and, as such, this transmitter designation process will not create, and should not be construed

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[10] The OPA Report, p. 20.
[11] The IESO Feasibility Study, p. 11.
[12] The OPA Report, p. 20.

as intended to create, contractual relations between the Board and the designated transmitter. At any time, the Board may in its sole discretion decide to not approve any plans or to terminate this transmitter designation process.

Ontario

Ontario Energy Board Staff Submission

EB-2011-0140

Proceeding to designate a transmitter to carry out development work for the East-West Tie line

Phase 1

April 24, 2012

Background

The Ontario Energy Board has initiated a proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line. The Board assigned File No. EB-2011-0140 to the proceeding.

The Board released its policy *Framework for Transmission Project Development Plans* EB-2010-0059 on August 26, 2010, dealing with transmission project development to accommodate the connection of renewable energy generation. The Policy described a process to designate a licensed transmitter to undertake development work on any transmission network expansions or enabler lines identified by the Ontario Power Authority as necessary to connect renewable generation. The designation process was intended to allow transmitters to move ahead on development work in a timely manner; to encourage new entrants to transmission in Ontario bringing additional resources for development work; and to support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers. The Policy set out general decision criteria for designation and approved generic filing requirements (G-2010-0059). At that time, the Board did not ascribe relative importance to the criteria.

The then Minister of Energy suggested, in a letter dated March 29, 2011, that the Board's designation process could be used to select the most qualified and cost-effective transmission company to develop the East-West Tie line. The OPA provided a report describing preliminary need for the line, the Independent Electricity System Operator provided a feasibility study identifying potential solutions, and the Board decided to initiate the designation process. In contrast to the drivers for competition in transmission contemplated in the Board's Policy, the East-West Tie line is proposed primarily to maintain a reliable, cost effective supply of electricity over the long term in Northwest Ontario. The Board delivered an information package to all transmitters who had registered an interest in the designation process on December 20, 2011. In that correspondence, the Board adopted as a Reference Option for the line the option identified by the OPA as its preferred solution, but also invited alternative solutions. As well, in order to establish appropriate standards for the line, the Board adopted Minimum Technical Requirements to specify general design concepts to be used in the design and costing of the Reference Option of the East-West Tie transmission line.

The Board has adopted a two phase process for the proceeding. In the first phase, the Board will establish specifics for the proceeding including decision criteria, filing requirements, obligations and consequences arising on designation, the hearing process for phase 2 and the schedule for the filing of applications for designation. In phase 2, registered transmitters will have an opportunity to file their applications for designation, and the Board intends to select one of the applicants as the designated transmitter through a hearing process. In procedural order #2, the Board approved an issues list for phase 1 of the hearing.

Board staff's submission is structured around the issues list for phase 1 approved by the Board. Although in some sections of this document Board staff expresses a view, the primary purpose of this document is to elicit submissions from other parties on the issues in phase 1.

Submissions are particularly invited on Appendix A to this document, Board staff's proposed Filing Requirements for the Designation Process for the East West Tie Line. A discussed in detail later in this submission, these proposed filing requirements are intended to supersede, for the purposes of this particular designation proceeding, the original 2010 filing requirements (G-2010-0059). In Board staff's view, the criteria for selection of a designated transmitter, use of the decision criteria for evaluating applications for designation, and the filing requirements for the applications are inextricably linked, and submissions addressing decision criteria and their use must also address any consequent amendments to the filing requirements. Similarly, staff has attempted to seek through the proposed filing requirements information regarding reporting obligations, performance milestones and the consequences of designation. Staff reminds parties to propose specific additions, deletions or changes to the filing requirements to implement any submissions they may have.

Decision Criteria: Issues 1 - 4

1. ***What additions, deletions or changes, if any, should be made to the general decision criteria listed by the Board in its policy Framework for Transmission Project Development Plans (EB-2010-0059)?***

2. ***Should the Board add the criterion of First Nations and Métis participation? If yes, how will that criterion be assessed?***

3. ***Should the Board add the criterion of the ability to carry out the procedural aspects of First Nations and Métis consultation? If yes, how will that criterion be assessed?***

4. ***What is the effect of the Minister's letter to the Board dated March 29, 2011 on the above two questions?***

As noted earlier, the purpose of the East-West Tie line is somewhat different than the purpose of transmission infrastructure originally envisioned for designation in the Board's Policy. However, Board staff submits that the decision criteria originally identified in the Policy remain valid and appropriate. Staff recommends that the Board retain the existing criteria, as all these criteria are important to the success of the East-West Tie line. These criteria were listed at page 14 of the Policy as:

- Organization
- Technical capability
- Financial capacity
- Schedule
- Costs
- Landowner and other consultations
- Other factors

Failure in any of organization, technical capability, financial capacity or consultations would likely lead to failure of the project. The schedule and costs are fundamental to the economic efficiency, and therefore the need for the line. For example, if costs of construction are too high, other options identified by the OPA for satisfying demand in Northwest Ontario could be preferable. The ability of the designated transmitter to successfully complete landowner, First Nation and Métis, and other necessary consultations is also critical to the success of the project.

Board staff is not recommending the addition of any new criteria, as staff believes the original criteria can include the factors necessary to the Board's selection of a designated transmitter. However, staff wishes to highlight the importance of the Minister's letter to the Board dated March 29, 2011. In that letter the Minister said:

> "…I would expect that the weighting of decision criteria in the Board's designation process takes into account the significance of aboriginal participation to the delivery of the transmission project, as well as a proponent's ability to carry out the procedural aspects of Crown consultation."

Staff submits that the letter is not a Directive within the meaning of sections 27 and 28 of the *Ontario Energy Board Act, 1998*, and does not have the legal force and effect of a Directive. Staff does submit, however, that the Board should give serious consideration to the Minister's expectations, and that these expectations can be met through supplementing the original filing requirements.

The original filing requirements sought information on both participation by First Nation and Métis groups (in the section entitled "Organization and Applicant's Experience) and the ability of the applicant to conduct successful consultations with First Nation and Métis groups (in the section entitled Landowner and Other Consultations). In the proposed filing requirements attached as Appendix A to this submission, Board staff is recommending expanded informational requirements in these areas, to recognize the importance of the Minister's letter. The question for the Board, in staff's view, is whether "aboriginal participation" and "a proponent's ability to carry out the procedural aspects of Crown consultation" should have the status of individual criteria, and invites submissions from all parties on this question.

Staff acknowledges that, as yet, no delegation has been made by the Crown that would impose the responsibility for the procedural aspects of Crown consultation on the designated transmitter. However, the fact that the Minister's letter does emphasize the importance of this ability suggests that such a delegation is contemplated. In staff's submission, the lack of a present delegation of this responsibility is not a bar to the Board considering an applicant's abilities to bear the responsibility for the procedural aspects of Crown consultation.

Staff submits that if the Board is contemplating adding new criteria, the Board should keep in mind the stated aims of the original Policy for transmission project development planning (that were reiterated in the Minister's letter), which included timeliness of new work, encouragement of new entrants, the availability of additional resources for project development and the benefits of economic efficiency through the support of competition. In his letter the Minister also highlighted importance of the East-West Tie line in ensuring reliability and maintaining efficiency and flexibility of the transmission system. Staff notes that the creation of any additional criterion means that the relative importance of the original criteria is necessarily reduced. Staff suggests that if the Board proposes to increase the number of decision criteria, a criterion specifically tailored to the East-West Tie line: Line capacity and reliability, could be added, as the capacity and reliability of the line are fundamental to achieving the need identified for this project by the OPA.

Issues 2 and 3 include questions regarding how the potential additional criteria of First Nation and Métis participation, and the ability to carry out First Nation and Métis consultation, would be assessed. Board staff's general submissions on assessment of decision criteria appear in the next section of this document. However, staff offers the following submission on an issue raised at a meeting of all parties: when consultation with First Nations and Métis peoples should begin; specifically, will the Board look with favour on an applicant that has already commenced consultation before filing an application for designation?

It is Board staff's submission that applicants who have commenced consultation with First Nations and Métis groups before they apply for designation should not be regarded more favourably than those who have not commenced consultation but have a comprehensive and practical plan for consultation that would be initiated upon designation. There are two main reasons for this submission.

The Board in creating its Policy, noted at page 14:

> "…the Board has removed a question [from the filing requirements] that implied that transmitters must undertake consultation as part of plan preparation."

This suggests that the Board does not consider that an applicant must undertake consultation before filing an application for designation.

Secondly, as Board staff understands it, the duty to consult is the responsibility of the Crown, although the Crown can delegate certain aspects of consultation. The letter from Jon Norman of the Transmission and Distribution Policy Branch of the Ministry of Energy to the General Counsel of the OPA dated May 31, 2011 deals with the roles of the Crown and the OPA in any duty to consult on the East-West Tie project. The letter indicates that the Crown has decided to delegate certain procedural aspects of consultation to the OPA "during the period prior to any Ontario Energy Board transmitter designation". This suggests that any responsibility for consultation will remain with the OPA until designation. Board staff is not aware that the Crown has made any other delegation of this responsibility.

Board staff understands that the OPA has completed its planned consultation activities for the East-West Tie line. It may be that potential applicants for designation may choose to establish relationships with First Nation and Métis communities so as to prepare for or begin to undertake consultation. However, it is Board staff's submission that the clear responsibility for undertaking procedural aspects of the Crown's duty to consult does not arise in the absence of a delegation from the Crown of that responsibility. Staff also notes that the determination of the adequacy of consultation with First Nation and Métis peoples is part of the Environmental Assessment process.

Use of the Decision Criteria: Issues 5 and 6

5. ***Should the Board assign relative importance to the decision criteria through rankings, groupings or weightings? If yes, what should those rankings, groupings or weightings be?***

6. ***Should the Board articulate an assessment methodology to apply to the decision criteria? If yes, what should this methodology be?***

Board staff does not propose any particular ranking or weighting for the decision criteria the Board selects. As stated earlier, failure on any one criterion could mean failure of the project, and all the criteria are important. Staff recommends that the Board assess the applications in the same manner it does in any hearing, weighing and testing the evidence.

Staff submits that at a basic level, the Board should be seeking to choose the transmitter who best understands the challenges of the East-West Tie line project, who has the best plan for meeting those challenges, and has the best track record of meeting similar challenges in the past. Each applicant must demonstrate it has the financial capacity, technical capability and experience to complete the project. Any applicant that cannot demonstrate that it has basic competence in each of these areas could be rejected, even if the application was otherwise sufficient. The Board could choose to rank applicants who demonstrate this competence on each decision criterion based on the quality of their plan for the line and accompanying information in the application.

Staff recognizes that assigning weights to the decision criteria could be helpful in preparing applications for designation, but submits that the record in this proceeding may be as yet insufficient for the Board to understand fully the relative importance of the various decision criteria. In a sense, the Board and the potential applicants for this designation are facing a unique challenge, in that this is the first designation process for transmission infrastructure in Ontario, and there are no Ontario Energy Board precedents providing weightings or an assessment methodology. Staff submits that any assessment methodology that parties suggest must be consistent with principles of fairness and practical to implement.

Staff submits that the filing requirements that the Board determines in this phase of the process will provide a good indication of what the Board will evaluate in selecting a transmitter for designation. Staff reminds parties that any proposal for an assessment methodology should be reflected in the filing requirements.

In preparing the filing requirements appended to this submission, Board staff considered whether some items could be evaluated on a pass/fail basis. Staff identified several items that could be suitable as threshold tests. These items appear in section 1 of the proposed filing requirements. For other items, the Board would evaluate the quality of the filings. Staff is mindful of the Board’s statement at page 13 of the Policy regarding the use of threshold or pass/fail tests for the criteria of organization, technical capability and financial capacity. The Board said:

> "…the Board's process is not the same as a procurement process. The Board's hearing process does not lend itself to threshold tests nor is the Board convinced that it will be possible to examine those three criteria without substantial reference to the evidence regarding cost, scheduling, and consultation plans for the project."

Staff interprets this statement to indicate that the Board will generally need to evaluate the evidence and exercise judgement in assessing the applicants against each decision criterion. Staff suggests that aside from the items identified in section 1 of the appended filing requirements, the remainder of the evidence will need to be evaluated beyond meeting a threshold.

Board staff invites parties views on whether the Board should select one or more "runners-up" for designation. The Board will likely choose one successful designated transmitter. Should alternates also be selected? In theory, the selection of a runner-up would create efficiencies if the successful designee failed to bring an application for leave to construct (for reasons within the control of that designee). However, staff notes that the runner-up might be in a difficult position, in that that company may be uncertain as to whether it will be called upon to develop the line, or whether it can direct its resources to other projects.

Filing Requirements: Issues 7 and 8

7. ***What additions, deletions or changes should be made to the Filing Requirements (G-2010-0059)?***

8. ***May applicants submit, in addition or in the alternative to plans for the entire East-West Tie Line, plans for separate segments of the East-West Tie Line?***

Based on the original filing requirements for designation contained in G-2010-0059 *Filing Requirements: Transmission Project Development Plans*, Board staff has prepared the document attached as Appendix A to this submission "Filing Requirements for the Designation Process for the East-West Tie Line". Board staff suggests that these filing requirements be adopted to guide potential applicants in preparing applications for designation in this proceeding.

In preparing the appended filing requirements, Board staff has made several deletions from the original filing requirements. For example, staff deleted requirements that referred to a Plan containing multiple projects, as the East-West Tie line is considered to be a single project for the purposes of designation. Staff also deleted the requirement to assess the economic efficiency of the Plan, as staff understands that economic efficiency will depend on the revised OPA assessment of need, which will not be available until after development work has been largely completed. Staff also notes that the OPA has stated that it is seeking input on the proposed in-service date for the line, and economic efficiency cannot be assessed in the absence of an in-service date.

Staff has proposed several items be added to the original filing requirements; for example, information specifically related to the necessary characteristics of the East-West Tie line. Staff has also proposed increased requirements relating to First Nation and Métis participation and consultation with these groups, in recognition of the expectations expressed in the Minister's letter of March 29, 2011.

The proposed filing requirements are organized around the original decision criteria set out by the Board in its Policy. However, as noted elsewhere in this submission, if the criteria change, the filing requirements will need to be modified.

Staff notes that the Board's Minimum Technical Requirements contain, in section 2.1.5, three bullets requiring certain filings from applicants. Staff has included the items in bullets 2 and 3 in the appended filing requirements, but staff believes that the information required in the first bullet, "all proposed design assumptions" will not be available to the applicants before development work for the line is well underway, and therefore recommends that this information not be required of applicants for designation.

Staff invites parties to address whether some of the information proposed to be filed in the appended filing requirements is also too specific to be available at the time of an application for designation. For example, is the information sought in sections 5.1 and 8.3 too specific prior to development work being undertaken?

In addition, Board staff asks parties to consider the level of detail in general in the proposed filing requirements. Staff recognizes that more detailed requirements may assist applicants in the preparation of their applications. However, staff submits that the Board may have more opportunity to assess the judgement of an applicant if the filing requirements are not overly prescriptive.

Obligations and Milestones: Issues 9 - 12

9. ***What reporting obligations should be imposed on the designated transmitter (subject matter and timing)? When should these obligations be determined? When should they be imposed?***

10. ***What performance obligations should be imposed on the designated transmitter? When should these obligations be determined? When should they be imposed?***

11. ***What are the performance milestones that the designated transmitter should be required to meet: for both the development period and for the construction period? When should these milestones be determined? When should they be imposed?***

12. ***What should the consequences be of failure to meet these obligations and milestones? When should these consequences be determined? When should they be imposed?***

When considering the imposition of performance milestones and reporting obligations (issues 9 and 11), Board staff submits that one of the key purposes of designation is to encourage timely development of infrastructure. On page 16 of the Board Policy, the Board notes that:

> "If a designated transmitter is failing to make progress on developing the project and is not making progress toward bringing a leave to construct application, the Board needs the ability to rescind the designation both to limit the exposure of the ratepayer and to allow a different transmitter to be designated. Therefore, the Board order of designation will have conditions such as performance milestones (in particular, a deadline for application for leave to construct) and reporting requirements on progress and spending that, if not met, will result in designation being rescinded and will put further expenditures at risk."

After phase 1 of the hearing, Board staff submits there are three time periods:

- Application preparation, which ends once the applications for designation are filed;
- Development, which ends with the leave to construct proceeding; and
- Construction, which occurs after leave to construct is granted.

Most activities necessary to the eventual construction and operation of the East-West Tie line will extend over all three of these time periods. It may be difficult to draw a line along the continuum of an activity separating any of these time periods from another. Some work will be necessary during the plan preparation phase to provide cost estimates and schedules for the application for designation. More significant work will be necessary during the development phase in preparation for a leave to construct application. The preparatory work is not completed until the line is energized.

The Board could set development milestones in phase 1 of the hearing and include these in setting filing requirements. This approach would give potential applicants more certainty regarding expectations.

However, each of the transmitters who have registered their interest in the East-West Tie is, or is associated with, an experienced transmitter and has developed projects in the past. Each will have its own method for carrying out the work. Staff submits that the Board should not impose a development work plan and therefore method of work on the transmitters by setting specific milestones in the filing requirements. Instead, the Board should obtain input from the transmitters themselves as part of their applications for designation. One of the areas that the Board might use to differentiate the transmitters is the judgement that they bring in proposing milestones and a schedule in each application.

Staff therefore recommends that the Board require transmitters to propose performance milestones in their applications for designation. In its order the Board would impose performance milestones and reporting requirements related to those milestones through an amendment to the designated transmitter's licence. Staff further submits that the milestones and reporting obligations that the Board should consider imposing on the successful applicant for designation should apply to the development phase only and not be drawn from the construction phase of the project. Any reporting requirements for the construction phase could be determined and imposed in the hearing for leave to construct. The filing requirements proposed by staff as part of this submission reflect this requirement.

Board staff invites all parties to assist the Board by commenting on this submission. Parties are invited to suggest milestones and timing for reports if they submit that pre-determined milestones are preferable.

With respect to performance obligations (issue 10), Board staff is not recommending any specific performance bond or other obligation. Staff is not clear as to what such an obligation would guarantee or how it would be enforced. The designation process is not a procurement exercise and will not result in a contract between the designated transmitter and the Board. Staff invites parties that believe a performance obligation should be required to explain the purpose of the obligation and the authority through which the Board would collect the amount of the bond.

Staff also notes that the designation process is, at base, concerned with the provision of an incentive to interested transmitters: the ability to recover from ratepayers the development costs for the East-West Tie line. Failure to complete the development process for reasons within the transmitter's control could result in the denial of this incentive. Given this context, and the absence of a resultant contract, staff submits that any performance obligation would be useful only to cover the costs of the designation proceeding itself. Staff acknowledges that there is a cost to the ratepayer for the designation process. If the designated transmitter fails to complete development (i.e. obtain leave to construct the line) for reasons under its control and the line still needs to be developed, the Board may want to have some remedy to ensure that the costs of the process do not have to be repeated.

With respect to issue 12, staff suggests that the Board's filing requirements for designation include a requirement that applicants identify their proposals for the consequences of failure to complete the development (i.e. failure to file for, or obtain a leave to construct order from the Board). The consequences of failure should be set out in the designation order.

Alternatively, the Board could determine the consequences of failure or delay as part of its phase 1 decision. If the Board chooses to make a ruling on this matter in phase 1, staff submits that the Board should have regard to the consequences outlined in the Board's Policy at p. 16: failure to meet the performance milestones or reporting requirements could include loss of designation, with the Board designating an alternate transmitter, and the inability to recover any further development costs. This issue is related to issue 16, which is discussed below.

Staff acknowledges that delays and difficulties may arise that could not have been anticipated by a diligent transmitter. Staff proposes that the Board, in its order regarding performance milestones and reporting obligations, include the opportunity for the designated transmitter to seek amendments to the timelines established for performance and reporting in accordance with the Board Policy on page 16. Staff further recommends that the Board require the designated transmitter to be vigilant in identifying potential sources of failure or delay and to mitigate them to the extent possible. Where the designated transmitter anticipates unavoidable sources of failure or delay, staff submits that the Board should require the transmitter to report to the Board as soon as it has exhausted its ability to mitigate the problem. Such a special report would be in addition to any regular reporting required of the transmitter.

Consequences of Designation: Issues 13 – 16

13. ***On what basis and when does the Board determine the prudence of budgeted development costs?***

14. ***Should the designated transmitter be permitted to recover its prudently incurred costs associated with preparing its application for designation? If yes, what accounting mechanism(s) are required to allow for such recovery?***

15. ***To what extent will the designated transmitter be held to the content of its application for designation?***

16. ***What costs will a designated transmitter be entitled to recover in the event that the project does not move forward to a successful application for leave to construct?***

Board staff submits that the prudence of budgeted development costs will be assessed through the hearing process in phase 2 in which a transmitter is selected for designation. The level of development costs proposed by an applicant will be an important consideration for the Board, as this is the amount that will be recovered from ratepayers if the transmitter is designated. In this proceeding, competition will, in a sense, be a surrogate for regulation; the applicants for designation will be compared in part on the level of risk their plan for the East-West Tie line poses to the ratepayer.

Staff recommends that the Board reiterate its intention that any development costs in excess of budgeted development costs that are put forward for recovery from ratepayers will be subject to a thorough review for prudence.

The Board's Policy indicates that the designated transmitter will be entitled to recover its budgeted development costs. However, it is not clear from the policy whether "development costs" include the preparation of an application for designation. At page 11 the Policy indicates that "Only the transmitter that is successful in being designated will be able to recover the costs of preparing a plan". However, at page 15 of the Policy, the Board indicates that development costs begin when a transmitter is designated and end when a leave to construct application is submitted. The costs of preparing a plan are incurred before designation. The Board's letter of December 20, 2011 appeared to clarify the issue, stating:

> "As described in the Ontario Energy Board's policy *Framework for Transmission Project Development Plans* a designation process is a hearing of the Board, convened to identify a licensed transmitter who will be entitled to recover its prudently incurred development costs for a specific transmission project. Development costs begin when a transmitter is designated and end when a leave to construct application is submitted. The designated transmitter will also be able to recover its cost of becoming designated. Unsuccessful applicants will not."

Staff submits that the successful applicant for designation should be able to recover its costs of preparing a plan for an application for designation. However, staff suggests that these costs would begin to be incurred following the issuance of the Board's phase 1 decision. In proposing this time frame, staff is attempting to prevent burdening transmission ratepayers with costs related to the creation of the applicant companies, the licence application process and the development of strategy for the designation process. One stated purpose of the Board's Policy is to drive economic efficiency for the benefit of ratepayers. It would seem contrary to this policy to allow recovery of costs that would not be incurred in the normal course by an incumbent transmitter.

Staff acknowledges that applicants for designation will have incurred costs before the phase 1 decision is issued, and that other stated purposes of the Board's Policy are to encourage new entrants and support competition in transmission in the province. Staff invites comments on this issue from all parties.

Regarding the mechanism for recovery, the Board may choose to create a deferral account for the designated transmitter to provide for cost recovery. The Board could do this through licence conditions as well, for example section 70(2) of the OEB Act provides for conditions regarding the keeping of accounting records and methods or techniques to be applied in determining the licensee's rates. Section 78(3.0.5) may also be important, as it allows the Board to adopt rate setting methods that provide for incentives and cost recovery for work related to siting, design and construction of an expansion to a transmission system

Issue 16 asks what costs a designated transmitter will be entitled to recover if the project does not move forward to a successful application for leave to construct. Staff submits that the answer to this question is dependent on the reason that leave to construct is not granted. The Board's policy at page 15 states:

> "The Board accepts the premise that designation should carry with it the assurance of recovery of the budgeted amount for project development. When subsequent analysis by the OPA suggests that a project has ceased to be needed or economically viable (e.g. FIT applications have dropped out of the reserve such that the project falls below the economic threshold), the transmitter is entitled to amounts expended and reasonable wind-up costs."

Staff submits that this quote indicates that if the projects fails for reasons outside the designated transmitter's control, the transmitter can recover budgeted development costs already expended and reasonable wind-up costs. However, staff suggests that if the designated transmitter fails to obtain a leave to construct order from the Board due to some incompetence or failure within the transmitter's control, recovery of all budgeted development costs and reasonable wind-up costs should not be automatic. In such a case the Board would have to consider whether ratepayers should bear all such costs. Staff acknowledges that the Board's Policy does not address the recovery of budgeted development costs and wind-up costs where failure is due to some problem within the designated transmitter's control, and invites parties to address this issue in their submissions.

With respect to issue 15, to what extent will the designated transmitter be held to the content of its application for designation, staff submits that the Board should ensure that applicants are judged on plans to which they are committed. Staff suggests that, at a minimum, commitment should be given and met on the following matters:

- Adherence to the IESO required standards
- Adherence to the Minimum Technical Requirements
- Adherence to the performance milestones and reporting requirements imposed
- Adherence to planned First Nation and Métis participation
- Recovery of no more than budgeted development costs (in the absence of extraordinary circumstances)

Failure to meet these commitments could result in the rescinding of designation, or failure to obtain an order for leave to construct.

Board staff acknowledges that there are some aspects of the applicants' plans for which insufficient information will be available at the time that plans are filed to require a definite commitment. Construction costs, for example, may be compared during the evaluation of plans, but staff recommends that the Board should not require any definite commitment from applicants on these costs. Construction costs will be reviewed in the leave to construct application, and it would be premature to expect accurate estimates before development work is complete.

Process: Issues 17 – 23

17. ***The Board has stated its intention to proceed by way of a written hearing and has received objections to a written hearing. What should the process be for the phase of the hearing in which a designated transmitter is selected (phase 2)?***

18. ***Should the Board clarify the roles of the Board's expert advisor, the IESO, the OPA, Hydro One Networks Inc. and Great Lakes Power Transmission LP in the designation process? If yes, what should those roles be?***

19. ***What information should Hydro One Networks Inc. and Great Lakes Power Transmission be required to disclose?***

20. ***Are any special conditions required regarding the participation in the designation process of any or all registered transmitters?***

21. ***Are the protocols put in place by Hydro One Networks Inc. and Great Lakes Power Transmission LP, and described in response to the Board's letter of December 22, 2011, adequate, and if not, should the Board require modification of the protocols?***

22. ***Given that EWT LP shares a common parent with Great Lakes Power Transmission LP and Hydro One Networks Inc., should the relationship between EWT LP and each of Great Lakes Power Transmission LP and Hydro One Networks Inc. be governed by the Board's regulatory requirements (in particular the Affiliate Relationships Code) that pertain to the relationship between licensed transmission utilities and their energy service provider affiliates?***

23. ***What should be the required date for filing an application for designation?***

Board staff proposes that phase 2 of the hearing should remain a written hearing. It is not clear to staff what advantage would be obtained through an oral hearing. Concerned parties are invited to identify what information necessary to the Board's decision cannot be obtained through a written hearing.

Staff recommends that the phase 2 hearing contain the following elements:

- Applications for designation filed with the Board
- All parties file with the Board proposed interrogatories (not directly sent to applicants)

- Interrogatories to applicants from the Board, informed by suggestions from all parties
- Answers to interrogatories from all applicants
- Oral questions from Board if necessary
- Written submissions from all parties
- Reply submissions from applicants

Staff acknowledges that this process differs from the Board's standard hearing process in at least two fundamental ways: the funnelling of interrogatories through the Board (which may involve culling and editing) and the absence of cross-examination by the parties of the applicants. Staff is recommending this process due to the unique nature of this proceeding.

The process is competitive and, although not a procurement, has certain elements that resemble procurement. It will be vital to treat all applicants fairly and equally and, to the extent possible, treat them identically. Staff recommends that the same questions be sent to the applicants from the same source (i.e. the Board), and that the questions to applicants differ only to the extent that their applications differ.

Secondly, staff recommends that the Board exercise a significant degree of control over the process, partly to ensure fairness, but also to reduce the possibility of an expensive and drawn-out process. Neither applicants nor ratepayers would benefit from inefficiencies. Staff recommends that the Board select the process elements that it needs to obtain the information to make an informed and well-reasoned choice between applicants.

With respect to the role of the Board's expert advisor, it is staff's understanding that this person will act as an advisor to Board staff as necessary, not as a private advisor to the Board panel. His advice will therefore be provided in the same manner as that of Board staff, and will be made known to the parties in the proceeding through the medium of interrogatories and submissions.

Board staff invites the other entities named in issue 18 to file a submission outlining their intended role in the designation process. Staff suggests that the IESO would propose interrogatories and make submissions in phase 2 where proposals from applicants will affect the system. In addition, during the plan

preparation period, the IESO will need to assist potential applicants with the feasibility of non-Reference Option proposals.
The OPA may choose to propose interrogatories, provide information and make submissions to clarify matters related to the OPA's mandate. Board staff suggests that neither the IESO nor the OPA would make submissions supporting a particular applicant for designation, but remain neutral as between applicants.

Hydro One Networks Inc. has a special role in the process as the transmitter to whose system the new East-West Tie line will attach. Hydro One Networks Inc. will need to provide information, including costing information for station work, to assist potential applicants with plan preparation. In phase 2, staff expects that Hydro One Networks Inc. could choose to propose interrogatories and make submissions on proposals that affect its infrastructure. Similarly, staff suggests that Great Lakes Power Transmission LP would provide any relevant information it has to potential applicants and propose interrogatories and make submissions on any proposals that affect its infrastructure. Board staff believes that it is very important that these two transmitters do not favour any particular applicant for designation, but provide the same information and assistance to all potential applicants.

Hydro One Networks Inc. and Great Lakes Power Transmission LP have each filed lists of documents and information in their possession that relate to any preliminary development work previously undertaken in relation to the proposed East-West Tie line or were previously requested or discussed among the parties. As Board staff understands the context of these lists, this was information gathered or produced within the regulated utility. It is staff's submission that all the listed information relevant to the development of the East-West Tie line should be produced. Staff believes that such information would be of assistance to potential applicants and the Board in understanding the challenges presented by construction and maintenance of the EW Tie.

On April 20, 2012 counsel for TransCanada Power Transmission Ltd., on behalf of his client and four other registered transmitters, wrote a letter to the Board seeking that the Board direct Hydro One Networks Inc. and Great Lakes Power Transmission LP to advise of their position on the production of documents and to produce whatever documents that they do not object to producing by April 25, 2012. The stated reason for this request is that all parties could have the information in time to inform their submissions for the scheduled date of May 7, 2012.

Board staff notes that Hydro One Networks Inc. and Great Lakes Power Transmission LP are intervenors in this proceeding. Rather than make the direction sought in the letter of April 20, 2012, the Board could direct Hydro One Networks Inc. and Great Lakes Power Transmission LP to address these matters in a submission filed May 7, 2012. Staff notes that all parties would have a chance to respond to this submission on May 16, 2012. Board staff recommends that the Board, in its phase 1 decision, set a date by which the information is to be produced. Staff does not understand why earlier production would be useful, as it appears that the listed information is related to plan preparation.

Board staff acknowledges that there may be reasons (for example, confidentiality or security concerns) why all the listed information cannot or should not be produced, or that production should be restricted. Staff recommends that the Board direct Hydro One Networks Inc. and Great Lakes Power Transmission LP to explain in detail, in their submissions, the reasons that any of the listed items should not be produced to all parties in the designation proceeding. Further, staff invites these utilities to indicate whether the Board's *Practice Direction on Confidential Filings*, and the form of declaration and undertaking provided in that Practice Direction, would provide sufficient protection for confidential documents.

Board staff recognizes that difficulties, and possibly disputes, may arise during the application preparation period (after the Board's decision on phase 1 and before the filing of applications for designation) as to what information should be produced. Staff suggests that reference to the level of detail required in the filing requirements that the Board approves in its phase 1 decision may be of assistance in determining what information is necessary to produce for the purpose of preparing applications for designation. Staff is willing to facilitate meetings between Hydro One Networks Inc. and Great Lakes Power Transmission LP and the registered transmitters, if those parties believe such facilitation would be helpful. If matters cannot be settled, staff suggests that the matters in dispute be brought to the Board for resolution by way of motion.

Board staff has no particular measures to suggest addressing the concerns raised by issues 20, 21 and 22. Staff asks that parties that are seeking conditions or other measures explain the harm they are seeking to prevent, how the proposed condition or measure mitigates that harm without causing other harm, and whether the proposed condition or measure should apply to all similar participants in the interest of fairness. In addition, staff makes the following observations with respect to these issues.

Two of EWT LP's limited partners are incumbent transmitters; however, these limited partners are not "affiliates" of EWT LP within the meaning of the Board's *Affiliate Relationships Code for Distributors and Transmitters* (the "ARC"). The various rules regarding relationships with affiliates in the ARC therefore do not apply to the relationship between EWT LP and its limited partners. Board staff notes that these rules also do not apply to any registered transmitter whose licence is not yet in effect.

Issue 22 refers specifically to the relationship between licensed transmission utilities and their energy service providers. There are three types of restrictions in the ARC that are specifically targeted at this relationship: provisions regarding the sharing of employees in section 2.2.3, provisions regarding the endorsement of marketing activities in section 2.5.1 – 2.5.2, and provisions relating to the sharing of system planning information in sections 2.6.4 and 2.6.5. Board staff presumes that the concerns surrounding issue 22 relate to any informational advantage EWT LP may have as a result of its relationship with its partners; specifically preferential access to system planning and technical information related to the development of the East-West Tie line.

Board staff submits that equal access by all designation applicants to information held by incumbent transmitters relevant to the development of the East-West Tie line is vital to the fairness of the Board's designation process. Staff also accepts that Hydro One Networks Inc. and Great Lakes Power Transmission LP may have done work relating to the development of the East-West Tie line as regulated, ratepayer-funded utilities. As noted in staff's submission on issue 19, staff submits that all such information should be disclosed, unless there are serious confidentiality or security concerns that militate against its disclosure. However, staff does not understand why a Board order made pursuant to issue 19, along with the protocols mentioned in issue 21, are inadequate to ensure equal access by all designation applicants to information that the incumbent transmitters may have. Board staff invites all parties to address the adequacy of these measures.

Finally, staff proposes that the Board consider a date for the filing of applications for designation. The Board's Policy at page 12 indicated that three months would be the default period for filing after notice was given, although the period could be as long as six months. The original notice for the designation proceeding was given on February 2, 2012, but staff regards the issuance of the Board's phase 1 decision as equivalent to notice in the circumstances of this particular designation process. Some aspects of the Board's phase 1 decision, particularly relating to the filing requirements and any prerequisites to designation, will have to be taken into account in setting the date for filing. In the absence of any significant additional issues arising in the phase 1 decision, Board staff proposes that the Board require the filing of applications for designation four months after it renders its phase 1 decision.

However, Board staff acknowledges there may be issues that the Board cannot anticipate at the time of its phase 1 decision. An alternative to setting a date in the phase 1 decision could be a requirement on registered transmitters, or all parties, within 60 days of the Board's phase 1 decision, to propose a filing date for applications. Board staff invites all parties, but particularly the registered transmitters, the IESO, the OPA and Hydro One Networks Inc. to comment on this issue.

All of which is respectfully submitted to the Board.

FILING REQUIREMENTS FOR THE DESIGNATION PROCESS FOR THE EAST-WEST TIE LINE

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FILING REQUIREMENTS FOR THE DESIGNATION PROCESS FOR THE EAST-WEST TIE LINE

An application for designation will contain two main sections. Together, these sections of the application address the Board's decision criteria for the East-West Tie line:

- Evidence addressing the capability of the applicant to carry out the East-West Tie line project;

- The applicant's Plan for the East-West Tie line.

In addition to the items listed in these Filing Requirements, the applicant may choose to file any other information that it considers relevant to its application for designation.

CAPABILITY OF THE APPLICANT

1. Background Information

The applicant must provide the following information:

1.1 The applicant's name.

1.2 The applicant's OEB transmission licence number.

1.3 Any change in information provided as part of the transmitter's licence application.

1.4 Confirmation that the applicant has not previously had a licence or permit revoked and is not currently under investigation by any regulatory body.

1.5 Confirmation that the applicant is committed to the completion of the development work for the East-West Tie line, and to the filing of a leave to construct application for the line, to the best of its ability.

1.6 A statement from a senior officer that the application for designation is complete and accurate to the best of his/her information and belief.

2. Organization

The applicant shall identify how, from an organizational perspective, it intends to undertake the East-West Tie line project. In particular, the applicant, if it intends to involve First Nation or Métis communities as participants in the East-West Tie line project, the must file evidence of its experience with Aboriginal participation in development, construction or operation of transmission line projects. If the applicant has no direct experience with such participation, the applicant must describe its plan to source that experience for the East-West Tie line project. To that end, the applicant must file:

2.1 An overview of the organizational plan for undertaking the project, including:

- any partnerships or contracting for significant work;
- identification and description of the role of any third parties that are proposed to have a major role in the development, construction, operation or maintenance of the line; and
- a chart to illustrate the organizational structure described.

2.2 Identification of the specific management team for the project, with resumes for key management personnel.

2.3 An overview of the applicant's experience with:

- the management of similar transmission line projects; and
- regulatory processes and approvals related to similar transmission line projects.

In addition, the applicant must file evidence of one of the following:

2.4 If arrangements for First Nation and Métis participation have been made, a description of:

- The First Nation and Métis communities that will be participating in the project;
- The nature of the participation (e.g. type of arrangement, timing of participation);
- Benefits to First Nation and Métis communities arising from the participation;
- Benefits to transmission ratepayers of the First Nation and Métis participation;

- Costs of First Nation and Métis participation included in the development and construction budgets for the line; and
- Whether participation opportunities are available for other First Nation and Métis communities in proximity to the line.

2.5 If arrangements for First Nation and Métis participation have not been made but are planned, a description of:

- The plan for First Nation and Métis participation in the project, including the method and schedule for seeking participation;
- The nature of the planned participation;
- Planned benefits to First Nation and Métis communities arising from the participation;
- Planned benefits to transmission ratepayers of the First Nation and Métis participation; and
- Estimated costs of First Nation and Métis participation included in the development and construction budgets for the line.

2.6 If no First Nation or Métis participation in the project is planned, detailed reasons for this choice.

3. Technical Capability

The applicant must demonstrate that it has the technical capability to engineer, plan, construct, operate and maintain the line, based on experience with projects of equivalent nature, magnitude and complexity. To that end, the following must be filed:

3.1 A discussion of the type of resources, including relevant capability (in-house personnel, contractors, other transmitters, etc.) that would be dedicated to each activity associated with developing, constructing, operating and maintaining the line, including:

- design;
- engineering;
- material and equipment procurement;
- licensing and permitting;

- construction;
- operation and maintenance; and
- project management.

3.2 Resumes for key technical team personnel.

3.3 A description of sample projects, and other evidence of experience in Ontario and other jurisdictions in developing, constructing and operating transmission lines involving similar:

- terrain;
- climate and other environmental conditions; and
- reliability requirements.

3.4 Evidence that the applicant's business practices are consistent with good utility practices for the following:

- design;
- engineering;
- material and equipment procurement;
- right-of-way and other land use acquisitions;
- licensing and permitting;
- consultations;
- construction;
- operation and maintenance; and
- project management.

3.5 A description of:

- the challenges involved in achieving the required capacity and reliability of the EW Tie line, including challenges related to terrain and weather; and
- the plan for addressing these challenges though the design and construction of the line (e.g. number and spacing of towers, planned resistance to failure).

4. Financial Capacity

The applicant must demonstrate that it has the financial capability necessary to develop, construct, operate and maintain the line. To that end, the applicant shall provide the following:

4.1 Evidence that it has capital resources that are sufficient to develop, finance, construct, operate and maintain the line.

4.2 Evidence that the financing, construction, operation, and maintenance of the line will not have a significant adverse effect on the applicant's creditworthiness or financial condition.

4.3 The applicant's financing plan, including:

- the estimated proportions of debt and equity; and
- the estimated cost of debt and equity, including:
    - the use of variable and fixed cost financing;
    - short-term and long-term maturities; and
    - a discussion of how the project might impact the applicant's cost of debt.

4.4 If the financing plan contemplates the need to raise additional debt or equity, evidence of the applicant's ability to access the debt and equity markets.

4.5 Evidence of the applicant's ability to finance the project in the case of cost overruns, delay in completion of the project and other factors that may impact the financing plan.

4.6 Evidence of the applicant's experience in financing similar projects.

4.7 The identification of any alternative mechanisms (e.g., rate treatment of construction work in progress) that the applicant is requesting or likely to request.[1]

PLAN FOR THE EAST WEST TIE LINE

5. PLAN OVERVIEW

The applicant must provide an overview of its Plan for the East-West Tie line. The overview must include:

[1] See Report of the Board on The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario, http://www.oeb.gov.on.ca/OEB/_Documents/EB-2009-0152/Board_Report_Infrastructure_Investment_20100115.pdf

5.1 A summary description of how the Plan meets the specified requirements for the East-West Tie Line. This description should include, for example:

- the length of the proposed transmission line;
- terminal points;
- number of circuits;
- voltage class;
- load carrying capacity;
  - summer continuous rating (MVA)[2]; and
  - summer emergency rating (MVA)[3] ;
- resulting <u>total</u> transfer capability for the East-West Tie (MW);
- anticipated lifetime of the line (minimum 50 years);
- Structures and conductors (to the extent known at the time of filing the application for designation. If unknown, describe method and criteria for selection):
  - number and average spacing of towers;
  - tower structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.);
  - conductor size and type; and
    protection against cascading failure and conductor galloping; and
- Other relevant transmission facility characteristics.

The applicant must also file:

5.2 Confirmation that the line will interconnect with the existing transformer stations at Wawa and Lakehead, and an indication of whether the line will be switched at the Marathon transformer station.

5.3 A signed affidavit from an officer of the licensed transmitter to confirm:

- that the line will meet the existing NERC, NPCC and IESO reliability standards; and
- that the line will meet the Board's Minimum Technical Requirements; or documentation of where the applicant seeks to differ from the Minimum Technical Requirements and evidence as to the equivalence or superiority of the proposed alternative option.

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[2] Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 93ºC
[3] Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 127 ºC

5.4 An indication as to whether the Plan will be based on the Reference Option for the East-West Tie line. Where the Plan is not based on the Reference Option, the applicant must file:

- a description of the main differences between the applicant's Plan and the Reference Option;
- a description of the interconnection of the line with the relevant transformer stations; and
- a Feasibility Study performed by the IESO, or performed to IESO requirements.

5.5 A brief description which highlights the strengths of the Plan, which may include:

- any technological innovation proposed for the line;
- reduction of ratepayer risk for the costs of development, construction, operation and maintenance;
- local benefits (e.g. employment, partnerships); and
- enhanced reliability for the transmission grid.

5.6 The estimated total costs associated with the Plan, broken down as follows:

- development;
- construction; and
- operation and maintenance.

5.7 An indication as to whether the applicant's present intention is to own and operate the line once the line is in service.

6. Schedule

The applicant must file, as part of its Plan:

6.1 A project execution chart showing major milestones for both line development and line construction phases of the project.

6.2 For the development phase of the project:

- A detailed line development schedule identifying significant milestones, and proposed dates for completing the milestones, for significant activities that are part of the development phase of the project;

- Proposed reporting requirements for the development phase;
- Proposed consequences for failure to meet the required performance milestones and reporting requirements for the development phase;
- A chart of the major risks to achievement of the line development schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and
- A description of the applicant's strategy to mitigate or address the identified risks.

6.3 For the construction phase of the project:

- A preliminary line construction schedule identifying significant activities that are part of the construction phase of the project, and estimates of time required to complete those activities;
- A chart of the major risks to achievement of the construction schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and
- A description of the applicant's strategy to mitigate or address the identified risks.

6.4 Evidence of the applicant's past success in completing similar transmission line projects within planned time frames. Such evidence could include a comparison of the construction schedule filed with a regulator when seeking approval to proceed with a transmission line project and the actual completion dates of the milestones identified in the schedule.

6.5 Any innovative practices that the applicant is proposing to use to ensure compliance with, or accelerate the line development and line construction schedules.

7. Costs

As part of its Plan, the applicant must file a detailed budget for the development of the line up to the filing of the leave to construct application, and supporting evidence for that budget. This section of the Plan must include:

7.1 The amount already spent for preparation of an application for designation, and an estimate of remaining costs to achieve designation.

7.2 The estimated total development costs of the line, broken down by category of cost, including, where relevant:

- permitting and licensing;
- engineering and design;
- procurement of material and equipment;
- consultations;
- First Nation and Métis participation costs;
- land use rights;
- contingency budget; and
- other significant expenditures.

7.3 The basis for and assumptions underlying the cost estimates.

7.4 A schedule of development expenditures.

7.5 A chart of the major risks that could lead the applicant to exceed the line development budget, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the budget (e.g. minor, moderate, major), and a description of the applicant's strategy to mitigate or address the identified risks.

7.6 A proposed threshold of materiality for prudence review of cost overruns for the costs of development.

7.7 A statement as to the allocation between the applicant and transmission ratepayers of risks relating to costs of development. For example:

- if the costs of development are less than budgeted, does the applicant propose to recover only spent costs, or all budgeted costs (spent and unspent) or spent costs plus a portion of unspent cost (savings sharing); and

- If the costs of development exceed budgeted costs, does the applicant plan to seek recovery of the excess costs.

7.8 An estimated budget for the construction of the line, noting any significant anticipated contingencies.

7.9 If the Plan is not based on the Reference Option, evidence as to the difference in cost (positive or negative) of work required at the transformer stations to which the line connects and at any other location identified by the IESO.

7.10 A list of the major risks that could lead the applicant to exceed the line construction budget, and the applicant's strategies to mitigate or address those risks.

7.11 The estimated average annual cost of operating and maintaining the line.

7.12 Evidence of the applicant's past success in completing similar transmission line projects within planned budgets. Such evidence could include a comparison of the budget filed with a regulator when seeking approval to proceed with a transmission line project and the actual costs of the project.

8. Land Owner and Other Consultations

The applicant must demonstrate the ability to conduct successful consultations with landowners, First Nations and Métis communities and other relevant parties. In addition, the designated transmitter will be required to satisfy environmental and other requirements that are outside the jurisdiction of the Board.

As part of its Plan, the applicant must file:

8.1 An overview of:

- the rights-of-way and other land use rights, presented by category, that would need to be acquired for the purposes of the development, construction, operation and maintenance of the line;
- the applicant's plan for obtaining those rights; and
- a description of any significant issues anticipated in land acquisition or permitting and a plan to mitigate them.

8.2 A consultation plan for the line, including:

- identification of the categories of parties to be consulted;
- the applicant's plan for consultation for each party or category of party, including method and tentative schedule in relation to the overall project schedule;
- a list of First Nation and Métis communities that may have interests affected by the project; and
- A description of any significant issues anticipated in consultation and a plan to mitigate them.

8.3 If the applicant has identified a proposed route for the line, the applicant must file:

- General description of the planned route for the line;
- Approximate right-of-way width;
- Approximate portion of the route that is:
  - adjacent to the existing corridor (%); or
  - along a new corridor (%):
- A brief description of the environmental challenges posed by the proposed route; and
- An estimate of ownership by category of lands along the proposed route:
  - Crown (federal or provincial) (%);
  - Private (%);
  - First Nation or Métis (%); and
  - Other (%);

8.4 If a proposed route for the line has not been identified, the applicant must file:

- a list of alternative routes;
- an explanation of the method and decision criteria for route analysis and selection; and
- the planned schedule for route selection.

8.5 The applicant must file evidence of its experience with:

- the acquisition of land use rights from private landowners and the Crown;
- the acquisition of necessary permits from government agencies;
- successfully obtaining environmental approvals similar to the environmental approvals that will be necessary for the East West Tie line;

- community consultation; and
- successful completion of the procedural aspects of Crown consultation with First Nation and Métis communities.

ADDITIONAL INFORMATION

The applicant should include any other information that it considers relevant to its application for designation.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0140

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

BEFORE: Cynthia Chaplin
Presiding Member and Vice-Chair

Emad Elsayed
Member

Cathy Spoel
Member

EAST-WEST TIE LINE DESIGNATION

PHASE 2 DECISION AND ORDER

August 7, 2013

DESIGNATION DECISION

The Board has decided that the designated transmitter for the development phase of the proposed East-West Tie line is Upper Canada Transmission Inc. This selection is based on the submitted applications as well as the subsequent interrogatory answers and submissions.

BACKGROUND

This decision is the result of a process initiated by the Ontario Energy Board to designate a transmission company to undertake development work for the proposed East-West Tie line. The Ontario Government published its Long Term Energy Plan in November of 2010. The Plan identified five priority transmission projects, one of which was the East-West Tie, an electricity transmission line running between Thunder Bay and Wawa, Ontario. On March 29, 2011, the Minister of Energy wrote to the Board to express the government's interest in the Board undertaking a designation process to select the most qualified and cost-effective transmitter to develop the East-West Tie line.

Origin of Designation

The origin of the designation process is the Board's policy for transmission development. That policy was developed through a consultation process and culminated in the Board's report entitled *Board Policy: Framework for Transmission Development Plans.*[1] The report describes the issues considered through the consultation and the Board's conclusion that economic efficiency in transmission service is best pursued by introducing competition, and that providing greater certainty for cost recovery of development work would encourage participation in the competitive process. In describing the goals of the policy, the Board said:

> The Board believes that this policy will:
> - allow transmitters to move ahead on development work in a timely manner;

[1] EB-2010-0059 issued August 26, 2009.

- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.

A transmission utility seeking to build a major transmission line applies to the Board under section 92 of the *Ontario Energy Board Act, 1998* ("the OEB Act") for leave to construct the line. Before bringing an application for leave to construct, the transmitter incurs costs to complete "development" work, which includes negotiating access and land rights, acquiring permits, conducting environmental assessment activities, consulting with affected communities, preparing line design and engineering studies, conducting economic feasibility studies, and obtaining a system impact assessment. The development phase ends with the filing of an application for leave to construct the line.

Board Authority to Implement Designation

The Board does not have the jurisdiction or authority to procure transmission services, or the authority to enter into contracts with transmitters to build or operate transmission infrastructure. The Board premised its original policy on its authority under section 70(2.1) of the OEB Act to require the filing of plans for the expansion of the transmission system to accommodate the connection of renewable energy generation facilities. The East-West Tie line is not primarily needed for the connection of renewable energy generation facilities. However, the Board has broad licensing and rate making jurisdiction under sections 70, 74 and 78 of the OEB Act to prescribe conditions under which a transmitter engages in owning or operating a transmission system, to amend transmission licences, and to set transmission rates. Subsection 78(3.0.5) specifically provides the Board with authority to provide incentives to a transmitter for siting, design and construction of an expansion to the transmitter's transmission system. In this decision, the Board will make an order under the authority of these sections to give effect to its decision on designation.

Implications of Designation

Designation does not carry with it an exclusive right to build the line or an exclusive right to apply for leave to construct the line. A transmitter may apply for leave to construct the East-West Tie line, designated or not. In designating a transmitter, the Board is providing an economic incentive: the designated transmitter will recover its development costs up to the budgeted amount (in the absence of fault on the part of the transmitter), even if the line is eventually found to be unnecessary. The designation may be rescinded and costs denied if the designated transmitter fails to meet the performance milestones for development or the reporting requirements imposed by the Board in this decision.

Initiation of Designation for the East-West Tie Line Project

After receiving the Minister's letter, the Board sought and received from the Ontario Power Authority (the "OPA") a preliminary assessment of the need for the East-West Tie line, which provided planning justification to support the implementation of a designation process. The OPA indicated that the primary driver for the East-West Tie line is the need to ensure long-term system reliability in northwestern Ontario. The Board also received a feasibility study of options for meeting the transfer capability requirements for the line from the Independent Electricity System Operator (the "IESO").

A double circuit 230 kV electricity transmission line already exists between Thunder Bay transmission station ("TS") and Wawa TS. The East-West Tie line project involves the construction of a new transmission line which, in conjunction with the existing line, will increase capacity and reliability of electrical transmission between northeast and northwest Ontario. The length of the new line will be approximately 400 kilometres.

The specifications for the East-West Tie line project were defined as follows:

- A new line that, in conjunction with the existing line, will provide total eastbound and westbound capabilities in the East-West corridor in the order of 650 MW, while respecting all NERC (North American Electric Reliability Corporation), NPCC (Northeast Power Coordinating Council), and IESO reliability standards.
- Lifetime of at least 50 years.

- Target in-service date: 2017 (applicants were invited to propose alternate in-service dates).
- The East-West Tie line is to be built in 2 segments:
  - Wawa TS to Marathon TS; and
  - Marathon TS to Lakehead TS.
- The demarcation points of each segment are the first transmission line structures outside the fence of the Wawa TS, Marathon TS and Lakehead TS, but within 250 metres of that fence.
- The East-West Tie line segments will dead-end on the demarcation point structures with a mid-span opener for non-compensated lines.
- If the proposal involves series compensated AC line or DC lines, the East-West Tie line will include the protection system, associated communications, and line isolation breaker(s).

For the purposes of designation, the Board assumed that the new East-West Tie line between the demarcation points would be owned and operated by the designated transmitter once constructed, although this was not an absolute requirement.

The Board invited transmitters to register their interest in filing a plan for development of the line.

Process Adopted by the Board for Designation

On February 2, 2012, the Board published notice in English, French, Cree and Ojibway that it was initiating a proceeding to designate an electricity transmitter to undertake the development work for the East-West Tie line, and invited intervention and public comment. The notice was published in the Globe and Mail, Ottawa Le Droit and seven newspapers in communities local to the existing line. The notice was also served on municipalities and First Nation and Métis communities in the area of the line. The Board received thirty-one requests for intervenor status, including the seven transmitters who had initially registered an interest in the project. The list of intervenors is attached as Appendix A to this decision. All materials on the record of the proceeding are available on the Board’s website.

The Board used a two phase process to reach its designation decision. In Phase 1 of the East-West Tie designation process, the Board established criteria and filing requirements specific to the East-West Tie line project, considering the Minister's letter, the reports from the OPA and the IESO, and the submissions of all parties. The Board issued its Phase 1 decision on July 12, 2012. The Phase 1 decision is attached as Appendix B to this decision. The Phase 1 decision required transmitters seeking designation to file applications by January 4, 2013. The following six transmitters applied for designation:

- AltaLink Ontario LP ("AltaLink"): a wholly owned subsidiary of AltaLink Investments LP, which is wholly owned by SNC Lavalin Group Inc.
- Canadian Niagara Power Inc. ("CNPI"): owned by FortisOntario Inc., which is owned by Fortis Inc.
- EWT LP: a partnership of Hydro One Inc., Great Lakes Power Transmission EWT LP, and Bamkushwada LP.
- "Iccon/TPT": a joint application by Iccon Transmission Inc. (a wholly owned subsidiary of Isolux Infrastructure Netherlands B.V.), and TransCanada Power Transmission (Ontario) LP (a wholly owned subsidiary of TransCanada Corporation)
- RES Canada Transmission LP ("RES"): a partnership of Renewable Energy Systems Canada Inc., MEHC Transmission Canada Limited Partnership, and RES Canada Transmission GP Inc.
- Upper Canada Transmission Inc. ("UCT"): a partnership of NextEra Energy Canada (a wholly owned subsidiary of NextEra Energy Resources LLC), Enbridge Inc. and Borealis Infrastructure Management.

The Board adopted a written hearing process and tailored its process to suit the nature of the proceeding. The Board found in its Phase 1 decision that as the proceeding involved multiple competitive applicants and had some similarity to a procurement process, it called for specific procedures that respected fairness and efficiency in that context.

For example, while the Board invited parties to propose written interrogatories for the applicants to answer, the Board itself issued the interrogatories, having combined, edited and eliminated some interrogatories proposed by parties. The Board was of the view that the applicants should be compared on the basis of the applications as filed, and attempted to avoid providing opportunities for applicants to fill any gaps in their applications. Parties were also invited to file written argument, with applicants filing an argument in chief, other parties filing responding arguments and applicants filing reply argument.

The Board convened an oral session in Thunder Bay to allow representatives of intervenors from communities local to the existing East-West Tie line to make oral presentations. The presentations were not sworn testimony, but oral commentary on matters concerning local interests. The oral session occurred on May 2 and 3, 2013, subsequent to the filing of argument in chief and prior to the receipt of arguments from non-applicant intervenors.

EVALUATION OF APPLICATIONS

The record of this proceeding demonstrates that all applicants spent a significant level of effort and resources to prepare these applications and to respond to interrogatories. Given that this is the first such competitive process for a transmission project in Ontario, it is encouraging that there are qualified entities which are willing to commit resources to compete in this market.

There was a significant amount of information for the Board to assess in order to arrive at a final decision. The overriding principle in establishing and executing the evaluation methodology is that it be fair and equitable and result in an outcome that serves the public interest. The evaluation was largely based on the applications as originally submitted. Information provided in response to interrogatories was used for clarification purposes, and not to enhance the original application. For example, the original applications included cost estimates for development, construction, and operation and maintenance phases of the project. In order to properly compare these estimates, the Board asked the applicants to break down these estimates into specific common components. The expectation was that the original bottom line cost estimates would not change, and if they did, then a full explanation would be provided to ensure that the answer did not represent an attempt to improve the proposal.

The intervenor and applicant submissions assisted the Board in deciding how to apply the criteria and evaluate the applications. However, any new facts provided through submissions were given little weight.

Evaluation Methodology

The evaluation was based on the decision criteria established in the Phase 1 Decision and Order. The headings of these criteria are provided below, and the information that was required of the applicants under each heading can be found in the Filing Requirements (Appendix A of the Phase 1 Decision and Order).

In its Phase 1 Decision and Order, the Board did not articulate an assessment methodology to be applied to the decision criteria, nor did it ascribe any relative importance to the decision criteria through a weighting system. The Board stated that it was unwilling to remove the discretion and flexibility it might need in evaluating the applications, and that it would exercise its judgment for each criterion, with the assistance of the evidence presented and the submissions received from all parties.

The Board has found no compelling reason to assign different weights to the decision criteria, and has therefore weighted them all equally at ten points each.

The criteria are:

- Organization
- First Nations and Métis participation
- Technical capability
- Financial capacity
- Proposed design
- Schedule; development and construction phases
- Cost; development, construction, operation and maintenance phases
- Landowner, municipal, and community consultation
- First Nations and Métis consultation

“Other Factors” was a criterion listed in the Phase 1 decision. Under that criterion, however, all applicants reiterated what they believe are strong features of their proposals. Since these features have already been evaluated as part of the other criteria, the Other Factors criterion was not included in the evaluation.

For each of the criteria, the applications were reviewed and the proponents were ranked from 6 to 1, with 6 being the best. A score was assigned to each of the rankings with scores of 6, 5, 4, 3, 2, and 1 corresponding to the respective rankings. Given the qualitative nature of the ranking, if two or more applications were judged to rank equally in a certain criterion, they were given the same ranking with a corresponding average score (e.g. if two applicants were ranked at 5, they were each given a score of 4.5). The applicant's score for each criterion was then multiplied by ten. The process was repeated for each decision criterion and the scores added to determine the total score for each application. The application with the highest overall score was determined to be the most qualified applicant for designation.

EVALUATION RESULTS

Background Information

Background information was requested from the applicants in the Filing Requirements. All applicants provided the requested information and the Board has no substantive concerns with the information provided.

The Board also invited applicants to indicate whether they would be willing to be "runner up". The runner up would have the right of first refusal to undertake the project development work if the designated transmitter fails to fulfill its obligations. AltaLink confirmed that it would be willing to be runner up without qualification. CNPI, Iccon/TPT, and RES also confirmed but with some conditions attached, while UCT and EWT LP stated that they would not be willing to be runner up. As indicated in the Phase 1 Decision and Order, an applicant's willingness to be runner up had no influence on the assessment of the application.

In the following sections, the results of applying the methodology described above are summarized for each of the decision criteria, and the resulting ranking of the six applications for the particular criterion is provided.

Organization

The applicants were required to provide, among other things, a project organizational plan, a chart illustrating the organizational structure, identification of the project management team with resumés for key management personnel, and an overview of the applicant's experience with similar projects.

Subsequently, by interrogatories in Procedural Order No. 6, issued March 4, 2013, the applicants were asked to provide the following information regarding organization:

- Proposed organizational charts for the various project phases (development, construction, operation and maintenance) showing the various functions, including those listed in section 4.1 of the Filing Requirements, as well as the reporting structure.
- The names of members of the proposed management team (including the project manager / lead) and technical team who would be leading each function.
- Confirmation as to whether the project manager / lead will be dedicated to this project, and a description of this person's experience in managing similar projects.
- The specific proposed project / operation and maintenance role for each member of the "key technical team personnel" provided in response to section 4.2 of the Filing Requirements. (This item is evaluated under Technical Capability.)

In evaluating the applications in the area of Organization, the Board ranked applicants by considering the following factors:

- Clarity of the organizational structure for the various project phases and inclusion of all key project functions.
- Clarity as to who is accountable for the overall management of the project.
- Clarity as to the governance structure and lines of accountability, including the role of any third parties.
- Quality of the overall organization and the strength of the supporting structure.
- The relevance and extent of the experience of the proposed project manager and the management team in terms of size, type and complexity of projects.

- Experience in managing similar large projects.

The more of these characteristics which a proponent demonstrated through its application, the higher the Board ranked the proponent. Below, the Board sets out the proponents in ranked order for Organization and provides a brief discussion of the main characteristics of each application.

UCT (6)

UCT provided a project organizational structure with clearly defined accountabilities for all major areas of work, which would be used for all three phases of the project to ensure a seamless transition. The overall project management accountability and associated oversight structure were well defined. The structure consists of a Management Team with a Project Director having an overall accountability for the project, supported by an Operations Committee and an Aboriginal Advisory Board, all reporting to the Board of Directors. The proposed Project Director has significant experience with the transmission business and associated projects. UCT confirmed that the Project Director will be dedicated to the project. Names and resumés were provided for each of the positions in the chart which showed a strong combination of technical and managerial experience. UCT indicated that it would mostly use in-house resources seconded to it from partner organizations, supplemented by third-party contractors as required. UCT also proposed that, once in the operations phase, it will have an operation and maintenance contract with NextEra and that the Project Director will be replaced by a President of NextBridge Infrastructure to reflect the change in the nature of the role. UCT provided a description of its significant experience with relevant projects involving many aspects that are similar to this project, both in and outside Ontario.

AltaLink (5)

AltaLink provided two charts including all the key functions; one for the project (development and construction) and one for operations and maintenance with a description of the roles and accountabilities of proposed key management positions. Although the overall project management accountability was well defined, the oversight structure above the project lead was not clear. The proposed project lead has significant project experience with transmission and other infrastructure projects in Canada and abroad. Names as well as a brief description of experience were provided for those leading the functions shown in the project chart, which showed strong technical and managerial experience. AltaLink confirmed that the project lead will be dedicated to this project and will be responsible for project delivery from development to in-service. AltaLink provided a detailed overview of its extensive experience with specific similar projects, mostly in Alberta. AltaLink also indicated that project planning and development as well as engineering, procurement and construction management services will be provided by SNC Lavalin, Altalink's owner.

EWT LP (4)

EWT LP provided two charts; one for the development phase and one for the construction phase of the project, including the key functions. In both charts, the project management function is split between two individuals; a Project Manager reporting to a Project Director who has three Special Advisors representing the three partners (Hydro One Inc., Great Lakes Power Transmission EWT LP ("GLPT-EWT"), and Bamkushwada LP ("BLP")). The distinction between these two roles in terms of the overall project management accountability is not clear. The charts showed the Project Director reporting to EWT LP, but the nature of this reporting (i.e. oversight) was also not clear. Names and resumés were provided only for those leading the functions shown in the project development chart. No names or detailed functions were provided for the construction phase. While the proposed Project Director and Project Manager appear to have extensive operational experience in transmission and other related areas, it is not apparent that they have significant experience in managing major projects first hand. EWT LP confirmed that the Project Manager will be dedicated to the project for the development phase only, while the Project Director will continue to the construction phase. EWT LP proposed that GLPT-EWT will be responsible for managing the development and construction phases of the project on EWT LP's behalf supported by a number of contractors. EWT LP did not provide an operations and maintenance organizational chart and contemplated that the ongoing operation of the facilities will be outsourced to Hydro One Networks Inc. ("HONI"). EWT LP provided an overview of its experience with similar projects which shows extensive experience in the development and construction of large transmission projects in Ontario.

RES (3)

One project organization chart was provided for the project development phase with a project management team representing the key project functions and led by a Project Manager. No charts were provided for the construction or the operation and maintenance phases. The oversight structure above the Project Manager was not clear. Although the proposed project management team appears to have significant relevant experience, RES was non-committal in terms of assigning the key personnel to the project and stated that it will "use its reasonable efforts" to ensure they remain involved. However, in its answer to interrogatory #2, RES confirmed that the Project Manager will be dedicated to the project. Names and resumés were provided for those leading the functions shown in the project chart which showed significant relevant experience. RES also indicated that it will use a "qualified owner's engineer" to augment its design review effort. RES provided an overview of its extensive relevant experience with similar projects. RES did not provide information for the operation and maintenance phase stating that a plan will be prepared during the project development phase.

CNPI (2)

The organizational chart provided initially by CNPI was not a functional chart, but rather a chart of participating organizations. Three charts were provided in answer to interrogatory #1 for the various phases which included key functions. The lead for all three phases (development, construction, operation and maintenance) is provided by an Executive Lead, managing the project on Fortis Inc.'s ("Fortis") behalf, and supported by a number of Fortis personnel as well as Aboriginal advisors. The structure and associated accountabilities below the Executive Lead for the development and construction phases of the project are not clear (i.e. the distinctive role of a Project Manager reporting to an Executive Sponsor, reporting to the Executive Lead). CNPI confirmed that the Executive Lead will be dedicated to the development and completion of the project. A list of proposed management team members was provided with names and resumés but without their specific project function. A long list of "key technical team personnel" was provided which included internal as well as third-party consultants; however, it was not clear to what degree they will all be involved in this project. CNPI also provided an overview of its relevant experience with several transmission projects, mostly involving Fortis.

Iccon/TPT (1)

Iccon/TPT initially proposed that a management committee will govern the general partnership, with the day-to-day management of the partnership provided by a management team reporting to the management committee. The organizational chart provided initially by Iccon/TPT was not a functional chart, but a chart of participating organizations. In its answer to interrogatory #1, Iccon/TPT provided one chart for the development and construction phases of the project showing a General Manager reporting to the management committee with three functions reporting to the General Manager (a Project Director, Legal/Environment/Regulatory, and Controller/Finance). No further detail was provided beyond that level, which hampered the Board in its assessment of the proposed organization's effectiveness. Iccon/TPT did not provide an organizational chart for the operation and maintenance phase of the project. Iccon/TPT proposed that the preliminary engineering, detailed engineering, procurement and construction (EPC) management will be contracted to Isolux Ingenieria, which is an EPC company owned by Isolux Corsan. Iccon/TPT confirmed that the proposed General Manager, who has significant relevant experience, will be dedicated to the project. A "preliminary" list of personnel to be considered for the management team was provided but with no commitment of which personnel would actually be on the team. Iccon/TPT also provided an overview of its relevant extensive experience with similar projects in Canada and globally.

First Nation and Métis Participation

Applicants were required to describe their approach to First Nations and Métis participation in the project. They were asked to indicate whether or not arrangements have already been made and, in either case, to provide further details.

There is a distinction between this criterion (First Nations and Métis Participation) and the criterion addressed later in this decision (First Nations and Métis Consultation). The former arises from Ontario socio-economic policy and the latter is related to a constitutional obligation. Ontario's Long Term Energy Plan states:

> Where new transmission lines are proposed, Ontario is committed to meeting its duty to consult First Nations and Métis communities in respect of their aboriginal and treaty rights and accommodate where those rights have the potential to be adversely impacted. Ontario also recognizes that Aboriginal communities have an interest in economic benefits from future transmission projects crossing through their traditional territories and that the nature of this interest may vary between communities.
>
> There are a number of ways in which First Nation and Métis communities could participate in transmission projects. Where a new transmission line crosses the traditional territories of aboriginal communities, Ontario will expect opportunities be explored to:
>
> - Provide job training and skills upgrading to encourage employment on the transmission project development and construction.
> - Further Aboriginal employment on the project.
> - Enable Aboriginal participation in the procurement of supplies and contractor services.
>
> Ontario will encourage transmission companies to enter into partnerships with aboriginal communities, where commercially feasible and where those communities have expressed interest.

In evaluating the applications in this area, the Board kept in mind the distinction between participation and consultation, and considered the following factors:

- Whether the existing arrangement or plan provides for equity participation by First Nations and Métis communities.
- The extent to which the existing arrangement or plan provides for other economic participation such as training, employment, procurement opportunities, etc. for all impacted communities.
- The degree of commitment to the plan.

The more that an application demonstrably provided opportunities for participation and was committed to that participation, the higher the Board ranked the proponent. Below, the Board identifies the proponents in ranked order for this criterion and provides a brief discussion of the main characteristics of each application.

It should be noted that one of the key considerations in the ranking process was articulated in the Board's Phase 1 Decision and Order which stated:

> The Board will not look more favourably upon First Nation and Métis participation that is already in place at the time of the application than upon a high quality plan for such participation, supported by experience in negotiating such agreements.

AltaLink (6)

AltaLink indicated that it had contacted the18 First Nations and Métis communities identified by the Ministry of Energy as being potentially affected by the project (May 31, 2011 letter), and engaged Ishkonigam (Phil Fontaine) in preparing its participation plan. AltaLink proposed to offer up to 49% equity ownership of the project to affected First Nations and Métis communities, to be held by a single entity in a limited partnership. AltaLink indicated that if requested, it would assist participating First Nations and Métis communities in arranging financing for their equity through independent financial institutions; and if necessary, AltaLink would provide loans. In addition to equity partnership, AltaLink proposed economic participation such as employment, contracting, and training and development. Priority for those forms of economic participation would be given to affected communities. AltaLink believes that no directly or indirectly affected First Nation or Métis community should be excluded; however, its plan provides for different levels of participation depending on the nature of the impact resulting from the project.

EWT LP (5)

One of EWT LP's partners is BLP which consists of six First Nations, all located within 40 km of the existing East-West line. In addition to having one-third equity in the partnership, BLP's participating First Nations will have priority for economic participation in areas such as employment, training, etc. However, according to EWT LP, other First Nations and Métis communities are not precluded from competing to provide goods and services that the participating First Nations may not be able to provide. While EWT LP's plan is good for the six First Nation partners comprising BLP, there are more limited opportunities for other affected First Nations and Métis communities to participate in the various aspects of this project, and no opportunity for equity participation.

CNPI (5)

CNPI has formed a joint venture with Lake Huron Anishinabek Transmission Company Inc. (LHATC). LHATC is made up of 21 First Nations, two of which are on the project's list of affected First Nations. CNPI proposed that LHATC, along with other interested First Nations, will have the right to acquire in aggregate up to 49% equity interest in the project. It was not clear to what extent, if any, CNPI expected the Métis communities to be equity participants. However, CNPI stated that it is prepared to work towards negotiations resulting in meaningful participation by the Métis communities in this project. If needed, CNPI indicated that loans from Fortis could be provided to facilitate participation. CNPI is also prepared to offer First Nations and Métis communities opportunities for employment, apprentice training, preferential consideration for Aboriginal businesses, and a Skill Builder Program. CNPI's economic participation offer goes well beyond the identified affected communities but does not specify what criteria would be used to determine who participates. This has the potential of causing confusion and delay.

UCT (3)

As described in the Organization section of its application, UCT has created an Aboriginal Advisory Board to provide independent oversight in the areas of aboriginal participation and consultation. UCT indicated that it intends to offer negotiated participation in the project to the affected First Nations and Métis communities, including BLP; a partner of EWT LP. It has developed an initial set of approaches (e.g. preferred equity/limited partnership, common equity/limited partnership, lump sum payment, First Nations and Métis Adder) which it intends to explore with affected communities and other stakeholders and to finalize prior to submitting its leave to construct application. Some aspects of the proposals such as lump sum payments and an "adder" are not really in the nature of participation and may cause unanticipated costs for ratepayers. UCT's plan includes economic participation components such as employment, education and training, procurement and contracting, strategic community investment, and access to other supporting programs. UCT provided a participation plan and schedule for each stage of the project (prior to designation, development, construction, and operation), and indicated that priority for these opportunities will be given to affected communities.

RES (3)

RES indicated that it invited the 18 First Nations and Métis communities identified by the Ministry of Energy in the project area to become involved in the development of its participation plan, and that some communities responded. RES provided a First Nations and Métis participation plan, which was supported by former Ontario Grand Chief John Beaucage, and indicated that it is prepared to offer as much as $50 million investment opportunity to affected First Nations and Métis communities, provided that that investment does not exceed 20% equity in the project. As an alternative, RES offered to negotiate Impact Benefits Agreements with those communities, although this type of arrangement may cause unanticipated costs for ratepayers. RES also proposed economic participation by the affected communities in areas such as employment, training, procurement of supplies and services, etc.

Iccon/TPT (1)

Iccon/TPT had initial communication with a number of affected First Nations and Métis communities (9 listed) in the spring of 2011. It provided an Aboriginal Engagement Plan which contained details in areas such as engagement process, capacity funding, Aboriginal working group, Traditional Ecological Knowledge, education and training, employment, contracting, and other areas. Iccon/TPT has not proposed equity participation at this time but indicated that, if selected, it would engage with affected communities as well as those who express an interest. Iccon/TPT described TransCanada's project experience and its role in leading the execution of its Aboriginal Engagement Plan. Iccon/TPT's participation plan is less well-defined than the other applicants' plans and does not distinguish sufficiently between participation and consultation.

Technical Capability

To demonstrate their technical capability to plan, engineer, construct, operate and maintain the East-West Tie line, the applicants were required to provide details regarding their technical resources in various disciplines, resumés of key technical team personnel, a description of experience with relevant projects and activities, and other related information. It should be noted that there is some overlap in the contents of this section and Organization in the applications.

In evaluating the applications in the area of Technical Capability, the Board ranked applicants by considering the following factors:

- Strength of the applicant's internal technical capability. A strong and diverse internal technical capability is considered by the Board to be a desirable feature where the resources are specifically identified, committed, and readily available.
- Strength of the proposed technical team in relevant areas and the clarity of their project roles, including the role of any third-parties. Where the utilization of third-parties is proposed, it is advantageous to identify who they are and what their specific role is.
- Level of experience in similar projects and activities in terms of technical complexity, geography, regulatory process, etc.
- Evidence of solid internal business practices.
- Thoroughness of assessing the technical challenges associated with achieving the required capacity and reliability of the line and the proposed measures to address these challenges.

The more of these characteristics which a proponent demonstrated through its application, the higher the Board ranked the proponent. Below, the Board sets out the proponents in ranked order for Technical Capability and provides a brief discussion of the main characteristics of each application.

UCT (6)

UCT provided details of its strong internal technical capability in the various project functions. For the most part, UCT is proposing to utilize internal resources in all phases of the project, supported by third-party consultants as needed. UCT identified its proposed key technical team members, provided their detailed resumés and described their specific project roles. The proposed technical team demonstrates strong and diverse technical skills with significant relevant project experience. UCT also indicated that its partner NextEra will take the lead role in the operation and maintenance phase of the project. UCT provided information regarding its partners' experience with relevant projects and activities. It also provided many examples where its partners have been recognized by third parties for significant achievements in key business areas. It also described an internal approach to project management consistent with best practices, including work breakdown structure, risk management, and overall project controls. UCT identified what it perceives as potential technical challenges in this project and described its plan for addressing them.

AltaLink (5)

As described under Organization, AltaLink indicated that project planning and development as well as engineering, procurement and construction management services will be provided by SNC Lavalin. Third party contractors are expected to be used in project construction. In addition, local contractors will be used for operation and maintenance under AltaLink's General Manager's direction. AltaLink provided details of its technical capability in the various project functions, mostly from SNC Lavalin, including names, role, and brief descriptions of experience for each of the proposed key technical team personnel. Although the resumés of the team members were not sufficiently detailed to assess the individuals' specific project experience, the proposed team demonstrates good collective relevant experience. Altalink also provided information regarding its (SNC Lavalin's) extensive experience with projects of similar complexity (e.g. in Alberta). It also provided examples of business practices (standards and management systems) in various project areas that it considers to be consistent with good utility practices. It provided a comprehensive list of what it perceives as potential technical challenges in this project and described its plan for addressing them.

EWT LP (4)

EWT LP indicated that it plans to utilize third-party consultants and contractors for significant portions of the work in this project under EWT LP's management and oversight (e.g. engineering, environmental assessment work, land rights acquisition, public engagement, procurement, and construction). It identified many of the consultants and contractors that it plans to utilize and described their areas of expertise. EWT LP also proposes to contract HONI to provide operating services, and may also outsource ongoing maintenance. A list of external technical team members was provided, but their specific project roles were not identified. Also, the internal list was primarily for its proposed management team (see Organization section) as opposed to the key technical team personnel. Information regarding its team's experience with relevant projects and activities was also provided. EWT LP also provided some examples of its partners' business practices in various areas that it considers to be consistent with good utility practices. EWT LP also identified some potential technical challenges and plans to address them.

Iccon/TPT (3)

As described under Organization, Iccon/TPT proposed to contract the engineering, procurement, and construction management (EPC) functions of the project to Isolux Ingenieria, with some contribution from local sub-consultants, under the direction of its General Manager. It also plans to outsource operation and maintenance to one or two companies. Iccon/TPT provided a "preliminary" list of its technical team members, without identifying their specific project roles. A description of its extensive experience with large transmission projects was provided, but did not explain how this experience was relevant to this project in terms of the specific technical challenges. Iccon/TPT provided examples of business practices in various areas that it considers to be consistent with good utility practices. It also provided a short description of what it perceives as potential technical challenges in this project and described its plan for addressing them.

CNPI (2)

CNPI intends to use a mix of internal and external resources in this project. Among the functions to be contracted out partially or fully are engineering/design, construction, operation and maintenance, project management, environmental and regulatory approvals, and community and stakeholder relations. CNPI identified a list of key technical internal (Fortis) and external team personnel and described their areas of expertise, but it was not clear what the specific project role would be for some of them. There also appeared to be some overlap in these roles between internal staff and external consultants. Also, some of the proposed technical team members seem to have limited direct experience with similar projects. CNPI described some of the relevant project experience of Fortis and its other partners, and provided detailed examples of Fortis's business practices in various areas that it considers to be consistent with good utility practices. CNPI also identified, in general terms, what it perceives as potential technical challenges in this project and described its plan for addressing them.

RES (1)

RES intends to use a mix of internal and external resources in this project. Although RES indicated that the vast majority of the work will be done by external resources (approximately 80% of the development budget) with the internal team essentially limited to an oversight role, it was non-committal in terms of who it plans to use. It identified some of the potential external resources that it may utilize in the various project components and described their areas of expertise, but indicated that the actual determination of the specific external service providers will happen at the "appropriate time". RES is proposing that critical roles such as the owner's engineer and EPC contractor will be contracted using a competitive process. RES's significant experience with similar projects was described in detail.

Financial Capacity

Information was required from the applicants to demonstrate that the applicants have the financial capability necessary to develop, construct, operate and maintain the line. The information included capital resources, credit ratings, financing plan, and experience in financing similar projects.

The Board concludes that all the applicants provided information to substantiate that they have solid financial backing and, therefore, financial capacity was not a distinguishing factor among the applicants. All applicants were given the same ranking.

Proposed Design

The applicants were required to provide an overview of some of the characteristics of their proposed design to the extent known at the time of their applications. The Board, in the information it provided to potential applicants, identified a "Reference Option", which was based on the preferred option identified by the OPA and the reference case analyzed by the IESO. The applicants were required to indicate whether their plan for the line was based on the Reference Option, and if not, to describe the differences and to provide a feasibility study for their plan performed by the IESO, or performed to IESO standards. The applicants were also required to highlight the strengths of their plan in terms of innovation, reduction of ratepayer risk, lower cost, local benefits, and enhanced grid reliability.

In this evaluation, the Board will not make determinations on specific technical design issues. Making technical determinations at this point is premature since part of the project development process is to further investigate design options for the purpose of preparing a definitive proposal in the form of a leave to construct application. However, the Board notes the submissions of the IESO and the OPA regarding design, and will consider the adequacy of the design in meeting the need identified by the OPA at the time of the leave to construct proceeding.

Each applicant confirmed that its proposed design meets or exceeds existing reliability standards and the minimum technical requirements for the project, so these factors are not addressed in the following sections. In evaluating the applications in the area of Proposed Design, the Board ranked applicants by considering the following factors:

- Have any innovative alternatives or special design features been proposed, and how significant are their potential benefits?
- Have the proposed design and any alternatives been supported on a preliminary basis and is there an appropriate plan to assess the proposed design and alternatives during development?

The better the approach to these factors which a proponent demonstrated through its application, the higher the Board ranked the proponent. Below, the Board sets out the proponents in ranked order for Proposed Design and provides a brief discussion of the main characteristics of each application.

RES (6)

RES presented two design options: a Reference Design and a Preferred Design. The Preferred Design involves the use of single-circuit transmission line with a combination of single-circuit tubular steel H-Frame structures and single-circuit steel-lattice structures. RES provided a comprehensive comparison of the two designs and indicated that, compared to the Reference Design, the Preferred Design would have superior electrical attributes, lower construction cost (about $80 million), and shorter construction schedule . RES also suggested that a staged installation of transfer capacity with the Recommended Design could result in a significant cost reduction to the ratepayers (approximately $62.5 million). Two feasibility studies, prepared by the IESO for the Reference Design and Preferred Design, were provided.

UCT (6)

UCT evaluated a number of different technology, routing, and structural options. Its Recommended Plan is based on the Reference Option with one major exception which is the use of Guyed-Y towers instead of self-supported steel-lattice towers. UCT stated that the Guyed-Y towers have better lightning performance, a smaller footprint, and a potential cost saving of about $33 million relative to the conventional self-supported steel-lattice towers. The IESO confirmed that the recommended structural change will not impact the existing Reference Plan feasibility study and that a new feasibility study is not required at this time. UCT indicated that Guyed-Y towers are used in several locations in British Columbia, Manitoba, and Quebec. Although these installations are for single-circuit designs, UCT indicated that the double-circuit application has been well researched and will be subject to further testing during the development phase. UCT also provided a consultant's assessment of, among other things, the proposed use of Guyed-Y structures for its Recommended Plan.

EWT LP (4)

EWT LP's proposed design is based on the Reference Option with one exception (40m right-of-way instead of 50m). It also presented three alternative designs; a modified double-circuit reference based design, a single-circuit design, and a single-circuit design with guyed cross-rope suspension type structures. EWT LP has not assessed these alternatives, but indicated that it plans, early in the development phase, to test the key assumptions underlying the Reference-based design and undertake the studies necessary to determine whether a different design can be adopted at a lower cost. EWT LP estimated that these alternative designs have the potential of reducing the project's capital cost by $47 million to $116 million.

AltaLink (3)

Altalink's plan proposed to use the Reference Option, but with some features aimed at reducing the project cost and environmental footprint. One of the main features to be considered is the use of a mix of H-Frame wood pole structures (2 single-circuit structures) in place of double-circuit steel-lattice towers along various parts of the right-of-way. This feature was presented to the IESO and it agreed that no new feasibility study is required. Other features suggested by AltaLink included the use of screw pile foundations for steel-lattice towers (used throughout Alberta according to AltaLink), off-site assembly yards, helicopter erection techniques, sequencing of construction work, and alternatives for cost recovery. AltaLink's plan was not specific, however, in terms of how some of these concepts (e.g. H-Frames) will be assessed.

Iccon/TPT (2)

Iccon/TPT's plan is based on the Reference Option. Iccon/TPT identified a number of possible innovative measures to be explored during the development phase including the design and testing of a new tower family specifically engineered for this project, the use of different materials, reducing the number of "dead ends", and designing lattice towers that span above the tree tops. Iccon/TPT presented limited supporting information or analysis for these proposals.

CNPI (1)

CNPI's plan is based on the Reference Option. CNPI has not identified any proposed design innovations or cost reduction measures.

Schedule

The applicants were required to provide an overall project execution chart showing major milestones for both the development and construction phases of the project. They were also asked to provide detailed schedules for both phases with estimated completion dates, as well as the proposed consequences for failure to meet key milestone dates. In addition, they were required to provide a description of major risks associated with meeting these schedules, and their plan to mitigate these risks. Evidence of past schedule performance in similar projects, as well as any proposed innovative practices to meet or accelerate the project development and construction were also requested. For proper comparison of dates and durations, the duration of the development phase of the project is defined as the period from the designation decision to the leave to construct application. It should be noted that the applicants were not ranked higher or lower based on their proposed project durations. The proposed construction phase schedules are only indicative at this stage and do not constitute a commitment on the part of the applicants. As for the development phase schedules, there is no specific benchmark as to what an appropriate duration may be. However, the Board notes that for the more aggressive schedules, the applicants would still be required to complete all the necessary work for purposes of completing the Environmental Assessment and leave to construct processes (including consultation) in an appropriate manner and would be at risk for any additional costs which result from schedule delays.

In evaluating the applications for the criterion of Schedule, the Board considered the following factors:

- Level of detail and clarity of the project execution chart and schedules.
- Demonstrated ability to identify the major risks impacting these schedules and a description of how these risks will be mitigated.
- The planned approach to achieving the proposed completion dates.

- Level of commitment to the proposed schedules, proposed reporting requirements, and proposed consequences for failure to meet key milestones.
- Past schedule performance for similar projects. It should be noted that the applicants were asked in interrogatory #32 to provide more specific information about past schedule performance for large transmission projects (greater than 100 km in length) over the past 10 years. This information is factored into the following evaluation. The Board's assessment of past schedule performance was qualitative in nature considering the fact that there were variations among the applicants in terms of when the project schedules were established and the reasons for the variances.

The Board's ranking was based on how well the proponents demonstrated the above characteristics. Below, the Board sets out the proponents in ranked order for Schedule and provides a brief discussion of the main characteristics of each application.

UCT (6)

UCT provided a clear, detailed schedule for both phases of the project with key milestones. Its proposed completion date for the development phase is October 2014, assuming designation by May 2013 (i.e. duration of approximately 18 months). The proposed in-service date is December 2017. UCT explained that its proposed overall schedule (development and construction) can be accomplished using parallel work streams and other measures. A comprehensive list of what UCT considers to be major schedule risks and mitigating measures was provided. UCT proposed a monthly progress reporting process. Although UCT did not propose specific consequences for failure to meet major milestones, it did suggest a process for notifying the Board of potential milestone delays and mitigating measures before they occur. UCT provided a description of past performance in a number of projects which showed very good schedule performance as most of the cited projects were completed on or ahead of schedule.

EWT LP (5)

EWT LP provided a high level schedule for the overall project and a more detailed schedule for the development phase with key milestones. Its proposed completion date for the development phase is March 2016, assuming designation by August 2013 (i.e. duration of approximately 32 months). The proposed in-service date is November 2018. A comprehensive list of what EWT LP considers to be major schedule risks and mitigating measures was provided. EWT LP proposed a bi-annual progress reporting process which is likely insufficient. It also proposed possible ultimate consequences for failure to meet major milestones in the development phase which would only be warranted for the "most egregious failures". EWT LP provided a description of past performance in a number of projects which showed average schedule performance.

Iccon/TPT (4)

Iccon/TPT provided a high level schedule for both the development and construction phases as well as a more detailed schedule for the development phase. Its proposed completion date for the development phase is February 2015, assuming designation by July 2013 (i.e. duration of approximately 18 months). Iccon/TPT indicated that its relatively short development schedule is achievable subject to meeting certain milestones for items which are beyond its control such as regulatory approvals. The proposed in-service date is October 2018. A detailed list (risk register) of what Iccon/TPT considers to be major schedule risks and mitigating measures was provided for the overall project. Iccon/TPT did not provide any detail about progress reporting or potential consequences for missing major schedule milestones. Iccon/TPT provided a description of past performance in a number of projects showing schedule performance by quarter. Iccon/TPT in its answer to interrogatory #32 provided additional information for major transmission projects which showed average schedule performance.

AltaLink (3)

AltaLink provided a high level schedule for both the development and construction phases as well as a more detailed schedule for the development phase. Its proposed completion date for the development phase is June 2014, assuming designation by April 2013 (i.e. duration of approximately 14 months). The proposed in-service date is November 2018. AltaLink's proposed development schedule seems to be on the optimistic side which, according to AltaLink, is achievable given what it described as a significant amount of "pre-development work" completed before submitting its application. A short list of what AltaLink considers to be major schedule risks and mitigating measures was provided for the overall project. AltaLink proposed a bi-monthly progress reporting process but did not provide details about potential consequences for missing major schedule milestones. AltaLink provided a description of past schedule performance in a number of projects which did not show good performance. In the original application, AltaLink stated that, for projects completed in 2010, it came within one month of the estimated preliminary in-service date 20% of the time. For the four projects listed in response to interrogatory #32, two are in the construction stage and are on schedule and the other two are significantly (11 to 26 months) behind schedule.

CNPI (2)

CNPI provided a high level schedule for the construction phase of the project as well a more detailed table for the development phase with key milestones. Its proposed completion date for the development phase is May 2015, assuming designation by April 2013 (i.e. duration of approximately 25 months). The proposed in-service date is December 2019. A list of what CNPI considers to be major schedule risks and mitigating measures was provided. CNPI proposed a quarterly progress reporting process with a limited level of detail which is likely insufficient. It also proposed potential consequences for missing major milestones involving extreme cases of negligence. CNPI also mentioned that a bonus/penalty scheme for contractors could be considered during the construction phase. CNPI initially provided a description of past schedule performance in a number of projects which showed good performance. However, the additional information provided by CNPI in response to interrogatory #32 showed average schedule performance.

RES (1)

RES provided a high level schedule for both the development and construction phases as well as a more detailed schedule for the development phase. Its proposed completion date for the development phase is June 2015, assuming designation by June 2013 (i.e. duration of approximately 25 months). The proposed in-service date is December 2018. A list of what RES considers to be major schedule risks and mitigating measures was provided for the overall project. RES proposed various progress reporting intervals and detail level (weekly, monthly, and quarterly). RES also provided a description of past schedule performance in a number of projects which did not show good performance. Three projects were listed in response to interrogatory #32, all of which were significantly late (12 to 32 months).

Cost

The applicants were required to provide estimated costs for the development, construction, and operation and maintenance phases of the project. Further details were required for development costs including a cost breakdown, assumptions used, expenditure schedule, as well as risk assessment, mitigation and allocation. The construction cost estimate could be expressed as a range. The applicants were also required to provide information regarding risk and mitigation measures for the construction phase, information on cost performance for past projects, and proposals for how construction cost risk could be allocated between ratepayers and the applicant. For the operation and maintenance phase, the applicants were required to provide their estimated average annual cost, which could also be expressed as a range.

In order to facilitate cost comparison among applicants, they were asked in an interrogatory to provide the three cost estimates (development, construction, and operation and maintenance) broken down in certain common components, and to be expressed in 2012 dollars. This was intended to assist the Board in comparing the cost estimates on an equivalent basis, particularly the development phase budget. They were also required to provide more specific information about past cost performance for large transmission projects (greater than 100 km in length) over the past 10 years.

By designating one of the applicants, the Board will be approving the development costs, up to the budgeted amount, for recovery. The School Energy Coalition submitted that there is insufficient information for the Board to determine that the development costs are just and reasonable. The Board does not agree. The Board has had the benefit of six competitive proposals to undertake development work. In the Board's opinion, the competitive process drives the applicants to be efficient and diligent in the preparation of their proposals. With the exception of Iccon/TPT, the development cost proposals ranged from $18.2 million to $24.0 million which is relatively narrow given the overall size of the project. Therefore, the Board finds that the development costs for the designated transmitter are reasonable, and will be recoverable subject to certain conditions.

In evaluating the applications in the area of Cost, the Board ranked applicants by considering the following factors:

Development Cost

- Rank order of the cost estimate.
- Clarity and completeness of the cost estimate.
- Thoroughness of the risk assessment and mitigation strategy.
- Any proposal for allocation of the development cost risk which could benefit ratepayers.

Construction Cost

- Clarity and completeness of the cost estimate.
- Thoroughness of the risk assessment and mitigation strategy.
- Any proposal for allocation of the construction cost risk which could benefit ratepayers.
- Past cost performance for similar projects.

Operation and Maintenance Cost

- Clarity and completeness of the cost estimate.

The Board's ranking was based on how thoroughly the proponents demonstrated the above characteristics. Below, the Board sets out the proponents in ranked order for Cost and provides a brief discussion of the main characteristics of each application.

Unless stated otherwise, all cost estimates presented in this section are in 2012 dollars. The cost estimates are provided below to the nearest $0.1 million for the development cost, $1 million for the construction cost, and $0.1 million for the operation and maintenance cost.

AltaLink (6)

AltaLink's development cost estimate is $18.2 million (the lowest among the applicants). Its construction cost estimate is $454 million and its estimated annual operation and maintenance cost is $1.7 million. AltaLink did not provide an expenditure schedule for the development cost. It provided a combined risk list and mitigation measures for the project's cost and schedule. AltaLink suggested two alternatives for dealing with development cost variances; the first is to seek recovery of incurred cost subject to prudence review, and the second is a risk/reward model where variances of up to 10% are shared 50/50, and variances above or below 10% are subject to prudence review. It also presented three alternatives for construction cost recovery; a traditional cost of service model, a negotiated target price with 50/50 risk/reward sharing up to a pre-determined cap (e.g. 10%) with costs in excess of the cap subject to prudence review, and a lump sum fixed price. AltaLink provided a general description of past performance in a number of projects, but the level of granularity was insufficient to make a definitive assessment (i.e. AltaLink indicated that the collective cost performance of 112 projects was within 10% of the total estimate but did not provide specific individual project information).

UCT (6)

UCT's development cost estimate is $22.2 million (third lowest among the applicants) which is the same for the Reference Plan and Recommended Plan. Its construction cost estimate is $409 million for the Reference Plan and $378 million for the Recommended Plan. Its estimated annual operation and maintenance cost is $4.4 million. UCT provided an expenditure schedule for the development costs as well as a detailed description of associated risks and mitigating measures. UCT proposed that the project's development phase be treated as a cost of service case whereby any expenditure in excess of the approved budget would be recoverable, subject to a prudence review. UCT's construction cost estimate is the mid-point of anticipated range of costs. The only cost difference between the Reference Plan and the Recommended Plan is the use of Guyed-Y steel-lattice towers instead of self-supported steel-lattice towers. UCT presented a detailed description of the risks associated with the construction phase and its plan to mitigate these risks. UCT indicated that, at the project's leave to construct stage, it will present to the Board a proposal for performance-based ratemaking for the project's construction phase. UCT provided a description of past performance in a number of projects which showed average cost performance.

RES (4)

RES's development cost estimate is $21.4 million which is essentially the same for the Reference Design and the Preferred Design (second lowest among the applicants). As stated in its application, its construction cost estimate is $472 million ($2013) for the Reference Option / Preliminary Preferred Route and $392 million ($2013 according to its application and $2012 according to its response to interrogatory #26) for the Preferred Design / Preliminary Preferred Route. However, the submission from HONI suggested that the amounts estimated for the cost of work necessary at HONI's stations was not developed in consultation with HONI. RES' estimated annual operation and maintenance cost is $2.2 million for the Preferred Design and $2.8 million for the Reference Design (the latter not included in the original application). RES provided an expenditure schedule for the development cost as well as a description of associated risks and mitigating measures. RES stated in its application that it is prepared to offer a firm development and construction price of $413 million ($2013) for the preferred design / preferred route option or $494 million ($2013) for the reference design / preferred route option, based on an incentive bonus / penalty methodology. RES presented a description of the risks associated with the construction phase and its plan to mitigate these risks. RES also provided a description of past performance in a number of projects which showed average cost performance.

EWT LP (3)

In EWT LP's application, the development cost estimate was $22.1 million and the construction cost estimate was $427 million for the double circuit option. It was not clear whether these cost estimates were escalated or not. EWT LP indicated in its application that the accuracy of it estimates is ±8% and ±22% for the development and construction costs, respectively. In response to interrogatory #26, EWT LP increased its development cost estimate to $23.7 million in $2012 (third highest among the applicants) and also increased the construction cost estimate for the double circuit option to $490 million in $2012. It also provided a construction cost estimate for the single circuit option ($350 million in $2012), but the submission from HONI suggested that the amounts estimated for the cost of work necessary at HONI's stations was not developed in consultation with HONI. EWT LP's estimated annual operation and maintenance cost is $7.1 million. EWT LP explained in its application that this estimate includes $1.9 million for "Administration and General" which, if excluded with its share of the contingency, would bring their estimate down to $4.9 million/year. EWT LP provided an expenditure schedule for the development cost as well as a detailed description of associated risks and mitigating measures. EWT LP did not propose any risk sharing arrangements with benefits for ratepayers. EWT LP also presented a detailed description of the risks associated with the construction phase and its plan to mitigate these risks. EWT LP provided a description of past performance in a number of projects which showed below average cost performance.

CNPI (2)

CNPI's development cost estimate is $24.0 million (second highest among the applicants) and its construction cost estimate is $527 million. In its application, CNPI's estimated annual operation and maintenance cost was approximately $1.0 million, but was increased to $1.7 million in response to interrogatory #26 to account for administration and regulatory costs that CNPI indicated were not included in the initial estimate. CNPI provided an expenditure schedule for the development cost as well as a brief description of associated risks and mitigating measures. CNPI did not propose any risk sharing arrangements with benefits for ratepayers. CNPI presented a brief description of the risks associated with the construction phase and its plan to mitigate these risks. CNPI provided a description of past performance in a number of Fortis projects which showed average cost performance.

Iccon/TPT (1)

In Iccon/TPT's application, the estimated development cost was $45.5 million (highest among the applicants). It was not clear in the application whether this cost estimate was escalated or not. This estimate was reduced by Iccon/TPT in response to interrogatory #26 to $30.7 million. Iccon/TPT explained that, in addition to de-escalation, the difference is due to the fact that the earlier estimate included post leave to construct activities. Iccon/TPT's construction cost estimate is $487 million and its estimated annual operation and maintenance cost is $4.9 million. Iccon/TPT provided an expenditure schedule for the development cost as well as a combined risk register for both the development and construction phases. For development costs, Iccon/TPT did not propose any risk sharing arrangements with benefits for ratepayers. To reduce construction cost risk, Iccon/TPT intends to enter into a fixed fee EPC contract with Isolux Ingenieria. Iccon/TPT provided a description of past performance in a number of projects which showed average cost performance.

Landowner, Municipal, and Community Consultation

The applicants were required to demonstrate their ability to conduct successful consultations with landowners, municipalities and local communities, and to provide a consultation plan including potential significant issues and mitigating measures. Additional details such as an overview of land rights acquisition activities and a description of any proposed route, or plan for identifying a route, were also requested.

In evaluating the applications in this area, the Board ranked applicants by considering the following factors:

- Clarity of the consultation plan, including methodology and schedule.
- The breadth and scope of potential significant stakeholder issues identified and the suitability of proposed mitigating measures.
- Adequacy of the description of the line route (or alternatives) and demonstrated appreciation of challenges involved in the route(s).

The more of these characteristics which a proponent demonstrated through its application, the higher the Board ranked the proponent. Below, the Board sets out the proponents in ranked order for this criterion and provides a brief discussion of the main characteristics of each application.

EWT LP (6)

EWT LP provided a comprehensive consultation plan as part of the description of its proposed environmental assessment process, which included a description of key elements and a list of stakeholders. The plan conveyed a clear picture as to how consultations would be conducted and how the communities would be approached. Details regarding land use rights acquisition approach by category, potential issues and proposed mitigation were provided. For the purposes of the application, EWT LP assumed a route adjacent to the existing line but indicated that the final route will be based on consultation with landowners, municipalities and communities. A detailed study of potential routes was provided where potential route options were identified and described, including the evaluation criteria, process, and a proposed schedule for route selection.

RES (5)

RES provided a consultation plan that included a schedule, issue identification and resolution strategy. The plan provided for the formation of a Municipal Advisory Group, if appropriate. RES provided an overview of the required land use rights and a two-phase plan for acquiring these rights (pre and post leave to construct). A detailed land valuation and acquisition plan was provided. Potential significant issues and mitigating measures were also identified. RES identified a preliminary preferred route and stated that some route refinements may be required as a result of stakeholder consultation.

UCT (5)

UCT provided a consultation plan which included a list of stakeholders, consultation activities and schedule. UCT also provided a mitigation strategy to deal with significant issues. It also provided a land acquisition plan which included methodology for various types of land rights as well as an approach to compensation and mitigation. One of the mitigating measures is to identify three route variances to the proposed route as contingencies. UCT identified a 3-stage approach to route determination; conceptual (already completed), preliminary, and final.

AltaLink (3)

A consultation plan was provided as part of AltaLink's draft environmental assessment terms of reference, including methods and schedules. AltaLink provided a list of required land use rights for the various project phases and a plan to obtain these rights, including compensation principles. Some issues associated with obtaining these rights were identified and a plan to address them was provided based on AltaLink's experience in Alberta. Altalink's plans were generic in nature rather than specific to this project. AltaLink identified a proposed route and some of the environmental constraints associated with it, subject to detailed design, environmental assessment, and stakeholder input.

CNPI (2)

A brief consultation plan was provided for the different project phases, including potential issues and mitigation. CNPI provided a brief description of the various categories of right-of-way and land use rights and its plan for obtaining these rights. A short list of potential issues associated with land acquisition and permitting was provided and mitigating measures proposed. Although the proposed route has been identified, CNPI is prepared to consider an alternate route.

Iccon/TPT (1)

A description of the proposed consultation plan was provided which was generic and brief. Iccon/TPT provided an overview of the required land use rights in the various project phases and a plan for acquiring these rights. A brief description of associated risks and mitigating measures was also provided. Iccon/TPT has not identified a planned route for the line at this time, but has conducted a routing analysis and identified several potential routing corridors. A methodology and decision criteria were described which will be used to evaluate these routing options during the development of the terms of reference for the environmental assessment.

First Nations and Métis Consultation

The duty to consult, as described in the Supreme Court decision *Haida Nation* v. *British Columbia (Minister of Forests)*[2], arises where the Crown has knowledge, real or constructive, of the potential existence of Aboriginal right or title and contemplates conduct that might adversely affect it. In some cases, the duty to consult may lead to a duty to accommodate. The precise extent of the duty to consult and, possibly, accommodate will vary depending on the facts of each situation. The Crown can

[2] [2004] 3 S.C.R. 511

delegate certain aspects of consultation to a project proponent. The Deputy Minister of Energy issued a letter on November 26, 2012 stating the Ministry's expectation that the designated transmitter will enter into a Memorandum of Understanding with the Ministry that will set out the respective roles and responsibilities of the Crown and the transmitter in consultation. None of the applicants objected to this requirement.

The applicants were required to demonstrate their ability to conduct successful First Nation and Métis consultations and to provide a consultation plan including a list of affected First Nations and Métis communities. They were also required to describe their engagement approach as well as potential significant issues and mitigating measures.

In evaluating the applications in this area, the Board ranked proponents by considering the following factors:

- Clarity and comprehensiveness of the proposed consultation plan, including methodology and schedule.
- Identification of potential significant issues and proposed mitigating measures.
- Relevant successful past experience.

The Board's ranking is based on how well the proponents demonstrated the above characteristics. Below, the Board sets out the proponents in ranked order for this criterion and provides a brief discussion of the main characteristics of each application.

UCT (6)

UCT provided a comprehensive consultation plan for all project phases (pre-designation to operation). A record of actual communication (letters, phone calls) with the 18 affected communities was provided as well as a list of potential key issues and proposed mitigation. UCT referenced NextEra's First Nations and Métis Relationship Policy and Enbridge's Aboriginal and Native American Policy as the basis for its plan. UCT described existing relationships with a number of First Nations and Métis communities who would be engaged as part of this project. UCT also described its relevant past experience with a number of projects involving the engagement, consultation and economic participation of First Nations and Métis communities.

EWT LP (5)

EWT LP provided a comprehensive consultation and communication plan and stated that it will commence consultation upon designation. A comprehensive list of expected issues was provided and mitigating measures were suggested. Relevant past experience with consultation activities was described which involved EWT LP's partners and consultants. EWT LP indicated that the consultation process would be facilitated by BLP. Having some of the affected First Nations lead the consultation process with other affected First Nations and Métis communities on behalf of the owners may give rise to fairness concerns which would need to be addressed.

AltaLink (5)

Altalink provided a preliminary consultation plan including steps and milestones and indicated that the final plan will be developed and agreed to jointly with each of the communities. It also provided a plan for the Traditional Ecological Knowledge and Traditional Land Use studies for the project. AltaLink indicated that all 18 affected communities were contacted in 2012, and that it met with 12 of them (excluding the 6 involved with BLP). A short list of potential issues was provided as well as a general description of possible mitigation. AltaLink described its longstanding relationship and engagement approach with the Aboriginal communities in Alberta as well as SNC Lavalin's experience in Ontario and Manitoba.

RES (3)

RES provided a detailed but generic consultation plan and identified potentially affected First Nations and Métis communities which included the previously identified 18 communities plus others. RES contacted all 18 plus one more, met with three of them and received correspondence from two others. RES identified a short list of potential issues and a plan to deal with these issues. RES described its experience with similar consultation in a number of projects in Canada and the U.S.A.

Iccon/TPT (2)

Iccon/TPT provided a general engagement plan as well as a record of actual communication with some of the affected First Nations and Métis communities. A list of potential significant issues and a preliminary plan to address them were also provided. Iccon/TPT indicated that it plans to contract with TransCanada's Aboriginal and Stakeholder Engagement Group to lead its First Nations and Métis Consultation process in this project. Iccon/TPT's plan was less comprehensive than plans filed by other applicants and, as mentioned earlier, does not effectively distinguish between participation and consultation.

CNPI (1)

CNPI indicated that some contacts have been made with affected communities (the 2 involved in LHATC plus 6 others), but that all 18 affected communities will be included in the consultation process. CNPI stated that an Aboriginal Consultation and Engagement Plan will be developed at the start of the environmental assessment process. The application included only a very high level summary consultation plan identifying some potential issues and possible generic mitigating measures. The plan lacked the detail contained in the plans of other applicants. Relevant recent experience was described with some Fortis projects and other related activities.

CONCLUSION

Based on the evaluation methodology described earlier, and the ranking given to each applicant for the various decision criteria, the Board has determined the total score and the resulting overall ranking of the applicants, as shown below. Note that the maximum possible score is 540:

1. UCT (455)
2. EWT LP (385)
3. AltaLink (385)
4. RES (280)
5. CNPI (200)
6. Iccon/TPT (185)

Therefore, the Board has decided that the designated transmitter for the development phase of the proposed East-West Tie line is UCT. UCT either ranked first or was tied for first in 7 of the 9 decision criteria. AltaLink and EWT LP are tied. EWT LP stated that it is not willing to be named runner-up, and the Board names AltaLink as the runner-up.

The Board finds that the development costs budgeted by UCT of $22,187,022 (in $2012) are reasonable. The Board will establish a deferral account in which UCT is to record the actual costs of development. The Board expects that UCT, at the time it applies for leave to construct the East-West Tie line, will file a proposal for the disposition of the development cost account.

The licence of UCT will be amended to have an effective date and to include special conditions regarding reporting to the Board. The Board notes that per Section 3.1.1. of the Reporting and Record-keeping Requirements, UCT will be required to report balances in the deferral account to the Board on a quarterly basis.

UCT proposed certain milestones at page 100 of its application, and at page 59 of its argument in chief indicated that the milestones proposed by Board staff at page 4 of its Phase 2 submission were directionally appropriate. The Board requires UCT to prepare a revised schedule of development milestones including those from its application, as well as the milestones proposed by Board staff. In addition, UCT shall include proposed milestones related to: the development and finalization of its First Nations and Métis participation plan; progress on landowner, municipal and community consultation; progress on First Nations and Métis consultation; and progress towards finalization of structure engineering work and final choice of structure design. If any of these milestones are, for UCT's development plan, impractical or not demonstrative of progress, UCT may omit or rephrase the milestone and provide an explanation for the proposed change.

As part of the schedule of milestones, UCT must also indicate what filing, form or other document could be offered as proof of completion of the milestone if the Board so required. For example, UCT proposed the milestone "Substantial Land / Right-of-Way Rights Acquired". What could be filed with the Board if the Board called upon UCT to demonstrate successful completion of that milestone? The schedule of milestones should be provided in the following format:

Milestone	Proof of Completion	Target Date

A consequence of this designation decision is that, if it meets its obligations, UCT will be able to recover the costs of project development (up to the budgeted amount) from transmission ratepayers, even if the final assessment of need indicates that the line is no longer required. The Board therefore believes that it is important to limit the risk to ratepayers from unnecessary development work. The Board recognizes that the OPA reaffirmed the continuing need for the East-West Tie line in its Phase 2 submission, but also notes that the OPA offered to provide a more detailed need assessment after the designation decision. The Board will require the OPA to file a schedule for the production of an early detailed need update (for example, 60 days from the date of this decision) and a further need update at the approximate mid-point of the development work. The Board recognizes that a final need assessment will also form part of the leave to construct application. The OPA's proposed schedule should be developed in consultation with UCT to co-ordinate with the development schedule.

The Board therefore orders that:

1. The licence of UCT is amended to have an effective date of August 7, 2013, with a term of 20 years.

2. The following special conditions will be included in the licence:

    a) UCT shall report to the Board on a monthly basis, beginning no more than 60 days from the date of this decision and ending when a leave to construct application is filed for the East-West Tie line, on the following matters:

        i. Overall project progress: An executive summary of work progress, cost and schedule status, and any emerging issues/risks and proposed mitigation.
        ii. Cost: Actual cost and cost variance relative to the original project budget, as well as an updated budget forecast projected

out to a leave to construct application. A description of the reasons for any projected variances and mitigating measures should be provided. The report must also indicate the percentage of budgeted development costs spent as at the time of the report.

iii. Schedule: The milestones completed and the status of milestones in-progress. For milestones that are overdue or delayed, the reasons for the delay, the magnitude and impact of the delay on the broader development schedule and cost, and any mitigating steps that have or will be taken to complete the task.

iv. Risks and Issues Log: An assessment of the risks and issues, potential impact on schedule, cost or scope, as well as potential options for mitigating or eliminating the risk or issue.

b) UCT shall advise the Board immediately of any change to its governance, or any change in its financial status, that adversely affects or is likely to adversely affect the completion of the East-West Tie line.

3. UCT shall, within 21 days of the date of this decision, file for review and approval of the Board a revised development schedule, identifying milestones, proposed proofs of completion and target completion dates as described above. The time span for the activities in the schedule must be consistent with the schedule filed in UCT's application, taking into account the actual date of this decision.

4. A deferral account is established for UCT in which the actual costs of development of the East-West Tie line are to be recorded, from the date of this decision up to the filing of a leave to construct application, or such other time as the Board may order. The account shall include sub-accounts for the development activities listed in Attachment 1 to UCT's response to interrogatory 26 in this proceeding.

5. UCT shall, within 21 days of the date of this decision, file for review and approval of the Board a draft accounting order for the account and sub-accounts described

in paragraph 4, with detailed descriptions of the account and sub-accounts and how they will be used.

The Board further orders that:

1. The OPA shall, within 21 days of the date of this decision, file with the Board a schedule for the production of an early detailed need update and a further need update at the approximate mid-point of development work, as described above.

The Board further orders that:

1. The cost awards to eligible intervenors and the Board's own costs will be recovered from licensed transmitters whose revenue requirements are presently recovered through the Ontario Uniform Transmission Rate (and the costs will be apportioned among the transmitters based on their respective transmission revenues).

2. Eligible parties shall submit their cost claims for Phase 2 of the designation proceeding by August 28, 2013. A copy of the cost claim must be filed with the Board and one copy is to be served on each of Canadian Niagara Power Inc., Five Nations Energy Inc., Great Lakes Power Transmission LP and Hydro One Networks Inc.

3. Canadian Niagara Power Inc., First Nations Energy Inc., Great Lakes Power Transmission LP and Hydro One Networks Inc. will have until September 16, 2013 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

4. The party whose cost claim was objected to will have until September 25, 2013 to make a reply submission as to why its cost claim should be allowed. A copy of the submission must be filed with the Board and one copy must be served on the party who objected to the claim.

DATED at Toronto, August 7, 2013
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO BOARD DECISION AND ORDER

EAST-WEST TIE LINE DESIGNATION - PHASE 2

BOARD FILE NO.: EB-2011-0140

DATED August 7, 2013

LIST OF INTERVENORS

EAST-WEST TIE LINE DESIGNATION - PHASE 2

BOARD FILE NO.: EB-2011-0140

DATED August 07, 2013

LIST OF INTERVENORS

REGISTERED TRANSMITTERS:

AltaLink Ontario, LP

Canadian Niagara Power Inc.

EWT LP

Iccon Transmission, Inc.

RES Canada Transmission LP

TransCanada Power Transmission (Ontario) L.P.

Upper Canada Transmission, Inc.

Please note: Each of Iccon Transmission Inc. and TransCanada Power Transmission (Ontario) L.P. acted as intervenors in Phase 1 of the proceeding, but filed a joint application in Phase 2.

OTHER INTERVENORS:

Association of Major Power Consumers in Ontario

BayNiche Conservancy

Building Owners and Managers Association Toronto

Canadian Manufacturers and Exporters

City of Thunder Bay and Northwestern Ontario Associated Chambers of Commerce and Northwestern Ontario Municipal Association Energy Task Force

Consumers Council of Canada

Enbridge Inc.

Energy Probe Research Foundation

Great Lakes Power Transmission EWT LP

Great Lakes Power Transmission LP

Hydro One Inc.

Hydro One Networks Inc.

Independent Electricity System Operator

Lake Superior Action-Research-Conservation

Métis Nation of Ontario

Municipality of Wawa and the Algoma Coalition

National Chief's Office on Behalf of the Assembly of First Nations

Nishnawbe-Aski Nation

Northwatch

Ojibways of Pic River First Nation

Ontario Power Authority

Power Workers' Union

School Energy Coalition

Mr. Rod Taylor

APPENDIX B

TO BOARD DECISION AND ORDER

EAST-WEST TIE LINE DESIGNATION - PHASE 2

BOARD FILE NO.: EB-2011-0140

DATED August 7, 2013

PHASE 1 DECISION AND ORDER

Ontario

EB-2011-0140

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

BEFORE: Cynthia Chaplin
Presiding Member and Vice-Chair

Cathy Spoel
Member

PHASE 1 DECISION AND ORDER

July 12, 2012

INTRODUCTION

On February 2, 2012, the Ontario Energy Board issued notice that it was initiating a proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line. The Board assigned File No. EB-2011-0140 to the designation proceeding. Seven transmitters registered their interest in the designation process.

The Board developed the Framework for Transmission Project Development (EB-2010-0059) (the "Policy") as a way to encourage the timely development of electric transmission construction in Ontario. A number of transmission projects were expected to be identified by the Ontario Power Authority ("OPA") through an Economic Connection Test or an Integrated Power System Plan to accommodate the connection of renewable generation. The designation process outlined in the Policy has, nevertheless, been adopted by the Board in this proceeding for a single bulk transmission line that was identified in the Minister's Long Term Energy Plan to address reliability issues. The East-West Tie line will run between Thunder Bay and Wawa, and connect to the bulk transmission system in Northern Ontario at transformer stations owned by Hydro One Networks Inc. ("HONI").

This designation proceeding represents an evolving process as the Board applies the Policy for the first time. The Board has adopted a two phase process for the designation proceeding. In Phase 1, which is the subject of this decision and order, the Board establishes specifics for the proceeding including decision criteria, filing requirements, obligations and consequences arising on designation, the hearing process for Phase 2 and the schedule for the filing of applications for designation.

In Phase 2, the registered transmitters will have an opportunity to file their applications for designation, and the Board intends to select one of them as the designated transmitter through a hearing process. The Board notes that this proceeding is voluntary on the part of the registered transmitters and intends that this Phase 1 decision and order will assist them in deciding whether to make an application for designation in Phase 2. The Board will not, at this stage, compel any transmitter to file a plan for the line.

It is important to remind participants of the limited scope of this process, which is the selection of a designated transmitter to do development work for the East-West Tie line. The final determination of the need for the line will be considered in a subsequent leave to construct proceeding. In general, environmental matters are not within the mandate of the Board and the necessary environmental assessment will be conducted in another forum.

THE PROCEEDING

On February 2, 2012, the Board issued a Notice of Proceeding for this designation proceeding. On March 9, 2012, the Board issued Procedural Order No. 1, granting intervenor status to the seven transmitters registered in this proceeding, namely: AltaLink Ontario, L.P. (“AltaLink”); Canadian Niagara Power Inc. (“CNPI”); EWT L.P.; Iccon Transmission Inc. (“Iccon”); RES Canada Transmission L.P. (“RES”); TransCanada Power Transmission (Ontario) L.P (“TPT”); and Upper Canada Transmission, Inc. (“UCT”).

The Board’s Decision on Intervention and Cost Award Eligibility, dated March 30, 2012, and the Board’s Procedural Order No.2, dated April 16, 2012, granted intervenor status to 24 parties (or, in some instances, groups of parties) and cost award eligibility for the proceeding to nine of those parties. The matter of costs is discussed in further detail at the end of this decision.

Procedural Order No. 2 included the Board-approved issues list for Phase 1. On June 14, 2012, the Board issued its Phase 1 Partial Decision and Order to deal specifically with issue 19 of the issues list. This decision ordered HONI and Great Lakes Power Transmission LP (“GLPT”) to file with the Board, and provide to other parties, certain documents in their possession which may be relevant to the development of the East-West Tie line. This decision addresses the other issues identified for Phase 1 of the proceeding.

BOARD FINDINGS ON THE ISSUES

The Board’s primary objective in this proceeding is to select the most qualified transmission company to develop, and to bring a leave to construct application for, the East-West Tie line. The Board recognizes that the key to achieving this objective is the establishment of an efficient and transparent competitive process that avoids bestowing any unfair advantage upon a particular applicant or group of applicants. The Board’s view is that competition is best served by creating an open, fair and cost-efficient proceeding that encourages multiple qualified proponents to participate. The Board has considered each of the issues in this light.

Decision Criteria: Issues 1 – 4

Issue 1. What additions, deletions or changes, if any, should be made to the general decision criteria listed by the Board in its policy Framework for Transmission Project Development Plans (EB-2010-0059)?

For the reasons given under issues 1 to 4, the Board's criteria for this designation process are:

- Organization
- First Nation and Métis participation
- Technical capability
- Financial capacity
- Proposed Design for the East-West Tie line
- Schedule
- Costs
- Landowner, municipal and community consultation
- First Nation and Métis consultation
- Other factors

Original criteria

There was general support among the parties for the retention of the original criteria from the Policy. The Board agrees that these original criteria remain valid for the East-West Tie line project, and will retain the following criteria in their original form: organization, technical capability, financial capacity, schedule, costs, and other factors. The criterion "landowner and other consultations" will be subdivided, as described below.

Several parties suggested that the Board provide guidance as to the way in which it would asses the criteria "cost" and "other factors". Regarding cost, the Board acknowledges, as several parties observed, that one of the purposes of the development work itself will be the estimation of construction and operation and maintenance costs, and that therefore applicants for designation will likely not be in a position to provide an accurate estimate of construction and operating and maintenance costs at the time of their application. Nevertheless, the Board finds that it must consider all costs in assessing the merits of the various applications. Providing benefit to ratepayers through economic efficiency is a core objective in the Board's Policy, and the reasonableness of the total costs of the project will be a critical component in achieving that objective. The Board will therefore require that parties include in their applications an estimate of all costs, including those related to: preparation of an application for designation; development; construction; and operation and maintenance of the line.

However, in recognition of the uncertainty inherent in estimating costs of construction and operation and maintenance of the line, the Board will accept these estimates expressed as a range. All the transmitters who have registered their interest in the East-West Tie line project have, or have access to, experience in the construction of major infrastructure projects, and the Board expects that they will be able to create a reasonable estimated range for these costs, and provide justification for the cost estimates and width of the range. The Board will also require applicants to provide evidence of their plan to manage the costs of construction and operation and maintenance, and of their track record in estimating construction costs and keeping to those estimates.

Applicants should also describe any proposals they have regarding the recovery of the various categories of costs from ratepayers. For example, the Board notes TPT's submission that no applicant, including the designated transmitter, should be able to recover the costs of participating in the designation process. While this is not the Board's ruling (see issue 14 below), the Board invites any applicant to distinguish itself by proposals that reduce costs or risks for ratepayers for any category of cost.

The Board will retain the criterion "other factors", but will not specify at this time what factors or evidence will be considered under this criterion. This criterion offers applicants the opportunity to bring forward any distinguishing feature of their application that is not addressed in the other criteria. The Board acknowledges that this criterion is open-ended. However, all potential applicants are in the same position and have the same opportunity to provide evidence under this criterion. Experienced transmitters, such as those who have registered their interest in this proceeding, may bring forward useful information that the Board cannot anticipate at this stage in the proceeding.

Additional criteria, other than First Nation and Métis issues

The submissions of parties contained several proposals for additional criteria. The Board will not add a specific additional criterion relating to facilitating competition and new entrants. The facilitation of competition and the encouragement of new entrants to transmission in the province was part of the context for the Board's Policy, and are being recognized by the initiation of this designation process. Any applicant who wishes to bring evidence of any advantage to Ontario ratepayers of the designation of a new entrant for this project is invited to do so as part of the "other factors" criterion.

The Board finds that there is no need to create additional criteria related to the provision of socio-economic benefits, the ability to mitigate environmental impacts, regulatory expertise, or location-specific experience. Each of these issues will be considered to some degree under the criteria "technical capability" and "organization". The Board notes that mitigation of environmental and socio-economic impacts is considered as part of the Environmental Assessment process. The Board will not require evidence of an applicant's ability to mitigate these impacts, but will require evidence of the applicant's ability to successfully complete regulatory processes similar to Ontario's Environmental Assessment process.

With respect to regulatory expertise, the Board will require evidence under the criterion "technical capability" of an applicant's ability to successfully complete the regulatory processes necessary for the construction and operation of the line.

The Board will not necessarily favour experience in Ontario over experience in other jurisdictions. It is important that the designated transmitter be fully capable of constructing and operating an electricity transmission line that meets the needs identified by the OPA and the Independent Electricity System Operator ("IESO") in the location proposed in the transmitter's plan. However, the experience necessary to achieve this capability may have been gained in other jurisdictions. The Board invites applicants to bring evidence of their experience and to demonstrate its relevance to the East-West Tie line project.

The Board finds that three additional criteria are appropriate to address the specific circumstances of this designation process. The Board will add the new criterion "Proposed Design for the East-West Tie Line". In creating this additional criterion, the Board has particularly considered the submissions of Board staff, the IESO, RES, the

Power Workers Union ("PWU") and EWT LP. The evidence to be filed to satisfy this criterion is largely that listed in section 5 of Board staff's proposed filing requirements presently titled "Plan Overview". The criterion is intended to be assessed as pass/fail in respect of whether the applicant's plan for the line meets the targeted transfer capability while satisfying all applicable reliability standards. However, the other evidence to be filed under this criterion by each applicant will be compared against the plans of the other applicants to assess the relative strengths of the proposed designs. An applicant may demonstrate under this criterion the ways in which its technical design for the line provides advantages to the transmission system, local communities or transmission ratepayers, or demonstrates advantageous innovation, or in some way exceeds the minimum requirements while remaining cost effective.

The Board will divide the original criterion "landowner and other consultations" into two criteria: "landowner, municipal and community consultation" and "First Nation and Métis consultation". The delineation of "landowner, municipal and community consultation" from the more general original criterion is intended to make explicit the need for consultation with municipalities and communities located along the transmission line corridor.

Issue 2. Should the Board add the criterion of First Nations and Métis participation? If yes, how will that criterion be assessed?

Issue 3. Should the Board add the criterion of the ability to carry out the procedural aspects of First Nations and Métis consultation? If yes, how will that criterion be assessed?

Issue 4. What is the effect of the Minister's letter to the Board dated March 29, 2011 on the above two questions?

The Board finds that the Minister's letter is not a directive within the meaning of the *Ontario Energy Board Act, 1998.* However, the letter is an expression of the government's interest in promoting First Nations and Métis participation in energy projects, and is consistent with government policy as articulated in the Long Term Energy Plan.

The Board will create the criterion "First Nation and Métis participation" and, as indicated in the previous section, divide the original criterion "Landowner and other consultations" into two criteria: "landowner, municipal and community consultation" and

"First Nation and Métis consultation". The Board recognizes that First Nation and Métis consultation is unique in being a constitutional obligation on the Crown, certain aspects of which may be delegated to the designated transmitter. Applicants will be required to demonstrate their ability to conduct successful consultations with First Nation and Métis communities, as may be delegated by the Crown, by providing a plan for such consultations, and evidence of their experience in conducting such consultations.

The Board will not look more favourably upon First Nation and Métis participation that is already in place at the time of application than upon a high quality plan for such participation, supported by experience in negotiating such arrangements. "Participation" can mean many things, and the Board will not restrict its consideration to any particular type of participation. Applicants are invited to demonstrate the advantages of whatever type and level of First Nation and Métis participation they have in place, or are proposing to secure.

The Board notes the proposal of the Ojibways of Pic River First Nation ("PRFN") that the First Nation and Métis participation criterion be categorized, weighted, and scored by the impacted relevant communities. The Board will not adopt this methodology for assessing the criterion, which could amount to an improper delegation of its decision making power. The Board will evaluate this criterion through the public hearing process, and the various intervenors representing First Nation and Métis interests, along with the other parties, can seek input from their constituencies and bring that information forward for the Board's consideration in the hearing.

Use of the Decision Criteria: Issues 5 and 6

Issue 5: ***Should the Board assign relative importance to the decision criteria through rankings, groupings or weightings? If yes, what should those rankings, groupings or weightings be?***

Issue 6: ***Should the Board articulate an assessment methodology to apply to the decision criteria? If yes, what should this methodology be?***

The Board will not, at this time, articulate an assessment methodology to be applied to the decision criteria, nor will it ascribe any relative importance to the decision criteria through a weighting system. The Board appreciates the points made in the submissions from some parties that assigning weights or rankings to the criteria would assist applicants in focusing their applications towards factors that the Board considers important. However, the Board is unwilling to remove the discretion and flexibility it may need in evaluating the applications for designation. The Board will exercise its judgment for each criterion, with the assistance of the evidence presented and the submissions received from all parties.

The Board notes that in providing decision criteria and filing requirements, it has provided some guidance to potential applicants, and that all applicants face the same challenge in designing their proposals around these criteria and filing requirements. All the decision criteria are important, and the Board is unwilling to restrict its ability to give full consideration to each criterion before it is informed by the content of the applications for designation.

Filing Requirements: Issues 7 and 8

Issue 7. What additions, deletions or changes should be made to the Filing Requirements (G-2010-0059)?

As part of its Policy, the Board issued its “Filing Requirements: Transmission Project Development Plans” (G2010-0059) dated August 26, 2010. Board staff proposed revisions to the original filing requirements to take into account the specific circumstances of the East-West Tie line. These revised filing requirements were attached as Appendix A to Board staff’s April 24, 2012 submission. Most parties agreed with the reorganization of the filing requirements proposed by Board staff, but had specific suggestions for additions, deletions or changes.

The approved filing requirements for the East-West Tie line designation process are attached as Appendix A to this decision. The filing requirements have been modified from Board staff’s proposed filing requirements to reflect the Board’s findings in this Phase 1 decision. Certain issues raised by parties, and not otherwise addressed in this decision, are discussed below.

Background Information

AltaLink submitted that an additional requirement should be added to require each applicant to file a statement from a senior officer that the applicant is not in a position of an actual or perceived conflict of interest. The Board finds that this requirement is unnecessary at this time. The Board, in issues 20 – 22 in this decision, addresses issues arising from the participation of entities related to incumbents. The Board can address this issue further through Phase 2 in the event additional concerns are identified.

Technical Capability

AltaLink and Iccon submitted that references to experience in Ontario and experience involving similar terrain, climate and other environmental conditions should be excluded from the filing requirements. EWT LP submitted that experience in Ontario and in similar terrain, climate and other environmental conditions is important when assessing a transmitter's technical experience.

As mentioned under issue 1 in this decision, the Board finds that it is appropriate for applicants to document their experience, wherever gained, and to demonstrate the relevance of that experience to the East-West Tie line project.

The Board will not, as urged by TPT, change the wording in the filing requirements to refer only to “linear infrastructure”, but recognizes that such experience may be relevant to the construction and operation of the East-West Tie line.

The Board will require evidence of consistency with good utility practice in the areas of safety, environmental compliance, and regulatory compliance.

Financial Capacity

School Energy Coalition (“SEC”) recommended the addition of a requirement for information on the current credit rating of the applicant and its parent company. The Board has adopted this proposal.

Plan Overview (now Proposed Design)

Some parties submitted that the requirements listed in Section 5.1 of Board staff’s proposed filing requirements are too detailed for the designation applications since providing this information would require development work which should not be part of the designation process. EWT LP suggested that these requirements should be determined by the designated transmitter once designated and that only a description of the development activities planned to determine these requirements should be included in the designation application.

The Board is of the view that the filing requirements should require the applicant transmitters to provide sufficient detail to allow the Board to carry out a meaningful, thorough and accurate assessment of the applicant transmitters and their proposed plans. However, the Board also recognizes the time, effort and cost associated with preparation of detailed designation applications. If an applicant is unable to provide certain information, then it can provide a description of the methodology it will use to develop the information. The Board has made the list under this section (now 6.1) optional rather than mandatory, and provided the option of describing the method and criteria for the determination of these parameters.

Board staff noted that section 2.1.5 of the Board's Minimum Technical Requirements requires that "all proposed design assumptions" be provided by the applicant. Board staff recommended that the need to provide "all proposed design assumptions" be excluded from the designation application because this information will not be available to the applicants before development work for the line is well underway.

The Board agrees with Board staff that it would be premature to expect the applicants to be able to provide this information prior to having done at least some development work, and will not include a requirement for "all" design assumptions in the filing requirements. As a general rule, the Board agrees with UCT and PWU that if the filing requirements require detail which is impossible or impractical to obtain, the applicant should respond to the best of its ability and identify the factors that prevent a full response or require deviation from the filing requirements. The Board also acknowledges, as submitted by RES, that plans will evolve during the development phase.

The Board will adopt the proposal of the OPA (supported by SEC) for a requirement to outline how a proposed plan leads to a lower cost solution than other alternatives while meeting the project requirements. The Board is not, at this stage, asking applicants to compare their plans to those of other applicants, but to other options for the East-West Tie line that could reasonably be considered to satisfy the need for the line.

Schedule

EWT LP suggested that section 6.3 of Board staff's proposed filing requirements related to information regarding the construction phase of the project should be eliminated since this would require environmental assessment work and consultation which will not have been done at the time of filing the applications. Some parties suggested that specific milestone dates should be removed.

The Board is of the view that the requirements in section 6.3 will be helpful to the Board in assessing the merits of the applicants' proposed plans and that they should remain in the filing requirements. The Board is not seeking a commitment, but information to assist it in understanding the applicant's overall strategy for completion of the project. The Board recognizes that the construction schedule will change as a result of the more detailed development work to be carried out by the designated transmitter.

Costs

Board staff's revisions to the original filing requirements propose a number of additions including, among other things, amounts already spent for preparation of an application, major risks that could cause the applicant to exceed its development budget, strategy to mitigate risks, threshold of materiality for prudence review of cost overruns and evidence of the applicant's past success in completing similar transmission line projects.

The Board finds that it is reasonable to simplify the development cost breakdown by grouping some categories of cost. The Board is of the view that, while development cost estimates will be considered, the magnitude of development costs will be small in comparison to the total costs of the East-West Tie project. Consequently, an applicant's demonstrated ability to manage complex projects and control all costs is more important for the selection of a designated transmitter than the estimate of development costs.

Also, the Board concludes that the applicants are not required to propose a threshold of materiality for prudence review if cost overruns occur for the costs of development. Instead, the Board will ask parties to address this matter in their submissions in Phase 2.

Consultation

The Board determined under issue 1 that there will be a separate criterion for First Nation and Métis consultation, and the filing requirements have been modified accordingly. The Board has adopted most of the wording for this section proposed by the Métis Nation of Ontario ("MNO").

Several parties submitted that the information regarding routing in staff's proposed section 8.3 should not be required as this information will be unreliable until environmental assessment work has been done. The Board will permit applicants to file routing information at the level of detail they believe is appropriate, and will be assisted by such description as the applicant can provide regarding the route or routes it is considering.

Issue 8: May applicants submit, in addition or in the alternative to plans for the entire East-West Tie Line, plans for separate segments of the East-West Tie Line?

The Board will not permit applicants to submit plans for separate segments of the East-West Tie line. The Board recognizes that the proposed line could possibly be considered two segments, one from Wawa to Marathon and one from Marathon to Thunder Bay. However, the need identified by the OPA and the IESO cannot be satisfied by one of these two segments alone, and the project is best considered as a single unit. The Board agrees with those parties that submitted that attempting to consider separate applications for the two line segments would add cost and complexity to the designation process, require extensive co-ordination between the two selected transmitters, and could create additional risk for ratepayers and confusion for communities that are to be consulted. However, the Board would consider a joint venture or joint application from two or more parties who together propose to complete the entire East-West Tie line. Such a joint application would have to include a clear acceptance of risks and obligations by each party for the completion of the entire project.

Obligations and Milestones: Issues 9 – 12

Issue 9: ***What reporting obligations should be imposed on the designated transmitter (subject matter and timing)? When should these obligations be determined? When should they be imposed?***

Issue 10: ***What performance obligations should be imposed on the designated transmitter? When should these obligations be determined? When should they be imposed?***

Issue 11: ***What are the performance milestones that the designated transmitter should be required to meet: for both the development period and for the construction period? When should these milestones be determined? When should they be imposed?***

Issue 12: ***What should the consequences be of failure to meet these obligations and milestones? When should these consequences be determined? When should they be imposed?***

The Board will not impose a “performance obligation” in the sense of a performance bond or other financial instrument on the designated transmitter. Those parties who chose to address this issue in their submissions largely agreed with Board staff that a financial performance obligation was not necessary. The Board accepts the submission of EWT LP that the regulatory risk of cost disallowance is a deterrent to a voluntary failure to perform. The Board also agrees with SEC that the Board has the authority to impose conditions through amendments to the designated transmitter’s licence if non-financial obligations are necessary.

The Board agrees with Board staff and other parties that it will be necessary to impose performance milestones and reporting obligations on the designated transmitter. The objectives of the milestones and reporting are:

- to ensure that the designated transmitter is moving forward with the work on the East-West Tie line in a timely manner;
- to facilitate early identification of circumstances which may undermine this ability to move forward; and

- to maintain transparency, as the costs of development work are intended to be recovered from ratepayers.

The Board will require, through its filing requirements, applicants for designation to propose performance milestones and reporting obligations that accomplish these objectives. The Board is reluctant to pre-determine the milestones and reporting that the successful applicant must accept, and expects that the experience in major project management that the applicants will bring to the designation process will be of assistance to the Board in setting appropriate conditions.

The proposed milestones and reporting obligations should apply to both the development phase and construction phase of the project, although the Board accepts that the milestones and reporting for the construction phase will be reconsidered and finalized during the Board's consideration of the leave to construct application. The Board will consider construction milestones and reporting only as indicative, and does not intend to impose those obligations at the time of designation.

Potential applicants for designation and other parties should note that the Board is not limited to imposing on a designated transmitter only those performance milestones and reporting obligations that the transmitter proposed in its application. All parties may choose to make submissions concerning the appropriate milestones that should be imposed on any transmitter that may be selected for designation. The Board will not impose novel conditions without providing designation applicants the opportunity to address the appropriateness of such conditions. The Board will establish the reporting requirements and performance milestones through an amendment to the designated transmitter's licence.

The Board finds that is it premature to determine in this Phase 1 decision the consequences for failure to meet the required performance milestones and performance obligations. Applicants for designation must include in their applications their proposals regarding the consequences of failure to meet their proposed performance milestones and reporting obligations.

The Board's policy indicates that the loss of designation and the inability to recover development costs are two potential consequences of failure. The Board is of the view that the severity of the consequences should be proportional to the severity of the breach, and take into account the designated transmitter's mitigation efforts. In determining how to address any failure the Board will consider:

- the nature and severity of the failure
- the specific circumstances related to the failure
- the consequences of the failure
- the designated transmitter's proposal to address the failure

The Board notes SEC's submission that if a designated transmitter does not bring forth a leave to construct application, it must relinquish ownership of all information and intellectual property that it created or acquired during the development phase. AltaLink and others argued in response that to require delivery of all such information and intellectual property would be punitive, confiscatory and contrary to the public interest. The Board will not determine this issue at this time. However, if failure of the project occurs, and development costs are to be recovered from ratepayers, the Board may wish to consider whether information gathered and even design work completed at ratepayer expense must be made available to a substitute transmitter.

Runner up

Board staff, in its submission, asked parties to comment on the issue of whether one or more "runners-up" for designation should be selected by the Board. Some of the registered transmitters were not in favour of the Board selecting a runner-up, in part because keeping capital and human resources on hold awaiting potential failure of the designated transmitter would not be practical. However, several parties mentioned the potential efficiency to be gained, as if the original designee failed, no new designation process would be required to continue work on the project.

The Board will invite applicants for designation to indicate whether they are willing to be named as a runner-up. If the designated transmitter fails to fulfill its obligations and the line is still needed, the Board could offer the development opportunity to the runner-up. The runner-up would not be under an obligation to take on the project, but would have right of first refusal to undertake the work. Applicants that indicate their willingness to be named runner-up should also provide in their application any conditions that they believe are necessary to enable them to take on this role. The Board will not consider willingness to take on the runner-up role in its selection of the primary designated transmitter. This is a choice for applicants, not a requirement.

Consequences of Designation: Issues 13 – 16

Issue 13: On what basis and when does the Board determine the prudence of budgeted development costs?

The Board agrees with the general tenor of parties' submissions that the time to review the budgeted development costs put forward in applications for designation is during Phase 2 of this designation proceeding. The level of development costs, which are expected to be recovered from ratepayers, will be a factor in the Board's selection of a designated transmitter. In this light, the Board does not foresee a circumstance, as suggested by SEC, in which it would adjust the amount of development costs proposed by a transmitter at the time the Board designates that transmitter.

The level of development costs is only one aspect of the proposal put forward by a transmitter. The Board does not intend to adjust this part of the proposal any more than it would adjust the proposed organization, design, financing or any other aspect. Unlike an application for rates or approval of a facility, this proceeding concerns itself with choosing from among several competing proposals. The Board will compare these proposals to each other and will determine which proposal is best overall. It would be inappropriate and unfair to the applicants to expect any of them to adjust their applications once they have been filed.

This does not mean that the development costs proposed in applications for designation cannot be questioned. The Board will receive and consider interrogatories and submissions regarding the level of these budgeted costs during Phase 2 and will take that evidence into account in assessing the applications. The selection of a transmitter for designation will indicate that the Board has found the development costs to be reasonable as part of an overall development plan. This selection will also establish that the development costs are approved for recovery. The Board will not select a transmitter for designation if it cannot find that the development costs are reasonable. However, applicants should be aware that costs in excess of budgeted costs that are put forward for recovery from ratepayers will be subject to a prudence review, which would include consideration of the reasons for the overage.

Issue 14: Should the designated transmitter be permitted to recover its prudently incurred costs associated with preparing its application for designation? If yes, what accounting mechanism(s) are required to allow for such recovery?

The Board finds that the designated transmitter will be permitted to recover from ratepayers its prudently incurred costs associated with preparing its application for designation, with one restriction. Cost recovery will be restricted to costs incurred on or after the date that the Board gave notice of the proceeding, February 2, 2012. This date represents the beginning of the proceeding and therefore is a date after which the designated transmitter could reasonably expect to recover its costs.

Applicant transmitters should identify the costs already incurred to prepare an application, as well as an estimate of the costs required to complete the designation proceeding, as part of their budgeted development costs. The Board will establish a deferral account for the designated transmitter in which the budgeted development costs, including amounts incurred after February 2, 1012 for the preparation of the application for designation, will be recorded for future recovery. As noted earlier in this decision, an applicant transmitter can choose not to seek recovery of all its costs, as a way to reduce the costs of its proposal to ratepayers.

Issue 15: To what extent will the designated transmitter be held to the content of its application for designation?

The Board will be choosing a designated transmitter based on the plans that applicants for designation file. Therefore, the Board will generally expect the designated transmitter to conform to its filed application, as it formed the basis for designation. However, the Board understands that there is a need for some flexibility, as the plan for the line will evolve as development work takes place.

The Board has discussed in the previous section of this decision the need for performance milestones and reporting obligations, and the expectation that these will be adhered to. Any development costs in excess of budgeted costs may not be recovered from ratepayers, and will be subject to a prudence review if recovery is sought. The leave to construct proceeding will provide an opportunity for the Board to assess the reasonableness of any deviations from other aspects of the designated transmitter's plan, and the Board may choose to deny the leave to construct application or impose special conditions on its approval if warranted.

Particular concern was expressed by some parties regarding commitment to construction costs, First Nation and Métis participation, and First Nation and Métis consultation. The Board recognizes that these three areas in particular may be subject to modification to accommodate new information, and changing needs and circumstances. Nevertheless, in the leave to construct proceeding, the Board will compare the actual performance of the designated transmitter in these areas to the evidence filed in its designation application to assess the reasonableness of any deviations from the application.

Issue 16: What costs will a designated transmitter be entitled to recover in the event that the project does not move forward to a successful application for leave to construct?

On the issue of cost recovery after a failure to obtain an order for leave to construct the line, the Board agrees with Board staff and other parties that the reason for failure will be an important consideration in determining what costs, if any, are to be recovered from ratepayers. Generally, if the project does not move forward due to factors outside the designated transmitter's control, the designated transmitter should be able to recover the budgeted development costs spent and reasonable wind-up costs. If failure occurs due to factors within the designated transmitter's control, neither recovery nor automatic denial is certain. The Board will review the circumstances of the failure to determine a fair level of cost recovery. The Board acknowledges that it may not be possible to attribute failure to a single cause, and the sources of failure may be both internal and external to the designated transmitter. It is not possible to decide on the level of cost recovery in the abstract at this time, as the specific circumstances of the failure will need to be considered.

Process: Issues 17 – 23

Issue 17: The Board has stated its intention to proceed by way of a written hearing and has received objections to a written hearing. What should the process be for the phase of the hearing in which a designated transmitter is selected (phase 2)?

The Board will continue to proceed for the present by way of written hearing, and adopt the procedural steps proposed by Board staff (and largely supported by the registered transmitters). The Board is master of its own process, within the limits set by the *Ontario Energy Board Act, 1998* and the *Statutory Powers Procedure Act*. In the interests of fairness to all applicants and of keeping the costs of the designation proceeding within reasonable limits, the Board will exercise considerable control over the process. The Board's primary aim in Phase 2 is to obtain a good record upon which to make a decision on designation. The Board will ensure, as it does in all its hearings, that the process is open, transparent and fair.

The Board notes the concern of parties over the suggestion by Board staff that interrogatories be funneled through the Board, and that "culling and editing" may occur before the Board sends the interrogatories to the applicants. The Board will require all parties to send their interrogatories to the Board, and the Board panel (not Board staff) reserves the right to combine and edit interrogatories for matters such as relevance, duplication and excessive demands upon the applicants. The primary purpose of the interrogatory process is to create a good record for the Board to assist it in making a determination in this designation proceeding. The fact that this proceeding involves multiple competitive applicants and has elements similar to a procurement process that are absent from most Board proceedings calls for specific procedural approaches that respect fairness and efficiency.

Some parties suggested that an oral hearing is necessary to ensure full participation from non-applicant intervenors, particularly First Nation and Métis intervenors, and intervenors from northern communities. The Board will evaluate the need for an oral component to this proceeding, including the scope and location of any oral component, as the hearing proceeds.

The Board will not adopt the proposal of the PWU to remove intervenor status from the registered transmitters. The Board expects to receive useful information and submissions from all intervenors.

Issue 18: Should the Board clarify the roles of the Board's expert advisor, the IESO, the OPA, Hydro One Networks Inc. and Great Lakes Power Transmission LP in the designation process? If yes, what should those roles be?

The Board agrees with the description of the roles of the IESO and the OPA provided in their respective submissions. The Board panel will not receive information from either of these participants privately, and requires that any advice they have to offer be provided on the record of the hearing. The Board expects that the OPA and the IESO will remain neutral as between applicants. Consistent with the reply submissions from the OPA and the IESO, the Board does not anticipate that the participation of these entities in this proceeding will be affected by Bill 75, which contemplates their merger.

The Board panel will communicate with Board staff both on and off the record. The panel will be vigilant to ensure that Board staff continues to remain neutral as between other parties in the proceeding, and provides any new information or any opinion on the record so that other parties may respond to it. The Board will not receive any advice off the record from the Board's expert advisor, and expects any information from this expert to be placed on the record by Board staff.

HONI and GLPT must remain neutral as between applicants. The Board expects that the primary role of these transmitters will be to respond to reasonable requests for information. The Board would also appreciate receiving comment from these transmitters on any technical matters, or matters affecting existing infrastructure, as they see fit, through submissions in Phase 2 of the proceeding.

Issue 19: What information should Hydro One Networks Inc. and Great Lakes Power Transmission be required to disclose?

The Board ruled on this issue in the Phase 1 Partial Decision and Order, dated June 14, 2012.

Issue 20. Are any special conditions required regarding the participation in the designation process of any or all registered transmitters?

Issue 21. Are the protocols put in place by Hydro One Networks Inc. and Great Lakes Power Transmission LP, and described in response to the Board's letter of December 22, 2011, adequate, and if not, should the Board require modification of the protocols?

Issue 22. Given that EWT LP shares a common parent with Great Lakes Power Transmission LP and Hydro One Networks Inc., should the relationship between EWT LP and each of Great Lakes Power

Transmission LP and Hydro One Networks Inc. be governed by the Board's regulatory requirements (in particular the Affiliate Relationships Code) that pertain to the relationship between licensed transmission utilities and their energy service provider affiliates?

Board staff did not suggest any particular measures to address the concerns raised by issues 20 through 22, but asked that parties requesting such measures "explain the harm they are seeking to prevent, how the proposed condition or measure mitigates that harm without causing other harm, and whether the proposed condition or measure should apply to all similar participants in the interest of fairness."

EWT LP submitted that all designation applicants should be prohibited from working together or coordinating the preparation of plans or strategies and, moreover, that any party found to be coordinating or communicating with other designation applicants with respect to their designation plans or designation strategy be disqualified. In their reply submissions, a number of the other parties disagreed and, instead, suggested that a prohibition of co-operative submissions or co-development agreements was not only unwarranted but potentially counter-productive.

As discussed in the Board's findings on issue 8, the Board will not prohibit co-operation or co-ordination between the prospective applicants, whether among themselves or with other parties. As there may be potential for certain parties to demonstrate that their co-operation and co-ordination of efforts will be to the advantage of ratepayers, the Board will not impose conditions to preclude this. However, the nature and extent of any co-operation or co-ordination must be disclosed in the application(s).

A number of the parties submitted that there should be special conditions placed specifically on EWT LP, generally in furtherance of the Board's objective for a fair process. In particular, these applicants point to a perceived informational advantage of EWT LP given its relationship with HONI and GLPT, and submit that such advantage should be negated by preventing the sharing of employees between them, or by precluding EWT LP from participating altogether. Several of the parties submitted that EWT LP's relationship with HONI and GLPT should be governed by the Board's Affiliate Relationships Code for Electricity Distributors and Transmitters ("ARC"). As well, a number of these parties suggested that the protocols put in place by HONI and GLPT are insufficient to address data management and data access for shared employees, and they proposed various remedies, including modifications to the protocols.

EWT LP argued that the current protocols are adequate, and that they have effectively served to ensure that no information from HONI and GLPT was or will be provided to EWT LP that was or will not also be provided to all proponents. EWT LP also submitted that it is neither an affiliate of HONI nor GLPT; that the activities of EWT LP are not analogous to the activities of energy service providers; that EWT LP is comprised of three arm's length partners each of whom is unable to control EWT LP; and that, ultimately, the circumstances for which the ARC was developed do not apply to their circumstances.

The Board acknowledges the arguments of EWT LP that neither transmission development nor participation in the designation process is an activity controlled by the ARC and that no affiliate relationship exists between EWT LP and either of GLPT or HONI. The Board also appreciates the point made by PWU that, as the licenses currently stand, the ARC would not apply to many of the proponents.

In the Board's view, while the ARC does not apply to the relationship between EWT LP and each of HONI and GLPT, the types of harm that the ARC seeks to prevent in the context of affiliate relationships can also exist in other contexts. The Board notes that almost all of the parties to this proceeding have referred to HONI and GLPT as the "incumbents". While it is true that each of them (as well as CNPI) are transmission utilities operating in the Province of Ontario, the position of HONI is unique. HONI has information critical to the proposed East-West Tie line, as it owns the assets to which the East-West Tie line will connect and, under the Reference Option, the East-West Tie line will be located beside HONI's existing line and right of way. While GLPT, and to a lesser extent CNPI, may have some knowledge of similar terrain and the local transmission system, neither has the advantage of owning and operating an existing line in this specific area, or of determining the conditions and costing related to connection of the new line to the existing transmission system.

The Board believes that HONI and GLPT have been and will continue to be diligent in following the existing protocols. However, the Board is not satisfied that the protocols provide adequate protection against the inadvertent sharing or disclosure of information between HONI and EWT LP, if they continue to share employees in Phase 2 of this proceeding. While the Board is confident in the commitment of staff at HONI to not intentionally share information with one applicant that is not also shared with all other applicants, the legitimacy and integrity of this process requires that, going forward, there be no opportunity during Phase 2 of this process for the disclosure or sharing (whether intentional or inadvertent) of any relevant information by HONI to EWT LP.

In order to avoid any real or perceived informational advantage, the Board will require that EWT LP make arrangements to ensure that no individual will be performing work concurrently for HONI and EWT LP during Phase 2 of this proceeding. This condition will be effective as of fifteen days from the date of issuance of this decision until the close of the record in Phase 2 of this proceeding.

Employees engaged by EWT LP must be placed in the position where they cannot inadvertently acquire advantageous information from employees currently employed by HONI, and, therefore, the work location of EWT LP must also be physically separated from the HONI offices until the record is closed in Phase 2 of this proceeding. This means, at a minimum, that HONI and EWT LP must not share a computer system or other data management system, and must occupy separate premises.

EWT LP's continued participation as an intervenor and as a registered transmitter is dependent on compliance with these conditions, as well as its role in adhering to the protocols established by HONI and GLPT.

Except for this ruling requiring a separation of employees and premises between EWT LP and HONI, the Board will not impose regulatory conditions governing the relationship between EWT LP and each of HONI and GLPT. However, the Board reminds both HONI and GLPT that careful separation of costs attributable to EWT LP's creation and participation in the designation process must be maintained.

Issue 23: What should be the required date for filing an application for designation?

The Board has considered the various timelines, and reasons for those timelines, proposed in the submissions on this issue. The Board finds that it will require applications for designation to be filed no later than January 4, 2013. This filing date should allow sufficient time for the preparation of applications, and is consistent with the period of six months which many transmitters proposed. The Board is of the view that this relatively generous timeline is appropriate because this is the first designation proceeding for transmission in Ontario, and all parties may need time to resolve matters related to the provision of information and the preparation of plans.

THE BOARD ORDERS THAT:

1. The Board adopts the filing requirements attached as Appendix A to this decision for the purpose of applications for designation to undertake development work for the East-West Tie line.

2. EWT LP must make arrangements so as to ensure that no individual will be performing work concurrently for HONI and EWT LP during Phase 2 of this designation proceeding, and the work location of EWT LP must also be physically separated from the HONI offices as described in this decision. This condition will be effective as of fifteen days from the date of issuance of this decision until the close of the record in Phase 2 of this proceeding. EWT LP must provide confirmation to the Board that this condition has been implemented, within 21 days of the date of this decision.

3. A licensed transmitter seeking designation to undertake development work for the East-West Tie line must file its application for designation no later than January 4, 2013.

Cost Claims for Phase 1 of the Proceeding

On March 30, 2012, the Board issued its Decision on Intervention and Cost Award Eligibility. Procedural Order No. 2 issued on April 16, 2012 also, to some extent, dealt with the issues of interventions and cost award eligibility. As a result of these orders, certain parties have been ruled eligible to apply for cost awards in both phases of this designation proceeding and certain other parties have been ruled eligible to apply for limited cost awards relating to their attendance at an all party conference in Phase 1 of this designation proceeding.

In total, nine parties have been determined to be eligible to apply for cost awards in both phases of this designation proceeding. These parties will be referred to as the "eligible parties". They are:

- the coalition representing the City of Thunder Bay, Northwestern Ontario Associated Chambers of Commerce and Northwestern Ontario Municipal Association;

- the coalition representing the Municipality of Wawa and the Algoma Coalition;
- Consumers Council of Canada;
- MNO;
- National Chief's Office on Behalf of the Assembly of First Nations;
- Nishnawbe-Aski Nation;
- Northwatch;
- PRFN; and
- SEC.

Each of the following parties has been granted eligibility for an award of costs up to a maximum of 12 hours if it attended the all party conference in Phase 1 of this proceeding on March 23, 2012:

- Association of Major Power Consumers in Ontario (“AMPCO”);
- Building Owners and Managers Association Toronto (“BOMA”);
- Canadian Manufacturers and Exporters (“CME”); and
- Energy Probe Research Foundation (“Energy Probe”).

The cost awards to the eligible parties, the cost awards to AMPCO, BOMA, CME and Energy Probe, and the Board’s own costs will be recovered from licensed transmitters whose revenue requirements are recovered through the Ontario Uniform Transmission Rate (and the costs will be apportioned between the transmitters based on their respective transmission revenues). These transmitters are:

- CNPI;
- Five Nations Energy Inc. (“FNEI”);
- GLPT; and
- HONI.

A schedule for claiming cost awards for Phase 1 is provided in the Board’s order below. A decision and order on cost awards will be issued after these steps have been completed.

Furthermore, parties claiming cost awards are reminded that they must submit their cost claims in accordance with the Board's *Practice Direction on Cost Awards* and ensure that their claims are consistent with the Board's required forms and the Cost Awards Tariff.

THE BOARD FURTHER ORDERS THAT:

1. Eligible parties shall submit their cost claims for Phase 1 of the Designation Proceeding by **July 26, 2012**. A copy of the cost claim must be filed with the Board and one copy is to be served on each of CNPI, FNEI, GLPT and HONI.

2. AMPCO, BOMA, CME and Energy Probe shall submit their cost claims up to a maximum of 12 hours if they attended the all party conference in Phase 1 of the Designation Proceeding on March 23, 2012 by **July 26, 2012**. A copy of the cost claim must be filed with the Board and one copy is to be served on each of CNPI, FNEI, GLPT and HONI.

3. CNPI, FNEI, GLPT and HONI will have until **August 2, 2012** to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

4. The party whose cost claim was objected to will have until **August 9, 2012** to make a reply submission as to why its cost claim should be allowed. A copy of the submission must be filed with the Board and one copy must be served on the party who objected to the claim.

All filings with the Board must quote the file number EB-2011-0140, and be made through the Board's web portal at www.errr.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, July 12, 2012
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

To Phase 1 Decision and Order

East-West Tie Designation Process

Filing Requirements for Designation Applications

Board File No: EB-2011-0140

FILING REQUIREMENTS

EAST-WEST TIE DESIGNATION APPLICATIONS

An application for designation will contain three main sections. Together, these sections of the application address the Board's decision criteria for the East-West Tie line designation process:

(A) Evidence addressing the capability of the applicant to carry out the East-West Tie line project;

(B) The applicant's Plan for the East-West Tie line; and

(C) Other factors.

(A) CAPABILITY OF THE APPLICANT

1. Background Information

The applicant must provide the following information:

1.1 the applicant's name;

1.2 the applicant's OEB transmission licence number;

1.3 any change in information provided as part of the transmitter's licence application;

1.4 confirmation that the applicant has not previously had a licence or permit revoked and is not currently under investigation by any regulatory body;

1.5 confirmation that the applicant is committed to the completion of the development work for the East-West Tie line, and to the filing of a leave to construct application for the line, to the best of its ability;

1.6 a statement from a senior officer that the application for designation is complete and accurate to the best of his/her information and belief;

1.7 an indication of whether the applicant is willing to be named as a runner up designated transmitter and a statement of any conditions necessary to this role.

1.8 a description of any co-ordination or co-operation with other parties that has contributed to this application.

2. Organization

The applicant shall identify how, from an organizational perspective, it intends to undertake the East-West Tie line project. The applicant must file:

2.1 an overview of the organizational plan for undertaking the project, including:

- any partnerships or contracting for significant work;
- identification and description of the role of any third parties that are proposed to have a major role in the development, construction, operation or maintenance of the line; and
- a chart to illustrate the organizational structure described.

2.2 identification of the specific management team for the project, with resumés for key management personnel.

2.3 an overview of the applicant's experience with:

- the management of similar projects; and
- regulatory processes and approvals related to similar projects.

2.4 an explanation of the relevance of the applicant's experience to the East-West Tie line project.

3. First Nation and Métis Participation

The applicant must address its approach to First Nation and Métis participation in the East-West Tie line project. To that end, the applicant must file evidence of one of the following:

3.1 If arrangements for First Nation and Métis participation have been made, a description of:

- the First Nation and Métis communities that will be participating in the project;
- the nature of the participation (e.g. type of arrangement, timing of participation);
- benefits to First Nation and Métis communities arising from the participation; and
- whether participation opportunities are available for other First Nation and Métis communities in proximity to the line.

3.2 If arrangements for First Nation and Métis participation have not been made but are planned, a description of:

- the plan for First Nation and Métis participation in the project, including the method and schedule for seeking participation;
- the nature of the planned participation; and
- the planned benefits to First Nation and Métis communities arising from the participation;

3.3 If no First Nation or Métis participation in the project is planned, detailed reasons for this choice.

4. Technical Capability

The applicant must demonstrate that it has the technical capability to engineer, plan, construct, operate and maintain the line, based on experience with projects of equivalent nature, magnitude and complexity. To that end, the following must be filed:

4.1 a discussion of the type of resources, including relevant capability (in-house personnel, contractors, other transmitters, etc.) that would be dedicated to each activity associated with developing, constructing, operating and maintaining the line, including:

- design;
- engineering;
- material and equipment procurement;
- licensing and permitting;
- completion of environmental assessment and other regulatory approvals;
- consultations, both with First Nation and Métis, and other communities;
- construction;
- operation and maintenance; and
- project management.

4.2 resumés for key technical team personnel;

4.3 A description of sample projects, and other evidence of experience in Ontario and/or other jurisdictions in developing, constructing and operating transmission lines or other infrastructure and why these projects and experience are relevant to the East-West Tie line project. The evidence should include a description of experience with:

- the acquisition of land use rights from private landowners and the Crown;
- the acquisition of necessary permits from government agencies;
- obtaining environmental approvals similar to the environmental approvals that will be necessary for the East-West Tie line;
- community consultation; and
- completion of the procedural aspects of Crown consultation with First Nation and Métis communities.

4.4 Evidence that the applicant's business practices are consistent with good utility practices for the following:

- design;
- engineering;
- material and equipment procurement;
- right-of-way and other land use acquisitions;

- licensing and permitting;
- consultations, both with First Nation and Métis, and other communities
- construction;
- operation and maintenance;
- project management;
- safety;
- environmental compliance; and
- regulatory compliance

4.5 A description of:

- the challenges involved in achieving the required capacity and reliability of the East-West Tie line, including challenges related to terrain and weather; and
- the plan for addressing these challenges though the design and construction of the line (e.g. number and spacing of towers, planned resistance to failure).

5. Financial Capacity

The applicant must demonstrate that it has the financial capability necessary to develop, construct, operate and maintain the line. To that end, the applicant shall provide the following:

5.1 evidence that it has capital resources that are sufficient to develop, finance, construct, operate and maintain the line;

5.2 evidence of the current credit rating of the applicant, its parent or associated companies;

5.3 evidence that the financing, construction, operation, and maintenance of the line will not have a significant adverse effect on the applicant's creditworthiness or financial condition;

5.4 the applicant's financing plan, including:

- the estimated proportions of debt and equity; and
- the estimated cost of debt and equity, including:
  - the use of variable and fixed cost financing;
  - short-term and long-term maturities; and
  - a discussion of how the project might impact the applicant's cost of debt.

5.5 if the financing plan contemplates the need to raise additional debt or equity, evidence of the applicant's ability to access the debt and equity markets;

5.6 evidence of the applicant's ability to finance the project in the case of cost overruns, delay in completion of the project and other factors that may impact the financing plan;

5.7 evidence of the applicant's experience in financing similar projects;

5.8 the identification of any alternative mechanisms (e.g., rate treatment of construction work in progress) that the applicant is requesting or likely to request.[1]

(B) PLAN FOR THE EAST-WEST TIE LINE

6. Proposed Design

The applicant must provide an overview of its proposed design for the East-West Tie line including:

6.1 a summary description of how the Plan meets the specified requirements for the East-West Tie Line to the extent known at the time of the designation application. This could include the items listed below as well as any other relevant information the applicant may wish to provide. For items that are unknown, the applicant should describe the method and criteria for determination.

- length of the proposed transmission line;
- number of circuits;
- voltage class;
- load carrying capacity;
  - summer continuous rating (MVA)[2]; and
  - summer emergency rating (MVA)[3] ;
- resulting total transfer capability for the East-West Tie line (MW);
- anticipated lifetime of the line;
- structures and conductors
  - number and average spacing of towers;
  - tower structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.);
  - conductor size and type; and
  - protection against cascading failure and conductor galloping;
- design assumptions; and
- other relevant transmission facility characteristics.

6.2 confirmation that the line will interconnect with the existing transformer stations at Wawa and Lakehead, and an indication of whether the line will be switched at the Marathon transformer station.

6.3 a signed affidavit from an officer of the licensed transmitter to confirm:

---

[1]See Report of the Board on The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario.

[2] Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 93ºC

[3] Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 127 ºC

- that the line will be designed to meet or exceed the existing NERC, NPCC and IESO reliability standards; and
- that the line will be designed to meet or exceed the Board's Minimum Technical Requirements; or documentation of where the applicant seeks to differ from the Minimum Technical Requirements and evidence as to the equivalence or superiority of the proposed alternative option.

6.4 an indication as to whether the Plan will be based on the Reference Option for the East-West Tie line. Where the Plan is not based on the Reference Option, the applicant must file:

- a description of the main differences between the applicant's Plan and the Reference Option;
- a description of the interconnection of the line with the relevant transformer stations; and
- a Feasibility Study performed by the IESO, or performed to IESO requirements.

6.5 a brief description which highlights the strengths of the Plan, which may include:

- any technological innovation proposed for the line;
- reduction of ratepayer risk for the costs of development, construction, operation and maintenance;
- how the plan satisfies the identified need for the line at a lower cost than other options;
- local benefits (e.g. employment, partnerships); and
- enhanced reliability for the transmission grid.

6.6 an indication as to whether the applicant's present intention is to own and operate the line once the line is in service.

7. Schedule

The applicant must file, as part of its Plan:

7.1 a project execution chart showing major milestones for both line development and line construction phases of the project.

7.2 for the development phase of the project:

- a detailed line development schedule identifying significant milestones that are part of the development phase of the project, and estimated dates for completing these milestones;
- proposed reporting requirements for the development phase;
- proposed consequences for failure to meet the required performance milestones and reporting requirements for the development phase;
- a chart of the major risks to achievement of the line development schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and
- a description of the applicant's strategy to mitigate or address the identified risks.

7.3 for the construction phase of the project:

- a preliminary line construction schedule identifying significant milestones that are part of the construction phase of the project, and estimated dates for completing these milestones;
- proposed reporting requirements for the construction phase;
- proposed consequences for failure to meet the required performance milestones and reporting requirements for the construction phase;
- proposed in-service date for the line (can be 2017 or another date);
- a chart of the major risks to achievement of the construction schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very

likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and

- a description of the applicant's strategy to mitigate or address the identified risks.

7.4 evidence of the applicant's past experience in completing similar transmission line or other infrastructure projects within planned time frames. Such evidence could include a comparison of the construction schedule filed with a regulator when seeking approval to proceed with a transmission line project and the actual completion dates of the milestones identified in the schedule.

7.5 any innovative practices that the applicant is proposing to use to ensure compliance with, or accelerate, the line development and line construction schedules.

8. Costs

As part of its Plan, the applicant must file a summary of the total costs associated with the Plan, divided into development costs, construction costs and operation and maintenance costs. In addition, the applicant must file:

8.1 the amount already spent for preparation of an application for designation, and an estimate of remaining costs to achieve designation.

8.2 the estimated total development costs of the line, broken down by the following categories of cost:

- permitting, licensing, environmental assessment and other regulatory approvals
- engineering and design
- procurement of material and equipment;
- costs of the acquisition of land use rights, First Nation and Métis participation, and consultations with landowners, municipalities, the public and First Nation and Métis communities;

- contingencies; and
- other significant expenditures.

8.3 the basis for and assumptions underlying the development cost estimates, and a description of how the applicant plans to manage the cost of development;

8.4 a schedule of development expenditures.

8.5 a chart of the major risks that could lead the applicant to exceed the line development budget, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the budget (e.g. minor, moderate, major), and a description of the applicant's strategy to mitigate or address the identified risks.

8.6 a statement as to the allocation between the applicant and transmission ratepayers of risks relating to costs of development. For example:

- if the costs of development are less than budgeted, does the applicant propose to recover only spent costs, or all budgeted costs (spent and unspent) or spent costs plus a portion of unspent cost (savings sharing)? and
- if the costs of development exceed budgeted costs, does the applicant plan to seek recovery of the excess costs?

8.7 an estimated budget for the construction of the line. This budget and its elements may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range;

8.8 if the Plan is not based on the Reference Option, evidence as to the difference in cost (positive or negative) of work required at the transformer stations to which the line connects, and at any other location identified by the IESO.

8.9 a list of the major risks that could lead the applicant to exceed the line construction budget, and the applicant's strategies to mitigate or address those risks.

8.10 evidence of the applicant's past experience in completing similar transmission line projects within planned construction budgets. Such evidence could include a comparison of the budget filed with a regulator when seeking approval to proceed with a transmission line project and the actual costs of the project.

8.11 a statement as to the allocation between the applicant and transmission ratepayers of the risks relating to construction costs;

8.12 the estimated average annual cost of operating and maintaining the line. This cost may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range.

9. Landowner, Municipal and Community Consultation

The applicant must demonstrate the ability to conduct successful consultations with landowners, municipalities and local communities. In addition, the designated transmitter will be required to satisfy environmental and other requirements that are outside the jurisdiction of the Board.

As part of its Plan, the applicant must file:

9.1 an overview of:

- the rights-of-way and other land use rights, presented by category, that would need to be acquired for the purposes of the development, construction, operation and maintenance of the line;
- the applicant's plan for obtaining those rights; and
- a description of any significant issues anticipated in land acquisition or permitting and a plan to mitigate them.

9.2 a landowner, municipal and community consultation plan for the line, including:

- identification of the categories of parties to be consulted;

- the applicant's plan for consultation for each party or category of party, including method and tentative schedule in relation to the overall project schedule; and
- A description of any significant issues anticipated in consultation and a plan to mitigate them.

9.3 If the applicant has identified a proposed route for the line, the applicant must file a general description of the planned route for the line and may include:

- approximate right-of-way width;
- approximate portion of the route that is:
  - adjacent to the existing corridor (%); or
  - along a new corridor (%):
- a brief description of the environmental challenges posed by the proposed route; and
- an estimate of ownership by category of lands along the proposed route:
  - Crown (federal or provincial) (%);
  - Private (%);
  - First Nation or Métis (%); and
  - Other (%).

9.4 If a proposed route for the line has not been identified, the applicant must file:

- a list of alternative routes;
- an explanation of the method and decision criteria for route analysis and selection; and
- the planned schedule for route selection.

10. First Nation and Métis Consultation

The applicant must demonstrate the ability to conduct successful consultations with First Nation and Métis communities, as may be delegated by the Crown.

As part of its Plan, the applicant must file:

10.1 a proposed First Nation and Métis consultation plan, including:

- a list of First Nation and Métis communities that may have interests affected by the project;
- an approach for engaging with affected First Nations and Métis communities, along with rationale or other justification for such an approach;
- a description of any significant First Nation or Métis issues anticipated in consultation and a plan to address them;
- an overview of expected outcomes from the proposed consultation plan.

10.2 evidence of experience in undertaking procedural aspects of First Nations and Métis consultation in the development, construction or operation of transmission lines or other large construction projects. If applicable, previous engagement or existing relationships with the First Nation and Métis communities to be engaged.

(C) OTHER FACTORS

The applicant should provide any other information that it considers relevant to its application for designation, for example, any distinguishing features of the application.

Updated Assessment of the Rationale for the East-West Tie Expansion

October 8, 2013

ONTARIO
POWER AUTHORITY

1.0 EXECUTIVE SUMMARY

This report provides an updated assessment of the rationale for the East-West Tie ("E-W Tie") expansion project, as ordered by the Ontario Energy Board ("Board"). It builds upon and updates the Ontario Power Authority's ("OPA") June 2011 Report, titled "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion" ("June 2011 Report"), which established the context for the E-W Tie expansion in terms of meeting the long-term electricity needs of Ontario's Northwest.

Since the June 2011 Report, the OPA has undertaken a stakeholder process to update the load forecast for the Northwest, resulting in a more robust outlook for demand growth driven largely by proposals for expansion in the mining sector. Available resources to supply the Northwest were also updated, with the suspension of the conversion of the Thunder Bay Generating Station ("GS") to natural-gas fired operation reflected in this update.

These developments, combined with other changes in the supply and demand outlook, strengthen the case for the E-W Tie expansion. An analysis of its cost-effectiveness compared to the alternative of providing supply resources within the Northwest indicates significant net benefits across a range of assumptions. In addition, the E-W Tie expansion would provide other system benefits that the non-expansion alternative would not.

The E-W Tie expansion continues to be the OPA's recommended alternative to maintain a reliable and cost-effective supply of electricity to the Northwest for the long term.

2.0 INTRODUCTION

The Ontario Government's Long Term Energy Plan, published in November 2010, identified five priority transmission projects needed for maintaining system reliability, enabling renewable energy connections, and accommodating increasing electricity demand. One of these priority projects is a new E-W Tie line, which would expand the existing E-W Tie, a transmission line running between Wawa and Thunder Bay. On March 29, 2011, the Minister of Energy wrote to the Board to express the Government's interest in the Board undertaking a designation process to select the most qualified and cost-effective transmitter to develop the E-W Tie project.

In response to the Minister's letter, the Board initiated a process to designate a transmitter to undertake development work for the E-W Tie project. The Board requested that the OPA provide a report documenting the preliminary assessment of the need for the E-W Tie expansion. In response, the OPA produced its June 2011 Report. The Board then proceeded with the designation process, which concluded on August 7, 2013, when the Board issued its Phase 2 Decision and Order, and identified Upper Canada Transmission Inc. (o/a NextBridge Infrastructure) as the designated transmitter. In its decision, the Board also ordered the OPA to provide two further need updates, one in the early stages of NextBridge Infrastructure's development schedule and one at the mid-point. The OPA committed to providing these need update reports to the Board by October 8, 2013 and May 5, 2014, respectively, and on September 26, 2013 the Board issued a Decision and Order, which requires the OPA to file by these dates.

This report constitutes the early detailed need update report requested by the Board. The June 2011 Report provided substantial background information on the history and development of the power system in Northwestern Ontario to set the context for the E-W Tie expansion. Rather than repeat that material, which has not substantially changed, this report focuses on major changes that have occurred since the June 2011 Report and, based on these changes, an updated statement of the need for the E-W Tie expansion.

Section 3 of this report provides an updated conservation and demand forecast for the Northwest. It reflects changes since 2011 and identifies major drivers for future electricity demand. Sections 4 and 5 analyze current and future internal and external resources that supply the Northwest and provide an update on Northwest capacity and energy supply needs. Section 6 provides an updated analysis of two alternatives to maintain a reliable electricity supply to the Northwest: meeting the needs exclusively through the addition of gas-fired generation in the Northwest; and the E-W Tie expansion combined with incremental gas-fired generation. Section 7 concludes that these updated factors strengthen the case for the E-W Tie expansion, and states that the E-W Tie expansion continues to be the OPA's recommended alternative to maintain a reliable and cost-effective supply of electricity to the Northwest for the long term.

3.0 NORTHWEST CONSERVATION AND DEMAND

One of the major changes in this update is the potential for more robust growth in electricity demand in the Northwest. This growth is primarily driven by activities in the mining sector in the region over the past few years. Because Northwest demand is dominated by large industrial facilities, historical and forecast future demand in the Northwest fluctuates significantly in response to changing economic and market conditions. Going forward, future demand is expected to be driven by the pace and extent of industrial recovery and growth in the Northwest.

3.1 Historical Northwest Demand

As presented in the June 2011 Report, electricity demand in the Northwest peaked at 1,200 MW in 2002, and then steadily declined over the last decade. Altogether, the drop in Northwest demand since the 2002 peak has been about 500 MW and 4.1 TWh. In the two years since the June 2011 Report, regional demand appears to have levelized at around 700 MW and 4 TWh (see Figure 1).

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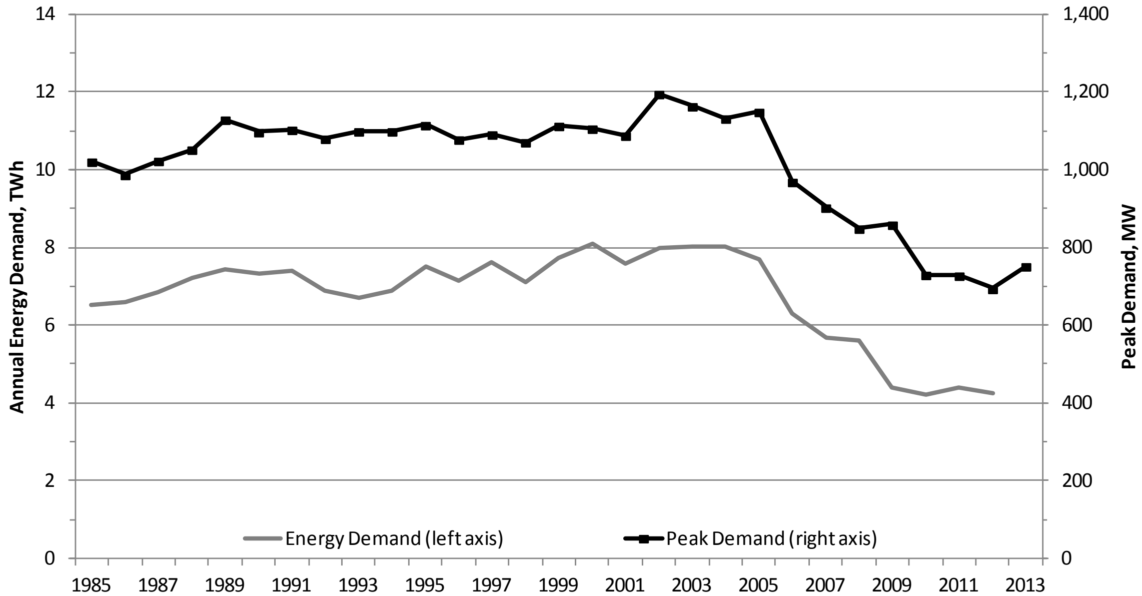
Figure 1. Historical Northwest Electricity Demand



Note: 2013 peak demand is preliminary. Energy demand for 2013 is not available at this time.

3.2 Drivers of Northwest Demand

Since the filing of the June 2011 Report, the OPA has undertaken an extensive process to understand the drivers for demand in the Northwest through engagement with stakeholders such as Common Voice Northwest and mining companies, as well as discussions with the Ontario Ministry of Northern Development and Mines. The updated forecast reflects the potential for substantial changes in the outlook for industry, as well as other developments in the Northwest.

This update considers changes in the following factors driving Northwest demand: expansion in the mining sector, including Ring of Fire development; recovery of the pulp and paper and forestry sectors; connection of remote communities; residential, commercial and other industrial activities in the region; and conservation impacts.

Mining sector and Ring of Fire

Electricity demand growth in the Northwest is expected to be driven primarily by mining sector growth, which is affected by factors such as commodity prices, the cost to develop resources, access to capital, and required regulatory approvals. Commodity market fundamentals in the past few years have been generating numerous proposals for the expansion of existing mines, development of new mines and reconnection of old mines in Northwest Ontario. The prospects for developing these proposals depends on various factors, which are discussed below.

Currently, around twenty projects are in development in the Northwest with their proponents working toward being in operation before the end of the decade, a number of them within the next three to five years. In addition, mining development in the Ring of Fire area, including mines and ore processing facilities, may add load to the Northwest through transmission expansion.

To forecast the number, size and timing of mining developments, the OPA looked to the following key milestones as indicators of project development status: the project's stage in the mining development cycle (i.e., from preliminary economic assessment through to construction); whether the project has applied to the Independent Electricity System Operator ("IESO") for a System Impact Assessment; whether a positive feasibility study has been completed; and whether the project is in the process of conducting an environmental assessment ("EA") or has received EA approval. Projects that have achieved some or all of these milestones are considered more likely to materialize than other projects that are in the preliminary economic assessment phase. Based on stakeholder input, the OPA has obtained a better understanding of the progress of these anticipated mining projects. Nonetheless, there is uncertainty in the location, size and timing of actual mining load development, and a range of scenarios was used to develop the forecast. Overall, forecast growth in mining sector demand contributes close to 70% of the forecast peak demand growth in the Northwest.

Pulp and paper and forestry sectors

These sectors have seen significant declines in the last decade due to decreasing demand for their products. Pulp and paper sector demand in the Northwest dropped by about 70% between 2004 and 2012, and the remaining mills continue to be affected by temporary shutdowns and have been operating at roughly half of their pre-downturn capacity. The strengthening of the Canadian dollar, the slowdown in the U.S. housing sector, and the recent economic recession have also led to declining forestry sector demand.

As the remaining pulp and paper mills are restructured and work to improve the cost-competitiveness of their operations, it is expected that the remaining operating facilities will slowly recover. In addition, recovery in the U.S. housing market is creating the potential for revitalization of the lumber industry, and a few new sawmills are currently being constructed in the region.

Connection of remote communities

There are 25 remote communities in the Northwest that are currently served by diesel generation and are not connected to the transmission network. Consistent with the OPA's August 2013 "North of Dryden Draft Reference Integrated Regional Resource Plan", this demand forecast includes the connection of 21 remote communities to the Northwest electricity grid between 2017 and 2025.

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Residential, commercial and other industrial sectors

Residential and commercial sector electricity demand growth is driven by growth in population and economic activity, which is linked to industrial sector activity in the Northwest. The load forecasts for these sectors were developed to be consistent with the scenarios of industrial growth and development in the Northwest considered in this forecast update. Population during the forecast period is projected to increase by 11% to 23%, depending on the extent of industrial sector activity. Demand growth from other industries is also included in the updated forecast.

Conservation

The effects of planned conservation are included in the load forecast. Planned conservation is based on provincially established targets and is achieved through incentive programs operated by local distribution companies and the OPA, as well as savings achieved through codes and standards and time of use rates.

3.3 Northwest Demand Scenarios

An updated demand forecast for the Northwest was developed taking into account the impacts of the various drivers described above. To account for the significant uncertainties inherent to these drivers, the OPA developed three demand scenarios to explore the robustness and flexibility of transmission and supply options under a range of outcomes. Key aspects of the scenarios are as follows:

- **Reference Scenario**. In this scenario, mining sector demand includes proposed mines that have passed significant development milestones, as well as a portion of additional proposals, including a moderate level of Ring of Fire activity. Mining loads are assumed to persist for the expected lifetime of proposed mining development; this is reflected in the variation in demand in the later years of the forecast. This scenario reflects some growth in the pulp and paper sector and a recovery in the forestry sector to its 2004 demand level. Residential and commercial sector demand growth is in line with the economic view of this scenario. Demand growth from residential and commercial sectors, the connection of remote communities, and other industrial sectors is also included.
- **High Scenario.** This scenario is based on stronger development of the mining sector, with all currently proposed facilities being fully developed, and additional load assumed to connect in the Ring of Fire area. This scenario also reflects growth in the pulp and paper sector. Higher residential and commercial sector growth is also forecast, consistent with these higher levels of industrial activity.
- **Low Scenario.** This scenario describes the impact of more modest growth in the mining sector. Assumptions for other sectors are the same as in the Reference scenario.

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The resulting Northwest peak and annual energy demand scenarios, net of savings from planned conservation, are shown in Figures 2 and 3. The Reference demand scenario brings the Northwest forecast back to the level of demand that was sustained for over a decade before the downturn, and the High and Low scenarios reflect uncertainty in the underlying factors driving demand.

For comparison, the scenarios prepared for the June 2011 Report are included in Figures 2 and 3, along with actual historical demand for the last decade. While the outlook for electricity demand in the Northwest is for higher net growth than was previously forecast, the actual loads for 2011 and 2012, which were not available in the June 2011 Report, provide some support to the new outlook, as they are higher than the previous forecast. It should be noted that in the June 2011 Report, Demand Scenario A (the higher of the two scenarios produced) was used as the Reference assumption for analysis purposes. As a result, the Reference load forecast assumption in this update is roughly 100 MW greater in 2025 than that used previously, and by 2031 the two planning scenarios converge.

Figure 2. Northwest Peak Demand Forecast Scenarios

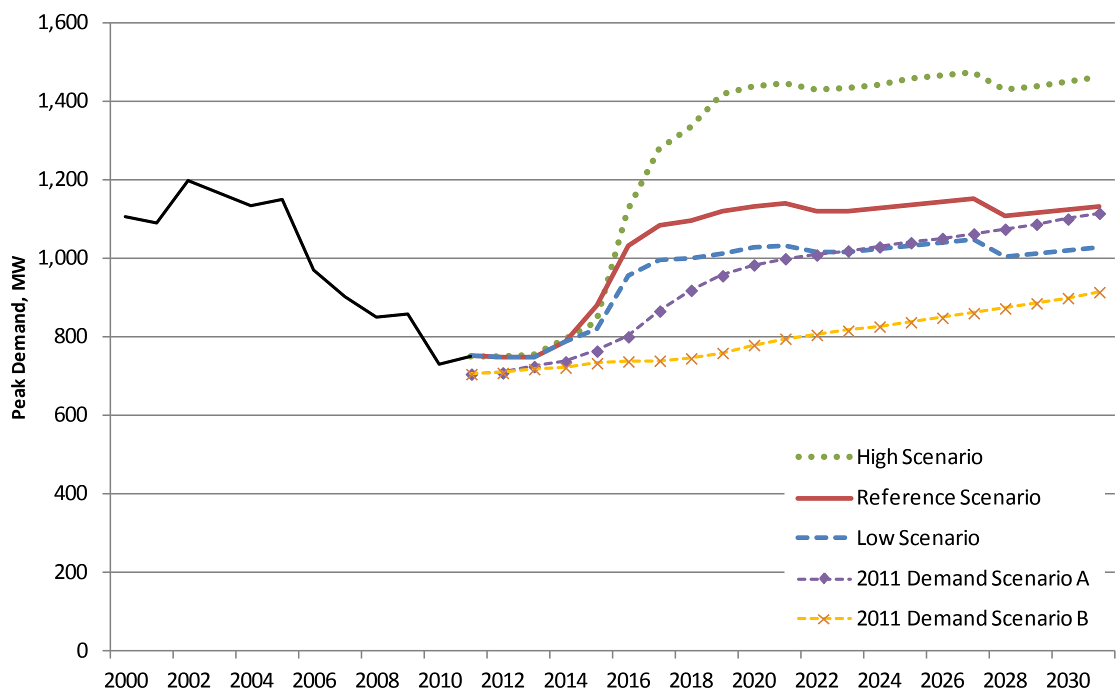

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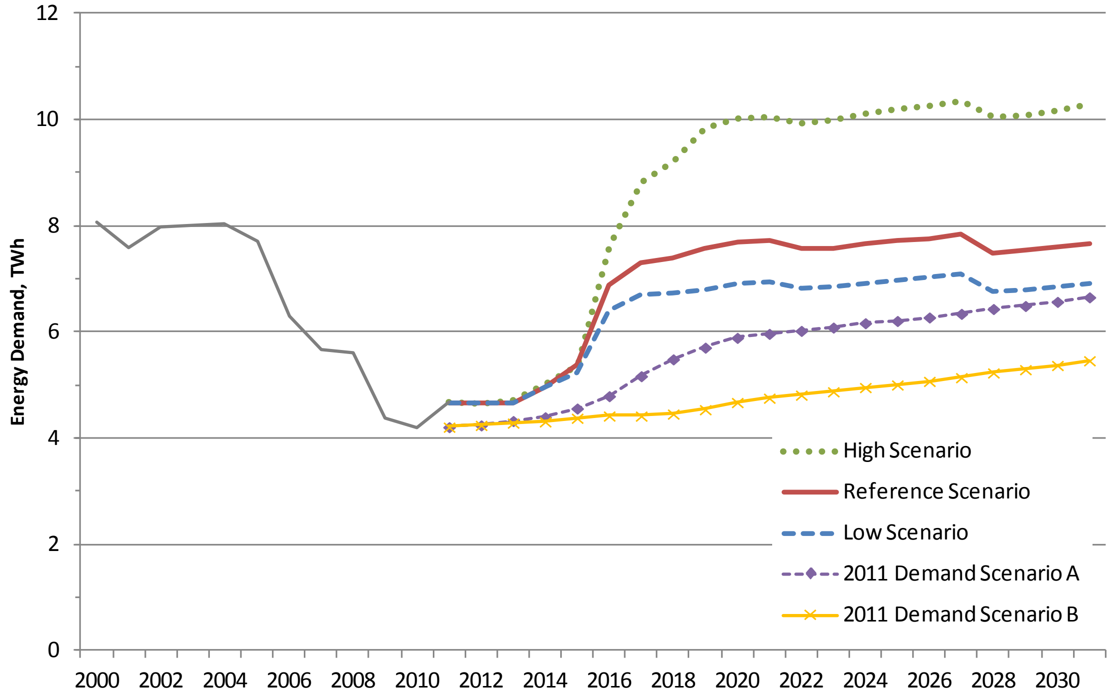
Figure 3. Northwest Energy Demand Forecast Scenarios



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4.0 EXISTING RESOURCES TO SUPPLY NORTHWEST DEMAND

As noted in the June 2011 Report, the Northwest relies upon both internal resources (generation located in the Northwest) and external resources (generation outside the Northwest accessed through existing ties) to meet its electricity supply requirements. An update on the Northwest supply outlook since the June 2011 Report is provided below.

4.1 Internal Resources in the Northwest

The province has continued to move forward with the shut-down of coal-fired resources, including the coal facilities in the Northwest. The conversion of Atikokan GS to biomass operation is underway and is expected to be in-service in 2014. In the interim, while Atikokan GS is offline, the IESO has concluded that one of the two Thunder Bay GS units is required to maintain reliability in the Northwest.[1] Accordingly, Ontario Power Generation ("OPG") and the IESO executed a Reliability Must Run ("RMR") agreement in February for the year 2013.

A major change in the assumptions for internal generation in this update is the availability of Thunder Bay GS after 2014. At the time of writing the June 2011 Report, based on the planned conversion of Thunder Bay GS to natural-gas fuelled operation, the OPA assumed that the full 300 MW capacity of this facility would be available to supply the Northwest between 2014 and 2024. Since that time, the government has announced that it is suspending this conversion. Although a final decision on the future of Thunder Bay GS is still pending, Thunder Bay GS is not assumed to be available in this update.

Assumptions regarding other internal resources are similar to those in the 2011 analysis, with the following developments:

- In the June 2011 Report, it was assumed that the 40 MW combined-cycle generating facility at Nipigon, a Non-Utility Generation (NUG) facility, would remain in operation after its contract expires in December 2022. In this update, based on current information, it is expected to retire in that year.

- In addition to 50 MW of non-hydroelectric renewables that were in service as of the June 2011 Report, about 150 MW of additional renewable generation has come into service. A further 100 MW has been contracted through various programs (e.g., FIT and microFIT), which is expected to come into service over the next several years.

[1] See *IESO-OPG Reliability Must-Run Agreement for Procurement of Physical Services from Thunder Bay Generating Station*, included as Attachment 1 in OPG's Request for Approval of a Reliability Must-Run Agreement for Thunder Bay GS, filed with the OEB on February 27, 2013.

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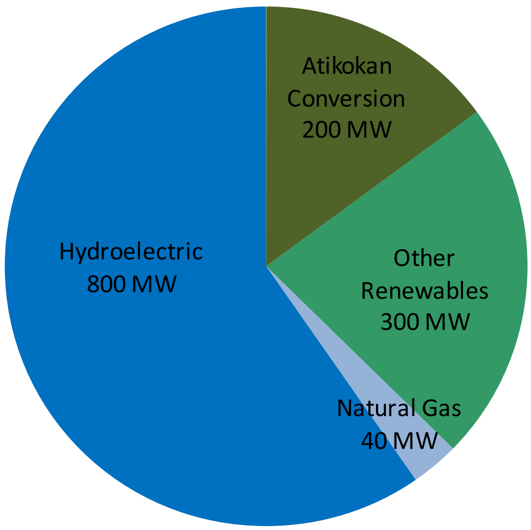
- Currently, about 50 MW of demand response ("DR") capacity is under contract through the DR-2 program. This contract is expected to expire in November 2014. In the June 2011 Report, 90 MW of DR was assumed to be available in the Northwest. In this update, there are no committed DR resources in the Northwest beyond 2014. DR will be treated as a potential alternative to meet identified needs.

The mix of internal resources in the Northwest in 2015 is shown in Figure 4.

Figure 4. Northwest Internal Resources by Type in 2015 (Installed Capacity)



4.2 External Resources Supplying the Northwest

The Northwest also relies on external resources that can be accessed through the existing E-W Tie, as well as interconnections with Manitoba and Minnesota. There has been no change in the capability of these ties since the June 2011 Report. As described in that report, the existing E-W Tie has a transfer capability of 175 MW, as defined by current reliability criteria.

4.3 Summary of Existing Resources

The existing internal and external resources assumed to be available to supply the Northwest in this planning analysis are shown in Figure 5. The figure reflects the available capacity of internal resources to meet Northwest peak demand under low water conditions. It also includes the capability of the existing E-W Tie. Imports from Manitoba and Minnesota are not included for planning purposes as there are presently no contracts in effect for firm import capacity.

As Figure 5 indicates, existing supply is expected to be reduced at two points in the planning horizon. After 2014, the removal of the remaining coal-fired generation in the Northwest will result in reduced

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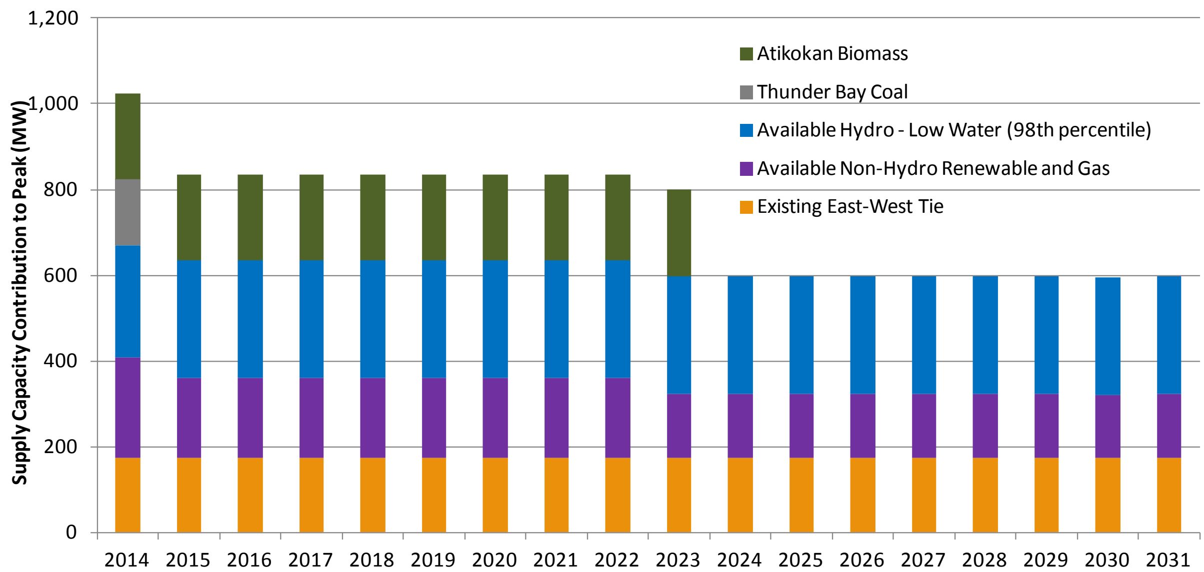
supply. A second reduction in available resources is expected in 2024, corresponding with the expiry of the contract for Atikokan biomass generation.

Figure 5. Northwest Supply Capacity under Low Hydro Conditions



5.0 THE NEED FOR ADDITIONAL SUPPLY FOR THE NORTHWEST

Based on the current outlook for Northwest demand and supply, an assessment of the reliability and adequacy of the Northwest energy system was conducted. Based on this assessment, the OPA forecasts a need for additional capacity and energy supply to meet forecast peak and energy demand in Ontario's Northwest. These needs are described below.

5.1 Expected Capacity Need

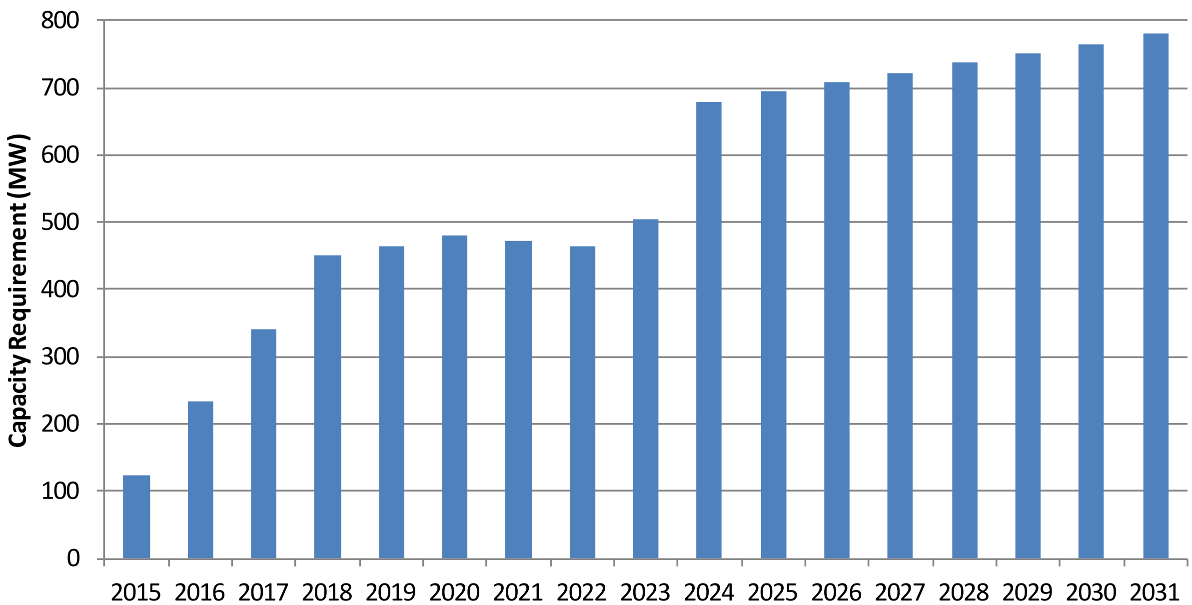
To assess capacity needs in the Northwest, the OPA conducted a reliability assessment using a probabilistic analysis approach to determine capacity requirements, which are expressed as a loss of load expectation. As water conditions have a strong impact on overall supply availability in the Northwest, a range of water conditions was analyzed.

The resulting capacity shortfall, based on the Reference peak demand scenario, is shown in Figure 6. The shortfall is expected to begin in 2015, with the retirement of coal-fired resources, and to grow over the next few years as load increases in the Northwest. During these early years, there may be a need for interim resources to supply Northwest demand until a long-term solution can be brought into service. The OPA has been working with the IESO to develop interim measures for this period to ensure that demand can be met in the Northwest. Potential options include negotiating firm imports from

Manitoba/Minnesota, contracting for demand response, updating the Special Protection System ("SPS") for the region to operate the existing transmission system to higher capability, and the addition of gas-fired generation. While the first three options could be short term in nature, the potential addition of gas-fired generation would have longer-term value.

Between 2018 and 2023, the capacity shortfall is expected to be about 500 MW, with slight variations reflecting expected changes in load and the supply mix. In 2024, with the expiry of the Atikokan biomass contract, the shortfall rises to nearly 700 MW. After 2024, the shortfall gradually increases due to continued forecast load growth, eventually reaching almost 800 MW in 2031.

Figure 6. Expected Northwest Capacity Requirement

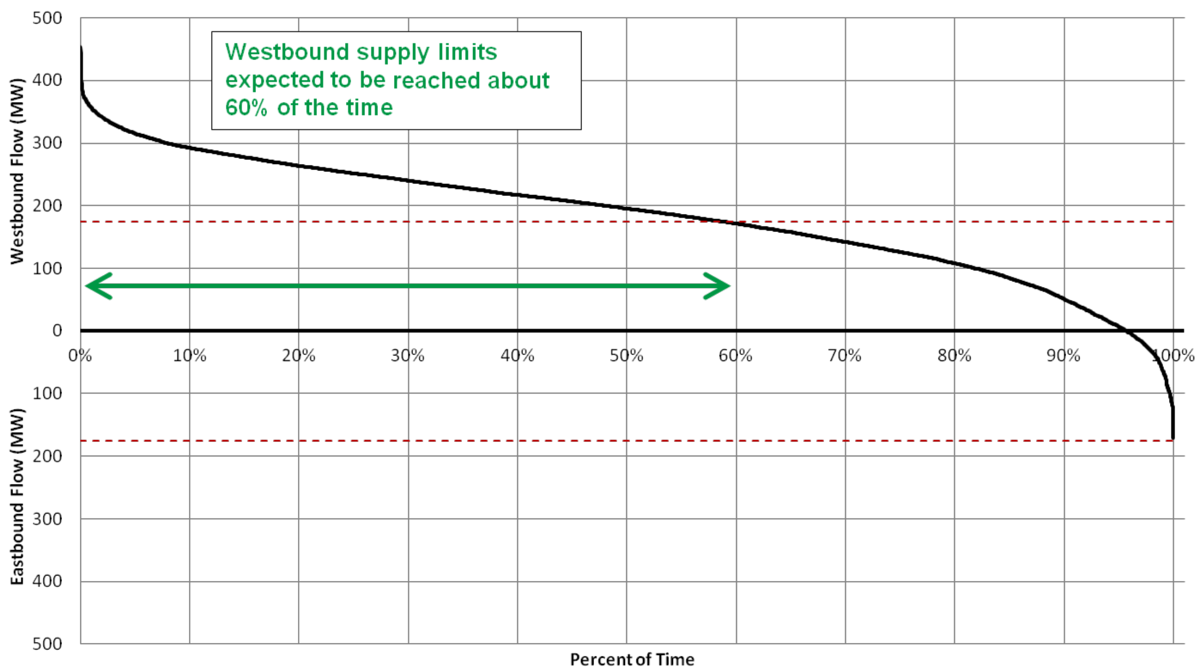


5.2 Expected Energy Need

The region's energy needs arising from expected changes in Northwest supply and demand were also analyzed. An indication of the need for energy to supply the Northwest is provided by analyzing expected flows on the E-W Tie. Figure 7 shows an illustrative duration curve for the unconstrained flow on the existing E-W Tie, expressed as a percentage of time, for the year 2020 under median-water conditions. This curve represents the amount of energy that would be expected to flow across the E-W Tie, under the current Northwest supply and demand outlook, if there were no transmission constraints. Its shape indicates that, under these conditions, the E-W Tie would be expected to supply the Northwest through westbound flows 95% of the time, while eastbound flows would occur only about 5% of the time. The horizontal dotted lines in Figure 7 indicate the 175 MW eastbound and westbound transfer limits on the existing E-W Tie. Under the conditions shown, the supply limit would be exceeded approximately 60% of the time. When the supply limit is exceeded, other sources of supply would need to be found to meet Northwest demand. This could include uneconomic dispatch of Northwest generators, or reliance on imports.

As noted, the analysis in Figure 7 is based on median water conditions. Under low water conditions, the required westbound flows are expected to be above the existing E-W Tie capability almost all the time.

Figure 7. Unconstrained E-W Tie Flow and Planning Limits



6.0 ANALYSIS OF ALTERNATIVES TO MEET NORTHWEST SUPPLY NEEDS

Based on the updated planning assessment presented above, there is a need to provide capacity and energy supply to meet forecast demand in the Northwest. Two alternatives for meeting these needs were evaluated:

(1) **No E-W Tie expansion.** In this alternative, all of the forecast capacity and energy needs are met through the staged addition of new gas-fired generation within the Northwest. In the Reference scenario, this involves the installation of a total of 800 MW of gas-fired generation over the study period.

(2) **E-W Tie expansion.** In this alternative, the E-W Tie expansion project provides a foundation for meeting the Northwest's needs, with additional generation included to meet any incremental

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supply requirements that arise in the long term. The expansion project, as previously specified, involves a new line between Wawa and Thunder Bay, switched at Marathon; it would bring the combined transfer capability of the E-W Tie from 175 MW to 650 MW. In the Reference scenario, a need for additional supply beyond the capability provided by the E-W Tie expansion emerges after 2024. As a result, 200 MW of peaking gas-fired generation is assumed to be added at that time.

In the June 2011 Report, the OPA compared these two alternatives in terms of their cost-effectiveness and other benefits. Based on recent changes in the outlook for the Northwest, the cost-effectiveness analysis has been revised and is described below.

The other benefits discussed in the June 2011 Report—system flexibility, removing barriers to resource development, reduced congestion payments, reduced losses, and improved operational flexibility—are all still applicable. As there has been no change to these benefits, which are largely qualitative (or in some cases difficult to quantify), an update is not provided in this report.

6.1 Cost-Effectiveness Comparison of Generation and Transmission Alternatives

An economic analysis of the two alternatives was conducted and their relative net-present-value (“NPV”) was compared. A sensitivity analysis was performed to test the impact of a variety of factors on the results. The assumptions used in the analysis are as follows:

- The study period extends from 2018 to 2062, to capture the full lifetime of the station upgrades associated with the E-W Tie expansion. For planning purposes, the expanded E-W Tie was assumed to come into service by early 2018. The life of the stations was assumed to be 45 years, and 70 years for the line.
- NPV analysis was conducted using a 4% real social discount rate. Sensitivities were performed using a range of real social discount rates. The results are expressed in 2015$.
- The Reference demand scenario was used in the Reference case. A sensitivity analysis was performed to test the impact of the Low load growth scenario on the cost-effectiveness analysis.
- For planning purposes, capital cost estimates of $100 million for the station facilities and $500 million for the line were used. As costs are expected to be refined through project development work, the OPA employed the same cost estimates used in the July 2011 Report in this update.
- Existing supply resources described in section 4 were included in the analysis. A sensitivity analysis was performed to determine the impact of adding 100 MW of gas-fired peaking generation in the Northwest as a solution to meet interim needs.

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- New capacity in the Northwest and the rest of Ontario was added, as required, to satisfy reliability criteria. These capacity needs were determined as described in section 5.1.
- Median-water hydroelectric energy output was used for energy simulation purposes.
- Natural gas prices were assumed to be an average of $5.50/MMBtu throughout the study period. A sensitivity analysis was performed with average gas prices of $8.50/MMBtu.

Under the Reference assumptions, the E-W Tie expansion results in a net benefit of just over $300 million compared with the no-expansion alternative. The sensitivity analysis indicates that the economics are robust across the range of conditions tested, with positive NPV results in all cases. Based on the sensitivities tested, the E-W Tie expansion ranges from a net benefit of just over $400 million to a break-even proposal associated with a real social discount rate of 7%. Under the Low load growth scenario, the economic benefit of the E-W Tie was lower but still significant, with a net benefit of $120 million.

As discussed previously, the E-W Tie expansion would provide additional benefits, beyond simply meeting the supply needs of the Northwest, which the non-expansion alternative does not provide: system flexibility, removal of barriers to resource development, reduced congestion payments, reduced losses, and improved operational flexibility. While these benefits are not reflected in the cost-effectiveness comparison of the two alternatives, they do form an important part of the rationale for the E-W Tie expansion. The OPA expects to provide a more detailed discussion of these benefits than was provided in the June 2011 Report as part of future evidence in support of the E-W Tie expansion.

7.0 CONCLUSION AND RECOMMENDATION

As outlined in this report, a number of factors have evolved since the publication of the OPA's June 2011 Report. Electricity demand forecasts for the Northwest have increased, due to increased activity in the mining sector. At the same time, with fewer internal resources available to supply this demand (i.e., the suspension of the conversion of Thunder Bay GS to natural gas), there is a greater urgency to plan supply for the Northwest. The expanded E-W Tie provides a long-term foundation for supplying the Northwest, providing greater system flexibility around which internal supply resources can be developed. Together, these updated factors strengthen the case for the E-W Tie. The OPA continues to recommend the E-W Tie as the preferred alternative to maintain a reliable and cost-effective supply of electricity to the Northwest over the long term.

It is the OPA's expectation that the new E-W Tie line will be a double-circuit design, providing total westbound capability of 650 MW in conjunction with the existing E-W Tie. Given the current outlook for supply and demand in the Northwest, the OPA also expects that the E-W Tie project be designed to provide the full 650 MW transfer capability when the line comes into service, rather than staging the

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expansion. A double-circuit design has greater potential for future expandability, which means its capability could be increased in the future through the addition of further voltage control or compensation equipment, resulting in a higher thermal rating of up to about 800 MW.

The E-W Tie expansion is an important component of the long-term integrated plan for the Northwest. The OPA notes that a 2018 in-service date is appropriate for the E-W Tie project, and would not recommend increasing costs significantly in order to bring the line into service by 2017. Development work for a double-circuit line, as proposed by NextBridge Infrastructure, should proceed at this time, toward an in-service date of early 2018.

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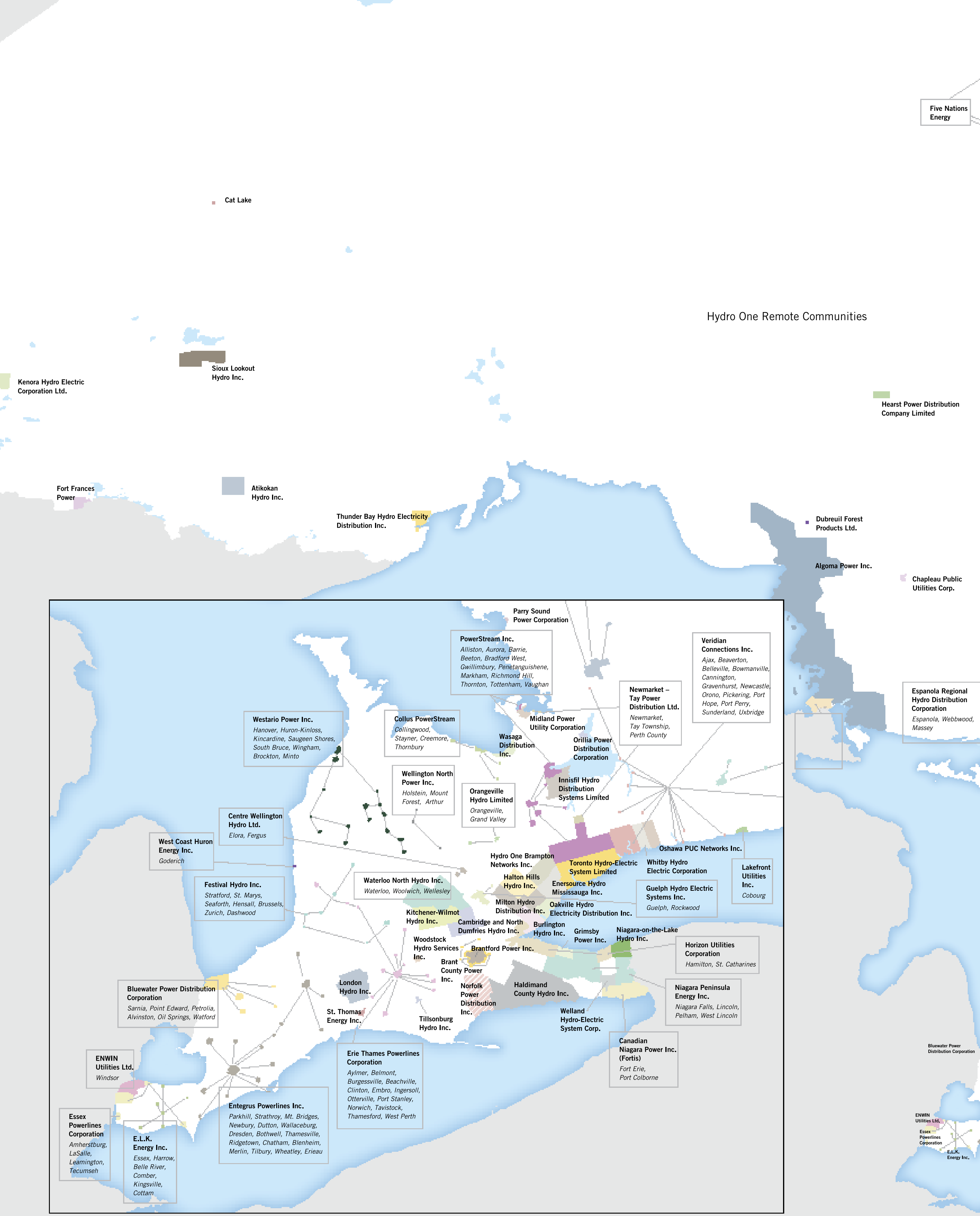
Achieving Balance

Ontario's Long-Term Energy Plan

Ontario



Service areas shown here are approximate.

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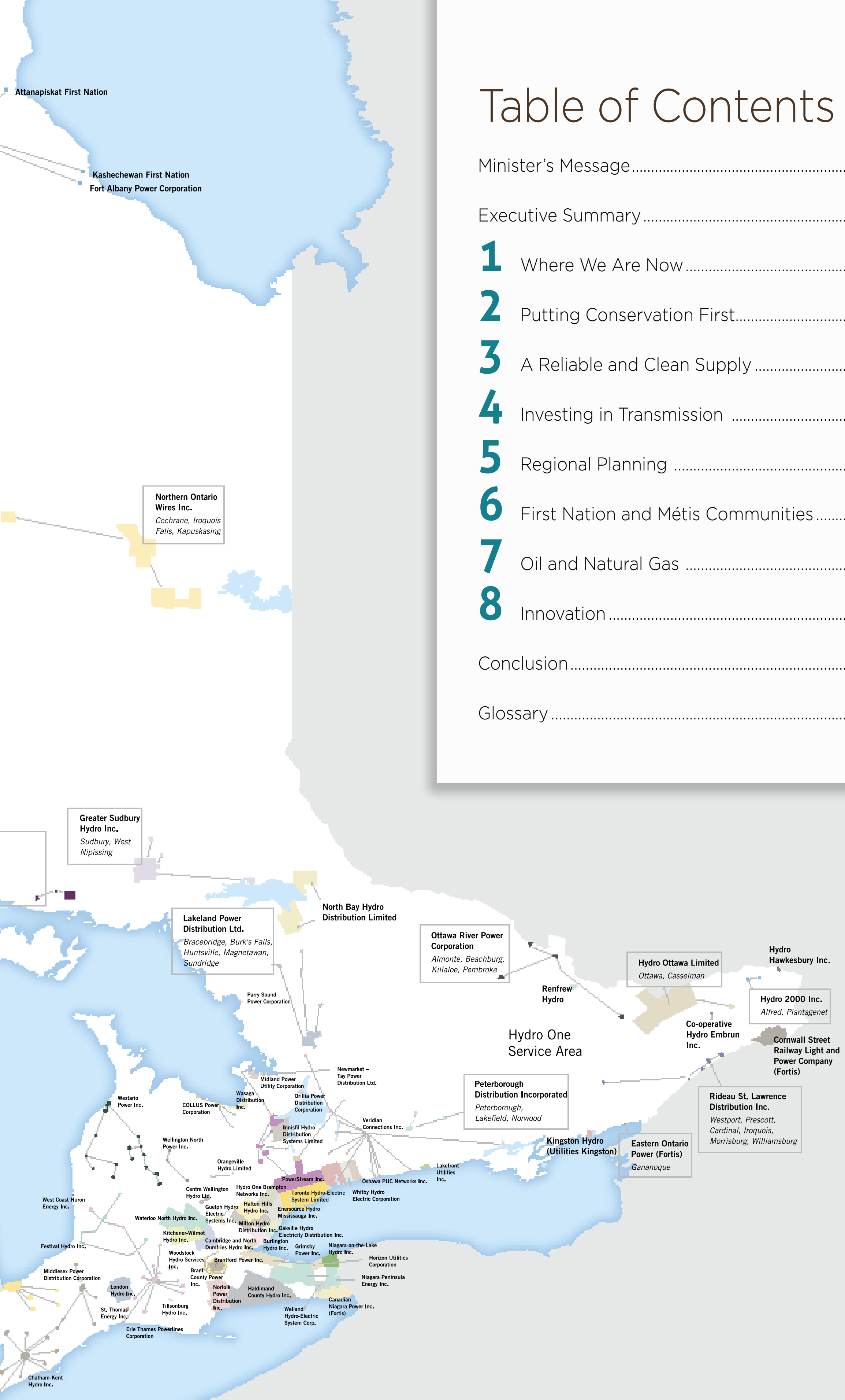
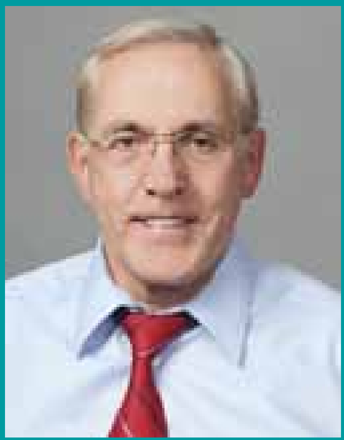


Source: Independent Electricity System Operator
November 2013

ACHIEVING BALANCE

Minister's Message



Ontario has come a long way since 2003, when we were faced with aging energy infrastructure, a shortage of supply and a system that relied on expensive imports and dirty coal.

Our government has made significant progress transforming our electricity system into one that Ontarians can count on.

To build and maintain a clean, reliable and affordable electricity system, more than $11 billion has been invested in transmission and distribution networks by Hydro One alone since 2003. This investment has contributed to the province's annual gross domestic product (GDP) by an average of $835 million and supported 8,000 direct and indirect jobs. Beyond that, Ontario's other distributors have invested a further $8 billion since 2003. Also, more than $21 billion has been invested in cleaner generation. Ontario has virtually eliminated coal from our electricity system, with the last plant to close in 2014. The phase out of coal is the single largest climate change initiative in North America. Coal use had accounted for $4.4 billion per year in financial, health and environmental costs.

Today, Ontario is a world leader in energy technology, innovation and smart grid solutions. Smart meters and consumer demand response programs are allowing ratepayers to control and understand their electricity consumption better while additional smart grid technologies are being used by utilities to operate an advanced, more efficient and modern grid. All told, our investments are making Ontario's grid modern, clean and reliable and a foundation for future growth and prosperity.

Ontario's energy use has changed substantially in the last decade. As our economy continues to grow, our homes, businesses and industries are becoming more efficient. Our demand projections have been updated to reflect this new reality and to address areas of growth around the province.

This review of the Long-Term Energy Plan was the most comprehensive consultation and engagement process the Ministry of Energy has ever undertaken. Sessions were held online and around the province with municipalities, Aboriginal communities, stakeholders and the public. This process informed the direction of the Long-Term Energy Plan and we will make continued engagement a priority.

Communities must be allowed to take a more central role when implementing provincial policy objectives. The opportunity for communities to participate in energy infrastructure must be balanced with their responsibility to take ownership of local decisions.

Ontario has adopted a policy of Conservation First, focusing on rate mitigation over major investments in generation or transmission to curb costs for ratepayers. This will mean pursuing lower-cost options to meet energy needs when and where we need it.

The Long-Term Energy Plan will be flexible; Ontario will plan for a lower demand scenario, with the ability to adjust to potential demand changes. For that reason, an annual Ontario Energy Report will be issued to provide an outline of how supply and demand are tracking and also to review progress in implementing the Long-Term Energy Plan.

A major advantage of Ontario's supply mix is the diversity of our generation, which includes solar, wind, natural gas, nuclear, combined heat and power, bioenergy, hydroelectric and waste to energy. Rate mitigation will be top of mind as we leverage this diversity to maximize value for ratepayers.

Ontario will continue to invest in new renewable generation, and explore flexible options such as storage technologies by applying balanced planning principles in a measured and sustainable way.

Nuclear generation will continue to be the backbone of Ontario's supply, and we have confirmed our commitment to nuclear with the refurbishment of the Bruce and Darlington sites. Due to the strong supply situation, we have deferred the construction of new nuclear generating units.

Finally, we will work with our agencies and the province's local distribution companies to ensure they operate more efficiently and produce savings that will benefit Ontario's ratepayers.

This updated Long-Term Energy Plan will encourage conservation, and provide the clean, reliable and affordable energy Ontario will need now and into the future. Our plan will build on our past accomplishments, and achieve a better balance.

Bob Chiarelli
Minister of Energy
December 2013

Executive Summary

Ontarians are benefitting from a clean, reliable and affordable energy system.

By the end of 2014, Ontario will be coal free. At the same time, increased energy efficiency and the changing shape of Ontario's economy have reduced the demand for electricity.

Ontario is currently in a strong supply situation and has time to consider how to address future needs. Ontario is committing the resources to meet electricity demand growth that will be lower than anticipated as the economy continues its transition to an efficient, lower energy intensive future. We are ensuring we have the supply to meet the likely demand, and are keeping options open to meet higher demand if needed. We will report annually on the outlook for supply and demand. This will give us the opportunity to make adjustments so we can be both prudent and flexible in our energy investments.

The 2013 Long-Term Energy Plan (LTEP) takes a pragmatic approach. The plan is designed to balance the following five principles: cost-effectiveness, reliability, clean energy, community engagement and an emphasis on conservation and demand management before building new generation.

The 2013 LTEP, by taking a pragmatic and flexible approach and balancing these five principles, builds on the foundation laid in the 2010 LTEP while also lowering the projected total system costs. The key elements of the 2013 LTEP include:

Conservation First

- The Ministry of Energy will work with its agencies to ensure they put conservation first in their planning, approval and procurement processes. The ministry will also work with the Ontario Energy Board (OEB) to incorporate the policy of conservation first into distributor planning processes for both electricity and natural gas utilities.
- The province expects to offset almost all of the growth in electricity demand to 2032 by using programs and improved codes and standards. This will lessen the need for new supply. Our long-term conservation target of 30 terawatt-hours (TWh) in 2032 represents a 16% reduction in the forecast gross demand for electricity, an improvement over the 2010 LTEP.
- Ontario is aiming to use Demand Response (DR) to meet 10% of peak demand by 2025, equivalent to approximately 2,400 megawatts (MW) under forecast conditions. To encourage further development of DR in Ontario, the Independent Electricity System Operator (IESO) will evolve existing DR programs and introduce new DR initiatives.

- The IESO will continue to examine and consult on the potential benefits and development of a capacity market, where different generation and demand resources compete to address capacity needs.
- The government is committed to promoting a co-ordinated approach to conservation and will encourage collaboration of conservation efforts among electricity and natural gas utilities.
- The government will work to make new financing tools available to consumers starting in 2015, including on-bill financing for energy efficiency retrofits.
- To help consumers choose the most efficient products for their homes and businesses, Ontario will provide information and incentives; it will also continue to show leadership in establishing minimum efficiency requirements for products such as water heaters, clothes dryers, televisions, fluorescent lamps, motors and boilers.
- The Green Button Initiative will give consumers access to their energy data and the ability to connect to mobile and web-based applications so they can analyze and manage their energy use.
- Social benchmarking can increase awareness of energy use and promote conservation. A social benchmarking pilot program is under way, led by the Ontario Power Authority (OPA) to test different approaches that enable consumers to compare their energy consumption with other similar consumers. Pending the success of the pilot program, the government will explore expanding social bench-marking and including other sectors.
- The government is also working with Ontario EcoSchools to bring more resources about energy conservation to the curriculum for students and teachers.

Annual Reporting

- An annual Ontario Energy Report will be issued to update the public on changing supply and demand conditions, and to outline the progress to date on the LTEP.

Nuclear

- Ontario will not proceed at this time with the construction of two new nuclear reactors at the Darlington Generating Station. However, the Ministry of Energy will work with Ontario Power Generation (OPG) to maintain the site licence granted by the Canadian Nuclear Safety Commission (CNSC).
- Nuclear refurbishment is planned to begin at both Darlington and Bruce Generating Stations in 2016.
- During refurbishment, both OPG and Bruce Power will be subject to the strictest possible oversight to ensure safety, reliable supply and value for ratepayers.
- Nuclear refurbishment will follow seven principles established by the government, including minimizing commercial risk to the government and the ratepayer, and ensuring that operators and contractors are accountable for refurbishment costs and schedules.
- The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.
- Ontario will support the export of our home-grown nuclear industry expertise, products and services to international markets.

Renewable Energy

- By 2025, 20,000 MW of renewable energy will be online, representing about half of Ontario's installed capacity.
- Ontario will phase in wind, solar and bioenergy over a longer period than contemplated in the 2010 LTEP, with 10,700 MW online by 2021.
- Ontario will add to the hydroelectricity target, increasing the province's portfolio to 9,300 MW by 2025.
- Recognizing that bioenergy facilities can provide flexible power supply and support local jobs in forestry and agriculture, Ontario will include opportunities to procure additional bioenergy as part of the new competitive process.
- Ontario will review targets for wind, solar, bioenergy and hydroelectricity annually as part of the Ontario Energy Report.
- The Ministry of Energy and the OPA are developing a new competitive procurement process for future renewable energy projects larger than 500 kilowatts (kW), which will take into account local needs and considerations. The ministry will seek to launch this procurement process in early 2014.
- Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program.

Natural Gas/Combined Heat and Power

- Natural gas-fired generation will be used flexibly to respond to changes in provincial supply and demand and to support the operation of the system.
- The OPA will undertake targeted procurements for Combined Heat and Power (CHP) projects that focus on efficiency or regional capacity needs, including a new program targeting greenhouse operations, agri-food and district energy.

Clean Imports

- Ontario will consider opportunities for clean imports from other jurisdictions when such imports would have system benefits and are cost effective for Ontario ratepayers.

Rate Mitigation and Efficiencies

- The 2013 LTEP cost and price forecasts are lower than previously forecast in 2010.
- Significant ratepayer savings will be realized as a result of reduced Feed-in Tariff (FIT) prices, the ability to dispatch wind generation, the amended Green Energy Investment Agreement, and the decision to defer new nuclear.
- The government will continue to work with its agencies—Hydro One, OPG, the IESO, the OPA and the OEB—to develop business plans and efficiency targets that will reduce agency costs and result in significant ratepayer savings.
- The government will encourage OPG and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians.
- The Distribution Sector Review Panel, which delivered its report in late 2012, identified the potential for significant savings among the province's Local Distribution Companies (LDCs). The government expects that LDCs will pursue innovative partnerships and transformative initiatives that will result in electricity ratepayer savings.
- The government will look closely at key features of the OEB's new regulatory framework for LDCs such as the Scorecard, which will report annually on key LDC performance metrics, to develop further distribution sector policy options.

Enhanced Regional Planning

- The government will implement the IESO and the OPA recommendations for regional planning and the siting of large energy infrastructure.
- The ministry, the IESO and the OPA will work with municipal partners to ensure early and meaningful involvement in energy planning.
- Municipalities and Aboriginal communities will be encouraged to develop their own community-level energy plans to identify conservation opportunities and infrastructure priorities. The Municipal Energy Plan Program and the Aboriginal Community Energy Plan Program will support these efforts.

- Regional plans will promote the principle of Conservation First while also considering other cost-effective solutions such as new supply, transmission and distribution investments.

Transmission Enhancements

- Hydro One will be expected to begin planning for a new Northwest Bulk Transmission Line to increase supply and reliability to the area west of Thunder Bay. The area faces growth in demand, some of which is beyond what today's system can supply. Hydro One and Infrastructure Ontario will be expected to work together to explore ways to ensure cost-effective procurement related to the line.
- Connecting remote northwestern First Nation communities is a priority for Ontario. Ontario will continue to work with the federal government to connect remote First Nation communities to the electricity grid or explore on-site alternatives for the few remaining communities where there may be more cost-effective solutions to reduce diesel use.
- All regions of the province can expect timely local transmission enhancements as needs emerge. Upgrades and investments will meet system goals, such as maintaining or improving reliability or providing the infrastructure necessary to support growth.

Aboriginal Engagement

- The government understands the importance of First Nation and Métis participation in the development of energy and conservation projects. The government will continue to review participation programs to ensure they provide opportunities for First Nation and Métis communities.
- Ontario will launch an Aboriginal Transmission Fund in early 2014 to facilitate First Nation and Métis participation in transmission projects.
- The province expects that companies looking to develop new transmission lines will, in addition to fulfilling consultation obligations, involve potentially affected First Nation and Métis communities, where commercially feasible and where there is an interest.
- The government will continue to encourage Aboriginal participation, including through the FIT program and future large renewable energy procurements, in a way that reflects the unique circumstances of the First Nation and Métis communities.

Energy Innovation

- Ontario's energy sector is an innovation leader. The government will seek to expand the Smart Grid Fund and build on previous success. The Smart Grid Fund has created more than 600 jobs and supported 11 projects developing innovative technologies.
- The government intends to initiate work, on a priority basis, to address regulatory barriers that limit the ability of energy storage technologies to compete in Ontario's electricity market.
- By the end of 2014, the government will include storage technologies in our procurement process, starting with 50 MW and assessing additional engagement on an ongoing basis.
- The new competitive procurement process for renewable energy projects larger than 500 kW will also provide an opportunity to consider proposals that integrate energy storage with renewable energy generation.

Oil and Natural Gas

- Ontario relies on oil and natural gas to support basic needs such as heat and transportation. These fuels are also essential to Ontario's economy and quality of life.
- The government will work with gas distributors and municipalities to pursue options to expand natural gas infrastructure to service more communities in rural and northern Ontario.
- Ontario has adopted principles it will use to review large scale pipeline projects to ensure that they meet the highest environmental and safety standards as well as benefit Ontario's economy.

1

Where We Are Now

Ontario can be proud of what it has accomplished in energy in the past decade. The elimination of coal-fired electricity generation is the single largest greenhouse gas reduction measure in North America. This is helping to improve Ontarians' health, environment and quality of life.

Last year, coal accounted for less than 3% of total generation, and Ontario will be coal free by the end of 2014. This is a big change from a decade ago, when coal-fired generation provided 25% of Ontario's electricity supply. This has produced a real improvement in air quality in Ontario. Since 2003, the emissions of sulphur dioxide coming from coal-fired generation in the electricity sector have dropped by 93%, there has been a 90% reduction in nitrogen oxides, and mercury levels are at their lowest in 45 years. Greenhouse gas emissions have been reduced by almost 90%.

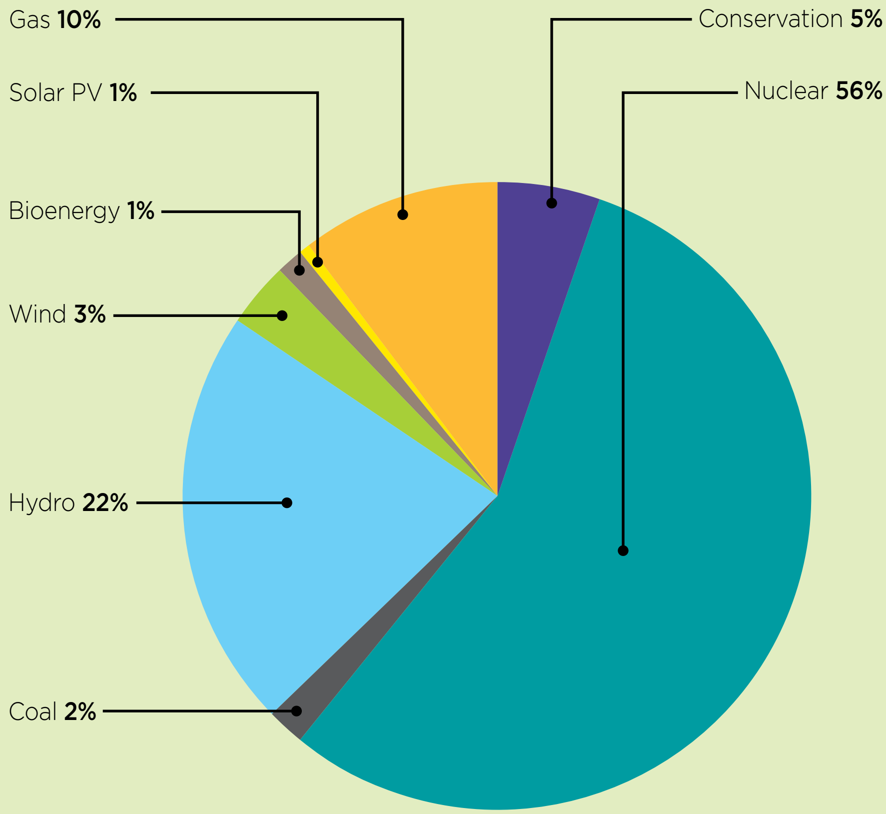
The province now has a reliable foundation on which to build. In 2004, Ontario's supply outlook was not sufficient to meet North American reliability standards. Today's margins are above required levels. This reflects the strong supply of electricity the province is enjoying. Ontario has gone from a deficit of 3,800 MW in 2003 to a comfortable surplus in 2013.

Figure 1 shows the current supply mix (generation and conservation) on which Ontarians rely.

Ontario is in a strong supply position and is benefitting from a decade of investments in conservation, generation, transmission and distribution.

- The province has added about 12,000 MW of new and refurbished generation since 2003 — enough electricity to power both the Greater Toronto Area and the City of Ottawa. Wind-powered generation now provides more electricity than coal-fired generation.

Figure 1: Ontario's Electricity Production and Conservation, 2013 (TWh)



Source	Energy Production and Conservation (TWh)
Conservation	8.6
Gas	16.6
Solar PV	1.0
Bioenergy	2.0
Wind	5.4
Hydro	35.5
Nuclear	90.8
Coal	3.0
Total	**162.9**

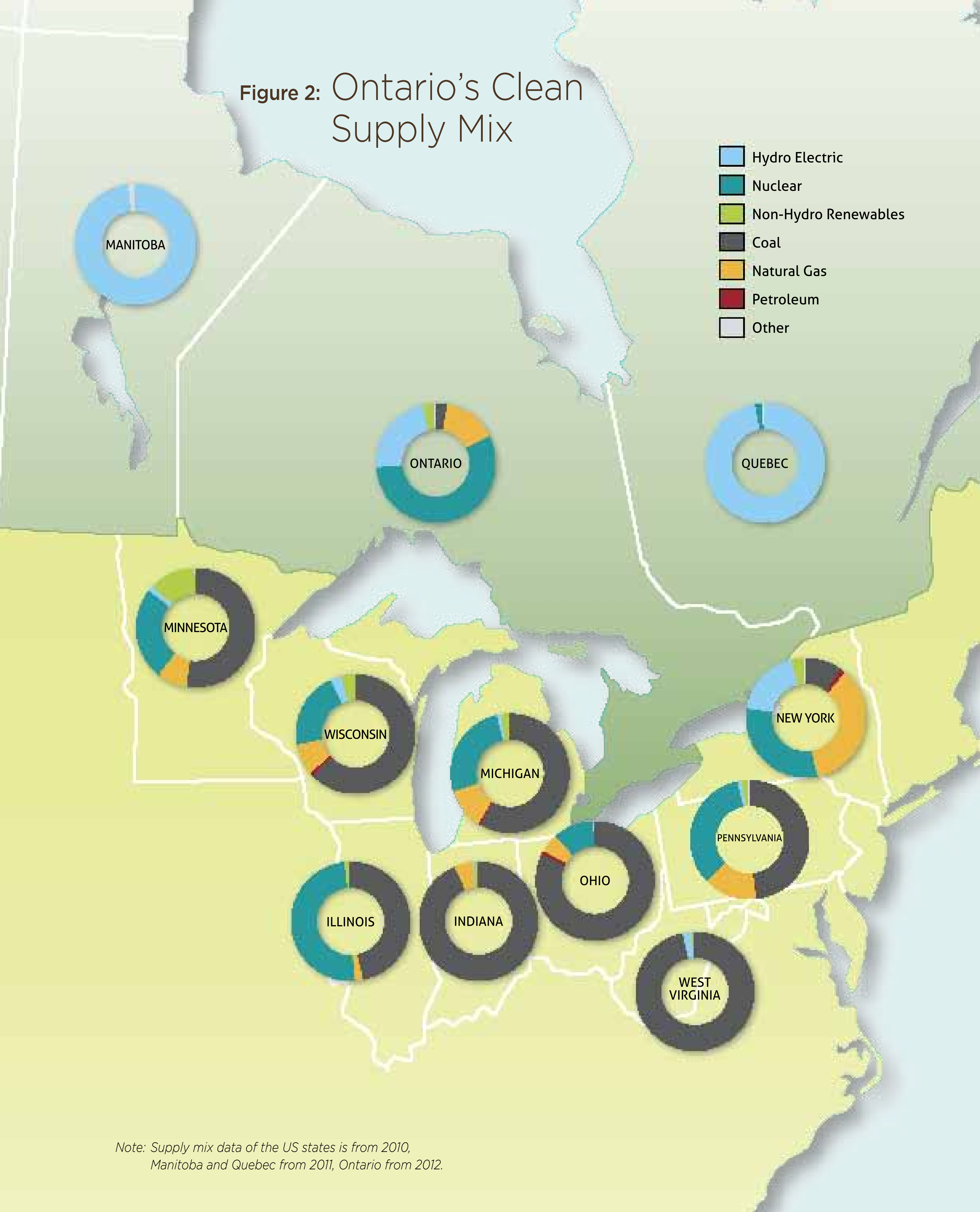
Source: Ontario Power Authority, November 2013

Note: Numbers represent actual production up to October 2013 and forecast for November and December.

Conservation values represent actual verified results to 2012 and forecast for 2013.

Figure 1 does not include diesel fuel. In 2013, diesel fuel is expected to generate about 0.1 TWh of electricity in remote First Nation communities in northwestern Ontario.

Figure 2: Ontario's Clean Supply Mix



Note: Supply mix data of the US states is from 2010, Manitoba and Quebec from 2011, Ontario from 2012.

- From 2005 to the end of 2013, it is projected that Ontarians will have conserved 8.6 TWh of electricity — enough to power a city about the size of Mississauga.
- Water is now flowing through the third tunnel at Niagara Falls, producing enough electricity to power 160,000 homes, or a city the size of Barrie.
- The Lower Mattagami project will add almost 440 MW of new hydroelectric capacity when completed. Construction on the project is currently underway, and about 1,600 workers are employed, including more than 250 First Nation and Métis individuals. This $2.6-billion investment in Northern Ontario will upgrade four generating stations located about 70 km northeast of Kapuskasing.
- More than 35 First Nation and Métis communities are involved in wind, solar and hydroelectric projects. They are participating in 239 projects, representing over 1,000 MW of clean electricity.
- Since 2003, Hydro One has upgraded more than 10,000 km of its transmission and distribution lines. That is equivalent to a round trip from Montreal to Vancouver. These investments have contributed to increasing the province's transmission capacity by about 10,000 MW.

These accomplishments have produced a cleaner electricity system than those of our neighbours in the United States. We have done this without the abundant supply of hydroelectric resources enjoyed by Manitoba and Quebec.

As we look to the future, we must acknowledge that forecasting is not an exact science. In the 2010 LTEP, the government developed its plans to accommodate a moderate amount of growth in the demand for electricity. However, events since 2010 demonstrate why plans should be flexible to meet changing conditions.

In the past few years, demand for electricity in Ontario has declined because of across-the-board reductions by the average household, business and industrial user; changes in the composition of Ontario's industrial sector; notable increases in the efficiency of energy use; and savings from conservation programs.

The future promises to be less energy-intensive than the past, because the demand for energy is no longer as closely linked to economic growth, due to improvements in residential, commercial and industrial electricity intensity. While economic activity is increasing as the recovery takes hold, the demand for electricity continues to be relatively flat, and is expected to remain so for the next decade. This is certainly a welcome development because while economic growth continues to be positive and productivity increases, demand for electricity remains flat.

The energy profile of the Ontario economy has changed for a variety of reasons. In 2005, the five largest industrial sectors of transmission-connected electricity consumption (pulp and paper, mining, iron and steel manufacturing, petroleum products and auto manufacturing) accounted for 12% of total electricity consumption in the province. By 2012, this share had fallen to 9%, for a total decline of 5.5 million kWh, roughly the equivalent of the annual production from one of Ontario's nuclear units.

There was new growth as well. Low electricity demand no longer means low economic growth. Recent gains in energy efficiency and improvements in commercial and industrial electricity intensity have reduced the system costs associated with economic growth. As we continue to support a growing economy with less energy, Ontario's net economic productivity will increase. In the past decade, Ontario has seen a burgeoning advanced technology sector that holds much promise for the future growth of the provincial economy. These new industries require less energy to produce goods and support jobs.

Energy efficiency has also reduced demand. Ontario's Building Code has been updated, requiring the construction of more energy-efficient homes, offices and industrial facilities. At the same time, homeowners and businesses are buying more energy-efficient products, as they replace their existing equipment, technology and appliances.

It is clear that we need to prepare for an energy-efficient future in Ontario. That's why Ontario is committing resources to meet a lower-demand forecast while maintaining flexibility to respond to higher needs. In the future, a new annual energy reporting process will help us identify changes in demand and plan prudently for more resources if and when they are needed.

Figure 3: Residential Electricity Intensity*

Households are becoming more efficient

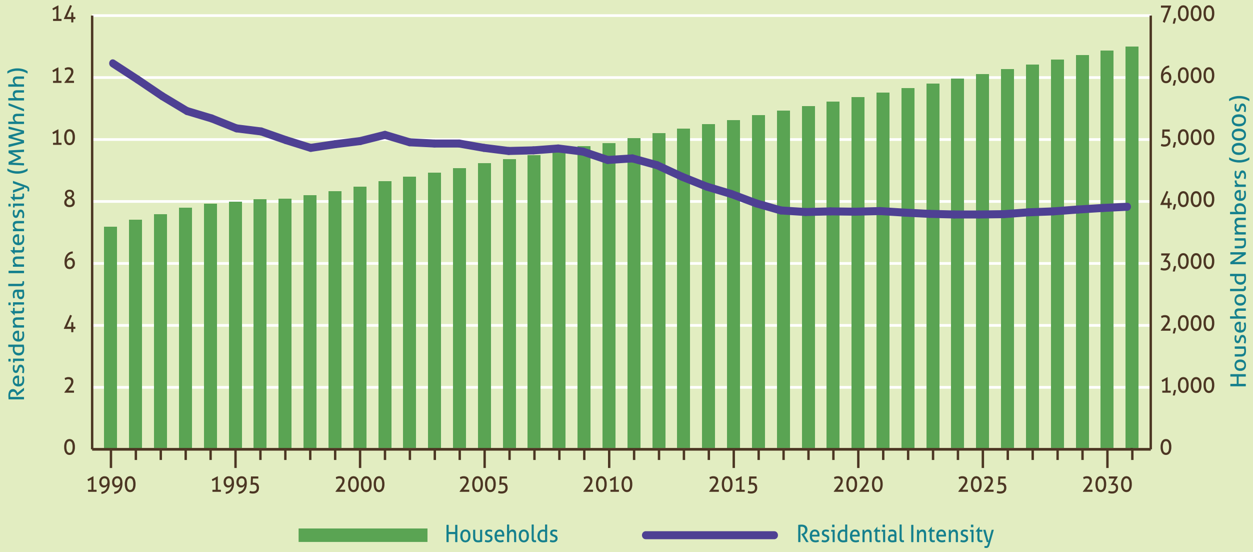


Figure 4: Commercial Electricity Intensity*

Businesses are becoming more efficient

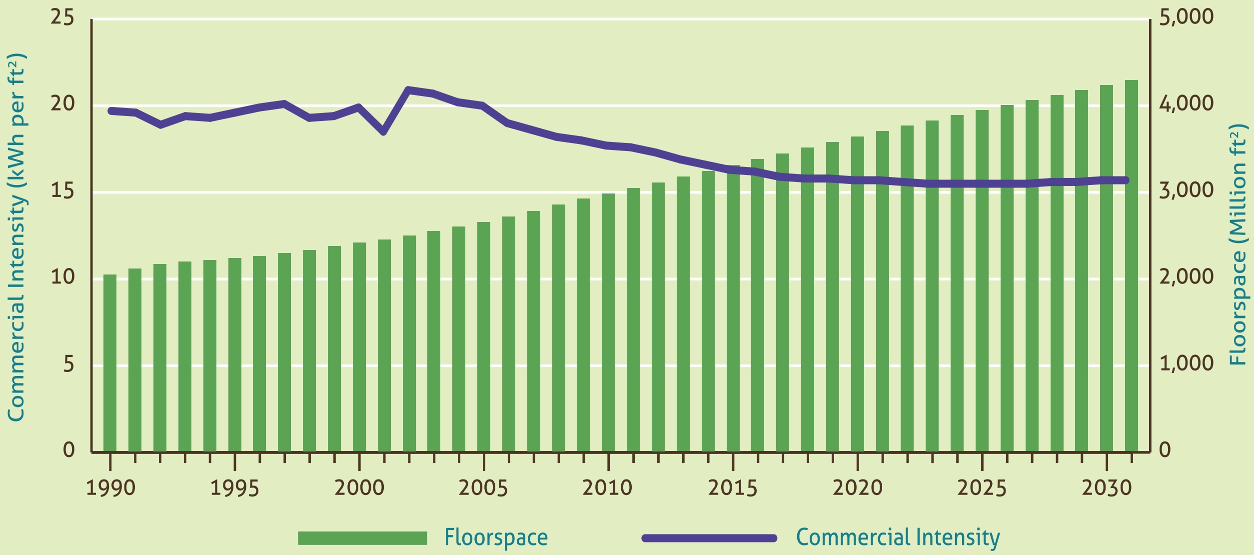
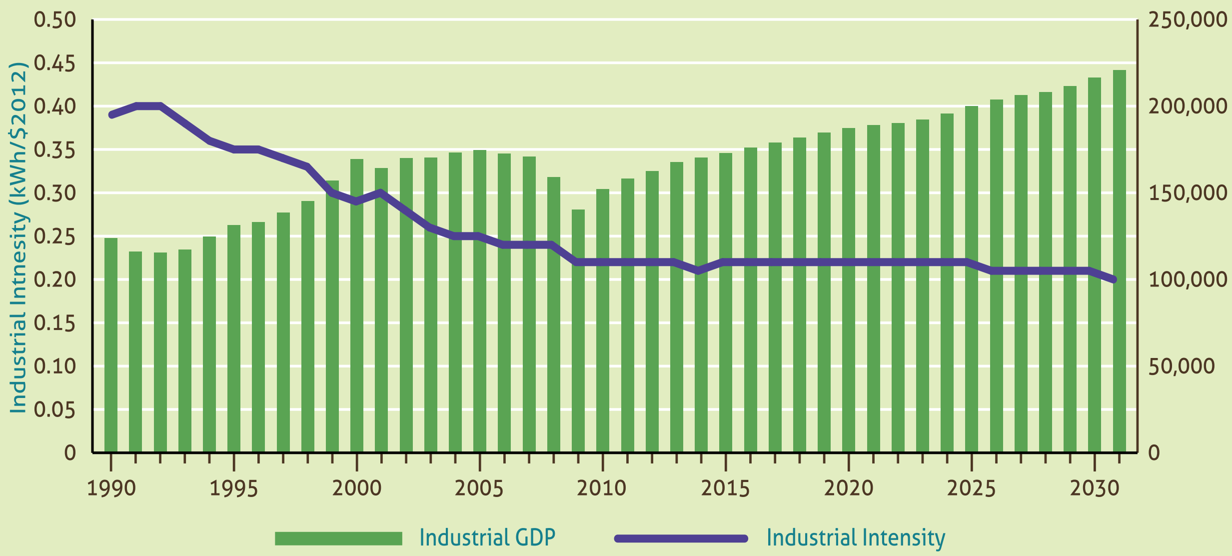


Figure 5: Industrial Electricity Intensity*

Industries require less energy to produce goods and support jobs



**Source: NRCan 1990-2004, OPA from 2004 onwards.*

Note: Intensity based on gross demand forecast. Opportunity for planned conservation initiatives would further reduce electricity intensity.

MANAGING ELECTRICITY COSTS

The government introduced the Ontario Clean Energy Benefit (OCEB), which gives residential customers, small businesses and farms a 10% reduction on their electricity bills for the first 3,000 kWh they use every month until the end of 2015. Beyond 2015, the OCEB program's future would require legislative changes and would need to take into account a number of factors including the province's fiscal position.

The government is committed to ensuring that where possible and appropriate, industrial electricity rate mitigation programs can help support a dynamic and innovative climate for business to thrive, grow and create jobs.

Northern Industrial Electricity Rate (NIER) Program

The province has extended the NIER program to 2016 to support continued growth and development in the northern resource and manufacturing sector. Originally set to end in 2013, the $360-million program extension ($120 million per year) provides electricity price rebates of 2 cents per kWh to qualified large northern industrial consumers. This represents about a 25% reduction in electricity prices and helps qualified facilities that commit to an energy management plan.

Industrial Electricity Incentive (IEI) Program

This program assists in the management of electricity demand by encouraging increased industrial production.

Eligible companies in the manufacturing and resource-extraction sectors can qualify for a reduced electricity rate for bringing new investment and employment opportunities to the province. The benefits of incremental industrial electricity demand to the electricity system include reduced surplus energy volumes. The IEI program offers up to 5 TWh of annual electricity consumption, and is currently allocated in two distinct streams:

- Stream 1 is capped at 3 TWh and is for industrial consumers willing to operate a facility and undertake a large capital investment in technologies, products or processes that are not currently being used or produced in Ontario.
- Stream 2 is capped at 2 TWh and is for current consumers that will expand their existing, or build a new, industrial facility.

The government will actively pursue opportunities to broaden this program, based on updated supply forecasts to align with the power needs of industry looking to make investments in Ontario. The government will seek to open a new program intake window in 2014.

Industrial Conservation Initiative

This initiative helps the province's largest industrial and manufacturing facilities reduce their electricity consumption during peak periods, lower their costs and increase competitiveness. Charging the Global Adjustment (GA) based on peak demand is a form of demand response that incents Ontario's largest customers to shift their consumption away from peak periods thereby improving reliability and lowering system costs. About 200 of Ontario's largest energy consumers are part of this initiative.

This contributed to industrial rates for large users (more than 5 MW) being on average 25% lower in 2012 than those forecast in the 2010 LTEP.

Industrial Accelerator Program

The Industrial Accelerator Program is run by the OPA and helps transmission-connected electricity users fast-track capital investment in major energy-efficiency projects.

The program provides attractive financial incentives to encourage investment in innovative process changes and equipment retrofits so that the rate of return is competitive with other capital projects. In exchange, participants will commit under contract to deliver specific conservation savings within a set period of time and to maintain them over the expected life of the project.

Global Adjustment Review

The IESO is undertaking an independent review of the GA to examine the possibility of greater responsiveness from customers. Stakeholders have been consulted to ensure that the approach and analysis in this review are comprehensive. The IESO will publish a report on its findings.

ADDITIONAL MEASURES: ELECTRICITY RATE MITIGATION AND SECTOR EFFICIENCY

Currently in Ontario, the electricity system costs about $18 billion per year to operate. That makes it essential for all the players in the sector—agencies, generators, transmitters, distributors and the like—to operate as efficiently as possible.

Reducing future capital investments will mitigate upward pressure on rates. The province has undertaken a wide range of initiatives to help reduce electricity rates outlined below.

Amending the Green Energy Investment Agreement

The province, in collaboration with the Korean Consortium, revised provisions of the Green Energy Investment Agreement (GEIA). The revised GEIA reduces contract costs by $3.7 billion, assures continued clean energy investment by the Korean Consortium, and protects existing job commitments to 2015, while adding a commitment to job creation that extends to 2016.

Feed-in Tariff Program (FIT) Prices

The OPA achieved further cost savings with a significant reduction in the purchase price of renewable electricity in new FIT contracts. The lower FIT prices have reflected the reduction of domestic content requirements and a reduction in technology prices, saving $1.9 billion.

Non-Utility Generators (NUG) Negotiations

The government has directed the OPA to negotiate new contracts with the province's thermal non-utility generators (NUGs) as they expire, only if the new contracts result in cost and reliability benefits for Ontario's electricity consumers. The new contract structure will reduce NUG costs and greatly reduce NUGs' contribution to surplus baseload generation.

Sector Efficiencies

Over the past three years, Hydro One and OPG have achieved efficiency savings of approximately $500 million. These are driven by transformative initiatives that are tailored to the needs and realities of each organization. For example, OPG has increased productivity by centralizing and streamlining corporate and support functions. Hydro One has improved the efficiency of its operations as a result of investments in intelligence tools designed to augment the availability and performance of its key assets.

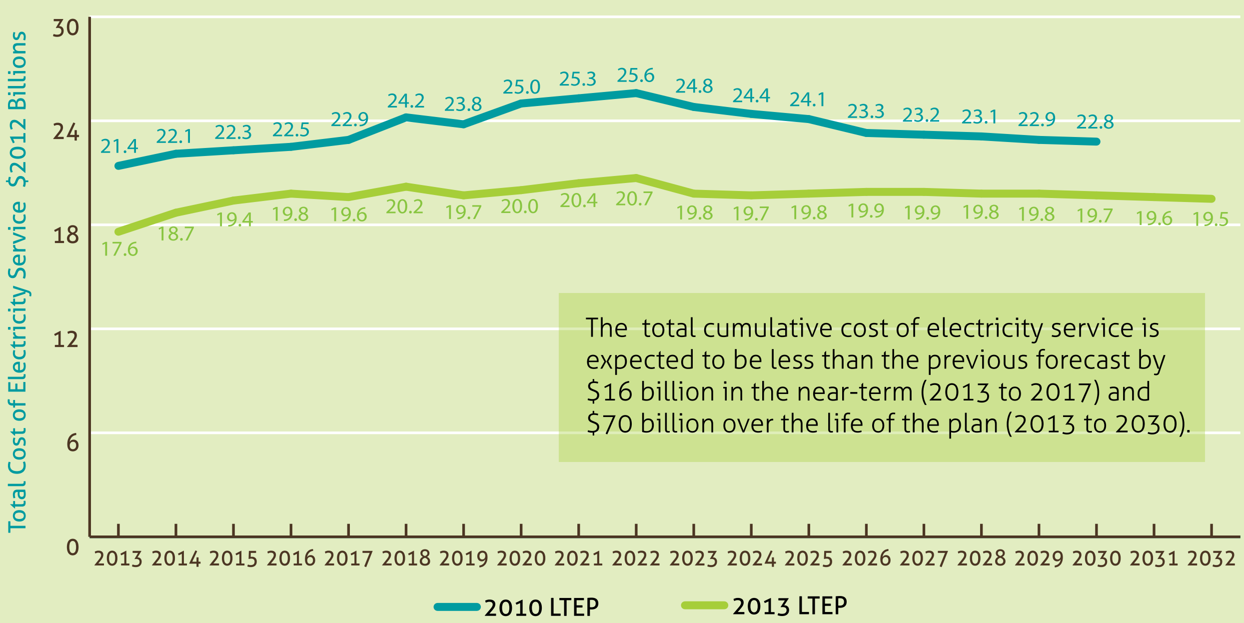
Wind Dispatch

The IESO has brought in new rules to allow transmission-connected wind generation to be dispatched when the system does not require it. This could save ratepayers up to $200 million per year. In addition, related OPA contract amendments could save ratepayers up to $65 million over the next five years.

Deferral of New Nuclear

Due to lower forecast demand growth, the government recently announced that the construction

Figure 6: Total Cost of Electricity Service Forecast



of two new nuclear units at OPG's Darlington site will be deferred. This represents up to $15 billion in capital investments that are not currently required.

Early Coal Closure

In early 2013, Ontario announced it would cease coal-fired generation at the Lambton and Nanticoke plants by the end of 2013, one year earlier than previously planned. Ratepayers will save $95 million with the early closure of these stations. Savings will arise from reduced maintenance and project costs.

The work to mitigate electricity rate increases and secure efficiencies in the electricity sector will not end there:

- The government will encourage OPG and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities would allow OPG and Hydro One to leverage their existing areas of expertise and grow revenues for the benefit of Ontarians.
- The government will also work with its energy agencies to develop efficiency targets, reduce costs and save money for ratepayers. For example, over a five-year period, ratepayers could expect to save close to $400 million if energy agencies were to reduce their operations, maintenance and administration expenses by 2%.
- Since distribution costs play an important part in consumers' electricity bills, the government established the Distribution Sector Review Panel. The panel, which delivered its report in late 2012, identified the potential for significant savings and recommended the consolidation of the province's LDCs. As a result, the government expects that LDCs will pursue innovative partnerships and transformative initiatives to drive efficiencies that will result in ratepayer savings.

Megawatt (MW): A unit of power equal to 1,000 kilowatts (kW) or one million watts (W)

- The OEB is currently implementing a renewed regulatory framework for the electricity distribution sector. This framework is expected to set performance outcomes that improve productivity and drive efficient investment in the distribution sector. As this is implemented, the government will look closely at some of its key features, such as the Scorecard, to develop further distribution sector policy options. The Scorecard will help measure performance; distributors will be required to report their progress annually based on key performance outcomes such as customer service, operational effectiveness, public policy responsiveness and financial performance.

2013 LTEP COST AND PRICE FORECASTS

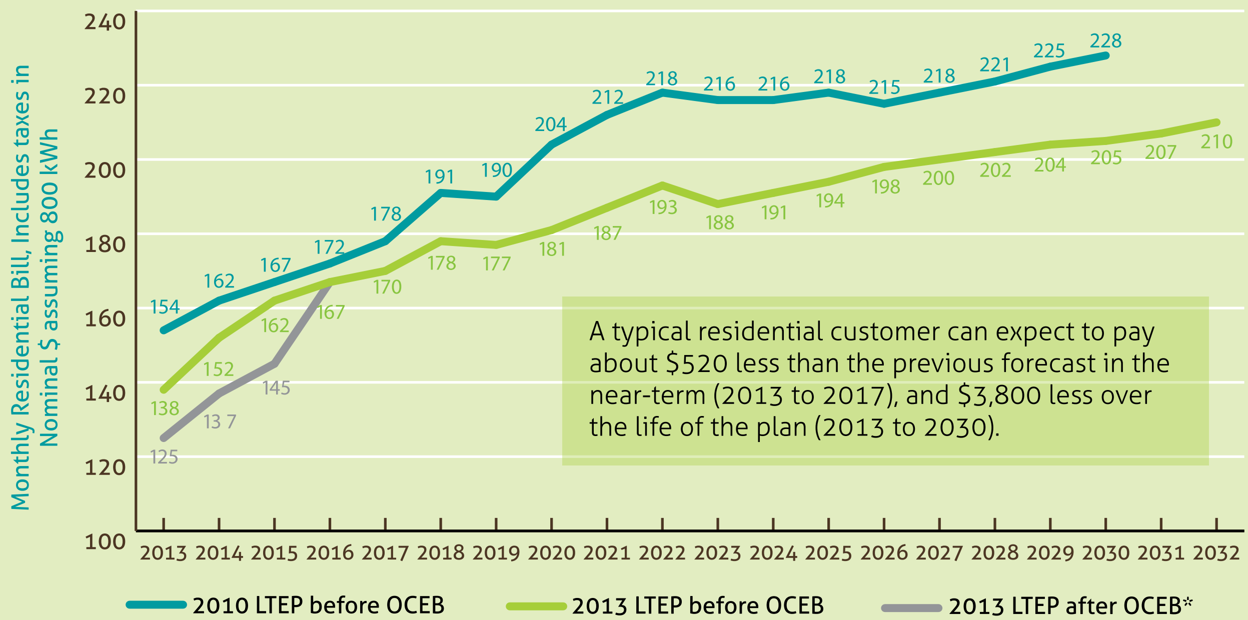
Since the 2010 LTEP, electricity prices have not increased as much as they were forecast to at that time.

Figures 6, 7 and 8 illustrate the 2013 LTEP forecasts for the total cost of electricity service, for a typical monthly residential bill, and for industrial electricity prices. These forecasts are based on the 2013 LTEP conservation and supply mix elements, including Conservation First and DR targets, anticipated demand, renewable targets and planned nuclear refurbishments as well as the other elements described throughout this document.

Overall electricity costs show a decrease from the 2010 projections for all years, based on several factors, including lower demand forecasts and the various rate mitigation measures enacted by government, described in the previous section. Recent decisions, such as the deferral of new nuclear and the reduction in FIT contract pricing, as well as an emphasis on conservation, are responsible for the significantly lower projections after 2018. Containing costs and mitigating rate increases will continue to be a priority as the 2013 LTEP is implemented. Since the 2010 LTEP, the Ontario government has taken strong action that has started to mitigate rate increases and decrease the pressure on Ontario electricity consumers.

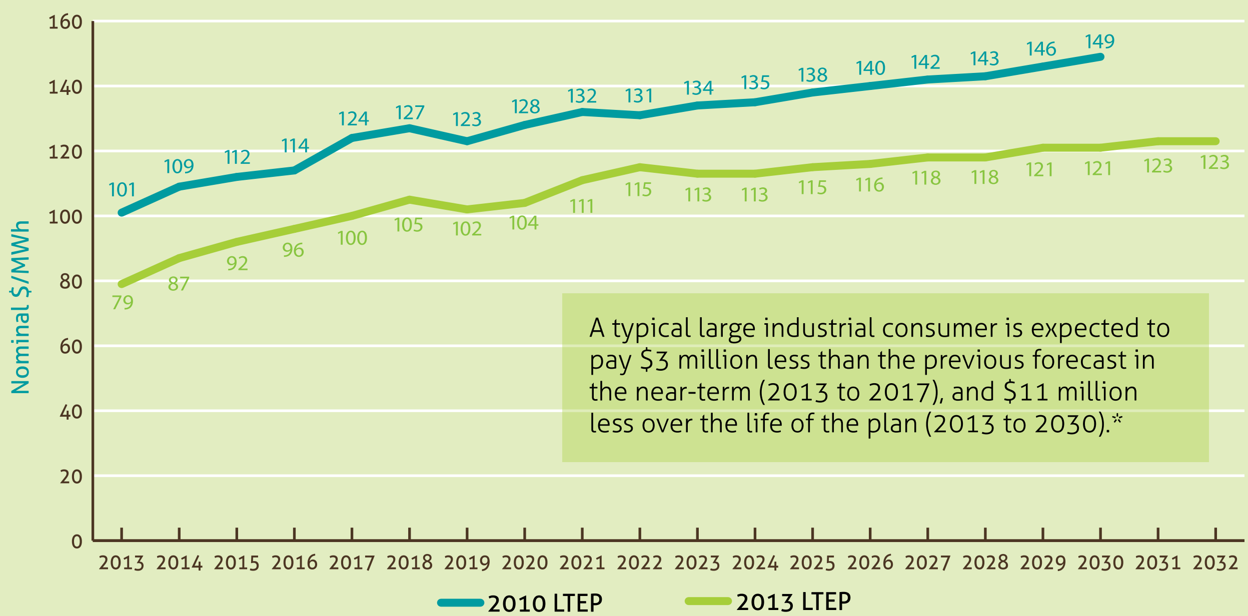
Rate mitigation measures undertaken by the government, in collaboration with energy agencies as well as private sector partners, result in savings that last over the life of the plan.

Figure 7: Typical Residential Electricity Bill Forecast



* *Beyond 2015, the OCEB program's future would require legislative changes and would need to take into account a number of factors including the province's fiscal position.*

Figure 8: Industrial Electricity Price Forecast



* *A typical large industrial customer has a demand of 5 MW and a 75% capacity factor.*

In Summary

- The 2013 LTEP cost and price forecasts are lower than previously forecast in 2010.
- Significant ratepayer savings will be realized as a result of reduced Feed-in Tariff (FIT) prices, the ability to dispatch wind generation, the amended Green Energy Investment Agreement, and the decision to defer new nuclear.
- The government will continue to work with its agencies — Hydro One, OPG, the IESO, the OPA and the OEB — to develop business plans and efficiency targets that will reduce agency costs and result in significant ratepayer savings.
- The government will encourage Ontario Power Generation and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians.
- The Distribution Sector Review Panel, which delivered its report in late 2012, identified the potential for significant savings among the province's Local Distribution Companies (LDCs). The government expects that LDCs will pursue innovative partnerships and transformative initiatives that will result in electricity ratepayer savings.
- The government will look closely at key features of the OEB's new regulatory framework for LDCs such as the Scorecard, which will report annually on key LDC performance metrics, to develop further distribution sector policy options.
- An annual Ontario Energy Report will be issued to update the public on changing supply and demand conditions, and to outline the progress to date on the LTEP.

2 Putting Conservation First

As we plan for Ontario's electricity needs for the next 20 years, conservation will be the first resource to be considered. It is the cleanest and most cost-effective energy resource, and it offers consumers a way to reduce their electricity bills. The government intends to ensure that conservation will be considered before building new generation and transmission facilities, and will be the preferred choice wherever cost-effective.

The ministry will work with its agencies to ensure that they put conservation first in their planning, approval and procurement processes. The ministry will also work with the OEB to incorporate the policy of Conservation First into distributor planning processes for both electricity and natural gas utilities.

Our agencies and partners will achieve this goal with a combination of tools, including the Total Resource Cost Test, the Program Administrator Cost Test and a hurdle rate, to screen program proposals. A hurdle rate would consider the cost of delivering a conservation program against the avoided cost of procuring supply.

Ontarians are making considerable progress in embracing a culture of conservation. Since 2005, conservation efforts have

On-Bill Financing

Manitoba Hydro offers a financing program that makes energy efficiency accessible to homeowners. Using on-bill financing, the Power Smart PAYS Financing Program provides Manitoba residential customers with a convenient option for completing energy-efficient upgrades to their homes while keeping the upfront costs and future monthly finance payments as small as possible.

Source: Manitoba Hydro

increased significantly, and it is projected that by the end of 2013, Ontarians will have conserved 8.6 TWh of electricity — enough to power a city about the size of Mississauga.

The province expects to offset most of the growth in electricity demand to 2032 using programs and improved codes and standards. This will lessen the need for new supply. Our long-term conservation target of 30 TWh in 2032 represents a 16% reduction in forecast gross demand for electricity — the equivalent to more than all the power used by the City of Toronto in 2012 — an improvement over the 2010 LTEP.

Putting conservation first will require a number of changes to our approach. In collaboration with its agencies and partners, the ministry will work on new conservation initiatives, significantly increase Demand Response capability, and give LDCs a greater role and more flexibility to address local conditions.

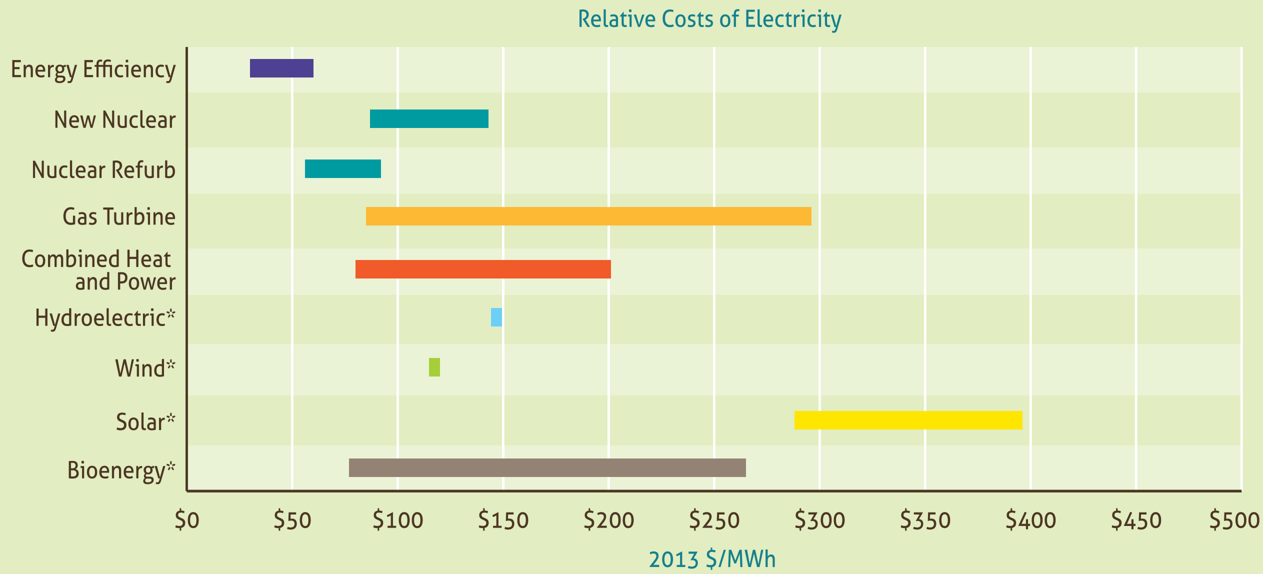
The government is committed to promoting a co-ordinated approach for all customers, including both electricity and natural gas utilities.

The government will work to make new financing tools available to consumers starting in 2015. These tools will include on-bill financing to help them with the upfront cost of making energy efficiency retrofits to conserve electricity and natural gas. The government has already enabled municipal governments to offer Local Improvement Charges to recover energy efficiency and renewable energy investments with repayment through property taxes. This allows consumers to save money on their energy bill and pay off conservation investments over time as they receive the benefits of conservation.

To help consumers choose the most efficient products for their homes and businesses, Ontario will provide information and incentives and continue to show leadership in establishing minimum efficiency requirements for products such as water heaters, clothes dryers, televisions, fluorescent lamps, motors and boilers.

The government, its energy agencies and its partners are also developing new ways to get consumers the information they need to make more informed decisions about their energy consumption.

Figure 9: Generation and Conservation Cost of Options



** Updated for January 2014 Feed-in Tariff prices*

The Green Button Initiative gives consumers access to their energy data and the ability to connect to mobile and web-based applications so they can analyze and manage their energy use. The combination of data and the innovative applications could also guide them in making the investment decisions necessary to improve their energy efficiency.

The government looks forward to releasing the results of the innovative, forward-looking *Energy Apps for Ontario Challenge* in early 2014. This consumer-friendly initiative will enable Ontarians to better manage and track their electricity use and encourage conservation.

Social benchmarking can increase awareness of energy use and promote conservation. A social benchmarking pilot program is under way, led by the OPA, to test different approaches that enable consumers to compare their energy consumption with other similar consumers. Pending the success of the pilot program, the government will explore expanding social benchmarking.

From the outset, Green Button was designed with privacy and security principles embedded into the standard. Social benchmarking initiatives will also take proactive steps to ensure consumer privacy is protected by embedding privacy directly into the design of technologies, business practices and networked infrastructures.

The government is also working with Ontario EcoSchools to bring more information about energy conservation into classrooms. Ontario EcoSchools uses the local school as an energy education resource, encouraging students to reduce energy use in the classroom and providing them with skills they can take back home.

Demand Response

Ontarians may not be familiar with the concept of Demand Response (DR), but many practice it every day with their smart meters and time-of-use (TOU) pricing. DR occurs when people and businesses shift electricity use from periods of peak demand to periods of lower demand, or reduce use during peak periods. This helps avoid the cost of building costly generation and transmission to meet a few short periods of peak demand a year.

Ontario consumers can participate in DR programs in several different ways. One program is *peaksaver* PLUS, where homeowners agree to reduce their electricity consumption during critical periods of peak demand. Another program encourages large commercial and industrial facilities to make firm commitments to reduce energy use during high demand periods. This can mean turning off lights or motors or shifting production to other times of the day.

Ontario is aiming to use DR to meet 10% of peak demand by 2025, equivalent to approximately 2,400 MW under forecast conditions. To encourage further development of DR in Ontario, the IESO will evolve existing programs and introduce new initiatives. This will allow the IESO to work directly with large electricity consumers such as commercial and industrial facilities, and other large facilities that can reduce their electrical consumption on demand in response to system need. The IESO, as the system operator, is in the best position to enable these large consumers to provide DR to the grid in a manner that puts DR on par with comparable generation options.

Additionally, the IESO will continue to examine and consult on the potential benefits and development of a capacity market, where different generation and demand resources, including electricity storage technologies, conservation initiatives and clean imports compete to address capacity needs.

Conservation and Demand Management Framework

Ontario has achieved a great deal through conservation, but we did not accomplish this alone. LDCs are the face of electricity conservation for most Ontarians, delivering programs to their local communities.

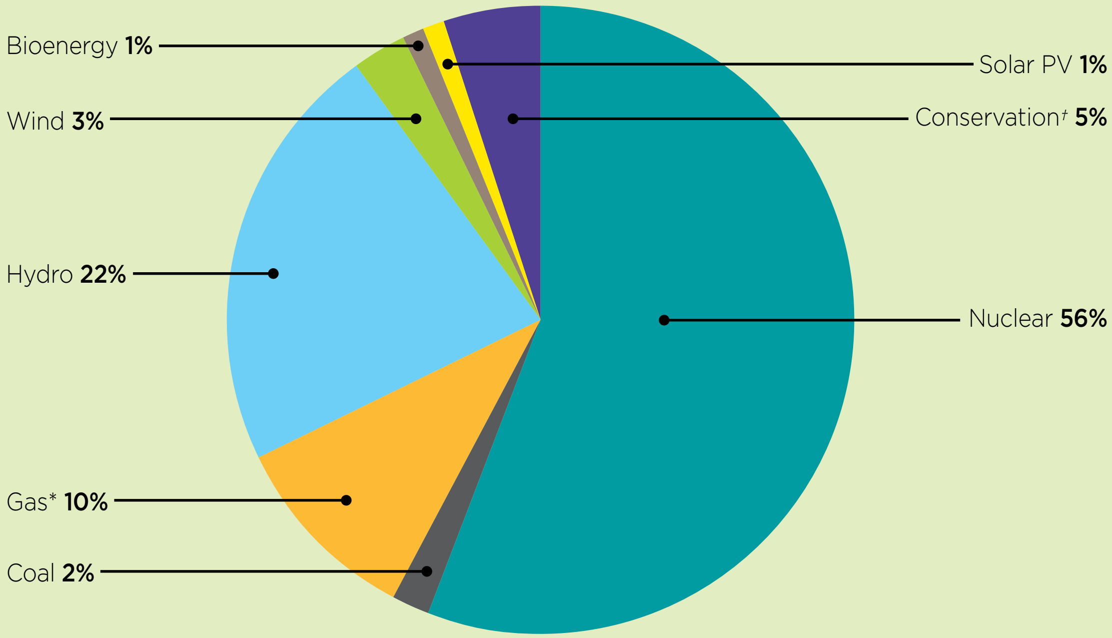
In 2010, the government established a Conservation and Demand Management Framework that included mandatory conservation targets for LDCs. While we've made real progress, full achievement of our goals has been difficult because of reduced opportunities for conservation. This came about because of the decreased demand for electricity and the constrained financial circumstances that made many businesses reluctant to invest in conservation. Challenges associated with the Framework itself, such as a lack of flexibility and slower than expected roll-out of programs, also made it difficult to achieve the conservation targets.

The government, in co-operation with LDCs and energy agencies, is developing a new Conservation and Demand Management Framework to begin in January

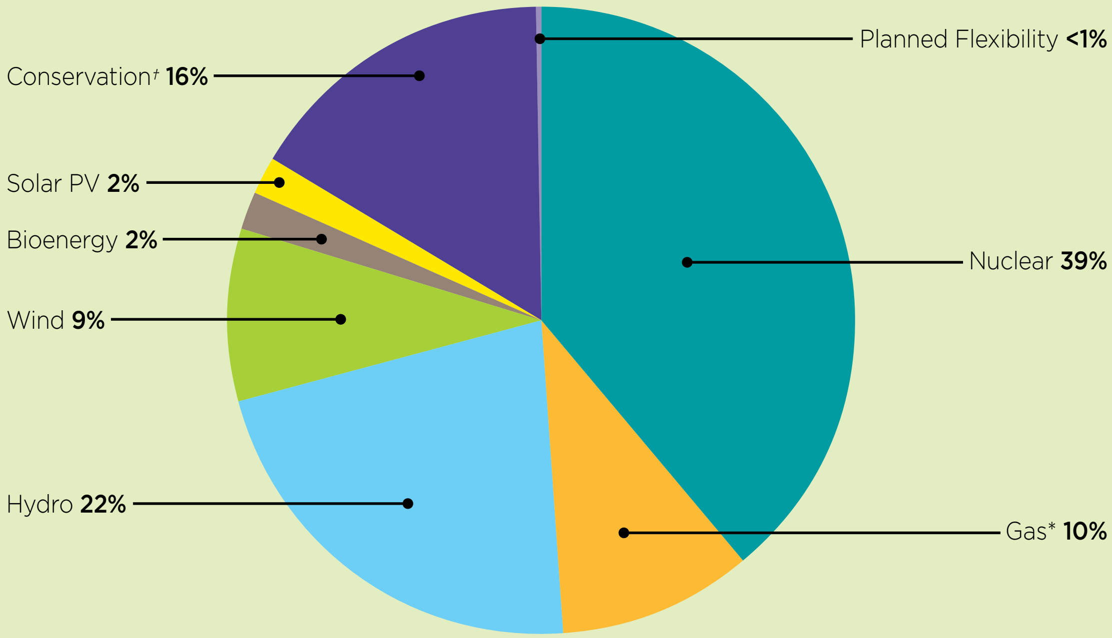
Figure 10: THE VALUE OF CONSERVATION

Figure 11: The Role of Conservation is Growing

Forecast Energy Production (TWh) 2013



Forecast Energy Production (TWh) 2032



Note: Charts represent total forecast energy production. For comparative purposes, total production has been increased by the amount of energy conserved to demonstrate the role of conservation.

† Conservation is forecast to contribute 30 TWh of energy efficiency in 2032, which is equal to 16% of the forecast gross demand.

** Includes Lennox Generating Station – dual fueled with natural gas and oil.*

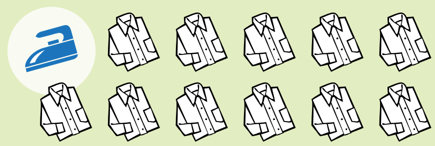
Figure 12: How Much is a Kilowatt Hour?

Electricity helps us perform everyday tasks such as cooling our homes and cooking meals. Here's a quick guide to what one kilowatt-hour of electricity will do for you:

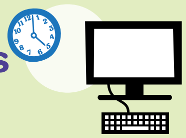
ieso
Power to Ontario. On Demand.
The IESO balances the supply of and demand for electricity in Ontario and then directs its flow across the province's transmission lines.

Brew **90** cups of coffee

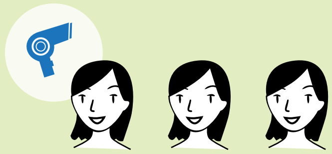
Iron **11** shirts



Surf the web for **five** hours



Blow dry your hair **three** times



Bake **one** birthday cake

The typical Ontario household uses between 800 and 1000 kWh a month, often more in the summer when air conditioners are running. You can see changes in the province's demand for electricity throughout the day at the IESO web site at www.ieso.ca

THE SMALL PRINT: Electricity consumption varies by appliance model and use. You can use a plug-in energy meter to find out exactly how much energy your appliances use.

Ontario EcoSchools

Ontario EcoSchools is an environmental education and certification program for grades K-12 that helps school communities develop both ecological literacy and environmental practices to become environmentally responsible citizens and reduce the environmental footprint of schools.

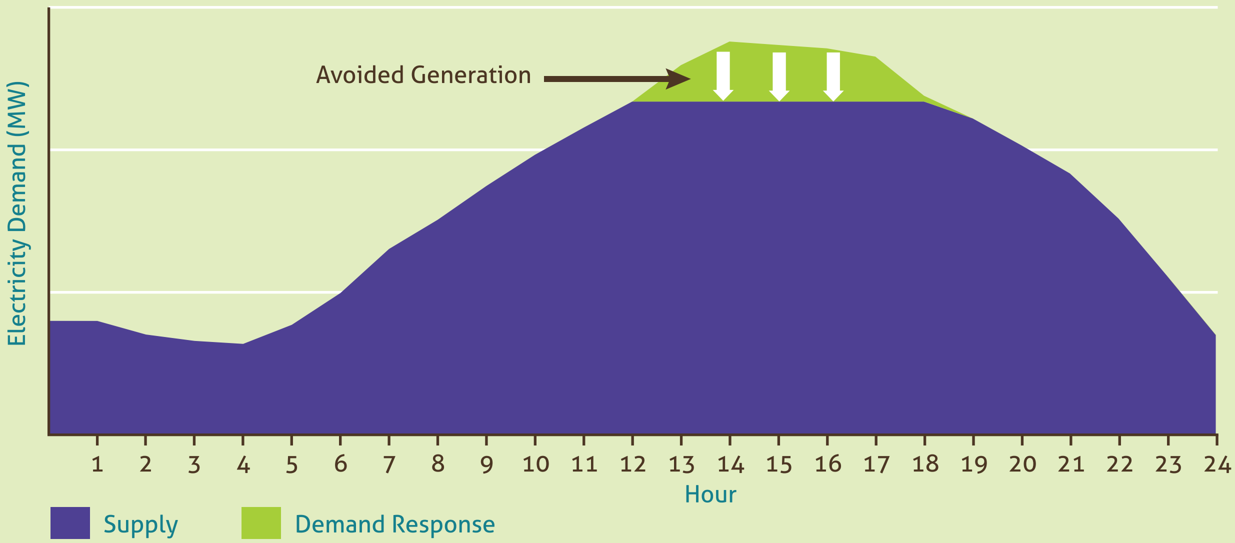
The key areas of focus and achievement are: Teamwork and Leadership, Energy Conservation, Waste Minimization, School Ground Greening, Curriculum, and Environmental Stewardship.

Schools may use the program free of charge.

Source: http://ontarioecoschools.org/

Figure 13: Demand Response

Demand Response programs can reduce the need to build costly peaking generation that would only be required during the highest demand hours of a hot summer day.



Note: For illustrative purposes only, not to scale.

2015, lasting for six years and replacing the one that is currently winding down. Subject to further discussion with our partners, the government intends to build the new Framework on the following principles:

- There will be long-term, stable funding for conservation so that customers and LDCs have the certainty they need to implement and deliver programs.
- Customers will be given more program choice along with streamlined oversight and administration.
- LDCs will have accountability for meeting their assigned conservation goals, and will be provided the authority and means for meeting them cost-effectively.
- The new Framework will encourage innovation and the adoption of new technologies.
- While there will be conservation programs available for all residential, commercial and industrial sectors, the value of conservation investments may be higher in some sectors than others.
- There will be renewed efforts to deepen consumer awareness of conservation, and more broadly, of the electricity system.
- Conservation programs for low-income residential customers will be improved.
- For Aboriginal communities, the role of LDCs in the delivery of conservation programs will be enhanced, particularly for on-reserve First Nation customers.
- Industrial and transmission-connected customers will continue to have access to the OPA's conservation programs, which will be expanded to facilitate broader program choice and financing flexibility.

To ensure value for ratepayers, the new Framework will continue to provide cost-effective conservation programs at less than the cost of new supply.

In Summary

- The Ministry of Energy will work with its agencies to ensure they put conservation first in their planning, approval and procurement processes. The ministry will also work with the Ontario Energy Board (OEB) to incorporate the policy of conservation first into distributor planning processes for both electricity and natural gas utilities.
- The province expects to offset almost all of the growth in electricity demand to 2032 by using programs and improved codes and standards. This will lessen the need for new supply. Our long-term conservation target of 30 terawatt-hours (TWh) in 2032 represents a 16% reduction in the gross demand for electricity, an improvement over the 2010 LTEP.
- Ontario is aiming to use Demand Response (DR) to meet 10% of peak demand by 2025, equivalent to approximately 2,400 megawatts (MW) under forecast conditions. To encourage further development of DR in Ontario, the Independent Electricity System Operator (IESO) will evolve existing DR programs and introduce new DR initiatives.
- The IESO will continue to examine and consult on the potential benefits and development of a capacity market, where different generation and demand resources compete to address capacity needs.
- The government is committed to promoting a co-ordinated approach to conservation and will encourage collaboration of conservation efforts among electricity and natural gas utilities.
- The government will work to make new financing tools available to consumers starting in 2015, including on-bill financing for energy efficiency retrofits.
- To help consumers choose the most efficient products for their homes and businesses, Ontario will provide information and incentives; it will also continue to show leadership in establishing minimum efficiency requirements for products such as water heaters, clothes dryers, televisions, fluorescent lamps, motors and boilers.
- The Green Button Initiative will give consumers access to their energy data and the ability to connect to mobile and web-based applications so they can analyze and manage their energy use.
- Social benchmarking can increase awareness of energy use and promote conservation. A social benchmarking pilot program is under way, led by the Ontario Power Authority (OPA) to test different approaches that enable consumers to compare their energy consumption with other similar consumers. Pending the success of the pilot program, the government will explore expanding social benchmarking and including other sectors.
- The government is also working with Ontario EcoSchools to bring more resources about energy conservation to the curriculum for students and teachers.

3

A Reliable and Clean Supply

While Conservation First is an important element of the LTEP, a clean, reliable and affordable supply of electricity also requires a diversity of generation types. Ontario will continue to develop new sources of supply to ensure that we reach these goals.

Nuclear

Ontario has made important investments in nuclear generation. The Canadian Manufacturers and Exporters reports that 15,600 people are employed in the operation and support of nuclear plants in Ontario, and 9,000 more would be employed for the refurbishment of the Ontario plants, for a total employment of approximately 25,000 people during the refurbishment period. The Organization of Canadian Nuclear Industries reports that an additional 30,000 people are employed in the nuclear manufacturing, engineering, construction and consulting, fuel fabrication, research and development, and medical isotopes sectors, in support of domestic and offshore nuclear projects.

The industry has been successful in exporting Canadian technology around the world to countries including Argentina, South Korea, China, Romania and India. International opportunities to use the nuclear expertise based in Ontario will continue to be explored.

Nuclear power is also part of Canada's science and innovation advantage, involving more than

Workers complete installation of a mock calandria in the Darlington Energy Centre. It will be used to test tooling and train workers before beginning refurbishment work inside the reactor vaults of the Darlington Nuclear Generating Station

30 universities and six major research centres, many of them in Ontario. The nuclear industry generates $2.5 billion in direct and secondary economic activity in Ontario every year. Retaining this nuclear expertise is crucial.

The province's nuclear generating stations at Darlington, Bruce and Pickering have historically provided about half of the province's electricity supply. The 2010 LTEP forecast that new capacity would need to be built at Darlington. New nuclear capacity is not needed at this time because the demand for electricity has not grown as expected, due to changes in the economy and gains in conservation and energy efficiency. The decision to defer new nuclear capacity helps manage electricity costs by making large investments only when they are needed.

Ontario continues to have the option to build new nuclear reactors in the future, should the supply and demand picture in the province change over time. The ministry will work with OPG to maintain the licence granted by the Canadian Nuclear Safety Commission, to keep open the option of considering new build in the future.

The government will ensure a reliable supply of electricity by proceeding with the refurbishment of the province's existing nuclear fleet taking into account future demand levels. Refurbishment received strong, province-wide support during the 2013 LTEP consultation process. The merits of refurbishment are clear:

- Refurbished nuclear is the most cost-effective generation available to Ontario for meeting baseload requirements.
- Existing nuclear generating stations are located in supportive communities, and have access to high-voltage transmission.
- Nuclear generation produces no greenhouse gas emissions.

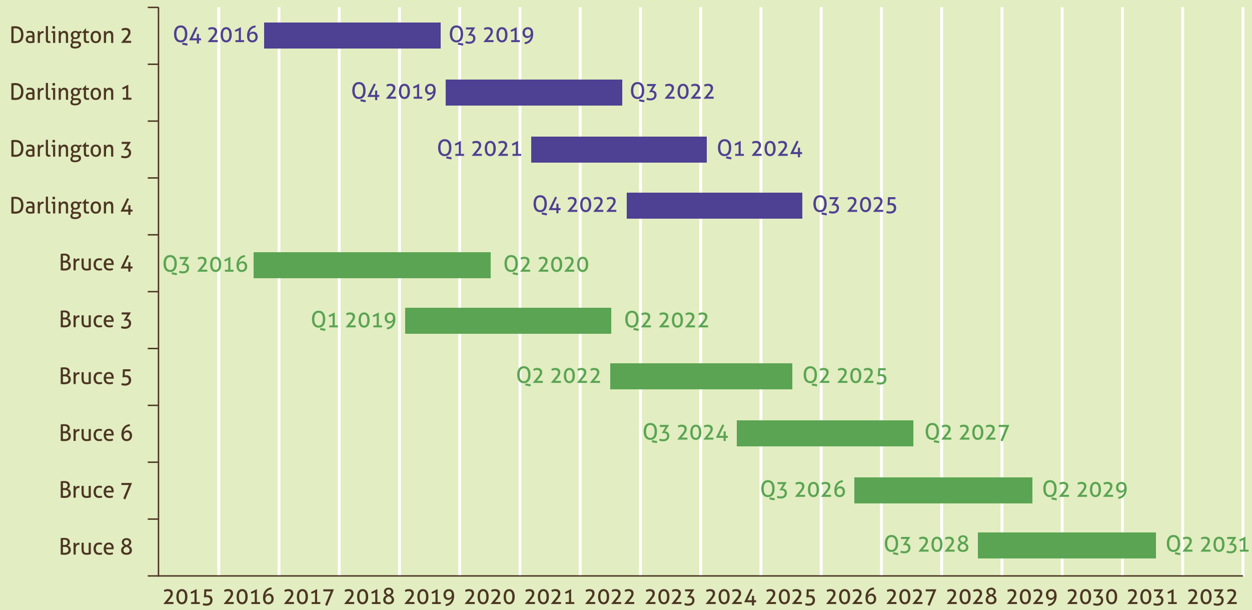
Ontario plans to refurbish units at the Darlington and Bruce Generating Stations. The refurbishment has the potential to renew 8,500 MW over 16 years. The province will proceed with caution to ensure both flexibility and ongoing value for Ontario ratepayers. Darlington and Bruce plan to begin refurbishing one unit each in 2016. Final commitments on subsequent refurbishments will take into account the performance of the initial refurbishments with respect to budget and schedule by establishing appropriate off-ramps.

The nuclear refurbishment sequence shown in Figure 14 will be implemented subject to processes designed to minimize risk to ratepayers and to government. For example, appropriate off-ramps will be implemented should operators be unable to deliver the projects on schedule and within the established project budget.

The nuclear refurbishment process will adhere to the following principles:

1. Minimize commercial risk on the part of ratepayers and government;
2. Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
3. Entrench appropriate and realistic off-ramps and scoping;
4. Hold private sector operator accountable to the nuclear refurbishment schedule and price;
5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
6. Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
7. Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

Figure 14: Nuclear Refurbishment Sequence



These principles reaffirm ratepayer value as the fundamental driver behind decisions on future refurbishment. The government will encourage the province's two nuclear operators, Bruce Power and OPG, to find ways of finding ratepayer savings through leveraging economies of scale in the areas of refurbishment and operations. This could include arrangements with suppliers, procurement of materials, shared training, lessons learned, labour arrangements and asset management strategies.

The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.

The government is committed to nuclear power. It will continue to be the backbone of our electricity system, supplying about half of Ontario's electricity generation.

Renewables

Since launching the Feed-in Tariff (FIT) program in 2009, Ontario has firmly established itself as a North American leader in renewable energy.

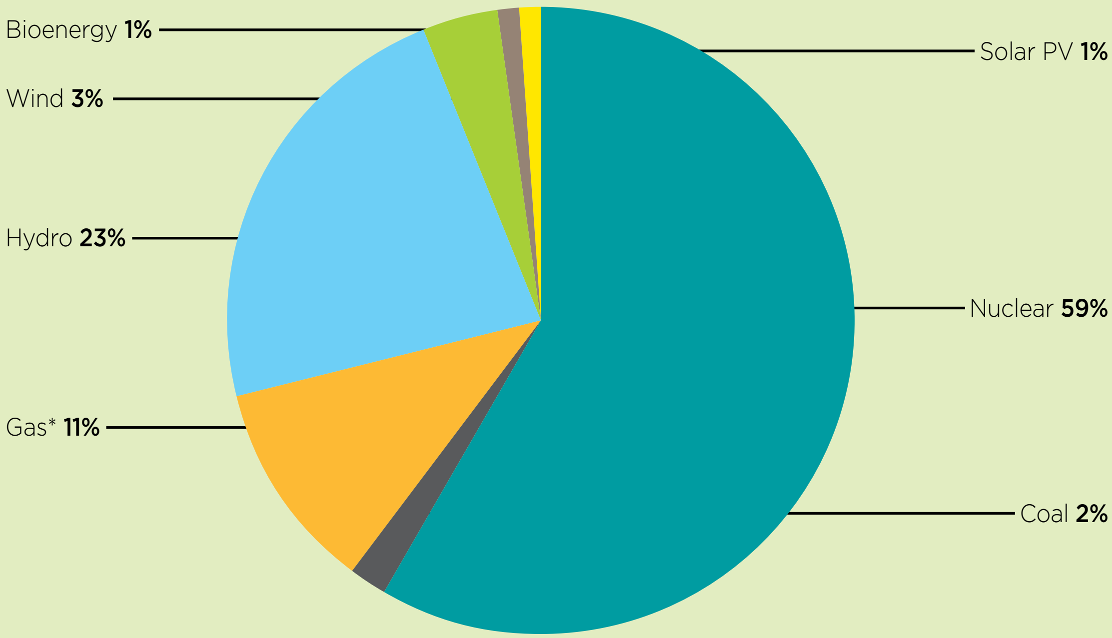
To date, Ontario has more than 18,500 MW of renewable energy online or announced, which includes more than 9,000 MW of hydroelectric capacity and more than 9,500 MW of solar, wind and bioenergy capacity.

This is remarkable progress, and Ontario is proud of the role renewable energy is playing in the supply mix. This investment in clean, renewable energy sources is helping Ontario reduce its reliance on fossil fuels. The coal phase-out is the single largest climate change initiative in North America, reducing greenhouse gas emissions and air pollution. Coal use had accounted for $4.4 billion per year in health, environmental, and financial costs. At the same time, Ontario's clean energy initiatives have attracted billions of dollars in new private sector investment, and have contributed to the creation of more than 31,000 clean energy jobs across the province.

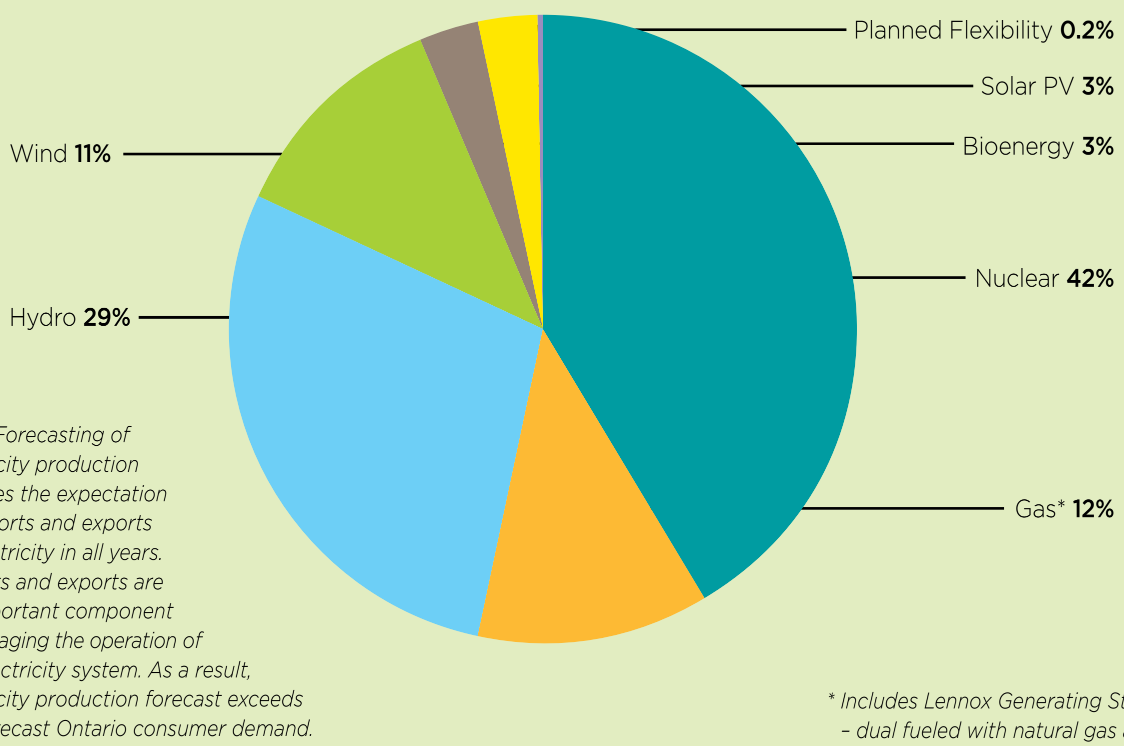
Earlier this year, the government committed to making 900 MW of new capacity available between 2013 and 2018 for the FIT (systems larger than 10 kW up to 500 kW) and microFIT programs. Starting in 2014, FIT will have an annual procurement target of 150 MW, with a 50 MW annual target for microFIT. These projects are expected to create more than 6,000 jobs while producing enough electricity each year for more than 125,000 homes. Annual price reviews for these programs are expected to reduce costs, as we saw in the recent price reviews.

Figure 15: Nuclear Will Remain a Major Source of Baseload Power

Forecast Energy Production (TWh) 2013



Forecast Energy Production (TWh) 2025



Note: Forecasting of electricity production includes the expectation of imports and exports of electricity in all years. Imports and exports are an important component in managing the operation of the electricity system. As a result, electricity production forecast exceeds the forecast Ontario consumer demand.

** Includes Lennox Generating Station – dual fueled with natural gas and oil.*

Exporting Ontario's Nuclear Expertise

Commercial nuclear power plants have been operating in Ontario for approximately 45 years. This has resulted in the development and growth of supporting industries to provide products and services. These may be exported to jurisdictions where nuclear generation currently exists, as well as to developing nations currently seeking to build nuclear power plants.

Ontario's power workers have developed expertise in the successful day-to-day operation of large nuclear power plants. In 2012, OPG's Darlington Generating Station was awarded the Institute of Nuclear Power Operators award of excellence in recognition of its world-class performance. In addition, expertise in the execution of complex projects, such as unit refurbishments and safe storage shutdowns successfully completed by Ontario's plants, is worthy of export to other jurisdictions.

The refurbishment of Ontario's nuclear fleet represents a multi-billion dollar investment and continued support of the province's nuclear supply chain and operations for decades to come. This will create a strong foundation where Ontario's nuclear suppliers can market their products and services to a global nuclear industry that could reach over 500 reactors by 2030. By working with Ontario's nuclear operators, Bruce Power and OPG, these suppliers will demonstrate their capability to deliver domestically and internationally, creating jobs and economic opportunities for the province. The province will encourage operators to compete internationally and consider opportunities and partnerships.

Expertise in the design of sophisticated systems for current and future reactors and required structures, systems and components exist in the skilled and knowledgeable engineering and technical staff working at laboratories in several Ontario communities. Both domestic and offshore nuclear projects are supported by Ontario's nuclear supply chain through companies largely located in Ontario. For example, Babcock and Wilcox Canada Limited, headquartered in Cambridge, employs experts in the design and fabrication of nuclear plant specific equipment, such as steam generators. The company plans to export nuclear components to the Tennessee Valley Authority in support of the development of Small Modular Reactors. Laker Energy Products of Burlington is another company that has exported nuclear reactor components to Romania, China and Argentina for several years. Atikokan Generating Station

A Bruce Power mechanical maintainer completes a task in the fuel handling maintenance shop

The government decided to end large renewable procurements through the standard offer FIT program (projects greater than 500 kW), instead directing the OPA to move to a competitive procurement model. The competitive procurement model will allow for the consideration of contract awards for cost-efficient and well-supported projects. The OPA will consult with the public, municipalities, Aboriginal communities and other stakeholders on the design of the program in early 2014, and seek to launch the procurement process for new large renewables before the end of the first quarter of 2014.

The program will adhere to the following principles:

- Follow a provincial and/or regional electricity system need;
- Consider municipal electricity generation preferences;
- Engage early and regularly with local and Aboriginal communities;
- Occur in multiple successive rounds, providing opportunity for a diverse set of participants;
- Identify clear procurement needs, goals and expectations; and
- Encourage innovative technologies and approaches, including consideration of proposals that integrate energy storage with renewable energy generation.

Further, the government would like to provide the renewable sector with a predictable procurement schedule. The government will extend the existing target of 10,700 MW for wind, solar, and bioenergy to 2021, and expand the existing hydro target of 9,000 MW to 9,300 MW by 2025. By 2025, 20,000 MW of renewable energy will be online, representing about half of Ontario's installed capacity. Annualized renewable energy procurement targets will be realized through a new competitive process.

Ontario plans to make available for procurement up to 300 MW of wind, 140 MW of solar, 50 MW of bioenergy and 50 MW of hydroelectric capacity in 2014. In 2015, the targets would be up to 300 MW of wind, 140 MW of solar, 50 MW of bioenergy and 45 MW of hydroelectricity. Any capacity that is not procured under these procurements, or not developed under existing contracts, would be reallocated for procurement in 2016 for each renewable technology. Through annual reporting and the next LTEP update, Ontario will review and consider expanded targets for wind, solar, hydroelectricity and bioenergy.

This procurement schedule will provide proponents the predictability and stability for large

Atikokan Generating Station

The Atikokan Generating Station is located approximately 200 km west of Thunder Bay. In 2008, a biomass testing program was implemented using wood pellets to produce electricity. In September 2012, Atikokan burned its last piece of coal. The conversion from coal to biomass is on track to be completed in 2014.

The conversion project represents an investment of $170 million – growing clean power capacity in Ontario and supporting jobs in the community. The project is expected to help sustain jobs in the forestry sector, create more than 150 new jobs through the fuel supply contracts, and create approximately 200 construction jobs. Plant modifications were required for the conversion, involving the construction of a fuel storage and handling system that can deliver up to 90,000 tonnes of biomass fuel annually from two, new 43-metre tall storage silos.

Upon completion, the 205 MW facility will be one of the largest biomass plants in North America and provide peaking capacity to northwestern Ontario. Atikokan is expected to generate 150,000 MWh of renewable power annually – enough to power approximately 15,000 homes each year.

Thunder Bay Generating Station

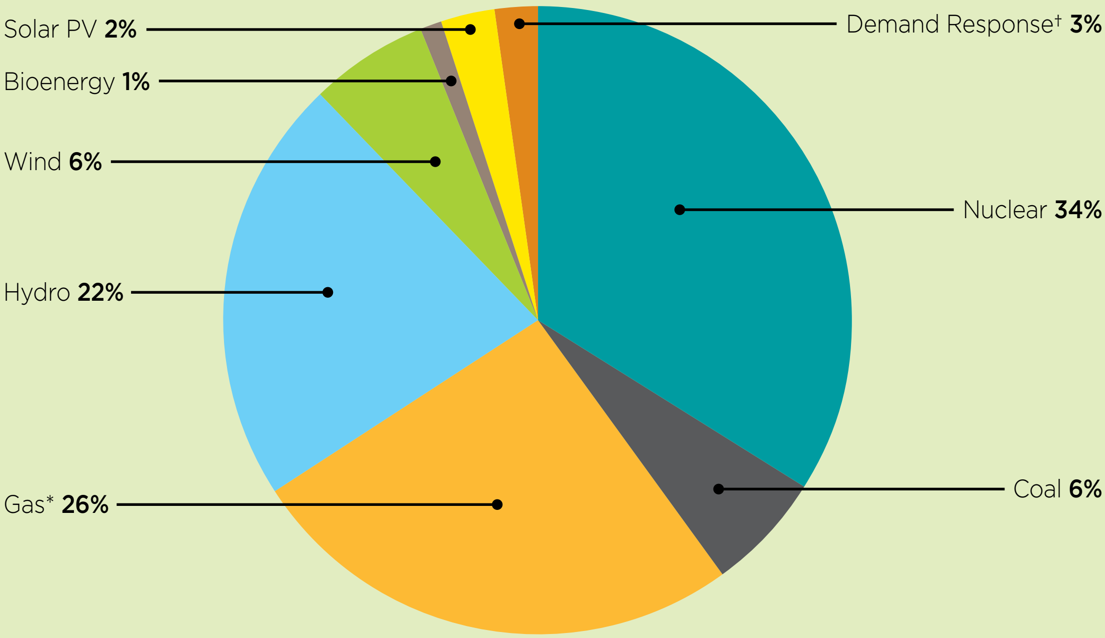
As part of Ontario's effort to phase out coal-fired generation by the end of 2014, the government intends to convert one unit at the Thunder Bay Generating Station to run on advanced biomass over a five-year term, starting in 2015, preserving operational capacity for the future. Ontario is also maintaining the option to convert the second coal-fired unit to run on advanced biomass in the future.

An advanced biomass conversion can be done with minimal capital expenditure, and the fuel is well suited to the type of valuable peaking operation that coal plants have historically provided to the province.

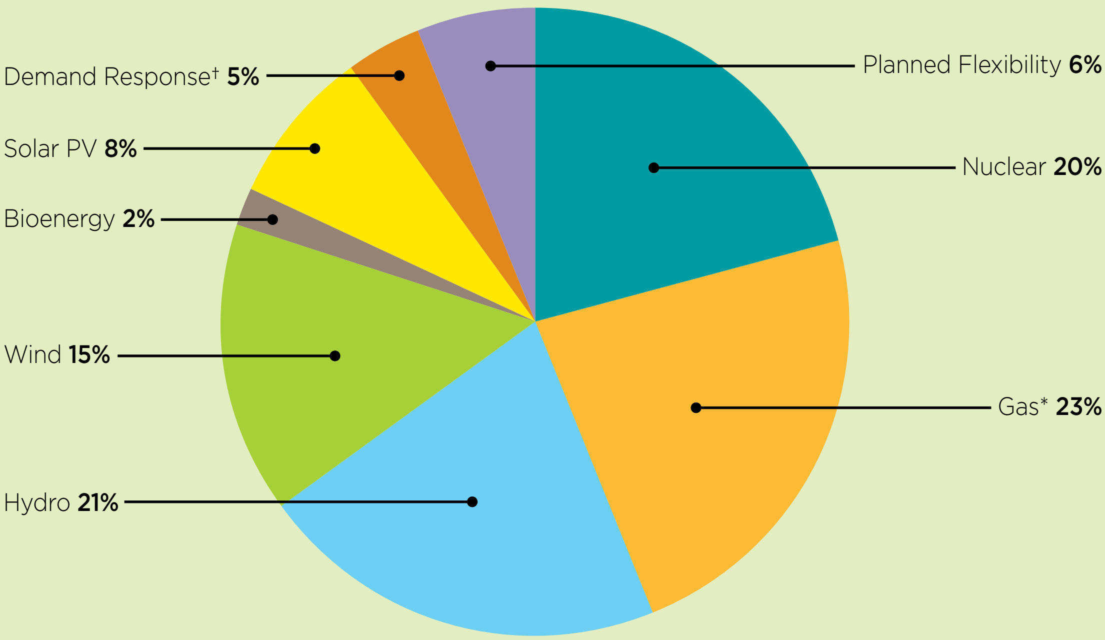
The conversion will be the first of its kind globally and will put Ontario on the leading edge of the emerging advanced biomass industry. This enables Ontario to develop knowledge and expertise that can be exported around the world to enable cost-effective conversion of coal plants to renewable fuels.

Figure 16: Renewables will grow to 46% of Ontario's generating capability by 2025.

Installed Capacity (MW) 2013



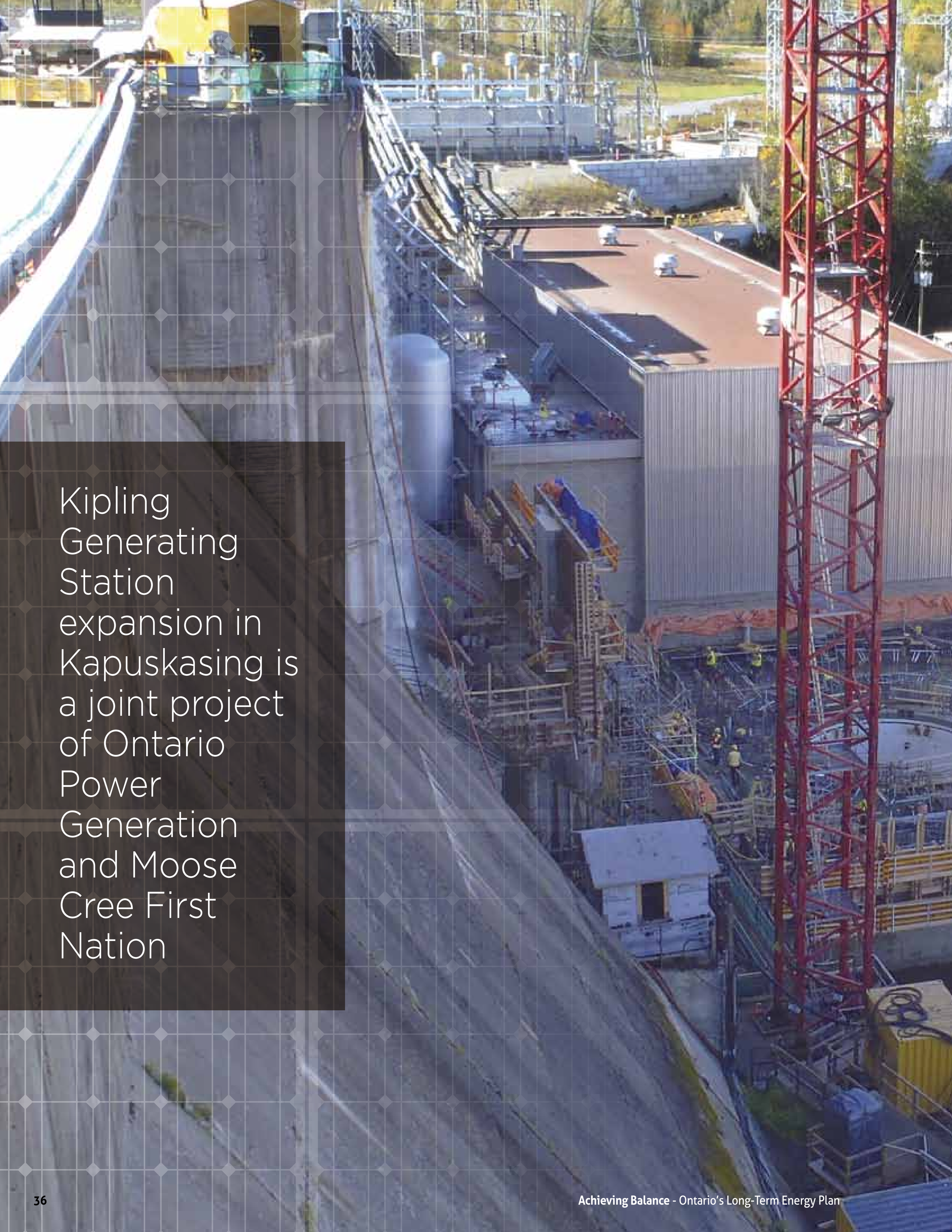
Installed Capacity (MW) 2025



Note: Total installed capacity represents the total generating capability of all resources. Adjustments are applied to calculate the capacity available at the time of peak demand.

† *The Demand Response capacity consists of the DR programs and the dispatchable customer loads under contract in the market. When considered together with Demand Response from Time-of-Use rates and the Industrial Conservation Initiative, total demand response resources are equal to 10% of the forecast net demand in 2025.*

* *Includes Lennox Generating Station – dual fueled with natural gas and oil.*



Kipling Generating Station expansion in Kapuskasing is a joint project of Ontario Power Generation and Moose Cree First Nation

What is Combined Heat and Power?

Combined Heat and Power (CHP) is the simultaneous production of electricity and heat using a single fuel such as natural gas or biomass. In most applications, heat produced from the electricity generating process (for example, from the exhaust system of a gas turbine) is captured and used to produce steam or hot water that can be used for industrial and commercial heating or cooling purposes. Alternatively, waste heat can be captured at the end of a process and used to power a turbine and generator to produce electricity.

Assuming that the heat is well-used, CHP can achieve the highest use of the energy available from a fuel, making it the most efficient way to use fossil fuels while generating electricity. CHP can achieve up to 80% overall efficiency when it is designed to follow the heat load.

renewable procurements that have previously been announced for FIT and microFIT programs.

A key aspect of attainable renewable energy targets is ensuring there is space on the transmission system to incorporate safely and effectively the power generated by additional renewable energy facilities. Factoring in generators' responsibility for connecting their projects to the grid, both the 2021 target for wind, solar and bioenergy, and the 2025 hydroelectric target are expected to be accommodated on the existing transmission system. This can be done without the need for new major transmission projects beyond those already in progress, such as upgrades to key area stations or the rewiring of a line west of London.

Wind

Wind projects are an important part of Ontario's energy mix, creating thousands of jobs across Ontario and providing clean, renewable energy to power our homes and businesses.

Ontario now has more than 2,300 MW of wind power online, which is expected to produce enough electricity each year to power more than 600,000 homes.

A clean, reliable energy system relies on a balance of resources. When clean energy from the wind is available, it reduces our need to rely on fossil fuel sources of electricity that contribute to smog, pollution and climate change.

Wind energy creates new, high-value jobs, and provides economic benefits and opportunities to municipalities and local businesses. Development of wind power in Ontario has created opportunities for landowners, local community co-operatives, Aboriginal communities and municipalities to partner with wind project developers, or lead their own wind projects, which ensures that the benefits of the project remain in the local community.

Ontario has been working to integrate wind energy more fully into Ontario's electricity system. This includes improved forecasting of when wind energy will be available to supply power to the grid. New rules will allow the IESO to tell wind generators to reduce or stop producing power when the electricity system does not require it. From a system perspective, the IESO estimates that these changes to the market rules could save ratepayers up to $200 million per year. Related OPA contract amendments could save ratepayers up to $65 million over the next five years.

Solar

Ontario is a leader in the use of solar photovoltaic (PV) electricity to power our homes and businesses. Ontario has the most solar PV capacity of any jurisdiction in Canada, with more than 900 MW of generation capacity online. This amount is expected to produce enough electricity to power more than 100,000 homes each year.

District Energy

District Energy systems can make effective and efficient use of CHP technology to heat, cool and power densely populated areas such as city centres, university campuses and hospitals.

Markham District Energy – (5.85 MW)

Markham District Energy's two most recent OPA supported plants at Bur Oak and Birchmount are due to become operational in September 2014.

The Bur Oak Energy Centre CHP facility will have 3.25 MW of OPA- contracted capacity and will supply thermal energy to buildings in the area, including the Markham Stouffville Hospital, East Markham Community Centre, a fire station, a health services building and new developments in the vicinity.

The Birchmount Energy Centre will have 2.6 MW of OPA- contracted capacity and will provide space heating and domestic hot water to buildings served by the Markham Centre District Energy System, owned and operated by Markham District Energy Inc., as well as electricity generation.

London Cogeneration Facility (12 MW) – London

London Co-generation Facility is a natural gas-fired 12 MW CHP facility. In addition to electricity production, steam from the co-generation facility will be used to provide space heating and cooling to nearby commercial, government and residential buildings.

Durham College District Energy (2.3 MW) – Oshawa

Durham College District Energy is a natural gas-fired 2.3 MW CHP facility at Durham College in Oshawa. In addition to behind–the-meter electrical production, hot water is provided to Durham College for space heating and domestic use.

Greenhouse Operations

Greenhouse operations are a particularly suitable candidate for CHP. They consume electricity for lighting, pumping and refrigerated storage of produce. They also require heat to supplement solar gain, especially at night. In addition to these benefits, greenhouses can also use the CO_2 produced by the generation to enhance the growth of plants. This is sometimes called tri-generation (electricity, heat and CO_2 are all used).

Rosa Flora Limited (4.04 MW) – Dunnville

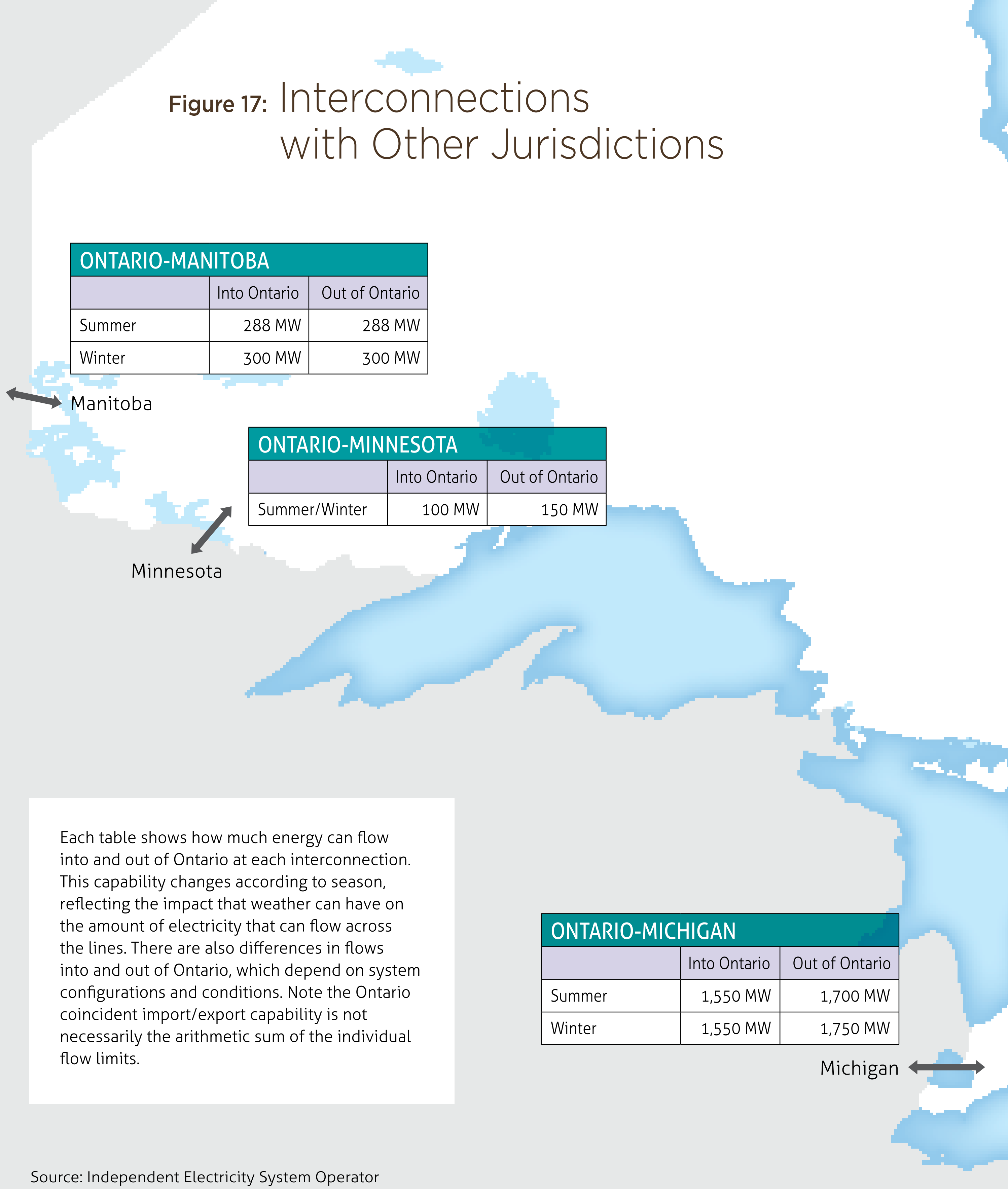
Rosa Flora, one of Canada's largest cut-flower producers, recently entered into a combined heat and power contract with the OPA to produce 4.04 MW of electricity to stay ahead in a highly competitive international market. This project will provide greenhouse heating and electricity that can be used internally for lighting, pumps and other uses, or exported to supply grid needs.

Great Northern Hydroponics (11.3 MW) – Kingsville

The Great Northern tri-generation facility is a natural gas-fired 12 MW combined heat and power facility that operates on the property of Great Northern Hydroponics, in Kingsville. Great Northern Hydroponics specializes in tomato production through the application of state-of-the-art hydroponics technology.

In addition to electricity production, hot water and carbon dioxide from the co-generation facility is used by Great Northern Hydroponics for heating and fertilizing crops in the existing 50-acre hydroponics greenhouse.

Figure 17: Interconnections with Other Jurisdictions



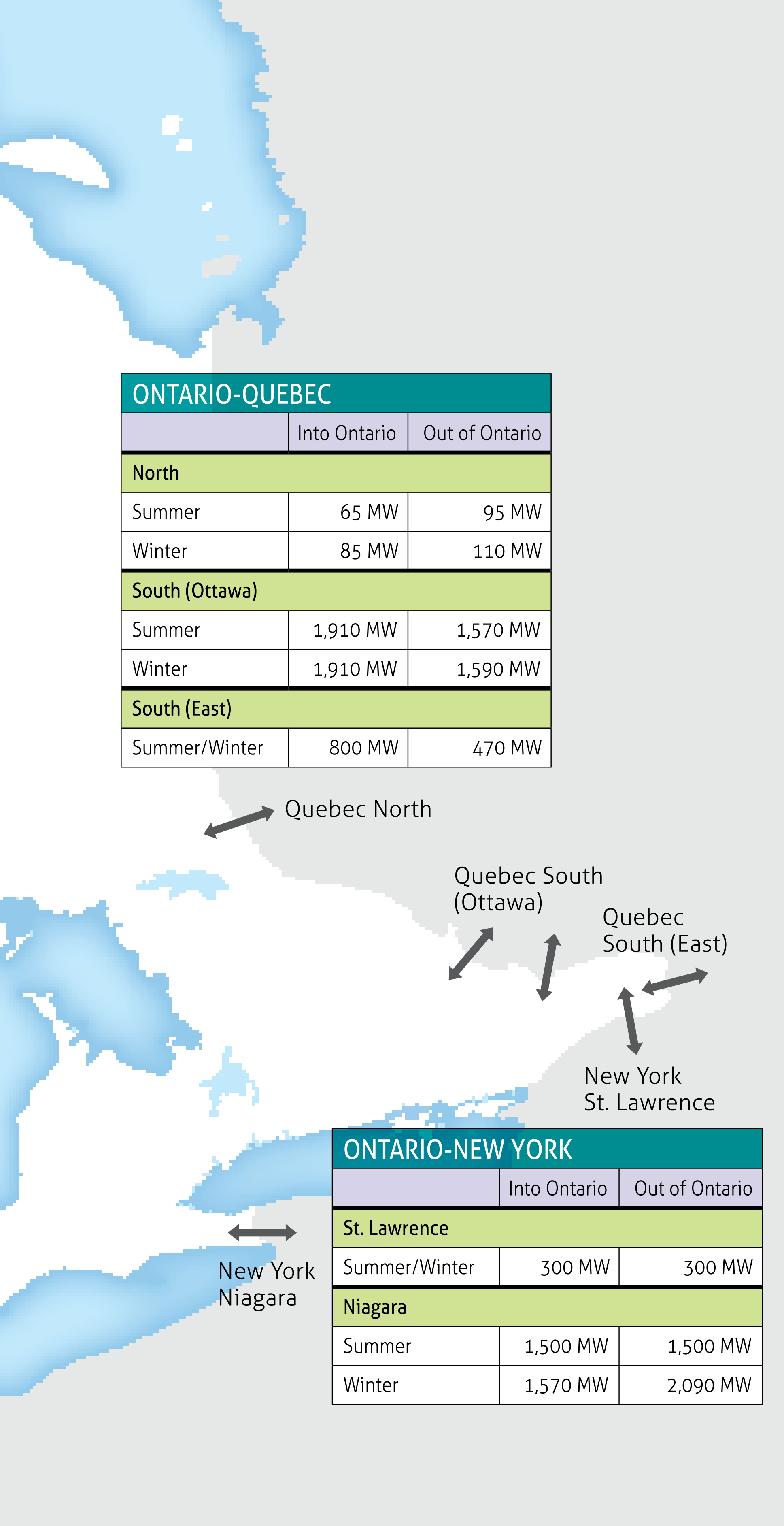
ONTARIO-MANITOBA	Into Ontario	Out of Ontario
Summer	288 MW	288 MW
Winter	300 MW	300 MW

ONTARIO-MINNESOTA	Into Ontario	Out of Ontario
Summer/Winter	100 MW	150 MW

ONTARIO-MICHIGAN	Into Ontario	Out of Ontario
Summer	1,550 MW	1,700 MW
Winter	1,550 MW	1,750 MW

Each table shows how much energy can flow into and out of Ontario at each interconnection. This capability changes according to season, reflecting the impact that weather can have on the amount of electricity that can flow across the lines. There are also differences in flows into and out of Ontario, which depend on system configurations and conditions. Note the Ontario coincident import/export capability is not necessarily the arithmetic sum of the individual flow limits.

Source: Independent Electricity System Operator



ONTARIO-QUEBEC		
	Into Ontario	Out of Ontario
North		
Summer	65 MW	95 MW
Winter	85 MW	110 MW
South (Ottawa)		
Summer	1,910 MW	1,570 MW
Winter	1,910 MW	1,590 MW
South (East)		
Summer/Winter	800 MW	470 MW

ONTARIO-NEW YORK		
	Into Ontario	Out of Ontario
St. Lawrence		
Summer/Winter	300 MW	300 MW
Niagara		
Summer	1,500 MW	1,500 MW
Winter	1,570 MW	2,090 MW

Solar PV systems produce most of their power during the afternoon, which helps us meet summer peak electricity demand from air conditioning systems. This peak shaving helps our grid operate more effectively, and reduce the use of fossil fuel electricity generation on hot, smoggy days. When solar PV systems are located on rooftops that are close to electricity users, this reduces the need for the grid to transport electricity long distances, and may help offset future requirements for grid upgrades.

The cost of solar PV systems has previously been affected by high material costs. New innovations and global market expansion are helping to substantially reduce the cost of these systems. Since the FIT and microFIT programs were launched in 2009, Ontario has seen a reduction in the average costs for new solar PV systems – of at least 40% – and the industry aspires to reach grid parity.

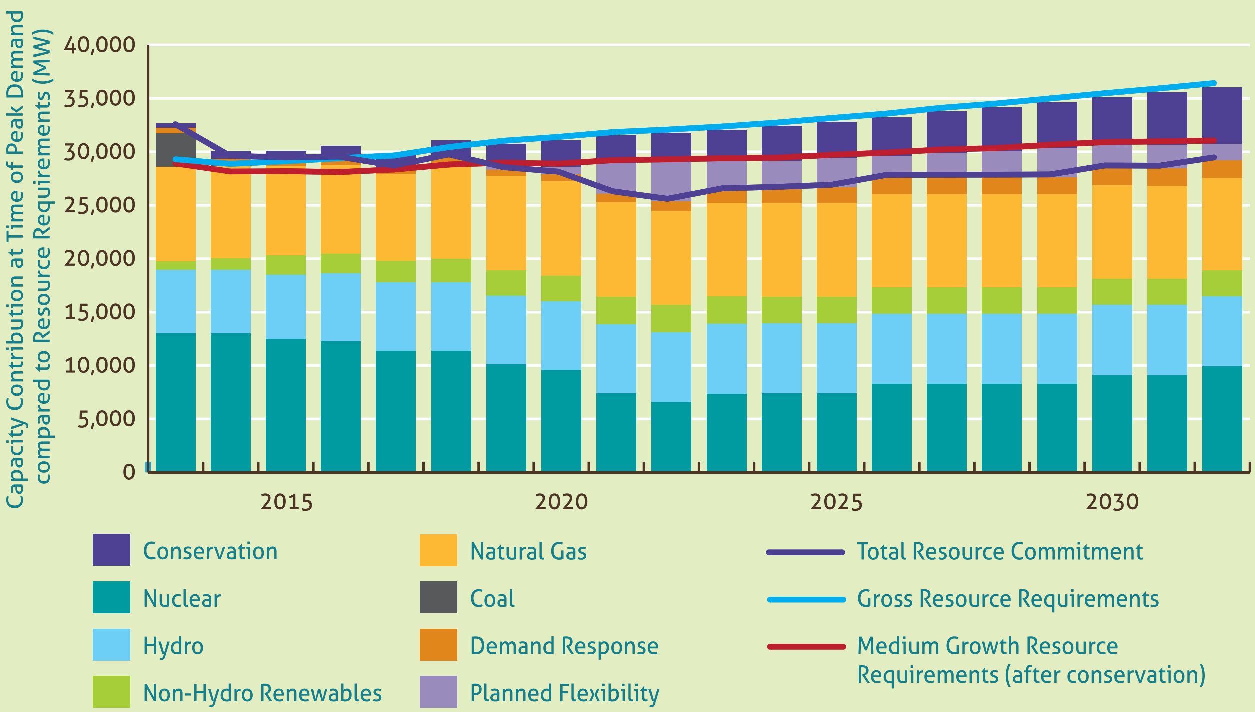
Reductions in costs and the ability to deploy solar energy systems close to the customer also offer the opportunity to expand and enhance net metering, where homeowners use solar-generated power to offset their own electricity needs. Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program.

In addition, homes and businesses can use solar thermal systems to heat water and supplement their space heating needs.

Bioenergy

Energy from organic material is another key clean and renewable resource. Currently, there are almost 300 MW of bioenergy generation capacity online in Ontario, including biomass, biogas and landfill gas systems.

Figure 18: Ontario's Planned Supply Mix (MW)



Bioenergy systems are valued for their ability to turn organic waste streams into a renewable, flexible and clean source of power particularly suited to rural and remote communities.

Using bioenergy helps to support Ontario's forestry and agricultural industries, and optimizes the use of available biomass resources. Bioenergy systems can also be closely integrated with local jobs and industry in small rural communities.

Biomass systems can use residues from forestry and agriculture to generate electricity and useful heat. Biogas systems can help manage farm waste while generating electricity, and also produce organic by-products that can be added to the soil.

Biomass and biogas systems can adjust their output to generate power during times of peak electricity demand. This helps reduce our reliance on fossil fuel during peak times. Biomass and biogas systems can also operate constantly, helping contribute to our baseload electricity supply.

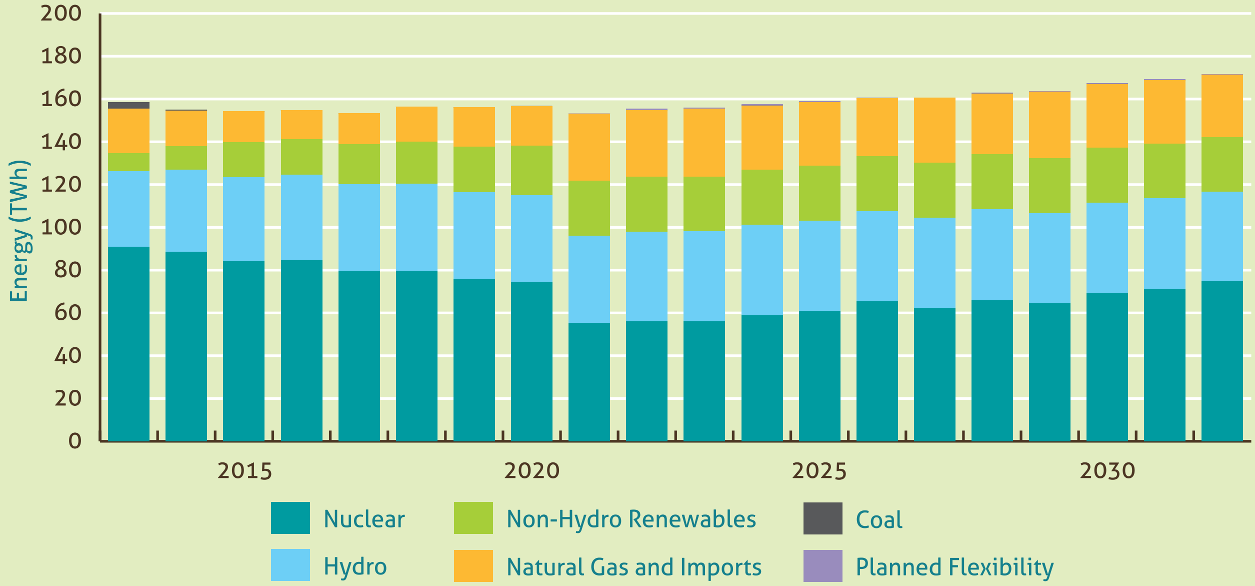
Generating electricity from landfill gas not only offsets fossil fuel use but also reduces the greenhouse gas impact of methane on the environment. It is truly a win-win situation for Ontario.

Hydroelectric

Ontario has a long and productive history with water power. More than half of Ontario's renewable energy supply comes from hydroelectric facilities, which continue to provide more than 20% of the province's electricity. Existing hydro has been the lowest-cost form of generation in Ontario, and in many cases, has provided reliable generation to meet peak demand. The province's hydroelectric resources generated the energy to power approximately 3.5 million homes in 2012. This shows that hydroelectric power will continue to play a significant role in Ontario's diverse supply mix.

Today, Ontario has well over 8,000 MW of water power in service and enough projects contracted and under development to meet our 2010 LTEP target of 9,000 MW of installed hydroelectric capacity by 2018. Earlier this year, the government directed the OPA to procure additional hydroelectric capacity, including up to 40 MW from existing facilities with the potential to expand capacity, and up to 60 MW from new municipal projects under the recently launched Hydroelectric Standard Offer Program. In addition, the government directed the OPA to enter into negotiations with OPG and

Figure 19: Ontario's Forecast Electricity Production (TWh)



Notes: The Planned Flexibility identified in Figure 19 is required to meet peak requirements and represents less than 1 TWh of energy per year. Forecasting of electricity production includes the expectation of imports and exports of electricity in all years. Imports and exports are an important component in managing the operation of the electricity system. As a result, electricity production forecast exceeds the forecast Ontario consumer demand.

the Taykwa Tagamou Nation for a power purchase agreement to procure electricity from the proposed New Post Creek hydro-electric generating station, with a capacity of approximately 25 MW.

The government will continue to build on this foundation by adding to the hydroelectricity target, increasing the province's hydroelectric portfolio to 9,300 MW by 2025. With this increased target, Ontario will maximize the potential for new large-scale hydro facilities on what the current transmission system can support.

Ontario will continue to work with the sector to assess future hydroelectric development carefully, so it is ready to generate power when and where we need it. The ministry is reviewing the potential of both large and small hydroelec-tric sites in Northern Ontario, including projects close to off-grid First Nation communities. The ministry will also continue to work with the sector to examine the use of existing dam sites to generate hydroelectric power.

Pumped Hydro Storage

Pumped hydro storage can be used to store energy when it is not needed and deliver it to the grid during periods of peak demand. Projects will continue to be examined to determine their cost-effectiveness and their ability to provide value to ratepayers.

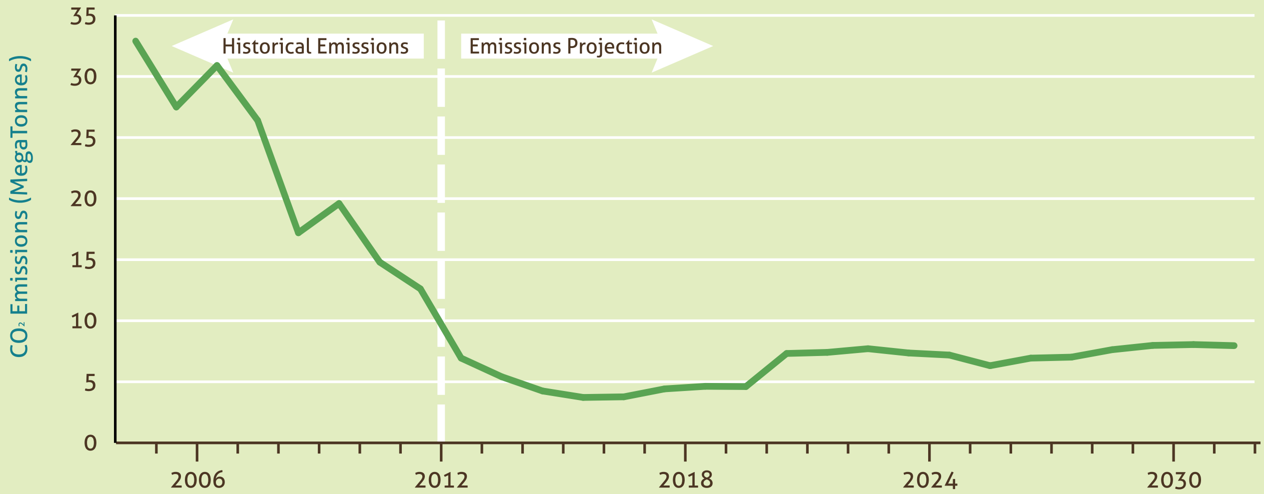
Natural Gas

While the government will not require new natural gas procure-ment to fill province-wide needs over the near term, this form of energy will still be an essential element of our responsive and flexible electricity system. Natural gas generation is cost effective to operate and can provide some of our lowest-cost capacity. Its output can be dispatched quickly to match changes in demand, and supports variable resources such as wind and solar. From 2003 to 2012, as Ontario succeeded in phasing out coal-fired generation, natural gas generation increased by 38%, from approximately 16 TWh to approximately 22 TWh.

Ontario's natural gas fleet has capacity and flexibility to fill energy needs arising during the nuclear refurbishment period.

The province's existing NUGs, contracted in the 1990s with the former Ontario Hydro, currently provide 1,200 MW of natural gas generation. The contracts for 75% of that capacity will expire by the end of 2018. The OPA has been directed to enter into new contracts with the NUGs after

Figure 20: Greenhouse Gas Emissions Forecast



Note: Emissions in any one year could be higher, or lower, than the projection depending on the specific operating conditions experienced in the system. For example, changes in demand and/or energy production from non-emitting resources could contribute to higher or lower emissions.

the current ones have expired, but only if the contract results in cost and reliability benefits to Ontario ratepayers.

Natural gas prices have declined sharply since 2008, and are expected to remain relatively low over the next decade. The price of natural gas, though is historically quite volatile, and is affected by factors outside of Ontario's control. It is therefore in Ontario's best interest to keep a balanced supply mix, and not depend too heavily on natural gas, as a hedge against this volatility.

Combined Heat and Power

Combined Heat and Power (CHP) can be an efficient way to use natural gas to generate electricity as well as useable heat or steam. Given the right circumstances, CHP can help support regional economic development, and local energy needs, while reducing carbon dioxide (CO_2) emissions at a competitive cost.

The OPA has run four rounds of competitive procurements and two standard offer programs for small-scale CHP since 2005, resulting in 420 MW of capacity from CHP projects – 414 MW of which are in commercial operation. Approximately 6 MW are under development, and scheduled to be in service in 2014.

We have learned that in general, CHP projects work better if they are driven primarily by the need for heat, with electricity as a by-product. CHP projects need to be the right size, in the right location and at the right price to ensure optimal benefits to the electricity system, in addition to serving the needs of their heat loads.

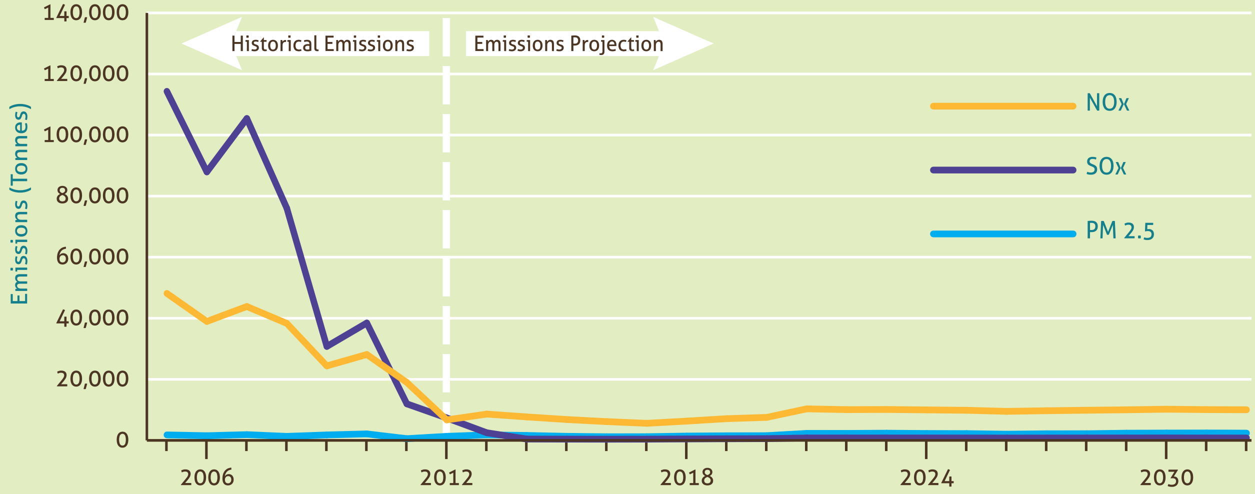
The OPA has conducted procurements for CHP projects representing a wide range of technologies, applications, industries and geographic locations. Future procurements will focus on considerations such as efficient CHP applications and locations with regional capacity. These could include a new program for CHP at greenhouse operations, agri-food and district energy projects.

The way that CHP supports economic development while reducing CO_2 emissions is best illustrated in the examples on page 39.

Energy from Waste

Energy from Waste (EFW) refers to waste treatment technologies that generate electricity and/or heat by burning various kinds of waste material.

Figure 21: Nitrogen Oxides, Sulphur Oxides and Particulate Matter Emissions Forecast



Note: Emissions in any one year could be higher, or lower, than the projection depending on the specific operating conditions experienced in the system. For example, changes in demand and/or energy production from non-emitting resources could contribute to higher or lower emissions.

Most EFW facilities burn the waste material directly to obtain energy but there are alternative technologies being developed that promise better efficiency and lower greenhouse gas emissions than conventional EFW.

To encourage the development of these new technologies in Ontario, the OPA is considering projects that have received Ministry of the Environment approval. These Ontario-based projects offer the potential for job creation and export opportunities. Testing will verify whether new technologies can operate successfully with environmental performance superior to conventional EFW technologies.

Clean Imports

Ontario has several interconnections with the provinces of Manitoba and Quebec as well as with the states of Minnesota, Michigan and New York. Taken together, Ontario has approximately 4,500 to 5,200 MW of import-export capacity. However, actual power flows do not reach these levels because of operational constraints in and outside Ontario.

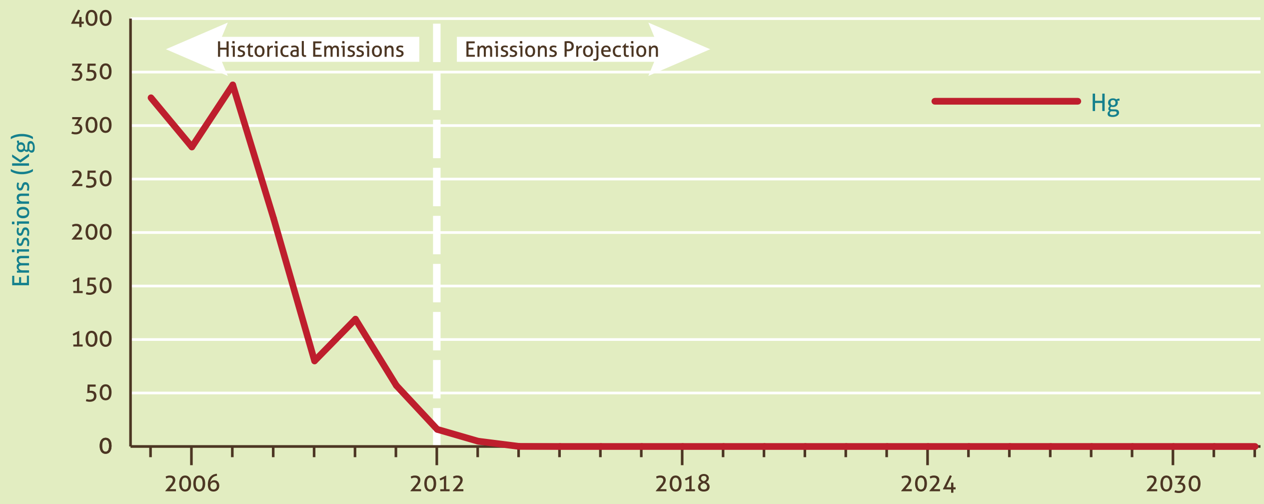
Ontario exports and imports a significant amount of electricity as part of the regular operation of its electricity market and is expected to have sufficient energy and capacity in the near term to meet province-wide needs. The electricity wholesale market has proven to be extremely effective in enabling power to flow between Ontario and its neighbours.

Ontario will continue to rely on the wholesale market to provide flexibility and to balance power flows on a short-term basis. However, an import arrangement with a neighbour to guarantee the firm delivery of clean power could offer a cost-effective alternative to building domestic supply. Import contracts can be structured to meet multiple system needs such as capacity for peaking, ramping, backup or reserve purposes, or the firm delivery of energy over a specified timeframe, or a combination.

Contracted energy imports can provide value if their price is less than domestic generation. They can also further diversify Ontario's supply. While clean energy imports offer potential benefits to Ontario, the value to Ontario depends on the willingness of those supplying imports to offer a product that matches Ontario needs and represents better value than the domestic alternatives.

Ontario will only pursue contractual arrangements for firm imports where cost effective and well matched to Ontario's electricity needs.

Figure 22: Mercury Emissions Forecast



Planned Flexibility

While the OPA is forecasting lower growth in electricity demand, we must take into account the element of uncertainty inherent in all forecasts. The government has to be prepared to respond if the economy or energy demand does not evolve as expected. In other words, Ontario needs to be flexible to meet the inherent uncertainty of predicting how demand will grow. Therefore, the government will plan for a wide range of possibilities but only commit resources as needs become clearer, while ensuring Ontarians have the energy they need, when and where they need it.

Starting in 2014, an Ontario Energy Report will be issued annually to update Ontarians on the energy supply and demand picture for the province, and review progress in implementing the LTEP.

The LTEP will continue to be updated every three years. These annual reports will give everyone an opportunity to monitor progress and understand developments that will be important in the next formal review.

This is a direct response to what we heard during the LTEP engagement sessions, where ratepayers, members of the public, stakeholders and Aboriginal communities wanted to be involved in an ongoing dialogue about energy planning.

2013 LTEP Supply Mix

Figures 18 and 19 present an integrated picture of the supply mix elements as described above including the Conservation First and DR targets, forecast demand, renewable targets and planned nuclear refurbishments. Reflecting the need to maintain flexibility as circumstances change, future options to be determined are also illustrated here.

Since 2003, greenhouse gas emissions from coal-fired generation in the electricity sector have been reduced by nearly 90%. In addition, the emissions of sulphur dioxide and nitrogen oxides have dropped by 93% and 90%, respectively, while mercury levels are at their lowest level in 45 years.

Figures 20, 21 and 22 are historical and forecast emissions of greenhouse gases, sulphur dioxide, nitrogen oxides, particulate matter and mercury for Ontario's electricity sector.

Air emissions from Ontario's electricity sector are expected to remain at historically low levels, although there may be variations in future emissions attributable to changes in demand, the use of natural gas, clean imports, and demand response.

In Summary

Nuclear

- Ontario will not proceed at this time with the construction of two new nuclear reactors at the Darlington Generating Station. However, the Ministry of Energy will work with Ontario Power Generation (OPG) to maintain the site licence granted by the Canadian Nuclear Safety Commission.
- Nuclear refurbishment is planned to begin at both Darlington and Bruce Generating Stations in 2016.
- During refurbishment, both OPG and Bruce Power will be subject to the strictest possible oversight to ensure safety, reliable supply and value for ratepayers.
- Nuclear refurbishment will follow seven principles established by the government, including minimizing commercial risk to the government and the ratepayer, and ensuring that operators and contractors are accountable for refurbishment costs and schedules.
- The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.
- Ontario will support the export of our home-grown nuclear industry expertise, products and services to international markets.

Renewable Energy

- By 2025, 20,000 MW of renewable energy will be online, representing about half of Ontario's installed capacity.
- Ontario will phase in wind, solar and bioenergy over a longer period than contemplated in the 2010 LTEP, with 10,700 MW online by 2021.
- Ontario will add to the hydroelectricity target, increasing the province's portfolio to 9,300 MW by 2025.
- Recognizing that bioenergy facilities can provide flexible power supply and support local jobs in forestry and agriculture, Ontario will include opportunities to procure additional bioenergy as part of a new competitive process.
- Ontario will review targets for wind, solar, bioenergy and hydroelectric annually as part of the Ontario Energy Report.
- The Ministry of Energy and the OPA are developing a new competitive procurement process for future renewable energy projects larger than 500 kilowatts (kW), which will take into account local needs and considerations. The ministry will seek to launch this procurement process in early 2014.
- Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program.

Natural Gas/Combined Heat and Power

- Natural gas-fired generation will be used flexibly to respond to changes in provincial supply and demand and to support the operation of the system.
- The OPA will undertake targeted procurements for Combined Heat and Power (CHP) projects that focus on efficiency or regional capacity needs, including a new program targeting greenhouse operations, agri-food and district energy.

Clean Imports

- Ontario will consider opportunities for clean imports from other jurisdictions when such imports would have system benefits and are cost effective for Ontario ratepayers.

4 Investing in Transmission

Transmission planning and upgrades are driven by system reliability needs, load growth, and integration of generation resources, including renewable resources. Maintaining the high voltage transmission lines that form the backbone of the electricity system is vital to ensure reliability of the grid.

Having the transmission we need to enable our supply mix goals is a key driver of electricity planning. The existing transmission system, including projects in progress, will be sufficient to enable supply mix targets identified in this LTEP.

A Focus on Northwestern Ontario

Northwestern Ontario has recently received a lot of attention when it comes to electricity planning. That's in part because while provincial demand is generally flat, there could soon be a significant increase in energy demand in northwestern Ontario, largely because of an expected increase in mining activity.

In 2010, Ontario began moving forward with a plan for the northwest, when the new East-West Tie transmission line was identified as a priority project. As part of an integrated plan to meet the needs of the Northwest, work on that new line has begun. The new East-West Tie line will reduce transmission constraints and allow a greater two-way flow of electricity across Northern Ontario. Efforts are currently focused on detailed engineering work and seeking necessary approvals such as the Environmental Assessment and engagement with First Nation and

Journeyperson Electrician bolting together a steel structure, Burlington Transformer Station

Ring of Fire

The Ring of Fire, 540 km northeast of Thunder Bay, has the potential to become a significant economic development driver for Northern Ontario and First Nation communities. To help realize this potential, Ontario has:

- Announced its intention to partner with industry, First Nations and the federal government to create an infrastructure development corporation.
- Appointed former Supreme Court of Canada Justice Frank Iacobucci as lead negotiator on behalf of Ontario in community-based discussions with Chiefs of the Matawa Tribal Council on regional considerations in resource development in the Ring of Fire.

Energy is part of the successful development in the Ring of Fire region. We are committed to working with key partners to meet energy needs and maximize benefit for communities.

Ontario has taken a leadership role in planning for development, however, the federal government must step up and provide support. Ontario will continue to work on the smart, sustainable and collaborative development of the Ring of Fire.

Métis communities. The proposed project is expected to be finished in 2018 and will create hundreds of jobs in the service and construction industries for the duration of development and construction.

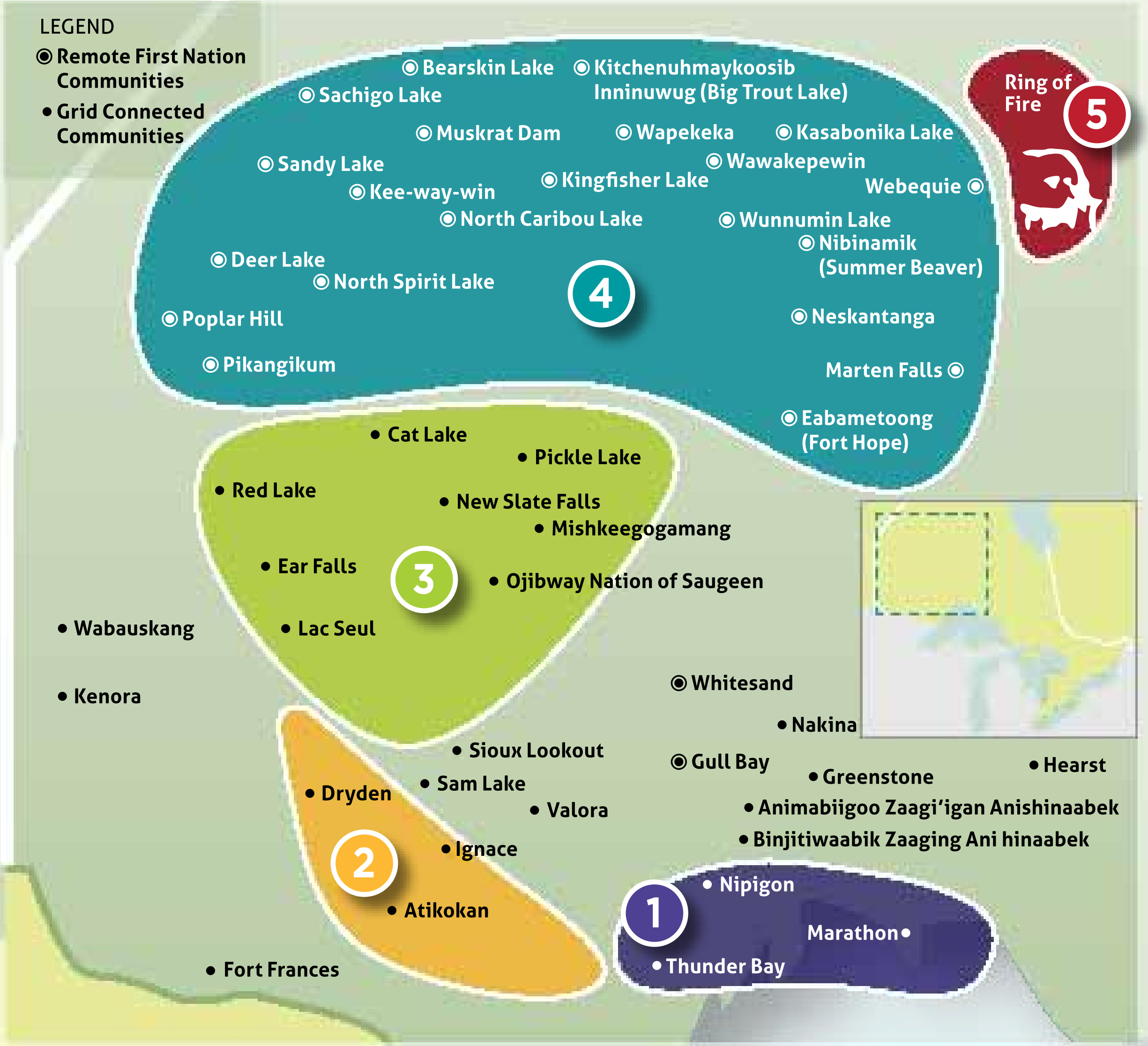
While the new East-West Tie line will provide a new source of supply for the northwest, the 2013 LTEP anticipates that new resources may also be needed to make sure that users in specific parts of the northwest have the power they need.

Planning for the northwest has a number of different facets, some of which focus on areas within the region. The OPA's analysis of the needs and solutions for the North of Dryden area identified the need to meet the increased electricity demand from mining. Among other things, the report assessed what needs to be done to the electricity system serving Red Lake and Pickle Lake to increase capacity to serve new demand. The OPA's report looked at transmission and generation options.

The Ring of Fire, the vast mineral-rich area north of Long Lac and east of Pickle Lake on the edge of the Hudson Bay Lowlands, could be a game-changer for the northern economy. Mining developers have shown significant interest in this area in recent years. The province is committed to ensuring its plans reflect the long-term potential for demand at the Ring of Fire while recognizing the role of electricity customers in planning for their supply needs.

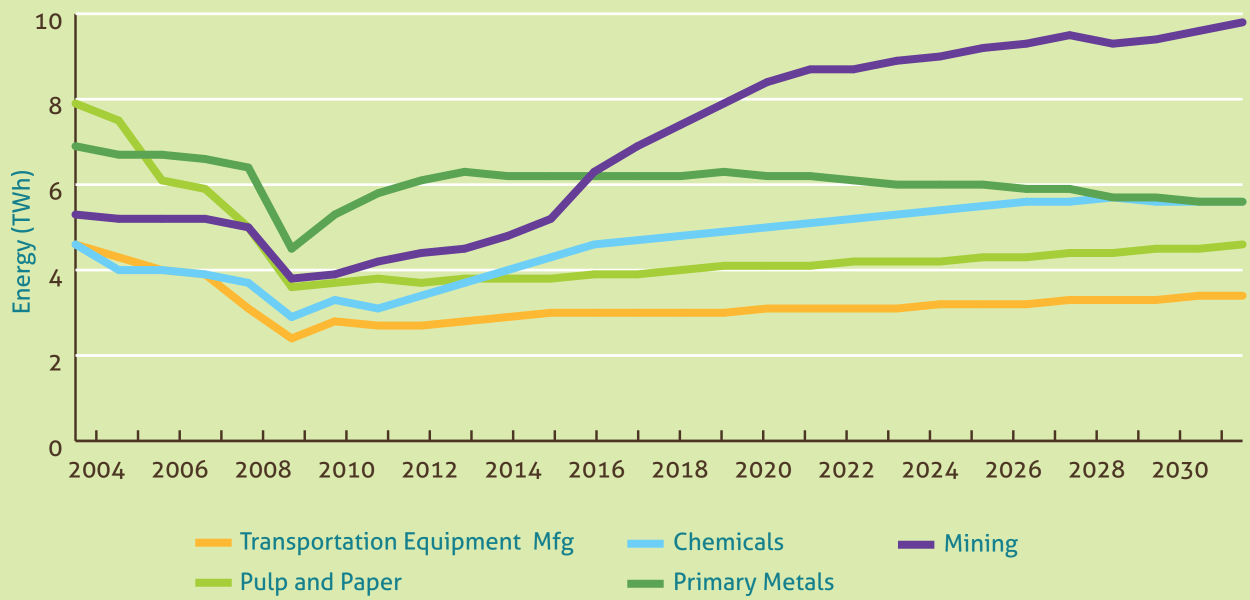
However, mining demand is not limited to the area north of Dryden or the Ring of Fire. There is additional mining potential elsewhere in the northwest, including, for example, in the areas near Fort Frances and Atikokan. Working with Aboriginal communities, local municipalities

Figure 23: Key Areas and Projects in Northwestern Ontario



Area	Projects under Development	Status/Outcome
1 Thunder Bay to Wawa	East-West Tie development	- Expected to be in service by 2018 - Will enhance reliability to the northwest - Needs in Greenstone area to be studied
2 Dryden area to Thunder Bay	Northwest Bulk Transmission Line	- The project could come into service as early as 2020, dependent on demand - Will help alleviate transmission constraints within the northwest
3 4 5 North of Dryden Region, remote First Nation communities, and Ring of Fire	New Line to Pickle Lake Improvements on Line from Dryden to Red Lake Remote Connections	- Projects will increase capacity to support new demand, including from mining, connect remote communities and potentially the Ring of Fire

Figure 24: Electricity Consumption by the Industrial Sector



and businesses, the province will ensure adequate supply across the region.

As part of the longer-term set of solutions for the area, the government expects Hydro One to begin planning for a new Northwest Bulk transmission line, west of Thunder Bay, with the project scope to be recommended by the OPA. A new line would increase transmission capacity and provide a means for new customers and growing loads to be served with the clean and renewable sources that comprise Ontario's supply mix. Over the long term, it would also enhance the potential for development and connection of renewable energy facilities, which can be factored into future plans. Because of its importance to the region, this new line has been identified as a priority project. Hydro One and Infrastructure Ontario will be expected to work together to explore ways to ensure that the project is developed and delivered in a cost-effective manner, and results in value for Ontario electricity customers.

Another driver for transmission investment in the northwest is the move toward a cleaner supply of power in Ontario's First Nation remote communities.

Following up on a commitment made in the 2010 LTEP, the OPA has looked at the costs of connecting the remote First Nation communities in the northwest; these communities are currently not connected to the province's electricity grid and rely instead on expensive diesel fuel to generate their electricity. Connecting the remote First Nation communities in Northwestern Ontario is a priority, but federal commitment and co-operation will be required to make it a reality. For those communities where grid connection is not feasible, the province, working with key stakeholders, will explore options to reduce reliance on diesel. Chapter 6 - First Nation and Métis Communities discusses the connection of remote First Nation communities in more detail.

Taken together, the tasks of connecting remote communities and meeting the demand from new mining development are likely to require significant investment in transmission capacity. In fact, Ontario has initiated planning that could lead to about $2.2 billion in

transmission investments in the northwest over the long term. Projects that are in the planning stage include:

- East-West Tie Expansion;
- A new Northwest Bulk transmission line;
- A new line to Pickle Lake;
- Red Lake Area transmission upgrades; and
- Grid connection of remote communities – depending on federal contributions.

These transmission projects, if implemented, would increase the reliability and flexibility of the system in the northwest. They would also help to ensure sufficient supply to meet the forecast load growth in the region, or provide new connections for remote communities.

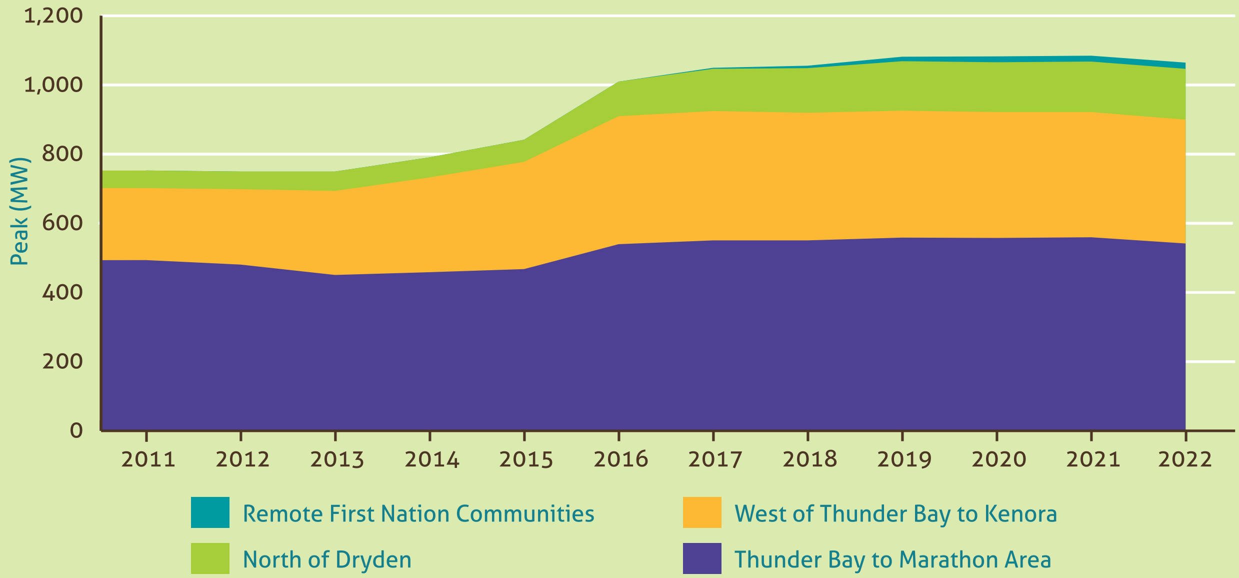
Transmission investment of this magnitude would be expected to support a total of about 1,800 jobs in the services and construction industry and its supplier industries over the course of development and construction.

A new line to Pickle Lake, first identified as a priority in the 2010 LTEP, is integral to regional needs and economic development. It will help serve new demand in the area north of Dryden, as well as provide increased capacity to connect remote communities north of Pickle Lake. Given its importance to the connection of remote communities, this project continues to be a key priority for Ontario.

Ontario's northwest has been a focus for transmission planning because of the complexity and size of the needs there, but it is not the only place in Ontario where transmission planning and investments have been made.

Many of Ontario's distributors in other areas, such as York Region, Toronto, Ottawa and Leamington, are also seeing growth. They are engaged with the IESO and the OPA on regional planning for specific areas where demand

Figure 25: Projected Northwestern Ontario Peak Demand



Source: OPA. For an indication of the approximate areas identified above, see Figure 23.

growth and intensification are leading to new needs and pressures on the electricity system. The focus here is on identifying needs and the options to meet those needs. This is further discussed in Chapter 5 - Regional Planning.

In other regions across the province, planning is complete and new equipment is being put in place. For example, Hydro One's Wood Pole Replacement program is driven by the need to replace and refurbish existing assets that have been in place for decades. Hydro One's re-wiring of a line west of London is ensuring that additional power from clean and renewable sources can be safely and reliably integrated into the transmission system. Some projects, such as transmission reinforcement in Guelph, are being driven by growth in demand and the need to maintain the dependable, reliable power supply we've come to expect.

These essential investments in new and refurbished transmission and distribution infrastructure ensure the reliable delivery of power, keeping the lights on for customers and supporting jobs and local economies. All told, Hydro One alone has invested more than $11 billion in its transmission and distribution systems since 2003 — nearly $1.5 billion in each of 2011 and 2012, and more than $600 million in the first half of this year. Hydro One's capital investments since 2003 supported an average of 8,000 jobs, both directly — including through Hydro One's own employees and those of its contractors — and indirectly, through broader supply chains. They have also contributed to Ontario's gross domestic product by an average of $835 million annually. Some examples of these recent investments are shown on pages 54-57.

ONTARIO

Wood Pole Replacement Program

Province wide

Est. Cost: $56.8 million

Exp. In-Service: 2013/2014

Hydro One has about 7,000 km of transmission lines that use wood pole structures, most of which are in Northern Ontario. There are about 42,000 of these wood poles in all.

Wood structures deteriorate over time due to environmental factors such as weather, and even the presence of insects and wildlife. Hydro One regularly tests the condition of poles and replaces them as needed.

A total of 1,700 wood pole structures that have reached the end of their service life will be replaced in 2013 and 2014.

CENTRAL ONTARIO

Peterborough-Ottawa Area

C25H Line Refurbishment

Est. Cost: $80.8 million

Exp. In-Service: 2017

The 170 km high voltage transmission line between Peterborough and the Ottawa area is 84 years old and is at the end of its useful life.

Refurbishing the line will help maintain reliable electricity service for customers and serve future load growth.

South Georgian Bay/ Muskoka

Circuit Breaker Replacement at Orangeville Transformer Station

Est. Cost: $28.1 million

Exp. In-Service: 2014

The Orangeville Transformer Station is a key station that enables the flow of power between south-western and central Ontario. Circuit breakers are being replaced to maintain the reliability of the local system, and reduce the risk of further equipment deterioration.

NORTHEASTERN ONTARIO

Sudbury/Algoma

Circuit Breaker Replacement at Hanmer Transformer Station

Est. Cost: $26.1 million

Exp. In-Service: 2013

Hydro One is investing $26 million to replace the circuit breakers in the important Hanmer Transformer Station. The Hanmer Transformer Station is critical for getting electricity from hydroelectric dams in northeastern Ontario to where it can be used.

The project will, among other things, help ensure a reliable supply of electricity for mining and associated operations in the Sudbury area. The work is expected to be completed this year.

North/East of Sudbury

Replacement and Relocation of Circuit Breakers from Abitibi Canyon Switching Station to Pinard Transformer Station

Est. Cost: $47 million

Exp. In-Service: 2013

Additional circuit breakers are being replaced and moved from the Abitibi Canyon Switching Station to the Pinard Transformer Station. The Abitibi Canyon Switching Station is a key station for getting clean, renewable water power from generation sites in the northeast to places where the power is needed. The enhancement is expected to cost $47 million, and will be in service in 2013.

East Lake Superior

Replacement of Wooden Line Support Structures in Sault Ste. Marie

Est. Cost: $4.9 million

Exp. In-Service: 2014

Great Lakes Power is replacing wooden transmission poles and towers with metal structures in Sault Ste. Marie. Many of the deteriorating wooden structures are located close to residences and institutions, so their replacement will enhance public safety, as well as maintain reliability.

SOUTHERN ONTARIO

Hamilton Area

Station Equipment Replacement

Est. Cost: $13.2 million

Exp. In-Service: 2015

The Kenilworth Transformer Station in Hamilton serves an industrial area vital to the local economy. Hydro One is investing $13 million to replace equipment that is nearing the end of its expected service life to ensure customers in the Hamilton area continue to receive a reliable supply of electricity.

SOUTHWESTERN ONTARIO

Chatham/Lambton/Sarnia

Equipment Replacement at Wallaceburg Transformer Station

Est. Cost: $26 million

Exp. In-Service: 2013

Transformer equipment at Wallaceburg Transformer Station required replacement to reduce operational risks and maintain local system reliability.

GREATER TORONTO AREA

Toronto Area

Station Upgrades at Leaside, Hearn and Manby

Est. Cost: $148 million

Exp. In-Service: 2014-2015

With more than 700,000 customers in Toronto, efforts are under way by Hydro One to upgrade equipment at its Hearn Switching Station and the Manby and Leaside Transformer Stations in Toronto. These three major transmission stations provide Toronto with about 40% of its electricity needs.

The changes will improve local reliability and increase the amount of new and renewable generation that can be connected to distribution systems in the Greater Toronto Area.

Toronto Area

Richview Transformer Station - Air Breaker Replacement

Est. Cost: $61.2 million

Exp. In-Service: 2017

The City of Toronto relies on eight major supply points for its electricity – seven large transmission facilities and one generating plant.

Hydro One is replacing aging equipment at the Richview Transformer Station, a critical station for the city's west end. This will help maintain the reliability of electricity supply for residents living and working in the west end and downtown Toronto.

Toronto Area

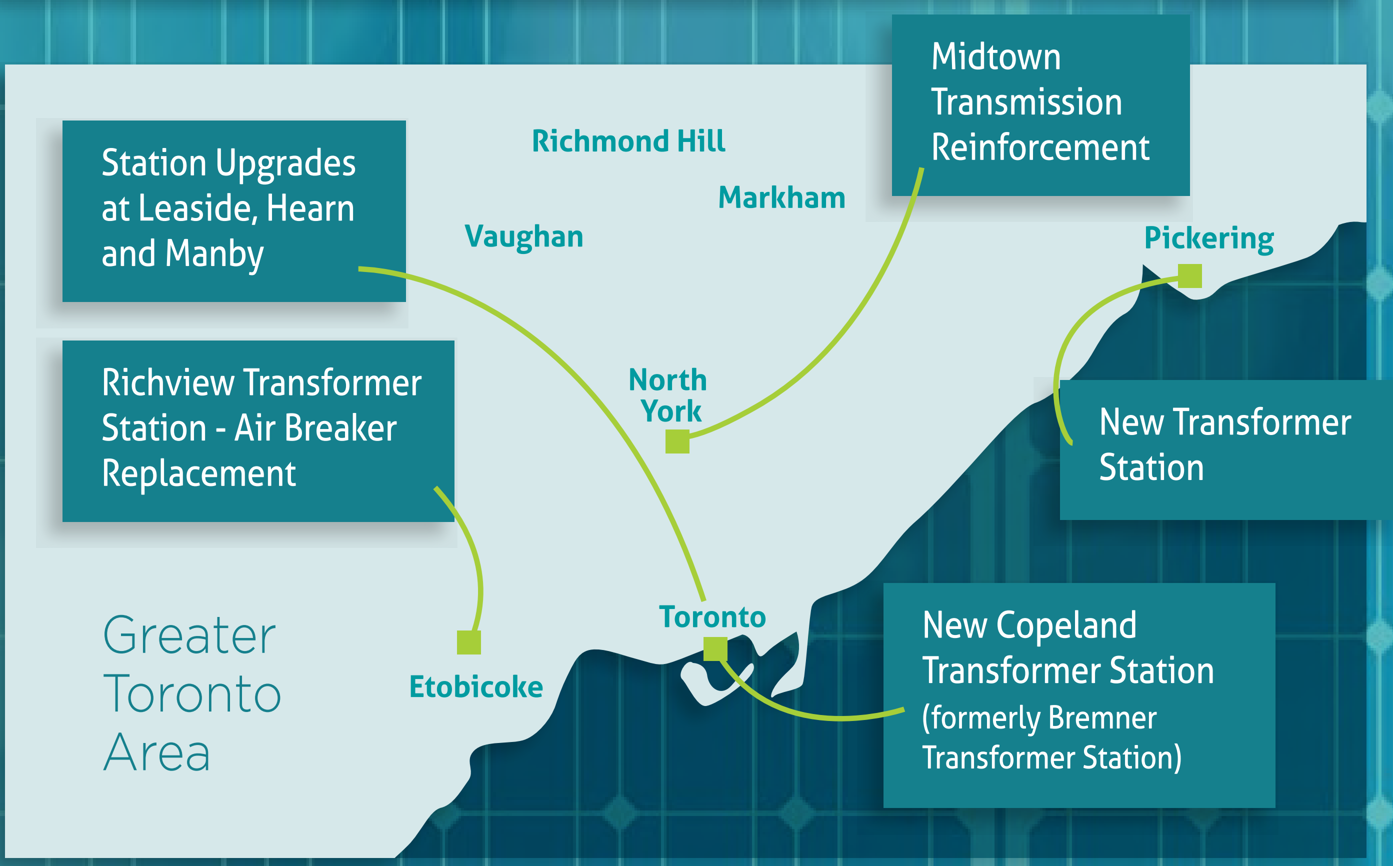
Midtown Transmission Reinforcement

Est. Cost: $115 million

Exp. In-Service: 2015

A joint effort between Hydro One and Toronto Hydro, the Midtown Transmission Reinforcement project will strengthen the transmission system through midtown Toronto. Replacing aging equipment and building a new transmission line, part of which is underground, will ensure a safe and reliable supply of power to customers and provide adequate supply to meet future load growth through midtown Toronto.

Construction has been underway since 2011.



Toronto Area

New Copeland Transformer Station (formerly Bremner Transformer Station)

Est. Cost: $195 million

Exp. In-Service: 2014*

Downtown Toronto's power distribution system is currently served by five transformer stations. The new Copeland Transformer Station will ensure reliable supply for the fast-growing downtown core, and take stress off the existing Windsor Transformer Station, which currently serves 9 of the 10 largest buildings in Toronto. It will also provide power to the redeveloped waterfront.

This new station in downtown Toronto will help to alleviate the strain on neighbouring stations and will help to serve the growing customer base. It will also permit critical asset renewal at neighbouring stations to take place.

*First Phase. Source: Toronto Hydro

Clarington Transformer Station

New Transformer Station

Est. Cost: $297 million

Exp. In-Service: 2017

The Pickering Nuclear Generating Station is a critical source of electricity for the eastern part of the Greater Toronto Area. The Clarington Transformer Station, which will connect high voltage 500 kV lines and 230 kV lines in the area, will be required to come into service before Pickering Generating Station can be shut down, to ensure reliable supply for customers in the Eastern Greater Toronto Area.

The station will also enhance the reliability of supply to parts of Durham region. The project is pending a decision from the Minister of the Environment on whether an individual Environmental Assessment is required.

In Summary

- Hydro One will be expected to begin planning for a new Northwest Bulk Transmission Line to increase supply and reliability to the area west of Thunder Bay. The area faces growth in demand, some of which is beyond what today's system can supply. Hydro One and Infrastructure Ontario will be expected to work together to explore ways to ensure cost-effective procurement related to the line.
- Connecting remote northwestern First Nation communities is a priority for Ontario. Ontario will continue to work with the federal government to connect remote First Nation communities to the electricity grid or explore on-site alternatives for the few remaining communities where there may be more cost-effective solutions to reduce diesel use.
- All regions of the province can expect timely local transmission enhancements as needs emerge. Upgrades and investments will meet system goals, such as maintaining or improving reliability or providing the infrastructure necessary to support growth.

5

Regional Planning

Engaging Local Communities

An exchange of information and engagement with municipalities, Aboriginal communities, stakeholders and members of the general public will now be the cornerstone of energy planning discussions.

The release of the 2013 LTEP follows the most comprehensive set of consultations and engagements ever undertaken by the Ministry of Energy. Almost 8,000 people took an on-line survey and shared their views on conservation, energy supply, regional planning and imports. Over 1,000 submissions were received though the Environmental Registry and by the Ministry of Energy.

Staff also sat down with representatives of 50 LDCs to obtain their views and suggestions on how to improve and maximize the delivery of conservation in Ontario.

Ministry of Energy and agency staff travelled to 12 communities including Kenora, Windsor, Sault Ste. Marie and Ottawa to hear Ontarians' views on the Long-Term Energy Plan. They also met with representatives of close to 100 First Nation and Métis communities and organizations in 10 engagement sessions across Ontario.

Increased public participation and community engagement in the development of energy plans and policy is vital and has a number of beneficial outcomes:

- Policy makers hear first-hand what Ontarians think about energy policy, and the current issues of the day. They will learn how their policies affect people's day-to-day lives.
- Communities feel they were listened to, that their voices were heard.
- While they may not always agree with the final decision, the public has an increased understanding of the trade-offs involved in what is often a very complex area of policy and system planning.

Ensuring there is a local voice in energy planning is critical. Since 2005, the IESO has had a Stakeholder Advisory Committee with broad representation that meets regularly to provide its Board of Directors and management with advice and recommendations on market initiatives and planning decisions. The OPA has recently created its own Stakeholder Advisory Committee.

In May 2013, the government asked the IESO and the OPA to recommend a new integrated regional energy planning process that would improve how large infrastructure facilities are sited and would propose how to involve municipalities, Aboriginal communities and other stakeholders in developing regional energy plans.

The IESO and the OPA heard that Ontarians wanted to be involved in the siting of large energy facilities, and in the plans for their region's energy use:

"A common theme that emerged from the feed-back received from the engagement sessions and face-to-face meetings was the need for a major education effort about Ontario's electricity needs, including a better understanding of the electricity planning and siting processes. This would help municipalities, First Nation and Métis communities, stakeholders, and the general public to become involved early and participate effectively in decision-making".

The IESO and the OPA published their report *Engaging Local Communities in Ontario's Electricity Planning Continuum* in August 2013 and the government decided to adopt these recommendations. These recommendations will improve municipal engagement and public consultation and ensure that large infrastructure is located in the right place from the start. The report's recommendations are grouped under the following themes:

Bringing Communities to the Table

- The government and its energy agencies will reach out to local communities early and often. Regional Advisory Committees will be created across Ontario to ensure that representatives of municipalities, First Nation and Métis communities and local businesses can participate in the planning of their regions' energy needs.

Linking Local and Provincial Planning

- Regional electricity needs will be integrated into applicable municipal plans, and the government will enhance regional energy plans, which could include the consideration of social, environmental and economic development objectives. The government has recently launched programs to support the development of Municipal and Aboriginal Community Energy Plans.

LONG-TERM ENERGY PLAN

Province-wide Consultation & Engagements

12 COMMUNITIES VISITED

13 PUBLIC OPEN HOUSES

AND

10 FIRST NATION & MÉTIS SESSIONS

WHAT WE HEARD

OVER **1000** SUBMISSIONS

VIA THE ENVIRONMENTAL REGISTRY AND DIRECTLY

ALMOST **8000** RESPONSES

TO THE ONLINE QUESTIONNAIRE


DEMAND RESPONSE
SOLAR
RELIABILITY
WIND
ENVIRONMENTAL IMPACTS
REDUCING GREENHOUSE GASES
TRANSMISSION AND
REGIONAL PLANNING
SITING
BIOGAS
ABORIGINAL
ENERGY IMPORTS AND EXPORTS
SMART GRID
HYDRO
STORAGE
SUPPLY
SMART METER DATA
AFFORDABLE
CONSUMER PROGRAMS
AND PRICING
JOBS AND ECONOMY
ENERGY EFFICIENCY STANDARDS
INCENTIVES
TIME-OF-USE PRICING
SMART GRID TECHNOLOGIES
ELECTRICITY PRICES
NATURAL GAS
TRANSMISSION EXPANSION

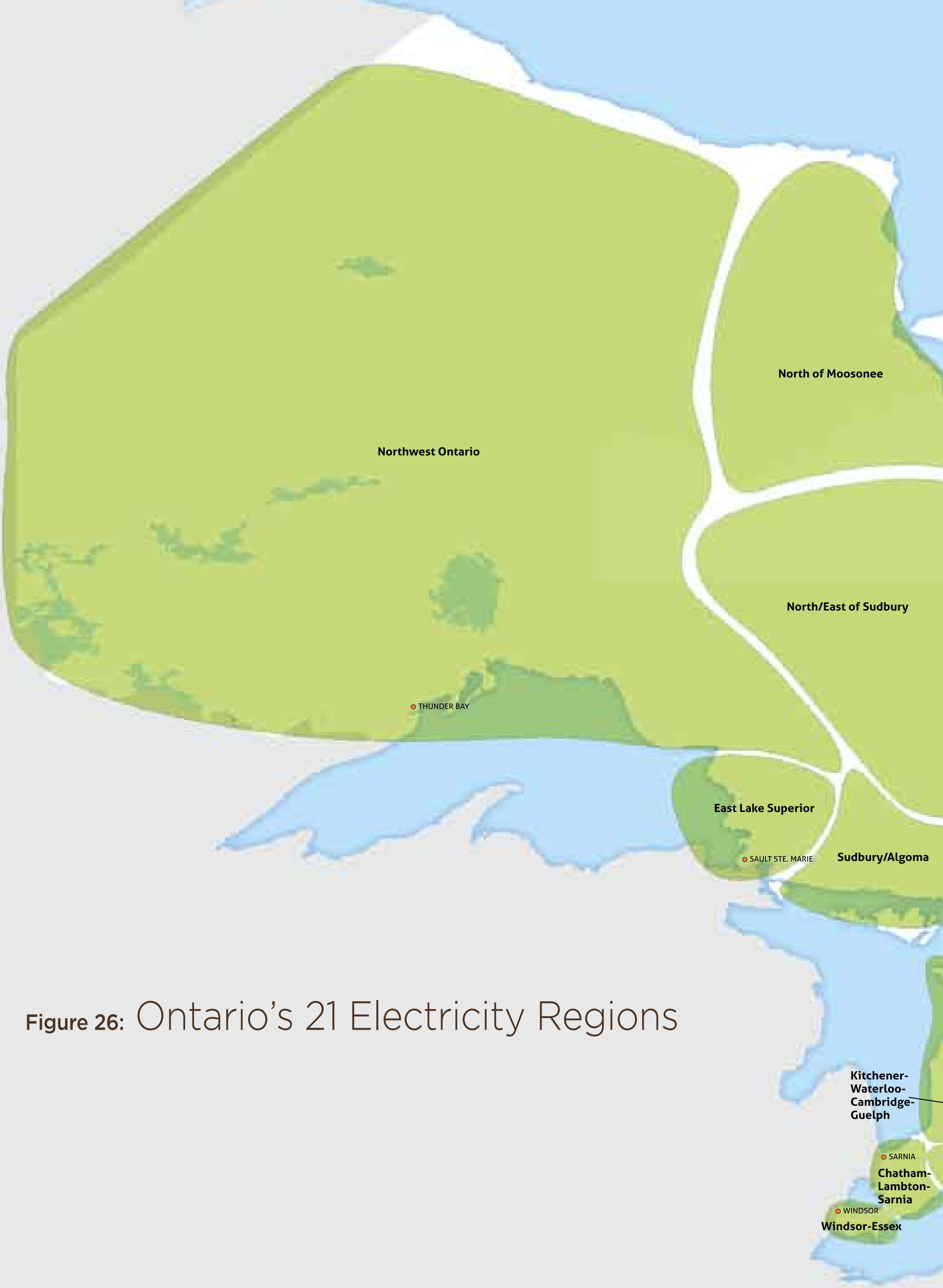


Figure 26: Ontario's 21 Electricity Regions

Source: Independent Electricity System Operator

Reinforcing Planning

- The OPA will give greater consideration to local priorities in the siting of generating facilities.
- The government will work with the OEB to consider standardizing the procurement process for generation, including the requirement for appropriate consultation on siting.

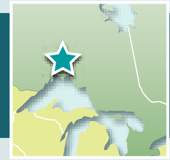
Enhancing Awareness

- The Ministry of Energy and its partner agencies will continue to introduce public education tools to improve energy literacy, including emPOWERme (see page 66).
- The ministry will develop a strategy to increase public understanding of our energy needs, the options for meeting them, and opportunities for people to get involved.
- The IESO and the OPA will set up regional open data web sites, with accessible information on the energy needs and supply options for each of the 21 electricity regions in Ontario.

The ministry has begun working with other provincial ministries, the IESO and the OPA to develop a plan to implement the regional planning recommendations. Where items fall under the responsibility of the IESO and the OPA, the two agencies have already begun to take action.

Much effort has gone into the process that should be followed and the input that's needed in planning infrastructure for regional needs. Much effort has also gone into conducting regional planning for various parts of the province. Below are some current examples that illustrate how regional planning efforts can meet growth needs, prudently manage investments and costs, and provide local input to ensure the planning reflects the region's priorities.

NIPIGON-GREENSTONE



The Nipigon-Greenstone area hosts several energy-related activities. Exploratory mining activity is on-going in the area. There is hydroelectric potential in the region including OPG's Little Jackfish hydroelectric project which would require a transmission line to connect the project to the grid if it is developed. As the proponents for these and potentially other projects advance their plans, the government is prepared to address the needs of the area as conditions warrant to ensure options are evaluated from an integrated perspective.

KITCHENER-WATERLOO-CAMBRIDGE-GUELPH AREA

Refurbishment and Upgrade

Est. Cost: ~$110M

Exp. In-Service: 2016

Transmission reinforcements in the growing Kitchener-Guelph-Waterloo-Cambridge area are part of an integrated plan that includes conservation and distributed generation.

Two projects are expected to be in-service in 2016: an upgrade to five-km of transmission line and the expansion of two Guelph area stations, and an expanded transformer station in Cambridge.

These projects will reinforce electricity supply to South-Central Guelph and to the Kitchener/Cambridge areas. The projects will also accommodate the expected demand growth from new business development in the Hanlon Creek Business Park which, according to the City of Guelph, is expected to attract about 8,500 new jobs over the next eight years.

OTTAWA AREA

The Ottawa area has undergone substantial urbanization in the outlying districts, which are supplied by a relatively sparse electricity system. There are plans for a new transit line, the connection of new government or educational facilities, and the redevelopment of industrial lands.

Hydro One is making substantial improvements to the Hawthorne Transformer Station, and efforts are being focused on meeting requirements in downtown Ottawa, Kanata/Nepean and East Ottawa/Orleans.

YORK REGION

York Region is one of the fastest-growing areas in Ontario. Extensive urbanization means that growth in electricity demand has been greater than the provincial average.

Early planning work has identified two near-term projects: the installation of new equipment at the Holland Transformer Station, and new facilities along the existing Highway 407 transmission corridor.

LEAMINGTON

The Windsor-Essex area has the largest concentration of greenhouse vegetable production in North America. As a result, the region's electricity needs are increasing.

Hydro One is in the early stages of planning for a new line and station to address load growth and anticipated expansion in the agricultural sector. Cost recovery for transmission expansion will be established during the approvals process.

CENTRAL-DOWNTOWN TORONTO

Toronto is the fourth largest metropolis in North America. Between 2006 and 2011, the population in parts of the city's downtown increased by more than 50 per cent.

A regional planning exercise on long term needs and options to accommodate future growth in electricity demand is underway and consultations are expected in the coming months.

Near-term investments by Hydro One and Toronto Hydro include line refurbishment projects in Midtown and along the lakeshore and a new station downtown.

Regional Planning

There are 21 electricity regions in Ontario (refer to Figure 26). These regions were developed by Hydro One and the OPA for regional planning purposes. The boundaries were set by considering common supply systems, electrical interrelationships, shared supply and system performance impacts in the OEB's Renewed Regulatory Framework for Electricity.

Over the next five years, the needs in all 21 electricity regions in Ontario will be assessed, and new regional plans will be developed if required.

If a regional plan is required, the OPA would conduct a scoping assessment. If a transmission and distribution solution is required, a Regional Infrastructure Plan, led by the transmitter, will be developed. If a solution involves conservation, demand management and local generation alternatives, a more comprehensive Integrated Regional Resource Plan, led by the OPA, will be required.

Working with transmitters, LDCs and the IESO, the OPA is already developing comprehensive plans for eight regions of the province: Greater Ottawa, Burlington to Nanticoke, GTA North and GTA West, Kitchener-Waterloo-Cambridge-Guelph, Toronto, Northwestern Ontario and Windsor-Essex.

emPOWERme

Given the complexity of the province's electricity system, it is difficult to understand how it all operates, what it means for ratepayers, and how it impacts a household energy bill.

In response to calls for better tools and resources to improve energy literacy, Ontario has launched emPOWERme, a web feature that uses videos, graphics, interactive tools and fact sheets to explain the fundamentals of electricity in plain language and compelling imagery.

Learn more at Ontario.ca/empowerme

In Summary

- The government will implement the IESO and the OPA recommendations for regional planning and the siting of large energy infrastructure.
- The ministry, the IESO and the OPA will work with municipal partners to ensure early and meaningful involvement in energy planning.
- Municipalities and Aboriginal communities will be encouraged to develop their own community-level energy plans to identify conservation opportunities and infrastructure priorities. The Municipal Energy Plan Program and the Aboriginal Community Energy Plan Program will support these efforts.
- Regional plans will promote the principle of Conservation First while also considering other cost-effective solutions such as new supply, transmission and distribution investments.

6 First Nation and Métis Communities

The Ontario government has recognized that Aboriginal participation in the energy sector is one of the keys to the economic development of First Nation and Métis communities. Ontario also understands that these communities need opportunities to engage and participate in ways that align with their unique community needs and interests.

Ontario takes its duty to consult First Nation and Métis communities very seriously. The government is committed to ensuring that First Nation and Métis communities are consulted on any energy activity that could potentially affect their Aboriginal or treaty rights.

New Post Creek

OPG and its partner, Coral Rapids Power LP, a wholly owned company of Taykwa Tagamou Nation, are moving forward with the 25-MW New Post Creek hydroelectric development. As an equity owner in the project, the Taykwa Tagamou Nation will benefit from long-term revenues over 50 years to support community development. Construction of this clean, renewable hydro power project is expected to begin in 2014. At peak construction, the development is expected to create up to 100 construction jobs. The project will also provide Taykwa Tagamou Nation members with experience and skills for future opportunities.

Ontario has brought in a range of policies and programs over the past four years to increase the involvement of Aboriginal communities in the sector:

- The Aboriginal Energy Partnerships Program helps communities plan and participate in the development of electricity infrastructure such as clean energy generation projects.
- Aboriginal participation is an important component of the Feed-in Tariff program, with price adders and contract set-asides for Aboriginal led or partnered renewable energy projects.
- The Aboriginal Loan Guarantee Program (ALGP) helps communities secure financing for their equity participation in clean energy and transmission projects. It started with $250 million, which was expanded to $400 million.

Ontario will continue to support and encourage participation by both First Nation and Métis communities in new generation and transmission projects and in conservation initiatives.

- Ontario recently launched the Aboriginal Community Energy Plans (ACEP) program, to support the energy planning activities of First Nation and Métis communities, including the identification of needs, interests and opportunities for conservation and small-scale renewable generation projects.
- The government expects to see Aboriginal involvement become the standard for the future development of major, planned transmission lines in Ontario. First Nation and Métis communities are interested in a wide range of opportunities — from procurement to skills training to commercial partnerships. When new, major transmission line needs are identified, the province expects that companies looking to develop the proposed lines will, in addition to fulfilling consultation

Grand Renewable Energy Park

The Six Nations community has negotiated a 10% equity interest in Samsung's Grand Renewable Energy Park, a 149 MW wind project and a 100 MW solar project partially located on Ministry of Infrastructure controlled lands in the Haldimand Tract area. Details of the agreement between Samsung and Six Nations include a 10% equity interest in the Grand Renewable Energy Park, estimated to represent up to $65 million in net profit for the community; and a Capacity Funding Agreement which includes post-secondary scholarship funding and provisions making construction and maintenance jobs at the Grand Renewable Energy Park available to Six Nations members. These benefits to the community will last the 20-year term of the project. In addition, Ontario has committed to the transfer of funds from the province to Six Nations equivalent to the lease payments made by Samsung to the province for the lease of the Ministry of Infrastructure controlled lands.

obligations, work to involve potentially affected First Nation and Métis communities, where commercially feasible and where there is an interest.

- Ontario will also launch the Aboriginal Transmission Fund (ATF) in early 2014 to help First Nation and Métis communities undertake the due diligence required before becoming involved in new major planned transmission line projects. The fund will help Aboriginal communities examine whether economic participation in a proposed transmission line is the right choice for them, and whether a potential partnership is meaningful and will bring lasting benefits to their community members.
- Ontario will continue to encourage Aboriginal participation, including through the FIT program and the future large renewable energy procurement program.

Building local capacity and providing skills training will be critical to driving participation levels and long-term success. The province recently extended education and capacity building funding delivered by the OPA to Aboriginal communities and organizations. This funding will be available to support education and capacity-building activities that better equip First Nation and Métis communities to participate in and develop renewable energy projects and initiatives.

Ontario will work with Hydro One to expand its training and skills development initiatives for Aboriginal peoples seeking to work in the transmission/distribution sector, including working with its existing college consortium to focus on Aboriginal opportunities as it relates to trades and technicians.

Conservation can and will play an important role for Aboriginal communities that identify high electricity costs as a significant challenge. Earlier this year, the OPA launched the Aboriginal Conservation Program, which delivers direct, customized conservation information and programs to First Nation communities on reserve and outreach to urban Aboriginal and Métis peoples.

First Nation and Métis community representatives across the province have expressed a desire for conservation measures that reach a greater number of communities, as well as a desire to work with their local electricity service provider on reducing their bills.

Ontario will give LDCs an enhanced role in the delivery of Aboriginal conservation programs, particularly for on-reserve First Nation customers. Where appropriate, the province will work with federal partners to implement provincial conservation initiatives effectively.

While the government works to ensure First Nation and Métis communities have access to procurement and conservation programs that will support their economic development, it also recognizes the unique problems faced by 25 remote First Nation communities in the province's northwest. They are not connected to the grid, and get their electricity

Lower Mattagami

Moose Cree First Nation successfully obtained a loan guarantee under the ALGP to support its purchase of up to 25% equity ownership in the $2.6-billion Lower Mattagami hydroelectric project. The community is partnering with OPG to build the project, which will add up to 440 MW of clean, renewable energy to Ontario's electricity supply mix when it comes online in 2015. The partnership will also help Moose Cree First Nation develop commercial capacity and infrastructure to take advantage of future development opportunities. Construction on the project is currently under way, with about 1,600 workers employed, including more than 250 First Nation and Métis individuals.

from on-site generators burning diesel fuel. These are increasingly expensive sources of electricity that pollute the environment. For most communities, diesel fuel has to be brought in on ice roads in the winter, even though the shipping season is getting shorter because of warmer winters. When roads are not available, reliance on even more expensive airfreight is often the only option to bring in diesel fuel.

Remote First Nation Communities

The OPA developed a draft plan for connecting many of the remote First Nation communities. The OPA's study shows that there is a strong economic case for connecting up to 21 of the remote First Nation communities with new transmission and distribution lines. The OPA's analysis indicates that over the next 40 years, grid connection could be 30% to 40% less expensive than the continued use of diesel fuel. Such savings would amount to about $700 million in avoided costs for the parties who currently subsidize and fund the diesel systems — the federal government and the province.

Figure 27: Remote First Nation Communities

Connecting the remote communities is a priority for Ontario. Ontario will continue to work with the federal government to connect remote First Nation communities to the electricity grid or find alternatives where it is not economically feasible to do so.

Since the release of the draft Remote Community Connection Plan, the OPA has engaged most of the participating communities and received feedback. The OPA is planning to engage the remaining communities so that the plan can be updated and finalized by the end of 2013. As mentioned in Chapter 4 — Investing in Transmission, a key first step to connecting some of the remote communities will be the new line to Pickle Lake.

Success in connecting the remote communities will depend on contributions from all of the parties that benefit from the new transmission lines and other infrastructure, particularly the federal government, whose commitment and co-operation will be required to make this priority project a reality. The federal government, which is responsible for supporting First Nation community infrastructure, would also share in the savings, as the costs associated with using diesel fuel would be reduced.

The federal government would receive additional benefits beyond the diesel related savings. Once the remote communities are connected, there would be a reduction in the environmental impact and environmental liabilities associated with diesel spills, lower greenhouse gas emissions, improved social and living conditions for remote community residents, and increased opportunities for economic development within First Nation communities.

Because of these benefits, and its current responsibility for costs in remote communities, federal participation is a critical element in moving forward to connect remote communities. The project will not be possible without it.

Another important step in the connection of remote communities will be the development of transmission and distribution plans by proponents interested in the connection of remote communities, and securing all required approvals.

While transmission appears to be the most economic solution for up to 21 of the 25 remote First Nation communities, there may be more cost-effective alternatives for the remaining First Nation communities. Ontario will continue to explore other opportunities to reduce diesel use in the north for these communities.

Preliminary studies by the OPA indicate that, within these First Nation communities, renewable generation can be integrated into the existing diesel-based electricity systems in a cost-effective manner. Alternative options are being considered that could significantly reduce the use of diesel fuel and result in a cost saving of approximately 20%.

The province will work with the federal government, energy partners and communities to support innovative solutions for supplying electricity in these remote First Nation communities, including consideration for on-site renewables, micro-grids and conservation. Ontario has already started focusing on conservation opportunities through its Aboriginal Conservation Program, which has a dedicated category for remote communities.

The OPA will continue to work with these remote communities to identify and develop on-site options for reducing their dependence on diesel fuel. The implementation plans (expected by the end of 2014) will consider community economic development interests, such as the use of renewable or other generation opportunities that may be identified, as well as the opportunities for federal and provincial funding.

The government remains committed to an on-going and regular dialogue with First Nation and Métis communities. Ontario will work with Aboriginal leadership to identify effective mechanisms to discuss energy issues, such as the cost of electricity for First Nations on reserve, as well as share information in a timely way. Dialogue is the only way to ensure that support programs, conservation initiatives, procurement processes and electricity infrastructure projects reflect the needs, interests and capacity of Aboriginal communities, and maximize opportunities for participation.

In Summary

- The government understands the importance of First Nation and Métis participation in the development of energy and conservation projects. The government will continue to review participation programs to ensure they provide opportunities for First Nation and Métis communities.
- Ontario will launch an Aboriginal Transmission Fund in early 2014 to facilitate First Nation and Métis participation in transmission projects.
- The province expects that companies looking to develop new transmission lines will, in addition to fulfilling consultation obligations, involve potentially affected First Nation and Métis communities, where commercially feasible and where there is an interest.
- The government will continue to encourage Aboriginal participation, including through the FIT program and future large renewable energy procurements, in a way that reflects the unique circumstances of the First Nation and Métis communities.

7 Oil and Natural Gas

Oil and natural gas play an essential role in the daily lives of Ontarians, supplying three-quarters of the province's primary energy use. There are approximately 3.5 million residential, commercial and industrial natural gas customers in Ontario. Natural gas is used for space heating and domestic hot water within our homes and businesses, steam and process heat for industry, as well as providing approximately 15% of the electricity generated within Ontario. Oil continues to be the primary energy source for our vehicles.

Photo: Grafiks Marketing & Communications, Sarnia, Ontario

Almost all of Ontario's oil and natural gas comes from outside the province and is delivered by interprovincial pipelines, which are under federal jurisdiction and regulated by the National Energy Board.

Within our province, the OEB regulates the natural gas sector by approving distribution rates and commodity prices, as well as licensing gas marketers. The oil sector is not subject to economic regulation by Ontario.

It is expected that there will be ample future supply of natural gas from the US Great Lake states for Ontarians. The adoption of new technologies allows gas to be economically extracted from shale and coal beds. It is estimated that North America now has a 100-year supply of natural gas.

The increase in production of oil in Western Canada, and shale gas from the US has had a significant impact on the oil and natural gas market in Ontario. The government must continue to ensure that Ontario consumers are able to benefit and the interests of its residents are protected.

Ontario's geographic location and natural gas infrastructure put it in a strategic position to take advantage of North America's changing natural gas market. The Dawn and Tecumseh underground natural gas storage facilities play an important role in the delivery of natural gas within Ontario as well as supporting the delivery of natural gas to consumers in Québec and the northeastern United States.

The Union Gas Dawn storage hub in southwestern Ontario is the largest underground storage facility in Canada, with 155 billion cubic feet of highly deliverable storage. The Enbridge Gas Distribution Tecumseh storage facility has 100 billion cubic feet of storage and is located adjacent to Dawn. Both natural gas storage facilities are regulated by the OEB.

These facilities can store massive quantities of natural gas and provide it to customers on demand. Natural gas can be bought and stored when prices are low and then sold when demand and prices are higher. This helps suppliers minimize price volatility and ensure that sufficient gas is available to meet peak heating demand.

It is anticipated that the Dawn and Tecumseh storage facilities will increase in strategic importance as US pipeline infrastructure expansion allows for increased delivery of shale gas from the Marcellus and Utica basins to southwestern Ontario.

Natural gas is a key input for Ontario's petrochemical industry. Focused in Sarnia and employing about 12,000 people, the industry is strategically located to take advantage of Ontario's southwestern natural gas storage facilities.

Ontario wants to make sure communities have access to natural gas to take advantage of the changing North American market and low prices. Natural gas heating is significantly less expensive than that provided by electricity or heating oil. There is also increasing interest in the use of compressed or liquid natural gas as a transportation fuel for corporate car and truck fleets, to reduce costs and the emissions of greenhouse gases.

The quality of life and economic prosperity of Ontario depends on having secure access to competitively priced natural gas and an equally competitively priced natural gas transmission and distribution system.

For the oil market, industry developments have led to major pipeline proposals directly affecting Ontario that require thoughtful consideration. The government must ensure the province's interests are taken into account.

One such undertaking involves the proposed TransCanada Energy East project, which would repurpose a section of its Canadian Mainline natural gas pipeline to crude oil service across Canada. Within Ontario, the Energy East project would cross northern Ontario, run through North Bay and southeast to Cornwall where a section of new pipeline running to the Québec border is proposed.

While approval of the Energy East project is a federal responsibility, Ontario's input is crucial in making any decision. To that end, the Ministry of Energy has asked the OEB to undertake consultation with the public, including First Nation and Métis communities, local communities, and stakeholders on the proposed Energy East project. These consultations will be broad and transparent, allowing time and opportunity for stakeholders and the public to express their views through oral and written comments.

The government evaluates oil and natural gas energy pipeline projects using the following six principles:

- Pipelines must meet the highest available technical standards for public safety and environmental protection;
- Pipelines must have world-leading contingency planning and emergency response programs;
- Proponents and governments must fulfill their duty to consult obligations with Aboriginal communities;
- Local municipalities must be consulted;
- Projects should provide demonstrable economic benefits and opportunities to the people of Ontario, over both the short and long term; and
- Economic and environmental risks and responsibilities, including remediation, should be borne exclusively by the pipeline companies, who must also provide financial assurance demonstrating their capability to respond to leaks and spills.

Natural gas storage facilities at Dawn, Ontario.
Photo: Union Gas Limited

Oil and natural gas, as well as the pipelines that deliver these products are essential to the quality of life and economic prosperity that Ontarians enjoy. Ontario will continue to work with its federal and provincial partners to ensure that oil and natural gas are delivered economically while maintaining the highest safety and the environmental standards.

In Summary

- Ontario relies on oil and natural gas to support basic needs such as heat and transportation. These fuels are also essential to Ontario's economy and quality of life.
- The government will work with gas distributors and municipalities to pursue options to expand natural gas infrastructure to service more communities in rural and northern Ontario.
- Ontario has adopted principles it will use to review large scale pipeline projects to ensure that they meet the highest environmental and safety standards as well as benefit Ontario's economy.

8 Innovation

The history of electricity in Ontario is one of constant innovation and this is still true today. Ontario maintains its place as an innovation leader because of accomplishments with the Smart Grid. The installation of sensors and computer chips into formerly passive distribution networks not only allows many utilities to detect and fix outages quickly, but will also enable Ontarians to better manage their personal energy use.

Demand for services and apps, to enable consumers to better manage, monitor and control their energy use is increasing. According to a recent study by Accenture Consulting, *Actionable Insights for the New Energy Consumer,* an increasing number of consumers … "are seeking added value, personal connection and products and services that align with their lifestyles – all of which go beyond the traditional energy experience."

ECHO (ECological HOme) is a 'smart' home designed and built by students from Team Ontario — Queen's University, Carleton University and Algonquin College — to promote sustainable living and participate in the U.S. Department of Energy's Solar Decathlon 2013.

Photo: Stefano Paltera/U.S. Department of Energy Solar Decathlon

Ecobee delivers intelligent energy management solutions for commercial properties. The company works with local utilities in the deployment of its Programmable Communicating Thermostats, which provide automated energy conservation through demand response programs.

Enbala's smart grid technology platform is helping Ontario to maintain grid reliability. By connecting a network of large-scale commercial and industrial electricity users to their versatile GOFlex™ platform, they can automatically increase or decrease electricity consumption in response to moment by moment changes in the electricity needs of the grid. This will help Ontario integrate its renewable energy sources more efficiently and reliably.

Team Ontario is a collaboration of more than 100 students from Carleton University, Algonquin College and Queen's University selected to compete in the US Department of Energy Solar Decathlon. Team Ontario designed and built ECHO (ECological HOme), a "smart" home that incorporates modern technologies such as predictive shading, real-time energy monitoring, an integrated mechanical system and a user-friendly mobile application to control features of the home.

Energate is developing tools that make it easier for consumers to monitor and manage their home energy use and costs. Energate's software, mobile applications and devices such as smart thermostats and in-home energy displays also help to manage the system by reducing peak demand. The Smart Grid Fund is helping Energate test and demonstrate these tools for consumers in homes across Ontario, including Peterborough, Vaughan, and Cambridge.

Temporal Power, a Mississauga company, develops and manufactures advanced low-loss flywheel energy storage technology systems. In partnership with Hydro One Networks, Temporal Power will demonstrate how novel flywheel technology can help integrate wind energy into the electricity grid.

Ontario has undertaken a number of initiatives to help utilities take on innovation challenges. These initiatives are building a thriving smart grid ecosystem that can lead to innovation that both enhances the grid's operation and improves asset management to help mitigate system and customer costs.

The Smart Grid Fund

The $50-million Smart Grid Fund was launched in 2011 to help local distribution and Smart Grid companies test and build the technologies needed to modernize the grid. The fund currently supports 11 organizations that are developing applications that track energy use, balance voltage on the grid, and automate control systems for LDCs. These smart grid solutions will also help LDCs integrate new promising technologies into Ontario's electricity system that could help operators use grid assets more efficiently, including storage and electric vehicles.

Technological innovation from the Smart Grid could also help bring clean energy to remote communities that have economic challenges connecting to the province's transmission grid. These communities, which currently rely on diesel fuel to generate electricity, could have their own micro distribution grid. This would integrate and balance diesel generation with the electricity that comes from wind, solar, storage and hydroelectric resources.

The Smart Grid Fund helps Ontario businesses compete with advanced technology companies from around the world. It has already led to the creation of more than 600 jobs. According to the Ontario Centres of Excellence, our growing cluster of energy technology entrepreneurs is developing the products that will drive the jobs of tomorrow. Supporting this emerging industry is in Ontario's best interests.

Energy Data and Green Button

The government believes that smart meter data can be used in ways that go beyond supporting customer billing. While respecting the principles of privacy and security, new value-added services and applications for consumers could be developed by enabling better access and analysis of electricity consumption data. This type of data is essential to designing efficient and effective programs to further benefit consumers.

An important example of providing consumers with access to data is the Green Button Initiative. The Green Button Initiative provides customers with access to their electricity consumption information in a standardized format. Developers will be able to use the data to provide innovative software applications that allow consumers to view and

Solantro Pilot Program

The pilot demonstration project will field test technologies for grid-ready (plug-and-play) AC photovoltaic that improve economics, reliability and performance of solar energy. The pilot will focus on Nano and Micro-inverters and DC Optimizer Reference Designs. The project will be conducted between 2012 and 2015.

Inverters play a crucial role in the performance of a solar panel: they convert the direct current from solar panels to alternating current that then can be used directly, stored or fed into the power grid. Reference Designs allow developers to fine tune the DC Optimizer to maximize the energy produced by the solar panel.

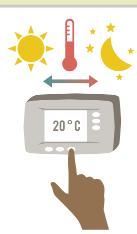
The result is a plug-and-play integrated circuit chip (the inverter) on the back of each solar panel that constantly optimizes efficiency and reduces the costs of design and installation.

Figure 28: The Green Button Initiative

HOW IT WORKS

BENEFITS

Energy consumption data can be used to:



Track and analyze your energy use to conserve energy and save money

Assist with retrofit planning to increase the energy efficiency of your home

Optimize the size cost-effectivene rooftop solar par manage their energy use. In October 2013, Ontario announced the *Energy Apps for Ontario Challenge*, offering $50,000 to support the best new apps that use the Green Button standard.

Ontario has made significant progress with its Green Button Initiative since it was launched in 2012. Seven LDCs have implemented the first phase of the program, providing access to Green Button to almost 60% of the province's electricity customers. More LDCs have signaled their intention to follow quickly.

The next phase of the initiative, Connect My Data, will allow customers to automate the transfer of data securely to mobile and web applications that can be used on computers, smartphones and tablets. London Hydro and Hydro One launched the first Connect My Data pilots in November 2013, giving their customers innovative and creative applications that will help them manage and conserve their electricity use.

Energy Storage

Energy storage technologies have the potential to revolutionize the electricity system, increasing its efficiency, lowering costs and increasing reliability for the consumer. With storage, electricity could be stockpiled during periods of low cost generation, and then used when demand and prices are highest.

Storage technology offers the potential to increase the useable energy from renewable energy sources.

The IESO has been integrating new technologies to correct small, sudden changes in the electric current frequency to ensure the stability of our electricity system. Ontario is home to a number of innovative companies that are at the forefront of the energy storage sector.

By the end of 2014, the government will include storage technologies in our procurement process starting with 50 MW and assessing additional engagement on an ongoing basis.

This will include:

- Commissioning an independent study to establish the value of energy storage's many applications throughout the system;
- Examining the opportunities for net metering and conservation policies to support energy storage; and
- Providing opportunities for storage to be included in large renewable procurements.

The government also intends to initiate work, on a priority basis, to address regulatory barriers that may limit the ability of stored energy resources to compete in Ontario's electricity market. For example, some energy storage applications are currently required to pay various retail, uplift and Global Adjustment charges twice — once when energy is captured and again by the end-user.

In Summary

- Ontario's energy sector is an innovation leader. The government will seek to expand the Smart Grid Fund and build on previous success. The Smart Grid Fund has created more than 600 jobs and supported 11 projects developing innovative technologies.
- The government intends to initiate work, on a priority basis, to address regulatory barriers that limit the ability of energy storage technologies to compete in Ontario's electricity market.
- By the end of 2014, the government will include storage technologies in our procurement process, starting with 50 MW and assessing additional engagement on an ongoing basis.
- The new competitive procurement process for renewable energy projects larger than 500 kW will also provide an opportunity to consider proposals that integrate energy storage with renewable energy generation.

Conclusion

The government is building on a decade of achievements with this LTEP, and is fine-tuning its policies to meet the future needs of Ontario.

Ontario has virtually eliminated coal from our electricity system. The phasing out of coal is the single largest climate change initiative in North America.

Through this LTEP, the government will ensure the continued delivery of a cost-effective, reliable and clean energy supply, one that is shaped by community engagement and emphasizes conservation and demand management before the construction of new generation.

The government will build on the initiatives it has already put in place to keep electricity rates as low as possible. These have included the Ontario Clean Energy Benefit, the early phase out of coal-fired generation, and the decision not to proceed at this time with the construction of new nuclear facilities.

The government has built flexibility into this LTEP. Forecasting is not an exact science and plans need to be flexible to meet changing conditions. That's why Ontario is committing resources to meet a lower demand forecast while maintaining flexibility to respond to higher needs. Overbuilding the system will unnecessarily increase electricity rates.

Annual energy reporting will also help us prudently plan for more resources if and when they are needed. The Ontario Energy Report will give Ontarians an update of the energy supply/demand picture for the province, and will allow the government to review its progress in implementing the LTEP.

The LTEP will continue to be updated every three years, and these annual reports will give everyone an opportunity to monitor progress for course corrections and to understand developments that will be important in the next formal review.

Glossary

Baseload Power: Generation sources designed to operate more or less continuously through the day and night and across the seasons of the year. Nuclear and many hydro generating stations are examples of baseload generation.

Bioenergy: Energy produced from living or recently living plants or animal sources. Sources for bioenergy generation can include agricultural residues, food-process by-products, animal manure, waste wood and kitchen waste.

Demand Response (DR): Programs designed to reduce the amount of electricity drawn from the grid during peak demand periods. Customers could be responding to changes in the price of electricity during the day, incentive payments and/or other mechanisms.

Dispatchable Generation: Generation sources such as natural gas that can be increased or decreased at the request of power grid operators; that is, output can be increased or decreased as demand or availability of other supply sources changes.

Distribution: A distribution system carries electricity from the transmission system and delivers it to consumers. Typically, the network would include medium-voltage power lines, substations and pole-mounted transformers, low-voltage distribution wiring and electricity meters.

Feed-in Tariff (FIT): A guaranteed rate that provides stable prices through long-term contracts for energy generated using renewable resources.

Global Adjustment (GA): The GA is the difference between the total payments made to certain contracted or regulated generators and demand management projects, and market revenues. The GA serves a number of functions in Ontario's electricity system; it provides more stable electricity prices for Ontario's consumers and generators; it maintains a reliable energy supply; and, it recovers costs associated with conservation initiatives that benefit all Ontarians. The GA is calculated each month by taking into account the following components: Generation contracts administered by the Ontario Electricity Financial Corporation; OPG's nuclear and baseload hydroelectric generation; and OPA contracts with generators and suppliers of conservation services. Consumers on the regulated price-plan (RPP) pay a fixed price set every six months by the Ontario Energy Board which includes the GA, while customers who have a retail contract pay the contract price for their electricity plus the Global Adjustment.

Greenhouse Gas (GHG): Gas that contributes to the capture of heat in the Earth's atmosphere. Carbon dioxide is the most prominent GHG. It is released into the Earth's atmosphere as a result of the burning of fossil fuels such as coal, oil or natural gas. GHGs are widely acknowledged as contributing to climate change.

Grid Parity: The point at which new generation technologies become cost competitive with conventional technologies.

Integration: The way an electricity system combines and delivers various generation sources, conservation and demand management to ensure consumers have dependable and reliable electricity.

Intermittent Power Generation: Generation sources that produce power at varying times, such as wind and solar generators whose output depends on wind speed and solar intensity.

Kilowatt (kW): A standard unit of power that is equal to 1,000 watts (W). Ten 100-watt light bulbs operated together require one kW of power.

Kilowatt-hour (kWh): A measure of energy production or consumption over time. Ten 100-watt light bulbs, operated together for one hour, consume one kWh of energy.

Load or Demand Management: Measures undertaken to control the level of energy use at a given time, by increasing or decreasing consumption or shifting consumption to some other time period.

Local Distribution Company (LDC): A utility that owns and/or operates a distribution system for the local delivery of energy (gas or electricity) to consumers.

Megawatt (MW): A unit of power equal to 1,000 kilowatts (kW) or 1 million watts (W).

Megawatt-hour (MWh): A measure of energy production or consumption over time: a one MW generator, operating for 24 hours, generates 24 MWh of energy.

MicroFIT: A program that allows Ontario residents to develop a very small or micro renewable electricity generation project (10 kilowatts or less in size) on their properties. Under the microFIT Program, they are paid a guaranteed price for all the electricity they produce for at least 20 years.

Net Metering: A program made available to customers with renewable energy installations which allow them to generate electricity for their own use before it is made available to the electricity grid. When renewable energy is made available to the electricity grid from the renewable installation, the customer receives a credit on their electricity bill.

North of Dryden: The North of Dryden area refers to the part of the Ontario transmission system bounded by Dryden to the southwest, Red Lake to the northwest, and Pickle Lake to the northeast, as well as a group of remote First Nation communities, an operating mine and the mine development area known as the Ring of Fire north of the existing transmission system.

Ontario Clean Energy Benefit (OCEB): A five-year program that provides a benefit equal to 10% of the total cost of electricity on eligible consumers' bills, including tax, limited to the first 3,000 kWh of electricity consumed each month. The program is scheduled to end December 31, 2015.

Peaking Capacity: Generating sources typically used only to meet the peak demand (highest demand) for electricity during the day; typically provided by hydro or natural gas generators.

Peak Demand: Peak demand, peak load or on peak are terms describing a period in which demand for electricity is highest.

Photovoltaic: A technology for converting solar energy into electrical energy (typically by way of photovoltaic cells or panels comprising a number of cells).

Program Administrator Cost (PAC) Test: The PAC Test measures conservation program benefits and costs, from the perspective of a program administrator. For the PAC test, avoided energy costs only include avoided costs associated with the electricity system.

Pumped Storage: The most-deployed and mature energy storage technology in the world that uses off-peak electricity to pump water from lower to upper reservoir, and releases this water to generate electricity on demand.

Smart Grid: A Smart Grid delivers electricity from suppliers to consumers using modern information and communications technologies to improve the reliability and efficiency of the electricity system. It empowers consumers with the ability to manage their energy consumption — saving energy, reducing costs and providing choices.

Supply Mix: The different types of resources that are used to meet electricity demand requirements in a particular jurisdiction. Normally the mix is expressed in terms of the proportion of each type within the overall amount of energy produced.

Terawatt-hour (TWh): A unit of power equal to 1 billion kilowatt-hours. Ontario's electricity consumption in 2012 was around 141.3 TWh.

Total Resource Cost (TRC) Test: The TRC Test measures benefits and costs from a societal perspective. For the TRC Test only, avoided supply costs include avoided energy costs associated with electricity, natural gas, water, fuel oil and propane savings, where applicable. Incentive costs are a transfer from a program-sponsoring organization to participating customers, and consequently do not impact the net benefit from a societal perspective.

Transmission: The movement of electricity, usually over long distance, from generation sites to consumers and local distribution systems. Transmission of electricity is done at high voltages. Transmission also applies to the long distance transportation of natural gas and oil.

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Assessment of the Rationale for the East-West Tie Expansion

Third Update Report

Submitted to the Ontario Energy Board
(EB-2011-0140)

December 15, 2015

Connecting Today.
Powering Tomorrow.

1.0 KEY FINDINGS/RECOMMENDATIONS

This update confirms the rationale for the East-West Tie (“E-W Tie”) expansion project based on updated information and study results. Under the Reference assumptions, the E-W Tie expansion, which permits more effective utilization of provincial resources to meet electricity needs identified for northwestern Ontario (“the Northwest”), provides a net economic benefit of $1.1 billion compared to a local generation alternative. To test the robustness of this result against uncertainty in the assumptions, the IESO considered high and low sensitivities on a number of key parameters, of which forecast demand growth, discount rates, and capital and fixed costs for generation and transmission had the largest impacts. Based on the sensitivities tested, the net benefit of the E-W Tie project ranges from a break-even outcome associated with the Low demand forecast scenario, to $1.7 billion under high demand growth.

The E-W Tie expansion project continues to be the IESO’s recommended alternative to maintain a reliable and cost effective supply of electricity to the Northwest for the long term. The IESO supports the continuation of development work in order to maintain the viability of the E-W Tie expansion project with a targeted in-service date by the end of 2020.

2.0 INTRODUCTION

The Ontario Government’s Long-Term Energy Plans (“LTEP”) have both anticipated the expansion of a new E-W Tie transmission line. The 2010 LTEP, published in November 2010, identified the E-W Tie as a priority transmission project,[1] and the government’s subsequent 2013 LTEP, published in December 2013 focused on the unique needs of Northern Ontario and included the E-W Tie expansion project.[2] The E-W Tie expansion project is intended to increase the transfer capability into the Northwest by adding a new transmission line roughly parallel to the existing E-W Tie transmission line, which extends between Wawa and Thunder Bay.

The Minister of Energy’s letter to the Ontario Energy Board (“Board”) of March 29, 2011 was the impetus for the Board undertaking a designation process to select the most qualified and cost-effective transmitter to undertake development work for the E-W Tie project. Early in the proceeding (EB-2011-0140), the Board requested that the former Ontario Power Authority (“OPA”)[3] provide a report documenting the preliminary assessment of the need for the E-W Tie expansion. In response, the OPA filed its original report in June 2011, titled “Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion” (“June 2011 Report”).

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[1] Ontario’s 2010 Long-Term Energy Plan: Building Our Clean Energy Future, Figure 12, page 47.

[2] Ontario’s 2013 Long-Term Energy Plan: Achieving Balance, page 52.

[3] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that combined the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator. Any assessments prior to January 1, 2015 were provided by the former OPA.

This report constitutes the Independent Electricity System Operator's ("IESO") third updated assessment of the rationale for the E-W Tie expansion project, as ordered by Board decisions Regarding Reporting by Designated Transmitter dated September 26, 2013 and January 22, 2015.[4] It builds upon and updates three previous E-W Tie reports prepared by the OPA: i) the original June 2011 Report; ii) the first update report, filed with the Board in October 2013, titled "Updated Assessment of the Rationale for the East-West Tie Expansion" ("October 2013 Report"); and iii) the second update report titled "Assessment of the Rationale for the East-West Tie Expansion" filed with the Board on May 5, 2014 ("May 2014 Report").

This report focuses on major changes that have occurred since the May 2014 Report and, based on these changes, provides an updated statement of the rationale for the E-W Tie expansion. This report also follows several additional filings with the Board in the E-W Tie proceeding, namely: i) the OPA's September 30, 2014 need update letter regarding the development schedule, including a recommendation and explanation of the rationale for revising the project's in-service date from 2018 to 2020; ii) the OPA's December 19, 2014 submission, titled "Context for Revised Development Schedule" filed with Upper Canada Transmission, Inc.'s ("UCT") December 19, 2014 response to the Board's October 29, 2014 letter requesting that UCT and the OPA collaborate to produce a revised development schedule for the E-W Tie based on the OPA's September 30th updated information; iii) the IESO's supporting letter of May 5, 2015 to UCT's May 15, 2015 filing with the Board provided to confirm that UCT's revised development schedule is consistent with the IESO's current information regarding the need for the E-W Tie expansion project.

In the filings referenced above, the OPA and IESO advocated that the additional time for development work afforded by the deferral of the in-service date from 2018 to 2020 be used to investigate potential cost savings for the project. To this end, UCT (o.a. NextBridge Infrastructure), the transmitter designated to develop the E-W Tie expansion project, requested that Parks Canada reconsider its decision regarding access to Pukaskwa National Park, but in June 2014 was denied that request. The IESO has also investigated the potential for cost savings from staging the project's implementation, and has refined the models and assumptions underlying this analysis, based on more detailed analysis and research.

The remainder of this report is organized as follows. Section 3 describes new activities undertaken to refine models and assumptions in preparing this update. Section 4 provides an updated conservation and demand forecast for the Northwest. It reflects changes since May 2014 and identifies major drivers for future electricity demand. Sections 5 and 6 analyze current and future internal and external resources that supply the Northwest and provide an update on Northwest capacity and energy supply needs. Section 7 provides an updated analysis of two alternatives to meet these needs: a case with no E-W Tie expansion, in which gas generation addresses the Northwest supply needs; and the E-W Tie expansion. Section 8 summarizes the IESO's recommendation.

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[4] Board Decision and Order Regarding Reporting by Designated Transmitter dated September 26, 2013, page 4, and January 22, 2015, page 5.

3.0 ACTIVITIES UNDERTAKEN IN PREPARING THIS UPDATE

In the year since the OPA issued its letter deferring the E-W Tie expansion, the IESO has undertaken a variety of activities to investigate potential areas for cost savings, update system capability and Northwest operational needs, and refine and update the models and assumptions used in this assessment. These activities are introduced here, to provide context for the updated results and information presented in subsequent sections of this report.

Updated Transmission Cost Estimates

For this update, the IESO asked the respective transmitters to review the capital cost estimates for the new line and the station upgrades. Based on the most recent information, and accounting for Parks Canada's decision not to allow a route through Pukaskwa National Park, the previous planning estimate of $500 million for the line was confirmed by NextBridge Infrastructure.

For the station costs, Hydro One provided a revised estimate of approximately $150 million for the 650 MW E-W Tie expansion, up from the previous planning estimate of $100 million, reflecting more detailed design work than was previously available. This estimate accounts only for costs directly attributable to the E-W Tie project. Costs associated with a portion of the station upgrade work that would be required to enable the existing system to meet new NERC standards while maintaining system capability and operational requirements, regardless of whether the E-W Tie expansion goes ahead, was deducted from the station cost estimates.

Staging of Station Facilities

The IESO has identified a potential opportunity to defer costs by staging the installation of station facilities, while still maintaining reliability. This would involve an interim stage consisting of "twinning" the circuits, creating two "super-circuits", one carried by the existing E-W Tie line structures and the other on the new line. This interim stage would provide a westbound transfer capability of approximately 450 MW.

The interim stage would allow for approximately $100 million of the station facility costs to be deferred.

Refined Transmission System Limits

The IESO has continued to refine its studies of transmission system limits and interface capabilities, reflecting the most up-to-date available supply and demand information and application of new reliability criteria. These updated limits are reflected in updates to the capacity and energy models underlying the E-W Tie analysis.

Previously, the reported westbound capability of the existing E-W Tie was based on voltage and transient stability limitations. In this update, the westbound capability of the existing E-W Tie has been revised downward based on further study to assess thermal limitations on the existing system (see section 5.2). This means that the incremental capacity provided by the E-W Tie expansion is greater. It also has the effect of increasing the generation capacity requirements in the generation alternative, all else being equal, compared to the higher existing E-W Tie limit used in the May 2014 Report.

The transfer capabilities of transmission interfaces outside the Northwest have also been refined in this update. The eastbound limit on the interface between Wawa and Sudbury, and the southbound limit between Sudbury and southern Ontario, have both been modeled to more accurately reflect their current capabilities to export power under system peak conditions. In the generation alternative, this has the effect of reducing the effectiveness of Northwest generation in providing capacity to the rest of the province.

Refined Resource Assumptions

The IESO continually updates its assumptions and models by observing market trends and conducting research. Since the May 2014 Report was published, the IESO has updated its assumptions for natural gas-fired generation, with a particular emphasis on generation sited in the Northwest, through third party consultants, external resources, and past procurement experience.

New learning suggests that to provide reliable peak capacity in the Northwest, storing reserve fuel on-site, at a relatively small capital and operating cost increase, is more cost-effective than procuring "firm" Gas Delivery and Management ("GD&M") services. Due to pipeline infrastructure, limited natural gas storage capacity in northern Ontario, and a mismatch in the commitment timeframes for gas and electricity, procuring "firm" service in the Northwest is expected to be more costly than the same level of GD&M service in southern Ontario. Having fuel on-site would allow a developer to procure "interruptible" GD&M services for natural gas as the primary fuel, but with a backup fuel supply in case service is interrupted. The onsite fuel could feasibly be diesel fuel oil, liquefied natural gas or compressed natural gas. Based on discussions with natural gas distribution companies about historical gas demand interruptions in the Northwest, the on-site fuel is expected to rarely be called upon.

In this update, the cost and technology assumptions for new-build natural gas-fired generation installed in the Northwest—i.e., the alternative to the E-W Tie assessed in this report—are based on this on-site reserve fuel strategy.

4.0 NORTHWEST CONSERVATION AND DEMAND

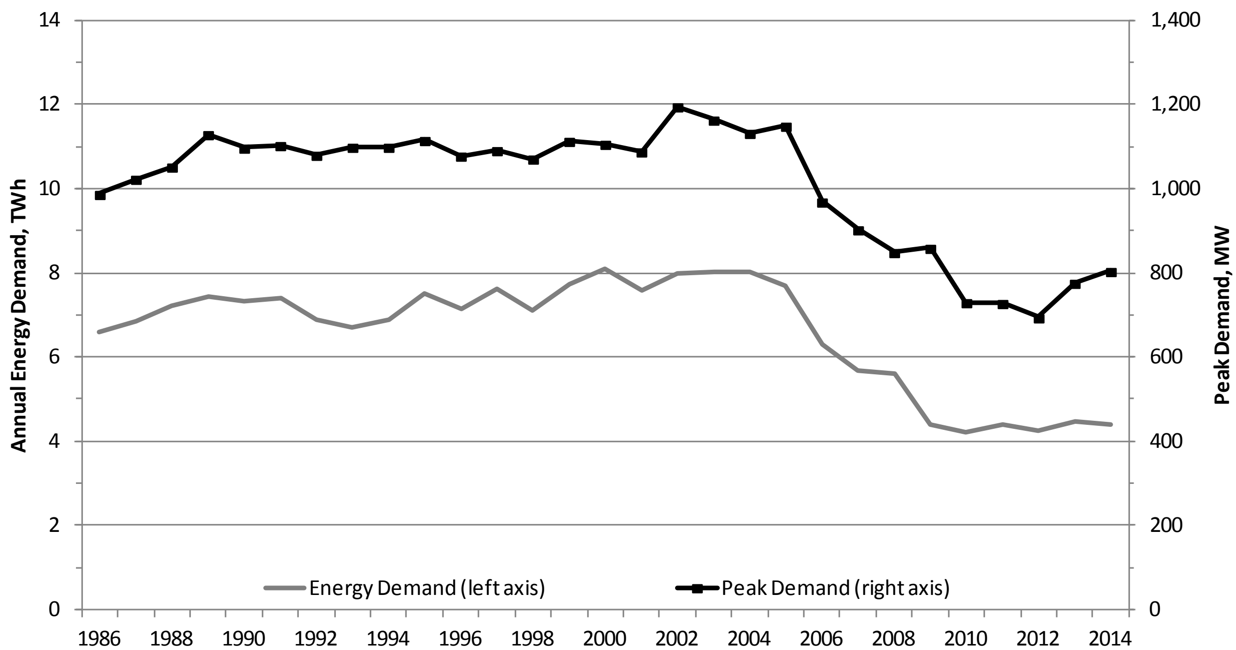
Throughout the planning and development of the E-W Tie expansion project, the IESO has maintained regular discussion with stakeholders and customers in the Northwest and continues to monitor developments that may affect electrical demand in the region. The forecast in this report reflects updated information and provides a range of demand scenarios based on the inherent uncertainty of industrial development in the region. As noted in the previous two need update reports, Northwest electrical demand is dominated by large, industrial customers and can fluctuate significantly in response to changing economic and market conditions. The Northwest is a winter-peaking region, in contrast to southern Ontario where electricity demand usually peaks during the summer months.

In this update, the demand forecast has increased marginally in magnitude, with growth occurring slightly later than in the May 2014 forecast, based on updated information of various developments.

4.1 Historical Northwest Demand

Historical electricity demand in the Northwest is presented in Figure 1 below. This update includes actual energy and demand data from 2014, which was not available when the May 2014 Report was prepared. The winter of 2014 saw an increase in demand in the Northwest driven by extreme temperatures and modest growth in the industrial sector. The Northwest electricity system performed well under the higher demand conditions of 2014, which included a winter peak of approximately 800 MW, and annual energy demand of almost 4.5 TWh.

Figure 1. Historical Northwest Electricity Demand



4.2 Drivers of Northwest Demand

The IESO continues to work together with interested parties to understand the drivers for demand in the Northwest, including engaging with stakeholders such as Common Voice Northwest, mining companies and industry associations, and carrying out discussions with the Ontario Ministry of Northern Development and Mines. The updated forecast reflects changes in the outlook for industry, as well as other developments in the Northwest.

In comparison to the May 2014 Report, drivers of Northwest demand that have changed include: more certainty in the development of several mining projects; updated information on the electricity requirements and timing associated with the TransCanada PipeLines Limited ("TCPL") proposed "Energy East" project; and consideration of recent plant closures in the pulp and paper sector.

Mining Sector

The IESO has continued to engage mining companies with developments in Ontario and review technical documents to understand the feasibility, timing and likelihood of various developments. Factors such as commodity prices, access to capital and environmental considerations act as indicators of potential growth in the sector. Several mining projects in the Fort Frances and Red Lake areas have advanced to construction or initial production phases and various other projects throughout the region have had success raising capital and advancing their feasibility and environmental assessments. On the other hand, several other projects have experienced set-backs due to factors such as low commodity prices and environmental hurdles. The demand forecast considers the latest available information on the location, size and stage of development of mining projects in the Northwest.

Pulp and Paper Sector

Ontario's pulp and paper sector has been in decline for over 10 years. This decline continued in 2014 with the closure of two Ontario plants, one in the Northeast and one in the Northwest. There is a potential for demand stabilization from the retrofitting of old pulp and paper facilities to produce other fibers such as Rayon, however a substantial recovery of the pulp and paper sector is considered unlikely.

TransCanada Energy East Pipeline

This updated forecast includes updated information on the electrical requirements of the Energy East pipeline project. Two demand forecasts were considered for this project—medium and high—reflecting the impacts on Northwest demand of two alternate connection options proposed by TCPL.

Other Forecast Components

Minimal or no change has been made for the remaining components of the Northwest demand forecast since the May 2014 Report:

- Forestry sector
- Connection of remote communities remains on track for 2020
- Natural growth in residential, commercial and other industrial sectors

The IESO remains engaged in working with local distribution companies ("LDC") to implement the Conservation First framework, consistent with the 2013 LTEP and the March 31, 2014 Conservation First Directive from the Ministry of Energy to the OPA. LDC progress towards meeting the conservation targets will continue to be tracked through Conservation and Demand Management ("CDM") Plans and evaluation, measurement and verification ("EM&V") activities, and the conservation assumptions for the Northwest will continue to be updated accordingly.

4.3 Northwest Demand Scenarios

An updated demand forecast for the Northwest was developed, taking into account the impacts of the various drivers described above. Consistent with the previous two update reports developed by the

OPA, the IESO has represented demand growth uncertainty in the region by developing three scenarios to explore the robustness and flexibility of transmission and supply options under a range of outcomes. Key aspects of the scenarios are as follows:

- **Reference Scenario.** In this scenario, mining sector demand considers proposed mines that have passed significant development milestones. Mining loads are assumed to persist for the expected lifetime of the proposed developments. This scenario assumes modest growth in the forestry sector in the short and medium term and does not assume recovery of the pulp and paper sector. This scenario assumes the Energy East pipeline will proceed to production in 2020 under the medium demand forecast for this project.
- **High Scenario.** This scenario considers the impact of stronger and faster development in the mining sector which could potentially be driven by factors such as increased commodity prices. This scenario also reflects the stabilization of the pulp and paper sector and assumes the high demand forecast for the Energy East pipeline conversion project.
- **Low Scenario.** This scenario describes a more restrained outlook in the mining sector, continuing decline in the pulp and paper sector, and it assumes that the Energy East pipeline conversion project does not proceed.

The demand assumptions for Remote Communities, residential, commercial and other industries (other than those mentioned above) are the same in each scenario.

The resulting Northwest peak and annual energy demand scenarios, net of savings from planned conservation, are shown in Figure 2 and Figure 3. The Reference demand scenario shows the Northwest forecast increasing quickly in the medium term, due to advancing mining developments which are expected to come online, followed by more gradual growth in the long term. The wide range between the High and Low scenarios reflects the uncertainty in the assumptions underlying the forecast.

For comparison, the Reference scenario prepared for the May 2014 Report is also included in Figures 2 and 3. The current Reference forecast has a slower near-term growth rate than the May 2014 Reference forecast but is higher than the May 2014 Reference forecast in the long term.

Figure 2. Northwest Net Peak Demand Forecast Scenarios

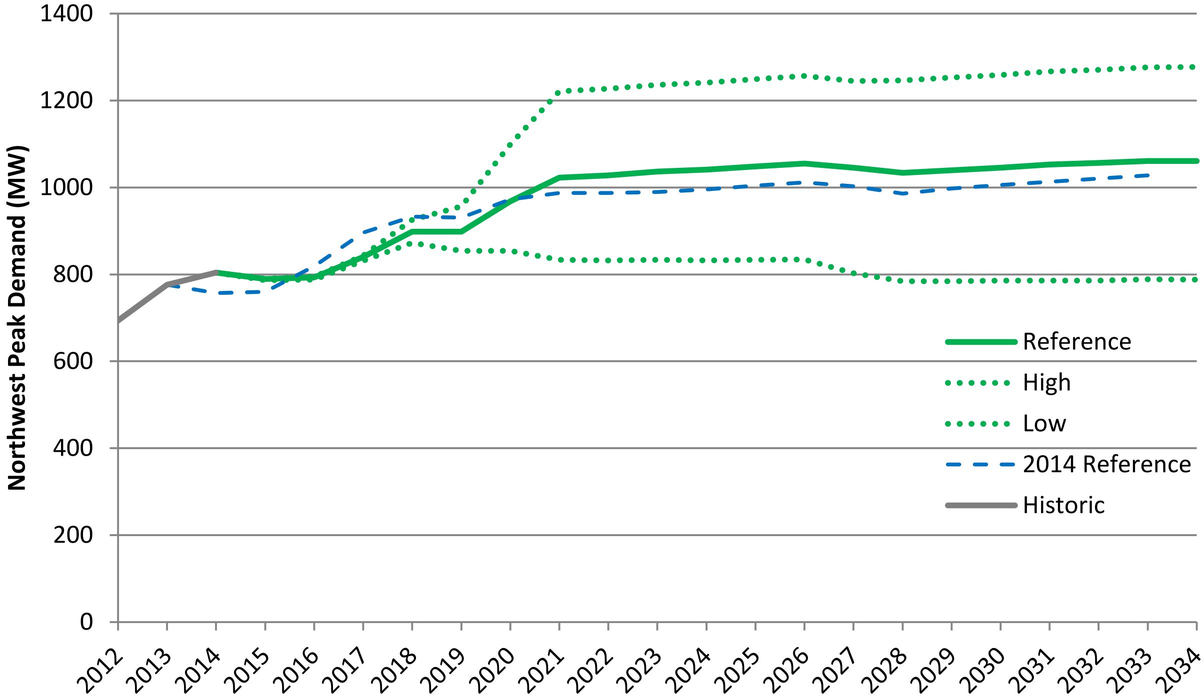
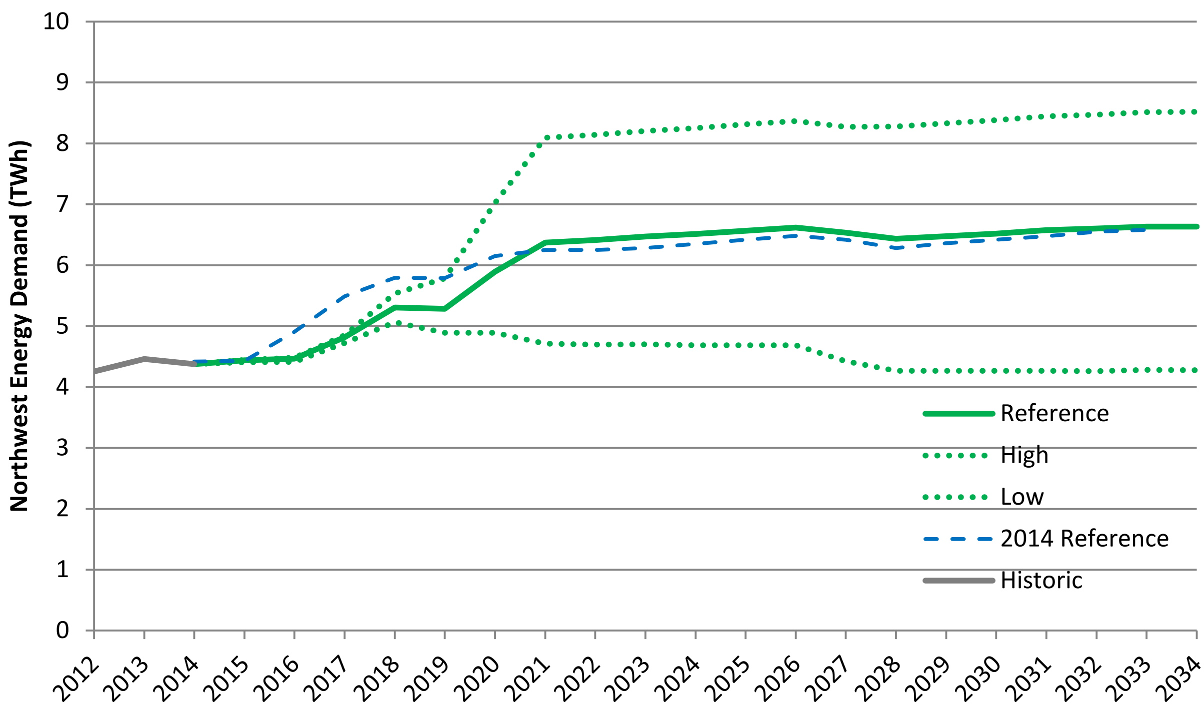


Figure 3. Northwest Net Energy Demand Forecast Scenarios



5.0 EXISTING RESOURCES TO SUPPLY NORTHWEST DEMAND

The Northwest relies upon both internal resources (generation located in the Northwest) and external resources (generation outside the Northwest accessed through existing ties) to meet its electricity supply and reliability requirements. An update on the Northwest supply outlook since the May 2014 Report is provided below.

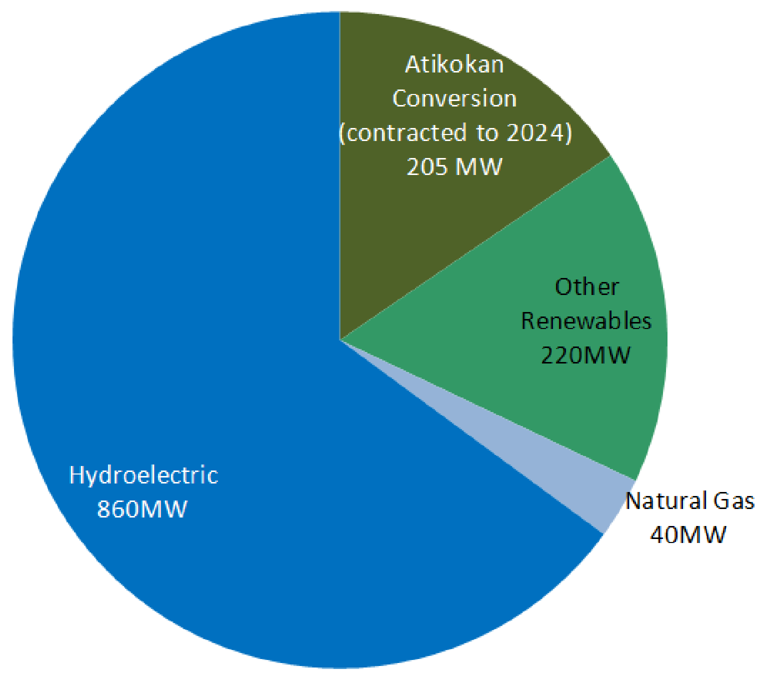
5.1 Internal Resources in the Northwest

The IESO has updated its assumptions regarding supply resources in the Northwest, where new information is available. The following changes have been made since the May 2014 Report:

- The 60 MW generator at Fort Frances, previously considered as embedded generation, has been removed from service as the operation has shut down.
- The rated capacities of the Atikokan Biomass Generating Station and the Thunder Bay Advanced Biomass Generating Station have been adjusted upward slightly based on updated contract and performance data.
- The maximum contracted hydroelectric capacity over the planning period has increased from 835 MW to 861 MW, due to projects that received contracts in the first phase of the Feed-in Tariff (“FIT”) program coming into service.
- The capacity contribution (expected available capacity during peak hours) of hydroelectric generation has been updated based on new data and ongoing model improvements. The May 2014 Report assumed a winter capacity contribution of around 32% during low water years; in this report, the winter capacity contribution during low water years has been increased to 45%.
- The expiration of wind and solar generation contracts has been accounted for in this update.
- Some small-scale distribution-connected solar and gas plants that began operation prior to 2014 are now included in the demand forecast as embedded loads; these resources have been removed from the supply side model.
- 40 MW of new hydroelectric and solar capacity contracted primarily through the FIT program have come into service since the previous analysis was completed.

The updated installed capacity of Northwest internal resources in the year 2020 is 1,325 MW and is shown by fuel type in Figure 4.

Figure 4. Northwest Internal Resources by Type in 2020 (Installed Capacity)



5.2 External Resources Supplying the Northwest

Additional supply is provided to the Northwest through the existing E-W Tie; a 230 kV double-circuit transmission line that extends between Wawa TS and Lakehead TS, linking the Northwest system to the rest of Ontario.

In the May 2014 Report, the westbound transfer capability of the E-W Tie was quoted as 240 MW. This represents the operational limit for transfers across the E-W Tie that will ensure that both transient and voltage stability will be maintained following a double-circuit contingency (fault) involving the E-W Tie.

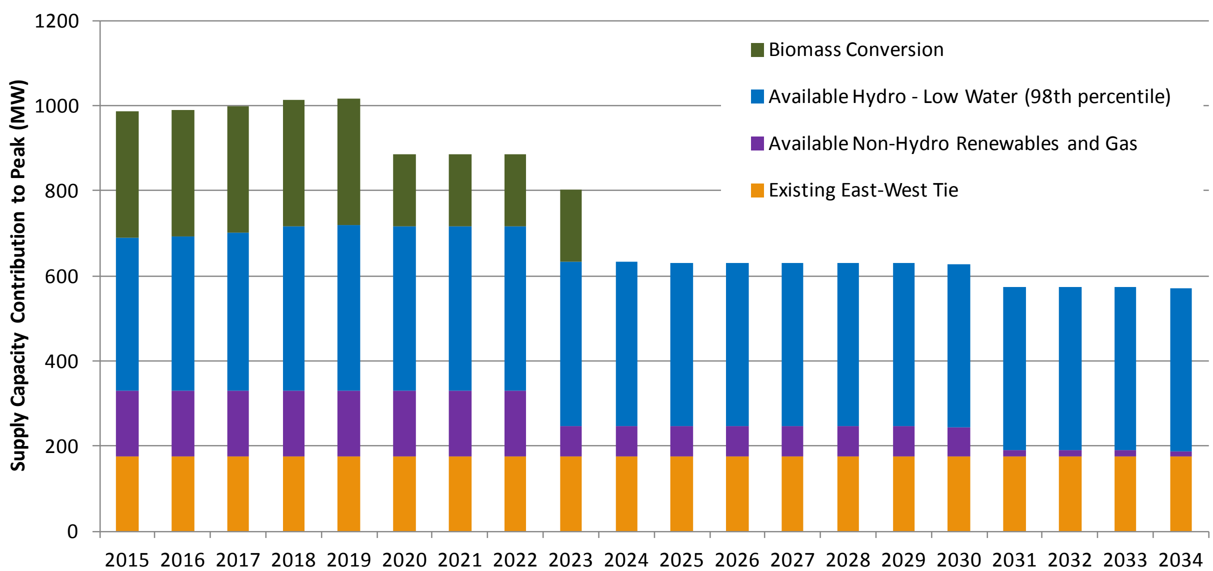
It has subsequently been recognized that following the loss of the double-circuit line between Marathon TS and Lakehead TS, the thermal rating of the parallel 115 kV single-circuit line can be more limiting under certain ambient conditions. Based on the ambient temperatures specified in the Ontario Resource and Transmission Assessment Criteria ("ORTAC") that are to be used in planning studies, the maximum transfer that can occur across the E-W Tie will be limited to 175 MW during the winter period and 155 MW during the summer by the thermal rating of this 115 kV line. Since these latter values are more restrictive, they have been used in the analysis underlying this report.

5.3 Summary of Existing Resources

The existing internal and external resources assumed to be available to supply the Northwest in this planning analysis are shown in Figure 5. The figure reflects the available capacity of internal resources at the time of Northwest peak demand under low water conditions. It also includes the westbound capability of the existing E-W Tie.

As Figure 5 indicates, available peak supply capacity is expected to be reduced at two points in the planning horizon: in 2020, corresponding to the expiry of the contract for Thunder Bay Advanced Biomass Generating Station; and in 2024, when the contract for Atikokan biomass operation expires.

Figure 5. Northwest Peak Supply Capacity under Low Water Conditions



6.0 THE NEED FOR ADDITIONAL SUPPLY FOR THE NORTHWEST

As described in previous reports, the forecast supply needs for the Northwest consist of both capacity and energy components. Based on the current outlook for Northwest demand and supply, and incorporating refined assumptions and models described in section 3, the IESO updated the assessment of the reliability and adequacy of the Northwest system. The updated capacity and energy requirements are described below.

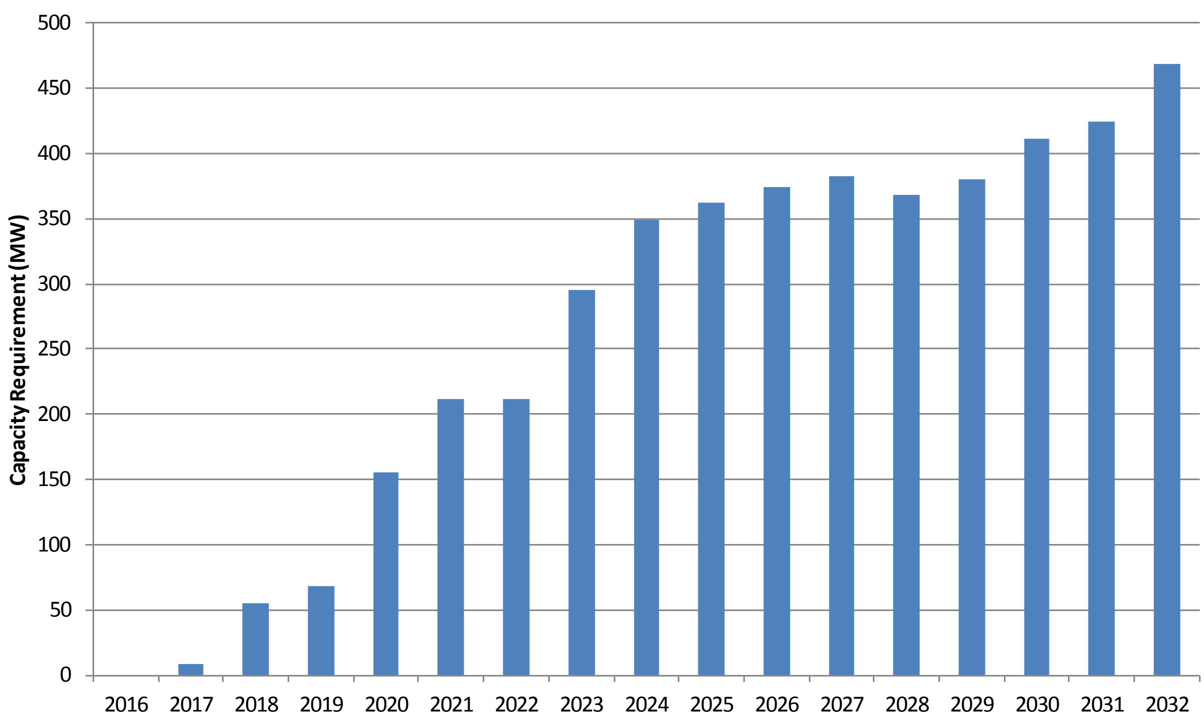
6.1 Expected Capacity Requirement

Consistent with the May 2014 Report, the IESO conducted a reliability assessment using a probabilistic approach to determine capacity requirements in the Northwest. As water conditions have a strong impact on overall supply availability in the Northwest, the probabilistic approach utilizes a range of water conditions.

The updated capacity need, based on the Reference peak demand scenario with no E-W Tie expansion, is shown in Figure 6. The capacity need increases from approximately 150 MW in 2020 to around 350 MW with the expiry of the Nipigon NUG and the Atikokan biomass contracts in 2023 and 2024 respectively. The need for additional capacity continues to climb gradually through the remainder of the planning period due to further load growth and the expiry of some smaller supply contracts, approaching 500 MW in the early 2030s.

As noted in the May 2014 Report, there is a small projected capacity need in the interim years before the E-W Tie expansion, based on assessment of planning criteria.[5] This need is lower than in the May 2014 Report due to the updated demand forecast as well as updated data and assumptions about hydroelectric availability during peak periods, and is associated with low-water years only. The IESO will continue to monitor this need and, if necessary, deploy short-term options to bridge the gap until the E-W Tie expansion comes into service.

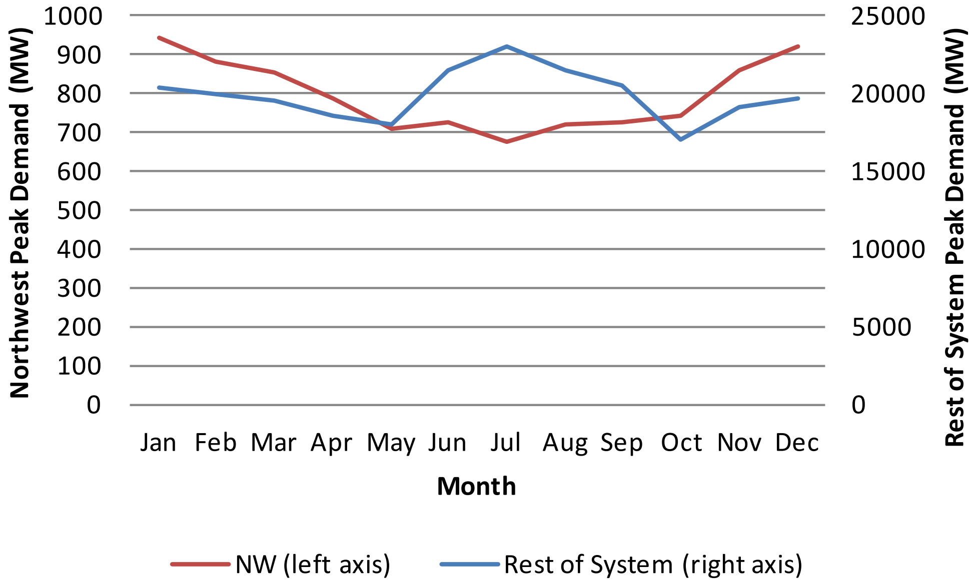
Figure 6. Expected Incremental Northwest Capacity Requirement under Reference Demand



As demand in the Northwest is winter-peaking, the incremental capacity requirements in the Northwest are greatest during the winter months. This is in contrast to southern Ontario, where peak demand requirements are highest during the summer months. This is demonstrated in Figure 7, using 2020 as an example year. This offset in capacity requirements enables the sharing of resources for capacity adequacy and increased system efficiency for energy arbitrage with the E-W Tie expansion.

[5] Assessment of the Northwest system based on operating criteria indicates that there is no capacity need prior to 2020.

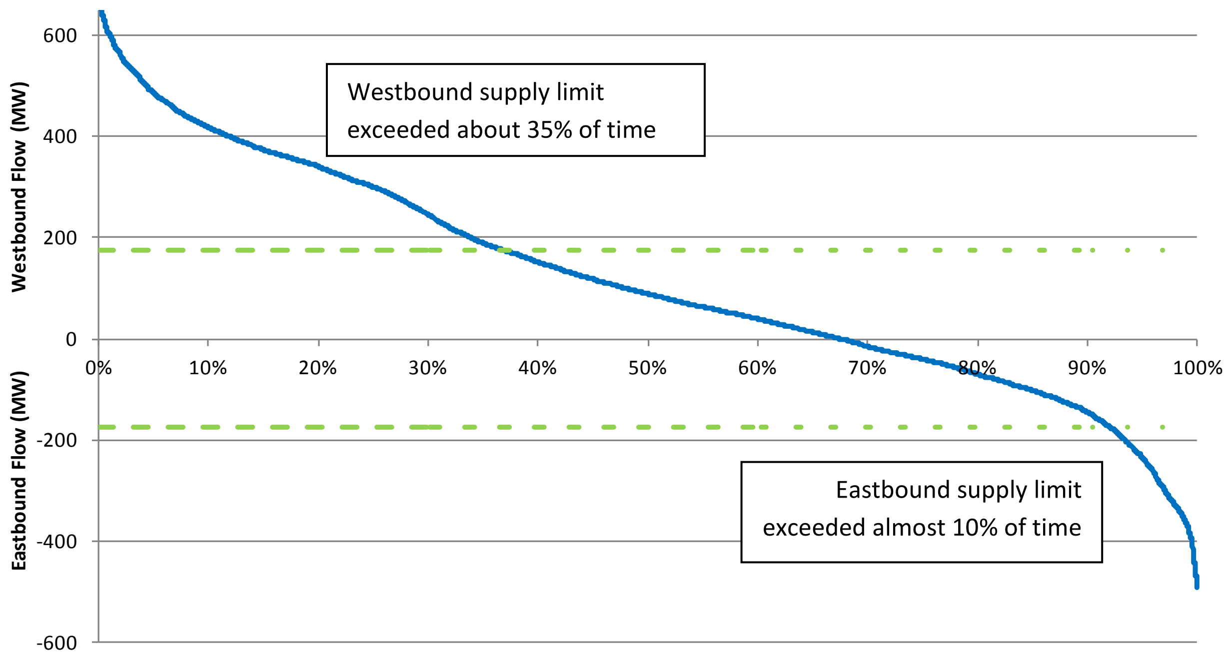
Figure 7. Timing of Demand in the Northwest vs. Rest of Ontario in 2020



6.2 Expected Energy Requirement

The expected energy requirement in the Northwest is defined by the energy demand forecast, as well as the supply capabilities of local generation and the existing E-W Tie. Figure 8 provides an updated forecast E-W Tie flow duration curve, for all hours of the year 2021, based on the latest Reference demand forecast and median water conditions. In this update, expected westbound flows exceed the existing E-W Tie capability approximately 35% of the time. This is based on application of the winter rating of 175 MW throughout the year. Applying the more restrictive limit of 155 MW during the summer months would likely result in a higher level of westbound congestion. Going eastbound, congestion is expected to occur just under 10% of time in 2021. The energy requirement is expected to grow with the demand forecast over the planning horizon.

Figure 8. Unconstrained Flow and Planning Limits on the Existing E-W Tie for the Year 2021



7.0 ANALYSIS OF ALTERNATIVES TO MEET NORTHWEST SUPPLY NEEDS

As in previous reports, two alternatives to meet the Northwest capacity and energy needs were evaluated based on the capacity needs identified for each of the demand scenarios: Reference, Low and High. The alternatives are broadly defined as follows:

(1) **No E-W Tie expansion.** In this alternative, all of the forecast capacity and energy needs are met through the addition of new gas-fired simple cycle gas turbine ("SCGT") generation in the Northwest, with the size of units and the timing of installation defined to meet the needs as they arise during the planning period. Under the Reference demand forecast, a total of 500 MW of generation is included.

(2) **E-W Tie expansion.** In this alternative, the E-W Tie expansion project provides a foundation for meeting the Northwest needs, with additional generation installed to meet any incremental supply requirements. In this update, a staged implementation of the E-W Tie expansion was adopted, with the interim 450 MW E-W Tie stage and the final 650 MW stage installed as required to meet the capacity needs throughout the study period. For the High growth forecast, a need for additional supply beyond the capability of the expanded E-W Tie emerges in the later years of the forecast; this supply is included in the analysis.

In both alternatives, local generation is assumed to consist of new-build natural gas-fired generation, utilizing on-site reserve fuel. For the reasons discussed in the May 2014 Report, continuing to operate the Atikokan and Thunder Bay conversions beyond their contemplated expiry dates was not assumed in the alternative analysis.

Another alternative that was not analyzed in this (or previous) updates is a potential firm import purchase from Manitoba. The existing intertie between Ontario and Manitoba has a capacity of about 300 MW. Currently, it is used for short-term economic trades between the two jurisdictions and there are no contractual obligations to provide firm capacity in effect. For imports to be a viable alternative, the Northwest system would need to be able to absorb the required capacity beyond the border and transfer it within the Northwest to where it is needed. Currently, without major system expansion, only about 150-200 MW can be accommodated before running into constraints on the transmission system between Kenora and Dryden. Moreover, utilizing the existing intertie for firm import purchases would reduce its availability for economic transactions that currently can assist in meeting operational needs.

7.1 Cost-Effectiveness Comparison of Generation and Transmission Alternatives

Consistent with previous E-W Tie expansion need update reports, an economic analysis of the two alternatives was conducted and their relative net-present-value (“NPV”) was compared. A sensitivity analysis was performed to test the robustness of the results under a variety of conditions. Among the sensitivities tested were the Reference, Low and High demand forecast scenarios, ranges in the cost of the generation alternative, and various other factors.

In addition to reflecting the updated capacity and energy needs, the economic analysis includes the refined assumptions identified in section 3.

Changes in assumptions since the May 2014 Report are as follows:

- The Reference demand forecast was updated as per the changes identified in section 4.3. Sensitivities to test the impacts of the updated Low and High demand growth scenarios on the NPV were performed.
- The updated existing supply resources described in section 5, including the updated westbound ratings for the existing E-W Tie, are reflected in the analysis.
- Eastbound constraints on the transmission interfaces between Wawa and Sudbury, and between Sudbury and southern Ontario, were included in the energy and capacity models based on refined studies of the capabilities of these interfaces.
- Additional study has identified that due to diversity in the demand profiles of the Northwest and the rest of Ontario (see section 6.1), fewer provincial resources are required to supply the Northwest in the E-W Tie expansion alternative.
- The transmission costs for the E-W Tie expansion are assumed to be $500 million for the line and $150 million for the stations (see section 3). A portion of the station costs is deferred consistent with the staged expansion of the E-W Tie included in this update.

- A better understanding of needs internal to the Northwest has influenced the SCGT technology type, sizing, and location, resulting in a net increase in capital costs for the "No E-W Tie expansion" alternative. A sensitivity of +/- 25% was assessed on the capital and ongoing fixed costs for generation.
- The study period extends from 2021, the first full year that the E-W Tie expansion would be in service, to 2050, when the first replacement decision is expected; this decision is associated with the generation alternative.
- Natural gas prices were assumed to be an average of $4.50/MMBtu throughout the study period. A sensitivity was performed with average gas prices of $8.50/MMBtu.
- The assessment is performed from a ratepayer perspective, and now includes all costs incurred by developers, which are passed on to ratepayers.[6]

The following assumptions remain unchanged from the May 2014 Report:

- The NPV of the cash flows is expressed in 2015$ CDN.
- The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 2% and 8% were performed.
- Median-water hydroelectric energy output was used for energy simulation in the economic analysis.
- The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the generation assets was assumed to be 30 years.
- New capacity in the Northwest and the rest of Ontario was added, as required, to satisfy reliability criteria. These capacity needs were determined as described in section 6.1. A sensitivity to determine the impact of adding 100 MW of gas-fired generation in the Northwest was performed.

Under the Reference assumptions, the E-W Tie expansion provides a net economic benefit of $1.1 billion compared to the no-expansion alternative. To test the robustness of this result against uncertainty in the assumptions, the IESO considered high and low sensitivities on a number of key parameters, of which forecast demand growth, discount rates, and capital and fixed costs for generation and transmission had the largest impacts. Based on the sensitivities tested, the net benefit of the E-W Tie project ranges from a break-even outcome associated with the Low demand forecast scenario, to $1.7 billion under high demand growth.

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[6] The previous analyses were completed from a societal perspective. Taxes and returns assumed to change hands within Ontario were therefore not included in the economic analysis.

The E-W Tie expansion would provide additional benefits, beyond meeting the reliability requirements of the Northwest: system flexibility, removal of a barrier to resource development, reduced congestion payments, reduced losses, and improved operational flexibility. These benefits are additive to the economic benefits and form an important part of the rationale for the project.

8.0 CONCLUSION AND RECOMMENDATION

The IESO's most recent analysis illustrates that the E-W Tie expansion is economic under a wide variety of conditions. On this basis, the IESO continues to recommend the E-W Tie expansion as the preferred alternative to maintain a reliable and cost-effective supply of electricity to the Northwest for the long term.

Based on the updated demand forecast, the timing of the needs is consistent with the 2020 in-service date recommended in the OPA's 2014 letter. Therefore, the IESO continues to recommend that project development proceed toward a targeted 2020 in-service date, and to support the continuation of development work to ensure the continued viability of the project.

Ministry of Energy

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Received
MAR 1 1 2016
Office of the Chair
Ontario Energy Board

Ontario

MC-2016-569

MAR 1 0 2016

Ms Rosemarie LeClair
Chair and Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms LeClair:

The East-West Tie, identified as a priority project in the 2013 Long-Term Energy Plan, is a cornerstone of this government's policy to support expansion of transmission infrastructure in northwestern Ontario. The East-West Tie continues to be the Independent Electricity System Operator's recommended alternative to maintain a reliable and cost-effective supply of electricity to northwestern Ontario for the long term.

Under the authority of section 96.1(1) of the *Ontario Energy Board Act, 1998*, ("the Act") the Lieutenant Governor in Council made an order declaring that the construction of the East-West Tie transmission line is needed as a priority project. The Order in Council took effect on March 4, 2016 and is attached to this letter.

Please do not hesitate to contact my office with any questions.

Sincerely,

Bob Chiarelli
Minister

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Ontario considers it necessary to expand Ontario's transmission system in order to maintain a reliable and cost-effective supply of electricity in the Province's Northwest, increase operational flexibility, reduce congestion payments and remove a barrier to resource development in the region;

AND WHEREAS Ontario considers the expansion or reinforcement of the electricity transmission network in the area between Wawa and Thunder Bay composed of the high-voltage circuits connecting Wawa TS with Lakehead TS (the "East-West Tie Line Project"), with an in service date of 2020, to be a priority;

AND WHEREAS the Lieutenant Governor in Council may make an order under section 96.1 of the *Ontario Energy Board Act, 1998* (the "Act") declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project;

AND WHEREAS an order under section 96.1 of the Act requires the Ontario Energy Board, in considering an application under section 92 of the Act in respect of the electricity transmission line specified in the order, to accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96 of the Act;

NOW THEREFORE it is hereby declared pursuant to section 96.1 of the Act that the construction of the East-West Tie Line Project is needed as a priority project, and that the present order shall take effect on the day that section 96.1 of the Act comes into force.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: MAR 0 2 2016
Date

____
Administrator of the Government

O.C./Décret 326/2016

Ministry of Energy

Office of the Minister

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Ontario

AUG 0 4 2017

MC-2017-1148

Mr. Peter Gregg
President and CEO
Independent Electricity System Operator (IESO)
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Gregg:

I am writing with regard to the East West Tie transmission project currently under development by Upper Canada Transmission Inc. (operating as NextBridge Infrastructure).

I have been made aware that NextBridge filed an application with the Ontario Energy Board (OEB) to obtain Leave to Construct in respect of the East West Tie project. This application includes updated cost estimates for completing the project that are significantly higher than both the previous estimates by NextBridge and cost estimates used by the Independent Electricity System Operator (IESO) in its prior need assessments for the project. The scale of the cost increases is very concerning to the Ontario Government and it would be appropriate for the IESO to review all possible options to ensure that ratepayers are protected.

As you know, the Government of Ontario passed an Order-in-Council on March 4, 2016 to name the project as a priority under S.96.1 of the Ontario Energy Board Act and this action has the effect of scoping the OEB's Leave to Construct hearing. The decision to pass this Order-in-Council was based in part on the IESO's need assessments, including the last update completed in December 2015 which indicated that the transmission project was needed and the lowest cost alternative to ensuring a reliable and adequate supply of electricity in Ontario's northwest.

Given the new cost information in NextBridge's submission and the time since the previous assessment, it is prudent for the IESO to update its assessment on the basis of the latest costs and system needs. To this end, I request that the IESO prepare an updated need assessment, consistent with the scope of previous need assessments requested by the OEB, to be delivered to the Ministry by December 1, 2017.

Sincerely,

Glenn Thibeault
Minister

c: Rosemarie Leclair, Chair and CEO, Ontario Energy Board

Updated Assessment of the Need for the East-West Tie Expansion

Submitted to the Ministry of Energy

December 1, 2017

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

1.0 KEY FINDINGS/RECOMMENDATIONS

This report has been prepared in response to the August 4, 2017 direction from the Minister of Energy ("Minister") requesting the IESO to prepare an updated need assessment, similar in scope to the previous update reports prepared for the Ontario Energy Board ("OEB"). This report confirms the rationale for the East-West Tie ("E-W Tie") Expansion project based on updated information and study results. This project continues to be the IESO's recommended option to maintain a reliable and cost-effective supply of electricity to the Northwest for the long term.

The E-W Tie Expansion project provides approximately $200 million in net cost savings compared to the least-cost local generation alternative. The IESO also considered high and low sensitivities on a number of key parameters, such the assumed cost of the generation alternative. Based on the sensitivities tested for the Reference outlook, the E-W Tie Expansion project, compared to the least-cost local generation option, ranges from a net cost savings of approximately $500 million to a net cost of just under $100 million.

The IESO continues to recommend an in-service date of 2020 for the E-W Tie Expansion project. Discussions with the transmitters confirmed their ability to meet this date, dependent on timely regulatory approvals. The IESO will continue to support the implementation of the project and monitor electricity supply and demand in the Northwest until the E-W Tie Expansion project comes into service.

2.0 INTRODUCTION

The Ontario Government's 2010[1] and 2013[2] Long-Term Energy Plans ("LTEP") have both identified the expansion of the E-W Tie transmission line as a priority project. The E-W Tie Expansion project is intended to increase the transfer capability into the Northwest by adding a new transmission line roughly parallel to the existing E-W Tie transmission line, which extends between Wawa and Thunder Bay.[3]

The Minister's letter to the OEB of March 29, 2011 was the impetus for the OEB undertaking a designation process to select the most qualified and cost-effective transmitter to undertake development work for the E-W Tie project. Early in that proceeding (EB-2011-0140), the OEB

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[1] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, Figure 12, page 47.

[2] Ontario's 2013 Long-Term Energy Plan: Achieving Balance, page 52.

[3] The route deviates from that of the existing E-W Tie by travelling around Pukaskwa National Park rather than through, and travelling north of Loon Lake and west of Ouimet Canyon Provincial Park.

requested that the former Ontario Power Authority ("OPA")[4] – now the Independent Electricity System Operator ("IESO") and hereinafter referred to as the IESO – provide a report documenting the preliminary assessment of the need for the E-W Tie Expansion. In response, the IESO filed its original report in June 2011, titled "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion" ("June 2011 Report"). As a result of the designation proceeding, Upper Canada Transmission, Inc. (o/a "NextBridge Infrastructure") was selected as the proponent to develop the E-W Tie.

The OEB's Phase 2 Decision and Order Regarding Reporting by Designated Transmitter, and the subsequent update due to the deferral of the in-service date from 2018 to 2020, dated September 26, 2013 and January 22, 2015[5] respectively, required the IESO to provide updates to the OEB on the need for the E-W Tie Expansion. In response, three previous E-W Tie reports were prepared by the IESO for the OEB: i) the first update report, was filed in October 2013, titled "Updated Assessment of the Rationale for the East-West Tie Expansion" ("October 2013 Report"); ii) the second update report titled "Assessment of the Rationale for the East-West Tie Expansion" was filed with the OEB on May 5, 2014 ("May 2014 Report"); and iii) the third update report titled "Assessment of the Rationale for the East-West Tie Expansion" was filed on December 15, 2015 ("December 2015 Report").

Following the December 2015 Report, the former Ontario Minister of Energy, Bob Chiarelli, issued a letter to the OEB stating that the E-W Tie Expansion continues to be the IESO's recommended alternative to maintaining a reliable and cost-effective supply of electricity in Northwestern Ontario for the long term and that the government had accordingly issued an Order in Council ("OIC") on March 10, 2016 declaring that the E-W Tie Expansion was needed as a priority project. Consequently, on December 6, 2016, the OEB issued an additional revision to their Phase 2 Decision and Order Regarding Reporting by Designated Transmitter relieving the IESO of the obligation of completing a 2016 need update report.

On July 31, 2017, NextBridge and Hydro One Networks Inc. ("Hydro One") filed Leave to Construct ("LTC") applications[6] with the OEB for the E-W Tie Expansion project. Their

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[4] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that combines the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator. Any assessments prior to January 1, 2015 were provided by the former OPA.

[5] OEB Decision and Order Regarding Reporting by Designated Transmitter dated September 26, 2013, page 4, and January 22, 2015, page 5.

[6] The OEB assigned file numbers EB-2017-0182 and EB-2017-0194 to the NextBridge and Hydro One applications respectively.

applications included new evidence provided by the IESO related to the preferred staging of the project's station facilities. Staging the construction of the station facilities was recommended to reduce the cost of the project, by deferring costs until the facilities are needed. The OIC, issued under the authority of section 96.1(1) of the *Ontario Energy Board Act, 1998*, satisfies the usual need requirement for obtaining section 92 approval.

The project costs included by NextBridge in its LTC application are higher than what was assumed in the IESO's December 2015 Report. Therefore, on August 4, 2017 the Minister requested the IESO to prepare an updated need assessment, consistent with the scope of previous need assessments requested by the OEB. The 2017 LTEP, published in October 2017, also addressed the need to review all options for meeting capacity needs in the Northwest to ensure ratepayers are protected as the E-W Tie Expansion project continues to be developed.[7]

This report provides an updated assessment of the E-W Tie Expansion project, reflecting changes that have taken place since the December 2015 Report, namely revised project costs and an updated demand and supply outlook for the Northwest.

3.0 CHANGES TO THE PLANNING ASSUMPTIONS

Major changes to the planning assumptions since the December 2015 Report are identified here in order to provide context for the updated results and the information presented in subsequent sections of this report.

Cancellation of TransCanada's Energy East Pipeline Project

The December 2015 Report included demand associated with TransCanada's Energy East project, in both the Reference and High demand outlooks. On October 5, 2017, TransCanada announced the termination of the Energy East project.[8] As a result, the anticipated demand associated with the Energy East project is no longer considered in any of the demand outlooks.

The Energy East project accounted for approximately 110 MW of peak demand and 1 TWh of energy demand in the December 2015 Report's Reference demand outlook.

[7] Ontario's 2017 Long-Term Energy Plan: Delivering Fairness and Choice, page 39.

[8] "TransCanada Announces Termination of Energy East Pipeline and Eastern Mainline Projects", https://www.transcanada.com/en/announcements/2017-10-05-transcanada-anounces-termination-of-energy-east-pipeline-and-eastern-mainline-projects/.

Updated Load Supply Needs

The analysis in the December 2015 Report included a westbound E-W Tie limit of 155/175 MW[9] based on the thermal limitation of the underlying 115 kV circuit from Marathon TS to Lakehead TS. It is assumed that this limit remains the planning limit for the existing E-W Tie. This limit, however, relies on support from Manitoba following contingencies on the E-W Tie. The magnitude of support required is the highest for the loss of the E-W Tie from Wawa TS to Marathon TS since that contingency separates Northwestern Ontario from the rest of the province and leaves it connected only to Manitoba and Minnesota.

Relying on short-term support from neighbouring jurisdictions is an assumption made when operating the system province-wide. However, this support should not be relied on for an extended period of time without an agreement with the neighboring jurisdiction. The current practice is to operate the system such that we're not counting on this support for more than 30 minutes following a disturbance.[10]

The requirement to return the flow on the Manitoba and Minnesota interfaces to zero, or to the scheduled flow, within 30 minutes following a contingency on the E-W Tie is a requirement that is now being included in this update report when determining whether the Northwest has adequate resources to reliably meet its outlook for demand.

Staging of Station Facilities

In September 2014, as a result of the findings of the May 2014 Report , the IESO wrote a letter to the OEB recommending the deferral of the in-service date of the E-W Tie Expansion from 2018 to 2020. The letter indicated that the additional time would allow for the optimization of equipment and system design, including the staged construction of station facilities. Prior to Hydro One's LTC application being filed in July 2017, the IESO worked closely with Hydro One to evaluate the technical and economic feasibility of different staging alternatives for the required station facilities. The IESO's evidence outlines the staging alternatives that were compared and the rationale behind the recommended staged implementation of the station facilities.

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[9] The planning limit for the existing E-W Tie is a thermal limitation, 155 MW reflects summer conditions and 175 MW reflects winter conditions.

[10] Market Manual 7.4: IESO Grid Operating Policies

The recommended staging includes an initial stage that provides 450 MW of transfer capability, with a station facility cost of $147 million. The second stage would be implemented only once the full 650 MW transfer capability of the line is needed, at an additional cost of $60 million.

Updated Transmission Cost Estimates

For this update, the IESO used the updated capital cost estimates for the new line and the station upgrades that the transmitters filed with the OEB on July 31, 2017 in their LTC applications. Based on its filed evidence, NextBridge estimates a cost of $777 million for the E-W Tie line, an increase from the previous planning estimate of $500 million used in the December 2015 Report. NextBridge has stated that the cost increase reflects unbudgeted costs, new scope requirements, other unforeseeable factors such as the delay to the in-service date, and development phase project refinements.

As previously outlined, the cost of the station facilities required for the 650 MW E-W Tie Expansion project is approximately $207 million, up from the previous planning estimate of $150 million. This estimate accounts only for costs directly attributable to the E-W Tie Expansion project. As outlined in the IESO's evidence filed with the OEB in support of Hydro One's LTC application, facilities required to address the existing high voltage problem at Lakehead TS are required regardless of whether the E-W Tie project proceeds and are not considered as part of the cost of the E-W Tie station facilities.

The total project cost for the initial 450 MW stage is $924 million, and implementing the full 650 MW would increase overall costs to $984 million.

4.0 NORTHWEST DEMAND OUTLOOK

Throughout the planning and development of the E-W Tie Expansion project, the IESO has held regular discussions with stakeholders, customers and communities in the Northwest and the IESO continues to monitor developments that may affect electricity demand in the region. The demand outlook in this report reflects updated information and engagement which has taken place since the Minister's request for the IESO to provide a need update. Engagement with stakeholders and communities in the Northwest continues to provide valuable insight into the status of future developments. The IESO's outlook considers the likelihood of identified projects proceeding under three potential economic outlooks.

The Reference, Low and High demand outlooks reflect the inherent uncertainties related to industrial development in the Northwest. As noted in the previous three need update reports, Northwest electrical demand is dominated by large, industrial customers and can fluctuate significantly in response to changing economic and market conditions. The Northwest remains a winter-peaking region, in contrast to Southern Ontario, where electricity demand usually peaks during the summer months.

In this update, the demand outlook has materially decreased in magnitude. This is driven by two significant developments: a continued decline in historical demand in the Northwest and the cancellation of TransCanada's Energy East Pipeline project and its subsequent removal from the Reference and High demand outlooks.[11]

4.1 Historical Northwest Demand

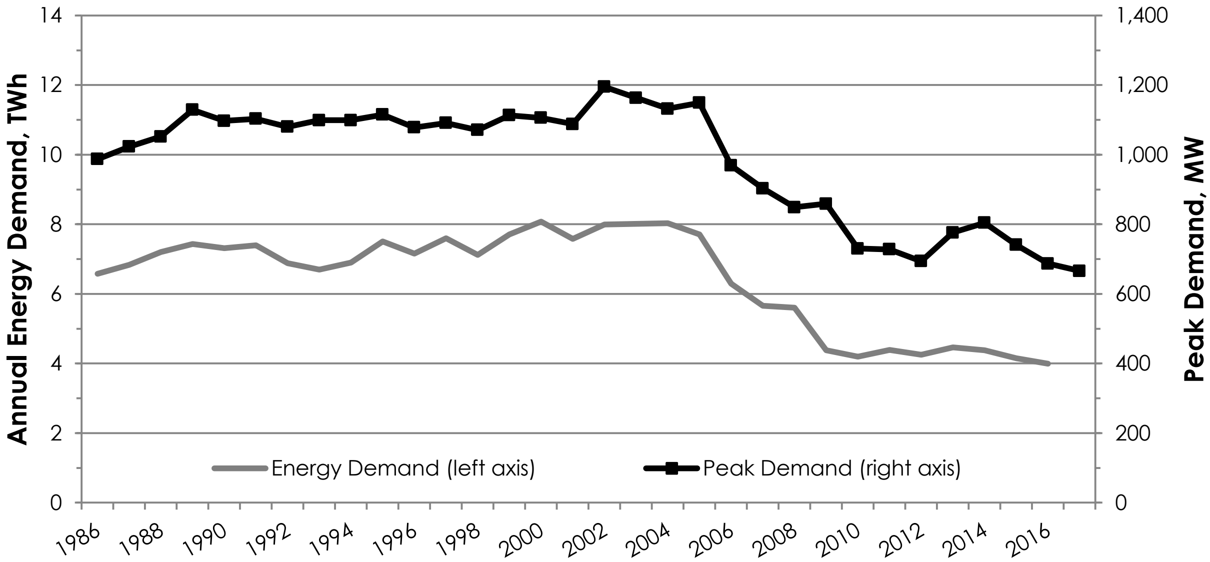
Historical electricity demand in the Northwest is presented in Figure 1 below. This update includes actual energy and peak demand data from 2015 and 2016 and preliminary data from 2017, which was not available when the December 2015 Report was prepared. While the winters of 2013 and 2014 saw an increase in demand in the Northwest, this was primarily driven by extreme low temperatures in the Northwest caused by a southward shift of the North Polar Vortex.[12] This resulted in a higher than average electric heating demand, driving winter peak demand to its highest level in five years.

Historical data now available for 2015 and 2016 and preliminary data available for 2017 shows a continuation of the declining trend for electrical demand in the Northwest due to the impacts of continued population decline, conservation, distributed generation and continued decline of the pulp and paper industry. This provides a lower starting point than in the December 2015 Report.

[11] The Energy East project was never included in the Low demand scenario.

[12] "Thunder Bay has coldest winter in 35 years, stats say", http://www.cbc.ca/news/canada/thunder-bay/thunder-bay-has-coldest-winter-in-35-years-stats-say-1.2580059.

Figure 1. Historical Northwest Electricity Demand



4.2 Drivers of Northwest Demand

The IESO continues to work with interested parties to understand the drivers of demand in the Northwest, engaging with stakeholders such as Common Voice Northwest ("CVNW"), mining companies, industry associations, and the Ontario Ministry of Northern Development and Mines. The updated outlook reflects changes in the status of developments throughout the Northwest.

In comparison to the December 2015 Report, the Northwest demand outlook has been impacted by a few key factors including: updated information on the status of mining developments; cancellation of TransCanada's proposed Energy East project; and continuing decline in the pulp and paper sector.

Mining Sector

The IESO has continued to engage mining companies with developments in Ontario and review technical documents to understand the feasibility, timing, and likelihood of potential mining developments. Factors such as commodity prices, access to capital and environmental considerations are indicators of potential growth in the sector. A mining project in the Fort Frances area has advanced to construction and initial production, and various other projects throughout the region have had success raising capital and advancing both their feasibility and environmental assessments. However, several other projects have experienced set-backs due to factors such as low commodity prices. The demand outlook considers the latest available information on the location, size, and stage of development of mining projects in the Northwest.

Pulp and Paper Sector

Ontario's pulp and paper sector has been in decline for over 10 years and this decline has continued since the December 2015 Report was published. While there is potential for demand stabilization, a return to the demand levels of a decade ago is considered unlikely.

TransCanada Energy East Pipeline

Demand associated with the Energy East Pipeline project which was previously included in both the Reference and the High demand outlooks has been removed.

Remote Communities

Connection of remote communities is assumed to begin in 2024, a delay of four years compared with the December 2015 Report.

Other Components of the Demand Outlook

Minimal or no change has been made to account for the remaining components of the Northwest demand outlook since the December 2015 Report:

- Forestry sector
- Natural growth in residential, commercial and other industrial sectors

The IESO continues to work with local distribution companies ("LDCs") to implement the Conservation First Framework, consistent with both the 2013 and 2017 LTEPs and the March 31, 2014 Conservation First Directive from the Ministry of Energy to the IESO. LDC progress towards meeting the conservation targets was tracked through Conservation and Demand Management ("CDM") Plans and evaluation, measurement and verification ("EM&V") activities, and the conservation assumptions for the Northwest were updated accordingly.

4.3 Northwest Demand Outlooks

An updated demand outlook for the Northwest was developed, taking into account the impacts of the drivers described above. Consistent with the previous three update reports, the IESO has represented demand growth uncertainty in the region by developing three outlooks to explore the robustness and flexibility of options to meet the need in the Northwest under a range of outcomes. Key aspects of the outlooks are as follows:

- **Reference demand outlook -** In this outlook, mining sector demand includes proposed mines that have passed significant development milestones. Mining loads are assumed to persist for the expected lifetime of the proposed developments. This outlook assumes modest growth in the forestry sector in the short term and assumes stabilization of the pulp and paper sector.

- **High demand outlook -** This outlook considers the impact of stronger and faster development in the mining sector which could potentially be driven by factors such as increased commodity prices. This outlook also reflects modest growth in the forestry sector and the stabilization of the pulp and paper sector.
- **Low demand outlook -** This outlook describes a more restrained outlook in the mining sector and continuing decline in the pulp and paper sector.

The demand assumptions for Remote Communities, residential, commercial and other industries (other than those mentioned above) are the same in each outlook. The Energy East Pipeline project is not included in any outlook.

The resulting Northwest peak and annual energy demand outlooks, net of savings from planned conservation, are shown below in Figure 2 and Figure 3. The Reference demand outlook shows demand in the Northwest increasing quickly in the medium term, due to advancing mining developments that are expected to come online, followed by more gradual growth in the long term. The range between the High and Low outlooks reflects the uncertainty in the assumptions underlying the electricity demand growth in the Northwest.

For comparison, the Reference outlook prepared for the December 2015 Report has also been included in Figures 2 and 3. The current Reference outlook has a slower near-term growth rate than the December 2015 Reference outlook and is lower in the long term due to the continued decline in Northwest historical electrical demand and the cancellation of the Energy East Pipeline project.

Figure 2. Northwest Net Peak Demand Outlooks

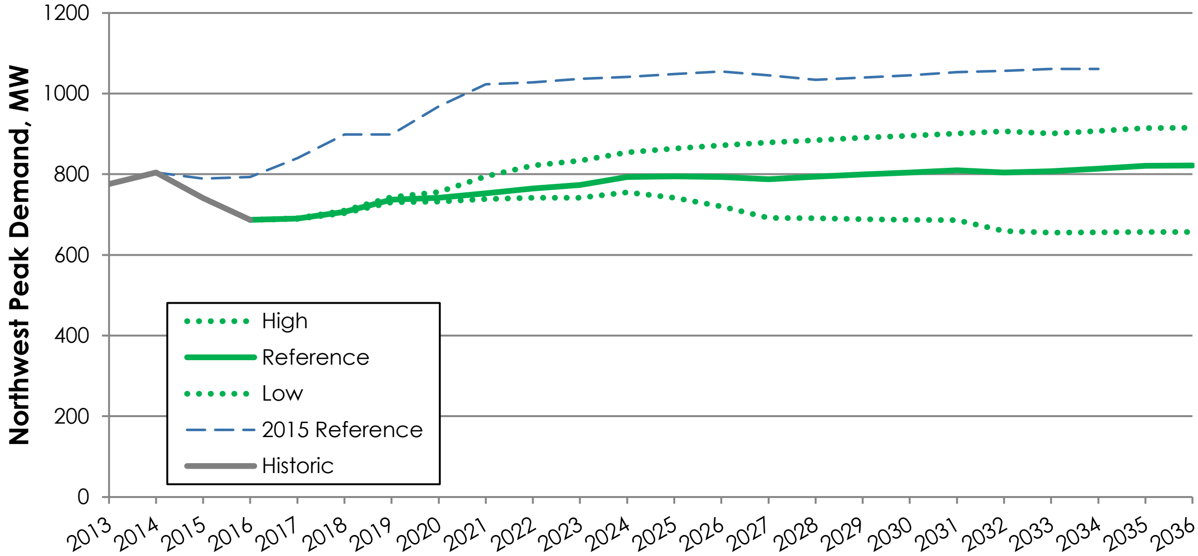
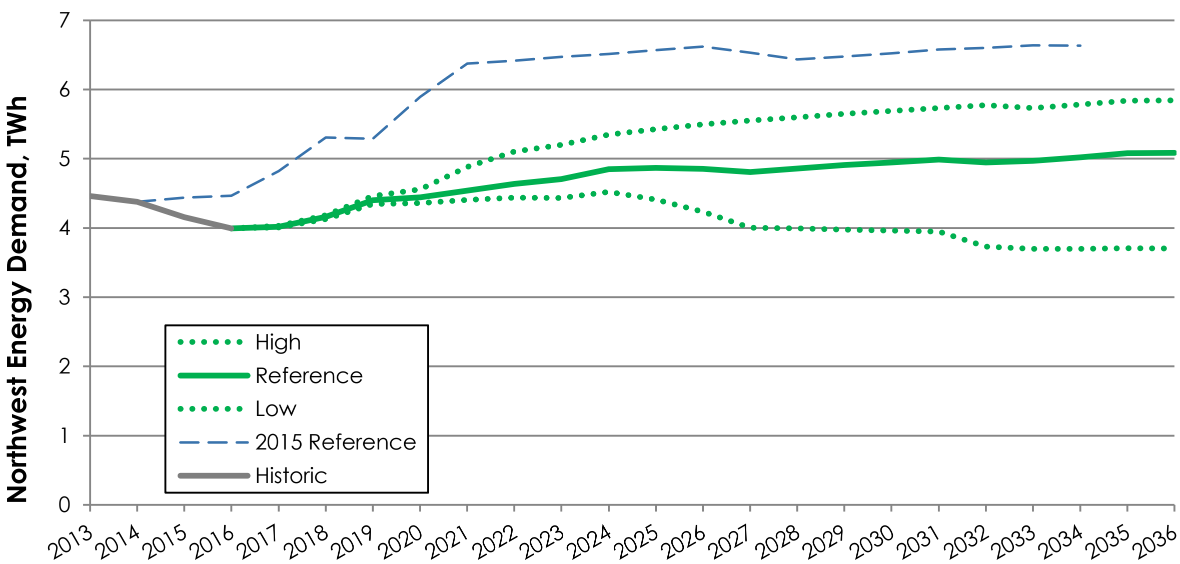


Figure 3. Northwest Net Energy Demand Outlooks



5.0 EXISTING RESOURCES TO SUPPLY NORTHWEST DEMAND

The Northwest relies upon both internal resources (generation located in the Northwest) and external resources (generation outside the Northwest accessed through existing ties) to meet its electricity supply and reliability requirements. An update on the Northwest supply outlook since the December 2015 Report is provided below.

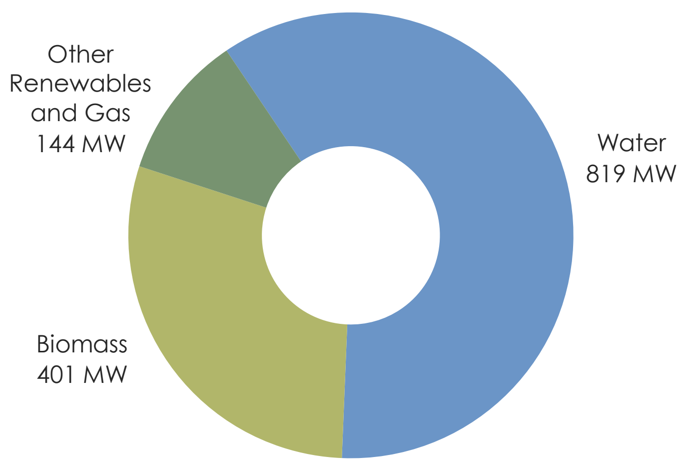
5.1 Internal Resources in the Northwest

The IESO has updated its assumptions regarding supply resources in the Northwest, where new information is available. The following material changes have been made since the December 2015 Report:

- Improved representation of water resources in the Northwest to better reflect run-of-river limitations.
- Incorporation of additional historical water data for the Northwest to better inform the probability of low water conditions.
- Some small-scale distribution-connected generation that began operation prior to 2017 is now included in the demand outlook as embedded generation; these resources have been removed from the supply-side model.

The installed capacity of internal resources in the Northwest for the year 2018 is approximately 1,360 MW and is shown by fuel type in Figure 4.

Figure 4. Northwest Internal Resources - Installed Capacity



5.2 External Resources Supplying the Northwest

Additional supply is provided to the Northwest through the existing E-W Tie; a 230 kV double-circuit transmission line that extends between Wawa TS and Lakehead TS, linking the Northwest system to the rest of Ontario.

The E-W Tie planning limit, consistent with the December 2015 Report, is 155/175 MW which respects the loss of the E-W Tie from Marathon TS to Lakehead TS. Staying under this limit ensures that, following contingencies on the E-W Tie, voltage levels in the Northwest are within acceptable ranges, and equipment, including the Manitoba and Minnesota ties, stays within thermal limits.

However, as previously discussed, this E-W Tie planning limit relies on support from Manitoba following contingencies on the E-W Tie, which cannot be counted on for more than 30 minutes. As a result, there must be sufficient capacity in the Northwest to not only adequately supply the expected demand in the Northwest while staying under this planning limit, but also to reduce flows on the Manitoba and Minnesota ties to zero (or the scheduled transfer level) within 30 minutes.

For example, following the loss of the E-W Tie from Wawa TS to Marathon TS, the Northwest will be separated from the rest of Ontario and power will automatically flow from Manitoba and Minnesota to supply the Northwest. Action must then be taken to re-dispatch resources within the Northwest to return to scheduled flow levels and there must be sufficient capacity in the Northwest to do so.

6.0 THE NEED FOR ADDITIONAL SUPPLY FOR THE NORTHWEST

As described in previous reports, the outlook for supply needs in the Northwest comprises both capacity and energy components. The IESO updated its assessment of resource adequacy in the Northwest system, which is described below.

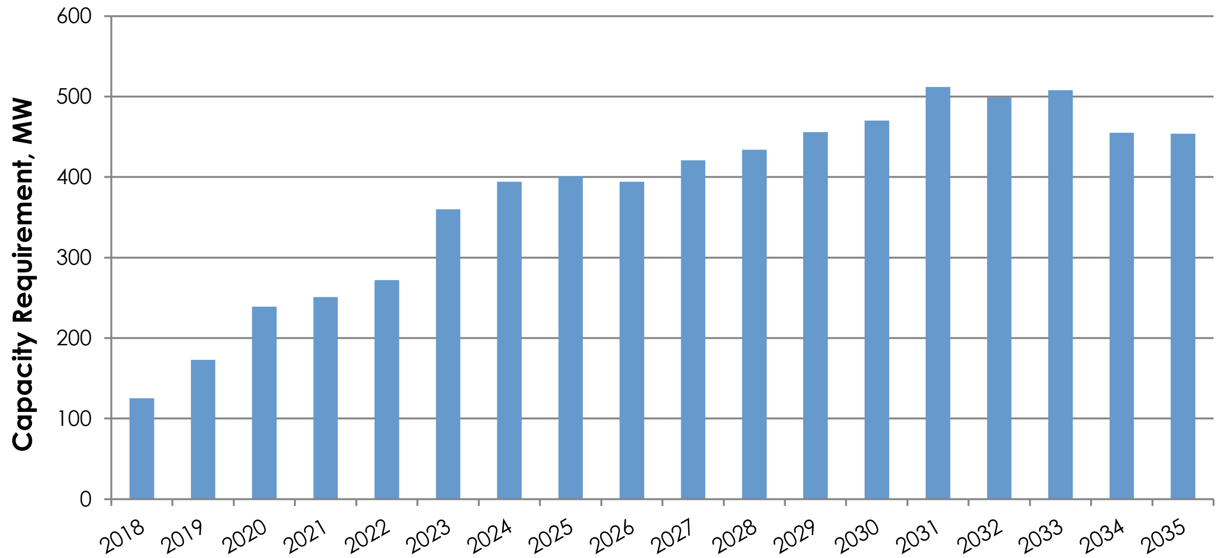
6.1 Capacity Adequacy Requirement

Consistent with the December 2015 Report, the IESO conducted a reliability assessment using a probabilistic approach to determine capacity requirements in the Northwest. As water conditions have a strong impact on overall supply availability in the Northwest, the probabilistic approach reflects a range of water conditions.

The updated capacity need, based on the Reference demand outlook with no E-W Tie Expansion, is shown in Figure 5. A 100 MW capacity need already exists today, and this need continues to grow to approximately 240 MW by the original 2020 in-service date. By 2022, the capacity need exceeds 260 MW, and grows to approximately 400 MW by 2024. The need for additional capacity increases to about 500 MW by 2035 as demand continues to grow and as supply changes.

As noted in earlier need update reports, there is a projected capacity need in the interim years before the E-W Tie Expansion in-service date, based on an assessment of applicable planning criteria. The near-term need is higher than in the December 2015 Report because it includes the capacity needed to reduce the flow from Manitoba to zero (or the scheduled flow level) following a contingency on the E-W Tie.

Figure 5. Expected Incremental Northwest Capacity Requirement under Reference Demand

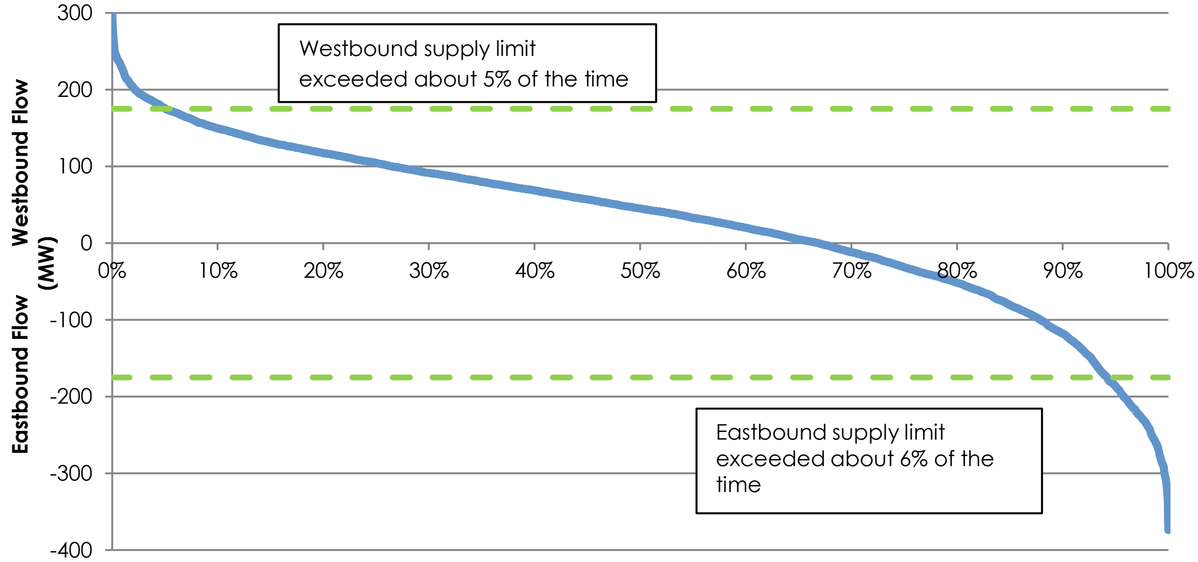


6.2 Energy Requirement

The expected energy requirement in the Northwest is defined by the energy demand outlook, as well as the supply capabilities of local generation and the existing E-W Tie. Figure 6 provides an updated E-W Tie flow duration curve, for all hours of the year 2023,[13] based on the updated Reference demand outlook and median water conditions. In this update, expected westbound flows exceed the existing E-W Tie capability approximately 5% of the time. This is based on application of the winter rating of 175 MW throughout the year. Applying the more restrictive limit of 155 MW during the summer months would result in a higher level of westbound congestion. Eastbound congestion is expected to occur approximately 6% of the time in 2023. The westbound energy requirement is expected to increase with the demand outlook over the planning horizon.

[13] The year 2023 has been shown for illustrative purposes. The energy assessment was carried out for years 2022 to 2035.

Figure 6. Unconstrained Flow and Planning Limits on the Existing E-W Tie for the Year 2023



7.0 ANALYSIS OF ALTERNATIVES TO MEET NORTHWEST SUPPLY NEEDS

In this updated need assessment, a number of alternatives to the E-W Tie Expansion were assessed taking into consideration updated information since the December 2015 Report. The two lowest cost options to meet the Northwest capacity and energy needs were identified to be: i) meeting Northwest needs through the addition of new local natural gas-fired generation, and ii) expanding the existing E-W Tie. These options are described further below:

(1) **No E-W Tie Expansion -** In this option, all of the identified capacity and energy needs are met through the addition of new natural gas-fired simple cycle gas turbine ("SCGT") generation in the Northwest, with the size of units and the timing of installation defined to meet the needs as they arise during the planning period. Under the Reference demand outlook, a total of 500 MW of generation is added. As in the previous update, it was assumed that, due to the difficulty and cost associated with obtaining firm gas service in the Northwest, all new-build natural gas-fired generation utilizes on-site reserve fuel.

(2) **E-W Tie Expansion -** In this option, the E-W Tie Expansion project provides a foundation for meeting the Northwest needs, with additional generation installed to meet any incremental supply requirements. In this update, a staged implementation of the E-W Tie Expansion was adopted, with the interim 450 MW E-W Tie stage and the final stage, to provide the full 650 MW transfer capability, added as required to meet the

capacity needs throughout the study period. Under the Reference demand outlook only the interim stage of the E-W Tie Expansion is required.

The assumptions and the results of the economic analysis comparing these two options are presented in section 7.1. As in the previous update reports, the economic analysis includes an assessment of the sensitivity of the results to changes in key variables to better understand their impact on the economic merits of both options.

No E-W Tie Expansion Option – Other Considered Alternatives

A number of the non-gas options for meeting Northwest needs were discussed in the May 2014 and December 2015 Reports. These were re-examined in the IESO's 2017 assessment. These options include utilizing existing biomass resources in the Northwest, building new non-emitting generation including storage, and firm imports from Manitoba. Although opportunities may exist to develop these resources to meet future provincial electricity needs, they were found to be insufficient for meeting the identified need in the Northwest due to technical and economic considerations.

New non-emitting resources such as wind and/or storage were also considered in this assessment. These were identified to be uneconomic for meeting Northwest needs relative to new natural gas-fired generation, and additional investments in transmission would be required to connect these resources. In addition, without expansion of the bulk transmission system, additional non-emitting generation resource development in the Northwest would increase surplus energy and congestion during periods of increased energy production from existing hydroelectric resources.

The use of the existing Manitoba intertie for either a short-term deferral of the need, or as part of an integrated solution for the long term, was also revisited. As discussed in the December 2015 Report, without major system expansion, only about 150-200 MW of firm capacity imports from Manitoba can be accommodated before running into constraints on the transmission system between Kenora and Dryden. Due to the magnitude of the need, firm Manitoba imports alone would not be sufficient to meet Northwest needs and would need to be paired with other resources.

7.1 Cost-Effectiveness Comparison of Generation and Transmission Alternatives

Consistent with previous E-W Tie Expansion need update reports, an economic analysis of the E-W Tie Expansion and the lowest cost generation option was conducted and their relative net present value ("NPV") was compared. A sensitivity analysis was performed to test the robustness of the results under a variety of conditions. Among the sensitivities tested were the

Reference, Low and High demand outlooks, ranges in the cost of the generation and transmission alternatives, and other cost-related assumptions.

Changes in assumptions since the December 2015 Report are as follows:

- The Reference demand outlook was updated as per the changes identified in section 4.3. Sensitivities to test the impacts of the updated Low and High demand growth outlooks on the NPV were performed.
- Existing supply resources were updated as described in section 5.
- Operating conditions were used in the energy assessment to better reflect the potential economic impact of each option.
- The transmission costs for the E-W Tie Expansion were assumed to be $777 million for the line and $207 million for the stations (see section 3). A portion of the station cost is deferred consistent with the staged expansion of the E-W Tie included in this update. The second stage is only required under the High demand outlook.
- The study period extends to 2051, when the first asset replacement decision is expected; this decision is associated with the generation alternative. Sensitivities of a 20-year and 70-year study period were assessed based on the typical planning horizon and the lifetime of a transmission line, respectively.
- Natural gas prices were assumed to be an average of $5.80/MMBtu throughout the study period – inclusive of carbon price. Sensitivities were assessed with the combined gas and carbon price ranging from $4.50/MMBtu to $10.50/MMBtu.
- The USD/CAD exchange rate was assumed to be 0.78. Sensitivities were assessed for 0.67 and 1.
- Additional sensitivities were analyzed including +20% and -15% for transmission capital costs, a +/- 75 MW margin of error on the capacity need analysis, and the impacts of electricity trade on energy prices.
- The NPV of all cash flow is expressed in 2017 $CDN.

The following assumptions remain unchanged from the December 2015 Report:

- The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 2% and 8% real social discount rate were also performed.
- The assessment is performed from an electricity ratepayer perspective.
- Median-water hydroelectric energy output was used for energy simulation in the economic analysis.
- Dual-fuel gas-fired generation was assumed to be added to the Northwest due to natural gas fuel supply limitations. Oil was assumed as the on-site reserve fuel. Other

options, such as compressed natural gas and liquefied natural gas stored on site, were also considered. However, these are expected to be higher cost than oil back-up.

- A sensitivity of +/- 25% was assessed on the capital and ongoing fixed costs for generation in the Northwest.
- The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the generation assets was assumed to be 30 years.
- New capacity in the Northwest and the rest of Ontario was added, as required, to satisfy Northeast Power Coordinating Council, Inc. ("NPCC") resource adequacy criteria.[14] These capacity needs were determined as described in section 6.1.

Under the Reference case assumptions, the E-W Tie Expansion project is approximately $200 million lower in net present cost compared to the no-expansion alternative. To test the robustness of this result against uncertainty in the assumptions, the IESO considered high and low sensitivities on a number of key parameters, of which changes to the demand outlook, discount rates, and assumed cost of the generation alternative had the largest impacts. Based on the sensitivities tested, the E-W Tie Expansion project, compared to new gas-fired generation in the Northwest, ranges from a net cost savings of approximately $500 million to a net cost of about $100 million.

The E-W Tie Expansion provides additional benefits, beyond meeting the reliability requirements of the Northwest, which are unique to a transmission solution. These include system flexibility, removal of a barrier to resource development, reduced congestion payments, reduced line losses, increased economic imports from Manitoba, decreased carbon emissions, and improved operational flexibility. These benefits are additive to the economic benefits and form an important part of the rationale for the project.

8.0 COMMUNITY INPUT

Stakeholder and community input is an important aspect of the planning process. Providing opportunities for input throughout the IESO's planning processes enables the views and preferences of stakeholders throughout the community to be considered in the development of demand outlooks and in the consideration and development of different alternatives to address identified needs.

[14] NPCC Regional Reliability Reference Directory # 1. Design and Operation of the Bulk Power System.

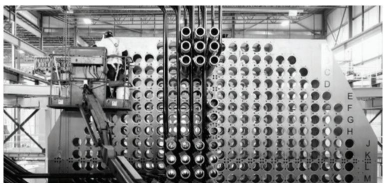
As part of the E-W Tie need update process, stakeholders throughout the Northwest were contacted to provide input into the outlook for electricity demand. The stakeholders directly involved included mining customers and other large industrial power consumers, CVNW, the Ministry of Northern Development and Mines, Union Gas Limited, TransCanada PipeLines Limited, and Thunder Bay Hydro Electricity Distribution Inc. Stakeholder input helped inform the status of developments in the region and their associated demand impacts. The list of stakeholders contacted throughout the development of the demand outlooks was consistent with previous update reports. The IESO also received written feedback from a variety of stakeholders, speaking to their continued support for the East-West Tie Expansion.

Finally, the IESO hosted a planning forum in Thunder Bay in October 2017 where stakeholders once again voiced their support for the project. Some have provided recommendations regarding alternatives to be considered for meeting Northwest capacity needs. Stakeholders at the forum also commented that the chosen solution should have the flexibility to accommodate demand uncertainty, decreasing the impediment to additional developments.

9.0 CONCLUSIONS AND RECOMMENDATIONS

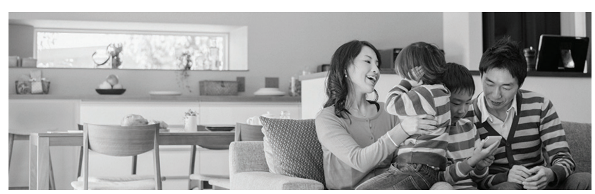
The IESO's updated assessment of Northwest capacity needs and the options to address them demonstrates that the E-W Tie Expansion project continues to be the preferred option for meeting Northwest supply needs under a range of system conditions.

The IESO continues to recommend an in-service date of 2020 for the E-W Tie Expansion project. Discussions with the transmitters confirmed their ability to meet this date, dependent on timely regulatory approvals. The IESO will continue to support the implementation of the project and monitor electricity supply and demand in the Northwest until the E-W Tie Expansion project comes into service.



ONTARIO'S
LONG-TERM
ENERGY PLAN
2017

Delivering Fairness and Choice



Ontario

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2017 Long-Term Energy Plan

Minister's Message

Ontario's 2017 Long-Term Energy Plan is principally focused on the consumer while ensuring a reliable and innovative energy system. *Delivering Fairness and Choice* makes an important commitment: we will strive to make energy more affordable, and give customers more choices in their energy use, ensuring that Ontarians and their families continue to be at the center of everything we do.

Ontarians are benefiting from the years of investment we have made in the province's electricity system. We can be proud of what we have all accomplished. These investments mean we no longer have to worry about brownouts or blackouts. By eliminating coal-fired generation, we now have an electricity system that is more than 90 per cent free of emissions that cause climate change. The phase-out of coal-fired generation and our investments in clean generation have contributed to dramatically improved air quality in Ontario – smog advisories have dropped from 53 as recently as 2005 to zero in 2016. This means that our children can play outside without their health being threatened by smog and air pollution. Our investments are delivering a robust supply of electricity, one that is expected to meet Ontario's electricity demand into the middle of the next decade, and makes us well positioned to plan for and meet future challenges. Our success in building a clean and reliable electricity system means we can maintain our focus on helping Ontarians and their families.

We have already taken steps through Ontario's Fair Hydro Plan to make the electricity system as affordable as possible. Ontario's Fair Hydro Plan reduced electricity bills for residential consumers by an average of 25 per cent and will hold any increases to the rate of inflation for four years. These benefits aren't limited to residential consumers; as many as half a million small businesses and farms are also benefiting from the reduction. Lower-income Ontarians and those living in eligible rural and northern communities are receiving even greater reductions, as much as 40 to 50 per cent. These measures were the right thing to do. They're better for Ontario, and fairer for families.

Delivering Fairness and Choice would not have been possible without your suggestions and advice. This Plan is the product of the most extensive consultations and engagements my ministry has ever undertaken. Thousands of organizations, communities, businesses and citizens wrote to us. Hundreds came to the 17 open houses that were held across the province. We also engaged with representatives of more than 100 different First Nation and Métis organizations and communities.

In written submissions and at meetings, you told us that affordability is a top priority and that you wanted more control and choice over how you use and pay for electricity. Our government has listened to what you had to say. *Delivering Fairness and Choice* recognizes that a retired couple in London uses energy differently than a condo-dweller living in Vaughan. Pricing pilots are underway to help inform new electricity pricing plans that could give consumers greater choice, and the ability to reduce their monthly electricity bills.

Delivering Fairness and Choice ensures that consumer protection remains a top priority for this government. We have already given the Ontario Energy Board the authority to prohibit disconnections when customers are more vulnerable, such as over the winter months. We will now give added protection to consumers living in condominiums and other multi-unit residential buildings who are billed for electricity by private companies that provide metering services to their unit. These consumers will benefit from increased oversight of fees charged by those providers. Consumers will also benefit from the Board's new *Consumer Charter*, which ensures all energy consumers have the right to a fair, reasonable and timely process for resolving their complaints.

On another front, the Ministry of Energy is working with local distribution companies to redesign electricity bills to give consumers easily accessible information they find valuable and can use. The electricity bill is, after all, the most common way for consumers to receive information about their electricity system.

Ontario is helping consumers keep pace with rapidly changing technology. The costs of new wind and solar energy installations are coming down, and new smart grid and storage technologies are becoming more readily available. Updates to the Province's net metering framework will increase the ability of consumers to generate their own renewable electricity and receive a credit on electricity bills for any extra power they send to their local distribution company.

All of this is possible because Ontario has a stable electricity system that produces a steady supply of electricity. *Delivering Fairness and Choice* is using this opportunity to move ahead with innovative ideas for managing the system and reducing costs. Initiatives such as Market Renewal will ensure the province has appropriate sources of electricity at the lowest possible price. This initiative could save Ontarians up to $5.2 billion over a 10-year period.

Energy is key to the well-being and prosperity of the people of Ontario. Our plan will ensure we can all depend on a clean and reliable supply of affordable energy to power our households and businesses for many years to come. From this position of strength, we are able to make an important commitment to Ontario's energy consumer: that we will strive to give consumers more choices in their energy use and ensure that Ontarians and their families will continue to be at the heart of everything we do.

Glenn Thibeault
Minister of Energy

EXECUTIVE SUMMARY

Overview

The 2017 Long-Term Energy Plan, *Delivering Fairness and Choice*, builds on the years of investment that Ontarians made to renew and clean up the province's electricity system. As a result of phasing out coal-fired electricity generation in 2014, emissions for Ontario's electricity sector are forecast in 2017 to account for only about two per cent of the province's total greenhouse gas emissions. The province's robust supply of electricity will be sufficient to meet Ontario's foreseeable electricity demand well into the next decade. This leaves the province well positioned to plan for and meet future challenges.

Ontario's success in building a clean and reliable energy system means we can renew our focus on helping Ontarians and their families. That is the key priority of *Delivering Fairness and Choice*. The government has already brought in a number of measures to reduce electricity costs. The *Fair Hydro Act, 2017* reduced electricity bills for residential consumers by an average of 25 per cent and will hold any increases to the rate of inflation for four years. Ontario's Fair Hydro Plan is also helping as many as half a million small businesses and farms. Lower-income Ontarians and those living in eligible rural and northern communities are receiving even greater reductions, of as much as 40 to 50 per cent. *Delivering Fairness and Choice* will continue our focus on managing electricity system costs over the long term.

Since the release of the 2013 Long-Term Energy Plan (LTEP), Ontario has taken a number of measures to combat climate change. These include the passage of the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, the introduction of Ontario's cap and trade program, and the release of the first Climate Change Action Plan. *Delivering Fairness and Choice* builds on the province's leading role in the global fight against climate change.

Key Elements of Delivering Fairness and Choice

Below is a summary of the key initiatives identified in *Delivering Fairness and Choice.*

Chapter 1. Ensuring Affordable and Accessible Energy

The projected residential price for electricity will remain below the outlooks published in the 2010 and 2013 LTEPs. The projected electricity prices for large consumers will, on average, be in line with inflation over the forecast period. This is the result of previous investments that delivered a cleaner and more reliable energy system, anticipated benefits from Market Renewal, and cost-reduction measures.

- Ontario's Fair Hydro Plan reduced electricity bills by an average of 25 per cent for residential consumers and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction. Ontario's Fair Hydro Plan builds on previous actions that reduced electricity costs for families, farms and businesses.
- Ontario will share the costs of existing electricity investments more fairly with future generations by refinancing a portion of the Global Adjustment, spreading the cost of the investments over a longer period of time.
- Residential customers served by local distribution companies (LDCs) with some of the highest rates are getting enhanced distribution rate protection. This will save eligible customers as much as 40 to 50 per cent on their electricity bills.
- The First Nations Delivery Credit reduces the monthly electricity bills of on-reserve First Nation residential customers of licensed distributors.
- The government will enhance consumer protection by giving the Ontario Energy Board (OEB) increased regulatory authority over unit sub-meter providers.
- The government will continue to support expanded access to natural gas, giving consumers greater choice and aiding in the economic development of their communities.

Chapter 2. Ensuring a Flexible Energy System

While the demand for electricity is expected to remain steady, and the demand for fossil fuels is expected to decline, Ontario needs a flexible energy system that can meet any of the possible future outlooks. Market Renewal in the electricity sector will allow the province to adjust to changes and cost-efficiently acquire the electricity resources that are needed to meet future demand.

- Market Renewal will transform Ontario's wholesale electricity markets and ultimately result in a more competitive and flexible marketplace.
- The Market Renewal process will develop a "made in Ontario" solution, taking lessons learned from other jurisdictions while collaborating with domestic market participants and taking into account the Province's greenhouse gas (GHG) emission reduction targets.
- Ontario's cap and trade program, as well as programs and initiatives in the Climate Change Action Plan will support efforts to decarbonize the fuels sector.
- *Delivering Fairness and Choice* aims to maximize the use of Ontario's existing energy assets in order to limit any future cost increases for electricity consumers.
- Cap and trade will increase the price of fossil fuels and affect how often fossil-fueled generators get called on to meet the province's electricity demand. This will help reduce the province's greenhouse gas emissions and shift Ontario towards a low-carbon economy.
- The government will direct the Independent Electricity System Operator (IESO) to establish a formal process for planning the future of the integrated provincewide bulk system.
- Ontario will continue to exercise strict oversight of nuclear refurbishments and ensure they provide value for ratepayers.

Chapter 3. Innovating to Meet the Future

Innovative technologies have the potential to transform Ontario's energy system. New pricing plans, net metering, energy storage and the electrification of transportation will give customers more control and choice over how they generate, use and pay for energy.

- The government will work with the OEB to provide customers greater choice in their electricity price plans.
- The net metering framework will continue to be enhanced to give customers new ways to participate in clean, renewable energy generation and to reduce their electricity bills.
- Barriers to the deployment of cost-effective energy storage will be reduced.
- Utilities will be able to intelligently and cost-effectively integrate electric vehicles into their grids, including smart charging in homes.
- The government's vision for grid modernization in Ontario focuses on providing LDCs the right environment to invest in innovative solutions that make their systems more efficient, reliable and cost-effective, and provide more customer choice. The government will build on its success and renew and enhance the Smart Grid Fund. This will continue the Province's support of Ontario's innovation sector and help overcome other barriers to grid modernization.

- The IESO will work with the government to develop a program to support a select number of renewable distributed generation demonstration projects that are strategically located and help inform the value of innovative technologies to the system and to customers.
- The government intends to fund international demonstration projects to help Ontario's innovative energy companies diversify to foreign markets.
- The Province will collaborate with the federal government, universities and industry to support the province's nuclear sector.
- The government will work with the IESO to explore the development of a pilot project that explores the energy system benefits, and GHG emission reductions, from the use of electricity to create hydrogen.
- Innovative uses for Ontario's natural gas distribution system will be pursued.

Chapter 4. Improving Value and Performance for Consumers

As the energy sector becomes more consumer-focused, users will want increased transparency and accountability from the companies and agencies that provide energy services. Utilities and regulators will need to respond by renewing their focus on efficiency and reliability, and looking at new ways of doing business.

- The Province expects the OEB to continue to enhance its efforts to improve the performance of LDCs.
- The government will look to the OEB to identify additional tools and powers that could be used to make utilities more accountable to their customers, promote efficiencies and cost reductions, encourage partnerships, and ensure regulatory processes are cost-effective and streamlined while also accommodating changing utility business models.
- The government will work with the OEB and LDCs to redesign the electricity bill to make it more useful for consumers in understanding and managing their energy costs.
- The government will look to the OEB to review the standards for reliability and quality of service for transmitters and distributors and for options to improve the standards and will ask the IESO to review how its planning and policies can improve reliability for customers.
- The government will direct the IESO to develop a competitive selection or procurement process for transmission, and to identify possible pilot projects.
- The government will look to the IESO and the OEB to promote the right-sizing of transmission and distribution assets at their end of life.

- A new transmission corridor is needed in the northwest Greater Toronto Area given the size of the forecasted growth. Further studies will identify a specific corridor.
- The Province will provide greater transparency for consumers on gasoline pricing through the OEB's transportation fuels review.

Chapter 5. Strengthening our Commitment to Energy Conservation and Efficiency

Ontario is committed to putting conservation first, both as a resource for the energy system and as a tool for consumers to manage their energy costs. The government and its agencies will continue to assess the achievable potential for energy conservation, explore how to integrate existing conservation programs with new Green Ontario Fund programs, and empower consumers with access to data and tools, such as through the Green Button initiative. The transition to a capacity auction will present opportunities for demand response to grow further and compete with other resources, based on system needs.

- Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.
- The government will continue to set advanced efficiency standards for products and appliances, and will explore setting or updating energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants.
- The government and its agencies will further encourage LDCs to pursue energy efficiency measures on their distribution systems to achieve customer electricity and cost savings.
- The Green Ontario Fund will provide energy consumers with a co-ordinated, one-window approach to encourage conservation across multiple energy sources and programs.
- The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, enable it to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data.
- Beginning July 1, 2018, combined heat and power projects that use supplied fossil fuels to generate electricity will no longer be eligible to apply for incentives under the Conservation First Framework or the Industrial Accelerator Program. Behind-the-meter waste energy recovery projects will continue to be eligible, as will renewable energy projects, including those paired with energy storage systems.

Chapter 6. Responding to the Challenge of Climate Change

Ontario's robust supply of electricity will play a key role in enabling the transition to a low-carbon economy. The Province will continue to work to support the deployment of clean energy technologies.

- Ontario remains committed to an electricity system that includes renewable energy generation and supports the goals of Ontario's Climate Change Action Plan.
- The government will encourage the construction of near net zero and net zero energy and carbon emission homes and buildings to reduce emissions in the building sector.
- The government is proposing to expand the options for net metering to give building owners more opportunities to access renewable energy generation and energy storage technologies.
- The government will continue to work with industry partners to introduce renewable natural gas into the province's natural gas supply and expand the use of lower-carbon fuels for transportation.
- Building on current activities, the government will strengthen the ability of the energy industry to anticipate the effects of climate change and integrate its impacts into its operational and infrastructure planning.

Chapter 7. Supporting First Nation and Métis Capacity and Leadership

First Nations and Métis are showing leadership in Ontario's energy sector, with an unprecedented level of involvement. At the same time, First Nations and Métis face unique challenges in accessing clean, reliable and affordable energy – challenges the province and its agencies will work with them to address.

- The government will review current programs in order to improve the availability of conservation programs for First Nations and Métis, including communities served by Independent Power Authorities.
- The Province, working with the federal government, will continue to prioritize the connection of remote First Nation communities to the grid and support the four First Nation communities for which transmission connection is not economically feasible.
- The Aboriginal Community Energy Plan program will be expanded to help communities implement their energy plans and support Ontario's Climate Change Action Plan.
- The government will engage with First Nations and Métis to explore options for supporting energy education and capacity building, the integration of small-scale renewable energy projects, net metering and other innovative solutions that address local or regional energy needs and interests.

- Innovative financing models and support tools will be investigated to address barriers to the financing of projects led or partnered by First Nations or Métis.
- The government will report back to First Nations and Métis between LTEPs to provide updates on the Province's progress and seek ongoing feedback.
- The government's Natural Gas Grant Program will support the expansion of natural gas access to First Nation communities.

Chapter 8. Supporting Regional Solutions and Infrastructure

The Province is working with regions and local communities to develop plans for meeting their diverse energy requirements.

- The government will continue to work with its agencies to implement the Conservation First policy in regional and local energy planning processes.
- With the first cycle of regional planning completed, the government is directing the IESO to review the regional planning process and report back with options and recommendations that address the challenges and opportunities that have emerged.
- Ontario's Climate Change Action Plan has reinforced the importance of community energy plans, and indicated the government's continued support for them.
- The Province has established seven pipeline principles to evaluate oil and natural gas pipelines, and is committed to public engagement when it undertakes reviews of major pipeline projects.

ENSURING AFFORDABLE AND ACCESSIBLE ENERGY

1

ENSURING AFFORDABLE AND ACCESSIBLE ENERGY

Ontario's electricity system is well positioned to meet any challenges and pursue any opportunities that may occur over the next 20 years.

Nearly $70 billion has been invested in the electricity system since 2003. These investments have several benefits, including providing a clean, reliable electricity system.

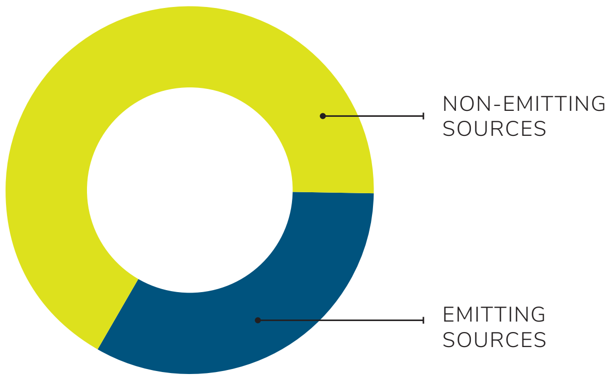
This is a significant change compared to 2003, when power from sources emitting greenhouse gases (GHG) made up one-third of the province's generation mix.

WHAT WE HEARD FROM YOU

- Electricity costs are too high
- High prices hurt industrial competitiveness
- Reduce rates by funding from tax base
- Consider new technologies and methods to manage energy use
- Promote the benefits of conservation for both customers and the system
- Delivery charges should be the same provincewide
- Expand access to natural gas

FIGURE 1.

2003 Total Generation By Emitting and Non-Emitting Sources (TWh)



Non-Emitting Sources
99.1 TWh
67%

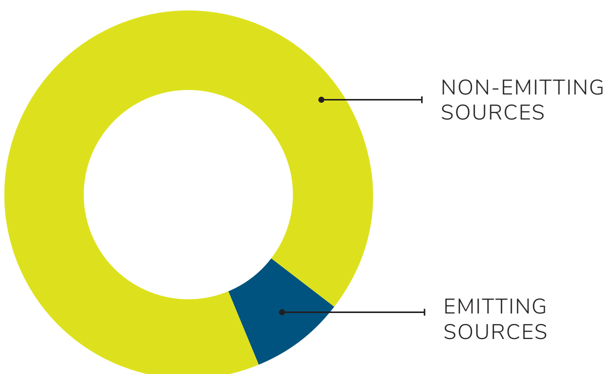
Emitting Sources
48.3 TWh
33%

TOTAL GENERATION
147.4 TWh

Source: IESO

FIGURE 2.

2016 Total Generation By Emitting and Non-Emitting Sources (TWh)



Non-Emitting Sources
143.8 TWh
92%

Emitting Sources
12.8 TWh
8%

TOTAL GENERATION
156.6 TWh

Source: IESO

DID YOU KNOW?

In 2003, the electricity sector represented about 20 per cent of Ontario's total greenhouse gas emissions. As a result of phasing out coal-fired electricity generation in 2014, emissions for Ontario's electricity sector are forecast in 2017 to account for only about two per cent of the province's total greenhouse gas emissions.

Making Energy Affordable

The much-needed investments in our electricity system have led to higher electricity prices. As a result, Ontario's Fair Hydro Plan was developed to relieve the cost pressures caused by these system improvements. It builds on actions already taken over the past several years that reduced electricity costs for families, farms and businesses, including:

- Deferring the construction of two new nuclear reactors at the Darlington Nuclear Generating Station, avoiding an estimated $15 billion in new construction costs;
- Driving down the cost of renewable energy generation through annual reviews of Feed-In Tariff (FIT) pricing, revised procurement totals, and the introduction of competitive procurement for large renewable projects. This reduced the cost of renewable energy generation by at least $3 billion, compared to the forecast in the 2013 Long-Term Energy Plan (2013 LTEP);
- Suspending the second round of the large renewable procurement process (LRP II) and the Energy-from-Waste Standard Offer Program. This is expected to save up to $3.8 billion compared to the forecast in the 2013 LTEP;
- Renegotiating the Green Energy Investment Agreement with Samsung, reducing contract costs by $3.7 billion;
- Starting the refurbishments at the Bruce Nuclear Generating Station in 2020, instead of 2016, helping to save $1.7 billion compared to the forecast in the 2013 LTEP; and
- Pending regulatory approvals, continuing to operate the Pickering Nuclear Generating Station up to 2024, for an estimated saving for ratepayers of as much as $600 million.

Ontario's Fair Hydro Plan

On June 1, 2017, the *Fair Hydro Act, 2017* became law, providing additional help for electricity consumers. Ontario's Fair Hydro Plan:

- Reduces electricity bills by an average of 25 per cent for residential consumers, and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction;
- Expands the Ontario Electricity Support Program (OESP) by increasing the on-bill credits by 50 per cent and making more Ontarians eligible for the program;

- Provides enhanced distribution rate protection for residential customers served by the local distribution companies (LDCs) that have some of the highest rates. This will let eligible customers save as much as 40 to 50 per cent on their electricity bills. The enhanced distribution rate protection broadens the support provided under the existing Rural or Remote Electricity Rate Protection (RRRP);
- Reduces the monthly electricity bills for on-reserve First Nation residential customers of licensed distributors by giving the customers a 100 per cent credit on the delivery line or service charge of their bills. This provides eligible customers with an average monthly benefit of $85;
- Shifts the funding of the OESP and most of the RRRP program from electricity bills to provincial revenues. This will reduce the regulatory charges paid by all Ontario ratepayers;
- Allows smaller manufacturers and greenhouses with average monthly peak demand greater than 500 kilowatts (kW) to participate in the Industrial Conservation Initiative (ICI). This gives them a strong incentive to lower their consumption during peak hours and can reduce their bills by an average of one-third;
- Includes the 8 per cent rebate that took effect on January 1, 2017, a reduction equal to the provincial portion of the Harmonized Sales Tax; and
- Establishes an Affordability Fund to help Ontarians who do not qualify for low-income conservation programs to make energy efficiency improvements to their homes, improvements that could not otherwise be done without the support.

Additional Details on Ontario's Fair Hydro Plan

Ontario Electricity Support Program

In order to benefit more low-income Ontarians and provide them with additional support, Ontario has expanded the eligibility criteria for the OESP and increased the monthly credits on their electricity bills by 50 per cent. This means that:

- A single customer earning under $28,000 can now receive $45 per month, up from $30;
- A family of four with combined earnings under $48,000 can now receive $40 per month; and
- Seven or more people living together who earn a total of $39,000 or less can receive $75 per month, up from $50.

Electricity customers are eligible if they meet the program's household size and income requirements. The amounts of the basic credits are in figure 3.

FIGURE 3.

Amounts of Monthly Credits of Ontario Electricity Support Program (OESP) by Household Income Level

HOUSEHOLD INCOME AFTER TAX	HOUSEHOLD SIZE (NUMBER OF PEOPLE LIVING IN HOUSEHOLD)						
	1	2	3	4	5	6	7+
$28,000 or less	$45	$45	$51	$57	$63	$75	$75
$28,001 - $39,000		$40	$45	$51	$57	$63	$75
$39,001 - $48,000			$35	$40	$45	$51	$57
$48,001 - $52,000					$35	$40	$45

If a customer is eligible, uses electric heat as their primary heating source, has certain electrically intensive medical devices, or is Indigenous or lives with Indigenous family members, the OESP provides an enhanced credit (see figure 4).

FIGURE 4.

Amounts of Monthly Credits of Ontario Electricity Support Program (OESP) by Household Income Level – Energy Intensive

HOUSEHOLD INCOME AFTER TAX	HOUSEHOLD SIZE (NUMBER OF PEOPLE LIVING IN HOUSEHOLD)						
	1	2	3	4	5	6	7+
$28,000 or less	$68	$68	$75	$83	$90	$113	$113
$28,001 - $39,000		$60	$68	$75	$83	$90	$113
$39,001 - $48,000			$52	$60	$68	$75	$83
$48,001 - $52,000					$52	$60	$68

Ontario is also working to improve co-ordination across provincial programs that provide support to low-income Ontarians. Synchronizing the OESP with social assistance programs will help get more vulnerable consumers into the program so they can receive the support they need on electricity bills. This includes ensuring that anyone deemed financially eligible for Ontario Works or the Ontario Disability Support Program will automatically be eligible for the OESP.

Distribution Rate Protection

The RRRP program lowers the distribution rates paid by rural and remote customers who face higher distribution costs compared to other areas.

Ontario has expanded this rate protection to provide distribution rate relief to residential customers served by LDCs with some of the highest rates. About 800,000 customers now benefit from the enhanced distribution rate protection.

LDCs whose customers are benefiting from the enhanced distribution rate protection include: Hydro One (medium- and low-density rate classes), Northern Ontario Wires, Lakeland Power (Parry Sound service territory), Chapleau, Sioux Lookout, InnPower, Atikokan and Algoma. The level of benefits differs from utility to utility.

First Nations Delivery Credit

The First Nations Delivery Credit benefits approximately 21,500 residential customers living on reserves.

The credit provides much needed relief from the high electricity costs faced by First Nation on-reserve households and encourages their socio-economic well-being. This is an important step towards reconciliation and strengthening the relationship between Ontario and First Nations.

> "The elimination of the delivery charge will assist our citizens by reducing energy poverty in our communities. It also represents recognition for the use of the land in the development and expansion of the provincial energy grid." "Poverty, lack of opportunity and choosing to pay for electricity over food is a reality that affects our people. Ontario's commitment is commendable and allows a path forward for greater quality of life for First Nations in Ontario."
>
> **Ontario Regional Chief Isadore Day**

Industrial Conservation Initiative

The Industrial Conservation Initiative (ICI) provides incentives to large electricity consumers to reduce their consumption and lower their electricity costs during peak hours. This also benefits the electricity system by deferring the longer-term need for new peaking generation.

To give more businesses the opportunity to participate in the ICI, Ontario has lowered the threshold for entry and increased the number of companies that can benefit. As of July 1, 2017, all customers with an average monthly peak demand of greater than one megawatt (MW) are eligible for the program. In addition, small manufacturing companies and greenhouses with average monthly peak demand greater than 500 kW and one MW or less are also eligible.

Affordability Fund

Ontario offers a suite of conservation and energy efficiency programs that can help customers manage their energy usage and reduce their costs over the long-term. The government has recently taken steps to improve the availability of programs so that all Ontarians can take advantage of conservation opportunities (see Chapter 5). Among these, the government has launched an Affordability Fund to help those Ontarians not eligible for low-income conservation programs and who need support to improve the energy efficiency of their homes. The fund is expected to pay for the installation of household improvements such as energy-saving LED light bulbs, power bars, better insulation, and energy-efficient window air conditioners and refrigerators.

The Affordability Fund is administered by an independent trust that distributes funds to the LDCs that apply. LDCs, working with community partners, are in the best position to provide energy efficiency improvements to consumers in need of assistance.

Refinancing the Global Adjustment to Ensure Intergenerational Fairness

Ontario's Fair Hydro Plan helps electricity consumers by refinancing a portion of the Global Adjustment (GA). The GA pays costs associated with contracted and rate-regulated generation, as well as conservation and demand management programs in Ontario.

The majority of the province's electricity generators have 20-year contracts, but many facilities are expected to operate beyond the life of those contracts and thus provide additional benefits to Ontarians in the future.

Present-day consumers should not be burdened with paying a disproportionate share of investments that provide benefits for decades to come. To relieve the burden on today's ratepayers and share costs more fairly with future generations, a portion of the GA is being refinanced to spread the cost of electricity investments over a longer period of time. This refinancing, which reflects the expected longer life cycle of existing facilities, provides significant and immediate rate relief and helps ensure intergenerational fairness.

Expanding the Low-Income Conservation Program

To enhance and improve the availability of conservation programs helping low-income customers, the government directed the Independent Electricity System Operator (IESO) in August 2017 to centrally design, fund and deliver a conservation program for low-income customers. The program, to start in January 2018, is expected to enhance and increase access to the Save on Energy Home Assistance Program. LDCs may continue to deliver their own program if the IESO determines they have demonstrated a commitment to serve this sector.

Existing Help for Families and Individuals

The measures included in Ontario's Fair Hydro Plan build on existing programs that Ontario families and individuals can use to help reduce their electricity costs. This assistance includes:

- The Ontario Energy and Property Tax Credit, for low- to moderate-income individuals;
- Low-income Energy Assistance Programs, for emergency situations;
- The Save on Energy for Home programs, which help households to become more energy efficient; and
- The Northern Ontario Energy Credit, for eligible families and individuals living in Northern Ontario.

In addition, new incentives programs, to be created under the Climate Change Action Plan, will provide increased benefit to low-income households.

Existing Help for Businesses and Industry

There are a number of measures already in place to help industries, business and commercial operations and institutions lower their electricity costs. These measures include:

- The Industrial Accelerator Program (IAP), which assists eligible transmission-connected companies and their distribution-connected sites to fast-track the capital investment needed for major energy conservation projects;
- The Save on Energy for Business programs, which provide financial incentives that help distribution-connected businesses to reduce their electricity use and manage costs though energy audits, retrofits and process and system improvements; and
- The Northern Industrial Electricity Rate (NIER) Program, which provides rate rebates to Northern energy-intensive industries facing competitiveness pressures due to higher energy costs. The program also assists industrial consumers in developing and implementing energy management plans to manage their usage and reduce costs.

In addition to these measures, Ontario is looking for new ways to provide electricity rate assistance to consumers that are too large to be eligible for the OEB's Regulated Price Plan (RPP). The government and the Ontario Energy Board (OEB) are working together on potential approaches to regulatory changes including how the GA is charged to these consumers, also known as non-RPP Class B consumers. For these consumers, the GA is charged at the same rate regardless of the time that they consume electricity. A GA charge that varies with time of use would lower prices for some Class B consumers and encourage more efficient consumption. Consultations will take place before any changes would be made.

Ontario will continue to explore innovative ways to provide assistance to these mid-sized consumers, while striving to increase system efficiency. The government will continue to engage with businesses and industry to explore options to reduce costs for these consumers. The government is collaborating with the Ontario Chamber of Commerce to raise awareness about energy efficiency and the savings programs available for small and medium businesses.

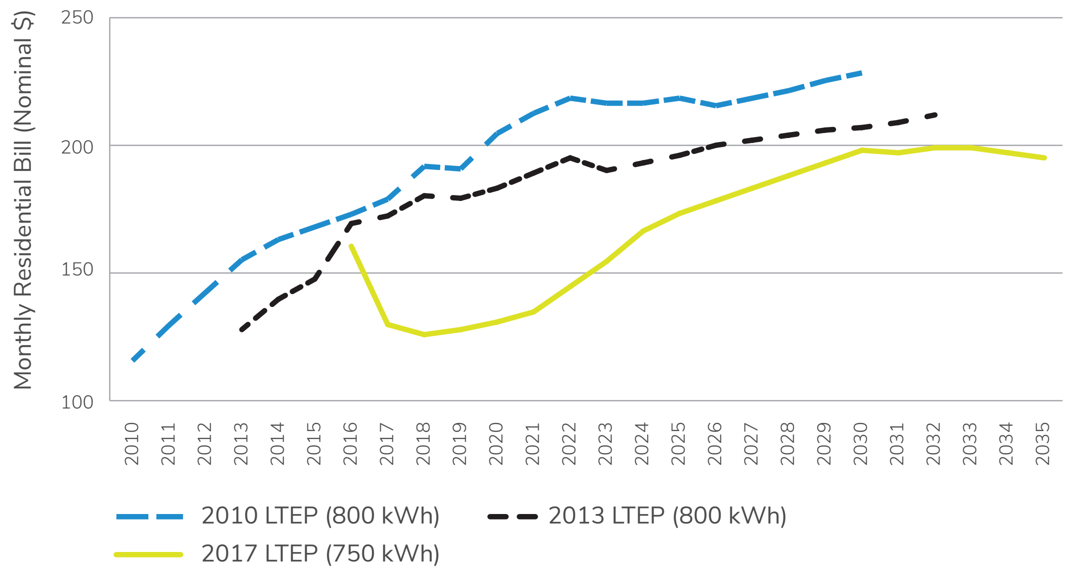
Program offerings through the new Green Ontario Fund will help Ontario businesses and industries increase their use of low-carbon technologies while also reducing costs.

Electricity Price Forecast

The 2017 LTEP's outlook for residential prices shows progress compared to earlier outlooks in the 2010 and 2013 LTEPs. The residential price outlook in the 2017 LTEP remains below the 2013 LTEP outlook for the full forecast horizon due to the Ontario Fair Hydro Plan, removing costs from the electricity system, the anticipated benefits from implementing Market Renewal initiatives, and more efficient consumption of electricity. The outlook also considers the impacts of cap and trade and assumes that some of our generation assets will continue to be available for the duration of the planning outlook.

FIGURE 5.

Electricity Price Outlook – Residential Consumers



Source: IESO, Ministry of Energy

Note: Forecasts used in *Delivering Fairness and Choice* reflect prevailing patterns of consumption. Between late-2009 and mid-2016, the OEB defined the typical residential customer as a household that consumed 800 kWh of electricity per month. As of May 2016, the OEB changed their typical residential consumption to 750 kWh per month, due to declining household consumption.

Electricity Price Outlook – Residential Consumers

	2010 LTEP (800 kWh)			**2013 LTEP** (800 kWh)			**2017 LTEP** (750 kWh)		
	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)
2010	$114								
2011	$128	$14	12%						
2012	$141	$13	10%						
2013	$154	$13	9%	$125					
2014	$162	$8	5%	$137	$12	10%			
2015	$167	$5	3%	$145	$8	6%			
2016	$172	$5	3%	$167	$22	15%	$158		
2017	$178	$6	3%	$170	$3	2%	$127	-$31	-20%
2018	$191	$13	7%	$178	$8	5%	$123	-$4	-3%
2019	$190	-$1	-1%	$177	-$1	-1%	$125	$2	2%
2020	$204	$14	7%	$181	$4	2%	$128	$3	2%
2021	$212	$8	4%	$187	$6	3%	$132	$4	3%
2022	$218	$6	3%	$193	$6	3%	$142	$10	8%
2023	$216	-$2	-1%	$188	-$5	-3%	$152	$10	7%
2024	$216	$0	0%	$191	$3	2%	$164	$12	8%
2025	$218	$2	1%	$194	$3	2%	$171	$7	4%
2026	$215	-$3	-1%	$198	$4	2%	$176	$5	3%
2027	$218	$3	1%	$200	$2	1%	$181	$5	3%
2028	$221	$3	1%	$202	$2	1%	$186	$5	3%
2029	$225	$4	2%	$204	$2	1%	$191	$5	3%
2030	$228	$3	1%	$205	$1	0%	$196	$5	3%
2031				$207	$2	1%	$195	-$1	-1%
2032				$210	$3	1%	$197	$2	1%
2033							$197	$0	0%
2034							$195	-$2	-1%
2035							$193	-$2	-1%

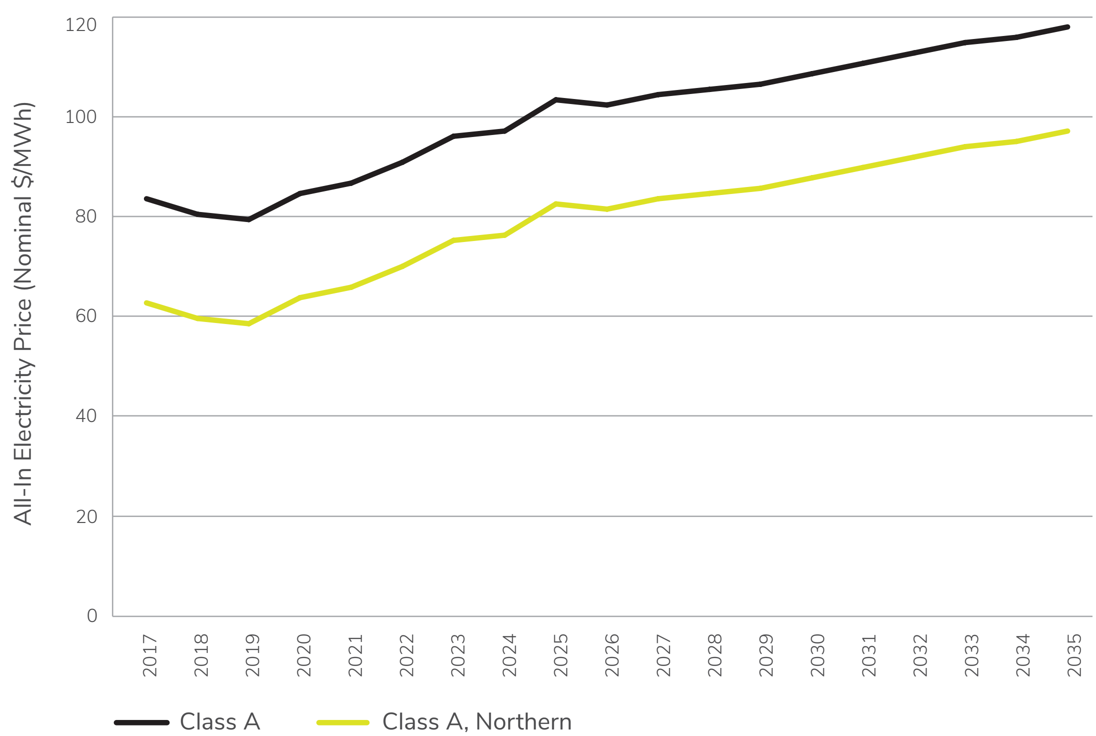
Note: The Ontario Energy Board (OEB) determined rates effective July 1, 2017 under Ontario's Fair Hydro Plan (OFHP) that resulted in an average bill of $121, which is 25 per cent lower than the $162 bill that would have been in place absent the OFHP. All data series in Figure 5 represent average monthly bills for each calendar year.

As shown in Figure 6, the 2017 LTEP price outlook for large industrial electricity consumers reflects average increases in line with inflation over the forecast period. The actual price paid by a large industrial electricity consumer is dependent on their consumption patterns and can vary among industries and specific consumers.

Currently, the electricity price for industrial electricity consumers in Ontario is lower than the average price in the Great Lakes region as reported by the U.S. Energy Information Administration. Consumers in Northern Ontario that participate in the NIER Program can achieve even lower rates.

FIGURE 6.

Electricity Price Outlook – Large Industrial Consumers



Source: IESO, Ministry of Energy

Note: Commodity price based on forecast Hourly Ontario Energy Price (HOEP) and GA averaged across Class A. Actual prices for Class A are dependent on each consumer's participation under ICI. Class A above reflects a transmission-connected facility. Participants in the NIER Program, which is funded through provincial revenues, receive a $20/MWh reduction.

Electricity Price Outlook – Large Industrial Consumers

	Class A			Class A, Northern		
	All-In Electricity Price (Nominal $/MWh)	Annual Change ($)	Annual Change (%)	All-In Electricity Price (Nominal $/MWh)	Annual Change ($)	Annual Change (%)
2017	$83			$63		
2018	$80	-$3	-4%	$60	-$3	-5%
2019	$79	-$1	-1%	$59	-$1	-2%
2020	$84	$5	6%	$64	$5	8%
2021	$86	$2	2%	$66	$2	3%
2022	$90	$4	5%	$70	$4	6%
2023	$95	$5	6%	$75	$5	7%
2024	$96	$1	1%	$76	$1	1%
2025	$102	$6	6%	$82	$6	8%
2026	$101	-$1	-1%	$81	-$1	-1%
2027	$103	$2	2%	$83	$2	2%
2028	$104	$1	1%	$84	$1	1%
2029	$105	$1	1%	$85	$1	1%
2030	$107	$2	2%	$87	$2	2%
2031	$109	$2	2%	$89	$2	2%
2032	$111	$2	2%	$91	$2	2%
2033	$113	$2	2%	$93	$2	2%
2034	$114	$1	1%	$94	$1	1%
2035	$116	$2	2%	$96	$2	2%

Note: Data table shows the all-in electricity prices in nominal $/MWh.

Increasing Consumer Protection

The Province has been working consistently to increase protection for electricity consumers. On January 1, 2017, new provisions of the *Energy Consumer Protection Act, 2010*, came into force that protect Ontario consumers from fraudulent claims and high-pressure sales tactics by restricting the door-to-door sale of energy contracts. Additionally, the Protecting Vulnerable Energy Consumers Act, 2017 gave the OEB the authority to prohibit disconnections during certain periods of time, such as winter. The Province will now turn its attention to protecting consumers who live in condominiums and other multi-unit residential buildings and are served by unit sub-meter providers (USMPs).

USMPs are private companies that meter and send bills directly to residents of units in multi-unit residential buildings for the electricity they consume. The OEB currently licenses 28 USMPs that provide services to 326,000 individually-metered units in 2,500 buildings. Residential customers inherit the pricing arrangements; costs are agreed to by the owner or developer of the building or by the condominium board.

Consumers have told both the Province and the OEB that they would like to know more about how these decisions are made and what they are being asked to pay for. That is why the government will enable the OEB to increase its oversight of sub-metering companies and bring in new consumer protection measures.

Improving consumer protection and strengthening the OEB's regulatory powers over USMPs would ensure that their fees and charges are just and reasonable, and that customers served by these companies receive value for money. It would also give the OEB more insight into how these companies determine their costs and set their rates and how they set up their contractual agreements with developers.

The Province intends that broader USMP regulation will enable consumers living in condominiums and other multi-unit residential buildings to enjoy similar protections as LDC customers. Consumers served by USMPs could benefit from:

- Clarity about what goes into the prices they are charged;
- Practices regarding disconnections; and
- Access to the OEB's processes to resolve issues regarding the quality of service USMPs provide to their customers.

The Minister of Energy will request that the OEB make it a priority to review these issues.

Natural Gas Expansion

Ontario is expanding access to natural gas to give consumers greater choice in their energy supply and to aid the economic development of their communities. To do this, the government launched a new $100 million Natural Gas Grant Program in April 2017. It supports both the expansion of natural gas pipelines and the construction of new infrastructure for liquefied or compressed natural gas. The average consumer could save an estimated $1,100 a year under this program by switching from heating with oil to natural gas.

A new regulatory framework issued by the OEB in November 2016 makes natural gas expansion more economically feasible for unserved communities by giving utilities more flexibility in how they structure their rates. The framework also encourages multiple utilities to compete to serve these communities. On August 10, 2017, the OEB released its first decision under the new framework, approving an expansion of natural gas service to several communities. Natural gas is one of several different energy options that provide greater consumer choice and can help to reduce overall energy costs.

Summary

- Ontario's Fair Hydro Plan reduced electricity bills by an average of 25 per cent for residential consumers and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction. Ontario's Fair Hydro Plan builds on previous actions that reduced electricity costs for families, farms and businesses.
- Ontario will share the costs of existing electricity investments more fairly with future generations by refinancing a portion of the Global Adjustment, spreading the cost of the investments over a longer period of time.
- Residential customers served by local distribution companies with some of the highest rates are getting enhanced distribution rate protection. This will save eligible customers as much as 40 to 50 per cent on their electricity bills.
- The First Nations Delivery Credit reduces the monthly electricity bills of on-reserve First Nation residential customers of licensed distributors.
- Residential electricity prices over the 2017 LTEP outlook period are forecast to remain below the level forecast in the 2013 LTEP. The outlook for electricity prices for large business reflects average increases in line with inflation over the forecast period.
- The government will enhance consumer protection by giving the Ontario Energy Board increased regulatory authority over unit sub-meter providers.
- The government will continue to support expanded access to natural gas, giving consumers greater choice and aiding in the economic development of their communities.

2 ENSURING A FLEXIBLE ENERGY SYSTEM

2

ENSURING A FLEXIBLE ENERGY SYSTEM

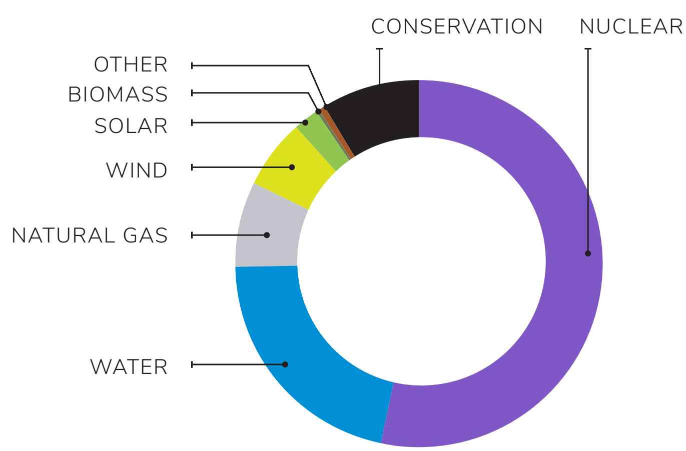
Ontario has made significant progress in rebuilding its electricity system. Nearly $70 billion has been invested in Ontario's electricity system since 2003.

Ontario now has an electricity system that is well-positioned to pursue emerging opportunities and meet future challenges, including the fight against climate change.

In 2016, Ontario produced more than 50 per cent of its electricity from nuclear, with renewable resources providing about 30 per cent and emitting generation providing less than 10 per cent. Conservation reduced energy consumption by about nine per cent.

FIGURE 7.

Ontario's Electricity Generation and Conservation, 2016 (TWh)



	Nuclear	53.5%
	Water	21.3%
	Natural Gas	7.5%
	Wind	6.2%
	Solar	2.0%
	Biomass	0.4%
	Other	0.4%
	Conservation	8.6%

Source: Ministry of Energy

Note: Generation reflects the sum of transmission and distribution connected sources. Conservation value represents persistent savings in 2016 from programs and codes and standards since 2006.

WHAT WE HEARD FROM YOU

- Consider costs first when deciding on supply
- Use a technology-neutral competitive process to acquire electricity supply
- Optimise use of our existing energy facilities and infrastructure, including nuclear generation
- Acquire more power from neighboring jurisdictions
- Both support and concerns expressed about various forms of generation
- Innovation should include storage solutions

Ontario's electricity system provides the province with a firm base on which to take further steps to fight climate change. Currently, the province's fuels sector supplies most of the energy needed for our transportation, heating and manufacturing. Ontario's clean and reliable electricity system provides the province with the energy to increase electrification and reduce greenhouse gas (GHG) emissions. The province's existing network of pipelines and retail outlets can also be used to deliver future alternative fuels, such as renewable natural gas.

The Need for Flexibility

Ontario's current robust supply provides us with the opportunity to explore and efficiently implement new approaches to procuring electricity resources. These approaches will need to be designed to be flexible enough to ensure that Ontario is well positioned to accommodate and benefit from emerging energy technologies, while also ensuring that system needs are met at the lowest cost to ratepayers.

Ontario is moving away from relying on long-term electricity contracts and is enhancing its market-based approach to reduce electricity supply costs and increase flexibility. Electricity system operators in New England, New York and the Pennsylvania-New Jersey-Maryland Interconnection have successfully implemented this type of approach.

The Independent Electricity System Operator (IESO) has begun a Market Renewal initiative to redesign the province's electricity markets. This undertaking is expected to save up to $5.2 billion between 2021 and 2030 and forms a key component of the government's plan to bring down the cost of electricity.

The Market Renewal Initiative consists of three work streams: energy, capacity and operability. The IESO will continue its work on the design of mechanisms for these streams in order to maximize the benefits to the system while ensuring reliability and affordability. When new supply needs are identified, the IESO would use competitive mechanisms to procure new supply resources. An example of a market-based mechanism that could be used is an incremental capacity auction.

Generators, demand response providers, importers and emerging new technologies could all participate in the auction, with the most cost-effective resources winning out. Market Renewal will ensure that resources will be able to provide flexibility, reliability and ancillary services. This will help provide transparent revenue streams for the needed services and ensure that all resources can compete on a level playing field.

Market Renewal is expected to result in a more competitive marketplace that more flexibly and efficiently meets system needs and government policy goals. Market Renewal will be aligned with the objectives of Ontario's Climate Change Action Plan, and will be designed to meet system needs, reduce ratepayer costs and reduce GHG emissions. It can be flexible enough to meet various scenarios from higher demand due to increased electrification of our economy to lower demand scenarios as a result of increased use of distributed energy.

Market Renewal will help Ontario prepare for the future by creating a competitive framework that cost-effectively incorporates clean energy resources and new and emerging clean technologies. This will help meet our climate change and GHG reduction commitments. The IESO, together with its sector partners, has identified the need to ensure that this new framework can properly value environmental attributes and the benefits they provide to the system. At the same time, existing resources will be able to continue to meet system needs in the redesigned electricity markets. Maximizing the use of these assets will allow Ontario to limit future cost increases.

A reformed electricity market would not only help reduce costs, but also increase two-way electricity trade with other jurisdictions. Imports and exports could be scheduled more frequently on the interties, which are the transmission lines going to states and other provinces. This could allow more imports of lower-cost generation, and provide greater revenue and access to export markets for Ontario generators.

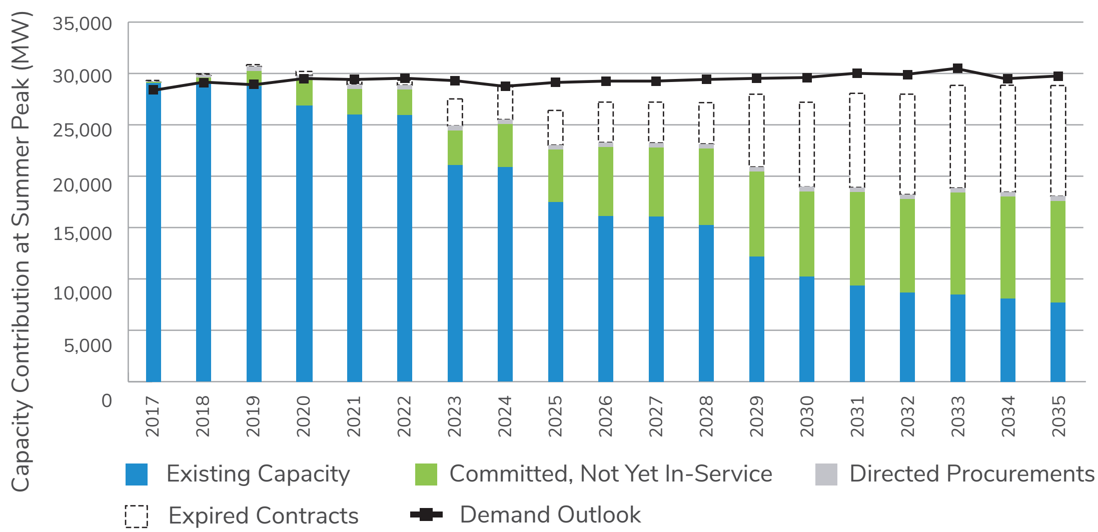
The IESO is working closely with partners in the electricity sector to design the significant changes that will become the foundation of Market Renewal and a plan for bringing them into effect. The plan will specify the changes to be implemented and the timelines for completing the work. This will allow the IESO and its partners to address the known challenges of our existing markets and lay a solid foundation for a more competitive and flexible energy market that can meet future needs.

Electricity Supply and Demand

While there is currently an adequate supply of electricity, a shortfall in capacity is expected beginning in the early-to-mid 2020s as the Pickering Nuclear Generating Station reaches its end of life, and nuclear units at Darlington and Bruce are temporarily removed from service for refurbishment.

FIGURE 8.

Supply and Demand Outlook (2017-2035)



Source: IESO

This need for additional capacity will be met through initiatives under Market Renewal. The auction will allow existing and new clean generation facilities to compete in a robust market with clean imports, demand-side initiatives and new emerging technologies. In addition, the continued growth of distribution-connected wind and solar power is expected to reduce local demand and the need for LDCs to draw electricity from the province's transmission networks.

The demand for electricity is forecast to be relatively steady over the planning period. In the long-term, the IESO projects an increase in overall demand as electrification of the economy increases. The possibility of electrification exists in nearly every part of the energy system. In particular, there is a great potential in the transportation sector, where electrification would be an economical and clean alternative to fossil-fuel powered engines. The outlook assumes the equivalent of approximately 2.4 million electric vehicles by 2035. The outlook also includes the electrification of the GO rail system, as well as new light rail transit projects in Hamilton, Mississauga, Kitchener, Toronto and Ottawa.

Transmission

The IESO's demand outlook indicates that there will be no need for any major expansion of the province's transmission system beyond the projects already planned or under development. See figure 9 for some of the major projects planned or underway on the high-voltage transmission system. Regional electricity needs are discussed in Chapter 8.

The government will direct the IESO to establish a formal process for planning the future of the integrated provincewide bulk system, which includes the high voltage system that typically carries 230 and 500 kilovolts (kVs) in Ontario. As part of the process, the IESO will engage with its partners and communities around the province.

FIGURE 9.

Major Transmission Projects Under Development Across Ontario

LEGEND

Northwest Bulk East West Tie Lake Erie Connector

Hawthorne to Merivale Reconductoring

Note: All projects are subject to regulatory approvals.

1 Northwest Bulk Transmission Line

The Northwest Bulk line is needed to support growth and maintain a reliable electricity supply to areas west of Atikokan and north of Dryden. The project will proceed in phases:

- **A** **Phase One,** a line from Thunder Bay to Atikokan, should come into service as soon as is practical, and no later than 2024.
- **B** **Phase Two,** a line from Atikokan to Dryden, should come into service by 2034 unless the IESO's outlook on the demand forecast suggests an earlier date.
- **C** **Phase Three,** a line from Dryden to the Manitoba border, could be needed after 2035 (or earlier if recommended by the IESO) to enable the better integration of provincial electricity grids.

Development work for Phases One and Two will proceed at the same time.

2 East-West Tie Transmission Line

The East-West Tie Line would provide a long-term, reliable supply of electricity to meet the growth in demand and changes to the supply mix in Northwest Ontario. As the project has moved through development, estimates on its total cost have increased. This is a concern, as Ontario is focused on making the electricity system more cost-effective. The government will review all options to protect ratepayers as the project continues to be developed.

3 Greater Toronto Area West Bulk Reinforcement

Growth in demand, the eventual retirement of the Pickering Nuclear Generating Station and new renewable generation all impact the bulk transmission system in the western section of the Greater Toronto Area (GTA). The IESO is presently studying the need for and timing of reinforcements to the transmission system in the region. Transmission solutions being investigated include building new transmission lines along the existing Parkway Belt West transmission corridor (between Milton Switching Station to Hurontario Switching Station) and expanding station facilities at the existing Milton switching station.

4 Hawthorne to Merivale

The 230 kV circuits between the Hawthorne and Merivale transformer stations require upgrades to their capability to serve growth in western Ottawa and optimize the use of its interties with Québec. This project is being developed by Hydro One and is expected to be in service in 2020.

5 Lake Erie Connector

ITC Lake Erie Connector LLC is proposing to build a 1,000 MW High Voltage Direct Current transmission cable under Lake Erie, running from Nanticoke, Ontario to Erie County, Pennsylvania. The two-way line would provide the first direct link between Ontario electricity markets and markets in 13 states in the Eastern U.S. The generators and electricity traders who would transmit electricity and related products over the line would pay the entire cost of the project. Under this merchant funding model, the costs of the project would not impact the transmission rates paid by Ontario ratepayers.

6 Clarington Transformer Station

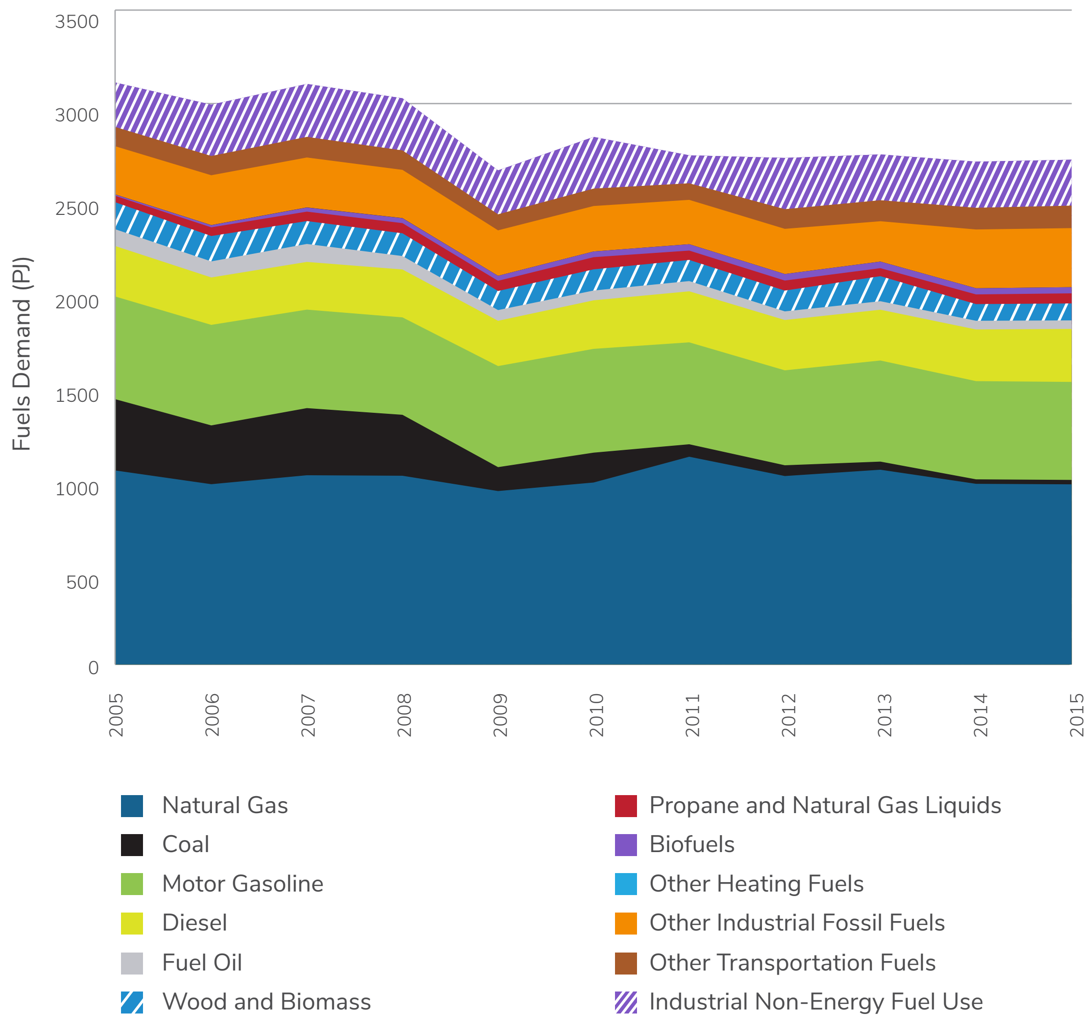
To meet the needs of the growing eastern GTA and prepare for the eventual retirement of Pickering Nuclear Generating Station, Hydro One is building the Clarington Transformer Station in the Municipality of Clarington. Hydro One expects to bring the station into service in 2018.

Fuels Supply and Demand

Fuels are an important component of the province's economy, and are critical for households, businesses and industry. Ontario's fuels sector is multi-faceted in its sources and uses. Natural gas and transportation fuels, such as gasoline and diesel, make up the majority of Ontario's fuels supply. There are also a variety of other fuels such as propane, wood, aviation fuel and biofuels.

FIGURE 10.

Historical Fuels Energy Use



Source: Fuels Technical Report, 2016

Fuels consumption has generally declined between 2005 and 2015, largely due to the retirement of coal-fired generating stations. In the past few years, fuels consumption has been relatively flat with lower use of natural gas being offset by higher use of transportation fuels. About 10 per cent of Ontario's fuels are used for non-energy uses such as feedstock for manufacturing.

Ontario's fuel supply is produced and delivered through a variety of means and markets, including supplies of crude oil and natural gas from outside of the province. As such, the government does not have the same policy and planning functions as it does for electricity.

Nonetheless, Ontario's cap and trade program provides efficient, market-based incentives to transition from conventional fuels to renewable and lower-carbon sources. In addition, programs and initiatives in the Climate Change Action Plan and delivered by the Green Ontario Fund will further support efforts to decarbonize the fuels sector. Over the next 20 years, the electrification of transportation, enhanced conservation and switching to lower-carbon fuels are expected to transform the fuels sector. As a result, both the demand for fuels and the emissions they release are expected to decline.

The outlook for the supply and demand of fuels will depend on policy and program decisions over the next 20 years, as well as on technological innovation and adoption. Given these uncertainties, the government will continue to undertake modelling and analysis to identify opportunities to decarbonize the fuels sector consistent with the provincial target of reducing GHG emissions by 37 per cent from 1990 levels in 2030.

The Influence of the Carbon Market

On January 1, 2017, the Province implemented a cap and trade program. This program is a flexible, market-based program that will be a cornerstone in Ontario's fight against climate change, and is the most cost-effective way of achieving reductions in GHG emissions. In addition, all proceeds from the cap and trade program will be used to fund actions to reduce GHG emissions, such as supporting Ontarians in shifting away from fossil fuels and investing in emerging clean technologies.

The price of fossil fuels such as natural gas, gasoline, diesel and propane includes a carbon cost as a result of the cap and trade program. The price signal provided by the cap and trade program will help move the province's energy system to even cleaner sources.

The costs that regulated natural gas utilities incur when they comply with cap and trade, including the cost of acquiring emission allowances, are subject to approval by the OEB. These costs are included in the rates charged to consumers. Natural gas utilities whose rates are not regulated by the OEB and large facilities that must independently comply with cap and trade will decide on their own how to manage their compliance costs. Alternative fuels that do not incur cap and trade charges – like renewable natural gas – could be used to reduce emissions and mitigate cap and trade costs in the natural gas sector.

Suppliers of other fuels in Ontario, such as gasoline, diesel and propane, operate in a competitive market. They are responsible for complying with cap and trade regulations and are expected to pass through their compliance costs to retail consumers. Switching to renewable fuels like ethanol, bio-based diesel and renewable diesel, and to lower-carbon transportation fuels such as natural gas are ways for consumers and obligated parties to reduce emissions and lower their cap and trade costs.

Maximizing Existing Assets

Delivering Fairness and Choice aims to limit any future cost increases for electricity consumers by maximizing the use of the province's existing energy assets. This can be achieved because many of the electricity generation facilities built in the last decade-and-a-half will be able to generate power beyond their planned contract life.

Renewable Energy

Contracts for over 4,800 MW of wind energy, 2,100 MW of solar energy, and 1,200 MW of hydroelectric generation will expire between 2026 and 2035, with most expiring after 2030. While wind and solar contracts last for 20 years and hydroelectric contracts for 40 years, wind turbines and photovoltaic panels are often able to still generate electricity after their contracts expire, and we know from experience that hydroelectric facilities can operate for as long as a century.

Due to the substantial decline in the cost of wind and solar technologies over the last decade, renewables are increasingly competitive with conventional energy sources and will continue to play a key role in helping Ontario meet its climate change goals.

In many cases, the province's wind and solar energy facilities can be upgraded with new or more efficient technology so they can continue operating, increase their output and provide additional system benefits.

There is an opportunity to get more from existing waterpower assets, including increasing their operational flexibility. The performance of older hydroelectric projects can be improved by using new, more efficient turbines. With the growing need for flexibility in our electricity system, Ontario's pumped storage potential could also play an important role in the provision of services that ensure the electricity system operates reliably.

As part of the IESO's ongoing work to find efficiencies and the best value for ratepayers, maximizing value from existing assets is key for Market Renewal, which will provide an open platform for project upgrades to participate in meeting Ontario's future resource adequacy.

Natural Gas

The natural gas generating stations that produce electricity in Ontario can respond quickly to match any changes in demand. The province relies on these generators to meet its needs during the periods of highest demand, including hot summer days and cold winter nights. Natural gas can also be used to ensure the reliability of the power supply when other generators are unavailable or require maintenance.

Most of Ontario's natural gas generating stations could operate beyond the life of their contracts. This will be important over the coming decade during ongoing nuclear refurbishments and with the retirement of the Pickering Nuclear Generating Station in 2024. In the early-to-mid 2020s, it is forecasted that there will no longer be enough contracted and rate-regulated facilities to meet reliability requirements.

Many of the existing generation contracts will expire over the same time frame. These natural gas facilities could continue to be available during times of peak demand by participating in a capacity auction being considered under Market Renewal, but only if they are more competitive relative to other resources.

Nuclear

Refurbishing Nuclear

The most cost-effective option for producing the baseload generation the province needs while releasing no GHG emissions is to refurbish Ontario's nuclear generating stations. Ontario is moving forward with the plans laid out in the 2013 LTEP to refurbish a total of ten nuclear units between 2016 and 2033 – four units at Darlington and six units at Bruce.

The Darlington Nuclear Generating Station, in the Municipality of Clarington, and the Bruce Nuclear Generating Station, in the Municipality of Kincardine, are two of the world's best-performing nuclear power plants. Together, Darlington and Bruce provide around 50 per cent of the province's electricity needs.

Refurbishing these 10 units will lock-in more than 9,800 MW of affordable, reliable and emission-free generation capacity for the long-term benefit of Ontario. It will also support the 180 companies and 60,000 jobs that make up Ontario's globally-recognized nuclear supply chain.

Ontario Power Generation (OPG) is taking a phased approach to refurbishing the Darlington Nuclear Generating Station. This approach benefits from the lessons learned during previous refurbishment projects, which highlighted the need for in-depth planning and preparation prior to starting the work.

In November 2015, OPG's Board of Directors approved a total estimated cost of $12.8 billion for refurbishing all four Darlington units. This includes all spending to date, interest and inflation, and is $1.2 billion lower than OPG's original estimate in 2009.

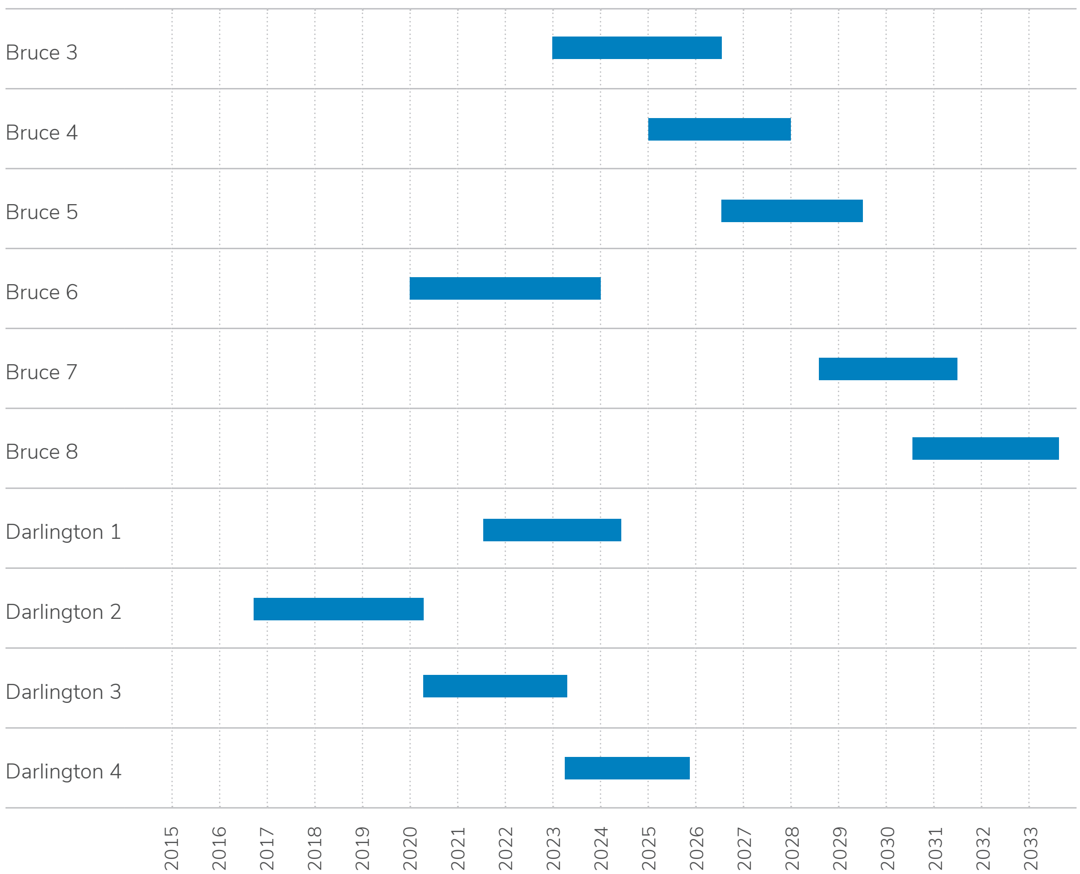
In January 2016, the government gave OPG approval to proceed with refurbishing the first of the Darlington units. In April 2017, OPG announced it had successfully completed the first of four major phases in refurbishing Unit 2 and isolated the unit from the rest of the Darlington plant. OPG has now moved on to the next phase of work and is on track to complete the entire project on budget and on schedule.

The refurbishment and continued operation of Darlington is expected to contribute a total of $90 billion to Ontario's gross domestic product and increase employment by an average of 14,200 jobs annually.

In December 2015, the IESO updated its contract with Bruce Power for the refurbishment of six nuclear units at the Bruce Nuclear Generating Station. Bruce Power plans to invest approximately $13 billion of its own funds in the project. Ontario further adjusted the schedule for refurbishment to get the most value out of the existing nuclear units. The new schedule will see construction start in 2020, instead of the previously-estimated start date of 2016. This updated agreement saved $1.7 billion for electricity customers, compared to the cost forecast in the 2013 LTEP.

FIGURE 11.

Nuclear Refurbishment Schedule



Source: IESO

BRUCE POWER AND OPG COLLABORATION

As operators of Ontario's nuclear fleet, OPG and Bruce Power have a long-standing relationship, regularly sharing best practices and information with one another.

On November 12, 2015, Bruce Power and OPG signed a Memorandum of Understanding (MOU) that was facilitated by the Ministry of Energy to formalize the collaboration between the two companies on nuclear refurbishment and power plant operation.

The MOU addressed a key objective of the 2013 LTEP: that the two companies work together to identify efficiencies and innovation that lower costs for ratepayers, share lessons learned on refurbishments and leverage economies of scale to ensure Ontario's refurbishments remain on time and on budget.

Bruce Power is currently undertaking a number of activities in support of the Bruce refurbishments and their long-term operation, including:

- Implementing an asset management program to optimize the life of the Bruce units before and after refurbishment;
- Developing a final cost estimate for refurbishing the first unit, Unit 6;
- Executing contracts with suppliers across Ontario, including BWXT Canada and SNC-Lavalin; and
- Developing a regional network of suppliers to benefit local communities in the Bruce region.

The refurbishment and long-term operation of Bruce are expected to generate up to $4 billion in economic benefits annually and increase employment by up to 22,000 jobs.

ONTARIO PARTNERS WORKING ON NUCLEAR REFURBISHMENT

CAMECO

Cameco is one of the world's largest uranium companies with facilities in Blind River, Cobourg and Port Hope.

In May 2017, Cameco agreed to continue supplying fuel to Bruce Power for another 10 years, reducing the cost of electricity to Ontarians by an estimated $200 million over the 10-year period. This stable partnership will also bring long-term economic benefits to the County of Northumberland.

Cameco is also supporting the Darlington refurbishment, and in May 2017 delivered a first shipment of more than 200 calandria tubes ahead of schedule and on budget. Calandria tubes hold nuclear fuel and coolant and play a critical role in the safe and efficient operation of the reactor.

BWXT

BWXT Canada Ltd employs 850 people in Ontario, including at its headquarters in Cambridge and facilities across the province such as Peterborough and Arnprior. The company is a leader in the design, manufacturing, commissioning and servicing of nuclear power generation equipment.

BWXT played a key role in defueling Darlington's Unit 2 ahead of schedule. The company will continue to manufacture the feeder tubes that deliver coolant to the reactor as part of the Darlington refurbishment program.

BWXT will also supply eight new steam generators for the Bruce refurbishment. That contract is worth about $175 million and will secure more than 100 jobs.

ONTARIO PARTNERS WORKING ON NUCLEAR REFURBISHMENT

LAKER

Laker Energy Products is a leading supplier of reactor components for the CANDU nuclear power industry. This Ontario company is building on its success and exporting its precision-tooled products around the world.

Laker recently purchased a new 65,000 square foot facility to handle more than $130 million in contracts to help refurbish the Bruce and Darlington nuclear reactors. The facility will also support Laker's sales to international markets, including existing and new-build projects in Argentina, Romania, China and the United Kingdom.

ONTARIO'S LABOUR UNIONS –
POWER WORKERS' UNION AND SOCIETY OF ENERGY PROFESSIONALS

For more than four decades, Ontario's electricity sector labour unions have been key partners in Ontario's nuclear industry. Today, Power Workers' Union and Society of Energy Professionals together represent more than 23,000 employees in Ontario's electricity system, including our nuclear plants and supply chain companies. OPG and Bruce Power will continue to rely on their skills and expertise to refurbish our nuclear fleet and ensure safe operation for decades to come.

LABOURERS' INTERNATIONAL UNION OF NORTH AMERICA

Labourers' international Union of North America (LiUNA) is a building trades union representing more than 100,000 members and retirees in Canada. LiUNA members are involved in the construction of highways, bridges, waterways and dams, hospitals, schools and government institutions. Today, LiUNA is an important partner in Ontario's refurbishment program. To ensure the smooth and successful execution of refurbishments, LiUNA and all key building trade unions have struck special nuclear project agreements with OPG and Bruce Power that will remain in force through the period of peak refurbishment activities, until December 31, 2032.

Managing the Risks

One of the principles of the 2013 LTEP was to include potential off-ramps for nuclear refurbishment. Off-ramps ensure that refurbishments only proceed if they continue to deliver value for ratepayers.

The Province has established off-ramps for the Darlington refurbishment that may be used in the event of OPG failing to adhere to the approved costs and schedule. This could result in the Province not proceeding with the remaining units.

Ontario's contract with the privately-owned Bruce Power also includes strong protection from cost overruns with the refurbishments. For example, Bruce Power is paying for approximately $2 billion in cost overruns that occurred when two of the Bruce units were refurbished and restarted in 2012.

Under its recently updated agreement with the IESO, Bruce Power will be assuming the risk of any cost overruns during the execution of the refurbishment of each of the six remaining Bruce units. Contractual off-ramps allow Ontario to stop work on any Bruce refurbishment if the estimated cost exceeds a pre-defined amount. Refurbishment at Bruce can also be stopped if demand drops or lower-cost resources emerge.

Ontario is protecting ratepayers by strictly controlling the cost and timetable of refurbishments. There is strict oversight of OPG and Bruce Power to ensure that they complete the refurbishments on time and on budget.

In addition to OPG's oversight of the Darlington refurbishment, the government has its own independent advisor to ensure that it has continued and effective oversight. All of OPG's expenditures on nuclear refurbishment will also be reviewed by the OEB as part of its rate-setting process.

The government subjected the updated agreement with Bruce to extensive due diligence, as did the financial and technical advisors who were engaged by the IESO when it negotiated the contract.

The IESO will continue to manage the Bruce contract and closely scrutinize the basis for costs underlying the refurbishment and ongoing operation of the Bruce reactors. It has full-time representatives on-site and will regularly report back to the Province.

Pickering Nuclear Generating Station

OPG is working on plans to continue to operate the Pickering Nuclear Generating Station until 2024. The continued operation of Pickering will ensure Ontario has a reliable source of emission-free baseload electricity to replace the power that will not be available during the Darlington and initial Bruce refurbishments. The continued operation of Pickering would also reduce the use of natural gas to generate electricity, saving up to $600 million for electricity consumers and reducing GHG emissions by at least eight million tonnes.

The Province announced in January 2016 that it had approved OPG's plan to ask the OEB and the Canadian Nuclear Safety Commission (CNSC) to approve the continued operation of Pickering until 2024. The OEB will ensure that the costs of OPG's plan for continued Pickering operation are prudent, while the CNSC will ensure that Pickering operates safely during this period. OPG will still need to get final approval from the government to proceed with the continued operation of Pickering after these regulatory reviews are completed. OPG will also update the government on the safety and operational performance of Pickering as part of its regular reporting and business planning.

Summary

- Market Renewal will transform Ontario's wholesale electricity markets and ultimately result in a more competitive and flexible marketplace. This Market Renewal process will develop a "made in Ontario" solution, taking lessons learned from other jurisdictions while collaborating with domestic market participants and taking into account the Province's greenhouse gas emission reduction targets.
- Ontario's cap and trade program, as well as programs and initiatives in the Climate Change Action Plan will support efforts to decarbonize the fuels sector.
- *Delivering Fairness and Choice* aims to maximize the use of Ontario's existing energy assets in order to limit any future cost increases for electricity consumers.
- Cap and trade will increase the price of fossil fuels and affect how often fossil-fueled generators get called on to meet the province's electricity demand. This will help reduce the province's greenhouse gas emissions and shift Ontario towards a low-carbon economy.
- The government will direct the Independent Electricity System Operator to establish a formal process for planning the future of the integrated provincewide bulk system.
- Ontario will continue to exercise strict oversight of nuclear refurbishments and ensure they provide value for ratepayers.

3

INNOVATING TO MEET THE FUTURE

3

INNOVATING TO MEET THE FUTURE

The way we deliver and use electricity is changing.

New technologies allow us to capture, store and use energy locally and deliver it in new and innovative ways. Clean, distributed energy resources are powering our economy and moving closer to home. New tools and devices are appearing on smartphones and in homes, harnessing the power of data that can give customers greater choice and control over their energy use. Customers' expectations of their utilities are rising.

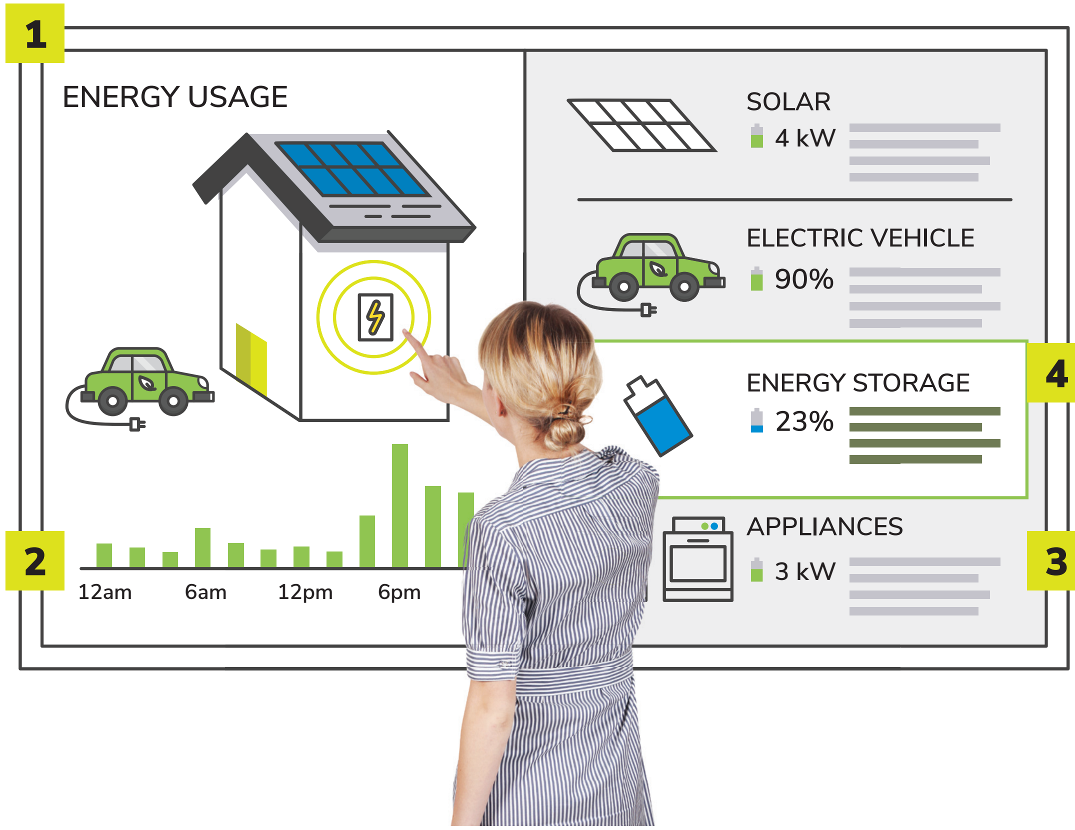
WHAT WE HEARD FROM YOU

- Support increased use of electric vehicles (EVs)
- Support and enable options for home energy storage, including EV batteries
- New business models can drive innovation
- Offer more pricing plans
- Modernize regulations and rate designs
- Customers will decide which technologies best meet their needs
- Government support is needed for research and development
- Distributed generation will transform conventional electricity distribution networks

Modernizing the System

These new technologies present a significant opportunity to make Ontario's electricity systems more efficient, reduce costs and give customers more choice.

FIGURE 12. Customer of Tomorrow



1. **Energy Management System** – An energy management system can give users real time information on how they are using electricity, reduce their electricity bills, and can balance their preferences with the needs of the system to make the best use of energy.

2. **Flexible Pricing** – Consumers can choose the electricity pricing plan that works best for their needs and complements their lifestyle.

3. **Internet of Things** – Technologies already on the market can connect appliances, lighting and other plugged-in electronics to smart controllers. Smartphones can turn on lights and a dishwasher, or consumers can let an energy management system run the show.

4. **Distributed Energy Resources** – Prices continue to drop for solar panels, home energy storage and electric vehicles, giving consumers more choice and making them less dependent on electricity from their local distribution company (LDC). The connected smart home will make the best use of these emerging technologies.

Innovative Pricing Plans

The government is working with the Ontario Energy Board (OEB) to give consumers more choice in their electricity price plans. As part of its review of the Regulated Price Plan (RPP), the OEB is using pilot projects to test innovative time-of-use price structures. Consumers can better manage their costs with time-of-use pricing by reducing or shifting their consumption to off-peak times when electricity is less expensive to produce. Time-of-use pricing also ensures that consumers pay a price for electricity that reflects the cost of producing it at peak and off-peak times.

The pilot projects are testing a variety of innovative price structures, including:

- Different ratios between on and off-peak prices;
- Different times for on- and off-peak periods;
- Prices that increase during critical peaks – the short time periods with extremely high demand; and
- Seasonal pricing plans that have a flat rate for spring and fall, and on- and off-peak price periods for summer and winter.

Some of the pricing pilots will be combined with smart technologies, such as smart thermostats, energy use apps and electric vehicles, to give customers additional ability to manage their electricity use.

The pilots have begun rolling out and will run for at least one calendar year. The results will help guide OEB decisions on potential new price plans that could give customers greater control, reduce their bills and help improve system efficiency.

In addition to these pilot programs, the government and the OEB are considering changes to the way the Global Adjustment is charged to mid-sized commercial and industrial consumers, otherwise known as non-RPP Class B consumers. For these consumers, the GA is a fixed charge that is the same regardless of the time that they consume electricity. Consultations will take place before any changes would be made.

Net Metering

Changes to Ontario's net metering framework will give businesses and consumers more opportunities to generate and store renewable electricity.

Net metering is a billing arrangement with an LDC that allows a customer to offset the electricity they buy from their LDC with electricity generated by their own renewable energy systems. Net-metered customers also receive credits on their electricity bill for the electricity they send to the grid, reducing their total bill charges. These credits can be carried over for up to 12 months for application on future bills. A net-metered customer is still able to draw power from the local distribution grid when needed.

FIGURE 13.

How Net Metering Works

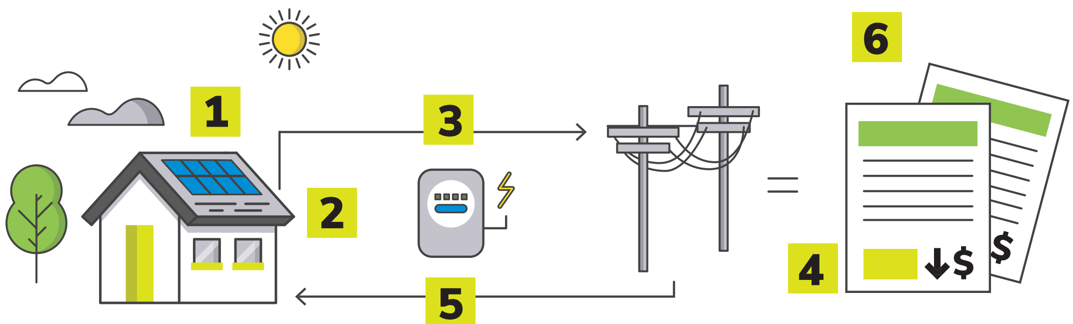


Figure 13 describes a rooftop solar net metering arrangement for a typical home. Other types of renewable energy can also be net-metered in Ontario.

1 Solar panels mounted on the roof of a house generate electricity.

2 The electricity generated is used to power the house first.

3 Any extra electricity generated is sent to the local grid.

4 Net-metered customers receive credits on their electricity bill for electricity sent to the local grid.

5 Electricity is drawn from the local grid when the home's electricity needs are higher than the amount of electricity generated by the solar panels.

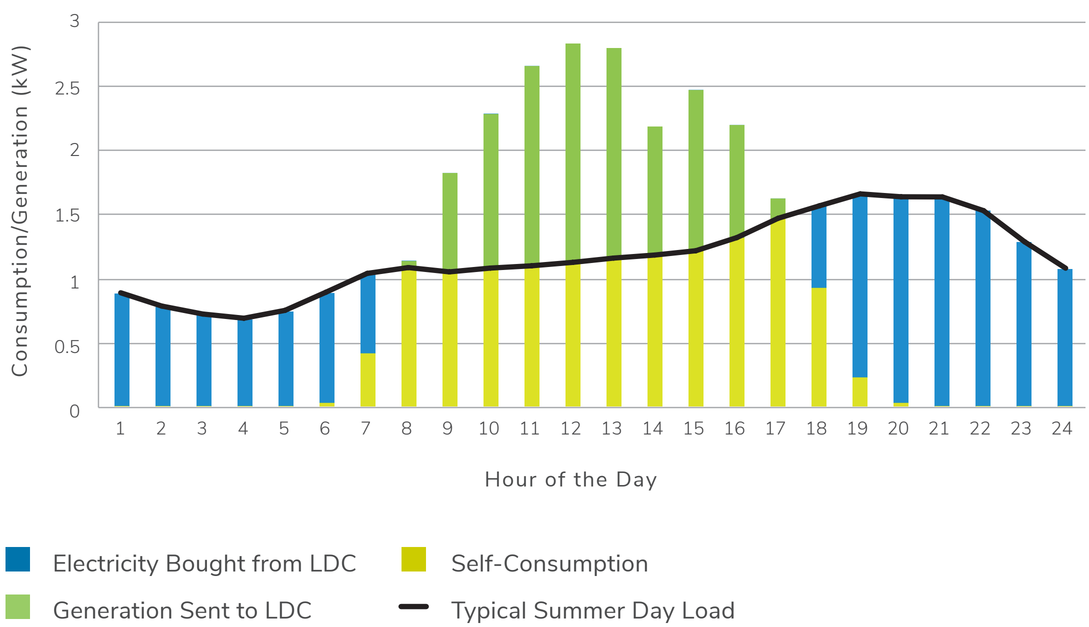
6 Net-metered customers' monthly electricity charges are calculated based on the difference between the amount of electricity used from the local grid and the credits received from any electricity sent to the local grid from the solar panels.

Figure 14 shows the electricity generated by a typical net-metered solar installation on a residential rooftop in the summer:

- The blue columns show the electricity bought from their LDC;
- The yellow columns show the electricity generated and used on-site; and
- The green columns show the electricity that is generated and sent back to their LDC.

FIGURE 14.

Residential Net-Metering with 4 kW Rooftop Solar PV



Source: Ontario Ministry of Energy

The government has recently taken significant steps to enhance net metering by removing the limit on the size of eligible generation systems and allowing them to be paired with energy storage technologies.

The government will expand and enhance net metering by proposing legislative and regulatory amendments that would allow third-party providers to own and operate net-metered renewable generation systems while ensuring appropriate consumer protection measures are in place. This would give Ontario electricity consumers added opportunities to reduce their electricity bills by offsetting their electricity purchases with clean power generated on-site. Net-metered renewable energy systems can also help reduce peak demand and defer or avoid the need for LDCs to invest in certain costly upgrades to their networks.

The government will also propose legislative and regulatory amendments that would enable the deployment of demonstration projects for virtual net metering. The government will work with the Independent Electricity System Operator (IESO) to develop a program to support a select number of innovative renewable distributed generation demonstration projects, as well as virtual net-metering demonstration projects. Virtual net metering could allow Ontarians who may not be able to install their own renewable energy system to participate in renewable energy projects located away from their homes or businesses, and still receive a credit offsetting their electricity bill. It could also support the siting of renewable generation where the electricity is most needed and valuable on the distribution grid. The goal of these demonstration projects would be to better understand the impacts of virtual net metering and guide future policy decisions on net metering. Proposed legislative amendments are expected to be brought forward in fall 2017. Pending passage of legislative amendments, regulatory changes would be made in 2018.

Taken together, these proposed enhancements would provide a platform for future innovation in clean, distributed energy and put Ontario at the forefront of renewable energy integration in Canada.

OXFORD COUNTY

In 2015, Oxford County became the first municipality in Ontario to commit to 100 per cent renewable energy by 2050. This means that Oxford County will meet or exceed 100 per cent of its net energy demand from renewable sources. Oxford's 100 per cent Renewable Energy Plan outlines the county's investment in innovative technologies and approaches like renewable energy, conservation, energy storage, microgrids and sustainable transportation. *Delivering Fairness and Choice* supports communities like Oxford County in achieving its community sustainability goals.

Energy Storage

Energy storage is a game-changing technology. Sometimes, it acts like a home or business, consuming electricity from a local network. At other times, it acts like a power plant, sending out electricity when needed.

Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings.

The Province has made it a priority since 2013 to understand the value of energy storage for Ontarians. This includes:

- procuring 50 megawatts of different types of energy storage to test how they can support Ontario's electricity network;
- using the Smart Grid Fund to support several energy storage projects and test the full range of their capabilities on distribution systems; and
- undertaking studies that look at realizing the different benefits of storage.

A March 2016 study by the IESO found that energy storage facilities can provide many of the services needed to ensure the electricity system in Ontario operates reliably. The government also commissioned Essex Energy to study the benefits of storage for distribution networks. The study found that energy storage can provide many benefits including cost reduction, for larger consumers.

Customer-connected energy storage could also provide benefits to the grid, particularly if the LDCs partner with these customers to share both the cost and the benefit. However, as discussed in the Barriers to Innovation section later in this chapter, the rules are not clear about how these partnerships could work. The Government and its agencies will move forward to provide the right environment for LDCs and customers to partner on storage where it makes sense for both parties.

The unique aspects of energy storage come into conflict with some of the rules governing the electricity system. The government started to understand these challenges in the 2013 LTEP, and since that time has been engaging with agencies and the energy storage industry to target the barriers that unfairly disadvantage this technology.

The government has now identified these market and regulatory barriers and is updating regulations, including addressing how the GA is charged for storage projects. Concurrently, it is seeking support from the IESO and OEB to take similar steps with their respective codes and rules that prevent the cost-effective development of energy storage where it can provide value to customers and the electricity system.

Electrification of Transportation

Ontario's Climate Change Action Plan focuses significant attention on using low-emission transportation to drive down greenhouse gas emissions in the province. This is critical to establishing a low carbon economy. The continued adoption of EVs will have an impact on our distribution networks. If too many EVs in a neighbourhood charge at the same time, important parts of the distribution system could be strained. As EVs become more popular, pressures on our distribution networks will grow and utilities will need the tools to manage this change in a cost-effective way.

Utilities have begun to test ways to work with EV owners to minimize these impacts. FleetCarma, a clean tech firm based in Waterloo, successfully tested a project that guarantees EV owners the amount of charge they need in the morning, but allows an LDC to control charging to minimize the impact on its network. Burlington and Oakville Hydro are testing how to do the same thing by offering smart chargers at a reduced cost in exchange for some control of the charging activity.

The government wants to provide LDCs with more options for integrating EVs into their networks at the lowest cost. The OEB will support this goal by looking at how LDCs can facilitate investments in technologies such as residential smart chargers that would avoid more costly system upgrades. These new technologies could also use incentives to give more choices to EV owners. For example, an EV owner could be rewarded for allowing the car to be charged at times when the distribution network is being used less. The customer would work with the LDC to find the right combination of preferences so both parties can benefit from smart charging.

The government will also promote the sharing of information and data on EV usage, and work to harmonize the province's energy, climate change, transportation, and infrastructure policies. Beyond personal EVs, the government is broadening its attention to include other types of mobility, including electrified transit and school buses.

GOLDCORP AND ELECTRIC MINING

Goldcorp produces roughly half of Ontario's yearly gold production. The company employs over 3,000 Ontarians, 99 per cent of them in Northern Ontario.

Goldcorp is developing an all-electric mine in Borden. Teaming up with Sandvik Mining and MacLean Engineering, nearly all the underground vehicles at Borden will be powered by batteries. By using electricity to power its equipment, Goldcorp can avoid 7,000 tonnes of carbon dioxide emissions, and eliminate the need for 2 million litres of diesel and 1 million litres of propane.

Vehicle-Grid Integration

Vehicle-grid integration is a perfect example of what can be gained by modernizing the grid. It provides more choice for customers while giving utilities the information and tools to optimize their systems.

A car is parked 95 per cent of the time. For EVs, some of that time is dedicated to charging; the rest of the time, it sits idle, waiting for its next trip. In the future, the battery of an electric vehicle could be used to deliver electricity to the home in the event of an outage. The battery could also deliver electricity back to the community, or even to the entire grid. Essentially, the EV becomes a distributed energy resource, one that can help avoid system upgrades and reduce costs for everyone.

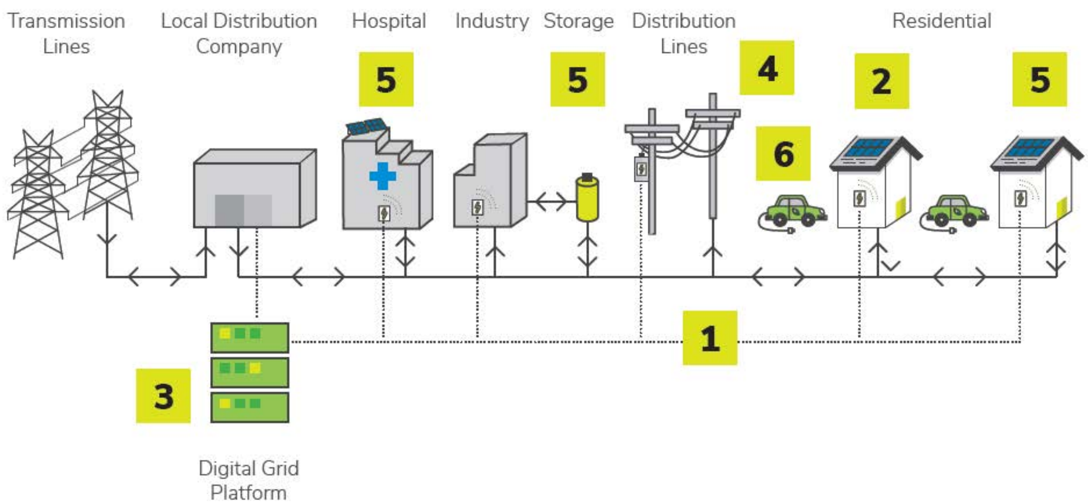
The government will engage with its partners in the energy sector and vehicle manufacturers to develop a roadmap for vehicle-grid integration that will look closely at this technology and what it could mean for Ontario.

Grid Modernization

Electricity distribution is a critical piece of Ontario's grid. The province's LDCs are the final step in a system that delivers electricity from generators to homes and businesses. Ontario is a world leader in deploying smart meters, which are the foundation for a smart grid. The meters continue to provide data to LDCs, allowing them to locate and respond more quickly to power outages, monitor their systems and better plan for the future – all to the benefit of Ontario's consumers.

A modern grid is a digital grid. It harnesses the power of data so that customers and utilities can make the right decisions. For LDCs, it means having the information critical to making their networks run as smoothly as possible. For customers, it means the local network will be ready when you want to buy an electric vehicle, install a battery, put up solar panels or choose a new pricing plan. It means more tools for you to track your energy usage. It means a more efficient, reliable and resilient grid. Above all, it means potential savings on your bill.

FIGURE 15. Distribution Grid Modernization



1 **Communication Lines** – Data from smart meters is sent to the LDC using communications infrastructure. In the future, this will also include data from sensors and other devices monitoring the entire grid.

2 **Smart Meters** – In addition to their use for billing, smart meters also provide critical data on system health for LDCs and smart meters can also be used for distributed energy resources (DERs) and large consumers to provide even more information on how the grid is operating.

3. **Digital Grid Platform** – LDCs use powerful software platforms to analyze data and use that information to make their networks as efficient and reliable as possible, potentially avoiding costly upgrades.

4. **Sensors** – Sensors instantaneously feed data back to the LDC about the health of its network's wires, transformers, and other assets.

5. **Distributed Energy Resources** – Today, DERs are mostly renewable generation. In the future, they will include energy storage, microgrids and even electric vehicles. DERs have a range of benefits that are optimized by a Digital Grid Platform.

6. **Vehicle Grid Integration (VGI)** – In the future, EVs can be used to power homes and even support the local network. VGI can turn EVs into highly responsive DERs and give owners more services and choice.

A modern grid can also give customers more choice, ranging from flexible pricing to enabling home energy management systems and realizing the full value of EVs. A modern grid can ensure that distributed energy resources like solar power, storage and microgrids can be integrated in the most efficient way possible. Above all, a modern grid can drive down costs for customers.

Now is the time to build on our investments in smart meters and the smart grid. A study by an expert third party in 2015 found that Ontario's consumers and businesses stand to gain $6.3 billion in economic, environmental and reliability benefits if the grid is modernized over the coming decades. A modern grid would be more resilient to the effects of climate change and utilize the real-time data needed to respond to problems or address them before they happen.

However, that same study found there were several barriers to modernizing the grid further in Ontario. LDCs, for example, are challenged by diffuse benefits. This is when they bear the costs of technologies such as energy storage, but do not get the benefits, which can accrue to customers other parties in the electricity sector. Without clear rules for addressing diffuse benefits, LDCs are less motivated to explore solutions that may be more cost-effective and provide greater benefits to the grid. Ontario is committed to removing these barriers so that utilities can make the right investments.

Grid modernization can also support new business models. One exciting opportunity is peer-to-peer frameworks for transactive energy. One way to implement transactive energy is through Blockchain, a computer protocol that tracks transactions within a marketplace. Blockchain uses secure, distributed databases to enable, for example, the management of EVs, the trade of renewable electricity and peer-to-peer demand response opportunities.

Combining other distributed energy resources with Blockchain technology holds the potential to provide significant value to the electricity sector, including:

- Increasing system reliability by providing greater visibility on where and how distributed energy resources and loads are affecting the system;
- More efficient balancing of the needs of the provincial grid with those of the local distribution system;
- Allowing DERs to participate and provide service in Ontario's electricity markets;
- Facilitating new business models like community-owned DERs and virtual net metering;
- Providing instantaneous feedback on how DERs are responding to price signals; and,
- Encouraging new participants in the electricity sector, which can lead to greater customer choice.

Transactive energy and Blockchain pilots are being undertaken in many jurisdictions. These models are also being studied and developed in Ontario, and the government plans to explore how Blockchain and other transactive energy models could benefit Ontarians.

Enhancing the Smart Grid Fund

The Smart Grid Fund was launched in 2011 to support innovation in Ontario's electricity sector. Innovation has produced a wide range of technologies – home energy management, grid automation, energy storage, microgrids, cyber security and EV integration. Through the Fund, Ontario companies have solved problems on distribution grids, and utilities have increased their understanding of how the smart grid can benefit the system and their customers.

The Smart Grid Fund is also supporting jobs and growth in the province. The Fund has given Ontario businesses the support they need to turn demonstrations into commercial successes. A number of recipients and products are gaining traction in foreign markets, including:

- N-Dimension Solutions, a cyber security firm with over 100 utility customers in North America;
- Utilismart's distribution monitoring software, which has been installed by over 140 utility customers; and
- A transformer sensor manufactured in Ontario by GRID20/20, which has been tested in 11 countries.

As part of the government's grid modernization strategy, now is the right time to build on this success by renewing and enhancing the Smart Grid Fund. An enhanced Smart Grid Fund will focus on encouraging a culture of innovation within the electricity sector that explores new solutions for integrating many technologies, tests new business models, integrates electricity and other energy resources and generates new ideas for advancing grid modernization.

POWER.HOUSE

Alectra Utilities launched the POWER.HOUSE pilot in 2015 with the support of the IESO's Conservation Fund. This innovative program for residential solar storage installed solar panels on 20 homes, and equipped them with an energy storage device and an energy management system that allows the homes to communicate with the LDC.

The pilot allows Alectra to treat the 20 homes as a single, virtual power plant and provide demand response or electricity when outages occur. The 20 homeowners saved money, and Alectra saw how POWER.HOUSE could delay the need for upgrades to its distribution network, which benefits all customers. Alectra believes POWER.HOUSE could be expanded to include 30,000 homes in Markham, Richmond Hill and Vaughan alone.

FleetCarma

With support from the Smart Grid Fund, FleetCarma developed a system that lets LDCs control when an EV is charged, helping them protect their local network infrastructure. FleetCarma's solution takes the needs of EV owners into account as well. They can opt out on a day-to-day basis and set a minimum, guaranteed charge for the morning commute.

FleetCarma is a great example of Ontario exporting its expertise. Building on its success from its Smart Grid Fund project in the Toronto area, the company announced in April 2017 that the New York City utility Con Edison will be using its system to dampen the impact of EV charging on the grid while collecting critical data on how EVs are used.

Distributed Energy Resources

A distributed energy resource (DER) is a decentralized source of energy that provides electricity services to individual customers or to the wider system located nearby.

Specific examples of DER include:

- **Distributed generation (DG)** – electricity generated for self-consumption and/or export to the distribution grid;
- **Energy storage** – energy stored for use close to where it is needed;
- **Microgrid** – a mini network that can operate independently when it is disconnected from the main electricity grid;
- **Energy efficiency** – measures to reduce overall electricity use, either behind the customer's meter, or on the distribution system (see Chapter 5); and
- **Demand response** – a temporary reduction or shift in demand in response to higher prices or requests from a system operator.

Each DER offers its own distinct benefits. However, the biggest gains occur when LDCs use smart communications systems to integrate a number of the technologies across their distribution networks.

Renewable Distributed Energy Resources

Renewable generation systems, such as solar photovoltaic (PV) panels, are becoming more widely adopted across the province. When strategically located and combined with smart communications and control systems, renewable distributed generation can benefit LDCs and their customers: utilities can defer or avoid certain costly investments in their local distribution networks, and customers can generate and store their own power, lowering bills and ensuring reliable access to electricity when power from their network is not available.

The government will work with the IESO to develop a program to support a select number of innovative renewable distributed generation demonstration projects strategically located and paired with other DERs and smart grid technologies, as well as virtual net metering demonstration projects. These demonstration projects will help inform the value of DG and DER to customers and the grid, and inform future grid modernization and net-metering policies, guide the treatment of renewable DG by regulators and energy markets, and steer further integration of these resources into Ontario's energy system.

Barriers to Innovation

Ontario's approach to grid modernization is to create the right environment for LDCs to make the best decisions for their systems and their customers. To get there, the government and its partners need to address the barriers to innovation. Many of these barriers are a legacy of the old way of doing things, when power only flowed one way and the technologies were simple and straightforward.

The government has taken a number of steps to encourage innovation in a changing energy sector. In 2010, it directed the OEB to give guidance to utilities on building smart grid technologies into their systems and putting innovation into their business practices. The OEB incorporated these ideas through a new regulatory framework. The OEB also established a Smart Grid Advisory Committee in 2013 to provide it with ongoing assistance in facilitating grid modernization.

Despite these efforts, there has been an unclear and uneven level of investment in grid modernization by Ontario's LDCs. Some of them, such as Hydro Ottawa and Greater Sudbury Utilities, are implementing plans to build a modern grid and a culture of innovation within their organizations. Nevertheless, the Electricity Distributors Association found that half of Ontario LDCs still approach innovation in a gradual or incremental way. It is clear that barriers to innovation remain. With the rapid development of new technology and the increase in customer expectations, the time to address these barriers is now.

To encourage change in the energy sector, the government will work with utilities and other partners to build a culture of innovation, and will look to the OEB to explore, where cost-appropriate:

- Building a stronger culture of innovation in the sector;
- Ensuring that there are no unfair barriers that disadvantage the deployment of energy storage;
- Utility participation in residential smart charging;
- The deployment of renewable distributed generation and other distributed energy resources that provide value to customers;
- The use of innovative, non-wires solutions that could, among other things, allowing utilities to manage their systems better and encourage customer choice including the principles of efficiency and cost-effectiveness;
- The regulatory treatment of LDC capital and operational expenditures, which can inhibit the uptake of these non-wires solutions;
- A cost-benefit framework that provides clarity on the treatment of investments, such as those with localized costs that provide benefits to other electricity system participants (also known as the diffuse benefits issue);

- The ability of utilities to make non-traditional distribution system investments and participate in market opportunities that would ultimately reduce ratepayers' costs associated with capital or other investments; and
- Opportunities for utilities to partner with their customers to use in-front and behind-the-meter applications to address system needs.

Taking these actions should create the right environment for LDCs to overcome barriers and modernize their businesses and systems. In such an environment, LDCs will have more clarity on how they can pursue the innovation contemplated under the *Strengthening Consumer Protection and Electricity System Oversight Act, 2015* and invest in solutions that make the most sense for the systems and their customers.

As part of this effort, the government will encourage LDCs to develop plans that demonstrate how they intend to modernize their grids and their businesses. These modernization plans could be incorporated into a LDC's asset management practices and their filings to the OEB.

IESO Market Renewal and Innovation

The IESO is preparing for the future by laying the foundation through Market Renewal, which will develop a made-in-Ontario solution to create better price signals and establish more competitive market-based mechanisms to meet system needs. The long-term goal of Market Renewal is to create a more dynamic market where all resources, including new technologies, have the opportunity to compete alongside traditional forms of supply for a variety of system products such as energy, capacity and operability. As costs come down and new business models are developed, emerging technologies, often at the local level, will be increasingly competitive compared to traditional resources. At the same time, the existing and new markets will present opportunities and choice to a wide variety of consumers looking to become more active in Ontario's energy markets.

Market Renewal also aims to enhance and improve existing market mechanisms and create new mechanisms that will allow new technologies like energy storage to compete on an equal footing with traditional assets and showcase the different values they provide in meeting system needs, including managing surplus baseload generation, regulation, operating reserve and flexibility.

Building on the Success of Renewables

The tremendous growth of Ontario's clean tech and renewable energy sectors has attracted billions of dollars in investment to Ontario and led to the creation of thousands of new jobs across many trades and professions. That explains why a broad coalition of employers, labour and industry groups, including the International Union of Operating Engineers, the Laborers' International Union of North America (LiUNA) and the Aboriginal Apprenticeship Board of Ontario, support Ontario's investment in renewable energy.

Ontarians have every reason to expect that these economic benefits will continue. According to a report from an expert third-party, the renewables sector is forecast to contribute nearly $5.4 billion to Ontario's gross domestic product and create 56,500 jobs between 2017 and 2021. Many of the companies that participated in Ontario's expansion of renewable energy are now poised to export their expertise and products to foreign markets. This could contribute as much as $1 billion to Ontario's GDP and could add as many as 10,700 jobs between 2017 and 2021.

Ontario-based manufacturers of hydroelectric components have been successfully exporting to the United States for years. Many of Ontario's solar manufacturers are also reporting increased export activity to the U.S., despite strong global competition. Wind component manufacturers have also developed expertise that will help them succeed in nearby American markets that are replacing coal-fired generation with renewables and other clean sources of electricity.

Exporting Ontario's Energy Expertise

Ontario's energy innovators are experts in smart grid, renewables, nuclear and other technologies, and are using the solid base they have established in the province to export to other markets in North America and around the world.

A NORTHERN ONTARIO SUCCESS IN MANUFACTURING

Heliene Canada has been manufacturing solar PV panels in Sault Ste. Marie since 2010. The company's manufacturing facility uses state of the art technology and currently exports over half of its modules to the U.S. and other markets. Heliene collaborates with other industry players and universities, such as ePower, the micro-electronics laboratory of Queen's University and the Rotman School of Business at the University of Toronto, to create a link between academic research and industrial applications.

The government continues to support the dynamic and innovative business climate that made this possible and will expand assistance to Ontario companies wanting to diversify their energy-related goods, services and expertise, by:

- Working with the federal and other provincial governments, industry and postsecondary institutions to develop and support trade initiatives that support market entry and new business opportunities;
- Developing market intelligence that determines which foreign markets hold promise for Ontario's energy goods and services;
- Participating in energy-related trade missions abroad; and
- Promoting Ontario's technical expertise at appropriate international forums.

In consultation with industry and the federal government, the government intends to develop a pilot program that provides financial support for the demonstration of locally-developed technologies abroad. The pilot will help Ontario energy companies get a foothold with utilities and buyers in global markets, and support the Province's commitments to help Ontario companies go global.

> "Global economies are demanding clean and low-cost energy solutions and Ontario entrepreneurs are poised to seize that opportunity."
>
> **MaRS Cleantech**

Nuclear Innovation

Ontario's expertise in nuclear energy has enabled it to be a leading jurisdiction in nuclear research and nuclear medicine. Ontario can help create new export opportunities for nuclear innovations, such as:

- **Small Modular Reactor (SMR) Technology:** This is a new generation of nuclear power reactors that have smaller footprints than conventional reactors and the promise of lower costs from mass production. In 2016, the government released a consultant's study on the feasibility of SMRs for remote mining applications in Ontario, which found that SMRs could be an economic and emission-free alternative to diesel power. The government continues to monitor SMR technologies and engage with key stakeholders involved in advancing these innovative designs.
- **Nuclear Fuel Research:** Technological innovations could lead to the reprocessing or recycling of used nuclear fuel or the use of thorium to power nuclear reactors.
- **Hydrogen:** Ontario's nuclear technology could be used for the large-scale production of hydrogen. Hydrogen is a source of low-carbon energy that could, in the future, replace gasoline for transportation or natural gas for heating.

Ontario is keenly interested in collaborating with the federal government, universities and industry partners to continue its support of the nuclear industry for both energy and non-energy applications.

MEDICAL ISOTOPES

Ontario's nuclear reactors transform chemical elements, such as cobalt, into isotopes that can diagnose and treat life-threatening diseases. These isotopes can also sterilize medical equipment such as hospital gowns, gloves, masks, implantable devices and syringes, as well as some food products.

Cobalt-60 is a key isotope for medical applications. Currently, 70 per cent of the world's supply of the medical-grade Cobalt-60 isotope is produced in nuclear reactors at Chalk River, Pickering and Bruce B. The isotope is used for 10 million cancer therapy treatments around the world every year, as well as for medical imaging, equipment sterilization and non-invasive brain surgery. Bruce Power has also established a new long-term supply of medical-grade cobalt from Bruce B that will help replace the supply from Chalk River's reactor when it is closed in March 2018.

Recently, Cobalt-60 harvested from the Bruce reactor was used in the Sterile Insect Technique or SIT, to combat the spread of Zika, West Nile and dengue viruses.

The Ottawa-based health-sciences company Nordion is exploring the use of the Bruce A and Darlington reactors to expand the production of Cobalt-60.

Innovative Uses for Ontario's Natural Gas System

Renewable Natural Gas

Renewable natural gas (RNG) can be an innovative Ontario-made source of energy. RNG is a low-carbon fuel produced by the decomposition of organic materials found in landfills, forestry and agricultural residue, green bin and food and beverage waste, as well as the waste from sewage and wastewater treatment plants. Because it comes from organic sources, the use of RNG does not release any additional carbon into the atmosphere. Ontario's new *Waste-Free Ontario Act, 2016* and its Organic Waste Action Plan, will create more opportunities to use organic waste to produce clean energy. As an added benefit, RNG can use the existing natural gas distribution system to replace the use of conventional natural gas in today's stoves and furnaces.

A PILOT PROGRAM FOR RENEWABLE NATURAL GAS IN TRANSPORTATION

Ontario's Climate Change Action Plan commits the Province to increasing the availability and use of lower-carbon fuel.

The government is now developing a pilot program that would extract methane from agricultural materials or food waste and use it for vehicle fuel. The pilot is expected to demonstrate the business models and technology that will allow agricultural and food sectors to produce RNG, and support businesses as they upgrade their vehicles and fueling infrastructure to use RNG.

In May 2017, the government issued a discussion paper to gather feedback from businesses, partners and the public to help guide the design of the program.

Power-to-Gas

Electrolysis, also known as power-to-gas, uses electricity to break down water molecules into hydrogen and oxygen. This transforms electricity into hydrogen gas, another type of fuel. Hydrogen can be stored or transported in existing natural gas pipelines and used to heat homes and fuel vehicles.

Power-to-gas could potentially become a new and important link between the province's electricity system and its natural gas system. The IESO recognizes this, and has already awarded a contract to Hydrogenics, an Ontario-based manufacturer of electrolysis and fuel cell technology, to provide electricity grid services during the production of hydrogen.

Using electricity to create hydrogen is one way to help decarbonize the natural gas supply. The Province has acknowledged the potential versatility of this fuel and is undertaking a feasibility study of using hydrogen to fuel GO Transit passenger trains.

To support this technology going forward, the government will work with the IESO to evaluate the development of a pilot project that explores the energy system benefits and GHG emission reductions from the use of electricity to create hydrogen.

Summary

- The government will work with the Ontario Energy Board to provide customers with greater choice in their electricity price plans.
- The net metering framework will continue to be enhanced to give customers new ways to participate in clean, renewable energy generation and to reduce their electricity bills.
- Barriers to the deployment of cost-effective energy storage will be reduced.
- Utilities will be able to intelligently and cost-effectively integrate electric vehicles into their grids, including smart charging in homes.
- The Province's vision for grid modernization focuses on providing LDCs the right environment to invest in innovative solutions that make their systems more efficient, reliable, and cost-effective, and provide more customer choice.
- The government will build on its success and renew and enhance the Smart Grid Fund. This will continue the Province's support of Ontario's innovation sector and help overcome other barriers to grid modernization.
- The Independent Electricity System Operator will work with the government to develop a program to support a select number of renewable distributed generation demonstration projects that are strategically located and help inform the value of innovative technologies to the system and to customers.
- The government intends to fund international demonstration projects to help Ontario's innovative energy companies diversify to foreign markets.
- The Province will collaborate with the federal government, universities and industry to support the province's nuclear sector.
- Innovative uses for Ontario's natural gas distribution system will be pursued.
- The government will work with the IESO to explore the development of a pilot project that evaluate the energy system benefits, and GHG emission reductions from the use of electricity to create hydrogen.

4

IMPROVING VALUE AND PERFORMANCE FOR CONSUMERS

The government and its partners are focusing their efforts on improving service to the province's electricity consumers.

This requires a continuous search for efficiencies, and maintaining a culture of innovation in the sector. These new technologies and systems can benefit energy consumers by enabling more intelligent planning and investments. The Province expects transmission and distribution utilities to deliver high-quality service while finding efficiencies and opportunities to lower costs.

WHAT WE HEARD FROM YOU

- Eliminate regulatory barriers
- Encourage consolidation and partnerships
- Expedite approvals for new technologies
- Support innovative business models
- Improve reliability

Continued innovation in the electricity sector enables customers to use data and information in their decision-making and gives them the additional choice they have in many other parts of their lives. However, more choice requires more information, so consumers will need more openness and information from energy companies and agencies. The government is making this change possible by ensuring that the standards and performance of the sector's entities are readily accessible.

Modernizing the Utility Business

Ontario's local distribution companies (LDCs) are the main point of contact when customers deal with the electricity system. They provide the services that consumers count on, such as restoring power after outages, maintaining the safety of the system and fielding calls and questions.

In the coming years, utilities will face a number of challenges as to how they conduct their business. New and innovative technologies and companies are ready to respond to changing consumer expectations. LDCs need to determine how they will continue to provide value to consumers and participate effectively to meet system needs in the future.

The Ontario Distribution Sector Review Panel determined in 2012 that the consolidation of LDCs could reduce costs from the distribution sector by $1.2 billion over 10 years. The Ontario Energy Board (OEB) must lead, innovate and provide LDCs with incentives to become more cost-effective and efficient. The OEB has made improving LDC performance a priority.

The OEB's Performance Scorecard uses several key measures, such as resolving customer complaints during the first phone call or the first visit, to track whether LDCs have improved their performance. The Scorecard also allows customers to see if the service they receive from their LDC meets OEB standards. The OEB is planning to enhance this framework to encourage greater efficiencies and make LDCs more accountable to consumers.

The government will look to the OEB to further strengthen the accountability that both distributors and transmitters need to show to their customers. By focusing on the principles of transparency, responsiveness to customers, efficiency and cost-effectiveness, the OEB will support a future in which:

- Utilities (LDCs and transmitters) have incentives to cut costs and make annual improvements to productivity and cost-efficiency;
- Utilities are constantly striving to improve;
- Utilities are held to account when expectations are not met;
- Customers get the highest possible value from their electricity services; and
- Businesses and other large customers have a timely and predictable process to connect to the grid or modify their existing connections.

LDCs are already responding to the changing landscape and finding opportunities to achieve further efficiencies and savings.

Improving Grid-Connection Processes

Increasing efficiency and transparency in our electricity sector supports Ontario's Open for Business strategy. This strategy includes a Red Tape Challenge to cut unnecessary red-tape to save businesses time and money. As part of this initiative, the government will engage the mining sector and other large industrials to discuss opportunities to improve grid-connection processes so that they do not pose barriers to investment in Ontario.

Enhancing Reliability

Ontario's market participants must comply with standards that define the reliability requirements for planning and operating the interconnected North American bulk electricity system. The North American Reliability Corporation defines standards which address physical and cyber security, emergency planning and response, power system modelling and planning, and real time operating practices for the bulk electricity system. The Independent Electricity System Operator (IESO) is responsible for compliance monitoring and enforcement of the reliability standards in Ontario.

The OEB also sets reliability and quality of service standards for transmission and distribution utilities. Distributors report the frequency and duration of outages in their annual performance scorecard to the OEB. Transmitters also have customer standards, including a process to address areas of poor performance.

Reliability and quality of service are of vital importance to electricity consumers. This is especially true for communities on long, radial lines that can fail more frequently, and for businesses that are particularly sensitive to electricity outages or fluctuations. The OEB has considered a number of ways to improve reliability over the years and the government will look to the OEB to examine further cost-effective steps that could help provide customers with useful knowledge about the reliability of their service and opportunities to resolve their concerns.

The Province believes that an enhanced framework for the reliability and quality of service of transmission and distribution utilities could provide customers with increased benefits, for example by:

- Introducing incentives and consequences to ensure utilities are held to account for performance. For example, as in done in some other jurisdictions, Ontario customers could receive an on-bill credit when service standards are not met;

- Establishing new standards and measurements of reliability that, in addition to the current system-wide averages, give customers more detailed insights into the reliability of their local networks;
- Ensuring that utilities report whether they are meeting the standards in a way that customers find meaningful and easy to understand; and
- Setting out clear timelines and steps that utilities must follow when they do not meet reliability standards or when customers report problems with reliability, power quality or other quality of service issues.

The government will look to the OEB to review the standards that transmission and distribution utilities currently have for reliability and quality of service and for options to improve the standards. The government will also ask the IESO to review how its planning and policies can improve customer reliability.

EXAMPLES FROM OUTSIDE ONTARIO: COMPENSATING CUSTOMERS FOR POOR SERVICE

In Michigan, residential customers can get a credit of $25 USD if their utility fails to restore power after 16 hours of outage under normal conditions, after 120 hours under catastrophic conditions and after seven outages within a 12-month period.

RAISING AWARENESS OF LOCAL ISSUES

More detailed information about reliability would create greater transparency for customers and the regulator. This is particularly relevant for large transmitters and distributors.

For example, the current LDC scorecard requires Ontario distributors to report their system-wide reliability. This means a small distributor, like Whitby Hydro with approximately 40,000 customers, reports the same level of detail as a large distributor like Hydro One with 1.3 million customers.

Changing Business Models

To meet the challenges of the future, LDCs may need to adopt more flexible and innovative approaches to service delivery than have been allowed in the past.

Non-wires alternatives represent an opportunity for LDCs to adopt new approaches to how they deliver electricity and conduct business. While traditional investments are capital-intensive, non-wires alternatives often involve expenditures that the OEB considers "operational" in nature. The current regulatory framework inherently favours LDCs' capital investments over operational investments, reducing the incentive for utilities to explore these innovative solutions. As part of its review of barriers to innovation (Chapter 3) the government will look to the OEB for ways to appropriately address the treatment of LDC expenditures to ensure cost-effective outcomes for ratepayers.

Many LDCs have entered into joint service agreements to improve customer service and reduce their operating, maintenance and administration costs. Organizations such as GridSmart City, the Coalition of Large Distributors and Cornerstone Hydro Electricity Concepts are examples of LDCs leading the way in these partnerships.

ENCOURAGING PARTNERSHIPS AND EFFICIENCIES

GridSmartCity Cooperative is a partnership of 13 LDCs created to improve service to electricity customers by increasing the efficiencies of scale and scope within each of their operations. The partnership has reduced costs by having joint purchasing for services such as information technology, human resources and infrastructure procurement.

The government will look to the OEB to explore ways of facilitating these partnerships where they make economic sense. It will also consult with LDCs on additional ways to realize these savings and provide better customer service. The OEB will continue to promote efficiencies in its own rules and requirements so that LDCs and transmitters benefit from further regulatory streamlining.

Making Electricity Bills More Understandable

Electricity bills need to be clearer and more understandable. They are the customer's main window into the electricity system. Consumers have told both the Province and LDCs that they find current bills confusing and inaccessible. Action is underway to address this. Hydro One is introducing a redesigned electricity bill for its low-volume consumers in late 2017. Hydro One's redesigned bill, the product of testing and research into consumer behaviour, is expected to increase customers' understanding of their electricity charges.

To expand this effort across Ontario, the government is working with the OEB and LDCs to redesign electricity bills to give Ontarians the information they have said they want on the bill. This will make bills easier for customers to understand and ensure they get the most useful information out of their bills. Customers expect LDCs to adopt more consumer-friendly billing systems, such as bills that can be viewed and paid on mobile devices.

Improving Customer Choice through Data Accessibility

The Province is promoting improved access to data to help consumers view and understand the information they need to make decisions on their energy use. Recent initiatives include:

- The Ontario Energy Report, an online portal that provides consumers and stakeholders with an up-to-date snapshot of Ontario's energy sector;
- Green Button, a data standard that can give consumers access to data on their energy and water consumption. Green Button can also allow consumers to securely and automatically transfer that data to various applications that can help them manage and conserve energy and water; and
- Enhancing the Meter Data Management and Repository (MDMR), Ontario's central repository for smart meter data. The IESO Smart Metering Entity is leading a project that will support more rigorous analysis of consumption data across the province, with the end goal of making better planning decisions and improving services to customers.

The government will continue to improve peoples' ability to use data to make decisions. But it cannot stop there. Ontario's energy sector as a whole must continue to improve its ability to analyze data and use advanced mapping tools and other cutting-edge technologies to further modernize our grid. This is discussed further in Chapter 5.

These efforts always need to keep the individual in mind. While the digital economy is integral to an efficient government and an affordable energy sector, it will be built on the protection of personal privacy.

Cyber Security

Cyber security is increasingly important in protecting critical infrastructure, such as the province's electricity system. It includes a body of technologies, processes and practices designed to protect networks, computers, programs and data against attack, damage or unauthorized access.

Cyber security standards for the bulk electricity system are defined by the North American Electric Reliability Corporation. These Critical Infrastructure Protection standards have been adopted in Ontario and are enforced by the OEB and the IESO. Generators, transmitters and other industry participants are required to implement and comply with the standards.

Cyber security at the distribution level is an emerging issue, and is an operational necessity for the distribution sector. It includes both the protection of customer-specific information held by LDCs and the protection of distribution-level system operations.

The government is working with both the IESO and the OEB to ensure that cyber security is being addressed in the electricity system and that there is appropriate regulatory oversight to mitigate cyber risks and threats.

In the spring of 2017, the OEB issued a draft framework that will define cyber security guidance and reporting requirements for LDCs. This framework will be in place by the end of 2017.

Competitive Transmitter Selection

To help ensure lowest-cost solutions for transmission, the Energy Statute Law Amendment Act, 2016 enabled the IESO to use a competitive process to select companies or consortia for the construction of new transmission lines in Ontario.

As a first step in implementing the new legislation, the government will direct the IESO to develop a process for the competitive selection or procurement of transmission and identify possible pilot projects. The results of these pilots will be used to develop a procurement process that is clear, cost-effective, efficient and able to respond to changing policy, market and system needs.

Right-Sizing

The aging of transmission and distribution infrastructure across the province presents challenges for the electricity industry. These challenges include managing costs and the outage requirements necessary to deal with replacing or refurbishing end-of-life equipment, while maintaining safe and reliable service to customers. Equipment reaching end of life also presents opportunities to ensure that the new or refurbished facilities are “right-sized”. That means downgrading or removing equipment if demand is expected to decrease and upgrading equipment in communities with growing demand or increasing reliability needs. New facilities will also consider technological advances and other solutions that may be more cost effective in the long run.

The IESO and OEB have key information associated with forecasts for growth, changing customer needs and technological advancements based on government policies and programs, while transmitters and distributors have information related to asset end-of-life and the related reliability and other risks. Together, this information provides important perspectives on the likelihood and consequence of asset failure, the forecast of growth, changing customer requirements and the impact of new technologies, to ensure new and refurbished infrastructure is built to the right size and is capable of meeting the future service quality needs of customers.

As they exercise their respective responsibilities for planning, the government will look to the IESO and the OEB to promote a co-ordinated, streamlined and longer-term approach to the replacement of transmission and distribution assets that are at end of their lives. The approach needs to be consistent with the beneficiary pays principle, where the consumers that benefit from the asset are responsible for the costs.

Transmission Corridors

The Provincial Policy Statement, 2014 states that efficient patterns of land use and development are essential for healthy, livable and financially-viable communities. The statement connects the planning for land use and energy infrastructure by endorsing the planning and protection of transmission corridors and discouraging development that could preclude or limit the use of a planned corridor.

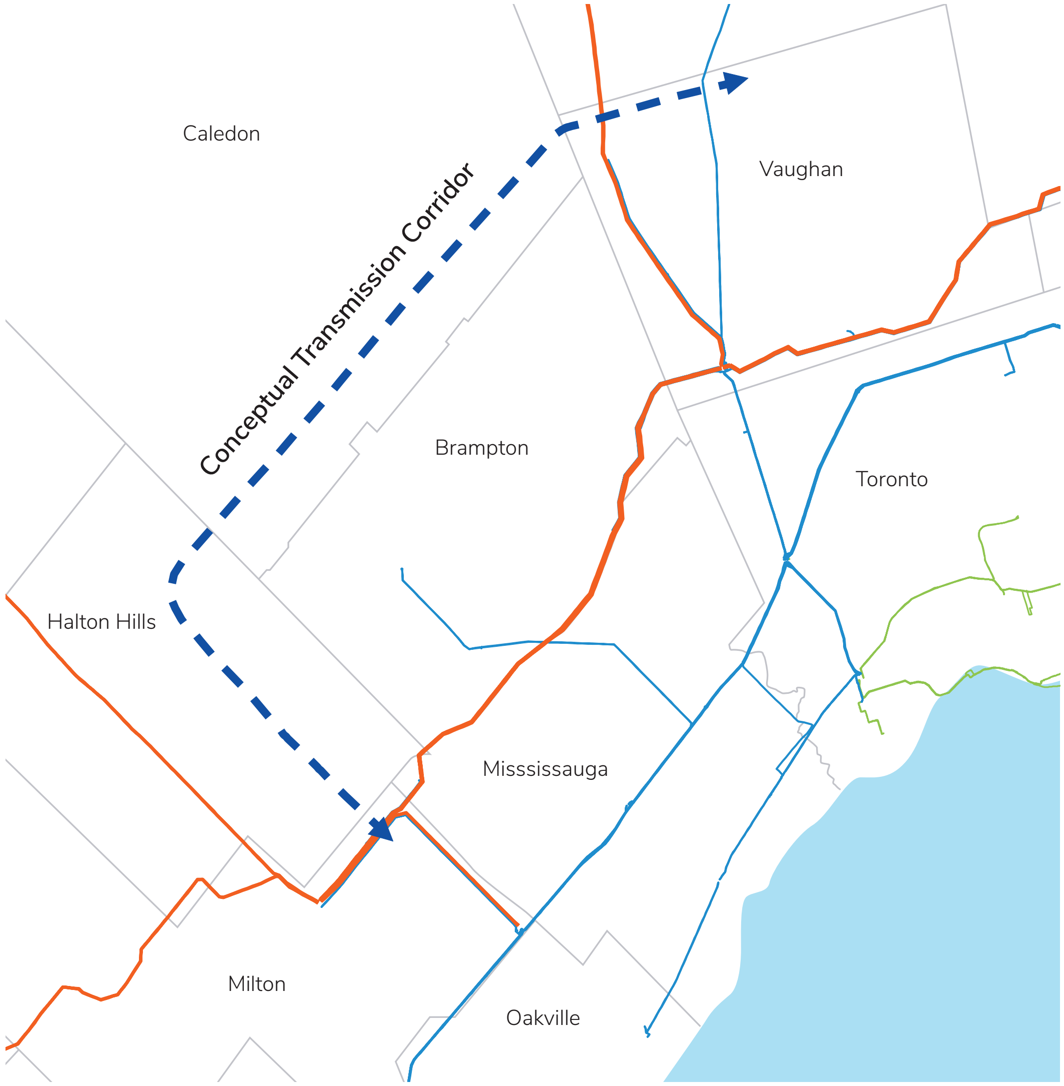
The Provincial Policy Statement is the foundation of the Growth Plan for the Greater Golden Horseshoe (2017), which requires the Province, municipalities and other public agencies to encourage the co-location of linear infrastructure, such as roads and transmission lines, when they are planning for development. The Growth Plan says governments and public agencies should also protect existing and planned corridors to meet current and projected needs.

The IESO's regional plan identifies that the northwest Greater Toronto Area has a long-term need for a transmission corridor (Figure 16). The IESO relied on the population and employment forecasts included in the Growth Plan to forecast demand for the area. The transmission corridor would supply portions of the Regions of Halton, Peel and York.

Given the size of the forecasted growth and the distance from existing transmission lines, alternatives to a new transmission corridor are either not economical or not technically feasible. The IESO estimates that there could be additional costs of hundreds of millions of dollars to build underground transmission lines later on, if an overhead transmission corridor is not reserved before the area develops. Further studies will identify a more specific corridor.

FIGURE 16.

Future Transmission Corridor in the West GTA



For illustrative purposes only

Transparency for Consumers on Gasoline Pricing

Many Ontario consumers pay attention to their gasoline prices. A number of components are part of the retail price of gas, including crude oil costs, taxes, the gross refining/wholesale margin and the gross retail margin. Families and businesses have requested more information about how gasoline and diesel retail prices are set.

As a result, the government asked the OEB in November 2016 to review the operation of Ontario's retail market for gasoline and diesel fuel. The review will focus on three main topics:

- The extent and causes of variations in retail prices over time and between one region in Ontario and another;
- How pricing and competition in Ontario compare with other jurisdictions; and
- The information available to consumers about pricing and price variations.

The OEB expects to report on its findings by the end of 2017. The government will review the OEB's report in detail and consider the information in its future decision-making.

The government monitors the supply and price of gasoline in the province and other jurisdictions, and makes this information publicly available through the quarterly Ontario Energy Report.

Summary

- The Province expects the Ontario Energy Board (OEB) to continue to enhance its efforts to improve the performance of local distribution companies (LDCs).
- The government will look to the OEB to identify additional tools and powers that could be used to make utilities more accountable to their customers, promote efficiencies and cost reductions, encourage partnerships, and ensure regulatory processes are cost-effective and streamlined, while also accommodating changing utility business models.
- The government will work with the OEB and LDCs to redesign the electricity bill to make it more useful for consumers in understanding and managing their energy costs.
- The government will look to the OEB to review the standards for reliability and quality of service for transmitters and distributors, and options for improving the standards, and will ask the Independent Electricity System Operator (IESO) to review how its planning and policies can improve reliability for customers.
- The government will direct the IESO to develop a competitive selection or procurement process for transmission, and to identify possible pilot projects.
- The government will look to the IESO and the OEB to promote the right-sizing of transmission and distribution assets at their end of life.
- A new transmission corridor is needed in the northwest Greater Toronto Area given the size of the forecasted growth. Further studies will identify a specific corridor.
- The Province will provide greater transparency for consumers on gasoline pricing through the OEB's transportation fuels review.

STRENGTHENING OUR COMMITMENT TO ENERGY CONSERVATION AND EFFICIENCY

5

STRENGTHENING OUR COMMITMENT TO ENERGY CONSERVATION AND EFFICIENCY

Ontario has been building a culture of conservation since 2005 and can be proud of what has been accomplished.

According to the Independent Electricity System Operator's (IESO) 2015 study on Ontario's conservation efforts, businesses are investing in energy-efficiency upgrades to increase their productivity and residents are choosing to install energy-efficient equipment in their homes, often with the help of Ontario's suite of residential and business conservation and demand management programs. Between 2005 and 2015, the average monthly household consumption of electricity decreased from more than 800 to about 750 kilowatt-hours (kWh).

WHAT WE HEARD FROM YOU

- Reaffirm and enhance commitment to Conservation First
- Improve building codes and standards
- Increase awareness of conservation and demand management programs and the value of conservation
- Ensure conservation and demand management programs are in sync with programs in the Climate Change Action Plan
- Expand conservation to other fuels
- Encourage energy efficiency on the distribution system

Energy efficiency is becoming more of a part of our everyday lives. Between 2006 and 2015, Ontario conserved 13.5 terawatt-hours (TWh) of electricity. That is equivalent to the electricity used annually by 1.5 million households, or the amount of electricity that powered the cities of London, Kingston, Ottawa, Peterborough and Thunder Bay in 2015. During the same time, the conservation programs delivered by Ontario's natural gas utilities saved more than 1,700 million cubic meters of natural gas, equivalent to the natural gas used by about 800,000 homes in a year, or taking about 750,000 cars off Ontario's roads for one year.

Since the 2013 Long-Term Energy Plan (2013 LTEP), the government, its agencies, and electricity and natural gas distributors have been putting Ontario's Conservation First policy into effect.

Conservation and energy efficiency require a sustained commitment if they are to achieve persistent savings over the long term. Ontario is enhancing its commitment to Conservation First to improve affordability and choice for people, businesses and communities, and to co-ordinate its conservation programs with Ontario's climate change objectives.

Additionally, the government will help Ontario homes and businesses transition to a low-carbon future by expanding program offerings through the new Green Ontario Fund.

The Savings from Conservation and Energy Efficiency

ELECTRICITY

1.01 billion kilowatt-hours
Energy savings achieved in 2015 through business conservation programs.

4.1 million
The coupons for energy-efficient products redeemed across the province in 2015.

$2
The added costs that are traditionally avoided in the electricity system every time $1 is invested in energy efficiency.

$0.04 per kWh
Cost of electricity conservation programs in 2015, which is cheaper than most forms of new supply.

NATURAL GAS

Over 80 million cubic metres
The amount of natural gas saved in 2015 through conservation programs for businesses.

8,000+
The energy efficiency projects completed through home energy audit and retrofit programs in 2015.

$7 to $11 per month
A typical household that participates in residential natural gas conservation programs can save about $7 to $11 per month.

$0.04 per cubic metre
The cost of natural gas conservation programs in 2015, significantly cheaper than the cost of purchasing natural gas.

Getting More from Conservation

Ontario has an adequate supply of energy. Any additional demand for electricity supply is not expected to appear until the early-to-mid 2020s. In this context, the Province will continue to use conservation programs and improved energy efficiency standards to drive toward its long-term target of saving 30 TWh of electricity in 2032, helping to offset almost all of the forecast growth in electricity demand. The government and its agencies will continue to assess the achievable potential for energy conservation, consider initiatives under Ontario's Climate Change Action Plan, and explore options to enhance the value of our existing investments in conservation.

The IESO is currently conducting a mid-term review of the 2015-2020 Conservation First Framework and the Industrial Accelerator Program for electricity conservation. The Ontario Energy Board (OEB) is conducting a similar review of the Demand Side Management Framework for natural gas programs. These reviews are looking at how the programs are meeting customer needs, distributor budgets and targets for conservation savings, and co-ordination with the Province's climate change objectives, including Green Ontario Fund programs.

The IESO is also using the mid-term review to look at how conservation programs can better meet the needs of local and regional electricity planning.

Demand Response

Demand response programs reward electricity customers for reducing their electricity use when needed. Demand response provides benefits to Ontario's electricity system by enhancing reliability, as well as reducing system costs and greenhouse gas (GHG) emissions. An example of demand response is a factory temporarily halting a process, or a group of residential consumers reducing their air conditioning when electricity demand is high.

The IESO has successfully transitioned away from using multi-year contracts to secure demand response, holding an annual competitive auction instead. The demand response auctions held in 2015 and 2016 reduced the cost of obtaining demand response resources by up to 27 per cent when compared to previous contracts. The IESO is now working with industry partners to use demand response to better respond to rapid increases or decreases in electricity demand. Demand response is spurring innovation in new technologies, such as smart thermostats, energy management software and communication technologies.

Through collaborative efforts by the IESO and the Demand Response Working Group, Ontario's demand response resources have grown significantly above the 2013 LTEP projections, and demand response has become a mature and competitive resource. Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.

DEMAND RESPONSE

Ontario has a number of initiatives that contribute towards its demand response capacity. These include the Industrial Conservation Initiative, demand response auctions, demand response pilots and time-of-use pricing. In 2015, demand response resources amounted to about 1,750 MW, which is over 20 per cent higher than what was projected in the 2013 LTEP.

Ensuring a Customer-Centred Approach

The current conservation frameworks encourage electricity and natural gas distributors to collaborate in providing more efficient programs and a streamlined experience for customers. Such partnerships can offer energy consumers a co-ordinated, one-window approach to help meet their energy management needs. Currently, 46 electricity distributors are involved in joint conservation plans, and electricity distributors are partnering with natural gas distributors to design and develop programs that cover multiple fuels. Partnerships can enable multi-fuel programs to improve customer convenience and expand choice.

Distributors are being encouraged to develop new and innovative programs for their customers. New pilots and programs include Hydro One's Heat Pump Advantage pilot, a provincewide Business Refrigeration Incentive Program (originally developed by Alectra Utilities), Toronto Hydro's incentive program for Energy Star pool pumps, and Enbridge Gas Distribution's School Energy Competition.

For its part, the IESO has launched the first full-scale, pay-for-performance program in North America. The Save on Energy Multi-Distributor Pay-for-Performance Program rewards businesses for improving their overall energy performance over a number of years. Businesses are paid for each kilowatt-hour they conserve, and are given flexibility on how they achieve those savings. Ratepayers benefit as well; participants only have to file a single project application, reducing the administration costs of the program.

BUSINESS REFRIGERATION INCENTIVE

Donaleigh's Irish Public House in Barrie installed energy efficient motors on its refrigeration units and reduced its annual electricity costs by $2,394. The project was implemented at no cost to the owner, as the Save on Energy Business Refrigeration Incentive Program covered the entire cost of $2,536 for materials and labour. The local electricity utility, Alectra Utilities, helped identify the specific energy-saving opportunity and developed a customized Energy Action Plan for the restaurant and pub.

"This is beneficial to the company and to our environmental footprint. We try to look at our footprint and make it as small as possible."

Don Kellett, Owner, Donaleigh's Irish Public House

UNION GAS AND SOCIAL HOUSING HALDIMAND NORFOLK HOUSING CORP

Haldimand Norfolk Housing Corporation is saving $14,000 a year and has improved tenant comfort by installing variable frequency drives on the heating systems of six rental buildings. The $14,500 incentive through Union Gas's Affordable Housing Conservation Program covered 50 per cent of the project's total cost and is reducing annual natural gas consumption by 45,000 cubic meters.

"This methodology has proven to save significant amounts of energy required to heat incoming fresh air. The resulting savings have been instant and the incentive was able to cut the payback time in half."

Marc Puype, Technical Services Manager, Haldimand Norfolk Housing Corporation

Expanding Home Retrofits

As part of its Climate Change Strategy, Ontario has invested $100 million from its Green Investment Fund to help eligible homeowners who primarily heat with natural gas, oil, propane or wood. They can improve the energy efficiency of their homes, reduce their energy bills and cut GHG emissions by participating in enhanced audit and retrofit programs offered by Enbridge Gas Distribution and Union Gas.

Launched provincewide in October 2016, the program is expected to allow about 37,000 additional homes to be audited and retrofitted by 2019, and cumulatively reduce their lifetime GHG emissions by approximately 1.6 million tonnes.

The Province made additional improvements to the home energy audit and retrofit programs in May 2017. Partnering with Enbridge Gas Distribution and Union Gas, the IESO expanded the program to include electrically-heated homes and added electricity savings measures for all participants. This 'Whole Home' approach is now providing residential consumers with a co-ordinated, one-window approach to energy efficiency improvements.

ENERGY EFFICIENCY FOR YOUR WHOLE HOME

Incentives from the Home Energy Conservation Program allow families like the O'Haras to reduce their energy bills, increase their home comfort, and cut GHG emissions. The O'Haras improved the efficiency of their more than century-old home by upgrading their furnace, hot water heater and windows. They also added basement insulation and air sealed their home. The upgrades will reduce the O'Hara's consumption of natural gas by 36 per cent, and cut their annual GHG emissions by 1.67 tonnes. In addition to retrofitting their home, the O'Haras installed a smart thermostat, which increases their savings by allowing them to reduce home temperatures when they are away.

Providing Choice Through Information, Tools and Access to Energy Data

Ontario is leading the way in helping consumers choose devices and technologies that can give them greater control over their energy use, and help them find opportunities to lower their energy bills.

Smart Thermostats

Smart thermostats can be an important piece of technology for homeowners or businesses who want to reduce their heating and cooling costs and carbon footprint. Smart thermostats:

- Give consumers more information about their energy use;
- Enable customers to use a smart phone app to remotely control the temperature of their home or small business; and
- Automatically adjust the temperature to respond to changes in pricing, a customer's schedule, or to changes in the season.

To standardize incentives for the purchase of smart thermostats and expand their availability across Ontario, the government's August 2017 direction enables the IESO to design and deliver, with the support of the Green Ontario Fund, a provincewide rebate program for smart thermostats. In addition, the Green Ontario Fund has launched the GreenON Installations program, which provides, on a limited basis and at no cost, a smart thermostat installation and in-home energy review.

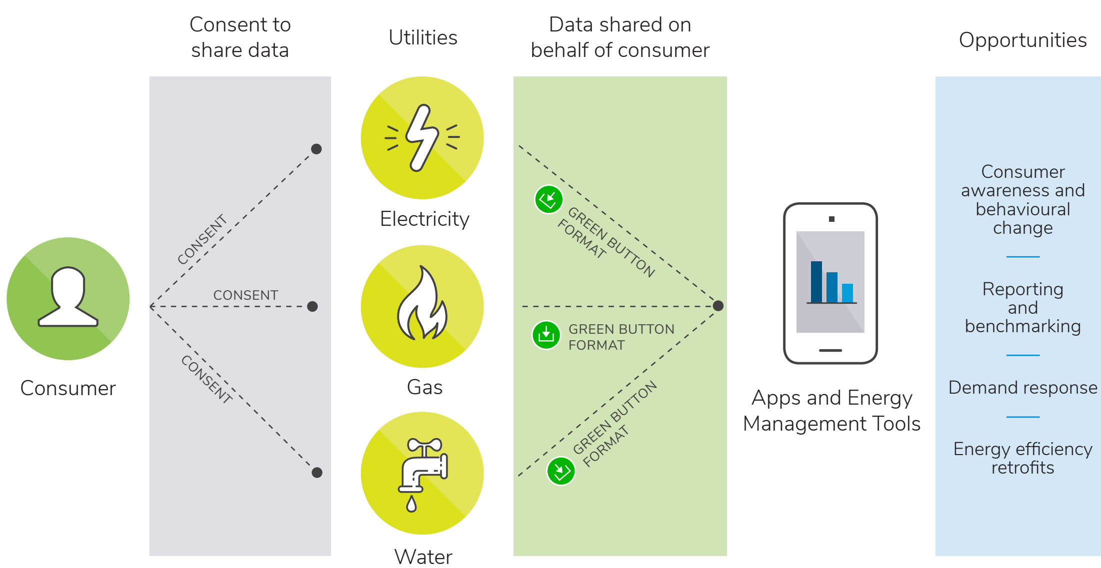
Green Button

Ontario's Climate Change Action Plan committed to expanding the Green Button initiative. Green Button Download My Data can give households and businesses easy electronic access to data on their energy and water consumption. Green Button Connect My Data lets households and businesses securely and automatically transfer their own data to applications of their choice. Greater access to information through Green Button will allow consumers to better understand their energy and water usage and use the information to make decisions, such as reducing or shifting their energy use or retrofitting their home or business to improve its energy efficiency. Green Button can also support energy reporting and benchmarking, and create new opportunities for economic development. In the long-term, implementing Green Button provincewide would support the Province's continued efforts to put conservation first and help drive toward its long-term target of saving 30 TWh of electricity in 2032.

The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, allow Ontario to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data. In addition, the government will collaborate with the province's electricity, natural gas and water utilities to adapt the Green Button standard, update existing guidance documents for LDCs and create new guidance documents for natural gas and water utilities. Guidance documents for water utilities will support those utilities with metering infrastructure to implement Green Button on a voluntary basis.

FIGURE 17.

Green Button Connect My Data



GREEN BUTTON

"Budweiser Gardens uses Event Assist, with information gathered through the Green Button initiative, to help us better understand the hydro usage associated with the size, type and configuration of each event. This has the capability to change how we book events in the future, not only for our building, but within the industry. Working with the team at London Hydro has shown me what a truly professional organization they are from top to bottom."

Gary Turrell, Director of Operations, Budweiser Gardens

Energy Benchmarking

The Province's energy benchmarking and rating initiatives give people and organizations the tools and information they need to understand the energy performance of their homes and businesses, and compare it with similar buildings. They can use this information to manage their usage and costs, and justify investments in energy efficiency. Fifteen local distribution companies (LDCs) have social benchmarking programs in their Conservation and Demand Management Plans; five of them are currently being offered to electricity customers. To promote participation in their residential audits and retrofits, Enbridge Gas Distribution and Union Gas are each including social benchmarking in their outreach and education programs.

Organizations in Ontario's broader public sector are required to annually report their energy consumption and GHG emissions to the Province and to make that information available to the public. Building on this success, as well as on lessons learned from similar programs in the United States, the government has introduced a requirement for energy and water reporting and benchmarking for large private sector buildings as well.

Starting July 1, 2018, and phased in over three years, owners of large commercial, multi-unit residential and some industrial buildings will be required to annually report their buildings' use of energy and water and their GHG emissions to the Province. Some of that data will be posted on Ontario's Open Data website every year, so that owners can compare the energy and water usage of their buildings with that of similar facilities, and identify where improvements can be made.

The Climate Change Action Plan envisions providing free energy audits for pre-sale homes in order to include energy ratings in real estate listings. The Province is examining options to deliver a Home Energy Rating and Disclosure program that would improve customer awareness by allowing homebuyers to compare homes by energy rating and encourage uptake of retrofit incentive programs.

Access to Energy Efficiency Financing

The Province is also exploring how to increase access to corporate financing for energy efficiency projects. The Investor Confidence Project gives financiers the information and tools they need to determine the viability of energy efficiency projects. The Project was established by the Environmental Defense Fund in the United States in 2013. The MaRS Advanced Energy Centre is partnering with the Province to pilot Investor Confidence Project protocols in Ontario and explore how they can be adapted for the Canadian market.

Raising the Bar for Energy and Water Efficiency

The Province continues to play a leading role in improving the energy efficiency of the equipment in homes, offices and factories. Since 2013, the government has improved or set new energy efficiency standards for more than 60 products. The gains in energy efficiency have endured and have helped consumers save on their energy bills. In addition, economies of scale have lowered the cost of the technologies, making them more popular, affordable and more available than ever before.

A 2016 amendment to the *Green Energy Act, 2009* allows the government to regulate the water efficiency of products that consume both energy and water. As a result, Ontario is now on a path to achieve more efficient use of water, even greater energy savings and reductions in GHG emissions.

DID YOU KNOW?

Ontario recently updated energy and water efficiency standards for clothes washers. Because of these improvements, in 2032 we expect to save:

- The amount of water that flows over Niagara Falls in 2.75 hours; and
- The amount electricity consumed by the City of Stratford in 2015.

The government will continue to set advanced efficiency standards for products and appliances and work with other provinces and the federal government to harmonize and raise the bar for energy and water efficiency standards.

Efficiency Standards for Drinking Water and Wastewater Treatment Plants

The Province is exploring opportunities to set or update energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants. As Ontario's Climate Change Action Plan pointed out, this would help municipalities to save on their electricity bills by reducing one of their largest uses of electricity.

"Municipal water and wastewater services are typically one-third to one-half of a municipality's total electrical use, so there is potential for reductions in both costs and emissions."

Climate Change Action Plan 2016, pg. 83

Expanding the Scope of Conservation

The government and its agencies have taken important steps to implement the Conservation First policy when planning to meet regional and local needs for electricity and natural gas, and are exploring how to further integrate this policy into their planning processes (see Chapter 8). During the LTEP consultations and engagements, LDCs and technology vendors expressed interest in using in front of the meter conservation (IFMC) technologies to help meet electricity conservation targets and reduce peak demand.

DID YOU KNOW?

In front of the meter conservation (IFMC) technologies reduce line losses and optimize voltage levels. LDCs deploy them on their distribution networks to save electricity and reduce their peak demand.

Several pilots across North America have demonstrated the potential benefits of deploying IFMC technologies, and the Smart Grid Fund and the Conservation Fund have supported pilots in Ontario. A recent study commissioned by the government estimated they can be cost-effectively deployed on 30 per cent of Ontario's electricity distribution networks.

The government and its agencies will encourage distributors to make their networks more energy efficient, by allowing them to use the electricity savings from IFMC measures to meet their targets for electricity savings under the 2015 to 2020 Conservation First Framework. IFMC project costs will continue to be funded through distribution rates, and subject to the OEB's review process. The OEB will also identify steps for pursuing energy efficiency measures on the distribution system.

Integrating Conservation and Climate Change Programs

Ontario's Climate Change Action Plan emphasized the need to increase the use of low-carbon technology, such as solar panels and heat pumps, in homes and businesses. Several programs to increase energy choices for Ontarians are being introduced, funded by the proceeds from auctions in the carbon market.

The Green Ontario Fund is helping Ontarians move to a low-carbon future by offering them incentives, financing and services to increase the use of technologies that reduce GHG emissions. The Green Ontario Fund website provides a co-ordinated, one-window approach where Ontarians can get help, information and access to its programs, as well as to other conservation and renewable energy programs in the province.

Green Ontario Fund programs are building on the success of the province's existing conservation and energy efficiency programs, providing Ontarians with more opportunities to reduce their energy costs and carbon footprint. The IESO is a partner in the delivery of certain Green Ontario Fund programs to help promote an efficient and customer-focused approach and minimize duplication with existing programs.

The government and its agencies will explore how to further integrate conservation and low-carbon technology programs for both electricity and fuels.

Under current conservation programs, combined heat and power projects that use supplied fossil fuels to generate electricity on-site are eligible for incentives because they can significantly reduce demand on the electricity grid. To help meet the Province's climate change goals, these projects will no longer be eligible to apply for incentives under the Conservation First Framework and the Industrial Accelerator Program (IAP), starting July 1, 2018.

Because of their energy efficiency and environmental benefits, behind-the-meter waste energy recovery projects and projects that use renewable energy, such as solar thermal water heating or biomass fuel for boilers, will continue to be eligible for funding under the Conservation First Framework and the Industrial Accelerator Program. Electricity distributors may also develop incentive programs for energy storage systems that are integrated with a customer's own renewable energy project. When added to on-site renewable generation, energy storage systems can provide reliability and help customers reduce their demand when prices are highest. This can help reduce peaks in demand on the local and provincial systems.

Summary

- Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.
- The government will continue to set advanced efficiency standards for products and appliances and is exploring setting or updating energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants.
- The government and its agencies will further encourage distributors to pursue energy efficiency measures on their distribution systems to achieve customer electricity and cost savings.
- The Green Ontario Fund will provide energy consumers with a co-ordinated, one-window approach to encourage conservation across multiple energy sources and programs.
- The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, enable the government to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data.
- Beginning July 1, 2018, combined heat and power projects that use supplied fossil fuels to generate electricity will no longer be eligible to apply for incentives under the Conservation First Framework or the Industrial Accelerator Program. Behind the meter waste energy recovery projects will continue to be eligible, as will renewable energy projects, including those paired with energy storage systems.

6 RESPONDING TO THE CHALLENGE OF CLIMATE CHANGE

6

RESPONDING TO THE CHALLENGE OF CLIMATE CHANGE

Ontario is taking a leading role in Canada and abroad in the global fight against climate change.

The energy sector will play a role in meeting the challenge. The robust supply of electricity will give it a central task in assisting the transition to a clean economy. At the same time, Ontario must strengthen its energy infrastructure and make it more resilient to lessen the damage that climate change can cause.

WHAT WE HEARD FROM YOU

- Support increased electrification of transportation
- Support options for home storage, including electric vehicle (EV) batteries
- Microgrids can help resiliency and northern communities
- Customers will decide which technologies work best
- Modernize regulations and rate designs
- Integrate conservation programs with initiatives announced in the Climate Change Action Plan
- Government support needed for research and development
- Distributed generation will transform conventional networks
- Introduce renewable natural gas into Ontario's natural gas supply

Ontario's cap and trade program came into effect on January 1, 2017. The cap and trade program is a flexible, market-based program that sets an annual cap for greenhouse gas (GHG) emissions, with the targets becoming more stringent over time. The cap will be lowered each year to enable Ontario to meet its GHG reduction targets.

Cap and trade creates a market to provide incentives to reduce emissions. Large emitters must have enough allowances to cover their GHG emissions. Switching from high carbon fossil fuels to lower carbon alternatives, including renewable fuels, is one way for large emitters to reduce emissions.

Putting a price on carbon through cap and trade will also impact the operation of the fuels market. Renewable alternatives do not incur cap and trade costs and, consequently, will become relatively more attractive than carbon intensive fuels. This could increase the adoption and use of fuels like renewable natural gas, ethanol and renewable diesel. Similarly, in the transportation sector, lower carbon alternatives like natural gas may become more attractive compared to diesel.

Some companies are currently allocated free allowances in recognition of their exposure to international trade and/or the amount of energy they need to use. Companies that emit more than their allocation can buy additional allowances through government auctions or from other companies that have more allowances than emissions.

Under the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, proceeds from Ontario's cap and trade auctions will be used to reduce the province's GHG emissions by helping Ontarians shift away from higher carbon fuels and reduce their energy consumption. Proceeds are projected to be $1.8 billion in 2017-18 and $1.4 billion annually, starting in 2018-19. These funds will help to fight climate change, reduce greenhouse gas emissions and transition Ontario to a low-carbon economy.

Putting a price on carbon through cap and trade will have a significant impact on the operation of the electricity market in Ontario. It will encourage a transition away from generation that uses fossil fuels towards a clean imports and generation that are free of GHG emissions. It will also encourage more efficient natural gas generation. As Ontario moves forward with Market Renewal, the cost of carbon will become increasingly important in the economics of electricity generation. Market Renewal has the potential to create a framework that effectively incorporates emerging clean technologies into our supply mix.

Together, cap and trade and Market Renewal initiatives can help to ensure electricity sector emissions remain well below historical levels, while also helping to meet our climate change and GHG reduction commitments.

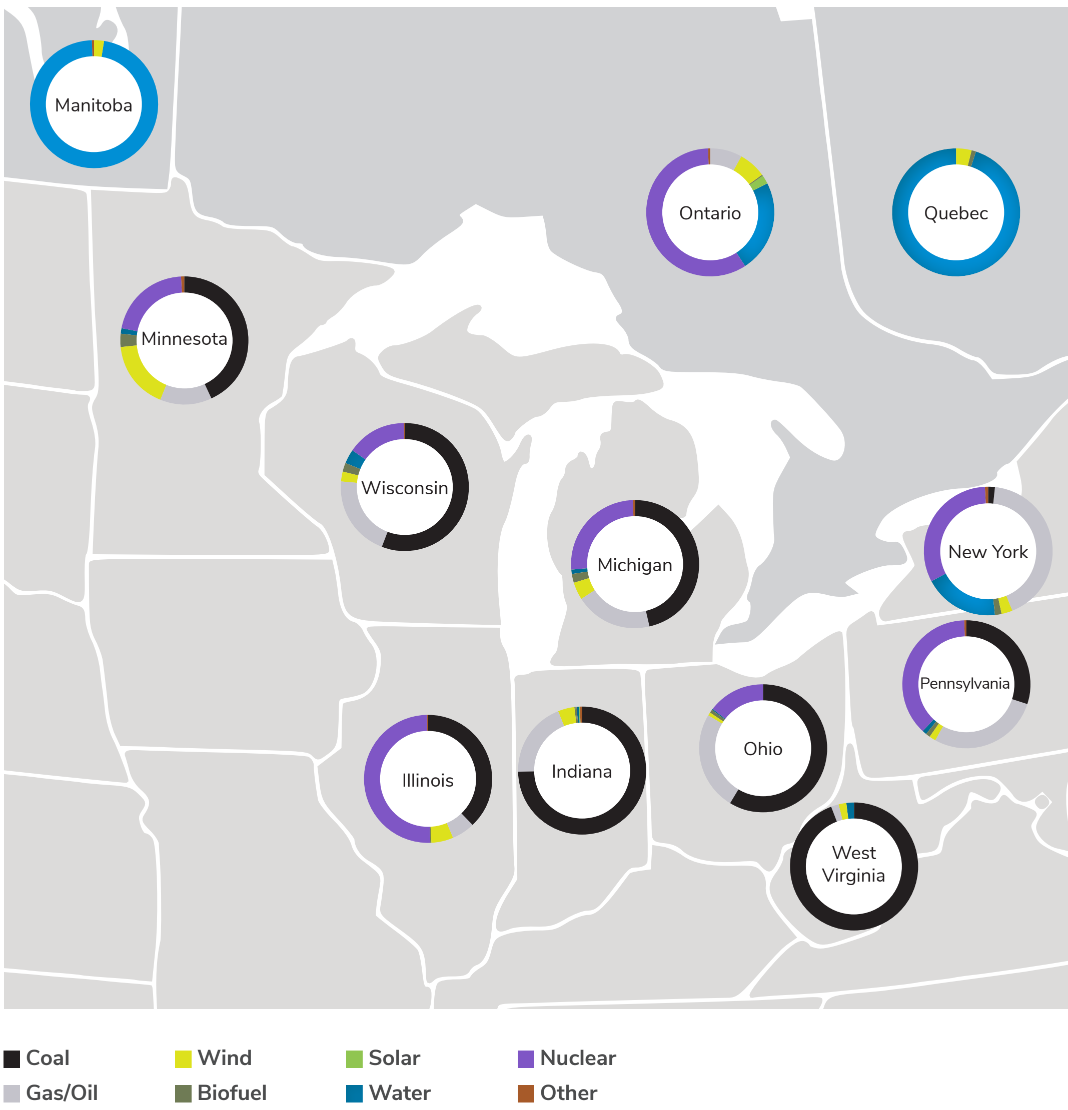
Building on a Clean Electricity System

About 90 per cent of the electricity used in Ontario in 2016 was free of GHG emissions, generated from sources such as water, nuclear, wind, solar and bioenergy. Our investments in these types of clean generation sources, along with the elimination of coal-fired electricity generation, have significantly reduced GHG emissions in the province.

In comparison to neighbouring states such as Michigan, Minnesota, Ohio, Pennsylvania and New York, which still rely heavily on fossil fuel-fired electricity generation, Ontario has a much cleaner electricity system. We have accomplished this without the abundant hydroelectric resources enjoyed by Québec and Manitoba.

FIGURE 18.

Ontario's Clean Generation Mix

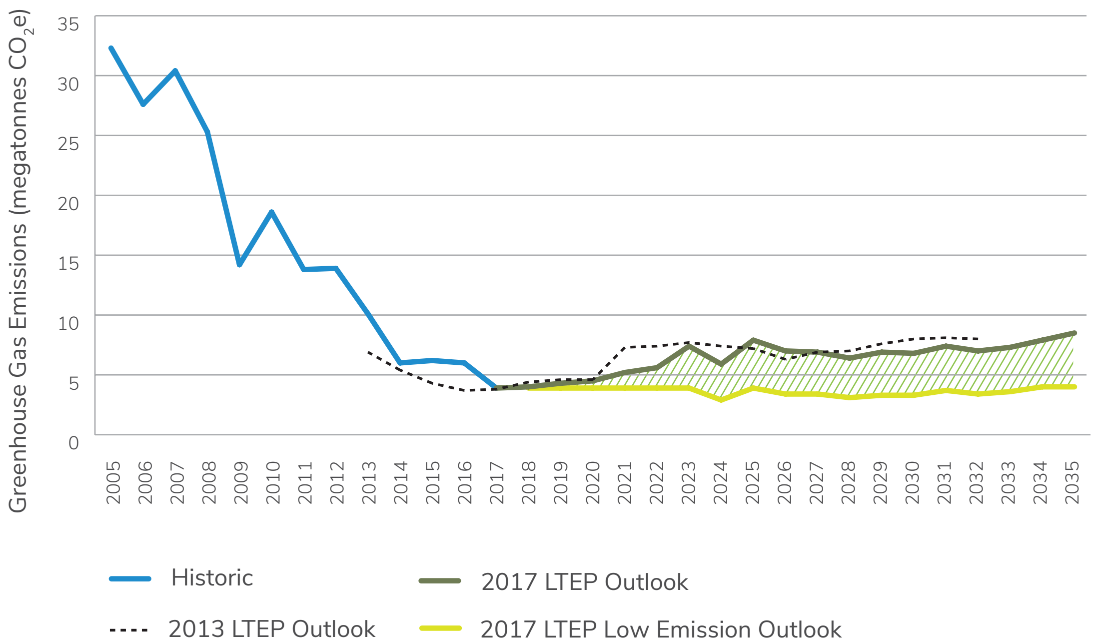


Source: IESO, U.S. Energy Information Administration, Manitoba Hydro, Hydro Quebec
Generation data for US states is from 2015; Ontario, Manitoba and Quebec Data is from 2016
Ontario generation data includes both transmission-connected and distribution-connected (embedded generation).
Data for Manitoba, Quebec and US states is for transmission-connected generation only.

Thanks to these investments, Ontario's electricity sector is forecast to account for only about two per cent of Ontario's total GHG emissions in 2017 and the emissions are forecast to be more than 80 per cent below 1990 levels. As shown in figure 19, emissions are expected to remain well below historical levels and to be relatively flat over the planning period. Ontario will continue to look for ways to keep GHG emissions in the electricity sector low, and work with carbon-free market participants to meet the Province's emissions targets.

FIGURE 19.

Electricity Sector GHG Emissions Outlook



Source: IESO, Environment Canada and Climate Change

These investments have significantly decarbonized Ontario's electricity sector, leaving it well positioned to help the province move towards a low-carbon economy and meet its emission reduction commitments. Ontario's clean and reliable electricity system gives the province a strong foundation on which to pursue increased electrification, including the use of more EVs.

The province's robust supply of energy will also allow it to combine different energy sources into integrated energy systems that provide new services for homeowners and businesses. Natural gas will continue to play a critical role in space and water heating, but we must use it as efficiently as possible and supplement it with the next generation of clean energy technologies, such as ground-source and air-source heat pumps. Proceeds from cap and trade auctions will help fund the further application of these technologies. By making the best use of our existing energy sources and infrastructure, a more integrated energy system will allow the Province to chart the most effective course for achieving its goals for reducing GHG emissions.

Renewable Energy Success

Ontario is Canada's leader in installed wind and solar power. There is more wind and solar capacity in Ontario than in any other province or territory. When you add hydroelectric generation and bioenergy into the mix, renewables accounted for 40 per cent of Ontario's electricity supply mix in 2015, up from 26 per cent in 2005. Currently, Ontario has 18,300 megawatts (MW) of wind, solar, hydroelectric and bioenergy generation capacity in operation or under development.

The introduction of the Large Renewable Procurement (LRP) process in 2014 resulted in strong competition between developers of large renewable projects, drove down prices and secured clean, reliable generation. This significantly reduced the costs of wind and solar energy, saving money for electricity ratepayers.

The results of the final Feed-in-Tariff (FIT) procurement were announced in September 2017, with a total of 390 contracts offered for small-scale renewable energy projects representing about 150 MW of clean generation.

A highlight of Ontario's renewable energy programs has been the success that individuals, schools, municipalities, co-operatives and Indigenous communities have had in participating in clean energy projects. In the FIT 5 procurement, more than 80 per cent of successful applications had Indigenous, municipal, public sector or community participation. From smaller home or farm-sized projects to larger community-scale projects, Ontarians are using renewable energy to help meet their community's electricity needs and reduce their demand on the provincial electricity grid.

Since 2009, prices paid for new electricity from FIT and microFIT projects have been reduced between 50 and 75 per cent, reflecting the decreasing costs of equipment and ensuring value to ratepayers.

As a result of annual price reviews, revised procurement totals and the introduction of competitive procurement for large renewable energy projects, the FIT, microFIT and LRP initiatives are expected to cost at least $3 billion less than forecast in the 2013 LTEP.

COMMUNITIES BENEFITING FROM RENEWABLE ENERGY

The Municipality of Chatham-Kent is widely recognized as one of Ontario's leading green energy communities, which has helped spur local economic development. The municipality has received significant benefits for hosting a number of wind energy projects. Recent and proposed wind projects will deliver an estimated $27 million in community benefits and property tax revenue over a 20-year period for the municipality.

Renewable energy companies have also invested heavily in the social fabric of the community through partnerships with local organizations for sponsorship of projects such as splash pads.

A Strong Renewable Future

The Province's renewable energy policies have made Ontario's electricity supply mix cleaner, and are providing real benefits for communities and municipalities. Recognizing this success, *Delivering Fairness and Choice* is focused more on outcomes rather than specifying targets and technologies. With a solid foundation of electricity provided by renewable energy, Ontario can now focus on new opportunities for innovation, modernization and exporting our expertise. Ontario is poised to take advantage of advances being made in distributed energy resources and smart-grid technologies that can help deliver a more efficient and cleaner electricity system. The government remains committed to having an electricity system where renewable energy generation plays an essential role, supporting the goals of the Climate Change Action Plan.

Wind

Wind power has become an important source of clean electricity for Ontario. There were only 15 MW of installed capacity in Ontario in 2003, compared with 4,800 MW today. That is enough wind energy to power approximately 1.4 million homes each year.

Wind power is also being produced more efficiently. Turbines use state-of-the-art controls to adjust their blades and orientation to get the maximum output of energy in changing wind conditions. The Independent Electricity System Operator (IESO) has been able to send instructions to renewable energy generators since 2013 to stop producing electricity when it is not required to meet provincial needs. Actively controlling wind energy generation results in the more efficient operation of the electricity system.

Solar

Ontario has become a North American leader in the development of solar photovoltaic (PV) systems with about 2,300 MW of capacity online, enough to power about 300,000 homes each year. Solar power can help the electricity system to meet Ontario's needs on hot and sunny days when air conditioning use is highest. Advances in solar PV technology have seen improved performance and a significant decline in costs, resulting in more cost-effective solar generation. Solar PV systems also support ongoing modernization of the grid. They can be large or small, and can be located close to where electricity is needed. Solar PV systems can also be paired with other innovative technologies like energy storage. These advantages mean that solar PV will continue to be a valuable asset for Ontario's distribution systems, and can help improve the operation of the electricity grid in the future.

Hydroelectric

Most of Ontario's supply of renewable energy continues to come from the province's hydroelectric facilities, which provided 23 per cent of Ontario's total generation in 2015. Ontario has approximately 8,800 MW of installed hydroelectric capacity.

Assessments over the years, including the November 2013 Northern Hydro Assessment – Waterpower Potential in the Far North of Ontario, have identified significant remaining waterpower potential in the province. These potential resources are mostly concentrated in Northern Ontario and major transmission enhancements would be required to effectively contribute to Ontario's electricity supply.

Additionally, there are opportunities to redesign older hydroelectric projects to improve performance by using new, more efficient turbines.

Bioenergy

Bioenergy refers to electricity that is generated by burning biomass, such as plant or animal by-products and wastes. It also describes biogas and landfill gas, which is methane gas produced by the decomposition of organic matter that is then burned in a generator to produce electricity. Ontario currently has about 500 MW of bioenergy generation capacity in operation.

Going forward, the shift toward Renewable Natural Gas (RNG), a low-carbon fuel produced by the decomposition of organic materials, gives biogas producers an additional market opportunity. Bioenergy systems also support the implementation of the Province's Strategy for a Waste-Free Ontario.

Shifting to Lower Carbon Gasoline and Diesel

Delivering Fairness and Choice recognizes the commitment in the Climate Change Action Plan to introduce a Renewable Fuel Standard (RFS) for gasoline. This is an important step towards reducing GHG emissions from the transportation sector. Since it uses the existing fuels infrastructure, an RFS standard is one of the more flexible and cost-effective ways to increase the use of renewable and low-carbon fuels.

The use of renewable and low-carbon transportation fuels can be expanded by:

- Increasing the use of renewable liquid fuels in existing vehicles. Drop-in fuels such as ethanol can be mixed with gasoline to produce blended fuels and can be used the same way as regular gasoline;
- Having existing fuel stations offer higher blends of ethanol and bio-based diesel;
- Making renewable liquid fuels available to more regions of the province;
- Adding biofuels to the crude oil that Ontario refineries process; and
- Lowering the carbon intensity of renewable fuels produced by Ontario manufacturers.

Delivering Fairness and Choice acknowledges there are other ways to achieve deep reductions in emissions and transform the transportation sector. While current outlooks predict an increased electrification of light-duty vehicles and the use of alternative fuels, including bioenergy for long-haul road freight and aviation, technological innovation remains inherently unpredictable. The technology-neutral approach of the RFS lets the alternatives compete on their merits.

Shifting to Renewable Natural Gas

Natural gas remains a reliable and cleaner option for many Ontarians, and will continue to play an important role in the province's energy supply mix. Homeowners, businesses and industries use natural gas for space heating, domestic hot water, steam and process heat. There were about 3.6 million natural gas customers in Ontario in 2016. Natural gas was also used to generate about 10 per cent of Ontario's electricity in 2015.

Ontario is looking at using renewable natural gas to lower the carbon intensity of the natural gas that people burn. RNG is a low-carbon fuel produced by the decomposition of organic materials found in landfills, forestry and agricultural residue, green bin and food and beverage waste, as well as in waste from sewage and wastewater treatment plants. Because it comes from organic sources, the use of RNG does not release any additional carbon into the atmosphere. As an added benefit, it can use the existing natural gas distribution system and replace the use of conventional natural gas in today's stoves and furnaces.

The government will continue to work with industry partners and the Ontario Energy Board (OEB) to introduce a requirement that natural gas contain some renewable content, fulfilling a commitment of the Climate Change Action Plan.

The government is also investing proceeds from the auctions in the carbon market to help introduce RNG in the province. The investment will help consumers with the cost of shifting to RNG, as it currently costs more than conventional natural gas.

Integrated Energy Solutions

Renewable energy technologies can be the foundation for innovative integrated clean energy systems that provide the space heating, cooling, and energy storage solutions that help to address the climate change challenges facing Ontario.

Power-to-Gas

Electrolysis, also known as power-to-gas, uses surplus electricity to break down water molecules into hydrogen and oxygen. The hydrogen can then be stored in the vast storage system that currently exists for natural gas in Ontario and transported in existing natural gas pipelines and used to heat homes and fuel vehicles.

Power-to-gas could potentially become a new and important link between the province's electricity and natural gas systems. The Independent Electricity System Operator (IESO) recognizes this, and has already awarded a contract to Hydrogenics, an Ontario-based manufacturer of electrolysis and fuel cell technology, which will deliver two MW of storage capacity in the Greater Toronto Area.

Heating and Cooling with Renewable Energy Technologies

Ontario aims to reduce greenhouse gas (GHG) emissions by increasing the use of low-carbon technologies, such as solar, air- and ground-source heat pumps, to heat and cool Ontario homes and businesses.

This has the potential to deliver a big payoff in the fight against climate change. Space heating accounts for approximately 75 per cent of the total fuels energy demand in Ontario homes, making it an important area to target for reducing GHG emissions.

The government will continue to work with its agencies, including the IESO and the Green Ontario Fund, to encourage the deployment of thermal and alternative technologies for residential, commercial, industrial and institutional buildings. This will involve planning how to integrate the technologies and the delivery of conservation and low-carbon technology programs into the province’s energy system.

Solar Air and Hot Water Heating

A typical residential solar hot water system can supply between 40 to 60 per cent of a home’s hot water needs. Solar air systems capture air warmed by the sun and circulate it to heat buildings.

Ground Source and Air Source Heating and Cooling

Ground-source heat pumps, also known as geothermal energy systems, use buried pipes to absorb heat from the ground and transfer it to a home or building, and can reduce heating bills by up to 70 per cent. Air-source heat pumps take air from outside, extract the heat and transfer it to the air inside a home or building. A heat pump, running on electricity, concentrates the heat from both sources, and moves it to where it is needed. The same systems can also be used to provide cooling in the summer; and more advanced air-source systems can even provide domestic water heating.

In July 2017, the Save on Energy Heating and Cooling Incentive program began offering incentives of up to $4,000 to help Ontarians who live in electrically-heated homes to purchase and install air-source heat pumps.

District Heating and Cooling

District energy systems generate and supply heating and cooling, domestic hot water and electricity for blocks or neighbourhoods in a community.

District heating and cooling can use local energy resources such as biomass, geothermal energy and mechanical waste heat from industrial operations to reduce GHG emissions.

Implementation can be made easier if underground district energy pipes are incorporated into the initial design of new residential or commercial developments. When used in more densely populated areas, district energy systems can be more cost-effective than providing heating and cooling systems for each individual building.

ENWAVE ENERGY CORPORATION

Enwave Energy Corporation is a Toronto-based company that provides sustainable energy services in Toronto, Windsor and numerous American cities, including Chicago, Houston, Los Angeles and Portland OR. In each community, the company operates highly efficient thermal energy plants that distribute steam, hot water and/or chilled water to customer buildings. Customers benefit from reduced operating costs, lower emissions, and increased reliability.

Enwave generates chilled water, steam, hot water and electricity which is distributed to more than 155 buildings in downtown Toronto. Their Deep Lake Water Cooling system is one of the world's largest sustainable cooling systems, using Lake Ontario to recycle energy from more than 70 buildings in downtown Toronto to the city's potable water system. Currently, this system reduces peak electrical demand by 61MW, with plans underway to expand.

The London system is a Combined Heat and Power (CHP) system that currently provides 15MW of electricity to the grid, and serves 60 customers with a steam and chilled water system. There are plans to increase the CHP plant capacity by an additional 18MW in the near future.

Near and Net Zero Carbon Emission Buildings

The Climate Change Action Plan aims to reduce emissions in the building sector by encouraging the construction of near net zero and net zero carbon emission homes and buildings. To help create a pathway to these new building standards, the electricity and natural gas conservation frameworks will continue to support the development and enhancement of high efficiency, low-carbon homes and buildings. New programs will also be offered through the Green Ontario Fund.

New high-performance standards for space and water heating equipment could significantly reduce the energy use, environmental footprint and GHG emissions of new and existing homes and buildings and lower consumers' energy costs.

Working with the federal and other provincial governments, Ontario is exploring opportunities to develop markets for new high efficiency technologies, such as air source heat pumps, supporting the joint aspirational goals on achievable energy performance levels and the transition to a low-carbon economy.

In addition, planned updates to the Ontario Building Code would make a significant contribution to reducing GHG emissions in the building sector and support Ontario's Climate Change Action Plan.

An important part of transitioning to near and net zero energy or carbon emission buildings is to minimize their energy use. Generally, the most cost-effective way is to first improve their energy efficiency, with increased insulation, advanced air sealing, and high efficiency heating and cooling systems. Once that has been done, some type of on-site renewable energy generation is generally required to achieve net zero energy or carbon emission status. The government is taking steps to expand and enhance its net metering framework, which would give building owners increased opportunities to integrate renewable energy generation and energy storage technologies.

REID'S HERITAGE HOMES – GUELPH

Reid's Heritage Homes built five net zero homes in Guelph in 2016. These homes were the first in Canada to meet new net zero home standards set up by the Canadian Home Builders' Association.

Key features include:

- Air source heat pumps;
- High efficiency water heaters;
- Increased insulation values in exterior walls, attic and basement;
- Advanced air sealing to avoid air leakage;
- Right sized mechanicals and energy recovery ventilators; and
- Solar panels.

WEST 5 – SIFTON PROPERTIES LIMITED - LONDON

The West 5 development in London is Ontario's first sustainable, net zero community. It will have a total of 2,000 apartments, condominiums and townhomes along with 400,000 sq. ft. of commercial and retail space, and a 1.6-acre central park. Construction of West 5 will create about 2,500 jobs over 10 years.

Key features include:

- Solar panels and solar streetlights;
- Solar parkades;
- Green roofs;
- EV charging stations;
- Community gardens; and
- Rainwater harvesting.

Climate Change Adaptation

Ensuring a Resilient Energy Supply

Ontarians need to have a reliable supply of energy, not just for for their economic prosperity but for their basic health and safety. In order to provide vital energy services to Ontarians, the province's energy system must remain resilient and able to withstand a changing climate.

The facilities and equipment that currently generate, transmit and distribute energy across the province can be threatened by the extended heat waves, high winds, severe rainfall and ice storms that come with climate change. Climate change may also lower the flows of rivers and the water levels and temperatures of lakes, possibly reducing the ability to generate electricity.

To address these concerns, Ontario's energy organizations are taking a number of actions that will ensure the province's energy system is better prepared to meet extreme weather events:

- Together with several partner organizations, the IESO studied Ontario's transmission system and found it resilient enough to substantially withstand most extreme weather scenarios. However, the study recommended continued monitoring and refinement of climate scenarios.
- More local distribution companies are making adaptation and system resilience a priority. Both Toronto Hydro and the former Horizon Utilities (now part of Alectra Utilities) conducted vulnerability assessments of their systems.
  A leader in this regard in Canada, Toronto Hydro is addressing climate change vulnerabilities by improving its engineering practices and tools, such as its load forecasting model, and installing more resilient equipment on its system. In its last rate application, Toronto Hydro identified extreme weather as a driver for its capital and maintenance expenditures.
- Local distribution companies (LDCs) such as Oshawa PUC Networks, Veridian and Whitby Hydro are developing adaptation plans to match the adaptation planning done by their local transit, water and communications authorities.

Building on its current activities, the government will strengthen the ability of the energy industry to prepare for the effects of climate change and integrate its impacts into their operational and infrastructure planning.

The government and its agencies will facilitate the exchange of information and knowledge among utilities and other partners to allow them to share best practices and increase their ability to adapt to climate change. Since these activities are best co-ordinated with other public services, the Province will encourage utilities to work with municipalities and other public and private infrastructure operators. This knowledge-sharing platform will be a key first step to help with the following initiatives:

- The government will help develop a vulnerability assessment of the energy distribution sector so utilities can develop state-of-the-art strategies to manage risk. This will complement the vulnerability assessment done of the transmission system in 2015.
- The OEB will give utilities guidance on cost-effectively integrating climate change adaptation into their planning and operations. The IESO will ensure that climate change adaptation is considered and integrated into the bulk system and regional planning processes.

ADAPTATION INITIATIVES BY LOCAL DISTRIBUTION COMPANIES

Building on its distribution system vulnerability assessment, the former Horizon Utilities (now part of Alectra Utilities), developed a long-term plan for adapting to climate change. The plan considers the risk of flooding when planning infrastructure, and improvements to the LDC's geographic information and outage management system reduce response times.

Hydro Ottawa focused its storm hardening initiative, completed in 2015, on revising the schedule for removing and trimming overhanging tree branches. As a result, public safety has been increased, the distribution system is less vulnerable to damage from high winds and ice storms, and the LDC's budget for vegetation management was reduced by $750,000.

Summary

- Ontario remains committed to a clean electricity system that includes renewable energy generation and supports the goals of the Climate Change Action Plan.
- The government will encourage the construction of near net zero and net zero carbon emission homes and buildings to reduce emissions in the building sector.
- The government is proposing to expand the options for net metering to give building owners more opportunities to access renewable energy generation and energy storage technologies.
- The government will continue to work with industry partners to introduce renewable natural gas into the province's natural gas supply and expand the use of lower-carbon fuels for transportation.
- Building on current activities, the government will strengthen the ability of the energy industry to anticipate the effects of climate change and integrate its impacts into its operational and infrastructure planning.

SUPPORTING FIRST NATION AND MÉTIS CAPACITY AND LEADERSHIP

7

SUPPORTING FIRST NATION AND MÉTIS CAPACITY AND LEADERSHIP

First Nations and Métis are leaders in Ontario's energy sector, bringing their unique perspectives, knowledge and leadership to energy planning, projects and policies.

They have created an unprecedented level of First Nation and Métis involvement in the energy sector:

- First Nations and Métis are now leading or partnering on over 600 wind, solar, and hydroelectric generation projects across Ontario, accounting for over 2,200 megawatts (MW) of clean energy capacity.
- First Nations lead, or are partners with, transmission companies on several major transmission lines.
- Nearly 100 First Nations are participating in the Independent Electricity System Operator's (IESO) Aboriginal Community Energy Plan program. These community-led energy plans assess a community's current energy needs and priorities and explore options for conservation and renewable energy.

The Province takes its duty to consult First Nation and Métis seriously and is committed to ensuring they are consulted on any energy activity that could potentially affect their Aboriginal and Treaty rights.

WHAT WE HEARD FROM YOU

- Need to connect remote communities
- Unreliable electricity service hurts quality of life and hinders community development
- Eliminate the on-reserve electricity delivery charge to improve electricity affordability
- Need for funding to assist with implementing Community Energy Plans
- Conservation programming should better meet community needs
- General preference for renewable energy over nuclear power
- Desire for First Nation and Métis ownership of and partnerships on projects
- Need for federal funding for connection of remote communities

Many First Nations and Métis across Ontario face energy-related challenges: the need for reliable and affordable power, energy-inefficient housing and inadequate infrastructure, to name just a few. The causes and solutions to these challenges are rooted in complex historical, jurisdictional, geographic and regulatory contexts, but progress is being made. The Province is committed to working together with First Nations and Métis to identify issues and propose actions that advance reconciliation and healing.

The Chiefs of Ontario and the Province signed the First Nations-Ontario Political Accord on August 25, 2015, creating a formal bilateral relationship framed by the recognition of the treaty relationship.

THE FIRST NATIONS-ONTARIO POLITICAL ACCORD

- Affirms First Nations' inherent right to self-government
- Commits the parties to work together on issues of mutual interest, such as resource benefits sharing and jurisdictional matters
- Sets a path for reconciliation

The Ontario-Métis Nation Framework Agreement, signed in 2008 and renewed in 2014, guides the Province's relationship with the Métis Nation.

ONTARIO-MÉTIS NATION OF ONTARIO (MNO) FRAMEWORK AGREEMENT

- Facilitates the recognition and advancement of Métis people in Ontario
- Fosters collaboration between the province and the MNO on issues of mutual interest to support the goals and objectives of the new agreement
- Increases awareness of Métis history, identity and culture

The Province will continue the direction established in the 2013 LTEP and support First Nation and Métis leadership and capacity in Ontario's evolving energy sector. Reflecting the Province's strong energy supply position, *Delivering Fairness and Choice* responds to the concerns heard through the LTEP engagement process and the ongoing dialogue between the government, its agencies and First Nation and Métis partners.

Building on the conversations during the LTEP engagement process, the Province commits to a more regular and ongoing dialogue with First Nations and Métis. This will include energy awareness and education initiatives, the involvement of youth in the energy conversation, and a more regular communication to ensure First Nations and Métis are informed about the Province's energy commitments and have opportunities to provide insight and feedback.

Addressing Electricity Affordability

A major priority for Indigenous and non-Indigenous electricity consumers is to improve the affordability of their electricity. The government is working to address the issue with programs such as:

- The Ontario Electricity Support Program (includes enhanced credits for First Nations, Métis and Inuit electricity consumers) (more details in Chapter 1);
- Ontario's Fair Hydro Plan (more details in Chapter 1);
- The Low-Income Energy Assistance Program (more details in Chapter 1); and
- The Conservation First Framework (more details in Chapter 4).

First Nation Delivery Credit

The Province recognizes that First Nation electricity consumers living on-reserve face unique challenges with respect to electricity affordability. Customers living on-reserve often pay higher distribution costs than customers in more populated areas because distribution rates are partially based on population density. The problem of higher distribution rates is often exacerbated by energy-inefficient homes on reserves that lead to higher levels of energy consumption.

To address these unique energy affordability challenges, First Nation leaders recommended the elimination of delivery charges for electricity transmission and distribution when they met with the Minister of Energy and other energy sector leaders at the First Nations-Ontario Energy Table in April 2016.

The minister directed the Ontario Energy Board (OEB) to work with First Nations to research options that would address energy affordability on reserves, and to report back on its findings. Acting on the OEB's findings and feedback from First Nations, the Province collaborated with the Chiefs of Ontario to develop the First Nations Delivery Credit. The First Nations Delivery Credit was implemented on July 1, 2017 and provides a credit equal to 100 per cent of the electricity delivery charge on the bills of on-reserve First Nation residential customers of licenced distributors. This collaborative effort between the Province and First Nations is another example of the Political Accord being brought to life.

Connecting Off-Grid First Nation Communities

Twenty-five remote First Nation communities in the province's northwest rely on diesel fuel to power their communities. The Province recognizes the distinct challenges they face and, because of the high cost of diesel fuel, there is a good economic case to connect as many as 21 of those communities to Ontario's electricity grid.

The Province has made it a priority to connect these remote First Nations. Communities cannot improve their housing, their water treatment systems or other community infrastructure if they do not have a reliable and adequate supply of electricity.

Connection to Ontario's low-carbon electricity grid will not only improve the quality of life of these communities and enable their economic development, but it will also reduce local pollution, greenhouse gas (GHG) emissions, and the environmental risks associated with transporting and storing diesel fuel.

FIGURE 20.

Reducing Diesel Generation in Remote First Nation Communities

Remote communities proposed for connection through the Wataynikaneyap power project

Remote communities that could be connected through future proposals

Remote communities uneconomical to connect where other diesel reduction initiatives will be pursued

Other First Nations

First Nation settlements

Roads

Transmission Line

230 kV

115 kV

For these reasons, the government has taken several steps to begin the connection of remote First Nation communities. These include:

- Selecting Wataynikaneyap Power as the transmitter for connecting most of the remote First Nations;
- Creating a mechanism for funding a portion of project costs; and
- Advocating for a fair cost-sharing arrangement with the federal government that ensures the project is fully funded and can proceed to construction.

ONTARIO POWER GENERATION AND GULL BAY FIRST NATION

Left to right: Gillian MacLeod, Anthony "AJ" Esquega, Wayne King and Ryan Morin

Ontario Power Generation (OPG) and Gull Bay First Nation (GBFN) are in the early stages of building an advanced renewable microgrid on the GBFN reserve on the western shore of Lake Nipigon. GBFN has an on-reserve population of 300 people and is one of the four remote First Nation communities that the IESO has determined to be economically unfeasible to connect to the provincial grid at this time.

The Gull Bay Diesel Offset Microgrid project will create a community microgrid by integrating new solar photovoltaic generation, battery energy storage, and a microgrid control system with the existing on-site diesel generators that currently supply the community's entire energy needs. The development, construction and operation of the project will create additional opportunities for capacity building and employment.

The Province also supports the connection of the five remote Matawa communities that are not currently part of the Wataynikaneyap Power project. Further steps will be taken to advance their connection when proposals are brought forward.

Grid connection is not currently feasible for four of the 25 remote First Nations in Ontario. Each of these communities has begun the planning and development work to add sustainable technologies that will reduce their reliance on diesel. Projects that reduce diesel reliance could include renewable microgrids, battery storage, and other innovative technologies that meet identified community needs.

The government will continue to partner with these communities and other collaborators, and is looking to the federal government to support these projects. The Government of Canada has agreed to financially support the early connection of Pikangikum First Nation and Wataynikaneyap Power plans to begin construction in 2017 to connect this First Nation.

Conservation

Over 40 First Nations participated in the Aboriginal Conservation Program between 2013 and 2015. The program funded energy efficiency upgrades such as new insulation, appliances and lighting for approximately 3,000 First Nations households.

Through the 2015–2020 Conservation First Framework, First Nation and Métis customers also have access to other energy efficiency and conservation programs, such as the Save on Energy programs offered by local distribution companies.

CONSERVATION ON THE COAST

Local Distribution Companies (LDCs) owned by Attawapiskat, Kashechewan and Fort Albany First Nations are collaborating to provide conservation programs to their customers, using the name Conservation on the Coast (COTC).

COTC began in 2013 by conducting annual energy audits in the three communities.

By October 2017, 30 homes per community will have LED bulbs, power bars, low flow aerators and showerheads, hot water pipe wrap, and improved insulation. This has reduced electricity usage by 20 to 25 per cent per home. In addition to the energy savings, residents say their homes are more comfortable to live in, they are burning less wood, and moisture and mold problems have diminished.

WIKWEMIKONG FIRST NATION

In June 2017, the Wikwemikong First Nation launched its Ignite Energy and Infrastructure Project. This is a long-term community driven strategy to address the high energy costs faced by the community and upgrade its aging infrastructure. Phase One is a major retrofit and upgrade to LED lighting for three schools, a nursery school, the community's health centres, arenas, and the band administration office.

It is estimated this will save the community more than $157,000 per year in energy costs, a 58 per cent savings in the energy used for lighting. The $1.1 million project will be financed with a contribution of $127,900 from the IESO's Save on Energy Program and private debt financing.

Wikwemikong First Nation is also looking to expand its portfolio of renewable energy projects with the Wikwemikong Solar Micro-grid construction project. The 300kW micro-grid is expected to begin construction in 2018/19 and will include a solar generation plant, improvements to the energy efficiency through insulation and replacements of high energy heating and cooling systems of five community buildings and the development of a microgrid software program. This project will receive funding through the Small Communities Fund, co-funded by the Ontario and the federal governments.

While conservation programs are working well in some First Nation and Métis households, participants in *Delivering Fairness and Choice* engagement sessions said the programs need to be more flexible and more widely available.

In conjunction with the mid-term review of the Conservation First Framework and engagement with the Indigenous communities, the IESO will give the Province options for improving conservation programs and their availability for First Nations and Métis, including the 10 communities served by unlicensed LDCs in North-Western Ontario known as the Independent Power Authorities: Eabametoong, Keewaywin, Muskrat Dam, Nibinamik , North Spirit Lake, Pikangikum, Poplar Hill, Wawakapewin, Wunnumin and Weenusk.

The Climate Change Action Plan allocates $85-$96 million from cap and trade auction proceeds for collaboration with Indigenous communities. This includes establishing a fund for community level GHG reduction projects and for community energy and climate action planning in First Nation communities, particularly to reduce emissions from buildings and infrastructure, and for the development of carbon sequestration projects.

Implementing Community Energy Plans

Community energy plans are an important way to understand local energy needs better. They help communities identify opportunities for energy efficiency and clean energy and develop a plan to meet their community's energy goals. Close to 100 First Nations are now developing community energy plans, using funding from the Aboriginal Community Energy Plan (ACEP) program. The Province is committed to continuing this funding.

But energy plans are just a first step and the Province recognizes that further support is needed to turn these plans into tangible actions and results. That is why the ACEP program will be expanded to help communities implement their community energy plans and support the Climate Change Action Plan.

The IESO will engage with First Nation and Métis communities and organizations to identify the strengths and weaknesses of the current ACEP program, explore the use of conservation projects or other community-directed energy initiatives, and then recommend changes that allow community energy plans to flourish. Funding will come from the $10 million the IESO has dedicated annually for this and other support programs.

Supporting Local Opportunities

Building Sector Knowledge and Capacity

The IESO's Education and Capacity Building (ECB) program supports the education, training and skill building of First Nations and Métis. The ECB program will continue to support initiatives that help build local business skills, energy literacy, and youth engagement.

Exploring Energy Projects and Partnerships

The IESO's Energy Partnerships Program (EPP) supports First Nation and Métis communities and organizations that want to lead or be partners on renewable energy and transmission projects.

Three streams of funding from the EPP help support:

- Financial, legal and technical due diligence so First Nations and Métis can partner on major priority transmission lines and renewable energy projects;
- The development of renewable energy projects, including costs for regulatory approvals; and
- Initiatives that reduce the reliance on diesel fuel for the four First Nations that can't be feasibly connected to the transmission grid.

The government will engage further and explore how to change these programs so they better reflect the needs of First Nations and Métis within the current energy system. This may include an examination of how programs can help integrate small-scale renewable energy projects into the local energy system, or the use of net metering and other innovative solutions that address local or regional energy needs and interests.

Access to Financing

The development of energy projects requires significant financial and human capital. Barriers can prevent First Nation and Métis communities and organizations from accessing this capital so they can actively participate in the energy sector. Barriers to more widespread First Nation and Métis participation include:

- Lack of capital at reasonable terms;
- High financing costs; and
- A shortage of capacity around financing and building partnerships.

The Aboriginal Loan Guarantee Program has helped First Nations and Métis obtain lower-cost financing to participate in large-scale energy projects. However, Ontario recognizes that barriers to financing remain, particularly for smaller-scale projects. As a result, the government will engage with First Nations and Métis to identify gaps in financing, possible changes to existing programs, and alternative financing models.

WHAT IS THE ABORIGINAL LOAN GUARANTEE PROGRAM?

Launched in 2009, the $650 million Aboriginal Loan Guarantee program (ALGP) provides a provincial guarantee to support a First Nation or Métis corporation borrowing to purchase up to 75 per cent of the corporation's equity in a qualifying energy project application, to a maximum of $50 million. To date, the ALGP has supported First Nation or Métis equity interests in nine projects, including the 438MW Lower Mattagami hydro-electric project, the Bruce to Milton transmission reinforcement project, the 28MW Peter Sutherland hydro-electric project, and the 4MW Mother Earth Renewable Energy wind project.

The government can build on its strong record and apply innovative financing models to promote First Nation and Métis participation in energy projects. These financing models and social finance tools have been successfully used in the United States, Australia, and elsewhere in Canada to facilitate greater Indigenous economic participation.

The Province also appreciates the unique social benefits that can accrue to First Nations and Métis with their participation in energy projects. Measuring and assessing these non-financial benefits could help the government take a broader and more inclusive view of outcomes when deciding on energy policies and projects.

RAINY RIVER FIRST NATIONS SOLAR PROJECT

Rainy River First Nations signed a memorandum of understanding with Ontario Solar PV Fields to purchase three solar projects located in their community. The cost of the projects was around $154 million, of which $19 million was guaranteed by the ALGP.

Rainy River First Nations partnered with Clark, Conner and Lunn for the project. The projects are expected to generate around 37 million kilowatt-hours of electricity a year, enough to meet the needs of approximately 3,000 households.

Building on these and other successes across the province, Ontario will take the following actions to increase First Nation and Métis access to financing:

- Engage with leaders, organisations and financing experts to identify financing gaps and barriers to the participation of First Nations and Métis in energy projects;
- Investigate innovative financing models to better support First Nation and Métis participation in energy projects; and
- Develop methods to better capture the social, environmental, and local benefits of First Nation and Métis participation in energy projects.

Expanding Access to Natural Gas

Natural gas remains a clean, reliable energy option, and it will continue to play a critical role in Ontario's energy mix. Access to natural gas is an important issue, especially for First Nations.

To assist with natural gas expansion, the government launched a new $100 million Natural Gas Grant Program in April 2017. Through the program, municipalities and First Nation communities are able to work with natural gas utilities to bring forward proposals to expand access to natural gas. The guidelines for the Natural Gas Grant Program state that special consideration will be given to projects located in Northern Ontario or located within First Nation reserves. Successful applicants under this program can then apply to the OEB for leave-to-construct approval for their expansion projects.

Over the coming years, the Province looks forward to seeing natural gas expansion projects deliver greater consumer choice and economic growth to municipalities and First Nations in Ontario.

Summary

- The government will review current programs in order to improve the availability of conservation programs for First Nations and Métis, including communities served by Independent Power Authorities.
- The Province, working with the federal government, will continue to prioritize the connection of remote First Nation communities to the grid and support the four First Nation communities for which transmission connection is not economically feasible.
- The Aboriginal Community Energy Plan program will be expanded to help communities implement their energy plans and support Ontario's Climate Change Action Plan.
- The government will engage with First Nations and Métis to explore options for supporting energy education and capacity building, the integration of small-scale renewable energy projects, net metering and other innovative solutions that address local or regional energy needs and interests.
- Innovative financing models and support tools will be investigated to address barriers to the financing of projects led or partnered by First Nations or Métis.
- The government will report back to First Nations and Métis between Long-Term Energy Plans to provide updates on the province's progress and seek ongoing feedback.
- The government's Natural Gas Grant Program will support the expansion of natural gas access to First Nation communities.

8

SUPPORTING REGIONAL SOLUTIONS AND INFRASTRUCTURE

8

SUPPORTING REGIONAL SOLUTIONS AND INFRASTRUCTURE

Different regions and communities may require different solutions to address their specific energy needs and the local impacts of large energy infrastructure projects on their communities.

For example, some regions may experience an increase in demand due to population growth, while others may be more concerned about the reliability of their energy supply.

Regions also have different priorities for large infrastructure projects. It is crucial that the process for reviewing interregional projects such as pipelines reflects these priorities. Ontarians need to be able to influence these energy solutions through community planning and engagement.

Regional Planning

Since 2013, communities have participated in a formalized regional planning process to identify their electricity needs and develop cost-effective solutions for meeting them. It could mean additional supply from transmission lines, local resources like district energy or conservation, or a combination of both. Over the past three years, the electricity needs of all 21 of Ontario's planning regions have been evaluated, completing the first full cycle of regional planning assessments across the province.

WHAT WE HEARD FROM YOU

- Integrate electricity planning with municipal planning
- Consider impact on economic development
- Improve local reliability
- Innovative technologies and fuels face special barriers in the North
- Programs should meet customer and regional needs

ESSEX COUNTY

Agri-business is growing in rural Essex County, near Kingsville and Leamington. The region has the largest concentration of greenhouse vegetable production in North America. Greenhouses, food processing operations and increasing wineries-related tourism are adding to electricity demand, particularly in the summer months.

At the same time, other needs in the area are triggering infrastructure upgrades that would benefit not just the local agri-business sector, but those looking to connect distributed generation, other customers in the Windsor-Essex region and Ontario ratepayers as a whole.

If the infrastructure upgrades were carried out separately, they would have cost about $100 million. Instead, by looking at the totality of the needs, the recommended solution, which includes a new 13-kilometre line and a new transformer station in Leamington, addressed the same needs for over $20 million less. Collaborative solutions like these are critical to realizing the benefits of the enhanced regional planning.

Regional planning gives communities the opportunity to consider all the cost-effective resources for meeting their regional needs. It promotes the principle of Conservation First by first incorporating conservation targets into the forecasts of net regional electricity demand. Only then are other economical solutions considered, such as new supply, distributed generation, additional conservation and demand management or investments in transmission and distribution.

In order to increase the range of cost-effective solutions, barriers to non-wires solutions such as conservation, demand response and other distributed energy resources must be reduced.

> "Our Local Demand Response initiative at Cecil TS allows us to cost-effectively defer capacity investments and provide other valuable benefits. This project exemplifies Toronto Hydro's commitment to delivering customer value and building a more flexible, integrated grid."
>
> **Anthony Haines, CEO Toronto Hydro Corporation**

The Ontario Energy Board (OEB) is also working to integrate conservation into regional and local planning for natural gas infrastructure. The OEB's 2015-2020 Demand Side Management (DSM) Framework says natural gas utilities need to consider conservation as a key principle in their infrastructure planning. As part of the mid-term review of the DSM Framework that is currently underway, natural gas utilities are expected to propose transition plans to integrate natural gas conservation into their planning for future infrastructure.

ROLE OF CONSERVATION

Targeted conservation initiatives can be the most cost-effective solutions for meeting local and regional electricity needs. The Independent Electricity System Operator (IESO) is working with local distribution companies (LDCs) in Ottawa, Toronto, Barrie-Innisfil and Parry Sound-Muskoka to determine whether targeted conservation initiatives can defer costly upgrades to specific local distribution and transmission infrastructure. In the mid-term reviews of the 2015–2020 Conservation First Framework and Industrial Accelerator Program, the IESO is also exploring how to further integrate conservation initiatives into the regional planning process.

Local advisory committees have helped their communities to understand regional electricity issues. These committees allow residents to provide input, and their advice improves the implementation and the regional plan. Community engagement is also crucial to linking regional energy plans with community energy planning.

Now that the first cycle of regional planning has been completed, the government is directing the IESO to review the regional planning process and report back with options and recommendations to address the challenges and opportunities that have emerged.

Community Energy Planning

Ontario's Municipal Energy Plan program and the IESO's Aboriginal Community Energy Plan (ACEP) program both support the efforts of municipalities and Indigenous communities to assess their energy use and needs, consider the impact of future growth, and foster local economic development. Communities are encouraged to develop their own energy plans that identify opportunities for conservation and priorities for infrastructure. The resulting community energy plans have helped communities recognize opportunities to conserve energy, improve energy efficiency and reduce greenhouse gas (GHG) emissions. More information on the ACEP program can be found in Chapter 7.

ABORIGINAL COMMUNITY ENERGY PLAN

Funding is available:

- For up to $90,000 to create a new community energy plan.
- For up to $25,000 to update an existing plan.
- For remote communities, an additional $5,000 for both streams.

MUNICIPAL ENERGY PLAN

Funding is available:

- For 50 per cent of eligible costs, up to a maximum of $90,000 to develop a new plan.
- For 50 per cent of eligible costs, up to a maximum of $25,000 to enhance an existing energy plan.

Ontario's Climate Change Action Plan has reinforced the importance of community energy and community GHG plans, and indicated Ontario will continue to support them. The Climate Change Action Plan also includes a funding for projects to reduce GHG emissions proposed by a municipality that has completed a community energy or community GHG plan and meets program eligibility criteria. The government launched the Municipal GHG Challenge Fund in August 2017. Municipalities may request up to $10 million per project to reduce GHGs in the building, energy supply, water, transportation, waste and organics sectors. Any Ontario municipality with a community-wide GHG emissions inventory, emissions reduction targets and a strategy to reduce emissions is eligible to apply. Municipal Energy Plan program participation is one path to eligibility for the Municipal GHG Challenge Fund.

REGIONAL AND COMMUNITY ENERGY PLANNING BY THE NUMBERS:

21 Electricity Regions

11 Active Local Advisory Committees (including both general and First Nations)

97 Aboriginal Community Energy Plans underway

36 Municipalities have Municipal Energy Plans underway or complete

19 Regional Infrastructure Plans (RIP) underway or complete. An RIP, led by the transmitter, identifies investments in transmission and/or distribution facilities to meet a region's electricity needs.

16 Integrated Regional Resources Plans (IRRP) completed. An IRRP, led by the IESO, integrates a range of resource options to address the electricity needs of the region.

More information on your region can be found by entering your postal code online at http://www.ieso.ca/en/get-involved/regional-planning

FIGURE 21. Regional Highlights

North of Dryden and Remote Connection

The construction of a new line to Pickle Lake and the connection of remote First Nation communities currently served by diesel generators are priorities for Ontario. The regional plan for North of Dryden recommended two projects to meet the near-term electricity needs of the region:

- Building a new 230 kV transmission line from the Dryden/Ignace area to Pickle Lake; and
- Upgrading the existing transmission lines from Dryden to Ear Falls and from Ear Falls to Red Lake.

Together, these projects will substantially increase the ability of the systems in Pickle Lake and Red Lake to meet demand.

Wataynikaneyap Power is the proponent of the 230-kilovolt (kV) transmission line from the Dryden/Ignace area to Pickle Lake and is currently acquiring the necessary approvals. The line is expected to be in service in 2020.

Ring of Fire

The Ring of Fire is in one of the most significant mineral regions of the province and includes the largest deposit of chromite ever discovered in North America. Electricity supply for the development of mines and the connection of remote First Nations in the area was assessed in the North of Dryden regional plan and the most economic option was found to be transmission connection to the Ontario grid.

The final approach to electricity supply in the Ring of Fire will depend on decisions related to transportation infrastructure, Indigenous community preferences and the electricity needs of mining companies.

Ottawa

Work is underway or complete on five transmission projects to address the near-to-medium term reliability needs and growth in demand in the Ottawa region.

The projects include the upgrading of a 115-kV circuit to provide increased supply capability for downtown Ottawa and a new transformer station and transmission line to meet the growing electricity needs of new developments in South Nepean.

A Local Advisory Committee has been established to provide advice on the development of the region's longer-term electricity plan.

Central Toronto

Increased density, new large transit projects, system reliability and resilience, and aging infrastructure are all driving new investments in Toronto's electricity infrastructure.

Conservation will be a key component of meeting the city's future electricity needs, with conservation resources expected to offset nearly 40 per cent of the growth in demand until 2036.

Investments in the Runnymede, Horner and Copeland transformer stations will ensure new customers can be connected to the grid.

As early as the mid-to-late 2020s, two major autotransformer stations and key transmission facilities are expected to reach the limit of their ability to supply growth in Central Toronto.

A Local Advisory Committee has been established to provide advice on the development of the region's longer-term electricity plan.

Windsor-Essex

Agri-business is growing in the rural portion of Essex County, increasing the demand for electricity. Hydro One is building a new transmission line, a new transformer station near Leamington, and refurbishing the Kingsville and Keith transformer stations to address this growth and improve restoration timelines. The new line and transformer station are expected to be in service by 2018.

York Region

Several transmission projects are underway to address the near-term needs for capacity and reliability in York Region, including a new transformer station in the City of Markham.

Based on current projections, York sub-regions' electricity system is expected to reach its capacity to supply growth in the medium to long term. A Local Advisory Committee has been established to provide advice on the region's longer-term electricity plan.

CITY OF TEMISKAMING SHORES

The City of Temiskaming Shores began developing its Municipal Energy Plan (MEP) in 2015. Thanks to its MEP, the city has found ways to be more energy-efficient. For example, it installed LED lighting in 955 street lights, converted to smaller pumps and motors in water and wastewater treatment facilities, and installed more efficient heating systems. The energy efficiency changes the city made have resulted in 20 per cent reductions in the utility bills for some projects. The MEP ensures that city council will approve one energy-related project each year. Temiskaming Shores has also increased its public transit service to reduce the number of private vehicles on the road.

Setting Standards for Pipelines

Apart from a small share of domestic production, Ontario's oil and natural gas is delivered from outside the province by interprovincial and international pipelines. These pipelines are under federal jurisdiction and regulated by the National Energy Board (NEB). The 2013 Long-Term Energy Plan outlined a set of principles that Ontario will use to evaluate oil and natural gas pipelines. In November 2014, Ontario and Québec agreed on the following seven principles for pipeline reviews:

- Pipelines must meet the highest available technical standards for public safety and environmental protection;
- Pipelines must have world-leading contingency planning and emergency response programs;
- Proponents and governments must fulfill their duty to consult obligations with Indigenous communities;
- Local municipalities must be consulted;
- Projects should provide demonstrable economic benefits and opportunities to the people of Ontario, over both the short and long term;
- Economic and environmental risks and responsibilities, including remediation, should be borne exclusively by the pipeline companies, who must also provide financial assurance demonstrating their capability to respond to leaks and spills; and
- GHG emissions and the interests of energy consumers must be taken into account.

The Province is committed to public engagement on major pipeline developments. In November 2013, the government asked the OEB to conduct provincewide consultations regarding TransCanada's Energy East proposal. The consultation process focused on four areas of potential impact:

- The impacts on Ontario natural gas consumers in terms of rates, reliability and access to supply, especially those consumers in eastern and northern Ontario;
- The impacts on pipeline safety and the natural environment in Ontario;
- The impacts on First Nations, Métis and local communities; and
- The short and long term economic impacts of the project in Ontario.

The OEB undertook an extensive consultation and review process. It hired experts in the subjects of pipelines, environmental reviews and economics to assist in understanding of the project and made their reports public. The OEB visited seven cities and towns along the route, meeting with local residents, First Nations and Métis in the spring of 2014 and again in the winter of 2015, to get their views on TransCanada's application. In addition, the OEB received about 10,000 written submissions during its review.

In August 2015, the OEB published its report *Giving a Voice to Ontarians on Energy East*. The report concluded there was not an appropriate balance between the economic and environmental risks of the project and its expected benefits for Ontarians. The report will help guide Ontario's participation in the NEB's regulatory proceeding on Energy East.

To ensure its strategic interests in pipeline projects are represented, the government will continue to participate in regulatory proceedings at the NEB and at intergovernmental forums that discuss the delivery of energy in a safe and environmentally sustainable manner. Ontario is also working with the federal government on regulatory initiatives such as modernizing the NEB to ensure major energy projects are reviewed in a predictable manner that increases public confidence.

Summary

- The government will continue to work with its agencies to implement the Conservation First policy in regional and local energy planning processes.
- With the first cycle of regional planning completed, the government is directing the Independent Electricity System Operator to review the regional planning process and report back with options and recommendations that address the challenges and opportunities that have emerged.
- Ontario's Climate Change Action Plan has reinforced the importance of community energy plans, and indicated the government's continued support for them.
- The Province has established seven pipeline principles to evaluate oil and natural gas pipelines, and is committed to public engagement when it undertakes reviews of major pipeline projects.

CONCLUSION

CONCLUSION

Delivering Fairness and Choice sets out a vision for the future of Ontario's energy sector and highlights the commitment to a clean, affordable and reliable energy system. The primary focus is on Ontario's energy consumers.

The development of *Delivering Fairness and Choice* followed a new legislated long-term energy planning process. The process included the development of electricity and fuels technical reports, a comprehensive engagement process with Ontarians and the issuance of implementation directives to the OEB and IESO.

The next step is for the OEB and IESO to submit implementation plans to the Minister of Energy for approval. The implementation plans will outline the steps these agencies will take to implement the policies and programs outlined in the implementation directives. The government looks forward to working with Ontario's energy sector in the implementation of *Delivering Fairness and Choice*.

GLOSSARY

Aboriginal Rights – Rights held by Indigenous peoples though long-standing use and occupancy of the land, protected under Section 35 of the *Constitution Act, 1982*.

Baseload Generation – Generation sources designed to operate more or less continuously through the day and night and across the seasons of the year. Nuclear and many hydro generating stations are examples of baseload generation.

Behind-the-Meter Applications – A range of technologies that are installed on the customer's electricity system to help manage the customer's load.

Beneficiary Pays – An approach to cost allocation where consumers pay for an asset in proportion to the benefits they derive from it. This protects ratepayers from paying for infrastructure that benefits only a few customers.

Bioenergy – The conversion of energy from organic matter to produce electricity. Sources for bioenergy generation can include agricultural residues, food processing by-products, animal manure, waste wood and kitchen waste.

Biofuels – Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called "biofuels," to help meet transportation fuel needs. The two most common types of biofuels in use today are ethanol and biodiesel.

Cap and Trade Program – A market-based system that sets a hard cap on greenhouse gas emissions while giving flexibility to businesses and industry in terms of how they meet their obligations under the program. Companies must have enough allowances (also known as permits or credits) to cover their emissions. As the cap declines, companies can invest in clean technologies to become more efficient, switch to lower carbon fuels, or purchase additional credits from other participants that have more allowances and credits than they need.

Climate Change Action Plan – A five-year plan, part of Ontario's long-term fight against climate change. The current Climate Change Action Plan will be followed by a revised plan in 2020.

Climate Change Mitigation and Low Carbon Economy Act, 2016 – Ontario legislation that creates a long-term framework for climate action. The Act establishes the province's greenhouse gas reduction targets in legislation, sets out the framework for the cap and trade program, requires the creation of a climate change action plan, and ensures accountability and transparency in how cap and trade proceeds are spent.

Conservation First – Conservation First is Ontario's policy that makes conservation the first resource considered, wherever cost-effective, in planning to meet the province's energy needs.

Conservation First Framework – Launched January 1, 2015, the six-year Conservation First Framework, overseen by the IESO, governs the delivery of electricity conservation and energy efficiency programs in Ontario and provides the funding, guidelines and certainty needed for electricity distributors to deliver conservation and energy efficiency programs to their customers.

Demand Side Management (DSM) Framework – Launched December 22, 2014, the six-year DSM Framework, overseen by the OEB, governs the delivery of natural gas conservation and energy efficiency programs in Ontario and provides the funding, guidelines and certainty needed for natural gas distributors to deliver energy efficiency programs to their customers.

Demand Response – Provides price or financial incentives to residential and business users to shift or reduce their electricity usage away from peak periods of consumption.

Distributed Generation (also known as Embedded Generation) – Electricity produced by small, decentralized generators, such as wind turbines and solar panels.

Energy Audit – The process to determine where, when, why and how energy is being used by energy-consuming systems, such as buildings. The information can then be used to identify opportunities to improve efficiency, decrease energy costs and reduce GHGs.

Energy Retrofit – The process for upgrading a building's energy consuming systems. Retrofitting may involve improving or replacing lighting fixtures, ventilation systems, windows and doors, or adding insulation. Retrofitting also means including energy efficiency measures in all renovation and repair activities.

Energy Storage – Equipment or technology that is capable of withdrawing electrical energy from the grid for the purposes of re-injecting it back into the grid; storing it as another form of energy to offset electricity demand at a later time; or for converting and storing electricity as an alternative form of energy for secondary, non-electric uses.

Ethanol – A renewable fuel made from plants such as corn, sugar cane and grasses whose use can reduce greenhouse gases.

Gigawatt – A unit of power equal to one million kilowatts (kW) or one billion watts (W).

Global Adjustment (GA) – The GA is the difference between the total payments made to certain contracted or regulated generators and demand management projects, and market revenues. The GA serves a number of functions in Ontario's electricity system: it provides more stable electricity prices for Ontario's consumers and generators; it maintains a reliable energy supply; and it recovers costs associated with conservation initiatives that benefit all Ontarians. The GA is calculated each month by taking into account the following components: generation contracts administered by the Ontario Electricity Financial Corporation; OPG's nuclear and baseload hydroelectric generation; and IESO contracts with generators and suppliers of conservation services.

Green Button – A data standard that gives customers the ability to access and share their utility data in an electronic, standardized and secure way. Customers can share their data with innovative software applications that allow them to view and manage their energy and water use.

Heat Pumps – A device that heats or cools buildings by absorbing heat from one area and transferring it to another. Heat pumps can replace the need for furnaces and air conditioners.

In-Front-of-the-Meter Technologies – A range of technologies that are deployed on distribution networks or transmission networks. Examples include technologies that reduce line losses and optimize voltage levels.

Capacity Auction – A competitive market that commits a supplier to provide a specified amount of electricity in the future.

Independent Electricity System Operator (IESO) – The provincial agency that delivers key services across the electricity sector including: managing the power system in real-time, planning for the province's future energy needs, enabling conservation and designing a more efficient electricity marketplace to support sector evolution.

Independent Power Authority – An unlicensed LDC that serves one of 10 First Nation communities in Northwestern Ontario.

Kilovolt (KV) – One thousand volts.

Kilowatt (kW) – A standard unit of power equal to 1,000 watts. Ten 100-watt light bulbs operated together require one kW of power.

Megatonnes (Mt) – One million metric tons.

Megawatt (MW) – A unit of power equal to 1,000 kilowatts (kW) or one million watts (W).

Megawatt-Hour (MWh) – A measure of the energy produced by a generating station over time: a one MW generator, operating for 24 hours, generates 24 MWh of energy.

Microgrid – A local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

National Energy Board (NEB) – The federal agency that regulates the international and inter-provincial operations of oil and gas pipelines and electricity transmitters.

Net Metering – A billing arrangement allowing customers to generate their own electricity on site for their personal use and receive bill credits for any extra electricity sent to the local distribution system.

Net-Zero Energy Buildings – Buildings that annually produce at least as much energy as they consume.

Ontario Energy Board (OEB) – The OEB is the independent agency that regulates Ontario's electricity and natural gas sectors in the public interest.

Pumped Storage – A form of energy storage that uses electricity to pump water from a lower reservoir to a higher reservoir. When required, the water in the upper reservoir can be returned through turbines to the lower reservoir to generate electricity.

Regulated Price Plan (RPP) – A time-of-use pricing plan revised every six months by the OEB that sets the prices for electricity during peak, off-peak, and mid-peak periods of the day.

Terawatt-Hours (TWh) – One billion kilowatts of electricity used for one hour.

Time-Of-Use Prices – Prices for electricity that vary according to the demands put on the system. Under a time-of-use plan, prices are higher during periods of peak consumption when it costs more to generate electricity. Conversely, prices are lower during off-peak periods, when the cost of electricity is less.

Virtual Net Metering – A billing arrangement allowing customers who may not be able to install their own renewable energy system to participate in renewable energy projects located away from their homes or businesses. The electricity conveyed into the grid from the renewable energy system creates bill credits which can be used by one or more participating customers to offset charges on their electricity bills.

Watt (W) – A unit that measures how much electricity is generated or used at any one time.

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Ontario

Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion

Reliability Impacts and the Projected System Costs of a Delay to the Project In-service Date

June 29, 2018

Connecting Today.
Powering Tomorrow.

Introduction

This addendum is in response to a June 14, 2018 request from the Ontario Energy Board ("OEB") to assess the impacts of a delay to the in-service date of a 230 kV double circuit line from Thunder Bay to Wawa (the "E-W Tie Expansion"). Specifically, this addendum addresses the potential reliability impacts of delaying the in-service date of the E-W Tie Expansion beyond 2020 and the projected system costs associated with managing the capacity gap for each of 2020, 2021, 2022, 2023 and 2024.

The IESO continues to recommend an in-service date of 2020 for the E-W Tie Expansion. If the in-service date is delayed beyond 2020, using interim measures to manage the need will result in additional costs and increased risks to system reliability. This addendum identifies the end of 2022 as the in-service date beyond which these risks to system reliability and the associated cost uncertainties are unacceptable.

The potential reliability impacts and costs of a delay to the in-service date of the E-W Tie Expansion can be addressed under the following categories:

- the incremental capacity need in the Northwest and associated cost of temporarily acquiring that capacity until the E-W Tie Expansion is in service;
- the increased energy costs that will be incurred until the new E-W Tie Expansion is in service; and
- the increased transmission losses and associated costs that will be incurred until the new E-W Tie Expansion is in service.

The following sections describe these impacts and costs in further detail.

Capacity Cost

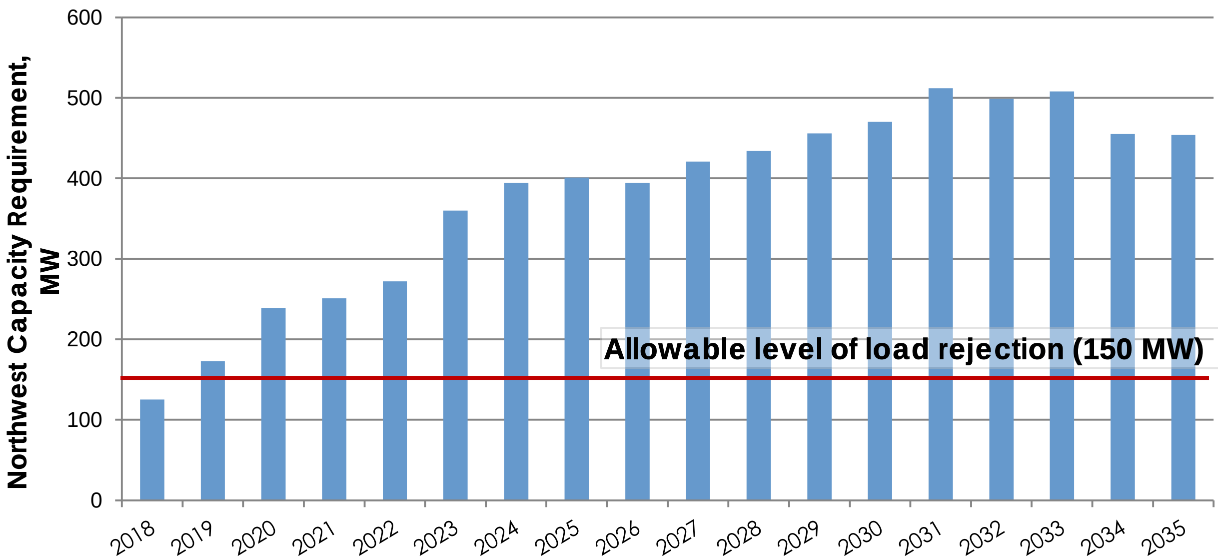
As noted in the 2017 Updated Assessment for the Need for the East-West Tie Expansion ("2017 Update Report"), there is a capacity need which exists prior to the recommended 2020 in-service date. This capacity need can be met on an interim basis by utilizing the existing Northwest Special Protection Scheme[1]. Ontario planning criteria allow for the rejection of 150 MW of load for the loss of the existing East-West Tie line, until new transmission reinforcements come into service, provided load can be restored within 8 hours[2].

[1] The Northwest Special Protection Scheme is an existing Special Protection Scheme ("SPS") that allows for load rejection or cross-tripping of transmission elements (e.g. lines, reactive devices) for a number of contingencies in the Northwest, including the loss of the existing East-West Tie.

[2] Load rejection via the SPS for the loss of the existing East-West Tie is intended to be used only as an interim measure (Ontario Resource and Transmission Assessment Criteria, section 3.4.1, section 7.2).

Figure 1 presents the incremental Northwest capacity need from the 2017 Update Report, as well as the allowable level of load rejection (150 MW). In order to maintain a similar level of reliability as that provided by the E-W Tie Expansion and comply with Ontario planning criteria, the incremental capacity gap above the 150 MW of allowable load rejection would need to be addressed through other interim measures for the duration of any delay.

Figure 1 Expected Incremental Northwest Capacity Requirement under Reference Demand (2017 Update Report)



A number of resource options were considered as potential interim measures to address this incremental capacity need, including demand response, firm imports from Manitoba, and contract extensions with existing resources. These options and applicable considerations are outlined in further detail:

- The 2018 demand response auction cleared 30 MW of demand response in the summer and winter in the Northwest for approximately $80/kW-year. However, the product's availability limits its contribution to meeting the capacity need in the Northwest and the extent to which additional demand response can be acquired in the Northwest on a cost-effective basis is unknown.

- The cost of firm import capability from Manitoba is uncertain; it would not be known until the time of negotiation and the price could be increased by the short commitment period and reduced competition due to the small size of the Northwest market. Currently, the firm import capability from Manitoba is also limited to between 150 – 200 MW[3]. To inform a decision with respect to acquiring firm imports, the cost of a

[3] It should be noted that estimated firm import levels are based on transmission capabilities considering planning criteria, in accordance with applicable reliability criteria, and not real-time operating limits.

firm capacity import from Manitoba would be compared to the cost of acquiring new local generating capacity. The lifetime levelized cost of new local generating capacity in Northern Ontario is approximately $180/kW-year[4].

- There are resources within the Northwest with contracts currently set to expire throughout the 2020-2024 period. Extending contracts for select facilities could be considered as an interim measure. While the contract terms for these facilities are not public, the capacity cost would be compared to the cost of acquiring new local generating capacity. However, there could be a mismatch between how long the IESO would need the facility to run to meet the need and the facility owner's required commitment period for re-acquiring the facility, which could contribute to additional costs.

Based on these considerations, the IESO believes it is reasonable to estimate the capacity cost of addressing a delayed in-service date of the E-W Tie Expansion using the lifetime levelized cost of new local generating capacity in Northern Ontario. A sensitivity range was also applied, with the low end of the range reflective of the recent cost of winter demand response resources in the Northwest and the high end reflecting a 25%[5] uncertainty range on the levelized cost of new local generating capacity. The incremental capacity required and the associated estimated cost for 2020, 2021, 2022, 2023 and 2024 are presented in Table 1.

To the extent the delay extends beyond the end of 2022, the IESO anticipates that the risk of no longer being able to manage the capacity need through interim measures and the cost of managing the associated risk will substantially increase, for the following reasons:

- There is a step change in the capacity need, requiring more capacity to be acquired.
- To fill this capacity gap an increasing number of interim measures would be required, which increases the risk that the IESO may not be able to implement the required interim measures. For example, prior to the end of 2022, the capacity need can be met by imports from Manitoba and by arming 150 MW of load rejection; however, beyond the end of 2022, additional measures will be required such as demand response or contract extensions.
- Since more than one interim measure would be required beyond the end of 2022, the cost uncertainties increase, especially if one of the measures is contract extensions (e.g. it is unclear over how many years the facility owner would want to recover any capital costs required for the contract extension).

Historical flows are not indicative of what firm import levels are achievable as different contingencies are respected under planning and operating criteria.

[4] The $180/kW-year reflects economies of scale associated with addressing a smaller capacity need in the interim as some of the need is managed through load rejection.

[5] Reflects the same sensitivity range for Northwest capacity costs used in the 2017 Update Report (page 18, line 3).

All of this uncertainty creates a risk that the IESO may not be able to acquire the needed capacity beyond the end of 2022. As such, the IESO's assessment is that the E-W Tie Expansion should not be delayed beyond the end of 2022 due to unacceptable risks to system reliability and the associated cost uncertainties.

Table 1 Projected Cost of the Incremental Capacity Requirements (2020-2024)

Year	Requirement (MW)	Allowable Load Rejection (MW)	Incremental Requirement (MW)	Projected Cost (2017$ millions)	Projected Cost Range (2017$ millions)
2020	239	150	89	$16	$7 to 20
2021	251	150	101	$18	$8 to 23
2022	272	150	122	$22	$9 to 27
2023	360	150	210	$38	$16 to 47
2024	394	150	244	$44	$19 to 55

The IESO plans the electricity system to required standards, set out in the Ontario Resource and Transmission Assessment Criteria ("ORTAC") and by the North American Electric Reliability Corporation ("NERC"). The IESO's recommended in-service date is based on these criteria, which require that a solution be implemented by 2020 when the potential capacity shortfall can no longer be met through permitted load rejection. In the event the E-W Tie Expansion is delayed beyond the recommended 2020 date, the IESO would take necessary action to acquire the required additional capacity.

The short duration being contracted for combined with the small size of the Northwest market means these costs are uncertain. Acquiring this capacity may come at a higher cost if there are insufficient or limited resources competing to provide this short-term capacity.

In summary, the costs associated with a delay beyond the end of 2022 are very uncertain and may materially increase, as new resources or capital investment in retired facilities would likely be required in addition to any interim measures taken during the 2020 to 2022 period. The number of interim measures that would need to be employed and the risks associated with each interim measure increase the overall reliability risk to the Northwest. In the event of a delay to the in-service date, the IESO does not support allowing the E-W Tie Expansion to be delayed beyond the end of 2022 as the increased risks to system reliability and the associated cost uncertainties are unacceptable.

Energy Cost

The existing East-West Tie is one of the northern Ontario transmission interfaces currently subject to congestion, contributing to an increase in the average cost of energy. As a result of congestion on the East-West Tie and the downstream interfaces, low-cost energy from hydro facilities is sometimes bottled in the Northwest, leading to higher priced – and often higher-emitting – resources being dispatched in southern Ontario to meet Ontario's energy needs.

The IESO used an energy dispatch model to estimate future congestion costs due to a delay to the in-service date of the E-W Tie Expansion; the model assumed median water levels. The estimated difference in energy production costs from delaying the in-service date of the E-W Tie Expansion is approximately $0.5 million (2017$) per year.

Additional Costs due to Losses

Due to the long length of the existing East-West Tie line, paralleling the facility with the new line will provide energy cost savings by decreasing the line losses. The projected hourly flows across the East-West Tie, from the IESO's energy dispatch model, were used along with power flow studies to produce an estimate of the cost savings. The estimated combined yearly savings that would be foregone due to a delay to the in-service date of the E-W Tie Expansion is approximately $0.7 million (2017$).

Conclusion

The IESO continues to recommend an in-service date for the E-W Tie Expansion of 2020. The recommended in-service date is based on applicable planning and reliability criteria to ensure the reliability needs in the Northwest are met and to avoid the additional risks and associated costs of not having expanded transmission capability between the Northwest and southern Ontario.

A summary of the annual costs that may be incurred if the E-W Tie Expansion is deferred is presented in Table 2 below.

Table 2 Summary of Potential Cost of Delay to In-Service Date (2020-2024)

Year	Potential Capacity Cost (2017$ millions)	Energy Cost (2017$ millions)	Foregone Loss Savings (2017$ millions)	Total Potential Cost of Delay (2017$ millions)
2020	$16	$0.5	$0.7	$17
2021	$18	$0.5	$0.7	$19
2022	$22	$0.5	$0.7	$23
2023	$38	$0.6	$0.7	$39
2024	$44	$0.6	$0.7	$45

While interim measures may be able to address the incremental capacity need for all years considered in Table 2, an increasing number of interim measures, each with their own risks, would be relied on as the capacity requirement grows throughout the early 2020s. The costs associated with implementing alternative measures to address a delay beyond the end of 2022 are highly uncertain as new resources (such as new Northwest generation) or capital investment in retired facilities would likely be required in addition to any interim measures taken during the 2020 to 2022 period.

The IESO continues to recommend an in-service date of 2020 for the E-W Tie Expansion. If a delay is to be incurred, relying on interim measures will result in additional risks to reliability and increased costs. In this case, the IESO does not support delaying the in-service date of the East-West Tie Expansion beyond the end of 2022 as the increased risks to system reliability and the associated cost uncertainties are unacceptable.