IPSP Planning and Consultation Overview

May 2011

ONTARIO POWER AUTHORITY

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1.0 INTRODUCTION

Last November, the Ontario government issued a Long-Term Energy Plan (LTEP) - *Building Our Clean Energy Future*, which sets out the province's electricity requirements until 2030 and establishes how to meet them. The LTEP will help guide the Ontario Power Authority (OPA) as it continues to plan for a clean, modern and reliable electricity system.

In February, the Ministry of Energy issued the Supply Mix Directive, included in Appendix A, which requires the OPA to prepare a 20-year Integrated Power System Plan (IPSP) to meet the government's goals as set out in this directive.

In developing the LTEP and the Supply Mix Directive, the government considered the input of a wide range of stakeholders, as well as the expert advice of the OPA, Ontario Power Generation (OPG), Hydro One and the Independent Electricity System Operator (IESO).

Long term planning is a continuous process in which refreshed plans are built on the foundations of previous research and experience. For the past five years, the OPA has solicited the views of industry partners, stakeholders and others. This advice helped direct OPA planning, programs and initiatives. For example, feedback has been received in the development and initial review of the IPSP that was submitted to the Ontario Energy Board (OEB) in 2007 (IPSP I), the development of procurements (including the Feed-in Tariff (FIT) Program), the development of conservation programs and in regular stakeholder discussions.

The OPA will continue the consultation process to assist in developing an updated IPSP (IPSP II). This IPSP Planning and Consultation document is intended to provide stakeholders with information on the status of and outlook for the electricity system to assist in the consultation process. The information presented in this report is designed to provide an update on the current status of the electricity system and to provide an outlook that takes into account the development work currently under way and the policy decisions that have been made. This information is intended to support a dialogue that will assist the OPA in developing an updated IPSP.

After a period in which it was not always certain that demand for electricity would be met, considerable progress has been made in recent years on a number of system priorities. By the end of 2010, the OPA had contracts for more than 18,100 megawatts (MW) of new and existing supply. This represents an investment of about $27 billion in the province's electricity system and marks a significant turnaround in reliability.

Ontario's focus over the past few years has been on enhancing system reliability as well as enabling the phase-out of coal-fired generation by the end of 2014. Furthermore, the *Green Energy and Green Economy Act, 2009* (GEA) laid the foundation for building the province's supply of clean energy.

Ontario is in good shape to meet the demand for electricity in the period to 2015. Demand is expected to remain stable, with conservation programs offsetting increases from population growth and the economic recovery. There is a high degree of confidence that expected supply will meet the reasonable range of demand and allow for the elimination of coal-fired generation.

For the period from 2016 to 2022, there is a high degree of confidence that reliability can be maintained, even with planning considerations such as the performance of the Pickering nuclear generating station and the significant addition of renewable resources.

Beyond 2023, the balance between supply and demand is expected to be maintained as existing nuclear units are returned to service following refurbishment.

The updated Integrated Power System Plan will reflect the goals set by the government and identify the investments in conservation, generation and transmission that will be needed.

It's an "integrated" Plan because it will address both conservation and new supply and will ensure that conservation, generation and transmission investments are looked at together, balancing risks, costs and environmental impacts.

And it's an "updated" Plan because it will build on IPSP I. Although many elements of IPSP I have been implemented, the IPSP is intended to be a living Plan that looks ahead 20 years and is updated every three years to address changes in areas such as demand, energy policy and technology.

This IPSP Planning and Consultation document is organized according to the core areas of the sector – demand (or load), conservation, supply, transmission and the development of a smart grid. The document also discusses opportunities to connect remote communities to the grid. It incorporates the requirements laid out in the LTEP and the Supply Mix Directive. This consultation document is a key part of the consultation process that the OPA will be undertaking to hear from stakeholders, agencies, First Nation and Métis communities and others.

1.1 The Long-Term Energy Plan

The Long-Term Energy Plan listed reasons why Ontario needs to plan now to improve supply capacity to meet the province's electricity needs beyond 2015:

- Insufficient investment prior to 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
- Population is projected to grow

One of Ontario's strengths is a diversified supply mix. Each type of generation has a role in meeting overall system needs and Ontario requires the right combination of assets to ensure a balanced supply mix that is reliable, modern, clean and cost effective.

Key points of the LTEP include:

- Demand is expected to grow moderately (about 15 percent) between 2010 and 2030.
- Ontario will be coal-free by the end of 2014. Eliminating coal-fired generation from Ontario's supply mix will account for the majority of the government's 2014 greenhouse gas reduction target. Two additional units at Nanticoke Generating Station (GS) will be shut down in 2011. Two units at the Thunder Bay coal plant will be converted to gas and Atikokan GS will be converted to biomass. Ontario will continue to explore opportunities to advance the closure of the remaining six coal units.
- Nuclear power will continue to contribute about 50 percent of Ontario’s electricity supply. Units at the Darlington and Bruce sites will need to be modernized and the province will need two new nuclear units at Darlington. OPG will invest in the refurbishment of Pickering B to extend its life until 2020.
- Ontario will continue to expand its hydroelectric capacity with a target of 9,000 MW by 2018.
- Ontario's target for clean, renewable energy from wind, solar and bioenergy is 10,700 MW by 2018 (excluding hydroelectric). Ontario will continue to foster the clean energy economy through the continuation of FIT and microFIT programs. Ontario will continue to look for opportunities to expand the development of renewable energy for the period after 2018.
- Natural gas generation for peak needs will be of value where it can address local and system reliability issues.
- The OPA will design and implement a program for combined heat and power (CHP) projects.
- Aboriginal participation in Ontario’s energy future will be enabled through conservation, renewable energy and transmission initiatives.
- Five priority transmission projects are needed immediately for reliability, renewable energy growth and changing demand. Future Plans will identify more projects as they are needed.
- Conservation targets will be broadened to 7,100 MW by 2030, a new target to reduce overall demand by 28 terawatt-hours (TWh) and will also include interim targets.
- Over the next 20 years, estimated capital investments totalling $87 billion will help ensure that Ontario has a clean, modern and reliable electricity system.
- As a result of these investments, residential bills are expected to rise by 3.5 percent per year over the next 20 years. Industrial prices are expected to rise by 2.7 percent per year over the next 20 years.
- To help with the increased costs of these investments, the government is providing residential consumers, farmers and small businesses with the Ontario Clean Energy Benefit – a 10 percent discount on the total electricity bill for five years.

1.2 Summary of Supply Mix Directive Requirements

The government also provided a Supply Mix Directive (see Appendix A) to the OPA on the objectives to be achieved in the updated IPSP. Through this directive, the OPA is required to meet certain resource targets and to include assumptions about the future demand for electricity and other associated resources.

The OPA now has the responsibility to consult and develop a detailed plan that demonstrates how the government's goals will be achieved. Once completed, the OPA will submit the updated IPSP to the Ontario Energy Board for review. This regulatory review must to be completed within one year from the date the IPSP is submitted.

The Supply Mix Directive contains several mandatory requirements in the form of prescribed amounts and/or targets for certain resource types to be in service by specific dates within the planning period. The directive also requires the OPA to accommodate certain outcomes with regard to some facilities and electricity demand.

- Meeting the medium electricity demand growth scenario with enough flexibility to accommodate the potential for a higher growth outcome, as set out in the LTEP.
- Achieving conservation and demand management (CDM) targets of 7,100 MW and energy savings of 28 terawatt-hours (TWh) by the end of 2030 with milestones along the way to measure progress towards achieving those targets. These targets are to be exceeded and accelerated if it is feasible and cost effective.
- The refurbishment of 10,000 MW of nuclear generating capacity (in accordance with a coordinated refurbishment schedule) and the government's procurement of about 2,000 MW of new nuclear generating capacity.
- Phasing out coal-fired generation by the end of 2014 and working with the IESO and OPG to determine opportunities to advance the closing of remaining units.
- The conversion of Atikokan GS to biomass by 2013 and of Thunder Bay GS to natural gas by 2014.
- An assessment of the conversion of some or all of the remaining units at Lambton GS and Nanticoke GS to natural gas so that the government may make a decision by 2012.
- Installed hydroelectric capacity to reach 9,000 MW by 2018.
- Installed non-hydroelectric renewable capacity of 10,700 MW by 2018.
- The procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area.
- Completion of five priority transmission projects identified in the Supply Mix Directive as well as a plan for remote community connections beyond Pickle Lake.

- Consideration of smart grid developments under way in Ontario and ensuring that distribution-level investment associated with smart grid and renewable connections is considered in the context of the IPSP.

- Carry out procedural aspects of any Crown constitutional duty to consult with First Nation and Métis communities in developing the Plan.

In addition, there are a number of existing government procurement directives issued to the OPA for conservation and supply. For more information, consult the OPA website at www.powerauthority.on.ca.

1.3 Development of IPSP II

In developing the IPSP, the OPA is required to comply with Ontario Regulation 424/04. The regulation outlines the timing of IPSP updates and requirements that must be followed.

The mandatory requirements of the Supply Mix Directive, combined with the existing resources available to meet the demand for electricity, mean that the focus of this IPSP is on implementation and future planning frameworks and not on the addition of new generation sources.

There are, however, areas of consideration in the Plan. These are:

- How should the IPSP meet the mandatory resource requirements in the Supply Mix Directive?

- How can challenges to meeting those requirements be addressed?

- What incremental capacity, energy and ramping requirements remain after the mandatory Supply Mix Directive requirements and other committed and directed resources have been accounted for?

- How should the IPSP address the mandate to implement, exceed and/or accelerate the CDM targets?

- How should alternative resources (firm imports, storage, etc), be considered in light of the OPA's planning considerations? When is it necessary or appropriate to decide among them?

- What are the IPSP's recommendations about the scope and timing of the five priority transmission projects?

- What other cost-effective transmission and distribution solutions should be addressed through the IPSP and other decision processes?

- How should current assumptions for demand, project timelines, technology and energy policy framework be kept current and realistic in future IPSPs?

- What should be the plan for connecting remote communities?

- How should the IPSP consider smart grid developments?

In addressing these requirements, the government asks in the Supply Mix Directive that the OPA specifically consider reliability and operability and be mindful of the total bill impacts and the impacts that the costs of choices made within the IPSP have on electricity rates generally.

In development of IPSP II, the OPA will continue to consider the set criteria that were developed in IPSP I:

- *Feasibility* - Comprising technical feasibility, commercial availability, technological maturity, sufficient infrastructure and lead time, and compliance with regulations
- *Reliability* - Resource adequacy and system security, which make up the components of this criterion, are necessary to maintain system reliability at all times throughout the planning horizon
- *Cost* - Encompasses cost of options on the planning horizon, the value of conservation, cost of services to consumers and impact on customers' bills
- *Flexibility* - Includes the flexibility of options in the future and the ability of the plan to be sufficiently adaptable to a range of future scenarios
- *Environmental performance* - Includes the amounts of greenhouse gas (GHG) emissions, conventional contaminant air emissions, radioactivity, water use and wastes generated
- *Societal acceptance* - Includes the matters that have significant socio-economic implications, meeting government policy and addressing stakeholder expectations.

Emphasis will be placed on further developing sustainability indicators for use in OPA planning activities.

The OPA will adopt an integrated approach early in the plan-development process and continue to develop its assessment framework so that the Supply Mix Directive's requirements are considered comprehensively. This approach should also be flexible enough so that it can be extended to individual elements of the Plan, where necessary.

The various directives received by the OPA and the requirements for planning assumptions in the Supply Mix Directive mean there are not expected to be any new procurements that will require separate approval by the OEB in this IPSP. There is adequate supply to meet near term needs and there is time to decide on options that may be required to address future needs.

1.4 Consultation and Review

In developing both the LTEP and the Supply Mix Directive, the government consulted extensively with Ontarians and stakeholders. By regulation, the OPA is required to consult with consumers, distributors, generators, transmitters and others who have an interest in the electricity industry as it develops the IPSP. This ensures the views of Ontarians are considered in the development of the updated 20-year plan.

This directive to provide an updated IPSP offers an opportunity to undertake a structured consultation program. The participation of Ontarians will be vital and there will be opportunity for input in a variety of formats.

The consultation includes an initial session for the launch of the IPSP process and a review of this IPSP Planning and Consultation Overview document.

In addition, sessions will be held to focus on various elements of the electricity system, including load (demand), conservation, supply and renewable energy, along with transmission and the smart grid. Specifically, this means:

- An overview of the assumptions that underline the demand forecasts from the Supply Mix Directive. Discussion will focus on what drives demand, the uncertainty related to future demand and the identification of indicators that should be monitored to inform future plans.

- An overview of the strategy for meeting Ontario's long-term conservation targets will be presented. The OPA will share information regarding experiences to date with conservation activities, including conservation and demand management (CDM) programs, supporting codes and standards development and supporting innovation and emerging technologies. The OPA will present its plan for achieving the targets set out in the Supply Mix Directive.

- Supply resources, including renewable energy, will be identified and planning assumptions will be presented. The focus of discussion will be on developing indicators for future supply planning and the challenges and solutions for integrating renewable energy in the near term.

- The Supply Mix Directive establishes the need for additional transmission facilities to meet the government's targets for renewable energy and to maintain reliability. The discussion of additional transmission facilities in this consultation document provides information on the prescribed facilities and an overview of planning activities that underline them.

1.5 Aboriginal Consultation

The OPA engages with Aboriginal communities on matters related to the OPA's mandate. It wishes to continue to engage and consult with Aboriginal communities in a thorough and transparent manner as part of the IPSP process. The OPA recognizes that important aspects of engagement and consultation on the IPSP include developing relationships, providing information, addressing concerns where appropriate and ensuring dialogue around the implications and benefits of the IPSP for Aboriginal communities.

The following principles guide the OPA's consultation process with First Nations and Métis communities:

- Engage with Aboriginal communities early in the process and continue engagement throughout the OEB review

- Provide Aboriginal communities with information regarding the IPSP in a timely and appropriate manner so communities can consider such information in determining their interests regarding the IPSP
- Provide opportunities to Aboriginal communities to identify issues and contribute to identifying potential future effects of implementation of the IPSP
- Respond to issues and concerns raised by Aboriginal communities
- Indicate how information from and concerns of Aboriginal communities have been considered and, where appropriate, taken into account by the OPA
- Avoid, reduce or mitigate, as appropriate, the adverse effects, if any, of the IPSP planning process on Aboriginal and treaty rights of Aboriginal communities; and
- Disseminate, to the extent possible, the results of the consultation process.

In line with these principles, the OPA's engagement and consultation with Aboriginal communities on the IPSP may include, but is not limited to, activities such as regional meetings, community meetings and reporting back.

Regional meetings

The OPA and the Ministry of Energy will meet with First Nations and Métis community representatives in regional meetings to discuss the IPSP. Regional meetings will be an opportunity to introduce the IPSP to Aboriginal community representatives and to gather feedback on the IPSP. It will also be an opportunity to provide updates and respond to questions on current OPA programs that support Aboriginal participation in the electricity sector (*e.g.* Aboriginal Energy Partnerships Program).

Community meetings

OPA staff will supplement consultations through regional meetings by meeting, as necessary, with Aboriginal communities to discuss the IPSP, respond to questions and collect direct feedback from community members. Where possible, these meetings will be coordinated with the assistance of community consultation coordinators.

Report back

The OPA will prepare a report highlighting various interests, concerns and comments raised throughout the consultation process. This report will be shared with each First Nation and Métis participant at the regional and community meetings, and the Ministry of Energy.

For additional details on the IPSP Aboriginal consultation process, consult the OPA website at www.powerauthority.on.ca. Feedback from this consultation will help inform the development of the updated IPSP.

1.6 Areas for Consultation

The OPA is seeking stakeholder input to support the development of the planning considerations and integrated planning areas. As mentioned above, IPSP II will reflect the goals set by the government in the Long-Term Energy Plan and comply with the requirements of the Supply Mix Directive. There are not expected to be any procurements in the Plan that will require approval through the IPSP process.

Nevertheless, there are many questions to be answered in the consultation process. These are identified in the subsequent chapters.

1.7 Ongoing Planning Activity

In addition to the formal IPSP development process, the OPA regularly engages in a number of planning-related activities. These activities will not be addressed in this IPSP; however the outcome of these planning activities may be integrated into future IPSPs. The planning areas in which the OPA is currently engaged -- or may be engaged in prior to the next IPSP update -- relate to:

- Preparation of a longer term load forecast methodology and planning scenarios
- Refinement of current CDM programs and their projected performance, based on actual delivery and evaluation results
- Development of the next generation of CDM province-wide programs
- Local area planning including:
    - Coordination of regional expansion plans
    - Role of CHP in urban areas
    - Continuation of planning dialogue with local distribution companies (LDCs)
- The coordination of OPA procurement contracting and market mechanisms under the IESO
- The scheduled two-year review of the FIT Program.

1.8 Summary

The IPSP is designed to be an integrated plan that will reflect the goals set by the government and identify the investments needed in conservation, generation and transmission to ensure a reliable, clean and modern electricity system for the next 20 years. It is intended to be a guide for future decisions.

New supply now online and procurements currently under way have given us breathing room. We also have more lead-time for decision-making.

The future of Ontario's electricity system is characterized by three time frames.

For the period to 2015, there is a high degree of confidence that expected supply will meet the reasonable range of demand and allow for the elimination of coal-fired generation. For the period from 2016 to 2022, there is a high degree of confidence that reliability can be maintained even with planning considerations such as the performance of the Pickering nuclear generation station and the significant addition of renewable resources. Beyond 2023, the balance between supply and demand is expected to be maintained as modernized nuclear units are returned to service.

This Plan will focus on the implementation of decisions that have been made and there is no expectation that additional facilities will be recommended beyond those identified by the government. The detailed sections that follow, including chapters on demand, supply, conservation, transmission, and the smart grid, will illustrate the outlook for Ontario's electricity system.

2.0 DEMAND

From the LTEP:

There are three potential future demand scenarios (net of conservation) for electricity demand: low, medium and high.

The three scenarios do not differ significantly until 2018, allowing time to adjust as future Plans are updated. For planning purposes, Ontario is using the medium-growth scenario but also planning to create sufficient flexibility in the system to accommodate the higher-growth scenario.

From the Supply Mix Directive:

The OPA shall use a medium electricity demand growth scenario. This balances the expected growth in residential and commercial sectors with modest, post-recession growth in the industrial sector.

Under this scenario, Ontario's demand would grow moderately, about 15 percent between 2010 and 2030 based on projected increases in population and conservation as well as shifts in industrial and commercial needs.

The IPSP needs to have flexibility to accommodate the potential for a higher growth outcome.

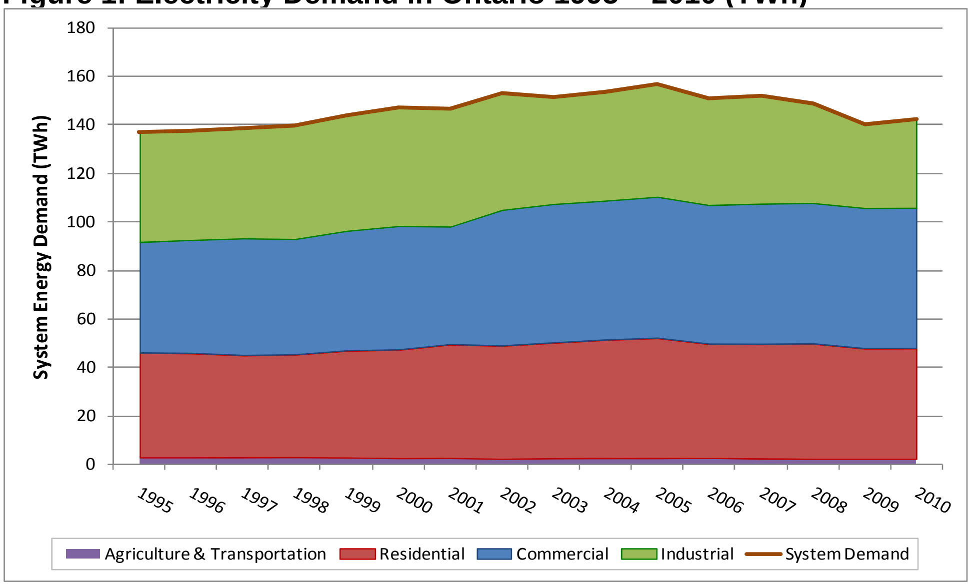
AREAS TO BE CONSIDERED IN THE IPSP:

How should current assumptions for demand, project timelines and technology be kept current and realistic in future IPSPs?

2.1 Recent History

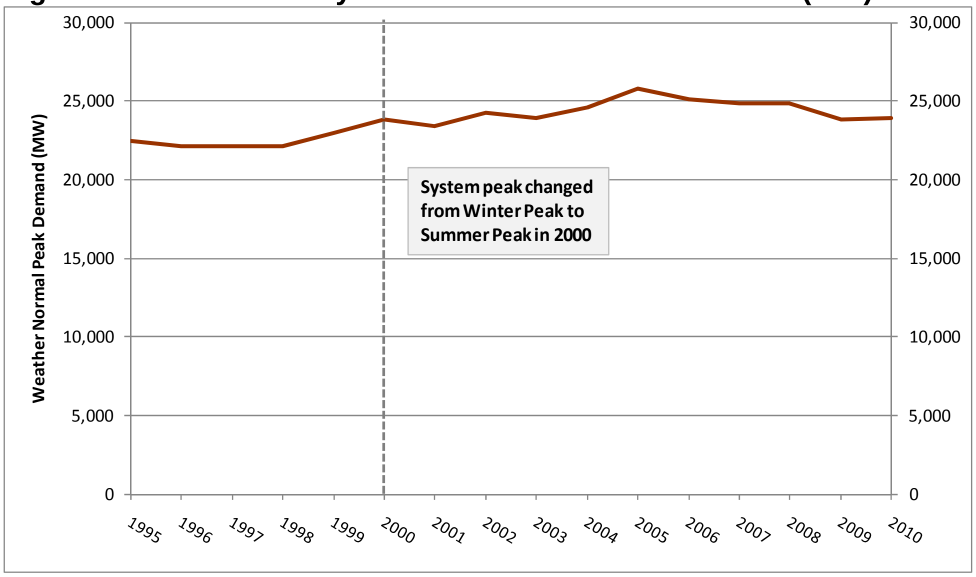
Annual demand for electricity in Ontario peaked in 2005 (as illustrated in Figure 1 and Figure 2 below). Since then, demand for electricity has declined by nearly 10 percent. Changes in the structure of Ontario's economy and the recent recession account for the majority of the decrease in demand between 2005 and 2010. Demand in the residential and commercial sectors has been relatively steady over recent years. Meanwhile, demand in the industrial sector has seen a pronounced decline.

Figure 1: Electricity Demand in Ontario 1995 – 2010 (TWh)



Note: Energy demand by sector not yet available for years 2008-2010. Demand by sector values above for 2008 – 2010 are estimated by the OPA
Source: NRCan, IESO, OPA

Figure 2: Peak Electricity Demand in Ontario 1995 – 2010 (MW)



Note: Data is weather normalized.
Demand peaked at more than 27,000 MW in 2006 under hotter than normal weather conditions.
Source: IESO

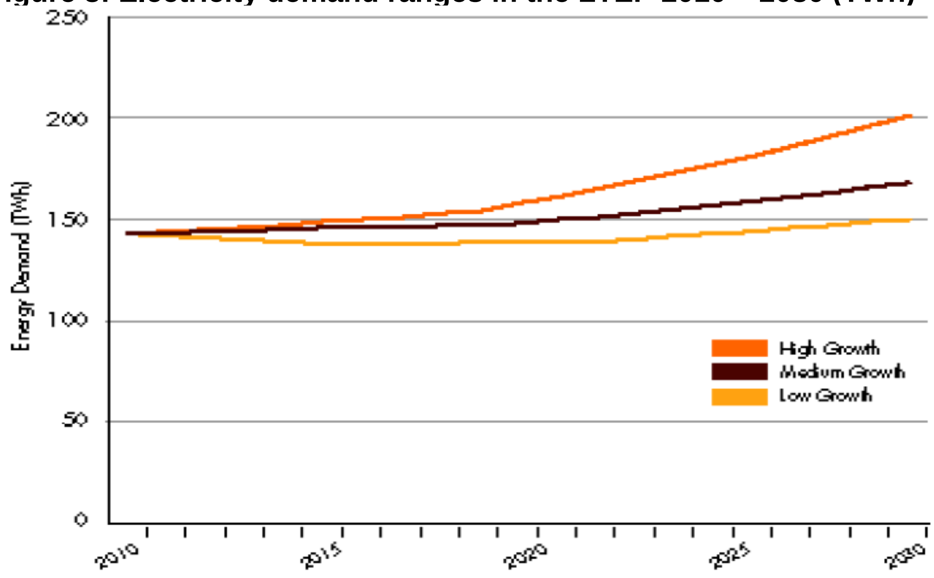
Factors such as demographics, population growth, the development of the economy, customer response to energy prices, technology developments, public policy on transportation and energy use all have an effect on the demand for electricity. They are all an integral part of demand forecasting.

2.2 Summary of Supply Mix Directive Requirements

The IPSP will incorporate three electricity demand scenarios described in the Long-Term Energy Plan and required by the Supply Mix Directive. These scenarios should be interpreted as a range of potential outcomes, not as end point predictions. Together, these scenarios help establish the context for long-term integrated planning.

These electricity demand growth scenarios are described in the government's Long-Term Energy Plan (LTEP), along with a low-growth scenario.

Figure 3: Electricity demand ranges in the LTEP 2010 – 2030 (TWh)



Source: Ontario government, Long Term Energy Plan

2.3 Medium-Growth Demand Scenario

According to the LTEP, under a medium-growth scenario, Ontario's electricity system should be prepared to provide 146 terawatt-hours (TWh) of generation in 2015, and increase to 165 TWh in 2030.

The medium-growth scenario assumes modest recovery in the industrial sector, as well as continued growth in the residential, commercial and transportation sectors. This scenario can be described as a status quo scenario with growth rates and trends returning to levels observed before the recent economic slowdown.

The medium-growth scenario is characterized by the recovery of most of Ontario's industrial sector from recent recessionary lows but with total industrial demand barely reaching 2005 levels by the end of the forecast period. Individual industries are expected to vary in their long-term growth. Some of the structural impacts of the recession remain going forward, with the pulp and paper sector continuing to negatively affect demand.

Existing conservation targets are assumed to be met. In this scenario, household numbers continue to grow, coupled with a decreasing intensity of electricity use per household despite increasing saturation of small appliances, especially entertainment electronics.

Meanwhile, in this scenario, electricity use for space heating and water heating continues the loss of market share that began in the 1990s, while growth in commercial floor space continues along with a decreasing intensity of electricity use per square metre. Commercial air-conditioning is the major contributor to summer peak growth while lighting, ventilation and auxiliary equipment, such as printers and computers, are the major contributors to energy growth. In the transportation sector, the scenario reflects a five percent penetration of electric, light duty vehicles in Ontario by 2020, consistent with the current government goal.

Conservation achievements under the medium-growth scenario are consistent with prescribed targets (13 TWh by end of 2015, 21 TWh by end of 2020, 25 TWh by end of 2025 and 28 TWh by end of 2030).

2.4 Factors to Consider in Meeting Demand While Maintaining Flexibility

Demand projections help establish the context against which planning decisions and options can be explored.

Demand can be affected by the growth or decline of any of the main sectors of the economy, including the residential, commercial, industrial, transportation and agricultural sectors. Demand can also be influenced by changes in technology, such as the development of more energy-efficient appliances; changes in government regulations that could include more stringent building codes and standards, or greenhouse gas policy; or, as we've seen, a global economic downturn. Each of the factors that influence demand is subject to its own multitude of uncertainties.

With so many moving pieces and potential outcomes, it is difficult to accurately predict demand over the long term. It is more useful in developing a plan to consider a range of potential outcomes through the use of scenarios.

The high-growth scenario is characterized by aggressive electrification. The key differences between a medium-growth and high-growth scenario over the long term are expected to occur in the residential, commercial and transportation sectors. A high-growth scenario assumes the application of aggressive North American greenhouse gas regulation, prompting consumers to switch from higher carbon sources of energy to lower ones. This would drive the electrification of heating and water heating in the residential and commercial markets, and lead to the faster adoption of electric vehicles, as well as the electrification of mass transit.

In addition to the potential factors that influence demand identified in the LTEP, there are a number of other factors that could also produce a similar, high-growth scenario. These might include a more rapid industrial recovery driven by greater export opportunities; the increased electrification of industrial processes as part of a low-carbon strategy; as well as growth in both the service and residential sectors, driven by an increase in job opportunities in the province.

The low-growth scenario illustrates a future in which industrial demand in Ontario continues to grow modestly in step with current trends. This reduced demand in the industrial sector is driven by a persistent move away from energy-intensive industries and is accompanied by a reduction in the growth rate of the residential and commercial sectors as the number of industrial jobs and related services declines.

The three electricity demand scenarios vary modestly in the near term. In this period, demand remains relatively flat or declines slightly as conservation efforts continue to offset growth and the pace of the economic recovery remains modest. Greater variability is seen over the longer term, however, as other factors that influence demand have a more dramatic impact.

The demand forecast is one of the planning areas that the OPA will continue to carry on outside the IPSP process. This ongoing work will address the fact that while these scenarios are depicted on a province-wide basis, the rate of demand growth will vary across Ontario and there may be a need for more localized planning in some cases.

By undertaking this kind of analysis on a continuing basis, we are able to interpret current events as signposts that give us clues about the future that can guide planning decisions as they need to be made. These signposts may include the performance of the industrial sector, growth trends in commercial floor space, progress toward conservation targets or new uses for electricity.

This type of analysis allows us to assess demand trends routinely and gauge them against assumptions we have made in the planning process. It is an ongoing cycle of monitoring new information and incorporating it into ever-evolving, long-term potential scenarios.

The Supply Mix Directive provides the context for the range of scenarios that will be assessed as options and decisions are made in developing the long-term plan. However, as this section has already noted, the LTEP demand scenarios do not diverge significantly in the near term and most of the planning decisions covering that timeframe have already been made.

2.5 Areas for Consultation

As outlined at the beginning of this chapter, the OPA is continuing to seek advice from Ontarians on aspects of electricity demand in the province as it prepares the IPSP. The OPA invites feedback from stakeholders and the public on these and other issues. The questions below are posed as a starting point for further discussion and feedback:

1) What are the key factors that influence electricity demand?

2) What are the most significant uncertainties related to long-term electricity demand forecasts in Ontario and what are their implications for planning?

3) How might transportation sector electrification, including prevalence, location and timing, have an impact on integrated planning?

4) What signposts or indicators should be monitored on a continuing basis to assess progress within the prescribed demand ranges?

5) Do you have specific advice or factors the OPA should consider related to demand for electricity?

3.0 SUPPLY

From the LTEP:

Since 2003, Ontario has brought about 8,700 megawatts (MW) of electricity online.

Ontario shut down eight coal units since 2003, representing 3,000 MW, and will close the remaining units by 2014 or earlier. Coal-fired generation now makes up just 13 percent of Ontario's electricity capacity.

IPSP I projected 7,708 MW of hydroelectric generating capacity by 2010. This goal was exceeded, with hydroelectric now representing 8,127 MW. Since 2003, 317 MW of new hydroelectric projects have been brought on line.

Ontario is now a leader in wind and solar capacity and home to Canada's four largest wind and solar farms.

- In 2003, Ontario had 10 wind turbines but today has more than 800.
- Since October 2003, the government has signed more than 16,000 renewable energy supply contracts from wind, water, solar and bioenergy sources.

From the SUPPLY MIX DIRECTIVE:

The government's commitment to replace all coal-fired generation by the end of 2014 will be met.

- The shutdown of two additional units at Nanticoke will take place before the end of 2011
- The OPA has been directed to negotiate with Ontario Power Generation (OPG) for a contract for biomass-fuelled generation from the Atikokan GS
- Two units at Thunder Bay GS are to be converted to run on natural gas
- The OPA shall work with the Independent Electricity System Operator (IESO) and OPG to determine opportunities for advancing the closing of additional units
- Assess the conversion of some or all of the remaining units at Lambton and Nanticoke GS to natural gas. The government will make the decision on conversion of some or all of these units in 2012.

Continue to plan for nuclear generation to account for approximately 50 percent of Ontario's electricity generation

- Plan shall provide for the refurbishment of 10,000 MW of existing nuclear capacity at Bruce nuclear generating station (NGS) and Darlington NGS
- Plan shall provide for the procurement of two nuclear reactors (about 2,000 MW) at Darlington.

Provide for installed hydroelectric capacity to reach 9,000 MW by 2018

- Additional cost-effective hydroelectric resources should be developed if they are identified
- The Plan shall provide for hydroelectric generation to account for approximately 20-25 percent of total electricity generation.

AREAS TO BE ADDRESSED IN THE IPSP:

- How does the IPSP accommodate the mandatory supply requirements in the Supply Mix Directive?
- How can challenges to meeting those requirements be addressed?
- What incremental capacity, energy and ramping requirements remain after the mandatory requirements and other committed and directed resources have been accounted for?
- How will alternative supply resources (facilities, firm imports, storage and transmission) be addressed by the OPA's planning considerations when it is time to consider conservation and supply resources in an integrated manner?
- How do the mandatory requirements contribute to meeting the demand forecast scenarios in the Supply Mix Directive?
- What are the challenges in meeting mandatory requirements and how will those challenges be met
- What are the incremental resource requirements?

FROM THE SUPPLY MIX DIRECTIVE (CONTINUED)

The OPA shall plan for 10,700 MW of renewable energy capacity, excluding hydroelectric, by 2018

- The plan shall provide for renewables, excluding hydroelectric, to account for approximately 10-15 percent of total electricity generation by 2018
- The government will look for opportunities to incorporate additional capacity from renewables.

The OPA shall continue to plan on natural gas for strategic uses. The procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area is necessary to ensure adequate regional electricity supply.

The Plan shall consider potential electricity storage, the availability of imports and other methods in order to meet reliability and operability requirements throughout the duration of the Plan.

Electricity supply has dramatically improved in Ontario since the early 2000s, when the province came close to brownouts and service interruptions on several occasions. Since then, substantial investments in conservation, transmission and generation have improved the reliability of the system and laid the foundation for a transformation to a supply mix with lower emissions of carbon dioxide and other pollutants.

As a result, Ontario is in good shape to meet the demand for electricity in the period to 2015. It is also well positioned to meet the goal of replacing coal-fired generation by the end of 2014. This enhanced reliability provides the breathing room to plan for the long-term future.

It is important to maintain a flexible approach that allows options to be kept open to meet changing circumstances.

Significant additions of hydroelectric and intermittent renewable sources are expected to be added to the supply mix over the next eight years. These sources will amount to about 30 to 40 percent of Ontario's electricity supply. There are a number of options to help in integrating new resources and to maintain the performance of the system.

Assuming the life of Pickering NGS can be extended until 2020, a short-term gap in supply between 2019 and 2022 is forecast, based on an estimate of moderate growth in the demand for electricity. This gap arises as existing capacity at Darlington and Bruce NGS is taken off line for modernization. There are options for meeting this gap, which include both additional conservation and supply. The supply options include a renegotiation of contracts for non-utility generators (NUGs) and the conversion of additional coal-fired generating stations to gas-fired operation. These supply options are being considered in a process outside the scope of the IPSP.

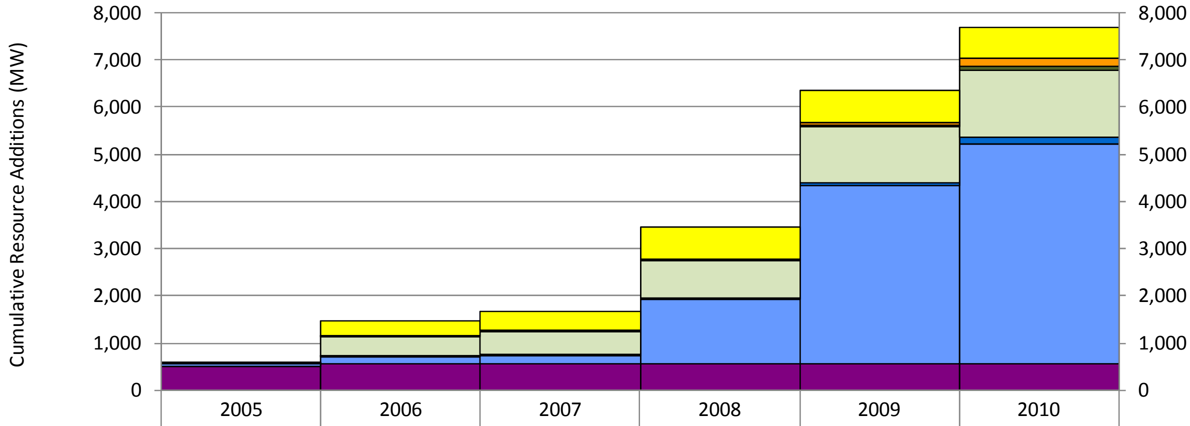
If the life of Pickering NGS is not extended, a short-term gap in supply is forecaset to exist between 2016 and 2022.

Beginning in 2015, there may also be a need for additional generation that can be dispatched quickly to meet rapid changes in demand and maintain operability. At this time, there is not expected to be a request for additional generation resources arising from this IPSP process. It is anticipated that capacity could be available from NUGs and coal-to-gas conversions (with possible biomass co-firing). In addition, system operators are developing new tools and processes for integrating renewable resources.

3.1 Recent History

Between 2005 and 2010, over 7,500 megawatts (MW) of cumulative resource additions were brought on to the system, as shown in Figure 1. This includes new generation in the form of natural gas, renewable resources and refurbished nuclear facilities, as well as demand response programs that can be dispatched to lower demand on the system.

Figure 1: Cumulative Resource Additions 2005 – 2010



	2005	2006	2007	2008	2009	2010
Demand Response	0	319	417	683	706	644
Solar	0	0	0	10	39	173
Bioenergy	3	3	28	34	35	86
Wind	2	401	482	782	1,190	1,439
Hydroelectric	18	18	24	53	66	130
Natural Gas	44	161	161	1,345	3,768	4,655
Refurbished Nuclear	515	564	564	564	564	564
Total	582	1,465	1,677	3,471	6,368	7,691

Source: OPA

A detailed list of the supply added in this period is shown in Table 1 below.

The additions include the return to service in the last quarter of 2005 of one nuclear unit at Pickering A and a number of new renewable and natural gas-fired resources. Demand response additions reflect a variety of programs administered by the Ontario Power Authority.

During the same period, about 1,100 MW of coal-fired supply was removed from service with the closing of the Lakeview generating station (GS) in the second quarter of 2005. In October 2010, the government announced the shutdown of two units at Nanticoke generating station (GS) and 2 coal units at Lambton GS. An additional two units at Nanticoke will be shutdown in late 2011.

Table 1: Detailed Resource Additions, 2005 – 2010

Status	Resource Type	Commitment	Project	MW
Existing Additions from 2005-2010 (7,692 MW)	Nuclear (564 MW)	Refurbishment	Pickering A Unit 1	515
		Upgrades	Bruce nuclear upgrades to BG5, 7, and 8	49
	Gas (4,655 MW)	Clean Energy Supply (1,948 MW)	Greater Toronto Airport Authority	117
			Greenfield Energy Centre	1,153
			St. Clair Energy Centre	678
		Accelerated Clean Energy Supply (2,286 MW)	Portlands Energy Centre	639
			Goreway Station	942
			Halton Hills	705
		Combined Heat and Power I (481 MW)	East Windsor Cogen	100
			Algoma Energy by-product cogen	63
			Thorold Cogeneration	287
			Warden Energy Centre	5
			Durham College District Energy	3
			Great Northern Tri-gen	11
			Countryside London Cogen	12
		Biomass Conversion	Conversion of Fort Frances from gas to biomass	-58
		Derates	Various	-2
	Hydroelectric (130 MW)	Renewable Energy Supply I	Umbata Falls	24
			Glen Miller/Sidney	8
		Hydroelectric Energy Supply Agreement	Lac Seul	12
			Healey Falls	17
			Hound Chute	10
		Upper Mattagami	Sandy Falls	6
			Wawaitin	15
			Lower Sturgeon	14
		Renewable Energy Standard Offer Program	Various	28
		Derates	Various	-4
	Wind (1,439 MW)	Renewable Energy Supply I (305 MW)	Kingsbridge 1	40
			Erie Shores	99
			Prince Wind Power Project 1	99
			Melancthon 1	68
		Renewable Energy Supply II (689 MW)	Prince Wind Power Project 2	90
			Ripley Wind Farm	76
			Melancthon 2	132
			Kruger Energy Port Alma Wind Power Project	101
			Enbridge Ontario Wind Farm	182
			Wolfe Island Wind Project	198
		Renewable Energy Supply III (150 MW)	Gosfield	51
			Talbot	99
		Renewable Energy Standard Offer Program	Various	194
		Feed-In Tariff	Various	1
		Upgrades	Various	10
	Bioenergy (86 MW)	Renewable Energy Supply I	Eastview Landfill Gas	3
			Trail Road Landfill Gas	5
			Hamilton Community Digester	2
		Biomass Conversion	Conversion of Fort Frances from gas to biomass	47
		Renewable Energy Standard Offer Program	Various	38
		Feed-In Tariff	Various	8
		Derates	Various	-17
	Solar (173 MW)	Renewable Energy Standard Offer Program	Various	164
		Feed-In Tariff & microFIT	Various	10
	Demand Response (644 MW)	Demand Response	Various Demand Response Programs	644
			Total	**7,692**

Source: OPA

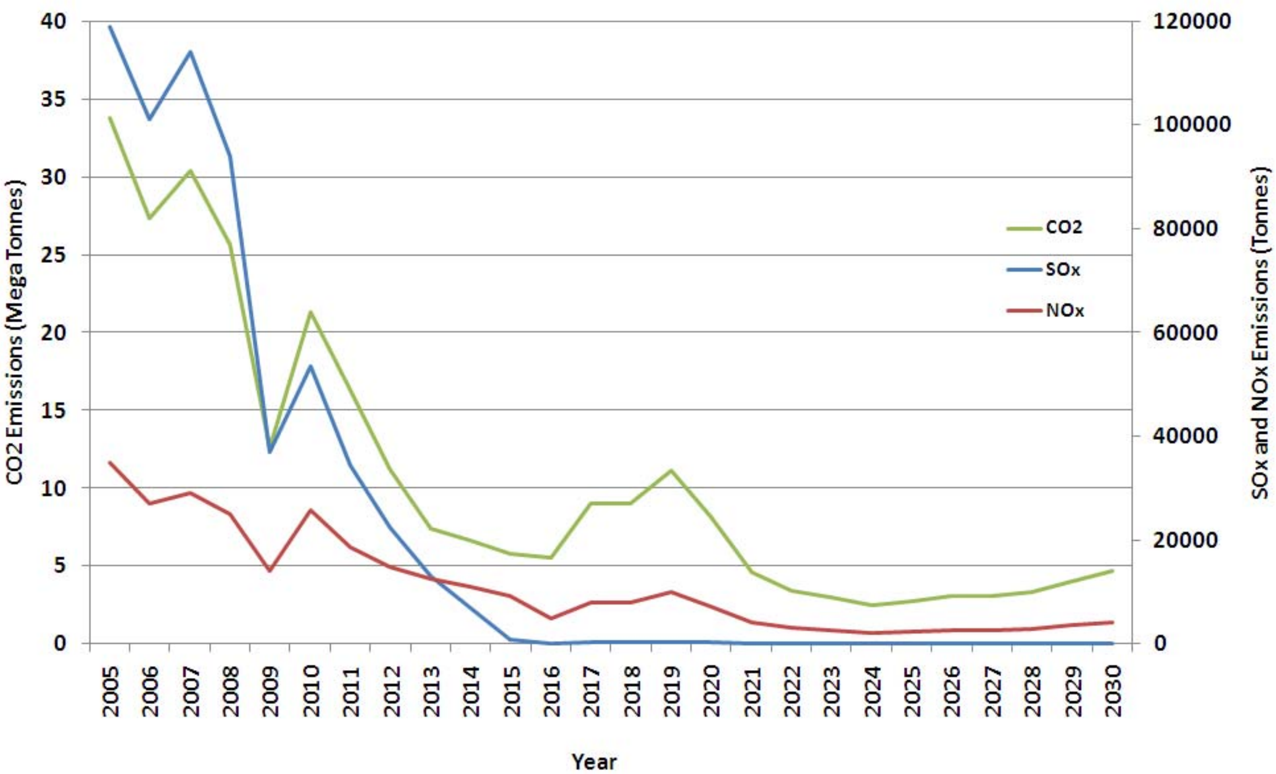
Note: The projects listed present their maximum capacities, which indicate the maximum technical output of a facility. This is not to be confused with the OPA contracted capacity, which is equal to or less than the nameplate capacity.

Emissions from 2005 to 2030

Emissions of carbon dioxide and other pollutants from electricity generation declined from 2005 to 2009. Part of the decline in the period is related to the reduction in coal-fired generation in those years, while the sharp drop in 2009 can be attributed to the economic slowdown that affected a range of businesses. Emissions increased slightly in 2010 as a result of low water conditions along with increased electricity demand stemming from improved economic conditions and a hot, humid summer. It is important to note, however, that although coal generation rose in 2010, it was 45 percent lower than in 2008 and roughly one-third of what it was in 2003.

Figure 2 shows the actual emissions produced between 2005 and 2010 and the estimated emissions for 2011-2030. In the figure, carbon dioxide (CO_2) emissions are graphed in megatonnes (Mt) on the left vertical axis, and sulphur oxide and nitrogen oxide are shown in tonnes (t) on the right vertical axis.

Figure 2: Emissions from Ontario Generation 2005-2030



Source: OPA and LTEP

The emissions that result from energy production as forecast in the LTEP show a continuing decline while coal phase-out is completed and then stabilize for the balance of the planning period. The OPA will update projections as it develops the IPSP.

3.2 Summary of Supply Mix Directive Requirements

The Supply Mix Directive requires the OPA to prepare a plan to meet government goals in a number of areas.

- The refurbishment of 10,000 MW of nuclear generating capacity (in accordance with a coordinated refurbishment schedule) and the government's plan to add about 2,000 MW of new nuclear generating capacity at Darlington
- Phasing out coal-fired generation by the end of 2014 and working with the Independent Electricity System Operator (IESO) and Ontario Power Generation (OPG) to determine opportunities to advance the closing of remaining units
- The conversion of Atikokan GS to biomass by 2013 and of Thunder Bay GS to natural gas by 2014
- An assessment of the conversion of some or all of the remaining units at Lambton GS and Nanticoke GS to natural gas so that the government may make a decision by 2012
- Installed hydroelectric capacity to reach 9,000 MW by 2018
- Installed non-hydroelectric renewable capacity of 10,700 MW by 2018
- The procurement of a natural gas-fired plant in Kitchener-Waterloo-Cambridge area

3.3 Resource Planning Process

To develop the IPSP, the OPA undertakes a continuous resource planning process. It seeks to reflect changes in economic outlook, system operation experience, revised cost projections and other factors that could have an impact on the future demand for or supply of electricity. A number of steps are involved.

- Establish the amount and timing of existing supply resources as well as new resources that are committed or directed

  The first step in the resource planning process is to identify those resources that currently exist, have an executed contract with the OPA or are the subject of a government directive. These are non-discretionary resources in the resource mix. In each case, it is necessary to determine the in-service date (for new resources) and the end-of-life date, if applicable.

- Determine the contribution of resources during peak periods

  It is necessary to determine the extent to which resources are available at time of peak. Due to their intermittent nature, wind and solar resources contribute less than their nameplate capacity. Gas-fired generation is de-rated during peak periods to account for increased cooling requirements during high summer ambient temperatures. The capacity contribution at summer peak assumed for each resource type is outlined in Table 6.

- Determine the amount of resources needed for adequacy

  The amount of resources needed in a given year is determined by the forecast annual peak demand plus planning reserve requirements. Planning reserve requirements are determined through the use of a model that takes into consideration load forecast uncertainty, the unreliability of generating units and the variability of renewable resources. The reserve margins are in accordance with the Northeast Power Coordinating Council (NPCC) resource adequacy criterion as stipulated in NPCC *Regional Reliability Reference Directory #1*. This criterion meets North American Electric Reliability Corporation (NERC) policies and standards. The reserve margin is expressed as a percentage of annual peak demand and represents the reserve level needed to meet the reliability criteria of an annual loss of load expectation (LOLE) of 0.1 days per year. For preliminary planning purposes, the OPA assumes a reserve margin of 17 percent of annual peak demand is required. This amount will be re-assessed for the IPSP.

- Determine the extent to which existing, committed and directed resources meet the resource requirement and identify if additional resources are needed

  The capacity gap is the amount of capacity required over and above existing, committed and directed resources to meet the resource requirement.

- Identify resource options

  The timing, magnitude and duration and operational characteristics are important considerations in identifying the type of resource options needed to address the capacity gap. For instance, if the gap occurs too soon, it could preclude long lead-time options. If a small capacity gap occurs and persists for a short period of time, options that do not involve a significant capital investment are appropriate.

- Develop scenarios for future options

  Options are based on the nature of the capacity gap and by application of the planning considerations discussed in s.1. Among these considerations are technical feasibility, system reliability, environmental performance and the cost of services to consumers.

- Perform simulations to give insight into the operation of the proposed resource mix

  Production-modelling simulations replicate the hour-by-hour operation of system resources and give insight into important operational parameters such as energy production, emissions, operating cost, surplus generation, energy shortfall and ramping requirements.

- Integrate findings into a plan

  Integrate findings from the production-model simulation into a plan. Determine if the plan meets the planning considerations and reiterate the process.

For discussion purposes, supply resources can be classified as existing and committed resources or directed resources. These categories are further described below.

3.3.1 Existing and Committed Resources

Existing resources are those that were in operation as of year-end 2010. Committed resources are those that were under contract to the OPA as of the end of the fourth quarter of 2010 or that are the subject of the Green Energy Investment Agreement.

The amount of existing supply is expected to decline from about 36,000 MW in 2010 to about 18,000 MW in 2030 as nuclear units reach the end of their nominal service lives, non-utility generator contracts expire, some existing demand response programs reach the end of the contract term and coal-fired units are removed from service.

3.3.2 Directed resources

Directed resources are those that are included in the Supply Mix Directive (including renewable, gas and nuclear facilities) or other ministerial directives, and are not existing or committed resources.

"Other potential resources" are those that are not existing, committed or directed and are amounts that are subject to a decision-making process that is outside of the IPSP.

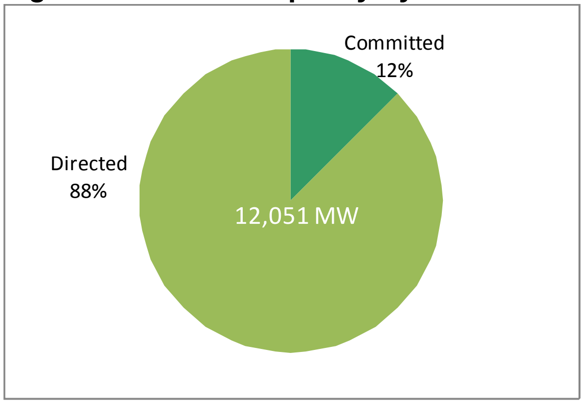
3.4 Nuclear Generation

The OPA is directed to continue to plan for nuclear generation to account for about 50 percent of total Ontario electricity generation. The directive requests that the OPA:

- Provide for the refurbishment of 10,000 MW of existing nuclear capacity at the Bruce NGS and the Darlington NGS
- Provide for the procurement of two additional nuclear generating units (about 2,000 MW) at the Darlington site
- Continue to work with OPG, Bruce Power and the Ministry of Energy to ensure that the IPSP contains an updated coordinated refurbishment schedule.

The Supply Mix Directive specifies that the government will pursue the procurement of the two nuclear generating units where it can be achieved in a cost-effective manner. The amount of nuclear capacity expected by 2030 is illustrated in Figure 3 and Table 2.

Figure 3: Nuclear Capacity by 2030



Source: OPA

Table 2: Nuclear Capacity by 2030

Resource Type	Status	Commitment	Project	MW
Nuclear (12,051 MW)	Committed	Modernization	Bruce A	1,500
	Directed	Modernization	Darlington	3,524
			Bruce A	1,540
			Bruce B	3,287
		Replacement Nuclear[1]	Darlington	(about) 2,000

Source: OPA

[1] Amount of replacement nuclear is subject to the technology selected in the procurement process.

The implementation challenges in the future include:

- Uncertainty related to the expected service life of the current nuclear fleet
- Managing simultaneous nuclear outages in the period between 2015 and 2020, which will be impacted by the availability of skilled workers and the lead time required
- Maintaining system reliability during the refurbishment period
- The status and timing of the replacement nuclear procurement to be located at the Darlington site.

3.5 Renewable Energy

Ontario has invested significantly in clean, renewable energy through various programs and initiatives:

- Renewable Energy Standard Offer Program (RESOP): In 2006, the OPA launched RESOP, which offered contracts for projects up to 10 MW. About 424 MW are in commercial operation under RESOP, with another 491 MW under development and construction.

- Renewable Energy Supply (RES) Programs: The OPA conducted the Renewable Energy Supply III program (RES III), following in the steps of the original RES I and RES II procurements, which had been carried out by the Ministry of Energy in 2004 and 2005. The RES procurements resulted in over 1,500 MW of renewable energy.

- Lower Mattagami Project: This expansion will add about 440 MW of clean generating capacity to the grid. It's the largest hydroelectric project undertaken in Ontario in 40 years and will provide $2.6 billion in investment in the north.

- Feed-in Tariff Program (FIT): Enabled by the *Green Energy and Green Economy Act, 2009* (GEA), FIT is a comprehensive program that offers stable prices under long-term contracts for renewable generation sources. The microFIT Program targets small renewable power projects that generate 10 kW or less. The FIT and microFIT programs have attracted significant investor interest and, combined with the 2,500 MW Green Energy Investment Agreement, amount to more than 4,500 MW of new committed resources.

  - As of the fourth quarter 2010, the OPA had executed 1,208 FIT contracts with a combined generating capacity of 2,590 MW. The OPA had received nearly 4,100 FIT applications with a combined capacity of over 16,200 MW. Applications continue to be accepted and processed.

  - As of the fourth quarter 2010, the OPA had received 24,047 microFIT applications with a capacity of about 220 MW and 18,370 conditional offers had been made with a capacity of over 167 MW. A total of 2,510 microFIT contracts had been executed with a capacity of 19.7 MW, almost all of it for solar projects.

- Hydroelectric Contract Initiative (HCI): The HCI provides for about 1,000 MW of contract capacity, in response to a directive to enter into a new contract with existing hydroelectric facilities that were connected to the provincial grid but not owned by Ontario Power Generation. In addition, the Hydroelectric Energy Supply Agreements (HESA) between the OPA and OPG will bring on an additional of about 440 MW of hydroelectric capacity.

As is to be expected, the OPA has experienced some attrition with its RES, RESOP and FIT procurements due to a number of factors. Attrition in these programs could potentially enable additional renewable energy projects.

In IPSP 1, the target for renewable energy was a single target. In the February 2011 Supply Mix Directive, the target for renewable energy is divided into two targets, one for hydroelectric and one for non-hydroelectric.

3.5.1 Renewables – Hydroelectric

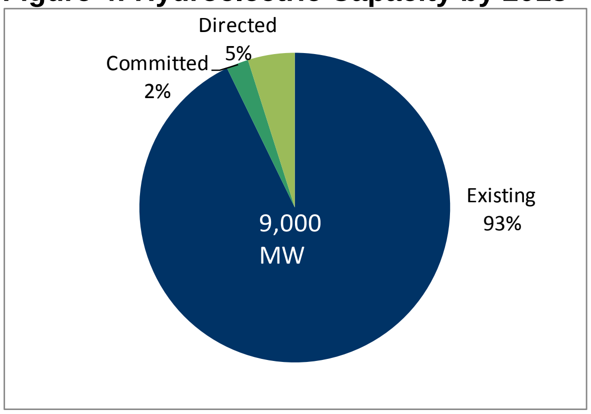
The Supply Mix Directive notes that new hydroelectric developments are underway by Ontario Power Generation, including the Niagara Tunnel and the 440 MW Lower Mattagami redevelopment, as well as additional private sector developments. It directs the OPA to:

- Plan for installed hydroelectric capacity to reach 9,000 MW by 2018

- Allow for future hydroelectric development where it is cost-effective to build and connect to the transmission system
- Plan for hydroelectric generation to account for about 20 to 25 percent of total Ontario electricity generation by 2018.

To date, almost 9,000 MW of hydroelectric generation has been committed through a number of procurement processes, including HCI, RES I and II, RESOP, HESA and the FIT Program. The amount of hydroelectric capacity expected by 2018 is illustrated in Figure 4 and Table 3.

Figure 4: Hydroelectric Capacity by 2018



Source: OPA

Table 3: Hydroelectric Capacity by 2018

Resource Type	Status	Commitment	Project	MW
Renewables: Hydroelectric (9,000 MW)	Existing	Existing	Various	8,351
	Committed	Renewable Energy Supply II	Island Falls	20
		Feed-in Tariff Program	Various	188
	Directed	Hydroelectric Energy Supply Agreement	Lower Mattagami	438
		Future Procurements [1]	Various	3

Source: OPA

[1] Future Procurements are amounts to meet Directed targets.

The incorporation of additional hydroelectric resources beyond the 9,000 MW directed level will require the consideration of the all-in cost of the generation; this includes any new transmission facilities necessary to transmit the power generated from these projects throughout the province.

3.5.2 Renewable Resources – Wind, Solar and Bioenergy

The Supply Mix Directive provides that:

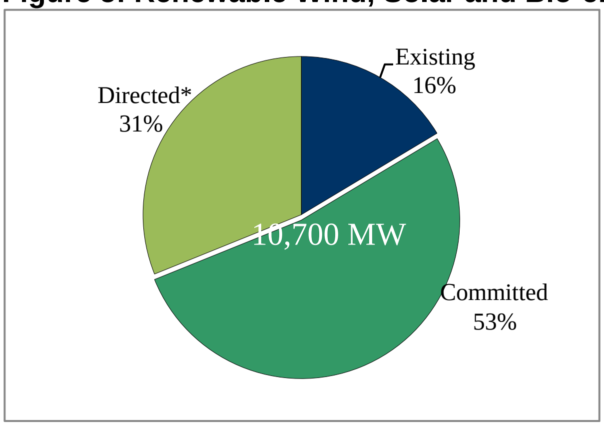
- The OPA shall plan for 10,700 MW of non-hydroelectric renewable capacity by 2018

The Supply Mix Directive also says that the government will look for opportunities to incorporate into the Plan additional capacity from renewable energy facilities, taking into consideration cost effectiveness for electricity consumers, planned transmission additions and electricity demand growth.

- The IPSP shall provide for non-hydroelectric renewable energy to account for about 10 to 15 percent of total Ontario electricity generation by 2018.
- The amount of renewable resources capacity, other than hydroelectric, expected by 2018 is illustrated in Figure 5 and Table 4.

For the most part, the additional resources to achieve the targets in this category will be related to FIT and microFIT. The OPA has experienced some attrition with its RES, RESOP and FIT procurements due to a number of factors. Attrition in these programs could potentially enable other renewable energy projects. Depending on changes in demand, future Plans will explore additional opportunities to increase the development of renewable energy projects and expand the capacity.

Figure 5: Renewable Wind, Solar and Bio-energy Capacity, by 2018



Source: OPA

Note : * For Directed attrition and changes in demand may enable additional renewable energy capacity

Table 4: Renewable Wind, Solar and Bio-energy Capacity, by 2018

Resource Type	Status	Commitment	Project	MW
Other Renewables: Wind, Solar, Bioenergy (10,700 MW)	Existing	Wind	Various	1,439
		Solar	Various	140
		Bioenergy	Various	174
	Committed	CHP III (Bioenergy)	Becker	15
			St. Mary's	30
		Renewable Energy Supply III (Wind)	Various	276
		Renewable Energy Standard Offer Program (Wind)	Various	132
		Renewable Energy Standard Offer Program (Solar)	Various	328
		Renewable Energy Standard Offer Program (Bioenergy)	Various	32
		Feed-in Tariff Program and microFIT Program (Wind)	Various	1,525
		Feed-in Tariff Program and microFIT Program (Solar)	Various	733
		Feed-in Tariff Program and microFIT Program (Bioenergy)	Various	47
		Green Energy Investment Agreement (Wind)	Various	2,000
		Green Energy Investment Agreement (Solar)	Various	500
	Directed	CHP III (Bioenergy)	Abitibi Bowater	40
		Atikokan Biomass Energy Supply Agreement (Bioenergy)	Atikokan	215
		Future Procurements [1] (Wind, Solar & Bioenergy)	Various	3,074

Source: OPA

[1] Future Procurements are amounts to meet Directed targets. Attrition and changes in demand may enable additional renewable energy capacity

3.6 Natural Gas

The OPA negotiated the Early Mover Clean Energy Supply (EMCES) projects in late 2005 and early 2006, resulting in 1,005 MW of contracted capacity. The OPA also conducted the Accelerated Clean Energy Supply (ACES) procurement in 2006 with a number of project developers, the biggest of which were Sithe Goreway GS and the Portlands Energy Centre.

3.6.1 Combined Heat and Power

Following these initiatives, the OPA carried out the first of three Combined Heat and Power (CHP) procurements based on directives from the Ministry of Energy. CHP I, II and III resulted in 10 projects with a total capacity of about 500 MW.

3.6.2 Other Procurements

In addition to the ministry-directed CHP procurements, three gas-fired facilities were procured to meet local reliability and growing demand in specific areas.

The first was the Halton Hills GS in 2006, a combined cycle plant with a contract capacity of 641.5 MW that became operational in the fourth quarter of 2010.

In 2008, the OPA conducted the Northern York Region procurement to meet growing demand in the area. The successful proposal, the simple-cycle York Energy Centre, has a contract capacity of 393 MW and a target for operation in the third quarter of 2012.

The third procurement was in the southwestern Greater Toronto Area. The OPA awarded a contract to the 900 MW combined-cycle Oakville GS. The procurement was suspended in October 2010 because of additional supply coming online and a change in the area's demand. A transmission solution to maintain reliable supply in the southwestern GTA will be pursued instead.

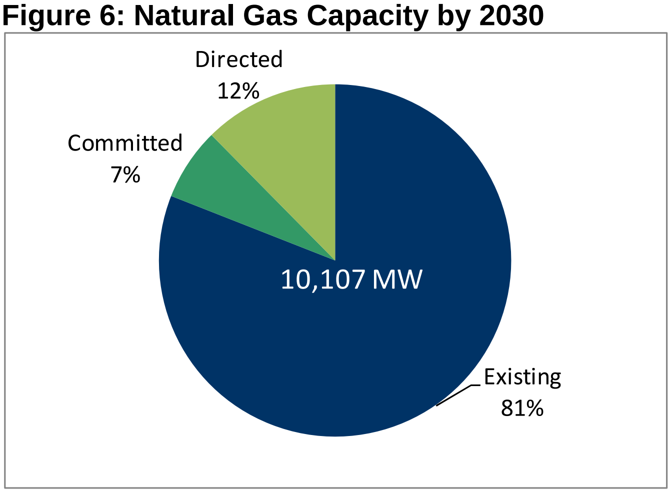
The OPA was also directed to negotiate and execute a new contract with Ontario Power Generation (OPG) with respect to the 2,140 MW Lennox GS.

The Supply Mix Directive requires that the OPA continue to plan on natural gas to:

- Play a strategic role in Ontario's supply mix by complementing intermittent supply, meeting local and system requirements and ensuring that adequate capacity is available as nuclear plants are modernized. This includes the conversion to natural gas of two units at Thunder Bay.
- As indicated in IPSP I, meet adequate regional electricity supply in the Kitchener-Waterloo-Cambridge area.

The amount of natural gas capacity expected by 2030 is illustrated in Figure 6 and Table 5.

Figure 6: Natural Gas Capacity by 2030



Source: OPA

Table 5: Natural Gas Capacity by 2030

Resource Type	Status	Commitment	Project	MW
Gas (10,107 MW)	Existing	Existing	Various	8,183
	Committed	Clean Energy Supply	Greenfield South	280
		Peaking Generation Contract	York Energy Centre	393
	Directed	Coal to Gas Conversion	Thunder Bay	300
		Future CHP Procurement	Various	501
		Peaking Generation Contract	KWC	450

Source: OPA

There are a number of considerations that need to be addressed in achieving the directed levels for gas resources. At Thunder Bay, since the technology is quite mature and the cost of conversion relatively well understood, the main issue will be timely approval of the permits, including an environmental assessment (EA) for the pipeline. The CHP targets are challenged by the limited areas of the transmission system that can accommodate additions.

3.7 Projected Supply 2011 to 2030

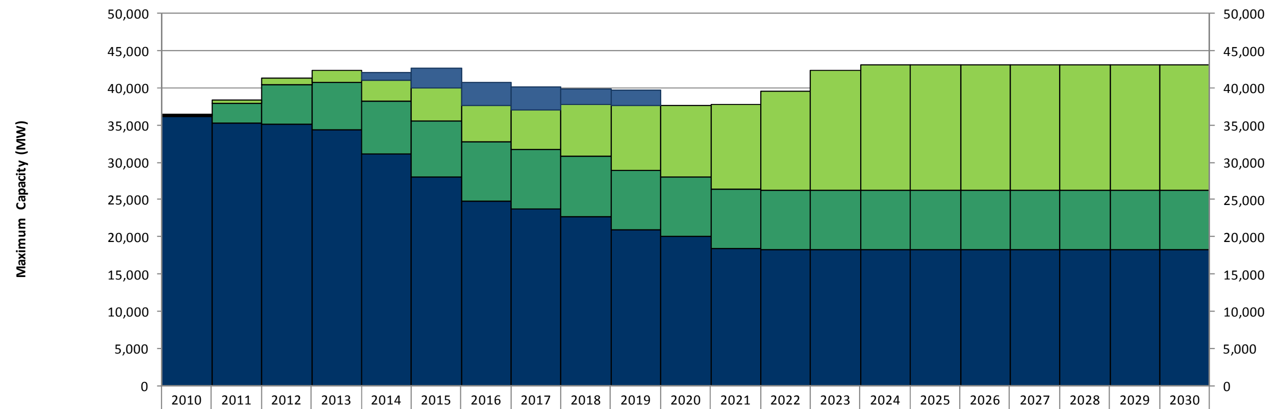
During this period, the supply portfolio will undergo a dramatic transformation as the amount of existing supply resources declines and they are replaced by renewable generation and clean gas-fired generation.

3.7.1 Total system capacity

Total system capacity is the sum of existing, committed and directed resources.

Figure 7 illustrates the total system capacity and identifies the additional contribution of Pickering NGS if its life is extended until 2020. The feasibility of extending the operating life of the Pickering generating units is being studied, and the government expects to have an update in 2012 on extending the life of these units. At that time, Ontario will consider whether additional resources are necessary for system reliability.

Figure 7: Total System Capacity *(with Pickering NGS Extended Operation)*

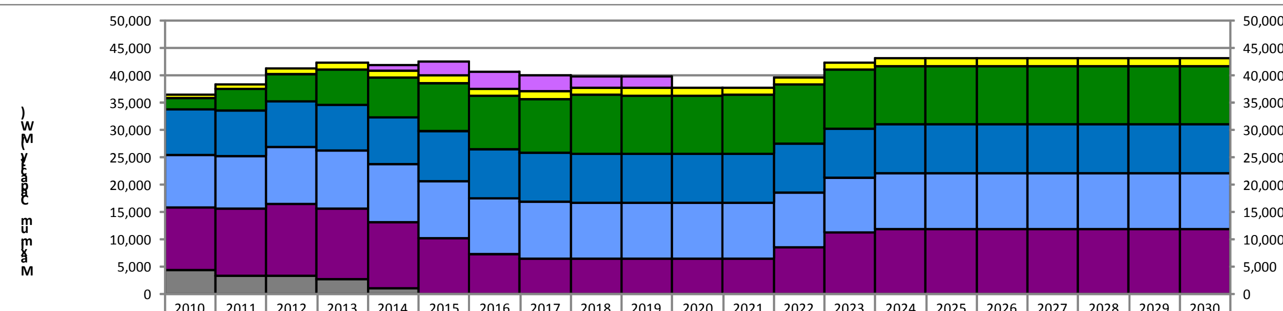


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Pickering Extended Operation	0	0	0	0	1,032	2,578	3,094	3,094	2,062	2,062	0	0	0	0	0	0	0	0	0	0	0
Directed	205	544	918	1,575	2,838	4,446	4,806	5,294	7,051	8,763	9,650	11,312	13,295	16,049	16,852	16,855	16,858	16,861	16,864	16,868	16,879
Committed	90	2,656	5,232	6,345	6,965	7,498	7,998	7,998	7,998	7,998	7,998	7,983	7,983	7,983	7,953	7,953	7,953	7,953	7,953	7,953	7,953
Existing	36,246	35,232	35,210	34,428	31,226	28,089	24,835	23,802	22,794	20,962	20,034	18,494	18,363	18,358	18,354	18,349	18,349	18,349	18,341	18,339	18,327
Total	36,540	38,432	41,361	42,347	42,060	42,612	40,732	40,188	39,907	39,788	37,729	37,836	39,688	42,437	43,210	43,213	43,216	43,218	43,214	43,216	43,219

Source: OPA

Figure 8 illustrates total system capacity by fuel type and identifies the additional contribution of Pickering NGS assuming its life is extended until 2020.

Figure 8: Total System Capacity by Fuel Type (*with Pickering NGS Extended Operation)*



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Pickering Extended Operation	0	0	0	0	1,032	2,578	3,094	3,094	2,062	2,062	0	0	0	0	0	0	0	0	0	0	0
Demand Response	644	842	1,009	1,180	1,317	1,319	1,322	1,325	1,327	1,330	1,333	1,336	1,339	1,341	1,344	1,347	1,350	1,353	1,356	1,359	1,362
Other Renewables	1,955	3,873	5,033	6,386	7,416	8,900	9,750	9,773	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700	10,700
Hydroelectric	8,380	8,393	8,413	8,440	8,529	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000
Gas	9,631	9,624	10,456	10,545	10,637	10,447	10,240	10,550	10,373	10,251	10,251	10,251	10,120	10,115	10,115	10,115	10,115	10,115	10,107	10,107	10,107
Nuclear	11,446	12,196	12,946	12,946	11,914	10,368	7,327	6,446	6,445	6,445	6,445	6,549	8,530	11,281	12,051	12,051	12,051	12,051	12,051	12,051	12,051
Coal	4,484	3,504	3,504	2,850	1,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	36,540	38,432	41,361	42,347	42,060	42,612	40,732	40,188	39,907	39,788	37,729	37,836	39,688	42,437	43,210	43,213	43,216	43,218	43,214	43,216	43,219

Source: OPA

3.7.2 Capacity Gap

As noted earlier, there is adequate generating capacity in the Ontario electricity system until about 2018 assuming the life of Pickering NGS is extended to 2020. If the life of Pickering NGS is not extended, there is adequate generating capacity until about 2016.

Beginning in 2015, there may also be a need for additional resources to meet rapid changes in demand to ensure that demand can be met in all periods. The capacity gap is determined by considering the contribution of each resource type at the time of the annual system peak demand. For intermittent renewable resources and gas-fired resources, the contribution at peak is less than their maximum capacity as described below. The contribution at time of peak of the total system capacity is then compared to the supply requirement, which is the peak demand plus planning reserve.

3.7.3 Contribution at Time of Peak

Due to their intermittent nature, resources such as solar and wind contribute less than their nameplate capacity. Gas-fired generation is de-rated during peak periods to account for increased cooling requirements during high summer ambient temperatures. For preliminary planning, the capacity contribution during summer peak for each resource type is outlined in Table 6. These amounts will be re-assessed for the IPSP.

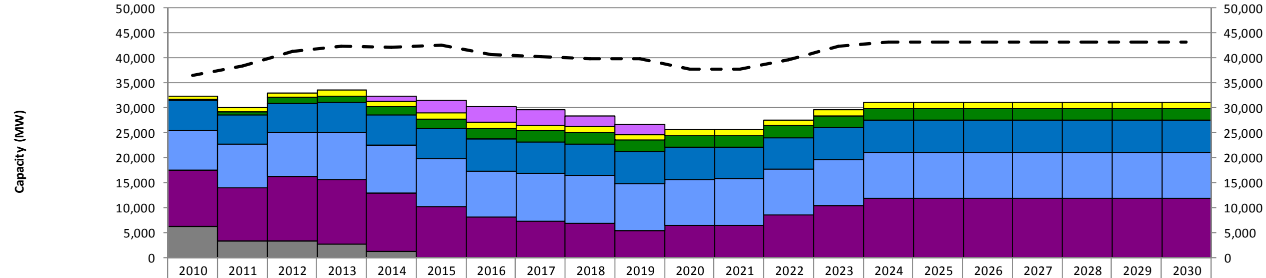
Table 6: Summer Capacity Contribution

Fuel Type	Capacity Contribution at Summer Peak
Coal	90 - 100%
Nuclear	95 - 100%
Gas (including NUGs)	50 - 100%
Wind	12 - 16%
Hydroelectric	66 - 73%
Bioenergy	65 - 100%
Solar	35 - 55%
Demand Response	35 - 95%

Source: OPA

Figure 9 illustrates the contribution at time of peak by fuel type of the total system resources, compared to their maximum capacity. It identifies the additional contribution of Pickering NGS based on its life being extended until 2020.

Figure 9: Contribution at Time of Peak by Fuel Type *(with Pickering NGS Extended Operation)*



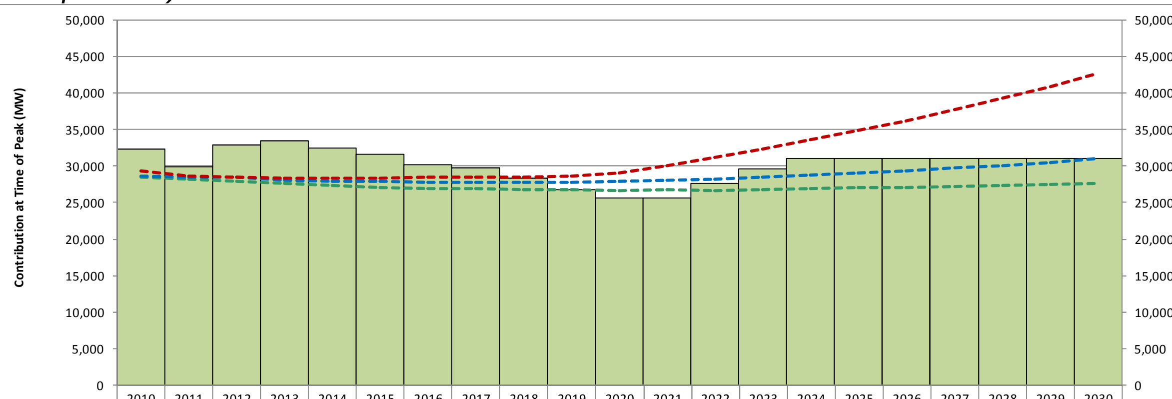
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Pickering Extended Operation	0	0	0	0	1,032	2,578	3,094	3,094	2,062	2,062	0	0	0	0	0	0	0	0	0	0	0
Demand Response	572	750	903	1,064	1,168	1,170	1,173	1,176	1,178	1,181	1,183	1,186	1,189	1,191	1,194	1,197	1,199	1,202	1,205	1,207	1,210
Other Renewables	372	619	1,059	1,370	1,646	2,029	2,125	2,207	2,323	2,323	2,323	2,310	2,323	2,323	2,323	2,323	2,323	2,323	2,323	2,323	2,323
Hydroelectric	5,880	5,929	5,939	5,963	5,979	6,056	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366	6,366
Gas	8,043	8,672	8,800	9,512	9,581	9,443	9,334	9,605	9,512	9,337	9,337	9,337	9,219	9,214	9,214	9,214	9,214	9,214	9,206	9,206	9,206
Nuclear	11,358	10,614	12,858	12,858	11,826	10,280	8,070	7,254	6,892	5,498	6,376	6,448	8,498	10,476	11,964	11,964	11,964	11,964	11,964	11,964	11,964
Coal	6,157	3,387	3,387	2,739	1,171	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	32,382	29,969	32,946	33,506	32,403	31,557	30,161	29,702	28,334	26,767	25,586	25,647	27,595	29,570	31,061	31,064	31,066	31,069	31,064	31,067	31,069
Maximum Capacity	36,540	38,432	41,361	42,347	42,060	42,612	40,732	40,188	39,907	39,788	37,729	37,836	39,688	42,437	43,210	43,213	43,216	43,218	43,214	43,216	43,219

Source: OPA

For long-term planning purposes, there must be sufficient supply to meet the annual forecast peak demand plus planning reserve requirements, which are assumed at this point to be 17 percent of peak demand but will be re-examined in the IPSP. In addition, the OPA will examine the potential requirement for additional planning reserve during the nuclear refurbishment period.

Figure 10 shows the contribution of the system resources during peak demand periods between 2010 and 2030, compared to supply requirements, assuming extended Pickering NGS operation

Figure 10: Supply Outlook Compared to Demand Requirements at Time of Peak (*with Pickering NGS Extended Operation)*



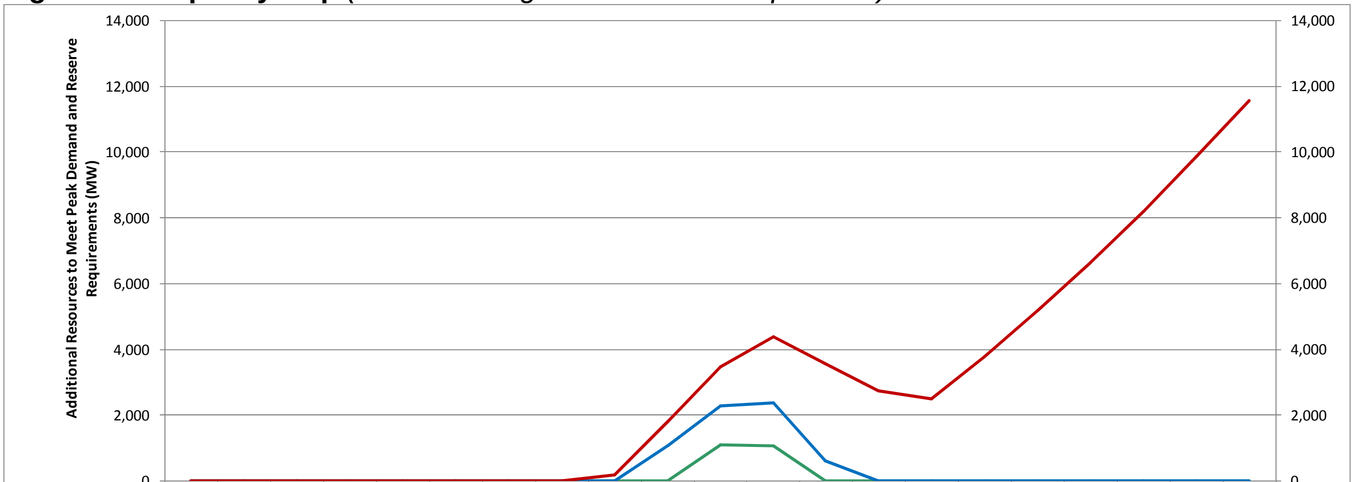
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Resources Available	32,382	29,969	32,946	33,506	32,403	31,557	30,161	29,702	28,334	26,767	25,586	25,647	27,595	29,570	31,061	31,064	31,066	31,069	31,064	31,067	31,069
Low Growth: Demand & Reserve	28,481	28,262	27,948	27,601	27,281	27,102	26,991	26,906	26,773	26,773	26,695	26,719	26,691	26,788	26,908	27,019	27,131	27,246	27,362	27,474	27,641
Medium Growth: Demand & Reserve	28,697	28,491	28,435	28,123	27,908	27,875	27,784	27,750	27,844	27,842	27,884	28,019	28,221	28,433	28,748	29,058	29,391	29,723	30,071	30,486	31,008
High Growth: Demand & Reserve	29,316	28,577	28,483	28,349	28,329	28,404	28,431	28,472	28,521	28,569	29,052	30,048	31,173	32,325	33,575	34,859	36,239	37,709	39,266	40,919	42,644

Source: OPA

Figure 11 summarizes the additional capacity needed to meet peak demand and planning reserve requirements under the low, medium and high-growth demand scenarios assuming that the life of Pickering NGS is extended until 2020.

Figure 12 assumes that the life of Pickering NGS is not extended.

Figure 11: Capacity Gap *(with Pickering NGS Extended Operation)*

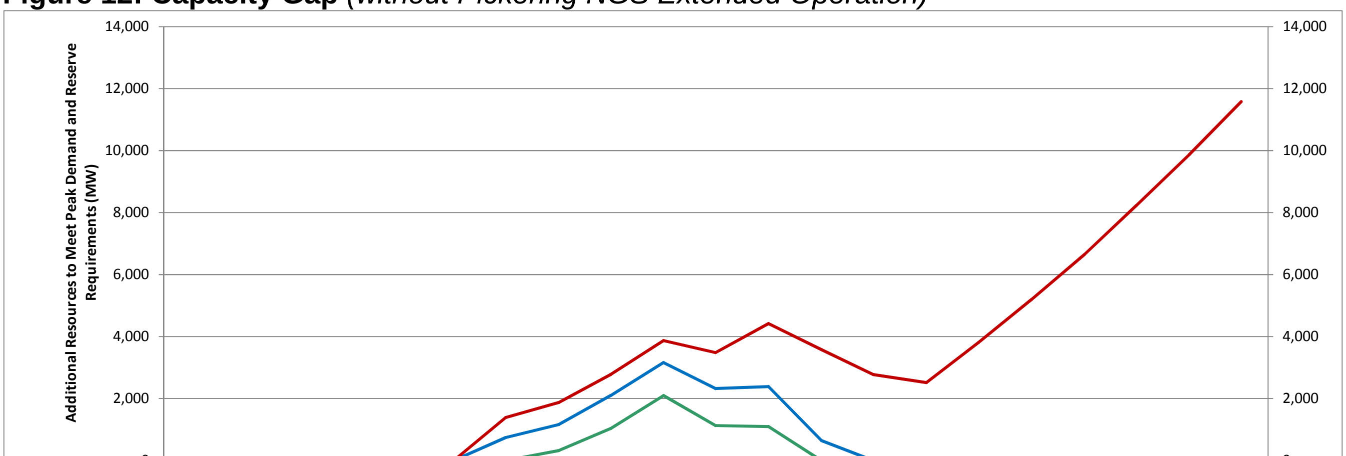


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low Growth	0	0	0	0	0	0	0	0	0	6	1,109	1,072	0	0	0	0	0	0	0	0	0
Medium Growth	0	0	0	0	0	0	0	0	0	1,075	2,299	2,372	626	0	0	0	0	0	0	0	0
High Growth	0	0	0	0	0	0	0	0	187	1,802	3,467	4,402	3,578	2,755	2,514	3,795	5,173	6,640	8,202	9,852	11,575

Source: OPA

With extended operation at Pickering, a supply shortfall emerges in 2019 and ends in 2022 under the medium-growth scenario. In the low-growth scenario, a supply shortfall emerges in 2020 and ends in 2021.

Figure 12: Capacity Gap *(without Pickering NGS Extended Operation)*



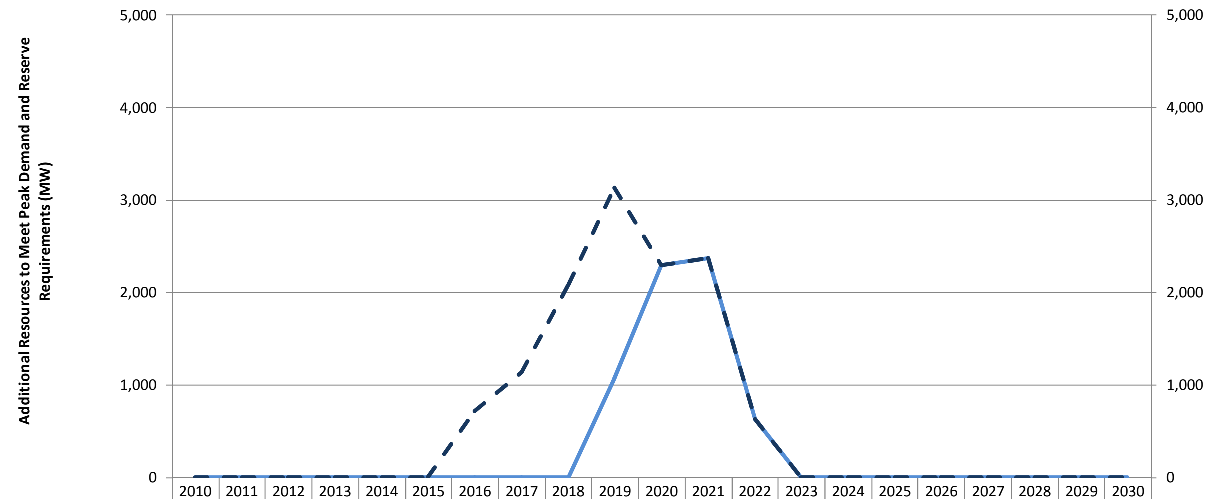
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low Growth	0	0	0	0	0	0	0	298	1,017	2,068	1,109	1,072	0	0	0	0	0	0	0	0	0
Medium Growth	0	0	0	0	0	0	717	1,142	2,088	3,137	2,299	2,372	626	0	0	0	0	0	0	0	0
High Growth	0	0	0	0	0	0	1,363	1,864	2,765	3,864	3,467	4,402	3,578	2,755	2,514	3,795	5,173	6,640	8,202	9,852	11,575

Source: OPA

If the extended operation of Pickering NGS is not feasible, a supply shortfall emerges in 2016 and ends in 2022 under the medium-growth scenario. In the low-growth scenario, a supply shortfall emerges in 2017 and ends in 2021.

The extended operation at Pickering helps diminish and delays the supply gap in the mid-term, as illustrated in Figure 13.

Figure 13: Capacity Gap *(with and without Pickering NGS Extended Operation under Medium Growth)*



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
With Pickering - Medium Growth	0	0	0	0	0	0	0	0	0	1,075	2,299	2,372	626	0	0	0	0	0	0	0	0
Without Pickering - Medium Growth	0	0	0	0	0	0	717	1,142	2,088	3,137	2,299	2,372	626	0	0	0	0	0	0	0	0

Source: OPA

In either case, there are available resource options and sufficient lead time to address the capacity gap.

3.8 Other Potential Resources

The category of other potential resources includes those that are not existing, committed or directed conservation or supply resources, including supply resources whose amount is subject to a decision-making process that is outside of the IPSP.

Potential supply resources include:

- Expiring non-utility generation (NUG) contracts that could be renegotiated in accordance with the November, 23, 2010 directive (to about 1,500 MW by 2030)
- Coal-fired units that could be converted to gas-fired operation as the result of a government decision in 2012 (to about 3,000 MW by 2030).

In addition, the category of other potential resources includes resources that could be available or developed to provide additional supply if and when required. These include:

- Squeezing operating flexibility from the current fleet
- Additional conservation and demand response

- Additional renewable supply (for example, development of potential renewable-energy sources in northern Ontario)
- Energy storage
- Firm imports from neighbouring jurisdictions
- Other gas-fired generation.

To maximize flexibility and keep options open, decisions on the above will be made as close as possible to the time that additional supply is needed. They will be based on the planning considerations discussed in Section 1 as well as lead-time requirements.

3.9 Planning Factors to be Considered

In the near term, planning uncertainty results primarily from the implementation of existing decisions. Medium-term uncertainty derives from the availability of resources while the longer-term uncertainty is driven primarily by demand.

During the period 2011 to 2014, coal units are being shut down and some are being converted to gas-fired operation. These activities require careful planning and coordination to ensure that system reliability is not at risk. The integration of intermittent renewable generation will also become more important. To maintain reliability, consideration of the requirements to ramp up the system to meet demand and the management of surplus baseload generation is required.

The situation between 2015 and 2022 will be influenced by nuclear modernization and the related uncertainty about the amount of time that units will be off line. The extended lifespan of Pickering NGS would provide additional capacity.

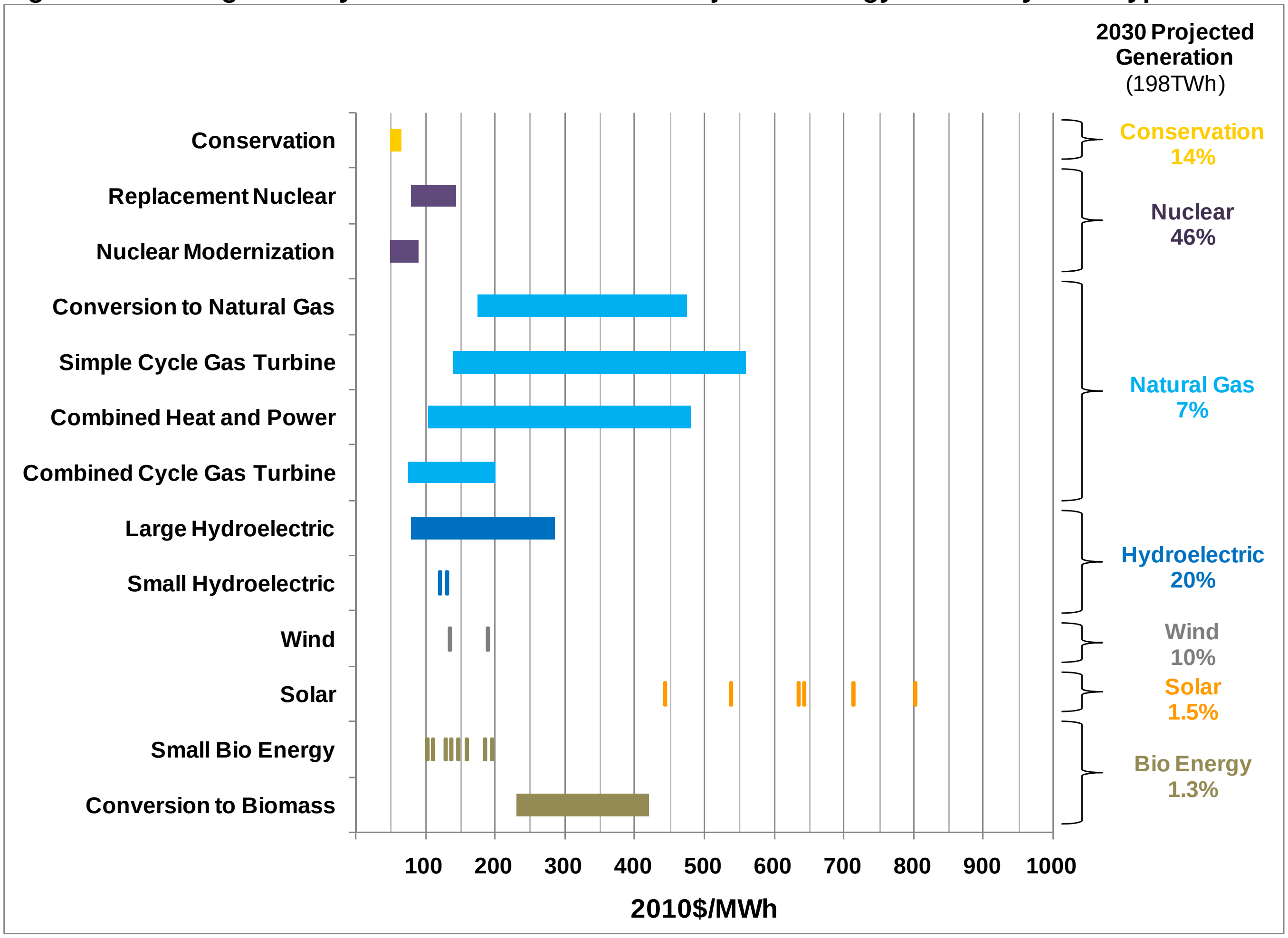
During the period beyond 2022, the prospect that carbon-mitigation policies will be – or have been -- enacted is a major source of uncertainty and could result in high demand growth as consumers switch fuels to deal with the price of carbon.

3.10 Projected Supply Costs

Figure 14 shows the potential range of levelized costs to be recovered for various supply options, expressed in 2010 dollars, as well as the projected energy production by 2030 for each resource in TWh.

Note that Figure 14 indicates the *real* 2010 dollar cost of options were they to be installed in 2011-2030, and operated over reasonably planned ranges of capacity factor. It also includes an updated outlook for 2011-2030 on various factors (for example, gas prices and higher nuclear capital costs), and considers potential projects for renewable resources (including large hydro).

Figure 14: Average Life Cycle Customer Cost and Projected Energy in 2030 by Fuel Type



Source: OPA

As part of the committed two-year review of the FIT Program in 2011, the government has indicated that the FIT prices will be re-examined. A new price schedule will be developed that recognizes advances in technologies and economies of scale and that also balancing ratepayer interest with the importance of encouraging investment in Ontario.

Based on estimates provided by the government in the LTEP, the forecast capital cost of the plan will be about $87 billion over the life of the plan. This forecast will be refined as the IPSP is developed.

3.11 A Balanced Supply Mix

The supply portfolio will undergo a dramatic transformation in the next two decades as the amount of existing supply resources declines and is replaced by renewable generation and cleaner, gas-fired generation. Coal-fired generation will be completely phased-out by the end of 2014, and 10,700 MW of additional intermittent renewable generation (not including the addition of hydroelectric generation) will be installed by 2018.

The Ontario electricity system will require additional system flexibility to deal with this transformation. System flexibility will be required to replace the dispatchability – the term for power that can be provided quickly to meet demand – that was previously provided by coal-fired generation and to provide back-up for the intermittent nature of output from renewable energy resources.

The need for additional flexibility must be compared to the dispatchability available from the existing, committed and directed resources in the planning period to determine if, and when, a shortfall between requirement and capability exists.

A preliminary analysis was conducted to determine whether the system has enough flexibility to implement the changes in the supply portfolio. The results show that there is flexibility, when the capability from the existing, committed and directed resources is considered together with the capability from Lambton GS and Nanticoke GS coal-to-gas conversions, potential re-negotiated NUG facilities and possible augmented interties with neighbouring jurisdictions.

3.12 Summary

This section has outlined Ontario demand-supply balance over the next 20 years. It is a period characterized by three main time frames.

For the period up to 2015, when coal is being phased out and a number of supply resources have and are well underway to being installed, there is a high degree of confidence that expected supply will meet the reasonable range of possible net demand assumptions. This enhanced reliability provides the breathing room to plan for the longer term.

The period from 2016 to about 2022 is mainly characterized by the assumption that the existing nuclear units at Darlington NGS and Bruce NGS are modernized. During this there will also be significant addition of renewable resources. The analysis presented here concludes that by supporting work to both reduce the uncertainty (for example, a Pickering condition assessment) as well as keeping supply options open (for example, through coal-to-gas conversions) there is a high degree of confidence that any gap in the demand-supply balance will be addressed.

The addition of significant amounts of intermittent renewables during this period will also present challenges for integrating the supply resources to maintain reliability. The assessment shows that there is sufficient time and options available to address these issues as well.

Beyond 2023, once the existing nuclear units are back in service, it is expected that under the assumed medium-load forecast the gap closes again and the balance is maintained. Under the higher-load growth assumption, there may be the need for additional resources but there is sufficient time to address that possibility.

As a result, there is no expectation that additional facilities will be recommended beyond those identified in the LTEP and the Supply Mix Directive.

3.13 Areas for Consultation

The OPA will seek input on supply issues in the IPSP process. The questions below are posed as a starting point for further discussion and feedback:

1) What are the challenges to meeting the mandatory supply requirements in the Plan?

2) What are the supply options for meeting the need for incremental resource requirements?

4.0 CONSERVATION AND DEMAND MANAGEMENT (CDM)

FROM THE LTEP:

From 1995 to 2003, there were no provincial conservation programs.

Since 2003, Ontario has not only created a culture of conservation, it has become a North American leader.

The province also raised its grade from a "C-" to an A+ in 2009 from the Energy Efficiency Alliance with its strong commitment to energy efficiency and conservation.

Smart meters and time-of-use (TOU) rates will help further the culture of conservation.

Provincial CDM targets will be met through a combination of programs and initiatives, including codes and standards, innovative energy efficiency programs for residential, commercial and industrial sectors and demand response programs.

As partners responsible for delivery, local distribution companies (LDCs) will become the recognizable "face of conservation."

FROM THE SUPPLY MIX DIRECTIVE:

The OPA shall plan to achieve through conservation and demand management (CDM) a peak demand reduction target of 7,100 megawatts (MW) and an overall energy savings of 28 terawatt-hours (TWh) reduction by 2030.

Further, the OPA shall plan to achieve interim CDM targets as follows:

- 4,550 MW and 13 TWh by 2015
- 5,840 MW and 21 TWH by 2020
- 6,700 MW and 25 TWh by 2025

The plan shall seek to exceed the achievement of these CDM targets if this can be done in a manner that is feasible and cost-effective. The targets are to be measured from a base year of 2005.

AREAS TO BE CONSIDERED IN THE IPSP:

How does the IPSP meet the mandatory CDM requirements set out in the Supply Mix Directive?

How can challenges to meeting those requirements be addressed?

How does the IPSP address whether the achievement of the Supply Mix Directive's CDM goals may be exceeded and accelerated?

4.1 Recent History

With the establishment of aggressive long-term provincial CDM goals[1] and the development and delivery of ratepayer-funded CDM programs through LDCs and the OPA, there has been a significant resurgence of CDM in Ontario over the past five years. CDM programs have delivered significant results to date that have assisted in the restoration of the reliability of the electricity system and have laid the foundation for the elimination of coal-fired generation by 2014. Through program experience, we have learned that CDM takes persistent effort and involves coordination of the delivery channels, the planners, the regulator and the involvement of customers.

From 2006 through 2010, Ontario has made significant progress in electricity CDM and is forecasting that about 1,700 MW of demand reductions and 4.6 TWh of energy savings will have been achieved. More than 90 percent of these savings have resulted from CDM programs. The remaining savings have come from codes and standards. Rollout of smart meters/time-of-use (TOU) rates will further enable conservation as we move forward.

Smart meter/TOU rate implementation is well under way and 80 percent of the province will be on TOU rates by the end of 2011. In addition, Ontario's building code has been revised to give prominence to energy efficiency.

The *Green Energy and Green Economy Act, 2009* (GEA) significantly changed the CDM landscape in Ontario. For the first time, LDCs have been given their own targets for the period between 2011-2014 as a condition of their distribution licenses. Those targets contribute to the overall provincial targets set out in the LTEP.

4.2 Summary of Supply Mix Directive Requirements

In the Supply Mix Directive, the government directed the OPA to "achieve through CDM a peak demand reduction target of 7,100 (MW) and a new energy savings target of 28 terawatt-hours (TWh) by the end of 2030. Further, the OPA shall plan to achieve interim CDM targets as follows: 4,550 MW and 13 TWh by the end of 2015; 5,840 MW and 21 TWh by the end of 2020; and 6,700 MW and 25 TWh by the end of 2025. These interim CDM targets are to serve as milestones to measure progress towards the overall 2030 target."

In addition, the directive stated: "The Plan shall seek to exceed and accelerate the achievement of these CDM targets if this can be done in a matter that is feasible and cost-effective. The targets are to be measured from a base year of 2005."

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[1]In the 2007 IPSP directive, the government set a conservation target of 6,300 MW of peak demand reduction by 2025. The directive also defined CDM as including energy efficiency, demand management, small-scale customer-based generation and fuel switching.

It also refined its definition of CDM to say that it should be inclusive of load reduction from initiatives such as geothermal heating and cooling, solar heating and fuel switching and exclusive of customer-based generation that is contracted-for under the OPA's Feed-in Tariff (FIT) and microFIT programs and other generation that is separately metered for the purpose of injecting electricity into the transmission system or a distribution system.

The directive also stated that CDM targets "shall include electricity savings forecasted through the implementation of codes, standards, regulations and other initiatives that are progressive and reasonable based on OPA analysis."

4.3 CDM as Part of Overall Integrated Planning

CDM is a resource available for integrated planning and a key input in forecasting electricity demand. CDM reduces demand and is typically a least-cost resource that can defer or avoid the need for expenditures on more expensive forms of electricity supply.

CDM will be a key element in planning as Ontario prepares for a lower-carbon future. It not only defers or avoids electricity supply costs, it increases economic efficiency, creates jobs, and can help customers manage their bills.

CDM is achieved through a mix of program-related activities, behavioural adjustments by customers in reaction to initiatives such as TOU prices and through mandated efficiencies from building codes and equipment standards. These three approaches complement each other to maximize CDM results.

This three-tier approach to CDM is consistent with the OPA's market transformation approach, which leverages incentive-based programs to "prime" the market, while codes and standards subsequently "lock in" program-based savings.

CDM is cost-effective when it defers or avoids the need for investment in more expensive alternative supply, and consequently lowers the total cost of delivering electricity. Over the past five years, Ontario invested an estimated $1.7 billion in CDM actions, which will save ratepayers an estimated $3.8 billion in avoided supply costs.

The OPA believes that a long-term CDM target of 7,100 MW and 28 TWh by 2030 is feasible, but also aggressive.

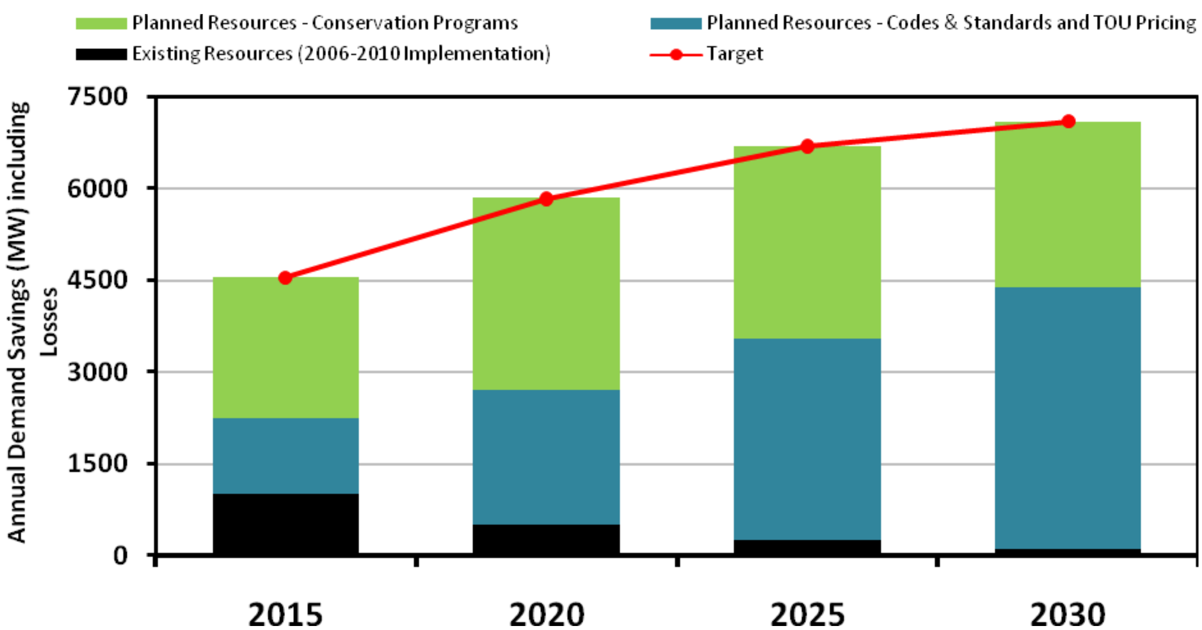
It will require the coordination and involvement of many— including consumers, installers, manufacturers, LDCs and regulators.

The updated IPSP (IPSP II) will provide a plan for achieving the CDM targets set out in the 2011 Supply Mix Directive. It will also address the assessment of feasibility and cost-effectiveness of exceeding and accelerating the achievement of the CDM targets.

4.4 Implementation Plan

The OPA plans to achieve the CDM goals set out in the Supply Mix Directive by employing three main approaches to drive customer action: programs, TOU prices and codes and standards. Energy efficiency and demand response are expected to contribute the most to achieving CDM targets. However, reductions from initiatives such as geothermal heating and cooling, solar heating and fuel switching will also contribute to energy savings. In the near term, the majority of savings will come from programs, while the contribution from codes, standards and TOU prices is expected to increase in the later stages of the Plan. The graphs below (Figures 1 and 2) provide a forecast of the contribution of each tool to achieving CDM targets, both from an energy and capacity perspective.

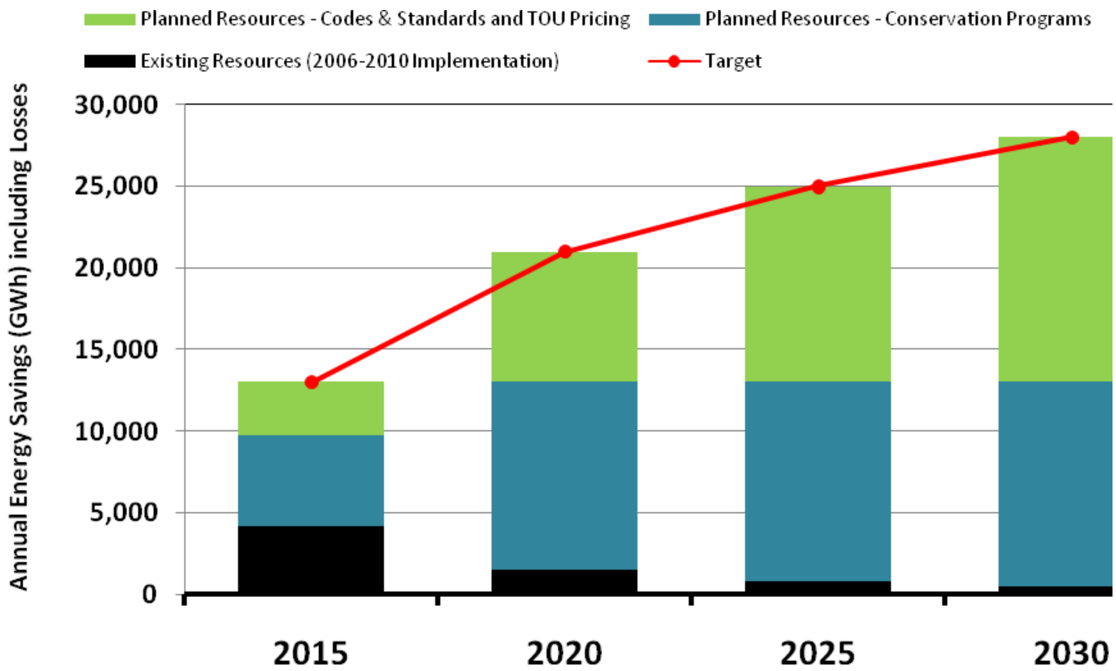
Figure 1: Annual Demand Savings



Note: Existing resources are conservation savings from programs implemented between 2006 and 2010

Source: OPA

Figure 2: Annual Energy Savings



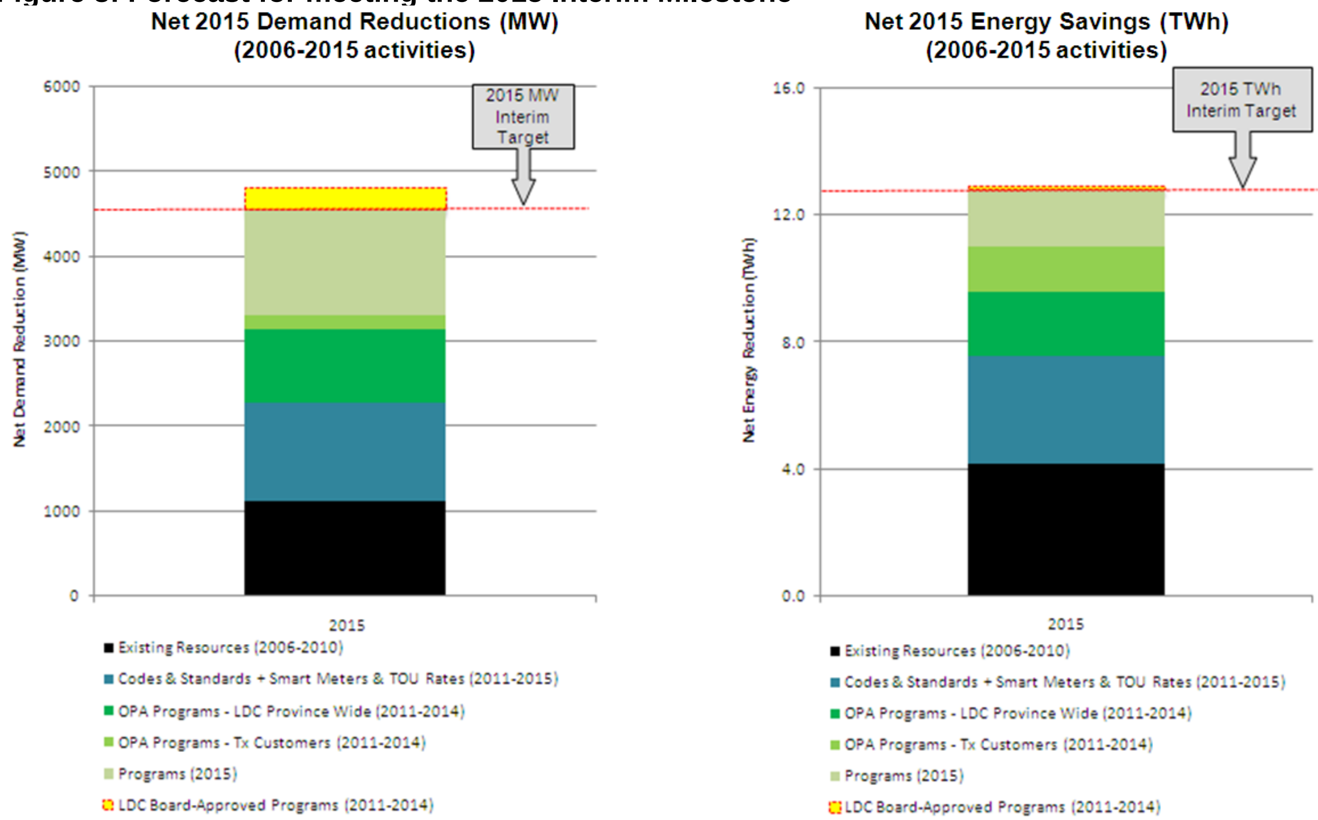
Source:OPA

The 2015 milestone is the first and IPSP II will provide greater detail on how it will be achieved. Figure 3 below shows the contributions of existing programs, 2011-2014 programs, 2015 programs, as well as codes, standards and regulations to achieving the 2015 milestone. This forecast may be adjusted prior to the filing of IPSP II based on additional analytical work.

The portfolio of programs to be delivered between 2011 and 2014 cover all sectors of the market and include incentives for energy efficiency, contracts for demand response and provide for the enabling of results. The majority of programs for distribution-connected customers will be delivered by LDCs while programs for transmission-connected customers and First Nation communities will be delivered by the OPA.

There are four province-wide programs designed in a collaborative effort between the OPA and the LDCs. These programs target consumer, business, industrial and low income markets. In addition to the LDCs having the option of delivering programs under contract with the OPA, they can also apply to the Ontario Energy Board (OEB) for approval to run programs, individually or in groups.

Figure 3: Forecast for meeting the 2015 Interim Milestone



Source:OPA

As with all electricity system planning, there is uncertainty around the forecasts of the performance of each tool and each will be monitored over the life of the plan. Adjustments will be made to the forecast if a tool is over- or under-performing. As well, the OPA will provide advice to the government or relevant stakeholders on recommended action, including program changes.

The OPA is adopting a market transformation strategy to achieve the forecasted savings described in Figures 1 and 2 above, and to ensure that CDM is sustainable, reliable, cost-effective and customer-focussed. Market transformation is about making CDM action an integral part of life and a business-as-usual choice for everyone in Ontario. In the context of CDM, market transformation is an outcome, defined as:

"Long-lasting sustainable changes in the structure or functioning of the market achieved by reducing barriers to the adoption of energy-efficiency measures to the point where further publicly funded intervention is no longer appropriate in that specific market."[2]

[2] *California Public Utilities Commission Decision 98-04-063, Appendix A.*

CDM market transformation aims to reduce market failures and eliminate barriers. These are diverse in nature and origin and no single tool addresses them. In market transformation many tools are used to pull and push products. The pull activities, such as incentives, publicly announced regulatory plans, and information and awareness building, create the economic and social acceptance for the push of regulatory and price tools. Once regulations (e.g. codes and standards) lock in savings, incentives are no longer necessary.

Typical market transformation steps include the following:

- **Stimulate innovation** – through research, demonstration of new concepts, and facilitating the market introduction of new products and processes
- **Accelerate market penetration** – increasing market acceptance of CDM action from emerging to niche to mass-market status. This is best achieved by working with both the supply chain and directly with consumers. Tools include incentives, electricity prices, information, training, voluntary standards and labelling, awareness-raising and leadership
- **Lock in CDM** – when CDM action becomes standard marketplace practice. Tools include mandatory codes and standards, other regulations and electricity prices.

Codes and standards are an effective means of achieving lasting CDM as they lock in savings by raising the baseline of efficiency available to customers. Codes and standards are also very cost effective from a ratepayer perspective as they don't require any investment in an incentive program in order to be achieved. However, customers and businesses may have to spend money to invest in more efficient equipment required by the regulation.

In the residential sector, the OPA estimates that the majority of energy savings from codes and standards will come from the regulation of lighting and small appliances in the home. In the commercial and institutional sector, lighting is anticipated to offer the biggest opportunity for savings through codes and standards, followed by cooling and ventilation.

The impact of codes and standards in the industrial sector is expected to be small, given the long life of industrial equipment and the capital intensity of industrial efficiency improvements.

The *Green Energy and Green Economy Act, 2009* (GEA) outlines the intent to give priority to energy efficiency in the Ontario Building Code and signals aggressive equipment standards development. The GEA states that the building code must be reviewed, taking into account provisions for energy conservation, and establishes the Building Code Energy Advisory Council to identify further opportunities for the enhancement of energy conservation standards.

As part of its market-transformation strategy, the OPA is stimulating innovation through both its Technology Development Fund and Conservation Fund, ensuring CDM resources are available now and in the future.

The Technology Development Fund promotes the development and commercialization of technologies or applications that have potential to improve electricity supply or CDM. High-efficiency lighting, advanced building controls and advanced cooling, smart grid and distributed generation-enabling technologies are priority areas for the fund. As of 2010, $4.5 million was available in annual funding.

The Conservation Fund provides support for new and innovative electricity CDM initiatives that help Ontario's residents, businesses and institutions reduce their demand for electricity and develop the groundwork for future improvements in provincial CDM programs. As of 2010, the fund had $5 million to invest annually.

Achieving the government's goals will require coordination among a number of parties and a division of responsibilities.

The OPA is responsible for developing a plan to achieve CDM targets as set out in the Supply Mix Directive.

In addition to developing the IPSP, the OPA has a number of roles in implementing CDM activities within the plan, including:

- Program design/delivery: Designing, in collaboration with LDCs, and funding province-wide CDM programs for delivery by LDCs in 2011-2014; procuring and managing third-party providers for delivery services within the province-wide LDC programs, which will afford significant administrative and/or cost savings from central coordination (such as rebate processing, appliance decommissioning); designing and delivering CDM programs for transmission-connected customers; designing and coordinating the delivery of CDM programs for First Nation and Métis communities; and designing and delivering initiatives to build the capability of CDM service providers and working directly with the supply chain to support market transformation.

- Providing advice to the OEB on allocation of CDM targets among LDCs.

- Providing advice to the OEB on the administration of LDC CDM activities.[3]

- Tracking and measuring progress: Undertaking evaluation, measurement and verification (EM&V) of OPA-funded CDM program results, and providing EM&V protocols and requirements for use by the OPA, LDCs and other delivery agents; and monitoring and tracking progress against the CDM targets established in the LTEP and providing reports on progress to the Environmental Commissioner of Ontario and the Minister of Energy.

[3] April 23, 2010 Minister of Energy directive states that OPA is to "provide advice to the OEB on the administration of LDC CDM activities, including but not limited to the use of OPA cost-effectiveness tests and the OPA protocol process and third-party vendor of record list in order to assess the cost-effectiveness of Board-Approved CDM Programs and to conduct Evaluation, Measurement and Verification (EM&V) of Board-Approved Programs, as requested by the OEB".

- Other market transformation activities: Providing support and funding for CDM research and innovation; funding conservation awareness initiatives and establishing metrics and tracking progress for the development of a culture of conservation; and collaborating with government to support the development of codes and standards and other policy tools to achieve CDM.

In the LTEP, the government set the targets and vision for Ontario. The provincial government will also play a very important part in the implementation of the plan, based on its roles in the following areas:

- Establishing the policy framework for CDM program funding and delivery
- Establishing codes and standards
- Establishing policy direction on electricity rate design and other instruments to encourage CDM.

The OEB is responsible for:

- Reviewing the IPSP and ensuring that an approved IPSP is facilitated in future decisions
- Establishing the CDM Code, which sets out the obligations and requirements that LDCs must comply with in relation to their CDM targets
- Reviewing and approving LDC applications for OEB-approved CDM programs
- Monitoring and publishing results of LDCs' progress against their CDM targets
- Establishing TOU rates.

LDCs are responsible for meeting their CDM targets, including working in collaboration with the OPA on the design of province-wide LDC programs, developing and filing CDM strategies with the OEB, and delivering CDM programs (OPA-contracted and/or OEB-approved).

In addition to the above roles and responsibilities, which primarily stem from regulations and policies, customers, those who work in the supply chain (including product manufacturers, distributors, retailers and other stakeholders such as non-governmental organizations) will need to be actively involved. Publicly funded CDM programs attempt to influence the market. But it is the market and consumers that must act.

4.5 Implementation Challenges

Long-term planning takes place within a context of shifting economic circumstances and policy change, which gives rise to a certain amount of uncertainty. Key areas of uncertainty which can affect CDM performance include:

- **Regulatory/policy framework for CDM**. Successful CDM requires a clear, stable framework in place for long-term investment in CDM resources to ensure there will be sufficient involvement from the supply chain (e.g. contractors, engineers, manufacturers, etc.) to meet the aggressive targets. There is also risk of potential inefficiencies or duplication of efforts in implementing

CDM resources. CDM effort will require collaborative and aggressive commitment by LDCs, the OEB, the OPA, government, supply chain and customers.

- **Codes and standards savings.** The OPA estimates CDM that may be achieved through codes and standards. The key assumptions and uncertainties are: implementation date; efficiency level; baseline efficiency of existing stock of equipment/buildings; and rate of existing stock turnover.

- **Performance of CDM programs**. The primary purpose of CDM programs is to acquire resources by offering incentives, information or other services. Programs are designed and projections for expected resource savings are developed using the best available information. Processes such as risk assessment and planning, program performance monitoring and tracking, evaluation and change management can be used for identifying variances between forecasted and actual results and for developing strategies for course corrections.

- **Electricity pricing**. The OPA estimates CDM resources that may be achieved from the implementation of electricity pricing mechanisms, such as TOU rates. There are several factors that influence the estimates, including: the number of customers on the pricing mechanism, prices and behaviour response.

- **External factors**. There are many external factors that could have a significant impact on the ability to achieve planned CDM resources. Examples include: economic factors, population trends, technology development, customer preferences and weather.

The OPA identifies and considers key uncertainties and risks in its CDM planning process. It has developed an assessment of performance scenarios and key risks for OPA-funded CDM programs over the next four years, along with risk mitigation plans.

4.6 Assessment of Performance Scenarios

The OPA performed an analysis related to the effects of key risks and uncertainties on resource savings forecasts (MW and MWh) for each of the OPA-funded programs

Performance scenarios were developed for each program-level forecast and for the portfolio as a whole. These scenarios, high and low, were developed based on program-specific changes to variables that were identified as key risks or uncertainties that could affect performance.

Key conclusions from this analysis include:

- Achievement by LDCs of their entire mandatory aggregate CDM target through province-wide programs is only projected to occur under the most optimistic scenarios. LDCs will supplement the Tier 1 OPA programs with OEB-approved Tier 2 and 3 CDM programs.

- Peak demand savings projections are highly sensitive to demand response projections and energy savings are highly sensitive to business and/or consumer projections.

4.7 Risk Mitigation Plans

A risk analysis was developed for each program, based on proposed program design and delivery strategies. Mitigation strategies were developed for those risks with moderate to high probability and impact of occurrence.

A risk assessment was completed for the Consumer Program, Business Program, Industrial Program and Low Income program. For each of the OPA-funded programs, the following information was provided:

- Key risks identified;
- Perceived likelihood of negative impact (i.e. high, medium, or low);
- Perceived significance of impact if risk occurs (i.e. high, medium, or low); and,
- Example mitigation measure(s).

The OPA will monitor the performance of the OPA-funded programs, with emphasis on the risks and uncertainties identified in a risk mitigation plan, and make/or advise appropriate modifications over the four-year period (2011-2014). The OPA-funded programs are not expected to remain static throughout the four-year period. Rather, it is envisioned that they will evolve to reflect implementation experience and opportunities for strategic and operational improvement.

4.8 Areas for Consultation

The OPA is seeking stakeholder input in the areas outlined below to support the development of IPSP II. Additional background information on these topics will be published in advance of the CDM stakeholder session.

Throughout 2010, the OPA worked collaboratively with LDCs on the design of the 2011-2014 OPA-contracted province-wide CDM programs. This design process also included a public consultation in which more than 200 organizations offered feedback in April 2010.

For the purposes of the IPSP consultation, the OPA is seeking input related to its process of identifying and mitigating program performance risks.

The OPA is adopting a long-term market transformation strategy for achieving Ontario's long-term CDM targets. This strategy includes three main steps: stimulating innovation; accelerating penetration; and locking in CDM – all of which are supported by capability building across the CDM supply chain.

1) What do you see as the challenging aspects of implementing this market transformation strategy in Ontario? What will be the greatest challenge?

2) How can implementation of this market transformation strategy in Ontario be enhanced?

3) What should be the role of the supply chain (manufacturers, distributors, retailers, etc.) in implementing Ontario's long-term market transformation strategy? How can it be developed/adopted?

4) The Supply Mix Directive indicates that CDM targets "shall also include electricity savings forecasted through the implementation of codes, standards, regulations and ***other initiatives that are progressive and reasonable based on OPA analysis.***" What other progressive and reasonable initiatives/policy instruments should the OPA consider for inclusion in the IPSP for the medium to long term?

5) The OPA supports innovation through the Conservation Fund and Technology Development Fund. Both funds have identified priority areas for investment. Are we on the right track? What additional approaches, if any, should be considered to support innovative strategies and technologies that facilitate conservation?

The OPA is incorporating the assessment of risks and uncertainty in its CDM planning processes. An assessment of performance scenarios and key risks for OPA-funded CDM programs in the next four years has been developed, along with risk mitigation plans.

6) Are there other key risks or uncertainties regarding performance of OPA-funded programs in the near term which have not been identified?

7) What mitigation strategies should be considered?

The Supply Mix Directive indicates that "the plan shall seek to exceed and accelerate the achievement of these CDM targets if this can be done in a manner that is feasible and cost effective."

8) Given the supply and demand context, what factors or approach should the OPA consider when deciding whether it is feasible and cost effective to accelerate or exceed the targets?

9) Are there other approaches or actions that the OPA should consider to exceed or accelerate that are not currently included in programs?

10) Are there other programs or policies that the OPA should consider to exceed or accelerate that are not currently included in the plan?

5.0 TRANSMISSION

FROM THE LTEP:

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.

Recent investments include:

- Launch of the Bruce-to-Milton project, which will connect refurbished nuclear units and additional renewable energy to the grid
- Work on reinforcing the power transfer capability between northern and southern Ontario
- New Ontario-Quebec connection, which has increased access to 1,250 MW of hydroelectric power and enhanced system reliability in eastern Ontario
- $400 million in additional transmission projects to facilitate the elimination of coal-fired generation
- Overhaul of 15 percent of transformer stations at an investment of $850 million
- Installation of nearly 4.3 million smart meters across Ontario
- Investments in smart grid infrastructure and technologies.

FROM THE SUPPLY MIX DIRECTIVE:

The Plan shall include the five priority transmission investment projects identified by the OPA for system reliability, serving new load and renewables incorporation out to 2018.

- Device(s) to enhance transfer capability in southwestern Ontario
- Upgrading existing line(s) west of London
- A new line west of London
- Enhance the east-west tie along the east shore of Lake Superior through a new line
- New line to Pickle Lake.

In addition:

- A transmission solution to maintain reliable supply in the southwest GTA will be required.
- Procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area is still necessary to ensure adequate regional electricity supply.

The OPA shall identify other cost-effective transmission and distribution solutions through ongoing decision processes - integrated planning and economic tests - and maximize use of the existing system.

Develop a plan for remote community connections beyond Pickle Lake, including consideration for the relevant cost contributions from benefitting parties, such as the federal government.

AREAS TO BE CONSIDERED IN THE IPSP:

- What are the OPA's recommendations on the scope and timing of the five priority transmission projects?
- What other cost-effective transmission and distribution solutions are addressed through the IPSP and other ongoing decision processes?
- What is the plan for remote community connections?
- How can challenges to meeting transmission requirements be addressed?

5.1 Recent Investments

Substantial upgrades to existing facilities and the addition of new transmission projects since 2003 were planned primarily to respond to four "drivers" or rationales:

- To enable the Ontario government's off-coal policy to eliminate coal-fired generation by the end of 2014
- To improve reliability of the provincial grid
- To enhance interconnections with neighbouring jurisdictions
- To connect renewable generation.

Together, these investments have met these objectives and allowed the transmission grid to keep pace with changes in supply and demand to ensure the integrity and reliability of the system. The projects and their drivers are summarized in Figure 1 and Table 1. They include:

Projects to facilitate the off-coal policy

Changes to the supply mix and the location of new generation capacity required to facilitate the elimination of coal-fired generation in Ontario by the end of 2014 have created a need for investments in bulk transmission. Several projects have been completed or are underway to facilitate coal replacement either directly (for example, by connecting new generation to the grid) or indirectly (by providing localized voltage support). These projects include the Bruce-to-Milton transmission line, voltage support facilities in northern and southwestern Ontario, reinforcement in the Sarnia area, and the new Parkway transformer station (TS).

Projects to improve system reliability

The location of new generation facilities to meet growth in demand in certain regions has provided the rationale for recent transmission investments. Projects pursued primarily to address system reliability include reinforcement in the Sault Ste. Marie area and several projects in the Greater Toronto Area (GTA). This includes the unbundling of the 500 kV circuits between Claireville TS and Cherrywood TS, station improvements at Claireville TS and local generation, including Portlands Energy Centre, Goreway generating station (GS) and Halton Hills GS.

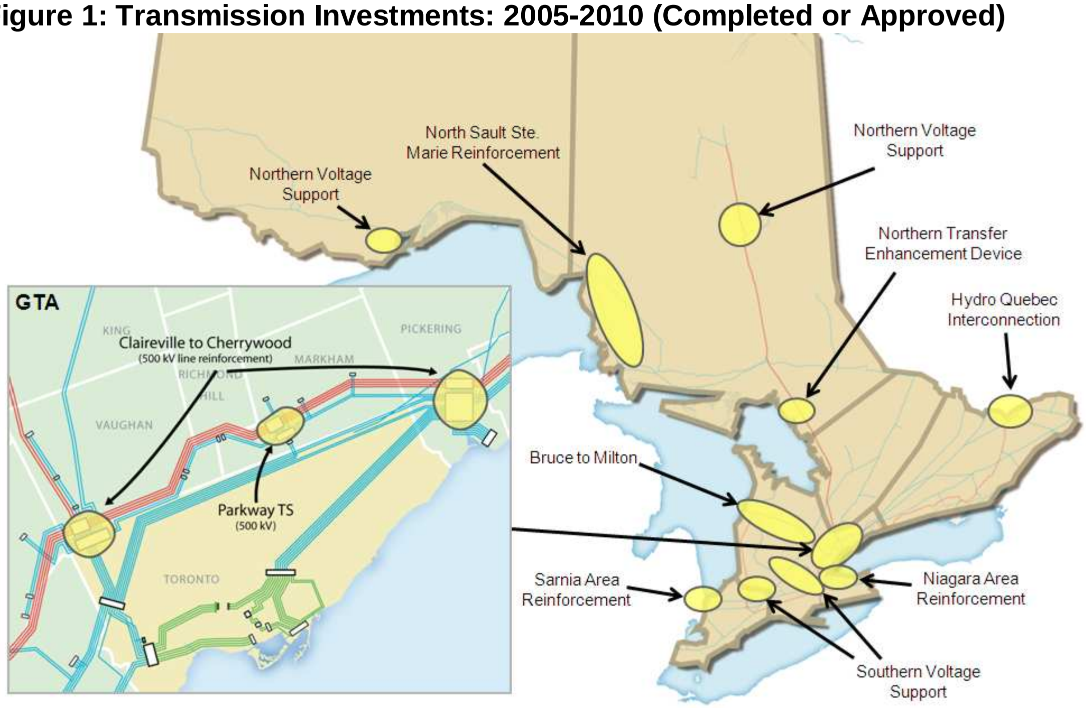
Projects to enhance interconnection capability

Recent investments in transmission have strengthened Ontario's interconnections with neighbouring jurisdictions. These investments, including a new interconnection with Quebec and reinforcements in the Niagara area, increase the capabilities of Ontario's interties and strengthen the bulk transmission system to facilitate power delivery and improve access to neighbouring electricity markets.

Projects to enable incorporation of renewable resources

Several of the transmission projects described above have also enabled the development of renewable generation by enhancing the capability of the transmission system to move energy between different points (see Table 1). In addition, some minor transmission upgrades were undertaken primarily to enable renewable generation, including upgrading of the 230 kV transmission line between Hanover and Orangeville, and voltage support facilities in the northeast to enable wind generation development.

Figure 1: Transmission Investments: 2005-2010 (Completed or Approved)



Source: OPA

Table 1: Transmission Developments and Drivers: 2005-2010 (Completed or Approved

Investment	Driver			
	Off-Coal Policy	Reliability	Interconnections	Renewable Generation
Bruce to Milton Transmission Project	✓			✓
Northern Ontario Voltage Support and Transfer Enhancement Facilities	✓			✓
Southwestern Ontario Voltage Support Facilities	✓			
Sarnia Area Transmission Reinforcement	✓			
Parkway TS- Transformer Addition	✓	✓		
North Sault Ste. Marie Transmission Reinforcement – Third Line TS to Wawa TS		✓		✓
Additional 500 kV Circuits Between Claireville TS and Cherrywood TS, and Claireville TS Station Improvements		✓		
Local Generation: Portlands Energy Centre, Halton Hills GS, Goreway GS	✓	✓		
Hydro Quebec HVDC Interconnection			✓	
Niagara Area Transmission Reinforcement			✓	✓

5.2 Summary of Supply Mix Directive Requirements

The Supply Mix Directive stated that the updated Integrated Power System Plan (IPSP II) shall include the five priority transmission investment projects identified by the OPA for system reliability, serving new load and renewables incorporation out to 2018.

The projects are:

- Device(s) to enhance transfer capability in southwestern Ontario
- Upgrading existing line(s) west of London
- A new line west of London
- Enhance the east-west tie along the east shore of Lake Superior through a new line
- New line to Pickle Lake

The Supply Mix Directive also directs the OPA to define and make recommendations on the scope and timing of these transmission projects on the basis of their rationale. It said the OPA should immediately work with Hydro One on the scope and timing of transmission projects to be undertaken by the transmitter pursuant to an amendment to its license conditions.

In addition, the Supply Mix Directive requires:

- A transmission solution to maintain reliable supply in the southwest GTA
- Procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area to ensure adequate regional electricity supply.

The OPA is also directed to:

- Identify other cost-effective transmission and distribution solutions through continuous decision processes – integrated planning and economic tests – and maximize use of the existing system.
- Develop a plan for remote community connections beyond Pickle Lake, including consideration for the relevant cost contributions from benefiting parties, such as the federal government. The Plan may also consider the possibility of interim solutions, as appropriate, that reduce consumption of diesel fuel.

In addition, there are a number of ongoing transmission planning processes that are outside the IPSP. For example, the OPA addresses transmission to facilitate renewable connections through the Feed-in-Tariff (FIT) Program processes, including station upgrades to facilitate connection of small-scale renewable generation. The OPA also addresses local and regional needs through joint regional planning studies with local distribution companies (LDCs), transmitters, and the Independent Electricity System Operator (IESO). These activities are conducted outside the IPSP as they require a high degree of coordination with LDCs to develop integrated plans that reflect specific local circumstances and opportunities, such as potential distribution solutions, LDC conservation activities, and distributed generation opportunities. The timing of these studies may not align with the schedule for the IPSP, so they are addressed through ongoing processes. Regional planning projects that are currently active include:

- Kitchener-Waterloo-Cambridge (KWC) area
- Greater Toronto Area (GTA)
- Downtown Toronto
- York Region
- Windsor-Essex
- Ottawa

The Ontario Energy Board (OEB) has recently announced a consultation process to develop a regulatory framework for regional planning aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

5.3 Transmission for Near-Term Needs to 2018

The Supply Mix Directive identified five priority transmission projects to ensure system reliability, serve new load and incorporate renewable sources of generation to 2018.

Transmission expansion to 2018 will respond to four primary drivers: meeting the requirements in Supply Mix Directive for 9,000 MW of installed hydroelectric capacity and 10,700 MW of non-hydro renewable capacity by 2018; facilitating non-renewable generation; enabling a changing generation mix in central and southwestern Ontario, and ensuring supply capacity and reliability.

While some transmission reinforcement has been required to facilitate development of hydroelectric resources, the OPA expects that the 9,000 MW target will not require further transmission expansion.

More than 5,000 MW of non-hydro renewable generation has been accommodated to date on the existing transmission system through a number of procurement processes, including the RES I-III procurements, RESOP, CHPIII, part of the Green Energy Investment Agreement development, and the FIT Program. Remaining capacity on the existing transmission system and the new Bruce-to-Milton transmission line will enable additional non-hydro renewables. However, transmission expansion will be required to integrate the remaining renewable generation needed to meet the target.

5.3.1 Priority Transmission Projects

The following sections describe the five priority transmission projects included in the Supply Mix Directive. This direction is based on the advice provided to the government by the OPA, which was derived from a continuous, long-term planning effort in which the views of industry partners, stakeholders and others are solicited.

The first three projects—transfer capability in southwestern Ontario, upgrading existing lines west of London and a new line west of London—along with the new Bruce-to-Milton line are expected to provide sufficient additional transmission capability to meet the 10,700 MW non-hydro renewables target. The OPA will continue to administer the FIT program as part of the procurement process to achieve this target. The OEB has amended Hydro One's license to require it to move forward with these projects.

The other two projects—new East-West tie and Pickle Lake lines—will provide supply capacity and reliability in the Northwest.

Transfer capability in southwestern Ontario

The Bruce area, bounded by the Lake Huron shore to the north, Owen Sound and Orangeville to the east and London and Stratford to the south, has significant wind energy potential. The area currently has constrained transmission but initiatives and upgrades are currently under way to alleviate constraints. The new Bruce-to-Milton transmission line, which is scheduled to come into service in late 2012, would connect refurbished nuclear units and enable about 1,200 MW of additional renewable generation in the Bruce region.

The addition of reactive compensation – in southwestern Ontario, through series capacitors or other equipment such as static-var compensators – would enable more generation in the Bruce area without building another new transmission line. (Reactive compensation regulates the flow of the transmission system to increase its efficiency.) This upgrade would maximize the capability of the transmission infrastructure in a resource-rich area. The planned in-service date for this project is the end of 2014. Detailed system studies for this project continue.

Upgrading existing lines west of London

The west-of-London transmission area is defined by the high-voltage transmission lines emanating from London toward Sarnia and Chatham. During the FIT Program launch period in the autumn of 2009, the OPA received applications from this area that represent more than 2,000 MW of renewable generation.

One of the near-term priority transmission projects identified in the Supply Mix Directive is the upgrade of a portion of an existing transmission line west of London to increase its capacity. This upgrade would maximize the capability of existing transmission infrastructure in this resource-rich area.

The OPA has conducted studies for the past year to identify possible upgrading options. In 2011, the OPA will work closely with Hydro One to finalize the project scope. The planned in-service date for this project is the end of 2014.

New transmission line west of London

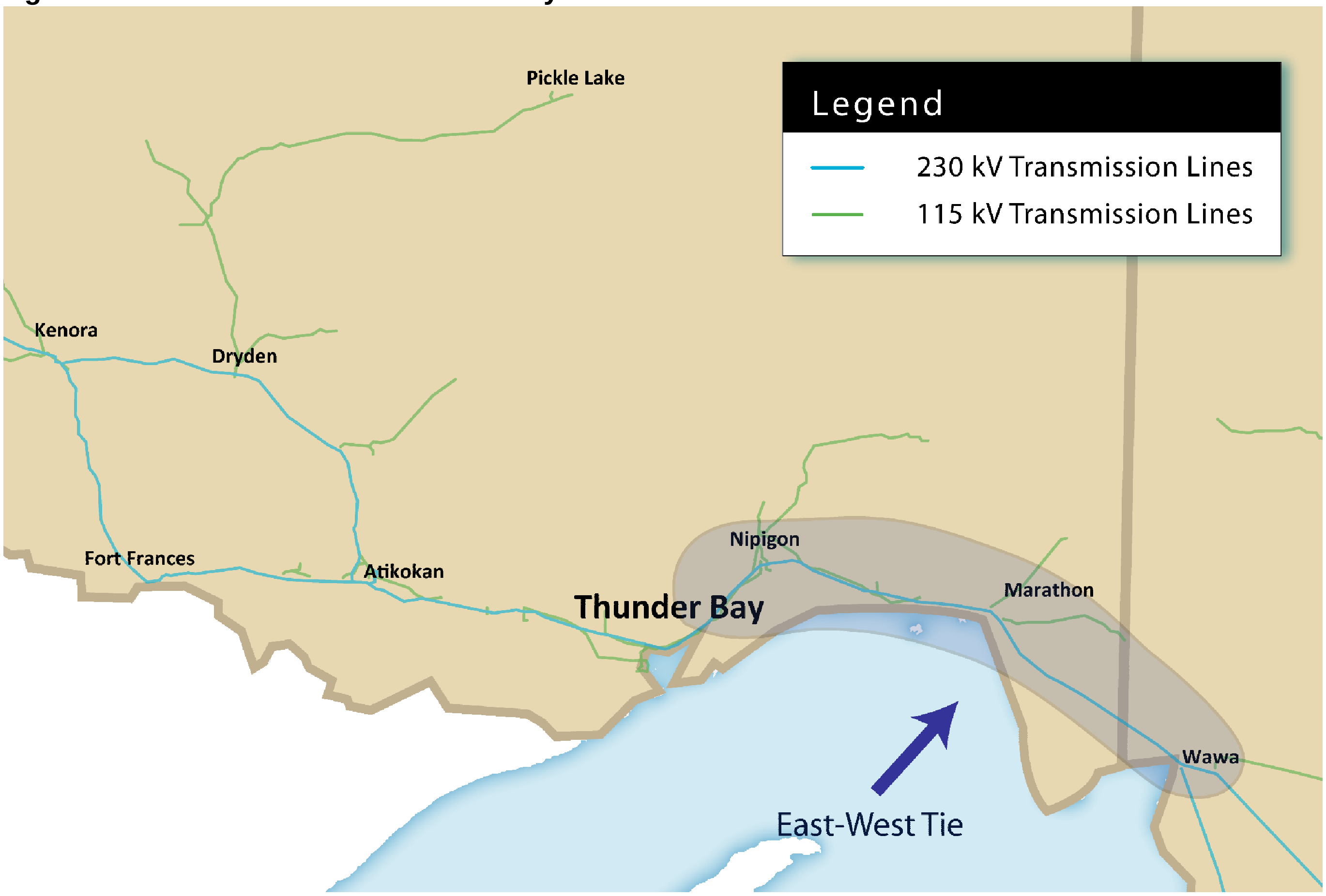
Another near-term priority transmission project identified in the Supply Mix Directive is the building of a new transmission line in the west-of-London area. This new line would enable the connection of a larger amount of additional generation in the west-of-London area and could facilitate both renewable generation development as well as the potential conversion to natural gas of the coal-fired Lambton GS in Sarnia. The need for a major transmission project of this kind must be anticipated well in advance, to allow sufficient time for planning work, completion of the required environmental and regulatory approvals and project construction. The planned in-service date for this project is the end of 2017.

To date, the OPA has initiated preliminary studies to identify the capability of different configuration and line options. The OPA will work closely with Hydro One as they initiate project development work. Once the preferred alternative for this project has been identified, Hydro One will begin the approvals process for the new line.

A new East-West tie line

Ontario's northwest stretches from the Manitoba border east to Wawa as shown in Figure 2. The region is supplied by local generation resources as well as a transmission connection to the rest of Ontario known as the East-West tie.

Figure 2: The Northwest Transmission System



Source: OPA, Hydro One Networks Inc.

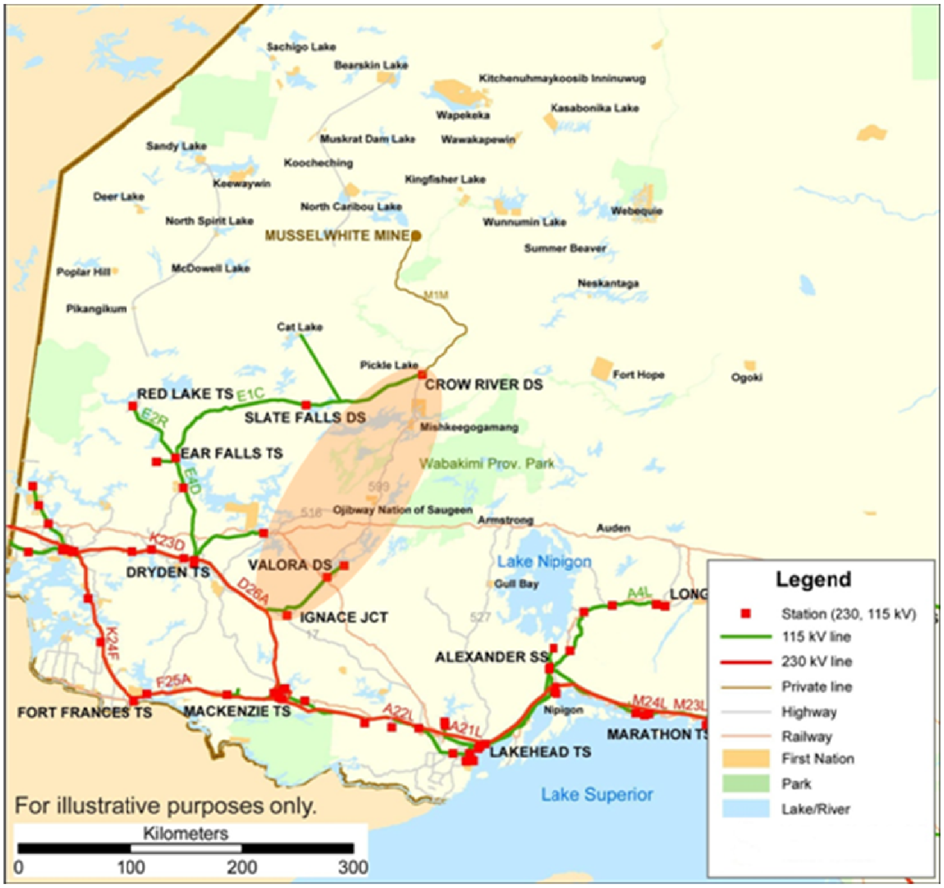
The East-West tie currently has limited power transfer capability to provide reliable and economic supply to the northwest subsequent to the shutdown of coal-fired units in the region. As a result, the Supply Mix Directive instructs the OPA to assume that a new East-West tie line, from Wawa to Thunder Bay, will proceed. The new line would also reduce power losses and congestion, provide opportunities for the development of renewable resources in the Northwest and enhance operational flexibility.

To maintain regional supply requirements in the Northwest, the government has directed the conversion of the Atikokan coal GS to biomass and Thunder Bay coal GS to gas-fired operation.

New line to Pickle Lake

The government indicated in its Long-Term Energy Plan that Ontario will focus on supplying Pickle Lake with a new line from the Ignace/Dryden area. Given the substantial load growth in the area north of Dryden, it is possible that reinforcements in addition to a new line to Pickle Lake may be required.

Figure 3: Supply to Pickle Lake



Source: Hydro One Networks Inc.; OPA

This is due to load growth from mining operations around Red Lake and Pickle Lake, which is projected to double between 2013 and 2025. As well, other mine sites are under various stages of reactivation, development or exploration in the area.

Transmission reinforcement to the area north of Dryden is needed to support these industrial expansions, which will also drive associated demand growth in communities that are already connected to the grid. Connection of remote First Nation communities in the area, as detailed in Section 5.5, will be an additional source of new demand in the area. The OPA is conducting a planning study to evaluate the possibility of transmission connection of remote First Nation communities north of Dryden.

There are a number of options for supplying mining activities in the area known as the Ring of Fire including through a transmission line from Pickle Lake. While there is no firm load estimate for the Ring of Fire, there are indications that about 30 MW could be required by 2015. In the long term, demand could grow up to about 150 MW. The OPA will continue to monitor the need for new supply as mining and other infrastructure develops in the area.

5.3.2 Other Transmission Solutions

Transmission is also needed to support the integration of non-renewable generation resources such as nuclear and gas-fired generation, and to ensure the reliability of supply in growing areas such as the GTA.

Nuclear generation

The Supply Mix Directive calls for continued planning for nuclear generation to account for about 50 percent of total Ontario electricity generation. To this end, the updated IPSP is to provide for the refurbishment of 10,000 MW of existing nuclear capacity at the Bruce Nuclear Generating Station (NGS) and at Darlington NGS. The IPSP is to also account for the procurement of two units totalling about 2,000 MW at the Darlington site.

Transmission system upgrades associated with continued operation of the Bruce NGS will be addressed by the new Bruce-to-Milton 500 kV transmission line, which is scheduled to come into service in late 2012. This new line will allow for operation of all eight nuclear generating units at Bruce NGS and also accommodate about 1,700 MW of new renewable generation in southwestern Ontario (1,200 MW in the Bruce area and about 500 MW west of London).

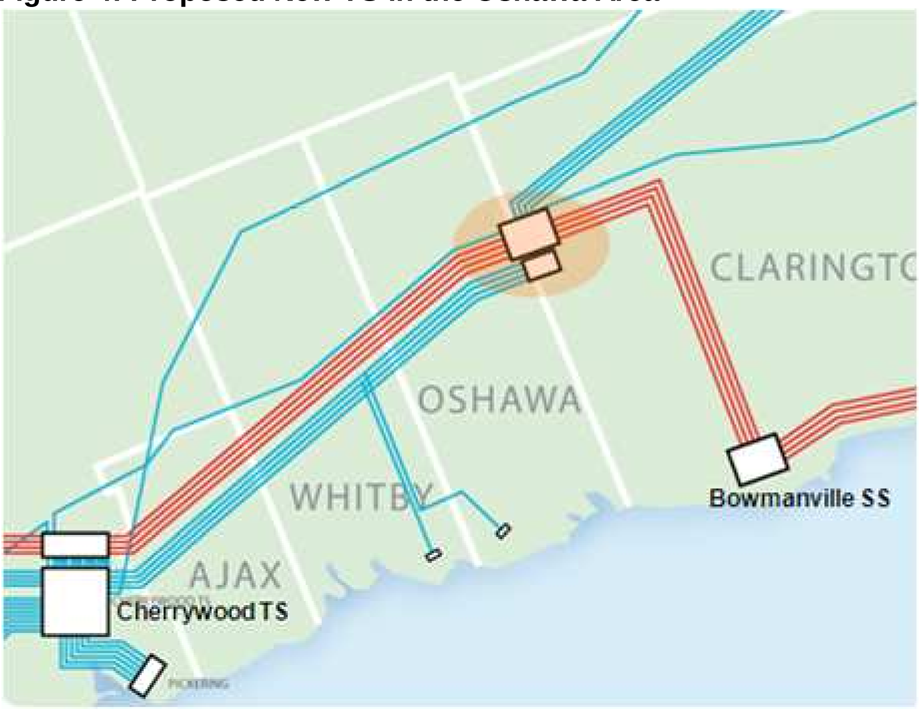
The units at Pickering NGS, which date from 1971, are the oldest in Ontario and a decision has been made not to refurbish them. As indicated in Section 3, a feasibility study that will be completed in 2012 will determine if the operating life of the units at Pickering can be extended to the end of this decade. If life extension is not feasible, the Pickering units could cease operation by the middle of this decade.

Retirement of the Pickering units, coupled with the addition of significant new generation resources west of the GTA, could begin stressing the transmission path from the Milton area toward the central GTA starting sometime between 2015 and 2020. This will continue until full operation of all planned units at Darlington is achieved.

In addition, the Pickering shutdown will affect the transmission facilities at Cherrywood transformer station (TS) supplying loads in the eastern GTA. As identified in IPSP I, a solution to address this situation would be the installation of a new transformer station in the Oshawa area (see Figure 4).

A site in Oshawa with sufficient space to accommodate these facilities is available. In addition to relieving the transformers at Cherrywood TS, this new station would also provide a new major supply point for serving load growth in the eastern GTA.

Figure 4: Proposed New TS in the Oshawa Area



The completion of an Oshawa-area TS could be needed as early as 2016, which is the earliest date all units at Pickering could be phased out. The decision on whether and when to proceed with the construction of this station will depend on the outcome of the feasibility study of extending the life of the units at Pickering GS.

In the longer term, transmission system upgrades will be required to accommodate full operation of the existing units at Darlington NGS as well as two new nuclear units.

Gas-fired generation

As stated in the Supply Mix Directive, natural gas will continue to play a strategic role in Ontario's supply mix by complementing intermittent generation sources, meeting local and provincial system requirements and ensuring that adequate generation capacity is available as nuclear plants are modernized. The OPA will continue to plan natural gas resources for these strategic purposes (see Section 3), including new facilities and conversion of coal plants.

Gas conversion and transmission needs

The Supply Mix Directive indicates that two units at Thunder Bay GS are to be converted to gas-fired generation. Additionally, the OPA is asked to assess the potential for conversion of some or all of the units at Lambton GS and Nanticoke GS. These are the implications on transmission planning from coal conversion:

- *Northwest*—As indicated in Supply Mix Directive, the government plans to convert Thunder Bay GS to run on natural gas. The conversion provides generation capacity for the City of Thunder Bay, northwestern Ontario and the province-wide system after the planned elimination of coal-fired generation by the end of 2014. No additional transmission is required to accommodate this conversion.

- *West of London*— If a decision is made to convert Lambton GS to run on natural gas, transmission reinforcement may be required, depending on the number of units converted and the nature of the plant's operation. The planned transmission improvements west of London would fulfill this need.

- *Nanticoke area*—If a decision is made to convert Nanticoke GS to run on natural gas, the existing transmission system likely has adequate capacity to accommodate its output. Nonetheless, the system impacts of the operation of this plant would need to be considered when planning the southwestern Ontario system.

New gas-fired generation

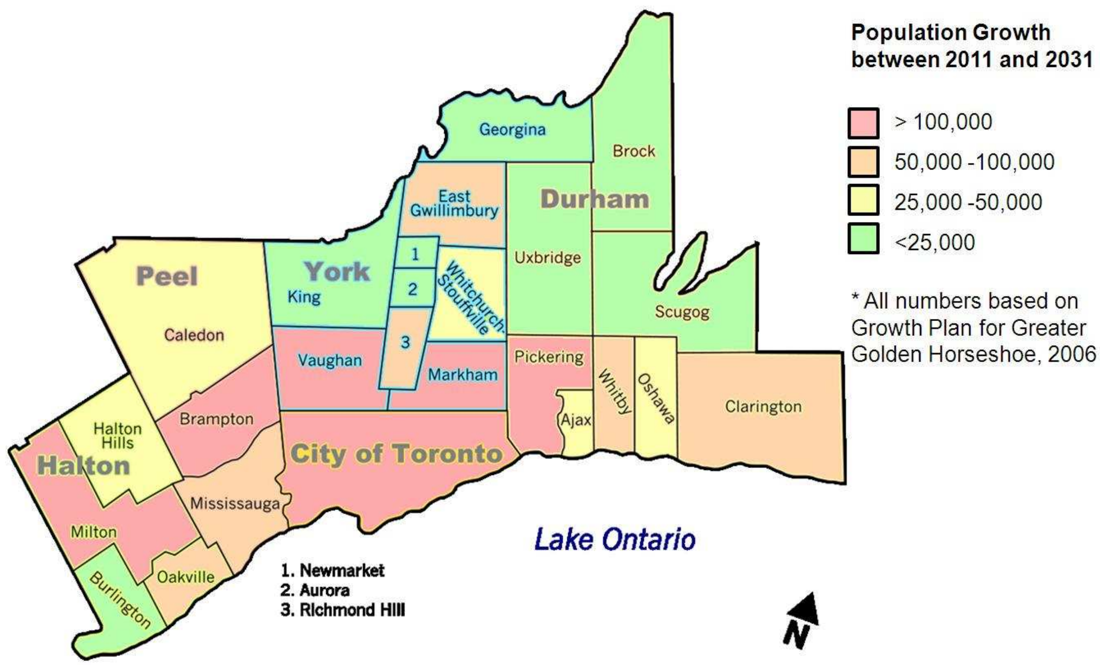
Previously, there was a need for three additional gas plants in the province, including one in the Kitchener-Waterloo-Cambridge (KWC) area. A drop in province-wide demand for electricity combined with the addition of about 8,400 MW of new supply since 2003, means that two of the proposed plants are no longer required. The plant in KWC is still required to meet system and area needs. This would ensure adequate regional electricity supply to this growing area and avoid the need to provide major new transmission to serve the area.

Western GTA demand growth and changing supply mix in central and southwestern Ontario

There are two main factors affecting the bulk transmission plan for the western GTA: electricity demand growth and changing sources of generation supply. Strong projections for electricity demand growth in the region will stress key transmission stations, or gateways, into the western GTA. In addition, changes in the generation supply mix in central and southwest Ontario will affect the nature of electricity flows on transmission paths into the western portion of the GTA. Options to address these needs involve the addition of new transformers and switching facilities in the western GTA and new line sections, or pathways, to reinforce supply capability in the area.

The western GTA is one of the fastest-growing areas in the province. The 2006 *Growth Plan for the Greater Golden Horseshoe* issued by the Ontario government projected an additional 580,000 people living in the combined regions of Halton and Peel over the next 20 years. As shown in Figure 5, the highest projected growth rates in the western GTA are in the municipalities of Milton, Oakville, Brampton and Mississauga. Strong growth is also expected in the City of Toronto, Vaughan, Markham and Pickering.

Figure 5: Forecast Population Growth in the Greater Toronto Area



Source: *Growth Plan for the Greater Golden Horseshoe*, 2006, Ministry of Infrastructure

Two major transmission gateways – Trafalgar and Claireville TS – serve the western GTA and portions of central and downtown Toronto. Preliminary studies show the transmission facilities at these two stations could reach their supply limitations before the end of this decade. Their locations are shown in Figure 6.

Figure 6: Western GTA Transmission System

Source: OPA

Over the same period of time, the generation supply mix in southern Ontario will change as new and refurbished resources come online, coal-fired generation is eliminated and the nuclear resources at Pickering NGS are retired. The additional supply resources will include about 6,000 MW of wind, solar, biomass, natural gas facilities and refurbished Bruce nuclear units in areas west and southwest of the GTA. The generating units at Pickering could begin retiring as early as 2014, with the last unit scheduled to operate until 2016. Ontario Power Generation (OPG) is investigating the feasibility of extending the life of the Pickering units until the 2018 to 2020 period but the technical feasibility of this option will not be known until 2012.

The modified supply mix will change electricity flows in the GTA, increasing flows on the 500 kV lines between the Milton and Claireville stations and the 230 kV lines between the Trafalgar and Richview stations. The dates at which these transmission paths will need relief are determined by the following factors:

- Rate of load growth in the western GTA
- The magnitude and timing of changes to the generation mix in southwestern Ontario
- The schedule for retirement of the Pickering nuclear units
- The schedule for refurbishing and installing new nuclear generation at the Darlington site.

In addition, since the new gas-fired generation previously planned for the southwest GTA is not proceeding, a transmission solution to maintain reliable supply in the area will be required.

Transmission options for addressing the bulk system overloads must relieve the 500 to 230 kV transformers at the Trafalgar and Claireville stations, as well as maintain power flows toward the GTA within established operational limits.

Transmission options that can meet these requirements include:

- *Option 1* - Provide new transformation and switching facilities at the existing Milton station, combined with building new 230 kV lines to transfer loads from the Trafalgar and Claireville 230 kV supply area to the Milton 230 kV station. This could include building a new 10-kilometre, 230 kV line section between the Meadowvale and Hurontario stations.

- *Option 2* – Provide new transformation and switching facilities at the existing Trafalgar station, combined with a new 500 kV line (about 14 kilometres long) along an existing transmission corridor between the Milton and Trafalgar stations, combined with building new 230 kV lines to transfer additional loads to the upgraded Trafalgar station. This could include building two new 230 kV line sections (about 10 kilometres long) along existing transmission corridors. One of the new 230 kV lines would be built on the north/south portion of the existing transmission corridor between Milton and Trafalgar to enable connection of the Trafalgar station to the Meadowvale station. The other 230 kV line section would enable the connection of the Meadowvale station to the Hurontario station as in Option 1.

5.3.3 Summary of Near-Term Needs

While the transmission developments presented in the previous sections have been described with reference to their primary rationale, many of them provide integrated solutions to meet a variety of needs. These are summarized in Table 2.

Table 2: Transmission Developments and Drivers to 2018

Investment	Driver			
	Enabling Renewable Generation	Enabling Nuclear Generation	Enabling Gas-Fired Generation	Providing Supply Capacity & Maintaining Reliability
Reactive compensation in southwestern Ontario	✔			
Upgrading existing lines west of London	✔		✔	
New transmission line west of London	✔		✔	
Oshawa-area TS		✔		✔
New gas-fired generation in the KWC area				✔
West GTA reinforcement	✔	✔	✔	✔
New East-West tie	✔			✔
New transmission line to Pickle Lake				✔

5.4 Transmission for Needs Beyond 2018

Beyond 2018, the need for additional transmission will be shaped by evolving conditions, including the status of the supply mix, changes in demand and advancements in technologies and standards over time. Given the long lead time to make decisions for this period, it is not necessary to recommend longer-term transmission options until their need becomes more certain. As such, future plans will study additional transmission projects as demand and changes to supply require.

Nonetheless, it is important to monitor longer-term supply option developments, as well as changing technologies and industry standards. Longer-term developments that the OPA anticipates could trigger the need for additional transmission development include:

- Higher demand enabling additional renewable energy
- Units at Darlington B
- Development of northern renewable energy potential
- Transactions with neighbouring jurisdictions
- Integration of energy storage.

Specific transmission solutions will be addressed in future plans as the need becomes more certain. The cost of transmission required to enable longer-term supply options will be considered when assessing the cost-effectiveness of various supply alternatives.

5.4.1 Units at Darlington B

The Supply Mix Directive requires the OPA to plan for the procurement of two nuclear generating units totaling about 2,000 MW at the Darlington site. The transmission lines connecting Darlington to the GTA between Bowmanville and Pickering provide adequate transfer capability for the existing Darlington units but reinforcement may be required to enable additional generation capacity.

The units at Darlington are currently planned to come into service while some of the existing units will be offline for refurbishment. The full expanded generation capacity at Darlington will not be operational until all the refurbished units return to service, currently planned for some time after 2018. Once the refurbished units return to service, the net increase in generation in the area may result in the overloading of the existing 500 kV transmission corridor west of Bowmanville switching station, where the Darlington units are situated. If it is determined that the existing transmission capability of this corridor is insufficient, there will be a need for a new line from the new Oshawa-area TS to the existing Bowmanville station. The existing transmission corridor has space for these facilities.

Given the long lead time for the expansion of Darlington capacity, transmission reinforcement does not need to be recommended at this time. The OPA will continue to monitor the situation and, if needed, transmission reinforcement to enable new nuclear at Darlington may be included in the next IPSP.

5.4.2 Northern Renewable Potential

The capability of the existing transmission system to support further renewable-energy development in northern Ontario is currently limited despite significant remaining hydroelectric and wind energy potential. This includes hydroelectric resources in the Albany and Moose River basins and wind along the shores of James Bay and Hudson Bay. Additional transmission will be required if northern renewable resource development is determined to be cost-effective in the long term and the cost of this would have to be factored into the calculation.

Significant resource development in northeastern and/or northwestern Ontario would likely trigger the need for additional transmission capacity along the North-South tie, which is the major delivery path between Sudbury and the GTA. Depending on where northern resources are developed, additional transmission reinforcement could also be needed to ensure adequate power transfer capability to Sudbury.

The OPA will continue to monitor conditions and, if warranted, develop transmission plans for the inclusion of further northern renewable resources in future system plans.

5.4.3 Transactions with Neighbouring Jurisdictions

Ontario currently does not maintain firm import or export supply contracts with neighbouring jurisdictions. If it is deemed economic, the negotiation of firm imports may be considered to satisfy short-term or long-term resource needs in the future. Import capacity may be limited, however, by the capability of the existing transmission system and significant levels of imports may trigger the need for additional transmission capacity.

If firm imports are considered as a longer-term supply option, the OPA will develop transmission plans to address any constraints.

5.4.4 Integration of Energy Storage

As described in the Long-Term Energy Plan, energy storage facilities can help balance the electricity grid by storing off-peak surplus generation for use during peak hours. Transmission expansion may be required to enable such storage facilities, depending on their size and location.

Storage facilities operate in response to market prices, behaving like loads during off-peak periods, drawing power from the grid, and, like generators during peak periods, feeding stored energy back into the grid. Transmission capacity must, therefore, be adequate to support power flows in both directions. This is particularly relevant for large-scale storage facilities, such as pumped storage. Small-scale storage applications, such as batteries and plug-in hybrid vehicles, will primarily have impacts on distribution systems.

The economics of energy storage facilities remain uncertain. If large-scale storage facilities are pursued in the long term, transmission needs will be studied as required. Widespread adoption of small-scale distributed storage facilities will be monitored for any net impacts on the transmission system.

5.4.5 Changes in Electricity Demand

The Supply Mix Directive states that in developing the plan, the OPA shall use a medium-growth scenario in which Ontario's demand for electricity would grow moderately (by about 15 percent) to 2030. The plan is also to have the flexibility to accommodate the potential for higher load growth. Higher electricity demand growth could result from the significant adoption of electric vehicles or the electrification of public transit. These developments influence transmission needs in the longer term. Since higher electricity demand growth may have impacts on the bulk transmission system or affect the dates at which grid reinforcements would be needed, the OPA will continue to monitor changes in load growth.

5.5 Remote Communities North of Dryden

There are 32 remote communities in Ontario with electricity generation and distribution systems that are not connected to the provincial transmission grid (see Figure 7).[1] This includes 21 First Nations north of Dryden. These communities are separated by long distances and do not have all-season road access. Winter roads provide seasonal access for one to two months per year; air transport is the only means in or out for the remainder of the year.

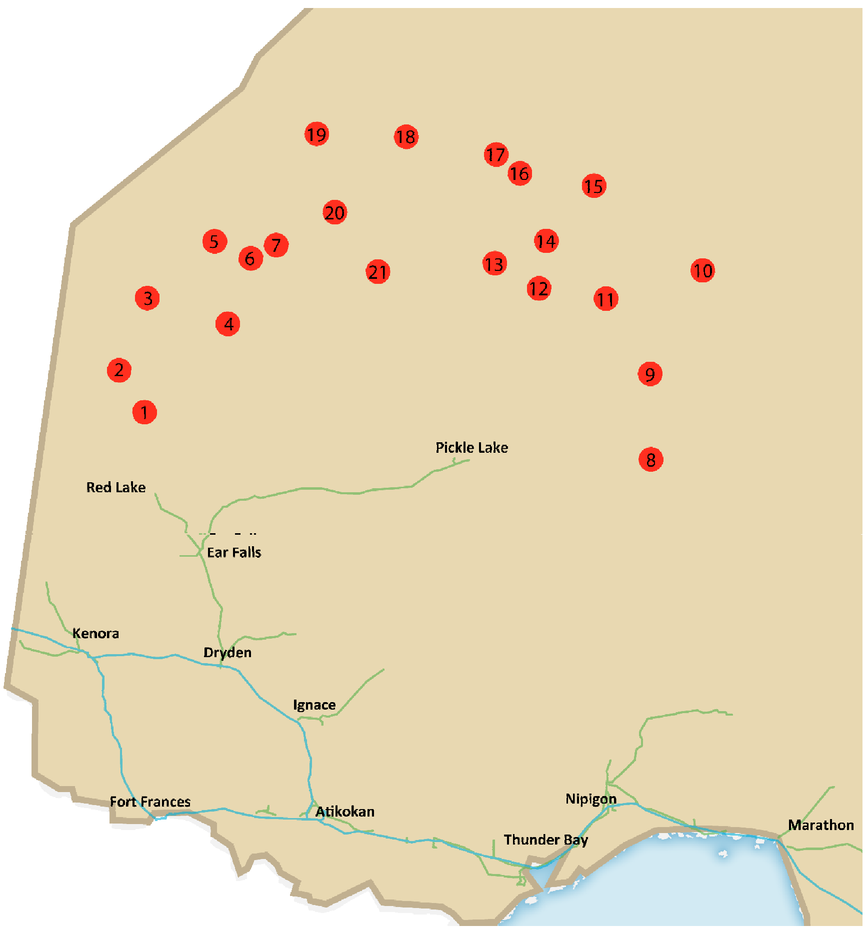
[1] The number of remote communities may vary depending on the source of information. In some cases, neighbouring communities are classified as a single community even though residents may self-identify as separate communities. Examples are Keewaywin and Koocheching, which tend to be shown as a single community on Hydro One maps, or the communities of Collins and Armstrong and the Whitesand First Nation. These communities and the First Nation are often shown as a single entity on maps.

Hydro One Remote Communities Inc. (HORCI), a provincially regulated entity, owns and operates the electricity systems in 11 of these remote First Nations communities. The remaining 10 communities operate their own systems as independent power authorities (IPAs) and are not provincially regulated.

The remote communities have a combined population of about 17,500 (4,800 electricity customers) and peak electricity demand is about 17 MW, both of which are growing faster than other regions of Ontario. The Supply Mix Directive requires the OPA to develop a plan for connecting remote communities beyond Dryden. It indicates that consideration should be given to financial contributions from those parties that would benefit from such a connection, such as the federal government.

The OPA is working with the Northwestern Ontario First Nations Transmission Planning Committee, which has representation from the communities in the area, to develop the plan.

Figure 7: Remote Communities North of Dryden



North West Ontario Remote First Nation Communities	
1	Pikangikum
2	Poplar Hill
3	Deer Lake
4	North Spirit Lake
5	Sandy Lake
6	Kee-Way-Win
7	Koocheching
8	Eabametoong(Fort Hope)
9	Neskantaga(Lansdowne House)
10	Webequie
11	Nibinamik(Summer Beaver)
12	Wunnumin Lake
13	Kingfisher Lake
14	Wawakapewin(Long Dog)
15	Kasabonika Lake
16	Wapekeka
17	Kitchenuhmaykoosib Inninuwug(Big Trout Lake)
18	Bearskin Lake
19	Sachigo Lake
20	Muskrat Dam
21	North Caribou Lake

5.5.1 Impact of Diesel-Fired Systems

The use of diesel electric generation in remote communities costs about three to 10 times more, on average, than the cost of producing electricity from the Ontario generation mix. The major cost component is the cost of diesel fuel and its transportation cost to the communities. Reliance on diesel fuel also exposes remote communities to environmental risk.

HORCI's operations are partly funded by Ontario electricity ratepayers through the Rural and Remote Rate Protection (RRRP) program. HORCI receives about $30 million annually through RRRP funding for remote community customers. Since the IPA community systems are not regulated by the Ontario Energy Board, they do not receive RRRP. Federally and provincially owned facilities/customers within the communities pay the full cost of electricity service through a special rate, termed the Standard A Rate. Funding for infrastructure in the remote communities, including electricity supply systems, is primarily the responsibility of Indian and Northern Affairs Canada.

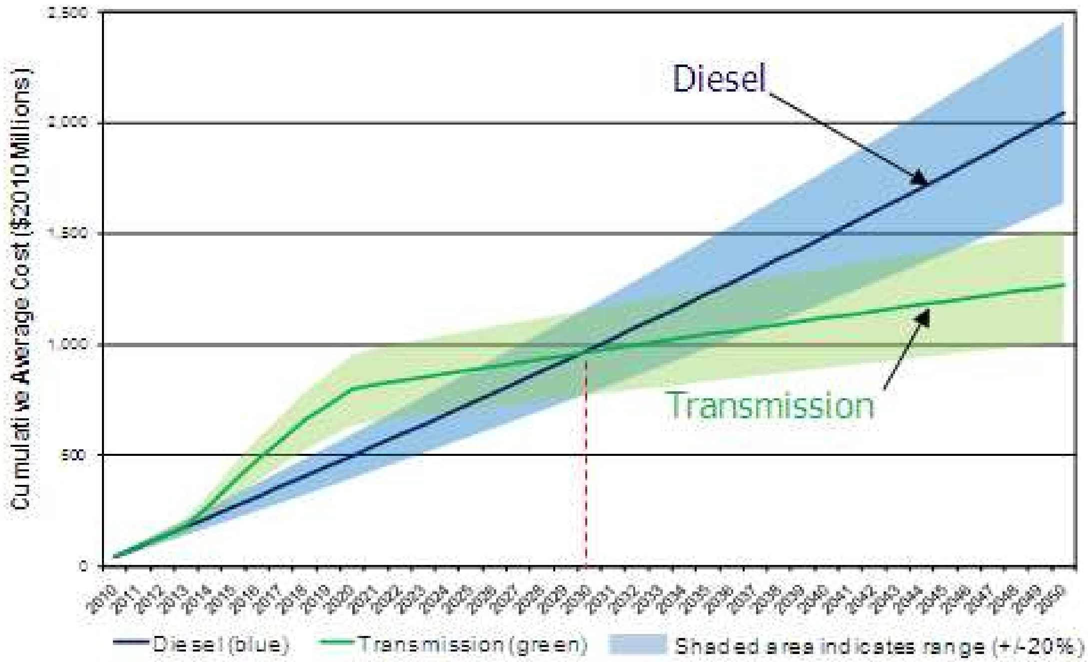
5.5.2 Opportunities to Reduce Reliance on Diesel

Conservation opportunities and Community Energy Plans are being implemented on a priority basis to reduce consumption of diesel in remote communities. A preliminary analysis indicates that small-scale local renewable generation options are significantly more expensive to incorporate than a transmission connection to a large number of the remote communities. A transmission connection to about 20 remote communities is the lowest-cost option over the long term and is the approach preferred by the First Nations to reduce reliance on diesel and to meet the growth requirements of the communities.

5.5.3 Preliminary Assessment of Transmission Connection

The OPA has completed a preliminary assessment of establishing a transmission connection to the 21 remote communities clustered north of Dryden. The assessment compared the cost of transmission to the avoided future cost associated with diesel generation. It identified that an investment in transmission to the remote communities could break even, compared to continuation of diesel supply, within 15 to 20 years from the start of project development work (see Figure 8). These preliminary results validate the need for more detailed analysis of various connection options. The results were also consistent with those conducted by an independent assessment funded by the Ontario Water Power Working Group led by the Ontario Water Power Association.

Figure 8: Preliminary Cost-Benefit Assessment of Diesel vs. Transmission to Supply Remotes



5.6 Areas for Consultation

1) Has the OPA provided sufficient information on the transmission plan?

2) What should be the most important considerations or objectives for long-term transmission planning?

3) Do you have any other advice for the OPA in developing options for the long-term transmission plan?

6.0 SMART GRID

FROM THE LTEP:

A smart grid is a more intelligent grid infrastructure, incorporating communications technology and automation that will:

- Maximize existing infrastructure by using information technology to improve and automate distribution instead of building more traditional infrastructure such as wires and poles
- Modernize the grid, which is essential for improving reliability, home automation and adapting to evolving transportation needs
- Lay the foundation for smart homes by putting 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* (GEA) 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 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. They also provide utilities with automatic notification of outages, save on in-person meter-reading costs and enable time-of-use (TOU) pricing.

Smart meters also help avoid system costs that in turn save money for ratepayers.

FROM THE SUPPLY MIX DIRECTIVE:

The OPA shall give planning consideration to the smart grid developments that are taking place in Ontario. The OPA should also ensure that distribution level investment associated with smart grid and renewable connections is considered in the context of the plan.

AREAS TO BE ADDRESSED IN THE IPSP:

How will the IPSP give consideration to the smart grid?

6.1 Recent History

The development of today's smart or smarter grid is premised on the concept that increased levels of electricity system flexibility and reliability are obtainable and that the investments required to enable such a system are becoming increasingly cost effective. The importance of modernizing the grid continues to increase as the amount of intermittent renewable energy in the supply mix grows, the portfolio of demand response offerings expand, and new end uses such as electric vehicles are adopted by customers.

The central component to any smart grid is a two-way communication network equipped with intelligent monitoring equipment that constantly meters flows and allows for control of specific system components and customer end-uses, also known as advanced metering infrastructure (AMI).

Significant investments have already been made to the province's infrastructure, including the installation of 4.5 million smart meters, which have created a much more intelligent system than we had even a few short years ago.

At the transmission level, system planners have long understood the value of a smart grid and have been investing in intelligent grid technology for decades. While the primary rationale for these investments has been to ensure ongoing system integrity and compliance with NERC[1], these enhancements have also increased the efficiency, reliability and flexibility of the grid, providing real-time feedback on system operational status and performance.

Distribution-level investments, specifically the development of AMI infrastructure, have been leading the way towards the development of Ontario's smart grid. Investments made to date are enabling customers to have greater control over their energy use and bills. The AMI-related investments listed below are significantly changing the landscape and operation of Ontario's electricity system:

- **Smart meters:** As of January 1, 2011, more than 4.5 million smart meters had been installed in the homes or places of business of residential and small commercial customers, enabling conservation opportunities and greater customer control over energy use
- ***peaksaver*®**: The residential and small commercial *peaksaver*® program, an air conditioner and hot water heater load control initiative, had provided approximately 70 MW of demand response capacity at year end 2010
- **Demand response**: A robust suite of demand response products that have enrolled 255 larger commercial and industrial participants and generated approximately 180 MW of demand response capacity by year end 2010
- **Customer-based generation**: AMI investments have enabled both Feed-in Tariff programs (FIT and microFIT) and other distributed generation.

To date, investments at the distribution level have focused on enabling customer control rather than overall grid management. Investment in distribution infrastructure is required to achieve the goals of the smart grid.

[1] North American Electric Reliability Corporation: http://www.nerc.com/

Part of the government's vision is a move away from centralized power plants that distribute electricity over long distances to a focus on efficient, localized generation from smaller, cleaner sources of electricity. This strategy, known as distributed generation, requires the integration of smart technologies to ensure reliability and adequacy standards are met.

Energy storage – the process of storing off-peak generation and using it during times of peak demand – is an emerging technology that will have significant impacts on the value derived through renewable sources of power. As with distributed generation, the government envisions energy storage technologies becoming a larger part of Ontario's electricity system in the future. To maximize their potential, energy storage facilities require intelligent infrastructure to effectively integrate their supply into an ever-evolving mix.

The key distribution-level investment required to facilitate the government's vision is sophisticated two-way telecommunications technology, such as that that currently exists in the transmission system. This is the technology that will allow distributed generation, energy storage technologies, distribution level system self-healing functionality, and electric cars – among other emerging technologies – to be effectively integrated into Ontario's power system.

The OPA is working hard to support the development and commercialization of technologies that have the potential to improve electricity supply, conservation and demand management through the development of innovative technologies that advance the opportunities and benefits of smart grids through both its Technology Development Fund and Conservation Funds.

The projects supported to date have applicability across sectors and can likely be used to develop tomorrow's smarter homes and improve and reduce costs of commercial and industrial operations.

6.2 Summary of the Supply Mix Directive Requirements

According to the Supply Mix Directive, "The OPA shall give planning consideration to the smart grid developments that are taking place in Ontario. The OPA should also ensure that distribution level investment associated with smart grid connections is considered in the context of the plan."

6.3 How the Smart Grid Fits in the Integrated Plan

Both the LTEP and the Supply Mix Directive have established initial direction on the future of Ontario's smart grid. The direction given is consistent with the government's desire to develop an increasingly intelligent infrastructure that enables the following[2]:

- Maximizes 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

[2] Ontario's Long-Term Energy Plan, *Building our Clean Energy Future*, 2010: http://www.mei.gov.on.ca/en/pdf/MEI_LTEP_en.pdf

- Modernizes 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

- Lays 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.

Although the eventual goals for Ontario's smart grid are clear, practical and attainable, the steps involved to achieve them are complex, involving a number of diverse participants. To inform how objectives can and will be met, the government has taken a number of steps. It has directed the Ontario Energy Board (OEB) to initiate the process of promoting and implementing the smart grid in the province, as enabled by the GEA. The Minister of Energy issued a directive to the OEB on November 23, 2010 requiring the OEB to establish guidelines for distributors to follow in developing their smart grid plans.

As a first step to meeting that directive, the OEB formed the Smart Grid Working Group (SGWG), which is an expert panel of industry professionals who represent smart grid stakeholders (distributors, transmitters and generators, smart grid technology vendors and service providers, electricity retailers, telecommunications, ratepayers and environmental groups). The mandate of the SGWG is to provide technical advice to the OEB that will be used to develop guidance for local distribution companies (LDCs) who will carry out smart grid investments in their distribution areas. There were also a number of factors identified by the directive that the OEB and the SGWG must consider to ensure government policy objectives are met[3]. These factors are listed in Table 1 below.

Table 1: Government Policy Objectives: November 23, 2010 Ministerial Directive to the OEB

Policy Objective	Policy Objective Description
Efficiency	Improve efficiency of grid operation, taking into account the cost-effectiveness of the electricity system
Customer value	The smart grid should provide benefits to electricity customers
Co-ordination	The smart grid implementation efforts should be coordinated by, among other means, establishing regionally coordinated Smart Grid Plans, including coordinating smart grid activities among appropriate groupings of distributors, requiring distributors to share information and results of pilot projects, and engaging in common procurements to achieve economies of scale and scope
Interoperability	Adopt recognized industry standards that support the exchange of meaningful and actionable information between and among smart grid systems and enable common protocols for operation. Where no standards exist, support the development of new recognized standards through coordinated means
Security	Cyber security and physical security should be provided to protect data, access points, and the overall electricity grid from unauthorized access and malicious attacks

[3] Developing Guidance for the Implementation of Smart Grid in Ontario – Board File No. EB-2011-0004: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2011-0004/Letter_OEB_SmartGridInitiative_20110113.pdf

Privacy	Respect and protect the privacy of customers. Integrate privacy requirements into smart grid planning and design from an early stage, including the completion of privacy impact assessments
Safety	Maintain, and in no way compromise, health and safety protections and improve electrical safety wherever practical
Economic Development	Encourage economic growth and job creation within the province of Ontario. Actively encourage the development and adoption of smart grid products, services, and innovative solutions from Ontario-based sources
Environmental Benefits	Promote the integration of clean technologies, conservation, and more efficient use of existing technologies
Reliability	Maintain reliability of the electricity grid and improve it wherever practical, including reducing the impact, frequency and duration of outages. The Board may consider such other factors as are relevant in the circumstances

A condition of LDC licenses now includes the filing of distribution system plans to the OEB that specify:

- How the LDC will facilitate the connection of renewable generation
- How the LDC will work to develop a smart grid within its jurisdiction.

When completed, the guidance documents will be used to assess whether the distribution system plan of the LDC or other regulated entities is in compliance with government objectives. These guidelines will also work to ensure localized smart grid investments can be effectively integrated into the province-wide system.

6.4 Considerations Concerning Smart Grid Developments in Ontario

Across North America, there is a significant level of interest in the concept of a smart grid. This level of interest has lead to the creation of several prominent private and public sector expert working groups as well as significant monetary investment in the technology that will support tomorrow's grid.

Ontario is an emerging leader in this area. Table 2 below details some of the efforts underway in Ontario to develop the smart grid. The work of these groups is expected to guide smart grid investments in the coming years.

Table 2: Smart Grid Activities in Ontario

Agency / Group Name	Mandate
Ontario Energy Board: *Smart Group Working Group (SGWG)*	The mandate of the SGWG is to provide technical advice to the OEB that in turn will be used to develop guidance documents for those regulated entities directed to carry out smart grid investments in the province.
Independent Electricity System Operator: *Smart*	The primary objective of the SGF is to advance the development of the Ontario

Grid Forum (SGF) & OEA Sponsored Corporate Partners Committee	Smart Grid by focusing on investment in GEGEA technologies and objectives In carrying out its activities to meet this objective the Forum will[4]: ▪ Provide advice to government, regulators, agencies, and industry in general to advance the effective implementation of a smart grid in Ontario ▪ Maintain a collective understanding of relevant developments in other jurisdictions ▪ Work to influence global developments in the interests of Ontario, such as necessary standards ▪ Identify barriers to investment and the means to address them ▪ Promote and support economic development by Ontario industry organizations and corporations and the export of smart grid expertise and knowledge ▪ Ensure that participation on the Forum appropriately reflects the diverse aspects of the Ontario electricity demand/supply chain ▪ On an annual basis, report to industry on progress towards achieving the Forum's objective and provide a brief update between reports Ontario Energy Association - Corporate Partners Committee (CPC): The CPC was developed to bring a greater level of private sector perspective to the work of the SGF and consists of a variety of companies that have interests in developing and implementing the smart grid.
Federal government: ***US – Canada Clean Energy Dialogue***[5]	The objectives of the US-Canada Clean Energy Dialogue include: **Expand clean energy research and development** ▪ A cleaner, more secure energy future for both nations will depend on significant investments today in energy research and development. ▪ The United States and Canada are collaborating on energy research related to advanced biofuels, clean engines, and energy efficiency. In order to address the energy and environmental challenges that we face together, the two nations agreed to expand collaboration in these and other key areas of energy science and technology. ▪ The senior-level Clean Energy Dialogue will review the existing forms of collaboration and identify high-return opportunities for expanded and new joint research. **Build a more efficient electricity grid based on clean and renewable generation** ▪ The two nations will consult and share information on the demonstration and deployment of smart grid technology, including installing smart meters in residential and commercial buildings, digitizing distribution systems, and employing information and measurement tools to manage the grid more effectively. ▪ To build a bigger grid, the United States and Canada will share analysis of new transmission options for integrating wind power and other clean generation sources and encourage development of a grid stakeholders group, building on

[4] Smart Grid Forum, Terms of Reference: http://www.ieso.ca/imoweb/pubs/smart_grid/TOR-SGF_r1.pdf
[5] Annex – U.S.- Canada clean energy dialogue: http://www.pm.gc.ca/eng/media.asp?id=2433

	the existing U.S.-Canadian collaboration among the States and provinces in the West, Midwest, and East. ▪ These investments will make electricity delivery more reliable, reduce congestion that can lead to blackouts and power losses, enable consumers to use energy more efficiently, and promote broader development of renewable power.
Provincial government: ***Ontario Smart Grid Fund***	The Smart Grid Fund, launching in spring 2011, will accelerate the growth of Ontario's smart grid industry by offering targeted financial support for projects that advance the smart grid, provide economic development opportunities and create new green jobs. Through the GEA, $50 million over five years has been allocated to investment into the smart grid.
General Electric: ***Smart Grid Innovation Centre***	On March 9, 2011, General Electric (GE) announced a new $40 million Grid IQ Innovation Centre to be located in Markham, Ontario. The facility is expected to open in the summer of 2012. The Innovation Centre is supported by a $7.9-million grant from the Ontario government. A quote from GE highlights the uniqueness of the facility, "GE's Grid IQ Innovation Centre should become a Canadian destination for companies and countries seeking to upgrade their energy systems. A testing and simulation laboratory can be utilized by global utilities to learn how the Centre's technologies can help their specific infrastructures with simulations and testing before deployment." Products researched and developed at the site will be manufactured there as well.

The OPA will consider smart grid advancements by continuing to contribute to the smart grid discussions listed and monitor the developments taking place in other jurisdictions.

6.5 Implementation Plan

The OPA realizes the timing for smart grid investments is opportune as we are in a period of significant change in the electricity sector. However, given the current status of smart grid development, the OPA believes that it is premature to fully define the role of the smart grid in IPSP II. The understanding of smart grid is evolving and it is the work of the various working groups listed in table 2 above that will inform the direction of future developments and investments in smart grid.

The OPA continues to plan with the evolving smart grid in mind, knowing that in the near term a smart grid can contribute to the achievement of conservation, the integration of renewable energy and the development of an adaptive and flexible electricity system.

To meet these objectives, the OPA will continue to monitor and participate in the initiatives to develop the smart grid and monitor transmission and distribution plans to understand the costs and benefits of smart grid investments.

6.6 Areas for Consultation

The OPA will be seeking advice from stakeholders on how it should consider the smart grid in the development of the IPSP.

1) What are the challenges associated with developing a smart grid?
2) How should we time smart grid investments/system enhancements? What investments should we target first?
3) How should the IPSP consider the smart grid?
4) What role should the OPA play in the ongoing development of the smart grid?
5) How could value for Ontarians be measured?

7.0 SUMMARY

The updated Integrated Power System Plan (IPSP) will reflect the goals for Ontario's electricity system that were set by the government in the Long-Term Energy Plan issued in November 2010 and in the Supply Mix Directive to the Ontario Power Authority on February 17, 2011.

The IPSP is an integrated plan that identifies the investments needed in conservation, generation and transmission to ensure a reliable, sustainable and cost-effective electricity system for the next 20 years. It is intended to be a roadmap to guide future decisions.

An IPSP was filed in 2007 and many of its features have been implemented to enhance system reliability and enable the phase-out of coal-fired generation by the end of 2014. It is now time for an updated IPSP to address changes in such things as demand, economic circumstances and generation technology.

The government has described its energy policy objectives in the Long-Term Energy Plan and established mandatory planning requirements in the Supply Mix Directive issued to the OPA. The OPA is now developing an IPSP that meets those requirements for review by the Ontario Energy Board.

In developing the IPSP, the OPA will be consulting with stakeholders. This IPSP Planning and Consultation document is intended to provide an overview of the status of and outlook for the electricity sector, and forms the starting point for the consultation.

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Ontario

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MC-2011-625

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

Dear Mr. Andersen:

In my capacity as the Minister of Energy and pursuant to the authority granted to me under subsection 25.30(2) of the *Electricity Act, 1998*, I am providing the Ontario Power Authority (OPA) with direction for the preparation of an integrated power system plan (the "Plan"). This Supply Mix Directive replaces the Supply Mix Directive issued on June 13, 2006 and the Supply Mix Directive issued on September 17, 2008.

Pursuant to this Authority, I hereby direct the OPA to prepare a Plan to meet the government's goals as set out in this Supply Mix Directive as follows:

Demand

In developing the Plan, the OPA shall use a medium electricity demand growth scenario. This scenario balances the expected growth in residential and commercial sectors with modest, post-recession growth in the industrial sector. Under this scenario, Ontario's demand would grow moderately (approximately 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.

It is feasible that technological changes could drive higher electricity demand growth through, for example, greater adoption of electric vehicles and the potential electrification of public transit. The Plan needs, therefore, to have the flexibility to accommodate the potential for a higher growth outcome.

Conservation

The OPA shall plan to achieve through Conservation and Demand Management (CDM) a peak demand reduction target of 7,100 megawatts (MW) and an energy savings target of 28 terawatt-hours (TWh) by the end of 2030. Further, the OPA shall plan to achieve interim CDM targets as follows: 4,550 MW and 13 TWh by the end of 2015; 5,840 MW and 21 TWh by the end of 2020; and 6,700 MW and 25 TWh by the end of 2025. These interim CDM targets are to serve as milestones to measure progress towards the overall 2030 CDM target.

The Plan shall seek to exceed and accelerate the achievement of these CDM targets if this can be done in a manner that is feasible and cost-effective. The targets are to be measured from a base year of 2005.

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The above-noted targets shall also include electricity savings forecasted through the implementation of codes, standards, regulations and other initiatives that are progressive and reasonable based on OPA analysis.

Consistent with my directive to the Ontario Energy Board (OEB) dated March 31, 2010, the definition of CDM should be inclusive of load reduction from initiatives such as geothermal heating and cooling, solar heating and fuel switching and customer-based generation for the purpose of load displacement. The definition should be exclusive of generation that is contracted-for under the OPA's Feed-in Tariff (FIT) and microFIT Programs and other generation that is separately metered for the purpose of injecting electricity into the transmission system or a distribution system.

Nuclear

The OPA shall continue to plan for nuclear generation to account for approximately 50 per cent of total Ontario electricity generation. To this end, the Plan shall provide for the refurbishment of 10,000 MW of existing nuclear capacity at the Bruce Nuclear Generating Station and the Darlington Nuclear Generating Station as well as the procurement of two new nuclear generating units (about 2,000 MW) at the Darlington site. The Government will pursue this procurement where it can be achieved in a cost-effective manner.

Nuclear refurbishment is a complex task and Ontario will need a coordinated plan for refurbishment that takes into account various considerations. To this end, the OPA shall continue to work with Ontario Power Generation (OPG), Bruce Power, and the Ministry of Energy to ensure that the Plan includes an updated coordinated refurbishment schedule.

Coal Phase-out and Potential Conversion

Since 2003, Ontario has shut down eight coal-fired generating units, including the recent closures of two units each at OPG's Nanticoke and Lambton Generating Stations. The shutdown of two additional units at the Nanticoke Generating Station will take place before the end of 2011.

The Government's commitment to replace all coal-fired generation by the end of 2014 will be met. The OPA shall work with the Independent Electricity System Operator (IESO) and OPG to determine opportunities for advancing the closure of additional units.

The Government has directed the OPA to negotiate with OPG for a contract for biomass fuelled generation from the 215 MW Atikokan Generating Station in Northwestern Ontario. It is expected that this plant could be operating on biomass by 2013.

Two units at OPG's Thunder Bay Generating Station are to be converted to run on natural gas over the period leading up to 2014. Opportunities to co-fire with biomass will continue to be examined.

In developing the Plan, the OPA shall assess the conversion of some or all of the remaining units at Lambton and Nanticoke to natural gas under a range of different scenarios for nuclear generation and system peaking requirements. The government will make a decision on conversion of some or all of these units in 2012. This decision will be made once planning work on continued operation of the operating units at the Pickering Nuclear Generating Station

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and the refurbishment of the remaining units at the Bruce and Darlington nuclear generating stations is further advanced, providing better information on the availability of nuclear capacity.

In order to plan properly for the possibility of conversion, the government anticipates that planning and approval work for the natural gas pipeline infrastructure required to Nanticoke will begin soon.

Renewables - Hydroelectric Resources

New hydroelectric developments are underway by OPG, including the Niagara Tunnel and the 440 MW Lower Mattagami redevelopment as well as additional private sector developments. The Plan shall allow for future hydroelectric development where it is cost-effective to build and to connect to the transmission system.

The Plan shall provide for installed hydroelectric capacity to reach 9,000 MW by 2018. The OPA shall continue to explore cost-effective opportunities for further hydroelectric development and maximize existing hydroelectric resources. Additional cost-effective hydroelectric resources should be developed if they are identified. It is expected that the Plan shall provide for hydroelectric generation to account for approximately 20-25 per cent of total Ontario electricity generation.

Renewables Other Than Hydroelectric (Wind, Solar, Bio-energy)

The June 2006 Supply Mix Directive required that the OPA plan to use the existing base of 7,850 MW of renewable energy (hydroelectric generation) and to double this capacity to 15,700 MW by 2025 including hydroelectric, wind, solar, and bio-energy.

Since then, there have been a number of renewable energy procurements through initiatives such as the Renewable Energy Supply (RES) programs (RES I, II and III), the Renewable Energy Standard Offer Program and the FIT Program. As a result of these successful procurements, as well as the Green Energy Investment Agreement, the additional renewable capacity expected to come into service is greater than the levels envisaged in 2006. Based on forecast assessments of what the system can accommodate, the OPA shall plan for 10,700 MW of renewable energy capacity, excluding hydroelectric, by 2018.

The government will look for opportunities to incorporate additional capacity from renewables into the Plan taking into consideration the cost-effectiveness for Ontario electricity consumers, planned transmission additions, and electricity demand growth.

It is expected that the Plan shall provide for renewables, excluding hydroelectric, to account for approximately 10-15 per cent of total Ontario electricity generation by 2018.

Natural Gas

Natural gas will continue to play a strategic role in Ontario's supply mix by complementing intermittent supply from sources such as wind and solar, meeting local and system requirements, and ensuring that adequate capacity is available as nuclear plants are modernized. The OPA shall continue to plan on natural gas usage for these strategic purposes.

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The 2007 Integrated Power System Plan submitted to the OEB included a forecasted need for three additional gas plants in the Province, including one in the Kitchener-Waterloo-Cambridge area and one in the southwest GTA. Due to 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 proposed plants, including the proposed plant in Oakville, are no longer required. A transmission solution to maintain reliable supply in the southwest GTA will be required.

As indicated in the 2007 Plan, procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area is still necessary to ensure adequate regional electricity supply.

Transmission

The government recognizes the need to pace transmission upgrades and the importance of striking a balance between a clean economy and limiting ratepayer cost burdens. Long-term planning for transmission should allow for the expansion of the system to include renewables in order to foster a cleaner economy and should also be able to adjust if conditions change.

The Plan shall include the five priority transmission investment projects identified by the OPA for system reliability, serving new load and renewables incorporation out to 2018. For the purposes of preparing the Plan, the OPA shall assume these projects will proceed. These priority projects are:

- Device(s) to enhance transfer capability, such as series or static var compensation, or other similar devices, in Southwestern Ontario
- Upgrading existing line(s) west of London;
- A new line west of London;
- Enhance the East West tie along the east shore of Lake Superior through a new line; and
- New line to Pickle Lake.

The OPA, as the provincial transmission planner shall define and make recommendations about the scope and timing of these transmission projects on the basis of their rationale, as part of the Plan. The OPA shall also immediately work in cooperation with Hydro One and make recommendation(s) on the scope and timing of transmission projects to be undertaken by the transmitter pursuant to an amendment of the transmitter's licence conditions resulting from a directive issued to the OEB by the Minister of Energy in early 2011.

In addition to this, the OPA shall identify other cost-effective transmission and distribution solutions through ongoing decision processes – integrated planning and economic tests – and maximize use of the existing system.

The OPA shall develop a plan for remote community connections beyond Pickle Lake, including consideration for the relevant cost contributions from benefiting parties, such as the federal government. This plan may also consider the possibility of interim solutions as appropriate that reduce consumption of diesel fuel.

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Smart Grid

The OPA shall give planning consideration to the Smart Grid developments that are taking place in Ontario. The OPA should also ensure that distribution level investment associated with smart grid and renewable connections is considered in the context of the Plan.

Reliability and Operability

The Plan shall consider potential electricity storage, the availability of imports from other jurisdictions and other methods in order to meet Ontario's reliability and operability requirements throughout the duration of the Plan.

The economics of storage technologies will depend on the differential between peak and off-peak costs, the capital and operating costs of the storage facility and the relative costs of other peak managing options. Examination of storage opportunities should include a determination as to whether the customer and system benefits exceed the development and operating costs of the storage system.

Impacts of the Plan on Electricity Consumers

The government recognizes that electricity investments are important for individual and business consumers from a variety of perspectives, including cost. The OPA shall develop the Plan mindful of total bill impacts and the impact that the costs associated with the choices it makes within the Plan has on electricity rates generally.

Consultation

Ontario's Aboriginal peoples play an important role in the development of Ontario's electricity system. The Government will retain responsibility for addressing Aboriginal economic opportunities in the energy sector. The Government expects the OPA to carry out the procedural aspects of any Crown duty to consult First Nation and Métis communities in developing the Plan.

Regulatory Observance

The Plan shall comply with Ontario Regulation 424/04 (Integrated Power System Plan) made under the *Electricity Act, 1998*, and all other applicable statutory and regulatory requirements, as amended from time to time.

Sincerely,

Brad Duguid
Minister

A-2 Summary of Consultation Questions

2.0 DEMAND FOR ELECTRICITY

1) What are the key factors that influence electricity demand?

2) What are the most significant uncertainties related to long-term electricity demand forecasts in Ontario and what are their implications for planning?

3) How might transportation sector electrification including prevalence, location and timing impact integrated planning?

4) What signposts or indicators should be monitored on a continuing basis to assess progress within the prescribed demand ranges?

5) Do you have specific advice or factors the OPA should consider related to demand for electricity?

3.0 GENERATION OF ELECTRICITY

1) What are the challenges to meeting the mandatory supply requirements in the Plan?

2) What are the supply options for meeting the need for incremental resource requirements?

4.0 CONSERVATION AND DEMAND MANAGEMENT

1) What do you see as the challenging aspects of implementing this Market Transformation Strategy in Ontario? What will be the greatest challenge?

2) How can implementation of this Market Transformation Strategy in Ontario be enhanced?

3) What should the role of the supply chain (manufacturers, distributors, retailers etc.) in implementing Ontario's long-term market transformation strategy? How can it be developed/adopted?

4) The Supply Mix Directive indicates that CDM targets "shall also include electricity savings forecasted through the implementation of codes, standards, regulations and ***other initiatives that are progressive and reasonable based on OPA analysis.***" What other progressive and reasonable initiatives/policy instruments should the OPA consider for inclusion in the IPSP for the medium to long term?

5) The OPA supports innovation through the Conservation Fund and Technology Development Fund. Both funds have identified priority areas for investment. Are we on

the right track? What additional approaches, if any, should be considered to support innovative strategies and technologies that facilitate conservation?

The OPA is incorporating the assessment of risks and uncertainty in its CDM planning processes. An assessment of performance scenarios and key risks for OPA-funded CDM programs in the next four years has been developed, along with risk mitigation plans.

6) Are there other key risks or uncertainties regarding performance of OPA-funded programs in the near term which have not been identified?

7) What mitigation strategies should be considered?

The Supply Mix Directive indicates that "the plan shall seek to exceed and accelerate the achievement of these CDM targets if this can be done in a manner that is feasible and cost effective."

8) Given the supply and demand context, what factors or approach should the OPA consider when deciding whether it is feasible and cost effective to accelerate or exceed the targets?

9) Are there other approaches or actions that the OPA should consider to exceed or accelerate that are not currently included in programs?

10) Are there other programs or policies that the OPA should consider to exceed or accelerate that are not currently included in the plan?

5.0 TRANSMISSION

1) Has the OPA provided sufficient information on the transmission plan?

2) What should be the most important considerations or objectives for long-term transmission planning?

3) Do you have any other advice for the OPA in developing options for the long-term transmission plan?

6.0 SMART GRID

1) What are the challenges associated with developing a smart grid?

2) How should we time smart grid investments / system enhancements? What investments should we target first?

3) How should the IPSP consider smart grid?

4) What role should OPA play in the ongoing development of the smart grid?

5) How could value for Ontarians be measured?