1.2 Supply Mix Advice and Recommendations

1.2.1 First Step to an Integrated Plan

The supply mix advice in this report marks the first step in preparing an Integrated Power System Plan (IPSP) for Ontario, which will guide the development of Ontario's entire power system, including transmission networks. The first IPSP will be developed and submitted to the Ontario Energy Board (OEB) in 2006.

Through the *Electricity Restructuring Act*, passed in December 2004, the Government amended the *Electricity Act* to give the Ontario Power Authority accountability for preparing an integrated power system plan and vested the OEB with the power to approve it. This initiative was consistent with a recommendation of the Electricity Conservation and Supply Task Force that had reported in January 2004.

Both the advice in this report and the IPSP take a long-term view. To allow for changes in outlook, however, the integrated plan will be updated on a three-year cycle. This provides the process with the flexibility to reflect changing circumstances, take advantage of future opportunities and better deal with contingencies.

The supply mix advice looks forward over a 20-year horizon but must be considered as prescriptive only over the first three years of that period. A long-range forecast is inherently imprecise, since its assumptions will inevitably miss the mark to a greater or lesser degree. That said, a 20-year outlook is essential to identifying the need for immediate action, especially on important supply sources with long lead times. The advice in this report therefore looks at a range of scenarios, and emphasizes the immediate decisions needed to ensure that the most suitable longer-term options are opened up and preserved.

1.2.2 Challenges for Ontario's Electricity Supply

There has been a net decline in installed generating capacity in Ontario over the past 12 years, while the population has grown by 15% and the economy has grown by 45% over the same period. This is a major factor in the tight supply situation that exists today and the situation may grow worse in future. There are several reasons behind the decline in installed capacity. One was the halt of expansion due to an apparent over-capacity in the early 1990s, which remained as a supply overhang into the mid-1990s, while growth in demand was slow. Since then, investments have not kept up with retirements of existing facilities, especially in the GTA.

This is particularly true in base-load generation, where the last such investment decision was made in the early 1980s.

The age and condition of Ontario's nuclear fleet has also contributed to the current situation. Several units were taken out of service in the mid-1990s. While most have either returned to service or are expected to return, some will not.

Concerns about the environmental and health impacts of burning coal led to a government policy to replace coal-fired generation stations by 2009, with one station now already closed. The policy followed from the unanimous recommendation of an all party legislative committee in 2002. Reducing dependence on coal-fired generation has been reflected in the broad energy policies of successive governments.

On the demand side, moderation in demand growth has helped to shield Ontario until recently from lack of additional supply. The recent strengthening in the rate of demand in the past 5 years has eroded the excess supply capacity of the early 1990s. Looking ahead, Ontario's rate of growth in demand for electricity is projected to be steady but at a lower rate than it has ever been over a similar period in the last century. The potential impact of conservation and greater energy efficiency on demand growth is discussed in the section entitled "The Potential for Conservation."

There are several procurement initiatives under way that aim to close the supply gap in the mid term. As Figure 1.2.1 shows, these procurements would extend system capability to 2014 if they all materialize.

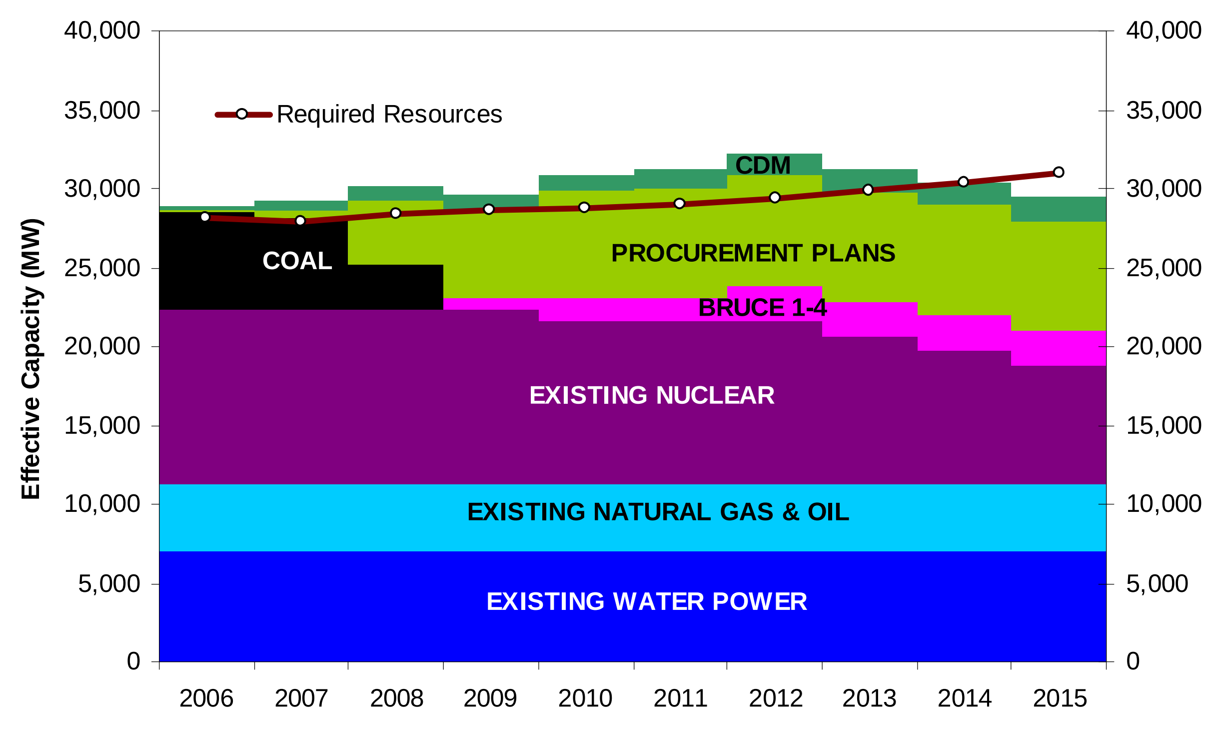
Figure 1.2.1 and many subsequent graphs show how the generation requirements are met by "effective capacity". The generation requirement is the amount required for summer conditions, under normal weather. The effective capacity describes the extent to which generating resources are available during the summer peak to meet the demand requirements. There are reductions from "installed capacity" – the nameplate rating of the generator – to arrive at effective capacity if the generator cannot be counted on to operate at full capacity during the summer peak. These reductions are most pronounced in waterpower and wind power.

Within the next 15 years, the nuclear units will be reaching the point where they must be either upgraded if they are to continue operating or taken out of service if this is not feasible or economical.

A focus for this report is therefore the period from 2014 to 2025 because this is not covered by current procurement initiatives. It is also the period during which the capacity of the nuclear generating units drops off significantly.

The purpose of the advice in this report is to build on current conditions and initiatives and look at the options for Ontario's supply mix out to 2025.

Figure 1.2.1: Current Procurement Initiatives and CDM Cover Needs to 2014



Source: OPA

1.2.3 Developing the Advice

The six principles set out in the summary – listening, sustainability, flexibility, embracing the future, managing risks and prudence – created a broad and well-defined set of criteria for solutions within the policy framework. These criteria took into account, on a full life-cycle basis, the overall cost of each supply option, the degree of financial risk it carried, and its general environmental impact. As combinations of options were developed, these were checked for reliability, feasibility and long-term flexibility.

The range of activities undertaken in developing this advice included:

- Consulting with Ontarians to determine their views and values about electricity planning, and to seek specific advice;
- Assessing the potential environmental, economic and reliability impacts of various supply sources and supply mixes;
- Refining and building on forecasts for electricity demand, and estimating the extent to which reducing demand and conserving electricity is achievable to help meet Ontario's needs;

- Assessing the risks, costs and benefits of possible supply mixes, to narrow down the suggested options to those that best align with the guiding principles, particularly prudence, and the request of the Minister; and
- Providing advice and setting out an action plan based on the above activities that, in our view, best responds to the Minister's request and lays a solid foundation on which to draw up the Integrated Power System Plan.

A task of this complexity could not have been completed without the specialized knowledge of expert consultants. A number of environmental, energy efficiency, planning, economic and public-opinion research firms made significant contributions. Volume 4 of this report includes all of their reports.

In developing this advice, a key step was to assess the views and concerns of people in Ontario, both citizens at large and those with a particular interest in the sector. A request for public submissions, as well as in-depth interviews and a broader survey conducted by Decision Partners with the assistance of Decima Research, yielded important information in these areas. Additional valuable contributions came from industry and environmental representatives and academic researchers who responded to requests for presentations in specific areas.

Together, the consultations revealed several important points:

- The vast majority of consumers in Ontario rank availability, reliability of supply and rate stability as highly important.
- The next most important concern among those interviewed or surveyed was environmental responsibility.
- Consumers and businesses place significant emphasis on the impact of supply choices on electricity prices and the provincial economy generally.
- Leadership, taking action, and looking at the long term in planning were all seen as important elements of moving forward.

In addition to these widely-expressed views, several industry and other participants with particular interests provided valuable thoughts and advice. An overview of all contributions is included in Part 2.3. The advice on specific initiatives for increasing conservation and getting more renewables, as well as addressing other industry issues, is included in Part 1.4.
We thank all those who took the time to provide their views and comments.

1.2.4 Estimating Demand

The annual electricity use in Ontario is currently running at about 155 terawatt-hours or TWh, which is a billion kilowatt hours. That is equivalent to every household in Ontario having fifty 100-watt light bulbs turned on 24 hours a day for the whole year. The forecasts for energy demand that extend to 2020 show demand in Ontario by that time ranging between 170-198

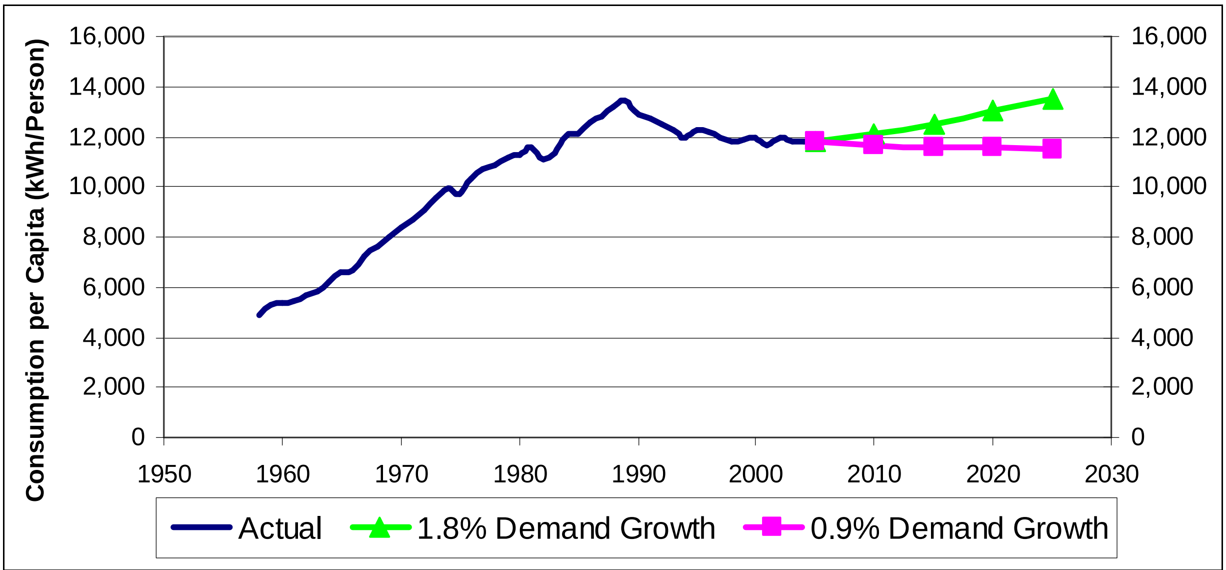
TWh. Section 2.5 provides more detail.

- Electricity use in the residential sector – the homes Ontarians live in – accounts for about 30% of total consumption and is projected to decline slightly.
- Highest electricity use is in what is collectively called the commercial sector – offices, shops, schools, warehouses, hospitals, hotels, etc. This sector accounts for over 40% of total electricity consumption today and is projected to grow the most.
- Industrial sector consumers use about 30% of the electricity consumed, and this is projected to stay about the same.

The variation in forecasts reflects differing assumptions about growth in Ontario's population and economy, as well as energy prices and technological improvements to equipment and appliances. For planning that includes conservation estimates, it is critical to know how much energy efficiency is assumed in any particular forecast. ICF Consulting helped to place electricity growth in the context of economic and demographic variables in developing this advice. Their report is included in Part 4.2.

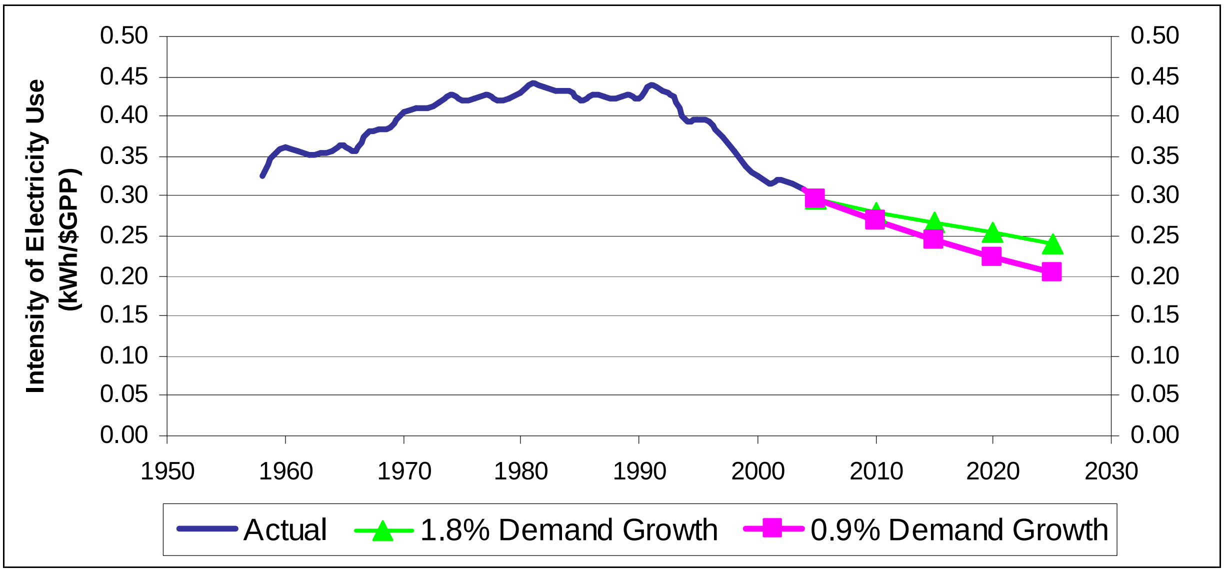
The graphs in Figures 1.2.2 and 1.2.3 show, for historical and forecast periods, two indicators of energy demand – how much electricity is used per capita, and the electricity intensity of the economy.

Figure 1.2.2: Ontario Electricity Consumption per Capita



Source: OPA, ICF

Figure 1.2.3: Ontario Electricity Intensity



Source: OPA, ICF; Note: GPP measure is in $CDN1997

The diverging lines show the impact of differing assumptions about load forecasts.

- Looking at per-capita consumption, the historical trend line shows an increase from the 1960s through to the 1980s but a drop since the early 1990s. Ontario's population is projected to increase by 25% by 2025, based on an average annual growth in population of 1.1%. A forecast of 0.9% a year growth in total demand therefore assumes that use per person will continue to fall in future. A forecast of 1.8% per year assumes an increase in use per person. Part 2.2 looks at Ontario's demographic context in more detail.
- Ontario's economy is projected to continue to grow at roughly 2.5% a year. In terms of electric intensity, the trend that began in the 1990s of using less electricity to produce each dollar of economic output is projected to continue.

In our view, the assumption of a lower rate of growth in electricity consumption is reasonable. This corresponds to an average annual rate of growth in energy demand of 0.9% and an energy demand of 185 TWh by 2025, up from 155 TWh in 2005.

It is important to bear in mind that these are broad measures of use. While overall growth is currently running at 0.9%, peak usage is growing faster. Peak demand is higher under extreme weather conditions – increasingly, the hottest summer days in Ontario. The planning assumption is that additional demand on extreme weather days will be met through interconnections with other jurisdictions and generation reserve margins that are required for reliability.

Based on the current average increase in peak of 1.3% a year, the corresponding demand for peak power demand under normal weather conditions would be 30,400 MW by 2025, up from

24,200 MW in 2005. Unless otherwise stated, "peak demand" refers to normal weather conditions.

There are local pockets of much higher growth in peak demand – for example, double or more the average in parts of the Greater Toronto Area. This has implications on reliability and adequacy of supply during peaks, which are becoming critical. Understanding why and where peak use is growing helps to focus on the need for conservation and demand management measures, as well as which supply facilities are needed most urgently. It also helps in identifying transmission needs, which the Integrated Power System Plan will address.

The Potential for Conservation

Reducing the use of electricity benefits individual consumers by lowering their bills, and the electricity system as a whole by limiting the need for new capacity. Smoothing the spikes of peak demand prolongs the usefulness of equipment and boosts the reliability of supply. Most importantly, conservation is the only way of balancing electricity demand and supply that has little or no long-term impact on the environment.

Conservation goes hand-in-hand with the related concepts of demand management, demand response and demand reduction. Conservation refers to a wide range of changes in behaviour and technology that result in lower demand for electricity. Demand management has an additional element, which is to change the timing of demand and reduce peaks through such means as demand response. Together, conservation and demand management (CDM) can reduce the supply capacity required to meet Ontario's needs.

The May 2004 report of the Province's Conservation Action Team recommended the appropriate scope for CDM in Ontario. It sees CDM as: energy efficiency, changes in behaviour or operations, such as the use of "smart" control systems, measures to better manage system load, for example by shifting demand to non-peak times, fuel switching and distributed generation, and higher standards for buildings, appliances and equipment, including cogeneration and back-up generation. For the purposes of this report, cogeneration is included under gas-fired resources.

In preparing the supply mix advice, the challenge was to examine how CDM might influence demand for electricity in future. This is a complicated exercise, because the starting point for the investigation was the base case load forecast. The forecast already includes assumptions about such factors as future gains in energy efficiency.

For the purposes of the supply mix advice, then, the focus was on estimating the potential for CDM beyond what is captured in the existing forecasts of demand. The rate at which energy efficiency increases across society depends on several factors, such as the age of existing equipment and appliances, the efficiency of newer models, the funds available to invest in replacement, the preferences of purchasers, and the price of electricity. The rate of uptake can increase through measures that range from educational programs to providing additional economic incentives, all of which involve costs.

The consultant on this work, ICF Consulting, used a hybrid approach to producing a forecast of the additional drop in demand that would result from incentive programs to achieve greater energy efficiency. An "experience-based" element of the approach looked at the savings achieved elsewhere through such measures and applied those findings to Ontario. An "accounting-based" element looked at potential across the sectors that make up Ontario's economy to try to estimate total gains.

Unfortunately, a lack of detailed data for Ontario's electricity use limited the usefulness of both elements. In comparisons with other jurisdictions, it was impossible to know whether the assumed starting point for Ontario was the same. This same limitation, lack of detailed Ontario data, also made a sectoral approach challenging. As well, the long time horizon added to the uncertainty.

The work estimated the reduction expected by 2025 in peak use – that is, the situation that would occur on a hot summer day. The lower bound of the ICF estimates is 1,500 MW and the higher limit is 4,000 MW. On a more moderate day, the range would be roughly 1,050 MW to 3,600 MW. (The difference reflects that on the hottest days an air conditioner will operate for a longer time than it will on a moderate day, so that the reduction in energy use for a higher-efficiency unit is correspondingly bigger on hotter days.)

Because of the acknowledged difficulties in developing these figures, the ability to plan supply after accounting for conservation is challenging. The recommended supply mix chooses to rely on the lower set of figures for gains in energy efficiency because the risks of planning less supply far exceed the risk of not adjusting to higher conservation. These are planning assumptions and not the targets of the OPA's Conservation Bureau. Since we also explored a scenario at the upper limit of the estimate, the recommendations have the flexibility to accommodate higher successes in achieving conservation.

It is important to bear in mind that these savings are in addition to conservation gains already targeted for 2007. They would also be in addition to the impact of smart electricity meters, which are to be installed for every customer by 2010, and are estimated to reduce demand by 500 MW. Procurement initiatives under way are expected to yield a further 250 MW in demand management and demand response initiatives. In addition, 10 MW are already under contract.

The experience developing this forecast suggests that more work is needed to determine the full potential for conservation, its components, and the areas in which investments will provide the greatest return.

1.2.5 New Renewable Sources

Increasing the share of renewable energy resources in Ontario's electricity system can have significant advantages. Typically, these sources involve lower impact on the environment, provide more sustainable supply over the long term, and generally have predictable operating costs once the necessary infrastructure is put in place.

Ontario's current supply mix, in which large hydro developments provide about one-third of capacity, reflects a long-standing reliance on renewable sources. In recent years, new technologies and concerns about the environmental and economic costs of non-renewable sources have opened up a rich range of possibilities for new sources of renewable supply. To this end, developing this advice involved extensive analysis of such sources, including wind, additional hydro, biomass and photovoltaic, which is a form of solar generation.

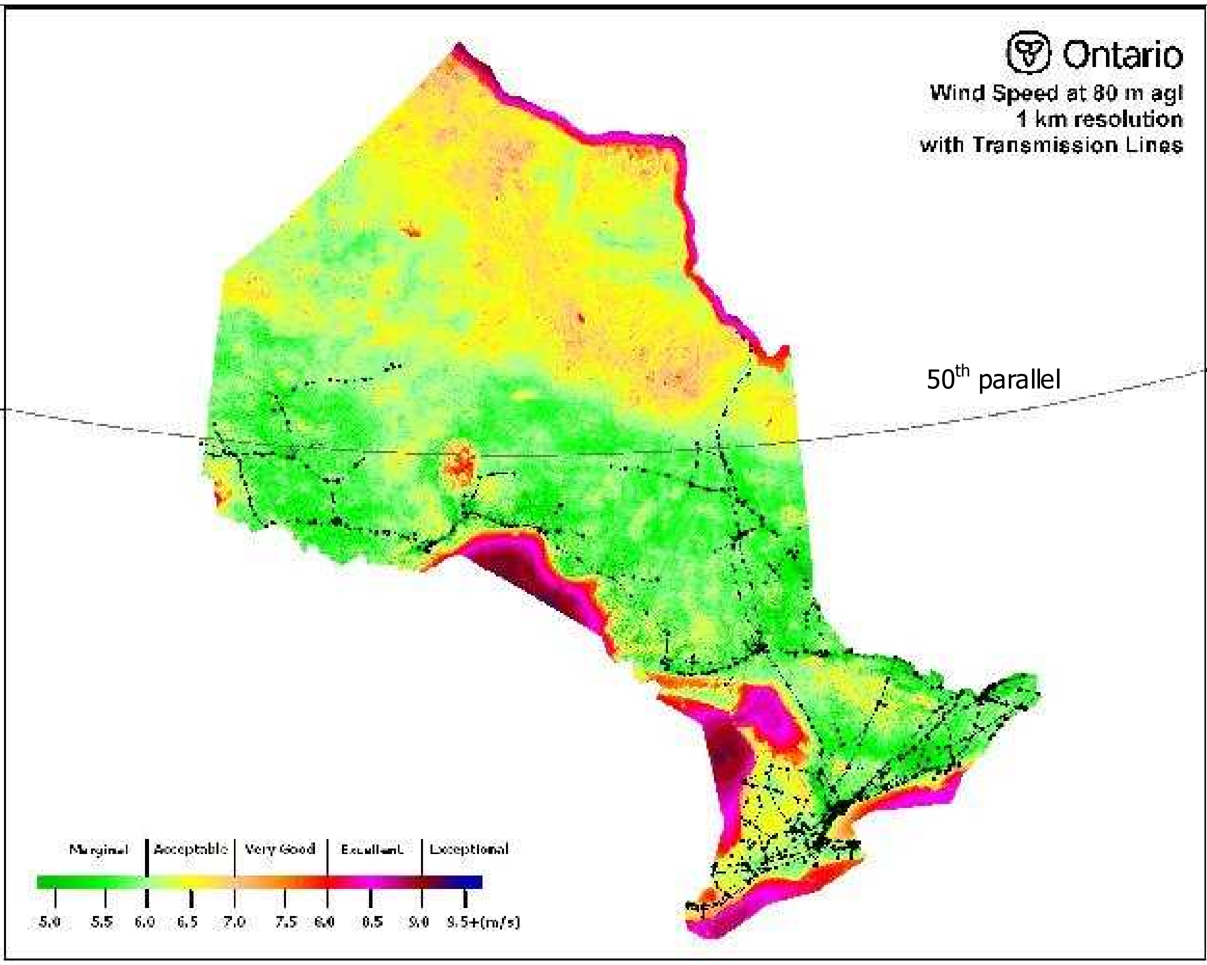
In addition to the summary provided here, Part 2.4 outlines the experience in other jurisdictions with developing renewable energy resources. Part 2.7 reviews the environmental and technical characteristics of renewables, Part 3.6 includes a background report on Ontario's potential for water resources and Part 4.5 contains a consulting report on Ontario's wind resources. Part 1.4 details the advice provided to OPA to obtain additional renewables.

It is important to keep in mind, when looking at potential renewable sources of electricity, that some of these technologies have not already been developed on a large scale because of significant challenges. The theoretical potential for renewable energy is typically large, but gets narrowed down by technical feasibility, then further by financial feasibility, and still further by social and environmental considerations.

Wind Power

The results of the analytical approach used to develop this advice show the extent to which wind power may have the potential to provide a considerable share of Ontario's energy needs by 2025. Helimax Energy of Montreal, a consultant to Hydro-Québec and the Canadian Wind Energy Association, provided much of the work in this area. The analysis involved merging data from the Ministry of Natural Resources' (MNRs) extensive and detailed Geographic Information Systems (GIS) on Ontario's wind resources with Hydro One Networks' GIS data on transmission and distribution. While the theoretical potential is vast – in the order of 600,000 MW, or roughly 20 times Ontario's current demand – the logistical and other constraints make it unrealistic to harvest all of this potential.

Figure 1.2.4: Ontario Wind Speed Map with Transmission Lines



Source: MNR

The constraints on developing wind power arise mainly from climate and geography. Wind power is generally considered to be economic only in those areas where the average annual velocity is greater than 6.5 metres per second at 80 metres above ground level (agl). Using MNR data and that threshold, Helimax determined the potential for wind generation capacity across Ontario as 630,000 MW, capable of producing 1,700 TWh of energy production annually. This estimate was based on removing areas with constraints, such as roads, parks and houses, and allowing for buffer areas. It did not, however, address local issues, such as land use regulations and social acceptability. It also did not address proximity to energy users.

One major obstacle to drawing on the potential is the distribution of areas of economic wind velocity: roughly 95% of the potential is located north of the 50th parallel of latitude, which lies above the northern-most stretches of the Trans-Canada Highway. This puts it effectively out of reach of Ontario's existing electric transmission system. There are significant engineering, environmental and economic issues to harvesting this wind, but further research should be done to better understand the challenge and opportunity. Looking at the land area south of the

50th parallel, however, there is still 29,000 MW of wind capacity and 79 TWh per year of wind energy production – a potential amounting to Ontario's current installed capacity, and about half of its energy consumption.

Table 1.2.1: Ontario Onshore Wind Potential

Area	MW*	TWh**
North of 50th Parallel	598,884	1,632
South of 50th Parallel	29,183	79
Entire Province	628,067	1,711

* Assumes 5 MW of capacity per suitable km^2 of area; ** Assumes 31.1% average net capacity

The question then becomes the distance from the best areas for wind development to the wires that deliver power to consumers. Cross-referencing the MNR data with Hydro One Networks' data showed that, south of the 50th parallel, there are roughly 7,000 MW of wind power within 10 kilometres (km) of high-voltage transmission lines.

If connected to the transmission network, this power would be available across the entire Ontario electrical syste`m. Almost 3,000 MW of power lies within 5 km of distribution stations. (See Part 4.6 for additional detail). This power, once connected to distribution networks, could be suitable as a resource for local customers, reducing the need for generation to be delivered to the area. These numbers are not additive, however, since some wind areas lay within both the 10-km distance to transmission and the 5km-distance to distribution. For this stage of the analysis, 7,000-9,000 MW potential was considered close to some part of the existing electricity system.

Three system planning and operation issues affect how much wind can be accommodated in Ontario's electricity system. Firstly, when considered as a resource to meet peak system demand, not all of wind's installed capacity can be considered available, because there may be times when demand is at peak levels and the wind is not blowing. The coincidence of wind and peak demand in the summer is only 10% or less, but is roughly 20% in winter. This is because wind speeds are higher and more consistent in winter, making wind generation better suited to meeting winter needs. Also, wind may be better for winter peaking needs than summer peaking needs because the days on which demand rises in winter are more likely to be windy.

Secondly, as the first point makes clear, wind is not a "dispatchable" resource. A dispatchable resource, such as a natural gas-fired generator, can increase energy production when called on to meet increased demand. Power from wind, in contrast, depends on the force of the wind. For reliable supply, dispatchable resources are needed to complement wind generation. A related issue is that there will be times when wind velocity drops, reducing supply from this source, but demand continues. Complementary resources that can be dispatched quickly are needed at those times.

Thirdly, even where wind resources are close to distribution or transmission lines, many of the lines and system equipment will need to be upgraded to accommodate the variability of power flows if wind power development is to be significantly increased.

These issues must be considered in planning for increased wind capacity, especially because of the economics involved, which currently make the price of wind power relatively high. Experience and studies from other jurisdictions, such as Alberta, California, Germany and New York, suggest that the costs and planning issues, especially related complementary supply, increase quickly after a certain threshold of reliance on wind in an integrated system. For this reason, an upper limit of 15% on the share of installed wind capacity in total supply appears to be a practical and reasonable assumption until there is more experience with integration of wind on an even larger scale.

In summary, there is potential for wind to become the major source of new renewable resources in Ontario. The greatest potential, in Ontario's north, will likely not be tapped within the time horizon of this advice. It is worth taking this into consideration if plans are developed for a transmission line for purchases from Manitoba, because the routing of this line could take into account the rich wind resources that lie between James Bay and the Manitoba-Ontario border.

Waterpower

Although Ontario developed most of its large waterpower or hydro sites early in the 20th century, many smaller sites still exist. MNR keeps data on these resources, and identifies 180 sites in Ontario with a technical potential of approximately 7,500 MW, including both new sites and improvements at existing sites. The new sites included in this technical potential are shown in Figure 1.2.5.

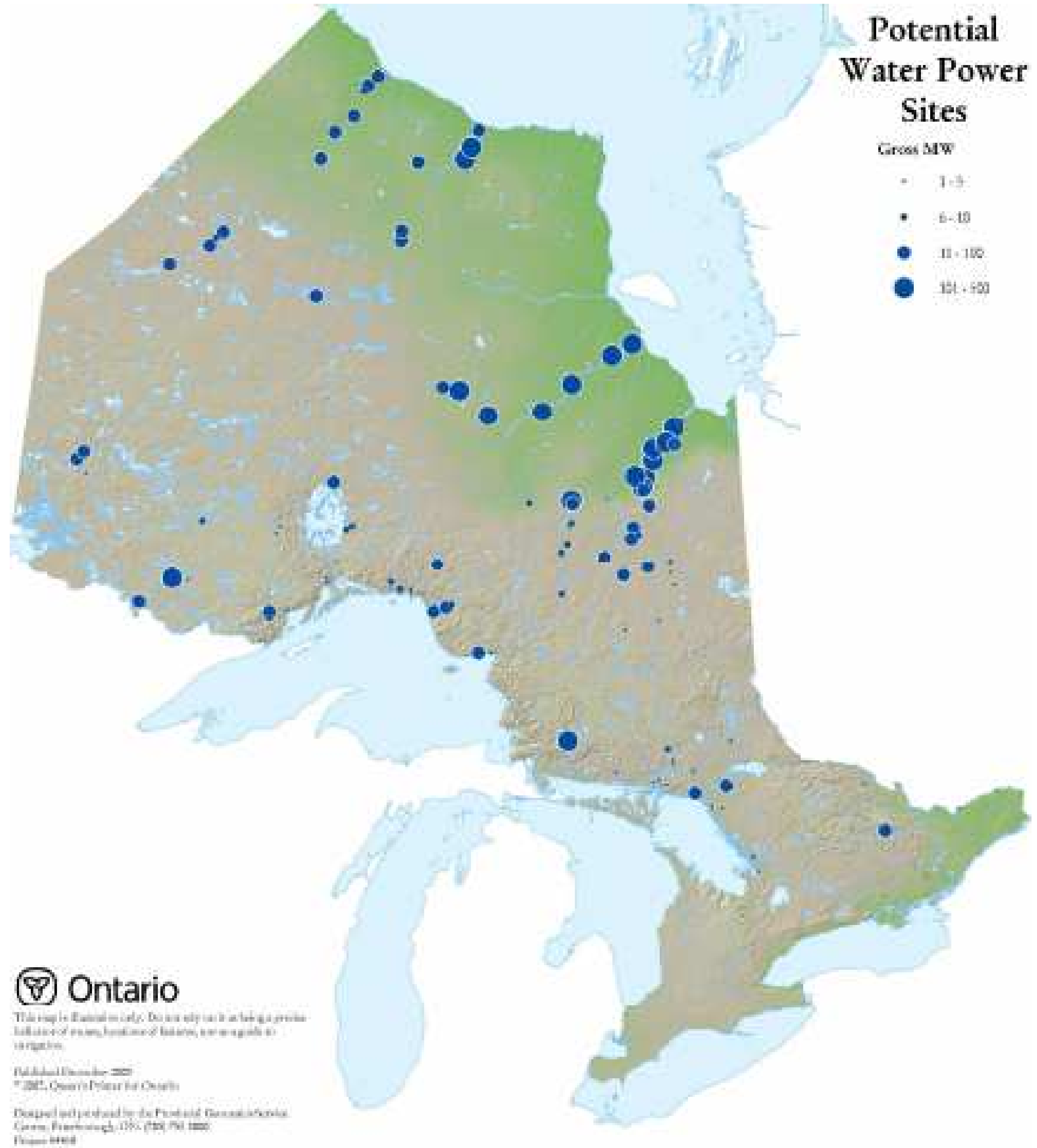
In line with the need to filter renewable sources for feasibility, OPA sought the assistance of MNR to screen the waterpower sites for policy impediments and other constraints such as tourism and other recreational use that would inhibit their development. Table 1.2.2 shows that there are roughly 1,500 MW in areas that are not protected from development.

Table 1.2.2: Ontario Potential for New Waterpower

Waterpower Categories	Total (MW)
Total Ontario Potential	7,585
Less: Parks and Conservation Reserves	(1,501)
Less: Subject to Agreements with First Nations and Fed. Gov't *	(4,637)
Remaining Potential for consideration at this stage	1,447

Source: OPA; *Moose River Basin and Northern Rivers

Figure 1.2.5: Ontario's Potential Waterpower Sites



Source : Ministry of Natural Resources

With the knowledge of the developable sites established, OPA worked with MNR and Hydro One Networks to determine the proximity of these sites to transmission and distribution systems. (While there are other transmitters and distributors in Ontario, Hydro One Networks' data was considered sufficient for this preliminary exercise because it is the utility in most of the rural and northern areas where the waterpower sites are situated.)

Table 1.2.3 - Waterpower Potential within Policy Guidelines by Site Size and Proximity (MW)

Connection Proximity of Site	Under 1 MW (50 sites)	1– 5 MW (28 sites)	5-10 MW (12 sites)	10-100 MW (7 sites)	Above 100 MW (2 sites)	Total
Within 5 km		39	33	311	660	1,043
5-25 km		17	41	69	0	127
Beyond 25 km		40	20	187	0	247
Total:	30	96	94	567	660	1,447

Source: OPA, MNR

Table 1.2.3 shows that only a small portion of the 1,500 MW potential, roughly 250 MW, is more than 25 km from a transmission line or distribution station. Developing this more remote waterpower would require a closer look at the economics of connecting to the electricity grid. The total includes additional capacity resulting from extensions and upgrades of existing hydroelectric facilities as well as a pumped storage site. Additional thoughts on this appear in Section 3.6, which contains additional detail on the potential sites. More detailed studies will be required to determine the need and economics of pumped storage.

A portion of the existing waterpower capacity is used for peaking demand, while another portion is used for base load. The new additions are expected to be mostly “run-of-the-river,” making them more suited to base-load service, but they are only well suited to play this role in winter, not in summer. The reason is that daily peaks last longer in summer than in winter and there are more constraints on operation in general, such as cottage use and environmental restrictions, in summer.

Waterpower is therefore more limited in its ability to meet peak demands in summer than in winter. Peak use in Ontario is shifting from winter to summer, as air conditioning use rises. There is the additional concern that global warming will reduce the energy output from current hydro facilities because of lower water levels. This advice takes into account the shift in peak and its impact on hydro in this role, as well as the potential lower production from current facilities.

Site-specific limitations on the potential for waterpower developments are the economics of such characteristics as water flow, head and distance from transmission, and environmental concerns around ponding and erosion.

Biomass

Ranges for biomass potential to generate electricity vary considerably, from a few hundred to several thousand megawatts. The largest share is theoretically in the forestry sector. The potential is significantly reduced by two constraints – the limited availability of forest resources and the cost of collecting material and transporting it to generating plant locations. While there are agricultural opportunities for using crop residue and animal waste (biogas digesters), growing crops specifically for electricity production is unlikely to be viable.

Municipal solid waste gasification and gas from wastewater (sewage) treatment plants and landfill are other potential sources, although public acceptability has been an historic concern, largely due to the perception that producing energy from these sources must involve incineration. In the environmental assessment of biomass, it was assumed to be carbon dioxide neutral, meaning that over its life cycle it produces as much as it captures. The cost of producing electricity from waste is higher than for many other sources, but to the extent that biomass generation reduces municipal disposal costs, it should receive an offsetting credit.

Municipal solid waste landfill sites and wastewater plants generate methane that can be collected to generate electricity. There are several such sites in Ontario already. The amount of power produced this way is likely to be small relative to total needs, because of the limitations of waste quantities, but it has nonetheless been included in planning for supply mix purposes. It is worth promoting this source because methane, when it escapes into the environment, is a potent greenhouse gas.

Solar Photovoltaic

When sunlight hits a photovoltaic cell, electricity is produced. Such solar-generated power has the advantage of using a free resource, has modularity that makes it suitable for connecting close to the load, and has significant potential for technological improvement. The challenge of solar-powered generation is its environmental life-cycle impact. This impact is dominated by the process to manufacture the photovoltaic cells, which itself is energy-intensive and creates toxic by-products. The cost of electricity from photovoltaics is of more than $180/MWh, higher than all other sources examined.

The Canadian Solar Industries Association suggested a potential for up to 40 MW of photovoltaic electricity supply by 2010. European countries have offered a high purchase price for solar-generated electricity that accelerated its use, particularly in Germany and Austria.

1.2.6 Conventional Generation

Hydro Imports from Neighbours

Ontario has significant capacity of interconnections with other jurisdictions, totalling 4,000 MW. The larger share is with New York and Michigan, with less interconnection capacity to Quebec, Manitoba and Minnesota. Interconnections increase reliability and permit trade in electricity.

Our analysis relies on interconnections for meeting extreme weather conditions. In addition, interconnections make ongoing, large-scale imports possible.

While Ontario long ago developed its most feasible and accessible large waterpower sites, Manitoba and Newfoundland and Labrador still have waterpower resources that could be developed and the output sold to Ontario. There are opportunities for importing from the United States, as well, but these are based mainly on nuclear, natural gas or coal-fired generation.

The advantage of additional large waterpower is that it is a renewable energy resource. On the other hand, the distances from the sites to the load centres in Ontario are great, up to 2,500 km, and significant transmission connections would be needed, with attendant costs and electrical losses.

Agreements would have to be reached with suppliers of the generation resource and with First Nations and other parties on the economic development and land use issues around transmission. Negotiations for long-term imports are at an early stage. However, if the line from Manitoba were built, it could form part of a national east-west electricity grid bringing additional generation from western Canada. It also could be used to carry wind generation from the Hudson's Bay lowlands.

A wide range of purchase prices must be used as estimates, because negotiations are still at a very early stage. For this analysis, the planning assumption is $50 to $120 per MWh, as shown in Figure 1.2.9, which includes the transmission cost associated with delivering the imported power.

The value of a hydro import increases if it can be scheduled to meet intermediate load needs and operating requirements. There are considerable synergies possible if water can be stored where the power is generated, so that this supply can be coordinated with the use of Ontario's base-load facilities. Scenarios to include imports are therefore based on the possibility of negotiating an agreement that provides value and fit with Ontario's long-term need.

Nuclear Power

Nuclear power was introduced on a commercial scale into the Ontario system in the 1970s. It grew to supply more than half of Ontario's electricity in the 1990s and currently provides about 37% of Ontario's generation capacity and roughly 50% of Ontario's electrical energy production needs.

As noted earlier and in Part 2.6, Ontario's most critical need in the long term is for base-load supply. Nuclear power is particularly well suited to this role, owing to its low operating cost and lack of air emissions during operation.

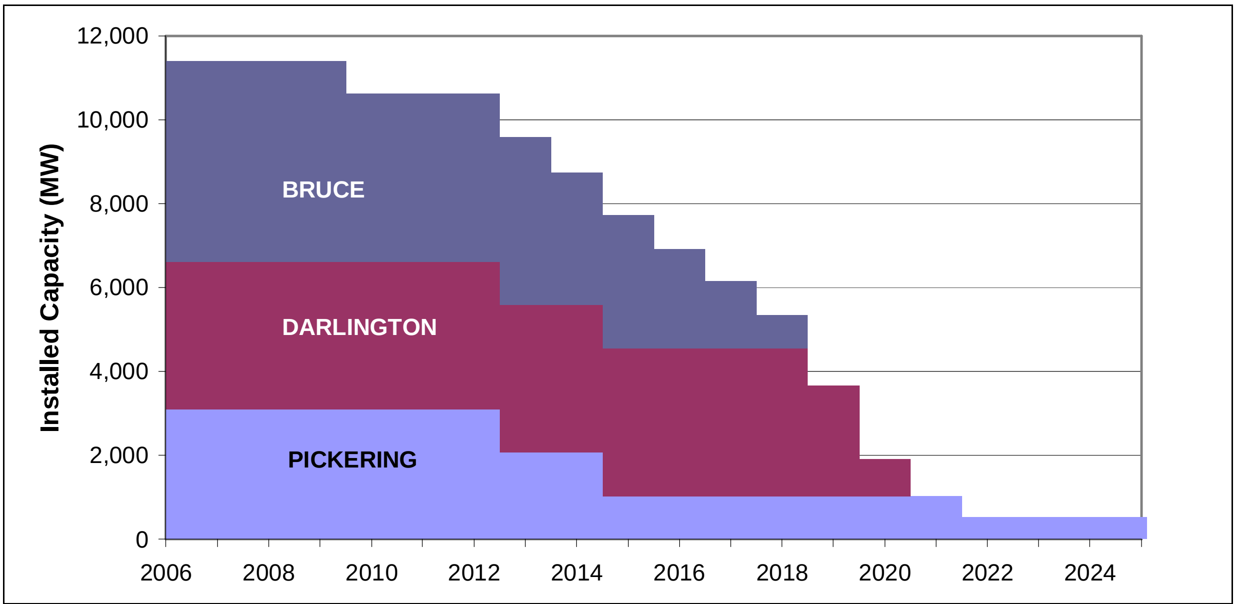
The environmental indicators show that nuclear energy has lower impact over its life cycle than many other supply sources, including natural gas generation. Storage of spent fuel is a critical part of a successful nuclear program. Considerable progress has been made in this area by the Nuclear Waste Management Organization, which issued its recommendations in November 2005. Part 3.7 reviews the recommendations in more detail.

However, nuclear energy in Ontario has faced many problems. There have been serious cost overruns on both initial construction and the refurbishing of older units. As well, it has been hard to achieve consistent operational excellence at some stations, which has reduced their cost advantage.

The mid-1990s marked the start of a particularly troubled period in the history of the nuclear fleet. Eight of Ontario's 20 units were taken out of service to focus attention on improving the performance of the remaining 12. Since then, a decision has been made not to restart two of the eight shut-down units, owing to the economics. Of the remaining six, four units have returned to service, with serious delays and cost overruns in one case, and contracts are in place to work on the remaining two, with a view to their ultimate return to service by 2009. By 2009, therefore, 18 out of 20 units are expected to be back in service.

Despite the returns to service, the fact remains that most of the current fleet was built in the 1970s and 80s. Figure 1.2.6 shows the potential points at which decisions would have to be made on extending the service life of units or taking them out of service:

Figure 1.2.6: Planning Assumptions Regarding Nuclear End-of-Service Dates



Source: OPA with advice from IESO and nuclear operators.

The decisions about how and whether aging units are to be refurbished or replaced are complex, calling for extensive assessment and coordination. In the case of refurbishment, the extent of the work may, in some cases, amount to essentially building most of a new unit in the place of the old one. This provides Ontario with the opportunity to take advantage of changes in nuclear technology that may be simpler to operate, cheaper to run and better performing. A number of options for new-build are possible; a further discussion is provided by Canadian Energy Research Institute (CERI) in Part 4.3.

It is also important to bear in mind that any nuclear work in Ontario, whether refurbishment or new-build, will be taking place in an environment that should allow much better management of the many concerns around such projects. Specifically:

- The corporate mandate and structure of Ontario Power Generation (OPG) and the involvement of private-sector capital have eliminated accounting and financing restrictions faced by the former Ontario Hydro that resulted in very large price increases when new plants it built went into service;
- Both OPG and Bruce Power, supported by capable supply, engineering and construction firms, now have considerably more experience in the successful management of nuclear projects;
- Access to international experience can contribute to a successful program in Ontario;
- New and more sophisticated approaches to financing major projects better allocate the risks among owner, operator, contractor, suppliers, customers and other parties; and
- Operational and performance audits and licensing processes will contribute to efficient operation and adherence to schedules.

At the same time, the long lead time for nuclear-related work presents special challenges, particularly given the large number of units that must enter into planning considerations. This makes it critical to decide soon what kind of work is to be done and when.

Another source of uncertainty is how well nuclear units, particularly those using new technology, will perform. Performance of nuclear units, which is measured by their "capacity factor," must be considered in supply mix advice, because it has implications both for the cost and the availability of nuclear supply. While it is impossible to predict accurately the performance of new technology, it is noteworthy that performance of most designs used world-wide and in the Ontario fleet has improved significantly in the last several years.

In summary, with construction and financial risk properly managed and if the nuclear fleet maintained high capacity factors and consistent operation, nuclear generation would provide an excellent alternative to the volatility of price and uncertainty of supply that are major drawbacks to gas-fired generation for base load.

If timely decisions enabled the nuclear generating options to be brought into service over a relatively short period of time, this would provide the added advantage of reducing further exposure to the risks associated with natural gas-fired generation.

Natural Gas-fired Generation

Natural gas is widely used for electricity generation. Ontario already has about 2,800 MW of natural gas-fired generation and another 2,100 MW of dual fuel oil-gas capacity at OPG's Lennox generating station. For the past 15 years, natural gas has been the fuel of choice for new generation projects in the United States.

The price of gas in the long-term, however, is linked to the price of oil and as such is highly volatile. Oil's price varies with geopolitical events and the ever-increasing global demand. The advent of increasing supply in the form of liquefied natural gas (LNG) to North America opens up the option of transporting natural gas by ship, making it a global commodity like oil.

The price of natural gas has increased sharply over the past five years – from $2 to $3 per million BTU to the current $12 to $14, reflecting increasing global demand for oil and gas and, more recently, the impact of Hurricane Katrina. Natural gas-fired generation had a cost advantage in the 1990s, based mainly on its relatively low capital and fuel costs, but today the fuel price has pushed up operating costs to eliminate that advantage.

The combination of rising natural gas prices and a market for natural gas that is very mature and liquid increases the likelihood that operators of natural gas-fired stations may choose to shut down generation to free up the gas fuel for more profitable resale in the gas markets. Since gas and electricity demand peaks tend to coincide in cold climates, this phenomenon increases both price and supply risks for many systems with a heavy reliance on natural gas. This has become evident in such regions as New England.

The other major issue is the impact a large commitment to natural gas-fired generation has on capacity for gas infrastructure and deliverability in Ontario, and the effect this could have on the cost of gas used for other purposes, including residential and commercial heating and industrial process use. The impact of a rapid adoption of natural gas-fired generation in Ontario for power generation is also becoming a concern for neighbouring jurisdictions.

Among emerging technologies, natural gas fuel cells show promise because of their potential to create electricity directly from the gas, similar to a battery's operation, with low environmental impact. While they promise to be quieter and more efficient than conventional natural gas-fired generation, as well as being modular, like photovoltaic generation, they are still in the development stage.

Gasification

Gasification converts a fuel source, such as municipal waste or coal, to a gas and then generates electricity from combustion products, in a way similar to natural gas. The advantages of gasification are the lower emissions than from burning the fuel directly and the lower price volatility of various possible fuels, including coal, when compared to natural gas.

A potential longer-term enhancement to gasification is carbon dioxide sequestration, a process that captures carbon dioxide from the combustion process and contains it in long-term storage, such as under an oil well head. The cost for gasification with sequestration is high, estimated at $80-95 per MWh. As discussed in the biomass section above, biomass such as municipal waste can also be used as feedstock in gasification.

The most significant challenge for gasification is the lack of larger-scale experience by utilities with Integrated Gasification Combined Cycle (IGCC) plants. Processes similar to gasification have been used to produce liquid fuels in South Africa for many years, and are used in the chemical and petro-chemical industries. While there are a handful of plants around the world, IGCC is not yet a widely-used technology for electricity generation.

Owing to the abundance of coal in North America and the rising concern over energy self-sufficiency in the United States, energy policy in other jurisdictions is likely to feature massive research and development programs in coal gasification for many years to come, activity from which Ontario can benefit.

Gasification of coal without carbon dioxide sequestration has the highest environmental loading of all technologies considered. With sequestration, its environmental loading is still higher than nuclear or biomass, the latter of which is deemed to be carbon dioxide neutral. While gasification with sequestration is not considered feasible at this time, this may change over the next 20 years and gasification could therefore make an appearance in Ontario's electricity supply mix in the future.

Given that potential and the location of existing coal-fired stations near both coal-handling and electrical transmission facilities, it would be useful to preserve the coal-handling facilities after these plants are shut down.

Coal-fired Generation

As noted, the replacement of conventional coal-fired generation in Ontario has been adopted as policy by the Government. Coal-fired generation is a significant part of the present supply mix and managing its timely replacement has an impact on future supply choices.

While coal replacement is not the focus of this report, its relevance relates to the nature of the replacement alternatives in the supply mix in the long-term. The current schedule relies on a number of elements falling into place in the relatively short period before coal-fired generation is replaced. Firstly, the procurement initiatives for replacement of supply capacity, which are the result of Government directives to the OPA, would need to materialize fully. Secondly, demand would need to remain essentially flat through intensive conservation efforts. Thirdly, major transmission investments and reconfigurations to bring new generation into the grid would have to be completed.

While it is impossible to quantify all of the risks at this point, the price and supply risk around gas as a generation source has grown significantly. Early indications from projects now at the siting stage suggest that, to meet the goal of reliability, officials involved in the approvals process would need to recognize and respond more clearly to the priorities arising from that goal.

Given a relatively small supply margin, as shown in Figure 1.2.14, and the relatively large combined risk of the many elements on which supply reliability depends, the replacement of the coal-fired plants needs to be monitored closely for circumstances that may require the development of alternatives.

One of the scenarios considered in this report looked at this case. The conclusion is that it would make sense to continue monitoring the timing risks around the current schedule.

1.2.7 Balancing the Options

Planning supply mix would be simple if a single resource were superior to others in all areas – environmental impact, reliability and costs – and could meet equally well the needs of base, intermediate and peak load. Because no such single resource exists, a combination of resources and technologies is needed, and tradeoffs and synergies among them must be considered. In developing this advice, it was considered critical to take into account the environmental, economic and social impact of the possible combinations.

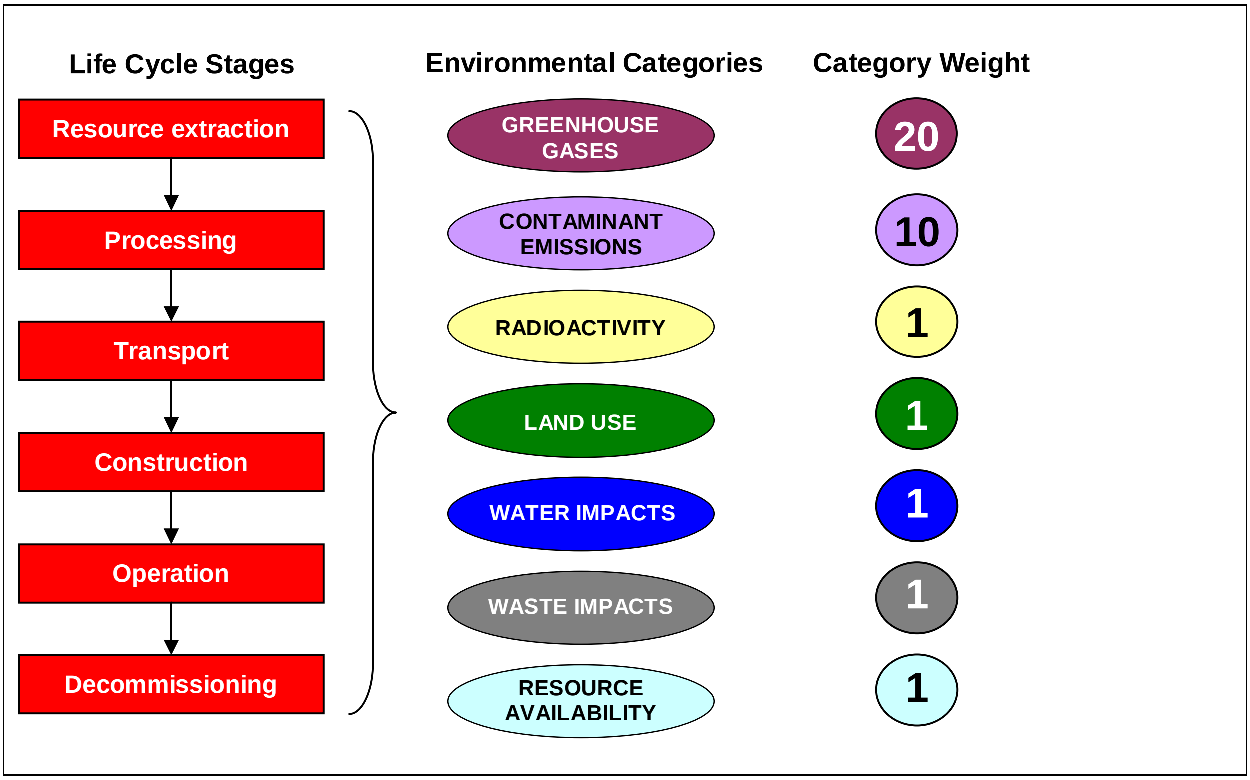
At this stage, the analysis looked at the broad picture. Therefore, without knowing siting and technology specifics, indicators of environmental impact, cost and reliability must, of necessity, be fairly broad. These indicators will be refined and become more specific for the Integrated Power System Plan. They will be more specific still at the stage when projects are being developed.

Environmental Impact

A "life-cycle" approach is valuable in weighing the environmental impacts of various supply sources and potential supply mixes. This approach looks at the environmental impact of all the stages of the life cycle of a supply source: resource extraction, processing, transport, construction, operation, and decommissioning. It evaluates each stage and estimates a life-cycle impact.

To allow comparisons, the analysis groups the environmental impacts of various supply sources into seven categories: greenhouse gases (GHGs), contaminant emissions, radioactivity, land, water, waste, and resource availability, as shown in Figure 1.2.7. The method produces both absolute and relative scores of impact. The latter are more helpful when comparing supply options.

Figure 1.2.7: Life Cycle Environmental Analysis for Generation Options



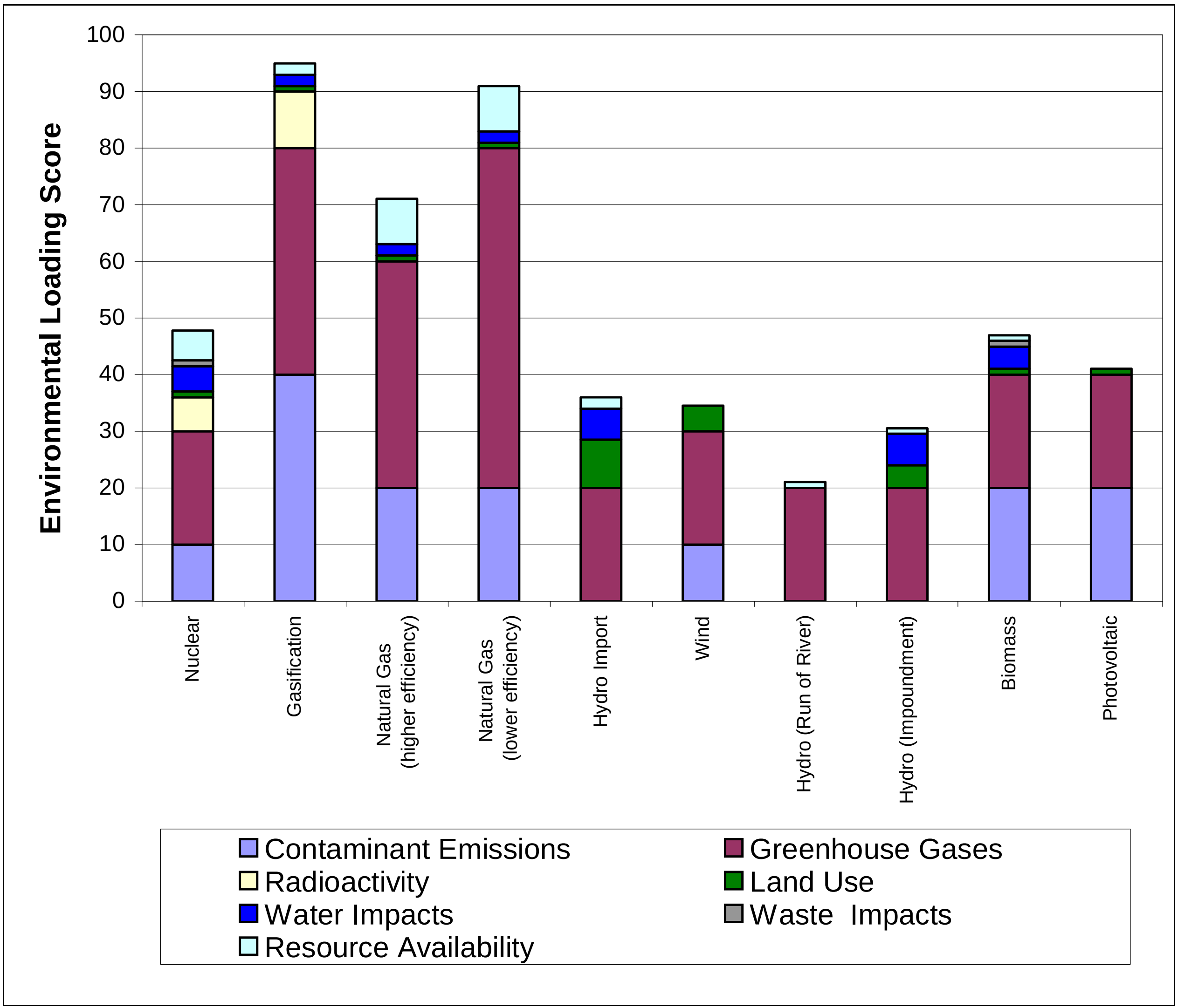
Source: SENES and OPA

The consultant carrying out this work was SENES Consultants. In the other volumes, Part 4.4 provides their full report, while Part 2.6 reviews technical and environmental considerations together, and Part 3.2 provides a background report on how power system planning takes environmental sustainability into account.

SENES provided a raw score, by technology choice, for the life-cycle environmental impact of each generation technology on each category. A technology with no impact on a category was assigned a score of 0, while the worst performing technology in that category rated a 10. To determine the total environmental loading score for a given technology, the relative weight of each environmental category must first be determined.

SENES recommended a weighting scheme based on the European Commission's exhaustive study of the life-cycle impacts of different generation options. It is considered a robust and well-researched study. In particular, the recommended weights were based on the monetized environmental impacts in France and the Netherlands. Section 4.4 contains more background on the work by SENES and the ExternE methodology.

Figure 1.2.8: Environmental Impact of Various Generation Options



Source: SENES and OPA; Notes: Gasification includes sequestration of carbon dioxide; biomass is carbon dioxide neutral

Adopting the SENES recommendation involved multiplying the raw score in each category –

greenhouse gases, contaminant emissions, radioactivity, land, water, waste and resource availability – by weights that reflected the relative environmental impact of each category. These weights are identified in Figure 1.2.7.

By adding the weighted score in each category together, a total environmental score for each technology choice can be calculated to give an indication of its total environmental loading. This aims to allow for meaningful comparisons of the environmental impacts of the different options.

It should be noted that the relative impacts of the various supply sources are highly sensitive to the weighting assumed for each factor. For example, greenhouse gases were given twice the weight of contaminant emissions, which assumes that their environmental impacts are twice as large.

The ranking of composite scores has produced some clear results. As Figure 1.2.8 shows:

- "Run-of-the-river" waterpower has the lowest impact on the environment, and waterpower generally has a favourable score
- Other renewables, particularly wind, also have relatively low impact
- Nuclear ranks at a level similar to biomass
- Technologies that burn fossil fuels have the greatest environmental impact
- Coal is actually responsible for higher radioactivity impacts than is nuclear – primarily due to release of radon gas in mining coal (see gasification results in Figure 1.2.8)

While not reported in Figure 1.2.8, the environmental loading score of conventional coal-fired generation is 216.5, approximately triple that of higher-efficiency natural gas-fired generation.

Relative Costs

The price of electricity clearly has an impact on consumers. For this project, CERI (Canadian Energy Research Institute) of Calgary undertook an evaluation of various supply technologies, resources and associated costs and risks from an economic perspective. The CERI report, which appears in Part 4.3, provides quantitative information on cost estimates, which we supplemented with updates and additional research.

The levelized unit energy cost (LUEC), expressed in dollars per megawatt-hour (MWh), is the most common way of comparing the life-cycle costs of different supply sources. It measures the direct costs of supply, not broader economic impacts such as job creation and other multiplier effects, nor the societal costs of environmental impairment.

The LUEC represents the constant amount of money that must be charged for each unit of electricity generated over the life of the supply source to recover exactly all life-cycle costs.

These would include the cost of construction, capital modifications, operating costs including fuel and its disposal, the cost of decommissioning, and the cost of capital. It can be thought of, not unlike a mortgage payment, as the amount that investors / consumers pay each year to retire the cost of a project over the life of the facility.

Risk adjusted cost of capital, or alternatively the discount rate used to determine present value costs and energy production, has an impact on the LUEC. It is generally accepted that equity investors require a higher return than do debt lenders. This means that the higher the share of equity in the capital structure, the greater the future cash flows must be. A higher equity share is reflected in a higher weighted average cost of capital (WACC) and, a higher discount rate in calculating the LUEC, all other factors being equal, results in a higher LUEC.

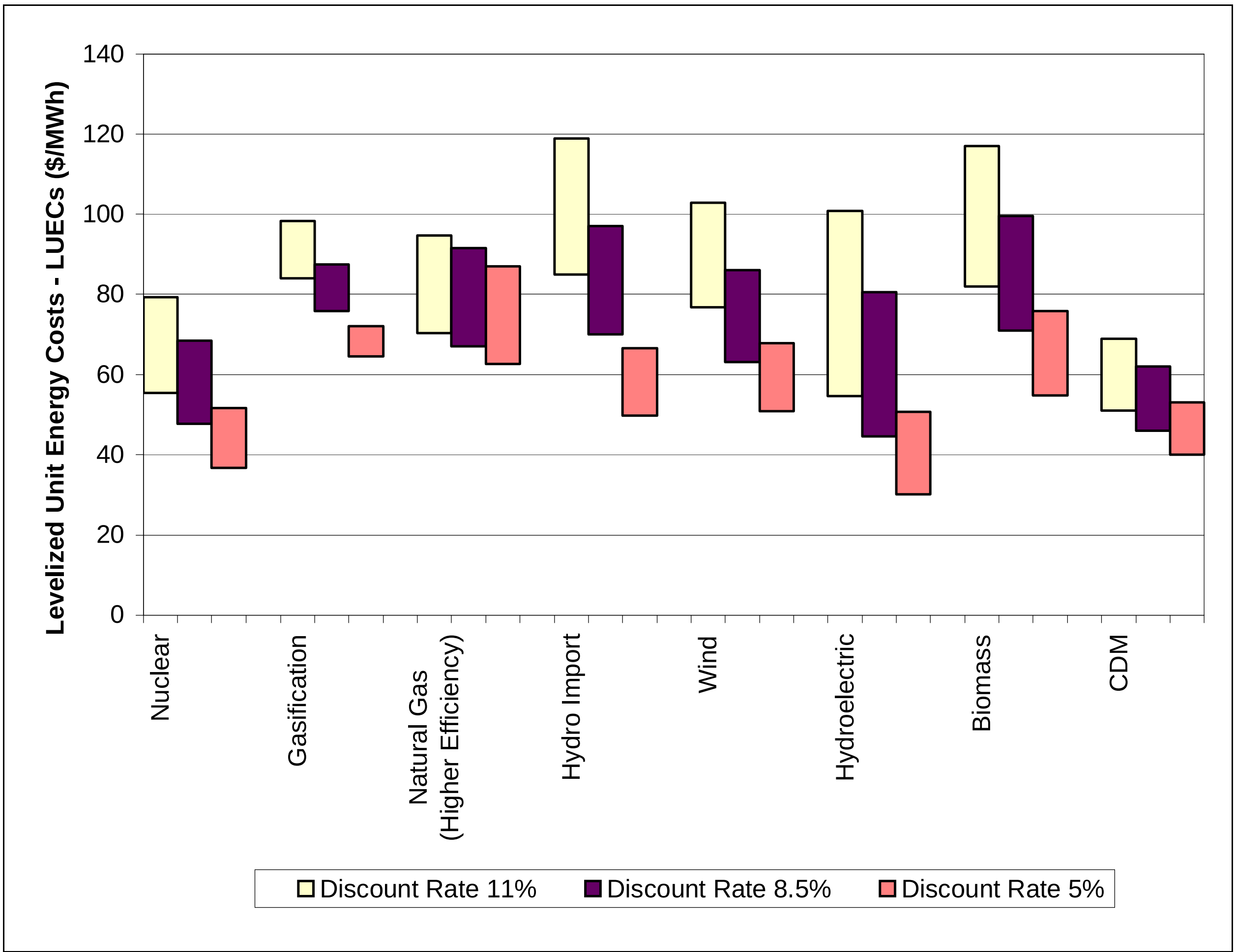
The impact on levelized costs of considering a range of discount rates is shown in Figure 1.2.9, which compares options under three assumptions – 5%, 8.5% and 11%.

In evaluating alternative generation options it is necessary to combine costs incurred throughout the complete life cycle of the various alternatives. Some costs are capital costs for initial construction and final decommissioning. These are large expenses at discrete points in time which must be combined with operating costs for maintenance and fuel. These are costs which occur continuously. Some generation options such as hydroelectric have high capital costs with low operating costs while others such as gas-fired plants have relatively low capital costs with high operating costs.

To compare all options on a common basis, the life cycle costs are reduced to a single "net present value" (NPV) by discounting costs from they time they are incurred in the future back to the present time. The discount rate used affects the relative attractiveness of plants with different ratios of capital to operating costs. A discount rate of 5% has been used in preparing the levelized unit energy costs (LUECs) for the supply mix advice. This rate is often referred to as a "social discount rate" and reflects the timescale over which electricity infrastructure contributes value to society. It is equivalent to the long term cost of public debt. In contrast a "commercial discount rate", which might be double the social discount rate, reflects the return on capital required by investors who are absorbing all the risks of developing, financing, owning and operating infrastructure. This approach of comparing LUECs based on a social discount rate is used in other jurisdictions.

CERI provided performance and cost characteristics for a number of specific generation technologies, together with updates and other data, which formed the basis of the graphs in Figures 1.2.9 to 1.2.11. LUECs are most useful for comparison purposes when the supply sources will fill the same role in the electricity mix. Figure 1.2.9 shows the LUECs for a range of generating options. Some are assumed to be operating to meet base-load needs, such as nuclear, natural gas and gasification. Others have their own operating characteristics dictated by resource availability, such as hydroelectric and wind. Part 2.6 provides detailed assumptions, calculations and sensitivity analysis.

Figure 1.2.9: Cost of Generation Options

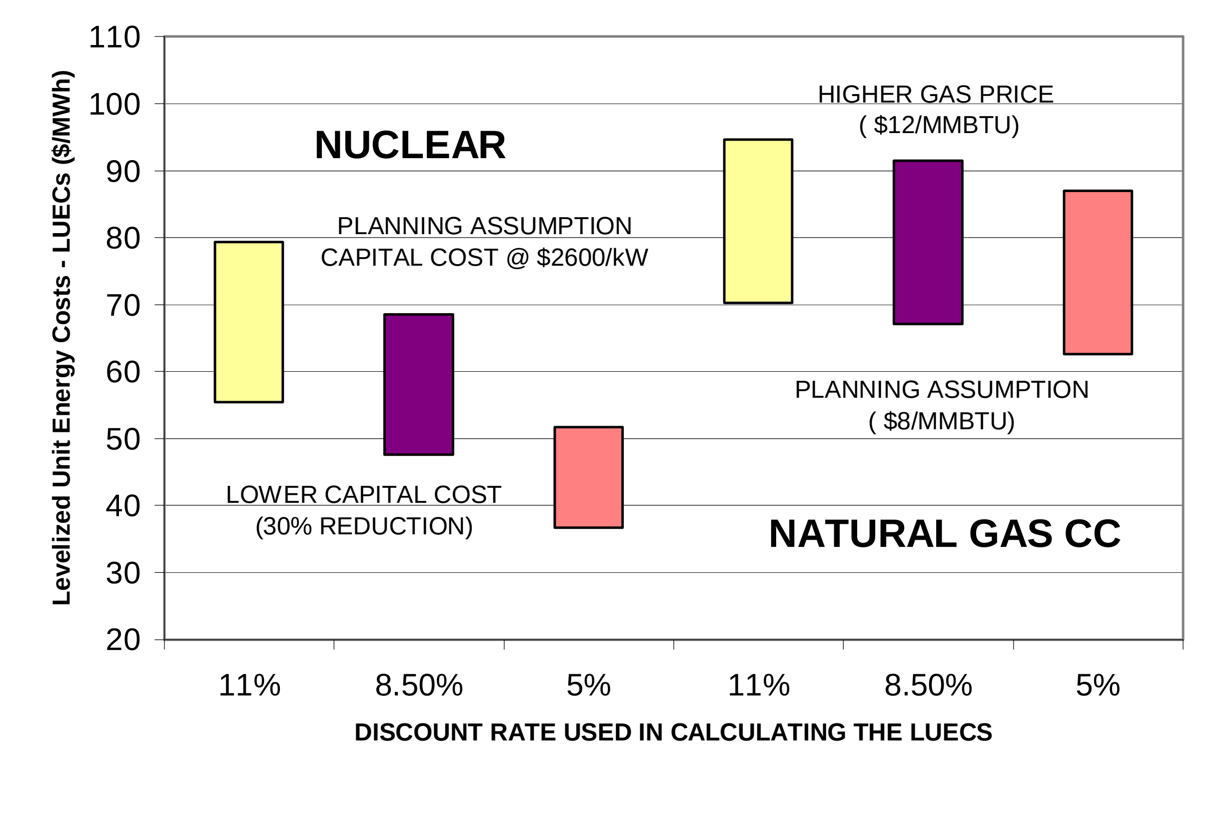


Source: OPA and CERI

Figure 1.2.10 is of particular interest, given Ontario's long-term needs, because it compares the costs of nuclear and gas-fired generation as base-load options. Gas and nuclear are reasonable candidates for meeting the balance of Ontario's needs in this area after conservation and new renewable supply sources have been factored in. LUECs for natural gas and nuclear options have been calculated under three discount rate assumptions – 5%, 8.5% and 11%.

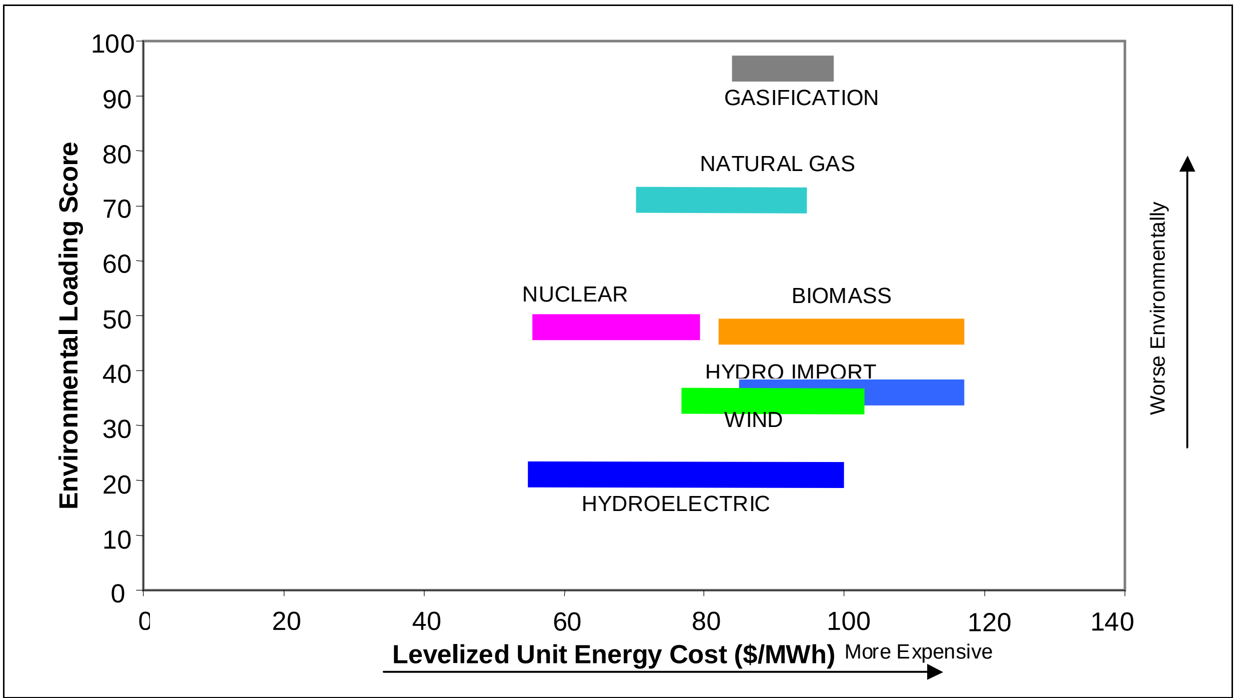
Figure 1.2.10 highlights that gas is much more likely to be a more expensive option for base-load needs. Under most discount assumptions, it would also be much less predictable in terms of costs over the long term, owing to gas price fluctuations.

Figure 1.2.10: Costs of Nuclear and Natural Gas Combined Cycle (CC)



Source: OPA and CERI; Note: Based on 85% Average Capacity Factor

Figure 1.2.11: Combined Environmental Impacts and Cost Ranges – Base Load



Source: OPA, CERI and SENES; Note: Levelized Cost based on 11% discount rate.

Considering Both Costs and Environmental Impact

The graph in Figure 1.2.11 combines the estimates of environmental impact with the LUECs from the preceding section. The closer a supply source is to the lower left-hand corner of the graph, the better it is from both an environmental and cost perspective.

Social Impact

The social impact of choices for the electrical system depends on the values of society. Public opinion research conducted for the supply mix advice showed that in Ontario, as elsewhere, reliability of supply is the most important concern. The key measure of social impact at this stage of planning, therefore, is whether electricity supply provided by the recommended mix will be reliable. Other broad concerns, including price and acceptability, also come into play.

Reliability has two dimensions – adequacy and security. Adequacy relates to confidence that there is enough capacity to meet needs. Security relates to confidence that power can be delivered to customers without interruption. This report, in providing advice about supply mix, is appropriately focused initially on adequacy. While security of supply is important, it also involves the distribution and transmission networks. It is therefore appropriate to consider this aspect further when developing the Integrated Power System Plan.

An additional concern for customers is price. To some extent this is covered in the discussion of relative cost above. For many consumers, however, it is not just the level of prices but the rate at which they change that is a concern. Ways to protect against significant changes include creating a diversified portfolio of supply sources and ensuring that a significant share of electricity comes from supply sources with low and stable operating costs. In addition, there are customers who are particularly affected by higher electricity rates, including low-income individuals and electricity-intensive industries. Specific measures, such as conservation and cogeneration, are needed to deal with the impact on these customers.

Finally, there is the important element of social impact that is specific to each proposed generating project: local acceptability. These issues tend to arise around specific projects and therefore cannot be adequately addressed in the more general averages that underpin analysis of supply mix. It is worth noting, however, that policies weighted toward overall provincial needs and priorities, in addition to those responding to local needs, can go a long way in reducing risks to electricity supply and reliability.

Table 1.2.4: Advantages and Challenges of Available Resources

Resource	Advantages	Challenges
Conservation and Demand Management	Low environmental impact, reduces energy and resource requirements, can be lower cost than generation, high potential	Relies on public uptake and behaviour, uncertainty around full extent of potential, and timing of adoption and implementation
Wind	Renewable, high availability of wind resource, low marginal cost, low environmental impact, coincident with winter peak, potential for cost reduction	Site feasibility limited by transmission access, intermittent, non-dispatchable, not coincident with daily summer peak
Waterpower	Renewable, low marginal cost, mature technology, low-medium environmental impact, ability to provide base-load, peaking/intermediate service	Site feasibility limited by transmission access and restrictions on use, greater new site availability for small waterpower than large waterpower, constraints on water use during summer peak
Biomass	Renewable, amenable to distributed and combined heat and power applications, amenable to landfill gas and municipal solid waste and wastewater applications	Potential constraints on fuel availability, economic feasibility, and local acceptance, medium environmental impact among renewables
Photovoltaic	Renewable, high availability of solar resource, coincident with summer peak, amenable to distributed applications, potential for cost reduction	High cost, intermittent, medium environmental impact from production and waste
Nuclear	Low operating cost, suitable for base-load service, potential for improved performance and cost reduction	Limited load-following capability, high capital cost, construction cost risk, long development and construction lead-times, complex waste disposal, public acceptance
Natural Gas	Fast construction lead-time, ability to provide load-following and peaking service, can be located to relieve transmission bottlenecks	Fuel price and volatility risk, higher environmental impact, potential for constraints on fuel deliverability
Gasification	Lower emissions than from burning fuel directly, lower fuel price volatility than natural gas, potential for carbon dioxide sequestration, potential for improved performance and cost reduction	Use of technology not yet widespread, uncertainty about operating performance and cost, potential constraints on site availability for carbon dioxide sequestration

Source: OPA

1.2.8 Developing the Appropriate Mix

Clear directions emerge from looking at the environmental impacts and costs of potential supply sources, as well as their reliability, feasibility and relative price stability. Harvesting full conservation potential, developing feasible renewables, managing exposure to natural gas prices, and protecting base-load capacity through refurbishing or building new nuclear units:

these are all strong footings for robust recommendations on supply mix. The next step is to look at combinations of the options to develop a sense of the total costs, benefits and risks of various strategies.

Starting Assumptions

The starting point for a long-term strategy on supply mix is the existing situation, life expectancy of each existing component, assessment of future growth, and upcoming changes that are reasonably certain because of procurements, policy directions, contracts and other arrangements already in place.
These were the starting assumptions:

Load Forecast:

Two sets of assumptions were explored, as represented in Table 1.2.5. Forecast 1, the planning assumption, is a moderate growth case. Forecast 2 assumes higher growth.

Table 1.2.5: Load Forecast Planning Assumption and Higher Growth Forecast

Forecasts for 2025	Peak Demand		Energy Production	
	Growth Rate %	Peak Demand (MW)	Growth Rate %	Energy Demand (TWh)
2005 Demand	--	24,200	--	155
Forecast 1 (Planning Assumption)	1.3	30,400	0.9	185
Forecast 2 (Higher Growth)	2.15	36,000	1.8	220

Source: OPA

Existing Resources that Remain in 2025:

It is assumed that 12,000 MW of effective capacity associated with the current generating capacity will remain in service in 2025. This is made up of hydroelectric, oil and gas, and one unit of Pickering A nuclear station.

Procurement Initiatives and Assumptions:

Procurement activities already under way or completed will add to the existing generating capacity and CDM potential. These are identified in Tables 1.2.6 and 1.2.7.

Table 1.2.6: Procurement Initiatives and Assumptions

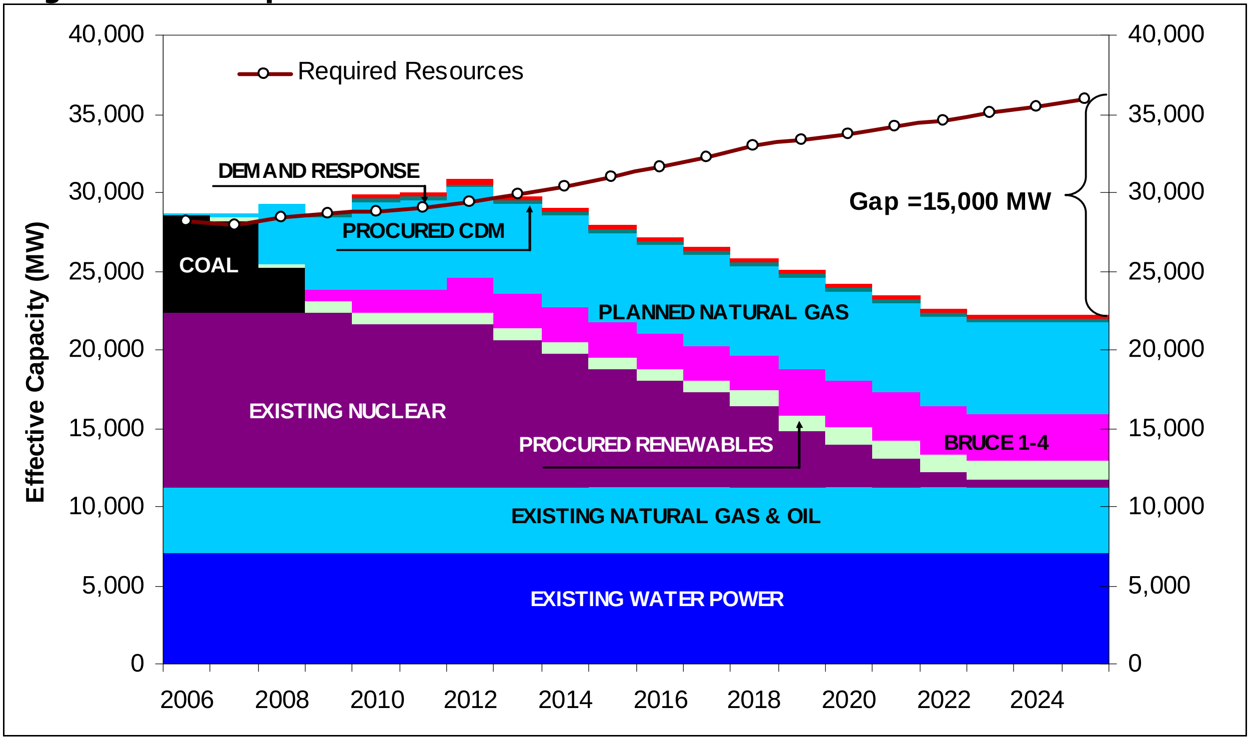
Additional Resources Already Planned by 2010	**Nominal MW**
Natural gas	5,990
Wind	1,390
Waterpower	150
Conservation and demand management	460
Landfill gas	30
Nuclear (Bruce A units 1 and 2)	1,500
Total procurements under way	9,520

Source: OPA

Table 1.2.14, in Appendix 2 (this section), provides an outline of the results of the Government's RFPs to date.

Given these assumptions about load growth and new capacity over the forecast period, the capacity needed still will amount to about 15,000 MW by 2025. This is shown in Figure 1.2.12. Of critical importance is that most of this 15,000 MW is for base-load generation capacity. This is significant because it dictates the types of resources which must be used to meet this need.

Figure 1.2.12: Gap In 2025 After Procurements



Source: OPA

Conservation and Demand Management (CDM):

The next step was to incorporate our planning assumptions around feasible CDM, which are depicted in Table 1.2.7.

Table 1.2.7: Conservation and Demand Management Assumptions

Conservation:	Planning Assumption (MW by 2025)	Higher Scenario (MW by 2025)
Conservation (incl. 200 MW in procurements)	1,050	3,550
Smart meters	500	500
DSM/Demand Reduction (including 260 MW in procurements)	260	260
Total CDM	1,810	4,310
Less CDM in procurement initiatives	460	460
CDM in addition to procurements	1,350	3,850

Source: OPA; Note: Assumes normal weather; conservation potential is higher on extreme weather days. These figures exclude cogeneration, which is included with natural gas-fired generation.

New Renewable Resources:

The figures for new renewables have some overlap with procurements. To illustrate the new renewables together and separate them from the procurements, Table 1.2.8 presents the total new renewables figures in both scenarios.

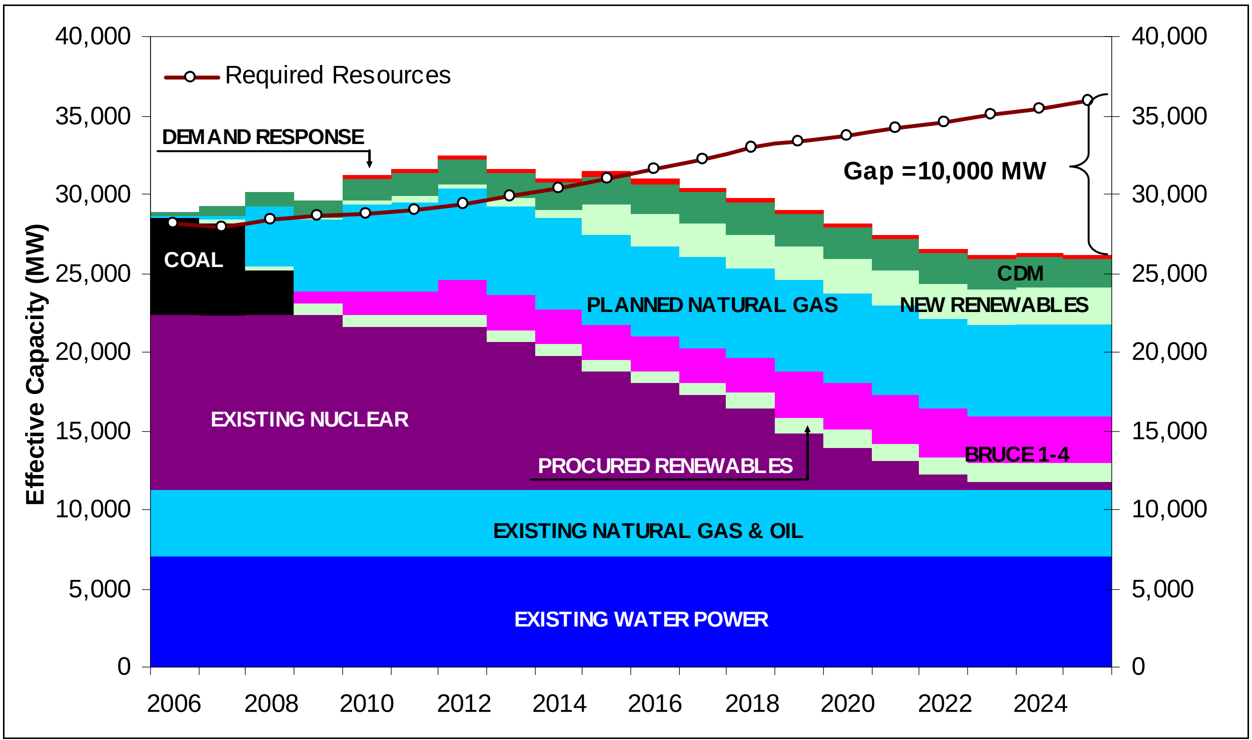
Table 1.2.8: New Renewable Sources, Installed Capacity

New Renewables	Planning Assumption (MW by 2025)	Lower Scenario (MW by 2025)
Biomass (including 28 MW in procurement)	500	250
Wind (including 1,391 MW in procurement)	5,000	2,500
Photovoltaic	40	20
Waterpower(including 151 MW in procurement)	1,500	600
Renewable Purchase	1,250	0
Total New Renewables	8,290	3,370
Less renewables in procurement initiatives	(1,570)	(1,570)
Total New Renewables in addition to procurement initiatives	6,720	1,800

Source: OPA

The contribution of current procurements, CDM and renewables is shown in Figure 1.2.13. The effective capacity associated with CDM and renewables closes the gap, leaving 10,000 MW of effective capacity still to be planned by 2025. (Effective capacity is less than installed or nameplate capacity, as explained earlier).

Figure 1.2.13: Current Procurements, CDM and Renewables Cover Needs to 2015



Source: OPA

Strategies

Two strategies that were considered for meeting the needs beyond 2015 were heavier reliance on nuclear, versus heavier reliance on gas. These were the two options that the early screening indicated were promising.

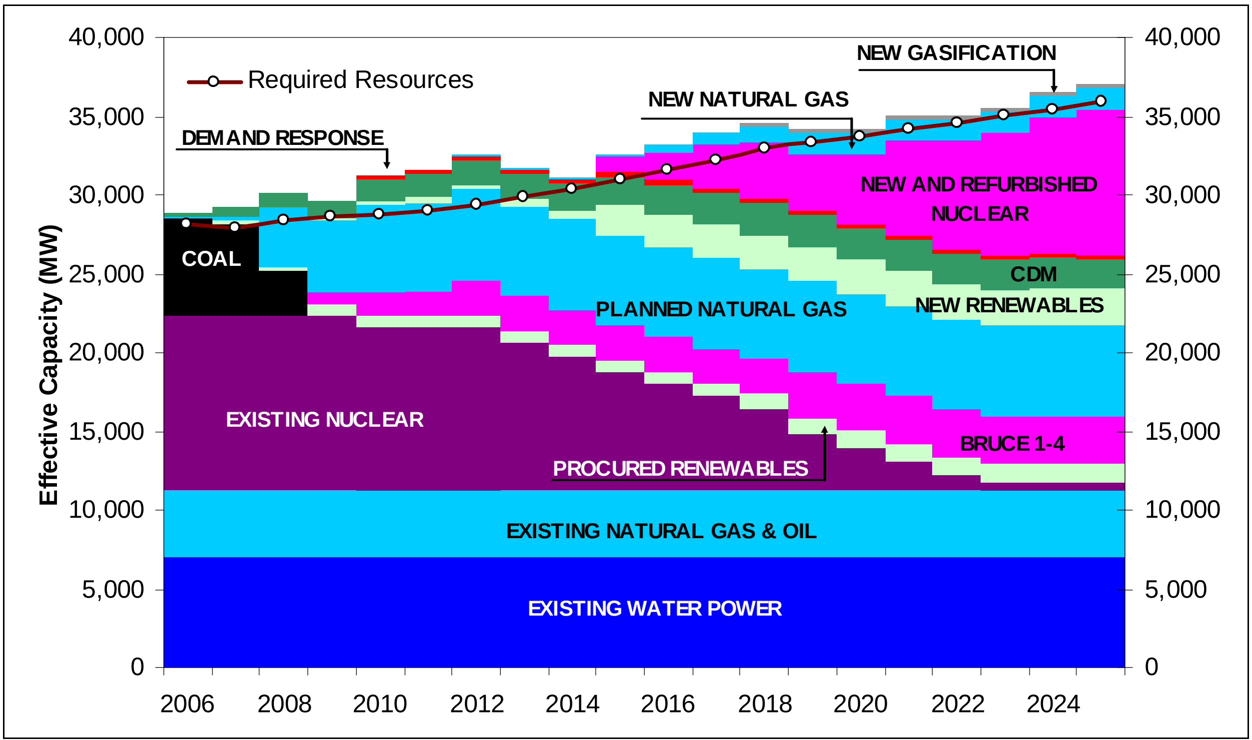
The assumptions about costs, risks and impacts of both nuclear and gas-fired generation were based on the discussion earlier in this report. Specifically:

- On nuclear generation, the analysis assumes the construction costs are $2,600 per KW of installed capacity. The levelized cost of $52/MWh, based on a discount rate of 5%, thus reflects the high end of the range shown for this discount rate in Figure 1.210.
- Refurbishments were assumed to be completed at a cost of $1.35 billion per unit. This is similar to the costs for the Bruce units 1 and 2 refurbishments.
- For gas-fired generation, the cost was based on a gas price of $8 per million BTU ($CDN), corresponding to the low end of the range provided in Figure 1.2.10, with the levelized cost

of $63/MWh corresponding to a discount rate of 5%

- For both sources, the risk distribution was based on historical volatility in gas prices and a range for construction cost variance of -15% to +35%

Figure 1.2.14: Meeting Additional Requirements to 2025 (With Nuclear and Gas)



Source: OPA

Gasification of coal on a large scale with sequestration could displace either nuclear or natural gas in future, should it become available at competitive prices, but could not be relied on as a definite supply source given its present state of development. Gasification of biomass or municipal solid waste is more likely to be developed, and is included in the scenario. Figure 1.2.14 illustrates how additional nuclear, natural gas and gasification can meet the remaining requirements.

A number of scenarios, which are described in the next section, were constructed to explore various possibilities and combinations of options. In our view, they all are possible. At the end of the analysis, we state, however, that it is not critical to decide now which scenario is more likely. There are common elements which constitute a common action plan and adaptation to the future as it unfolds will enable Ontario to respond to and take advantage of these scenarios.

Results

Planning Assumption Scenario: This scenario is based on procurements of 9,500 MW, coal replacement by 2009, new renewables and hydro imports of 6,700 MW and conservation and demand management of 1,800 MW, all according to planning assumptions. Two alternative portfolios were analyzed for this scenario:

- **Portfolio A:** Adds nuclear (9,400 MW) and natural gas fired-generation (1,000 MW), and fuel cells 500 MW starting in 2015
- **Portfolio B:** Adds natural gas-fired generation (9,300 MW), fuel cells (500MW) and coal gasification (720 MW)

Figure 1.2.15 shows the effective capacity for Portfolio A and Figure 1.2.16 shows the associated energy production. Figure 1.2.17 and 1.2.18 show effective capacity and energy production associated with Portfolio B.

The estimated costs of the portfolios were similar, but the risks were larger in Portfolio B and the environmental impact is larger. This is a direct result of the cost estimates and the environmental impacts scores described earlier. The details of the analysis are in Volume 2.

The conclusion is that Portfolio 1A offers lower risk and environmental impact than does Portfolio 1B. Variations on this scenario were then tested to determine the potential impact of other outcomes.

High Conservation Scenario:

This scenario showed the effects of higher success in harvesting conservation potential than the planning assumptions. Figures 1.2.19 and 1.2.20 illustrate what the effective capacity and corresponding energy production might look like if this materialized.

If it is assumed that the cost for all the conservation is lower than either nuclear or natural gas, then the result is that this scenario has lower cost, risk and environmental impact.

As sufficient confidence develops over the next several years that such a large potential for CDM is achievable, then the plans can adjust to take advantage of the increase in CDM. One possible adjustment shown in Figure 1.2.19 is to scale back on 1,200 MW of natural gas and 1,250 MW of hydro imports.

Figure 1.2.15: Scenario 1A – Nuclear for Base Load – Effective Capacity

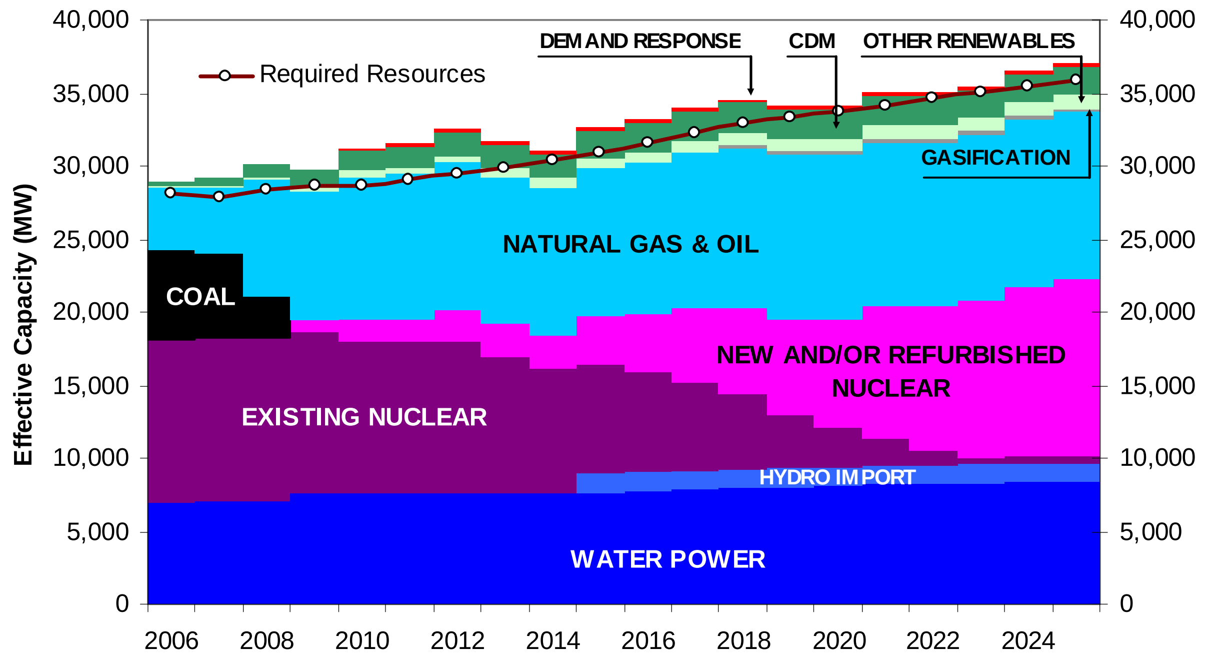
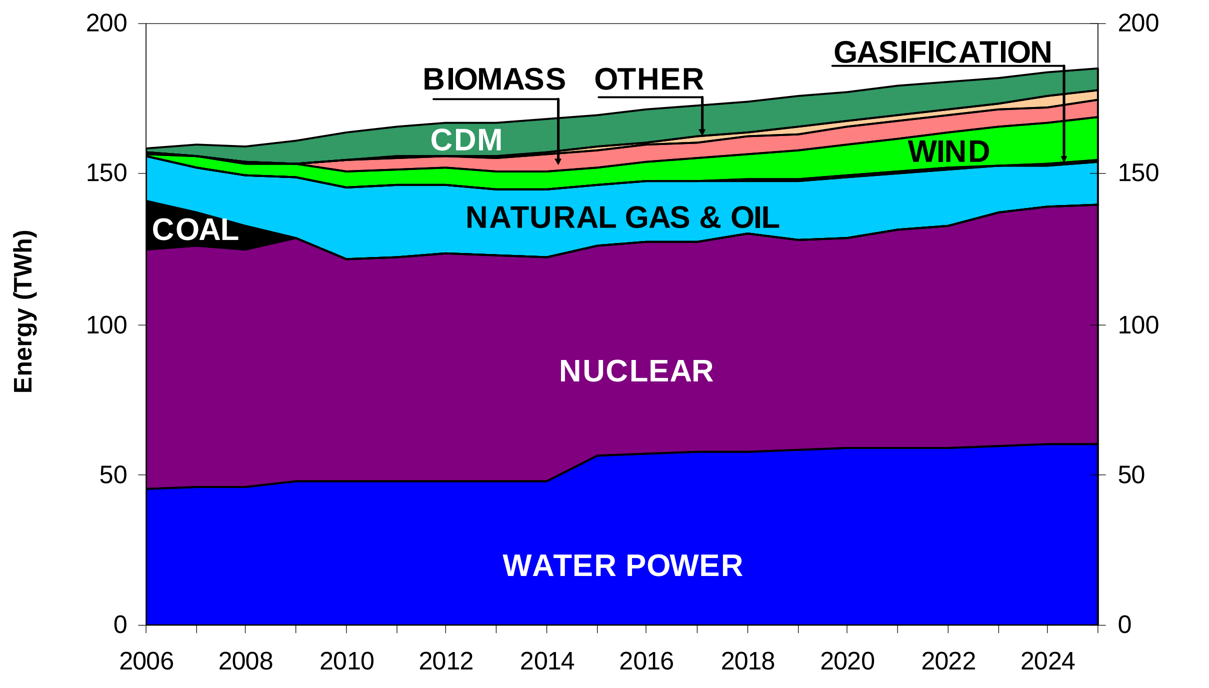


Figure 1.2.16: Scenario 1A – Nuclear for Base Load – Energy Production



Source: OPA

Figure 1.2.17: Scenario 1B – Natural Gas for Base Load – Effective Capacity

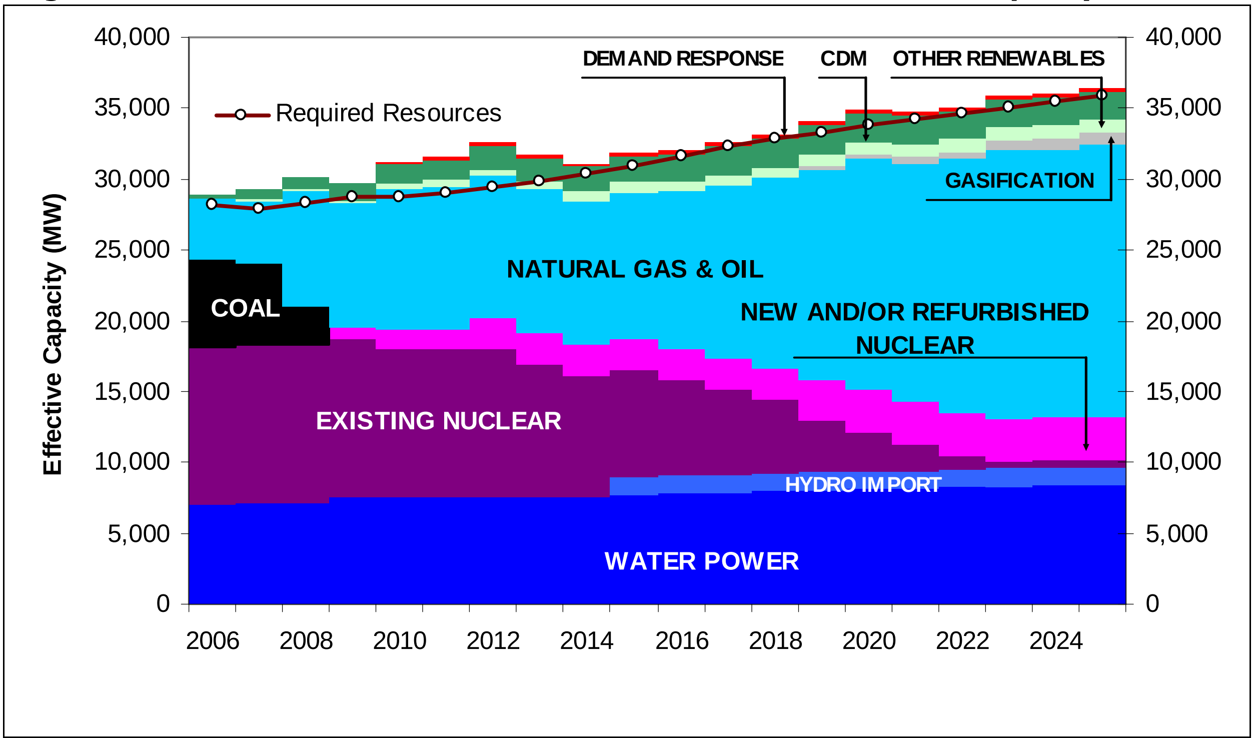
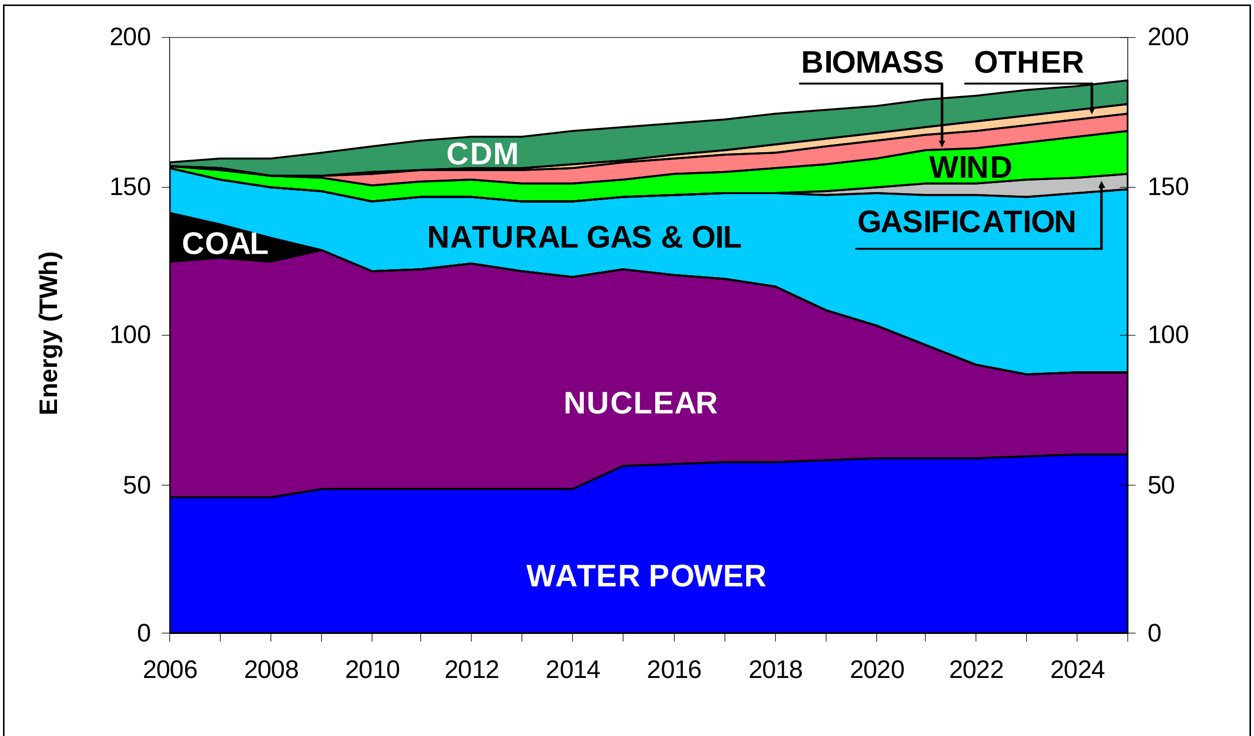


Figure 1.2.18: Scenario 1B – Natural Gas for Base Load – Energy Production



Source: OPA

Figure 1.2.19: Scenario 5B – Higher Success In Harvesting Conservation Potential – Effective Capacity

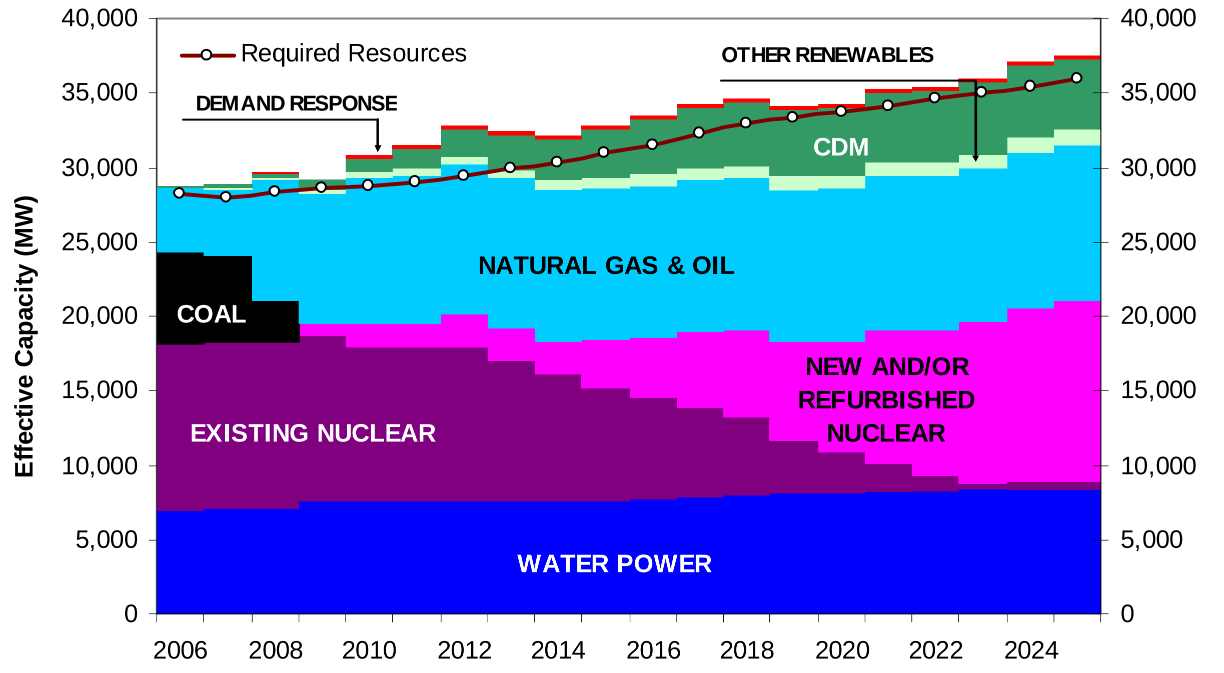
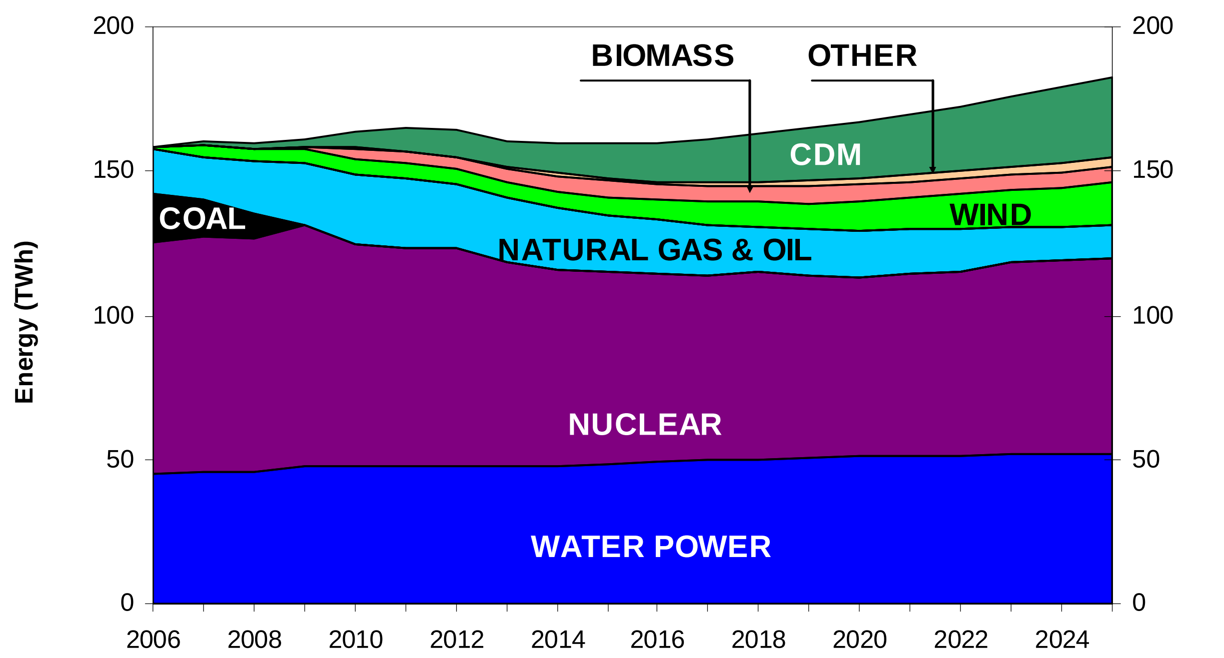


Figure 1.2.20: Scenario 5B – Higher Success In Harvesting Conservation Potential – Energy Production



Source: OPA

High Demand Scenario:

This scenario considered higher than expected growth in demand. This analysis quantifies the larger amount of resources required under such scenarios. The details are in Volume 2.

Delayed Coal Replacement Scenario:

This scenario explored the consequences of an unavoidable extension of the coal-fired generation replacement schedule. The results, in Volume 2, analyze how the portfolio can adjust in such an unavoidable delay.

Low Renewables Scenario:

This scenario looked at the possibility of lower-than-expected supply from renewables, no hydro imports, less cogeneration. The results, in Volume 2, quantify the larger requirements of either natural gas or nuclear to fill the shortfall and analyze the consequences of both strategies.

1.2.9 Recommended Supply Mix

This section provides specific response to the Minister's request for supply mix recommendations in the areas of conservation, renewables and additional supply. The recommendations are based on the basis of 0.9% per year load growth for energy production and 1.3% per year for installed capacity.

With Respect to Conservation:

The first requested recommendation is for conservation targets for the long term. OPA is not in a position to recommend long-term conservation targets at this time. The Chief Electricity Conservation Officer will address targets at a future date. In the meantime, the current target set by government for 2007 is sufficient to mobilize efforts and focus until further targets are set.

Recommendations on Conservation and Demand Management (CDM):

All economic conservation potential should be pursued as a matter of priority. For supply planning purposes, include 500 MW for smart metering, 260 MW for CDM and/or demand reductions, and 1,050-1,500 MW of efficiency improvement, with the range from energy efficiency showing the potential on an average day versus an extreme weather day. A total of 1,810 MW of CDM is therefore a prudent planning assumption for supply planning purposes by 2025. This is in addition to currently set targets and procurement initiatives under way.

With Respect to New Renewables:

The second requested recommendation is for additions of new renewable energy capacity. OPA recommends 3,000 MW by 2015, 5,000 MW by 2020, and 6,700 MW by 2025. These are in addition to currently set targets and procurements under way. In this respect, OPA makes the following recommendations.

Recommendation on Wind Power:

Ontario's future supply mix should include up to 5,000 MW of wind-powered generation by 2025, with 3,600 MW in addition to procurements already under way. This will be about 15% of Ontario's supply mix.

Recommendation on Waterpower:

Ontario's future supply mix should include up to 1,500 MW of additional waterpower resources by 2025, that is with 1,350 MW in addition to procurements under way. This includes the potential for pumped storage if it is economic to develop.

Recommendation on Hydro Imports:

For planning purposes, scenarios can consider up to 1,250 MW of hydro imports in the supply mix. This figure does not correspond to any of the projects discussed and is a rough estimate only, taking into account both the considerable potential and the considerable uncertainties involved.

Recommendation on Biomass:

Ontario's electricity supply mix should include up to 500 MW of biomass-powered generation, with 470 MW in addition to current procurements. Collection of methane from municipal landfills and wastewater plants and gasification of municipal solid waste should be considered as a component of this biomass planning assumption.

Recommendation on Solar Photovoltaic:

For planning purposes, up to 40 MW of solar-powered generation should be included in Ontario's electricity supply mix.

With Respect to Supply Sources for Remaining Demand:

The third requested recommendation is for the appropriate mix of electricity supply resources to satisfy the remaining expected demand in Ontario. In this respect, OPA makes the following recommendations.

Recommendation on Nuclear Power:

Ontario will require significant additions of nuclear power generation. Nuclear generation by 2025 should amount to between 12,900 MW and 15,900 MW. Of this capacity, there is already 3,500 MW that will be in place in 2025 made up of either what is already refurbished (Pickering A) or what is being refurbished (Bruce A). Ontario will therefore need between 9,400 to 12,400 MW of nuclear to be added by 2025. This should be achieved through at least the refurbishments of currently operating units, where it is economic, or replacement where it is not economic. Additional new capacity, beyond replacement, will also be required in certain scenarios.

Recommendation on Natural Gas:

Ontario's supply mix should not include significantly more natural gas-fired generation than has already been contemplated by recent procurement directives. While natural gas prices are expected to decline from their current all time high levels, we still recommend that any further additions should be part of a "smart gas" strategy that stresses the advantages of natural gas and limits the unnecessary exposure to price and supply risk. In addition to the current procurements, the portfolio should include up to 1,500 MW of natural gas. This may be 500 MW of fuel cells or other distributed generation and 1,000 MW of generation for relief of transmission bottlenecks.

Recommendation on Gasification:

The coal-handling facilities at existing coal-fired plants should remain in place after the replacement of coal-fired generation, in case gasification becomes economically and environmentally feasible in future. The recommendations include 250 MW of gasification towards the end of the planning period as we expect technologies acceptable to Ontario may become feasible.

Recommendation on Coal-fired Generation:

Schedule risks in the replacement of coal-fired generation should continue to be monitored closely. If required, alternatives should be developed to ensure the success of the coal replacement policy. The replacement should be completed in the context of the government's stated position that reliability is the "first principle" of the replacement plan.

Table 1.2.9 provides a summary of the supply resource recommendations. Tables 1.2.15 and 1.2.16, in Appendix 2 (this section), provide a listing of all the procurements and the recommendations beyond procurements.

Summary of Recommendations

Table 1.2.9: In Summary, Installed Capacity (MW)

	Existing Facilities Remaining in Service by 2025	Procurement Initiatives	Recommend-ation Beyond Procurement	Total Additions to 2025	Recommend-ation (Total, Existing and Additions)
CDM	0	460	1,350 – 3,850	1,810 – 4,300	1,810 – 4,300
Renewables	7,810	1,570	6,720	Up to 8,300	Up to 16,100
Nuclear	515	3,000	9,400 - 12,400	12,400 - 15,400	12,900 – 15,900
Natural Gas	5,000	6,000	750 – 1,500	Up to - 7,500	Up to 12,500
Gasification	0	0	250	250	250

Source: OPA

A Robust Portfolio

The analysis of the five scenarios, and sensitivities around them, confirmed the merits of a diversified portfolio of nuclear generation for base load, natural gas-fired generation for peaking, and renewables for energy production. This analysis suggested, at a minimum, keeping nuclear capacity at its current level through refurbishments and “new-build” nuclear, and adopting a “smart gas” strategy that takes advantage of the attractive features of natural gas without unnecessarily increasing exposure to price and supply risks. Adding renewables to the extent that is economically achievable reduces the environmental impact and risk.

The portfolio that can respond to any of these scenarios and take advantage of future developments is outlined in Table 1.2.10. A representative estimate of the cost of capital expenditures over the 20 years of the plan is $70 billion, made up of the cost elements in the same table.

Table 1.2.10: A Robust Portfolio for Meeting a Range of Scenarios

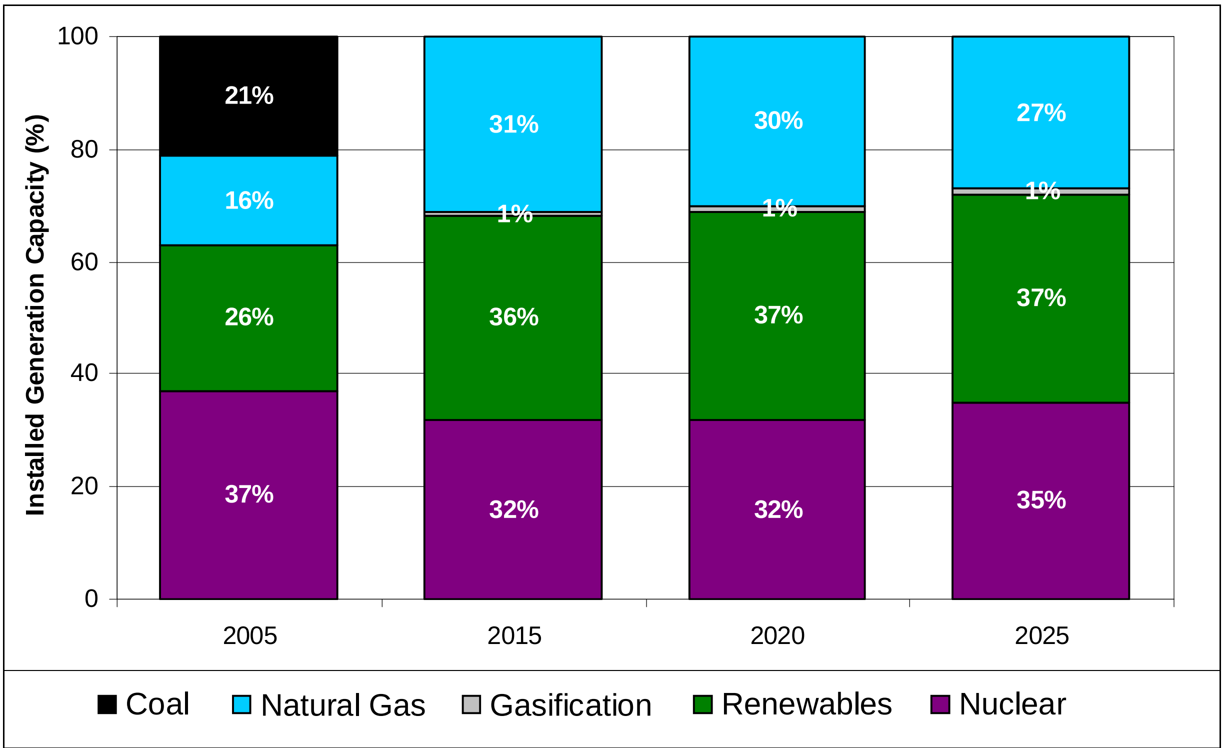
Resource	Installed Capacity (MW)	Capital Costs (as spent $Billions)
Conservation	1,800 to 4,300	5 – 11
Renewables	13,900 to 16,100	14 – 22
Natural gas-fired generation	10,200 to 12,500	7 – 10
Nuclear power	12,900 to 15,900	30 – 40

Source: OPA

The $70 billion capital expenditure averages $3.5 billion per year over the twenty-year period. To provide some context, the total of all electricity bills in Ontario is $12 billion per year. In addition to the capital costs in Table 1.2.10, there are significant operating, fuel and maintenance costs. A detailed analysis of costs is in Volume 2.

Recommended Supply Mix Outcomes in 2015, 2020, and 2025

Figure 1.2.21: Supply Mix Recommendations – Installed Generation Capacity

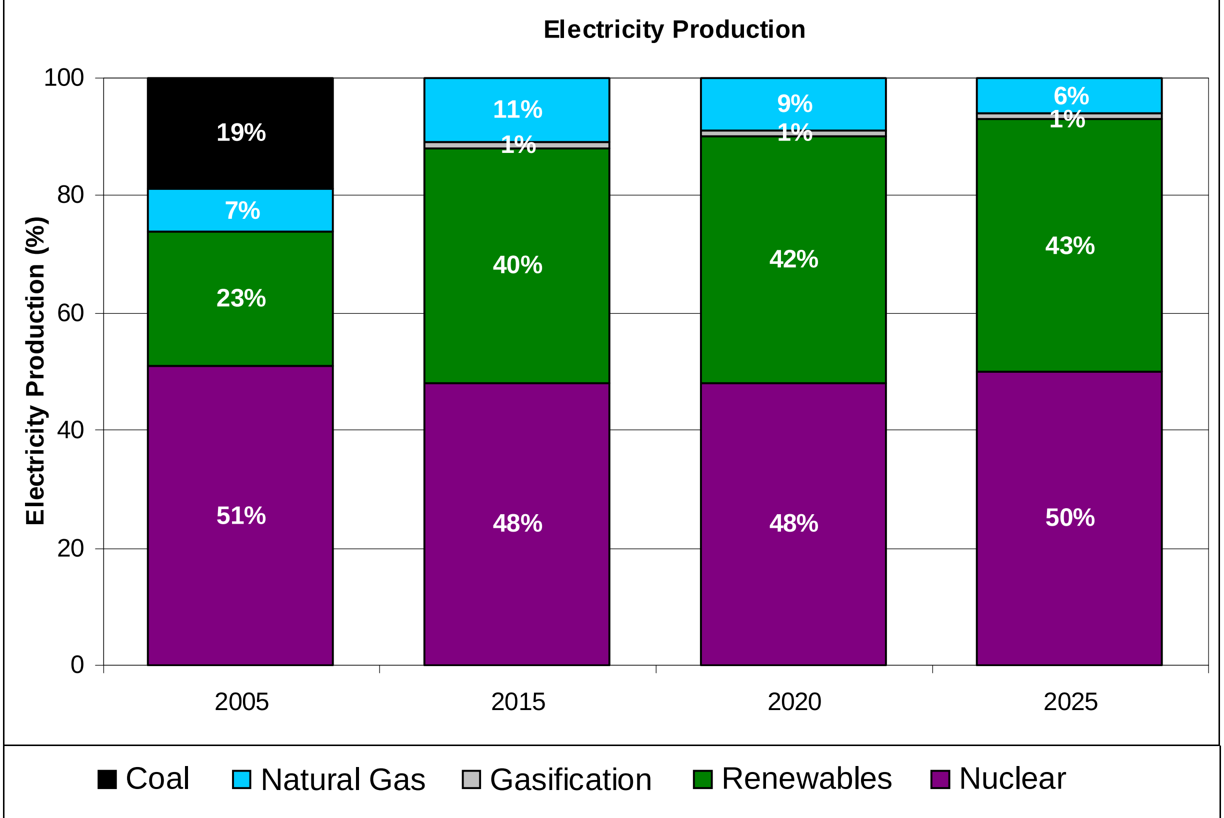


(%)	2005	2015	2020	2025
Nuclear	37	32	32	35
Renewables	26	36	37	37
Gasification	0	1	1	1
Gas	16	31	30	27
Coal	21	0	0	0

(MW)	2005	2015	2020	2025
Nuclear	11,397	11,000	12,000	15,000
Renewables	7,855	12,000	14,000	15,500
Gasification	0	125	250	250
Gas	4,976	10,500	11,000	11,000
Coal	6,434	0	0	0
Total	30,662	33,625	37,250	41,750

Source: OPA

Figure 1.2.22: Supply Mix Recommendations – Electricity Production



(%)	2005 (Estimate)	2015	2020	2025
Nuclear	51	48	48	50
Renewables	23	40	42	43
Gasification	0	1	1	1
Gas	7	11	9	6
Coal	19	0	0	0

(TWh)	2005 (Estimate)	2015	2020	2025
Nuclear	79	76	81	89
Renewables	36	64	71	77
Gasification	0	2	2	2
Gas	11	17	15	11
Coal	29	0	0	0
Total	155	159	169	179

Source: OPA

The average contribution of each option was calculated by averaging the three scenarios that were examined – the planning assumption scenario, low renewables and delayed coal replacement. See Tables 1.2.11 through 1.2.14 in Appendix 2 (this section) for the details. Additional explanation of this calculation is in Part 2.8 of Volume 2 of this report.

Results Delivered from Supply Mix Recommendations

Based on the above recommendations, the resulting contribution of renewables, natural gas, nuclear and gasification to the supply of electricity in Ontario to 2025 is illustrated in Figures 1.2.21 and 1.2.22. By adopting the above recommendations, the Minister of Energy would be in a position to set Ontario on a course to:

- Maximize conservation and demand management and their potential in the future
- Pursue as aggressive a course for renewables as is possible within current constraints, while looking at ways to reduce these constraints
- Implement base load options that need a long lead time, such as nuclear, hydro imports and gasification.
- Replace the current coal-fired generation in ways that manage the risks effectively.

Supply Mix Action Plan to Ensure Future Reliability and Flexibility

The following form the top ten elements of a prudent "action plan" for meeting Ontario's electricity capacity needs while managing environmental, economic and social risks.

1. Be ready to adapt for different possible futures, such as up to 1.8% annual growth in demand for energy production and capacity, while recognizing that the actual outcome is likely to be lower, close to 0.9% annual growth in demand.

    - Recognize that growth is uneven across Ontario, with growth in some parts of the GTA more than double the provincial average.

2. Move immediately to capture conservation opportunities and build the capability to better assess conservation and demand management potential.

3. Acquire up to 5,000 MW of wind generation, especially for winter needs, and up to 1,500 MW of waterpower over the planning period. This would include facilitating small waterpower developments that are available, along with extensions and upgrades to existing sites and exploring pumped storage feasibility.

    - Take into account system integration and transmission connection considerations to incorporate wind and waterpower and investigate how they can be collected together in an optimal way.

4. Seek to achieve full biomass and waste potential to generate electricity (estimated to be up

to 500 MW), and full solar photovoltaics potential (up to 40 MW).

- Accelerate development of gas from landfill, wastewater and forest and agricultural waste in the short term.
- Assess barriers to the wider use of farm and forest waste and municipal solid waste to generate electricity.

5. Continue to monitor closely risks to the coal replacement schedule as it progresses and develop alternatives if circumstances change.

- Keep the existing coal-fired generation infrastructure – at a minimum, the coal-handling facilities – until coal replacement is complete and the potential future use of coal gasification is more certain.

6. Adopt a "smart gas" strategy by using gas only in high-efficiency applications or applications where avoided costs are particularly high; these will include combined heat and power (CHP), cogeneration, peaking, relieving transmission constraints, and fuel cells, or other distributed generation.

   - Do not use natural gas for base-load generation, since this use results in higher exposure to natural gas price risks.
   - Recognize that natural gas will be more available for power generation in the summer, and will complement the operating characteristics of wind power.

7. Pursue hydro imports by continuing talks with neighbours for potential firm purchases, explore imports that can be scheduled and can meet intermediate load requirements. Assess transmission needs and the required associated permitting/approvals process.

8. Investigate the potential to refurbish existing nuclear units. Begin this immediately because the scope is complex and requires extensive planning and coordinating.

   - Coordinate other resource availability to ensure adequate supply during the periods of nuclear refurbishment.

9. Initiate approvals and permitting for new nuclear of up to 3,000 MW in addition to replacing the current fleet for a total capacity of up to 15,900 MW by 2025. This additional capacity will be needed if other options do not materialize or if load growth is higher than 0.9% a year.

   - Define a process that enables new nuclear development as early as possible, with scope to include proponent, site, technology and environmental assessment.

10. There is one further element to consider in making this proposed plan a reality: the need to develop transmission integration policies and plans, particularly as they relate to facilitating coal replacement, integration of renewables, and access to neighbouring markets. This is not strictly an element of supply mix, and so will be dealt with in more detail in the Integrated Power System Plan. Given the urgency of the needs, however, we recommend immediate initiatives to streamline approvals to ensure that necessary electricity system infrastructure can be developed with greater certainty than is possible at present.

Conclusion

In summary, we believe the recommendations and action plan, together, outline the critical path that will ensure a reliable electricity future that can also meet the Ontario Government's policy objectives for conservation, renewables and coal replacement.

1.2.10 Appendix 1: Remainder of the Supply Mix Volumes

Volume 1: Remainder of the Advice and Recommendation Report

- Compendium of Recommendations from Supply Mix and Annual Report of the OPA's Chief Energy Conservation Officer
- Compendium of Advice for OPA Supply Mix and Other Consultations
- Report Contributors
- Table of Contents and Figures for Remaining Volumes
- Glossary of Terms

Volume 2: Analysis Report

The purpose of this volume is to provide additional context and more details about how OPA conducted its analysis. The volume:

- Describes in more detail what the OPA was asked to do by the Minister
- Describes the societal context within which power system planning is taking place
- Summarizes what we heard from stakeholders
- Describes how other jurisdictions are approaching integrated planning
- Explains what criteria we used for developing and evaluating options and scenarios
- Provides more details on the analytical methodology we adopted
- Consolidates the relevant information on supply options that were considered
- Goes through the analysis of portfolios and scenarios and the results
- Provides conclusions with observations and insights gleaned from the analysis

Volume 3: Supporting Documents

The purpose of this volume is to share with stakeholders the background research that we conducted in areas that are critical to the task, as well as some basic information for those who are less familiar with this sector. These include:

- The evolution of power system planning in Ontario
- The applicability and relevance of sustainability principles to power system planning
- The state of Ontario's power system today and the basics on how it works
- The concepts of conservation and demand side management
- The concepts for dealing with uncertainties and risk analysis
- An analysis of the potential for additional hydroelectric power in Ontario
- A review of the provisions for managing nuclear spent fuel and decommissioning costs
- A status of gasification technology

- A review of the natural gas supply and price context

Volume 4: Consulting Reports

- Modelling and portfolio screening – Navigant Consulting
- Conservation and demand management – ICF Consulting
- Supply option technologies and resources – Canadian Energy Research Institute (CERI)
- Environmental impact assessment – SENES Consultants
- Stakeholdering – Decision Partners
- Wind resources – Helimax Energy

Volume 5: Supply Mix Submissions and Presentations (web only)

- Submissions
- Presentations

1.2.11 Appendix 2: Detailed Supply Mix Numbers

Table 1.2.11: Mixes Resulting From Three Scenarios in 2025

	Installed Capacity (MW), Range of Three Scenarios	% of Installed Capacity	Average of Installed Capacity (%)	Energy (TWh), Range of Three Scenarios	% of Energy	Average Energy (%)	Effective Capacity for Meeting Summer Peak (MW), Range of Three Scenarios	Effective Capacity for Meeting Summer Peak (%)	Average % of Effective Capacity for Meeting Summer Peak
Renewables	13,900 - 16,100	34% - 39%	37%	69 - 83	39% - 47%	43%	8,600 - 10,700	25% - 31%	28%
Nuclear	12,900 - 15,900	31% - 38%	35%	80 - 102	45% - 57%	51%	12,600 - 15,600	36% - 45%	41%
Gas	10,200 - 12,500	24% - 30%	27%	6 - 14	4% - 8%	6%	9,300 - 11,400	27% - 33%	30%
Gasification	250	1%	1%	0.5	1%	1%	240	1%	1%
Coal	0	0%	0%	0	0%	0%	0	0%	0%

Source: OPA

Table 1.2.12: Mixes Resulting From Three Scenarios in 2020

	Installed Capacity (MW), Range of Three Scenarios	% of Installed Capacity	Average of Installed Capacity (%)	Energy (TWh), Range of Three Scenarios	% of Energy	Average Energy (%)	Effective Capacity for Meeting Summer Peak (MW), Range of Three Scenarios	Effective Capacity for Meeting Summer Peak (%)	Average % of Effective Capacity for Meeting Summer Peak
Renewables	12,600 - 14,600	34% - 40%	37%	63 - 77	38% - 46%	42%	8,400 - 10,500	26% - 33%	30%
Nuclear	10,300 - 13,300	28% - 36%	32%	70 - 92	42% - 55%	48%	10,100 - 13,00	32% - 41%	37%
Gas	10,200 - 12,300	27% - 33%	30%	12 - 20	7% - 12%	10%	9,300 - 11,300	29% - 35%	32%
Gasification	250	1%	1%	0.7 - 0.8	1%	1%	240	1%	1%
Coal	0	0%	0%	0	0%	0%	0	0%	0%

Source: OPA

Table 1.2.13: Mixes Resulting From Three Scenarios in 2015

	Installed Capacity (MW), Range of Three Scenarios	% of Installed Capacity	Average of Installed Capacity (%)	Energy (TWh), Range of Three Scenarios	% of Energy	Average Energy (%)	Effective Capacity for Meeting Summer Peak (MW), Range of Three Scenarios	Effective Capacity for Meeting Summer Peak (%)	Average % of Effective Capacity for Meeting Summer Peak
Renewables	11,200 - 12,800	33% - 38%	36%	59 - 69	37% - 43%	40%	8,200 - 10,000	28% - 33%	31%
Nuclear	11,000	32% - 33%	32%	70 - 83	44% - 52%	48%	10,800	35% - 37%	36%
`Gas	10,100 - 11,100	29% - 33%	31%	16 - 20	10% - 13%	12%	9,200 - 10,100	30% - 34%	32%
Gasification	0 - 250	0% - 1%	1%	0 - 0.8	1%	1%	0 - 240	0% - 1%	1%
Coal	0	0%	0%	0%	0%	0%	0	0%	0%

Source: OPA

Table 1.2.14: Mixes Resulting From Three Scenarios in 2010

	Installed Capacity (MW), Range of Three Scenarios	% of Installed Capacity	Average of Installed Capacity (%)	Energy (TWh), Range of Three Scenarios	% of Energy	Average Energy (%)	Effective Capacity for Meeting Summer Peak (MW), Range of Three Scenarios	Effective Capacity for Meeting Summer Peak (%)	Average % of Effective Capacity for Meeting Summer Peak
Renewables	10,700	31% - 33%	32%	56 - 57	37%	37%	8,000	26% - 28%	27%
Nuclear	12,100	35% - 37%	36%	74 - 79	48% - 51%	49%	11,900	38% - 41%	39%
Gas	8,200 - 10,800	23% - 32%	27%	18 - 24	12% - 15%	13%	7,300 - 9,800	24% - 33%	28%
Gasification	0	0%	0%	0	0%	0%	0	0%	0%
Coal	0 - 3,900	0% - 11%	5%	0 - 2	0% - 1%	1%	0 - 3,700	0% - 12%	6%

Source: OPA

Table 1.2.15: RFP Procurements

Procurement	Nominal MW
Clean Energy Supply (CES) RFP: (Greenfield Energy Centre, St. Clair Power, Greenfield South, GTAA, Loblaw Properties)	1,992
Renewable Energy Supply (RES) I	395
RES II	975
RES III	200
West GTA	1,000
Downtown Toronto	600
Cogeneration	1,000
Conservation and Demand Management (CDM) and Demand Reduction	250
Thunder Bay Replacement	310
York Region	200
Goreway Station	894
Bruce Units 1 – 2 (Bruce Units 3 - 4 will add another 1,500MW beyond 2010)	1,500
Low Income & Social Housing CDM	100
Lighting/Appliance CDM	100
Total (rounded up)	9,520

Source: OPA, Ministry of Energy, IESO

Table 1.2.16: Procurements and Recommendations Beyond Procurements as Installed MW

Resource	Procurement Under Way	Recommendation Beyond Procurement	Total Additions to 2025
CDM	460	1,350	1,810
Wind Power	1,391	3,609	5,000
Waterpower	151	1,349	1,500
Biomass	28	472	500
Photovoltaic	0	40	40
Hydro Imports	0	1,250	1,250
Nuclear Power	3,000	9,400 – 12,400	12,400 – 15,400
Natural Gas	5,986	750 – 1,300	6,736 – 7,286
Fuel Cells	0	500	500
Gasification	0	250	250
Total	10,556		

Source: OPA; * The total is not the sum of all the components above it because not all the options will be required at the same time.

This page intentionally left blank