

**OPTIONS FOR COAL-FIRED POWER PLANTS IN ONTARIO**

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## **1.0 INTRODUCTION**

The Ontario Government has announced its intention to phase out the burning of coal for electricity production in Ontario by 2007 because of the resulting air pollution [1]. Coal-fired power plants, with an installed capacity of 7578 MW, supplied 36.2 TWh of electricity in 2003 [2], about 23% of Ontario's electricity [1]. Therefore, the expressed intention of the Government presents a major challenge - to avoid an electricity supply shortfall caused by taking the coal-fired power plants out of service. The challenge includes not only the replacement of the coal-fired plants but the accommodation of the forecast increase in electricity demand in Ontario of almost 9%, on a median-growth basis, from 155.1 TWh in 2003 to 168.9 TWh in 2014 and a growth in peak demand, the key to capacity needs, of about 10%, from about 24,100 MW to about 26,600 MW, over the same period [3]. The purpose of this paper is to consider options to meet this challenge. It is well beyond the scope of this paper to undertake an economic analysis of these options, but the need to take into account cost-benefit assessments in evaluating options is emphasized.

## **2.0 COAL-FIRED POWER PLANTS IN ONTARIO**

### **2.1 Ontario Power Plants and Air Pollution**

There are five coal-fired power plants in Ontario, as shown in Table 1, which gives data for 2003 [2], all operated by Ontario Power Generation (OPG). These plants are significant contributors to air pollution in Ontario, as discussed below in section 2.2. OPG also operates a large fossil-fuel plant, Lennox, which uses both oil and natural gas to generate electricity. As shown in Table 1, this plant typically generates only about 7% of the total OPG fossil fuel plant electricity generated in Ontario [2, 4], so that its contribution to air pollution is relatively minor, especially when burning natural gas which is used for about 70% of its generation. Electricity generated in nuclear (40% in 2003 [1]) and hydro (22% in 2003 [1]) plants in Ontario produces essentially no air pollution. A small percentage of electricity in Ontario is generated by Independent Power Producers (IPP) and by certain industries using natural-gas fired plants, small hydro plants and waste-fired (e.g., pulp waste) plants [4], making a minor contribution to air pollution in the province.

The annual capacity factors (ACF) for 2003 for the coal-fired plants given in Table 1 indicate that these plants are used mainly for intermediate-load service<sup>1</sup>. Nevertheless, some of these plants, particularly Nanticoke and Lambton, have been used in recent years partly in base-load service to compensate for the loss of base-load capacity resulting from the lay-up for refurbishment of the Pickering-A and Bruce-A nuclear units [4]. With the return to service of Bruce units 3 and 4 and Pickering unit 4 in 2003 and the recently announced intention of OPG to refurbish and return to service Pickering unit 1, as recommended by the OPG Review Committee [5], the need for the coal-plants to act as base-load plants will be reduced, thus reducing emissions of air pollutants.

The Lakeview plant, scheduled for shutdown in 2005, now plays an important role because of its proximity to Toronto by supporting system reliability and providing reactive support to maintain local voltages [4]. The Thunder Bay and Atikokan plants provide local generation in Northern Ontario for voltage support and transmission security [4]. See reference [6] for a discussion of the need to maintain voltage support in transmission systems.

TABLE 1  
ONTARIO POWER GENERATION FOSSIL FUEL POWER PLANTS

Data for 2003 [2] ACF: Annual Capacity Factor, %

Station	Fuel	No. of Units	Capacity, MW	Energy, TWh	ACF, 2003	Dates In Service	Original Retirement Date
Nanticoke	Coal	8	3938	20.4	59.1	1973/1978	2015
Lambton	Coal	4	1975	10.6	61.2	1969/1970	2010-2020
Lakeview	Coal	4	1140	2.8	28.0	1962/1969	2005
Thunder Bay	Coal	2	310	1.5	55.2	1981/1982	2021
Atikokan	Coal	1	215	0.9	47.8	1985	2025
TOTAL	Coal	19	7578	36.2	54.3		
Lennox	Oil/Gas	4	2140	2.8	14.9	1976/1977	2016

## 2.2 Emissions of Air Pollutants

The key air pollutants in Ontario are nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), fine (respirable) particulate matter, PM, volatile organic compounds (VOC), carbon monoxide and mercury [7, 8]. Both NO<sub>x</sub> and VOC lead to the formation of ozone, one major component of smog, while particulate matter is the other major component. Smog and SO<sub>2</sub> can irritate the lungs and lower one's resistance to respiratory infection as well as aggravating cardio-vascular

<sup>1</sup> Base Load: capacity required to meet relatively constant demand, i.e. the minimum demand on a utility. Peak Load: capacity required to meet intermittent high demands. Intermediate Load: capacity required above base but below peak demands, e.g., capacity needed during the day, but not at night, or during the week, but not on weekends.

disease. Mercury can cause cancer and reproductive and developmental effects; the main concern with mercury is that it can accumulate in the food chain, causing exposures significantly higher than those directly from the air [8]. The main source of carbon monoxide, which is fatal in high concentrations, is incomplete combustion in vehicles and other transportation sources [8].

The Ontario Medical Association (OMA) has estimated that approximately 1,900 premature deaths in the year 2000 may be attributed to the effects of air pollution in Ontario. Also, the OMA has estimated that, annually, about 9,800 people are admitted to hospital and some 13,000 people make emergency room visits due to the effects of air pollution in Ontario [7].

In addition to negative health effects,  $\text{NO}_x$  and  $\text{SO}_2$  cause acid rain which can damage lakes, vegetation and structures [8].

Of the total production of the most significant of these air pollutants in Ontario in 2000, OPG fossil-fuel power plants produced about 14.7% of the  $\text{NO}_x$ , 23.7 % of the  $\text{SO}_2$ , 22.6% of the mercury and essentially none of the VOC and carbon monoxide [8]. (Information on the percentage of fine particulate matter produced from fossil-fuel power plants in Ontario is not provided in reference 8) Thus, phasing out of the coal-fired power plants will certainly not eliminate these air pollutants in Ontario, particularly since about 50% of air pollution in Ontario comes from sources in the US mid-west, including coal-fired plants which contribute a much larger percentage of electricity in that region than coal-fired plants do in Ontario [7, 8]. This fact should be taken into account in examining options for the coal-fired plants in Ontario.

The issue of the emission of  $\text{CO}_2$ , a greenhouse gas, from the coal-fired plants is not addressed in this paper, since  $\text{CO}_2$ , as a natural constituent of the atmosphere, does not contribute to the negative health effects of the emissions which are the primary cause of the decision to shutdown the coal-fired plants.

### **2.3 Possible Options to Reduce Air Pollution from Coal-Fired Plants**

As pointed out in section 1.0, simply shutting down the coal-fired plants in Ontario by 2007 to reduce air pollution without taking any other action is not really an acceptable option. Nevertheless, there are a number of options that could reduce air pollution from coal-fired power plants in Ontario. These options comprise:

- Improve emission controls in the coal-fired plants,
- Convert the coal-fired plants to burn natural gas or build new gas-fired plants to replace the coal-fired plants,
- Replace at least some of the coal-fired generation by new renewable (alternative) energy sources,
- Reduce need for the coal-fired plants by greater importation of electricity,

- Replace the coal-fired plants by nuclear plants.

It should be recognized that the Manley Report [5], suggested that the Ontario government should consider improving emission controls on some of the coal-fired plants and converting others to gas firing as options to shutting them down. However, the Report did not make a recommendation to this effect.

Conservation, including the use of more efficient electrical systems and appliances, the adoption of time-of-use metering [3] and what is more properly termed improvement in the effectiveness of energy use [9], can delay the need for adding additional capacity by reducing the growth of electricity demand with any of these options. However, the 10-year forecast by the Independent Electricity Market Operator (IMO) already takes into account the effects of projected conservation, based on recent and proposed actions, on the growth rate of electricity demand in Ontario [3]. Thus, conservation alone is not really a separate option for reduction of air pollution from coal-fired plants in Ontario, although it will assist all of the options by reducing demand to some extent. See section 4.0 for a discussion of an initiative of the Ontario Ministry of Energy in this area.

In assessing these options, their costs of implementation and other factors should be taken into account as well as their benefits in the reduction of adverse health effects. An effective approach for doing so is the application of the ALARA and “De Minimis” principles as applied in the regulation of nuclear activities in Canada and elsewhere [10, 11]. The ALARA (As Low as Reasonably Achievable) principle means that economic and social factors are to be taken into account in setting limits for risk or exposure to adverse health effects on a societal basis, while ensuring that individuals are protected by specific legal requirements. The “De Minimis” principle states that risks of an activity need not be reduced below a level that is generally accepted as being of no significance to an individual or to a society. That is, risks need not be reduced below a level at which efforts to control the sources of risks would constitute an undue expenditure of societal resources for an insignificant benefit in health protection.

The following sections discuss the above-listed options and draw certain conclusions.

### **3.0 IMPROVEMENT OF EMISSION CONTROLS AT COAL-FIRED POWER PLANTS**

Emissions of air pollutants from coal-fired power plants can be significantly reduced by the application of emission control devices and procedures.

Emissions of NO<sub>x</sub> can be reduced by:

- improved combustion processes (low NO<sub>x</sub> burners, fluidized-bed combustion) that lower combustion temperatures to minimize NO<sub>x</sub> formation [12],

- computer controls of the combustion process (CCC) to minimize NO<sub>x</sub> formation,
- the application of Selective Catalytic Reducers (SCR) to remove NO<sub>x</sub> from flue gases,

Emissions of SO<sub>2</sub> can be reduced by:

- burning low-sulfur coal to reduce SO<sub>2</sub> formation,
- the application of Flue Gas Desulfurizers (FGD) using wet limestone scrubbing to remove SO<sub>2</sub> from flue gases [12],
- fluidized-bed combustion using limestone injection to remove SO<sub>2</sub> during combustion [12].

Emissions of particulate matter can be reduced by:

- burning low-ash coal to reduce PM formation,
- the application of Electrostatic Precipitators to remove PM from flue gases [12],
- the application of bag-house filters to remove PM from flue gases.

There is no technology currently in place for the removal of mercury from power plant emissions, although bag-house filters apparently can do so to some extent, as well as removing particulate matter [13]. However, it should be noted that a recent study has shown that mercury in soils in the USA (and its subsequent accumulation in the food chain) cannot be attributed to deposition from air of mercury emissions from fossil fuel plants and other human activities [14], so that the need to remove mercury from power plant emissions may not be as urgent as currently believed.

At one time, particularly in the UK, tall stacks at fossil-fuel power plants were considered an adequate means of controlling human exposure to air pollutants from these plants. However tall stacks obviously do not reduce air-pollutant emissions but simply reduce ground-level concentrations by dispersing the pollutants widely [12].

Emission control devices installed and procedures used at the OPG coal-fired plants are listed in Table 2. Electrostatic precipitators and low-sulfur coal are in use in all of the units at all five OPG coal-fired power plants and computer combustion controls and low NO<sub>x</sub> burners are in use in all of the units at the three large plants. Flue gas desulfurizers are installed in only two units at the Lambton plant and selective catalytic reducers, which have just come into operation this summer, are installed in only two of the eight units at the Nanticoke and Lambton plants.

TABLE 2

EMISSION CONTROL DEVICES AND PROCEDURES AT OPG COAL-FIRED PLANTS

Information from References 2, 4, 13, 15

Plant & Total Units	Elect. Precip.	Low S Coal	CCC	Low NO <sub>x</sub> Burners	FGD	SCR
Nanticoke/8	8 units	8 units	8 units	8 units	None	2 units
Lambton/4	4 units	4 units	4 units	4 units	2 units	2 units
Lakeview/4	2 units	4 units	4 units	4 units	None	None
Thunder Bay/2	2 units	2 units	None	None	None	None
Atikokan/1	1 unit	1 unit	None	1 unit	None	None

Nevertheless, the use of electrostatic precipitators, low sulfur coal, combustion computer control and low NO<sub>x</sub> burners at the three large coal-fired stations and the use of electrostatic precipitators and low sulfur coal at the two small stations plus low NO<sub>x</sub> burners at Atikokan have reduced emissions from previous levels. Total emissions from these plants have been reduced considerably since the early 1980s with NO<sub>x</sub> emissions being reduced by about 36% from 1983 to 1999 [4] and about a further 23% from 1999 to 2003 [2] and with SO<sub>2</sub> emissions being reduced by about 68% from 1983 to 1999 [4], although increasing somewhat since then [4]. Under 1999 Ontario regulations, OPG must meet annual aggregate caps of 60 Gg of NO<sub>x</sub> emissions and 175 Gg of SO<sub>2</sub> emissions from its fossil-fuel stations, including Lennox and , under additional 2001 regulations, OPG has been limited to 35 Gg of NO<sub>x</sub> and 153.5 Gg of SO<sub>2</sub> emissions in 2002 and 2003 [2].

As indicated in Table 2, further reductions in emissions of NO<sub>x</sub> and SO<sub>2</sub> from OPG's coal-fired stations would be possible by the installation of SCRs and FGDs at those units now without them. For example, the installation of SCRs at the six units without them at Nanticoke would reduce specific NO<sub>x</sub> emissions<sup>2</sup> from 1.50 kg/MWh to 0.37 kg/MWh [13] and the installation of FGDs at all 8 units would reduce specific SO<sub>2</sub> emissions from 4.15 kg/MWh to 0.77 kg/MWh [13]. Assuming an annual capacity factor of 65%, as in reference 13, and assuming that the specific emission coefficients for units with and without SCRs and FGDs for Nanticoke apply also at Lambton, the annual emissions of NO<sub>x</sub> and SO<sub>2</sub> from Nanticoke and Lambton and the total from both stations are shown in Table 3. The installation of FGDs would also help to reduce PM emissions and the installation of baghouse filters would further reduce PM emissions [13].

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<sup>2</sup> Evaluated as NO<sub>2</sub>

TABLE 3

NO<sub>x</sub> AND SO<sub>2</sub> EMISSIONS AT NANTICOKE AND LAMBTON STATIONS

Assumed Annual Capacity Factor = 65%

	NO <sub>x</sub> , Gg/a Current	NO <sub>x</sub> , Gg/a SCRs on all units	SO <sub>2</sub> , Gg/a Current	SO <sub>2</sub> , Gg/a FGDs on all units
Nanticoke	33.6	8.3	93.1	17.3
Lambton	16.9	10.6	37.1	22.9
Total	50.5	18.9	130.2	40.2

Table 3 shows that the application of SCRs and FGDs to all the units at Nanticoke and Lambton would reduce the total emissions of NO<sub>x</sub> and SO<sub>2</sub> to about 19 and 40 Gg per year, which would contribute significantly to ensuring that total OPG emissions would be kept well below the aggregate caps specified by current Ontario regulations.

From the experience of installing the existing SCRs at Nanticoke and Lambton and the existing FGDs at Lambton, it appears that it would be possible to complete the installation of SCRs and FGDs at these stations by the end of 2007, if the commitment to do so were made now.

However, the cost effectiveness of such steps compared to other options must be assessed. For example, the installation of SCRs at two units at Nanticoke and two units at Lambton cost approximately \$262 million [2] and the installation of two FGDs at Lambton in the mid 1990s cost about \$500 million [2], so that the installation of these technologies at the remaining units at Nanticoke and Lambton would involve expenditures of the order of \$3.0 billion. A somewhat lower expenditure estimate, \$2.1 billion, for such an installation results from data provided in reference 13. These rough estimates should be compared to the costs of other options discussed later. In doing so it should be recognized that closing the coal-fired plants in 2007 will result in a write-off of valuable assets, considering the original retirement dates shown in Table 1. OPG has already shown a debit of \$576 million in its 2003 financial statements to account for this loss of assets [2].

#### 4.0 REPLACEMENT OF COAL-FIRED GENERATION BY NATURAL GAS-FIRED GENERATION

##### 4.1 Current Commitments and Plans

OPG is a partner, together with ATCO Power Canada and ATCO Resources, in the Brighton Beach Venture: a 580 MW combined-cycle gas turbine (CCGT) plant burning natural gas, located at the old J.C.Keith power plant site near Windsor, Ontario [1]. Construction began in 2002 and the plant is scheduled to be in service in the summer of 2004, at a projected capital cost of \$403 million, or about \$700/kW, which is now expected to be exceeded [1].

OPG is also a partner, with TransCanada Energy Ltd, in the Portlands Energy Centre Venture, the assessment of the viability of a natural-gas fuelled energy centre in the port area of downtown Toronto. The Centre would comprise a 550 MW combined-cycle gas turbine facility and a co-generation facility which would provide steam for district heating [1]. An Environmental Review report was submitted to the Ministry of Environment in November, 2003 [1].

Assuming that the Portlands Energy Centre materializes, these ventures would provide about 1130 MW of capacity which would be in service before 2007, offsetting about 15% of the coal-fired capacity to be phased out by that date. While this capacity is just about equal to that of the Lakeview plant near Toronto it would not be available next year, when the Lakeview plant is scheduled for shutdown. Nevertheless, the locations of these plants, in Toronto and Windsor, meets an important requirement of the Independent Electricity Market Operator since, with few exceptions, replacement capacity must be located in same general area as the plant being closed, as well as having similar operating characteristics, to avoid system operability and transmission inadequacy problems [3]. See section 4.3 for further discussion of the Lakeview plant.

Finally, a small addition to Ontario capacity is being built by Northlands Power, a 25 MW gas-fired plant near Kirkland Lake [3].

## **4.2 Ontario Ministry of Energy Initiative**

In partial response to the need to find replacements for the coal-fired plants that are to be phased out by 2007, the Ontario Ministry of Energy (OME) has issued a request for qualifications and interests to provide 2500 MW of new “clean” generation capacity or demand reduction measures [16, 17]. Based on responses to this request, a request for proposals (RFP) will be issued by about the end of September, 2004.

To be eligible under this RFP, proposals for new capacity, for either base, intermediate or peak generation, must:

- have a capacity of 5 MW or greater,
- not burn coal or oil as a fuel,
- not be an upgrade or expansion of an existing generating facility,
- be located in Ontario,
- be in commercial operation no later than June 1, 2009.

It is somewhat surprising to note that the date for the start of commercial operation is June 1, 2009. The RFP is implicitly recognizing that the target date for the shut down of the coal plants of the end of 2007 will not be met.

The new capacity may be connected to the IMO grid, to a local distribution network or supply electricity directly to the user. Note that there is no requirement that a proposed new plant must be located in the same general area as one of the plants to be closed, contrary to the preference

of the IMO, as stated above in section 4.1. This requirement is particularly important for the planned closure of the Atikokan and Thunder Bay coal-fired plants, which play important roles in providing generation in the north-western part of Ontario.

While small hydro developments would be eligible under this RFP<sup>3</sup>, it is probable that most proposals would be for natural-gas fired capacity, as implied in reference 17. The RFP document also states that proposed facilities should be suitable for intermediate-load service, as were the coal-fired plants historically, and should be capable of cycling on and off overnight and of ramping to meet load changes. The RFP document also states that proposals for facilities for peaking service are unlikely to be accepted. In addition, a condition of the RFP for a specified heat rate<sup>4</sup> for the proposed facilities of 7500 BTU/kWh (7912 kJ/kWh), or a thermodynamic efficiency of 45.5%, will essentially limit them to combined-cycle gas turbines or CCGTs plus co-generation plants, effectively excluding lower-efficiency plants such as steam plants burning natural gas or simple-cycle gas turbines

Requirements are also specified for proposals for demand reduction measures, including a requirement to be in effect by the end of 2007.

If the objective of this RFP is met, about one-third of the current coal-fired capacity would be replaced by new capacity or demand reduction measures within the period between the end of 2007 and June 1, 2009. Thus, other measures would still be necessary to enable the phase-out of all OPG coal-fired plants by the target dates.

### **4.3 Conversion of Coal-Fired Plants to Natural Gas**

The requirement that a proposed facility under the Ontario Ministry of Energy RFP not be an upgrade or extension of an existing facility appears to rule out consideration of converting the existing coal-fired plants to natural-gas firing. However, such conversions certainly should be considered as a means of ensuring that replacements are in service when the coal-fired capacity is phased out.

It appears that the only really practical means of converting to natural gas fuel would be to modify the furnace of a coal-fired unit to burn natural gas instead of coal to produce steam in its steam generators. While this step would result in relatively low thermodynamic efficiency, about 30%, or a heat rate of about 12,000 kJ/kWh, it would enable most of the components of the coal-fired plant to be retained, with only the scrapping of the coal and ash handling equipment being required, and their replacement by gas burners and any needed modifications to the furnaces. Conversion of the coal-fired plants to simple-cycle or combined-cycle gas turbine plants would involve scrapping most of the existing components at the plants and replacing them with the appropriate components for the gas-turbine cycles. It appears that it

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<sup>3</sup> The Ontario Ministry of Energy has also issued a request for expressions of interest for the provision of 300 MW of renewable energy capacity [16, 17, 18], as discussed in section 5.0 of this paper.

<sup>4</sup> The heat rate is the ratio of energy provided by the fuel to the kilowatt-hour electrical output, expressed in terms of BTU/kWh or kJ/kWh. Accounting for proper units, the heat rate is inversely proportional to the thermodynamic cycle efficiency.

would be more practical to build entirely new gas-turbine plants to replace the existing coal-fired plants rather than converting them..

The Nanticoke Conversion Study of 2001 provides information on the possibility of building of a combined-cycle gas turbine plant to replace the Nanticoke coal-burning plant [13]. The estimated capital cost of a CCGT plant plus gas pipeline connections is about \$814/kW in 2001 Canadian dollars for a total capital cost for the replacement plant of \$3.20 billion. The study also found that the present value of the capital cost of a CCGT for Nanticoke and of operating it to 2030 would be about \$5.3 billion greater than the present value of the current Nanticoke with SCRs, FGDs and baghouse filters installed on every unit and operating the plant to the same year [13].

While conversion of all the present coal-fired capacity to more efficient simple or combined cycle gas turbines may not be very practical, for the reasons given above, the Lakeview plant presents a special case for the simpler conversion to gas firing of its furnaces. As mentioned in section 2.1, the 1140 MW Lakeview plant, scheduled to be closed in 2005, plays an important role in maintaining system reliability and sustaining local voltages by its proximity to Toronto. To enable Lakeview to continue to fulfill these important functions, its conversion to the burning of gas to generate steam for its turbines, at a heat rate of about 12,000 kJ/kWh compared to a typical current heat rate of about 10,800 kJ/kWh [4], might be worth consideration, rather than simply closing it next year<sup>5</sup>.

#### **4.4 Natural Gas Availability and Cost Issues**

Replacement of coal-fired generation by gas-fired generation in Ontario, raises at least two issues of importance: the supply of natural gas for this purpose and the effect of long-term natural gas costs on electricity costs. These issues are discussed in this section of this paper.

##### **4.4.1 Natural Gas Availability**

An upper limit to the increased demand for natural gas in Ontario can be estimated by assuming that all the OPG coal-fired plants would be converted to, or replaced by, gas-fired plants and by making certain additional assumptions. As stated earlier, the coal-fired plants have been and are mainly used for intermediate-load service and it can be assumed that gas-fired plants will also be used for such service, as indicated by the RFP of the OME described in section 4.2. Therefore, assume that the gas-fired plants would operate at an average annual capacity factor of 60%.

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<sup>5</sup> The Independent Electricity Market Operator had directed OPG to retain the option to convert two of the Lakeview units to synchronous condenser operation [3] but this directive was later rescinded. See reference [6] for information on this role.

As discussed in section 4.3, coal-fired plants could be converted to gas-fired plants or the coal-fired plants could be replaced by simple-cycle gas turbines or combined-cycle gas turbines<sup>6</sup>. Typical thermodynamic cycle efficiencies (heat rates) for these plants are:

- Gas-fired steam plants: 30% (HR:12,000 kJ/kWh)
- Simple-cycle gas turbine plants [19]: 30% to 35% (HR: 12,000 to 10,286 kJ/kWh)
- Combined-cycle gas turbine plants[19]: 45% to 50% (HR: 8,000 to 7,200 kJ/kWh)

Choosing an average cycle efficiency of 40%, or a heat rate of 9000 kJ/kWh, with the assumed annual capacity factor of 60%, and based on the thermodynamic properties of methane, the quantity of natural gas required to replace all the OPG coal-fired plants with gas-fired plants would be about  $9.82 \times 10^9$  cubic metres, or 347 billion cubic feet (Bcf), per year. The total primary demand for natural gas in Ontario in recent years has averaged about 986 Bcf/yr [21, 22]. Therefore, to replace all the OPG coal-fired plants with natural gas-fired plants would require an increase of Ontario's primary demand for natural gas by about 35%, all by pipeline from Alberta. TransCanada's Canadian Mainline design capacity to Ontario is now about 1370 Bcf/yr [23] so that an excess capacity of about 384 Bcf/yr exists now. Therefore, converting all of the OPG coal-fired plants to natural gas would require almost all of this excess capacity.

Although complete replacement of the OPG coal-fired plants by gas-fired plants by the target date of 2007 (or even 2009) may not be realistic, partial replacement is certainly possible. The quantities of natural gas required to meet the needs of the cases discussed in section 4.3 can be estimated by making assumptions about annual capacity factor and heat rate appropriate to the particular case. The results are shown in Table 4, together with the above estimate for complete replacement of coal-fired generation by natural gas-fired generation. For the Ontario Ministry of Energy RFP case, it is assumed that 80% the total 2500 MW of new capacity or demand reduction is met by gas-fired projects.

For the committed or planned cases discussed in section 4.3, cases 1 to 4, Table 4 shows that the total additional annual natural gas requirements would be 114.5 Bcf/yr, or about 12.6 % of Ontario's present primary demand. This still represents a significant increase of natural gas demand over the next few years, on top of increasing demands for other uses. Table 4 also shows the additional incremental and total gas supplies needed should the Nanticoke and Lakeview conversions discussed above be implemented so as to ensure that all of the present coal-fired capacity is replaced by natural gas-fired capacity as well as to allow for some growth in intermediate load in the next five years. The resulting total gas requirements would be 339.7 Bcf/yr, or again about 35% of the present Ontario consumption. It is not clear that such an increase in capacity over the next three years, or even five years, could be realistically accommodated in the existing gas transmission system. Considering the forecast increase of demand for natural gas for all purposes in Ontario in the next few years [24], additional

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<sup>6</sup> Cogeneration plants that combine electricity production with the provision of heat for industrial, district heating or other industrial purposes are very effective in their employment of energy [9, 20] and are sometimes credited with high cycle efficiencies (low heat rates) because of this [17]. However, this high efficiency, or low heat rate, does not apply to their electricity generation function and therefore is not relevant for this analysis.

pipeline capacity would be needed much sooner than previously anticipated if the OPG coal-fired plants are to be converted to gas by the end of 2007, the desired date for closing down the coal-fired stations, or even by June 1, 2009, as implied by the OME RFP.

TABLE 4  
NATURAL GAS REQUIREMENTS AND COSTS FOR VARIOUS  
GAS-FIRED GENERATION CASES FOR ONTARIO

Case	Capacity, MW	Assumed ACF, %	Assumed Heat Rate, kJ/kWh	Gas Required Bcf/a	Gas Required % Ontario Present Total	Gas UEC, Cents/kWh	Annual Gas Cost, \$ Billions
Total Capacity	7578	60	9,000	347	35.2	4.95	1.97
1 Brighton Beach	580	60	6,500	19.2	2.0	3.58	0.109
2 Portlands	550	60	6,500	18.2	1.8	3.58	0.103
3 Northlands	25	60	6,500	0.83	0.08	3.58	0.005
4 OME RFP	2000 <sup>7</sup>	60	7,500	76.3	8.7	4.13	0.434
Total, 1 to 4	3155			114.5	12.6		0.651
5 Lakeview Conversion	1140	60	12,000	69.6	7.0	6.60	0.395
6 Nanticoke Conversion to CCGT	3920	65	7,200	155.6 <sup>8</sup>	15.7	3.96	0.884
Total, 1 to 6	8340			339.7	35.3		1.93

In addition to the issue of pipeline constraints to large increases in gas supply in the short term, there is the longer-term issue of adequate gas supply over the lifetime of the gas-fired plants. Although the production rate of natural gas from conventional sources in western Canada is flat at this time, in spite of significant drilling, projections indicate that the availability of natural gas in Canada from all sources, including gas from the Arctic, the east coast and liquefied natural gas imports, will increase in the future [24]. However, there will be increasing

<sup>7</sup> Assuming 80% of OME RFP proposals will be for natural gas-fired plants.

<sup>8</sup> According to The Nanticoke Conversion Study, the gas requirement for the CCGT plant would be 162 PJ/a [13]. For a gas heating value of 1000 BTU/cf [13], this is equivalent to 153.6 Bcf/a, in excellent agreement with the present estimate.

demands for gas exports, for oil-sands recovery and upgrading and other purposes [24], which could jeopardize the reliable supply of gas for electricity generation in Ontario.

#### 4.4.2 Natural Gas Cost

Replacement of coal-fired generation in Ontario by gas-fired generation will increase significantly the unit energy costs of electricity and the total annual fuel costs for these plants. Current natural gas prices in Canada are about \$7/GJ [24, 25] and natural gas prices are expected to average somewhat above \$5/GJ for the next ten years [24]. Assuming an average gas cost of \$5.50/GJ and the heat rates given in Table 4, the current gas unit energy cost (UEC) in cents per kilowatt hour for the cases considered in section 4.4.1 can be calculated and are also given in Table 4. From this value, the total annual current cost of gas for these cases can also be calculated for the given capacities and capacity factors, as also given in Table 4.

Thus, the replacement of coal-fired generation by the committed or planned natural gas fired generation would increase fuel costs for these plants by a factor of about 2.5. Also, it should be noted that the fuel UEC for the committed or planned gas-fired generation, about 3.6 to 4.1 cents/kWh, is a significant fraction of the capped price of electricity for low-volume residential and other designated users in Ontario of 4.7 cents/kWh [26], meaning that this electricity will most probably be sold at a loss, once other operating and maintenance costs as well as capital-costs recovery are taken into account. Considering the increased future demands for natural gas as mentioned in section 4.4.1, there could very well be significant price increases and volatility even with the additional sources of supply. Thus, the costs of electricity from gas-fired power plants in Ontario could be even higher than estimated here

For comparison, assuming a current coal cost in Ontario of about \$46 per tonne [13], assuming a higher heating value of 12,000 Btu/lb (27,900 kJ/kg) for the coal, the present UEC and total annual cost for the OPG coal plants can be calculated to be about 1.49 cents/kWh and about \$0.60 billion, respectively.

## **5.0 REPLACEMENT OF COAL-FIRED GENERATION BY NEW RENEWABLE (ALTERNATIVE) ENERGY SOURCES**

### **5.1 Current Situation**

First of all, the meaning of “renewable energy sources” must be clarified. The Ontario Ministry of Energy RFP effectively excludes large-scale hydro power plants [17], which provided about 37,000 GWh, or about 23%, of electricity in Ontario in 2003 [27]. In any case, there are no remaining large-scale hydro sites in Ontario that can be readily developed economically, although the Ontario Water Power association estimates that a potential of 1200 MW to 4000 MW of hydro capacity could perhaps be added [1]. Only small hydro plants, 100 MW or less, are considered “renewable energy sources” for the present purposes [17]. Thus, a more appropriate term, “alternative energy sources”, is often used.

Nevertheless, a limited expansion of conventional hydro power has been committed in Ontario. The construction of an additional water tunnel at the Adam Beck hydro plant on the Niagara river will add about 200 MW capacity and provide about 1.6 TWh per year of electricity<sup>9</sup> [28]. However, this expansion will take about 4 ½ years to complete and so will not be available by the end of 2007, when the coal-fired plants are to be closed, but should be available by about the same target date as that of the new clean generation called for by the OME RFP [17].

At present, sources classified as renewable energy sources provide only about 1% of Ontario's electricity, 1835 GWh per year, with about 90% of this energy, 1635 GWh/yr, from wood and pulp mill waste and only about 10%, 180 GWh per year, or 0.1% of the total, from wind [27].

As noted in section 4.2, the Ontario Ministry of Energy issued, on April 28, 2004, a request for expressions of interest and qualifications for the provision of 300 MW of renewable energy sources of electricity [16, 17, 18], as a step towards meeting targets of 1350 MW by 2007 and 2700 MW by 2010. Specified as renewable energy sources in this request are wind, solar, water, biomass and landfill gas. The Ministry has received 90 expressions of interest to this request with proposals totalling 4400 MW and has requested that firm proposals be submitted by August 25, 2004 [30].

## **5.2 Inherent Weaknesses of Alternative Energy Sources for Large-Scale Power Generation**

Since this paper deals with options for Ontario's coal-fired plants, we need to understand the role of alternative energy sources for this purpose. This requires a recognition of the characteristics of these sources, in particular, wind and solar, which are often proposed or suggested alternatives to conventional electricity generation. Solar and wind have two inherent weaknesses for large-scale electricity production: low intensity<sup>10</sup> and intermittency<sup>11</sup>. The low intensity requires large areas to collect the energy and intermittency means that the energy is not always available when needed. The intermittency drawback can be overcome to some extent by provision for energy storage when it is feasible, but this provision may increase the area requirements for collection of energy even further. For example, an analysis has shown that the land area required for a solar-thermal electricity plant to replace the Pickering nuclear power plant near Toronto in providing base-load service, i.e., including provision for storage as thermal energy, in a typical December would be over 600 sq.km., about the size of the Toronto metropolitan area, compared to the area of the Pickering plant, 2 sq.km.[31]. The land costs for the solar plant would be astronomical and the use of so much land for a single purpose in a densely populated area would be socially disruptive.

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<sup>9</sup> The lack of economic sites for large-scale hydro development in Ontario is underlined by the results of a study of the feasibility of building a new 600 MW hydro power unit at the Adam Beck site which found that this proposal was uneconomic [28, 29]

<sup>10</sup> Since solar energy generates wind energy by differential heating of the earth's surfaces, the low intensity of wind energy results from the low intensity of solar insolation, about 1 kW/m<sup>2</sup> maximum and about 0.14 kW/m<sup>2</sup> on an average at the earth's surface in Canada [12].

<sup>11</sup> Biomass also has the limitation of low intensity, since its production is governed by solar energy. The intermittency deficiency is overcome by storage of solar energy by photosynthesis in the biomass. However, this process takes considerable time to provide quantities needed for large-scale power production..

While large-scale solar electricity generation has not been seriously proposed for Ontario, wind power already produces about 180 GWh/yr from an installed capacity of 110 MW [27], proposals for additional wind plants have been made and wind plants will probably contribute to the 300 MW of new renewable energy called for by the Ontario Ministry of Energy [30]. The low intensity of wind power results in a requirement for many large wind turbines to generate any significant power. Furthermore, these turbines have to be well-spaced to ensure that wake effects on adjacent turbines do not reduce blade efficiency, and thus power generation, significantly. Based on data from different sources, the power-to-area intensity for wind farms varies from about 2.8 MW/km<sup>2</sup> to about 5.0 MW/km<sup>2</sup> [32, 33, 34]. Therefore, to replace the capacity of the OPG coal plants by wind power plants, assuming an optimistic power intensity of 4 MW/km<sup>2</sup>, would require a total area of about 1,900 sq.km., about three times the size of metropolitan Toronto. The cost and difficulty of assembling adequate wind sites over such an area in southern Ontario would be prohibitive, even though some of the required area would also still be usable for agricultural purposes. In addition, the total electricity produced annually by this capacity would be considerably less than that produced by the coal-fired plants because of the low annual capacity factors of the wind plants. From the above data on the current installed capacity and energy production of wind power plants in Ontario, the annual capacity factor of these plants is 18.7%, compared to about 60% to 65% for the coal-fired plants. An ACF of 18.7% is on the low side of the range of ACFs for existing wind farms, 20% to 30% [35]. Assuming an average ACF of 25%, replacing the coal-fired plants by the same capacity of wind-fired plants would result in the generation of only about 40% of the electricity produced in a year by the coal-fired plants. Furthermore, unlike power from the coal-fired plants, power from the wind plants would not be available on demand to meet varying loads, but would depend on the variability of the wind. Since there is no practical means of storing electricity directly on a large scale, building additional wind plants to overcome this intermittency would not be helpful<sup>12</sup>.

In effect, wind plants cannot really replace the coal-fired plants, since they cannot meet the requirements of intermediate-load service, that is, being available on demand to meet varying loads over a day or other period. Similarly, wind plants cannot be used for base-load to provide continuous power or for peaking plants to provide peak power on demand. Wind generation is only useful for now as displacement energy, being accepted by the grid, when it is available, in preference to energy from conventional plants whose operating costs at that time are greater than those of the wind energy plants .

It is informative to consider why large-scale hydro plants, generating 23% of Ontario's electricity and about 58% of Canada's in 2003 [27], are not constrained by the limitations of low intensity and intermittency that affect solar and wind energy plants, in spite of being themselves renewable energy plants depending ultimately on solar energy through the hydrologic cycle. For a large-scale hydro plant, nature herself makes up for these deficiencies by collecting precipitation over a large area, the drainage area of the river on which the plant is

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<sup>12</sup> Conceptually, wind power plants could be used with indirect storage systems, such as by providing electricity when available for a pumped hydro system or, in the future, for hydrogen production by electrolysis, but the technical and economic feasibility of such applications have not been demonstrated. In any case, they are not available now as options to the OPG coal-fired plants.

located, thus compensating for the low intensity but also smoothing out the intermittency of the precipitation over the drainage area. Nevertheless, nature generally still has to be assisted in compensating for intermittency, by the building of a dam or dams on the river to provide water storage.

A significant practical problem would arise should the fraction of electricity generated by wind in Ontario reach more than a few percent of the total as is the case in Denmark, where wind energy provides about 12% of electricity<sup>13</sup> in a typical year [36]. The management of the stability of the electricity grid with such a fraction of unreliable and randomly varying generation becomes very challenging.. This challenge has been described by a senior Danish utility manager as akin to attempting to manoeuvre a rapidly moving tractor-trailer with no brakes, clutch, accelerator or steering wheel [37]. Meeting this challenge in Denmark is possible mainly because of the strong interconnections between the Danish grid and the Swedish and German grids [37], which can provide reliable nuclear and coal-fired electricity to Denmark, as needed, to compensate for the variability of the winds. While this problem is not likely ever to arise in Ontario, it represents another aspect of the limitations imposed by the intermittency of supply from wind power plants.

Because of the predominance of wind energy amongst alternative energy sources, the rest of this section will deal solely with aspects of wind energy.

### **5.3 The Economics of Wind Energy**

Wind plants, like hydro plants, have very low operating costs because they have no fuelling costs, only labor and maintenance costs. Unit energy costs for the recovery of capital, however, are high because of the large structures, wind turbine-generators and gearing and control components needed as well as the large land requirements. Most large-scale wind turbine-generators today have capacities in the range of about 500 kW to 2 MW, with production beginning on 3 MW units [35, 38]. The 3 MW unit will sit on a 75 metre tower and has turbine blades about 90 metres in diameter [38], so that the tips of the blades are as high as 120 metres above the ground, about the height of a 40 storey building. Smaller units still require tall towers, 50 metres for utility-scale turbines, to ensure exposure to adequate wind speeds, and large-diameter blades, typically 40 to 50 metres [35]. Thus, for a relatively small wind farm of 100 MW capacity, about 34 of the 3 MW units would be required, requiring about 25 sq. km of land. The capital cost, exclusive of land cost, for large-scale wind power plants today is about \$1000/kW (US), or about \$1350/kW (Can.), for land-based plants [36, 39] and about 1.5 to 2 times as much for off-shore plants, such as have been built in Denmark, the UK, Germany and elsewhere [36]. Therefore, unit energy costs for capital recovery for a land-based plant, assuming a 15% discount rate and a capacity factor of 25%, would be about 9.2 cents per kilowatt-hour, ignoring land costs. Operating and maintenance costs would add one or two cents per kWh. Thus, the real unit energy cost of wind energy would be well above the capped price to domestic and other small consumers in Ontario [26]. The subsidy provided until 2007 for wind power installations in Canada by the Canada Wind Power Production Initiative of 0.8 to 1.2 cents/kWh [40] would reduce, but not make up, this difference.

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<sup>13</sup> The remainder is provided by coal-fired plants and by imported electricity from Sweden and Germany.

## 5.4 Wind Energy and the Environment

Wind power, like hydro power, emits essentially no air pollutants in operation and therefore is held in high regard by environmentalists and the public. Nevertheless, large-scale wind generation does result in certain environmental impacts that need to be recognized. In addition to the large surface areas required, these include:

- \* bird kills by the moving turbine blades, particularly at night and where wind turbines are located on migratory bird flyways [32, 41, 42],
- \* low-frequency noise resulting from the turbine blades passing the supporting towers, which may have adverse health effects as well as causing annoyance to those living nearby [32, 43] ,
- \* interference with defence radar, which has resulted in the refusal for permission to build an offshore wind farm in the UK, and with radio and television reception [32, 44],
- \* visual impacts of large wind farms which have resulted in opposition to wind farms in some locations, particularly in national parks [32, 45],
- \* potential impacts of turbine blade failure on nearby residents [32, 39] .

Siting of wind farms at well-chosen offshore sites, such as on the Great Lakes, would alleviate or overcome many of these difficulties, but at the expense of increased capital costs as noted in section 5.3. To avoid health impacts, the risk of injury and noise effects, some jurisdictions have required wind turbines to be located a minimum distance of from 500 to 1000 metres from roads or houses, generally increasing land requirements and thus costs [32, 46].

A thorough assessment of the environmental impacts of large-scale wind power developments and the pros and cons of large-scale wind power in general, in the context of a proposed wind power development in Prince Edward County, Ontario, is provided on a website maintained by a local group in that county [32]. A recent press report has summarized growing opposition in Europe to wind farms because of these environmental issues [47] and a political party has been formed in Scotland to oppose further development of wind power there [48].

These issues do not mean that wind power does not have a role to play in providing electricity in Ontario, but it must be recognized that such issues coupled with wind power's inherent deficiencies will severely limit its contribution to reliable electricity generation in this province. For example, should the target of the Ontario government to achieve 2700 MW of wind power capacity by 2010 be met, the annual electricity generation would be less than that of one of the Bruce-B nuclear units, based on typical annual capacity factors, and, unlike electricity from the Bruce-B, would not be available on a predictable schedule.

## **6.0 REPLACEMENT OF COAL-FIRED GENERATION BY INCREASED IMPORTATION OF ELECTRICITY TO ONTARIO**

The Ontario grid is interconnected with three American states: Minnesota (150 MW capacity), Michigan (2450 MW capacity) and New York (2500 MW capacity, 2 connections) and two Canadian provinces: Manitoba (245 MW capacity) and Quebec (1395 MW capacity, 4 connections) [1, Fig.6b]. All these interconnections can be utilized for exports as well as imports. In 2003, Ontario was a net importer of electricity, with 2240 GWh from Quebec, 645 GWh from Manitoba and 2000 GWh from the US [27]. Early in the 1990s, Ontario was a net exporter of electricity, but the lay-up of the nuclear plants in 1997 and 1998 resulted in Ontario becoming a net importer since then [49]. While the total capacity of the interconnections is about 6600 MW, the effective capability for electricity imports to Ontario is about 4000 MW [3].

Although interconnection of the Ontario grid with US grids resulted in the Ontario power blackout of August 2003 [50, 51], interconnections in general are valuable since they improve the economics and reliability of power generation as well as reducing the need to build new capacity [1, 21]. The interconnections with the US, with utilities with a roughly similar generation mix, enable overall reductions in generating costs by taking advantage of the diversity of loads over the interconnected grids. However, the US interconnections do not provide access to any significant unused capacity that could provide firm power over a prolonged period beginning in three years and thus they cannot serve as replacements for the coal-fired plants.

The interconnections with Manitoba and Quebec could possibly provide Ontario with access to low-cost hydro power on a firm basis, assuming further development of hydro projects in those provinces, such as the Lower Churchill project, which is in Labrador but to which Quebec has access through long-term firm contracts [27].

However, energy to replace the Ontario coal-fired plants from any development in Manitoba would require a significant increase in the capacity of the interconnection from its present 245 MW capacity. Construction of larger-capacity transmission lines would be very costly, would take considerable time and would have to be based on firm commitments for new hydro development in Manitoba as well as the guarantee of long-term energy supply contracts to Ontario. Also, supply by transmission line from Manitoba would not satisfy the condition of the IMO that replacements be located in the same general area as the replaced plant and be similar in characteristics.

The interconnections with Quebec have more capacity, about 1400 MW, than that with Manitoba, and an additional 1250 MW interconnection has been proposed [27]. Nevertheless, as with Manitoba, additional transmission lines would have to be built over the next few years and firm long-term contracts would have to be available to enable the coal-fired plants to be replaced with hydro power from Quebec. Again the IMO condition for replacement power would not be satisfied.

## **7.0 REPLACEMENT OF COAL-FIRED GENERATION BY NUCLEAR GENERATION**

### **7.1 Recent Additions to In-Service Nuclear Capacity**

With three laid-up nuclear units, one at Pickering-A (unit 4) and two at Bruce-A (units 3 & 4), returning to service in 2003 and early 2004, Ontario's nuclear power in-service capacity has been increased by about 2015 MW [27, 52] in the last year. Addition of this nuclear base-load capacity to the Ontario grid has reduced the need for the coal-fired plants to operate as base-load plants, as they have done periodically since the Pickering-A and Bruce-A units were laid up, as mentioned in section 2.1 of this report, and thus will reduce air-pollutant emissions to some degree. Recent information from the IMO website shows that reduced operation of the coal-fired plants is already occurring because of the recently added capacity in Ontario. During the months of June, July and August, 2003, the coal-fired plants produced 9.9 TWh of electricity, while they produced 5.5 TWh during the same months in 2004, a reduction of about 45% [53].

### **7.2 Committed and Potential Additions to Nuclear Capacity**

Additional nuclear generation could be provided by restarting the remaining laid-up reactor units, three at Pickering-A and two at Bruce-A. However, certain issues needed to be dealt with before these restarts could begin.

In the case of the Pickering station, the actual cost of the refurbishment of Pickering unit 4, about \$1.25 billion, exceeded the estimated cost by a factor of almost three and the schedule slipped by more than two years from the original projection, so that questions arose about the economics and practicality of restarting the remaining units<sup>14</sup>. The Ontario government appointed a Pickering Review Panel to determine the causes of the cost and schedule overruns of the unit 4 restart [54]. The Review Panel identified the causes of the overruns and made recommendations to avoid them, should the government decide to restart the remaining units. Based on the findings and recommendations of the Review Panel and its own assessment of these, another body appointed by the government, the OPG Review Committee [5], recommended that Ontario proceed with the refurbishment of Pickering unit 1, based on two key findings: procedures to prevent the problems with unit 4 from reoccurring were in place and refurbishment of unit 1 was the least expensive and quickest means for Ontario to build needed new capacity. Based on this recommendation, the Ontario government has recently approved the return to service of Pickering unit 1 [55], which will provide an additional 515 MW of base-load capacity to the Ontario system when the refurbishment, estimated to cost about \$900million<sup>15</sup>, is completed in about 15 months, i.e., before the end of 2005. The OPG Review Committee also recommended, and the government has agreed, that OPG wait until

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<sup>14</sup> The refurbishment of Bruce units 3 & 4 cost about \$720 million and was completed within about six months of the scheduled date [52].

<sup>15</sup> This amount includes sunk costs of about \$325 million, covering work already done on unit 1, as part of the original refurbishment project [5]. Reference 5 cites a total cost, including sunk costs, of \$825 million and an in-service date of September 1, 2005 for the Pickering-1 restart.

there is clear evidence of success on the unit 1 project before proceeding with any further work on refurbishing Pickering units 2 and 3 [5].

In the case of the Bruce-A station, the cost and schedule of restarting units 1 and 2 is expected to be higher than those associated with the restart of units 3 and 4 because of the need to replace the steam generators, which was not the case for units 3 and 4. Bruce Power is evaluating the case for the restart of these two units, but a decision has not yet been made [56].

However, additional nuclear capacity will be provided over the next few years by improvements at the Bruce-B units. Bruce-B capacity will be increased by about 400 MW by the use of new CANFLEX Low Void Reactivity Fuel bundle design, developed by AECL, and the installation of higher-efficiency low-pressure turbines [57]. The new-design fuel bundles have already been loaded into Bruce unit 6 and the new turbines are now being installed in that unit [57, 58].

Therefore, with the restart of Pickering-A unit 1 and the Bruce-B upgrade, additional nuclear capacity totalling about 915 MW will be available to the Ontario grid over the next few years. There is also the potential of restarting Pickering-A units 2 and 3, adding 1030 MW, and Bruce-A units 1 and 2, adding 1500 MW, for a total of 2530 MW capacity that may be added to the Ontario system. Bruce Power is also assessing the eventual refurbishment of the four Bruce-B units to extend their lifetime well into the future [56].

### **7.3 Limitations of Nuclear Generation in Replacing Coal-Fired Generation**

As discussed above, about 2930 MW (1030 MW at Pickering-A, 1500 MW at Bruce-A and 400 MW at Bruce-B) of nuclear capacity will have been added to the Ontario grid from 2003 to 2007, which will reduce the need for the coal-fired plants to function as base-load plants and will thus reduce emissions of air pollutants, as is already happening as noted above [53]. This added capacity will also reduce the need to import electricity into Ontario from the US, thus indirectly reducing the concentrations of air pollutants in Ontario from emissions from coal-fired plants in the US.

Nevertheless, this added nuclear capacity would not completely displace the equivalent coal-fired plant capacity in meeting intermediate loads, i.e. in load-following over a day or a week. The nucleonic characteristics of the natural uranium CANDU core and the design of the power control systems place constraints on changes in power level [59]. Current CANDU reactors do not normally operate at steady power levels less than about 60% of full power, because reducing the power from full power to a level lower than about 60% results in the build up of fission product xenon, a strong neutron absorber, in the fuel to the extent that the control system is unable to prevent the reactor from “poisoning out”, i.e., shutting down [51, 60]. Also, should a CANDU unit operating at full power be shutdown to zero power, the restart must begin within about half an hour; otherwise it cannot be brought back up to full power

until after the xenon in the fuel decays sufficiently, about 36 hours later<sup>16</sup>. It will then take about five hours to bring the reactor to full power from zero power. These constraints hinder nuclear plants from readily meeting intermediate loads on a regular basis.

Even if there were no physical constraints on load-following with the Ontario reactors, economic penalties will be incurred by this mode of operation. With the high capital costs of nuclear power plants compared to those of coal-fired plants, the nuclear plants must be operated at high annual capacity factors, i.e., as base-load plants, to keep unit energy costs reasonably low [12].

#### **7.4 Future Need for Nuclear Generation in Ontario**

The demand for electricity in Ontario is expected to grow considerably in the future. The Independent Electricity Market Operator forecasts that demand will grow by as much as 17% from now to 2014 [3] while the National Energy Board forecasts an increase of 21% by that date and by about 40% by 2025 [27]. Therefore, there is a consequent need for additional base-load capacity in Ontario to ensure that this increasing demand can be met and to ensure an adequate reserve margin. Base-load capacity requirements in Ontario are now met mainly by the nuclear plants and by the large-scale run-of river hydro plants [3]. There is little possibility of increasing large-scale hydro generation in the future in Ontario, as noted in section 5.1 and new coal-fired plants would not be acceptable. The cost of natural gas is too high and its long-term supply is too questionable to rely on CCGT plants for base-load power. The unreliability of wind power and other alternative sources preclude their use for base-load purposes.

Therefore, the only realistic option for future base-load power is to increase nuclear generation, as recognized by many knowledgeable organizations and individuals [3, 5, 27, 54, 56, 61]. The restart<sup>17</sup> of the remaining laid-up nuclear units at Pickering-A and at Bruce-A would just get Ontario back to where it was with nuclear capacity in the first half of the 1990s and new reactor capacity will be needed. Bruce Power is now assessing the building of new nuclear generation [56], using AECL's Advanced CANDU Reactor 700 MW (ACR-700) design, featuring considerably reduced capital costs, low operating costs and, eventually, a 36-month construction schedule [63]. The ACR should be market-ready by mid-2007 and the first two units could come on line by about 2012. A recently released study by the Canadian Energy Research Institute, confirms that nuclear power, either the ACR-700 or a CANDU-6 design, would provide the most economic base-load power for Ontario under public financing conditions, compared to a combined cycle gas turbine plant and a coal plant equipped with flue-gas desulfurizers [64].

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<sup>16</sup> In an emergency, Ontario nuclear plants can disconnect from the grid and continue to operate at 60% load by transferring energy to the steam generators as in normal operation, with the steam being discharged to atmosphere (Pickering-A, Pickering-B and Bruce-A) or recirculated to the condensers (Bruce-B and Darlington). For the Pickering plants and Bruce-A, this mode of operation could continue as long as de-mineralized water was available and for Bruce-B and Darlington, it could continue indefinitely. A plant can then be brought back on line as needed. The latter procedure was followed at three Bruce-B units and one Darlington unit following the power blackout of August, 2003, which enabled these units to begin producing power for the grid within a few hours after the blackout started [50, 51].

<sup>17</sup> The Ontario government has just announced that it is to begin negotiations to restart units 1 and 2 at Bruce [62].

As nuclear generation grows as a fraction of the total generation in Ontario, it would eventually be advantageous for nuclear units to load-follow more readily than they can now, so it would be useful for the ACR to have enhanced load-following capability. In this regard, with the projected unit capital cost of the ACR, about \$1350/kW, much reduced from that of current CANDU-6 reactors, about \$2200/kW, the economic penalty associated with intermediate-load operation would be less with the ACR design than with the current CANDU-6 design.

Nevertheless, nuclear generation for a number of years in the early 1990s produced over 60 % of Ontario's electricity [65], so that a significant increase in nuclear's present contribution of about 40% is clearly feasible, in spite of any physical and economic limitations to the operation of nuclear power plants as intermediate-load plants.

## **8.0 CONCLUSIONS**

Based on the foregoing assessments, certain conclusions can be reached on the various options for the coal-fired plants in Ontario. In reaching these conclusions, a commitment of the Ontario government about the closing of the coal-fired plants must be kept in mind: "We remain committed to replacing coal-fired electricity generation in the province. In so doing, we will never put Ontario consumers in jeopardy and will be totally satisfied that adequate alternatives are in place before we replace coal." [66] .

In reaching conclusions on these options, it should be kept in mind, as discussed in section 2, that conservation alone is not really a separate option for reduction of air pollution from coal-fired plants in Ontario, although it will assist any of the options by reducing demand to some extent.

### **8.1 Actual and Committed Additions to Ontario Intermediate Load Capacity, 2003 to 2009**

From the foregoing assessment, the actual and committed additions to the Ontario grid are summarized in Table 5, which also shows the suitability of the added capacity for intermediate-load operation, as would be needed to replace the coal-fired generation.

As shown in Table 5, actual and committed additions to the Ontario grid that are fully capable of meeting intermediate loads total 3355 MW, but this capacity will only be fully available by June 1, 2009, at the earliest. In addition, additional nuclear capacity of 2930 MW will be fully available by about 2007, but there are limitations to the ability of this capacity to meet intermediate loads. The ultimate total capacity in these two categories is about 6800 MW, less than the 7578 MW capacity of the coal-fired plants, and not all of this added capacity is capable of meeting intermediate loads on a regular basis. Therefore, it is apparent that the Ontario coal-fired plants cannot be completely replaced by the actual and committed additions to the grid, and these replacements will not be completely available until the middle of 2009.

**Therefore, the Ontario coal-fired plants cannot all be shut down by 2007 if the commitment of the Ontario government that adequate alternatives will be in place before coal plants are replaced is to be fulfilled.**

TABLE 5

ACTUAL AND COMMITTED ADDITIONS TO ONTARIO CAPACITY  
2003 TO 2009

PROJECT	MW, INTERMEDIATE LOAD CAPABLE?			IN-SERVICE <sup>18</sup>
	YES	PARTLY	NO	
Brighton Beach	580			2004
Portlands	550			?
Northlands	25			?
M of E RFP	2000 <sup>19</sup>			June 1, 2009
Beck Tunnel	200			2008
Renewables			300	Dec. 31, 2007
Pickering-4		515		Sept.25, 2003
Bruce-4		750		Oct. 7, 2003
Bruce-3		750		Jan.9, 2004
Pickering-1		515		2005
Bruce-B Upgrade		400		2007
Total	3355	2930	300	

## 8.2 Improvement of Emission Controls at Coal-Fired Power Plants

Table 3, in section 3, shows that the installation of selective catalytic reducers (SCR) and flue gas de-sulfurizers (FGD) at the Nanticoke and Lambton coal-fired plants, representing almost 6000 MW of capacity, about 80% of the total coal-fired capacity in Ontario, would result in significant reductions in emissions of the major air pollutants NO<sub>x</sub> and SO<sub>2</sub>, with emissions of NO<sub>x</sub> being reduced to 37% and of SO<sub>2</sub> to 30% of the present amounts. Installation of this equipment at these plants would require an investment in the estimated range of \$2.1 billion to \$3.0 billion. However, maintaining these plants in operation with these emission controls added would avoid the premature write-off of valuable assets, at an annual charge of about \$576 million.

<sup>18</sup> Date of final addition of capacity

<sup>19</sup> Assumes that 500 MW of the RFP request will be met by demand-reduction measures, which, as a minimum, will be balanced by demand growth.

**Before deciding to close the Nanticoke or Lambton plants in 2007, it would be prudent to undertake a cost-benefit analysis of the addition of SCRs and FGDs at least at one of these plants, taking into account health benefits resulting from the significantly reduced emissions, as suggested in the Manley Report [5]. Keeping the Nanticoke plant open by adding SCRs and FGDs would have the benefit of reducing emissions significantly while retaining over 3900 MW of intermediate-load capacity for the Ontario system, which, with the committed and planned gas-fired capacity, would provide about 7300 MW of intermediate-load capacity, almost the same as now provided by all the coal-fired plants. This step could be completed by about 2007 if the commitment were made soon and would avoid any economic penalties and operational difficulties resulting from having to operate nuclear plants as load-followers.**

### **8.3 Replacement of Coal-Fired Generation by Natural Gas-Fired Generation**

It is evident from Table 5 that committed and planned natural gas-fuelled generation, about 3155 MW, will only be able to replace about 42% of the total 7578 MW of coal-fired power. The cost of replacing most of the rest of the coal-fired power with natural gas-fired power, for example by building a CCGT plant to replace Nanticoke, would be very high and would face issues of gas supply and costs over the lifetime of the gas-fired plants, as discussed in section 4.

**It is concluded that increasing the reliance on natural gas-fired generation in Ontario much beyond present commitments and plans would raise concerns about the reliability of gas supplies and would probably result in increasingly high costs of electricity generation.**

**Shutdown of the coal-fired plants at Thunder Bay and Atikokan would require replacement capacity of about 500 MW to be located in the same general areas to meet the IMO requirement for voltage support and for transmission security. Since gas transmission costs to these areas would be less than to central Ontario, gas-fired generation would be appropriate for this purpose, so that some of the proposed or future gas-fired plants should be located there.**

**As a special case, the conversion of the Lakeview plant to the burning of natural gas to generate steam for its turbines, rather than closing it in 2005, might be considered because of its important role in maintaining transmission system reliability and sustaining local voltages by its proximity to Toronto.**

### **8.4 Replacement of Coal-Fired Generation by Renewable (Alternative) Energy Sources**

As made clear in section 5, wind and solar sources suffer from two inherent deficiencies for large-scale electricity production, low intensity and intermittency. The low intensity results in a requirement for very large surface areas for a given capacity. Replacement of the Ontario coal-fired capacity by wind power would require suitable sites over an area of about 1900 km<sup>2</sup>, but

this capacity would produce only about 40% of that produced by the coal plants because of wind intermittency. Because of its intermittency, wind generation cannot really replace the coal plants in meeting intermediate loads, since it is not available on demand and cannot be cycled to meet changing load demands. Also, experience in Denmark shows that stability problems arise when wind power becomes more than a relatively small contributor to an electricity grid.

Because of the need for many large wind turbines for any significant generation capacity, the capital costs of wind energy are high, and the wind's intermittency means that capacity factors of wind farms are very low, only 20% to 30%. Thus, the unit energy costs for recovery of capital are very high, typically about 9 or 10 cents per kWh, well above the capped rate for small consumers in Ontario.

The operation of wind plants, while avoiding emissions of air pollutants, is not free from all environmental impacts, as described in section 5.

**It is concluded that wind energy is not a realistic option to replace the coal-fired plants and will continue to play only a very minor role in electricity generation in Ontario.**

### **8.5 Replacement of Coal-Fired Generation by Increased Importation of Electricity to Ontario**

The effective capability for electricity imports into Ontario from the US, Manitoba and Quebec is now about 4000 MW, as stated in section 6. The US interconnections do not provide access to any significant unused capacity that could provide firm power over a prolonged period and thus they cannot serve as replacements for the coal-fired plants.

The interconnections with Manitoba and Quebec could possibly provide Ontario with access to low-cost hydro power on a firm basis. However, since the capacity of these interconnections is low, construction of larger-capacity transmission lines would be needed, would be very costly, would take considerable time and would have to be based on guarantees of long-term firm energy supply contracts.

**While strengthened interconnections with the US and Quebec and Manitoba would be generally beneficial, increased importation of electricity into Ontario is not a viable solution on its own for replacing coal-fired generation by the target dates.**

### **8.6 Replacement of Coal-Fired Generation by Nuclear Generation**

As discussed in section 7, technical limitations constrain the operation of CANDU units as intermediate load plants and there also is an economic penalty for such operation. The economic penalty of operating at reduced load will be less for the ACR-700 design than for the CANDU-6 design.

**Almost 3000 MW of nuclear capacity will have been added to the Ontario grid in the period from 2003 to 2007, which will reduce, or even eliminate, the need for the coal-fired plants to function as base-load plants, as is already occurring, and will thus reduce emissions of air pollutants. This added capacity will also reduce the need to import electricity into Ontario from the US, thus indirectly reducing the concentrations of air pollutants in Ontario from emissions from coal-fired plants in the US.**

**Strong growth of electricity demand in Ontario is expected in the future. New base-load generation capacity will be needed soon, in addition to that which may be provided by the restart of the four remaining laid-up reactor units at Pickering and Bruce. The only realistic option for new base-load capacity in Ontario is nuclear, using either the new Advanced CANDU Reactor or the well-established CANDU-6 design**

**As the percentage of nuclear generation in Ontario grows to and beyond the level of about 60% attained in the early 1990s, the ability of CANDU reactors to operate to some degree as load followers will become more important, so enhanced ability in load following should be a design criterion for new nuclear generation in Ontario.**

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### **Corrections**

1. Table 2: Number of units at Lambton plant corrected January 10, 2006
2. Table 3: Reduction in emissions from Lambton plant corrected January 10, 2006
3. Section 3.0, p.7 and Section 8.2, p.23. Corrections in text from corrections 1 and 2, January 10, 2006

