


ONTARIO POWER AUTHORITY


November 15, 2006

Ontario's Integrated Power System Plan

Discussion Paper 7: Integrating the Elements— A Preliminary Plan

Ontario Power Authority™

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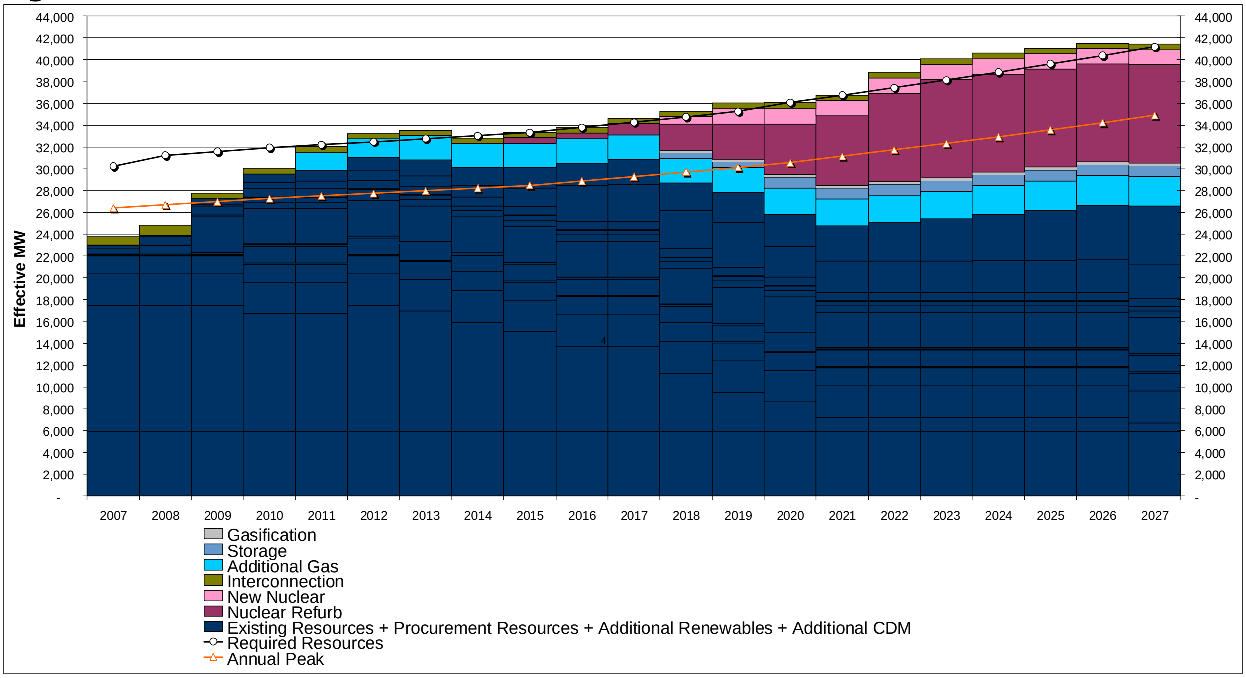
Figure 2.17 – Conventional Resources



Source: OPA

2.7 Step Seven: Contribution of Coal and the Coal Replacement Plan

This section describes the plan for coal replacement called for in the ministerial directive:

> *"Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electric system reliability in Ontario. The OPA should work closely with the IESO to propose a schedule for the replacement of coal-fired generation, taking into account feasible in-service dates for replacement generation and necessary transmission infrastructure."*

As indicated in Figure 2.17, the resources in the Preliminary Plan described to date, without consideration of the existing coal-fired resources, do not meet minimum resource requirements in the period to 2011. As other resources were maximized in the short term, existing coal-fired generation represents a resource to meet the gap to 2011 to ensure adequate generating capacity and system reliability.

Considerations in Developing the Replacement Plan

The development of the replacement plan for the coal-fired generation facilities was based on the following key considerations:

- maximize options that can replace coal
- address uncertainties and ensure that system reliability can be maintained

- determine the earliest practical phase-out of coal, taking uncertainties into account
- explore the potential for use of emission reduction technology.

Examine Alternatives to the Use of Coal in the Short-Term

In developing the coal replacement plan, the OPA considered alternatives for accelerating the replacement of coal-fired generation units. The alternatives considered are in addition to the plan elements previously reviewed. We considered the contributions from CDM and renewable resources to be at the practical attainable level in the near term and therefore adding more is not feasible. The options considered include the following:

- **Increased use of natural gas.** Conversion of existing coal-fired boilers to gas-fired boilers involves the cost of burner tip replacement, the cost of new or expanded gas pipeline capacity, and the cost of natural gas. According to OPG, the conversion of existing boilers at Nanticoke to burn natural gas could cost in the range of $30 million to $50 million per unit ($240 million to $400 million for all eight units) and take about five years to complete. In addition, gas pipeline costs are likely to be in the order of $300 million to $350 million, resulting in a total conversion cost ranging from about $540 million to about $750 million. The fuel cost and low efficiency at Nanticoke will result in operating costs for generating electricity at close to $100 per MWh (close to the cost of Lennox GS). Putting these three factors together (lead time, cost and inefficiency) leads to this option not being recommended.

  Building new combined cycle gas turbine units would represent a higher efficiency solution than conversion of existing boilers, but has similar long lead-time requirements. The Preliminary Plan already includes a substantial amount of gas-fired generation, which is a challenge to implement. Much more new gas will result in the use of gas for baseload and intermediate load applications, and that is not consistent with public policy as reflected in the Minister's directive. If several thousand MW of new gas-fired capacity were built in the short term to replace coal, it would be surplus to the desired long-term generation mix. For these reasons, the increased use of natural gas is not considered to be a feasible alternative to the continued operation of coal-fired units for a limited period of time.

- **Electricity imports.** Opportunities for the import of clean energy should continue to be explored. Firm capacity imports could potentially enable coal replacement to proceed more quickly. When and if such arrangements are put in place, the coal replacement plan will be reviewed to assess the opportunities for advancement of coal replacement. The proposed 1,250 MW intertie (transmission connection) with Quebec has some potential in this regard.

Address Uncertainties and Ensure Reliability

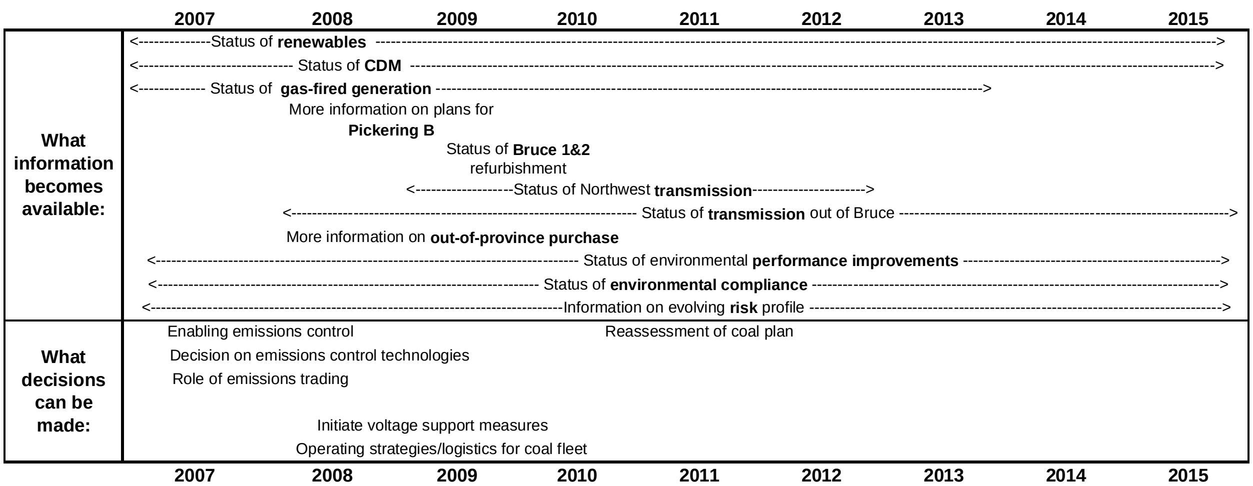
Factors related to ensuring system reliability include maintaining adequate system capacity, maintaining system security, both locally and provincially, and ensuring that the system remains operable at all times.

While the 1,200 MW Lakeview Generating Station was taken out of service in 2005, the remaining coal-fired generation remains a significant component of Ontario's electric system, with a current installed capacity of 6,434 MW (equivalent to 21 percent of the total installed capacity), and producing 30.9 TWh of electricity in 2005 (or 19 percent of the total electricity production). Coal-fired generation has historically contributed to meeting peak and intermediate demand, and reserve requirements. Replacing any of the remaining coal-fired generation represents a significant challenge during a period of transformation as Ontario's future electricity system takes shape.

As committed resources are built in the near term, and further new resources are committed, there will be continuous assessment of reliability as new information becomes available. The corresponding implications on planned requirements, as well as on risk profiles and uncertainties, will therefore require regular review and adjustment to the plans and mitigating provisions, as necessary. This requires the replacement plan for the coal-fired generation facilities to be flexible and adaptive, because it absorbs most of the uncertainties associated with other resources.

The OPA has identified a number of factors that will affect the evolution of the coal-fired generation replacement plan in response to new information that materializes from implementing various elements of the IPSP in the time period from now to 2014/2015. These are illustrated in Figure 2.18.

Figure 2.18 – Issues and Evolving Information that Affect the Coal Replacement Plan



Source: OPA

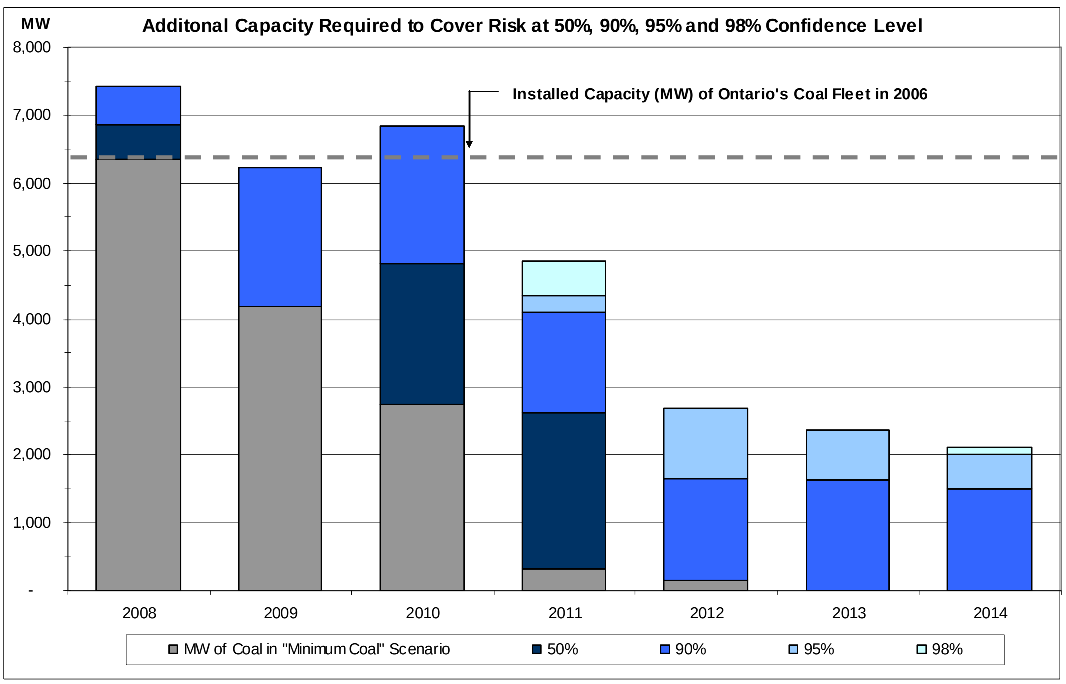
These factors relate to the status and outcome of ongoing developments on a number of issues, such as uptake and performance of new renewable resources, CDM, plans for nuclear refurbishments and transmission infrastructure. As discussed earlier, these will necessitate regular review and adjustment of the plan, without losing sight of its primary objective of replacing coal. Figure 2.18 also identifies a number of issues that will require decisions to be made in the near term relating to the operational and environmental performance of the operating coal-fired units until they are taken out of service.

An uncertainty analysis was performed to estimate the net impact of the various risk elements on capacity requirements. In the analysis, a probability distribution of system capacity impacts was calculated based on possible combinations of risk conditions and the joint probability of these combinations occurring.

Figure 2.19 shows the results of this analysis based on an assessment of risks and uncertainties as of the fall of 2006. Results are expressed in terms of the capacity requirements necessary to achieve different levels of confidence in meeting system adequacy requirements, e.g., 50 percent, 90 percent.

The Minimum Coal Requirements in Figure 2.19 represent the amounts of coal-fired generation required to meet generation adequacy requirements, assuming all planned resources (CDM, gas, renewable resources and transmission) are implemented on time. They are based on the set of assumptions in the Preliminary Plan. In 2008, measures in addition to the retention of coal-fired generation may be required, such as electricity imports. In subsequent years, risk coverage is improved and the installed coal capacity is more than adequate to provide the requisite risk coverage at high confidence levels.

Figure 2.19 – Range of Coal Capacity Requirements as Seen in 2006



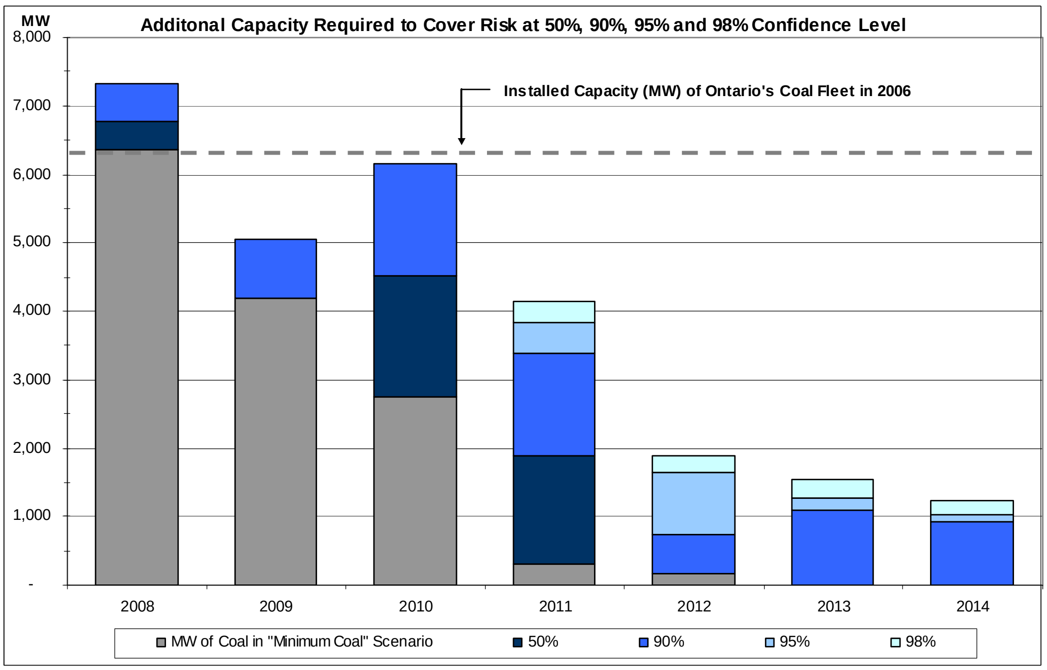
Source: OPA

Based on the risk analysis results as shown in Figure 2.19, we consider it prudent to:

- retain the existing coal-fired generation capacity in-service to at least 2010
- gradually reduce the coal-fired capacity starting in 2011 to about half of the current installed capacity, after which the coal-fired generation is removed from service by 2015.

With the passage of time, better information concerning many of the risk factors will become available, for example, the status of generating units scheduled to be placed in-service and the success in achieving CDM potential. As this information becomes available, our assessment of future risks will change, and it may be possible to reduce the amount of coal-fired generation required to cover these risks. Figure 2.20 illustrates the range of coal capacity requirements that would be assessed at the end of 2008 if all of the resources planned to be placed in-service up to and during 2008 were on time, and all other conditions remained the same. Clearly, the uncertainties are reduced if the projects planned for 2007 and 2008 are all successful.

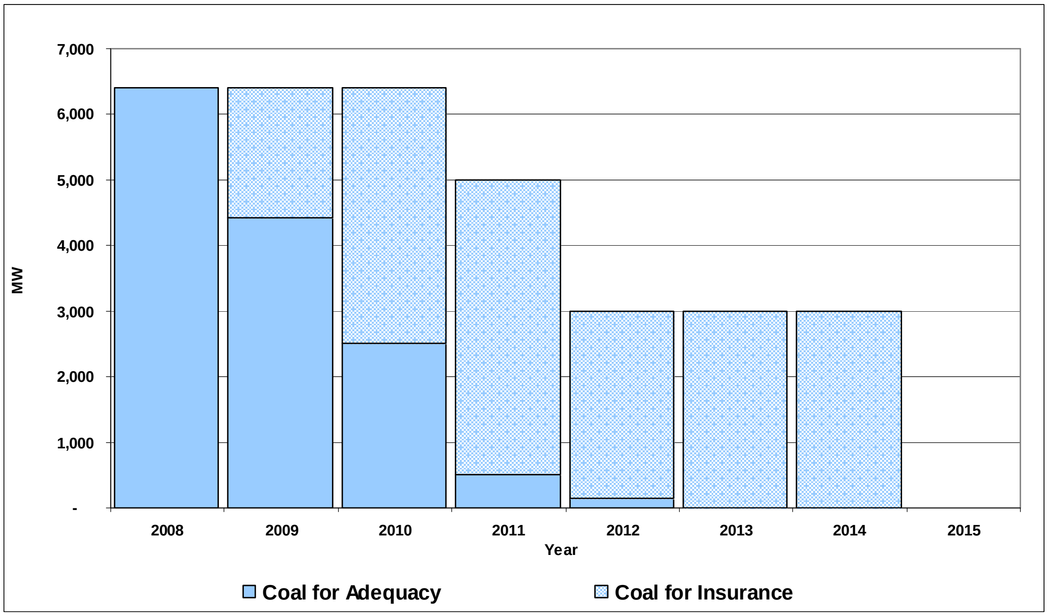
Figure 2.20 – Illustrative Range of Coal Capacity Requirements as Seen in 2008 Assuming All Goes According to Plan to 2008



Source: OPA

Based on the range of capacity requirements shown in Figure 2.19, we consider it prudent to plan on maintaining sufficient coal capacity in-service to cover the adequacy and insurance requirements shown in Figure 2.21.

Figure 2.21 – Range of Coal Capacity Requirements



Source: OPA

Explore the Potential for Emission-Reduction Technology

Figure 2.22 shows the forecast range of coal-fired energy production during the period 2008 – 2014, first assuming that only the minimum amount of coal-fired generation is producing energy, and then assuming the amount of coal-fired generation required for insurance is producing energy. With minimum coal-fired generation, energy production declines steadily, from about 30 TWh in 2008 to zero in 2012. However, if all the insurance coal is operating until the end of 2014, the forecast coal production declines from about 30 TWh in 2008 to about 15 TWh for the period 2012 through 2014. Prudent planning requires that Ontario plan on using the insurance coal until the end of 2014.

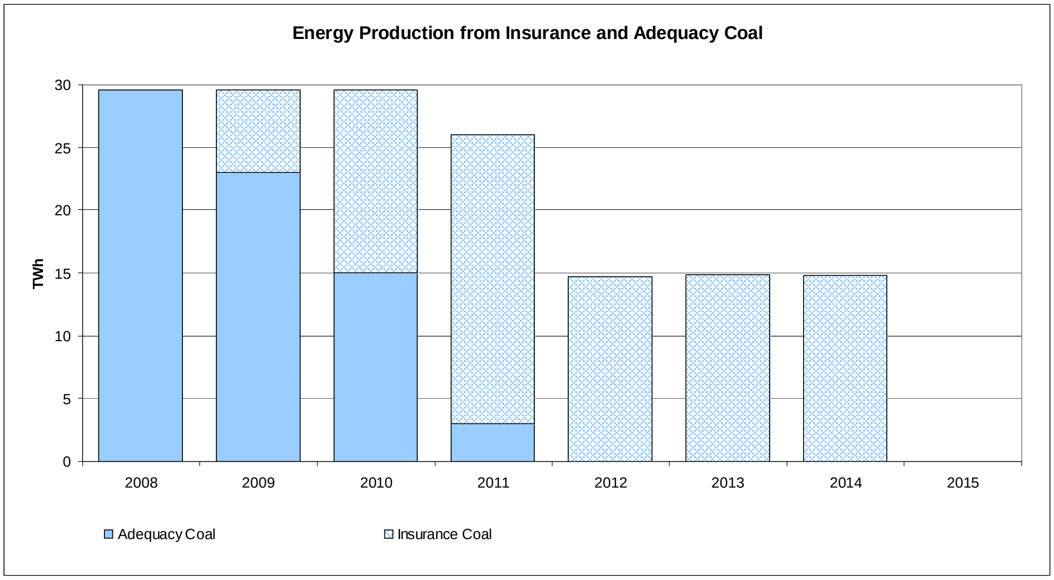
Figure 2.23 shows a range of forecast emissions in 2010 based on the production levels shown in Figure 2.22, before emission control technology improvements are considered. The lower amount represents emissions with minimum coal and the higher amount represents emissions with insurance coal. These are compared to historical emissions during the period 1985 – 2005.

Actual emissions have generally declined over the period, and this trend is continued if the minimum coal burn is achieved. However, if insurance coal continues to be required in 2010, there is a potential for increased emissions of mercury and NOx. Consideration should be given to emission control technology improvements to mitigate the environmental impacts of burning coal. In particular, the following alternatives should be considered:

- installation of Selective Catalytic Reduction facilities on Nanticoke units 5 and 6
- installation of baghouses
- installation of scrubbers on some or all of Nanticoke units 5 – 8
- maximizing the use of biomass feedstock for co-firing of boilers.

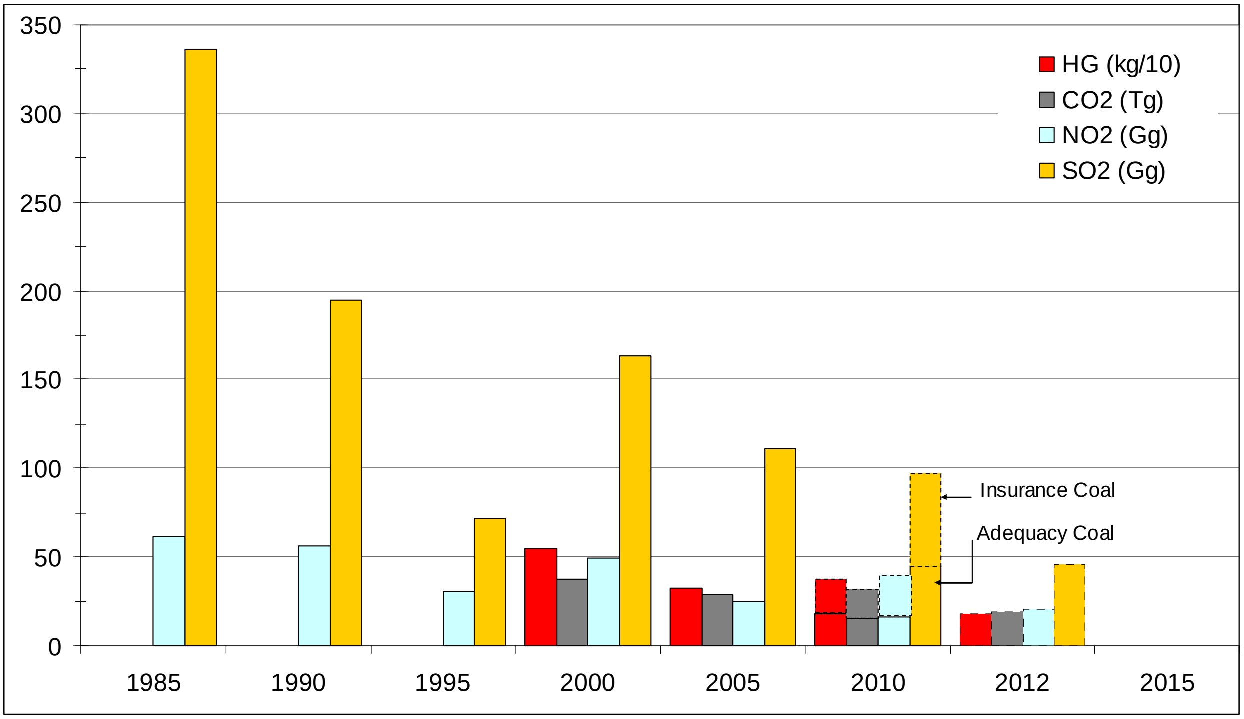
Work is in progress to assess the environmental impact of various emission control technology options. We will be providing further information on the environmental aspects in a future appendix to this report.

Figure 2.22 – Forecast Coal-Fired Energy Production



Source: OPA

Figure 2.23 – Historical and Forecast Emissions From Coal Generation



	1985	1990	1995	2000	2005	2010	2012	2015
HG (kg/10)				55	32	18 - 36	0 - 18	-
CO2 (Tg)				38	29	16 - 28	0 - 19	-
NO2 (Gg)	62	56	31	49	25	17 - 39	0 - 20	-
SO2 (Gg)	336	195	72	163	111	45 - 96	0 - 46	-

Source: OPA (Forecast), OPG (Historical).

The Proposed Coal Replacement Plan

The coal requirements shown in Figure 2.21 are required to manage system capacity risks based on the current view of risks. However, during the next few years, as additional CDM initiatives are implemented and supply resources are placed in-service, the assessment of capacity risk will change, and if resources are placed in-service as scheduled, it will be possible to reduce the amount of insurance required to manage the revised assessment of risks. This creates the opportunity to shut down coal-fired generating units earlier. The proposed coal-fired generation replacement plan comprises the following components:

1. Retain the existing coal-fired generation capacity in-service to 2010 concurrent with the ability to produce 20-25 TWh of electricity per year. This can be accelerated under certain favourable conditions.
2. Gradually reduce the coal-fired capacity starting in 2011 to about half of the current installed capacity and plan to operate this reduced capacity to the end of 2014.
3. Improve the environmental performance of the operating coal-fired generation facilities to the extent practical during the transition period to 2014, in accordance with the

recommended capacity requirements identified in Figure 2.21, and consistent with meeting applicable and evolving regulatory requirements.
4. Retain plan flexibility and adjust the plan as necessary, based on regular review of risk profiles and new and pertinent information that becomes available.
5. Consider options for potential future use of the coal-fired generation sites.

Continuous monitoring of conditions will require close cooperation and consideration with the IESO and OPG to determine the specific role of the coal-fired generation units over the next several years. This is particularly true for Atikokan GS and Thunder Bay GS, which are important not only for overall system adequacy, but also to ensure adequacy in the northwest system. Based on preliminary OPA studies, there is a potential requirement to maintain generation capacity at Atikokan in-service until replacement generation becomes available. This could include conversion of the plant to biomass operation. Additional studies will be conducted for the IPSP to confirm this requirement.

Close cooperation and coordination is also required for the shutting down of units at Nanticoke GS. As outlined in paper #5, replacement reactive power is required for voltage support before all Nanticoke units can be removed from service.

2.8 Step Eight: Transmission Integration

2.8.1 Renewable Resources and Transmission Integration

More than any other resource type, the development of renewable resources is highly affected by the availability and capability of the transmission system. Renewable potential in Ontario is large, but much of it is located in remote areas of the province that presently have no grid access, or where the existing transmission system does not have the capacity to deliver the power output from a major resource development. Thus, an integrated resource development plan that has a sizeable component of renewable resources, such as the IPSP, must have an associated transmission development plan that enables the resource development.

In the development of this integrated renewable resources/transmission plan, there are a number of key considerations:

- amount of renewable resources in the plan – this is provided by the resource plan (step 5 of this paper)
- location of the renewable resource potential – this is based on the information provided by the various referenced studies carried out for the IPSP, as summarized in the supply resources paper (#4), plus assessment of feasibility
- transmission capabilities and reinforcement options – this is discussed in detail in the transmission discussion paper (#5)
- lead time requirements – information specific to the renewable or transmission development element