A Comparison of Combustion Technologies for Electricity Generation

2006 Update Including a Discussion of Carbon Capture and Storage in an Ontario Context

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# A Comparison of Combustion Technologies for Electricity Generation

2006 Update Including a Discussion of Carbon Capture and Storage in an Ontario Context

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Notes to the Reader

Acronyms and Abbreviations

AFBC  Atmospheric Fluidized Bed Combustion
CAC  Criteria Air Contaminants (NOx, SOx, PM, VOCs, CO)
CCPI  Clean Coal Power Initiative
CCS  Carbon Capture and Storage
CO  Carbon Monoxide
CO2  Carbon Dioxide
COE  Cost of Electricity
DOE  U.S. Department of Energy
ESP  Electrostatic Precipitators
FGD  Flue Gas Desulphurization
H2S  Hydrogen Sulfide
HHV  High Heating Value
IGCC  Integrated Gasification Combined Cycle
LHV  Low Heating Value
LNB  Low NOx Burners
MW  Megawatt
NG  Natural Gas
NGCC  Natural Gas Combined Cycle
NOx  Oxides of Nitrogen
PCC  Pulverized Coal Combustion
PFBC  Pressurized Fluidized Bed Combustion
PM  Particulate Matter
SCR/SNCR  Selective Catalytic Reduction/Selective Non-catalytic Reduction
SOx  Oxides of Sulphur
VOCs  Volatile Organic Compounds
Executive Summary

This report updates the Pembina Institute’s 2001 publication A Comparison of Combustion Technologies for Electricity Generation, republished in 2004 as Appendix 4 in Power for the Future: Towards A Sustainable Electricity System in Ontario.¹

The electricity generation technologies examined include the following:

- High-efficiency coal combustion technologies: Pulverized Coal Combustion (PCC), Atmospheric Fluidized Bed Combustion (AFBC), Pressurized Fluidized Bed Combustion (PFBC), and Integration Gasification Combined Cycle (IGCC).
- “End-of-pipe” or add-on pollution control options for coal such as Flue Gas Desulphurization (FGD), Low NOx Burners (LNB), Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR), Electrostatic Precipitators (ESP) and Baghouses.
- Natural gas-fired options: Natural Gas Combined Cycle (NGCC) and Combined Heat and Power.

The review concludes that none of the coal-fired options are as environmentally favourable as the natural gas-fired options. Among the coal-fired options, IGCC showed the best opportunity for environmental performance, although it still has high CO2 emissions relative to natural gas-fired options.

The review also notes that IGCC technologies may theoretically be combined with carbon capture and storage (CCS) technologies. However, the review concludes that carbon storage options for Ontario are unproven and speculative, and that, given the extent of the research required to demonstrate their viability, they cannot be considered a serious possibility within the current 20-year electricity policy planning horizon.

1.0 Introduction

1.1 Report Context and Goals
In May 2004 the Pembina Institute and the Canadian Environmental Law Association jointly published Power for the Future: Towards a Sustainable Electricity System for Ontario. Included in the report was Appendix 4: A Comparison of Combustion Technologies for Electricity Generation, itself originally published in 2001. That appendix, the key findings of which are reproduced here as Appendix 1, included a review of the economic and environmental performance of a range of coal and natural gas combustion technologies for electricity generation.

These technologies included the following:
- Higher-efficiency coal combustion technologies, such as Pulverized Coal Combustion (PCC), Atmospheric Fluidized Bed Combustion (AFBC), Pressurized Fluidized Bed Combustion PFBC, and Integration Gasification Combined Cycle (IGCC).
- “End-of-pipe” or add-on pollution control options for coal such as Flue Gas Desulphurization (FGD), Low NOx Burners (LNB), Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR), Electrostatic Precipitators (ESP) and Baghouses.
- Natural gas-fired options, such as Natural Gas Combined Cycle (NGCC) and Combined Heat and Power.

The 2001 review found that none of the coal-fired options were as environmentally favourable as the natural gas-fired options. Among the coal-fired options, IGCC showed the best opportunity for environmental performance, although it still had high CO2 emissions relative to natural gas.

In light of Ontario’s recent retreat from the coal-phase out plan originally scheduled to be completed by 2009, but now deferred, this paper updates the 2001 combustion technology analysis. In particular, it investigates the current commercialization status and performance of IGCC technology for power generation, as this is the most significant area of change relative to the original 2001 analysis. The report also explores the possibilities of greenhouse gas (GHG) capture and storage in Ontario, as a means of managing GHG emissions associated with fossil fuel-fired electricity generation.

1.2 Study Methodology
To prepare the report, researchers drew upon secondary sources (reports, journal articles, etc.) and conducted interviews with select government, industry and academic representatives. It is important to note that, while the report outlines the environmental and economic performance of combustion technologies for electricity generation, it does not address the environmental or economic impacts of coal or natural gas extraction, production, and delivery systems.

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2.0 An Overview of Combustion Technologies for Electricity Generation

All coal combustion technologies rely on the generation of high pressure steam using heat produced by burning coal. This high pressure steam then drives a turbine, which is attached to an electrical generator and produces electricity.

Exhaust gases from combustion of the coal are typically cleaned by a series of processes. Particulates are removed by electrostatic precipitators or fabric filters (baghouses), and sulphur oxides (SOx) are removed by one of a range of possible flue gas desulphurization (FGD) processes. Nitrogen oxide (NOx) production can be controlled by in-furnace features such as low NOx burners. A Selective Catalytic or Non-Catalytic Reduction process can further reduce NOx emissions.

The combustion of coal in the boiler can be accomplished in various ways, described below. In general, the most energy-efficient plants have the lowest emissions, as they produce more electricity per unit of coal burned. However, emissions from less-efficient plants can be reduced with “add-on” pollution control options.

2.1 Subcritical and Supercritical Pulverized Coal Combustion (PCC)

Coal combustion has traditionally occurred at atmospheric pressure to produce subcritical steam, but today, greater efficiencies can be obtained by using higher steam pressures in the supercritical range. Both subcritical and supercritical processes begin with coal being ground into a fine powder. The powdered coal is blown with air into the boiler through a series of burner nozzles where combustion takes place at temperatures from 1,300–1,700°C, depending largely on the coal type. Combustion occurs at near-atmospheric pressure, which simplifies the burner and coal handling facilities. Subcritical pulverized coal combustion (PCC) plants use steam in the range of 16 megapascals (MPa) pressure and at 550°C while supercritical PCC plants use steam with pressures as high as 30 MPa and at 600°C. The higher steam pressure in supercritical plants results in higher energy efficiency of 38–45%, compared with 33% for subcritical plants. However, supercritical plants have higher capital costs and some added risk due to the higher pressure and temperature. They have only come into commercial service in Canada recently.

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4 At atmospheric pressure, water bubbles at boiling point before turning into steam; above a certain critical pressure, it enters a “supercritical” state, where it undergoes a continuous transformation directly into steam.
5 The first such facility in Canada, EPCOR’s Genesee Facility, came into service in 2006.
2.2 Atmospheric and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used with high sulphur coal. In an FBC plant, hot air blown up through the floor of the boiler suspends or “fluidizes” powdered coal mixed with a sorbent such as powdered limestone. The combustion of the coal in the presence of the sorbent facilitates the capture of sulphur dioxide (SO$_2$). Conventional boilers, by contrast, simply burn the fuel on a grate in the firebox. FBC plants can remove up to 98% of the SO$_2$ and the coal burns more efficiently because it stays longer in the combustion chamber.

Atmospheric fluidized bed combustion (AFBC) plants operate at atmospheric pressure, and NOx generation is minimized due to lower combustion temperatures (815–875°C) than in conventional PCC plants. In contrast to AFBC plants, pressurized fluidized bed combustion (PFBC) plants operate at elevated pressures. PFBC plants are typically more compact than similar capacity AFBC and PCC plants due to the higher pressure. The PFBC design allows for potentially greater efficiency, reduced operating costs and less waste than the AFBC design. PFBC plants use the same process as AFBC plants to fluidize or float the coal/sorbent mixtures. In both AFBC and PFBC plants, the reacted sorbent forms a dry, granular material that is easily disposed of or used as a commercial by-product. The reacted sorbent is removed with the bed ash through the bottom of the boiler and with the fly ash that has been collected in the dust collectors at the top of the boiler stacks.

In PFBC plants, additional energy is captured when the combustion gases that leave the fluidized bed are cleaned in a gas cleanup system and then re-burned in a gas turbine. The gas turbine is connected to an electrical generator thereby improving the plant’s efficiency. The use of a steam turbine and a gas turbine improves performance by creating a highly efficient combined cycle system. The operating temperatures of fluidized beds are between 760 and 870°C, approximately half the temperature of a conventional boiler. This relatively low temperature is below the threshold where thermally induced NOx forms. Thus, the fluidized bed designs have reduced SO$_2$ and NOx emissions compared to PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels.

2.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants are potentially cleaner and more efficient than traditional coal-fired systems. In IGCC plants, coal is not burned in a traditional boiler but is converted into a hydrocarbon vapour (syngas) in a gasifier. The syngas (principally hydrogen (H$_2$) and carbon monoxide (CO)) then undergoes a gas-water shift, converting the CO to CO$_2$ and producing and forming more H$_2$. Lastly the H$_2$ is separated from the CO$_2$. The H$_2$ can then be used instead of natural gas as fuel in a conventional combined cycle plant (see below for a description of the natural gas combined cycle plant), while the CO$_2$ can be compressed for transport and storage. The result is an integrated gasification combined-cycle configuration that offers the potential for lower pollution levels and high system efficiencies, while facilitating the possibility of carbon capture and storage (CCS). The combination of IGCC with CCS, however, has not yet been put into practice.

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For a detailed discussion of these processes see Mary Griffiths, Paul Cobb and Thomas Marr-Laing, Carbon Capture and Storage: An Arrow in the Quiver or a Silver Bullet to Combat Climate Change? — A Canadian Primer (Drayton Valley, AB: The Pembina Institute, 2005), 24–26. www.pembina.org/pdf/publications/CCS_Primer_Final_Nov15_05.pdf.
2.4 Natural Gas Combined Cycle (NGCC)

While the natural gas combined cycle process (NGCC) is not a coal combustion process, it is included here for the purpose of comparison with the various coal-fired options. Commercial-grade natural gas burns more cleanly than other fossil fuels because it consists mostly of methane and has already been cleaned of sulphur. In NGCC plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the hot exhaust gas from the turbine is used to generate steam in a waste heat recovery unit. The steam is then used to produce more electricity in the same way as described for the PCC options above. The output from both the gas turbine and the steam turbine electrical generators is combined to produce electricity very efficiently. NOx control in gas turbines is proven technology and can be accomplished with relatively inexpensive “low NOx burners.” In addition, NOx can be reduced still further with such “add-on” control technology as Selective Catalytic Reduction. Emissions of particulate matter generated with this method are also quite low, although some secondary particulate matter is produced through atmospheric chemistry reactions involving NOx.

A variation of the NGCC is the natural gas combined heat and power cycle (NGHPC). In such plants, the waste heat recovered from the turbine exhaust gas is not used to produce steam for electricity generation; instead, it is used to supply heat to an adjacent facility, such as a refinery. The end result is a plant that produces both electricity and useful heat. NGHPC plants have even higher overall energy efficiencies than NGCC plants, at lower capital costs, due to the elimination of the steam cycle. Several NGHCC systems are being used in oil, gas and petrochemical industries across Canada.
3.0 PCC, IGCC and NGCC: Environmental and Economic Performance

Table 1 highlights key performance standards for current/future PCC and IGCC, current IGCC demonstration plants, and current NGCC. The cost and performance data for IGCC are updated from the original 2001 combustion technologies assessment and include up-to-date information and the actual performance of the operating Wabash River and Polk IGCC plants.

Table 1: Comparison of Present and Projected Environmental Performance and Economic Costs of PCC, IGCC and NGCC

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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PCC</td>
<td>IGCC</td>
<td>PC</td>
<td>IGCC</td>
<td>PC</td>
<td>IGCC</td>
</tr>
<tr>
<td>Capital Cost (US$/kW)</td>
<td>1,000–1,200</td>
<td>1,200–1,500</td>
<td>900–1,100</td>
<td>1,000–1,200</td>
<td>900–1,000</td>
</tr>
<tr>
<td>Efficiency (% HHV)</td>
<td>40–43</td>
<td>40–44</td>
<td>45–50</td>
<td>45–50</td>
<td>50–53</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th></th>
<th>PCC</th>
<th>IGCC</th>
<th>PC</th>
<th>IGCC</th>
<th>PC</th>
<th>IGCC</th>
<th>Wabash IGCC</th>
<th>Polk IGCC</th>
<th>NGCC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO₂ Emission Rate without Capture (kg/MWh)</strong></td>
<td>722–941&lt;sup&gt;12&lt;/sup&gt;</td>
<td>682–846&lt;sup&gt;12&lt;/sup&gt;</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>CO₂ Reduced by 20%&lt;sup&gt;13&lt;/sup&gt;</td>
<td>-</td>
<td>344–364&lt;sup&gt;12&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>CO₂ Emission Rate with capture (kg/MWh)</strong></td>
<td>59–148&lt;sup&gt;12&lt;/sup&gt;</td>
<td>70–152&lt;sup&gt;12&lt;/sup&gt;</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>40–63&lt;sup&gt;12&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>SO₂—Coal Specific (ng/J)</strong></td>
<td>198–1,462</td>
<td>43</td>
<td>4.5–5</td>
<td>4.5–5</td>
<td>&lt;1 Matching to NGCC</td>
<td>51.6&lt;sup&gt;14&lt;/sup&gt;</td>
<td>64.5&lt;sup&gt;14&lt;/sup&gt;</td>
<td>0–0.7&lt;sup&gt;15&lt;/sup&gt;</td>
<td></td>
</tr>
<tr>
<td><strong>NOₓ (ng/J)</strong></td>
<td>219–258</td>
<td>64</td>
<td>4–5</td>
<td>&lt;4</td>
<td>64.5&lt;sup&gt;14&lt;/sup&gt;</td>
<td>116.2&lt;sup&gt;14&lt;/sup&gt;</td>
<td>5&lt;sup&gt;18&lt;/sup&gt;</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Mercury Removal (%)</strong></td>
<td>n/a</td>
<td>50</td>
<td>70–90</td>
<td>&gt;90</td>
<td>0.0019 (ng/J)&lt;sup&gt;14&lt;/sup&gt;</td>
<td>0.0022 (ng/J)&lt;sup&gt;14&lt;/sup&gt;</td>
<td>0&lt;sup&gt;15&lt;/sup&gt;</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PM&lt;sub&gt;10&lt;/sub&gt; and PM&lt;sub&gt;2.5&lt;/sub&gt; (ng/J)</strong></td>
<td>15–30</td>
<td>5</td>
<td>2–3</td>
<td>&lt;2</td>
<td>5.2&lt;sup&gt;14&lt;/sup&gt;</td>
<td>6.5&lt;sup&gt;14&lt;/sup&gt;</td>
<td>2&lt;sup&gt;15&lt;/sup&gt;</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>VOCs (mg/Nm³ flue gas)</strong></td>
<td>1/150 of permitted</td>
<td>1</td>
<td>&lt;1</td>
<td>11.3 (ng/J)&lt;sup&gt;16&lt;/sup&gt;</td>
<td>-</td>
<td>1&lt;sup&gt;15&lt;/sup&gt;</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Efficiency Derating for 90% CO₂ Removal (%HHV)</strong></td>
<td>7–12</td>
<td>6–8</td>
<td>4–7</td>
<td>4–5</td>
<td>2–4</td>
<td>2–3</td>
<td>-</td>
<td>-</td>
<td>7.4&lt;sup&gt;12&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Capital Cost for CO₂ Removal (US$/kW)</strong></td>
<td>700–900</td>
<td>300–800</td>
<td>500–600</td>
<td>200–500</td>
<td>300–400</td>
<td>100–300</td>
<td>-</td>
<td>-</td>
<td>373–1330&lt;sup&gt;12&lt;/sup&gt;</td>
</tr>
</tbody>
</table>


Environmental Performance

A review of the available information indicates that IGCC and NGCC outperform all other coal combustion technologies for environmental performance, including PCC. Further, NGCC strongly outperforms coal combustion in every emissions category, while the same is true for IGCC vis-à-vis PCC. It should also be noted that NGCC’s environmental performance today still outperforms (or is comparable) to future projections for PCC and IGCC out to 2025.

Specifically, when compared to IGCC (and in the absence of carbon capture on either process) NGCC emits:

- ~1/2 the CO$_2$ (344–364 kg/MWh versus 682–846 kg/MWh)
- ~0 SO$_2$ emissions (0–0.7 ng/J versus 43 ng/J)
- <1/12 the NOx emissions (5 ng/J versus 64 ng/J)
- 0 mercury emissions (0 versus 50% removal)
- <1/2 the PM emissions (2 ng/J versus 5 ng/J)

Meanwhile, IGCC clearly outperforms PCC (also in the absence of carbon capture) by emitting:

- slightly less CO$_2$ (682–846 kg/MWh versus 722–941 kg/MWh)
- <1/4 of the SO$_2$ emissions (43 ng/J versus 198–1,462 ng/J)
- <1/12 the NOx emissions (64 ng/J versus 219–258 ng/J)
- <1/3 the PM emissions (5 ng/J versus 15–30 ng/J)

IGCC offers the additional advantage of cheaper and easier carbon capture and storage (CCS) possibilities over PCC and NGCC. As such, proponents of IGCC often mention CCS as a viable add-on to the technology, with some observers$^{18}$ having gone so far as to analyze varying degrees of IGCC-based capture for technical and economic performance. In light of such

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speculative discussions in the Ontario context, this report examines the potential for CCS in Ontario (section 5).

### 3.2 Capital Costs

NGCC outperforms all coal combustion technologies in terms of capital cost. Table 1, above, illustrates this outperformance relative to both PC and IGCC at current and even future projections out to 2025. The capital costs of both coal combustion options exceed that of NGCC by more than 200%. In fact, the high capital cost of IGCC has impeded its economic attractiveness.

Current capital costs estimates for the three technologies are shown in Table 2.

<table>
<thead>
<tr>
<th>Generating Technology</th>
<th>Cost (US$/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NGCC</td>
<td>450</td>
</tr>
<tr>
<td>IGCC</td>
<td>1,200–1,500</td>
</tr>
<tr>
<td>PC</td>
<td>1,000–1,200</td>
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</table>

As shown in Table 3, the incremental capital cost of adding CO₂ capture is lower for IGCC than for either NGCC or PC.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Additional Capital Cost of CO₂ Capture (US$/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NGCC</td>
<td>373–1,330</td>
</tr>
<tr>
<td>IGCC</td>
<td>300–800</td>
</tr>
<tr>
<td>PC</td>
<td>700–900</td>
</tr>
</tbody>
</table>

In the future companies will likely be expected to include measures or offsets to reduce GHG emissions.

### 3.3 Operating Costs — Fuel

The key weakness of NGCC power systems is the volatility of feedstock (natural gas) prices. While natural gas may serve as an ideal bridging fuel to a sustainable future, questions remain over whether an adequate supply is available to meet Ontario’s increase in demand for natural gas that could result from a phase out of coal and nuclear power.\(^\text{19}\) Further questions remain over whether natural gas as an input will be available at a level and stability of price that would keep NGCC generation cost competitive relative to electricity production from other fuel sources, such as coal. The high level of volatility in natural gas prices has been a “concern to investors

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\(^{19}\) For a discussion of the potential role of natural gas as a transitional fuel in Ontario see Winfield, Horne, McClenghean and Peters, *Power for the Future.*
and developers of natural gas-fired facilities\textsuperscript{20} with the price of natural gas fluctuating by as much as $8 \text{ Cdn} per gigajoule in a calendar year.

A review of projected future North American natural gas prices, gathered from a variety of projections from government, industry and industry observer sources, is presented in Table 4.

### Table 4: Projected North American Natural Gas Prices 2005–2025

<table>
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<tr>
<td><strong>Canadian Market</strong></td>
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</tr>
<tr>
<td>NEB (Industrial use) Supply Push scenario\textsuperscript{21}</td>
<td>1986 Cd$/GJ</td>
<td>5.00</td>
<td>5.40</td>
<td>5.10</td>
<td>4.90</td>
<td>4.75</td>
<td>5% decrease</td>
</tr>
<tr>
<td>NEB (Industrial use) Techno-vert\textsuperscript{22}</td>
<td>1986 Cd$/GJ</td>
<td>4.90</td>
<td>4.85</td>
<td>4.60</td>
<td>4.40</td>
<td>4.25</td>
<td>13% decrease</td>
</tr>
<tr>
<td>NRCan (AECO-C)\textsuperscript{23}</td>
<td>Cdn$/GJ</td>
<td>6.25</td>
<td>6.75</td>
<td></td>
<td></td>
<td></td>
<td>8% increase</td>
</tr>
<tr>
<td>Power for the Future (AECO-C)</td>
<td>Cdn$/GJ</td>
<td>4.50</td>
<td>4.70</td>
<td>5.00</td>
<td>4.30</td>
<td>4.90</td>
<td>9% increase</td>
</tr>
<tr>
<td><strong>American Market</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sproule (Henry Hub)</td>
<td>US$/mmbtu</td>
<td>7.34</td>
<td>6.14</td>
<td>6.62</td>
<td>7.12</td>
<td>7.67</td>
<td>4% increase</td>
</tr>
<tr>
<td>NRCan (NYMEX)\textsuperscript{24}</td>
<td>US$/mmbtu</td>
<td>5.55</td>
<td>6.25</td>
<td></td>
<td></td>
<td></td>
<td>13% increase</td>
</tr>
<tr>
<td>Energy Information Assoc. (Lower 48 wellhead)</td>
<td>2003 US$/mcf</td>
<td>5.30</td>
<td>3.64</td>
<td>4.16</td>
<td>4.53</td>
<td>4.79</td>
<td>10% decrease</td>
</tr>
<tr>
<td>Global Insight</td>
<td>2003 US$/mcf</td>
<td>3.84</td>
<td>3.96</td>
<td></td>
<td></td>
<td></td>
<td>3% increase</td>
</tr>
<tr>
<td>Energy Ventures Analysis</td>
<td>2003 US$/mcf</td>
<td>3.71</td>
<td>3.98</td>
<td></td>
<td></td>
<td></td>
<td>7% increase</td>
</tr>
<tr>
<td>DB</td>
<td>2003 US$/mcf</td>
<td>3.66</td>
<td>3.66</td>
<td></td>
<td></td>
<td></td>
<td>No change</td>
</tr>
<tr>
<td>Strategic Energy and Economic Research</td>
<td>2003 US$/mcf</td>
<td>3.9</td>
<td>4.26</td>
<td></td>
<td></td>
<td></td>
<td>9% increase</td>
</tr>
<tr>
<td>Altos</td>
<td>2003 US$/mcf</td>
<td>3.92</td>
<td>5.78</td>
<td></td>
<td></td>
<td></td>
<td>47% increase</td>
</tr>
</tbody>
</table>

The data provided in Table 4 were used to calculate simple averages, shown in Table 5.\textsuperscript{25}


\textsuperscript{21} National Energy Board, Canada’s Energy Future: Scenarios for Supply and Demand to 2025 (Calgary: NEB, 2003), \url{www.neb.gc.ca/energy/supplyDemand/2003/supplyDemand2003_e.pdf}.

\textsuperscript{22} National Energy Board, Canada’s Energy Future.

\textsuperscript{23} Natural Resources Canada, Natural Gas Review of 2004 & Outlook to 2020: Executive Summary, (Ottawa: NRCAN, Natural Gas Division Petroleum Producers Branch, Energy Policy Sector, 2005), \url{www2.nrcan.gc.ca/energy/Capsules/NaturalGas2004EnG_e.pdf}.

\textsuperscript{24} Natural Resources Canada, Natural Gas Review of 2004 & Outlook to 2020.
Table 5: Aggregated Natural Gas Projected Price Changes 2005-2025

<p>| | |</p>
<table>
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<tbody>
<tr>
<td>Average of all positive and negative 2025 changes (%)</td>
<td>13.4</td>
</tr>
<tr>
<td>Average of all positive increases only (%)</td>
<td>21.0</td>
</tr>
<tr>
<td>Average of positive increases (without Altos 47% outlier) (%)</td>
<td>11.7</td>
</tr>
</tbody>
</table>

In summary, the available long-term projections of natural gas prices, a key factor in the operating costs of NGCC, suggest only moderate increases in price out to 2025. Studies completed by Professor Peter Douglas at the University of Waterloo suggest that NGCC is the preferred option for achieving reductions of electricity-related CO$_2$ emissions in Ontario within these projected price ranges.\(^{26}\)

### 3.4 Summary of Key Findings

The key findings of this section are as follows:

- NGCC outperforms all coal-based options in all categories of emissions now and into the foreseeable future.
- Among the coal-based options, IGCC outperforms all other options in all categories of emissions now and into the foreseeable future.
- NGCC outperforms IGCC and PCC in terms of capital costs (100–200%) if there are no requirements to offset or capture CO$_2$ emissions.
- The incremental costs of adding carbon capture to IGCC are lower than with all other generating options, although IGCC with carbon capture has yet to be put into practice.
- Long-term projections of natural gas prices, a key factor in the operating costs of NGCC, suggest only moderate increases in price out to 2025.

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\(^{25}\) Where price forecasts dated 2005 were not listed, an extrapolated point was generated by doubling the percentage increase from 2015 to 2025 to account for the time between 2005 and 2015 assuming that the trend of percentage increase can be extrapolated back to 2005. Then the aggregate percentage increase was taken as 2005 to 2025 for all data points.

4.0 IGCC Commercialization

4.1 Plants Currently in Operation in North America

IGCC is still a rarely used technology for coal combustion-based electricity generation. As of 2004 there were only a few IGCC commercially sized electricity generation plants operating worldwide; two of these are in North America (both in the United States).\(^{27}\) Of note, only one has a dedicated coal fuel stream. The existing plant locations, their generating capacity, fuel stream, and the year completed are as follows:

- Wabash River, USA, 262 MW, coal and/or coke, 2001
- Polk, Tampa, USA, 250 MW, coal and/or coke, 2001
- Buggenum, Netherlands, 253 MW, coal, 2000
- Shell Pernis Netherlands, 120 MW, cogeneration, refinery bottoms
- Elcogas, Puertollano, Spain, 298 MW, 50:50 coal:petroleum coke, 1998
- Sarlux, Italy, 551 MW, petroleum coke
- Negishi, Japan, 342 MW, asphalt, 2003

The IGCC plants in Wabash River and Polk are demonstration projects to which the U.S. Department of Energy (DOE) provided a 50% capital cost subsidy. Details on their costs and performance are outlined here:

- Wabash River, a re-powered plant, started production in November 1995 with a total capital cost of US $438 million, of which US $219M (or 50%) was provided by the DOE.\(^{28}\) Plant efficiency\(^{29}\) is 37.8–40.2%. The project initially encountered environmental problems, such as the presence of arsenic, selenium, and cyanide in wastewater streams, and SO\(_2\) and NO\(_x\) emissions exceeding *Clean Air Act* requirements.\(^{30}\)
- The Polk plant, the first U.S. greenfield IGCC plant,\(^{31}\) started production in September 1996 with a total project cost of US $303.3 million, of which US $151M (49%) was provided by the DOE. Emissions of sulphur oxides, nitrogen oxides, and particulates are well below regulatory limits, with an efficiency of 35.4% HHV, though this is slightly lower than the design efficiency of 38.6%.\(^{32}\)


\(^{27}\) Ontario Power Authority, *Supply Mix Advice and Recommendations Report*, (2005),
www.powerauthority.on.ca/Report_Static/1139.htm

\(^{28}\) U.S. Department of Energy, National Energy Technology Laboratory, *Wabash River Coal Gasification Repowering Project*.

\(^{29}\) Where efficiency describes how much energy in the fuel is converted into electrical energy.

\(^{30}\) U.S. Department of Energy, National Energy Technology Laboratory, *Wabash River Coal Gasification Repowering Project*.

www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html

Despite a total project cost of US $335.9 million, of which US $167.9M (50%) was provided by the DOE, equipment problems with the filter-fines removal system and the gasifier resulted in discontinuation of the plant startup in 2001.\textsuperscript{33}

### 4.2 Proposed Plants in North America

Despite the mixed performance and reliance on subsidization amongst the U.S. IGCC plants, many more such plants are planned. Currently, there are 140 proposed coal plants in the U.S, promising a total of 85 GW of power at an investment of US $119 billion. The addition of this power capability is roughly equal to the power needed to supply 85 million homes.\textsuperscript{34} Of the 140 coal power plants proposed, 14 are slated to be IGCC plants, with one that will incorporate CCS. Nine of the 14 are scheduled to be completed by 2012.

The 14 proposed plants are listed below:

- **FutureGen**, 275 MW, location still to be determined. A ten-year, US $1 billion project integrating IGCC with CCS, with the power industry contributing 20% of the capital costs.\textsuperscript{35} Scheduled to be in service by 2012.\textsuperscript{36}
- **Excelsior Energy — Mesaba**, 531 MW, near Hibbing, Minnesota. Scheduled to be in service by 2010. The DOE will provide US $36 million (1.8%) toward the US $1.97 billion cost.\textsuperscript{37}
- **Orlando Utilities Commission**, 285 MW, Orange County, Florida. Scheduled to be in service by 2010.\textsuperscript{38} The DOE will contribute US $235 million (42%) of the estimated US $557 million total cost.\textsuperscript{39}
- **American Electric Power**, 600 MW, Meigs County, Ohio. Scheduled to be in service by 2010.\textsuperscript{40}
- **The ERORA Group**, 770 MW, near Taylorville, Illinois.\textsuperscript{41} The DOE will provide US $60 million (14.5%) in funding support for the US $414 million total cost.\textsuperscript{42} Scheduled to be in service by 2010.\textsuperscript{43}

\textsuperscript{S8pCpG/native/805670.pdf}.


\textsuperscript{36} FutureGen Alliance, “Timeline,” www.futuregenalliance.org/about/timeline.stm.

www.netl.doe.gov/publications/factsheets/project/Proj342.pdf

\textsuperscript{38} U.S. Department of Energy, National Energy Technology Laboratory, \textit{Tracking New Coal-Fired Power Plants}.  


\textsuperscript{40} U.S. Department of Energy, National Energy Technology Laboratory, \textit{Tracking New Coal-Fired Power Plants}.


\textsuperscript{43} U.S. Department of Energy, National Energy Technology Laboratory, \textit{Tracking New Coal-Fired Power Plants}.  

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\textsuperscript{14} The Pembina Institute • \textit{A Comparison of Combustion Technologies for Electricity Generation}
The Global Kentucky Pioneer Energy project (540 MW), scheduled to start up in 2004 in Clark County, Kentucky, was cancelled due to permitting issues, financing, and the loss of their power-purchase agreement. The DOE has provided US $78 million in cost shared funding support of the estimated US $432 million project cost.

4.3 Barriers to Commercialization of IGCC

Despite the expansion of IGCC projects in the U.S., such projects have not proceeded without funding from the U.S. DOE; the technology is thus considered by some to still be commercially unproven. IGCC plants account for only 14 of 140 proposed new coal plants in the U.S. and none in Canada.

The National Association of Regulatory Utility Commissioners (NARUC) completed a detailed, comprehensive survey analyzing the barriers impeding IGCC commercialization in the U.S. The survey consisted of 48 participants who were experts and/or institutional stakeholders representing energy companies, technology-engineering companies, government organizations, and consulting companies.

One of the key barriers identified was financial, including high capital costs, reliance on government subsidies and high front-end engineering costs. Other observers noted political
barriers, such as a lack of public and political demand for IGCC-based plants. In Canada in particular these barriers included the political uncertainty around Canadian federal government changes to Canada’s climate change strategy and its participation in the Kyoto Protocol, and the corresponding uncertainty of emissions reduction-based tax credits and favourable environmental regulations.  

Finally, the NARUC study listed two technology barriers: the risk of low plant availability in the early stages of operation (existing IGCC plants have had varying rates of availability) and the poor initial performance records of the Wabash River and Pinon Pine plants. These risks are aggravated by a lack of performance guarantees from a single vendor, as IGCC projects are normally constructed through a mosaic of vendors and service providers.

In a future context of CO$_2$ emissions pricing as a result of, for example, “cap-and-trade” regulations, the economic attractiveness of IGCC may improve. The Pembina Institute has constructed a range of plausible future scenarios of CO$_2$ emissions pricing for new large industrial facilities in Canada. Under these scenarios, the financial liability from emissions pricing results in an additional cost for an illustrative coal-fired electricity generation facility of about 1 to 5¢/kWh in 2025 and about 5 to 15¢/kWh in 2050.  

When building a new generating plant, these escalating future financial liabilities may make using either IGCC or IGCC with carbon capture economically preferable to conventional coal-fired technologies.

### 4.4 Summary of Key Findings

The key findings of this section are as follows:

- IGCC is still a rarely used technology for coal combustion-based electricity generation, with only one plant using dedicated coal as a fuel source, and two others using a coal and coke mix. There are no IGCC plants yet operating in Canada.
- Two IGCC plants are currently in operation in North America, both in the U.S.: Wabash River and Polk. Approximately half their capital costs were covered by the U.S. DOE.
- Fourteen IGCC-based plants are currently being proposed in the U.S., one of which will feature CCS.
- There are still financial and technological barriers to IGCC commercialization, particularly the high capital costs associated with the technology. The financial attractiveness of the technology would be improved by the pricing of CO$_2$ emissions, as is likely to occur in the near future.

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58 Manfred Klein (Electricity and Industrial Combustion Division), in discussion with author, April 20, 2006.
5.0 Carbon Capture and Storage Options for Ontario

One of the features of IGCC technology is that, in theory, it is more feasible to capture the CO$_2$, the most important of the long-lived GHGs, from the operation of IGCC facilities than from other fossil fuel-fired technologies. This opens the possibility that GHG emissions from the IGCC facilities might be captured and stored or sequestered, rather than released into the environment.

The Pembina Institute’s earlier work on carbon capture and storage (CCS) focussed on the possibilities of applying this technology in western Canada.$^{60}$ This section explores the possibilities for applying CCS in an Ontario context.

To geologically store CO$_2$, the storage locations must meet several requirements, as outlined by Stefan Bachu of the Alberta Geological Survey:$^{61}$

- Adequate space to store large volumes of CO$_2$ emissions
- Injectivity of the formation to accept CO$_2$ at efficient delivery rates
- Confining ability of the formation to prevent leakage and migration
- Adequate depth (>1000 m)
- Minimally faulted, fractured, folded
- Ability to avoid contamination of energy, mineral, and groundwater resources
- Ability to avoid risk to life (plants, animals, humans)
- Ability to minimize leakage for the desired time period.

Many of these criteria can be met in some areas of Alberta, but are less likely to be met in Ontario. The geology of the Canadian Shield, which constitutes the bulk of northern Ontario, is inappropriate for CCS. Furthermore, preliminary work completed by the Alberta Research Council for Natural Resources Canada concluded that the sedimentary strata of southwestern Ontario and southern Quebec were considered the lowest priority in terms of their potential for CCS. The Western Canada Sedimentary Basin, and basins in Nova Scotia and Manitoba, were identified as more likely candidates.$^{62}$

Other important factors to include are site accessibility, surface infrastructure, distance to CO$_2$ source (to minimize transportation costs), surface/subsurface/social conflicts, avoidance of emissions penalties and low seismic risk.$^{63}$

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$^{60}$ Griffiths, Cobb and Marr-Laing, *Carbon Capture and Storage.*


$^{63}$ Stefan Bachu, “Site Selection for CO$_2$ Capture and Geological Storage (CCGS).”
Two methods of current commercial carbon sequestration are injection into oil and gas wells, and into deep saline aquifers. While deep coal seams are another sequestration option at other locations, no deep coal seams exist in Ontario.\(^{64}\)

### 5.1 Oil and Gas Wells

Since 1858, southern Ontario has seen a cumulative production of 1.3 Tcf natural gas from 262 gas pools and 85 million barrels of oil from 137 oil pools, producing 6,502 abandoned wells. While depleted oil and gas reservoirs may offer an opportunity to sequester and store CO\(_2\), the possible issues associated with CO\(_2\) storage in hydrocarbon reservoirs include unplugged wells, small pool sizes, and shallow depths.\(^{65}\) As such, a substantial amount of historical and technological research would be required to determine whether CO\(_2\) storage in depleted oil and gas reservoirs is a viable option in Ontario.

The current condition of Ontario’s oil and gas reservoirs is not well documented\(^{66}\) nor have long-term storage issues been explored.\(^{67}\) Wells in Ontario have been abandoned anywhere between 20–90 years, requiring testing to determine the quality, quantity, and strength of existing cement plugging. The possibility of CO\(_2\) reacting with the cement plugging (thereby resulting in leakage) requires investigation as well.\(^{68}\) For oil and gas reservoir sequestration to occur, these wells must be investigated in detail to determine their status, their ability to prevent leaks under sequestration pressure, and the impact that would result should a failure occur.\(^{69}\)

The situation is further complicated by seismic instability in southern Ontario. It has been suggested that a magnitude 7 earthquake could occur, on average, once every 3,000 years in the region.\(^{70}\)

Other information required to determine the possibility of CO\(_2\) sequestration in hydrocarbon reservoirs in Ontario would include\(^{71}\)

- the location of unmapped faults and fractures
- the presence of undiscovered hydrocarbons
- the possibility of abandoned well cap corrosion by CO\(_2\)
- the porosity, permeability, migration pathways and migration distance of potential reservoir locations
- reservoir temperature
- sweep efficiency and potential geochemical reactions.

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\(^{65}\) Carter and O’Connor-Hames, “Geological Opportunities for Carbon Sequestration in Ontario.”


\(^{67}\) Carter and O’Connor-Hames, “Geological Opportunities for Carbon Sequestration in Ontario.”

\(^{68}\) Shafeen, Croiset, Douglas, Chatzis and Seckington, “Techno-Economic Assessment of Geological CO\(_2\) Sequestration in Ontario.”


Gathering this information would itself be a major technical and scientific undertaking.

## 5.2 Saline Aquifers

A saline aquifer is underground porous rock filled with salty or saline water.\(^{72}\) For the purpose of carbon sequestration, CO\(_2\) is pumped into the pore spaces displacing the salty water. The CO\(_2\) rises to the top of the aquifer and, over tens to hundreds of years, eventually dissolves into the salty water, reacting with minerals in the formation to form stable compounds similar to carbonate.\(^{73}\) One example of commercially operated saline aquifer sequestration is the Sleipner Project operated by Statoil in the North Sea off the coast of Norway, where CO\(_2\) is compressed and pumped into a 200 m thick sandstone layer located 1,000 m below the sea floor. Approximately one million tonnes of CO\(_2\) have been sequestered annually since 1996.\(^{74}\)

Saline aquifers have been identified as the preferred option for CO\(_2\) sequestration in Ontario by the CANMET Energy Technology Centre. The saline aquifers identified in Ontario are 800 m below the surface and contain suitable cap rock for CO\(_2\) to be sequestered under supercritical conditions.\(^{75}\) Still, risks associated with saline aquifer sequestration include migration, leakage to atmosphere and seismic hazards. Saline aquifers require cap rock to prevent the vertical leaks of CO\(_2\) back up to the surface and horizontal migration.

Despite the availability of aquifers, the CANMET researchers acknowledge that it will be difficult to get public support for CCS in southwestern Ontario because of the population density of the surrounding areas, safety concerns around blowouts, environmental concerns related to Lake Erie, proximity to the U.S. border and the necessity of state-of-the-art monitoring.\(^{76}\) The seismically active nature of the region would add further complications.

In addition there is emerging evidence that CO\(_2\) sequestered in saline aquifers changes the acidity of the brine, causing carbonates in the rock to dissolve rapidly. Naturally occurring minerals that had previously sealed the pores and fractures in the rock would then be able to leak CO\(_2\) and fouled brine.\(^{77}\)

Before CCS in Ontario saline aquifers can be considered a viable option, further studies will be required. These would include\(^{78}\):

- reservoir characterization (drilling experimental wells, identifying formation water chemistry, identifying formation water hydrodynamics, determining sweep efficiency, identifying fault characteristics)
- reservoir modeling
- evaluation of pipeline routes
- evaluation of seismic activity induced by deep well injection

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\(^{72}\) Carter and O’Connor-Hames, “Geological Opportunities for Carbon Sequestration in Ontario.”


\(^{74}\) Herzog, “What Future for Carbon Capture and Sequestration?”

\(^{75}\) Shafeen, Croiset, Douglas, Chatzis and Seckington, “Techno-Economic Assessment of Geological CO\(_2\) Sequestration in Ontario.”

\(^{76}\) Shafeen, Croiset, Douglas, Chatzis and Seckington, “Techno-Economic Assessment of Geological CO\(_2\) Sequestration in Ontario.”


\(^{78}\) Shafeen, “CO\(_2\) Sequestration Opportunities for Ontario.”
evaluation of caprock integrity

determination of abandoned well status

investigation of legal issues, including coordination with affected U.S. jurisdictions (e.g., Michigan, Pennsylvania, Ohio, New York)

investigation of undiscovered hydrocarbons

testing of abandoned well integrity for CO₂ corrosion

more detailed evaluation of porosity and migration.

These investigations would again be a major technical and scientific undertaking and may ultimately lead to the conclusion that CCS is not a viable option.

5.3 Economic Barriers

Even if CCS options were to become feasible, it has been estimated that, for CCS to be used with IGCC, there must be a carbon tax or equivalent above US $90/ton and natural gas prices exceed a threshold of US $4-6/GJ. Other studies have suggested that the IGCC and CCS technologies would become attractive at an avoided cost of CO₂ ranging from US $20–190/tonne.

5.4 Summary of Key Findings

The key findings of this section are as follows:

Two potential options for CCS have been identified in Ontario: storage in depleted oil and gas reservoirs, and sequestration in saline aquifers.

The current condition of Ontario’s oil and gas reservoirs is not well documented, and therefore their suitability for CCS is difficult to assess. Significant technical and scientific investigations would be required to establish their viability for storage.

Saline aquifers have been identified as the preferred option for CO₂ sequestration in Ontario by one group of researchers. However, significant technical and scientific investigations would be required to establish the viability of this option.

There is emerging evidence showing that the addition of CO₂ to saline aquifers can increase the acidity of the brine, with the potential to dissolve minerals in surrounding rock, thus

79 Carter and O’Connor-Hames, Geological Opportunities for Carbon Sequestration in Ontario.
80 Carter and O’Connor-Hames, Geological Opportunities for Carbon Sequestration in Ontario.
81 Carter and O’Connor-Hames, Geological Opportunities for Carbon Sequestration in Ontario.
82 T.G. Kreutz and R.H. Williams, “Competition Between Coal and Natural Gas in Producing H₂ and Electricity Under CO₂ Emission Constraints” (paper presented at the 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada).
raising the possibility of leaks of CO₂ and fouled brine.

- The potential for seismic activity in southern Ontario presents significant barriers to CCS options in the region.
- In addition to these technical challenges, CCS options in Ontario would face significant political, economic and social barriers.
- In light of these findings, CCS can only be considered speculative discussion in an Ontario context. It cannot be considered a serious possibility for the purposes of the province’s current electricity policy planning horizon (i.e., 20 years).
Conclusions

6.0 Conclusions

This study updates previous studies on the environmental and economic performance of various coal- and natural gas-fired technologies for electricity generation and examines the viability of CCS as an option for dealing with GHG emissions arising from the use of these technologies for electricity generation. The key findings are as follows:

Combustion Technologies for Electricity Generation

- NGCC outperforms all coal-based options in all categories of emissions now and into the foreseeable future.
- Among the coal-based options, IGCC outperforms all other options in all categories of emissions now and into the foreseeable future.
- IGCC is still a rarely used technology for coal combustion-based electricity generation, with only two commercial-sized facilities operating in North America. There are no IGCC plants yet operating in Canada.
- NGCC outperforms IGCC and PCC in terms of capital costs (by 100–200%) if there are no requirements to offset or capture CO₂ emissions.
- The incremental costs of adding carbon capture to IGCC are lower than with all other generating options, although IGCC with carbon capture has yet to be put into practice. An IGCC facility with carbon capture is currently being proposed for North America.
- Full commercialization of IGCC faces financial and technological barriers, particularly the high capital costs associated with the technology. The financial attractiveness of the technology would be improved by the pricing of CO₂ emissions, as is likely to occur in the near future.
- Long-term projections of natural gas prices, a key factor in determining the operating costs of NGCC, suggest only moderate increases in price out to 2025.

Carbon Capture and Storage in Ontario

- Two potential options for CCS have been identified in Ontario: storage in depleted oil and gas reservoirs, and sequestration in saline aquifers.
- The current condition of Ontario’s oil and gas reservoirs is not well documented, and therefore their suitability for CCS is difficult to assess. Significant technical and scientific investigations would be required to establish their viability for storage.
- Saline aquifers have been identified as the preferred option for CO₂ sequestration in Ontario by one group of researchers. However, significant technical and scientific investigations would be required to establish the viability of this option.
- There is emerging evidence showing that the addition of CO₂ to saline aquifers can increase the acidity of the brine, with the potential to dissolve minerals in surrounding rock, thus raising the possibility of leaks of CO₂ and fouled brine.
- The potential for seismic activity in southern Ontario presents significant barriers to CCS options in the region.
- In addition to these technical challenges, CCS options in Ontario would face significant political, economic and social barriers.
- CCS can only be considered a speculative discussion in an Ontario context. It cannot be considered a serious possibility for the purposes of the province’s current electricity policy planning horizon (i.e., 20 years).
Appendix 1: A Comparison of Combustion Technologies for Electricity Generation

(Pembina Institute: First Published October 2001)

The following tables compare coal combustion technologies. They summarize the characteristics of the various coal-fired generating technologies and compare them with cleaner burning natural gas systems. Footnotes and a glossary of abbreviations appear immediately following the tables. All dollars are Canadian currency unless otherwise noted.

### Environmental Performance

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<td><strong>Plant Efficiency</strong></td>
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<td>38-43%</td>
<td>36%</td>
<td>42% ii</td>
<td>45%</td>
<td>52%</td>
<td>~60%</td>
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<td><strong>Heat Rate</strong> (GJ/MWh)</td>
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<td>9.5-8.4</td>
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<td>8.6</td>
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<td>6.0 per equiv. MWh</td>
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<td><strong>CO₂ (kg/MWh)</strong> ii</td>
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<td>870-770</td>
<td>920</td>
<td>790</td>
<td>735</td>
<td>400</td>
<td>350</td>
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<tr>
<td><strong>Heat Rate (GJ/MWh)</strong></td>
<td>10.9</td>
<td>9.5-8.4</td>
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<td>8.6</td>
<td>8.0</td>
<td>6.9</td>
<td>6.0 per equiv. MWh</td>
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<tr>
<td><strong>CO₂ (kg/MWh)</strong> ii</td>
<td>1000</td>
<td>870-770</td>
<td>920</td>
<td>790</td>
<td>735</td>
<td>400</td>
<td>350</td>
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<tr>
<td><strong>SO₂ (kg/MWh) – no FGD</strong></td>
<td>1.6 i</td>
<td>1.4 vi</td>
<td>0.3 vii</td>
<td>0.12 ii</td>
<td>~ zero</td>
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<td>~ zero</td>
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<td><strong>SO₂ (ng/J) – no FGD</strong></td>
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<td>221</td>
<td>30 vii</td>
<td>14</td>
<td>~ zero</td>
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<tr>
<td><strong>SO₂ (ng/J) – with FGD</strong></td>
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<td>&lt; 66</td>
<td>Not required</td>
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<td>Not required</td>
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<td>Not required</td>
</tr>
<tr>
<td><strong>NOₓ (kg/MWh) – no SCR</strong></td>
<td>2.1 i</td>
<td>1.8 vi</td>
<td>0.5 vii</td>
<td>&lt;0.7</td>
<td>0.25-0.45 ii (w/ LNB)</td>
<td>0.12 (w/ LNB)</td>
<td>0.12 (w/ LNB)</td>
</tr>
<tr>
<td><strong>NOₓ (ng/J) – no SCR and w/ LNB</strong></td>
<td>86-125 v</td>
<td>86-125 v</td>
<td>43</td>
<td>&lt;86 ii</td>
<td>31-56</td>
<td>18 x</td>
<td>18 x</td>
</tr>
<tr>
<td><strong>NOₓ (ng/J) – with SCR and LNB</strong></td>
<td>43-62</td>
<td>43-62</td>
<td>SCR not required</td>
<td>SCR probably not required</td>
<td>SCR probably not required</td>
<td>SCR probably not required</td>
<td>SCR probably not required</td>
</tr>
<tr>
<td><strong>PM (kg/MWh) – no ESP/Baghouse</strong></td>
<td>0.5</td>
<td>0.4 vi</td>
<td>~0.4</td>
<td>Better than PCC but not as good as IGCC</td>
<td>~ zero</td>
<td>~ zero</td>
<td>~ zero</td>
</tr>
<tr>
<td><strong>PM (ng/J) – no ESP/Baghouse</strong></td>
<td>46</td>
<td>42</td>
<td>~42</td>
<td>Better than PCC but not as good as IGCC</td>
<td>~ zero</td>
<td>~ zero</td>
<td>~ zero</td>
</tr>
<tr>
<td><strong>Mercury</strong></td>
<td>Depends on coal source</td>
<td>Depends on coal source</td>
<td>Depends on coal source</td>
<td>Better than PCC but not as good as IGCC</td>
<td>Little or no air borne mercury</td>
<td>Little or no air borne mercury</td>
<td>Little or no air borne mercury</td>
</tr>
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</table>
## Pollution Control Add-ons

<table>
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<tr>
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</thead>
<tbody>
<tr>
<td>Flue Gas Desulphurization (FGD)</td>
<td>FGD required to meet most standards. Wet FGD can achieve &gt;95% recovery, dry can achieve up to 70-80%.</td>
<td>FGD required to meet most standards. Wet FGD can achieve &gt;95% recovery, dry can achieve up to 70-80%.</td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
</tr>
<tr>
<td>NOx Control: Low NOx Burners (LNB)</td>
<td>LNB can reduce approx. 50% NOx formation.</td>
<td>LNB can reduce approx. 50% NOx formation.</td>
<td>May not be required due to low combustion temperature.</td>
<td>May not be required due to low combustion temperature and LNB on turbine.</td>
<td>Std equipment. Can achieve single digit ppm (better than 90%) NOx in flue gas with LNB.</td>
<td>Std equipment. Can achieve single digit ppm (better than 90%) NOx in flue gas with LNB.</td>
</tr>
<tr>
<td>NOx Control Selective Catalytic Reduction (SCR)</td>
<td>80% NOx removal without ammonia slip problems.</td>
<td>80% NOx removal without ammonia slip problems.</td>
<td>May not be required due to low combustion temperature.</td>
<td>May not be required due to low combustion temperature and LNB on turbine.</td>
<td>May not be required where LNBs are available to reduce NOx by at least 90%.</td>
<td>May not be required where LNBs are available to reduce NOx by at least 90%.</td>
</tr>
<tr>
<td>Note: Typically both LNB and SCR required in PCC plants to meet most standards.</td>
<td></td>
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</tr>
<tr>
<td>Baghouse or ESP</td>
<td>Requires bag house or ESP. Baghouse more efficient and less prone to upsets.</td>
<td>Requires bag house or ESP. Baghouse more efficient and less prone to upsets.</td>
<td>Requires bag house or ESP. Baghouse more efficient and less prone to upsets.</td>
<td>Requires bag house or ESP. Baghouse more efficient and less prone to upsets.</td>
<td>Not Required</td>
<td>Not Required</td>
</tr>
<tr>
<td>Mercury</td>
<td>With baghouse and FGD 60-70% removal. ESPs not as effective.</td>
<td>With baghouse and FGD 60-70% removal. ESPs not as effective.</td>
<td>With baghouse up to 70% removal.</td>
<td>With baghouse up to 70% removal.</td>
<td>Not Required</td>
<td>Not Required</td>
</tr>
<tr>
<td>CO2 Capture</td>
<td>From flue gas, difficult to recover.</td>
<td>From flue gas, difficult to recover.</td>
<td>From flue gas, difficult to recover.</td>
<td>Recovery should be similar to IGCC.</td>
<td>Relative to other options, recovery is more straightforward from off-gas.</td>
<td>From flue gas, difficult to recover.</td>
</tr>
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</table>
## Operational Performance

<table>
<thead>
<tr>
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<tbody>
<tr>
<td><strong>Commercially Proven</strong></td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
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<tr>
<td><strong>Scale</strong></td>
<td>100-1000 MW</td>
<td>100-1000 MW</td>
<td>400 MW guaranteed by manufacturer.</td>
<td>80 MW</td>
<td>100-300 MW</td>
<td>Any size in modular units</td>
<td>Any size in modular units</td>
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<tr>
<td><strong>Reliability and Uptime</strong></td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
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### Economic Performance

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</thead>
<tbody>
<tr>
<td>Capital Cost – main process ($/kW)</td>
<td>$1200-1500</td>
<td>$1275-1575</td>
<td>$1500-1950</td>
<td>$1725-2025</td>
<td>$1800-2100</td>
<td>$1,000</td>
<td>$940</td>
</tr>
<tr>
<td>Capital Cost – add-ons ($/kW)</td>
<td>FGD $105-180</td>
<td>$105-180</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
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<tr>
<td></td>
<td>SCR $60-120</td>
<td>$60-120</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
<td>N/R</td>
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<tr>
<td></td>
<td>LNB $7.5-15</td>
<td>$7.5-15</td>
<td>$7.5-15</td>
<td>$7.5-15</td>
<td>Std.</td>
<td>Std.</td>
<td>Std.</td>
</tr>
<tr>
<td>Total Capital Cost ($/kW)</td>
<td>1373</td>
<td>1448</td>
<td>1508</td>
<td>1733</td>
<td>1800</td>
<td>1000</td>
<td>940</td>
</tr>
<tr>
<td>Return (%)</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
</tr>
<tr>
<td>Life (yrs)</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
<td>35</td>
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<tr>
<td>Total Capital Cost ($/MWh)</td>
<td>23.68</td>
<td>24.97</td>
<td>26.01</td>
<td>29.89</td>
<td>31.06-34.94</td>
<td>17.25</td>
<td>16.22</td>
</tr>
<tr>
<td>Operating Cost ($/MWh)</td>
<td>Labour $2.08</td>
<td>$2.08</td>
<td>$2.32</td>
<td>$2.77</td>
<td>$2.77-3.12</td>
<td>$2.08</td>
<td>$2.08</td>
</tr>
<tr>
<td></td>
<td>Other (100% of labour)</td>
<td>$2.08</td>
<td>$2.08</td>
<td>$2.32</td>
<td>$2.77</td>
<td>$2.77-3.12</td>
<td>$1.63</td>
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<tr>
<td></td>
<td>Energy (GJ/MWh)</td>
<td>$10.9</td>
<td>$9.5</td>
<td>$10</td>
<td>$8.6</td>
<td>$6.9</td>
<td>$6</td>
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<tr>
<td></td>
<td>$/GJ</td>
<td>$1.18</td>
<td>$1.18</td>
<td>$1.18</td>
<td>$1.18</td>
<td>$1.18</td>
<td>$1.18</td>
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<tr>
<td></td>
<td>Energy Cost ($/MWh)</td>
<td>$12.86</td>
<td>$11.21</td>
<td>$11.80</td>
<td>$10.15</td>
<td>$9.44</td>
<td>$27.60</td>
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<tr>
<td>Operating Cost – add ons ($/MWh)</td>
<td>FGD $2.6</td>
<td>$2.6</td>
<td>$2.6</td>
<td>$2.6</td>
<td>$2.6</td>
<td>$2.6</td>
<td>$2.6</td>
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<tr>
<td>Total Operating ($/MWh)</td>
<td>$19.62</td>
<td>$17.97</td>
<td>$16.44</td>
<td>$15.69</td>
<td>$14.98 - 15.67</td>
<td>$31.31</td>
<td>$28.16</td>
</tr>
<tr>
<td>Overall levelized cost to produce electricity ($/MWh)</td>
<td>$43.30</td>
<td>$42.94</td>
<td>$42.45</td>
<td>$45.58</td>
<td>$46.04-50.61</td>
<td>$48.56</td>
<td>$44.38</td>
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</table>
## Rank

(1=Best, 7=Worst)

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</thead>
<tbody>
<tr>
<td>Efficiency/ GHG Ranking</td>
<td>7</td>
<td>5</td>
<td>6</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Sulphur Removal Ranking</td>
<td>7</td>
<td>6</td>
<td>5</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>NOx Control Ranking</td>
<td>7</td>
<td>6</td>
<td>4</td>
<td>5</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>PM Emission Ranking</td>
<td>7</td>
<td>6</td>
<td>5</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Mercury Emission Ranking</td>
<td>7</td>
<td>6</td>
<td>5</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Capital Cost Ranking</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Operating Cost Ranking</td>
<td>5</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
<td>7</td>
<td>6</td>
</tr>
<tr>
<td>Overall Cost to Produce Ranking</td>
<td>3</td>
<td>2</td>
<td>1</td>
<td>4</td>
<td>6</td>
<td>7</td>
<td>5</td>
</tr>
</tbody>
</table>

### Table Footnotes

i Environmental performance characteristics described are at the plant site only. These values do not consider any “upstream” impacts, such as from coal mining operations, natural gas production and processing.


iii Southern Illinois University, Coal Research Center, “Pressurized Fluidized Bed Combustion,” [www.siu.edu/~coalctr/presfbc.htm](http://www.siu.edu/~coalctr/presfbc.htm).

iv Application of terms of the U.S. EPA standard would result in at least 70% removal of sulphur, or about twice what would be required with Alberta standards and Alberta’s coal.

v From EPCOR’s EIA for Genesee 3.

vi Based on ratio of efficiencies (33% vs. 38%).


Appendix 1

xvi Wabash River (one of the U.S. IGCC Demonstration Projects) has begun repaying the DOE and has also achieved 79% overall reliability in 1999, “Clean Coal Today” Newsletter of the Office of Fossil Energy, U.S. DOE, DOE/FE-0215P Issue No. 39, Spring 2000.
xvii All currency in Canadian dollars.
xviii From EPCOR’s EIA for Genesee 3, Vol.1, Figure 2.2.1.
xix Calculation based on the average of Keeihills and Genesee 3 expansions.
xxi Calculated from TransCanada Pipeline’s Press Release for the Redwater and Carseland Cogeneration Projects.
xxii For the PCC options, cost of labour ($2.08/MWh) has been calculated using information from EPCOR’s Genesee 3 Expansion EIA: 60 people, 440 MW, $120,000 per person per year and 90% load factor. This labour cost has been assumed the same for the two natural gas options. Labour for IGCC and PFBC has been determined using EPCOR’s staffing model (60 people) and adding 15 more operators and 5 more maintenance/technical staff to handle the additional complexity of the IGCC and PFBC plants. Labour for AFBC assumes adding 5 more operators and 2 more maintenance/technical staff.
xxiii Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: SUS 35.50/t ($Cdn 53.25/tonne), less transportation at approx. $32/tonne (Vancouver - Edmonton), 18 GJ/tonne gives $Cdn 1.18/GJ. This assumes that value of coal in Edmonton area is related to world market prices for coal.
xxv Lower range of values for IGCC based on same reliability/uptime as for the other options. Higher range of values based on 11% worse reliability of IGCC when compared to the other options.

Glossary of Terms used in Tables

AFBC - Atmospheric Fluidized Bed Combustion
BACT - Best Available Control Technology
CC - Coal Combustion
CO₂ - Carbon Dioxide
ESP - Electrostatic Precipitators
FGD - Flue Gas Desulphurization
GHG - Greenhouse Gases
GJ - Gigajoule
IGCC - Integrated Gasification Combined Cycle
kg - kilogram
LNB - Low NOx Burners
MWh - Megawatt per hour
NGCC - Natural Gas Combined Cycle
NOₓ - Nitrogen Oxides
NR - not required
PCC - Pulverized Coal Combustion
PFBC - Pressured Fluidized Bed Combustion
PM - Particulate Matter
ppm - parts per million
SCR - Selective Catalytic Reduction
SO₂ - Sulphur Dioxide
SO₃ - Sulphur Oxides