
Appendix 4

A Comparison of Combustion Technologies for Electricity Generation

Appendix: A Comparison of Combustion Technologies for Electricity Generation

This appendix provides additional background information to the summary entitled “Best Available Pollution Control Technologies for Coal Combustion” that accompanies a Pembina Institute media release on July 24, 2001.

With commercially available coal-fired technology, it is possible to reduce emissions to levels considerably below those required by the Alberta government. In fact, some of the proven technologies reviewed in this document can achieve much better performance than the new Alberta standards demand; most are commonly used in jurisdictions in the U.S. and Europe and are economically viable at today’s prices for natural gas, electricity and coal. Consequently, the Pembina Institute believes that proponents of new or retrofitted coal-fired plants in Alberta should be required to implement options that have better environmental performance than what is specified in the latest, already outdated, Alberta regulations.

1. Overview of Technologies

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, and electricity is produced from an electrical generator attached to the steam turbine.

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

1.1 Subcritical and Supercritical Pulverized Coal Combustion (PCC)

Coal combustion has traditionally occurred at atmospheric pressure using subcritical steam, but today, greater efficiencies can be obtained by using higher steam pressures in the supercritical range.* Both the 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 1300-1700°C, depending largely on the coal type. Combustion occurs at near-atmospheric pressure, which simplifies the burner and coal handling facilities. Subcritical PCC plants use steam in the range of 16 megapascals (MPa) pressure and 550 °C while supercritical PCC plants use steam with pressures as high as 30 MPa and 600 °C. The higher steam pressure in supercritical plants results in higher energy efficiency – 38-45%, compared with 33% for subcritical plants. While supercritical plants have higher capital costs and some added risk due to the higher pressure and temperature, they have been in commercial use for many years.

* 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.

Most plants in Alberta currently use only low efficiency subcritical coal-fired processes. If conventional pulverized coal combustion is being considered, proponents should use supercritical steam processes to maximize efficiencies.

1.2 Atmospheric and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used with high sulphur coal. In a 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 (SO₂). Conventional boilers, by contrast, simply burn the fuel on a grate in the firebox. FBC plants can remove up to 98% of the SO₂ and the coal burns more efficiently because it stays longer in the combustion chamber.

AFBC plants operate at atmospheric pressure, and NO_x generation is minimized due to lower combustion temperatures (815-875°C) than in conventional PCC plants. In contrast to AFBC plants, 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 NO_x forms. Thus, the fluidized bed designs have reduced SO₂ and NO_x emissions when compared with PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels.

Given that most coal in Alberta has a low sulphur content (less than 1% and sometimes as low as 0.2%, compared with high sulphur coal, which contains up to 5%), it is unlikely that this process would be selected in Alberta.

1.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants are extremely clean 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 is then cleaned, stripped of impurities and used as fuel instead of natural gas in a conventional combined cycle plant (see description of the natural gas combined cycle plant, below). The result is an integrated gasification combined-cycle configuration that provides ultra-low pollution levels and high system efficiencies. The IGCC systems that are operating commercially have demonstrated exceptional environmental

performance. Emissions of SO₂ and NO_x are less than one-tenth of those allowed under U.S. New Source Performance Standards limits. Moreover, IGCC efficiency levels can be as high as 45%.

Most of the existing IGCC plants were built on a demonstration basis with government subsidies; however, these plants are nearing full commercial operation. For example, it is reported that the Wabash River plant in Indiana had an overall reliability of 79% in 1999 and operators are now receiving a lot of interest in their technology. A mechanism is in place for repayment of loans received from the Department of the Environment.

1.4 Comparison with Natural Gas Combined Cycle

The natural gas combined cycle process (NGCC) is not a coal combustion process, but a description is included here for 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. NO_x control in gas turbines is proven technology and can be accomplished with relatively low cost “low NO_x burners.” In addition, NO_x can be reduced still further with such “add-on” control technology as Selective Catalytic Reduction (see below). Emissions of particulate matter are also quite low, although some secondary particulate matter is produced through atmospheric chemistry reactions involving NO_x.

A variation of the NGCC is the natural gas combined heat and power cycle (NGHPC). In these plants, the waste heat recovered from the turbine exhaust gas is not used to produce steam; 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.

2. Add-on Pollution Control Options

A number of pollution control devices are commonly added onto conventional coal-fired plants. These add-ons can enable conventional coal-fired plants to achieve very low levels of emissions and, for some pollutants, the add-on options can result in coal-fired electrical generation being nearly as clean as natural gas-fired generation.

Flue Gas Desulphurization (FGD) – FGD is a process where lime or lime-like material is added to the flue gas to absorb sulphur compounds and reduce the amount of SO₂ emissions. The process can be wet or dry, regenerable or non-regenerable. Often the recovered sulphur or reacted absorbent can be sold as an industrial process chemical. Wet FGD systems can achieve up to 95% sulphur removal, while dry systems can remove up to 70-80% of the sulphur.

Low NO_x Burners (LNBs) – Low NO_x burners are used to control the combustion process to minimize the formation of NO_x. The design of LNBs for gas turbines is well proven and NO_x reduction from LNB-equipped gas turbines exceeds 90%. This level of reduction meets many of the more stringent NO_x regulations in the U.S. and Europe; however, further reductions in NO_x

can be achieved with an SCR unit added to the exhaust of a gas turbine. LNBs for sub and supercritical PCC plants is also well proven but NO_x reduction from LNB-equipped PCC plants is only 50%. This necessitates the use of additional NO_x control equipment such as selective catalytic reduction to enable PCC plants to meet the standards in many parts of the world (although not Alberta).

Selective Catalytic or Non-Catalytic Reduction (SCR or SNCR) – SCR or SNCR is a process that removes NO_x formed in the exhaust gases due to high combustion temperatures. SCR technology involves the injection of ammonia (NH₃) into the exhaust gas, which then passes through a catalyst bed where the ammonia and nitrogen oxides react to form harmless nitrogen and water vapour. SNCR involves a similar process but without the catalytic reaction. Both SCR and SNCR can reduce NO_x emissions by about 80% before ammonia slippage out of the exhaust stack becomes a problem. These technologies have been applied to both gas and coal-fired facilities to further reduce NO_x emissions.

Electrostatic Precipitators (ESPs) and Fabric Filters (Baghouses) – ESPs or baghouses are commonly added to all coal-fired power plants to remove particulate matter and flyash from the exhaust gases. ESPs use an electrostatic charge to attract small particles, whereas baghouses simply filter the particulate matter from exhaust gases using a self-cleaning fabric filter process. ESPs are more prone to upsets since they rely on an electrical charge, which is typically de-energized during a plant shutdown. Baghouses are less sensitive to upsets and are more efficient at removing most particulates. Both ESPs and baghouses are able to remove some mercury (that fraction of mercury emissions already associated with the flyash) if they are used on cooled exhaust gas. Baghouses are generally more efficient at removing mercury than ESPs.

3. Comparison of Coal Combustion Options

The following table compares coal combustion technologies. It summarizes the characteristics of the various coal-fired generating technologies and compares them with cleaner burning natural gas systems. Footnotes appear immediately following the table on page 8. All dollars are Canadian currency unless otherwise noted.

Coal Combustion Technology Comparison

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Environmental Performance ¹							
Plant Efficiency ²	33%	38-43%	36%	42% ³	45%	52%	~60%
Heat Rate (GJ/MWh)	10.9	9.5-8.4	10	8.6	8.0	6.9	6.0 per equiv. MWh
CO ₂ (kg/MWh) ²	1000	870-770	920	790	735	400	350
Sulphur Removal Standard	Alberta: 180 ng/J U.S.: 260 ng/J, 70-90% removal and BACT ⁴						
SO ₂ (kg/MWh) – no FGD	1.6 ⁵	1.4 ⁶	0.3 ⁷	0.12 ³	~ zero	~ zero	~ zero
SO ₂ (ng/J) – no FGD	229	221	30 ⁸	14	~ zero	~ zero	~ zero
SO ₂ (ng/J) – with FGD	< 70	< 66	Not required	Not required	Not required	Not required	Not required
NO _x Removal Standard	Alberta: 125 ng/J U.S.: 65 ng/J						
NO _x (kg/MWh) – no SCR	2.1 ²	1.8 ⁶	0.5 ^{7,8}	<0.7	0.25-0.45 ⁹ (w/ LNB)	0.12 (w/ LNB)	0.12 (w/ LNB)
NO _x (ng/J) – no SCR and w/ LNB	86-125 ⁵	86-125 ⁵	43	<86 ³	31-56	18 ¹⁰	18 ¹⁰
NO _x (ng/J) – with SCR and LNB	43-62	43-62	SCR not required	SCR probably not required	SCR probably not required	SCR probably not required	SCR probably not required
Particulate Matter Standard	Alberta: 13 ng/J U.S.: 13 ng/J						
PM (kg/MWh) – no ESP/Baghouse	0.5	0.4 ⁶	~0.4	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
PM (ng/J) – no ESP/Baghouse	46	42	~42	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
Mercury	Depends on coal source	Depends on coal source	Depends on coal source	Better than PCC but not as good as IGCC	Little or no air borne mercury	Little or no air borne mercury	Little or no air borne mercury

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Pollution Control Add-ons							
Flue Gas Desulphurization (FGD)	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%. ¹¹	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%. ¹¹	Not required	Not required	Not required	Not required	Not required
NO _x Control: Low NO _x Burners (LNB)	LNB can reduce approx. 50% NO _x formation.	LNB can reduce approx. 50% NO _x formation.	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	Std equipment. Can achieve single digit ppm (better than 90%) NO _x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO _x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO _x in flue gas with LNB.
NO _x Control Selective Catalytic Reduction (SCR)	80% NO _x removal without ammonia slip problems. ¹²	80% NO _x removal without ammonia slip problems. ¹²	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	May not be required where LNBs are available to reduce NO _x by at least 90%.	May not be required where LNBs are available to reduce NO _x by at least 90%.	May not be required where LNBs are available to reduce NO _x by at least 90%.
	Note: Typically both LNB and SCR required in PCC plants to meet most standards.						
Baghouse or ESP	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Not Required	Not Required	Not Required
Mercury ¹³	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse up to 70% removal.	With baghouse up to 70% removal.	Not Required	Not Required	Not Required
CO ₂ Capture	From flue gas, difficult to recover.	From flue gas, difficult to recover.	From flue gas, difficult to recover.	Recovery should be similar to IGCC.	Relative to other options, recovery is more straightforward from off-gas. ¹⁴	From flue gas, difficult to recover.	From flue gas, difficult to recover.

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Operational Performance							
Currently in use at:	Genesee, Keephills, Wabamun. Many plants worldwide.	Europe, Japan, U.S. Many plants worldwide.	Pt. Aconi, NS uses Circulating Fluidized Bed (185 MW plant), first one in Canada 1993. ⁷ Japan, Europe. Commonly used with high sulphur coal.	Sweden, Spain, U.S., 350 MW plant under construction in Japan. ¹⁵ Commonly used with high sulphur coal.	General coal gasification well proven. IGCC used at three U.S. plants (Polk, Wabash, ¹⁶ Pinon Pine) and in The Netherlands and Spain.	Many plants worldwide.	Many plants worldwide.
Commercially Proven	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Scale	100-1000 MW	100-1000 MW	400 MW guaranteed by manufacturer. ⁸	80 MW	100-300 MW	Any size in modulars	Any size in modulars
Reliability and Uptime	Good	Good	Good	Good	Good ¹⁶	Good	Good
Economic Performance ¹⁷							
Capital Cost – main process (\$/kW)	\$1200-1500 ¹⁵ \$1283 ¹⁸ \$1200 ¹⁹	\$1275-1575 ¹⁵ \$1322 ¹⁸ \$1200 ¹⁹	\$1500-1950 ¹⁵ \$1324 ¹⁸	\$1725-2025 ¹⁵ \$1429 ¹⁸	\$1800-2100 ¹⁵ \$1798 ¹⁸ \$1800 ²⁰	\$1,000	\$940 ²¹
Capital Cost – add-ons (\$/kW)							
FGD	\$105-180 ¹⁵ \$158-236 ²²	\$105-180 ¹⁵ \$158-236 ²²	N/R	N/R	N/R	N/R	N/R
SCR ¹⁵	\$60-120	\$60-120	N/R	N/R	N/R	N/R	N/R
LNB ¹⁵	\$7.5-15	\$7.5-15	\$7.5-15	\$7.5-15	Std.	Std.	Std.
Total Capital Cost (\$/kW)	1373	1448	1508	1733	1800	1000	940
(Sum of bold numbers above used in total capital cost)							
Return (%)	15%	15%	15%	15%	15%	15%	15%
Life (yrs)	35	35	35	35	35	35	35
Total Capital Cost (\$/MWh)	23.68	24.97	26.01	29.89	31.06-34.94	17.25	16.22
(Note: No Tax, No Depreciation)							
Operating Cost (\$/MWh)							
Labour ²³	2.08	2.08	2.32	2.77	2.77-3.12	2.08	2.08
Other (100% of labour)	2.08	2.08	2.32	2.77	2.77-3.12	1.63	2.08
Energy (GJ/MWh)	10.9	9.5	10	8.6	8.0	6.9	6
\$/GJ ^{17 24 25}	1.18	1.18	1.18	1.18	1.18	4.00	4.00
Energy Cost (\$/MWh)	12.86	11.21	11.80	10.15	9.44	27.60	24.00
Operating Cost – add ons (\$/MWh)							
FGD ²²	2.6	2.6					
Total Operating (\$/MWh)	19.62	17.97	16.44	15.69	14.98 - 15.67	31.31	28.16
Overall levelized cost to produce electricity (\$/MWh)	43.30	42.94	42.45	45.58	46.04-50.61 ²⁶	48.56	44.38

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Rank (1=Best, 7=Worst)							
Efficiency/GHG Ranking	7	5	6	4	3	2	1
Sulphur Removal Ranking	7	6	5	4	3	2	1
NO _x Control Ranking	7	6	4	5	3	2	1
PM Emission Ranking	7	6	5	4	3	2	1
Mercury Emission Ranking	7	6	5	4	3	2	1
CO ₂ Sequestration Ranking	More Difficult	More Difficult	More Difficult	Less Difficult	Less Difficult	More Difficult	More Difficult
Capital Cost Ranking	3	4	5	6	7	2	1
Operating Cost Ranking	5	4	3	2	1	7	6
Overall Cost to Produce Ranking	3	2	1	4	6	7	5

Table Footnotes

¹ 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.

² IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations - Pulverized Coal Power Plant," <http://www.ieagreen.org.uk/emis4.htm>, 40% efficiency emits 830 kg/MWh and 43% efficiency emits 770 kg/MWh.

³ Southern Illinois University, Coal Research Center, "Pressurized Fluidized Bed Combustion," www.siu.edu/~coalctr/presfbc.htm.

⁴ 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.

⁵ From EPCOR's EIA for Genesee 3.

⁶ Based on ratio of efficiencies (33% vs. 38%).

⁷ See Nova Scotia Power's website: <http://www.nspower.ca/OurEnvironment/EmissionControls/>. Port Aconi Power Plant in Nova Scotia removes 90% of the sulphur and 60% of NO_x.

⁸ Southern Illinois University, Coal Research Center, "Atmospheric Fluidized Bed Combustion," www.siu.edu/~coalctr/atmosfbc.htm.

⁹ IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Integrated Gasification Combined Cycle," <http://www.ieagreen.org.uk/emis6.htm>.

¹⁰ IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Natural Gas Combined Cycle," <http://www.ieagreen.org.uk/emis5.htm> based on 25 ppm (~ 18g/GJ).

¹¹ "Sorbent Injection Systems," www.siu.edu/%7ecoalctr/sorbinj.htm.

¹² Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," <http://www.siu.edu/~coalctr/postcomb.htm>.

¹³ Environmental Working Group, Clean Air Network and Natural Resource Defense Council, "Mercury Falling: An Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington DC.

¹⁴ CO₂ is recovered at the large gasification project at Great Plains, Dakota and injected into underground reservoirs for enhanced oil recovery at Weyburn, Saskatchewan. See Dakota Gasification Company website: <http://www.dakotagas.com/> and <http://ens.lycos.com/ens/jul2000/2000L-07-14-11.html>.

¹⁵ Energy Issues (The World Bank) No.14 August 1998, “Technologies for Reducing Emissions in Coal-Fired Power Plants” by Masaki Takahashi, <http://www.worldbank.org/html/fpd/energy/enls14.pdf>. Costs in \$US converted to \$Cdn at 1.50 exchange rate (1995\$).

¹⁶ 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-39 Issue No. 39, Spring 2000.

¹⁷ All currency in Canadian dollars.

¹⁸ From EPCOR’s EIA for Genesee 3, Vol.1, Figure 2.2.1.

¹⁹ Calculation based on the average of Keephills and Genesee 3 expansions.

²⁰ This number represents the actual cost of constructing the greenfield IGCC Polk Power Plant. U.S. DOE Publication “Techline DOE Sponsored Clean Coal Project Wins Power Magazine 1997 Award,” June 5, 1997, U.S. Department of Energy.

²¹ Calculated from TransCanada Pipeline’s Press Release for the Redwater and Carseland Cogeneration Projects.

²² Southern Illinois University, Coal Research Center, “Dry Flue Gas Desulfurization.”

<http://www.siu.edu/~coalctr/index.html>. \$US converted to \$Cdn at 1.50 exchange rate (1995\$).

²³ 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.

²⁴ Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: \$US 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.

²⁵ Gas price based on approximate daily AECO prices for June 28, 2001 from

<http://www.gasalberta.com/WebPublish/Web-Gas%20Price.htm>

²⁶ 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 Table

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 - Giga-Joules

IGCC - Integrated Gasification Combined Cycle

kg - kilogram

LNB - Low NOx Burners

MWh - Mega-Watt per hour

NGCC - Natural Gas Combined Cycle

NO_x - 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

SO_x - Sulphur oxides

The following summary compares the coal combustion options.

1. Efficiency and CO₂ – The coal combustion options are not as efficient as the natural gas options, and consequently all have significantly higher rates of greenhouse gas emissions. Of the coal-fired options, the IGCC process is the most efficient with the conventional subcritical PCC plants having the lowest efficiency.

2. SO₂ – Both the super and subcritical PCC options have high rates of sulphur emissions and require flue gas desulphurization to meet Alberta’s standards. None of the other options require any add-on sulphur removal equipment.

3. NO_x – All coal-fired options, except perhaps IGCC, typically require both low NO_x burners and SCR/SNCR to meet a U.S. Standard for NO_x. The less-stringent standard in Alberta makes it possible for proponents to meet the Alberta standards with only low NO_x burners.[†] The natural gas options may not require SCR/SNCR to meet the more stringent U.S. standards if the gas turbines are properly equipped with LNBs to reduce NO_x by 90+%. If LNBs are not available to reduce NO_x to sufficiently low levels, the design may have to include a combination of LNBs and SCR/SNCR.

4. Particulate Matter – Of the coal-fired options, only the IGCC option does not require supplemental dust control measures. All other coal-fired options require either a baghouse or ESP, with the preferred option being a baghouse due to the added benefits of removing other pollutants such as mercury.

5. Mercury – With the exception of the IGCC option, all coal-fired options emit mercury from their stacks. The addition of a baghouse helps remove some mercury; however, the baghouse does not reduce the mercury down to the levels achieved in IGCC or the natural gas-fired plants.

6. CO₂ Sequestration – CO₂ must be considered in the design of all future power plants. Of all the options considered (coal and natural gas), only the IGCC option has a design that can facilitate CO₂ capture. This is because the relatively high pressure of the exhaust gases in an IGCC plant allows for easier CO₂ removal. Of course, the amount of CO₂ emitted from a natural gas-fired power plant is approximately half that emitted from a coal-fired plant.

7. Proven Technology – Both the subcritical and supercritical PCC options are well proven and are used in thousands of plants worldwide ranging in size from 100 MW to 1000 MW. AFBC plants are also well proven with hundreds in commercial operation in the 200 MW size and a few operating in Japan and France at 350 MW. PFBC plants are in commercial operation in Sweden, Japan and the U.S. with most in the smaller size (that is, less than 100 MW). A 350 MW unit is currently under construction in Japan. Most of the IGCC plants were initially built on a demonstration basis; however, all of them are now approaching a commercial level of operation in the range of 200-300 MW. The production of syngas from coal, which is the first step in an IGCC plant, has been around for many years and is a well proven technology. Both natural gas-fired options are commercially proven with thousands of installations worldwide in various sizes.

8. Capital and Operating Costs – The natural gas-fired options have the lowest capital cost, but even with their high efficiency, their operating costs are somewhat higher than coal at today's current gas prices (\$4.00/GJ). Among the coal-fired options, the capital cost for the relatively basic design of the subcritical PCC option is the lowest, with progressively higher capital costs for the supercritical PCC, AFBC, PFBC and IGCC. Operating costs rank in more or less reverse order, with the AFBC and the supercritical PCC plants having the lowest operating costs.

9. Overall Levelized Cost to Produce Electricity – Comparing all options (coal- and natural gas-fired), the AFBC, super-PCC and the sub-PCC options can produce the least expensive electricity at around \$43/MWh. The highest cost option is the NGCC at approximately \$49/MWh at a \$4.00/GJ cost of natural gas. The IGCC system is also more expensive than other coal-fired options (generally 7-18% more, depending on the assumed reliability and other criteria used in the table), but is becoming competitive at today's electrical pool prices. At gas prices of approximately \$3.25/GJ, NGCC becomes economic relative to the supercritical PCC coal-fired option. While the economics for all options is extremely sensitive to the cost of energy (coal or natural gas), all options considered have overall levelized costs within 10% of the average.

[†] The Two Elk Power Generation plant that was recently approved in Wyoming is designed to achieve low emissions using both low-NO_x burners and Selective Catalytic Reduction. Ninety-five percent of the SO₂ will be removed using flue-gas desulphurization lime spray dryer.

4. Discussion

From an environmental standpoint, none of the coal-fired options is as favourable as the natural gas-fired options. However, among the coal-fired options, IGCC has the best environmental performance and comes very close to being as clean as the natural gas-fired options for all pollutants except CO₂. Natural gas-fired generation emits approximately half the CO₂ per amount of energy produced of any coal-fired option.

Based on the economic analysis presented in this paper, the IGCC option has an overall levelized cost of power that is within 7-18% of the supercritical PCC plant now being proposed in Alberta by EPCOR. The only area of concern with the IGCC option is its commercial viability on larger scale operations. With the number of IGCC plants moving into or already in commercial operation, this concern should be alleviated. Proponents of coal-fired plants should seriously consider IGCC, given its superior environmental performance for only a modest incremental increase in cost. The relatively high cost of today's natural gas (assumed to be \$4.00/GJ) means it costs slightly more (12%) to produce electricity with the NGCC option than with the supercritical PCC option. However, at gas prices of approximately \$3.25/GJ, the NGCC option has the same overall levelized cost as supercritical PCC plants. The natural gas combined heat and power cycle has very favourable economics even at today's gas prices due to its low capital cost and high efficiency.

With the deregulation of the electricity sector in Alberta, there is no longer a direct relationship between the cost of generation and the prices paid by consumers. In any hour, the price of generation is now set by the variable cost of the last unit dispatched. Even with the addition of more coal-fired capacity, consumers will typically be paying prices that are consistent with cleaner gas-fired generation. Allowing the proponents of new coal-fired generation to avoid the cost of installing more effective pollution control equipment on their plants will simply transfer the cost of the pollution onto society without providing offsetting benefits of lower cost power. While it is true that the addition of new coal-fired capacity will augment the supply of electricity in the province and lead to reductions in the market price of power in Alberta (from the average of \$133/MWh in 2000), these same reductions would be realized with the addition of an equivalent amount of gas-fired capacity. The fact is that, following the addition of this new coal-fired generation, consumers will be paying prices that are consistent with the costs of cleaner gas-fired power plants but will experience comparatively higher levels of pollution from the new coal-fired facilities. The Alberta government should ensure that consumers get what they pay for – clean, highly efficient gas-fired generation. There is no need to settle for less.

5. Conclusions

This paper clearly shows that:

- Natural gas-fired generation has superior environmental performance and acceptable economic performance when compared with the coal-fired option.
- Of the coal-fired options, only the IGCC option comes close to meeting the environmental performance of the natural gas options and this is achievable with acceptable economical performance (IGCC has an overall levelized cost of power that is within 7 to 18% of the most economic options).
- All options, along with their associated pollution control add-ons, are feasible at today's gas, coal and electrical prices.
- With the pollution control add-ons, the environmental performance of the more conventional PCC coal-fired options can be drastically improved while still producing economic electricity.

All the electrical generation options reviewed in this paper can comfortably meet the new Alberta standards, in some cases without the additional pollution control equipment that would be required to meet the standards in the U.S. and certain other jurisdictions.

Alberta has clearly not adopted the approach of using Best Available Control Technology in designing the latest environmental standards. This review shows that many different, proven technologies are commercially available and could be economically included in the design of any coal-fired plant in Alberta. Unfortunately, because Alberta's standards are not as strict as in some other jurisdictions, proponents of coal-fired plants in Alberta will not be required to use these technologies.