CANADIAN CLEAN POWER COALITION STUDIES ON CO_2 CAPTURE AND STORAGE

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OVERVIEW BY THE IEA GREENHOUSE GAS R&D PROGRAMME

Introduction

The IEA Greenhouse Gas R&D Programme (IEA GHG) has participated in a series of studies on capture and storage of CO_2 through its membership of phase 1 of the Canadian Clean Power Coalition (CCPC). IEA GHG joined the CCPC mainly as a cost-effective way of obtaining information on retrofit of CO_2 capture to power plants and the effects of coal rank on the costs of capture. This overview, written by IEA GHG, summarises the main results from the CCPC studies and provides a comparison with other studies carried out by IEA GHG. A longer summary report produced by the CCPC itself is also provided.

The CCPC was set up in mid 2001 by seven Canadian utility companies (ATCO Power, EPCOR Utilities, Luscar, Nova Scotia Power, Ontario Power Generation, SaskPower and TransAlta Utilities). Subsequently EPRI joined the coalition, followed by IEA Environmental Projects Ltd, on behalf of IEA GHG and the IEA Clean Coal Centre. Additional financial support was provided by the governments of Canada, Alberta and Saskatchewan.

The goals of the CCPC are:

- To secure a future for coal-fired electricity generation within the context of Canada's multi-fuelled electricity industry.
- To demonstrate that coal-fired electricity generation can effectively address all environmental issues projected in the future, including CO_2.
- To research and develop commercially viable clean coal technology, and thence to construct and operate a full scale demonstration project to remove greenhouse gas and all other emissions of concern by 2010.

Phase 1 of the CCPC consisted of conceptual engineering and feasibility studies to assess technologies and fuels that should be used in the demonstration plants and to identify options for storage of the CO_2 from a demonstration plant. Subsequent phases will involve preparation of a business case for the demonstration plant and detailed design and construction of the plant. IEA GHG will withdraw from the CCPC after Phase 1 because the costs of subsequent phases are beyond its financial resources.

The detailed reports of studies carried out in Phase 1 of the CCPC are confidential to members of the CCPC. The IEA GHG project team has copies of the reports. They can be made available to members of IEA GHG provided they sign the necessary confidentiality agreements and all of the members of the CCPC give their approval. This summary report contains only non-confidential information.

Study description

The studies carried out in Phase 1 of the CCPC are listed in table 1.

Table 1 Studies carried out in Phase 1 of the CCPC

Subject	**Contractor**
Pre-screening study	SFA Pacific
Retrofit technologies for control of non-CO_2 emissions	Neil and Gunter
Amine scrubbing and oxyfuel combustion	Fluor
Gasification	Fluor
CO_2 storage and utilisation in Western Canada	SNC Lavalin
CO_2 storage in coal beds in Nova Scotia	Geological Survey of Canada

The specifications for these studies were defined by the members of the CCPC before IEA GHG joined. Although IEA GHG could not influence the original study specifications it was involved in discussions which helped to determine the course of the studies after they had started, particularly the capture studies carried out by Fluor.

The pre-screening study recommended gasification for new greenfield power plants. Gasification may also be preferred for CO_2 capture at existing plants but most of the existing equipment would need to be discarded. Amine scrubbing and oxyfuel combustion would enable more of the existing equipment to be retained, which may appeal to some utilities. Based on these conclusions, the CCPC originally intended to evaluate amine scrubbing and oxyfuel technologies mainly for retrofits and to evaluate gasification mainly for greenfield plants. However, during the course of Fluor's studies it became apparent that retrofits would be less attractive than expected. The later stages of the studies therefore concentrated on greenfield applications for all technologies

Plant sites and coal analyses
The CCPC study was based on three Canadian power plant sites, each using a different local coal:

- Nova Scotia: bituminous coal
- Alberta: sub-bituminous coal
- Saskatchewan: lignite

Analyses and costs of these coals are given in table 2, along with those of the Australian bituminous coal used in IEA GHG's other studies. The CCPC bituminous coal is higher rank than IEA GHG's standard coal (for example the oxygen and moisture contents are lower) but the CCPC sub-bituminous coal and lignite are substantially lower rank. Similarly, the IEA GHG coal has sulphur and ash contents intermediate between the CCPC bituminous and sub-bituminous coals. The specific energy content per kg of carbon is slightly higher for the IEA coal than the CCPC bituminous coal and hence the specific CO_2 emissions are slightly lower. For the three CCPC coals, the energy content per kg C decreases with decreasing coal rank, and hence the specific emissions of CO_2 increase.

Table 2 Coal analyses and costs

	CCPC			IEA GHG
	Nova Scotia Bituminous	Alberta Sub-bituminous	Saskatchewan Lignite	Australian Bituminous
Moisture, wt% as-received	5.89	20.00	33.54	9.5
Ash, wt% as-received	7.95	13.93	13.46	12.2
Carbon, wt% dry-ash free	84.66	73.93	74.67	82.5
Hydrogen, wt% dry-ash free	5.99	4.26	4.85	5.6
Oxygen, wt% dry-ash free	5.07	20.51	18.30	9.0
Nitrogen, wt% dry-ash free	1.54	0.91	1.26	1.8
Sulphur, wt% dry-ash free	2.74	0.39	0.92	1.1
LHV, MJ/kg as-received[1]	28.95	17.81	13.56	25.87
Specific energy content, MJ/kg C	39.68	36.46	34.26	40.05
Cost, US$/GJ (LHV)	1.90	0.48	0.88	1.5

Economic basis
The economic analyses in the CCPC study were undertaken using an EPRI model with economic assumptions (rates of return on capital, taxation rates etc.) that are appropriate for power plants in Canada. IEA GHG uses a different economic model and assumptions for its own assessment studies. However, the overall effect of the differences is small, so the main conclusions of the CCPC studies would still apply if IEA GHG's economic model and assumptions had been used. To demonstrate this, the effects of the differences between the CCPC and IEA GHG economic bases are shown in the appendix to this summary for one type of plant; a bituminous coal IGCC[2].

The economics in the CCPC's reports are presented in Canadian dollars. For this IEA GHG overview they have been converted to US dollars, for consistency with IEA GHG's other reports, using an exchange rate of 1.56 Canadian dollars per US dollar. This is the exchange rate that was used by the contractors to convert equipment costs in US dollars to Canadian dollars at the time the study was carried out.[3]

The CCPC plants are designed for specific Canadian power plant sites. There are many location specific factors which can affect costs. Costs cannot be precisely converted to other locations, such as the Netherlands coastal location used for IEA GHG's own studies, using a market exchange rate.

Results and Discussion

Evaluation of technologies for control of non-CO_2 emissions
This study identified foreseeable new regulatory requirements for emissions of substances other than CO_2 in Canada and assessed the costs of technologies to achieve these requirements. A wide range of technologies for SO_x, NO_x, particulate and mercury emission control were assessed. When CO_2 is

[1] The Lower Heating Values (LHVs) quoted in this overview are calculated from the HHVs using a conversion factor published in the 7th edition of "Technical Data on Fuel" by J.W. Rose and J.R. Cooper, published by the British National Committee of the World Power Conference, for consistency with other IEA GHG reports. This takes into account all hydrogen in the coal, including the moisture. LHV's contained in the CCPC's own reports only take into account hydrogen contained in the dry-ash-free coal.
[2] Integrated gasification combined cycle
[3] The exchange rate at the time this summary was completed in early March 2004 was around 1.35:1.

captured, most other atmospheric emissions are also inevitably avoided, so the study provided a suitable baseline for assessment of the true incremental cost of CO_2 capture. Technologies and costs for control of non-CO_2 emissions are not described in this summary, as they are outside the scope of the IEA Greenhouse Gas R&D Programme, but information is provided in the summary report produced by the CCPC.

CO_2 capture retrofit

The first stage in the evaluation of amine scrubbing and oxyfuel combustion was a site selection study which compared retrofit of CO_2 capture at three existing power plants, with the aim of selecting one plant for a more detailed site optimisation study. The plants were:

- Trenton 6, a 156 MW plant in Nova Scotia, using bituminous coal
- Shand, a 272 MW plant in Saskatchewan, using lignite
- Genessee 1, a 391 MW plant in Alberta, using sub-bituminous coal

Results of the site selection studies are summarised in the CCPC's own summary report, which is attached to this overview. The studies showed that the Genessee plant is the most attractive for a capture retrofit as it has the lowest projected costs of CO_2 capture and electricity generation and has the greatest potential for utilisation of captured CO_2. However, the Shand site, which was the second best option, was selected for the more detailed site optimisation study, because of the ease of obtaining plant design data within the time frame of the study. Although Shand was not the preferred site it would be suitable for a retrofit or new power plant because there is plenty of plot space available and the existing infrastructure was designed with a second plant in mind. The existing Shand power plant is relatively modern, having been commissioned in 1992.

The specification for the site selection studies required that there should be no net loss of power sent out due to CO_2 capture retrofit. This was achieved by constructing an auxiliary coal fired boiler with CO_2 capture. The auxiliary boilers were found to be similar in size to the original power plant boilers. This was considered to be not an attractive option because the auxiliary power plant would have a lower efficiency than a greenfield power plant and less favourable economies of scale and the overall cost of a retrofit would probably be close to that of a greenfield power plant. The study also showed that there are significant opportunities to optimise the efficiency of an amine scrubbing plant by integration with the power plant. This may be more difficult to achieve in a retrofit than in a new plant. In the case of oxyfuel combustion the study showed that air infiltration was a major issue, as it would increase the concentration of inert gases in the CO_2 product, which would increase the cost of the product recovery and compression unit. A new power plant could be easily designed to have much lower air infiltration rates than existing plants. The site selection study also confirmed that the energy efficiency penalty for CO_2 capture would be substantial. This highlighted the need for the basic power cycle to have as high an efficiency as possible, which could only be achieved in a new plant. For these reasons, members of the CCPC decided that the more detailed site optimisation work should concentrate on greenfield plants for all technologies. An amine scrubbing retrofit at the Shand site was also evaluated but it did not include construction of an auxiliary boiler to offset the reduction in net power output.

The evaluation of amine scrubbing in the site selection study did not consider detailed integration between the existing plant and the retrofitted units and was based on Fluor's original Econamine FG^{SM} process rather than their improved Econamine FG Plus^{SM} process which became available during the course of the study. The heat consumption of the Econamine FG Plus^{SM} process is 21% lower than that of the conventional Econamine FG^{SM} process and the solvent degradation loss is substantially reduced. This is achieved mainly by split flow solvent circulation, improved solvent formulation, better heat integration and vacuum reclaiming of solvent. Heat integration with the vacuum condensate of the steam cycle brings the overall reduction in heat consumption to 32%.

The results of the detailed evaluations of retrofit and greenfield plants with amine scrubbing are shown in table 3.

Table 3   Comparison of retrofit and greenfield plants with CO_2 capture (lignite-fuelled)

	Retrofit	Greenfield
Plant performance		
Gross power output, MW	304.4	453.5
Boiler auxiliary power consumption, MW	26	21.4
Power loss due to CO_2 capture and pollutant control, MW	84.6	121.2
Net power output, MW	193.8	310.9
Thermal efficiency, % (LHV)	25.26	31.80
Costs		
Capital cost, US$/kW net output	1005	2826
US$/t CO_2 avoided	55.0	36.3

The thermal efficiency of the retrofitted Shand lignite-fuelled plant with CO_2 capture is significantly lower than that of a greenfield power plant at the same location. This is mainly because the existing Shand power plant has a lower efficiency steam cycle (12.6 MPa, 538/538C steam conditions, compared to 24.2 MPa, 593/593C in the greenfield plant).

The capital cost of US$1005/kW shown in table 3 for the retrofit is only the cost of the retrofitted CO_2 capture and other emission control equipment and it does not take into account the cost of new generating capacity which would have to be built elsewhere to make-up for the reduction in net power output due to CO_2 capture.

The overall cost of CO_2 capture, in $/tonne of CO_2 emissions avoided, is higher in the retrofit plant than the greenfield plant. For this overview, the make-up power for the retrofit plant is assumed to be provided by a new large coal-fired power plant with CO_2 capture, such as the greenfield plant shown in table 3. The quantity of CO_2 avoided is the emissions of the Shand plant without capture minus the sum of the emissions from the Shand plant with capture and the emissions from the make-up power plant. The costs would depend strongly on the costs and emissions of the plant that provides the make-up power.

In the CCPC study the retrofit and greenfield plants were both evaluated with a plant life of 20 years. In practice the operating life of a retrofitted plant is likely to be lower than that of a greenfield plant, so the capital cost of the capture equipment would have to be recovered over a shorter period of time, resulting in a higher cost of capture.

A conclusion of this assessment is that where new coal-based generating capacity is needed and there is a need to capture CO_2 it will be preferable to install CO_2 capture in the new plants rather than in retrofits.

CO_2 capture at greenfield plants

The gasification technology evaluation concentrated from the start on greenfield sites. The first stage was a screening evaluation to select gasification processes for each of the coals. ChevronTexaco, Shell, E-Gas and Noell gasification processes were assessed. ChevronTexaco gasification with water quench of the product gas was selected for bituminous and sub-bituminous coals, as it gave the lowest cost of electricity generation, and Shell gasification with product gas heat recovery was selected for lignite. ChevronTexaco stated that their process was not appropriate for lignite due to lignite's high inherent moisture content. The cost of electricity in the ChevronTexaco gasifier plant using bituminous coal was about 10% lower than in the comparable Shell gasifier plant. A recent study on IGCC published by IEA GHG (report PH4/19) gave a similar result.

Detailed evaluations were then carried out for bituminous and sub-bituminous coal-fuelled plants based on ChevronTexaco gasifiers and a lignite-fuelled plant based on Shell gasification. The plants were based on 2 GE7FA gas turbines, resulting in net power outputs of around 400 MW. The costs of CO_2 emission avoidance were calculated compared to pulverised fuel fired reference plants which used supercritical steam conditions and included FGD[4], SCR[5], and mercury and particulate removal. Pulverised fuel plants are the type of coal-fired plants that would probably be built in the near future if there were no requirement to abate CO_2 emissions. Performance and cost data for the IGCC plants with CO_2 capture and the pulverised fuel reference plants are shown in table 4.

Detailed evaluations of new lignite fired plants with amine scrubbing and oxyfuel combustion were also carried out. These plants were based on the supercritical steam conditions used in the reference plants. The amine scrubbing plant was based on Fluor's Econamine FG Plus[SM] process. The oxyfuel combustion plant was based on a boiler designed for low air infiltration.

Table 4 Greenfield plant evaluation

	Bituminous coal	**Sub-bituminous**	**Lignite**	**Lignite**	**Lignite**
Reference pulverised fuel plants without CO_2 capture					
Net power (MW)	424.5	424.5	424.5	424.5	424.5
CO_2 emissions (g/kWh)	771	852	883	883	883
Efficiency, % (LHV)	42.94	42.37	43.43	43.43	43.43
Capital cost (US$/kW)	1410	1502	1644	1644	1644
COE (USc/kWh)	4.87	3.73	4.45	4.45	4.45
Plants with CO_2 capture					
Technology	Gasification	Gasification	Gasification	Amine	Oxyfuel
Net power (MW)	444.5	436.8	361.1	310.9	373
Efficiency, % (LHV)	32.97	27.71	30.00	31.80	26.69
CO_2 captured (%)	87.0	92.0	85.7	95.0	90.0
CO_2 emitted, g/kWh	130	102	182	60	145
Capital cost (US$/kW)	1917	2190	2828	2824	3974
COE (USc/kWh)	6.84	6.21	8.39	7.43	9.74
CO_2 capture plants compared to pulverised fuel plants					
CO_2 emissions avoided, g/kWh[6]	641	750	701	823	738
Efficiency penalty for capture, %	9.97	14.66	13.43	11.63	16.74
Capital cost penalty, US$/kW	507	688	1184	1180	2330
Electricity cost penalty, USc/kWh	1.97	2.48	3.94	2.98	5.29
CO_2 avoided cost, US$/t CO_2	31	33	56	36	72

[4] Flue gas desulphurisation
[5] Selective catalytic reduction
[6] Some of the data in the CCPC reports include carbon emissions that are avoided due to unreacted carbon in ash. CO_2 emissions data in this summary are calculated from process stream data in the detailed CCPC reports and the quantities of CO_2 emissions avoided take into account only CO_2 that is captured as CO_2.

The thermal efficiencies of the reference pulverised coal plants are lower for lower rank coals, mainly because of lower boiler efficiencies. The specific emissions of CO_2 are higher for lower rank coals because of the lower efficiencies and because the specific carbon contents (kg C/MW of thermal energy) of lower rank fuels are higher, as shown in table 2. The capital costs are also higher for lower rank coals. The cost of electricity generation depends on the fuel cost, which in the Canadian context is lowest for sub-bituminous coal, as shown in table 2. For this reason, the overall cost of generation is lowest for sub-bituminous coal.

In general the IGCC plants with CO_2 capture show the same trends. An exception is that the lignite-fuelled plant has a higher efficiency than the bituminous coal plant. This is because the lignite plant is based on the Shell gasifier, which uses a dry coal feeding system and a heat recovery boiler, and the other plants use the ChevronTexaco quench gasifier, which uses a water slurry feed system and water quench cooling of the product gas. The specific emissions are lowest in the sub-bituminous coal-fuelled plant for detailed design reasons. The additional cost of generation due to CO_2 capture (c/kWh) and the cost of CO_2 emissions avoidance ($/t CO_2) are higher for lower rank coals, for example the cost of emission avoidance in the lignite-fuelled plant is twice as high as in the bituminous coal-fuelled plant.

For lignite-fuelled plants, the lowest cost CO_2 capture option, by a substantial margin, is amine scrubbing, followed by gasification, and the most expensive option is oxyfuel combustion. This is despite the fact that in this study the amine scrubbing plant has the smallest net power output and therefore the least favourable economies of scale. The amine scrubbing plant has further advantages; it has the highest thermal efficiency and the highest percentage CO_2 capture. The CO_2 capture rate in the amine scrubbing plants is 95%, which is higher than in the other plants and also higher than the 85% assumed in IEA GHG's own assessment studies. 85% CO_2 capture was assessed by the CCPC in a sensitivity study and it was found to increase the cost of CO_2 avoided by 2%. The sensitivity of cost to percentage CO_2 capture was not assessed for the other technologies but it appears unlikely that a higher percentage CO_2 capture would have significantly reduced the specific cost of capture.

Although gasification was shown to have a higher cost than amine scrubbing, the technology for lignite gasification is relatively immature and there is significant scope for improvements.

Oxyfuel combustion was shown to be the highest cost option but substantial improvements could be made to the design adopted in the CCPC studies. The oxyfuel combustion studies specified that the plants should retain full air firing capability, which resulted in high flow rates through the emission control equipment. Although this gives some operability advantages, it significantly increases costs. The boilers were designed to have an inlet oxygen concentration similar to that of air but pilot scale research has shown that oxyfuel boilers could have an inlet oxygen concentration of about 30%, which would substantially reduce the boiler and recycle gas flowrates, and hence the plant costs. There are also further opportunities to improve the efficiency and costs by optimising the flue gas cooling. Another option which may be advantageous particularly for the Saskatchewan lignite would be cyclone firing, which would greatly reduce the size of the boiler. Cyclone boilers are a proven technology but they have not been used much in recent years because of high NO_x emissions. However, this is much less of a concern in oxyfuel combustion.

The CCPC study is based on the Canadian coal prices shown in table 2. Coal prices may be different in different countries, leading to different relative costs of generation for different fuels. The sensitivity of electricity cost to coal price is shown in figure 1. Note these costs still include some site-specific costs for each fuel which may not apply in other locations

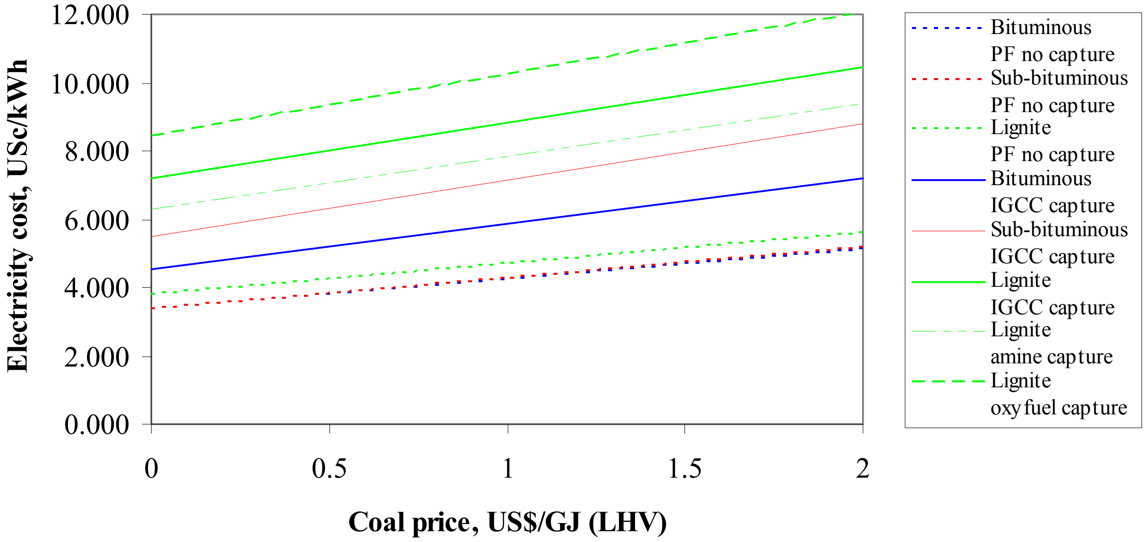

Figure 1 Sensitivity of electricity cost to fuel price

Comparison with other IEA GHG studies

IEA GHG has not carried out studies based on lignite, so there are no data to compare against the CCPC's detailed amine scrubbing and oxyfuel combustion plant data. Foster Wheeler recently carried out a study for IEA GHG on IGCC which included bituminous coal-fuelled IGCC plants based on ChevronTexaco gasification. A detailed comparison of that plant and the CCPC bituminous coal IGCC plant are included in the appendix to this overview and the main results are summarised in table A1 in the Appendix.

The thermal efficiency is slightly higher in the CCPC study and the capital cost is significantly higher, mainly because of less favourable economies of scale and higher costs for general plant facilities.

CO_2 storage and utilisation

Two studies on CO_2 storage and utilisation were carried out:

- A compilation and evaluation of CO_2 utilisation and storage options in Western Canada.
- An evaluation of the potential to store CO_2 in coal deposits in Nova Scotia

The study on Western Canada reviewed all storage and utilisation options and concluded that the only viable options were enhanced oil recovery (EOR), enhanced coal bed methane production (ECBM) and geological storage in depleted oil and gas fields and aquifers. The study concluded that the preferred storage option is EOR. While there do not appear to be any technical obstacles in general to EOR and storage in depleted oil and gas reservoirs and aquifers, there would be many questions for any specific project. ECBM is immature and is unlikely to proceed without significant technical development and pilot scale projects. Major uncertainties include permeability, gas content and CO_2 absorption ratios.

An EOR project taking CO_2 from a 400 MW power station would be one of the largest EOR operations in the world. It was determined that there could be 5 or 6 viable EOR projects in Alberta with sufficient capacity to store CO_2 from a commercial scale power plant over a 30 year life. Opportunities in Saskatchewan are much more limited and only one EOR project would be viable.

The cumulative investment for an EOR project taking CO_2 from a 400 MW power station (2.6 Mt/y) was estimated to be about US$600 million spread over the life of the project. The estimated investment cost for storage in depleted oil and gas reservoirs was about US$30 million. The cost of storage in deep saline aquifers was expected to be of the same order as storage in depleted oil and gas reservoirs, but probably slightly higher on average due to infrastructure requirements and generally higher initial formation pressures.

The CCPC estimated breakeven values for CO_2, i.e. the maximum that the storage operator could pay for CO_2, based on a 15% economic discount rate, an oil revenue of US$20/barrel and a natural gas revenue of about US$2.7/GJ (LHV). The breakeven values of CO_2 were US$27/tonne for EOR, US$6/t for ECBM and minus US$2.5/t for depleted oil and gas reservoirs. The breakeven CO_2 cost for EOR based on IEA GHG's standard 10% discount rate would be US$33/t. These figures do not take into account taxes and royalties. An EOR project would emit CO_2 equivalent to about 7-8% of the CO_2 delivered, mainly due to on-site gas recompression, although this could probably be reduced by optimising the gas/CO_2 separation. This CO_2 emission was not taken into account in the assessment.

CO_2 purity is a critical issue for EOR. Relatively low levels (1-2%) of N_2, O_2 or CO could potentially have a negative impact on EOR recovery, by increasing the minimum miscibility pressure. O_2 could also oxidise the oil making it more viscous and difficult to refine. H_2S and SO_2 would have the beneficial effect of reducing the minimum miscibility pressure, although a mixture of CO_2 and SO_2 might cause the deposition of elemental sulphur in a reservoir containing H_2S.

The study by the Geological Survey of Canada identified that there is significant potential for coalbed methane production and storage of CO_2 in the coalfields of Nova Scotia. Further work involving field testing is needed to investigate this potential further.

Expert Reviewers' Comments

The draft reports from the contractors were reviewed by representatives of the CCPC's members and other funding agencies. Most of the comments were minor and were taken into account in the final reports. However, it was suggested that some of the design assumptions used in the oxyfuel evaluation were excessively conservative, resulting in an unrealistically high cost for that technology. Further work would be needed to assess the implications of these comments.

Some inconsistencies in the detailed reports were identified after publication. Where possible these have been corrected in this summary.

Major Conclusions

The cost of capturing CO_2 in a new coal fired power plant would be lower than in an existing coal-fired power plant retrofitted with CO_2 capture. Retrofit would only be attractive if all new coal-fired power plants were being fitted with CO_2 capture and there was a need to achieve even greater emission reductions.

For lignite-fuelled plants, the costs of electricity generation and CO_2 capture are significantly lower for amine scrubbing than for IGCC or oxyfuel combustion.

The choice of CO_2 capture technology and the cost of capture depend highly upon coal rank.

The thermal efficiency and cost penalties for CO_2 capture in IGCC are higher for lower rank coals. However, based on Canadian coal prices, a sub-bituminous coal-fuelled plant with CO_2 capture would have the lowest cost of electricity generation.

Costs of CO_2 capture could be reduced by more design optimisation, particularly for oxyfuel combustion.

The preferred option for CO_2 storage in western Canada is EOR. The breakeven value of CO_2 to an EOR operator was estimated to be US$33/tonne, based on IEA GHG's standard economic assessment criteria.

Recommendations

The next phase of the CCPC project will aim at the involvement of a broader range of industrial participants and development of a business case for a demonstration plant. Some further technical studies will also be undertaken, including evaluation of co-production of hydrogen and steam, co-use of low rank coal and petroleum residues and production of a combined stream of CO_2 and sulphur compounds. It is recommended that IEA GHG should not participate in the next phase of the CCPC.

Lessons learned during the CCPC studies should be taken into account in IEA GHG's own on-going and future studies on CO_2 capture and storage.

APPENDIX

Comparison of CCPC and IEA GHG's evaluations of IGCC plants

This appendix compares the results of the CCPC's evaluation of a bituminous coal-fuelled IGCC and the results of an evaluation of a similar plant, carried out recently for IEA GHG by Foster Wheeler (report PH4/19, May 2003). The plants are both based on ChevronTexaco quench gasifiers and GE FA series gas turbines. In this Appendix the two studies are converted to the same economic basis, as far as possible, and differences between the performance and costs in the two studies are highlighted.

The main results of the CCPC and Foster Wheeler assessments are summarised in table A1. In the Foster Wheeler study, the penalty for CO_2 capture is calculated by comparing the IGCC plant with capture to a similar plant without capture. In the CCPC study the IGCC with capture is compared to a pulverised fuel boiler-steam cycle plant without capture.

Table A1. Overall comparison of CCPC and Foster Wheeler studies

	CCPC			Foster Wheeler		
	PF plant without capture	IGCC with capture	Capture penalty	IGCC without capture	IGCC with capture	Capture penalty
Net power output, MW	424.5	444.5		826	730	
Efficiency, % (LHV)	42.9	33.0	9.9	38.0	31.5	6.5
Capital cost, $/kW	1410	1917	507	1187	1495	308
Electricity cost, c/kWh	4.87	6.84	1.97	4.51	5.58	1.07
CO_2 emissions, g/kWh	771	130		833	152	
CO_2 captured, g/kWh		873		-	851	
Cost of CO_2 avoidance, $/t$CO_2$			30			16

The efficiencies of the IGCC plants in the two studies are similar but the power output is lower and the capital and operating costs are higher in the CCPC study. Reasons for this are explained in the following sections.

Plant performance

The performances of the plants are similar apart from their size, as shown in table A2. The overall power output of an IGCC plant is determined mainly by the number and type of gas turbines. Both plants are based on two gas turbines but the turbines in the CCPC plant are smaller. This is because the electricity system in Canada operates at a frequency of 60Hz, compared to 50Hz in Netherlands, and 60Hz turbines have substantially lower power outputs than corresponding 50Hz turbines. Apart from their size, the turbines in the two studies are similar.

A greater proportion of the total gross power is generated in the gas turbine in the CCPC plant (66% compared to 58% in the Foster Wheeler plant). This is due to various reasons. In the Foster Wheeler plant, half of the air for the air separation unit (ASU) is compressed in the gas turbine air compressor, which reduces the turbine efficiency, but in the CCPC plant all of the air for the ASU is compressed using electrically driven compressors. In the Foster Wheeler plant the expansion stage of the gas turbine is fully loaded mainly by adding compressed nitrogen from the ASU but in the CCPC plant this is achieved by adding more moisture to the fuel gas and nitrogen feeds in humidifiers. This reduces the amount of heat available for the steam cycle. Another reason for the difference is probably the difference in gasifier performance with the different coals.

The overall auxiliary power consumption as a fraction of the gross power output is very similar in the two plants and the percentage breakdown into the main process areas is also similar, despite the different plant configurations. The lower power consumption of the air compressor in the ASU in the IEA GHG plant is offset mainly by a larger nitrogen compressor power consumption.

A significant factor contributing to the lower efficiency in the Foster Wheeler plant is the difference in gasifier performance with the different coals. Gasifier performance data for both studies was provided by ChevronTexaco, the gasifier licensor.

Table A2 Detailed performance of IGCC plants with CO_2 capture

	CCPC		**Foster Wheeler**	
Plant definition				
Coal	Canadian bituminous		Australian bituminous	
Gasifier	ChevronTexaco-quench		ChevronTexaco-quench	
Gas turbines	2 x 7FA (60Hz)		2 x 9FA (50Hz)	
Air from GT to ASU, %	0		50	
CO_2 capture, %	87.0		84.8	
CO_2 output pressure, MPa	13.89		11	
Overall performance	MW	% gross power	MW	% gross power
GT power	394.00	66.3	563.4	57.9
ST power	196.49	33.1	398.2	40.9
Expander power	3.76	0.6	11.2	1.2
Gross power	594.25	100.0	972.8	100.0
Auxiliary power consumptions	149.70	25.2	242.5	24.9
Net power	444.55	74.8	730.3	75.1
Auxiliary power consumption				
Air separation	77.61	13.1	128.62	13.2
Coal prep /gasification /treating	7.36	1.2	14.54	1.5
Acid gas removal	22.24	3.7	33.04	3.4
Sulphur plant	0.56	0.1	3.56	0.4
CO_2 compression	27.44	4.6	38.5	3.9
Power block and miscellaneous	8.70	1.5	13.32	1.4
Cooling water system	5.79	1.0	10.94	1.1

Capital costs
The capital costs of the two plants are summarised in table A3.

Table A3 Capital costs (US$/kW)

	CCPC	**Foster Wheeler**
Coal reception and handling	49	13
Gasification	296	322
Air separation	208	169
Fuel gas treatment, including shift conversion	106	84
Acid gas removal	173	81
Sulphur plant	49	46
CO_2 compression	60	34
Power island, inc. feed gas heating/humidification	482	465
General facilities	492	189
Total plant cost (CCPC definition)	1916	1402
Owner's costs (land, fees, permits etc.)	166	92
Total plant cost (IEA GHG definition)	2092	1495

The total plant costs as quoted in the CCPC and Foster Wheeler studies have a slightly different definition. The cost in the Foster Wheeler study includes some owner's costs (land, fees and permits) which are included later in the CCPC study. When these costs, as stated in the CCPC report, are added the total specific cost in the Foster Wheeler study is 29% lower than in the CCPC study. Some of this difference is due to economies of scale. If the CCPC plant is scaled to the same size as the Foster Wheeler plant using a cost scale exponent of 0.7, the total plant cost becomes $1802/kW, reducing the cost difference to 17%. Factors which may contribute to this remaining difference are the different locations (Nova Scotia for CCPC, Netherlands for Foster Wheeler/IEA GHG), detailed site conditions, coal analyses, plant configurations, the trade-off between capital cost and efficiency and general uncertainties.

The capital cost breakdowns show a substantially higher cost in the CCPC study for general facilities. However, some items that are included in general facilities in the CCPC study are probably included in the process units, particularly the gasification and power island sections, in the Foster Wheeler study. The higher cost of acid gas removal in the CCPC study may be due to the higher percentage CO_2 capture in this unit; 99% compared to 90% in the Foster Wheeler study. The Foster Wheeler plant partly compensates for its lower percentage CO_2 capture in the acid gas removal unit by having a higher conversion of CO to CO_2 in the shift converter. Most of the CO_2 emissions from the CCPC plant result from combustion of CO in the gas turbine but in the Foster Wheeler a substantial proportion is un-captured CO_2.

Electricity generating costs
The difference in the cost of electricity generation between the CCPC and Foster Wheeler studies is due to differences in:

- Plant performance
- Capital costs
- Operating and maintenance costs
- Economic assumptions

To eliminate the effects of the economic assumptions, the CCPC costs have been converted as far as possible to the basis specified to Foster Wheeler by IEA GHG. The main technical and economic assumptions used in the two studies are summarised in table A4.

Table A4 CCPC and IEA GHG economic assumptions

	CCPC	IEA GHG
Location	Various Canadian locations	Netherlands coastal site
Bituminous coal price, US$/GJ, LHV	1.82hhv	1.5
Plant operating life, years	20	25
Return on equity, %	10% after tax	
Return on debt	9.25%	
Discount rate	After tax cost of money	10%
Costs during construction, %		
year 1	3.2	20
year 2	23.8	45
year 3	48.5	35
year 4	24.5	
Load factor, %	90	85

An annual capital charge factor can be derived to take into account the effects of discount rate, taxation, interest during construction, start-up costs and working capital. The CCPC and IEA GHG economic assumptions correspond to annual capital charge factors (annual capital-related costs divided by total plant cost including owners costs) of 14.2% and 12.8% respectively. When the higher load factor in the CCPC study (90% compared to 85% in the Foster Wheeler study) is taken into account, the annual capital charge factor per MWh is only 5% higher in the CCPC study.

A full breakdown of operation and maintenance (O+M) costs is not included in the CCPC report. Most of the O+M costs in the studies are based on the contractors' best judgements so it is not appropriate to change them for this comparison. An exception is the insurance and local property taxes, which are assumed to be 2%/year in the Foster Wheeler study and 0.8%/year in the CCPC study. The fixed O+M costs are adjusted to allow for the different load factors in the two studies.

The CCPC costs are converted, as far as possible, to the same economic basis as Foster Wheeler's IGCC study in table A5. The costs are also converted approximately to the same size of plant as in the Foster Wheeler study. After eliminating the effects of economic conventions and plant size, the costs of electricity in the CCPC and Foster Wheeler studies differ by about 5%.

Table A5 Conversion of CCPC costs to Foster Wheeler/IEA GHG economic basis

	CCPC plant			Foster Wheeler / IEA GHG plant
	CCPC report	IEA GHG cost basis	Scaled to IEA GHG plant size	
Net power output, MW	444.55	444.55	730.3	730.3
Capital cost, US$/kWe	1916	2092	1802	1495
Cost of electricity USc/kWh				
Fuel cost	2.08	1.64	1.64	1.72
O+M cost	0.98	1.24	1.12	1.29
Capital charges	3.78	3.61	3.11	2.57
Total	6.84	6.49	5.87	5.58

Conclusions

The thermal efficiencies of the bituminous coal IGCC plants in the CCPC study and a study carried out for IEA GHG by Foster Wheeler are similar.

Capital costs are lower in the Foster Wheeler study, partly due to better economies of scale.

When converted to the same plant size and economic conventions, the difference between costs of electricity generation in the CCPC and Foster Wheeler studies is only about 5%.

Overall, the different economic assumptions such as rates of return, plant life and load factor used in the CCPC and Foster Wheeler studies make only a small difference to the costs of electricity.

CANADIAN CLEAN POWER COALITION

CCPC Phase I Final Report

Summary Report on Conceptual Engineering and Feasibility Studies
conducted by the
Canadian Clean Power Coalition

Prepared by

CRI Consulting

February 2004

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Executive Summary

The Canadian Clean Power Coalition (CCPC) represents power generators and coal suppliers of over 90% of Canada's coal-fired power generation. The participants of the CCPC have been concerned about the level of greenhouse gas emissions resulting from the operation of their plants. As the challenge of potential climate change impacts became clear, coal and coal fired electricity producers began to evaluate strategies for net emission reduction.

Typically their strategies have evolved to consider several approaches as a means of extending the use of fossil fuels while meeting net reduction goals, and include the following elements:

- offsets and trading in the short term;
- carbon management by capture and storage or use of the carbon dioxide in the medium term; and
- capital stock turnover and for the development of new technology in the longer term.

These approaches recognize the importance of carbon management as a means of extending the use of fossil fuels to provide the time required for the development and introduction of new, less carbon intensive generation technologies in the future.

The participants have become increasingly involved in research projects involving the CO_2 issue. Topics include assessing the potential demand for CO_2 for Enhanced Oil Recovery in Alberta and Saskatchewan, assessing technologies for recovery of CO_2 from flue gas, investigations of technology options for utilizing CO_2, evaluations of storage in spent oil & gas reservoirs, aquifers and brines, and reductions of CO_2 by co-production of cement and power and by utilizing landfill gas.

A number of the participants held a series of discussions throughout 2000 and 2001 to identify a joint course of action to ensure that coal and coal fired electricity would continue to have a place in Canada's energy supply future, alongside both other conventional fuels and non-conventional renewable supplies. These discussions expanded and culminated in the formation of the CCPC, an association and formal agreement. That formal agreement describes the goals and the specific objectives of the CCPC, as well as the financial and non-financial commitments of each participant.

The CCPC Participation Agreement was signed in mid 2001 among ATCO Power Canada Ltd., EPCOR Utilities Inc., Luscar Limited, Nova Scotia Power Inc., Ontario Power Generation Inc., Saskatchewan Power Corporation, and TransAlta Utilities Corporation, with the concept of a private-public partnership to develop technology to meet the stated goals. Phase I of the project commenced in September 2001. Subsequently, the governments of Alberta, Saskatchewan, and Canada subscribed to support the CCPC. In addition, the participation of EPRI (Electric Power Research Institute of Palo Alto, CA) and IEA (International Energy Agency) was solicited and secured.

The CCPC established a goal to develop projects to demonstrate technology at a commercial utility scale for retrofit to existing plants, or for use in new coal fired power plants, that would allow all emissions, including CO_2, to be controlled to meet all foreseeable new regulatory requirements. The emissions target was to allow a coal-fired plant to be as clean as a modern natural gas fired gas turbine plant. The goal was to do this while maintaining overall efficiency at or above current levels, maintaining costs competitive with other generation technologies and enabling the CO_2 to be captured.

The demonstration projects will consist of the retrofit of an existing plant with new technology to be completed by 2007, and the design and construction of a new greenfield plant by 2010. Phase I of the project comprises the Conceptual Engineering and Feasibility Studies, undertaken from mid 2001 to mid 2003 and concluding with this summary report. Phases II and III, the next steps of the project, will relate to the detailed design and construction of the retrofit and greenfield plants respectively. This report summarizes the Phase I activities, completed in July 2003.

The objective of the conceptual engineering and feasibility studies was to determine the most appropriate technologies for the demonstration projects. The studies identified and evaluated candidate sites, as well as recommending the most suitable sites for the demonstrations. Implementation plans, preliminary designs and cost estimates were to be developed for those technologies and sites, recognizing the geographical variability of coal: western lignite and sub-bituminous coals, and eastern bituminous coals.

The fundamental principle underlying the goals of the CCPC was to identify a process that would produce electricity from coal in some fashion and that would also provide a relatively pure stream of CO_2 that could be captured, further processed as necessary, and subsequently used or stored.

Work Package 1 was a pre-screening study completed in November 2001 by SFA Pacific Inc. that evaluated the latest R&D in process developments suitable for commercial scale retrofit applications and for greenfield applications, that will meet the design goals of the project for control of NO_X, SO_X, particulates (PM_{10} and $PM_{2.5}$), mercury, CO_2 and other airborne toxics. This study led to the preliminary selection of the gasification process for greenfield projects, and amine scrubbing and oxyfuel combustion for retrofit projects. However, SFA Pacific also acknowledged that gasification could have an application in repowering scenarios. The subsequent work packages and contracts were developed on the basis of that recommendation.

An engineering study (Work Package 4) was awarded to Neill & Gunter Limited/ADA-ES in April 2002, with deliverables to identify emissions targets for all emissions to meet all foreseeable new regulatory requirements, except CO_2, and to evaluate and recommend retrofit technologies and to prepare a cost estimate to control all air emissions, except CO_2, for a commercial scale retrofit. Emission control targets were to be equal to, or better than, a natural gas fired combined cycle (NGCC) plant. The targets were to recognize the regional impact of different coals and geography. The CCPC recognized that when one captures CO_2, of necessity one also captures virtually all other emissions. Thus, the intention of the CCPC was to establish with some accuracy the cost to capture all emissions except CO_2, and by comparing the cost of advanced CO_2 capture technologies, thereby isolate and identify the true incremental cost to capture CO_2. The targets so identified would guide subsequent work on CO_2 capture technologies.

Neill & Gunter completed this work in October 2002. An estimate of the impact of these technologies on operating and maintenance costs was also provided. Table 1 identifies the resulting current and future missions targets. Table 2 identifies the technologies and costs that would be required to meet the targets. Neill & Gunter's work confirmed that the targets could be met in the relatively near future, with the assumption that technological development in near to commercial and emerging emissions abatement technologies will continue as they have in the past.

Table 1: CURRENT AND TARGET EMISSIONS LEVELS

Parameter	Units	Coal Plants						NGCC
Fuel		Lignite		Sub-Bituminous		Bituminous		Natural Gas
Boiler Type		Wall Fired		Tangential		Wall Fired		HRSG
Primary Targets		**Target**	**Current**	**Target**	**Current**	**Target**	**Current**	
NO_X	g/MWhr ng/J	50 4.5	- 258	50 4	- 219	50 5	- 258	28 5
SO_X	g/MWhr ng/J	55 5	- 602	55 5	- 198	55 4.5	- 1462	4.5 0.7
Particulates PM_{10}, $PM_{2.5}$	g/MWhr ng/J	28 2.5	- 30.1	28 2.4	- 15.1	28 2.8	- 25.8	15 2
Mercury	mg/MWhr pg/J	5.5 0.5	- 14	3.5 0.3	- 10	3.0 0.3	- 9	N/A
CO	ppmv	40		40		40		45
Chloride	mg/Nm^3	5		5		5		N/A
SO_3	ppmv	5		5		5		N/A
NH_3	ppmv	1		1		1		1
Secondary Targets								
VOC	mg/Nm^3	1		1		1		1
Heavy Metals:								
Selenium	mg/Nm^3	6		6		6		
Arsenic	mg/Nm^3	6		6		6		
Cadmium	mg/Nm^3	2		2		2		

Note: 1) Units based on 3% O_2 in flue gas.
2) NO_X values expressed as NO_2
3) SO_X, NO_X, $PM_{2.5}$, Hg based on a 720 hr rolling average.

Table 2: TECHNOLOGIES AND COSTS TO MEET TARGET EMISSIONS LEVELS

Fuel	Bituminous			Sub-Bituminous		Lignite	
	Option 1	**Option 2**	**Option 3**	**Option 1**	**Option 2**	**Option 1**	**Option 2**
Technology	• $LONO_X$ burners • SCR • Wet scrubber • $AquaNO_X$ scrubber	• $LONO_X$ burners • SCR • $LOTO_X$ • Airborne FGD • Wet stack	• Toxecon • $AquaNO_X$	• $LONO_X$ burners • SCR • Marsulex Activated Coke • COHPAC	• $LOTO_X$ • Airborne FGD • Wet stack	• $LONO_X$ burners • SCR • Marsulex Activated Coke • COHPAC	• $LOTO_X$ • Airborne FGD • Wet stack
Capital Cost ($millions)	283.6	365.2	234.8	237.1	274.6	301.7	258.8
Unit Size	165 gross			410 gross		298 gross	
Unit Cost ($/kW net)	909	1,171	753	717	721	1,110	952
O&M ($/MWhr)	6.73	6.57	5.53	9.49	4.19	11.24	6.52

NOTE: $LONO_X$ burners includes neural networks and OFA

The Neill & Gunter study confirmed the belief that meeting all emissions requirements, not including any requirements to limit CO_2 emissions, would require significant capital and have a major impact on the operating and maintenance costs of the plants. This fact could have a substantial influence on any decisions to capture CO_2 emissions.

Two studies (Work Packages 2 and 3) were awarded in 2002 to Fluor Canada to examine the candidate CO_2 abatement technologies (gasification, and amine and oxyfuel) in detail. These studies were completed in July 2003. The design goals for the studies were:

- No net loss of power output from the plant after retrofit (i.e., additional or self generation required),
- For the oxyfuel case the plant must also be capable of operation in an air fired mode,
- Control and safe disposal of all emissions from the plant,
- Capture of the CO_2 from the plant and from any auxiliary power generation required, and
- Evaluation of plant integration options and benefits.

It is important to highlight that the first requirement – no net loss of power output – implied that all auxiliary power for the CO_2 capture equipment would be required to be generated on site from additional, coal-fired capacity. *Furthermore this would require that all emissions from that additional capacity would also have to be captured, including the additional CO_2.*

The deliverable was a report for each technology that evaluated candidate sites for a full-scale demonstration project for each of the three coals, and included conceptual designs and cost estimates. An implementation concept for the demonstration project was developed for the one preferred site, taking into account the plant's operational status and the need to minimize plant outages. Table 3 summarizes the results.

Table 3: TECHNICAL AND ECONOMIC COMPARISON OF CO_2 ABATEMENT TECHNOLOGIES

Fuel		**Bituminous**	**Sub-bituminous**	**Lignite**	**Lignite**	**Lignite**
Technology		Gasification	Gasification	Gasification	Amine	Oxyfuel
COE (90%CF)	$/MWhr	**106.69**	**96.84**	**130.85**	**115.90**	**152.00**
Cost	millions $	1,329	1,492	1,593	1,370	2,313
CO_2 Emitted	Tonne/MWhr	0.1164	0.1114	0.1822	0.060	0.145
CO_2 Captured	%	86.4	89.0	85.7	95	90
CO_2 Avoided	Tonne/MWhr	.6546	.7406	.7008	0.823	0.738
Cost $_{CO2}$ Avoided*	$/tonne	46.88	52.20	87.73	56.60	111.96
Capacity	MW gross	594.25	629.24	555.35	453.5	629
Economic Capacity	MW net	444.55	436.82	361.10	310.9	373
Net Heat Rate	KJ/kWhr	11,408	13,806	13,239	12,526	14,882
Unit Cost	$/kW net	2,990	3,416	4411.5	4,406	6,200

*Note to Table 3. Cost of CO_2 avoided is defined as the increase in cost of electricity in $/MWhr (evaluated case minus selected base case) divided by the decrease in tonnes of CO_2 emitted per $MWhr_{net}$ (selected base case minus evaluated case).

Gasification was to be evaluated principally for greenfield applications. Since gasification was also being considered for the retrofit application, separation of greenfield costs was provided to allow a repowering scenario to be developed from this work. Alternative sites for the greenfield demonstration were investigated and an assessment of the environmental impact was carried out. Amine scrubbing and oxyfuel were to be evaluated mainly for retrofit applications, with some effort directed to evaluate them for greenfield projects.

In doing this work, the CCPC acknowledged that, while there are some slight differences in the emissions targets for gasification from those used for amine and oxyfuel, these are small enough to be considered insignificant.

As the Fluor studies progressed, additional information became available. As a result the CCPC Technical Committee requested some changes to the studies' scope. The amine and oxyfuel technologies were originally to be purely retrofit technologies, utilizing equipment currently operating in the sample plants. However, it became apparent during the preliminary site selection phase of the studies that retrofitting these technologies was a greater challenge than previously anticipated, and that both technologies would benefit significantly with new boiler designs and more integration in the designs. For example, the preliminary work showed that, in order to minimize the auxiliary power requirement for amine scrubbing as much as possible and to provide any of that auxiliary power as economically and efficiently as possible, integration was paramount. This then led the study to a supercritical boiler that precludes the use of an existing boiler and turbine. Similarly, the site selection studies demonstrated that the oxyfuel technology would benefit disproportionately from minimizing boiler infiltration, as well as the auxiliary power concerns mentioned above, that also led to a supercritical design. During the site selection stage in evaluating gasification, it also became apparent that it would not be practical to repower with gasification.

Thus, all technologies were ultimately evaluated as greenfield technologies. The technologies might be utilized at the same site as an existing facility, but existing equipment would in all probability be completely retired, and a new plant built on that site. The bulk of the work proceeded in this direction, and the above table reflects that.

It should be noted that there could be situations and specific site conditions where these technologies would be utilized as retrofits. There is some information to be derived from the reports if a utility had some reason that it wanted to prolong the operating life of a particular asset, and was willing to accept the attendant penalties in capital and O&M costs, or where the application was part of a larger overall CO_2 abatement strategy and replacement power was cheap. However, these are site specific, and the studies could not address them.

We note that the studies by Fluor evaluated gasification for all three fuels represented by the CCPC, but evaluated amine and oxyfuel in detail only for lignite. Early in the study, the CCPC Technical Committee and Fluor agreed that it would be better value to evaluate one fuel in depth for both amine and oxyfuel, than to evaluate all three fuels more superficially. This also reflected the fact that it required considerable more engineering effort to evaluate each case for these more novel technologies than for gasification.

The engineering and construction schedule was estimated in all cases to require a minimum of five years following site selection, assuming capital was committed and available. A significant departure from the traditional utility approach would also be required in the approach to the project execution. Fluor concluded that this would require an EPC (engineer, procure, construct) contract, with turnkey responsibilities as the only way to achieve the five year timeframe. (Note that this would put any demonstration project at 2008 at the earliest.).

A fourth study (Work Package 5) comprises a compilation and evaluation of CO_2 utilization and storage options in western Canada that could be used to offset the costs of collecting CO_2 from the retrofit and greenfield demonstrations. This study was awarded to SNC-Lavalin in September 2002 and was completed in July 2003. The study consolidated information on all aspects of CO_2 utilization. It created an inventory and characterization of storage and utilization options developed from a literature and knowledge review. The study also compiled all the factors, on a regional basis, that impact various utilization options, including an evaluation of capital and operating costs of each option, acknowledging such conditions as purity, contaminants and pressures required for each option.

SNC-Lavalin reviewed all options to store or utilize CO_2. They concluded that most uses would consume trivial amounts compared to the production from a single 300 MW coal fired plant (2.6 million tonnes per year, of a total of 78 million tonnes), and that the only viable options were enhanced oil recovery (EOR), enhanced coalbed methane recovery (ECBM), and geological storage, all in western Canada. SNC-Lavalin developed theoretical values for storage capacity, cost, and consumption rates. Table 4 summarizes the findings. However, the study also recognized that all three uses are still evolving technologies, and while there do not appear to be any technical obstacles to EOR and geological storage, there remain many questions for any specific project. ECBM technology is still immature and projects are unlikely to proceed without significant technical development and demonstration (pilot) size project.

Table 4: EVALUATION OF CO_2 STORAGE AND UTILIZATION OPTIONS

Parameter	EOR	ECBM	Depleted Reservoirs	Deep Aquifers
Development status	Commercial	Pilot stage	Commercial	Commercial
Public Acceptance Issues	None	Ground water	None	Possible
Capacity Limit (AB & SK)	6-7 projects	None	> 50 projects	None
Capital Cost (millions $)	900	170	45	Not evaluated
Breakeven Cost ($/tonne)	38	10	(4)	Not evaluated

Note that the “breakeven” cost represents the maximum that the storage operator could pay for the CO_2 and achieve a zero NPV at a 15% discount rate. Thus the geological storage options would require the utility to pay $4/t.

SNC-Lavalin concludes that the best option for storage of CO_2 from a utility CO_2 capture demonstration project is to an EOR project. Since EOR and ECBM project have significant capital expenditures and complex logistics, they further conclude that CCPC should initiate discussions with owners/operators of potential storage facilities as soon as possible. These discussions should include the uncertainties of reservoir performance, both for CO_2 storage, and for oil or gas production.

A last study, awarded to Geological Survey of Canada in August 2002, evaluates the potential of the Nova Scotia coal deposits for sequestering CO_2 and producing coal-bed methane. In particular this work evaluates the Cumberland, Pictou and Sidney coalfields. It was scheduled for completion in May 2003. However, as of this writing, the report is incomplete, and the results are not included in this report

In conclusion, it appears that a CO_2 capture project is most likely to be a greenfield project because CO_2 capture technologies are not sufficiently attractive on a retrofit project. The major technical challenges include

- Gasification of low rank coals,
- Scale up and demonstration of amine scrubbing process enhancements, and
- Demonstration and operation of full scale oxyfuel combustion.

There remain many uncertainties with respect to the siting of a capture project, and the siting for the storage of CO_2. There also remain uncertainties with respect to participants, financing, project structure, and government participation. If CCPC is to achieve its objective of having a demonstration project in operation by approximately 2010 it must act on these uncertainties immediately.

The set of conclusions that the Technical Committee of the CCPC has adopted as a result of the work of Phase I are itemized below. The future direction that the CCPC and the electricity industry might take to address these or any other findings of the Phase 1 work packages are being addressed in a forum outside of this report.

- Gasification is still not mature technology for power plant applications. Significant work remains to be undertaken to make this a competitive technology, although it is probably the most likely platform for the future if limits on CO_2 emissions are applied. Similarly, oxyfuel is not yet a mature technology. Amine scrubbing would appear to be relatively mature, one of the lowest cost alternatives, and ready to apply to power plant applications for capturing CO_2. Initiatives are required:
    - To explore and develop gasification for low ranked coals to make it more reliable and cost effective, and
    - To answer scale up questions regarding amine scrubbing.
- A demonstration project will require a substantial effort from industry and government if it is to proceed and to succeed. Such a project will require participation from the oil and gas industry - the potential consumers of CO2. A business case must be provided to them to develop their interest - to demonstrate to them what investment will be required of them, and where they can expect to obtain returns. In addition, government participation will be required to ensure that such a project can be financed, to ensure that the necessary permitting is provided, and to provide a substantial amount of the funding.

Table of Contents

1 INTRODUCTION 11

2 GOALS OF THE PHASE I WORK 13

3 EMISSIONS TARGETS.. 15

4 OPTIONS FOR CARBON CAPTURE FOR COAL FIRED PLANTS 17

4.1 Amine Scrubbing Option 18

4.2 Oxyfuel (CO_2/O_2) Combustion Option 28

4.3 Gasification Option 34

5 OPTIONS FOR CO_2 USE OR STORAGE 39

5.1 Western Canada 40

5.2 Ontario 46

5.3 Nova Scotia 46

6 CONCLUSIONS 46

1 Introduction

The Canadian Clean Power Coalition (CCPC) represents power generators and coal suppliers of over 90% of Canada's coal-fired power generation. Thus, all participants have a significant interest in coal burning assets. The participants of the CCPC, energy companies from across Canada, have been concerned about the level of greenhouse gas (GHG) emissions resulting from the operation of their plants. As the challenge of potential climate change impacts became clear, coal and coal fired electricity producers began to evaluate strategies for net emission reduction.

Several utilities began a series of discussions throughout 2000 and 2001 to identify a course of action to ensure that coal and coal fired electricity would continue to have a place in Canada's energy supply future, alongside other conventional fuels and non-conventional renewable supplies. These discussions expanded and culminated in the formation of the CCPC, an association and formal agreement. That agreement describes the goals and specific objectives of the CCPC, and the commitments required of each participant, both financial and non-financial.

The CCPC Participation Agreement was signed in mid 2001 among ATCO Power Canada Ltd., EPCOR Utilities Inc., Luscar Limited, Nova Scotia Power Inc., Ontario Power Generation Inc., Saskatchewan Power Corporation, and TransAlta Utilities Corporation, with the concept of a private-public partnership to develop technology to meet those goals. Phase I of the project commenced in September 2001. Subsequently, the governments of Alberta, Saskatchewan, and Canada subscribed to support the CCPC. In addition, the participation of EPRI, and IEA was solicited and subsequently secured. This Participation Agreement identified the work programme to be carried out, the results of which this report describes.

A pre-screening study (Work Package 1) completed by SFA Pacific Inc. in November 2001 evaluated the latest R&D in process developments suitable for commercial scale retrofit applications and for greenfield applications, that would meet the design goals of the project for control of NO_X, SO_X, particulates (PM_{10} and $PM_{2.5}$), mercury, CO_2 and other airborne toxics. This study led to the preliminary selection of the gasification for greenfield projects, and amine scrubbing and oxyfuel combustion for retrofit projects. However, that preliminary report also acknowledged that gasification could have an application in repowering scenarios.

Two major studies (Work Packages 2 and 3) were awarded to Fluor Canada in 2002 that examined the above technologies (gasification, and amine and oxyfuel) in detail, and that were completed in July 2003. The design goals for the studies were a) no net loss of power output from the plant after retrofit (i.e., additional or self generation required), b) control and safe disposal of all emissions from the plant, c) capture of the CO_2 from the plant and from any auxiliary power generation required, and d) evaluation of plant integration options and benefits.

Since gasification is also being considered for the retrofit application, separation of greenfield costs will be provided to allow a repowering scenario to be developed from this work. Alternative sites for the greenfield demonstration will also be investigated and an assessment of the environmental impact will be carried out. Similarly, some effort has been directed to evaluate amine and oxyfuel for greenfield projects.

The deliverable was a report for each technology that evaluated candidate sites for a full-scale demonstration project for each of the three coals, and included conceptual designs and cost estimates. An implementation concept for the demonstration project was developed for the one preferred site, taking into account the plant's operational status and the need to minimize plant outages.

Another study (Work Package 4) was awarded to Neill & Gunter Limited in April 2002, that identified emissions targets for air emissions, and evaluated and recommended retrofit technologies and preparation of a cost estimate to control all air emissions, except CO_2, for a commercial scale retrofit. Emission control targets that were also established by this study, were to be equal to or better than a natural gas combined cycle (NGCC) plant. This work was completed in October 2002. The information from this study provided the CCPC with a baseline indicative cost against which will be compared the cost to control all emissions, including CO_2, that will establish a true evaluation of the cost to capture CO_2 from an existing plant. An estimate of the impact of these technologies on the operating and maintenance costs was also provided.

A fourth study (Work Package 5) comprises a compilation and evaluation of CO_2 utilization and storage options in western Canada that could be used to offset the costs of collection of CO_2 from the retrofit and greenfield demonstrations. This study was awarded to SNC-Lavalin in September 2002 and was completed in July 2003. The study consolidated information on all aspects of CO_2 utilization. It created an inventory and characterization of storage and utilization options developed from a literature and knowledge review and a subsequent compilation of all the factors, on a regional basis, that impact various utilization options. This included an evaluation of capital and operating costs of each option, acknowledging such conditions as purity, contaminants, pressures, required for each option.

A last study, awarded to Geological Survey of Canada in August 2002, evaluates the potential of the Nova Scotia coal deposits for sequestering CO_2 and producing coal-bed methane. In particular this work evaluates the Cumberland, Pictou and Sidney coalfields. This work was scheduled for completion in May 2003, but as of this writing, it is not complete, and is not included in this summary report

The CCPC commissioned this Phase 1 Final Report to summarize the work produced from the various work packages, which comprises a large amount of material and detail. The CCPC anticipated that there would be too much detail in the individual reports for a person to gain a ready understanding of the work that had gone into the project. For example, if CCPC were to interest new investors in the demonstration project, a summary and final report would be required to give that party a full understanding of the project without disclosing proprietary knowledge. If a person subsequently wanted to evaluate the technologies in detail the individual reports would be made available under a confidentiality agreement. In addition, because the work packages were discrete pieces of work performed by different contractors with little reference to one another, it was felt that a summary report would provide significant value by relating the work of the individual studies to one another and by showing a comprehensive picture of the entire body of work. A third purpose for the summary report was to provide an assessment of the several technical reports against the original objectives of the CCPC for Phase 1, as it is important for any of the members of the CCPC, be they governmental funders or industrial participants, to determine if the objectives that were espoused at the inception of the CCPC and Phase 1 were met. The final objective of the summary report was to summarize the recommendations of the various contractors and the author on future directions for the CCPC. Prior to the finalization of this report, these last two objectives were removed from its scope.

This report contains the set of significant conclusions that the CCPC Technical Committee has reached from their review of the various Phase 1 reports. This is the most significant component of compiling and summarizing the other reports. The future direction that the CCPC and the electricity industry might take to address these or any other findings of the Phase 1 work packages are being addressed in a forum outside of this report.

2 Goals of the Phase I work

Electric utilities recognize that they will be operating in a carbon constrained world, and that coal and coal fired electricity generation businesses are seriously handicapped in this new world. Yet all participants have significant interest in coal burning assets. The CCPC was formed in response to that dilemma, its purpose:

- ***To secure a future for coal-fired electricity generation within the context of Canada's multi-fuelled electricity industry***
- ***To demonstrate that coal-fired electricity generation can effectively address all environmental issues projected in the future, including CO_2***
- ***To research and develop commercially viable clean coal technology, and thence to construct and operate a full scale demonstration project to remove greenhouse gas and all other emissions of concern from 1) an existing power plant by 2007, and 2) a greenfield power plant by 2010***

Phase I work of the CCPC was described as Conceptual Engineering and Feasibility Studies that would ultimately lead to Engineering and Construction of the demonstration project. More specifically, Phase I was to undertake the following:

Retrofit Technology

The process feasibility research will study the most appropriate process technology for retrofit to existing power plants, how it should be configured, what the costs for each option are, and what impact on the plant performance will occur if the technology were to be used. This would then allow the most appropriate technology to be selected.

Research will be carried out to evaluate the costs to control all air emissions except CO_2 for a commercial scale retrofit to determine and define the best options for CO_2 disposal during the demonstration projects and later commercial projects. The design goals will be: a) control of NO_X & SO_X; b) control of particulates, including PM_{10} & $PM_{2.5}$; and c) control of mercury and other air toxics. Control levels in each case are to be determined based on input from the project technical committee, with the target being to allow a coal fired plant to be as clean as a modern gas turbine based natural gas fired plant.

Alternative options for handling the CO_2 extracted from the commercial scale and demonstration plants in various parts of Canada will be evaluated. Options include Coal-Bed Methane (CBM) in Nova Scotia, sequestration in aquifers in Ontario, and Enhanced Oil Recovery (EOR), Coal-Bed Methane (CBM) and sequestration in aquifers in Saskatchewan and Alberta. This work was to be coordinated with other activities in western Canada on EOR and CBM. Measurement and monitoring requirements will be evaluated to ensure that amounts sequestered can be quantified. CO_2 infrastructure requirements to make these options viable will be evaluated in regard to transportation, temporary storage, and recycling from EOR or CBM projects.

Candidate sites for a full-scale demonstration project will be evaluated and an implementation concept for the demonstration project developed, taking into account the plant's operational status and the need to minimize plant outages.

New Plant Technology

This task will research the technology options for new plant concepts. Technologies such as supercritical pulverized coal, ultrasupercritical pulverized coal, pressurized fluidized bed combustion, integrated gasification combined cycles, and advanced gasification options will be integrated together with options to control all emissions, including CO_2, down to low levels. Developing technologies, such as the Los Alamos National Laboratory's hydrogasification with CO_2 sequestration in serpentine mineral (being developed by the Zero Emission Coal Alliance, ZECA) will be included, as well as other advanced gasification options.

Based on the results of the previous task, the top two technology options will be developed in more detail to determine the best candidate for the demonstration plant. Alternative sites for the demonstration will also be investigated and an assessment of the environmental impact will be carried out.

The final report, giving the results of the studies carried out will be prepared using the results from the previous two tasks. This will recommend the technology and site to be used for the demonstration project. Candidate sites for a full-scale demonstration project will be evaluated and an implementation concept for the demonstration project developed.

The goals of the CCPC in Phase I have largely been met. Technology has been identified, or in the case of retrofit, has been confirmed to be currently not available. Implementation plans have been developed, so far as engineering and construction are concerned. Further, the CCPC has identified specific areas where additional work is required because technology is not yet mature. In addition, an inventory of CO_2 storage options has been compiled and a CO_2 sink for a demonstration project has been identified. And several potential sites for a demonstration have been identified.

However, what none of the Phase I studies could provide is how the CCPC can make the transition to Phases II and III, that is, how to enlist interested utilities and other parties, how to structure the project, how to finance the project, how to enlist a CO_2 consumer/storage operator, how to enlist governments, and how to structure any government funding. This latter is critical since governments are not interested in funding commercial ventures. They are interested in solving environmental problems and in developing the appropriate technology. However, because of the large amounts of money involved, both industry and governments will have to be creative to create the correct financial climate for a demonstration project.

3 Emissions Targets

An engineering study (Work Package 4) was awarded to Neill & Gunter Limited/ADA-ES in April 2002, with deliverables to identify emissions targets for all emissions to meet all foreseeable new regulatory requirements, except CO_2, and to evaluate and recommend retrofit technologies and to prepare a cost estimate to control all air emissions, except CO_2, for a commercial scale retrofit. The targets so identified would guide subsequent work on CO_2 capture technologies. Emission control targets were to be equal to, or better than, a natural gas fired combined cycle (NGCC) plant. The targets were to recognize the regional impact of different coals and geography.

Based on a review of background emission trends, existing and emerging control technologies, public and regulatory perception, Neill & Gunter anticipated that foreseeable regulatory requirements will require emission levels from a coal fired power plant be comparable to a natural gas combined cycle plant (NGCC) with an SCR. This confirmed the validity of the CCPC guidelines for emissions targets. Neill & Gunter also expected that future emission guidelines will be output-based, and not (heat) input based as has been used in the past. Output based limits provide incentives for more efficient generation technology and operations by making efficiency count towards emission limits. If these targets can be achieved, and the full fuel life cycle is considered, then with the exception of CO2, coal fired power plants will be cleaner than NGCC, because of the significant upstream emissions in the extraction, processing and transportation of natural gas. The specific emission targets are identified in Table 3.2 below:

Three existing *reference* plants, each representing a different type of coal, were selected by the CCPC to be retrofitted with a pollution control system that would be able to meet new target emissions. The selected reference plants are identified below.

Table 3.1: CCPC reference plants

Reference Plant	Coal	Boiler Type
Genesee, Alberta	Sub-bituminous	Alstom, Tangential Firing
Shand, Saskatchewan	Lignite	B&W, Wall Fired
Trenton, Nova Scotia	Bituminous	B&W, Wall Fired

Neill & Gunter identified and evaluated over 50 various control options that are either commercially available, or currently under development for SO_X, NO_X, fine particulate and mercury. In addition to this, over 25 emerging multi-pollutant approaches for managing emissions in innovative and cost effective ways were also identified.

To identify the most appropriate emission control technologies, a systematic or "Decision Analysis" procedure was followed which evaluated the technologies against a list of criteria including:

- Removal efficiencies.
- Commercial availability.
- Favorable economics.
- Feasibility of retrofit and commercial development of technology.
- Risk associated with the installation on the overall system.

Each technology was then scored on its relative performance resulting in a comparative picture of the technologies. The technologies with the highest scores were selected for analysis relative to the reference plants. From the more than 75 technologies that were investigated at the outset, a total of 12 preferred technologies remained at the end of the Decision Analysis process.

Table 3.2: CURRENT AND TARGET EMISSIONS LEVELS

Parameter	**Units**	**Coal Plants**						**NGCC**
Fuel		Lignite		Sub-Bituminous		Bituminous		Natural Gas
Boiler Type		Wall Fired		Tangential		Wall Fired		HRSG
Primary Targets		**Target**	**Current**	**Target**	**Current**	**Target**	**Current**	
NO_X	g/MWhr ng/J	50 4.5	- 258	50 4	- 219	50 5	- 258	28 5
SO_X	g/MWhr ng/J	55 5	- 602	55 5	- 198	55 4.5	- 1462	4.5 0.7
Particulates PM_{10}, $PM_{2.5}$	g/MWhr ng/J	28 2.5	- 30.1	28 2.4	- 15.1	28 2.8	- 25.8	15 2
Mercury	mg/MWhr pg/J	5.5 0.5	- 14	3.5 0.3	- 10	3.0 0.3	- 9	N/A
CO	Ppmv	40		40		40		45
Chloride	mg/Nm^3	5		5		5		N/A
SO_3	Ppmv	5		5		5		N/A
NH_3	Ppmv	1		1		1		1
Secondary Targets								
VOC	mg/Nm^3	1		1		1		1
Heavy Metals:								
Selenium	mg/Nm^3	6		6		6		
Arsenic	mg/Nm^3	6		6		6		
Cadmium	mg/Nm^3	2		2		2		

Note: 1) Units based on 3% O_2 in flue gas.
2) NO_X values expressed as NO_2
3) SO_X, NO_X, $PM_{2.5}$, Hg based on a 720 hr rolling average.

NOTE: $LONO_X$ burners includes neural networks and OFA

Neill & Gunter developed multi pollutant control options and associated retrofit costs (capital and operating and maintenance) for *each* reference plant, including identification of system performance, synergistic effects, lifecycle issues, risk and identification of any adverse consequences of implementing a particular system. The costs are presented in Table 3.3 below and are based on manufacturers information, Neill & Gunter in house data base, EPRI Technical assessment guide and USEPA program Coal Utility Environmental Cost (CUE COST).

Table 3.3: TECHNOLOGIES AND COSTS TO MEET TARGET EMISSIONS LEVELS

Fuel	Bituminous			Sub-Bituminous		Lignite	
	Option 1	Option 2	Option 3	Option 1	Option 2	Option 1	Option 2
Technology	• $LONO_X$ burners • SCR • Wet scrubber • $AquaNO_X$ scrubber	• $LONO_X$ burners • SCR • $LOTO_X$ • Airborne FGD • Wet stack	• Toxecon • $AquaNO_X$	• $LONO_X$ burners • SCR • Marsulex Activated Coke • COHPAC	• $LOTO_X$ • Airborne FGD • Wet stack	• $LONO_X$ burners • SCR • Marsulex Activated Coke • COHPAC	• $LOTO_X$ • Airborne FGD • Wet stack
Capital Cost ($millions)	283.6	365.2	234.8	237.1	274.6	301.7	258.8
Unit Size	165 gross			410 gross		298 gross	
Unit Cost ($/kW net)	909	1,171	753	717	721	1,110	952
O&M ($/MWhr)	6.73	6.57	5.53	9.49	4.19	11.24	6.52

The Neill & Gunter study confirmed the belief that meeting all emissions requirements, not including any requirements to limit CO_2 emissions, would require significant capital and have a major impact on the operating and maintenance costs of the plants. This fact could have a substantial influence on any decisions to capture CO_2 emissions.

4 Options for Carbon Capture For Coal Fired Plants

Coal fired power plants are seriously at risk in a carbon constrained world since they emit large quantities of CO_2, larger than any other energy source. In addition, the CO_2 emitted is relatively impure, being diluted with large amounts of nitrogen, oxygen that has not been consumed in the combustion process, water vapour that is both a product of combustion and is entrained in the coal, as well as a multitude of other "pollutants" such as SO_X, NO_X, particulates, etc. In addition, the opportunities to store CO_2 generally require that the gas be relatively pure. The challenge, therefore, is to obtain a relatively pure stream of CO_2, with which it is feasible to do something.

The Technical Committee of the CCPC directed its attention to this issue, with a study to evaluate the best and most appropriate technologies that would provide a "pure" stream of CO_2 from a coal fired plant. SFA Pacific Inc undertook this work, and identified that for a greenfield plant, gasification was the only real option. They further identified that for a retrofit application, gasification would be appropriate in a repowering scenario, while amine scrubbing and oxyfuel combustion would also be viable alternatives. The Technical Committee agreed with the conclusions, but believed that there would be value in considering amine scrubbing and oxyfuel for greenfield applications as well. The specifications for the engineering studies were prepared accordingly.

During the contract negotiations with the selected contractors the CCPC agreed that the studies could be completed in two stages: 1) site selection and 2) site optimization. During the site selection stage the contractor was to develop the technical and design schemes in sufficient detail to identify the most cost effective and otherwise best site for detailed optimized design.

4.1 Amine Scrubbing Option

Amine scrubbing is a process in which the flue gases from a conventional coal-fired boiler are passed through a large vessel (an absorber tower) and mixed intimately with a chemical solution containing an amine, at which time the amine selectively captures (absorbs) the CO_2. The amine with the CO_2 is pumped to another vessel (CO_2 stripper) in which the amine is processed (with large amounts of low quality heat) to release the CO_2, thereby producing a pure stream of CO_2 for disposal and storage. The cleaned or stripped amine is returned to the absorber tower to capture more CO_2. See figure 4.1.

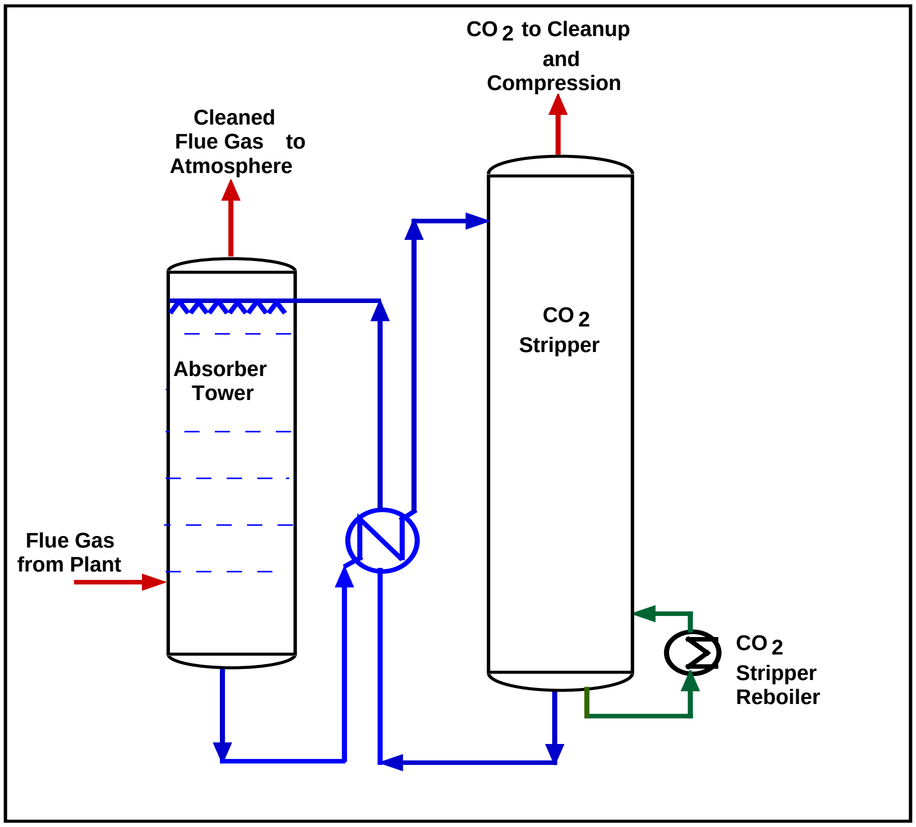

Figure 4.1. Amine Scrubbing Schematic

Amines can be tailored to capture any number of specific gases, and the process is well known and has been used by the chemical and petrochemical industries for many years to process a variety of gases.

Fluor was awarded a contract to evaluate amine scrubbing technology. As mentioned above, the study proceeded in two stages – 1) a site selection stage and 2) a site optimization stage.

Site Selection

The site selection study evaluated the impacts on performance and cost of removing all emissions including CO_2 from three sites having three different coals. The three sites selected for comparison were:

- Trenton 6, with a 156 MW boiler using bituminous coal
- Shand, with a 272 MW net boiler using lignite coal
- Genesee 1, with a 391 MW net boiler using sub-bituminous coal

Key constraints were set on the study that further set the basis for the comparative evaluation. These constraints are summarized as follows:

- There was to be no net power import or export. Hence, all additional auxiliary power requirements would be supplied by a new auxiliary coal-fired boiler located at the site.
- *All emissions from the auxiliary boiler, including CO_2, would have to be controlled to the same level.*
- The objective was to achieve the emission level set for NGCC. The targets used were those established by Neill & Gunter.
- The conventional Fluor Econamine FG^{SM} amine process is used to remove CO_2 from the flue gas. A capture rate of 90% is used for all three sites.

During the Site Selection Study, for simplicity no turbine steam extraction or heat integration was carried out between the existing plant and new CO_2 extraction plant.

The technology selection for removal of pollutants such as SO_X, NO_X, mercury and particulate was conducted by evaluating over twenty different licensor and vendor technologies. Licensors and vendors were contacted and their process performance evaluated with respect to the three different site conditions, boiler operation and coal quality. After evaluation, the same technologies were selected for all sites regardless of site conditions, boiler size, boiler operation and coal type. The selected pollutant control technology was also evaluated with respect to its compatibility with the downstream Econamine FG^{SM} process. The final pollutant removal selected technology is summarized below.

Pollutant	Technology Selection	
SO_X	Option A	Wet Scrubber with Limestone to produce Gypsum
	Option B	Wet Scrubber with Ammonia to produce Fertilizer
NO_X	Option A	Burner modification, SNCR followed by LoTOx™
	Option B	Burner modification, SNCR followed by ECO™
Mercury	Option A	LoTOx™ followed by Wet Scrubber and Wet ESP
	Option B	ECO™ followed by Wet Scrubber and Wet ESP
Particulate	Wet Scrubber followed by Wet ESP	

Since the two NO_X removal technologies are still in the demonstration stage, it was recommended that both options be maintained for future evaluation. Both NO_X removal technologies represent the best available technology that could be commercially demonstrated by 2005. With these technologies, the expected emission levels are shown in Table 4.1. These emissions are based on "net power" production, taking into account only the auxiliary power needs for the boiler and turbine. When expressed as "net power with CO_2 capture", the target for retrofit increases by an additional 40%.

TABLE 4.1: Emission Level Comparison of Key Pollutants from Retrofit Plant

Pollutant	Units	Current Levels	Expected Emissions	N&G Recommended	NGCC Expected
SO_X	g/MWhr (net)	7,346	Nil	55	4.5
NO_X	g/MWhr (net)	2,243	43	50	28
Particulate	g/MWhr (net)	662	22	28	15
Mercury	mg/MWhr (net)	43	7.6	5.5	N/A

Some of the key performance and economics numbers calculated for the three sites are shown in Table 4.2.

TABLE 4.2: Key Performance Parameters for Various Sites

Criterion	Trenton	Shand	Genesee
Boiler Size (Gross/Net), MW	165/156	298/272	410/381
Annual Capacity Factor, %	81	84.8	96.9
Auxiliary Boiler Load (Gross/Net), MW	124/117	319/291	364/338
Aux. Load as % of Original Boiler Load, %	75	107	89
Total CO_2 Production, tonnes/day	5,329	13,081	15,254
Total CO_2 Avoided, tonnes/day	2,791	5,563	7,283
Total Installed Cost, million $	545	1,077	1,254
Plant Installed Cost, $/kW (net plant output)	3,494	3,960	3,291
CO_2 Production Cost, $/tonne	70	51	48
Cost of CO_2 Avoided, $/tonne	134	121	100
Cost of Electricity, $/MWhr	100	103	80

The performance data shown in Table 4.2 is for site comparative purposes only and should not to be compared with the results for the Site Optimization Study. The trend in the results above can be explained due to the key differences among the sites. These differences are highlighted qualitatively below.

Trenton

Advantages

- Requires significantly less capital due to smaller size.

Disadvantages

- No nearby EOR site. Coal Bed Methane Recovery is a possibility but not attractive.
- Very congested site.
- High coal cost.
- Has the highest CO_2 avoided cost and cost of electricity due to small size.

Shand

Advantages

- Plenty of adjacent plot space available. Existing Shand infrastructure is designed with a second future power plant in mind.
- Good site for EOR application.

Disadvantages

- High moisture and ash content result in a high auxiliary power requirement.
- Zero discharge site results in a power and cost penalty.
- Need cooling tower to provide cooling needs.
- High ash disposal cost.

Genesee

Advantages

- Has the highest boiler plant availability factor.
- Excellent potential site for EOR utilizing CO_2.
- Plenty of plot space availability.
- Low coal and ash disposal cost.
- Larger size gives best economy of scale.

The Genesee site was the most attractive to continue with the site optimization, since it had the lowest \$/tonne of CO_2 avoided and the lowest cost to generate electricity. However, the Technical Committee selected the Shand site in its place because of the ease and availability of obtaining Shand plant design data within the time frame of the study.

Site Optimization

At the conclusion of the site selection stage, it was apparent to the Technical Committee that its requirements around the supply of auxiliary power to the plant was causing significant compromises in the design. Accordingly, the Technical Committee decided at the site optimization stage to evaluate amine technology as a simple add on piece of equipment, accepting any loss of boiler production. The Committee also recognized that to obtain the greatest benefit from amine technology it would be necessary to design a thermal plant (boiler, turbine, etc.) with full consideration for the energy requirements of the technology – essentially a greenfield design. Therefore, the scope of work for the Site Optimization Study was defined to consider the following two study cases:

- A retrofit demonstration project for SaskPower Shand Plant. In this study, the feasibility of retrofitting the existing Shand Boiler to capture CO_2 by using Econamine FG PLUS^{SM} was evaluated.
- A new greenfield supercritical lignite fired boiler near Shand. In this study, the feasibility of a new greenfield boiler with CO_2 capture using Econamine FG PLUS^{SM} was evaluated. This case allows comparison with the other technology options of oxyfuel and coal gasification.

The goal of the site optimization stage was to optimize the design, to take the design to a greater level of detail, and especially energy integration within the plant and with the existing system to increase the overall plant efficiency.

Retrofit Plant Optimization

The constraints on the work included the following:

- Auxiliary power for CO_2 capture was to be provided from existing boiler production and no new boiler is required.
- Maximize heat integration between the amine scrubbing process and the existing steam turbine system.
- Use Econamine FG PLUS^{SM} technology to get higher efficiency in capturing CO_2.

Pollutant removal technology selection, pollutant emission targets and level of pollutant removal did not change for this stage.

Significant process improvements achieved in this study that would result in improved economic performance are highlighted below:

Existing Plant Integration

- Process steam was extracted from the IP/LP section crossover of the existing turbine. The amount of steam extraction corresponded to 50% of the LP section steam at MCR. Extraction of such level of steam was feasible, but still requires a more detailed evaluation by the turbine manufacturer.
- Condenser condensate from the existing turbine was preheated to 116^{0}C by the waste heat in the CO_2 stripper condenser and boiler flue gases.

Pollutant Removal

- Flue gas was cooled to an optimum level to reduce power consumption by LoTOx™ and downstream blower. In addition, well-proven CHX cooler technology was utilized to cost effectively recover the heat.
- Utilized Reverse Jet Wet Scrubber to remove SO_X down to 8 ppm with a low capital and operating cost.
- Layered NO_X removal technology by a combination of burner modification, low cost SNCR and final LoTOx™ or ECO™ process trim.
- Optimized booster blower location.
- Discontinued LIFAC and achieved all flue gas desulphurization via Wet FGD scrubber. This allowed increased limestone utilization and minimizing of fly ash disposal cost. Existing limestone storage and delivery system were reused.
- Recycled the flue gas condensate into the Wet FGD scrubber.

Econamine FG PLUS℠

- Achieved a 21% reduction in heat rate by the Econamine FG PLUS℠ over the conventional Econamine FG℠ process by incorporating the following:
    - Split-flow technology
    - Improved heat recovery from the solvent
    - Lower solvent circulation due to improved solvent reformulation and loading
    - Added absorber intercooler
    - Vacuum reclaiming to reduce solvent degradation loss
- Achieved an additional 11% improvement in heat rate by condenser condensate heat integration. The final Econamine FG PLUS℠ heat rate is reduced from 4070 kJ/kg (1750 BTU/lb) to 2756 kJ/kg (1185 BTU/lb)
- Optimized the level of CO_2 capture to 95%.
- Recycled waste streams such as reclaimer waste and spent carbon to the boiler.
- Utilized a single large size train concept throughout.
- Maximized the use of existing Shand offsite infrastructure in the retrofit design.

CO_2 Compression

- Used a combination of compression and pumping to reduce 8% of compression power consumption.
- Achieved a 50% reduced compressor cost by incorporating single train single-shaft split-case compression instead of multiple train integrally geared compression.
- Optimized the selection and location of the CO_2 dehydration unit. Glycerol dehydration unit at compressor final stage discharge was found to be the optimum.

Offsite

- Incorporated water softening within the cooling tower blowdown cycle.
- Reduced energy in water treatment by incorporating reverse osmosis unit rather than utilizing brine concentrator.
- Integrated existing brine concentration unit blowdown within the new wastewater treatment unit crystallizer.

The overall retrofit plant performance for the average ambient conditions with 95% CO_2 capture is summarized below.

TABLE 4.3: Retrofit Plant Performance (95% CO_2 Capture)

Boiler Gross Production, average	304.4 MW
Boiler Auxiliary Power Consumption	26 MW
CO_2 and Pollutant Capture Auxiliary Power Consumption	84.6 MW
Total Net Production	193.8 MW
Auxiliary Power Percentage	36.3%
Net Plant Efficiency	22.9%
CO_2 Production	6,415 tonnes/day
CO_2 Recovery	95%

An analysis of the distribution of this auxiliary power consumption for two cases, one for 95% CO_2 capture and the other for 85%, showed that the net export of power increased by 2.5% when CO_2 capture is reduced. The amine scrubbing technology offers flexibility in that both the percent CO_2 capture and the amount of flue gas processed can vary to increase power production during peaking period with no significant impact on the rest of the system, especially with no impact on the power production.

The capital cost breakdown for the retrofit cases is shown on the following table.

TABLE 4.4: Capital Costs, Retrofit Cases (millions $)

Pollutant Removal System	86
Econamine FG PLUS^{SM}	113.7
CO_2 Compression System	29
Utilities and Offsite	75.1
Total Plant Installed Cost	**303.8**

Economic analysis for the 95% CO_2 capture retrofit case shows a cost of CO_2 avoided of $63.3/tonne and a cost of CO_2 capture of $53.6/tonne. This is based on assigning $50/MW cost for auxiliary power import and using a 90% plant operating factor. Both costs of CO_2 avoided and CO_2 capture are very sensitive to the cost assigned to imported auxiliary power.

Greenfield Plant Optimization

The greenfield optimization case is based on designing a new supercritical boiler for lignite fuel. A new air-fired boiler design provided by B&W as part of the oxyfuel combustion study was taken as the basis. This air-fired unit design is based on gross power production of 624.5 MW at 24,115 kPa(g) (3,500 psig) and 593^{0}C (1,100^0 F) steam temperature with a single reheat. The supercritical boiler had a gross/net efficiency of 42.1/40.1 (HHV). For the amine greenfield case, the size of the boiler was prorated to 450 MW gross to allow obtaining about a 300 MW net production.

The CO_2 capture plant and the pollutant capture plant was prorated from the retrofit case design. Similar process design features as discussed under the retrofit section for the pollutant removal and the CO_2 capture are used in the greenfield case.

Maintaining the same pollutant removal efficiencies as in the retrofit case, the greenfield case shows similar final pollutant levels and recoveries for SO_X, NO_X, particulates and mercury. The pollutant removal scheme is the same as for the retrofit with the exception of NO_X removal. For the NO_X removal, the boiler is designed with ultra low NO_X burners. This was followed by the addition of an SCR unit to remove NO_X down to 30 ppm. The final cleanup down to 5 ppm NO_X level is done by either the LoTOx™ or the ECO™ process.

The overall plant performance for the greenfield base case with 95% CO_2 capture is summarized in the following table 4.5. Economics for the greenfield plant with 95% CO_2 capture is shown in Table 4.6. The EPRI economic model was used in the economic analysis.

TABLE 4.5: Greenfield Plant Performance

	95% CO_2 Capture
Boiler Gross Capacity, average	453.5 MW
Boiler Auxiliary Power Consumption	21.4 MW
CO_2 and Pollutant Capture Auxiliary Power Consumption	142.7 MW
Total Net Capacity	310.9 MW
Auxiliary Power Percentage	31.46%
Net Plant Efficiency	28.83%
$CO2$ Production	8,547 tonnes/day
CO_2 Recovery	95%

Similar to the retrofit case, an analysis of the distribution of this auxiliary power consumption for 95% CO_2 capture versus 85% capture showed that the net export of power increased by 2.5% when CO_2 capture is reduced. Also similar to the retrofit case, the amine scrubbing technology offers flexibility in that both the percent CO_2 capture and the amount of flue gas processed can vary to increase power production during peaking period with no significant impact on the rest of the system, especially with no impact on the power production. In addition, that analysis showed that even though the 85% CO_2 capture reduces the cost of electricity by 5%, it results in a 2% higher cost of CO_2 avoided. Furthermore, the study found that the economy of scale does reduce the cost of electricity and cost of CO_2 avoided. An amine plant of 625 MW gross will result in a 5% reduction in cost of electricity and a 13% reduction in the cost of CO_2 avoided compared to the present 450 MW (gross) case.

TABLE 4.6: Cost Summary, Greenfield Plant (95% CO_2 Capture)

Capital Cost, millions $	
Boiler Plant	998.4
Pollutant Removal System	94.4
Econamine FG PLUS^{SM}	130.4
CO_2 Compression System	34.7
Utilities and Offsite	112.4
Total Capital Cost	1,370.4
Total Capital Requirement	1,907
Cost of Electricity, $/MW	
Cost of Electricity With CO_2 Capture	115.9
Cost of Electricity (no CO_2 capture)	69.4
Cost of Avoided Pollutant, $/tonne	
Cost/Tonne of CO_2 Avoided	56.6
Cost/Tonne of CO_2 Captured	40.6

Conclusions of the Study

The Econamine FG PLUS^{SM} technology is a well-proven CO_2 capture technology that has been used for over 20 years with 22 installed plants. The largest plant in operation is a 320 tonne/day of CO_2 capture plant in Bellingham, WA, that has been in operation for nearly 10 years. Scaling up these proven plants to a larger scale plant with an Econamine FG PLUS^{SM} technology represents a manageable challenge. Both the mercury removal technology and the NO_X removal from the well-proven 30 ppm level down to 5 ppm level will be a challenge. Currently these technologies exist only at a few MW demonstration stage.

The amine scrubbing technology to capture CO_2 provides a well-proven, scalable, flexible and cost effective approach to capturing CO_2. Moreover, it provides the option to remove other pollutants and allow emission from the coal-fired boiler to be as close as possible to the natural gas combined cycle plant. Even though both the retrofit and greenfield plant show very favorable economics, the amine scrubbing technology is especially suited for a retrofit case, where it can be applied with minimum impact to existing operation and downtime. It can also be applied where the flexibility of operation of the technology will demonstrate benefits, specifically, the technology can be designed and constructed for full load and 95% CO_2 removal, but it can be operated expediently on a slipstream or less than 100% of flue gas. This would permit much more capacity to be available to the system at peak load times, while capturing a very high percentage of CO_2 at other times and contributing in a major way to overall CO_2 reductions.

Path Forward

The following recommendations are the suggested path forward for this technology prior to proceeding with a FEED (Front End Engineering Design):

- Carry out similar feasibility evaluations for Sub-Bituminous and Bituminous coal. Based on the Site Selection Study results, the economics are generally more favorable for these coals.
- Incorporate the best boiler technology in the marketplace. No attempt was made in this study to search for the best available boiler technology. Every 1% increase in boiler efficiency reduces the CO capture cost by 3%.
- Allow for a phased approach for NO_X reduction. Significant penalty is paid for reducing the NO_X level from 30 to 5 ppm in terms of both cost and auxiliary power requirements.
- Evaluate LoTOx™ versus ECO™ process technology for NO_X reduction down to low levels. Both technologies are relatively new and are in the demonstration stage.
- Carry out a specific site market survey for production of wallboard-grade gypsum or fertilizer product. This study gave no credit for gypsum production.
- Take advantage of the scalability of the amine process and look at capturing CO_2 from a smaller flue gas slipstream for a demonstration project.

- Have a steam turbine vendor take a detailed look at the mechanical impact of steam extraction from the Shand existing turbine.

4.2 Oxyfuel (CO_2/O_2) Combustion Option

Oxyfuel combustion is a process in which coal is burned in an atmosphere of carbon dioxide (CO_2) and oxygen (O_2), rather than in a conventional atmosphere of air which is comprised largely of nitrogen (N_2) and oxygen (O_2). See Figure 4.2. Thus the process replaces N_2 with CO_2, and is possible because only oxygen is active in the combustion process. The CO_2 is obtained from the boiler outlet and is recirculated to the boiler inlet. It is enriched with oxygen from an air separation plant to a level that is suitable for stable combustion. The process provides a relatively pure stream of CO_2, which is cleaned of other contaminants and purified for sale or storage. Natural Resources Canada has been working with the concept for many years, and has developed a pilot plant. The technology has never been operated at full scale.

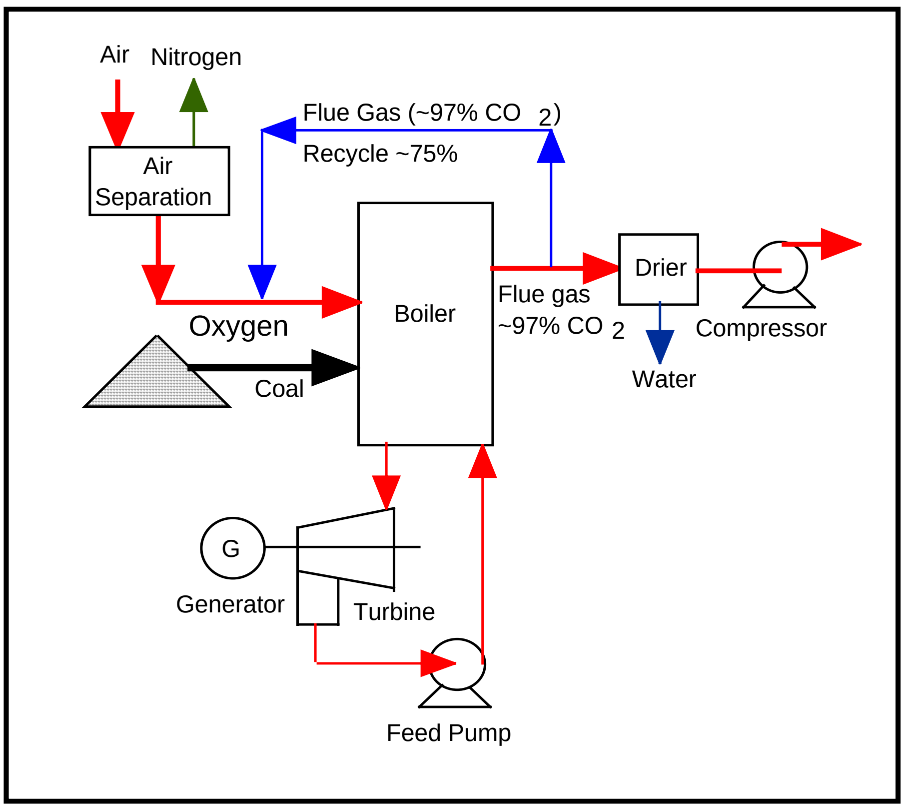

Figure 4.2. Oxyfuel Combustion Schematic

Similar to the amine scrubbing option, the study proceeded in two stages, site selection and site optimization.

Site Selection

Also similar to the amine scrubbing case, the site selection study constraints included the following:

- Evaluate the impacts on performance and cost of removing all emissions including CO_2 from three sites having three different coals. The three sites selected for comparison were:
  - o Trenton 6, with a 156 MW boiler using bituminous coal
  - o Shand, with a 272 MW net boiler using lignite coal
  - o Genesee 1, with a 391 MW net boiler using sub-bituminous coal
- No net power import or export. Hence, all additional auxiliary power requirements would be supplied by a new auxiliary boiler located at the site
- *Retain the capability to fire the unit on air at full load*
- The objective was to achieve the emission level set for NGCC. The targets used were established by Neill & Gunter.

Non CO_2 emission removal technology for all three sites comprised a simple wet ESP/wet FGD combination. This results from the relatively simple oxyfuel concept. It was anticipated in the site selection stage that the oxyfuel technology would require no NO_X removal, since there is little NO_X produced – combustion occurs in a CO_2 rich environment where CO_2 replaces N_2, thus, little NO_X is produced. Thus, NO_X would not have to be controlled, and the selected wet ESP/wet FGD would control all other emissions.

Key performance and economic numbers are shown in Table 4.7.

TABLE 4.7: Key Performance Parameters for Various Sites

Criterion	Trenton	Shand	Genesee
Boiler Size (Gross/Net), MW	165/156	298/272	410/381
Annual Capacity Factor, %	81	84.8	96.9
Auxiliary Boiler Load (Gross/Net), MW	122/115	316/288	297/276
Aux. Load as % of Original Boiler Load, %	74	106	72
Total $_{CO2}$ Production, tonnes/day	5,383	14,183	15,311
Total $_{CO2}$ Avoided, tonnes/day	2,824	6,008	8,105
Total Installed Cost, million $	1,120	2,014	1,902
Plant Installed Cost, $/kW (net plant output)	7,179	7,404	4,992
CO_2 Production Cost, $/tonne	126	78	66
Cost of CO_2 Avoided, $/tonne	240	184	124
Cost of Electricity, $/MWhr	181	170	110

Site Optimization

Following the results of the Site Selection Study, the CCPC selected the Shand site into the Site Optimization Study. As well, it was decided to change from a retrofit to a new unit scenario for the Shand site in order to allow the boiler to be sized appropriately to eliminate the smaller parasitic power plant. A new unit would also permit the boiler to be designed from the outset to minimize air infiltration into the boiler passages by arranging the boiler for pressurized operation. It would also allow the selection of a new supercritical boiler rather than the existing Shand boiler. Since the supercritical boiler is much more efficient, the resulting flue gas flow is lower with higher CO_2 concentration.

In addition to a more advanced boiler design the infiltration rate set for the boiler system has been lowered to 1% resulting in a slightly positive pressure operation. Finally, because of the more efficient supercritical boiler design, the pollutant level in the flue gas from the boiler is also lower as compared to that in the Site Selection Study. This has major positive impact on the Product Recovery Train, leading to lower energy consumption required to recover the CO_2 product.

Last, the CCPC also agreed to review the selection of the Air Separation Unit (ASU) in order to explore improving the efficiency for this process. A target of at least 300 MW (net) was set for the new plant in order to match the rating of the existing unit at this location. This sizing also ensured that reasonable economies of scale would be available, because lignite fueled power plants are physically much larger than units selected for better coals.

While it is understood that the Shand site is water limited, no specific attempt was made to integrate the considerable heat of condensation available from the water vapor present in the flue gas stream, that must be removed - one way or another - from the recovered product stream.

Significant process improvements achieved in this stage of the study that would result in improved economic performance are highlighted below:

Air Separation Unit

- Incremental capital cost was evaluated at $1,300/KW, allowing more capital to be spent to improve efficiency in operation. This resulted in a reduction of auxiliary power of 6.9% and reduced cooling water requirements by 27.4%
- Provision of liquid O_2 storage will allow the ASU to be turned down to 75% at peak load periods, while maintaining CO_2 capture, that in turn will allow increased plant output of 20 MW.

Product Recovery Train

- Integration of reboiler heat with the CO_2 compressor interstage cooling
- Evaluation of single shaft versus internally geared compressors. Single shaft confirmed
- Evaluation of different dehydration technologies

Wastewater Treatment

- Selection of Reverse Osmosis for wastewater treatment instead of Brine Concentrator.

The overall plant performance and cost summary is presented in the following tables:

TABLE 4.8: Greenfield Plant Performance

	90% CO_2 Capture
Boiler Gross Capacity, average	629 MW
Boiler Auxiliary Power Consumption	N/A
CO_2 and Pollutant Capture Auxiliary Power Consumption	256 MW
Total Net Capacity	373 MW
Auxiliary Power Percentage	40.70%
Net Plant Efficiency	24.2%
CO_2 Production	13,967 tonnes/day
CO_2 Recovery	90%

TABLE 4.9: Cost Summary, Greenfield Plant (90% CO_2 Capture)

Capital Cost, millions $	
Boiler Plant	1,290.6
Pollutant Removal System	330.1
ASU	338.3
Product Recovery Train	183.5
Utilities and Offsite	171.0
Total Capital Cost	2,313
Total Capital Requirement	3,246.4
Cost of Electricity, $/MW	
Cost of Electricity With CO_2 Capture	152
Cost of Electricity (no CO_2 capture)	69.4
Cost of Avoided Pollutant, $/tonne	
Cost/Tonne of CO_2 Avoided	111.96
Cost/Tonne of CO_2 Captured	63.3

Conclusions of the Study

The following is a summary of the results derived from the study:

- Though immature, oxyfuel technology is a viable technology for application to existing and to new facilities. It provides the attraction of part load operation and therefore dispatching a unit on a peaking basis. This is a feature that should be explored and evaluated fully by any utility looking to manage its CO_2 emissions while optimizing its capital investment and utilization of facilities.
- A new unit presents the most favorable conditions for application of oxy-fuel combustion for capture of CO_2 due to the ability to reduce air infiltration using a pressurized furnace.
- Decoupling the ASU, boiler and PRT allows for maximum operational flexibility and introduces the possibility of power peaking for short periods by using oxygen that has been stored in off-peak periods and/or by venting CO_2.
- A demonstration unit at Shand presents an opportunity to capture up to 4 mega-tonnes of CO_2 annually in reasonable proximity to emerging sequestration opportunities.
- The overall capital cost identified for the optimized Shand unit is about $3700 per gross kW installed.
- The cost of electricity produced while capturing the CO_2 from the optimized Shand unit is about $150/MWh.
- The cost of CO_2 avoided from the optimized Shand unit is about $110 to $115/tonne CO_2.

- The requirement to retain the capability for full air firing resulted in significantly higher mass flow through the boiler and commensurately larger equipment sizing for pollutant removal and gas cooling in the boiler flue gas exit flow than would be required for oxyfuel alone. This is an area that could benefit from additional review for specific projects.
- The optimized Shand unit presents little process risk and can be operated at loads anywhere up to 100% on air.

Path Forward

Oxyfuel technology is not yet a mature technology. Many issues remain in how to develop this technology for production purposes. However, it could provide flexibility by providing peaking power while maintaining CO_2 emissions limits. The study identified several key areas where significant improvements could be made which could make this a more competitive alternative. Based on the results of this study, the following is a list of items that should be considered for further evaluation to improve the overall plant efficiency and reduce the total cost:

- **Optimize Flue Gas Temperature -** As a result of the work in this study it has been recognized that insufficient cooling takes place within the wet FGD scrubber to attain the desired temperature for the PRT and perhaps the recycle stream. The studies recommended that further consideration be given to the use of heat exchange downstream of the wet FGD scrubber, as well as looking at the potential uses for the heat recovered within this heat exchanger that could have a significant impact on the overall cycle efficiency during oxy-combustion.

- **Optimize Air Heater Balance -** The current air heater balance is based on standard air heater design practice. Given the differences in gas composition and temperatures of the boiler outlet and recirculation gas flows as compared to conventional air firing, the studies concluded that it may be possible to achieve a more optimum air heater design that minimizes the performance penalty associated with the higher flue gas temperature leaving the air heaters during oxy-combustion. The study also concluded that other air heater designs should also be considered, including splitting the primary and secondary duties into separate air heaters in order to provide more opportunity to balance the performance under such widely varying conditions. The studies recommended that the air heater selection be further optimized in close cooperation with an air heater vendor.

- **Optimize Flue Gas Cooling -** To accommodate the current temperature requirement for the PRT the gas must be cooled beyond what is achieved in the wet FGD absorber. For this study the entire flue gas flow was reduced in temperature in a condensing heat exchanger to achieve 54^0 C. However, the fans and boiler cycle could be designed to accommodate the wet FGD outlet temperature that would be a bit higher than 68^0C, and only the stream to the PRT could be cooled. The higher recirculating gas temperature would result in somewhat larger FD fans with a higher power required due to the greater gas volume, and it is likely that the boiler efficiency would be reduced a little. The reduced boiler efficiency would mean increased fuel and oxygen consumption but a much smaller condensing heat exchanger. Since the CHX® is a relatively expensive component in the overall plant, this optimization should be pursued further to define the optimum economics for this heat exchanger. This optimization could lead to the following improvements:
    - Improved cycle efficiency through integration of heat recovery from flue gas moisture condensing duty (may be ideal for Shand site with high moisture content coal and water restrictions).
    - Possibility of eliminating Wet ESP if Condensing Heat Exchanger performance can be established, saving capital and operating costs.
    - Possibility of eliminating SO_2 scrubber if performance of PRT and reservoir can be established, saving capital and operating costs.

- **Optimize the Firing System -** Two types of firing systems can be used for this plant: pulverized coal (PC) or slagging cyclone type burners. B&W's latest low NO_X PC burners with overfire air were assumed for this study. However, additional development of the fuel firing system is necessary to both optimize the combustion process and confirm the basis for performance predictions. Two recommendations are provided in that regard: experimental testing of the lignite with DRB-4Z™ burner perhaps in B&W's 105.5 GJ/h (100 MMBTU/h) burner test facility and development of an oxy-fuel burner to effectively introduce the oxygen into the burner and improve NO_X reduction.

  The study described the potential benefits of Cyclone burners. This possibility for reducing the furnace size and consequently boiler cost versus the impact on NO_X

emissions should be further investigated, especially because of the fit between this firing technique and the particular fluxing characteristics of Saskatchewan lignite when fired under oxy-combustion conditions. Because of the specific fouling and slagging characteristics of Saskatchewan lignite, the proposed furnace chamber must be quite large to accommodate firing the fuel in pulverized form while keeping the furnace wall deposits in dry form for removal through the furnace bottom using conventional wall mounted sootblowers. A cyclone fired furnace could be much smaller since 60 to 70% of the coal ash would be tapped out the bottom of the furnace in molten form leaving a much smaller amount of ash that passes into the upper part of the furnace chamber and through to the convection pass. This is in contrast to a pulverized coal-fired unit in which 80% of the coal ash typically passes through to the convection pass.

The disadvantage of cyclone firing in the past has been the large amount of NO_X generated by the intensity of mixing and high temperatures experienced within the cyclone burners. Cyclone furnaces built in the 1960's and 1970's have not been able to be converted to low NO_X operation using pulverized coal firing and so this technology has not seen much development over the last 20 years. Oxyfuel combustion with flue gas recycle using lignite coals with low melting point ashes is an elegant approach to minimizing the size and therefore cost of the boiler proposed in this study. The study recommends that the CCPC consider a follow on study to identify the potential cost savings of a cyclone design for Saskatchewan lignite with due consideration the NO_X question, that should not pose a great challenge during combustion with oxygen due to the recycling of NO to the flame and the low availability of nitrogen within the flame.

4.3 Gasification Option

Coal gasification is the process by which the carbon in coal, in the presence of water and air, is converted directly to carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). See Figure 4.3. Thus, the process provides a relatively pure stream of CO_2 for disposal. Coal gasification has been used for more than a hundred years and is a technology that is well known by the chemical and petrochemical industries. The gasification process is marketed today by several technology licensors each of whom have different proprietary processes.

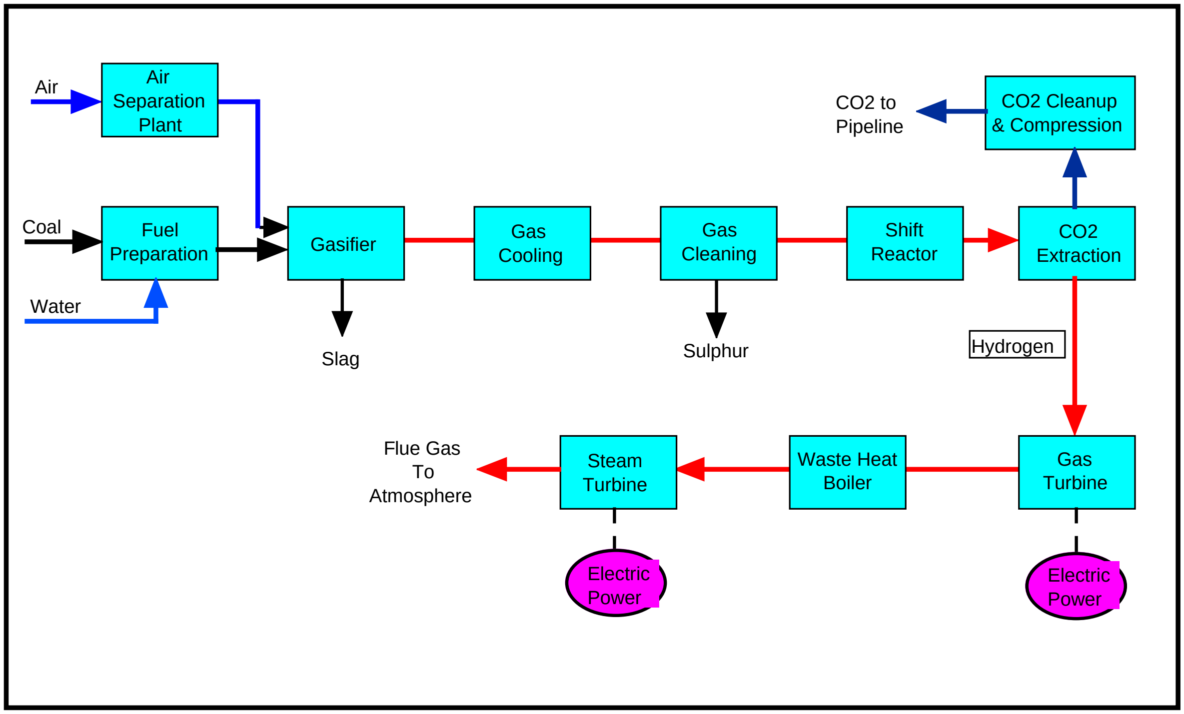

Figure 4.3. Coal Gasification Schematic

As with the amine scrubbing and oxyfuel studies, the study for gasification options proceeded in two stages. However, in this case the stages were identified as 1) technology selection and 2) technology optimization

Technology Selection

A qualitative technology evaluation was initially conducted of the various units that were considered be suitable for incorporation in a gasification-based plant. These technology options were then narrowed down to those that show performance and cost advantage over the alternative technologies, and also are available in the time frame being considered for the demonstration plant. The resulting recommended overall plant configuration consists of an oxygen blown Integrated Gasification Combined Cycle (IGCC) plant. Four gasification technologies: E-Gas, Noell, Shell and ChevronTexaco, were analyzed to provide CCPC a basis for selection of the appropriate gasification technology.

The first three gasification processes above were evaluated for all three coals, while the ChevronTexaco process was evaluated for the bituminous and sub-bituminous coals only. ChevronTexaco stated that they do not consider their process suitable for the lignite feedstock due to its very high inherent moisture content. Each of these oxygen blown gasification units is integrated with a combined cycle consisting of two General Electric 7FA+e gas turbines. The CO contained in the syngas produced by the gasification process is reacted with steam in sour shift reactor(s) to form CO_2; 80 to 90 percent of the CO_2 is then removed along with the sulfur compounds in a Selexol unit.

The mostly decarbonized clean syngas is fired in the gas turbines. The recovered CO_2 is compressed to 13800 kPa(g) prior to feeding it to a pipeline. Other effluents generated by the plant are elemental sulfur, low CO_2 content flue gas (from the combined cycle), slag and wastewater.

It is worth noting that Shell and Noell feed the gasifier with dried and pulverized fuel. Low rank coal contains large amounts of moisture, and drying it consumes a significant amount of energy. The thermal efficiency of plants using such fuels can be enhanced by drying the feedstock under pressure utilizing high pressure nitrogen produced by the air separation unit (or high pressure syngas). In turn, the effluent gas from the dryer with its accompanying moisture is returned to a gas turbine (after the moist gas is preheated and passed through a particulate filter). In this manner, the large amount of heat utilized by the drying operation, which tends to limit the overall thermal efficiency of the IGCC, does not become a thermal penalty on the process. The added moisture also decreases the NO_X emissions from the gas turbine. The net result is a process that shows a significant improvement in the plant net heat rate for the sub-bituminous coal and the lignite. This was the process evaluated by CCPC.

<u>Selected Overall Plant Configurations</u>

The results of the technology selection stage are summarized in the following table:

Table 4.10: Gasification Technology Selection Results

Fuel	Units	Bituminous	Sub-bituminous	Lignite
Technology		ChevronTexaco	ChevronTexaco	Shell
Carbon Recovery	%	81.2	85.6	85.7
Efficiency (HHV)	%	29.88	25.39	24.03
Capital Cost	Millions $CAD	1,774	2,095	2,317
Cost of Electricity	$/MWhr	76.5	69.29	86.82
Capacity	MW_{net}	413	428	402

Bituminous Coal

The total plant cost on a dollars per kW basis of the ChevronTexaco case was significantly lower than the corresponding Shell and E-Gas cases while its heat rate was similar to the Shell case and lower than the E-Gas Case. This resulted in making the cost of electricity the lowest for the ChevronTexaco case, about 10% lower than the Shell case and about 20% lower than the E-Gas case. Based on these results, the ChevronTexaco gasifier-based plant was selected by CCPC for further optimization and refinement of performance and cost estimates under the site-specific conditions.

Sub-Bituminous Coal

Again the total plant cost on a dollars per kW basis of the ChevronTexaco case was significantly lower than the corresponding Shell and E-Gas cases while its heat rate was lower than both the Shell cases (i.e., with low pressure and high pressure drying) and the E-Gas Case. This resulted in making the cost of electricity the lowest for the

ChevronTexaco case, about 20% lower than the Shell and the E-Gas cases. Based on these results, the ChevronTexaco gasifier-based plant was selected by CCPC for further optimization and refinement of performance and cost estimates under the site-specific conditions.

Lignite

The total plant cost on a dollars per kW basis of the Shell case with the high pressure drying was significantly lower than the corresponding Shell case with the low pressure drying as well as the E-Gas case. The heat rate of this Shell case with the high pressure drying was also significantly better, as much as 10% lower than the Shell case with the low pressure drying and more than 20% lower than the E-Gas Case. This resulted in making the cost of electricity the lowest for the Shell case with the high pressure drying, about 10% lower than the Shell case and about 20% lower than the E-Gas case.

A sensitivity case is also developed for the low pressure Shell case without any air extraction to assess the impact on the cost of electricity if air extraction from the gas turbine is not possible; i.e., without compromising the output of the engine. The cost of electricity for the case without air extraction did increase by approximately 10% over the corresponding case with air extraction. Even when this 10% increase is added to the Shell case with high pressure drying, this case still had a substantial advantage in cost of electricity over the E-Gas case.

Based on these results, the Shell gasifier-based plant with the high pressure drying was selected by CCPC for further optimization and refinement of performance and cost estimates under the site-specific conditions.

Technology Optimization

Design of the three cases above was then developed to approach a more optimized design under site-specific conditions. Performance and cost estimates were developed in much greater detail in order to provide a basis for CCPC to make the site selection for the demonstration plant as well as be able to compare the gasification option with alternate CO_2 capture options.

Table 3.12 presents the results of the gasification study, with a baseline of a conventional plant utilizing a supercritical boiler, capturing all emissions to extremely low levels, except CO_2. Plant costs are highly dependent upon the rank of the coal; the higher the rank, the lower the plant cost. However, the cost of electricity is the lowest for the sub-bituminous case, primarily due to the cost of the sub-bituminous coal being significantly lower than that of the bituminous coal. The cost of avoided CO_2 follows a trend similar to the plant installed costs, being lowest for the bituminous case and highest for the lignite. The cost of avoided CO_2 for the sub-bituminous case however, is only slightly higher than the bituminous case, primarily due to the cost of electricity for this case being lower than the bituminous case (the cost of the sub-bituminous coal being significantly lower than that of the bituminous coal, as mentioned earlier). Secondary reasons are that that the amount of carbon present in the coal per unit of the coal contained energy is higher for the sub-bituminous case (i.e., more carbon enters the plant than the other cases per unit of coal energy input to the plant) as well as the percentage of CO_2 captured is higher in the sub-bituminous case.

Table 4.11: Coal Gasification - Major Plant Performance and Cost Parameters

Coal		Bituminous		Sub-Bituminous		Lignite	
Technology		Boiler	Gasif.	Boiler	Gasif.	Boiler	Gasif.
CO_2 Captured, %		None	86.4	None	89.0	None	85.7
CO_2 Emitted	**Tonne/MWhr**	**0.7710**	**0.1164**	**0.8520**	**0.1114**	**0.8830**	**0.1822**
	ST/MWhr	0.8500	0.1284	0.9393	0.1228	0.9735	0.2009
CO_2 Avoided by Gasification Plants	**Tonne/MWhr**	**0.6546**		**0.7406**		**0.7008**	
	ST/MWhr	**0.7216**		**0.8165**		**0.7726**	
Net Heat Rate – HHV	**kJ/kWh**	**8,758**	**11,408**	**9,032**	**13,806**	**9,144**	**13,239**
	BTU/kWh	8,303	10,815	8,563	13,089	8,669	12,551
LHV	**kJ/kWh**	**8,429**	**10,979**	**8,736**	**13,354**	**8,798**	**12,738**
	BTU/kWh	7,991	10,408	8,282	12,660	8,341	12,076
Thermal Efficiency - HHV	**%**	**41.11**	**31.56**	**39.86**	**26.07**	**39.37**	**27.19**
LHV	**%**	**42.71**	**32.79**	**41.21**	**26.96**	**40.92**	**28.26**
COE @ 90% CF	**$/MWhr**	**76.00**	**106.69**	**58.19**	**96.84**	**69.37**	**130.85**
	USD/MWhr	48.72	68.39	37.30	62.08	44.47	83.88
Cost of Avoided CO_2	**$/tonne CO_2**	**46.88**		**52.20**		**87.73**	
	USD/ST CO_2	27.26		30.35		51.01	
Capacity	**(MW_{net})**	444		437		361	
Capital Cost	$ millions	1,329		1,493		1,593	

Conclusions of the Study

The reports concluded that from the above results, plant costs are highly dependent upon the rank of the coal; the higher the rank, the lower the plant cost. The cost of electricity is the lowest for the sub-bituminous case however, primarily due to the cost of the sub-bituminous coal being significantly lower than that of the bituminous coal. The cost of avoided CO_2 follows a trend similar to the plant installed costs, being lowest for the bituminous case and highest for the lignite. The cost of avoided CO_2 for the sub-bituminous case however, is only slightly higher than the bituminous case, primarily due to the cost of electricity for this case being lower than the bituminous case (the cost of the sub-bituminous coal being significantly lower than that of the bituminous coal, as mentioned earlier). Secondary reasons are that that the amount of carbon present per unit of coal, and thus the amount of energy, is higher for the sub-bituminous case (i.e., more carbon enters the plant than the other cases per unit of coal energy input to the plant) as well as the percentage of CO_2 captured is higher in the sub-bituminous case.

Finally, it should be noted that the CO_2 emission from these plants that ranges from 0.11 to 0.18 tonne/MWhr is significantly lower than that from a natural gas-fired state-of-the-art combined cycle that is about 0.35 tonne/MWhr.

Path Forward

During the course of this study, design options were identified that could improve the performance and the economics of these gasification plants. Thus, these options described below should be studied before the FEED package is developed:

- Evaluate the option of producing a sour CO_2 stream, i.e., bulk acid gas removal while letting the sulfur compounds leave the plant with the CO_2. Reduction in both the plant heat rate and cost may be realized. The pipeline will be classified, however as being in sour service and the increase in its cost should be taken into account in assessing the overall impact of incorporating this design option. Acceptability of the sour CO_2 by the end user as well as the safety issues should be investigated.
- Establish the availability of petroleum coke or bitumen for blending with the lower rank coals in order to increase the heating value of the feedstock and thus the performance and cost. Consumption of petroleum coke in this manner on its own accord could benefit the environment since its production is expected to grow while the consumption may not be able to keep pace with the possibility of having to stockpile this refinery waste. A study to establish the expected improvement in the performance and cost of the gasification option is required.
- Establish the market for H_2 in order to sell a high value by-product providing a revenue stream to offset some of the cost of capturing the CO_2. The incremental cost of producing the H_2 is expected to be small, the costs being associated with purifying a portion of the fuel gas supplied to the gas turbines in a Pressure Swing Adsorption unit. A study to establish the improvement in the performance and cost is required. This study may also include an evaluation of 1) transportation of the coal versus constructing and operating a pipeline to deliver the H_2 in case a low rank coal is considered and 2) the synergy of gasifying petroleum coke imported from a refinery while exporting the H_2 to the refinery and possibly steam.
- Define the basis for developing the FEED package. This activity would encompass the selection of the final technology for which the FEED package would be developed. Included in this study would be a comparison of the gasification option with the amine option for bituminous and sub-bituminous coals, the data generated by the current studies being useful for making the comparison of the technology options for lignite.
- Have General Electric perform a detailed aero-thermal analysis of the hot gas pathway of the turbine section of the gas turbine in order to truly assess the derate in the firing temperature and consequently the overall performance of the gas turbine.

5 Options for CO_2 use or storage

As part of its mandate, the CCPC needs to find an ultimate disposal or sink for any CO_2 captured from a power plant. Accordingly it developed a strategy to evaluate the options in each geographical area represented by the different types of fuels. This resulted in an objective to assess storage options in eastern Canada (bituminous), central Canada (bituminous and sub-bituminous), and western Canada (sub-bituminous and lignite). The following is a summary of that work

5.1 Western Canada

The CCPC awarded a contract to SNC-Lavalin (SLI) to evaluate utilization and storage options for CO_2 produced by coal fired power plants. Specifically the mandate was as follows:

- Prepare an inventory of CO_2 storage options in Alberta and Saskatchewan
- Evaluate key factors for each options
- Priorize the options based on technical and economic success criteria
- Estimate the total storage capacity for each option
- Provide a brief overview of current CO_2 storage projects.

SLI evaluated the following options

- Enhanced Oil Recovery (EOR)
- Enhanced Coal Bed Methane Recovery (ECBM)
- Storage in depleted oil and gas reservoirs
- Storage in deep saline aquifers
- Industrial usage and other potential options.

Modeling was to be done on the basis of the output from a 400 MW coal fired power plant in Alberta, assuming capture of 90% of the CO_2. Such a project would have flows of approximately 2.6 million tonnes per year or a 30 year life storage requirement of 78 million tonnes.

Enhanced Oil Recovery

Enhanced Oil Recovery involves the injection of a relatively pure CO_2 stream at elevated pressure into a producing oil field. Under a "miscible" EOR scheme the CO_2 dissolves into the oil, which both reduces the oil's viscosity and displaces the oil, increasing oil flow to the producing wells. Significant amounts of CO_2 are produced along with the oil and must be separated from the oil and associated hydrocarbon gas before re-injection into the reservoir. Figure 5.1 illustrates the process in a highly simplified flow diagram.

SLI reports that EOR is the most advanced and best proven technology for storage or utilization of CO_2. EOR projects have been reported in five countries, and total oil production from EOR is estimated at about 32,400 m^3/d from 76 projects. However, an EOR project designed to store the CO_2 from a 400 MW power plant would rank among the largest EOR operation in the world. SLI also proposed that an EOR project had the best chance to offset some of the costs of capturing CO_2.

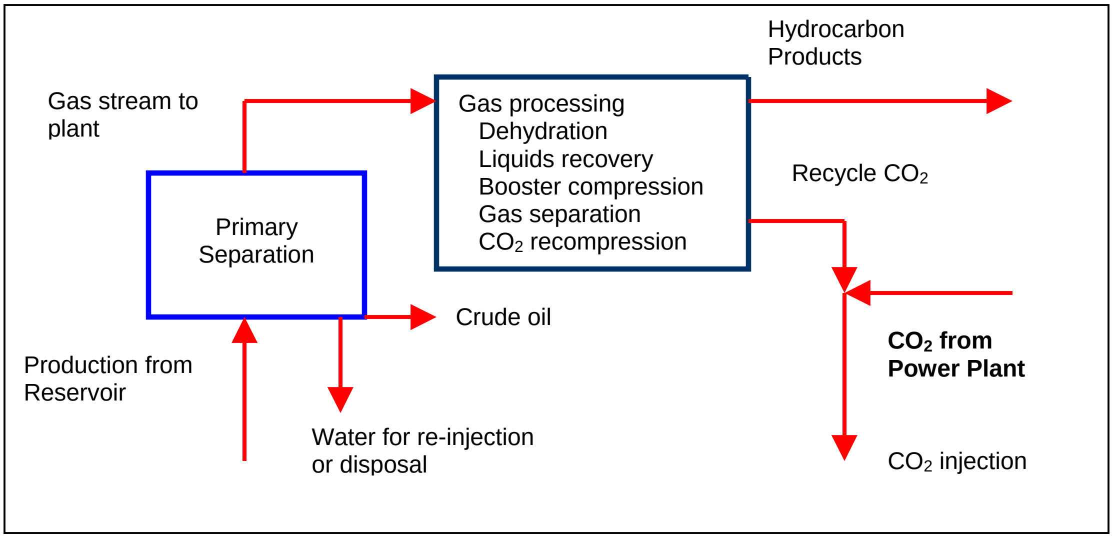

Figure 5.1. Process Schematic of Enhanced Oil Recovery

SLI worked together with Vikor Energy Inc. to analyze reservoirs and pools for storage. Based on the design CO_2 flow rates, they selected the oil pools required to store the CO_2, and developed projected rates for oil, gas, and water and recycle CO_2, as well as the wells and the distribution and gathering systems required in the field. In addition, they developed the requirements for delivery of the CO_2 to a central hub, processing the hydrocarbon rich production gas, separation of the gas and CO_2, and compression of the CO_2 for re-injection. Pan Canadian's Weyburn project consumes about 60% of the annual rates used for this study.

Pools were selected through a screening process that, among other things, includes an assessment of miscibility criteria – the ability of the CO_2 to dissolve in the oil. Immiscible floods have been operated, but the recovery and economics have generally been much poorer.

Six pools (modeled in the Swan Hills area) were required to store the design rates of CO_2 over the 30 year project life. Selected key data is summarized below:

- Total CO_2 stored was 81 million tonnes
- Total CO_2 injected, including recycle was 212 million tonnes
- Oil production was 284 million barrels
- Total gas produced was 530 BCF
- Total Water production was 750,000 e^3m^3
- Total capital costs were estimated to be in the order of $900 million over the project life.
- The CO_2 was assumed to be sold at $38/tonne, resulting in and EOR project NPV of $57 million, with oil and gas revenues.

SLI determined that there could be in the order of 5-6 viable EOR projects in Alberta with sufficient capacity to store the CO_2 output from a commercial scale power plant over thirty years, and offer potential significantly offset capture costs. Opportunities in Saskatchewan are much more limited, and SLI's assessment is that only one project would be viable.

SLI determined that issues include miscibility, safety and public awareness. Impurities in the CO_2 include nitrogen, oxygen, CO and H_2S, and could all have an impact on miscibility and therefore on oil production. Further, together with the CO_2 itself, they could present safety and corrosion concerns.

Enhanced Coal Bed Methane Recovery

ECBM involves the injection of CO_2 at elevated pressure into a coal seam. Coal seams contain sorbed methane gas, and the injected CO_2 will tend to sorb preferentially onto the coal, releasing the methane, and allowing it to flow to the projection wells (the word "sorb" is used by SLI because it is not well understood whether the methane is absorbed or adsorbed). A benchmark value for CO_2 sorption to the coal over methane is 2:1, but some studies indicate it can be as high as 10:1 or more. Water is normally produced with the gas, in varying quantity and quality, depending on the coal seam and the location. Figure 5.2 provides a simplified illustration of the process.

ECBM is based on the premise that the coal seam is relatively deep, uneconomic to mine, and would not be mined after CO_2 injection. Mining of the seam after CO_2 injection would release the stored CO_2 and yield a negative CO_2 life cycle debit.

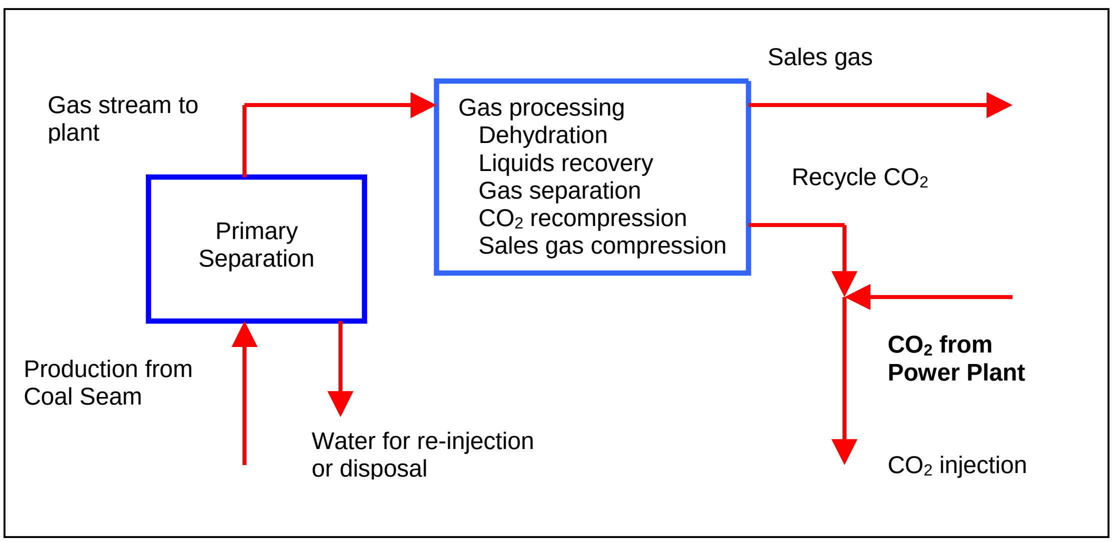

Figure 5.2. Process Schematic of Enhanced Coalbed Methane Recovery

ECBM is a much less mature technology than EOR, with no commercial projects and only a few pilot demonstrations. SLI worked with Alberta Research Council (ARC) to review previous studies and publicly available information to select coal reserves that could potentially store the CO_2 volume that would come from the selected 400 MW plant. The selection was based on the following criteria:

- Sufficient coal reserves to sequester the required CO_2
- Minimum depth to expect secure geological trapping of the CO_2
- Minimum depth to avoid impact on ground water
- Low water saturation
- Reasonable expectation of good permeability, and
- Coal reserve within 150 Km of Edmonton.

The team identified four coal seams:

- Ardley
- Horseshoe Canyon
- Belly River
- Mannville

It is particularly important to note the expectation of good permeability. Permeability is critical to the success of an ECBM project, and little permeability work has been done on Alberta coal seams. Therefore, there remains a large degree of uncertainty on the assumed values, and therefore on the production rates. Two cases are summarized below in Table 5.1.

Table 5.1: Key Production Data Summary

Description	Ardley	Mannville
Production wells	156	369
Injection wells	132	331
Total gas recovered, BCF	310	722
Initial flow per well, MCF/d	280	250
Peak water flow, m^3/d	700	6,000
CO_2 absorption ration	4.7	2.1
Gas recovery, BCF/section	2.0	2.0
Thirty year recovery, %	47	30

SLI chose to model the Ardley case due to significantly lower drilling costs for these wells, higher initial gas production, less water, and a higher 30 year recovery. Included in the model were

- CO_2 distribution to each well,
- Primary separation in the field and water handling facilities
- Drilling and completion of production, injection and water disposal wells

- High pressure CO_2 supply pipeline
- Dehydration and compression
- Membrane separation of produced gas and CO_2
- CO_2 compression for recycle
- High pressure sales gas pipeline

Total capital costs were estimated to be in the order of $ 170 million over the project life. SLI's analysis demonstrated that the breakeven cost for CO_2 is about $10/tonne, based on assumptions of $9/MCF for production gas,

SLI concluded that although technically feasible, and although there appear to be no practical constraints to the CO_2 storage capacity, there is little probability for a commercial ECBM project in Alberta without significant CBM development and demonstrations. ECBM could present an opportunity to offset CO_2 capture cost with potential revenue over the life of the project in the order of $1.2 billion. However, the uncertainties around permeability, gas content, and CO_2 absorption ratios remain potential stumbling blocks for an ECBM Project, and will need to be resolved before any such project can proceed. Thus, they recommend pilot demonstrations.

Storage in Depleted Oil and Gas Reservoirs, and Deep Saline Aquifers (Geological Storage)

SLI evaluated the technical and economic feasibility of storing CO_2, either in depleted oil and gas reservoirs or in deep saline aquifers. Their conclusions included the following:

- There are no technical obstacles to geological storage, and storage of CO_2 in depleted oil and gas wells is already being carried out in Alberta as an adjunct to acid gas injection and storage. Total current CO_2 injection is estimated at 300,000 tonnes per year. Although technically feasible, CO_2 storage in aquifers is much less developed with the only large scale demonstrations underway at StatOil's on-going Saline Aquifer CO_2 Storage project in the North Sea.
- There would be no revenue streams from this storage to offset capture and transportation costs.
- Perceived concerns regarding CO_2 storage in aquifers could mobilize public resistance to this option.
- Disposal charges of about $4/tonne of CO_2 would probably be required to make a project economic for a storage operator.
- The total project capital for one 400 MW plant could be in the order of $45 million.
- Practical overall storage capacity available in depleted oil and gas reservoirs is in the order of 3,500 million tonnes in Alberta, and 200 million tonnes in Saskatchewan – 45 and three commercial power plants respectively.
- There should be no practical limitation to storage in saline aquifers

- Of significance is that CO_2 purity is not a significant issue for geological storage.

Other Options

SLI also reviewed the following options for utilization or storage of CO_2. SLI concluded that none of the options were viable, principally based on the volumes involved and the timeframe considered. The options fell into one of the following categories:

- Sufficient capacity but high technical risk
- Low risk and potentially economically attractive, but very low ultimate capacity

Ocean Storage

Ocean storage had enormous capacity. Proponents of the technology argue that since the ocean already contains large amounts of CO_2, and since CO_2 in the air is naturally transferred to the oceans, ocean disposal is simply speeding up a natural process.

However, the only demonstration project that has been proposed (by the US DOE in Hawaii) was subject to large environmental protests. Due to these environmental concerns and the technical issues of delivering CO_2 more than 3000 meters below the surface, there is little probability of such a project meeting with success.

SLI notes as well that disposal for a western Canadian project would also introduce the challenges of delivering CO_2 from the interior to a storage site, therefore limiting this option to east of west coast projects. Environmental and public acceptance concerns will likely have significant negative impact as well.

Mineral Carbonization

SLI did not consider that mineral carbonization would contribute significantly to the CO_2 storage capacity requirements for at least the short term. While intriguing and theoretically possible, the time frame required to resolve the solids handling issues exceeds considerably the requirements for any CCPC demonstration project or short or mid term projects.

Industrial Applications

SLI reviewed a number of industrial applications including:

- Food and beverage production
- Fertilizer manufacture
- Industrial and welding gases
- Soda ash manufacture
- Water treatment and pulp and paper applications
- Plastics manufacture

- Fire fighting applications

One attractive feature of some of the above applications is that while they may require higher purity than would normally be produced by a power plant for an EOR project, it appears that the CO_2 for these applications can command a premium price. However, the amount of CO_2 produced worldwide for the above applications totals about 4,000 tonnes per day, or just over half the amount from one 400 MW power plant. Therefore most of the uses would be "niche" applications, and would be location specific. Notwithstanding this, it would be worthwhile for CCPC to evaluate if there are any opportunities for such a "premium CO_2" product in the vicinity of any demonstration.

5.2 Ontario

The CCPC Technical Committee had intended to include an assessment of storage options in Ontario in its work, and had budgeted accordingly. It was intended that this work might be carried out by the University of Waterloo. However, the CCPC never succeeded in agreeing on a mutually agreeable scope of work with the UW, and was not able to secure sufficient funding. Thus, no work took place to evaluate options for Ontario, and this summary has nothing to report.

5.3 Nova Scotia

The Geological Survey of Canada was to evaluate the potential of the Nova Scotia coal deposits for sequestering CO_2 and producing coal-bed methane. In particular this work was to evaluate the Cumberland, Pictou and Sidney coalfields. It was scheduled for completion in May 2003. However, as of this writing, that report is incomplete, and the results are not included in this report

6 Conclusions

After their review of the various reports summarized in this report, the CCPC Technical Committee adopted the following set of conclusions. The future direction that the CCPC and the electricity industry might take to address these or any other findings of the Phase 1 work packages are being addressed in a forum outside of this report.

The CCPC initiated Phase I of the project in 2001 to develop the next generation of coal power technology, leading to one or more demonstration projects. During Phase I, coal-fired power generation technology options that could control all emissions, including CO_2, were assessed. A number of detailed engineering design studies showed that:

- Technology is commercially available to control conventional air emissions (NO_X, SO_X, particulates, mercury) from Rankine cycle power plants to levels approaching that of natural gas power generation.

- Among the CO_2 capture technology options studied, gasification with Alberta sub-bituminous coal provide the lowest cost of electricity. Further improvements in cost may be expected with a fully optimized gasification process for low rank coals.
- However, costs of these technologies are currently high and further work was identified as being required to optimize the designs and to develop the new technology required to prepare a good business case for proceeding to the demonstration project.

Specifically, the studies also showed:

- Gasification processes for sub-bituminous coal and lignite are not yet fully commercial, and require significant development to attain the required availability levels.
- Recent developments of the Econamine amine scrubbing process have achieved substantial improvements in energy efficiency. Further refinements are possible and need to be compared with other processes to optimize the process selection.
- CO_2/O_2 combustion appears to have limited attraction as a retrofit or new plant technology due to high capital costs and low net efficiency.

Phase I was aimed at evaluating broad technology options and was not able to provide optimum designs for the three technology choices.