

# **Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO<sub>2</sub> Capture Project**

**Capture and Separation of Carbon Dioxide  
from Combustion Sources**

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## Chapter 14

# COKE GASIFICATION: ADVANCED TECHNOLOGY FOR SEPARATION AND CAPTURE OF CO<sub>2</sub> FROM GASIFIER PROCESS PRODUCING ELECTRICAL POWER, STEAM, AND HYDROGEN

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### ABSTRACT

The CO<sub>2</sub> Capture Project (CCP) was established by eight leading energy companies to develop novel technologies that significantly reduce the cost of capturing CO<sub>2</sub> for long-term storage. A significant focus of the project was in the area of pre-combustion technologies for the removal and capture of carbon dioxide (CO<sub>2</sub>) prior to fuel combustion.

This advanced technology study builds on previous CCP work that developed a conceptual process and engineering design for an integrated gasification combined cycle (IGCC) plant using petroleum coke as the feedstock to produce electrical power, steam, and hydrogen. Conventional absorption technology using the physical solvent Selexol was utilized for CO<sub>2</sub> removal and capture.

The subject of this study was the development of a conceptual process and engineering design of an IGCC plant using petroleum coke as the feedstock to produce electrical power, steam, and hydrogen utilizing Fluor's CO<sub>2</sub>LDSep<sup>SM</sup> advanced technology for CO<sub>2</sub> removal and capture.

The study concludes that CO<sub>2</sub>LDSep<sup>SM</sup> technology can reduce the cost of CO<sub>2</sub> capture by 16% when compared to the use of conventional Selexol technology. Neither the Selexol nor CO<sub>2</sub>LDSep<sup>SM</sup> technologies result in increased NO<sub>x</sub> or SO<sub>x</sub> emissions as compared to a baseline case with no CO<sub>2</sub> capture.

### INTRODUCTION

The CO<sub>2</sub> Capture Project (CCP) is a joint undertaking by eight major energy companies to develop new and novel technologies that significantly reduce the cost of capturing CO<sub>2</sub> for long-term storage. The CCP is divided into the following specialized technical teams for CO<sub>2</sub> capture.

- Post-combustion: carbon dioxide is removed from the exhaust gas of furnaces, boilers, and combustion turbines.
- Pre-combustion de-carbonization: carbon is removed from the fuel gas before combustion in furnaces, boilers, and combustion turbines.
- Oxyfuels: oxygen is separated from air and used to combust hydrocarbons to produce flue gas containing CO<sub>2</sub> and water with no nitrogen. The water can be easily condensed, leaving a highly concentrated carbon dioxide stream.

In addition to these three teams focusing on CO<sub>2</sub> capture technology another group known as the Storage, Monitoring, and Verification team was dedicated to the technical aspects of long-term underground storage of captured CO<sub>2</sub>. A fifth team, the common economic modelling (CEM) team, was charged with developing a common methodology to calculate the cost of CO<sub>2</sub> capture for a number of different technologies.

To ensure relevancy to member companies and to help focus the work of the CCP, four “real world” scenarios were identified and used by the project teams. These scenarios represent existing or future planned facilities that include combustion processes and fuel sources common to the operations of CCP participants. Technology “fit” across these scenarios was of prime consideration when selecting technologies for inclusion in the CCP program. Economic analyses evaluated technology performance in the context of these scenarios to determine the potential of any given technology to deliver CO<sub>2</sub> capture cost reductions.

The four scenarios are:

- large gas-fired turbine combined cycle power generation (the Norwegian scenario),
- small or medium sized simple cycle gas turbines (the Alaska scenario),
- petroleum coke gasification (the Canadian scenario), and
- refinery and petrochemical heaters and boilers (the UK scenario).

Further information on the four CCP scenarios can be found in Chapter 4 of this book.

Baseline studies were conducted for each of the four scenarios to establish reference costs for CO<sub>2</sub> capture. Since these baseline studies used technologies that were commercially available at the beginning of the CCP, they provided cost targets against which the CCP could measure success. The new technologies developed by the CCP would need to deliver CO<sub>2</sub> capture costs significantly lower than the baseline technologies.

Amine absorption was the baseline technology used in the Norwegian, Alaska, and UK scenarios to capture CO<sub>2</sub> from combustion flue gas. The cost reduction potential of all new technologies—be they alternative post-combustion technologies (i.e. something other than amine), pre-combustion technologies, or oxyfuels technologies—evaluated in one of these three scenarios was compared against this amine post-combustion baseline.

### *The Canadian Scenario*

The Canadian scenario is based on a petroleum coke feedstock containing about 6% by weight of sulphur from the bitumen production and upgrading facility at Suncor’s Oil Sands operations near Fort McMurray in northern Alberta, Canada. The petroleum coke is gasified in an integrated gasification combined cycle (IGCC) plant that produces refinery grade hydrogen for use in hydroprocessing, steam for in-situ bitumen recovery using steam-assisted gravity drainage (SAGD) technology, electrical power, and carbon dioxide for onshore enhanced oil recovery (EOR) in central Alberta. The Canadian IGCC scenario represents a conceptual plant and is not a facility in operation today.

The Canadian scenario is unique from the other three CCP scenarios insofar as it does not use a post-combustion baseline to establish the current cost of CO<sub>2</sub> capture. Since an IGCC facility is better suited to the incorporation of pre-combustion rather than post-combustion technologies, it made more sense to establish a pre-combustion baseline for the Canadian scenario. Thus, any new technologies evaluated for their cost reduction potential in the Canadian scenario were measured against a pre-combustion baseline that incorporated conventional absorption technology using the physical solvent Selexol for removal and capture of CO<sub>2</sub>.

As a result, a pre-combustion technology evaluated in the context of the Canadian scenario would have a cost advantage over a similar evaluation in one of the other three post-combustion scenarios. This is due to the significant capital investment required to reconfigure a conventional combustion process for incorporation of pre-combustion technologies. Changes required include the installation of new gasification or gas reforming equipment to convert the hydrocarbon feedstock into syngas followed by further processing (i.e. water gas shift reaction) for CO<sub>2</sub> removal. The Canadian scenario already has this capital investment included as part of its pre-combustion baseline. Since the Canadian scenario represents a new greenfield facility and not a retrofit application, it has the benefit of being able to be designed for pre-combustion CO<sub>2</sub> recovery from the outset. On the other hand, the UK and Alaska scenarios represent retrofit situations that require extensive reconfiguration to incorporate pre-combustion technologies into already existing conventional combustion process schemes.

Baseline studies were conducted by Fluor and involved developing a conceptual process and engineering design for both an uncontrolled case with no CO<sub>2</sub> recovery and a controlled case where Selexol (the commercially available technology) was used to capture over 90% of the produced CO<sub>2</sub>. In addition to the baseline studies a third case was done that incorporated Fluor's CO<sub>2</sub>LDSEp<sup>SM</sup> advanced technology for CO<sub>2</sub> removal and capture. All of the cases incorporated ChevronTexaco gasification technology (currently in the process of being purchased by General Electric) that uses high purity oxygen in a high pressure total quench gasifier. A total installed capital cost was calculated for each case. In addition to the capital cost, Fluor provided information such as catalyst and chemical summaries that were used by the CCP CEM team to develop operating cost estimates that were then factored into their economic calculation methodologies. The CEM team used this cost information prepared by Fluor to calculate a baseline CO<sub>2</sub> capture cost for the Canadian scenario. Because the uncontrolled baseline represents state-of-the-art with no CO<sub>2</sub> capture and the controlled baseline represents currently available commercial CO<sub>2</sub> capture technology, this capture cost is a reasonable estimate of the costs industry would incur today if they were required to capture CO<sub>2</sub>. Similarly, comparison of the controlled baseline cost to the advanced technology cost provides a measure of the cost reduction potential of the advanced technology [1].

## STUDY METHODOLOGY

### *Capital Cost Estimate*

For all the three cases (two baselines and CO<sub>2</sub>LDSEp<sup>SM</sup> case) Fluor prepared, as part of their study, the following documentation upon which the capital cost estimates were based.

- Process flow diagrams,
- Heat and material balances,
- Utility summaries,
- Catalysts and chemicals summary,
- Emissions and effluent wastes summary,
- Preliminary equipment lists with approximate sizes,
- Preliminary plot plan.

Using the above information Fluor prepared capital cost estimates with an accuracy range of approximately – 15 to +30%. The level of the estimates represent a Class 4 type category (feasibility type estimate) as defined in The Association for the Advancement of Cost Engineering (AACE) International Recommended Practice No. 18R-97.

Other notable points regarding the cost estimates include:

- All estimates are for a new grassroots (greenfield) IGCC plant.
- Costs are for an instantaneous second quarter 2003 timeframe.
- The cost is based on a site location in northern Alberta, Canada.
- The site is flat and level, grubbed and ready for construction, and with no interferences.
- An adequate supply of qualified and skilled workers is available to support construction of the plant.
- The construction labour work week is based on 40 h.
- There is sufficient laydown and parking areas for construction.
- The purchase of direct field materials is based on worldwide procurement.

### *Estimate Methodology*

The capital cost estimate or total installed cost (TIC) includes all items necessary for a full and complete installation of materials and equipment and was prepared using the Icarus 2000 cost estimating program. The TIC includes the following:

- direct field costs (includes direct field materials, subcontracts and labour),
- all-in wage rate (fully burdened) for direct hire union shop labour, adjusted for the site,
- labour productivity adjusted to the site from Fluor standard base manhours,

- scaffolding, winterization and freight (included as allowances),
- indirect field costs including:
  - construction management (included as allowance),
  - construction camp (included as allowance),
  - heavy haul/heavy lift (estimated on a labour rate basis),
- home office costs,
- contractor's risk and profit as a percent (included as allowance),
- contingency as a percent (included as allowance).

### **Design Basis**

The key process design objectives included:

- utilizing a cost effective approach,
- flexibility for turndown, and
- a 25 year operational life.

For all three studies the IGCC plant was designed to:

- produce 67,000 Nm<sup>3</sup>/h (60 MMSCFD) of hydrogen,
- generate 589,600 kg/h (1.3 million lb/h) of steam, and
- be self sufficient in all utilities including electrical power.

For both the controlled baseline and the CO<sub>2</sub>LDSEp<sup>SM</sup> case the design target was to capture 90% of the carbon in the petroleum coke feedstock.

Product specifications were identical for all three cases and are shown in Table 1

TABLE 1  
PRODUCT SPECIFICATIONS (TWO BASELINES AND CO<sub>2</sub>LDSEp<sup>SM</sup> CASE)

Commodity	Flow rate	Purity	Conditions
Hydrogen	67,000 m <sup>3</sup> /h (60 MMSCFD)	99.9 mol%; CO + CO <sub>2</sub> < 10 ppmv; N <sub>2</sub> + He < 1000 ppmv	103.5 bara at the Suncor oil sands facility
Steam	589,600 kg/h (1.3 million lb/h)	–	Saturated steam at 44 barg at user (i.e. Firebag)
Carbon dioxide (controlled baseline and CO <sub>2</sub> LDSEp <sup>SM</sup> cases)	90% carbon capture	97.0 mol% H <sub>2</sub> S < 30 ppmv H <sub>2</sub> O < 50 ppmv	80 barg 45 °C

## **RESULTS AND DISCUSSION**

This section details the process schemes utilized for the three considered cases; the two baselines (uncontrolled and controlled) and the CO<sub>2</sub>LDSEp<sup>SM</sup> advanced technology case. Performance characteristics are provided for each case along with the TIC. Note that for all cases the performance and cost basis for the Gasification Island were provided to Fluor by ChevronTexaco—one of the CCP participants.

Results from the CCP CEM team on CO<sub>2</sub> capture costs in the Canadian scenario are also presented and discussed.

## **Baselines**

### *The uncontrolled case*

Figure 1 shows a simplified process schematic of the uncontrolled baseline case and Table 2 provides a performance summary for the same case.

Petroleum coke is slurried with water and gasified with oxidant (99.5 mol% oxygen) from the air separation unit (ASU) to produce a raw syngas. The syngas from the gasifier is cleaned of particulates, carbonyl sulphide (COS) and hydrocyanic acid (HCN) are removed or destroyed, and the syngas is cooled to a temperature suitable for the acid gas removal (AGR) unit. Sulphur compounds are removed in the AGR unit and recovered as elemental sulphur product in the sulphur recovery unit (SRU). The clean fuel gas is expanded and provides refrigeration for the AGR solvent (Selexol).

A portion of the expanded fuel gas is saturated with water in a packed column. The majority of the saturated fuel gas is heated and shifted to increase the concentration of hydrogen in the syngas, cooled and then fed to the pressure swing adsorption (PSA) unit, from which a 99.9% purity hydrogen stream is produced. A small percentage of the saturated syngas is combined with unsaturated fuel gas from the AGR unit and compressed offgas from the PSA unit to comprise the fuel gas to the combustion turbines. The offgas from the PSA unit has a low heating value and cannot be utilized as fuel to a duct burner in the heat recovery steam generator (HRSG) to produce additional steam. Therefore, the offgas is compressed and combined with the fuel gas to the combustion turbines.

The feed rate of petroleum coke is determined by recovering 67,000 Nm<sup>3</sup>/h (60 MMSCFD) of hydrogen from the PSA and fully loading two General Electric Frame 7241 (FA) combustion turbines. The fuel gas mixture is further diluted with nitrogen from the ASU to control NO<sub>x</sub> formation in the combustion turbine. Heat is recovered from the combustion turbine flue gas to produce steam. The steam is fed to a steam turbine to produce additional electrical power. The parasitical power consumers of the IGCC plant will be satisfied from the gross electrical power produced with the remaining electricity sent for export.

The uncontrolled case produces stack emissions from two sources—the combustion turbine exhaust gas (downstream of the HRSGs) and the tailgas from the SRU. The NO<sub>x</sub> concentration has been calculated to be 15 ppmvd @ 15% O<sub>2</sub> in the turbine flue gas and 50 ppmvd @ 15% O<sub>2</sub> in the SRU tailgas. These NO<sub>x</sub> emissions are considered to meet best available control technology (BACT) for IGCC plants. For sulphur, the predicted SO<sub>2</sub> concentration in the turbine flue gas is 18 and 250 ppmvd @ 0% O<sub>2</sub> of SO<sub>x</sub> in the SRU tailgas. These SO<sub>x</sub> emissions meet Alberta regulatory requirements for an overall sulphur recovery of more than 98.6%.

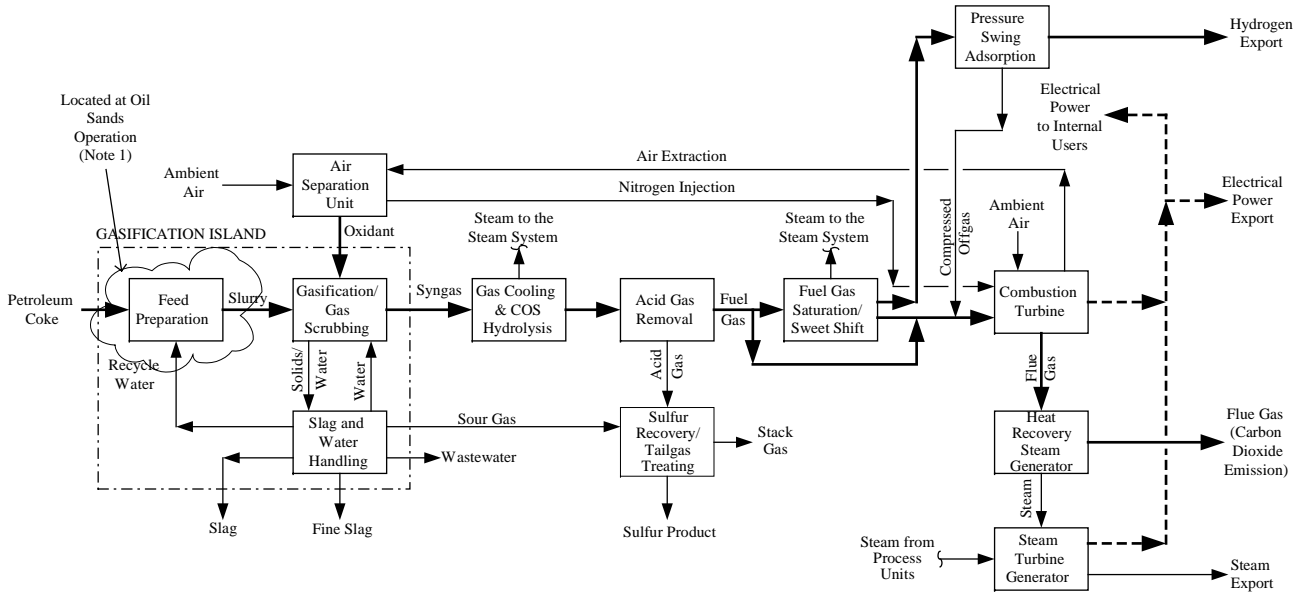
### *The controlled case*

Figure 2 shows a simplified process schematic of the controlled baseline case and Table 3 provides a performance summary for the same case.

In the controlled baseline case petroleum coke is slurried with water and gasified with 99.5 mol% oxygen from the ASU to produce a raw syngas. The syngas from the gasifier is cleaned of particulates, preheated, shifted (COS is converted to hydrogen sulphide in the water gas shift reactor so that, unlike the uncontrolled case, a dedicated COS hydrolysis is not required), and cooled to a temperature suitable for the AGR unit. The AGR unit is designed such that the overall carbon slip is 10% for the IGCC plant. Unlike the uncontrolled case, in the controlled case a sour shift of the hot syngas is done immediately following gasification. This is an ideal process configuration because the syngas exiting the gasifiers is fully saturated and provides enough water for the shift reaction to proceed. All of the syngas is shifted because CO<sub>2</sub> is more readily removed in the AGR unit than CO and allows 90% of the incoming carbon to be recovered.

In the AGR unit, the sulphur compounds and carbon dioxide are removed from the syngas. Carbon dioxide is recovered via an intermediate flash with a dedicated carbon dioxide removal column. The sulphur compounds are recovered as elemental sulphur product with carbon dioxide recovered as vent gas. The carbon dioxide from the intermediate flash and carbon dioxide vent are compressed and dehydrated for





Note:  
 1) Feed Preparation unit is located at the Oil Sands Operation; the bulk of the Integrated Gasification Combined Cycle plant is located at the Firebag Lease.  
 2) Some auxiliary equipment are not shown (e.g. condensate treating and utilities).

**Figure 1:** Process schematic of the uncontrolled baseline case.

TABLE 2  
PERFORMANCE SUMMARY UNCONTROLLED BASELINE CASE

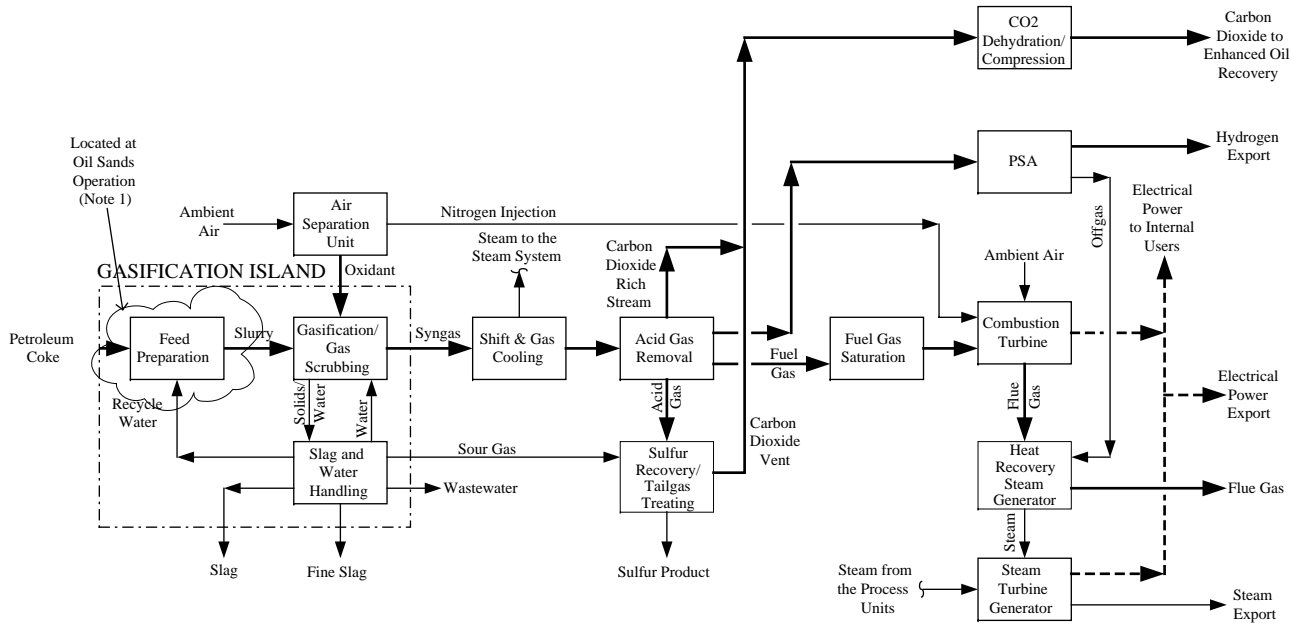
<i>Basis</i>	
Feed	Petroleum coke
Gas turbines	2 × General Electric 7241(FA)
<i>Site conditions</i>	
Dry bulb temperature	2.8 °C
Barometric pressure	950 mbara
Relative humidity	68%
<i>Performance</i>	
Petroleum coke feed rate	4581 mt/d
Total oxygen feed rate	4891 mt/d (100% O <sub>2</sub> )
Sulphur product	258 mt/d
<i>Power summary</i>	
Combustion turbines	380 Mwe
Steam Turbine	83 MWe
Fuel gas expander	7 MWe
Auxiliary power consumption	146 Mwe
Net plant output	324 Mwe
<i>Export streams</i>	
Hydrogen	67,000 Nm <sup>3</sup> /h (60 MMSCFD)
Steam (saturated at 44 barg @ user)	589,600 kg/h (1.3 MMlb/h)
<i>Carbon dioxide capture (@ 100% capacity)</i>	
Carbon dioxide emitted (million mt/yr)	4.9
Carbon dioxide recovered (million mt/yr)	0.0

storage and/or use in EOR operations. The clean fuel gas (containing mostly hydrogen) is divided between the PSA unit for hydrogen recovery and the fuel gas expander to provide refrigeration for the AGR solvent (Selexol). The expanded gas is saturated then further diluted with nitrogen and steam (if required) in the combustion gas turbines to control NO<sub>x</sub> formation.

The feed rate of petroleum coke is determined by recovering 67,000 Nm<sup>3</sup>/h (60 MMSCFD) of hydrogen from the PSA and fully loading three General Electric Frame 7241 (FA) combustion turbines. Three combustion turbines were used for this case. Due to the discrete sizes of combustion turbines, the net electrical power output of the controlled baseline ended up being 111 MWe higher than for the uncontrolled baseline. Design measures could have been taken to lower the power output (i.e. the use of smaller combustion turbines or duct firing). However, these items would have penalized the efficiency of the plant and thus were not considered.

Heat is recovered from the combustion turbine flue gas to produce steam. The offgas from the PSA has sufficient heating value for stable combustion and, therefore, is fired in a duct burner of the HRSG to produce additional steam. The steam is fed to a steam turbine to produce additional electrical power. The internal power consumers of the IGCC plant are satisfied from the gross electrical power produced with the remaining electricity sent for export.

The controlled case produces stack emissions from only a single source—the combustion turbine exhaust gas (downstream of the HRSGs). Tailgas from the SRU (an emission point in the uncontrolled base case) contains significant amounts of CO<sub>2</sub> and in order to meet the 90% carbon recovery design target this stream is combined with the main CO<sub>2</sub> product stream from the AGR unit. The NO<sub>x</sub> concentration has been



Note:

- 1) Feed Preparation unit is located at the Oil Sands Operation; the bulk of the Integrated Gasification Combined Cycle plant is located at the Firebag Lease.
- 2) Some auxiliary equipment are not shown (e.g. condensate treating and utilities).

**Figure 2:** Process schematic of the controlled baseline case.

TABLE 3  
PERFORMANCE SUMMARY CONTROLLED BASELINE CASE

<i>Basis</i>	
Feed	Petroleum coke
Gas turbines	3 × General Electric 7241(FA)
<i>Site conditions</i>	
Dry bulb temperature	2.8 °C
Barometric pressure	950 mbarg
Relative humidity	68%
<i>Performance</i>	
Petroleum coke feed rate	6863 mt/d
Total oxygen feed rate	7289 mt/d (100% O <sub>2</sub> )
Sulphur product	387 mt/d
<i>Power summary</i>	
Combustion turbines	588 Mwe
Steam turbine	181 Mwe
Fuel gas expander	6 MWe
Auxiliary power consumption	340 Mwe
Net plant output	435 Mwe
<i>Export streams</i>	
Hydrogen	67,000 Nm <sup>3</sup> /h (60 MMSCFD)
Steam (saturated at 44 barg @ user)	589,600 kg/h (1.3 MMlb/h)
Carbon dioxide	6.8 million mt/yr (100% capacity)
<i>Carbon dioxide capture (@ 100% capacity)</i>	
Carbon dioxide emitted (million mt/yr)	0.6
Carbon dioxide recovered (million mt/yr)	6.8
<i>Carbon dioxide product</i>	
Overall carbon capture	91.7%
Carbon dioxide purity	99.3 mol%
Hydrogen sulphide content	28 ppmv
Water content	– 51 °C dew point
Pressure	80 barg
Temperature	45 °C

calculated to be 15 ppmvd @ 15% O<sub>2</sub> in the turbine flue gas—the same level as in the uncontrolled base case. Emissions of SO<sub>2</sub> in the turbine exhaust gas are predicted to be 0.3 ppmvd—significantly less than the 18 ppmvd level in the uncontrolled base case. The difference in the amount of sulphur emitted between the controlled and uncontrolled cases (since SRU recoveries are equivalent in both cases) represents sulphur that is contained in the CO<sub>2</sub> product stream as 28 ppmv of H<sub>2</sub>S (Table 3).

#### **Advanced Technologies—Qualitative Screening**

A qualitative screening analysis was performed by Fluor and the CCP pre-combustion team on a number of advanced technologies prior to the selection of CO<sub>2</sub>LDSep<sup>SM</sup> as the subject of this study [2]. Ten candidate technologies were considered and evaluated against specific CCP objectives and the unique requirements of the Canadian scenario. Considered criteria included the ability of the technology to: (a) achieve CO<sub>2</sub> recoveries between 85 and 90%, (b) meet required CO<sub>2</sub> product purity specifications, (c) produce H<sub>2</sub> at pressure, and (d) perform in the presence of sulphur. The results of this qualitative analysis are contained in Table 4 and indicate that CO<sub>2</sub>LDSep<sup>SM</sup> appeared to be best suited to the Canadian scenario. As a result, Fluor were commissioned to develop a conceptual engineering

design that integrated CO<sub>2</sub>LDSep<sup>SM</sup> into the Canadian IGCC process scheme. A capital cost estimate was prepared to determine if this advanced technology could deliver reductions in CO<sub>2</sub> capture costs as compared to the controlled baseline case.

TABLE 4  
SCREENING OF ADVANCED TECHNOLOGIES

Advanced technology	Carbon recovery	Processing considerations		CO <sub>2</sub> Product stream	
	> 85% CO <sub>2</sub> capture	Delivers H <sub>2</sub> at pressure	Sulphur tolerant	< 30 ppmv H <sub>2</sub> S	> 97 mol% CO <sub>2</sub>
Hydrogen membranes	Yes	No	Yes	No	Yes
CO <sub>2</sub> membranes	No	Yes	Yes	No	No
Gemini pressure swing adsorption (PSA)	Yes	Yes	Yes	No	Yes
Membrane contactors	Yes	Yes	Yes	No	Yes
Electrical swing adsorption (ESA)	Note 1	Note 1	Note 1	No	Note 1
Sorption enhanced water gas shift reactor	Yes	Yes	Note 2	No	Yes
Membrane water gas shift reactor	Yes	No	No	No	Yes
O <sub>2</sub> transport membranes	Note 3	Note 3	Note 3	Note 3	Note 3
Hydrate CO <sub>2</sub> separation	No	No	Yes	No	Yes
CO <sub>2</sub> LDSep <sup>SM</sup>	Yes	Yes	Yes	Yes	Yes

*Note:* (1) The CCP decided not to continue pursuing this technology after its technical feasibility was questioned. (2) It is yet to be determined whether the water gas shift catalyst would retain its activity if sulphur co-adsorbed with the CO<sub>2</sub> resulting in an increase in the concentration of H<sub>2</sub>S across the reactor bed. (3) The CCP pre-combustion team determined that since this technology did not directly relate to capture and/or separation of CO<sub>2</sub>, it was better suited to consideration by the Oxyfuels team.

#### CO<sub>2</sub>LDSep<sup>SM</sup> Advanced Technology Case

CO<sub>2</sub>LDSep<sup>SM</sup> is a proprietary autorefrigeration technology that has been developed and patented by Fluor. The CO<sub>2</sub>LDSep<sup>SM</sup> process represents the unique application of a novel configuration of proven and established technology. It incorporates conventional equipment of the type used in other commercial processing applications and, hence, is viewed as having a low technical risk. Table 5 provides a performance summary for the CO<sub>2</sub>LDSep<sup>SM</sup> case.

In the CO<sub>2</sub>LDSep<sup>SM</sup> advanced technology case petroleum coke is slurried with water and gasified with oxidant (99.5 mol% oxygen) from the ASU to produce a raw syngas. The syngas from the gasifier is cleaned of particulates, preheated, shifted (a hot sour shift as per the controlled baseline), and cooled to a temperature suitable for the CO<sub>2</sub>LDSep<sup>SM</sup> Unit. Sulphur compounds are removed in the CO<sub>2</sub>LDSep<sup>SM</sup> unit and recovered as elemental sulphur product in the Sulphur Recovery and Tailgas Treating unit. The carbon dioxide is recovered and a hydrogen rich stream is produced for fuel gas to the combustion turbines and hydrogen export. The carbon dioxide is compressed and dehydrated for storage and/or use in EOR operations.

The purpose of the CO<sub>2</sub>LDSep<sup>SM</sup> Unit is to separate the carbon dioxide from the syngas feed. The unit consists of one 100% train and is considered a proprietary package unit supplied by Fluor. A brief non-confidential description of the unit follows.

- Shifted, cooled syngas from the low temperature gas cooling (LTGC) Unit enters at 35 °C and is first sent to a pretreatment unit, which among other things, removes the water and any particulates present in

TABLE 5  
PERFORMANCE SUMMARY ADVANCED CASE—CO<sub>2</sub>LDSEP<sup>SM</sup>

<i>Basis</i>	
Feed	Petroleum coke
Gas turbines	3 × General Electric 7241(FA)
<i>Site conditions</i>	
Dry bulb temperature	2.8 °C
Barometric pressure	950 mbarg
Relative humidity	68%
<i>Performance</i>	
Petroleum coke feed rate	6863 mt/d
Total oxygen feed rate	7105 mt/d (100% O <sub>2</sub> )
Sulphur product	387 mt/d
<i>Power summary</i>	
Combustion turbines	588 MWe
Steam turbine	173 MWe
Fuel gas expander	10 MWe
Auxiliary power consumption	301 MWe
Net plant output	470 MWe
<i>Export streams</i>	
Hydrogen	67,000 Nm <sup>3</sup> /h (60 MMSCFD)
Steam (saturated at 44 barg @ user)	589,600 kg/h (1.3 MMlb/h)
<i>Carbon dioxide capture (@ 100% capacity)</i>	
Carbon dioxide emitted	0.9 million mt/yr
Carbon dioxide recovered	6.4 million mt/yr
Carbon recovery	88%

the feed gas. Removal of water is essential due to the cryogenic operating temperatures in the CO<sub>2</sub>LDSEP<sup>SM</sup> Unit.

- The dry syngas is pre-chilled producing liquid carbon dioxide, which is separated from the gas as product. The chilled gas from the separator is expanded to produce additional liquid carbon dioxide. By chilling the feed to the expander, more condensation of the liquid carbon dioxide occurs for the same expansion ratio.
- The liquid carbon dioxide from the expander is separated from the gas in a knockout drum. The combined liquid carbon dioxide and cold gas from the expander is used to chill the feed to the expander for autorefrigeration. The gas is further pretreated and the carbon dioxide rich stream from the pretreatment step is compressed in two parallel, integral gear compressors. The remaining stream from the pretreatment step is sent for hydrogen compression and to the fuel gas saturator (for combustion turbine fuel).
- The compressed gas is then sent through a second stage of prechilling, expansion and separation resulting in additional liquid carbon dioxide streams and a hydrogen rich stream, which mixes with the fuel to the fuel gas saturator.
- There is also an internal purification and aftertreatment step, which produces additional carbon dioxide for export, two streams of acid gas for sulphur recovery, and sour water to the condensate stripper.

In summary, the CO<sub>2</sub>LDSEP<sup>SM</sup> Unit produces the following:

- carbon dioxide product at pressure,
- hydrogen export to hydrogen compression,

- hydrogen rich fuel gas to the combustion turbines,
- fuel gas to the Tail Gas Treating Unit,
- water to the Gasification Island,
- acid gas to Sulphur Recovery and Tailgas Treating Unit,
- sour water to the Condensate Stripper unit.

The feed rate of petroleum coke is determined by recovering 67,000 Nm<sup>3</sup>/h (60 MMSCFD) of hydrogen from the IGCC and fully loading three General Electric Frame 7241(FA) combustion turbines (same feed flow rate as the controlled baseline case). The hydrogen rich fuel gas mixture is diluted with nitrogen from the ASU to control NO<sub>x</sub> formation in the combustion turbine. Heat is recovered from the combustion turbine flue gas to produce steam. The steam is fed to a steam turbine to produce additional electrical power. The parasitical power consumers of the IGCC plant are satisfied from the gross electrical power produced with the remaining electricity sent for export.

Similar to the uncontrolled case, the advanced controlled case produces stack emissions from two sources—the combustion turbine exhaust gas (downstream of the HRSGs) and the tailgas from the SRU. NO<sub>x</sub> concentrations are predicted to be identical to the uncontrolled baseline case for both emission sources. Emissions of SO<sub>2</sub> in the turbine exhaust gas are predicted to be 0.3 ppmvd—the same as in the controlled baseline and significantly less than the 18 ppmvd level in the uncontrolled base case. In the SRU the tailgas concentration is predicted to be 250 ppmvd @ 0% O<sub>2</sub>—the same as the uncontrolled baseline.

### *CO<sub>2</sub> Capture Costs*

Capital cost estimates for the three cases described above are included as line items in the performance summaries contained in Tables 2, 3 and 5. Estimated TIS's are \$874 MM USD for the uncontrolled baseline and \$1364 MM USD for the controlled baseline. Although the steam and H<sub>2</sub> production is equivalent in both of these cases the amount of electrical power available for export is significantly different. In the uncontrolled case 324 MWe is exported whereas in the controlled case the corresponding figure is 435 MWe.

More electrical power is available for export in the controlled case (even though internal power consumption is 194 MWe higher in the controlled case as compared to the uncontrolled case (340 vs 146 MWe) due to the additional power load required to capture CO<sub>2</sub>) because it has three fully loaded combustion turbines as compared to only two in the uncontrolled case.

The TIC estimate for the CO<sub>2</sub>LDSep<sup>SM</sup> case is \$1399 MM USD which is \$35 MM USD higher than the controlled baseline. However, the CO<sub>2</sub>LDSep<sup>SM</sup> case produces an additional 35 MWe of electrical power as compared to the controlled baseline (and identical amounts of H<sub>2</sub> and steam) from the same amount of petroleum coke.

As a result of the different electrical power outputs, the three cases had to be normalized in order to calculate costs per tonne of CO<sub>2</sub> captured and per tonne of CO<sub>2</sub> avoided.

Avoided CO<sub>2</sub> accounts for any additional CO<sub>2</sub> that is produced as a result of the increased energy demand required to power CO<sub>2</sub> capture equipment. The difference between the amount of captured CO<sub>2</sub> and the amount of avoided CO<sub>2</sub> represents the amount of these incremental CO<sub>2</sub> emissions.

The CEM team expressed the three output streams of H<sub>2</sub>, steam, and electrical power on an equivalent energy basis (i.e. assuming all coke was used to generate electrical power). This allowed each IGCC case to be expressed as a single combined energy output [3].

Table 6 shows the cost per tonne of CO<sub>2</sub> avoided to be \$14.5 USD for the controlled baseline and \$12.2 for the CO<sub>2</sub>LDSep<sup>SM</sup> case. This represents a 16% reduction in cost for the CO<sub>2</sub>LDSep<sup>SM</sup> advanced technology as compared to the controlled baseline.

Compared to the other scenarios, the avoided CO<sub>2</sub> cost for the Canadian scenario is significantly lower. The reason is that, unlike the other scenarios, the Canadian scenario includes upfront syngas production

TABLE 6  
 AVOIDED CO<sub>2</sub> COSTS FOR THE CANADIAN SCENARIO

Technology	Combined output (net power, hydrogen and steam) MW	Incremental capital for capture systems	CO <sub>2</sub> captured million tonnes/yr MMUSD	CO <sub>2</sub> avoided million tonnes/yr	CO <sub>2</sub> capture cost		CO <sub>2</sub> avoided cost	
					USD per tonne CO <sub>2</sub>	% change relative to BL	USD per tonne CO <sub>2</sub>	% change relative to BL
<i>Pre-combustion</i>								
Baseline (BL) IGCC with conventional capture technology (Selexol)	588	519	6.80	5,28	11.1	0%	14.5	0%
IGCC with advanced capture technology CO <sub>2</sub> LDSep <sup>SM</sup>	699	516	6.44	5,22	9.9	- 11%	12.2	- 16%



systems that are included in both the uncontrolled and capture cases (i.e. the Canadian scenario has a pre-combustion baseline as opposed to a post-combustion baseline). As a result, the additional CO<sub>2</sub> capture units represent a smaller incremental capex investment per tonne of CO<sub>2</sub> than is the case for the other scenarios. From this perspective one might view an IGCC as a “pre-investment” for CO<sub>2</sub> capture.

However, even though the costs to capture CO<sub>2</sub> are relatively low for an IGCC as envisioned in the Canadian scenario, it has to be recognized that the cost of an IGCC plant of over a billion dollars represents a significant investment. An IGCC investment of this magnitude could be driven by the ever increasing cost of natural gas which would make combined cycle gas turbine plants less attractive for the production of steam and electrical power. The availability of low (or zero) value petroleum coke (as in the Canadian scenario) or heavy asphaltene material could offer very attractive alternatives. Another benefit to the IGCC is that it can also produce H<sub>2</sub>. The alternative of reforming gas for hydrogen production is also subject to the same natural gas price risks as a CCGT.

If the decision is made to construct an IGCC facility as per the Canadian scenario, the next decision of committing the additional capital required to capture CO<sub>2</sub> is made significantly easier by the relatively low capture costs.

## CONCLUSIONS

The conclusions of this study are:

1. The incremental capital cost required to capture CO<sub>2</sub> from an IGCC using the physical solvent Selexol, a conventional technology that is commercially available today, is less than \$15 USD per tonne of avoided CO<sub>2</sub>.
2. The proprietary CO<sub>2</sub>LDSep<sup>SM</sup> advanced technology can reduce the cost of CO<sub>2</sub> capture by 16% from today’s technology to just over \$12 USD per tonne of avoided CO<sub>2</sub>.
3. Capture of CO<sub>2</sub> using either Selexol or CO<sub>2</sub>LDSep<sup>SM</sup> technology results in NO<sub>x</sub> and SO<sub>x</sub> emissions that are equivalent to or lower than the levels from a baseline case with no CO<sub>2</sub> capture.

## RECOMMENDATIONS

Further studies should be done to determine how much the CO<sub>2</sub>LDSep<sup>SM</sup> cost can be reduced by relaxing the requirements on CO<sub>2</sub> recovery and the H<sub>2</sub>S specification on the CO<sub>2</sub> product stream.

## NOMENCLATURE

AACE	Association for the Advancement of Cost Engineering
AGR	acid gas removal
ASU	air separation unit
BACT	best available control technology
CEM	common economic modelling
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CCGT	combined cycle gas turbine
COS	carbonyl sulphide
CCP	CO <sub>2</sub> capture project
EOR	enhanced oil recovery
H <sub>2</sub>	hydrogen
H <sub>2</sub> S	hydrogen sulphide
HCN	hydrocyanic acid
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
lb/h	pound per hour
kg/h	kilogram per hour

LTGC	low temperature gas cooling
MM	million
MWe	megawatt-electrical
Nm <sup>3</sup> /h	normal cubic metres per hour
NO <sub>x</sub>	nitrogen oxides
ppmvd	part per million (volume and dry basis)
ppmv	part per million (volume basis)
PSA	pressure swing adsorption
SAGD	steam assisted gravity drainage
SCFD	standard cubic feet per day
SO <sub>x</sub>	sulphur oxides
SRU	sulphur recovery unit
TIC	total installed cost
USD	US dollars

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