Appendix F

Advanced IGCC Partial Carbon Capture

A Final Phase IV Report

Prepared by CCPC Technical Committee, June 2014

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Figures and Tables

Advanced IGCC Partial Carbon Capture

1. Background

Jacobs Engineering was contracted by the Canadian Clean Power Coalition (CCPC) to perform a study to develop project cost, performance and emissions data for a number of alternative green field Integrated Gasification Combined Cycle (IGCC) configurations, all with partial carbon capture. The quantity of carbon captured meets the Canadian government's recent regulations for fossil fuel based power plant carbon emissions, which includes gasification plants, of 420 kgCO_2/MWhnet, excluding CO_2 compression power.

The study consists of six cases using two coals and three gasification technologies. Two of the gasification technologies were part of the Advanced Gasification Technology Study completed by Jacobs for CCPC in 2010 and showed potential for significantly reducing cost and providing high efficiency. These are the Aerojet Rocketdyne (AR) compact gasification system and the SES U-Gas gasifier. Aerojet acquired the Rocketdyne portion of Pratt and Whitney Rocketdyne (PWR) in the first half of 2013 and the company is now known as Aerojet Rocketdyne.

The third technology is the CB&I Entrained-Slagging Transport Reactor (E-STR) gasifier. CB&I recently acquired the gasification technology from Phillips 66 and is again marketing the E-STR gasification configuration, which was previously evaluated in the Phase 2 CCPC study issued in 2008 by Jacobs. The AR and SES cases use the sub-bituminous Alberta coal used in Phases II and III at a site location near Edmonton, Alberta, Canada. The CB&I case uses a lignite coal that Saskpower has available in the Coronach area in Saskatchewan.

CCPC has selected the following process areas for evaluation to construct configurations more amenable to partial CO_2 capture:

- Air Separation Unit (ASU)
- Gasifier
- Sulphur Removal
- Full or Partial Shift
- Sweet or Sour Shift Catalyst
- CO_2 Removal
- Sulphur Recovery

Within these areas, technologies have been identified for evaluation as shown in Table 1. A comparative analysis was completed on more than 100 configurations employing these technologies. Jacobs identified the pros and cons of the various configurations and why they were or were not selected for the detailed analysis.

Table 1: Technologies Evaluated

Unit Operation	Technology
Air Separation	Cryogenic ASU
	Air Products ITM
Gasifier	AR – Compact Gasifier (formerly PWR)
	SES – U-Gas
	CB&I – ESTR (formerly Phillips 66)
Shift	Sweet
	Sour
	Partial
	Full
Sulphur Removal	RTI WGCU
	Selective Solvent
CO_2 Removal	CO_2 Selective Membrane
	High Recovery PSA
	Sour PSA
	Selective Solvent
	Non-selective Solvent
	H_2 Selective Membrane
	Cryogenics
Sulphur Recovery	Claus
	Wet Sulphuric Acid
	Modified Claus
	RTI Direct Sulphur Recovery Process
	(DSRP)
	LoCat

2. Summary of Cases

Based on the preliminary screening of the technologies in Table 1, the following case configurations were selected for detailed analysis within this report. Case 5 was developed for both AR and SES U-Gas gasifiers using Cases 2 and 4 to provide a direct comparison of the advantages of ITM compared to a standard cryogenic ASU.

Table 2 provides a description of the technologies used in each the cases.

Table 2: Description of Cases

Case	1	2	3	4	5-2	5-4	6
Air Separation	Cryogenic	Cryogenic	Cryogenic	Cryogenic	Air Prod ITM	Air Prod ITM	Cryogenic
Gasifier	AR	AR	AR	SES	AR	SES	CB&I
Shift	Sour	Sour	Sour	Sour, with bypass	Sour	Sour, with bypass	None
Sulphur Recovery	LO-CAT	LO-CAT	LO-CAT	LO-CAT	LO-CAT	LO-CAT	Selexol Claus/ SCOT
CO_2 Recovery	Partial Condensation	PSA	Membrane	Selexol	PSA	Selexol	Selexol
Gas Turbine	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas
Steam Turbine	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat

Case 1 AR Partial Condensation Case

Case 1 uses AR gasification technology with sour shift, LoCat and partial condensation out of the syngas with bypass for CO_2 removal. It comprises two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.

Case 2 AR PSA Case

Case 2 uses AR gasification technology with sour shift, LoCat and PSAs with bypass for CO_2 removal. It comprises two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.

Case 3 AR Membrane Case

Case 3 uses AR gasification technology with sour shift, LoCat and CO_2 Absorbing Membranes with bypass for CO_2 removal. It comprises two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.

Case 4 SES U-Gas Gasifier Case

Case 4 uses SES U-Gas gasification technology feeding a split flow two stage shift followed by LoCat and Selexol for CO_2 removal. It comprises three U-Gas gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.

Case 5-2 AR ITM Case 2

Case 5-2 is identically configured to Case 2 except that an ITM ASU is used instead of a cryogenic ASU. The additional load of the ITM requires a third gasifier.

Case 5-4 SES ITM Case 4

Case 5-4 is identically configured to Case 4 except that an ITM ASU is used instead of a cryogenic ASU.

Case 6 CB&I E-STR Lignite Case

Case 6 uses the E-STR gasifier with a lignite coal feed, no shift, Selexol AGR for acid gas and CO_2 recovery. It comprises two E-STR gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.

3. Performance Conclusions

The reduction in CO_2 capture requirements allows for a 2.3 per cent increase in efficiency. This is simply the reduced parasitic power loads of the CO_2 removal, CO_2 compression and diluent N2 compression. Using alternative technologies more than doubles this increase and significantly increases performance and overall efficiency for all cases. On average a 5 per cent increase in efficiency is realized, which translates into a 20 per cent increase in performance of the plants. Additionally, replacing a cryogenic ASU with an ITM ASU increases the efficiency 2.4 per cent for AR and 1.7 per cent for SES U-Gas. For the AR comparison (Case 2 vs. 5-2) ITM adds another 7 per cent to the plant performance.

Case 6, the CB&I E-STR gasifier, also shows significant efficiency gains considering the high moisture, high ash lignite that has been used. This is due to the combination of the improved efficiency of the E-STR technology and the reduced carbon capture requirements.

4. Economic Conclusions

The following economic results, in Figure 1, are based on un-levered economics employing a WACC of 9.2 per cent. Generally, first year levelized costs are provided. First year levelized costs are the price power must be sold for in the first year, when escalated by 2 per cent per year thereafter, which sets the net present value (NPV) of a project equal to zero. CO_2 credits are generated based on the sum of CO_2 captured less 12 per cent of the GHG emissions that would have otherwise been emitted by the technology without CCS. No value for the sale of CO_2 for use in enhanced oil recovery (EOR) has been included.

The in-service date for all cases is assumed to be January 2017. Coal costs were assumed to be $1.25/GJ in the first year. No cost for CO_2 pipelines or storage has been included.

Figure 1 shows the components that make up the first year cost of power. The first three columns shows the results for the PWR, SES and Siemens technologies with 90 per cent capture taken from the Phase III study work. The Phase III costs were escalated to 2017.

The final two cases are costs estimates for a new super critical coal plant with and without CCS. The final case assumes that post combustion capture will be used to meet the .42 t CO_2/MWh threshold. The cases in the middle are the partial capture IGCC cases. The partial capture cases have first year costs much lower than their base cases technologies configured to capture 90 per cent of CO_2. The best PWR Case 2 has a first year cost of power which is 74 per cent of the PWR case with 90 per cent capture. The best SES Case 5-4 has a first year cost 76 per cent of the SES case with 90 per cent capture. Case 5-4 has a first year cost of $136/MWh. This is almost half the cost for the Siemens case with 90 per cent CO_2 capture. The partial capture cases have significantly lower capital expenditure (CAPEX) and operations and maintenance (O&M) costs. They may also be more efficient reducing coal costs to a small extent. The partial capture cases, however, also have smaller CO_2 credits sales. All of the cases shown in the graphs below employ sub-bit coal except the ESTR case, which has been modelled to operate on lignite as a fuel. However, a separate price for lignite nor the cost of a SCPC operating on lignite was modelled. Therefore all costs for fuel and for SCPC plants were based on sub-bit.

Figure 1: First Year Cost of Power Components

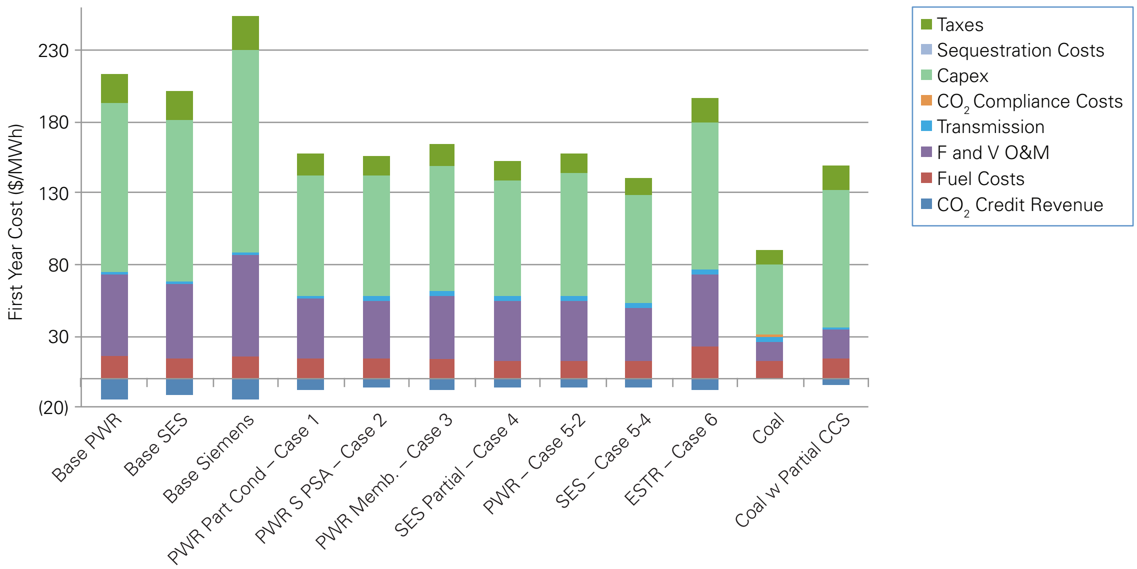


Figure 2 shows the first year cost of power net of any revenue associated with the sale of CO_2 credits. All of the first year costs for the partial capture IGCC cases, except Case 5-4, have first year costs of power similar to the estimated cost for a new supercritical coal plant with partial post combustion capture. Case 5-4 has a lower first year cost than that estimated for a coal plant with post combustion capture. However, all the partial capture cases are still significantly greater than $100/MWh and are therefore unlikely to compete with natural gas combined cycle (NGCC) plants, given prevailing natural gas prices.

Figure 2: First Year Cost of Power Net

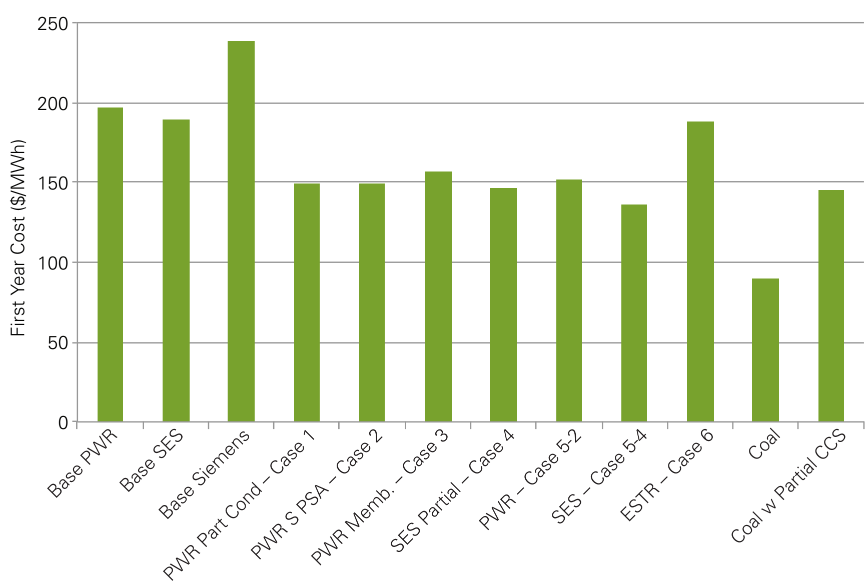


Figure 3 shows the components that comprise the cost of capture. The value of CO_2 credits sold or the cost of mitigating CO_2, in the instance of the reference coal case, have not been included. The cost of capture for the coal plant with CCS was estimated to be $90/t and is loosely based on Phase II estimates. The reference for all the cases is a super critical coal plant without CCS. The cost of capture and avoided cost are based on a reference plant without CCS.

The reference plant employed runs on sub-bit. We have not constructed a reference plant operating on lignite for the ESTR case was not modelled. One would expect that the cost of power for the lignite SCPC plant should be greater than that for a plant operating on sub-bit. Therefore, the cost of capture and avoided costs for the ESTR case are likely too high and would be lower if a SCPC operating on lignite were used as its reference case. For instance, if the cost of power for the SCPC case increases by $10/MWh, the capture cost decreases from $160/t to $148/t for the ESTR case. Likewise, the avoided cost decreases from $235 to $217/t for the ESTR case.

Notice also that the cost of capture on the coal plant is dominated by CAPEX, whereas the cost of capture for the partial capture IGCC cases is mostly CAPEX but also includes a fixed and variable O&M component almost as large as the CAPEX components.

Figure 3: Capture Cost Components

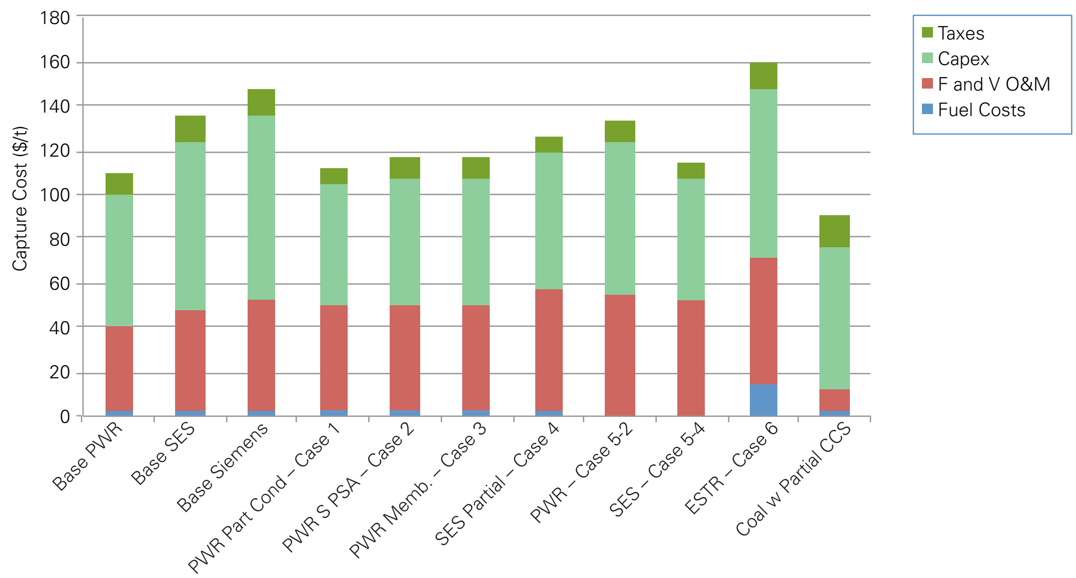
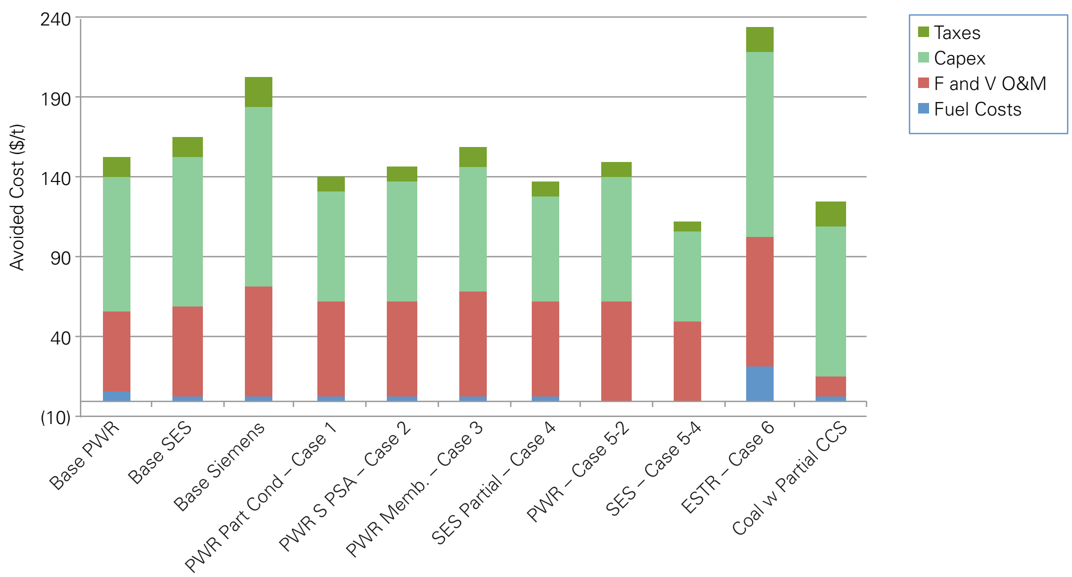


Figure 4 shows the components that make up the avoided cost. As with the capture values above, no benefit associated with the sale of CO_2 credits or the cost to mitigate CO_2 have been included. The avoided cost values add back the CO_2 that is emitted by the energy used to capture CO_2. Avoided costs also account for the fact that if a plant is derated by carbon capture then additional plant capacity emitting CO_2 must be built to replace the lost power. The avoided costs for all partial capture IGCC cases, except Case 1, are greater than the estimated cost for post combustion capture on a super critical coal plant. Case 4 has a lower avoided cost than Cases 2 and 3. Case 4 has a higher capture cost than Cases 2 and 3. Case 5-2 has a significantly lower avoided cost than Cases 2 and 3.

Figure 4: Avoided Costs Components



5. Conclusion

Case 4 is based on post gasification syngas processing technologies that are commercially available. Most of the other cases include technologies that are either unproven or significantly modified versions of commercial technology. While Case 4 has the lowest first year cost of power of the partial capture cases employing an ASU, it is not materially lower than these other cases. Given the accuracy of the cost estimation involved in the study, Cases 1 to 4 have essentially the same first year cost of power. It may be true, however, that replacing an ASU with an ITM may materially decrease the first year cost of power.

Partial capture of CO_2 is expected to significantly reduce the cost of producing power from IGCC plants compared to plants capturing 90 per cent of the CO_2. Many of the cases have a first year cost of power similar to a SCPC plant with 60 per cent capture. Case 5-4 has a cost of power less than that expected for a SCPC with CCS. These results are encouraging.

However, if it is assumed that a combined cycle plant has a non-fuel first year cost of power of $45/MWh and a heat rate of 7 GJ/MWh, we can derive the gas price that sets the cost of power to about $140/MWh. If the price of gas is about $14/GJ, the cost of power from this combined cycle plant would be about $140/MWh. That is, the natural gas price would have to rise to $14/GJ before any of these partial capture cases would be economically attractive.

Clearly further advances are required before IGCC with partial capture can complete with NGCC. In Phase III, EPRI completed work to estimate the impact of advances in IGCC technology, which may help reduce the cost of IGCC in the future. Some of those advances, such as advances in gas turbine technology, may reduce the cost of the partial capture IGCC cases even further.