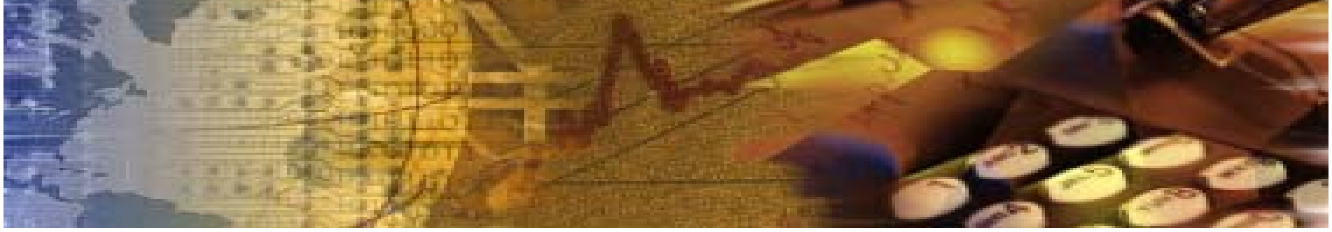
HUDP CO_2 Assessment Final Report



Prepared For

AERI

July 2009

JACOBS Consultancy

JACOBS Consultancy

525 West Monroe, Suite 1350
Chicago, Illinois 60661
Phone: +312.655.9207
Fax: +312.655.9706

HUDP CO_2 Assessment Final Report

Prepared For

AERI

For Jacobs Consultancy

Paul Zuehlke

Rich Hill

July 2009

Table of Contents

Table of Contents

Section **Page**

Appendices

Section A.

Executive Summary

Background

Jacobs Consultancy Inc. ("Jacobs Consultancy") has been commissioned by Alberta Energy Research Institute ("AERI") to provide technical services in support of its Hydrocarbon Upgrading Demonstration Program (HUDP). As part of the contract ending in 2008, Jacobs Consultancy is to perform an economic-based study concerning the CO_2 emissions and capture potential for various upgrader configurations, starting with those developed during the Phase 1 Study completed by Jacobs Consultancy in 2006.

The scope of work for this study focused on the following:

- Start with the Phase 1 upgrader configurations and add other commercially available flowschemes to develop the cost of CO_2 capture and change in the cases' economics.
- Develop high-level material balances and BFDs (block flow diagrams) for the various cases.
- Incorporate Steam Assisted Gravity Drainage (SAGD) bitumen production in the costs and emissions of the various cases.
- Analyze the results and provide conclusions to address the following questions:
  - How do co-located Upgrading/Refining and SAGD facilities impact CO_2 emissions and overall economics?
  - How does technology impact CO_2 emissions and overall economics?

The various cases were selected based on identifying the differences in technologies on a co-located and non-co-located basis, where integration means the co-locating of the upgrading facilities with the SAGD facilities. We also looked at alternate fuels using upgrader waste products as a fuel for SAGD steam generation. We did not evaluate mining or partial upgrading in the study. All upgrader configurations were selected to produce SCO or finished products. This requirement enabled us to build upon the HUDP Phase 1 study work completed by Jacobs Consultancy in 2006.

The scope of the study did not include a Life Cycle Analysis (LCA) of CO_2 for each case; rather, it focused on the CO_2 generated and released from the production sites at a granular level. Overall the relative results are applicable as input to an LCA study and, among similar cases, accurately determines the effect of co-locating facilities. However, dissimilar cases should be evaluated via LCA to accurately understand the GHG emissions, especially with regard to:

- SCO versus Fuels products—There are inherent inefficiencies in the upgrading followed by refining cases associated with upgrading bitumen to SCO and refining SCO to fuels products. Without exception, fuels produced from a combined upgrader/refinery will have a lower GHG burden than a similar technology case with the SCO intermediary.
- Coke handling or residue disposition—Landfilling coke in Alberta effectively stores a significant portion of the carbon in the bitumen. However, an LCA is required to accurately reflect the impact of the coke disposition if it is used for fuel elsewhere as opposed to being stored indefinitely.
- SAGD power generation—Bitumen producers that incorporate co-generation of power in the steam cycle have a lower overall efficiency but may, in fact, reduce the GHG calculated by LCA by offsetting power produced via a coal-based power plant.

Note that this study only analyzed the various technologies and flowschemes in terms of profitability and CO_2 impacts. At this study level, we did not incorporate risk analysis to quantify expected profitability.

Cases Evaluated

The cases evaluated are summarized in Table A-1 on the following page.

Table A-1.
Cases

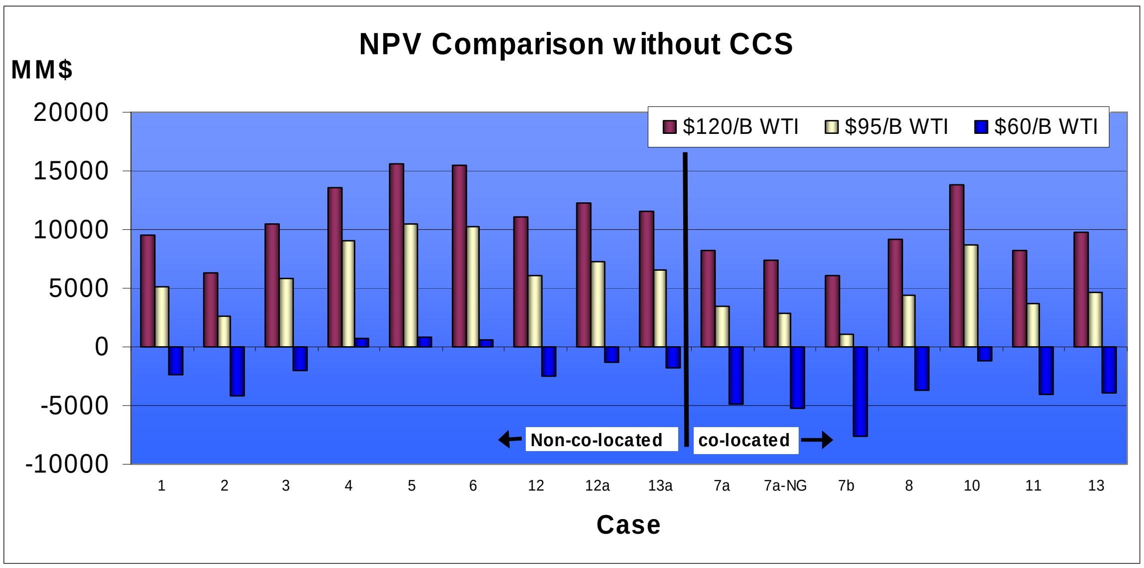
Case (Phase 1 Basis)	Co-located	Primary Upgrading Step	Product	Residue	Fuel for Steam	Boiler Tech	Water Treat Tech	Objective
1 (BC1)	N	DC	SCO	Landfill	NG	OTSG	WLS	Base Case
2 (BC1)	N	DC	SCO	Landfill	VB-emulsion	Drum Boiler	Evap	Alternate Fuel - clear definition needed for consistency with Alternate Fuels study
3 (BC1g)	N	DC	SCO	Gasifier	NG	OTSG	WLS	Gasifier impact
4 (BC2g)	N	DC	Fuels	Gasifier	NG	OTSG	WLS	Fuels versus SCO
5 (4B)	N	Slurry Phase HC	Fuels	Gasifier	NG	OTSG	WLS	H2 addition case
6 (4B sans gasifier)	N	Slurry Phase HC	Fuels	Emulsion	Emulsion/ NG	Drum Boiler	Evap	H2 addition case
7a (BC1)	Y	DC	SCO	CFBB	Petcoke	CFBB	Evap	Alternate Fuel - clear definition needed for consistency with Alternate Fuels study
7b (BC1)	Y	DC	SCO	CFBB	Petcoke Oxyfuels	CFBB	Evap	With Oxy Fuels
8 (BC1g)	Y	DC	SCO	Gasifier	Gasifier/ NG	OTSG	WLS	Gasifier impact in field
9	Y	DC	Fuels	Gasifier	NG	OTSG	WLS	Fuels versus SCO in field
10 (4B sans gasifier)	Y	Slurry Phase HC	Fuels	Emulsion	Emulsion	Drum Boiler	Evap	H2 addition - field location; capital cost delta vs. case 6
11 (2g2)	Y	C4 SDA	SCO	Gasifier	Gasifier	OTSG	WLS	Similar to Opti- Nexen (publicly available information) with CO2 capture
12 (New)	N	EB HCK	SCO	Emulsion	Emulsion/ NG	Drum Boiler/ OTSG	Evap	H2 addtion case - most common technology
12a (New)	N	EB HCK	SCO	SCO	NG	OTSG	WLS	H2 addtion case - most common technology
13 (New)	Y	EB HCK	SCO	Gasifier	Gasifier/ NG	OTSG	WLS	H2 addition- most common in field
13a (New)	N	EB HCK	SCO	Gasifier	NG	OTSG	WLS	H2 addition- most common in field

The various cases were compared based on NPV and CO_2 generation with and without carbon capture and storage (CCS). For the purposes of the study, CCS costs only included the capital and operating costs for the ISBL facilities including separation, concentration and compression to roughly 2000 psig. Pipeline costs, drilling and other costs for the CO_2 are not included. It's assumed that for a comparative basis, all cases would incur the sequestration costs in proportion to the CO_2 generated and the relative results would be accurate without including them. In this level of analysis, we factor OSBL costs of ISBL costs for estimating overall facility capital costs.

Results

Without CCS the NPV for the cases are shown in Figure A-1.

Figure A-1.
NPV without CCS



The key findings with respect to Figure A-1 are as follows:

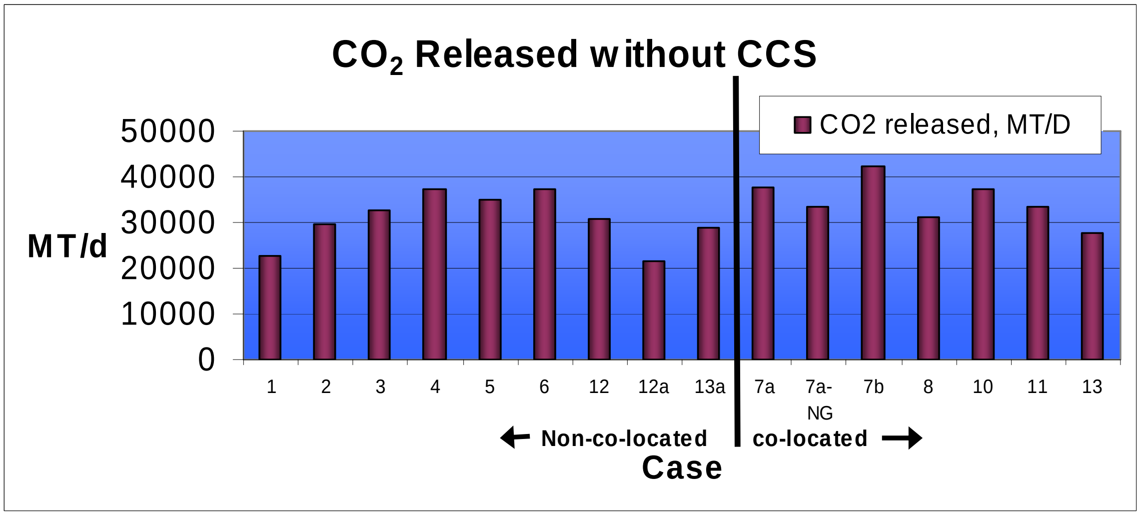
- As indicated by comparing Case 4 (Delayed Coking producing finished products) with Case 3 (Delayed Coking producing SCO), producing finished products has better economics than producing SCO.
- As indicated by Cases 5 and 6 in relation to Case 4, higher bottoms conversion improves NPV particularly at higher base crude prices.
- Cases 12, 12a and 13a (Ebullated Bed HCK) have better economics than Case 1 (Delayed Coking) due to higher bottoms conversion.
- As indicated by the line in the chart above separating the co-located from non-co-located cases, the NPV of the non-co-located cases is generally better than that of the co-

located cases, primarily due to location factor advantages for construction in the Industrial Heartland as opposed to the SAGD sites in the northern Alberta.

- Of the co-located cases, Case 10 (Slurry Phase HCK) has the best economics, again driven by higher bottoms conversion and the production of finished products instead of SCO.
- All projects are economically difficult at $60/BBL WTI or less.
- Gasification alone has little impact on overall economics, as shown in the comparison between Cases 1 and 3 (delayed coking with and without gasification, respectively) and Cases 5 and 6 (slurry phase HCK with and without gasification, respectively).
- In the Ebullating bed HCK cases, it is generally better to combine the residue into the product SCO as opposed to combusting or gasifying it, as shown in the comparison among Cases 12, 12a and 13a (Ebullating Bed HCK).

CO_2 released for each case is summarized in Figure A-2.

Figure A-2.
CO_2 released without CCS



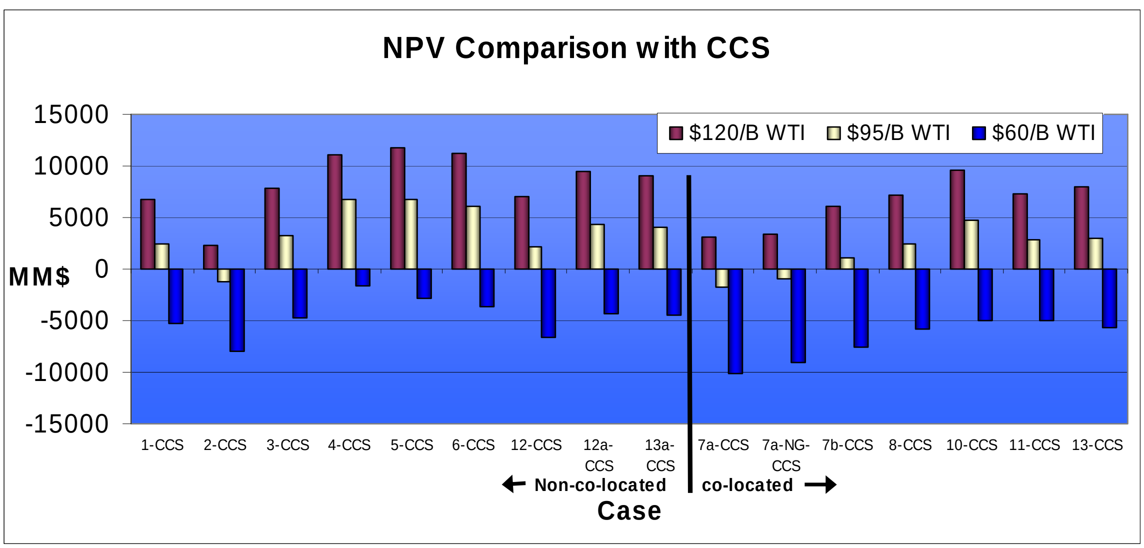
The key findings with respect to Figure A-2 are as follows:

- Not surprisingly, gasification or combustion of the residue increases CO_2 released because it displaces natural gas (lower carbon fuel source) either for SAGD steam generation or hydrogen addition.

- As indicated by Cases 1 (delayed coking with coke landfill) and 12a (Ebullating Bed HCK with pitch to SCO), storing or shipping some of the carbon in the bitumen reduces the CO_2 footprint; however, as mentioned earlier, a life cycle approach would be required for consistent comparison.
- As indicated by the line in the chart above, the CO_2 generation for the co-located cases is generally not any better than that for the non-co-located cases. On a case-by-case basis, the results are similar. For Cases 8 and 3 (delayed coker with coke gasification) and Cases 13a and 13 (ebullating bed HCK with gasification), the co-located cases have slightly less CO_2 generation.
- As indicated by the difference between Cases 6 (slurry phase HCK with pitch combustion) and 12 (ebullating bed HCK with pitch combustion), the higher conversion Case 6 has slightly more CO_2 generation due to the higher hydrogen demand from the steam methane reformer.

We then evaluated all of the cases with additional equipment and operating costs required for CCS. The NPV comparison of the cases is shown in Figure A-3.

Figure A-3.
NPV with CCS



The key findings with respect to Figure A-3 are as follows:

- In general, the relative rankings with CCS improve for the cases with gasification.

- In general, as indicated by the line in the chart above separating the co-located from non-co-located cases, the NPV of the non-co-located cases is better than that of the co-located cases, primarily due to location factor advantages for construction in the Industrial Heartland as opposed to the SAGD sites in the North.

- At higher oil prices, higher conversion technologies can nearly offset the cost of CCS as on an NPV basis at higher oil prices, as indicated by the following NPV comparisons:

  - Case 5—CCS (slurry phase HCK with gasification) with Case 4 (delayed coking with gasification)

NPV ($MM)			
Case	**$120/ BBL WTI**	**$95/ BBL WTI**	**$60/ BBL WTI**
Case 4	$13,570	$9,070	$670
Case 5-CCS	$11,820	$6,770	-$2,890

  - Case 12a-CCS (ebullating bed HCK with pitch to SCO) with Case 1 (delayed coking with coke to landfill)

NPV ($MM)			
Case	**$120/ BBL WTI**	**$95/ BBL WTI**	**$60/ BBL WTI**
Case 1	$9,540	$5,150	-$2,430
Case 12a-CCS	$9,440	$4,390	-$4,360

- Otherwise, the key findings are similar to those without CCS.

Even by assuming CCS on a “practical basis,” installing and operating CCS equipment has the capability to reduce the CO_2 released by around 50 to 80 percent. For the purposes of the study and explained in Section D, we assumed that CO_2 could be captured from a practical basis for the following large single point emitters:

- SAGD steam generators

- The feed side of SMRs (the fuel side was considered to be a smaller, dilute CO_2 source similar to other process heaters in the Upgrader/Refinery)

- Gasification using two-stage Rectisol® or Selexol® after sour shift

Figure A-4 and A-5 summarize the CO_2 generated and released after CCS.

Figure A-4.
CO_2 Released with CCS

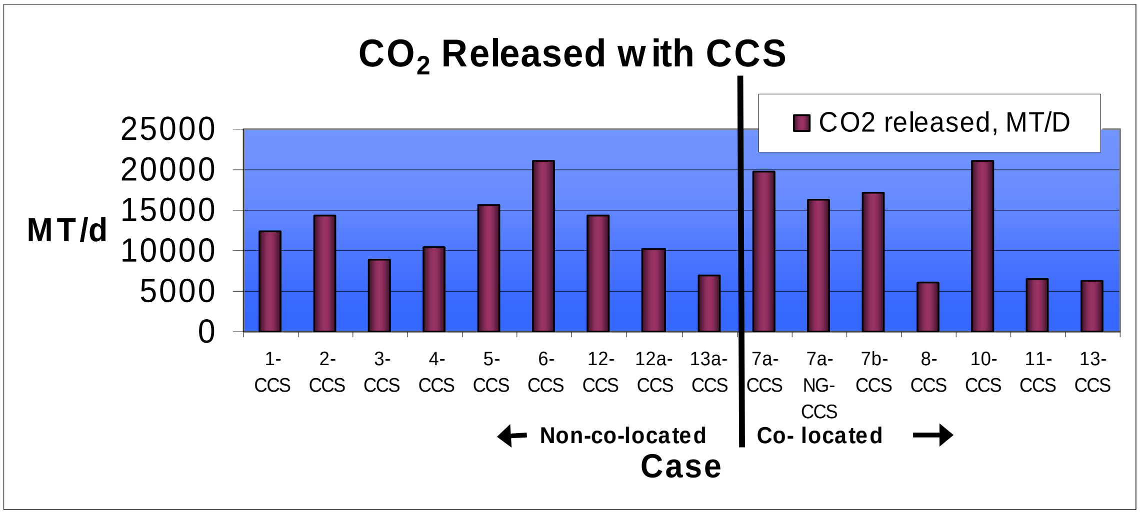
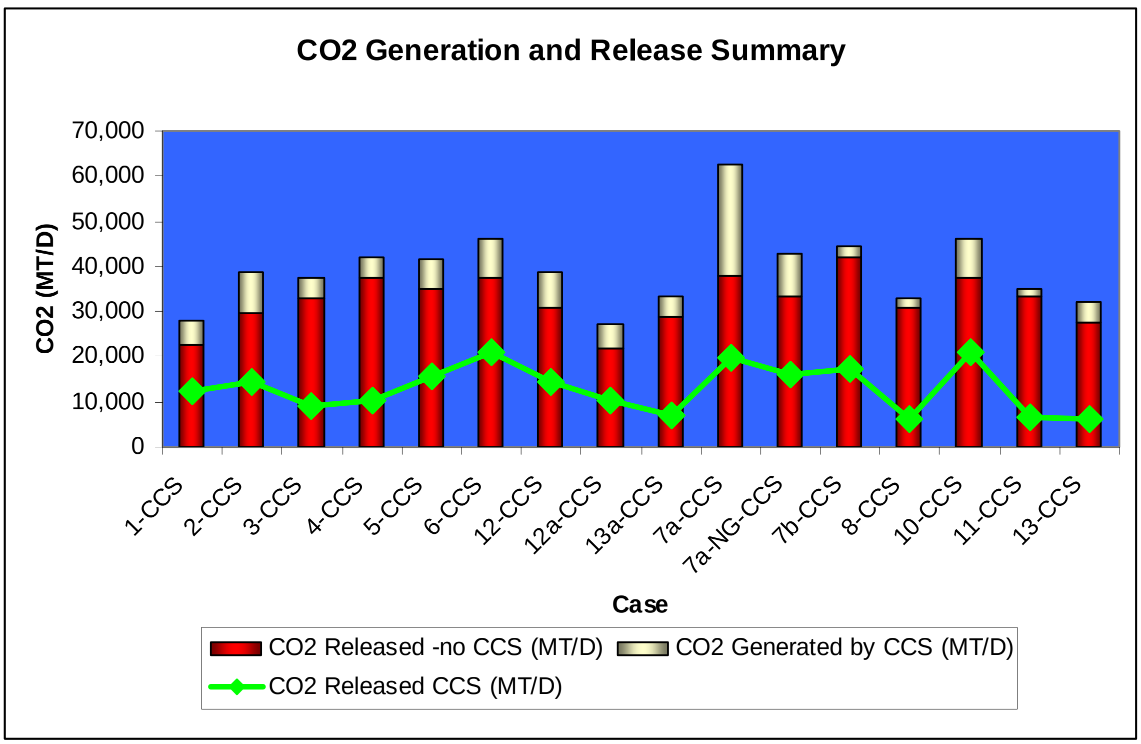


Figure A-5.
CO_2 Summary

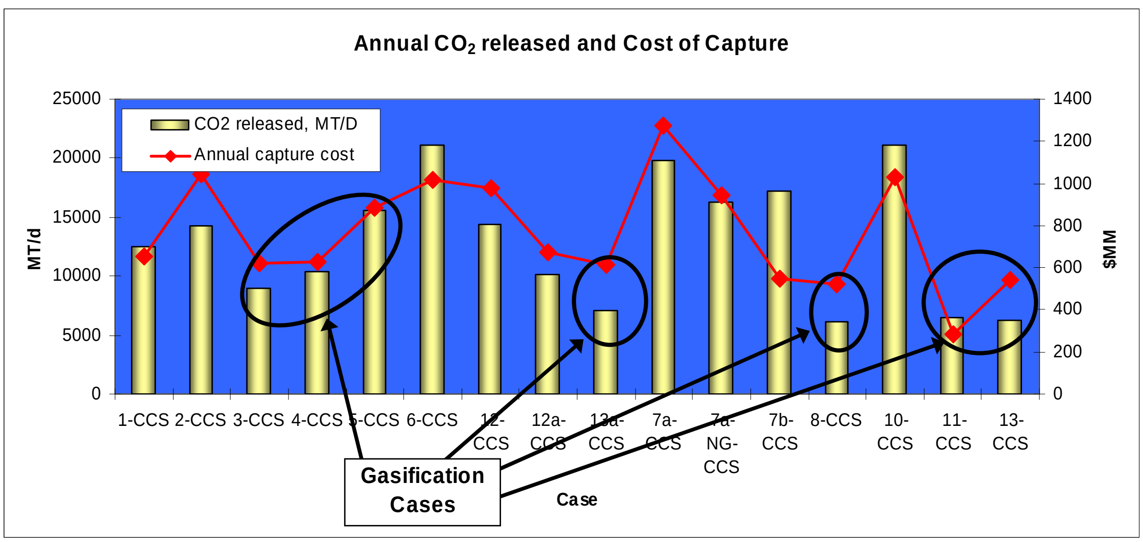


The key findings with respect to Figure A-4 and A-5 are as follows:

- The CO_2 released for the cases with gasification is invariably lower, as indicated by Cases 3, 4, and 8 (delayed coking), Cases 13 and 13a (ebullating bed HCK), and Case 11 (Solvent deasphalting/Thermal cracking). Case 5 is only slightly lower than Case 6 (slurry phase HCK) because the pitch volume is low; thus the gasification benefits are smaller.
- Again, co-located sites generally do not have lower CO_2 footprints than non-co-located cases, indicating little synergy from an emission standpoint between SAGD and upgrading.
- As indicated by comparing Case 3 (delayed coker with gasification) to Case 1 (delayed coker without gasification), the amount of CO_2 released is less with gasification than even landfilling the coke and despite the fact that nearly 50% more CO_2 is generated.

A more detailed look at CCS is shown in Figure A-6.

Figure A-6.
Annual CO_2 Released & Cost of Capture- $95/B WTI



The key findings with respect to Figure A-5 are as follows:

- The cases with the gasifier have a lower amount of CO_2 released and a lower annual cost of capture. This is true even when compared to Case 1—CCS (delayed coker, landfilling the coke).

- Case 5—CCS (slurry phase HCK with gasification) has a small amount of residue (about 5 wt% of the bitumen feed) and high hydrogen consumption, so the benefit of the gasifier is smaller from a GHG standpoint.

Opinions

Regarding the analysis of profitability and GHG emissions for SAGD bitumen production and Upgrading/Refining configurations, Jacobs Consultancy opines the following:

- CCS adds substantial cost to SAGD bitumen production and Upgrading/Refining operations regardless of the technologies employed or configuration used. Therefore, it is our opinion that there are modest return enhancements—including energy efficiency enhancements—that should be considered for CO_2 reduction before CCS.
- There is little CO_2 footprint benefit from integrating upgrading operations with SAGD in-situ production.
- Due to sustained location factor benefits for capital installed in Edmonton as opposed to remote SAGD sites, minimizing capital investment at the production site has better profitability.
- Higher conversion and therefore the minimization of resid from upgrading bitumen generally improve the profitability, especially at higher base crude and product prices.
- Although alternative fuels—particularly coke and pitch products—can be used for SAGD steam generation, economics favor gasification, especially if CCS is considered.
- An upgrading/refining sized gasifier in an Upgrader is economically neutral without CCS and slightly attractive with CCS.
- Gasification offers the best CO_2 capture potential.

Recommendations

Jacobs Consultancy recommends a focused approach for AERI to continue to accelerate the advancement of technology and work with other governmental and industry groups to support the following:

- Complete a study incorporating Life Cycle Analysis to identify more cost effective means at reducing CO_2 emissions in SAGD production and Upgrading/Refining operations than CCS, including energy efficiency improvements and technology development.

- Complete a feasibility study and consider cooperative investment in a gasifier targeted at providing hydrogen, petrochemical feedstocks and utilities for an upgrading complex or petrochemical cluster. Gasification offers the best current technology for the capture of CO_2, and the CAPEX can be minimized through economies of scale and provides a host site for the demonstration of new gasification technologies.

- As the market conditions change to favor upgrading, encourage industrial clusters because the synergy in utilities and infrastructure is greater among upgrading complexes than between upgrading and SAGD. This improves both the economics and CO_2 emissions.

- New technologies hold the key to managing the cost of CCS, both in terms of capture and sequestration technologies, but also in the development of upgrading technologies to maximize profitability despite the costs of CSS.

- Economically attainable CO_2 capture in terms of total CO_2 captured, CO_2 captured per unit of feed and product, and percent capture is impacted by technology selection. Therefore, CCS requirements need to take into account the constraints of the site in terms of residue disposition and upgrading technology.

- Finally, natural gas will continue to be the favored fuel for SAGD steam. Combusting upgrading residue for fuel is not cost competitive with natural gas and increases CO2 emissions as well as the costs for capture. Depending on natural gas prices and the capital cost environment, it may be economic to gasify upgrading residue for the hydrogen, power and petrochemical feedstocks and other industrial uses especially when CCS is required.