Impact of CCS Technology Study: Stage One Report

Prepared For

Alberta Innovates – Energy and Environment Solutions

June 2011

JACOBS Consultancy

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For Jacobs Consultancy

Ed Arnold **Rich Hill**

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Section 1.

Executive Summary

The Province of Alberta has been at the forefront of understanding environmental issues related to the development of the oil sands through several provincially-funded programs such as the Hydrocarbon Upgrading Demonstration Program (HUDP) and Life Cycle Analysis (LCA) and Carbon Capture and Sequestration (CCS) studies. In particular, the understanding and development of CCS represents both a major challenge and significant opportunity to the Province and its hydrocarbon industry.

Alberta Innovates – Energy and Environment Solutions ("AI-EES") in conjunction with the Alberta Minister of Energy ("ADOE") and Minister of Alberta Environment ("AENV"), retained Jacobs Consultancy Canada Inc. ("Jacobs Consultancy") and MK Jaccard and Associates ("MKJA") to identify and quantify the potential range of benefits, costs and risks associated with CCS to enable critical and informed decision-making regarding future investments in CCS. Jacobs Consultancy is providing quantitative and technical input parameters for economic modeling performed by MKJA. Both Jacobs Consultancy and MKJA are providing separate written reports to AI-EES. This report summarizes the technical and economic results from Jacobs Consultancy and should be used in conjunction with the separate report supplied by MKJA to fully understand the analysis.

The quantification of the costs and benefits of CCS is complex and involves a high level of uncertainty. The analysis takes into account a wide variety of factors including various scenarios regarding the cost of CCS, the expected timetable for the development and implementation of CCS, the expected demand for bitumen, the future cost of carbon emissions, and the various political and policy responses to greenhouse gas (GHG) emissions regulations in the future.

This study focused on quantifying the costs and benefits of implementing CCS based on the eight benefits that were identified in the RFP. This study does not address other potential benefits associated with CCS that are somewhat intangible and more difficult to quantify, such as:

- Continued license to enable the oil sands industry to grow
- Development of other GHG mitigation technologies and engineered solutions to reverse potential ongoing climate changes
- Development of goodwill within Canada, North America and the rest of the world

The Province of Alberta has laid out a climate change strategy that will reduce greenhouse gas emissions in the province by 50 megatonnes by 2020 and then by 200 megatonnes by 2050 through a combination of activities while maintaining economic growth. The plan calls for a combination of energy conservation and efficiency improvements, renewable energy production and CCS.

This study was undertaken in two stages. Stage One, the topic of this report, was a high-level, range-based analysis that quantified benefits, costs and risks in each area. The analysis took into account government policy and political factors, hydrocarbon market developments and balances, technology development and implementation costs, and risks and competitive pressures. This range-based analysis provided input into a sophisticated proprietary equilibrium economic model owned and maintained by MKJA. Based on the model inputs and analysis supplied by Jacobs Consultancy and output from the economic model, there is sufficient information for the Advisory Team to identify the most critical areas of study which could provide the highest potential benefit, and therefore those areas that will require more clarity and in-depth study.

Upon evaluation of this Stage One report and the accompanying Progress Workshop, the Advisory Team will decide if it wants to proceed to Stage Two. Stage Two will be completed under a separate agreement.

Potential Benefits

The RFP listed eight Potential Benefits to the implementation of CCS in Alberta. Due to the similarities in analysis for some of the benefits, we have collapsed the eight Potential Benefits into five study targets:

1. Benefit 1: Secure continued access to US markets
2. Benefit 2: Impact on value-added products
3. Benefit 4: CCS and CO_2-EOR
4. Benefits 3,5,6,7: Development of a knowledge-based industry
5. Benefit 8: Continued use of coal-based electrical generation in a carbon-constrained environment

Scenarios

Since the development of carbon regulations has a great deal of uncertainty, we have used three scenarios to provide a range of probable outcomes for the project. Both Jacobs Consultancy and MKJA used the three scenarios detailed in the IEA WEO 2010 report (IEA, 2010) in Stage One: Current Policies, New Policies and 450.

The Current Policies and 450 Scenario can be seen as bookends for the analysis. The Current Policies Scenario reflects a case in which no new regulations regarding carbon emissions are promulgated globally. The 450 Scenario represents a case in which very strong regulations are enacted to control carbon emissions. The target for these regulations will be to stabilize CO_2 concentration in the atmosphere at 450 ppm. The middle case, New Policies, takes a middle ground in which currently announced policies are enacted, yet not to their fullest level.

Each scenario also has a forecast of carbon prices, oil and gas prices and oil demand; these forecasts were used in the analysis of the impact of CCS.

Benefit 1: Secure Continued Access to US Markets

Non-Tariff Barriers

There are three potential non-tariff barriers to bitumen from Alberta: Cap-and-Trade on carbon emissions, the application of Best Available Control Technology (BACT) to reduce GHG from new or modified refining processes to handle bitumen or synthetic crude oil, and Low Carbon Fuel Standards (LCFS). While the first two non-tariff barriers, Cap-and-Trade and BACT, will not significantly affect bitumen sales, LCFS has the potential to significantly reduce bitumen sales.

A number of states and provinces as well as the EU have adopted or are considering adopting LCFS. The objective of LCFS is to reduce the carbon intensity (CI) of gasoline and diesel fuels over time by replacing petroleum-based fuels with alternative, lower carbon intensity fuels from biomass, compressed natural gas, electricity, *etc*. The California regulations are the most explicit and were the focus of this analysis.

Because bitumen and synthetic crude oil (SCO) are classified as HCICO under the California regulations, producers have three options to reduce the impact of these regulations:

1. Successfully petition the California Air Resources Board (CARB) to reclassify bitumen and SCO as non-HCICO, which allows the same CI values for gasoline and diesel as from other non-HCICO, more conventional crude oils. In its present form, LCFS classifies HCICO as delivered crudes with a CI greater than or equal to 15 g/MJ. This is the easiest approach and requires no GHG mitigation. CI data from SAGD in-situ bitumen production and from mining indicate that it should be possible to reclassify all mined bitumen and in-situ bitumen as non-HCICO provided that the SAGD steam-to-oil ratio (SOR) is 3 or lower. However, SCO from in-situ bitumen production will not meet non-HCICO CI requirements due to the additional CI impact of Upgrading.

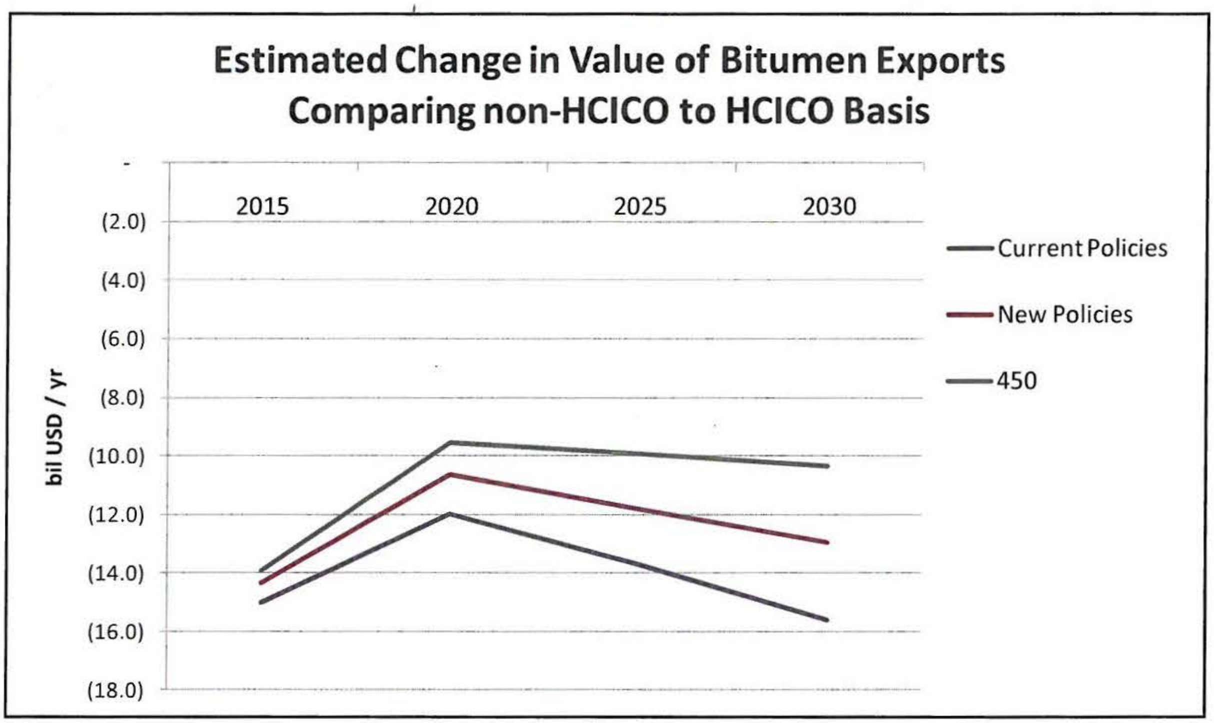
2. If CARB does not approve the reclassification of bitumen and SCO as non-HCICO, then carbon capture and storage can be considered to further reduce the CI of the delivered bitumen or SCO. Based on preliminary analysis, CCS installed in SAGD operations is sufficient to bring in SCO under the 15 g/MJ CI limit for non-HCICO.

3. If CARB does not approve bitumen and SCO as non-HCICO even after use of CCS to mitigate GHG from the production of bitumen, producers will have to develop new well-to-wheels (WTW) fuel pathways for bitumen and SCO to establish the CI for gasoline and diesel produced from them. In this case, CCS at the production facility will bring the CI from production of gasoline refined from diluted bitumen to roughly 95.9 g/MJ, which is equivalent to the LCFS simplification of 95.9 g/MJ for gasoline derived from non-HCICO crudes. For SCO, CCS would be required at both the production site as well as upgrading to achieve 95.9 g/MJ for gasoline.

The recommended approach is to successfully petition CARB to reclassify bitumen and SCO as non-HCICO so that the CI for gasoline and diesel fuel produced from them are the same as from other non-HCICO. Ideally, this reclassification can be done with little or no CCS. The long-term impact of LCFS is the severe supply reduction of hydrocarbon-based transportation fuels. Using CCS as a means to reduce the CI for gasoline and diesel produced from bitumen will put diluted bitumen (dilbit) on equal footing with other conventional crudes refined in the United States.

Depending on the IEA scenario as defined for this study, the difference in revenue back to Alberta is between US$10 and US$16 billion per year by 2030 for avoiding the reduction of bitumen export to the United States through implementation of CCS.

Figure 1-1.



Estimate of CCS Costs

We estimated costs on a Direct Avoided basis for four of the five main major sources of CO_2 in Alberta:

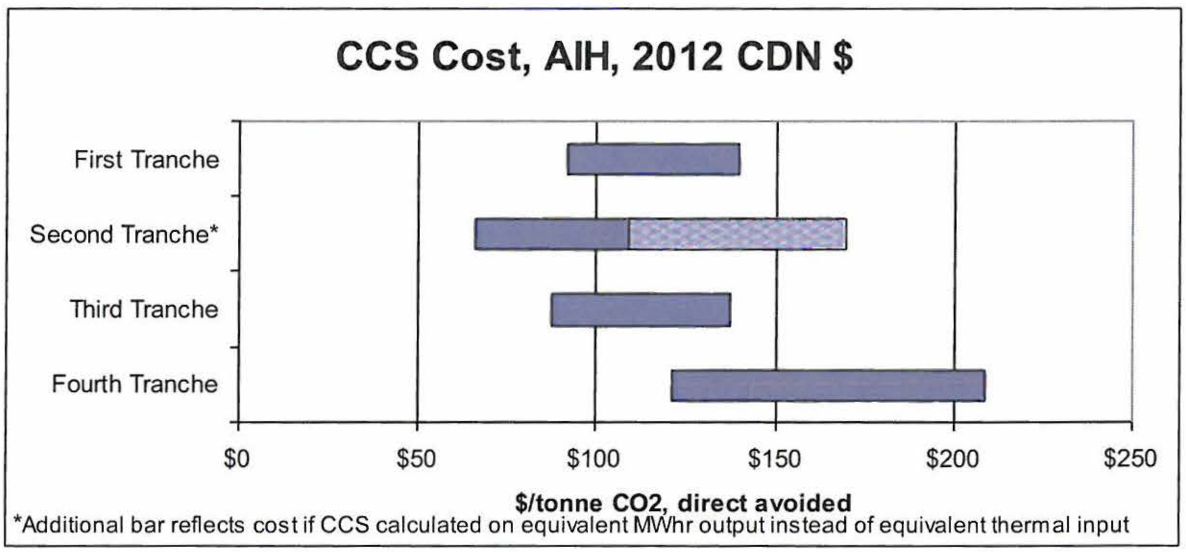
- *Tranche 1—CO_2 produced on the process side of a Steam Methane Reformer (SMR)*: A concentrated stream of CO_2 is produced in an SMR and can represent 25-30% of total CO_2 in a delayed coker-based upgrader.
- *Tranche 2—Post combustion capture from Natural Gas Combined Cycle (NGCC) power plants*: Due to the lower overall emissions and assumptions given in publicly available information, NGCCs have lower overall Avoided costs than coal-based plants. However, revising costs to an equivalent power production basis increases costs dramatically.
- *Tranche 3—Post combustion capture from coal-based and NGCC power plants*: A conventional coal power plant produces 2.3 - 2.5 times as much CO_2 as an NGCC per MW when thermal efficiency is taken into consideration.
- *Tranche 4—Steam Assisted Gravity Drainage (SAGD) steam production*: CO_2 sources consist primarily of large natural gas-fired boilers to produce steam for SAGD. A SAGD

facility producing 90,000 BPD of bitumen will generate about the same CO_2 as a single 500 MW natural gas combined cycle (NGCC).

- *Tranche 5—Smaller process heaters in Upgrading and Refining complexes*: Depending on the type of crude processed and the processing severity, miscellaneous process heaters including the SMR flue side produce approximately 50% of the total CO_2 emissions. We did not include Tranche 5 in the overall analysis of the economic benefits to Alberta for CCS based on the high relative costs and low overall contribution to Alberta's GHG emissions, currently estimated at 10 - 15 percent.

Figure 1-2 shows the range of CCS costs on a Direct Avoided basis for each tranche. The wide range of costs reflects the variation in the ease of capture for these streams as well as a large degree of uncertainty regarding the capital costs associated with CO_2 capture. A high level approximate cost breakdown of the estimated CAPEX and OPEX costs for each tranche can be found in Appendix 3.

Figure 1-2.



*Additional bar reflects cost if CCS calculated on equivalent MWhr output instead of equivalent thermal input

Benefit 2: Impact on Value-Added Industries

Impact on Gasoline and Diesel

To determine the impact on gasoline and diesel, we compared the effect of CCS investment in gasoline and ultra low-sulphur diesel (ULSD) producing refineries, in Alberta versus US

PADD 2. We used the three regulatory scenarios as the basis for fuels and energy prices and carbon tax levels.

US PADD 2 was chosen as the basis for comparison to Alberta production because PADD 2 is currently the largest market for Canadian bitumen. Furthermore, we expect that it will continue to be the largest US market for Alberta bitumen and (perhaps) Alberta-produced refined products for some time, until pipeline access to PADD 3 and other offshore markets is improved. This is due to the existence of multiple Alberta-to-PADD-2 pipelines and refineries in PADD 2 that can process dilbit into gasoline and ULSD. The next largest markets for Canadian bitumen are PADD 3 and PADD 4 refineries, and, within the accuracy of this study, the PADD 2 financial analysis will be a reasonable proxy for these districts as well.

Operating in a market environment as defined by the three IEA scenarios, CCS investment will, in the long run, not improve the market position of Alberta-produced gasoline and distillate. The Alberta feedstock advantage cannot compensate for the effect of a high capital cost investment in Alberta competing with installed refinery assets in PADD 2. If carbon taxes incentivized the installment of CCS technology in Alberta, they would do the same for a PADD 2 refinery.

Impact on Petrochemicals—Ethylene, Propylene and Ammonia

Jacobs Consultancy completed a project for AI-EES in July 2010 (Centralized Gasifier Study) regarding the economics of implementing a petroleum coke (petcoke) gasification complex in the Alberta Industrial Heartland (AIH). The economics of the project showed that such a complex would not be economic without reductions in the cost of the gasification complex. The study looked at a complex that could make various outputs including power, hydrogen, methanol and urea.

This Stage One study looked at the gasification complex as envisaged in the previous study but investigated the economics of manufacturing olefins and ammonia in the complex. The study examined the economics under the three IEA scenarios and compared the cost of production of olefins via petcoke gasification to methanol to olefins with CCS as compared to conventional olefin production. The study also examined the economics of ammonia production under the three IEA scenarios with the implementation of CCS.

None of the other potential products studied in the polygen gasification complex were significantly impacted by high CO_2 prices; therefore, the relative economics of petcoke gasification are largely determined by the price of natural gas and the capital cost of gasification.

The analysis showed that only in the scenario where there are high carbon prices and high gas prices is it less expensive to produce ammonia via the petcoke gasification route. However, the regional market for ammonia does not have sufficient capacity to absorb the incremental capacity from a new ammonia manufacturing facility. The scenario in which the high gas and carbon prices exist is in the 2035 time period; therefore, there is no near- to medium-term scenario in which the petcoke gasification route to ammonia would be economic, unless new gasification technology is commercialized, which substantially lowers the capital cost associated with a gasification complex. In addition, traditional ammonia production from natural gas produces a concentrated CO_2 stream on the process side, which can be considered a relatively low cost, Tranche 1-type stream for CCS.

Under all of the IEA scenarios, petcoke gasification to olefins is not cost competitive as compared to olefins cracker-based economics due to the high carbon intensity of the syngas and MTO process, the high cash cost of production using a methanol feedstock, and the capital intensity of the MTO process.

Other Markets for CO_2

With the anticipated significant increase in CO_2 available due to CCS, novel ways to use CO_2 as a chemical feedstock, in the production of biofuels from algae or as a feedstock for the production of fuels are being researched. These efforts are for the most part in the early stages of commercialization; no significant commercial activity is anticipated for approximately 10 years. For these technologies to have a significant effect on the economics of CCS they would need to be able to offtake CO_2 in quantities large enough to have a material impact on the CCS unit economics. At this time, none of the projected technologies are foreseen to have that impact. The largest volume application is in CO_2-EOR, and that opportunity is relatively small compared to the potential volumes of CO_2 that will need to be sequestered. Deployment of CCS will require a higher carbon market price than is anticipated for the economic deployment of the novel applications that are currently being developed.

In addition, regulations must be developed that would enable the CCS producer to gain credits for the sale of CO_2 into reuse applications. If these applications do not provide permanent storage of CO_2, then the CCS operator may be able to get the full credit for sequestering the carbon captured.

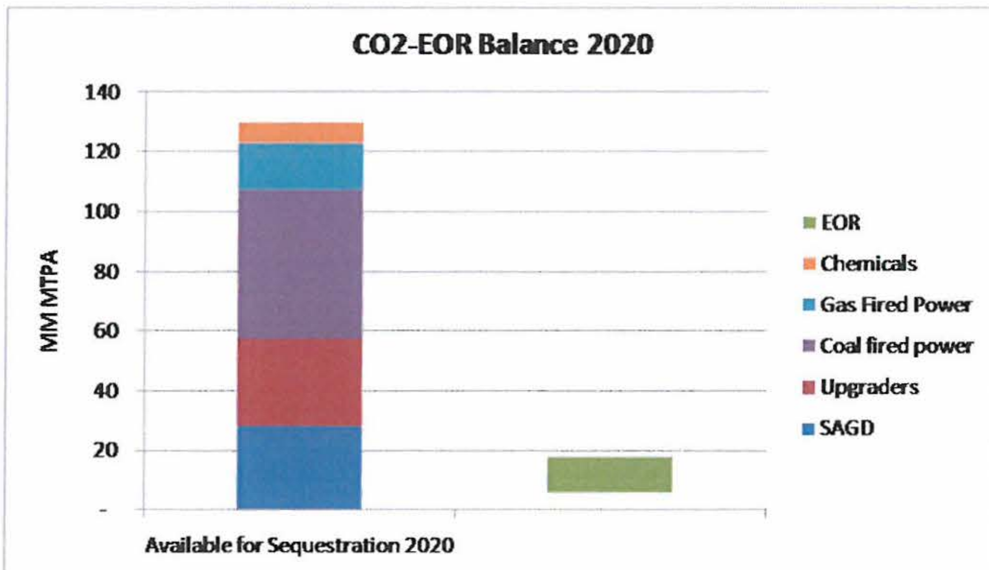
Although these applications do not create an opportunity to materially improve CCS economics, there may be the potential for small niche markets in construction materials or specialty chemicals that use low-cost CO_2 as a feedstock that could be developed in Alberta.

Benefit 4: CCS and EOR

Alberta has significant conventional oil deposits that are amenable to secondary or tertiary development through CO_2-EOR. This report examines the potential benefit to Alberta from two different viewpoints: the possibility of improving CCS economics through the sale of CO_2 to an EOR operator, or the possibility of enabling EOR projects through the supply of readily available, low-cost CO_2.

Jacobs Consultancy developed a balance of potential CO_2 supply from CCS and potential CO_2 demand from EOR. The balance shows that there is much more potentially available CO_2 to be sequestered than there are potential viable CO_2-EOR pools. If CCS is adopted in Alberta across all major carbon-emitting sectors, there will be a much greater supply of CO_2 than the demand for CO_2-EOR projects. With an oversupply of CO_2, it is projected that the price of CO_2 for EOR projects will be driven down within a relatively short time. Therefore, from a supply standpoint, we opine that the resulting CO_2 price would not significantly impact the producer's overall economics of CCS.

Figure 1-3.



However, the supply of low-cost CO_2 has the capability to increase the use of EOR in Alberta. Currently, CO_2 costs are approximately 20 - 25% of total costs for an EOR producer. Reducing the cost of CO_2 can substantially improve EOR project economics, but perhaps even more importantly, the availability of a consistent supply of CO_2 could provide an incentive for a number of CO_2-EOR projects to go forward.

Studies conducted for AERI have shown a range of potential incremental oil production in Alberta of 1,080 – 1,700 million barrels produced using CO_2-EOR. If we assume an average project life of approximately 30 years, that would be the equivalent of 100 – 155 thousand barrels per day of incremental oil. Using the CO_2 storage factors of 0.17 – 0.32 MT CO_2/barrel of oil, this is equivalent to a total potential CO_2 stored of 180 – 540 MM MT CO_2.

Total costs for an EOR unit are estimated to range from 23 - 38 $/bbl of incremental oil produced, depending largely on economy of scale and ease of implementation. From a capital standpoint, key equipment includes separation facilities to separate the CO_2 from the oil, CO_2 compressors and injection wells. Operating costs involve power for compression, CO_2 costs, well lease and maintenance costs.

The costs of production and total incremental oil data have been shared with MKJA and will be input into their model. The MKJA model will forecast the total incremental barrels of oil produced by EOR.

Benefit 3, 5, 6, 7: Technology Cluster Development and Job Creation

Globally, the market for CCS technology is forecast to grow substantially in the timeframe of this report. Current estimates for total global spending on CCS from 2015 – 2035 are $4.2 trillion for the New Policies scenario and $2.1 trillion for the 450 Scenario. Technology and engineering supply represent approximately 10 – 15% of CCS CAPEX; of that, technology licensing costs are typically a small percentage. We have estimated global technology and engineering supply for the period of 2015 – 2035 to be $250 - $375 billion for the New Policies Scenario and $120 - $200 billion for the 450 Scenario.

CCS spending in Alberta is forecast to be $45 billion from 2015 – 2035 with spending on services estimated to be $2 – 3 billion. It is likely that most of this would be spent in Alberta for the Province. There is not a substantial difference in the total spending for the New Policies or 450 Scenarios; however, the spending is forecast to occur earlier in the 450 Scenario than in the New Policies Scenario.

The market for providing CCS technology, engineering and services is a global market with many large multinational firms currently providing services. No single firm has emerged as a market leader. The global nature of the provision of technical services and the highly competitive nature of this market make it difficult for specific regions to create a long-term competitive advantage. Engineering firms will source man-hours from low-cost regions for low value-added services and will source technology and know-how from the sectors where the know-how resides, regardless of the geographical location.

Alberta firms are disadvantaged when competing for technology supply in a global market, due to:

- Relatively high engineering rates related to high internal demand of engineering skills
- Dissimilar technical focus to coal-focused areas such as Australia, US, UK, and EU
- Strong funding support for coal-fired power plant-related CCS from other nations
- Multiple technology clusters in existence with extensive public/private/university involvement

However, with regard to implementing CCS for the processes associated with the production of unconventional heavy oil, Alberta firms will have a competitive advantage over foreign firms for supply of engineering know-how due to:

- SCO and bitumen production-specific know-how
- Strong support from regulatory and government agencies related to heavy oil
- Experienced technology transfer agents through research-oriented universities
- In-depth knowledge of oil sands industry

Worldwide, it is difficult to estimate the amount of CCS that will be installed to reduce emissions for heavy oil production, upgrading and refining, but it is likely to be a small percentage of the total CCS investment given the dramatic difference in the global scale of fossil fuel-fired power generation as compared to heavy oil production in Alberta, Venezuela and China.

Benefit 8: Coal-Fired Power in Alberta

Approximately 55% of power currently generated in Alberta comes from coal. Thirty-six percent comes from natural gas, 3% from hydro and 6% from other sources (such as wind). Carbon reduction legislation will result in coal-fired power plants being required to address their carbon outputs. Depending on the form legislation takes, power producers have a few alternatives:

- Replacement of older, less-efficient plants with state-of-the-art plants
- Fuel switching to lower-carbon intensity fuels such as natural gas
- Increased reliance on renewables
- Carbon permit purchase (cap-and-trade or other similar mechanisms)
- CCS to reduce carbon emissions from their plants

These choices will be determined by:

- Cost of carbon permits and timetable for implementation
- Cost and timeframe of CCS implementation
- Cost of new coal-fired power plants and the extent of efficiency gain
- Cost of fuel switching and extent of carbon reduction required
- Availability and cost of renewables
- Level of projected increase in electricity demand
- Projected lifespan of existing power generation facilities

The Energy Resources Conservation Board (ERCB) forecasts a declining dependence on coal as power generated from natural gas and renewable sources gains in the generating mix.

Based on CCS costs and typical coal-fired power plants efficiencies, for new units, CCS is estimated to add 50 - 60 $/MWH to the cost of producing electricity in Alberta from coal-fired power plants. Increasing the cost of power based on coal-fired generation facilities would be a further reduction in the fraction of the total power generated that would be supplied via coal-fired power generation. Retail prices for electrical power in Alberta have ranged from 50 - 150 $/MWH over the past three years; therefore, if all CCS costs were passed on to the consumer, retail electricity prices could increase significantly.

If the carbon prices are such that coal-based power plants are required to implement CCS, then natural gas power plants must also implement CCS. Depending on the source and carbon footprint of the power capacity lost in implementing CCS, estimated CCS costs for new natural gas-based power plants could be lower on an Avoided basis, and certainly, the emissions/KWh are much lower. Therefore, natural gas power plants have a lower cost burden for CCS than coal-based power plants. The estimated additional cost of electrical power generation from a natural gas plant is 30-40 $/KWh.

Another option for reducing the amount of CO_2 produced for power generation is to replace existing coal-fired power plants with natural gas-fired power plants. Based on our analysis of the publicly available data, NGCC plants without CCS cost on the order of 60-70 $/MWH and, on an Avoided basis, offer 55-60% of the CO_2 reduction at a cost similar to installing a new coal facility with CCS. Although installing an NGCC without CCS provides a lower technical and cost risk, it is susceptible to market risks related to natural gas prices.

Finally, in our opinion, the additional cost burden of CCS on fossil fuel-based power generation will reduce demand for power overall and will stimulate demand for power generation from renewables.

Jacobs Consultancy has provided CCS cost information for power generation to MKJA, whose modeling work will forecast the changes in the power generation mix in Alberta as a result of carbon emission reductions regulations.

Summary

Jacobs Consultancy analyzed the potential implementation of CCS in Alberta in a range-based scoping study with the goal of identifying scenarios and quantifying inputs to be used in an economic model developed by MKJA. The analysis considered three business scenarios as outlined in the IEA World Oil Outlook 2010 (IEA, 2010): Current Policies, New Policies and 450 Scenario. These scenarios provided a broad range of possible carbon regulatory environments and corresponding forecast energy and carbon prices.

Besides the business scenarios selected, the primary inputs into MKJA's economic model are as follows:

- The costs of implementing CCS—Four tranches of implementation were selected to provide ranges of costs to be used in the model.
- The amount of CO_2 available for capture—For each of the four tranches, a percentage of Avoided CO_2 was provided along with the total CO_2 avoided.

- The costs required for the implementation of EOR
- The costs associated with installing additional upgrading and refining capacity in Alberta in comparison to PADD 2 CCS implementation

In addition to the model inputs, Jacobs Consultancy provided MKJA with our analysis of the potential impacts of LCFS; coordinated assumptions regarding industry knowledge and technology learning rates; and provided a review of MKJA's preliminary forecast.

In addition to the inputs required for the economic model, our analysis indentified the following preliminary conclusions regarding the potential benefits of CCS in Alberta:

Table 1-1.
Summary of Impacts of CCS in Alberta

Benefit 1 **Continued Access to US Markets**	If LCFS is broadly implemented with regulations similar to the current California regulations, CCS could be part of the process that enables bitumen-derived crudes to be categorized as non-High Carbon Intensity Crudes. This could prevent a \$10 to \$16 billion loss in revenue for Alberta bitumen exporters by 2030.
Benefit 2 **Value-Added Industries**	Due to the high capital cost of investing in capacity to add value to bitumen-derived feedstock, CCS was not found to have a positive impact on the economics of gasoline, ULSD, ethylene, propylene or ammonia production in Alberta. Small niche markets with early stage technology development programs were identified for alternate CO_2 uses.
Benefit 3,5,6,7 **Technology Cluster Development and Job Creation**	Alberta firms were determined to have a strong competitive advantage for providing technology and engineering know-how for domestic CCS or export projects that are associated with heavy oil. Alberta firms were not found to have a strong advantage for technology, engineering and service export for sectors outside those involved in heavy oil.
Benefit 4 **EOR**	Sales of CO_2 to EOR will not provide a long-term sustainable economic benefit to the CCS operator. Readily available quantities of low-cost CO_2 are forecast to spur new EOR project development.
Benefit 8 **Impact on the Coal-Fired Power Plant Industry**	CCS will substantially increase the cost of both coal-fired and natural gas power generation. It is likely that the development of CCS will cause demand destruction and a change in the electrical generating mix to include more renewables.

Section 2.

Introduction

The Province of Alberta has been at the forefront of understanding environmental issues related to the development of the oil sands through several provincially-funded programs such as the Hydrocarbon Upgrading Demonstration Program (HUDP) and Life Cycle Analysis (LCA) and Carbon Capture and Sequestration (CCS) studies. In particular, the understanding and development of CCS represents both a major challenge and significant opportunity to the Province and its hydrocarbon industry.

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- Continued license to enable the oil sands industry to grow
- Development of other greenhouse gas (GHG) mitigation technologies and engineered solutions to reverse potential ongoing climate changes
- Development of goodwill within Canada, North America and the rest of the world

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Scenarios

Since the development of carbon regulations has a great deal of uncertainty, we used three scenarios to provide a range of probable outcomes for the project. In agreement with the Steering Team, the three scenarios detailed in the IEA WEO 2010 report were used in Stage One of this study.

Assumptions across Scenarios

The IEA has assumed that GDP growth rates are consistent across scenarios. There are uncertainties surrounding the relationships between policy-driven changes in energy-related investment, the impact on climate change and the pace of economic growth. To simplify the analysis, it is assumed that GDP growth rates are consistent across scenarios. IMF projections were used for the growth rates to 2015. The underlying GDP growth forecast assumes that the global economy grows at 4.4% per year (on average) over the five years from 2010 to 2015. Over the long term, growth rates will slow to 3.1% during the period of 2015-2035.

Population growth is also assumed to be consistent across the scenarios. The underlying population growth rates in the scenarios are the UNPD (2009) projections. World population is expected to grow 0.9% on average to 2035, with growth slowing progressively throughout the forecast period. Population growth is overwhelmingly in non-OECD countries. Another major trend is the movement from rural areas to urban areas.

Scenario-Specific Assumptions

Table 2-1 summarizes the underlying assumptions for each scenario as outlined by the IEA. The Current Policies and 450 Scenarios can be seen as bookends for the analysis. The Current Policies Scenario reflects a case in which no new regulations regarding carbon emissions are promulgated globally. The 450 Scenario represents a case in which very strong regulations are enacted to control carbon emissions. The target for these regulations will be to stabilize CO_2 concentration in the atmosphere at 450 ppm. The New Policies Scenario takes a middle ground in which currently-announced policies are enacted yet not to their fullest level. Table 2-2 shows the regional targets by 2020 for each scenario.

The scenarios are also broken down by region with the assumption that countries will align their emissions regulations with other countries in the same region or development status. The EU leads the scenarios in terms of establishing carbon prices, but OECD carbon prices eventually merge with EU standards in the New Policies and 450 Scenarios. Other major economies include China, India and Brazil. Table 2-2 outlines the national emissions targets that underlie the New Policies and 450 Scenarios.

Each scenario also has a forecast of carbon, oil and gas prices and oil demand; these forecasts were used in the analysis of the impact of CCS. A number of assumptions are contained within the IEA scenarios, including:

- Natural gas supply, demand and pricing
- Disparities between natural gas and oil prices
- Reduction in crude demand due to carbon legislation and policies
- Changes in nuclear power policy
- Carbon prices
- Timing of the implementation of carbon legislation and policies and the effect on carbon markets
- Ability of nations to implement a consistent multi-country approach to GHG mitigation strategy or legislation

For this stage of the analysis, the IEA assumptions were assumed to be correct and we did not test the sensitivity of the analysis to changes in these assumptions.

Table 2-1.

Scenario	Policy	Fossil Fuel Subsidies	Implementation of Carbon Markets	Other
Current Policies	Only those regulations that have been formally adopted by mid-2010	Phased out in countries that already have policies in place to do so	No further implementation of carbon markets	
New Policies	Cautious implementation of currently announced policies to reduce GHG emissions	Consumption subsidies fully removed in importing regions where specific policies have already been announced	OECD countries establish a harmonized emissions cap-and-trade scheme covering the power and industry sectors	Extension of nuclear power plant lives by 5 – 10 years on a plant-by-plant basis For 2020-2035, additional measures that maintain the pace of global decline in carbon intensity from 2008-2020 such as LCFS and vehicle fuel economy standards
450 Scenario	Full implementation of the high-end of national policies and stronger policies after 2020 Intent is to limit CO_2e concentration in the atmosphere to 450 ppmv	Fully phased out by - 2020 in net importing regions - 2035 in net exporting regions (except the Middle East where subsidization rates decline to 20% by 2035)	Cap-and-trade systems in the power and industry sectors from 2013 in OECD+ and after 2020 in Other Major Economies International sectoral agreements with targets for iron, steel and cement industries	International agreements for fuel economy standards for light duty vehicles, aviation and shipping National policies and measures such as building efficiency standards

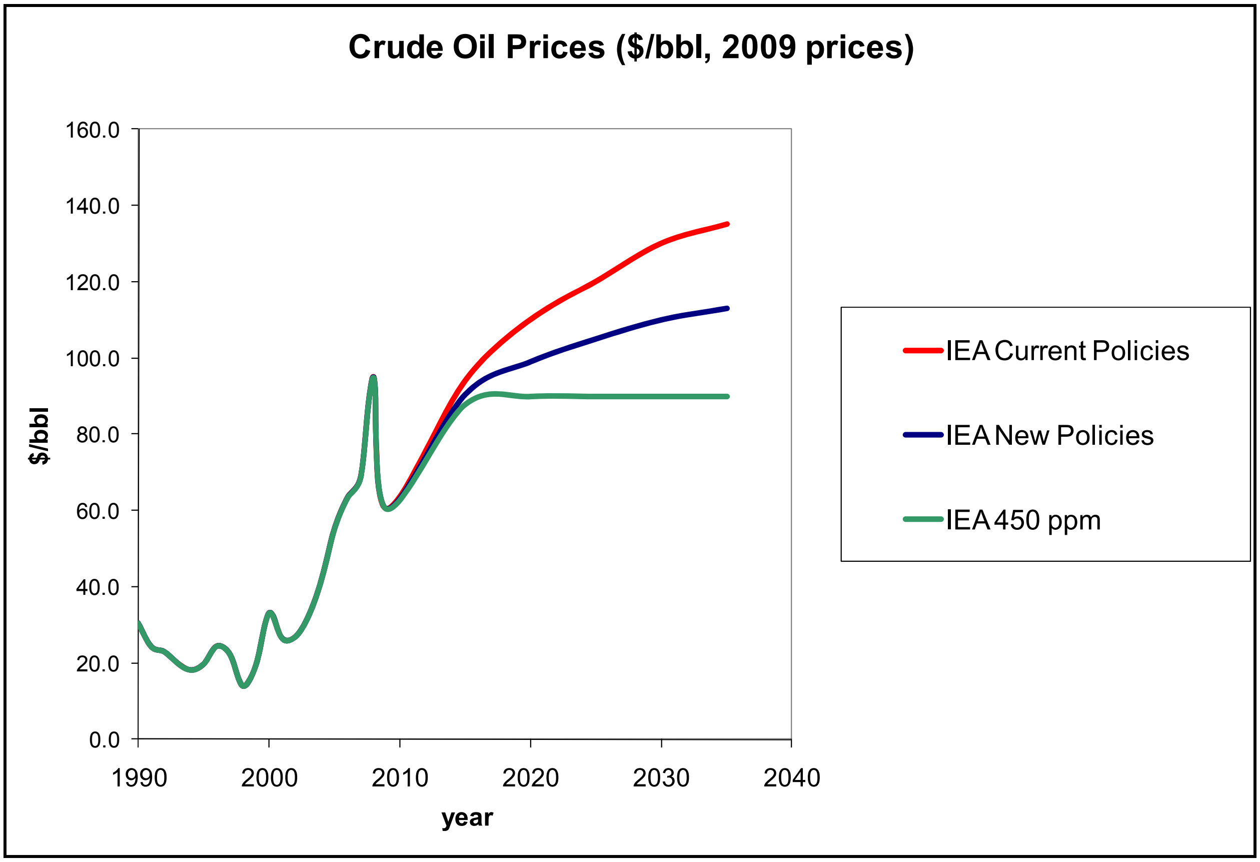
Table 2-2.
Regional Targets by Scenario

Region	New Policy	450
US	15% share of renewable	17% reduction in GHG compared with 1990
Japan	Implementation of New Energy Plan	25% reduction in GHG compared with 1990
EU	25% reduction in GHG compared with 1990	30% reduction in GHG compared with 1990
Russia	25% reduction in GHG compared with 1990	25% reduction in GHG compared with 1990
China	40% reduction in CO_2 intensity as compared to 2005	45% reduction in CO_2 intensity as compared to 2005
India	20% reduction in CO_2 intensity as compared to 2005	25% reduction in CO_2 intensity as compared to 2005
Brazil	36% reduction in GHG compared with BAU	39% reduction in GHG compared with BAU

Pricing by Scenario

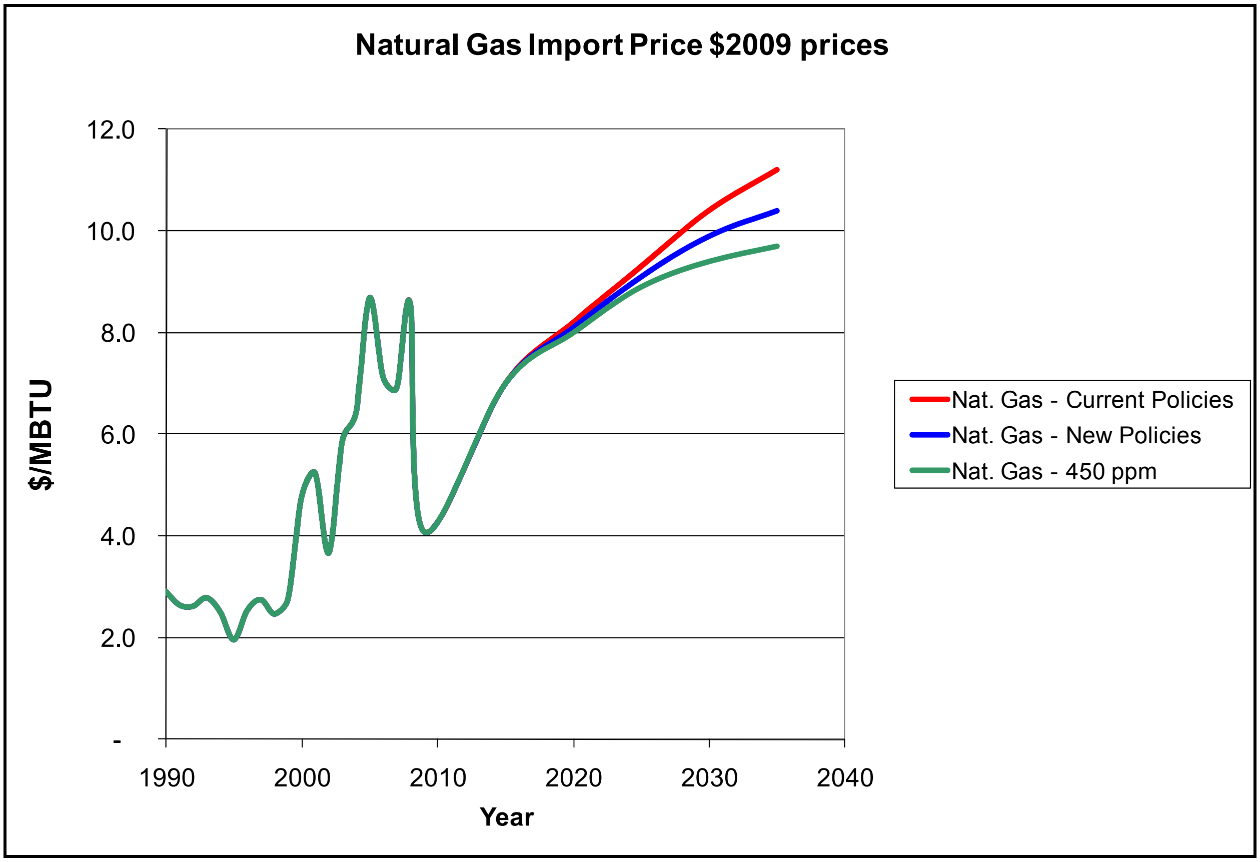
In each scenario, the different assumptions create a different set of oil, natural gas, and CO_2 prices. The following charts show the price sets for each scenario. Crude oil prices are expected to level out in the 450 Scenario due to the declining demand for fossil fuel-based energy in a highly carbon-constrained environment. Natural gas prices are less sensitive to assumptions regarding carbon legislation; however, the prices do tend to be higher than other industry forecasts for natural gas prices. CO_2 prices are a forecast of CO_2 pricing in an economy where there are cap-and-trade or other market-based systems in place to value CO_2. The assumptions in the 450 Scenario lead to significantly higher CO_2 prices.

Figure 2-1.
Crude Oil Prices by Scenario



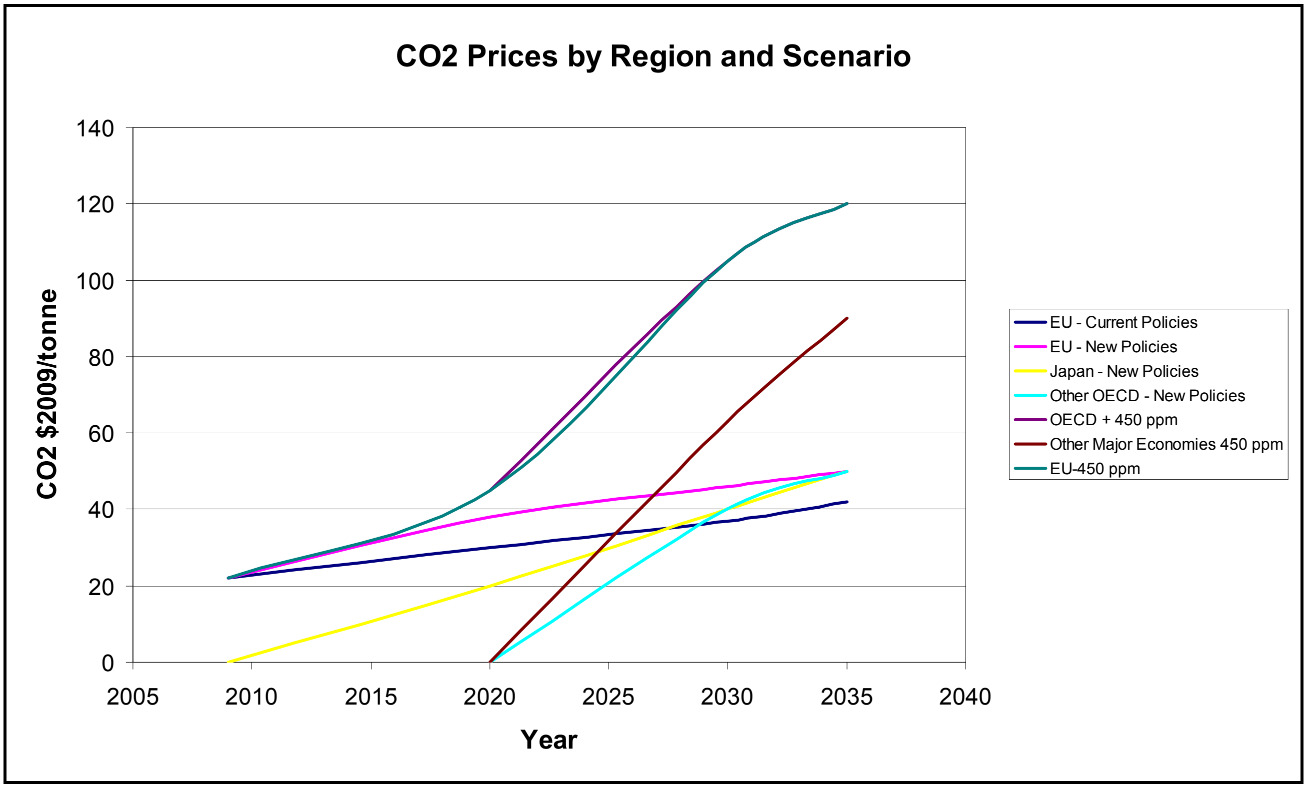
Source: IEA, 2010

Figure 2-2.
Natural Gas Prices by Scenario



Source: IEA, 2010

Figure 2-3.



Source: IEA, 2010

Methodology

The analysis has been done as a differential cost analysis that does not take into account the time value of money, financing effects or tax effects. The upside of a “point in time” differential cost analysis is that it provides a quick look at relative costs. Since we are selling identical products into the same market, looking only at differential costs and ignoring revenues is a reasonable “first pass” evaluation measure. This type of forecast also allows us to ignore forecasts for products values. In addition—and in particular to this study—this type of analysis exempts us from having to extrapolate the IEA market forecast and tax values beyond their singular date estimates. A key downside of a differential cost analysis is that it ignores the time-based value of money.

Investment in CCS

We have assumed that regulations will be in place that will allow firms to meet their carbon emissions reduction targets by paying a carbon tax or participating in a cap-and-trade market. Under this assumption, emitters will not build CCS facilities until the cost of the tax or the price of a carbon credit is more than the cost of building the CCS unit. We have also assumed that some reduction in CCS costs will take place over time and that emitters will choose to build facilities in advance of carbon tax reaching a price that is higher than the cost of implementing CCS. Table 2-3 summarizes where, in each scenario, CCS investment is considered.

In the IEA analysis, OECD nations are broken down into three categories:

1) EU
2) North America
3) Japan

The carbon prices for the IEA scenarios referenced in this report are those prices associated with OECD North America. We have assumed that the Canadian and US governments will implement aligned GHG regulations due to the close economic relationship between the two countries. The Canadian federal government has announced in the past that Canada will align its GHG regulations with that of the Unites States. Since Canada has a resource-intensive, export-oriented economy, carbon taxes and regulations that are more stringent than those in the US could cause increased costs for the Canadian energy supplier to the United States. Alternatively, Canadian energy suppliers that do not meet US regulations (such as LCFS) could be penalized when energy is supplied into US markets.

Table 2-3.

	Carbon Prices (from the IEA scenarios, for OECD countries, modified to include Alberta's current $15/MT carbon tax)			
	2012	**2020**	**2030**	**2035**
Current Policies Scenario	15	15	15	15
New Policies Scenario	15	15	40	50
450 Scenario	15	45	105	120
	CCS Investment in Alberta (made just in time to protect against effect of carbon regulations)			
Current Policies Scenario	No	No	No	No
New Policies Scenario	No	No	Yes	Yes
450 Scenario	No	Yes	Yes	Yes

Section 3.

Securing Access to US Markets

Estimating the Value of Non-Tariff Barriers

There are three potential non-tariff barriers to bitumen from Alberta: Cap-and-Trade on carbon emissions, the application of Best Available Control Technology (BACT) to reduce GHG from new or modified refining processes to handle bitumen or synthetic crude oil, and Low Carbon Fuel Standards (LCFS). While Cap-and-Trade and BACT will not significantly affect bitumen sales, LCFS has the potential to significantly reduce bitumen sales.

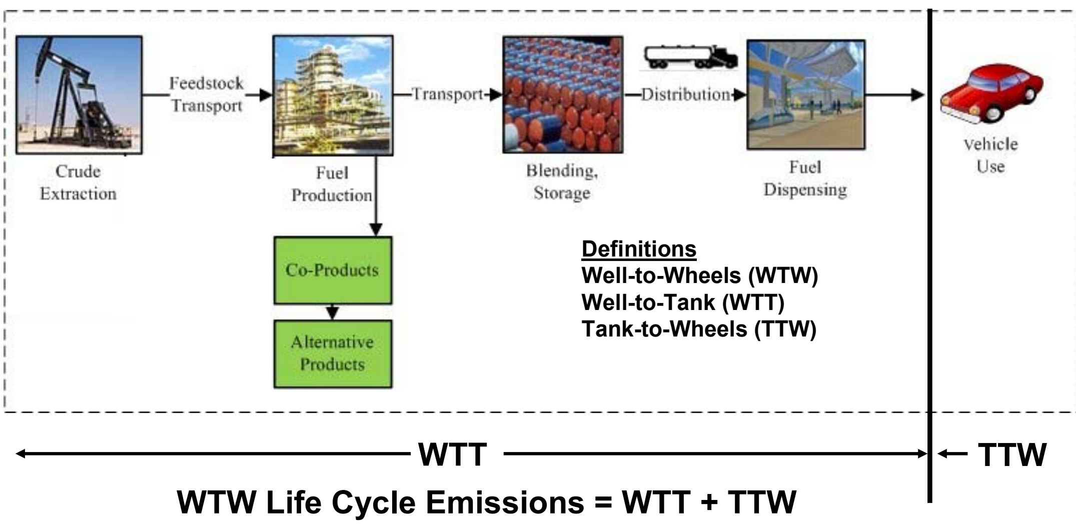
Cap-and-Trade regulations require sources of GHG to reduce emissions over time by either physical reduction in emissions or the purchase of credits to offset GHG emissions. In the case of refining, Cap-and-Trade could require refiners to increase the energy efficiency of their operations, process lighter crude oils, or buy GHG credits from other entities. Cap-and-Trade affects emissions from the refinery but does not specifically address how the crude is produced. Refinery emissions are typically higher when processing heavier crudes and, as a result, there may be some price impact on heavier crudes to offset the need to purchase or generate more carbon credits. Cap-and-Trade regulations are part of the California regulations reducing GHG emissions but are not yet a part of US federal regulations (California Cap-and-Trade Program, HR 2454).

As defined by the US EPA, GHG BACT applies when new sources of GHG emissions increase by more than 100 KT/yr or modified sources increase GHG emissions by more than 75 KT/yr (Federal Register). In most refineries, modest changes—for example, a new 15 MM standard cubic foot per day (SCFD) steam methane reforming hydrogen plant—will trigger a BACT review as part of the permitting process. In practice, BACT will focus on ensuring that the most energy-efficient designs are used by refiners. It is not anticipated that carbon capture and storage (CCS) will be implemented for the foreseeable future as part of GHG BACT until infrastructure issues, such as safe transport and storage, are resolved and the costs for CCS are significantly reduced. Most refinery expansions/modifications to process Canadian bitumen and SCO are likely to trigger GHG BACT. However, GHG BACT is not expected to significantly affect the crude choice by refiners because, in general, the economic advantage of processing lower-cost bitumen and SCO relative to other more expensive crudes will overwhelm the need to evaluate and apply BACT for GHG.

The impact of the Low Carbon Fuel Standards is different and could significantly affect sales of Canadian bitumen and SCO. The objective of LCFS is to reduce the carbon intensity (CI) of gasoline and diesel fuels over time by replacing petroleum-based fuels with alternative lower-CI fuels from biomass, compressed natural gas, electricity, *etc*. California has enacted LCFS under AB32 (California Assembly, 2006); the EU has enacted a form of LCFS under its fuels quality directive (EU Directive); British Columbia has enacted LCFS (BC Reg, 2011); Oregon is in the process of enacting LCFS (Oregon); and Washington State and states on the US East Coast are considering LCFS (Washington, NESCAUM).

LCFS require a reduction in carbon intensity of gasoline and diesel over time from a base value. Carbon intensity is determined on a well-to-wheels (WTW) basis, from crude oil production, crude oil transport to the refinery, crude oil refining to gasoline and diesel, transport of gasoline and diesel to the point of delivery to the vehicle, and emissions from combustion of the fuel in the vehicle. The steps in a WTW analysis are shown in Figure 3-1.

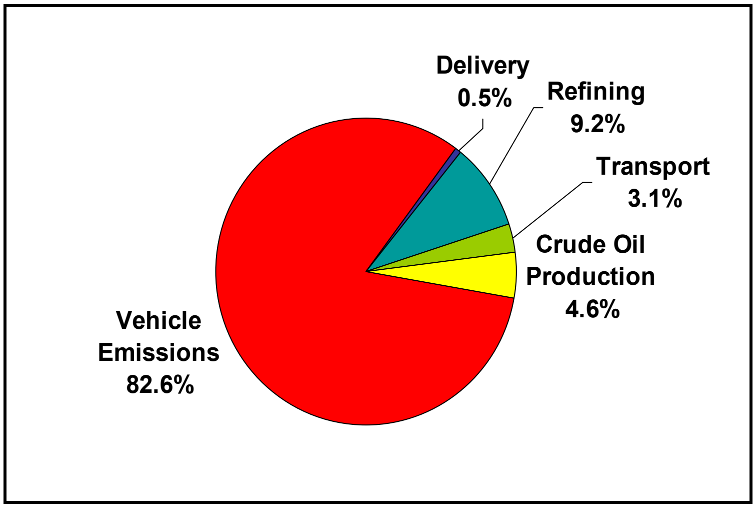
Figure 3-1.
WTW Pathway for Gasoline and Diesel



WTW Emissions Breakdown

The emissions breakdown from the steps in a WTW analysis for diesel fuel is shown in Figure 3-2 for a typical crude oil. Results are reported as g of GHG emissions per MJ of diesel fuel.

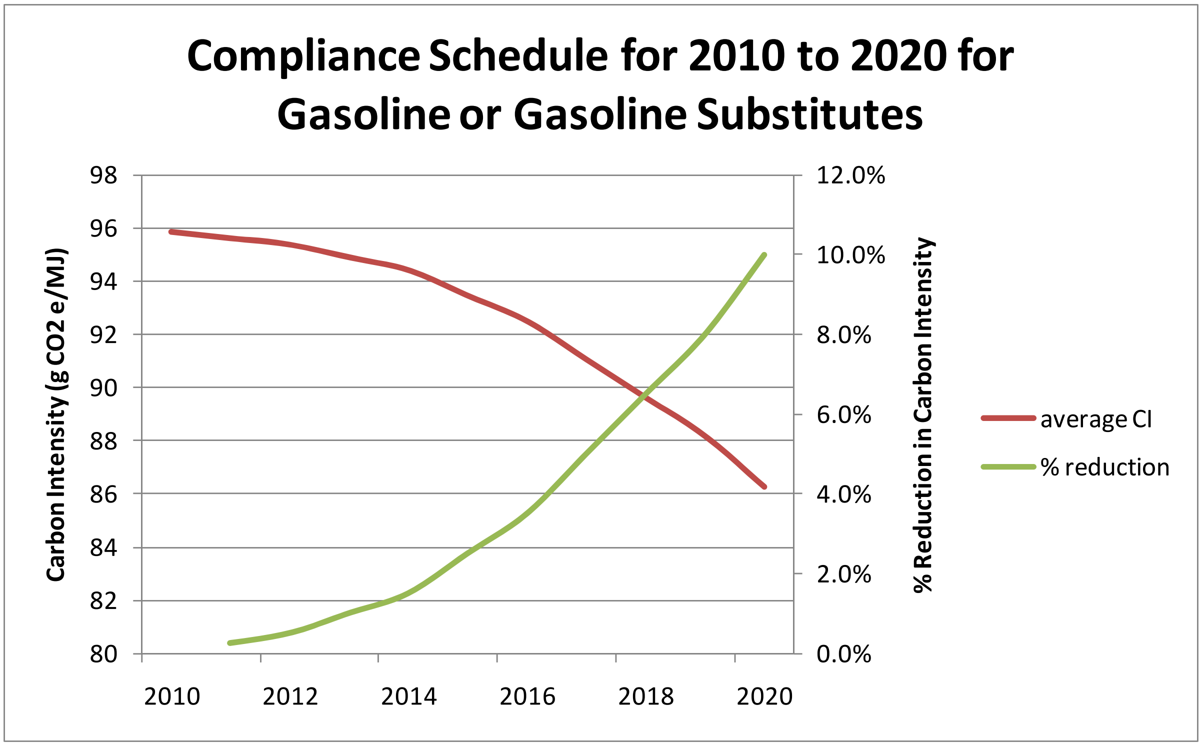
Figure 3-2.
WTW GHG Emissions from Diesel Produced from Arab Medium Crude Oil



Blending Gasoline under LCFS

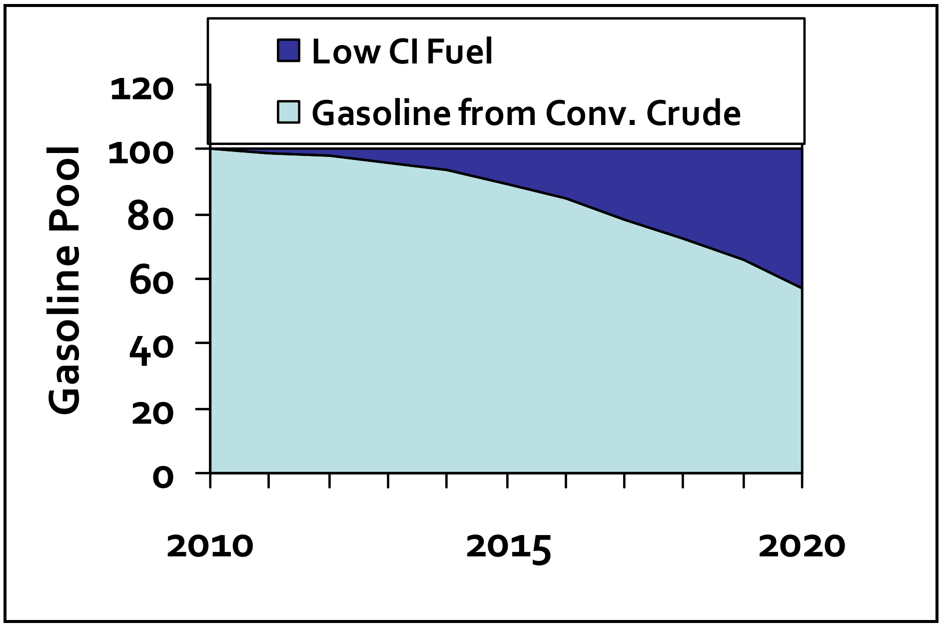
The California regulations call for a 10% reduction in the carbon intensity of gasoline and diesel by 2020 from a 2010 base. Figure 3-3 shows the reduction in carbon intensity of gasoline supplied to California.

Figure 3-3.
Compliance Schedule for Gasoline under the California LCFS



The EU regulations call for a 6% reduction in carbon intensity of gasoline and diesel by 2020 from a 2010 base. LCFS regulations assume that low-CI fuels will displace petroleum-based gasoline and diesel over time. Figure 3-4 shows that the petroleum-based proportion of the gasoline pool in California will decline over time and the proportion of non-petroleum-based gasoline like fuel (in this example, ethanol from Brazil produced with average production processes) will increase over time.

Figure 3-4.
California Gasoline Pool under LCFS



California has identified the WTW carbon intensities of a number of fuels that could be used to replace gasoline from petroleum (CARB, 2011). A subset of this list is provided in Appendix 2.

Segregation of Crude Oils under California LCFS

Both the California and EU regulations differentiate between gasoline and diesel from conventional crude oils and gasoline and diesel from non-conventional crude oils. The California regulations explicitly segregate crude oils into two categories:

1) Non-high carbon intensity crude oils (non-HCICO) or conventional crude oils
2) High carbon intensity crude oils (HCICO)
    - Crudes from thermal production
    - Crudes produced by mining
    - Crudes produced by upgrading
    - Crudes from countries determined to have high gas flaring

In California, if the crude oil is determined to be a non-HCICO, the CI of CARBOB is 95.86 g GHG/MJ of gasoline and the CI of diesel fuel is 94.71 g GHG/MJ of diesel. These are the values in the look-up tables abstracted in Tables A2-1 and A2-2 in Appendix 2. Note that the acronym CARBOB is for California Reformulated Blendstock for Oxygenate Blending, which is the hydrocarbon portion of the gasoline pool before blending in ethanol. Ethanol is generally blended at 10 vol% in the finished gasoline. For simplicity in the following discussion, the term “gasoline” will be used instead of CARBOB.

If the crude is an HCICO, a new WTW pathway for gasoline and diesel must be established. However, if the CI for producing and transporting the crude oil to California can be shown to be less than 15 g of CO_2e/MJ of crude, the crude may be reclassified as a non-HCICO and the look-up values for gasoline and diesel (95.86 g/MJ and 94.71 g/MJ) can be used. Any reclassification of a crude oil from HCICO to non-HCICO requires approval by the California Air Resources Board. Language from the regulations are subject to interpretation and are as follows (LCFS, 2010):

ii. Determination of Carbon Intensity Value for HCICO derived products, XD HCICO CI

A regulated party subject to section 95486(b)(2)(A) must determine the carbon intensity value for its CARBOB, gasoline or diesel fuel using any of the following that applies, subject to Executive Officer approval as specified in section 95485(a)(2) or as otherwise specified.

I. The carbon intensity value shown in the Carbon Intensity Lookup Table corresponding to the HCICO’s pathway; or

II. Except as provided in paragraph III. below, if there is no carbon intensity value shown in the Carbon Intensity Lookup Table corresponding to the HCICO’s pathway, the regulated party must propose a new pathway for its HCICO and obtain approval from the Executive Officer for the resulting pathway’s carbon intensity pursuant to Method 2B as set forth in section 95486(d) and (f); or

III. The regulated party may, upon written Executive Officer approval pursuant to section 95486(f), use the average carbon intensity value in the Carbon Intensity Lookup Table for CARBOB, gasoline or diesel fuel, provided the GHG emissions from the fuel’s crude production and transport steps are subject to control measures, such as carbon capture-and sequestration (CCS) or other methods, which reduce the crude oil’s production and transport carbon-intensity value to 15.00 grams CO_2e/MJ or less, as determined by the Executive Officer.

The EU is considering one carbon intensity value for gasoline and diesel produced from conventional crude oils and another higher value for products from all shale oils, bitumen, and coal-to-liquids fuels. This approach treats all conventional, non-thermally-derived crude oils as low in carbon intensity. At this time there is no mechanism for reclassifying bitumen, shale oil, or coal-derived liquids.

WTW Carbon Intensity of Gasoline and Diesel

As discussed above, the California LCFS regulations assume that the fuel pathways for gasoline and diesel from all conventional crude oils are the same (see Tables A2-1 and A2-2 in Appendix 2 for carbon intensities). However, the fuel pathways for gasoline and diesel from high carbon intensity crude oils (thermal or mined crude oils, upgraded oils, or crude oils produced with significant gas flaring) must be determined by a WTW assessment that determines their CI.

Work for Alberta Energy Research Institute (AERI) in 2009 identified WTW GHG emissions for gasoline and diesel fuel refined from a number of conventional crude oils, bitumen, and SCO (AERI, 2009). This study showed that the CI of gasoline and diesel from conventional crude oils varied widely because of differing amounts of gas flaring during crude oil production and because of differing amounts of energy used in crude oil production. In fact, this study showed that the carbon intensities of gasoline and diesel from bitumen and SCO were 10-15% higher than the carbon intensities of gasoline and diesel from more conventional crude oils, which is a far lower estimate than in prior work (Farrell). Results comparing the CI of gasoline and diesel refined from a number of crude oils, bitumen and SCO are shown in Figures 3-5 and 3-6.

Figure 3-5.
WTW Carbon Intensity of Gasoline

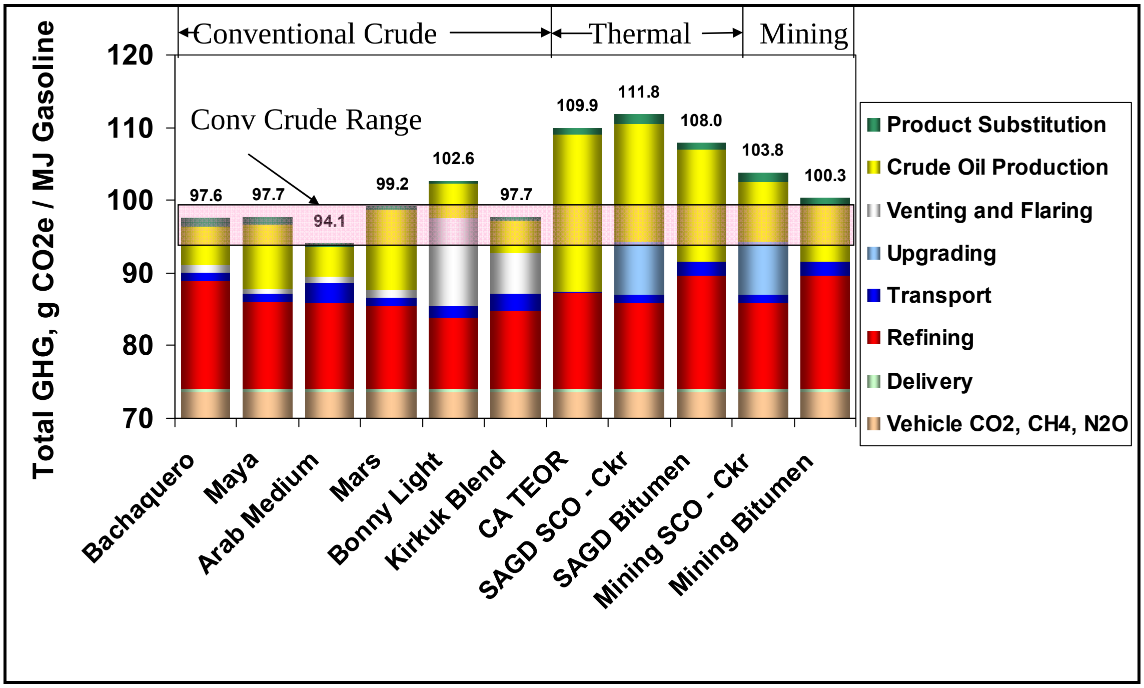
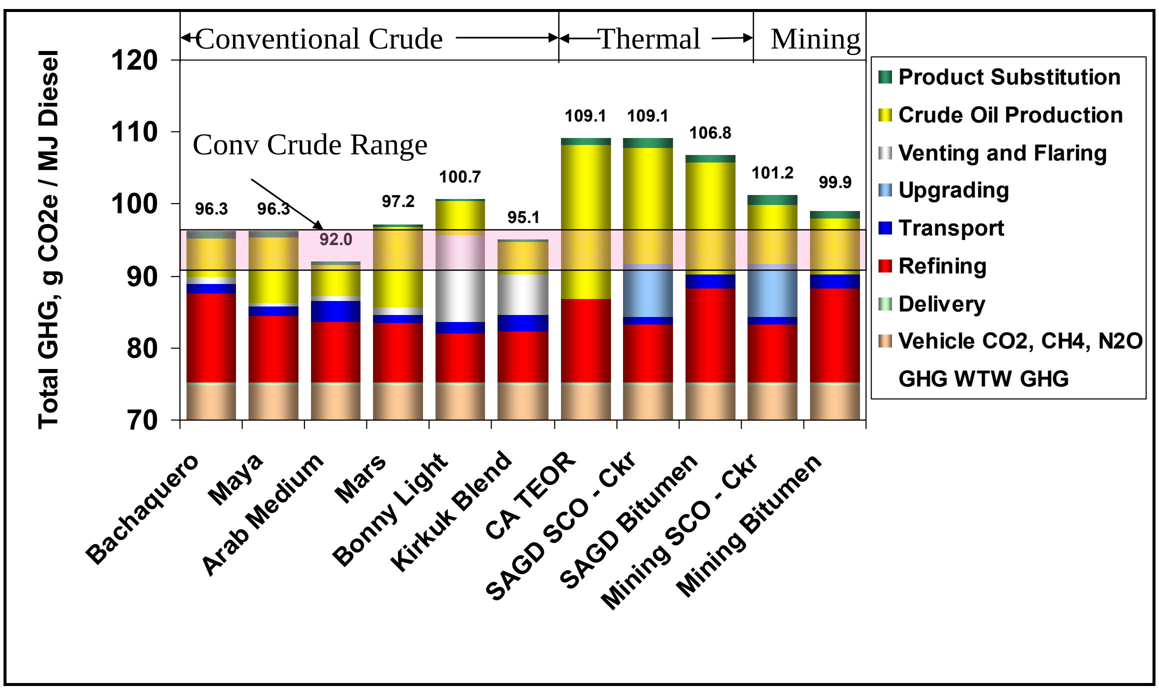


Figure 3-6.
WTW Carbon Intensity of Diesel



Note that the results shown in Figures 3-5 and 3-6 correct several errors in the original AERI study: first, eliminating double-counting GHG emissions from electricity consumption in refining; second, correcting several minor errors in natural gas and fuel gas emission factors; and third, improving the analysis of co-product substitution. While the carbon intensities of all the bars decrease as a result of correcting these errors, the relationships between the bars do not.

To determine the impact of the California LCFS regulations, let us restate the results in Figures 3-5 and 3-6 assuming that the CI of gasoline and diesel from conventional crude oils can be taken from Tables A2-1 and A2-2. Figures 3-7 and 3-8 show the CI of gasoline and diesel from conventional and non-conventional crude oils after restating the CI for gasoline and diesel from non-HCICO.

Figure 3-7.
Gasoline CI under California LCFS

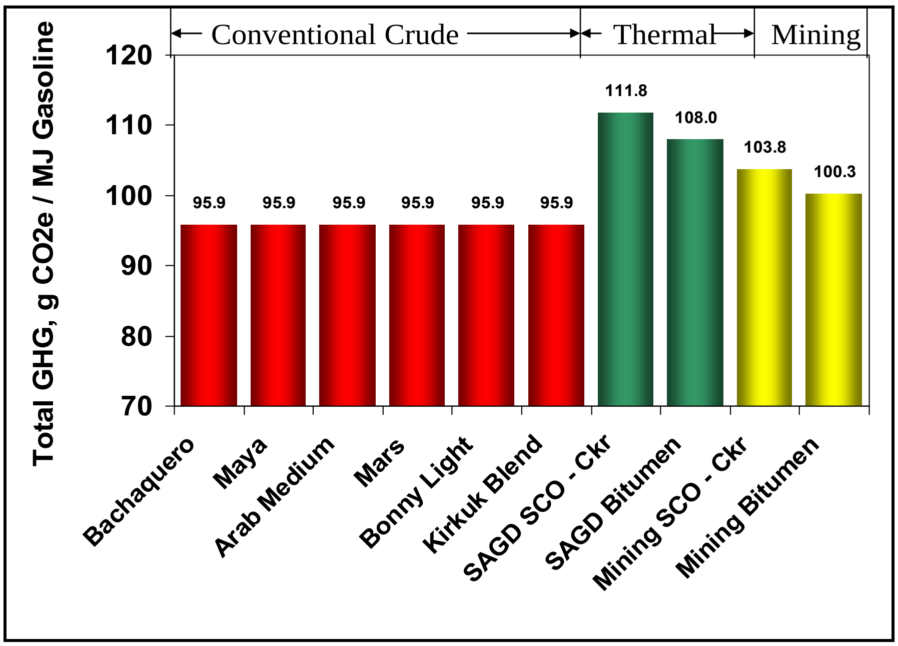
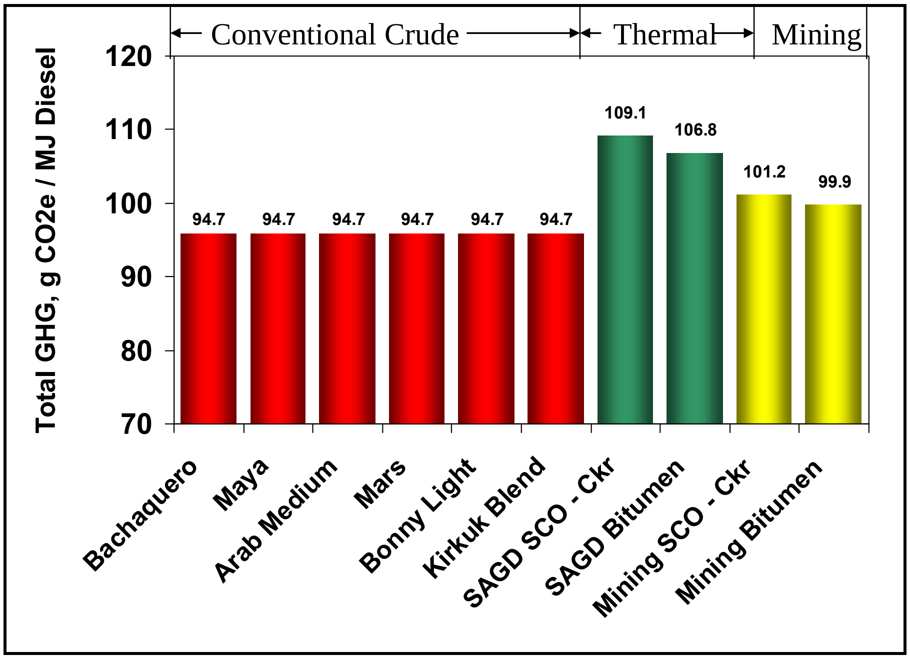


Figure 3-8.
Diesel CI under California LCFS



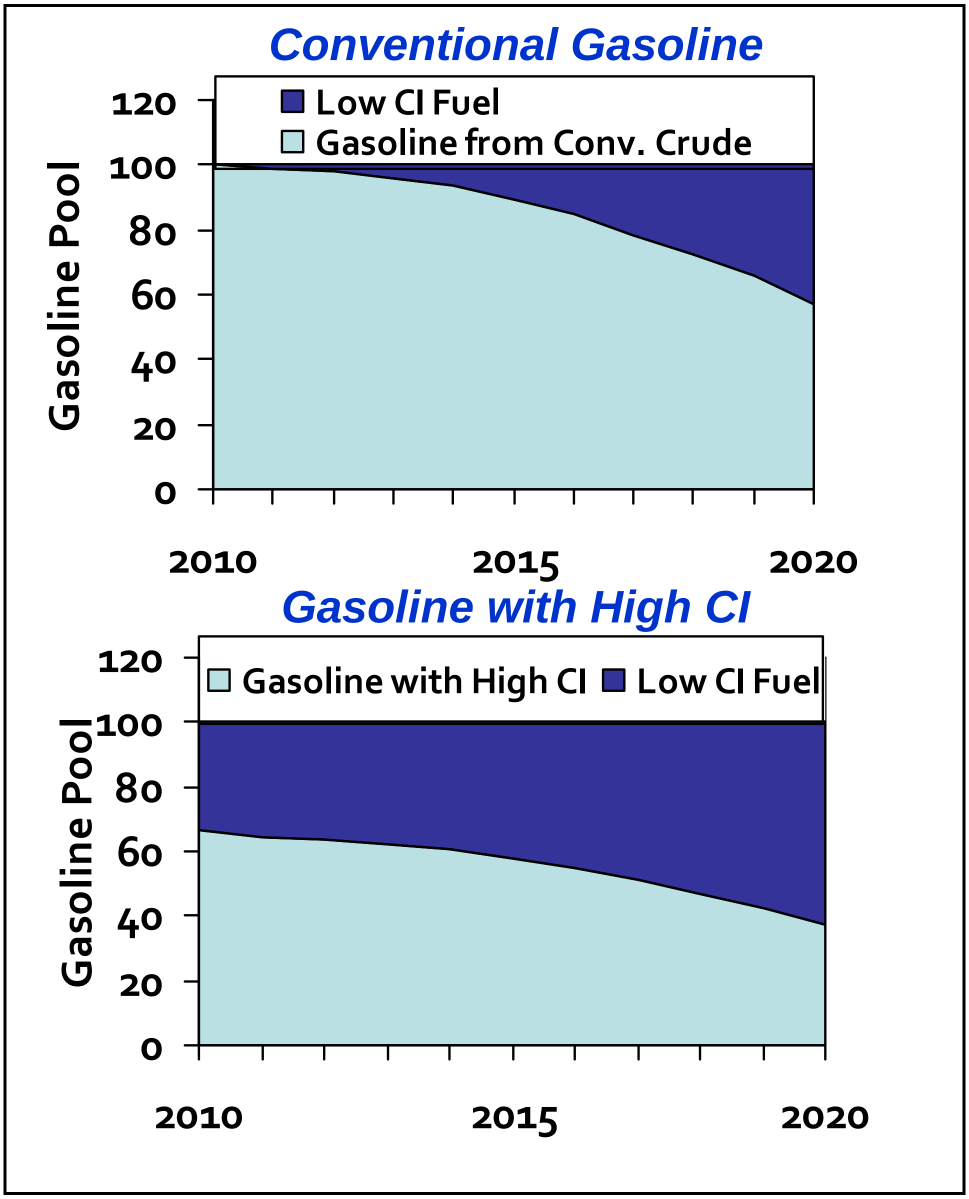
Meeting the California LCFS carbon intensity reduction targets with gasoline and diesel from HCICO will require more low-CI blendstocks to be used. Figure 3-9 compares the gasoline pool composition to meet the California LCFS regulations for gasoline produced from a non-HCICO and from bitumen, an HCICO. Note that more low-CI blendstock must be used for LCFS compliance when gasoline is produced from HCICO. In the absence of any change in price or mitigation of HCICO CI, it seems likely that an HCICO like bitumen or SCO will be a less attractive crude oil to a refiner because less can be processed and more of a non-refinery low CI product must be obtained to offset the CI of gasoline produced from the HCICO. Thus the HCICO producer must offer incentives to the refiner to use its crude oil, *i.e.,* a price break. The long-term impact of LCFS is to significantly reduce the demand for hydrocarbon-based transportation fuels.

The reduction in demand of transportation fuels and the value of the incentive that an HCICO producer might be required to offer to the refiner or fuel blender will be determined by factors such as:

- the cost and availability of low-CI blending stocks
- the blending limits of transportation fuel pool

- the vehicle fleet composition, *i.e.*, the portion of the fleet that is made up of E85, LPG or propane fueled or electric vehicles

Figure 3-9.
Gasoline Blending—Low-CI Conventional Gasoline vs. High-CI Gasoline

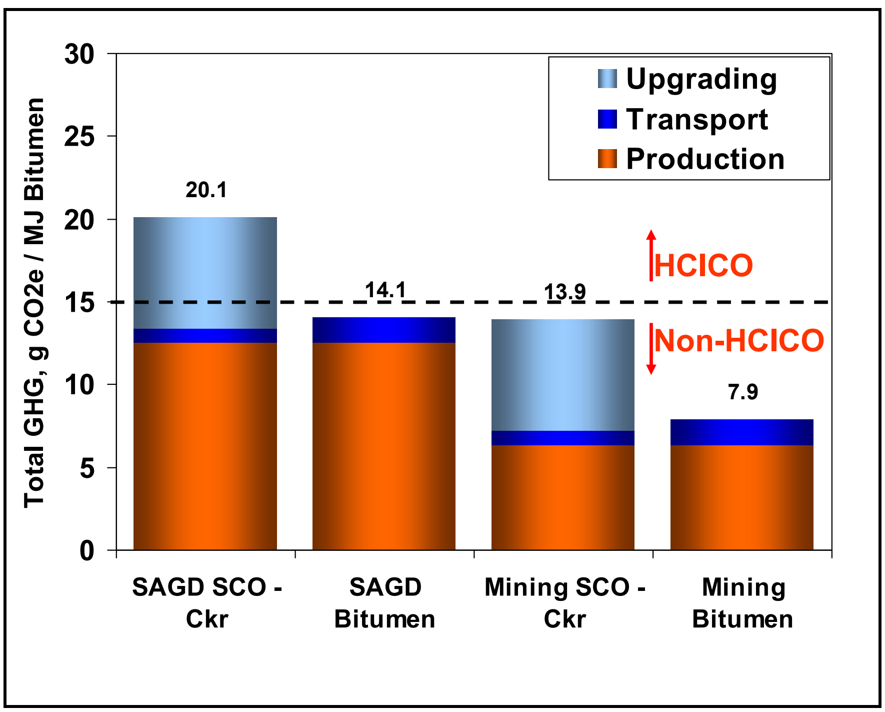


Options for Bitumen Producers under LCFS

The options for an HCICO producer under the California LCFS regulations are to either demonstrate to the Air Resources Board that the crude is actually a non-HCICO, or develop a new fuel pathway by a WTW GHG life cycle assessment, which might include GHG mitigation to reduce the CI of gasoline and diesel.

The dividing line between a non-HCICO and an HCICO is a carbon intensity for crude oil production and transport to the refinery of 15 g of GHG/MJ of crude oil. Figure 3-10 shows the CI for bitumen production by SAGD and mining and production of synthetic crude oil from bitumen. The CI shown includes the emissions for transport to the refinery. Note that the transport for bitumen includes emissions for returning diluent to Alberta. Results shown in Figure 3-10 are from the AERI study and assume a 3 steam-to-oil ratio (SOR) for bitumen production by SAGD, which is a typical level achieved in commercial production in Alberta (AERI, 2009).

Figure 3-10.
CI for Bitumen and Synthetic Crude Oil Production and Transport to the Refinery



Furthermore, emissions for SAGD bitumen can be reduced further through the implementation of certain efficiencies in the design of SAGD facilities, including:

- Mechanical lift via submersible pumps as opposed to gas lift
- Minimization of the ethylene glycol system and improvements in the configuration of the heat exchanger network
- Implementation of air preheat on the SAGD Once-Through-Steam-Generators (OTSGs)

At an SOR of 3, the efficiencies identified could reduce the CI of SAGD bitumen by approximately 1.9 g/MJ. Table 3-1 shows that SAGD operations below 3 SOR are achieved routinely in commercial operation. However, achieving ≤3 SOR depends on reservoir conditions and operation.

Table 3-1.
Commercial SAGD Production Demonstrating Cumulative Steam: Oil Ratio ≤ 3

	After 9 Months of Operation		Intermediate Results	Mar-10
Project	Date	SOR	SOR	SOR
Foster Creek	Jul-98	4.0	---	---
	Mar-10	---	---	2.5
MacKay	Jul-03	3.4	---	---
	Jul-05	---	2.5	---
	Mar-10	---	---	2.5
Christina Lake	May-03	2.8	---	---
	Mar-10		---	2.0
Firebag	May-04	7.3	---	---
	Aug-06	---	3.9	---
	Mar-10	---	---	3.3
Surmont				
Pilot	Aug-98	5.2	---	---
Pilot	Nov-99	---	3.5	---
Commercial	Mar-08	---	3.4	---
Commercial	Mar-10	---	---	3.0

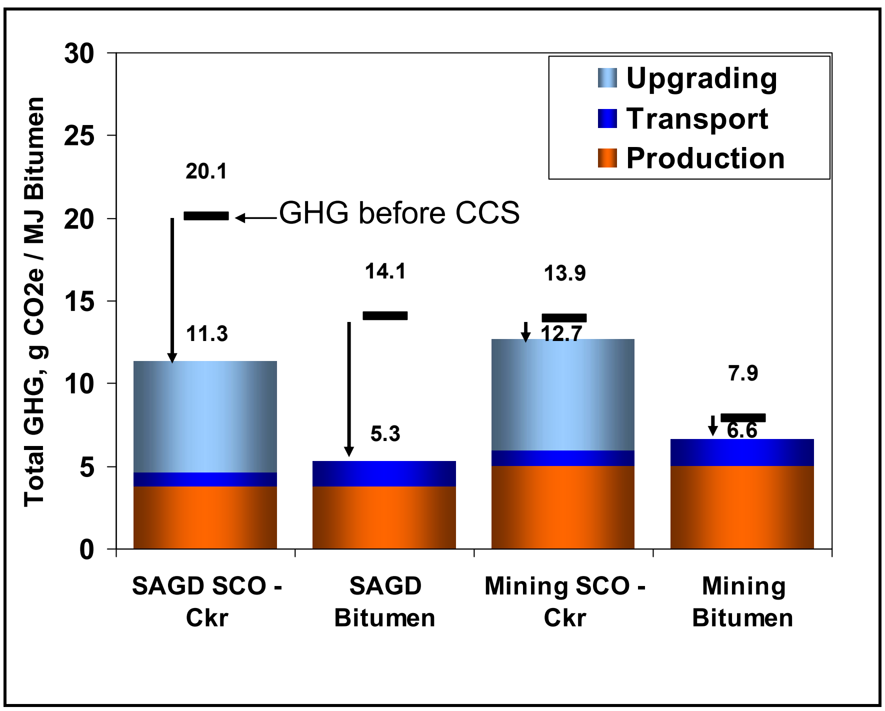
Source: Triangle Three Engineering

The prior discussion indicates that it should be possible to achieve a CI for bitumen production and transport to the refinery less than the 15 g/MJ of bitumen that is the cut-off between non-HCICO and HCICO. If the Air Resources Board accepts these results, bitumen will be treated like other non-HCICO and the CI for gasoline and diesel will be the same as those from other non-HCICO. The results in Figure 3-10 show that SCO from bitumen produced by SAGD will have a CI for production and transport to the refinery greater than 15 g/MJ of SCO and will be considered an HCICO unless GHG emissions are reduced. Another possible outcome is that the Air Resources Board may require bitumen producers to show GHG mitigation for their products to be reclassified as non-HCICO.

GHG Mitigation in Bitumen Production

Most of the GHG emissions in bitumen production from SAGD are from fuel combustion to generate steam for in-situ production. It may be possible to capture as much as 70% or more of the CO_2 emissions from SAGD. GHG emissions from mining come from the diesel-powered equipment used in mining and from fuel used to heat the hot water and recover the solvents used to separate bitumen from sand. While it is possible to recover GHG from stationary sources, recovering GHG from mobile sources such as trucks and earth-moving equipment is not. A conservative estimate is that perhaps 20% of the GHG emissions from mining are recoverable. Figure 3-11 shows the effect on CO_2 emissions for bitumen and SCO production, including transport to the refinery, assuming 70% GHG reduction in SAGD and 20% GHG reduction in mining.

Figure 3-11.
CI for Bitumen and SCO Production after GHG Mitigation

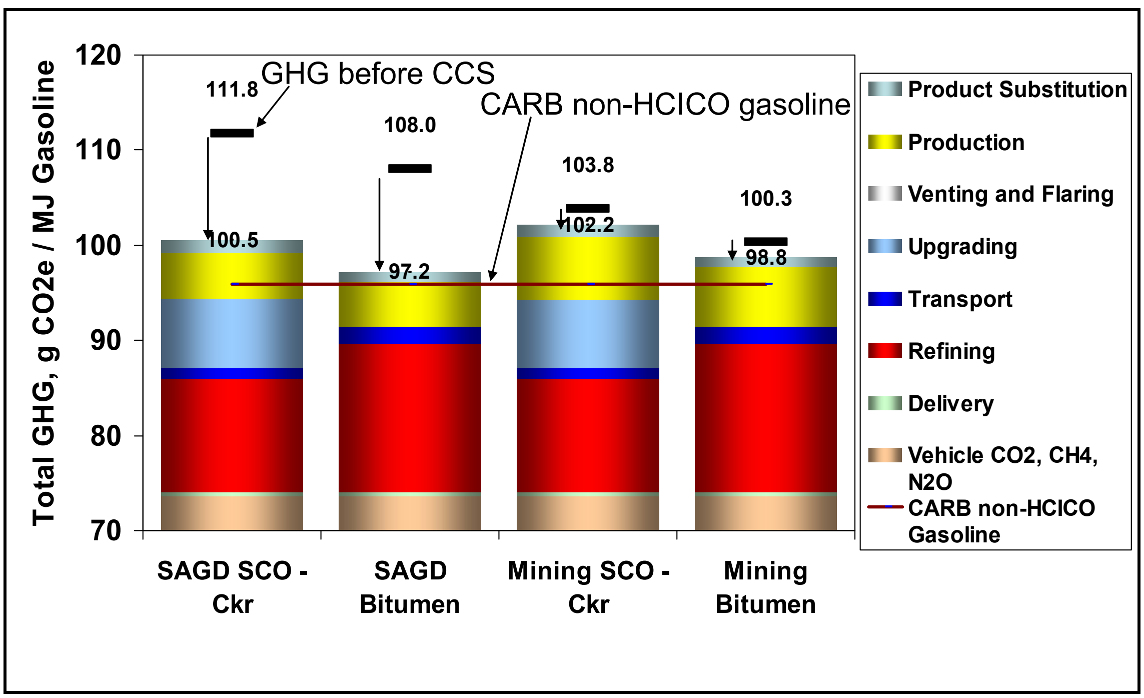


These results indicate that with GHG mitigation in the form of CCS, it should be possible to reclassify bitumen and SCO as non-HCICO under the California LCFS, which should allow these materials to be treated the same as all other conventional non-HCICO crude oils. However, if it is not possible to mitigate GHG emissions from bitumen and SCO production sufficiently or if the Air Resources Board does not allow reclassification, then bitumen and SCO producers must develop new fuel pathways for gasoline and diesel produced from their products.

New Fuel Pathways for Bitumen and SCO with GHG Mitigation

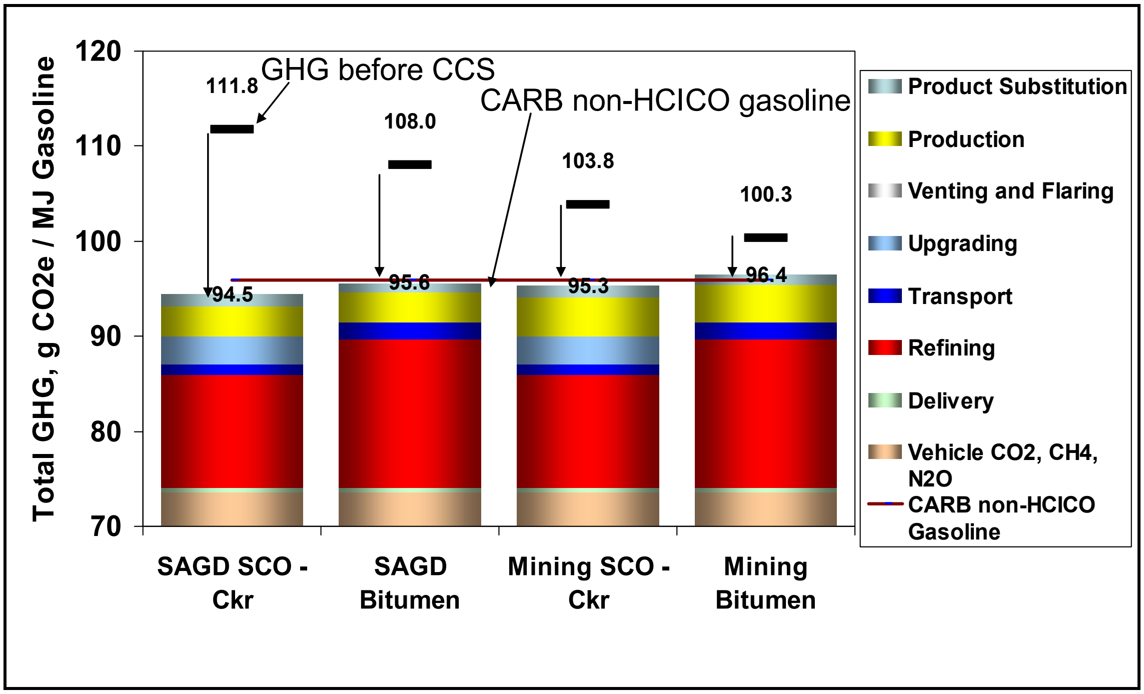
Taking the CI results for SCO and bitumen from Figure 3-5 and capturing 70% of the GHG from SAGD bitumen production and 20% of the GHG from bitumen production by mining brings the CI for gasoline to the levels shown in Figure 3-12.

Figure 3-12.
Gasoline CI after GHG Mitigation in Bitumen Production



These results show that 70% GHG mitigation in SAGD bitumen production and 20% GHG mitigation in mining is not sufficient to bring the CI of gasoline from bitumen and SCO to the CI of gasoline from non-HCICO. Higher levels of GHG mitigation must be achieved or GHG emissions must be recovered from upgrading. Figure 3-13 shows the CI from gasoline assuming that 80% of the GHG emissions can be recovered from SAGD bitumen production, 50% from mining, and 60% of GHG emissions from upgrading.

Figure 3-13.
Gasoline CI after GHG Mitigation in Bitumen Production and Upgrading



These results show that when it is necessary to develop a new fuel pathway, greater GHG mitigation may be required to bring the CI of gasoline and diesel from bitumen and SCO in line with the CI of gasoline and diesel of non-HCICO. Part of the reason is that heavy crude oils like bitumen require more energy to refine. For SCO, there is inherent inefficiency in making the components of SCO, mixing them together and then re-separating them at the refinery and continuing their conversion to gasoline and diesel.

It is also possible to implement CCS at a refinery to further reduce the CI of the transportation fuels. In the current form, LCFS does not distinguish between transportation fuels produced in the United States or those that are imported—all transportation fuels, no matter where they are produced, are subjected to the same LCFS restrictions. Therefore, the decision to produce transportation fuels in Alberta or the United States would be based strictly on an economic analysis. The analysis is considered in detail in Section 5 of this report.

Cost Impact of CCS on the Price of Bitumen

One of the biggest uncertainties is the effect of CCS on the resulting netback for bitumen prices. Figure 3-14 summarizes the impact of CCS price at varying levels of CI reduction and CCS costs, and translates this to the impact on bitumen price. For this analysis, bitumen is assumed to have a lower heating value of 6.3 GJ/bbl. Determining the cost of CI reduction simply takes the level of CI reduction (for example, 10 g/MJ of bitumen) and the cost of CCS (for example, \$100/ton of CO_2), and then calculates a cost to bitumen:

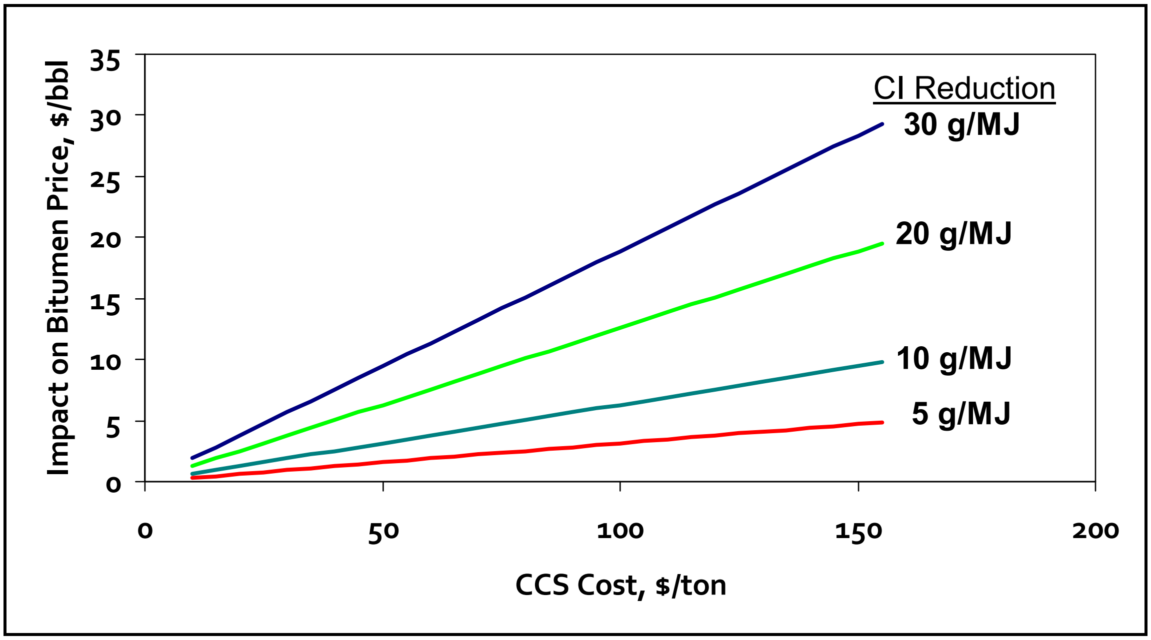
Example:

Cost of CCS to bitumen = Bitumen LHV * CI Reduction * Cost of CCS * Conv. Factors

Cost to bitumen = 6.3 GJ/bbl * 10 g/MJ * \$100/ton of CO_2* 1000 MJ/GJ * 1 ton/10^6 g

Cost to bitumen = \$6.3/bbl

Figure 3-14.
Impact of CCS Cost on Bitumen Price at Varying Levels of CI Reduction



Therefore, depending on the cost of CCS and the extent of CI reduction, the resulting impact on the netback to the bitumen producer could be substantial. For example, reducing the WTW CI for gasoline produced from SAGD bitumen to 95 g/MJ requires a 13 g/MJ reduction. At an average cost of $125/tonne on an Avoided cost basis, the cost impact for the producer is approximately $8/bbl.

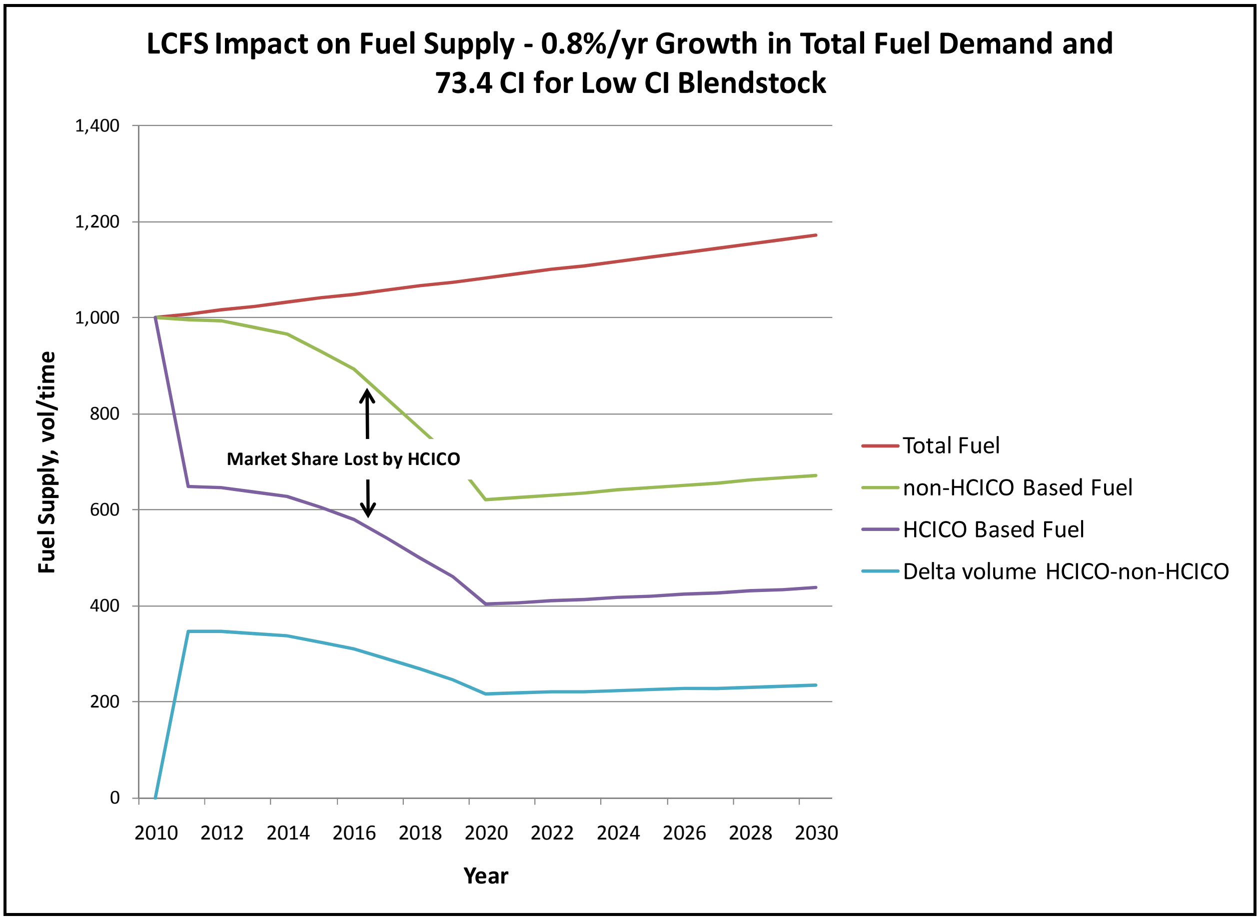
LCFS Impact on Demand for HCICO

One question is what is the market impact of LCFS on bitumen producers? There are two parts to the answer. First, if bitumen and bitumen-derived materials can be reclassified as non-HCICO, then the impact will be the same as on other crude oils: a reduction in demand over time because more non-crude oil-based fuels must be supplied to reduce the pool CI. Second, there will a further loss in market share relative to non-HCICO-derived fuels if bitumen and bitumen-derived materials cannot be reclassified as non-HCICO.

Figure 3-15 shows the impact of LCFS on demand for hydrocarbon-based gasoline derived from non-HCICO and from an HCICO (in this example, bitumen). Two scenarios are shown: i) Gasoline from non-HCICO plus low CI material; and ii) Gasoline from HCICO plus low CI material. Total gasoline demand is assumed to grow at 0.8% per year. Gasoline from HCICO has a CI of 108 g CO_2e/MJ, gasoline from HCICO has a CI of 95.86 g CO_2e/MJ, and the offsetting low CI gasoline-like fuel has a CI of 73.4 g CO_2e/MJ (equivalent to Brazilian ethanol).

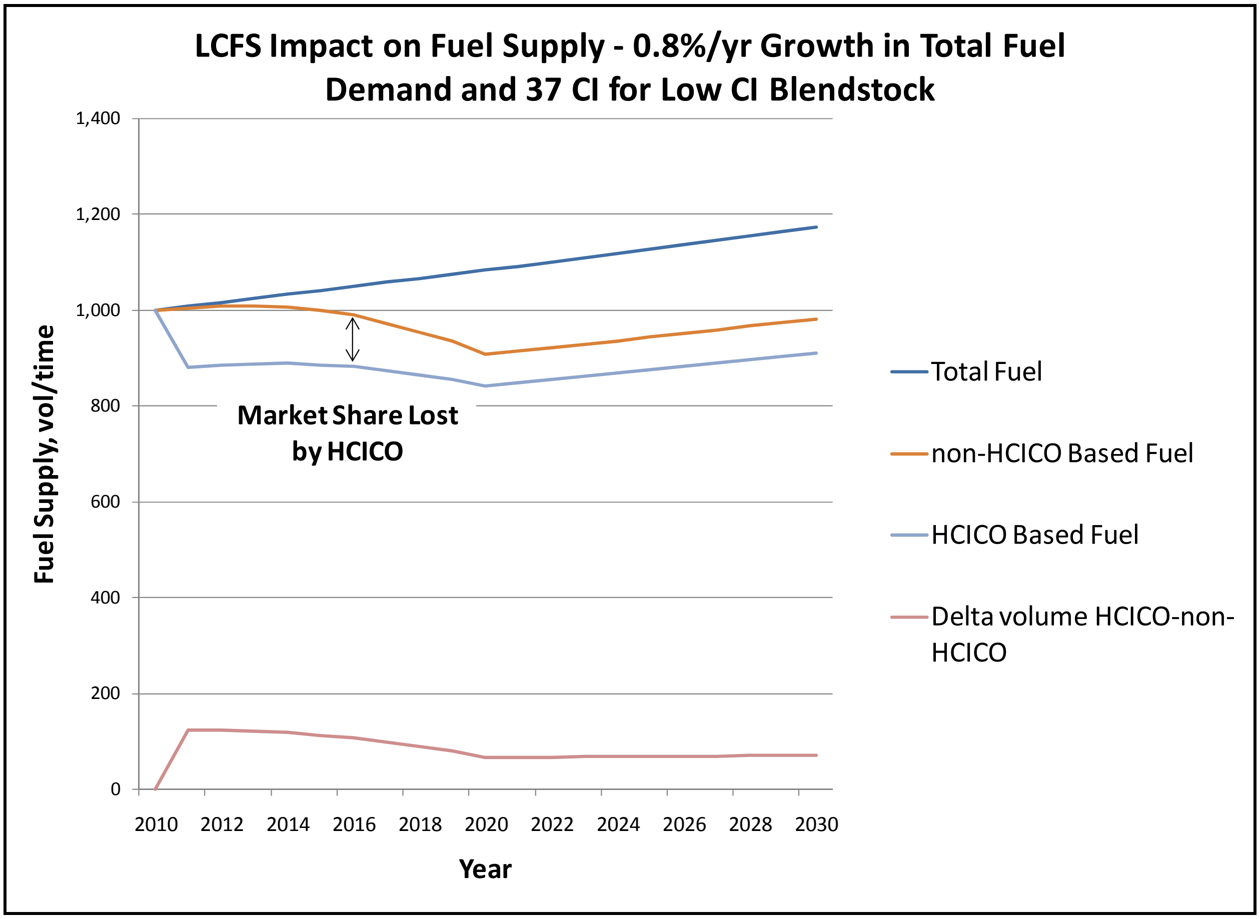
There is a significant drop in demand for hydrocarbon-based gasoline, which continues until 2020 after which the current LCFS regulations in California require no further reduction in the CI of the fuel supply. As a result, after 2020 hydrocarbon-based fuels resume growth at the same rate as the total fuel supply. Note that the demand for bitumen-derived gasoline is significantly lower than the demand for non-HCICO-based gasoline. This can be considered the market share lost by bitumen to non-HCICOs. In this example, with bitumen-based gasoline at 108 g CO_2e/MJ and the low CI other gasoline material at 73.4 g/MJ, bitumen-based gasoline will lose approximately 34% of the market.

Figure 3-15.
LCFS Impact on Fuel Supply: 0.8%/yr Growth in Total Fuel Demand and 73.4 CI for Other Gasoline-Like Fuel



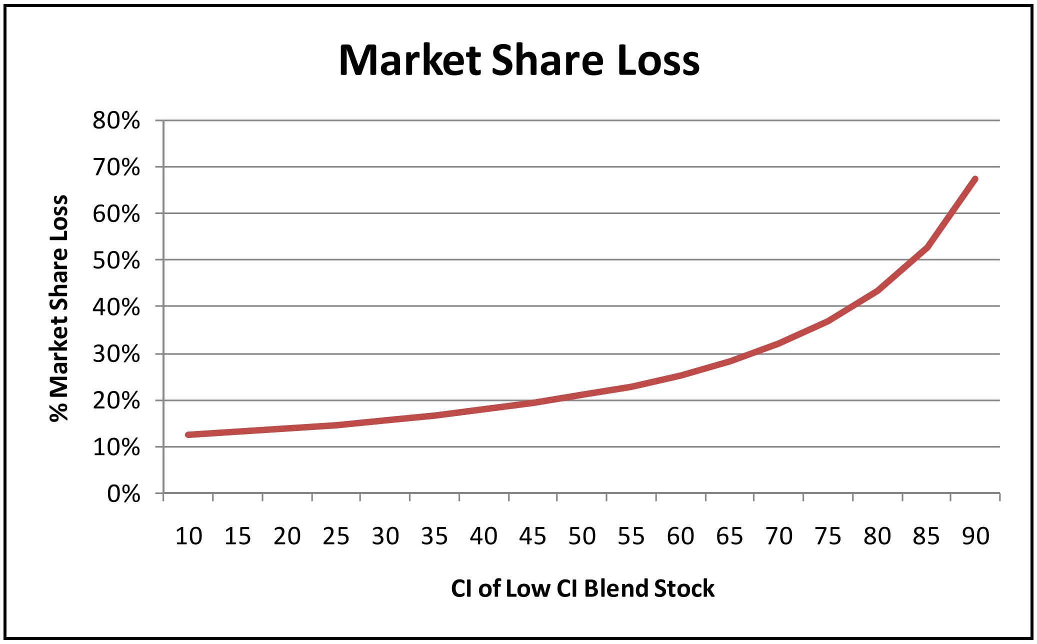
The market share loss of HCICO crudes is dependent on the CI of the blendstock that is available to reduce the overall CI of the fuel pool. If instead of using a non-hydrocarbon material with a CI of 73.4 g CO_2e/MJ a material with a CI of 37 g CO_2e/MJ is used, the demand for hydrocarbon-based gasoline will be greater and the impact of LCFS on the market share loss of bitumen-based gasoline will be approximately 17% relative to non-HCICO-based gasoline. Results are shown in Figure 3-16.

Figure 3-16.
LCFS Impact on Fuel Supply: 0.8%/yr Growth in Total Fuel Demand and 37 CI for Other Gasoline-Like Fuel



The impact of LCFS on market share for HCICO-based fuels depends on the CI of the HCICO fuel and the CI of the non-hydrocarbon-derived fuels used to meet overall fuel supply CI compliance. It is not dependent on total fuel demand growth.

Figure 3-17.
Market Share Loss of HCICO-Derived Fuels as Compared to non-HCICO-Derived Fuels under LCFS



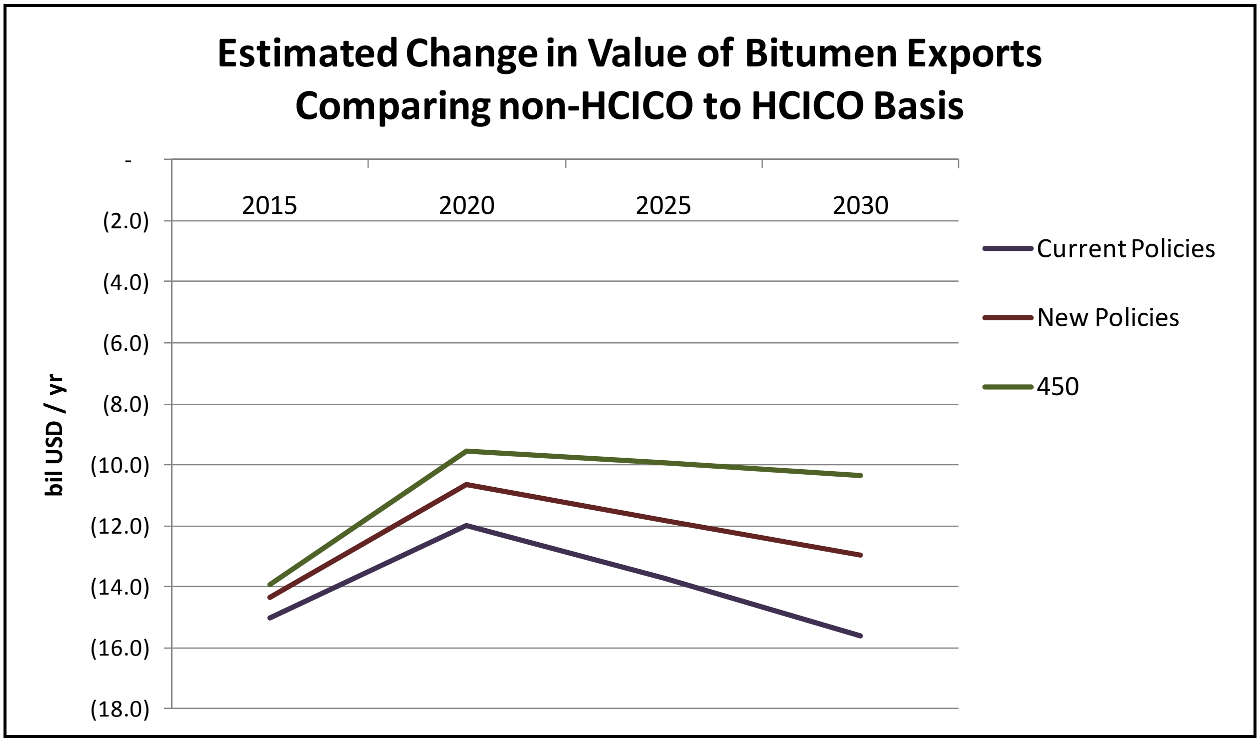
While MKJA's model will thoroughly consider the economic impact, we have estimated the potential impact on bitumen exports into the United States based on the following assumptions:

- US federal LCFS regulations are imposed now with the same structure as the current California regulations. If LCFS is imposed federally in the United States, it will likely be much later in the forecast period which will reduce the overall effect of LCFS-related reductions in bitumen shipments.
- World crude prices are as per the three IEA scenarios.
- The world crude oil - Hardisty price spread is $12/barrel (the average over the past 5 years) and this spread is maintained throughout the forecast period. There will most likely be a widening of the spread between world oil prices and bitumen prices to incentivize fuel blenders to use HCICO-based fuels when LCFS is imposed; however, that effect is difficult to quantify in this stage of the analysis. This effect will create a larger reduction in the value of bitumen-related exports than shown in the graph.
- US transportation fuel demand grows 0.8% per annum from 2010 – 2030.

- The blending stock available to meet LCFS regulations has an average CI of 73.4. If the blending stock has a lower CI, then there will be a smaller reduction in the value of bitumen-related exports than shown in the graph.

The analysis shows a reduction in the value of bitumen exports of approximately $10 – 16 billion/yr by 2030 due to the impact of LCFS.

Figure 3-18.
Estimate of Change in Revenues of Bitumen-Related Exports to the United States due to US Federal LCFS Regulations Comparing Fuels Made from non-HCICO Crudes to HCICO Crudes



Summary of Non-Tariff Barrier Impact on Bitumen and SCO

While Cap-and-Trade and BACT will not significantly affect bitumen sales, LCFS has the potential to significantly reduce bitumen sales. Cap-and-Trade and BACT address emissions from the refinery but do not restrict emissions of gasoline and diesel, as does LCFS.

Because bitumen and SCO are classified as HCICO under the California regulations, producers have three options to reduce the impact of these regulations:

1. Successfully petition the California Air Resources Board (CARB) to reclassify bitumen and SCO as non-HCICOs, which allows the same CI values for gasoline and diesel as from other non-HCICOs (more conventional crude oils). In its present form, LCFS defines HCICO as delivered crudes with a CI greater than or equal to 15 g/MJ. This is the easiest approach and requires no mitigation. CI data from SAGD in-situ bitumen production and from mining indicate that it should be possible to reclassify all mined and in-situ bitumen as non-HCICO provided that the SAGD steam to oil ratio (SOR) is 3 or lower. However, SCO from in-situ bitumen production will not meet non-HCICO CI requirements due to the additional CI impact of upgrading.
2. If CARB does not approve reclassification of bitumen and SCO as non-HCICO, then carbon capture and storage in bitumen production may be sufficient to bring bitumen and SCO under the 15 g/MJ CI limit for non-HCICO.
3. If CARB does not approve bitumen and SCO as non-HCICO after use of CCS to mitigate GHG from their production, producers will have to develop new WTW fuel pathways for bitumen and SCO to establish the CI for gasoline and diesel produced from them. Because a WTW GHG analysis captures the effect of refining heavy crude oil and the energy and feedstock inefficiency of making SCO and then refining it, rather than simply refining bitumen, greater GHG mitigation is necessary to bring the WTW CI of gasoline and diesel from bitumen and SCO in line with those of non-HCICO.

The recommended approach is to successfully petition CARB to reclassify bitumen and SCO as non-HCICO so that the CI for gasoline and diesel fuel produced from them are the same as that from other non-HCICO. Ideally, this reclassification can be done with little or no CCS. There may be some attraction to developing a fuel pathway for gasoline and diesel from bitumen and SCO using CCS to reduce the CI below that of non-HCICO gasoline and diesel; however, the effort and cost to do so will not be insignificant. Further, even if all the GHG from production, upgrading and refining could be captured, it would put the CI of gasoline and diesel in the realm of 72-74 g/MJ, which is not much better than many of the existing low CI alternative fuels.

The long-term impact of LCFS is the severe supply reduction of hydrocarbon-based transportation fuels unless CCS is implemented for the production, upgrading and refining of any crude to gasoline and diesel. Whether these steps will be taken depends on the cost to do so versus the availability and costs for alternative transportation fuels.

Quantification of this price effect may be considered for Stage 2 of this study.

Section 4.

Estimate of Capital and Operating Costs for CCS in Alberta

Jacobs Consultancy estimated the probable capital and operating costs for multiple configurations of CCS. This analysis was based on Jacobs' in-house information and publicly available sources. These costs have been submitted to MKJA for use in their economic model.

Variations in Capital and Operating Cost Estimates

Estimating the costs for CCS is difficult. The two main cost factors are capital cost and operating cost. Unfortunately, there are a myriad of factors that can have significant impacts on both of these components, including:

Table 4-1.

Factor	Impact
Stream Composition	In general, higher pressure and higher CO_2 concentrations have lower cost of capture than dilute and low-pressure streams. Impurities, however, are also important and may determine the technology available as well as other capital and operating costs.
Technology	Most of the current commercial technologies use absorption and stripping to purify and concentrate the CO_2 prior to compression. Higher-pressure streams, including those from a gasifier, can use a physical solvent such as Rectisol or Selexol. Lower-pressure streams, including those from a steam methane reformer or any of the flue gas streams, use a chemical, amine-based solvent. Chemical solvents have higher operating costs than physical solvent due to the heat necessary to break the chemical bonds to release the CO_2.
Location Factor	Capital costs vary dramatically from area to area, primarily driven by labour costs and productivity. For example, Total Installed Cost (TIC) in Alberta's Industrial Heartland is estimated to cost 30% more than the US Gulf Coast; TIC in Fort McMurray can cost 60% more.
Retrofit vs. New Construction	Retrofitting existing units for CCS is more costly per tonne of CO_2 than implementing CCS in the design of new units.
Size	Most often, TIC does not scale linearly with size. Larger complexes tend to have a lower per units cost than small ones. Unfortunately, the experience on CCS projects is limited and establishing a size factor is difficult.

Financial Assumptions

Capital costs in the CCS project are spent at the beginning of the project over a span of 2-4 years as the project is built. The financial treatment of these costs can be determined if a fully developed NPV model is used. However, NPV models require many inputs in terms of financing assumptions, capital spending rates, tax treatments and depreciation calculations. In calculating the capital cost of the CCS units for this analysis we used a simplifying set of assumptions. The capital costs are considered to be spent at the beginning of the project and averaged over 9 years to calculate the capital cost component per tonne of CO_2.

Cost Basis

In general, there are three different ways that CCS costs per MT of CO_2 are reported. In this report, we have used a Direct Avoided basis. This basis was chosen because MKJA's model calculates the amount of CO_2 that is associated with the power that is used by the CCS unit. By reporting on a Direct, Avoided costs basis, MKJA will not double-count CO_2 emissions.

Table 4-2.

Captured	Of the three commonly used bases, the amount of CO_2 captured is usually the largest volume, and therefore, has the lowest reported CCS costs on a per tonne basis.
Avoided	Due to the parasitic losses associated with CCS due to additional heat and power requirements, and the CO_2 generated to build, transport and install the CCS equipment, the amount of CO_2 generated by the process unit with CCS is higher than the process unit without CCS. Therefore, the CO_2 avoided is almost always lower than the captured CO_2 and results in a higher CCS cost on a per tonne of CO_2 basis.
Direct Avoided	A portion of the parasitic CO_2 emissions is the CO_2 emissions that are associated with imported power generation. This CO_2 is not under the direct control of the operator installing the CCS unit. Under the Direct Avoided basis, only CO_2 emissions directly associated with the operation of the complex are included in the calculation of the amount of CO_2 emissions avoided. The Direct Avoided CO_2 emissions are usually more than the Avoided, but less than the Captured amount, because a portion of the internally generated CO_2 is often captured. This was the basis for the CCS estimates provided to MKJA, because the indirect CO_2 avoided is handled via the economic forecasting of each individual sector. For example, for SAGD CCS, power has a large indirect CO_2 component and is handled in the economic modeling of power production.

CCS Cost Estimate Basis

The cost of CCS is little more than a scientific guess at this point, due to the lack of a database of designed, constructed and installed commercial-scale CCS facilities in North America. For this phase of the study, we used information from five sources to establish a range of costs:

- Two previous studies completed for entities associated with the Alberta Government:
  - HUDP CO_2 Assessment (Jacobs Consultancy, July 2009)
  - Alternative Fuels Study—Configuration Review (Jacobs Consultancy, December 2008)
- Studies completed by Jacobs Consultancy for two major oil and gas companies
- A NETL study – DOE/NETL-2010/1397 titled "Cost and Performance Baseline for Fossil Energy Plants" (DOE/NETL)
- A November 2010 report prepared by the US Energy Information Administration titled "Updated Capital Cost Estimates for Electricity Generation Plants"

For an overall consistency check, we compared our cost ranges to those included in studies completed by the Integrated CO_2 Network (ICO_2N).

We estimated costs on a Direct Avoided basis for four of the five main major sources of CO_2 in Alberta:

- *Tranche 1—CO_2 produced on the process side of a Steam Methane Reformer (SMR)*: A concentrated stream of CO_2 is produced in an SMR and can represent 25-30% of total CO_2 in a delayed coker-based upgrader.
- *Tranche 2—Post combustion capture from Natural Gas Combined Cycle (NGCC) power plants*: Due to the lower overall emissions and assumptions given in publicly available information, NGCCs have lower overall avoided costs than coal-based power.
- *Tranche 3—Post combustion capture from coal-based and NGCC power plants*: A conventional coal power plant produces 2.3 - 2.5 times as much CO_2 as an NGCC per MWhr when thermal efficiency is taken into consideration.
- *Tranche 4—Steam Assisted Gravity Drainage (SAGD) steam production*: CO_2 sources consist primarily of large natural gas-fired boilers to produce steam for SAGD. A SAGD

facility producing 90,000 BPD of bitumen will generate about the same CO_2 as a single 500 MW natural gas combined cycle.

- *Tranche 5—Smaller process heaters in Upgrading and Refining complexes*: Depending on the type of crude processed and the processing severity, miscellaneous process heaters including the SMR flue side produce approximately 50% of the total CO_2 emissions. We did not include Tranche 5 in the overall analysis of the economic benefits to Alberta for CCS based on the high relative costs and low overall contribution to Alberta's GHG emissions, currently estimated at 10 - 15 percent.

Of the four tranches included in the analysis, the costs associated with capturing CO_2 from power generation are important. Based on current data, approximately 45%-50% of the total CO_2 emissions for Alberta come from the generation of power from fossil fuels. Two main types of fossil fuel power plants provide most of the electricity for Alberta. They are natural gas-fired combined cycle power plants (NGCC) and sub-critical, conventional coal fired power plants. Newer, super-critical coal-fired power plants are in the planning phases, but from a cost of capture standpoint, offer minimal improvement over the conventional coal plants, and, therefore, will be considered as providing a lower bound of the costs of capture associated with coal power.

In coal-fired power plants, coal is combusted with air to produce steam that, in turn, drives turbine power generators. The steam is condensed after the last "condensing turbine" and is recycled as hot boiler feed water to produce steam again. Coal-fired power plants vary in efficiency but current technology options provide an overall efficiency of 37% - 38% based on the thermal energy of the coal feed. NGCC plants generate power in two places: the first is via shaft work from a pressurized gas turbine, followed by steam production and electrical generation from the waste heat on the gas turbine exhaust. Therefore, NGCC plants have a much higher efficiency and are in the range of 50 - 55 percent.

Due to differences in the feedstock composition and typical excess oxygen amounts, the flue gas from coal has a higher concentration of CO_2 than in a natural gas-fired plant. On a dry basis, the CO_2 concentration in the flue gas from a coal-fired power plant can be in the range 10-13 mol% depending on the coal composition. For a natural gas-fired plant, CO_2 concentration in the flue gas can be in the range of 3-6 mol%. Coal-fired powered plants generate nearly twice as much CO_2 than natural gas-fired plants on a thermal basis and, due to efficiency differences, 2.3 - 2.5 times as much per MW of generation.

Most of the information published estimating the cost of CCS on power plants is focused on the cost per unit of electrical generation. This can lead to some interesting results when trying to calculate the cost of capture for the power plants. For example:

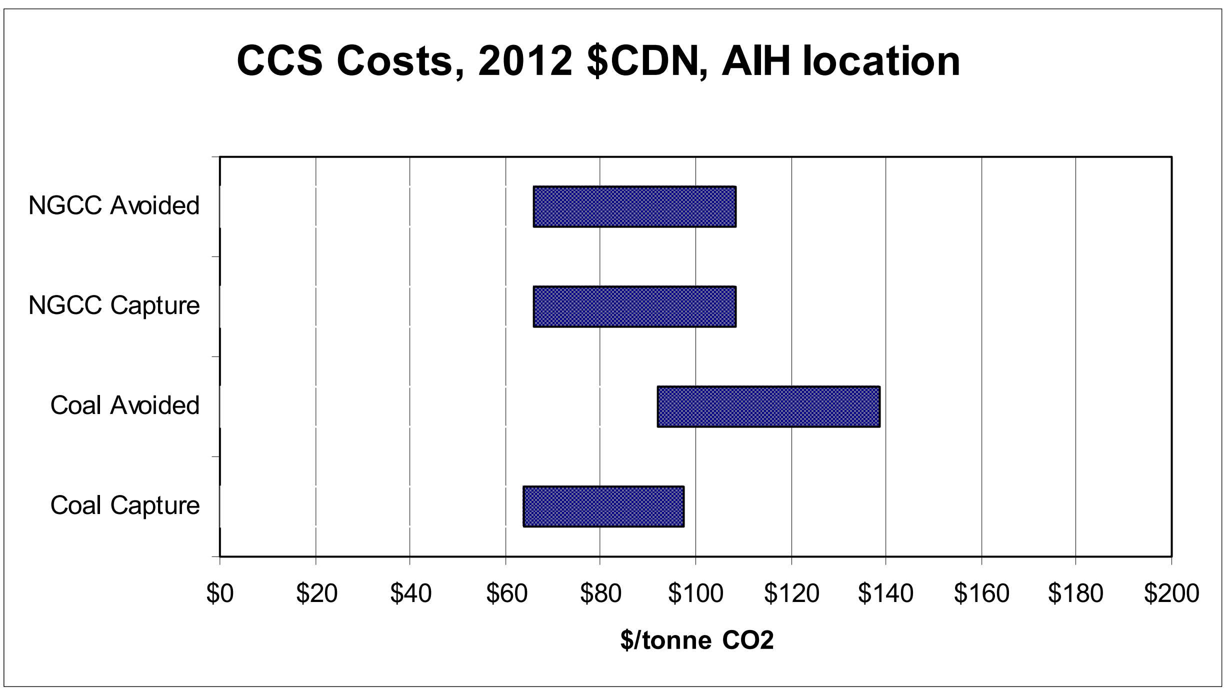
1. Most studies compare the cost of new facilities with and without CCS. Retrofit CCS applications are difficult to estimate and vary from plant to plant for a variety of reasons.

2. Coal-fired power plants with and without CCS are compared based on an equivalent net generation of power due to the ability to build larger boilers and larger steam generators to offset the parasitic energy required for CCS.

3. By contrast, NGCC plants with and without CCS have dramatically different net power outputs as they have been compared based on the same size gas turbine, air compressor and waste heat boiler (the term often used is “frame size”)—in other words, based on equivalent natural gas import. Therefore, the parasitic losses for CCS reduce the net power generation, while fuel imports remain the same.

These assumptions can have a dramatic impact on determining the cost of capture on both a Direct and Avoided basis. Figures 4-1 and 4-2 summarize the differences.

Figure 4-1.
Cost of Capture Ranges based on NGCC plant with CCS having lower output than without CCS

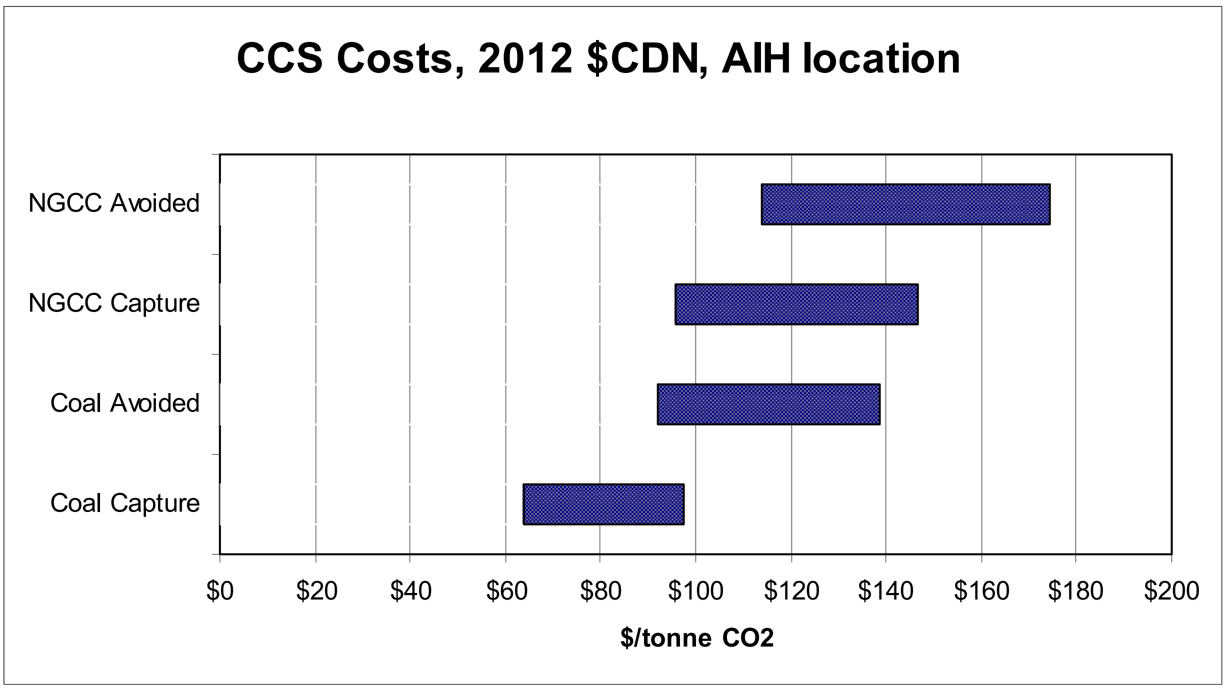


In this case, both the coal and NGCC have similar total costs of capture, but due to the higher carbon content of coal, the Avoided costs are higher for coal than for natural gas. In addition, one must keep in mind that the net power production for the CCS cases compared to the non-

CCS cases is different. In the coal case the output from the coal with CCS is the same as the output without CCS. For the NGCC cases, the CCS case produces nearly 25% less power than the case without CCS.

If the NGCC case with CCS is modified "on paper" to have the equivalent output of the non-CCS case, the difference in the calculated cost of captured CO_2 is dramatically different. While this change appears reasonable on paper, it may not be practical given the standardized sizes for gas turbine-based equipment, including the waste heat boiler and air compressor. However, if it were possible to scale the NGCC CCS case up to provide the same power output as without CCS, the calculated costs of capture change dramatically, as shown in Figure 4-2.

Figure 4-2.
Cost of Capture Ranges based on NGCC plant with CCS having the same output than without CCS



In this case the NGCC capture costs are substantially higher and the Avoided costs are more than the capture cost basis because additional fuel is consumed in scaling up the NGCC plant with CCS.

For the purposes of this study we show both NGCC costs, as indicated in Figures 4-1 and 4-2, to be consistent with the assumptions provided in the publicly available information and also account for a comparison based on equivalent output.

Capital Costs—Carbon Capture

The capital costs associated with CCS are primarily the TIC of the installed equipment necessary to capture the CO_2. For this study, we used a capital charge per year of 11%, which equates to a straight payout of a little over 9 years. We included CCS for four major sources in Alberta, and the estimated capital component ranges from 45% to 70% of the overall capture, compression, transportation and sequestration costs. Our estimates are “rough-order-of-magnitude” (ROM) estimates and do not represent cost estimates based on designed or sized equipment and installation.

For all four tranches of CCS considered, the capture mechanism is much the same and therefore the major pieces of equipment are similar. Major equipment consists of the following:

- An absorber to contact the amine and gas to nearly atmospheric temperature and pressure
- A reboiled stripper to evolve the CO_2 from the amine
- Miscellaneous amine pumps
- Heat exchangers to heat and cool the amine
- Driers and compressors to dry and compress the concentrated CO_2
- Gas preparation including SOx and NOx removal and cooling

The difference in capital cost among the different options is related to the following factors:

- Economy of scale—Costs are not directionally proportional to size. On a unit of CO_2 measurement, larger equipment typically costs less than small equipment. However, with certain equipment, there are maximum size restrictions related to technical or shipping constraints, which, in turn, require more parallel trains of equipment to handle more volume. At that point, the costs are relatively proportional to volume, and economies of scale tend to level out, so that any increase in CO_2 volume requires the same percent of increase in capital expenditure. Over time, maximum equipment sizes tend to increase as the boundaries are stretched.
- CO_2 concentration—All things being equal, higher CO_2 concentrations reduce the size of the absorber and any pretreatment equipment. However, the rest of the equipment is sized primarily by the amount of CO_2 captured and therefore is only impacted by scale.

- Incoming gas conditions—Temperature, pressure and other contaminants determine the amount of pretreatment necessary before contacting the absorber. The gas streams entering the absorber must be cool to enhance absorption and minimize amine carryover. In addition, certain contaminants will increase amine usage through the formation of heat stable salts and other stable amine compositions. For the steams listed above (with the possible exception of the SMR process), the pressures are all low and have little impact on the capital cost.

Therefore, among the four tranches analyzed, the relative capital costs are as follows:

- SMR process: Depending on the configuration, which in large part is determined by whether CCS was envisioned, the gas stream may be up to 10-20 bar. In addition, the gas is relatively clean and, again depending on the configuration, could have CO_2 concentrations above 15 percent. Therefore, of the three tranches shown, this option should have the lowest capital cost as driven by the smaller absorber and minimal pretreatment requirements.
- NGCC flue gas: Although the flue gas for NGCC is much the same as SAGD flue gas, the costs are lower for a variety of reasons identified in this report.
- Coal-based power flue gas: Due to higher CO_2 concentrations in the flue gas and larger equipment due to higher rates of CO_2, the capital costs are lower than an NGCC on a capture basis. However, due to the higher parasitic generation, the Avoided costs are in the ranges of NGCC based on equivalent feed rate and equivalent power production.
- SAGD flue gas: Capturing CO_2 from the SAGD flue gas should be similar to that from an NGCC except for the following qualitative differences:
  - Economy of scale: Although a 90,000 BPD SAGD facility is essentially the same as a 500 MW NGCC, there are many SAGD facilities that are smaller which could increase the capital cost per unit of CO_2.
  - Differences in centralization of equipment: SAGD OTSG boilers are, on average, smaller and will have multiple flue gas stacks, leading to an increase in the number of absorbers and pumping requirements.
  - SAGD facilities typically are in regions where labour costs are higher and productivity is lower, in contrast to where NGCC power plants are located.

Operating Costs—Carbon Capture

Operating costs are another important component of CO_2 capture and are largely a result of the increased utilities necessary to capture the CO_2. For amine-based capture, the fuel required to generate the steam to drive the CO_2 out of the chemical-based solvent is significant. This cost is typically the single largest share of the ongoing operating cost for CCS. Power requirements for compression of the CO_2 are also significant but smaller than the fuel costs. Chemical usage for the amine is another significant component of the operating expense, especially in “dirtier services” such as coal flue gas.

Among the four tranches considered in this study for capture, all required about the same energy per tonne of CO_2, but costs varied in terms of the cost of the energy and the chemical requirements.

Both power generation tranches, coal and natural gas, have lower operating costs due to the fact that they only have to purchase fuel for the parasitic power requirements of CCS. The other two tranches considered (Tranche 1 and 4) are assumed to purchase power resulting in a higher operating cost. Finally, as mentioned above, it must be noted that coal and natural gas are treated differently in the comparisons of CCS. Coal-based facilities are compared based on the same net power production, while the NGCC cases are compared based on the same natural gas feed rate. This difference impacts all factors of the CCS costs and, especially, the operating costs estimates. In the NGCC case, under the assumptions used in the literature sources, fuel requirements are the same with and without CCS, yet the coal cases require more fuel in the CCS case than the non-CCS case. This advantage disappears when calculated based on an equivalent power output.

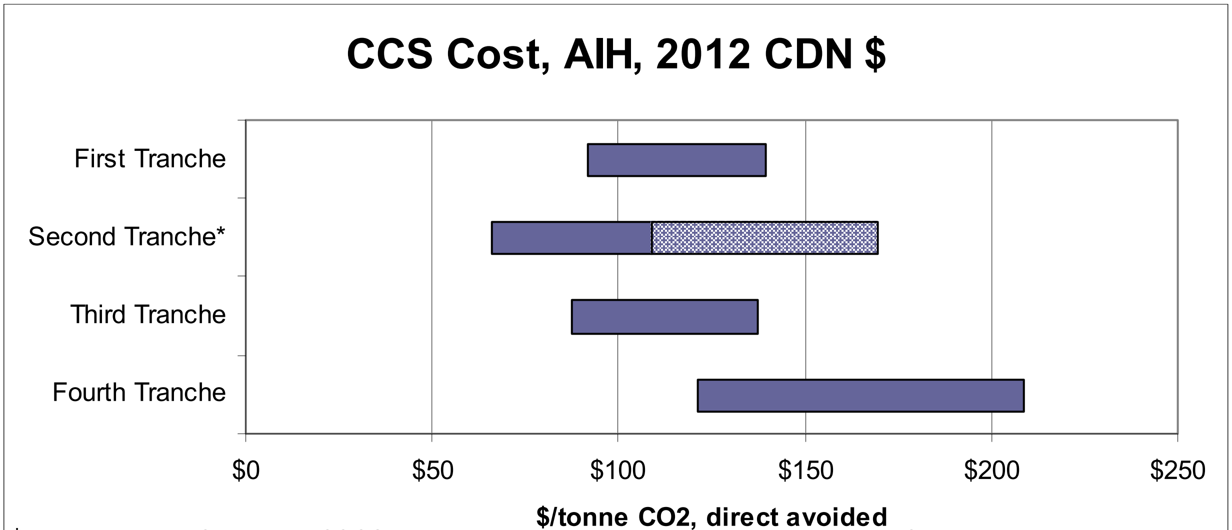
Transportation and Storage Costs

Transportation and storage costs were estimated based on literature values. Capital and operating costs were broken out using a 2/3 to 1/3 factor. Transport and storage costs make up a relatively small amount of total CCS costs.

Estimates of CCS Costs

Figure 4-3 shows the range of CCS costs on a Direct Avoided basis, including Transportation and Storage costs. Descriptions of the process technology associated with each tranche are in the preceding section. The wide range of costs reflects the variation in the ease of capture for these streams. A detailed cost breakdown of the CAPEX and OPEX costs for each tranche can be found in Appendix 3.

Figure 4-3.



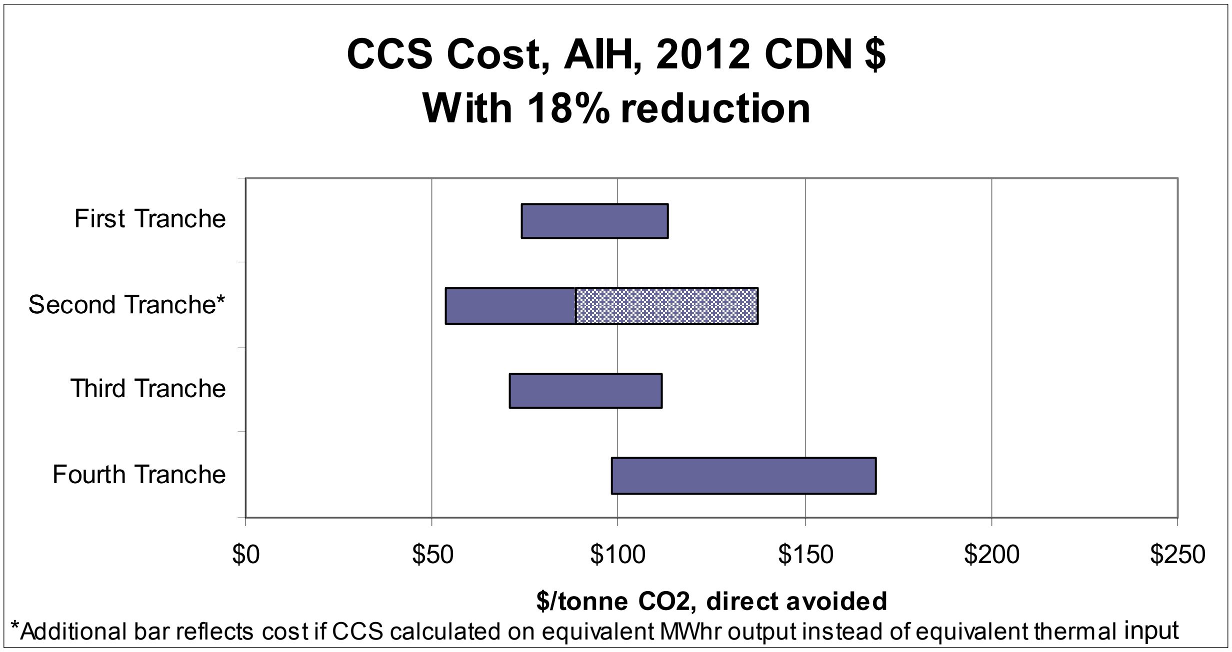
*Additional bar reflects cost if CCS calculated on equivalent MWhr output instead of equivalent thermal input

Opportunities for Cost Reduction

The costs reported are capital and operating costs that reflect the current state of the technology. We have not estimated the future possible costs of CCS due to the high degree of uncertainty in the current cost estimates and the high degree of uncertainty associated with the possibility for cost reduction. Future costs for CCS are likely to go down over time as the learning curve is established and technology improvements provide evolutionary and revolutionary cost reductions. Studies have shown that estimated costs typically go up in the early part of technology development and then trend downwards as technologies are commercialized. This trend has been observed in CCS technology and is in part due to escalations in labour and material costs over time, but also in a greater understanding of the costs that will be necessary to build the units.

Based on historical data for similar technology developments (such as flue gas desulphurization, gas turbine combined cycles, *etc*.), studies have estimated (Rubin, 2007) that after the first 100 GW of installed CCS, costs will be reduced through learning effects. It was estimated that capital reduction between 9.1% and 17.8% is possible. This cost reduction will be experienced due to engineering improvements in equipment sizing, heat integration, power usage and incremental improvements in process technology. Figure 4-4 shows the effect of an 18% reduction in costs. Significantly more cost reduction will need to take place for CCS costs to be reduced below the forecast cost of carbon for the New Policy Scenario.

Figure 4-4.
CCS Costs with Cost Reduction



In addition to opportunities for cost reduction through learning, there are many technologies under development that may provide a step-change in technology costs:

Chemical Absorption—New Chemicals

Research is being conducted to identify new chemicals for use in chemical adsorption reactions with the aim of reducing capital and operating costs by reducing the size of vessels and reducing the operating costs related to the energy required to evolve the CO_2 out of solution. Currently under development are technologies using aqueous ammonia, dry chemical absorbents and mixed chemical absorbents.

Membranes

The use of membranes to separate and purify the CO_2 in the flue gas stream is also being investigated. There are many challenges to this technology due to the large volumes of flue gas and the low concentration of CO_2 in flue gas streams.

Chemical Looping

Chemical Looping Combustion (CLC) uses a solid oxygen carrier to transport oxygen from air to fuel. The process generates two separate flue gas streams: a stream leaving the air reactor with nitrogen and some remaining fuel, and a stream leaving the combustion reactor with an almost pure stream of CO_2. The carrier releases the oxygen in a reducing atmosphere and the oxygen reacts with the fuel. The carrier is then recycled back to the oxidation chamber where the solid oxide is regenerated by contact with air. The benefit of the process is that no air separation plant or external CO_2 separation equipment is required. The additional energy requirements for the process should only come from the compressors that are required to boost the pressure of the CO_2 stream to the right pressure for transport and storage. The technology has been in development since the 1980s and is currently in the demonstration and pilot plant stage.

Gasification

Commercially-available gasification process can be designed to provide a concentrated and high-pressure source stream of CO_2, which can significantly lower the incremental cost associated with CCS through the use of physical solvents, fuel requirement optimization and minimal equipment modifications. However, the capital cost required to install gasification remains a hurdle and economic justification beyond CO_2 capture is needed for these projects to go ahead.

In the power industry, coal-fired IGCC power plants are being considered to enable much less expensive carbon capture, even though the initial capital costs of an IGCC plant are more expensive than conventional coal-based power plants.

Oxy Combustion

This eliminates combustion air, which concentrates the CO_2 in the flue gas. However, upfront costs to produce and inject oxygen are significant. Air Products and other industrial gas suppliers are focusing on cost reduction and energy requirements to be able to provide oxygen for CCS at reduced costs. This technology is currently in the demonstration stage.

Rotating Structured Adsorbent (Inventys)

Inventys has claimed a breakthrough in capture technology based on a rotating structured adsorbent that concentrates the CO_2 in the flue gas stream. The process is called the VeloxoTherm process and is an intensified temperature swing adsorption system using a carbon-based adsorbent on a monolith structure. The technology is in the pilot plant stages of commercialization.

Section 5.

Impact on Value-Added Industries

We examined the issues of how CCS can impact the market position or value of value-added products in Alberta. Specifically, we:

- Estimated the improved market (value) position of gasoline and ultra low-sulphur diesel refined from bitumen in Alberta processed with CCS.
- Estimated the improved market (value) position of selected products derived from the gasification of petroleum coke via the impact of CCS on the products' net emissions profile.

The analysis was a differential cost analysis that did not take into account the time value of money, financing effects or tax effects. The upside of a "point in time" differential cost analysis is that it provides a quick look at relative costs. Since we are selling identical products into the same market, looking only at differential costs and ignoring revenues is a reasonable "first pass" evaluation measure. This type of forecast also allows us to ignore the forecast for products values. In addition—and in particular to this study—this type of analysis will exempt us from having to extrapolate the IEA market forecast and tax values beyond their singular date estimates. A key downside of a differential cost analysis is that it ignores the time-based value of money.

If this study progresses to Phase 2, it may be warranted to consider tax effects and to generate a more-rigorous market opportunity valuation based on net present value analysis.

Impact of CCS on Gasoline and ULSD

We compared the effect of CCS investments in competitive gasoline and ULSD producing refineries, in Alberta versus the US PADD 2 area, to determine how CCS investment in Alberta would affect the market position of bitumen-derived transportation fuels exported to the United States. We used the three IEA-defined controlling business environment scenarios as the basis for fuels and energy prices and carbon tax levels.

PADD 2 was chosen as the basis for comparison to Alberta production because it is currently the largest market for Canadian bitumen, and we expect that it will continue to be the largest US market for Alberta bitumen and (perhaps) Alberta-produced refined products for some time. This is due to the existence of multiple Alberta-to-PADD-2 pipelines and refineries in PADD 2 that can process dilbit into gasoline and ULSD. The next largest markets for Canadian bitumen are PADD 3 and PADD 4 refineries, and, within the accuracy of this analysis, the PADD 2 financial analysis will be a reasonable proxy for these districts as well.

Method for Analysis

We developed a comparison of total cost of production estimates for gasoline and ULSD delivered into PADD 2 at particular points in time that coincide with the IEA's forecasts for energy product market values and carbon taxes (see Section 1 for a discussion of the IEA Scenarios). The operation with a significantly lower cost of production will have an advantage in the market.

We did not consider corporate income tax effects for this high-level Stage 1 comparison. If this study progresses to Phase 2, it may be warranted to consider tax effects and to generate a more-rigorous valuation based on net present value analysis.

When there is capital expenditure, capital cost recovery is assumed to be even over 9 years. We have also assumed a 12% return on capital, spread out evenly over the 9-year payback period. We are assuming "all equity" financing, so finance charges are not considered.

Basis for Analysis

The following assumptions were made for the analysis.

Alberta Production Facility

- The Alberta-based production system will be a newly constructed integrated operation that combines production of bitumen via SAGD and upgrading of the bitumen to (primarily) gasoline and ultra low-sulphur diesel (ULSD) products. Production will be in the Ft. McMurray area and upgrading will be in the Edmonton area. The two operations will be linked via pipelines.
- The steam for SAGD will be created using natural gas. The upgrading operation will be based on a delayed coker, and hydrogen for upgrading will be provided via gasification.
- Gasification has been picked over steam methane reforming (SMR) as a means of hydrogen production due to the relatively high prices of natural gas in the IEA scenarios.[1]
- The upgrader will include an FCC unit and a hydrocracking unit. All the gasoline and ULSD produced will be exported to PADD 2 via pipeline. The remaining products from the upgrader, such as benzene and C4s, will be sold in Alberta.

[1] This may deserve a re-evaluation in Stage 2 of the study.

- CCS investment in this facility will be a function of the scenario evaluated. (CCS will be added to the existing refinery, if and when there is apparent incentive via carbon emissions taxation to do so. Scenarios that are defined by more stringent environmental policy and GHG controls will typically see more or earlier CCS investment.)

PADD 2 Production Facility

- This production system will be based on an existing refinery located somewhere in PADD 2. CCS equipment will be added to this existing refinery, if and when there is apparent incentive via carbon emissions taxation to do so.

- We picked an existing refinery because we opine there is little chance for new refineries to be built in PADD 2 (or anywhere else in the United States over the analysis time period). There is an oversupply of refining capacity in the United States at this time. In addition, over the timeframe of this analysis we do not expect the market for petroleum-derived gasoline to grow in the United States. We expect that the market for ULSD in the United States will grow at a low rate, and that many refineries will gradually shift their gasoline-to-distillate production ratio to cope with probable diverging trends. Indeed, if dilbit volumes into the United States increase significantly, this could require some degree of coker addition to PADD 2 and PADD 3 refineries that are currently low conversion refineries.

- The potential effect of the coker addition trend is beyond the scope of this Stage 1 study. (Comparing an Alberta refinery against a refinery with a new coker addition would place Alberta refineries in a relatively better relative position versus competing with a refinery that already has coker capacity.)

- To simplify this high-level Stage 1 analysis, we assumed that the design of the PADD 2 dilbit refinery is relatively similar to the design of the Alberta dilbit refinery, except that the refinery will use an SMR unit to generate hydrogen versus a gasifier. This will change the CO_2 production and capture pattern for the PADD 2 refinery versus the Alberta refinery.

Investment in CCS—Table 5-1 summarizes where, in each scenario, CCS investment is considered.

Table 5-1.

	Carbon Prices			
	2012	**2020**	**2030**	**2035**
Current Policies Scenario	15	15	15	15
New Policies Scenario	15	15	40	50
450 Scenario	15	45	105	120
	CCS Investment in Alberta (made just in time to protect against effect of carbon regulations)			
Current Policies Scenario	No	No	No	No
New Policies Scenario	No	No	Yes	Yes
450 Scenario	No	Yes	Yes	Yes

For the Current Polices Scenario, a refinery project was started in Alberta in 2013, with start-up in 2017, even though no CCS investment was ever warranted. This was done to provide a point of comparison to investment in the New Polices and 450 scenarios.

Although there are carbon taxes indicated in Alberta of $15/MT in the Current Policies Scenario, these taxes are not included in the cost analysis. The cost analysis is a point-in-time analysis during the initial phase of the project. According to current Alberta regulations (Alberta Environment, May 2010), carbon taxes will not be imposed until the fourth year of operation. If the analysis was done on an NPV basis, the tax would increase the cost of the Alberta-based facility.

For the New Polices and 450 scenarios a refinery project was started in Alberta in 2013, with start-up in 2017, even though no CCS investment was ever warranted. This was done to provide a point of comparison to investments in those scenarios that would take place in response to carbon tax levels.

- **Procurement, Construction, Commissioning and Start-Up**—Years 2013 to 2016, with operations starting in January 2017; Period: 4 years.
- **Refinery Dilbit Feedstock Rate**—200,000 bpcd.
- **Pipeline Charges**—We assign appropriate pipeline charges for (a) delivery of dilbit to the upgrader and return of diluent to the SAGD operation, (b) delivery of Alberta ULSD and gasoline to PADD 2, (c) Delivery of dilbit to PADD 2 refinery and (d) return of diluent from PADD 2 refinery to Alberta. Pipeline costs are estimates based on Jacobs Consultancy's internal database values.
- **Products from Refineries**—Gasoline and ULSD are principal products. The refineries also produce some kerosene, C4s and fuel gas.
- **Cost Basis Year for Capital Costs**—All will be adjusted to a Year 2013 basis.
- **Fixed Costs and Sustaining Capital Estimates**—Assumed to be 6.5% of refinery replacement costs.
- **Water Costs**—We have assumed no charge.
- **Dilbit and Natural Gas Costs**—Per IEA scenario definition. Power costs are estimates based on natural gas costs.
- **Carbon Tax on Dilbit production**—Paid by producer. No carbon tax burden carried by dilbit into US PADD 2.
- **Pipeline Costs**—Best effort estimates from Jacobs Consultancy's internal databases.

Inflation Rate Assumptions

- **Underlying monetary inflation**—2% per annum (used to inflate the EIA's real basis energy and carbon prices, over 2009 to 2035 period)
- **North American project capital cost inflation**—3.6% per annum
- **Fixed costs and variable costs inflation**—2.5% per annum

Results of Analysis

Current Polices

- **Alberta New Refinery Investment—**This analysis was based on a one-time investment in a new refinery, without CCS, that comes on stream in 2017, after start of EPC in 2013. (This analysis was completed to provide a point of comparison. There are no carbon taxes in this scenario that would stimulate CCS investment.)

- **PADD 2 CCS Investment to Existing Refinery—**None. (There are no carbon taxes in this scenario that would stimulate CCS investment to the existing PADD 2 refinery.)

As indicated in Table 5-2, this analysis shows that the Alberta refinery has no cost advantage over the US PADD 2 refinery. In fact, the costs are substantially more than those of the PADD 2 refinery.[2] Note that the accuracy of many of the values in Table 5-2 is no better than +/- 30 percent. Capital cost estimates are at a +/- 50% level of accuracy.

[2] An NPV analysis would show that the NPV of the Alberta refinery was clearly less than the NPV of the PADD 2 refinery, due to the fact that the significant capital costs for the refinery would occur in the first 4 years, prior to any revenue generation, in combination with the time value of money effect.

Table 5-2.

Current Policies Scenario

Alberta Plant	Scenario	Current Policies Scenario
	Year	2020
	Plant	Alberta (without CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$2,457**
Variable Costs	$MM/year	**$1,014**
Fixed Costs	$MM/year	**$1,458**
Amortized Capital Costs and Return on Capital	$MM/year	**$2,291**
Carbon Tax Costs	$MM/year	**$0**
Total Costs	$MM/year	**$7,221**
Costs per bbl of Product (cents/gallon)	**cents/gallon**	**291**
PADD 2 Plant	Scenario	Current Policies Scenario
	Year	2020
	Plant	PADD 2 (without CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$5,018**
Variable Costs	$MM/year	**$528**
Fixed Costs	$MM/year	**$258**
Amortized Capital Costs and Return on Capital	$MM/year	**$0**
Carbon Tax Costs	$MM/year	**$0**
Total Costs	$MM/year	**$5,804**
Costs per bbl of product (cents/gallon)	**cents/gallon**	**213**
Differential (Alberta - PADD2)	**cents/gallon**	**79**

New Policies

- **Alberta New Refinery Investment (For 2030 and 2035)—**Values indicate effect of investment in a refinery that would come on stream in 2030, when carbon taxes come into effect. CCS assets have been added to this refinery.

- **PADD 2 CCS Investment to Existing Refinery—**Shows effect with investment in CCS. CCS operation will start in 2030, when carbon taxes come into effect.

Table 5-3 shows that, in the market environment, the Alberta refinery has a significant cost disadvantage versus the US PADD 2 refinery during the entire analysis period. Note that the accuracy of many of the values in Table 5-3 is no better than +/- 30 percent. Capital cost estimates are at a +/- 50% level of accuracy.

Table 5-3.

New Policies Scenario			
Alberta Plant	Scenario	New Policies Scenario	New Policies Scenario
	Year	2030	2035
	Plant	Alberta (with CCS)	Alberta (with CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$2,142**	**$3,330**
Variable Costs	$MM/year	**$1,612**	**$1,866**
Fixed Costs	$MM/year	**$2,640**	**$2,987**
Amortized Capital Costs and Return on Capital	$MM/year	**$4,579**	**$4,579**
Carbon Tax Costs	$MM/year	**$136**	**$170**
Total Costs	$MM/year	**$11,109**	**$12,931**
Costs per bbl of Product (cents/gallon)	**cents/gallon**	**448**	**522**
PADD 2 Plant	Scenario	New Policies Scenario	New Policies Scenario
	Year	2030	2035
	Plant	PADD 2 (with CCS)	PADD 2 (with CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$6,101**	**$7,036**
Variable Costs	$MM/year	**$796**	**$923**
Fixed Costs	$MM/year	**$412**	**$515**
Amortized Capital Costs and Return on Capital	$MM/year	**$182**	**$182**
Carbon Tax Costs	$MM/year	**$207**	**$259**
Total Costs	$MM/year	**$7,698**	**$8,914**
Costs per bbl of product (cents/gallon)	**cents/gallon**	**282**	**327**
Differential (Alberta - PADD2)	**cents/gallon**	**166**	**195**

450 Scenario

- **Alberta New Refinery Investment—**Investment in new refinery with CCS that comes on stream in 2017, after start of EPC in 2013.
- **PADD 2 CCS Investment to Existing Refinery—**CCS operation starts in 2017 after completion of EPC, which starts in 2013.

Table 5-4 shows that, in this market environment, the Alberta refinery has a significant cost disadvantage versus the US PADD 2 refinery.[3]

[3] An NPV analysis would show that the NPV of the Alberta refinery was clearly less than the NPV of the PADD 2 refinery, due to the fact that the significant capital costs for the refinery would occur in the first 4 years, prior to any revenue generation, in combination with the time value of money effect.

Table 5-4.

450 Scenario		
Alberta Plant	Scenario	450 Scenario
	Year	2020
	Plant	Alberta (with CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$1,593**
Variable Costs	$MM/year	**$1,083**
Fixed Costs	$MM/year	**$1,776**
Amortized Capital Costs and Return on Capital	$MM/year	**$2,791**
Carbon Tax Costs	$MM/year	**$153**
Total Costs	$MM/year	**$7,396**
Costs per bbl of Product (cents/gallon)	**cents/gallon**	**299**
PADD 2 Plant	Scenario	450 Scenario
	Year	2020
	Plant	PADD 2 (with CCS)
Feedstock Costs (including pipeline costs)	$MM/year	**$4,123**
Variable Costs	$MM/year	**$530**
Fixed Costs	$MM/year	**$328**
Amortized Capital Costs and Return on Capital	$MM/year	**$111**
Carbon Tax Costs	$MM/year	**$233**
Total Costs	$MM/year	**$5,325**
Costs per bbl of product (cents/gallon)	**cents/gallon**	**195**
Differential (Alberta - PADD2)	**cents/gallon**	**103**

Conclusions

Operating in a market environment as defined by the three IEA scenarios, CCS investment in Alberta will most likely not improve the market position of Alberta-produced gasoline and distillate.

The Alberta feedstock advantage cannot compensate for the effect of a high capital cost investment in Alberta competing with installed refinery assets in PADD 2. If carbon taxes incentivized the installment of CCS technology in Alberta they would do the same for a PADD 2 refinery.

Impact on Petrochemical Products Derived from Upgrading Offgasses and Petcoke Gasification in Alberta

Currently, Hydrogen, C_2 and C_3 saturated and olefinic molecules end up as fuel gas in some of the current refining and upgrading plants in Alberta. We considered the impact CCS implementation would have on the ability or incentive to recover these light gasses as either a hydrogen source for the plant or as a feedstock or low-purity product for ethylene and propylene production within the province.

Hydrogen

Most of the hydrogen consumed in upgrading and refining in Alberta is produced via a process called steam methane reforming (SMR). In the SMR, methane and steam are heated and shifted in the presence of catalysts to form CO_2 and H_2 along with a small amount of methane and CO. Purification of the reactor effluent steam is often accomplished via a Pressure Swing Absorber (PSA) which produces a high-pressure, high H_2 content stream and low-pressure tail gas containing CO_2, methane and H_2. Currently, without CCS, the tail gas is routed as fuel gas to the furnace to provide some of the heat for the SMR reaction. There is an option, however, with CCS to recover the CO_2 in either the PSA feed gas or the PSA tail gas and recover more H_2 per unit of methane consumed in the process side. Some of the benefit, though, is offset by the need to replace the thermal content of the tail gas with natural gas on the fuel side.

We estimate that the operating credit for CCS including the natural gas reduction and higher power requirements amounts to about $10-20/tonne of CO_2 at a natural gas price of $6/MMBTU and a power price of $75/MWhr. This amounts to a savings of about 11% per unit of hydrogen. Therefore, we opine that although CCS could realistically reduce the cost of hydrogen production, the credit would not offset the cost of CCS and, therefore, would not justify capital investment in CCS.

Other Upgrading Offgases

In a typical upgrader, the majority of ethane, ethylene, propane and propylene is produced by the delayed coker. On a bitumen feed basis, production of these components is in the range of 1.3-1.6 wt%. Typically these components are routed into the fuel system and satisfy around 15 - 20% of the total heat requirements for the upgrader. If these components were instead recovered from the delayed coker offgas, it would directionally reduce the amount of CO_2

produced by the upgrader because it would, in effect, decarbonize the fuel system to some extent by replacing C_2 and C_3 with natural gas imports. Based on our estimates the impact of the upgrader CO_2 emissions would be less than 1 percent. Therefore, in our opinion, recovery of these components would not materially impact the cost of CCS for the upgrader. Furthermore, it is our opinion that CCS would not have a material impact on the incentives to recover these light ends from the upgrader for ethylene and propylene production.

Gasification

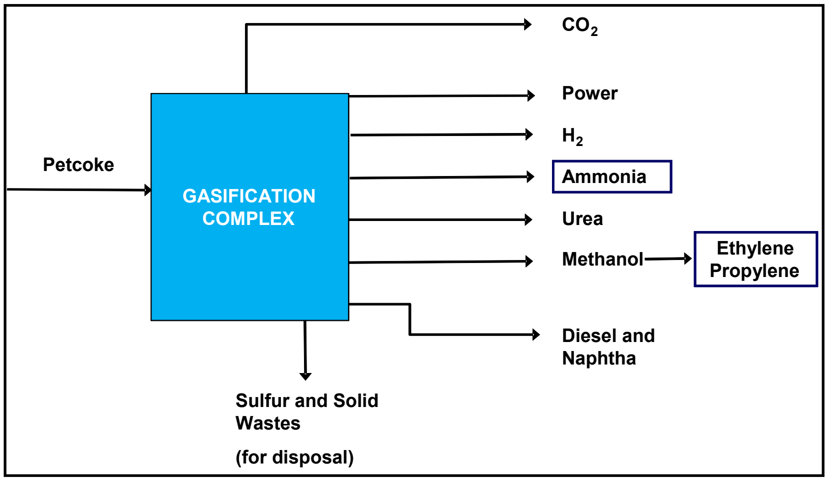
Jacobs Consultancy completed a project for AI-EES in 2010 (Jacobs Consultancy, July 2010) regarding the economics of implementing a petcoke gasification complex in the Alberta Industrial Heartland. The economics of the project showed that such a complex would not be economic without reductions in the cost of the gasification complex. The study looked at a complex that could make various outputs including power, hydrogen, methanol and urea.

This current study looked at the gasification complex as envisaged in the previous study but investigates the economics of manufacturing olefins and ammonia in the complex under the IEA scenario assumptions. The olefins would be produced through the implementation of an MTO unit downstream from the methanol unit. The cost of olefin production is compared to a conventional ethane cracker in the Alberta Industrial Heartland. The study also assessed the economics of ammonia production from syngas produced from the gasifier as compared to ammonia produced with natural gas as a feedstock.

None of the other potential products studied in the polygen gasification complex were significantly impacted by high CO_2 prices, and, therefore, the relative economics of petcoke gasification are largely determined by the price of natural gas and the capital cost of gasification.

The gasification complex flowscheme is shown in Figure 5-1.

Figure 5-1.



Ammonia

Ammonia production in Alberta is a cost-competitive efficient industry. The industry is technologically advanced and also enjoys a relatively low-cost feedstock position. The current production units are integrated with urea production units.

Ammonia transportation can be difficult due to the hazardous nature of ammonia; therefore, it is not widely traded on an international basis. Regional ammonia demand growth in Alberta and adjacent regions in Canada and the United States is low due to limitations in growth in arable land and because there is no expectation that farming intensity will increase in any significant way. New sources of ammonia production would then need to compete against the cash cost of production of existing plants, which have already fully paid for their capital. Regional excess ammonia capacity exists that can be re-started if ammonia demand increases and additional ammonia production capacity is required.

The analysis for ammonia production looked at two configurations:

i. New ammonia capacity using petcoke gasification and conventional ammonia production technology with a CCS unit

ii. Conventional ammonia manufacture with an existing plant and natural gas feedstock in the Alberta Industrial Heartland with a CCS unit

We evaluated the impact of carbon costs by using the carbon output associated with each configuration and the cost of carbon in each of the three IEA scenarios. Natural gas costs are an important component of ammonia manufacturing costs. We calculated the cost of ammonia manufacture using the natural gas costs from the IEA scenarios.

Figure 5-2 compares ammonia produced via petcoke gasification versus conventional ammonia production. The gas and carbon costs assumed in the analysis are shown in Table 5-5.

Figure 5-2.

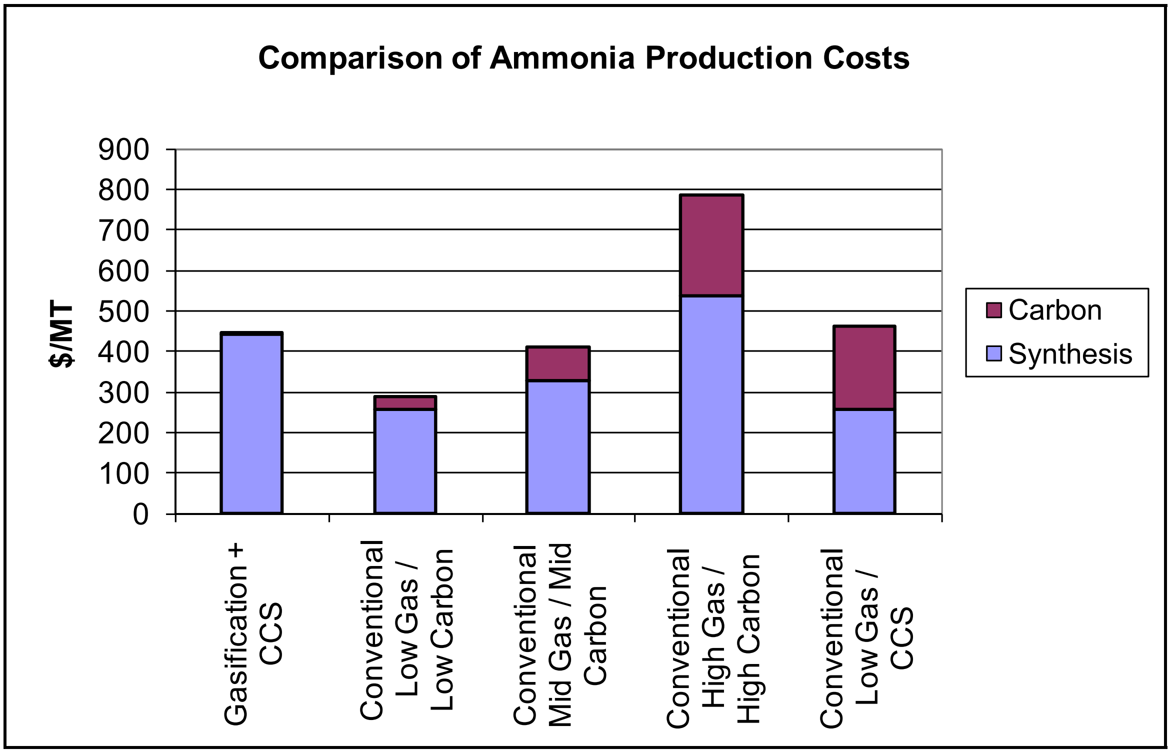


Table 5-5.

Scenario	Case	Gas Price (USD/MM BTU 2009$)	Carbon Price ($/MT CO_2)
Current Policies	Low Gas – Low Carbon	8	15
New Policies	Medium Gas – Medium Carbon	10.4	40
450 – 2035	High Gas – High Carbon	11.2	120

The analysis shows that only at high carbon prices and high gas prices is it lower cost to produce ammonia via the petcoke gasification route. However, the regional market for ammonia currently has excess capacity and could not absorb the incremental capacity from a new ammonia manufacturing facility. The scenario in which the high gas price and high carbon price exist is possibly in the 2035 time period; therefore, there is no near- to medium-term scenario in which the petcoke gasification route to ammonia would be economic, unless new gasification technology is developed that substantially lowers the capital cost associated with a gasification complex. In addition, traditional ammonia production from natural gas produces a concentrated CO_2 stream on the process side which can be considered a Tranche 1-type stream for CCS.

Ethylene and Propylene

Olefins market players must compete against global players in a highly competitive, commodity market. Prices are set by the lowest-cost producer. Olefins production in Alberta is globally cost competitive due to the low-cost feedstock and the large, technically advanced crackers in Alberta. Although ethylene producers in Alberta are well positioned, they also must compete against very low-cost production from the Middle East. This analysis examines the economics of producing olefins in Alberta via petcoke gasification to methanol to olefins via Methanol to Olefins (MTO) technology in a carbon-constrained environment.

Carbon Emissions

MTO technology is available through multiple licensors; however, although many units have been licensed, no units have been started up. The process produces ethylene and propylene in an exothermic reaction in a fluidized bed reactor over a zeolitic catalyst. Carbon or coke accumulates on the catalyst and is removed by combustion with air in a catalyst regenerator system. Catalyst regeneration is critical to maintain catalyst activity but it also increases the CO_2 production from the process. Table 5-6 shows the carbon burden for ethylene produced via the petcoke/methanol/MTO route as compared to the conventional olefin production route (IPCC). The significantly lower carbon burden for steam cracker olefins gives this route an advantage in a carbon-constrained environment.

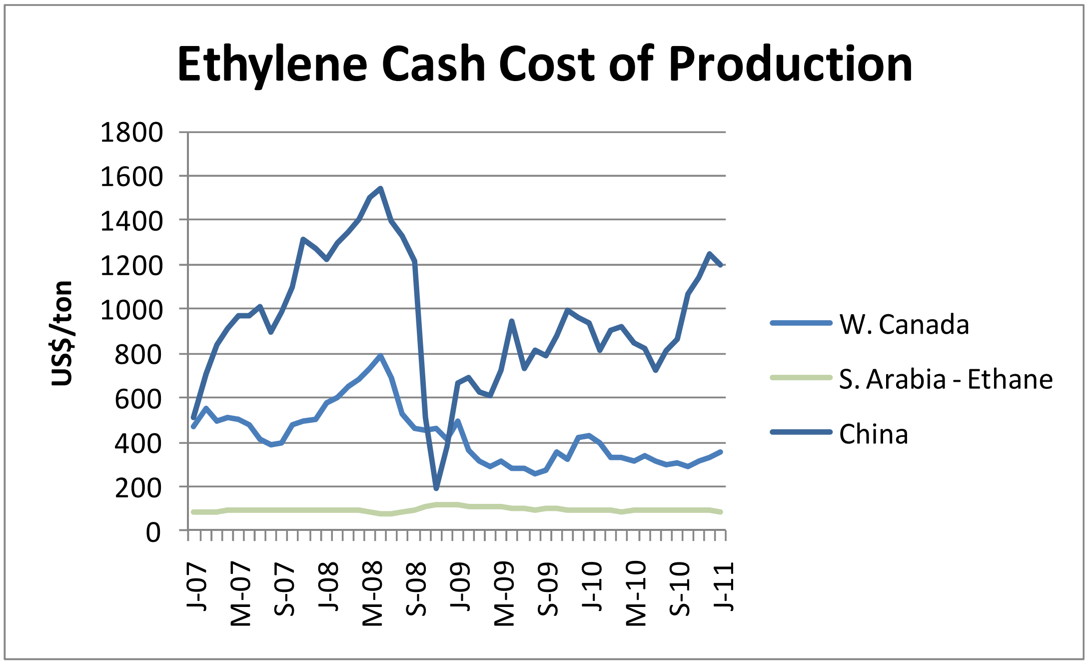
Table 5-6.
CO_2 Emitted per MT Ethylene Produced

	Syngas + MTO	Conventional Olefin Production					
Feedstock	Petcoke	Naphtha	Gas Oil	Ethane	Propane	Butane	Other
MT CO_2 / MT Ethylene	5.1	1.73	2.29	0.95	1.04	1.07	1.73

Production Costs

The MTO route is a relatively capital-intensive process. The high capital costs in the AIH provide a disadvantage to highly capital-intensive processes. Although the petcoke starting material is inexpensive, the additional costs of processing the syngas to methanol provide a disadvantage to MTO-based olefin processes. Figure 5-3 shows the current cash cost of production for three major ethylene-producing regions: the Middle East, Alberta and China. These regions were chosen because they represent the low and high ends of cash costs of production for olefins. The feedstock cost for the MTO process based on methanol from petcoke gasification is \$1200/ton olefins produced. Therefore, we can see that MTO is disadvantaged from a cash cost basis as well as a carbon emissions basis.

Figure 5-3.
Regional Ethylene Cash Costs



Notes:

1. Costs from Ethylene Competitiveness Review, Jacobs Consultancy
2. Methanol production costs from Jacobs Consultancy, Gasification Study
3. MTO feedstock basis from published information from UOP

Overall Competitiveness

Under all of the IEA scenarios, petcoke gasification to olefins is not cost competitive as compared to olefins cracker-based economics due to the high carbon intensity of the syngas and MTO process, the high cash cost of production using a methanol feedstock, and the capital intensity of the MTO process.

Other Products Derived from CO_2

Current Uses of CO_2

The current global demand for CO_2 is approximately 80 kmta, of which 50 kmta is used for EOR in the United States and Canada. Other than CO_2-EOR, CO_2 is currently used in relatively small amounts in specialty chemical applications, predominantly in beverage carbonation and food industry use. None of these applications offer any significant commercial opportunity for Alberta-based firms.

The current supply of CO_2 comes from naturally-occurring sources and from some pilot or demonstration carbon capture units.

Novel Uses of CO_2

With the anticipated significant increase in CO_2 available due to CCS, research is being conducted in many novel ways to use CO_2 as a chemical feedstock, in the production of biofuels from algae, and in the production of fuels. These efforts are for the most part in the early stages of commercialization. No significant commercial activity is anticipated for approximately 10 years.

For these technologies to have a significant effect on the economics of CCS, they would need to be able to offtake CO_2 in quantities large enough to have a material impact on the CCS unit economics. At this time, none of the projected technologies are foreseen to have that impact. The largest volume application is in CO_2-EOR, and that opportunity is relatively small compared to the potential volumes of CO_2 that will need to be sequestered. Deployment of CCS will require a higher carbon market price than is anticipated for the economic deployment of the novel applications that are currently being developed.

In addition, regulations must be developed that would enable the CCS producer to gain credits for the sale of CO_2 into reuse applications. If these applications do not provide permanent storage of CO_2, then the CCS operator may be able to get the full credit for sequestering the carbon captured.

Below we briefly review the following potential novel uses for CO_2 and indicate possible fits for the Alberta market:

- Mineralization
- Bauxite residue treatment

- Polymer feedstocks
- Biofuel feedstock through algae processing
- Feedstock for liquid fuels
- Urea productivity enhancement

Mineralization—Flue gas streams with dilute concentrations of CO_2 are reacted with mineral-loaded alkaline brine. Mineral carbonate precipitates can be further processed as an aggregate equivalent for the construction industry. In this form of re-use the CO_2 would be considered to be permanently sequestered. Calera and Skymine are actively working on commercializing this technology (the technology is still in the pilot plant stage of commercialization). Skymine has received funding from the US DOE/NETL, and Calera is endorsed by the US DOE. The market size is estimated to be greater than 300 Mtpa based on global aggregate consumption (Global CCS Institute, Accelerating the Uptake of CCS, 2011).

Cement Curing—CO_2 can also be used to replace steam used in curing precast concrete products. The technology is in the demonstration plant stage. Successful commercialization depends not only on economics but also on the construction industry accepting the final product performance. The market size is estimated to be 60 Mtpa globally (Global CCS Institute, Accelerating the Uptake of CCS, 2011).

Bauxite Residue Treatment—Bauxite residue can be treated with the addition of CO_2, lowering the pH of the residue. The pH of both the residue and decant liquor can be significantly reduced. The International Aluminum Institute claims that bauxite residue drying time is reduced, the mechanical strength of the residue is increased, and the potential for dust emissions is reduced. This end-use is not applicable to Alberta.

Polyols and Surfactants—Novomer is a start-up firm in the United States with significant US federal government support and industry partnerships with a number of major chemical companies. The technologies are currently in pilot plant stage. Novomer is focusing on making polyols and surfactants from ethylene and propylene oxides that are reacted with CO_2. The surfactants can be used in EOR. These end-use markets are relatively small compared to the total volume of CO_2 that would need to be sequestered from oil sands CCS units. This technology may be of interest as part of a value chain extension of the existing olefins and olefins derivatives manufacturing in Alberta. This technology is not considered to be a permanent carbon storage technology since the carbon would eventually be utilized or combusted and released into the atmosphere.

Biodiesel—A number of global biotech firms are looking at the conversion of CO_2 to biodiesel with the use of algae. These efforts are in the early to pilot plant stages of development and it is not anticipated that commercial technology will be available in the short term. These technologies face challenges in the high use of energy related to separation, purification and water removal of the product. Due to the required energy input, current estimates indicate that 20-30% of GHG can be offset by algae biofuels and protein production. High energy costs would be required in the Alberta climate since artificial light and heat would need to be used for significant parts of the year to enable the organisms to thrive.

Urea Productivity Enhancement—Mitsubishi Heavy Industries commercialized this technology in the 1990s and there are several commercial installations operating. Current ammonia/urea producers in Alberta do not use this technology to enhance urea production. It is possible that with readily available, low-cost CO_2, this technology may be more economically attractive. However, the technology does not permanently sequester CO_2.

Oil Sands Tailings Management—Research and development are currently underway to use CO_2 in oil sands tailings management (Oil Sands Alberta, 2011).

- A national network of researchers are collaborating on a method of injecting flue gases such as CO_2 into tailings ponds to feed the growth of micro-algae, which can then be processed into products such as ethanol, biodiesel and fertilizer.
- Canadian Natural Resource Limited's Horizon tailings plan is to use cyclones, thickeners and dewatering/drying technologies to reduce fluid tailings. The project will capture CO_2 emissions and pipe them to its extraction plant. The CO_2 reacts with silts in tailings to become a solid. This permanently traps the CO_2 and silts and will result in smaller tailings ponds, as water is recycled more quickly.

Summary

Niche applications for CO_2 re-use could provide value-added economics in the construction and specialty chemical sectors in Alberta. These applications will not sequester large amounts of CO_2 as compared to the total amount is emitted in Alberta; however, value-added industries could develop based on readily available low-cost CO_2.

Section 6.

CO_2-EOR and CCS in Alberta

Alberta has significant conventional oil deposits that are amenable to secondary or tertiary development through CO_2-EOR. This report examines the potential benefit to Alberta from two different viewpoints: the possibility of improving CCS economics through the sale of CO_2 to an EOR operator, or the possibility of enabling EOR projects through the supply of readily available, low-cost CO_2.

Opportunities to Use and Store CO_2 in CO_2-EOR

Currently EOR projects use different solvents depending on the nature of the oil deposit. These solvents range from water, to CO_2, to chemical solvents, to some combination of all of these solvents. It is not possible to effectively increase oil production from all reservoirs with CO_2; therefore, only a fraction of reservoirs that are available for EOR will be amenable to CO_2 flooding.

Of those reservoirs that are amenable to CO_2 flooding, only approximately 20 - 40% of the CO_2 that is used in the EOR process is actually considered to be sequestered in the reservoir. The CO_2 is removed from the produced oil and is recycled to continue the CO_2 flooding process. Eventually it is possible that, at the end of the EOR project, the resultant reservoir will be used to store the CO_2 for long periods of time, but the entire CO_2 stream is not considered to be stored during the EOR process. Current EOR projects that are designed and operated to maximize oil production and minimize operating costs are not designed to maximize CO_2 storage. Current operating practices include blowing down the reservoir at the end of the project life and separating the CO_2 for use in other projects or for sale. This practice also diminishes the storage capacity of EOR facilities. Table 6-1 compares the CO_2 use in EOR projects that are operating to minimize CO_2 costs to the operator, as compared to an EOR project that is used to maximize CO_2 storage.

Table 6-1.
CO_2 Usage Rates in CO_2-EOR Projects

MCF CO_2/bbl Additional Oil Produced	Net CO_2 Purchased	Recycled	CO_2 losses	CO_2 Sequestered
Conventional EOR	6	4	0.1	5.9
Conventional EOR with blowdown	2.1	4	0.1	2
High CO_2 use w/ field left at pressure	9	6	0.1	8.9

Source: Ruether et al.

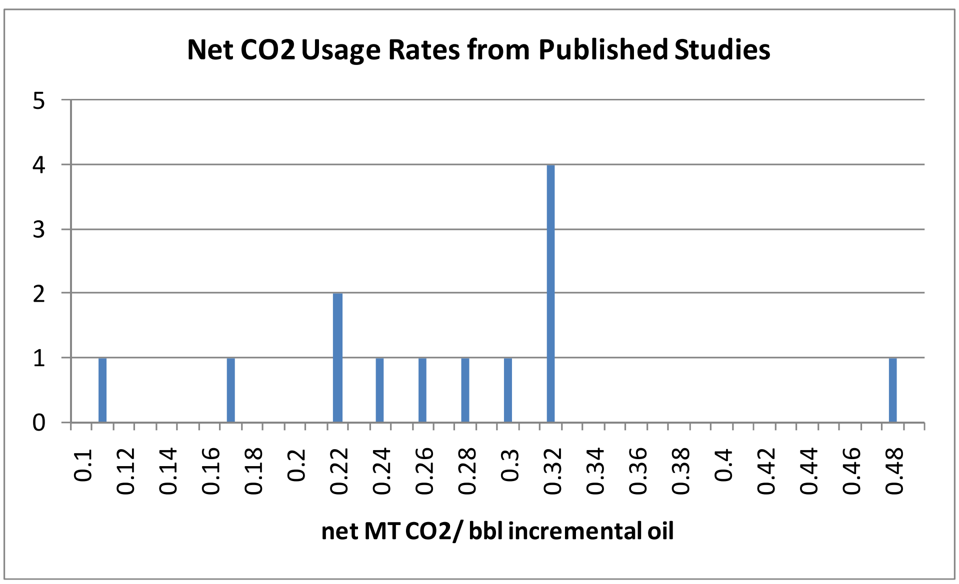
Capital and Operating Costs

We reviewed publicly available data and internal reports to determine a range of CO_2-EOR costs (EPIC, AERI, ARI, DOE/NETL). The published reports show a fairly wide range of CO_2 utilization factors. The CO_2 utilization rates shown here are net utilization rates. Capital costs are limited to the well costs, internal piping and CO_2 separation and compression equipment onsite. The CO_2 prices used in the analysis are as CO_2 delivered to the site.

Operating costs are highly dependent on CO_2 usage rates. Figure 6-1 shows net CO_2 usage rates from various published studies. These rates vary widely due to a number of factors:

- Operations goal—if the facility is operated to optimize the EOR operation, there is less CO_2 used than if the facility is being used to maximize CO_2 sequestration
- Geological nature of the site
- Previous secondary recovery methods used at the site (*e.g.,* solvent flood or water flood)
- EOR methodology—use of water flood or solvent flood interspersed with CO_2 flood

Figure 6-1.



Capital costs also vary widely depending on the installation. Most sites will already have well and drilling equipment on site. Sites that have already undergone secondary recovery will have existing equipment that may be able to be re-used. Equipment re-use can be problematic when switching over from solvent or waterflood to CO_2 flood due to the potential for fouling, emulsions, and corrosion that can occur from the use of supercritical CO_2. In addition, larger facilities will enjoy economies of scale.

Table 6-2.
Estimates of CO_2-EOR Costs

$/bbl incremental oil produced	Low	High
CAPEX	7.2	14.3
CO_2 cost	5.3	7.6
Well lease, operations maintenance	11.0	16.5
OPEX total	16.3	24.
Total Cost	23.5	38.4
CO_2 cost as % of total	23 %	20%

Notes:
1. CO_2 purchase price = $15/MT
2. Cost of CO_2 recycle stream = $13/MT
3. Net CO_2 usage rates range from 0.17 – 0.32 MT CO_2/incremental bbl
4. Capital costs have been adjusted to 2012 CDN $ and to an AIH capital cost basis with a 1.3 location factor

CO_2 Balance

We looked at the regional CO_2 balance in two ways. First, a top-down CO_2 supply/demand balance was developed. The supply side was determined by summing all potential sources for CO_2 from power plants, bitumen production and upgrading and chemical plants in Alberta. The demand side was determined by identifying the potential economic pools for CO_2-EOR using data from studies that were previously done for the Alberta government (ARC, EPIC). A second, medium-term project-by-project supply/demand balance was created using a list of announced EOR and CCS projects in Alberta.

Top-Down Balance

A CO_2 balance for Alberta was developed using the following assumptions:

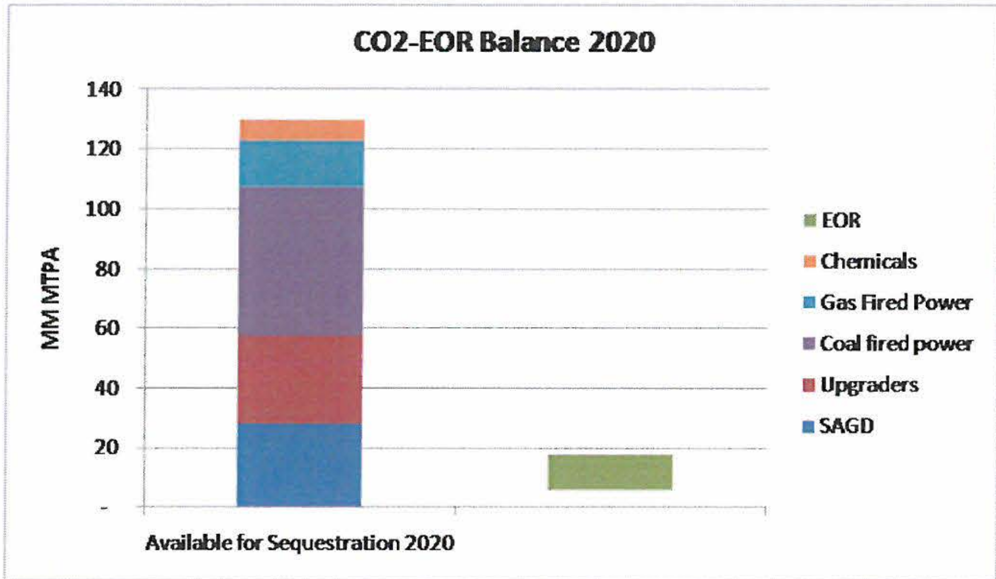
- CO_2 will be captured and available for sequestration from major emitting sources in Alberta, including:

- o Power generation—coal-fired and natural gas-fired
- o SAGD bitumen production
- o SCO production in upgraders
- o Ammonia and ethylene oxide manufacturing (chemicals)

- The amount of CO_2 captured was based on estimates developed by us while developing CCS costs for this report. This amount is less than the total amount of CO_2 emitted by these industries because the capture technologies do not capture all of the emissions from these industries. The amount is also less than the total CO_2 emitted in the province since we are only considering certain major emitters.
- The total EOR potential is a range based on the total potential for additional oil production through EOR in Alberta as calculated in *CO_2 Enhanced Hydrocarbon Recovery: Incremental Recovery and Associated CO_2 Storage Potential in Alberta, Summary Report,* prepared for the Alberta Energy Research Institute, December 2009, and *Alberta Enhanced Oil Recovery CO_2 Demand Study,* EPIC Consulting, prepared for Alberta Energy, November 2008.
- A range of net CO_2 usage factors was used to calculate the upper and lower bounds for CO_2 usage in EOR. The range selected was 0.17-0.32 MT CO_2/bbl incremental oil.

The top-down balance indicates that there is much more potentially available CO_2 to be sequestered than there are potential viable CO_2-EOR pools. If CCS is adopted in Alberta across all major carbon emitting sectors, there will be a much greater supply of CO_2 than the demand for CO_2-EOR projects. With an oversupply of CO_2, it is projected that the price for CO_2 for EOR projects will be driven down substantially. The operator that is evaluating a long-term sequestration project will not be able to sell the CO_2 to the EOR producer at a CO_2 price that could have a meaningful positive impact on the overall economics of CCS.

Figure 6-2.



Source: Jacobs Consultancy analysis

Project-by-Project Balance

We also examined the short- to medium-term CO_2 supply/demand balance that will be created as CCS is implemented in Alberta. There is a CO_2-EOR component in many of the announced projects.

Table 6-3 shows the project-by-project balance looking at currently announced projects in Alberta. This balance shows currently announced CO_2 capture projects and announced CO_2-EOR projects. The Shell project has announced plans to sequester the CO_2 in a deep saline aquifer; therefore, the CO_2 captured in that project is not shown as being available for EOR. Project Pioneer and Swan Hills Synfuels have announced that the CO_2 is intended for EOR projects but the specific EOR projects were not identified in publicly available documents. Thus, the CO_2 from those projects is shown as being available for CO_2-EOR projects.

This short-term balance shows that if these projects go ahead as announced, there will be excess CO_2 in the market available for EOR projects. If those producers are not able to secure contracts for the CO_2 then they will need to develop sequestration plans, which may hinder those projects from moving forward.

Table 6-3.
CO_2 Capture and EOR Projects

Projects	Type	MM MTPA CO_2			
		2012	2013	2014	2015
HARP (Redwater)	EOR	50	75	100	200
Clive, Fairborn Energy Trust	EOR	1600	1600	1600	1600
Agrium	Capture			1825	1825
Northwest Upgrader	Capture		1278	1278	1278
Swan Hill Synfuels	Capture			1460	1460
Shell Quest	CCS			1200	1200
Project Pioneer	Capture				975
CO_2 Captured			1278	5763	6738
EOR Needs		1650	1675	1700	1800
Planned Sequestration				1200	1200
CO_2 Available		(1650)	(398)	2863	3738

Notes:

1. Volumes, timing and CO_2 disposal plans from public announcements. No attempt was made to determine the likelihood of projects moving forward.
2. Public documents indicated that the HARP project would ramp up production. Production volumes based on Jacobs Consultancy estimate of ramp-up volumes.

CO_2-EOR Economics and CCS

The supply of low-cost CO_2 has the capability to increase the use of EOR in Alberta. CO_2 costs are approximately 20-25% of total costs for an EOR producer. Reducing the cost of CO_2 can substantially improve EOR project economics and thereby drive more EOR projects to be implemented. Perhaps even more importantly, the lack of availability of a consistent supply of CO_2 has reportedly held back a number of CO_2-EOR projects that would otherwise go forward.

For example, PennWest Energy is a leading EOR proponent in the Alberta market with significant ownership of oil fields in the Pembina Cambium region—a region that has been evaluated to have some of the highest potential for successful EOR projects in Alberta. PennWest had touted its EOR projects but backed off in 2010 because of concerns regarding CO_2 supply (*New Technology* magazine, 2010).

Studies conducted for AERI have shown a range of potential incremental oil production in Alberta of 1,080 – 1,700 million barrels produced using CO_2-EOR. If we assume an average project life of approximately 30 years, that would be the equivalent of 100 – 155 thousand barrels per day of incremental oil. Using the CO_2 storage factors of 0.17 – 0.32 MT CO_2/barrel of oil, this is equivalent to a total potential CO_2 stored of 180 – 540 MM MT CO_2.

The costs of production and total incremental oil data have been shared with MKJA and will be input into their model. The model will forecast the total incremental barrels of oil produced by EOR and will take into account the reduced costs for CO_2 that will occur if CCS is implemented in Alberta.

Section 7.

CCS-Driven Technology Cluster Development and Job Creation in Alberta

The analysis of technology cluster development and potential job development was undertaken as a competitive market analysis. We determined the overall size of the market and then examined the key competencies that are necessary for success. Finally we evaluated how firms in Alberta compared to the firms that are currently active in the global CCS marketplace.

CCS Spending

Global

We have estimated total planned global spending by looking at global power generation as forecast by the IEA for the three scenarios. Total power generated was multiplied by emissions factors and by spending / CO_2 emissions to estimate total spending on a $/$CO_2$ captured basis. It was assumed that approximately 75% of CCS spending is from the power sector.

Total global spending on CCS is estimated to be $4.2 trillion over the time period from 2015 – 2035 under the New Policies Scenario. Spending under the 450 Scenario will be approximately $2.1 trillion over the same time period. The 450 Scenario forecasts significantly lower fossil fuel power generation based on the assumption that the more stringent carbon regulations will be enacted and that significantly higher generating capacity for nuclear and renewable power will be built as compared to the New Policies Scenario. Under the 450 Scenario, CCS will be implemented earlier than under the New Policies Scenario.

We estimated that approximately 10 – 15% of CAPEX spending is for technology, engineering and services; therefore, the global market for this sector is approximately $250 – 375 billion for the New Policies Scenarios and $120 – 200 billion under the 450 Scenario.

These numbers are also in general alignment with the IEA Blue Map report (IEA, 2008) that estimates $130 billion in spending from 2010 – 2020 and $ 5.1 trillion from 2010 – 2050. The IEA Blue map shows global carbon reduction strategies with the goal of reaching CO_2 emissions that are half of 2005 emissions levels. This scenario is an extension of the 450 scenario.

Implementation rates are difficult to determine due to the massive scale of spending that would be required to meet proposed regulations. If we look at historical regulatory-driven capital spending patterns in the power and industrial sectors, such as the implementation of new MTBE capacity or flue gas desulphurization technology, there was a time in which retrofits and new processing capacity were installed to meet new regulations. After that period, spending rates significantly slowed as only new capacity additions required new capital spending and the retrofit market was saturated. Some additional spending continued to occur as firms continued to spend on maintenance, engineering services, technology and efficiency improvements and consumables.

It is not anticipated that the implementation of CCS will follow that pattern since different nations will be implementing different regulations and policies at different times. In addition, the world capacity for capital, engineering, construction labour and raw materials will limit the rate of new CCS additions. Implementation is also expected to happen over a period of time as the least expensive emissions will be captured first and the more difficult-to-capture emissions will be addressed at a later time.

Alberta

Total spending on CCS was calculated by estimating total emissions based on data from the ERCB and CAPP for the power and oil sands sectors, respectively. Chemical sector emissions were estimated using the data that were developed for the petrochemical sector in this report. Total spending was then estimated using the cost of CCS/MT of CO_2 developed for this report.

Total spending on CCS from 2015 – 2035 is estimated to be $45 billion. There is not anticipated to be a material difference in total spending under the two scenarios as it is anticipated that carbon prices will be sufficient under both scenarios to trigger CCS spending before 2035. The rate of spending will be different under the two scenarios in that spending will occur earlier in the 450 Scenario as carbon prices will be higher than CCS costs at an earlier date.

Total spending on engineering, services and technology is estimated to be 10 – 15% of total CAPEX spending. We have estimated total spending in Alberta in engineering, services and technology to be approximately $2 – 3 billion between 2015 and 2035. It is likely that most of this would be spent in Alberta for Alberta markets.

Global CCS Market Competitiveness

To understand how Alberta firms can compete effectively in the global CCS technology market, we examined the global community of firms, government institutions, non-governmental organizations and universities that are funding developing projects, as well as conducting research and development in the field. From this analysis, we can evaluate Alberta's position in the global market and the potential market share of Alberta firms.

Public Sector Support

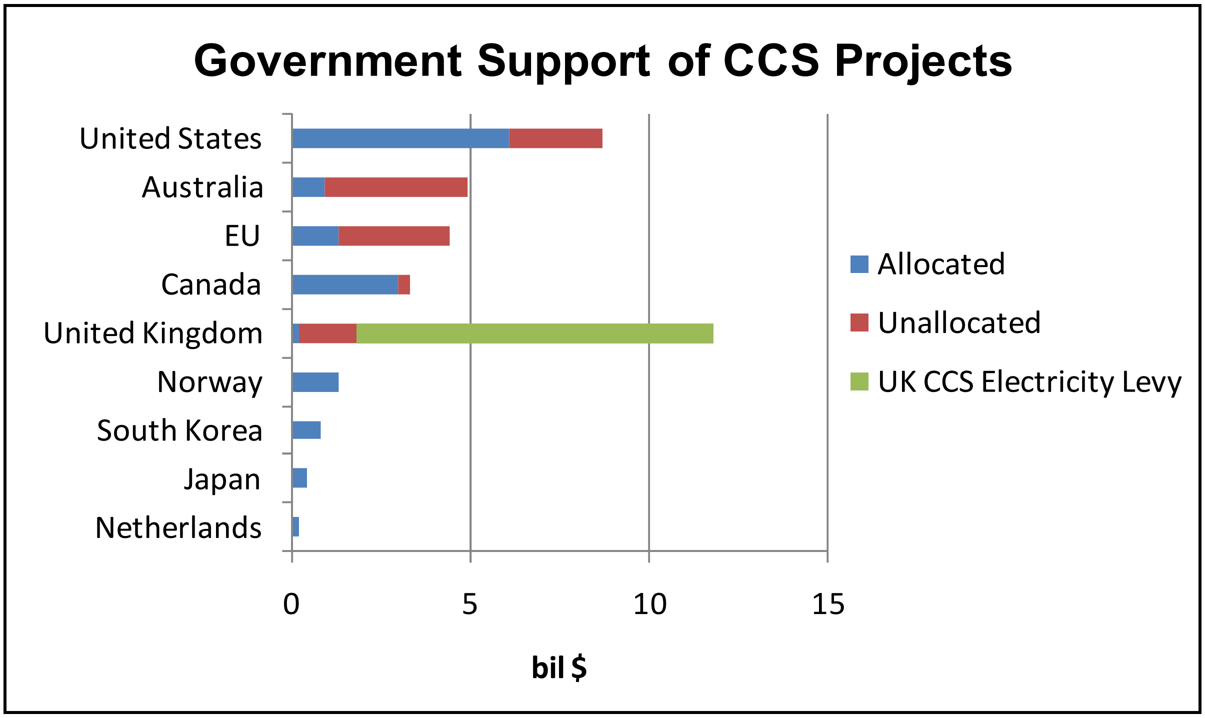
CCS technology development is challenging because large-scale, long-term demonstration units are required to demonstrate the effectiveness and safety of the technology and to provide data for cost reduction and efficiency improvements. These projects are expensive, GHG emissions regulations do not require firms to install CCS, and current and forecast carbon market pricing is well below the cost of CCS. Therefore a key element for companies to develop competencies in CCS will be public funding and support to enable demonstration projects.

Government support of CCS initiatives can take place in many forms:

- Direct project funding through grants
- Tax breaks or credits
- Debt financing such as loan guarantees or low-interest loans
- Indirect support such as feed-in tariffs or power purchase agreements
- Regulations that limit CO_2 emissions

Figure 7-1 shows current public funding commitments for CCS projects. As shown, not all funds that have been committed are allocated to specific projects. In the case of the EU, the unallocated funds represent funds that have been set aside to support projects that are still being selected for the NER300 program. For the United Kingdom, the funds have been committed for the CCS Demonstration Competition but the projects have not yet been selected. Canada has made significant funding allocations but lags other developed nations in total funds committed.

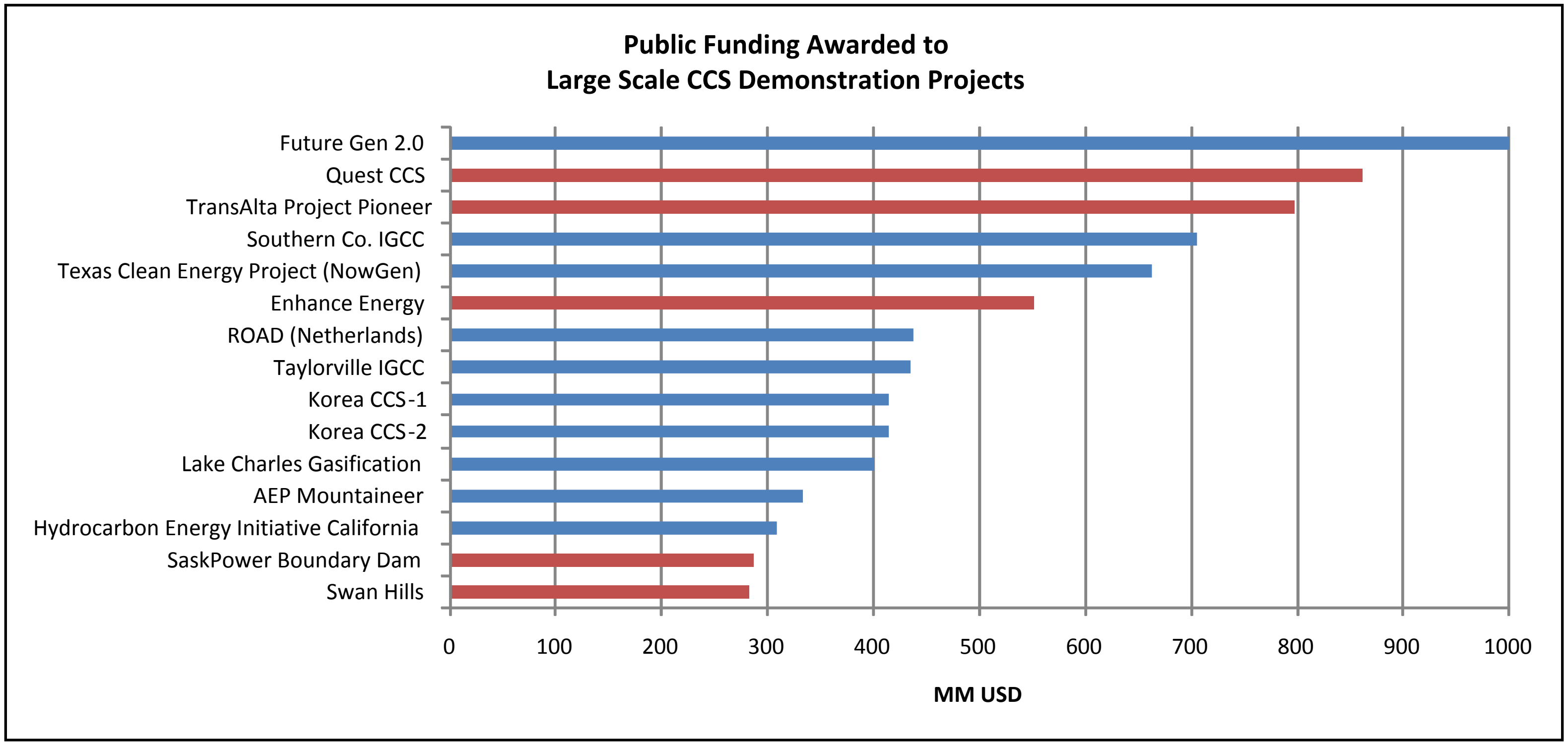
Figure 7-1.



Source: Global CCS Institute: The Global Status of CCS: 2010

Canada is one of the leading nations in allocating funds to large-scale demonstration projects. These projects are critical in the development of CCS technology. Figure 7-2 shows the world's top large-scale CCS demonstration projects ranked by level of public funding. Projects in red are Canadian projects; thus, five of the top fifteen large-scale projects are Canadian.

Figure 7-2.



Source: Global CCS Institute: The Global Status of CCS: 2010

NGOs and Private/Public Research Consortia

CCS is considered by coal companies, coal exporting countries and developed nations that use substantial amounts of coal in their electricity generation mix as critical to the continued use of coal. There are numerous existing research consortia whose stated goals are very similar to the interests of the Alberta CCS development goals. Table 7-1 lists some of the major consortia, their funding sources and focus. These consortia further the goal of accelerating CCS development and reducing costs, and also serve to make technology know-how widely available.

Table 7-1.
CCS Consortia

Organization Name	HQ	Partners	Funding Sources	Focus
CASTOR	IFP, France	Oil and gas cos Technolgy providers Research institutions and universities Energy companies	European Commision Industry	Best Practices Technology transfer
European CCS Demonstration Project Network	EU			Best Practices
CATO-2	Netherlands	40 partners from industry, NGOs, research institutions		Best Practices
Bellona	Norway	International NGO		Policy Development
ICONetwork	Canada	Oil and gas, oil sands producers Transalta Air Products	Partners	Policy development Best Practices Technology transfer
Carbon Management Canada	Canada	Universities		Research Technology transfer
CO2CRC	Australia	Australian universities Coal companies Energy companies	Partners In-kind and cash	Collaborative Research Technology transfer
Global Carbon Capture and Storage Institute	Australia	Over 300 members Industry Not for profits Research institutions Universities Governments Financial Institutions	US Dept of State Australian Govt Members	Policy development Best Practices Project Funding
Carbon Sequestration and Leadership Forum	Washington DC	Government entities	Member states	Technology transfer
NETL	Washington DC	US govt research		Best Practices Technology transfer
DOE	Washington DC	US govt research		Technology transfer

Source: internet searches, Global CCS Institute, 2011

Alberta Private Sector Firms

We completed a literature review to determine the nature of the private sector firms currently engaged in the CCS industry. The potential scale of the market and the wide scope of technologies required have driven many large engineering firms, as well as power and oil and gas technology providers, to develop offerings for the CCS market. Environmental firms, industrial gas providers, pipeline companies and measuring and verification companies also are active participants in technology development, pilot and demonstration plants, and regulations and standards development. No single firm has emerged as a market leader in providing CCS engineering services or technology.

Experience

Alberta is a leading region for large-scale CCS demonstration plants. Firms that are providing services to these projects will gain valuable knowledge and skills that could enable them to have an advantage as CCS plants are more widely implemented. However, engineering and technology supply for a major project such as a CCS unit is most likely to come from a consortium of multi-national firms. These companies source services from a variety of geographical regions based on factors such as know-how and experience for critical design components and cost of supply for services that have lower levels of complexity, such as piping layouts. Therefore, although the projects are being implemented in Alberta, not all technology and engineering services are coming from Alberta. For example, Northwest Upgrader has the following international companies providing engineering and technology to the upgrading project: UOP, Praxair, Lurgi, Jacobs, ChevronLummus Global, GE, Emerson Process Management, SNC-Lavalin and PCL (construction).

Technology Focus

The size of the market opportunity has attracted many strong global competitors. While many of the components of CCS are not application-specific, many critical areas of technology development—such as cost reduction through engineering improvements, scale-up, and technology integration into the emissions source process/plant—are application-specific. Outside of Alberta, most companies are focused on developing technology and scaling up technologies for coal-fired power plants. Alberta is focused on developing technology that is optimal for emissions generated in the production and upgrading of heavy oil. This can give Alberta firms an advantage in competing for oil sands-related projects but would not help when competing for coal-based projects.

Engineering Labour Pool

These services and technology development are engineering-based competencies. Alberta has a relatively small engineering labour pool compared to other regions, such as the US Gulf Coast. Most of that engineering talent pool at this time is focused on developing, designing and implementing SAGD projects to handle the growing demand for Canadian crudes. Engineering shortages are causing a rise in engineering wages that will make it more difficult for Alberta to compete in the provision of engineering services globally. Over the long term, however, market forces should enable Alberta firms to have access to engineering talent at competitive rates.

Export Opportunities

Due to their expertise in heavy oil production, Alberta-based firms are most likely to be successful exporting technology and know-how to other heavy oil-producing regions. The top countries in the world in terms of heavy oil resources (other than Canada) are China, Venezuela, and Nigeria. There are also smaller reserves in the United States, the Middle East and Russia. Exports of Canadian technology are most likely to regions with similar production technology as Canada's heavy oil market.

Canadian heavy oil sands are found in permeable sand formations. The most likely markets for Canadian technology will be in those regions with similar oil pools. Oil formations in China and the Middle East are primarily carbonate formations which require different technology to recover the oil than the technology used in Canadian oil sands. The Venezuelan market has the most potential for Alberta firms since the oil formations are most similar to those in Alberta and the reserves are very large. Currently Venezuelan heavy oil is being produced by cold methods, but SAGD type methods are being considered to increase oil production.

From a policy standpoint, Venezuela has been anti-CCS and has pushed back against including CCS as part of the CDM for cap-and-trade. In the long term, as government policies may change, Alberta could possibly look to Venezuela as an export market for CCS technology.

It is also possible that Alberta firms that develop specific CCS know-how and expertise due to their involvement in a large-scale demonstration plant may find ways to exploit that expertise to other developing CCS projects.

Technology Cluster Development

The development of a successful technology cluster has a number of critical components (Delgado et al):

- Active venture capital community
- Pro-technology transfer research institutions and universities
- Entrepreneurial environment

The development of SAGD technology is an example of successful technology cluster development. The government invested in private/public partnerships to develop the technology, and the technology was then transferred to private firms that commercialized the technology. Along with the successful commercialization of the technology by existing oil field players, new market entrants were also able to be successful. A substantial flow of start-up capital entered the Alberta market as venture capital firms and foreign investors sought equity in SAGD companies. Secondary job creation has been substantial as a host of small engineering, services and technical companies have been created to support SAGD enterprises. The experience of cluster development will assist Alberta in creating a new, related technology cluster because the critical elements to enable successful technology clusters are already in place.

CCS technology represents another opportunity to develop a technology cluster that can effectively deliver CCS technology to Alberta Industries. There are technology and know-how overlaps between SAGD technology and CCS that would enable firms that already have created the SAGD technology cluster to build upon those relationships and technology strengths and compete more effectively in the CCS market.

Technology Opportunities

The components of CCS technology are for the most part well understood and commercially proven. The development focus and where opportunities potentially lay for technology and engineering services firms are as follows:

- Site appraisal and selection know-how
- Integration of the technology into the CO_2 source facility
- Cost reduction

- Novel separation technologies
- Scale-up to commercial scale
- Pipeline development
- Development of the appropriate legal, regulatory, safety and monitoring standards, tools and know-how for CO_2 transport, injection, storage and monitoring

Site Appraisal and Site Selection

Alberta companies have a strong domestic competency in this area due to the extensive mapping and analysis that firms require for oil exploration, mining and SAGD projects.

Integration of Technology into the CO_2 Source Facility

This technology sector would not represent a potential major exportable technology or service opportunity for Alberta as its know-how will be developed in facilities associated with bitumen production, such as gasification and SMR for hydrogen production. Globally, the technology focus in this area will be coal power plants and integration into existing plants or into new IGCC plants. There would be a potential export opportunity for other heavy oil-producing regions such as California, China or Venezuela.

This does represent an area where Alberta-specific know-how will be a competitive advantage and Alberta-based firms will be more likely to secure contracts than firms from outside the region.

Cost Reduction

This sector is similar to technology integration in that it will be application-specific. It would therefore also be a relatively weak opportunity for technology export for the same reason as technology integration. It does represent a potential competitive advantage for Alberta-based firms with Alberta-specific experience.

Novel Separation Technologies

This is a potential area of strength for Alberta due to the following:

- There are strong university research groups who could focus on these technologies and who are experienced in technology transfer
- Alberta could benefit from the research work done from University of Regina on separation technologies
- Technology development in this area is less application-specific than integration or cost reduction development

Alberta firms must compete against global technology firms such as Alstom that have invested substantial amounts in separation technology and are currently working on a demonstration plant-scale in technologies such as aqua-ammonia.

Scale-Up to Commercial Scale

Scale-up know-how could possibly be a competitive knowledge set for Alberta. In this case, there would be first-mover advantage as the first firms to engage in scale-up activities will be the firms that will be farthest along the learn-by-doing curve. This is a competitive industry with technology sourced through major global engineering firms.

Pipeline Development and Construction

This could possibly be an opportunity for Alberta because Alberta firms can leverage the know-how and experience gained from building the Enhance pipeline. Alberta firms can also use information developed from the Saskatchewan project, which has a long history of successfully using a CO_2 pipeline to transport CO_2 from North Dakota to Saskatchewan. However, pipeline technology is relatively low in terms of value-added technology, which means that it will be less likely that Alberta firms can develop a sustainable advantage in pipeline technology supply.

Development of Technology and Know-How Related to Storage and Monitoring

This set of competencies has a relatively low technology value-added component and therefore does not represent a major opportunity for Alberta firms. Existing global monitoring and verification companies have already developed tools in this area and are leveraging their existing competencies to compete in this market space.

Summary of Technology Cluster and Job Creation Opportunities

There are diverse technology skills and know-how that will be required to serve the CCS technology market. The very large potential market and the high level of concern from governments has already drawn extensive public and private participation in the market, even though CCS technology is not yet fully commercial.

Alberta firms that wish to compete in this market space face challenges and opportunities:

- Alberta is one of the leading regions in the world in terms of public commitment to large-scale projects, but lags behind the United States, European Union, United Kingdom and Australia in total funding commitments.
- The Alberta CCS Fund is supporting four major large-scale projects which will give participating firms experience and know-how, and thereby improve their competitive position.
- Alberta engineering rates are high and engineering labour supply is limited.
- Engineering and technology support is routinely sourced globally in these markets and will be sourced from low-cost supply regions and from global firms that are active in the market.
- Companies with Alberta-specific experience in oil sands related technologies will have an advantage over firms without oil sands experience (*i.e.,* power generation or coal handling technology companies)
- Technology developments that focus on improvements specific to oil sands-related applications could be exportable to other heavy oil producing regions.
- Alberta firms can build upon successful technology development and commercialization expertise and cluster relationships that have been developed and built as part of the development of SAGD technology

Section 8.

Impact of CCS on Coal-Fired Power Production in Alberta

Currently, approximately 55% of power generated in Alberta comes from coal. Thirty-six percent comes from natural gas, 3% from hydro and 6% from other sources (such as wind) (ERCB). Carbon reduction legislation will result in coal-fired power plants being required to address their carbon outputs. Depending on the form legislation takes, power producers have a few alternatives:

- Replacement of older, less-efficient plants with state-of-the-art, high-efficiency plants
- Fuel switching to lower carbon intensity fuels such as natural gas
- Increased reliance on renewables
- Carbon permit purchase (cap-and-trade or other similar mechanisms)
- CCS to reduce carbon emissions from their plants

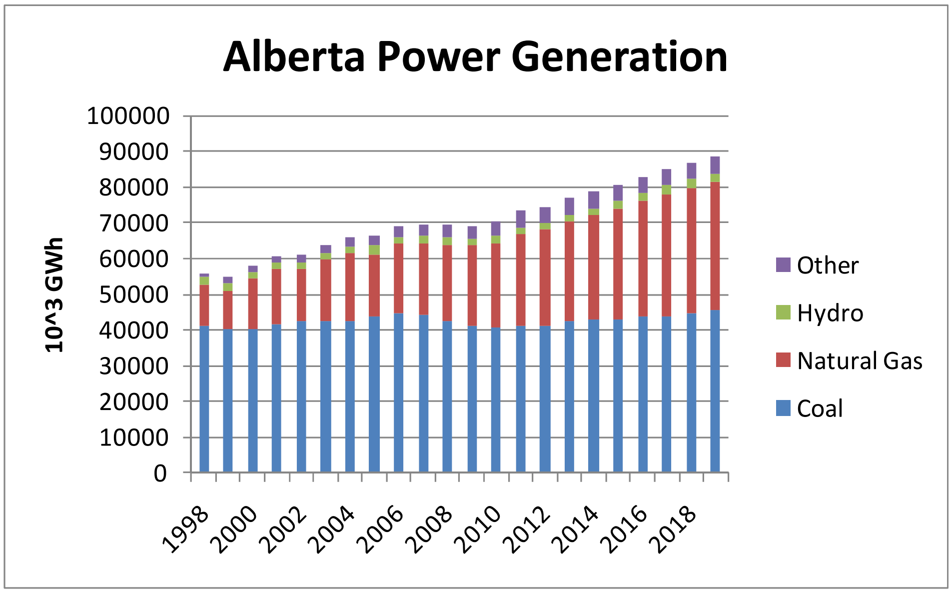
These choices will be determined by:

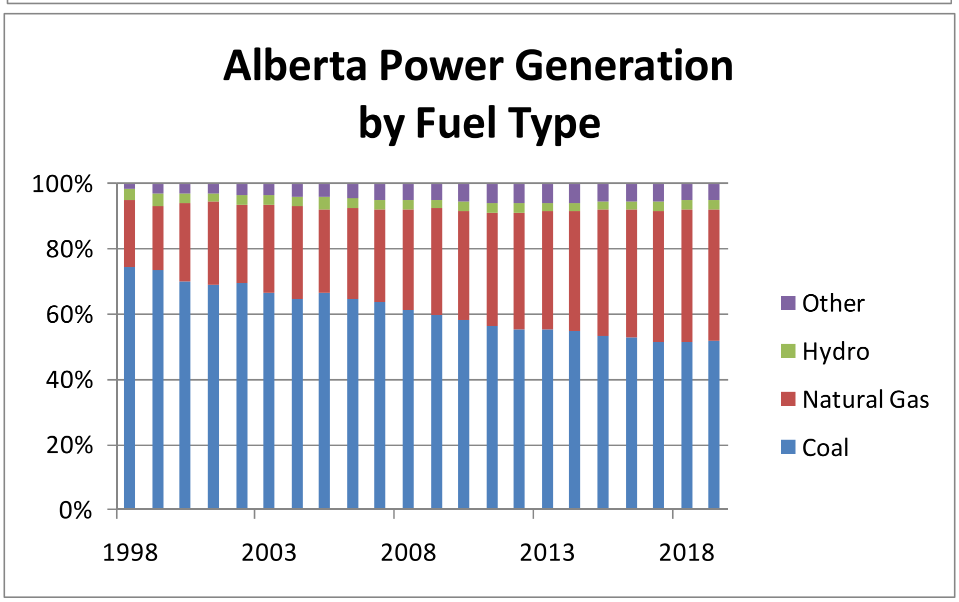
- Cost of carbon permits and timetable for implementation
- Cost and timeframe of CCS implementation
- Cost of new coal-fired power plants and the extent of efficiency gain
- Cost of fuel switching and extent of carbon reduction required
- Availability and cost of renewables
- Level of projected increase in electricity demand
- Projected lifespan of existing power generation facilities

Current and Forecast Alberta Power Supply

The ERCB gives the following breakdown and forecast of electrical power supply in Alberta. It forecasts natural gas to play a much more significant role in power generation than in the past. "Other" includes renewables such as wind, and is forecast to grow but still remain less than 10% of power generated. There is a very small growth forecast in coal-based power generation; therefore, no new coal-fired power plants are forecast to be required before 2020.

Figure 8-1.





Source: ERCB

CCS Cost for Coal-Based Power

The following CCS costs are based on information from NETL and EIA reports regarding coal-fired power generation. Cost estimates are for a typical 550-650 MW plant. Integration and site-specific costs will impact these cost estimates. These costs assume 90% of carbon capture.

Table 8-1.

$/MT CO_2 Direct Avoided Basis		Low	High
Capture and Compression	CAPEX	45	71
	OPEX – coal	6	7
	OPEX – electricity		
	OPEX – chemicals and other	20	24
Transportation and Sequestration		16	34
Total		87	137

Source: Jacobs Consultancy analysis, NETL

Additional Costs for Power with CCS

Based on CCS costs and typical coal-fired power plants efficiencies, for new units, CCS is estimated to add 50 - 60 $/MWH to the cost of producing electricity in Alberta from coal-fired power plants. Increasing the cost of power based on coal-fired generation facilities would be a further reduction in the fraction of the total power generated that would be supplied via coal-fired power generation. Retail prices for electrical power in Alberta have ranged from 50 - 150 $/MWH over the past three years; therefore, if all CCS costs were passed on to the consumer, retail electricity prices could increase significantly.

If the carbon prices are such that coal-based power plants are required to implement CCS, then natural gas power plants must also implement CCS. Depending on the source and carbon footprint of the power capacity lost in implementing CCS, estimated CCS costs for new natural gas-based power plants could be lower on an Avoided basis, and certainly, the emissions/KWh are much lower. Therefore, natural gas power plants have a lower cost burden for CCS than coal-based power plants. The estimated additional cost of electrical power generation from a natural gas plant is 30-40 $/KWh.

Another option for reducing the amount of CO_2 produced for power generation is to replace existing coal-fired power plants with natural gas-fired power plants. Based on our analysis of the publicly available data, NGCC plants without CCS cost on the order of 60-70 $/MWH and, on an

Avoided basis, offer 55-60% of the CO_2 reduction at a cost similar to installing a new coal facility with CCS. Although installing a NGCC without CCS provides a lower technical and cost risk, it is, however, susceptible to market risks related to natural gas prices.

Finally, in our opinion, the additional cost burden of CCS on fossil fuel-based power generation will reduce demand for power overall and will stimulate demand for power generation from renewables.

Jacobs Consultancy provided CCS cost information for power generation to MKJA, whose modeling work will forecast the changes in the power generation mix in Alberta as a result of carbon emission reductions regulations.

Section 9.

Summary and Discussion Regarding Stage Two

The Stage One analysis identified the following benefits associated with the implementation of CCS in Alberta. The MKJA analysis will provide more information regarding economic benefits.

Table 9-1.

Benefit 1 **Continued Access to US Markets**	If LCFS is broadly implemented with regulations similar to the current California regulations, CCS could be part of the process that enables bitumen-derived crudes to be categorized as non-High Carbon Intensity Crudes. This could avoid \$20-\$50 B/yr loss in revenue for bitumen exporters by 2030.
Benefit 2 **Value-Added Industries**	Due to the high capital cost of investing in capacity to add value to bitumen-derived feedstock, CCS was not found to have a positive impact on the economics of gasoline, ULSD, ethylene, propylene or ammonia production in Alberta. Small niche markets with early stage technology development programs were identified for alternate CO_2 uses.
Benefit 3,5,6,7 **Technology Cluster Development and Job Creation**	Alberta firms were determined to have a strong competitive advantage for providing technology and engineering know-how for domestic CCS or export projects that are associated with heavy oil. Alberta firms were not found to have a strong advantage for technology, engineering and service export for sectors outside those involved in heavy oil.
Benefit 4 **EOR**	Sales of CO_2 to EOR will not provide a long-term sustainable economic benefit to the CCS operator. Readily available quantities of low-cost CO_2 are forecast to spur new EOR project development.
Benefit 8 **Impact on the Coal-Fired Power Plant Industry**	CCS will substantially increase the cost of both coal-fired and natural gas power generation. It is likely that the development of CCS will cause demand destruction and a change in the electrical generating mix to include more renewables.

There are a number of key uncertainties in the Stage One analysis that should be further developed and analyzed in Stage Two:

- Potentially lower cost of CCS with new technologies: We analyzed the current state of CCS technologies; however, there is a high level of uncertainty associated with the cost of the technology. This uncertainty will be reduced as new large-scale units are built. In addition, new technology developments have the possibility to significantly reduce the costs of the technology.

- Sustained low natural gas prices in North America: The IEA scenario prices are higher than current forecasts for natural gas. It is possible that with the continued development of substantial shale gas fields in North America, natural gas prices will remain low within the forecast period.

- Increased crude oil demand: The IEA has forecast decreased crude oil demand due to the increased carbon regulatory environment. If this decrease does not happen, then crude oil prices may not decline as forecast by the IEA.

- Role of nuclear technology post Japanese crisis: The IEA scenarios also assume a greatly increased role for nuclear energy as part of the global strategy for carbon reduction. With the increased public concern regarding nuclear safety due to the nuclear crisis in Japan, the forecast increase in energy from nuclear plants may be greatly reduced.

- Assumptions regarding developing nations' alignment on CCS implementation.

- Political and possible technical risks regarding sequestration: Public concern regarding CO_2 leakage is high and activist groups could make it difficult to secure permits for sequestration and for CO_2 pipelines.

Many different industries and approaches are being considered to address global warming. These other technologies, such as geo-engineering, may represent a lower cost or more effective approach than CCS.

Appendix 1.

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Appendix 2.

California LCFS Look-Up Tables

Table A2-1.
California CI Look-Up Table for Gasoline and Fuels that Substitute for Gasoline

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Indirect Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	30	99.40
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66	30	95.66
	California; Dry Mill; Wet DGS; NG	50.70	30	80.70
	Midwest; Dry Mill; Dry DGS, NG	68.40	30	98.40
	Midwest; Wet Mill, 60% NG, 40% coal	75.10	30	105.10
	Midwest; Wet Mill, 100% NG	64.52	30	94.52
	Midwest; Wet Mill, 100% coal	90.99	30	120.99
	Midwest; Dry Mill; Wet DGS	60.10	30	90.10
	California; Dry Mill; Dry DGS, NG	58.90	30	88.90
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.60	30	93.60
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.80	30	86.80
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.20	30	84.20
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.44	30	77.44
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
	Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit	12.40	46	58.40
	Brazilian sugarcane with average production process and electricity co-product credit	20.40	46	66.40
Compressed Natural Gas	California NG via pipeline; compressed in CA	67.70	0	67.70
	North American NG delivered via pipeline; compressed in CA	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26	0	11.26
	Dairy Digester Biogas to CNG	13.45	0	13.45

Table A2-2.
California CI Look-Up Table for Diesel and Fuels that Substitute for Diesel

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Indirect Effect	Total
Diesel	ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies	94.71	0	94.71
Biodiesel	Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is required	15.84	0	15.84
	Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where "cooking" is not required	11.76	0	11.76
	Conversion of Midwest soybeans to biodiesel (fatty acid methyl esters -FAME)	21.25	62	83.25
Renewable Diesel	Conversion of tallow to renewable diesel using higher energy use for rendering	39.33	0	39.33
	Conversion of tallow to renewable diesel using lower energy use for rendering	19.65	0	19.65
	Conversion of Midwest soybeans to renewable diesel	20.16	62	82.16
Compressed Natural Gas	California NG via pipeline; compressed in CA	67.70	0	67.70
	North American NG delivered via pipeline; compressed in CA	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26	0	11.26
	Dairy Digester Biogas to CNG	13.45	0	13.45
Liquefied Natural Gas	North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency	83.13	0	83.13
	North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency	72.38	0	72.38
	Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency	93.37	0	93.37
	Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency	82.62	0	82.62
	Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA	77.50	0	77.50

Appendix 3.

Detailed CCS Costs

Direct Avoided Basis
Reconciled and Averaged costs, $/tonne of "direct" CO2 avoided, $2012 Cdn, Alberta

			Low	High	Comments
First Tranche	Capture and Compression	Capex	$37	$74	Range from various estimates
		Opex - NG	$28	$28	$6/MMBTU gas
		Opex - Elec	$13	$13	$75/MWhr power
		Opex- Chemicals and other	$2	$2	Amine, etc
	Sequestration and Transportation		$11	$22	
	Total		$92	$140	high pressure/ low CO2 concentrations or low pressure/ high CO2 concentration- SMR Reactor, Ammonia reactor - assumes 90% capture
Fourth Tranche	Capture and Compression	Capex	$55	$129	Range from various estimates
SAGD facilities		Opex - NG	$34	$34	$6/MMBTU gas
		Opex - Elec	$16	$16	$75/MWhr power
		Opex- Chemicals and other	$3	$3	Amine, etc
	Sequestration and Transportation		$13	$26	
	Total		$121	$208	Post combustion- SAGD Steam generation - assumes 90% capture
Third Tranche	Capture and Compression	Capex	$45	$71	Based on two publicly available sources with allowance on to accommodate higher range.
Coal Power		Opex - coal	$6	$7	$/1 GJ coal
		Opex - Elec	$0	$0	
		Opex- Chemicals and other	$20	$24	
	Sequestration and Transportation		$16	$34	
	Total		$87	$137	Post combustion- conventional coal power- assumes 90% capture
Second Tranche	Capture and Compression	Capex	$36	$65	Based on two publicly available sources with allowance on to accommodate higher range. Assumes no additonal natural gas as equipment size remains same and MW production decreases.
NG Power		Opex - NG	$0	$0	
		Opex - Elec	$0	$0	
		Opex- Chemicals and other	$19	$22	
	Sequestration and Transportation		$11	$22	
	Total		$66	$109	Post combustion- NGCC- assumes 90% capture
	Total based on same MW output		$114	$174	Post combustion- NGCC- assumes 90% capture

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