Carbon Neutral 2020

A Leadership Opportunity in Canada's Oil Sands

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Matthew McCulloch • Marlo Raynolds • Rich Wong

the PEMBINA institute
Sustainable Energy Solutions

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About the Pembina Institute

The Pembina Institute creates sustainable energy solutions through research, education, consulting, and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy and environmental governance. More information about the Pembina Institute is available at www.pembina.org or by contacting info@pembina.org.

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Notes to the Reader

Definitions / Acronyms / Abbreviations

bbl	barrel
CCS	carbon capture and storage
CO_2e	carbon dioxide equivalent
Emissions intensity	emissions per bbl (can be expressed as per bbl bitumen or per bbl SCO)
GHG	greenhouse gases (CO_2, CH_4, N_2O)
In-situ	extracting oil sands bitumen in place
M/E	mining and extraction of oil sands bitumen
ppmv	parts per million by volume.
SAGD	steam assisted gravity drainage —– a specific process (most commonly) used for in-situ extraction.
SCO	synthetic crude oil

Just the Facts

Canada is faced with the challenge and international obligation to reduce absolute greenhouse gas (GHG) emissions by 6% below 1990 levels by 2008–2012. Current projections suggest that, by 2010, emissions will be 32% higher than 1990 levels. A central cause of the projected increase in emissions is the rapid development of Canada's oil sands; this development is the single largest contributor to GHG emissions growth in Canada.

To support Canada meeting its commitment to significantly reduce emissions, this report estimates the cost for an oil sands operation to become carbon neutral by 2020. It examines two options for achieving this: carbon capture and storage (CCS) and GHG offsets. There are additional options companies can use to reduce emissions on-site, particularly implementing energy efficiency measures.

In this report three scenarios were considered:

1. Maximum CCS — all point sources are captured and stored
2. Moderate CCS — only CO_2 from hydrogen production is captured and stored; and
3. Maximum Offsets — CCS is not used and all emissions are offset.

Costs per tonne CO_2e abated using CCS were estimated as US \$34 to US \$100. Costs per tonne CO_2e abated using offsets were estimated as US \$22 to US \$66.

Figure E1 provides the results of these three scenarios under three operating situations: a) 55% mining and 45% in-situ; b) 100% mining; and c) 100% in-situ. All results presented are on a per barrel (bbl) basis.

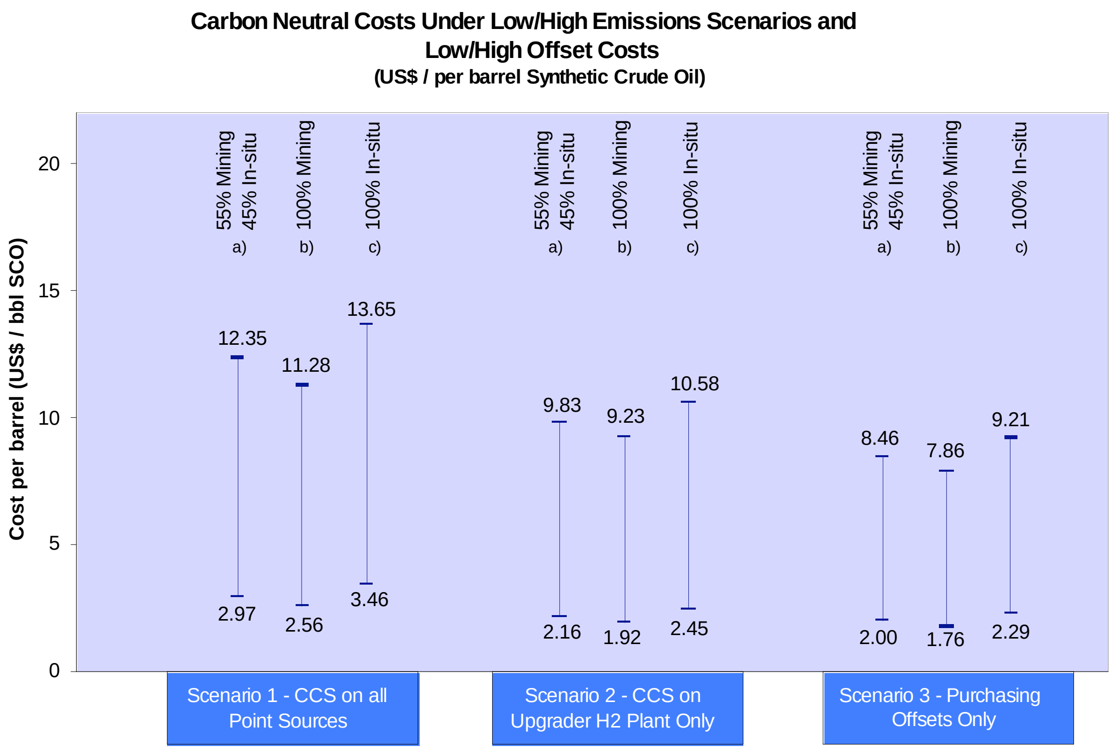

Figure E 1. Costs Ranges of Becoming Carbon Neutral

According to these results:

- costs could range from US $1.76 to US $13.65 per bbl.
- costs per bbl are slightly higher when maximizing CCS options over purchasing offsets.
- costs per bbl for both mining and in-situ are comparable, however, they are slightly lower for mining.

It is worth noting that the costs as reported here are likely conservative (i.e. over-estimated). Costs could come down to $1 per bbl should the price of offsets be in the US $11 per tonne range.

Key conclusions

- Canadian oil sands operations are the single largest contributor to GHG emissions growth in Canada.
- Carbon neutrality can be achieved through a combination of on-site GHG reductions using energy efficiency or fuel switching measures (switching to lower carbon fuels), using CCS, or purchasing offsets. Demonstrating leadership by identifying innovative energy efficiency and fuel switching opportunities should be the first priority for industry, and should be considered on a continual basis.
- While these costs could be higher in Alberta's current economic climate where labour and materials are becoming increasingly scarce and costly, they should be considered conservative as CCS costs will decrease with future technology improvements and revenues will be generated from enhanced oil recovery using captured CO_2.
- As oil prices are currently high and, as a result, oil sands companies are enjoying high profit margins, it appears economically feasible for oil sands operations to become carbon neutral by 2020. Furthermore, since legally mandated processes, such as sulphur and lead removal from fuel, are cost equivalent to reducing carbon in the oil sands on a per barrel basis, it lends further support for the possibility of achieving a carbon neutral state.
- The costs to become carbon neutral would decrease even further in an increasingly energy-constrained world where oil sands companies would be generating greater revenues per barrel.

Key recommendations

Oil sands companies should:

- take a leadership role in the oil sands sector and set a target of becoming carbon neutral by 2020.
- evaluate which approaches to reducing GHG emissions are best applicable to your own company.
- ensure extensive evaluation of all possible GHG reduction options through on-site energy efficiency and fuel switching measures.
- support the development of advancing capture technologies and find quality offsets.
- support immediate action on developing a domestic carbon offset trading system.

1. Introduction

Canada is faced with the challenge and international obligation of reducing absolute greenhouse gas (GHG) emissions by 6% below 1990 levels by 2008–2012. Current projections suggest that, by 2010, emissions will be 32% higher than 1990 levels.[1] This trend of rapidly increasing GHG emissions runs contrary to the urgent need to significantly reduce GHG emissions from industrial, residential and commercial sectors. We must achieve deep emission reductions if we are to stabilize atmospheric concentrations of GHGs at a safe level — estimated to be 400 parts per million by volume (ppmv) carbon dioxide equivalent (CO_2e).[2] Accomplishing this will require Canada to reduce its GHG emissions to 25% below 1990 levels by 2020, and 80% below 1990 levels by 2050.[3]

A central cause of the projected increase in emissions is the rapid development of Canada's oil sands — the single largest contributor to GHG emissions growth in Canada.[4] With production from the oil sands doubling between 1995 and 2004 to approximately 1.1 million barrels per day (bpd) the oil sands accounted for 3.4% of Canada's total GHG emissions in the year 2003.[5,6] While the economic success of the oil sands is clear, the commitment to addressing Canada's climate change challenge of increasing GHG emissions is not.

Aggressive growth in the oil sands, with 28 new projects in Alberta expected in the next ten years leading to the production of five million bpd by 2030, signals a need for immediate focus on reducing GHGs. Emission projections for the oil sands, in units of megatonnes (Mt) CO_2e, are presented in Figure 1. The projections show emissions from the oil sands rising to 7.5–8.2% of Canada's business-as-usual emissions (830 Mt) in 2010, or 11.0–12.1% of Canada's annual average Kyoto target emissions (560 Mt[7]) by 2012. They also indicate that oil sands could contribute 41–47% (36.7–42.7 Mt) of the projected business-as-usual growth (90 Mt = 830–740 Mt) in Canada's total annual emissions between 2003 and 2010.[8] This illustrates the incredible importance for industry to take responsibility and demonstrate leadership by deeply reducing their GHG emissions.

> Oil sands development is projected to contribute 41–47% of the projected business-as-usual growth in Canada's total annual emissions between 2003 and 2010.

[1] 2005. *Moving Forward on Climate Change – A Plan for Honouring our Kyoto Commitment*, p.12, http://www.climatechange.gc.ca/kyoto_commitments/. The figure of 32% has been obtained by adding 270 Mt to Canada's Kyoto target level of 560 Mt. The 270 Mt figure is described as the gap between Canada's business-as-usual emissions in 2010 and its Kyoto target, in Government of Canada. The source for the 560 Mt figure is provided in footnote 7 below.
[2] The Pembina Institute. 2005. *The Case for Deep Reductions: Canada's Role in Preventing Dangerous Climate Change,* p.3
[3] Ibid.
[4] D. Woynillowicz et al. 2005. *Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush*. The Pembina Institute. p.19.
[5] Alberta Energy and Utilities Board. 2004. *ST98-2004 – Graphs and Data – Section 2 Crude Bitumen*. Available online: http://www.eub.gov.ab.ca/bbs/products/STs/st98-2004-data-2-bitumen.ppt. Afformentioned information used as the source for the 1995 data. Source of 2004 data: Alberta Energy and Utilities Board, *ibid.*, p.2-2.
[6] Matthew Bramley et al. November 29th 2005. *The Climate Implications of Canada's Oil Sands Development*. Pembina Institute http://www.pembina.org/publications_item.asp?id=213. The emissions level calculated for 2003 is in agreement with a recent unpublished federal government estimate according to which the industry emitted 23.3 Mt in 2000 (information provided by Environment Canada to Robert Collier, *San Francisco Chronicle*, May 5, 2005, and then provided to the Pembina Institute).
[7] Environment Canada. 2005. *Canada's Greenhouse Gas Inventory, 1990–2003*, Annex 8, http://www.ec.gc.ca/pdb/ghg/inventory_report/2003_report/ann8_e.cfm.The 560 Mt figure is calculated as 6% less than Canada's emissions of 596 Mt in 1990.
[8] Pembina Institute. *The Climate Implications of Canada's Oil Sands Development: Backgrounder*. Available online: http://www.pembina.org/publications_item.asp?id=213. For projected emissions (low and high projections) associated with each oil sands project, and the associated assumption and caveats for the projections.

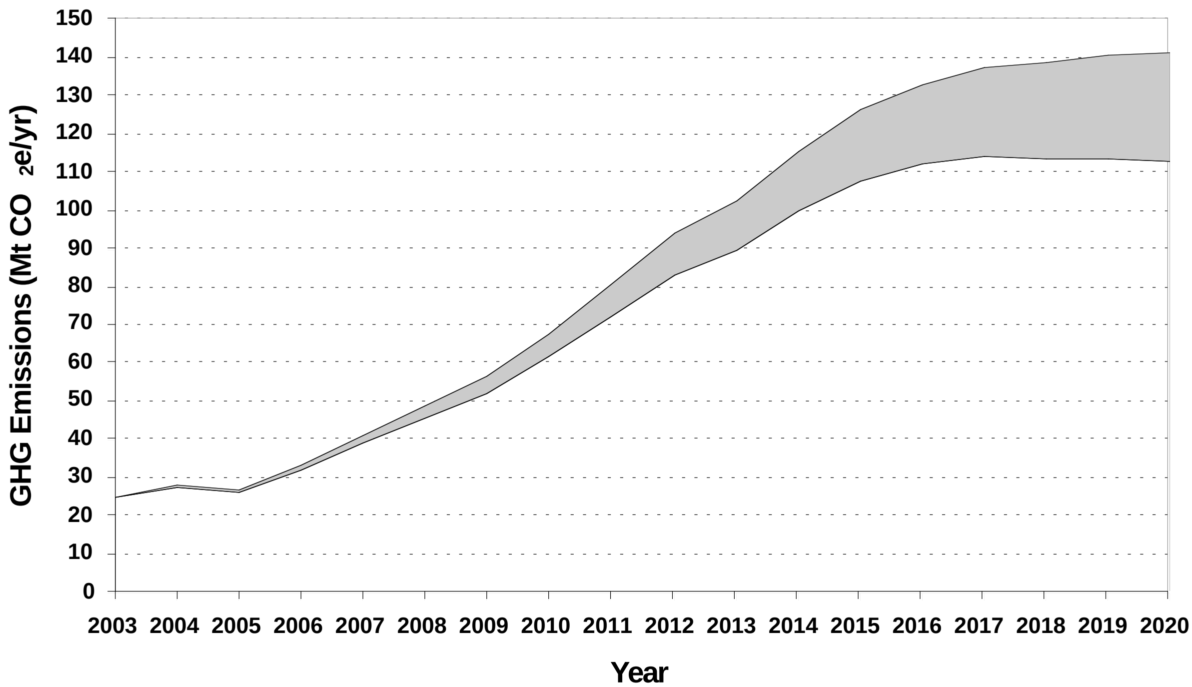

Figure 1. Annual Projected GHG Emissions (Mt CO_2e) from Canada's Oil Sands, 2003–2020 (showing the range between low and high projections)[9]

In the face of these projected increases, options are available to industry leaders in the oil sands to significantly reduce their emissions through such initiatives as energy efficiency, fuel switching, carbon capture and storage (CCS), or the purchase of GHG offsets.

Oil sands companies have the resources to make changes. The average earnings of four companies (Imperial, Shell, Suncor, Petro-Canada) with relatively large existing or planned operations in the oil sands between 1999 and June 2006 was recorded at CAN $1 billion per year. This equals a 42% average annual increase in income or 440% increase in total over this time period.[10] This was largely driven by the price of oil, which increased 156% between 1995 and 2005. Since 1995, there has been an increase in capital spending in the oil sands of over 1,600%.[11] For the four companies noted, this has lead to a return on average capital employed (a ratio indicating the efficiency and profitability of a company's capital investment) of 21% — a clear indication of the oil sector's ability to invest in capital projects.[12] Thus there can be no doubt that immediate and continued action to reduce GHG emissions is not only required, but is economically feasible for the oil sands sector.

With average earnings of over $1B per year since 1999, and an increase in capital spending of over 1600% since 1995, oil sands companies are considered well positioned to be investing in reducing GHG emissions.

The high prices of oil, averaged at US $70 per barrel as of September 2006, coupled with currently available technologies and the availability of GHG offsets create the conditions to empower companies to take action. Given the scale of the oil sands resource and increasing

[9] Matthew Bramley et al. November 29th 2005. *The Climate Implications of Canada's Oil Sands Development*. Pembina Institute.
[10] *Report on Business*. June 2006. *Available online:* http://www.theglobeandmail.com/v5/content/tp1000/index.php#
[11] *CAPP Statistical Handbook* and www.capp.ca.
[12] *Report on Business*. June 2006. Available online: http://www.theglobeandmail.com/v5/content/tp1000/index.php#

global attention, Canada's international reputation will depend on how we manage the environmental impacts, especially GHG emissions, while developing the oil sands. Based on this, the Pembina Institute seeks leadership from oil sands companies to become carbon neutral by the year 2020.

The Pembina Institute seeks leadership from oil sands companies to become carbon neutral by the year 2020.

Achieving this would demonstrate to the world that Canada is responsibly managing the GHG emissions associated with oil sands development. To support the feasibility of adopting carbon neutral oil sands, this paper aims to:

i. identify specific methods an oil sands operation could use to become carbon neutral by 2020; and,

ii. estimate the cost of an oil sands operation to become carbon neutral by 2020.

It is recognized that other sectors are major contributors to Canada's current and projected GHG emissions. The contribution of sectors such as electricity generation (generating 17% of Canada's GHG emissions), building use (11%), transportation (24%), and other industries (16%) must also be addressed in conjunction with the oil sands.[13] Indeed, there may be lower cost GHG reduction opportunities in some of these sectors, some of which could be achieved through implementing similar measures outlined in this paper, including CCS. This paper focuses on the oil sands for several reasons: the industry's current economic capability to invest in GHG reductions, the scale of development planned and associated impacts, the opportunity for industry collaboration given the relative proximity of operations, and the overwhelming contribution of oil sands development to Canada's projected GHG emissions growth.

> The oil sands is just one of many sectors that are major contributors to Canada's current and projected GHG emissions; all must play a part in reducing emissions and striving towards carbon neutrality.

This paper begins by providing an overview of oil sands operations and their associated GHG emission sources. It then goes on to describe opportunities to reduce these emissions, and finally reviews the costs of different GHG reduction scenarios. Although this paper is focused primarily on GHG emissions associated with oil sands production, information on the broader land, air and water impacts associated with such development is available at www.oilsandswatch.org.

[13] Environment Canada. 2006. *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990–2004*, p.xxii, 494, 507. The source mentioned above was used for GHG emission breakdown. Natural Resources Canada. 2005. *Energy Use Data Handbook, 1990 and 1997 to 2003*. p.99. Available online: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/handbook05/Datahandbook2005.pdf. This source provided the data for cars and trucks portion of transportation.

2. Overview of GHG Emission Sources from the Production of Oil Sands

Oil sands deposits are composed of sand, silt, clay, water and about 10–12% bitumen. Depending on the depth of the oil deposit, oil sands are either surface mined from open pits or steam heated so the bitumen can flow into a well and be pumped to the surface (this is known as in-situ extraction).

Oil sands operations in the Athabasca region generate GHG emissions from different sources. The operations themselves can be divided into several categories:

- Production of bitumen through mining and extraction processes
- Production of bitumen through in-situ processes
- Production of synthetic crude oil (SCO) through upgrading of bitumen

Figure 2 illustrates the basic activities in an oil sands operation that use both mining and in-situ resource extraction techniques.

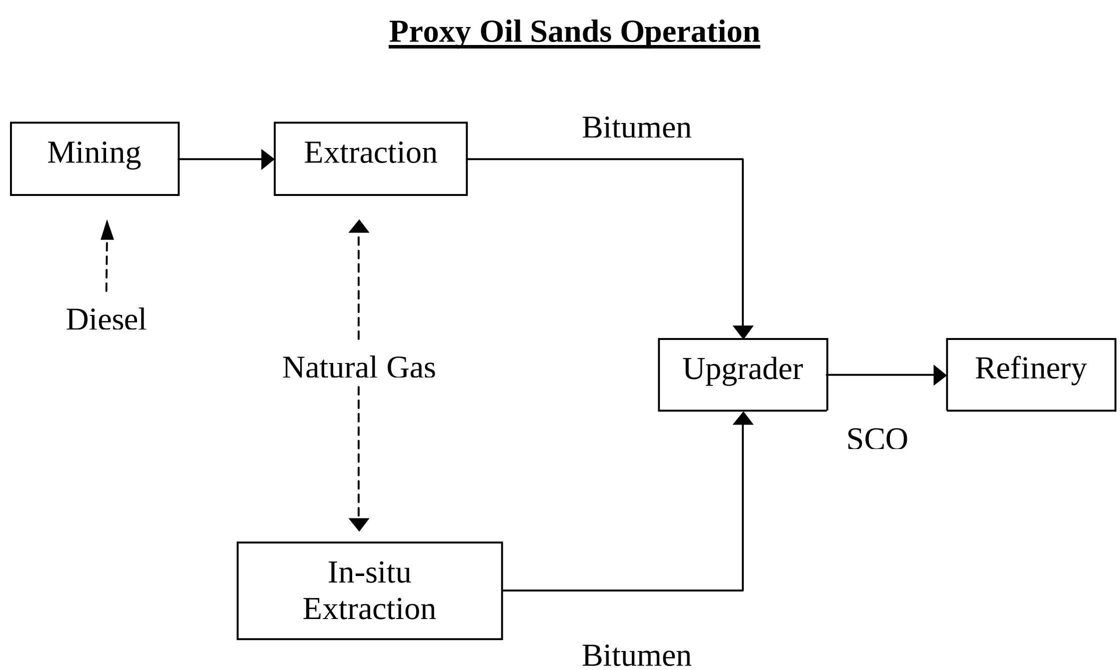

Figure 2. Proxy Oil Sands Operation Using both Mining and In-situ Resource Extraction Techniques

Some developers run both extraction and upgrading operations; others simply supply their produced bitumen to another company's upgrader operation (e.g., Petro-Canada's in-situ Mackay River project supplies bitumen to Suncor's upgrader). The primary product from the upgrading process is SCO (though diesel and gasoil may also be produced), which is then transported to refineries in either Canada or the United States.

GHG emissions and opportunities for reductions associated with the transportation of products to the refinery, the refining operations, or the consumption of gasoline and diesel, the primary end products of oil sands development, are not addressed in this report. While these are important emissions sources that need to be evaluated, this work focuses solely on the production of SCO from Alberta's oil sands resource.

2.1 Point and Non-point Source Emissions

GHG emissions can be classified into two groups: point and non-point.

'Point' source emissions originate from large stationary sources where it is technically feasible to capture GHGs for the purpose of CCS. Point source emissions are typically generated at centralized industrial operations with large-scale fossil fuel combustion.

'Non-point' source emissions include emissions that are geographically dispersed in smaller amounts than point source emissions and therefore technically more difficult to capture. In an oil sands operation, vehicle fleet (e.g., heavy hauler mine trucks) operations and fugitive emissions from tailings ponds and mine faces are examples of potential non-point source emissions.

Table 1 lists various point and non-point sources of emissions from oil sands operations, and both the amount of these sources generated, and their percentage contribution to total emissions generated, per barrel of synthetic crude oil (SCO) produced. The GHG emissions reported here are those generated by one low emissions intensity operation and one high emissions intensity operation to reflect a range of emissions intensity scenarios.

Table 1. Amount of Emissions Produced by Various Point and Non-point Sources of GHGs for Mining and Extraction, In-situ and Upgrading Oil Sands Processes

Process	Low Emissions Intensity (kg CO_2e /bbl SCO)	High Emissions Intensity (kg CO_2e /bbl SCO)
Mining and Extraction		
Point (utility heaters, power)	17 (61%) [14]	24 (62%) [15]
Non-point (fleet, mine face, tailings ponds)	11 (39%) [14]	15 (38%) [15]
Total	**28 (100%)**	**39 (100%)**
In-situ		
Point (boilers/plant energy)	48 (92%) [16]	55 (92%) [17]
Non-point (fugitive, vehicle fleets, flaring)	4 (8%) [16]	5 (8%) [17]
Total	**52 (100%)**	**60 (100%)**
Upgrading		
Point — Hydrogen Production	14 (27%) [18]	41 (52%) [19]
Point — Combustion Sources (coker, boilers)	37 (72%) [20]	37 (47%) [20]
Non-Point (fugitive)	1 (1%) [20]	1 (1%) [20]
Total	**52 (100%)**	**79 (100%)**
Total[21]	**91**	**127**

GHG emissions intensity for a given oil sands operation can vary depending on a number of key factors, including the following:

- Variability in bitumen quality
- Level of process integration (affecting level of energy efficiency)
- Technologies applied (gasification can greatly impact hydrogen production values)
- Fuel source for electricity generation
- Types of process controls utilized

These are all important in determining the GHG emissions intensity of any given operation.

Low and high scenarios were established using those information sources that best demonstrated a range in emissions. Comparative information outlining the specific differences between oil sands operations was not available as each operation would have unique factors affecting emissions intensity (factors such as ore quality, depth of ore, surface area of mine, distance to upgrader, and level of energy integration with existing facilities). Under the low emissions

[14] CNRL. June 2002. *Horizon Oilsands Project Application for Approval.*

[15] Imperial Oil Resources Ventures Limited. July 2005. *KEARL Oil Sands Project – Mine Development.*

[16] Flint, Len. March 31, 2004. *Bitumen & Very Heavy Crude Upgrading Technology*.

[17] Alberta Chamber of Resources. January 30, 2004. *Oil Sands Technology Roadmap Unlocking the Potential*. As the Alberta Chamber of Commerce report did not provide a breakdown of point vs. non-point GHG emission, the same breakdown as per the L. Flint report was applied.

[18] Keith, David. December 2002. *Towards a Strategy for Implementing CO2 Capture and Storage in Canada*.

[19] Suncor Energy. March 2005. *Voyageur Project Environmental Impact Assessment Volume 3*.

[20] CNRL. June 2002. *Horizon Oilsands Project Application for Approval.*

[21] Total assumes a ratio of 55% mining operations and 45% in-situ operations plus upgrading. See Section 4.1 for the rationale.

scenario, natural gas was the primary energy source for extraction, in-situ, and upgrading activities. Gasification of coke, a fuel by-product of bitumen upgrading, was included in the 'Higher Emissions Scenario' for hydrogen production for upgrading.[22]

2.2 Oil Sands Operations Described

2.2.1 Mining and Extraction

Oil sands located less than 100 metres from the surface are typically surface mined. The mined oil sands are then "washed" with high temperature water to extract the crude bitumen from the sand, silt and clay. This mining and extraction process recovers about 90% of the bitumen available in the deposit.

Typically, to produce 1 bbl of SCO requires removing approximately 2 tonnes of soil/rock above the deposit, 2 tonnes of oil sands,[23] 2–5 bbl of water,[24] and 7 m^3 (250 ft^3) of natural gas.[25]

As shown in Table 1 above, for mining and extraction operations, under both intensity scenarios, point source emissions make up approximately 60% of the total emissions produced, while non-point source emissions make up approximately 40%.

Figure 3 Surface Mining Activities Photo: C. Evans

2.2.2 In-situ Extraction

To access oil sands deposits greater than 100 metres in depth, in-situ recovery is required. Steam Assisted Gravity Drainage (SAGD) is the primary technology used to recover in situ bitumen deposits. SAGD injects high pressure steam deep underground to separate the bitumen from the sand. The heat from the steam also reduces the viscosity of the bitumen, thus allowing operators to pump the bitumen to the surface.

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[22] Gasification of coke yields a synthetic gas ('syngas') that may also be produced for energy supply purposes.
[23] http://www.cnrl.com/imageviewer.php?pic=/client/body/22.54/sco_process_zoom.gif&alt=.
[24] L. Flint. *Bitumen Recovery: A review of long term research and development opportunities*. p. 10, http://www.ptac.org/links/dl/osdfnlreport.pdf and L. Sawatsky, Golder Associates. March 22, 2004. *Improved Stewardship of Water Resources that are Entrusted to Oil Sands Mine* (presentation to "Water and Land Issues for the Oil and Gas Industry").
[25] Alberta Chamber of Resources. *Oil Sands Technology Roadmap – Unlocking the potential (2004)*, p. 14.

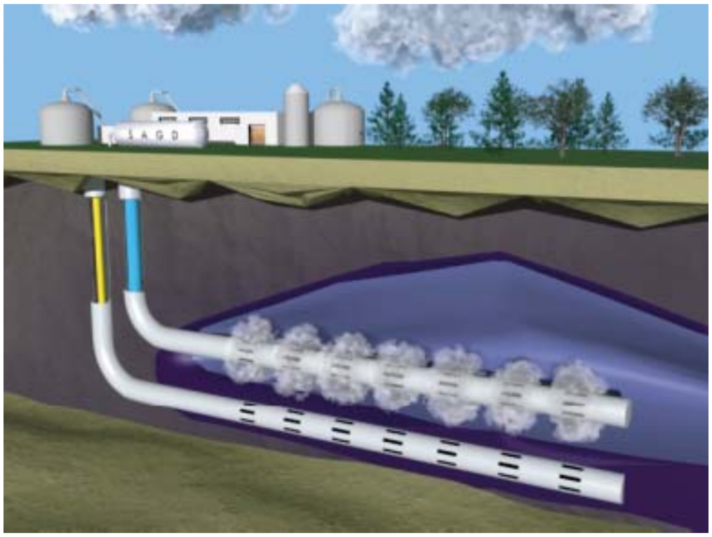

Figure 4. SAGD Extraction Technology Using a Paired Well

Figure 4 above shows a paired well used in SAGD extraction. High-pressure steam is injected into the upper well to heat and separate the bitumen from the sand. The separated bitumen and water drains to the lower well by gravity and is pumped up to the surface. A SAGD project may have multiple well pads, each of which contains between four and ten well pairs and ranges in area between one and seven hectares. A single project may have up to 25 well pads with interconnecting pipelines.[26]

The water and bitumen that is pumped to the surface is then sent by pipeline to a central facility where the bitumen is separated and the water is processed and recycled to produce more steam. The central facility also generates the high pressure steam that is distributed to the well pads.

SAGD extraction for 1 barrel of bitumen requires 2.5– 4 barrels of steam and 28 m^3 (1,000 ft^3) of natural gas.[27] Between 40% and 70% of the bitumen in a deposit is recoverable by SAGD processes.[28]

The emissions intensities for SAGD operations are summarized in Table 1 above (as In-situ) for point/non-point emissions.

2.2.3 Upgrading

Upgrading converts bitumen from a viscous liquid to higher quality synthetic crude that is used as feedstock for refineries. This requires two stages of upgrading:

The first stage aims to break long hydrocarbon chains into smaller hydrocarbons. This is accomplished using either coking, hydro-cracking or both:

- Coking — high temperatures (around 500°C) are used to crack the bitumen.
- Hydro-cracking — hydrogen is added with a catalyst to crack the bitumen.

The second stage of upgrading aims to remove nitrogen and sulphur from the bitumen with ‘hydro-treating,’ which requires hydrogen as a feedstock. Nitrogen is removed as ammonia and then typically used as a fuel, while sulphur is converted to elemental sulphur and sold to other

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[26] D. Woynillowicz et al. 2005. *Oil Sands Fever: The Environmental Implications of Canada’s Oil Sands Rush*. The Pembina Institute.
[27] Alberta Chamber of Resources. *Oil Sands Technology Roadmap – Unlocking the potential* (2004). p.14.
[28] Ibid.

industrial processes (fertilizer production) and/or stockpiled. Approximately 65% of bitumen is currently upgraded in Alberta[29] while the rest is transported via pipeline and upgraded elsewhere in North America.

The emissions intensities for upgrading operations are summarized in Table 1 above for point/non-point emissions.

The data illustrates that, under both the low and high intensity emissions scenarios for upgrading processes, 99% of all emissions generated are from point sources, while only 1% is from non-point sources.

Figure 5. Upgrading Facilities Photo: D. Dodge, Pembina Institute

Hydrogen plants can employ a Pressure Swing Adsorption (PSA) process, a Benfield Process or a hydrogen production process to produce the hydrogen needed for upgrading. While the Benfield process is the oldest of the three, PSA is increasing in popularity as it yields the highest purity hydrogen gas stream. The Benfield and PSA processes produce different CO_2 concentrations, and therefore have different carbon capture costs. The Benfield process yields a stream of high CO_2 concentration (~99% CO_2) while the PSA yields a lower concentration (~45% CO_2). Consequently, the PSA stream requires further processing to capture more CO_2 before it can be transported; as a result, the cost of carbon capture with this process is higher than it is for the Benfield process.

This report uses gasification technology on the high emissions intensity case for hydrogen production. This report also applies cost ranges for various capture technologies as described in recent research, incorporating both PSA and gasification hydrogen production processes.

[29] Alberta Chamber of Resources. *Oil Sands Technology Roadmap – Unlocking the potential* (2004), p.3.

3. GHG Reduction Opportunity Areas

This section outlines the specific GHG reduction opportunities that should be explored by oil sands companies. These opportunities are technically feasible and have been identified by experts in the field. It is generally recommended that owners and operators of oil sands operations publicly provide detail on the cost per CO_2e for each GHG reduction approach they plan to use to best compare these costs against those of purchasing offsets or implementing CCS applications.

Presented here are four options for reducing greenhouse gas emissions: energy efficiency, fuel switching, CCS and carbon offsets. The first three options (efficiency, fuel switching, CCS) involve direct reductions of GHGs from the operations themselves. The last option, carbon offsets, entails having another entity reduce emissions on behalf of the operation that purchases the reductions. Though each option is discussed briefly below, information on costs is reported only for CCS and carbon offsets. This is because costs associated with energy efficiency measures and fuel switching are variable across companies, and there is a lack of detailed information available on these costs. That being said, it is recognized that they may vary significantly depending on the scale and type of GHG reduction opportunity.

3.1 Energy Efficiency GHG Reduction Opportunities

Energy efficiency improvements are those that reduce the amount of energy required to produce a barrel of SCO and consequently reduce the total amount of fuel (energy) input required (primarily natural gas in oil sands operations). This in turn leads to a reduction in GHG emissions.

Table 2 below lists some current opportunities to improve energy efficiency and hence reduce GHG emissions. This is not an exhaustive list. Some of the opportunities are the subject of current research and it is recommended that oil sands operators invest in these opportunities to further commercialize the technology.

Table 2. Energy Efficiency GHG Reduction Opportunities[1]

Mining and Extraction

- Lower the temperature of the primary extraction process.
- Recycle hot primary extraction water through tailings thickening and clarification.
- Employ measurement and sensory technologies to improve process control.
- Improve slurry conditioning to improve ore processability.
- Use electric mine face extraction, using renewable based power.
- Incorporate mobile extraction equipment.

In-situ

- Use thermal solvent technology to reduce or eliminate steam generation requirements (technology currently in development). (Note: While this technology has demonstrated benefits, the life cycle environmental implications need to be evaluated and addressed prior to its full deployment.)
- Apply in-situ partial combustion processes (Toe-to-Heel Air Injection technology, in development).
- Lower the pressure of SAGD operations.
- Incorporate low-temperature catalysts to reduce energy requirements.
- Use microbes to reduce viscosity and partial bitumen upgrading.

Upgrading

- Use an Organic Rankine Cycle to generate electricity from waste heat where technically feasible.
- Insulate hydro transport pipelines and hot process vessels.
- Replace upgrading heaters with new, more efficient heaters.
- Apply improved controls and instrumentation to increase energy efficiency.
- Insulate and cover separation cells.
- Use high efficiency cokers and furnaces.
- To preheat combustion air or for space heating in buildings, capture and reuse heat from
  - flue gas desulphurization slurry waste
  - cooling water heat
  - flare stacks
  - power generation units
- Use membrane reactors for secondary upgrading.

General

- Improve leak detection and repair programs.
- Increase maintenance and control of pumps and drivers to increase efficiency.

3.2 Fuel Switching GHG Reduction Opportunities

It is possible to use lower carbon alternative fuel sources, such as biofuels, for selected oil sands operations. Many of the associated technologies are commercially available today. While other technologies currently require further development before reaching the commercialization stage, significant advancements can be expected over the next 10 to 15 years.

Currently there are two main categories for fuel switching using biofuels:

- Biodiesel — produced from a variety of renewable sources such as soybean oil, canola oil, sunflower oil, cottonseed oil, and animal fats.
- BioEthanol — produced from the starch of low-value grains or from cellulose-based materials such as straw, wood plantations, waste wood and agricultural residues.

Oil sands development offers a great opportunity for the use of biofuels: there is a large market potential within a given geographic region should a majority of the companies operating there participate in using these alternatives. Any surplus diesel produced on-site as a result of the use of these fuels could be delivered to downstream markets.

Table 3 below lists selected fuel switching opportunities for oil sands leaders to consider as part of an overall strategy to become carbon neutral by 2020.

Table 3. Fuel Switching GHG Reduction Opportunities[30]

Mining and Extraction

- Convert mine fleet to natural gas or use a biodiesel blend.
- Convert truck fleet to natural gas.
- Use bioethanol or biodiesel blends in truck fleet.

In-situ

- Use bioethanol or biodiesel blends in truck fleet.

Upgrading

- Employ bio-upgrading — a process that uses microbials to remove sulphur compounds or open hydrocarbon chains (technology currently only at bench scale)

While some fuel switching options may be considered too challenging for individual companies to undertake, significant opportunity would exist by industry pooling its resources together to develop an oil sands biofuel infrastructure from which all could benefit.

Nuclear energy has been identified as a non-fossil fuel based, low carbon, energy source for oil sands production. Today's nuclear technology is not considered to meet industry and society's expectations on cost, reliability, flexibility, safety, or environmental performance (particularly from upstream mining processes and the long-term waste management issues). Nuclear energy is therefore not considered a viable fuel switching option.

[30] Government of Canada. June 12, 1998. *Mining and Energy Summary Report*. Section 2.l.2,

3.3 Carbon Capture and Storage (CCS) GHG Reduction Opportunities

An alternative to reducing the generation of GHG emissions is to capture and store any CO_2 that is produced. The technology to capture CO_2 generated from point sources has existed for decades, and has been applied in the conventional oil and natural gas sector for many years. In Alberta, acid gas — a mixture of CO_2 and hydrogen sulphide (a waste product from treating sour natural gas) — has been injected deep underground since 1990. About 50 acid gas injection sites can now provide an analogue for CO_2 injection, with the Western Canadian Sedimentary Basin (WCSB), and especially that part of it lying in southern Alberta and Saskatchewan, recognized as one of the most suitable locations for geological storage in Canada. This study covers the cost of CO_2 capture, transportation and storage in the WCSB.

CCS costs (including transportation) in this report are primarily based on information provided by Natural Resources Canada's CANMET Energy Technology Centre.[31] These values were validated by information provided in a CCS report from the Canadian Energy Research Institute (CERI).[32] While CANMET did not report to which year the costs were to be applied, the original data came from a 2004 report. The CERI report draws its information from an internal 2001 study, using constant dollars for the year 2000.[33]

3.3.1 Capture Systems and Technologies

Table 4 below provides a brief description of three systems available for capturing CO_2: pre-combustion, post-combustion, and oxy-fuel. The table outlines the benefits and disadvantages of each technology, and provides a range of the cost to remove one tonne of CO_2. Costs are generally dictated by the industrial application; specifically, the higher the purity of the CO_2 captured, the lower the cost per tonne of removal. Note that different technologies may exist for the three types of systems considered. See Table 1 in Section 2.1 for a list of those point source emissions available for capture, and the percentage of emissions available for carbon capture and storage.

[31] NRCan. March 2006. *Canada's CO2 Capture & Storage Technology Roadmap*.
[32] CERI. June 2002. *Cost for Capture and Sequestation of CO2 In Western Canadian Geologic Media*.
[33] In addition to the constant dollars assumption, an exchange rate of U.S. 70 cents to the Canadian dollar, 10% real rate of return, a 30 year lifespan for the pipeline, 25 year lifespan for capture technology, and 10-30 years to complete storage were applied.

Table 4. CO_2 Capture Systems

System	Description	Benefits	Disadvantages	Cost Range (US$/t$CO_2$)
Pre-combustion	Fuel is gasified into a 'syngas', after which it undergoes a shift reaction where it is converted to hydrogen and CO_2.	Low incremental energy penalty. CO_2 separation and compression is relatively efficient.	Some questions of suitability of using gasification on lower quality fuels (e.g., coke). Hot gas clean-up, issues related to pure H_2 turbines.	18–44
Post-combustion	Flue gas is captured after it has been combusted.	System can be fitted on to many of the existing conventional combustion systems in the oils sands. Most mature technology.	Captures up to 20% of available CO_2. Separation is limited to absorption technologies. Other technologies (membranes or cryogenics) are not yet considered commercially viable. High energy input for separation.	44–62
Oxy-fuel	Fuel is combusted in an oxygen-rich environment, creating a high-purity CO_2 stream.	CO_2 stream is easily captured. NO_x emissions are greatly reduced.	Producing oxygen is energy intensive. High temperature ranges can have adverse effects on materials used.	12–71

There are various technologies that can be applied to these three capture systems. There are four categories of carbon capture technologies:

- Absorption – physical, chemical
- Adsorption – pressure swing adsorption, temperature swing adsorption, electric swing adsorption, vacuum swing adsorption
- Membrane – gas absorption, gas separation, water gas shift membrane reactor
- Cryogenics – compression and refrigeration

The costs provided in Table 4 for the different systems account for the use of different separation technologies. The capture systems technologies most commonly employed today are post-combustion capture (US $44–62 /tonne) and pre-combustion capture (US $18-44 /tonne) for a combined cost range of US $18-62 / tonne captured. The current costs of each system most likely lie toward the bottom of the ranges provided; the upper end of the range is based on historical prices and does not consider advancements made to date (and that will likely continue into the future).

In this study, capture costs provided have been increased by 37% to account for the generation of CO_2 emissions due to energy input into the capture systems themselves (referred to as cost per tonne abated).[34] As such, this study proposes a cost range of US $24 to $85 per tonne of CO_2 captured, assuming that different companies apply different technologies at different times. This paper also assumes that companies would not incorporate any capture technologies before 2020, thus allowing adequate time for transportation and storage systems to be in place as well as the appropriate capture technologies to be selected and incorporated. Note that energy efficiency gains of up to 30% could also be achieved by effectively integrating the energy requirements of the capture system with other existing facilities, thereby significantly reducing costs.[35] Companies not having completed facility design are well positioned to capitalize on these gains. Consider also that in the future, the technology will become increasingly efficient as more experience is gained, costs associated with integrating capture technology into operations (as opposed to retrofitting onto existing operations) will decrease, and economies of scale will increase. Indeed, cost reductions on the order of 25 to 30% (with the potential for reductions of up to 50%) are expected over the next two decades.[36]

3.3.2 CO_2 Transportation

Once CO_2 is captured, it must be transported either by pipeline or truck to a storage destination. As trucking is only economic over short haul distances, transport by pipeline is a better option for oil sands operations. Government and industry have been working together to evaluate the concept of establishing an integrated network at an estimated cost of US $330M.to transport CO_2 from oil sands facilities in Ft. McMurray and pipeline it to central Alberta for storage[37] CO_2 can be piped in either a gaseous or a liquid phase. Typically it is more economic to pipeline it in the dense liquid, or supercritical, phase. Doing so, however, uses more energy than pipelining it in a gaseous phase. The GHG emissions associated with this are not included in this analysis.

It is estimated to cost US $7/t to transport CO_2 by pipeline[38] 650 km in a common carrier network with a capacity of 14.5 Mt CO_2/yr.[39] As total GHG emissions from the oil sands, both current and projected, are well above this capacity, the network would either need to be increased or several pipelines would be required. When calculating costs of transportation and storage, this report assumes that CO2 would be transported to and stored in the Pembina gas field near Drayton Valley, Alberta.[40] The direct route distance from existing oil sands operations to this location is well within 650 km (less than 500 km for a direct route). Note that this cost range assumes one large pipe and full capacity; low utilization and multiple CO_2 source points would raise the overall costs (or toll).

While a discussion of pipeline routing and its associated impacts is not within the scope of this analysis, a detailed life cycle value assessment (i.e., considering broader economic, social, and environmental impacts from a systems perspective over the life of the project) will be a critical element of selecting a location and route.

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[34] CERI. June 2002. *Cost for Capture and Sequestation of CO2 in Western Canadian Geologic Media*. 37% taken as average of abatement cost premiums for eight different Alberta-based industry operations in the report. Note that the costs provided in the CERI report considered an exchange rate of CDA$0.70 for every US$1. Thus costs could be considered conservative with a stronger Canadian dollar.
[35] Ibid.
[36] NRCan. March 2006. *Canada's CO2 Capture & Storage Technology Roadmap*.
[37] CERI. June 2002. *Cost for Capture and Sequestation of CO2 in Western Canadian Geologic Media*.
[38] Ibid. Specifically for a 24 inch CO_2 pipeline from Syncrude and Suncor operations to central Alberta.
[39] NRCan estimated costs of CDA $6/tonne based on these pipeline characteristics; however CDA $8/tonne CO2 (translating to US $7/tonne) was used based on the more context specific data provided by CERI.
[40] Canadian Energy Research Institute. 2001.1,700 Mt of storage capacity in Central Alberta.

3.3.3 CO_2 Storage

Geological storage of CO_2 can occur in a variety of formations including depleted oil/gas/bitumen reservoirs, coal seams, deep saline aquifers, and salt caverns all using conventional drilling techniques. Other options for storage include mineralization (considered too costly) and deep ocean storage (considered infeasible for oil sands); these are not included in the cost estimations developed for this report.

The cost of storing CO_2 in Canada is currently estimated to be US $3–$8/tonne.[41] Included in this estimate is the cost of building injection facilities (US $44,300–$132,900), drilling (US $222–$620/metre), completing wells (US $133/metre), operations (US $1/tonne (labour, maintenance, contract services, lease rentals, insurance charges)), and electricity (US $53/MWh).[42] Storage costs in large depleted oil and gas reservoirs would be lower, while those in shallow small reservoirs would be higher.

CERI estimates that spent oil and gas reservoirs in the Western Canadian Sedimentary Basin (WCSB) could store approximately 15,000–20,000 Mt of CO_2. Considering oil sands emissions are estimated to total 140 Mt per year in 2020 (see Figure 1) this translates into over 100 years of local storage capacity.

CO_2 can also be used for enhanced oil recovery (EOR), providing financial returns to offset the capital costs of CO_2 storage. While this use is not considered in this analysis, these types of projects are now operating (e.g., Encana's Weyburn project[43]) and will likely continue to be developed prior to 2020.

3.3.4 Factors Influencing CCS Costs

The following are some key factors that can influence costs of carbon capture, transportation, and storage:

- Capture costs can vary depending on CO_2 flue gas concentration, and on the technology applied.
- Transportation costs should remain stable with little variability due to industry experience with pipeline construction and operation. These costs would be expected to increase should transportation distances exceed 650 km.
- Transport costs typically increase or decrease with the size of the pipeline, the volume of CO_2 transported, the routing and the length of the pipeline.
- CCS costs can vary depending on the depth of the storage reservoir, drilling requirements, and the size of the storage area.
- CCS costs could be lowered through revenue generated from enhanced oil recovery opportunities. EOR can increase oilfield output by up to 60% and extend well life by 20 years.[44] The Weyburn EOR project in Saskatchewan is expected to produce over 122 million barrels of incremental oil.[45]

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[41] NRCan. March 2006. *Canada's CO2 Capture & Storage Technology Roadmap*.
[42] CERI. June 2002. *Cost for Capture and Sequestation of CO2 in Western Canadian Geologic Media*.
[43] For further information, visit: http://www.co2captureandstorage.info/project_specific.php4?project_id=96
[44] Environmental Finance. *Big Potential Seen for CO2 Oil Recovery in US*, 2006.
[45] IEA Greenhouse Gas R&D Programme. *Weyburn Enhanced Oil Recovery Project*, 2005. Available online: http://www.co2captureandstorage.info/project_specific.php4?project_id=70

- Regional market conditions may increase or decrease prices accordingly. As Alberta has an overheated economy right now, costs may be higher than presented in international studies or older Canadian studies.
- Storage costs may decrease if large volumes are consolidated and capital costs are amortized over longer periods of time.

3.3.5 Responsible Implementation of CCS

While CCS may be considered one part of the solution for managing GHG emissions from the oil sands, key environmental and social risks must be carefully evaluated and managed in its design and implementation. The International Energy Agency (IEA) states: “A number of potential environmental, health, and safety risks associated with CO_2 sequestration are broadly acknowledged and require additional research to allow for a comprehensive risk assessment, particularly with regard to geologic storage.”[46] For successful use of CCS, the following should be ensured:[47]

- The uncertainty around intergenerational long-term retention (permanence) of stored carbon must be adequately addressed. While oil and gas fields are reasonably well understood over periods of a few decades, the long-term performance of seals and the character of other formations such as saline aquifers are much less well understood. CO_2 would need to be trapped permanently — meaning, at a minimum, for tens of thousands of years.
- All potential health effects are addressed, including the potential for slow leakage through ground and catastrophic leaks from CO_2 extraction plants, pipelines and wells.
- CCS is not considered ‘the’ solution to GHG management, and renewable fuels and energy efficiency are aggressively pursued in conjunction with CCS.

3.4 The GHG Market and Offset Prices

The purchase of GHG offsets is considered in this report as one way of helping to meet the goal of becoming carbon neutral. Two important factors must be stressed here:

i. Any company should seek to reduce or eliminate its operational emissions first, and consider the purchase of GHG offsets only as a secondary alternative.

ii. In the event that GHG offsets are purchased, only those having the highest environmental integrity and offering absolute certainty in real reductions should be considered. This is particularly important given the emergence of international GHG markets and the need for this approach to be credible and effective in meeting its intended objectives.

International carbon trading markets exist as an optional mechanism for both countries and companies to meet GHG reduction commitments. Currently, there are two internationally recognized mechanisms by which Kyoto compliant GHG emission reduction units can be purchased: the Clean Development Mechanism (CDM) and Joint Implementation (JI). The CDM generates certified emission reductions (CERs) from countries in economic transition, while the JI generates Emission Reduction Units (ERUs) from industrialized countries (ERUs exist starting 2008). Note that the European Union has set up its own trading system to help meet associated domestic commitments.

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[46] IEA. 2002. *Solutions for the 21st Century: Zero Emissions Technologies for Fossil Fuels*. p. 26.

[47] M. Griffiths et al. November 2005. *Carbon Capture and Storage: An Arrow in the Quiver or a Silver Bullet to Combat Climate Change — A Canadian Prime*. The Pembina Institute. Available online at: http://www.pembina.org/pubs/pub.php?id=584

GHG emission reduction units may come in the form of individual project-based offsets (CDM and JI) or through GHG allowances, whereby individual countries or companies are emitting below the amount of emission rights they were allocated. Both the CDM and the JI benefit from approved methodologies for independent validation of offsets. Multiple exchanges exist that can interface with these mechanisms, such as the Chicago Climate Exchange, New South Wales Trading Scheme in Australia, the European Climate Exchange, the newly founded Montreal Climate Exchange and the Asia Carbon Exchange. Such exchanges also facilitate voluntary and retail markets, as opposed to compliance-based markets. For project-based offsets, a key determinant of price is the level of certainty (or risk) that the offset will actual materialize and the quality of the offset itself.

Between 2001 and 2004 the GHG market (i.e., total available CDM/JI offsets) grew 725%, from 14 to 1,119 million tonnes CO_2e.[48] Of total international trading activity for project-based transactions, Europe and Japan dominated the market at 56% and 38%, respectively, of the total market, while Canada had a ‘negligible presence’.[49] Canada and Canadian companies are clearly far behind other countries and companies.

To date, a formal domestic offset system does not exist in Canada. Currently a number of technical working groups under the umbrella of the federal, provincial, and territorial governments are developing standards for Canadian GHG offset projects.[50]

This section describes price projections for offsets, given likely trading regimes, and the price range applied in this study.

3.4.1 Estimated Costs for Offsets[51]

Prices of tradable GHG emission units are likely to increase as a consequence of increasingly stringent national emissions targets during the decades post-2012 in order to meet necessary international GHG reduction objectives that will stabilize atmospheric concentration of GHGs. Assuming that prices are not regulated (see Section 5.3.3) and that no one player exerts significant market power, GHG prices, like any market prices, depend on the interaction of supply and demand. The tightening of overall limits on emissions in the emissions trading market will increase demand for emission units, while progress in lowering the costs of low-emission technologies will increase supply.

A sense of the levels that GHG prices might reach post-2012, and specifically during the 2020 timeframe, can be identified through the following:

i. projections by GHG brokers
ii. economic modelling results on a longer timescale
iii. prices used for future planning by GHG-emitting companies
iv. Canadian government projections.

[48] Doug Russell.March 16, 2006. *Overview and Status of CDM&JI and Global Carbon Markets and Opportunities for Canadian Technology*. Natsource. Used in a presentation.
[49] World Bank. May 2006. *State and Trends of the Carbon Market 2006*.
[50] Available online: http://www.climatechange.gc.ca/english/publications/offset_gg_tech/2c.asp. (Accessed June 29, 06.)
51 M. Bramley. October 2005. *Future Financial Liability for Greenhouse Gas Emissions from New Large Industrial Facilities in Canada*. (Section 4.3). Pembina Institute. Price information borrowed from source.

i) Projections by GHG Brokers

Natsource, the major GHG emissions broker and consultancy, has supported the likelihood of GHG prices rising in the decades post-2012. It recently suggested that GHG prices be assumed, as a "very rough proxy," to increase by 5% annually during the period 2015–40. Based on consideration of various levels of stringency of the targets-and-trading regime in place in Canada and the United States, combined with economic model results, Natsource suggests a range for the base price in 2015 of $19–$50 (US $17– US $44) per tonne of CO_2e.[52]

ii) Economic modelling results

Model results vary widely depending on the assumptions inherent in both the models themselves and the scenarios modelled. Relevant illustrative results obtained with models of the global[53] economy include the following:

- A recent review of modelling of the GHG prices (carbon tax levels) needed to reach a stabilized atmospheric concentration of 550 ppmv (it is not clear whether this is CO_2 or CO_2e) using eight different models produced widely varying predictions of future prices: $1.40 to $34 (US $1.24–US $30) per tonne CO_2 in 2020; $11 to $85 (US $10–US $75) in 2040/2050 and $51 (US $45) to almost $1,200 (US $1,063) in 2100 (in constant 2001 dollars).[54]
- Modelling of the stabilization of CO_2 concentrations at 400 to 450 ppm, commissioned by the German Advisory Council on Global Change (WBGU, an independent scientific body), projected GHG prices of about $12–$45 (US $11–US $40) per tonne CO_2 in 2020 and about $90 to $210 (US $80–US $186) in 2050 (in constant 1990 dollars).[55]

iii) Prices used for future planning by GHG-emitting companies

The practice of building a GHG price into investment decision making is now widespread among large companies in the electricity and oil and gas sectors. GHG prices used by companies for investment decision making in Europe are generally considered to be commercially confidential. However, public information is available from the United States:

- Electricity generator Scottish Power was described in 2004 as the "leading practitioner" in this area.[56] The company's United States subsidiary Pacificorp has used a range of prices between zero and $55/tonne (US $49/tonne) CO_2 in its Integrated Resource Planning process.[57]
- Several other United States electricity generators are building GHG prices into their planning and are beginning to be required to do so by regulators. Idaho Power Company

[52] Rosenzweig, R., and D. Russell. 2005. Untitled report for BC Hydro, p.12. Washington, DC: Natsource. Available online: http://www.bcuc.com/Documents/Other/2005/DOC_7836_B-11%20Supplemntal%20F2006%20Call%20Evidence.pdf. The document cited begins on p.150 of the pdf file.
[53] If Canada's GHG emissions targets-and-trading system remains fully open to the international GHG emissions market, as is planned for 2008–12 (see Section 3.1), the relevant GHG price is the global price.
[54] Rosenzweig, R., and D. Russell. 2005. Untitled report for BC Hydro, p.11–12. Washington, DC: Natsource;. Availble online: http://www.bcuc.com/Documents/Other/2005/DOC_7836_B-11%20Supplemntal%20F2006%20Call%20Evidence.pdf. The document cited begins on p.150 of the pdf file.
[55] Nakicenovic, N. and K. Riahi. 2003. *Model Runs With MESSAGE in the Context of the Further Development of the Kyoto Protocol*. p.38. Available online: http://www.wbgu.de/wbgu_sn2003_ex03.pdf. These prices are presented graphically, which adds a degree of approximation to the numbers cited. They have been converted to Canadian dollars using an exchange rate of $US1=$1.25.
[56] Innovest Strategic Value Advisors. 2004. *Carbon Disclosure Project — Climate Change and Shareholder Value in 2004*. p.56. Available online: http://www.cdproject.net/report.asp. The price of $US40 cited in this document has been converted to Canadian dollars using an exchange rate of $US1=$1.25.
[57] Rosenzweig, R.. 2005. *Testimony before British Columbia Utilities Commission*. p.9–11. Available online: http://www.bcuc.com/Documents/Other/2005/DOC_7836_B-11%20Supplemntal%20F2006%20Call%20Evidence.pdf. The document cited begins on p.135 of the pdf file.

has used a range of prices up to $67/tonne (US $59/tonne) CO_2 for the period beginning in 2008, and the company has characterized these prices as representing reasonable estimates of the risk faced by the company and its customers due to potential future regulation of GHG emissions.[58]

iv) Canadian government projections

International GHG price projections by the Canadian federal government for the 2008–2012 period of the Kyoto Protocol indicates prices substantially higher than the $15/tonne (US $13/tonne) CO_2e price cap put in place for this time period:

- The Government of Canada's *Climate Change Plan for Canada* (November 2002), which was the basis for Canada's ratification of the Kyoto Protocol, envisaged the possibility that the international GHG price could be as high as $50 (US $44) per tonne CO_2e during 2008–2012, while presenting economic modelling results showing only relatively modest macroeconomic impacts at that price.[59]
- Before the United States' withdrawal from the Kyoto Protocol in 2001, the Government of Canada was planning for the international GHG price during 2008–2012 to be in the range of $24–58 (US $21–US $51) per tonne CO_2e.[60]

3.4.2 Factors Influencing Offset Prices

Some key factors that will determine the price of offsets to consider are as follows:

- Quality of the offset — The increased certainty that the offsets are real and credible, and that this can readily be demonstrated, will drive price up.
- Volume and transaction costs — The larger the supply of offset for a given project the less the price per tonne would likely be. As well, the less time and fewer resources are required to validate projects, the more the price of an offset will be reduced.
- Pre-2008 vs. post-2008 — A new supply of CERs and ERUs will likely become available once Kyoto is in effect, thereby affecting price. However an increase in demand would also occur. Indeed, increasingly stringent GHG reduction targets would continue to drive up demand and therefore increase price.
- The level of CCS occurring in a given country will affect the price of other offset types within a given region. The more CCS that can be considered as offsets (through appropriate validation) the greater the volume of offsets, driving down the price of other types of offsets within a local market.
- Other market prices — Sellers of CERs may hold off selling until price goes up, should prices in other markets be higher.
- Global prices for carbon-based commodities (gas vs. coal).
- Delivery terms of offsets contract:
    - 'Off-take' contracts — where the seller can deliver any volume, at any time. These would be lower priced offsets.

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[58] *Ibid*.
[59] Government of Canada. 2002. *Climate Change Plan for Canada*. p.63–64. Available online: http://www.climatechange.gc.ca/english/publications/plan_for_canada/plan/.
[60] Analysis and Modelling Group. 2000. *An Assessment of the Economic and Environment Implications for Canada of the Kyoto Protocol*, p. 19–20. National Climate Change Process. Available online: http://www.nccp.ca/NCCP/national_process/issues/analysis_e.html#final.

- ‘Fixed volume contracts’ — where the seller is obligated to sell a fixed amount on an agreed date, and carries all the liability. These would be higher priced offsets in the short term, but would hedge against future price increases.

As demonstrated by the sources of information on GHG price projections, and the above influencing factors, there is a wide range in the potential prices during the 2020 timeframe and beyond. While the lower range of the projections can be quite low, indeed almost approaching zero, it should be cautioned that these are not likely to be representative of quality emission reductions and should not be promoted.

4. Carbon Neutral Scenarios and Associated Costs

The costs for a proxy oil sands operation to become carbon neutral will ultimately depend on how this is achieved. This report considers carbon neutrality being achieved through three potential scenarios — CCS, offsets or a combination of the two — for both a low emissions and a high emissions proxy plant. Whether the operation is mining, in-situ, or a combination is also considered.

4.1 Cost Estimates for Each Scenario

The three potential scenarios under consideration to achieve carbon neutrality are summarized in Table 5.

Table 5. Description of Scenarios

Scenario	Description
1. CCS Focus	CCS is maximized within oil sands operations, covering emissions from all point sources. Offsets are used only where emissions cannot be captured using existing or emerging technologies in the 2020 timeframe.
2. Combined CCS and Offsets	CCS is used on a very limited basis and only captures hydrogen plant operations. The application requires only (minor) retrofits. Offsets are used for the remaining emissions.
3. Offsets Only	Carbon capture is not used. Offsets are purchased for all GHG emissions.

Carbon neutral cost results for three proxy oil sands operations were determined, all of which include upgrading:

a. Proxy A: 55% of bitumen is sourced through mining and extraction and 45% through in-situ extraction. This is the same ratio of mining vs. in-situ for all existing, approved, and announced oil sands projects for 2020.[61] Note that in 2004 65% of oil sands production was from mining operations and 35% was from in situ; 61% of oil sands production is upgraded into synthetic crude oil.[62]

b. Proxy B: 100% surface mining and extraction operation.

c. Proxy C: 100% in-situ operation.

A summary of the cost estimates for CCS used in this analysis is provided in Table 6 below.

[61] R.B. Dunbar. April 2006. *Existing and Proposed Canadian Oil Sands Projects*. Strategy West.

[62] Alberta Energy and Utilities Board. September 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook 2004 – 2015*. Calculated from Figures 2.5 and 3.23.

Table 6. Summary of Costs Applied for CCS

	Capture (US$/tonne)	Transportation (US$/tonne)	Storage (US$/tonne)	Total (US$/tonne)
Low Cost Range	24	7	3	34
High Cost Range	85	7	8	100

A summary of the cost estimates for carbon offsets used in this analysis is presented in Table 7 below.

Table 7. Prices Applied for Offsets

	Offset Cost (US$/tonne)
Low Cost Range	22
High Cost Range	85

Note that a limitation of this analysis is the prices for offsets are considered in year 2010 constant dollars while the costs for CCS are taken to be year 2000 constant dollars[63]. Thus, the relative CCS costs could be marginally higher. In light of the uncertainty associated with capture costs in the future, this is considered negligible.

Figure 6 below summarizes costs per barrel for the three scenarios for each proxy operation type considered. The lower and upper limits of costs per barrel SCO to become carbon neutral are provided. The lower limit includes the lower GHG emissions plant and accordingly the upper limit includes the higher GHG emissions plant. For detailed costs, see the Appendix.

[63] The primary cost information source on CCS did not explicitly provide this information.

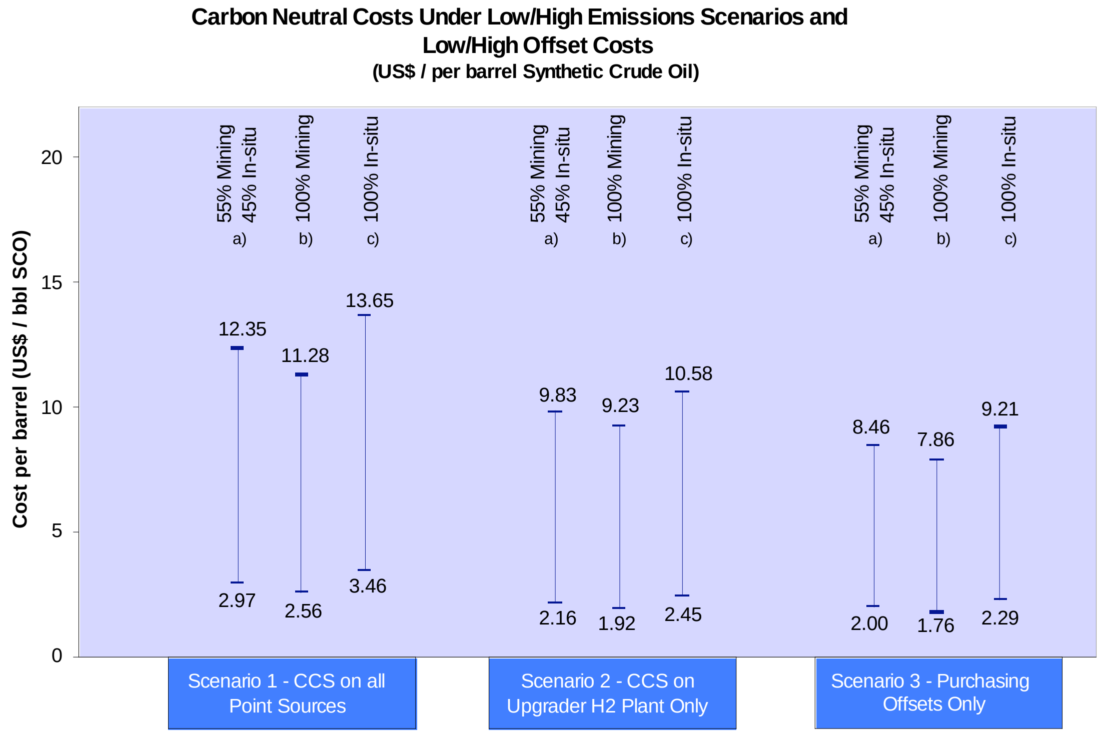

Figure 6. Range of Costs of Becoming Carbon Neutral

Key points that can be drawn from these results are:

- Costs could range from US $1.76 to $13.65 per bbl.
- Costs per bbl are slightly higher when maximizing CCS options over purchasing offsets.
- Costs could vary slightly based on several factors (see Section 3.3.4). Given current market conditions in Alberta, costs as reported here are likely underestimated. Costs would ultimately be determined based on market conditions at the time of construction. However, several factors help keep costs conservative. These are as follows:
  - CCS costs reflect present and historical costs, but do not consider future technological advances (the 'learning effect') and economies of scale. Market conditions in Alberta in 2020 would also likely be different than what they are today.
  - CCS costs do not consider potential revenue generation from enhanced oil recovery (EOR) using CO_2.
  - Hydrogen plant CO_2 recovery costs as reported here could be made lower with the generation of a higher purity CO_2 stream.
  - Offset costs will depend on the type of offset, the quality of the offset, and the level of associated risk.
- These costs do not include any energy efficiency or fuel switching measures that might be lower in cost than either CCS or offsets.
- The financial capability to implement these solutions is considered to be relative to oil prices and the cost of production.

To put the results into context, it costs a refinery approximately \$1–\$2 (US \$0.89–\$1.77) per bbl to remove lead from gasoline in today's dollars;[64] to reduce sulphur in diesel fuel to 15 ppm, thus meeting recent ultra-low sulphur diesel regulations, costs approximately \$1.30–\$1.80 (US \$1.15–\$1.59) per bbl.[65] Further, integrated oil sands companies are estimated to be economic with oil prices at US \$30–\$35 per bbl.[66] Given the past environmental challenges the oil and gas industry has overcome, and current market conditions, oil sands companies are well poised to begin aggressively reducing GHG emissions (see Section 1.0 for more information).

4.2 Cost Sensitivity Analysis

A straightforward sensitivity analysis was performed to test the influence of reducing capture costs and offset prices on the ultimate cost ranges for the given scenarios. In this analysis, costs were reduced by half to get an overall sense as to the level of influence. Of course, if costs were to be double, the equal and opposite level of influence can be assumed. The following provides a summary of the results:

- Halving CO_2 capture costs brings the cost range down to US \$1.74 (100% mining) to US \$8.02 (100% in-situ) per bbl for Scenario 1 (maximizing CCS). This sensitivity does not include reductions in cost for transportation or storage.
- In Scenario 3, reducing offset costs by half brings the lower limit to US \$0.88 per barrel, and the upper limit to US \$4.60 per bbl. For Scenarios 1 and 2, the lower limits are US \$2.43 and US \$1.19 per bbl, respectively.
- When halving both the capture costs and offset prices, Scenario 1 had a lower end of US \$1.61 and a higher end of US \$7.83 per bbl. The lower and upper limits for Scenario 2 were US \$1.03 and US \$5.60 per bbl, respectively.

While these results are likely not surprising, they do illustrate that costs could become much more reasonable with advancements in CO_2 capture technologies and future economies of scale assuming increased deployment. As discussed previously, there is good reason to believe that capture costs may be significantly reduced over time. Future decreases in offset prices, however, are less certain. Indeed, when considering offsets as one mechanism in achieving carbon neutrality, purchasing forward carbon contracts well before 2020 (for 2020 and beyond) may help to hedge against future price increases.

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[64] World Bank, 1997. *Pollution Prevention and Abatement Handbook*. Was the source used for information regarding removal of Lead from Gasoline. Data on volume of gasoline per barrel provided by the American Petroleum Institute. 1995 data in 2006 dollars adjusted for annual inflation in Canada and 2006 average exchange rate.
[65] October 2, 2004. *Canada Gazetted*. Vol. 138, No. 40 —2002 cost estimates converted 2006 dollars adjusted for annual Canadian inflation and average exchange rates. Includes removal of all sulphur (i.e. pre 500 ppm level).
[66] National Energy Board. June 2006. *Canada's Oil Sands Opportunities and Challenges to 2015: An Update*.

5. Key Conclusions and Recommendations

Key conclusions

- Canadian oil sands operations are the single largest contributor to GHG emissions growth in Canada.
- Carbon neutrality can be achieved by combining on-site GHG reductions using measures such as energy efficiency and/or fuel switching (to lower carbon fuels), carbon capture and storage, and/or purchasing offsets.
- Oil sands companies with mining operations would pay slightly less per barrel than those predominately using current in-situ (SAGD) technologies.
- Costs per barrel could be as low as US $2–3. Although an upper estimate of US $8–$14 per bbl is offered, it is anticipated that industry would not pay more than the lower limit of the upper boundary (i.e., US $8 for offsets rather than higher costs for CCS).
- The costs of becoming carbon neutral will continue to fall in an increasingly energy-constrained world where oil sands companies will be generating greater profits per barrel.
- Given high oil prices and the subsequent high profit margins for oil sands companies, becoming carbon neutral by 2020 appears economically feasible. This is further reinforced by the fact that the cost of reducing carbon is not much more, per barrel, than the cost of removing lead or sulphur from fuel.

Key recommendations to oil sands companies

- Take a leadership role in the oil sands sector and set a target of becoming carbon neutral by 2020.
- Evaluate which approaches are best applicable to your own company.
- Evaluate all possible GHG reduction options, from on-site energy efficiency to fuel switching measures.
- Support the advancement of capture technologies and finding quality offsets.
- Support immediate action to develop a domestic carbon offset trading system.

Appendices

Appendix 1: Scenario cost summaries

The following three sections detail costs for the three scenarios described in the report. Each section has two data tables:

1. The first data table summarizes the costs inherent in a carbon neutral oil sands operation and incorporates variability in emissions, CCS costs and offset costs.
2. The second table summarizes the total costs per barrel of producing SCO for the three proxy plant operations.

Scenario 1: Maximum CCS

Table A1- 1. Scenario 1: Costs for Low/High GHG Emitting Oil Sands Operations

		Carbon Capture		Carbon Offsets		Capture + Offsets Total	
		Low Cost CCS ($/bbl SCO)	High Cost CCS ($/bbl SCO)	Low Cost Offset ($/bbl SCO)	High Cost Offset ($/bbl SCO)	Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	M / E	0.58	1.71	0.24	0.73	0.83	2.44
	In-Situ	1.63	4.80	0.09	0.27	1.72	5.06
	Upgrading	1.72	5.06	0.02	0.05	1.74	5.11
High Emissions	M / E	0.83	2.45	0.34	1.01	1.17	3.46
	In-Situ	1.87	5.50	0.11	0.33	1.98	5.83
	Upgrading	2.65	7.78	0.02	0.05	2.66	7.82

Table A1- 2. Scenario 1: Summary of Range of Carbon Neutral Costs for Proxy Plant Operations

		Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**2.97**	**8.73**
	Total - 100% Mining + Upgrading	**2.56**	**7.55**
	Total - 100% In- Situ + Upgrading	**3.46**	**10.17**
High Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**4.20**	**12.35**
	Total - 100% Mining + Upgrading	**3.83**	**11.28**
	Total - 100% In- Situ + Upgrading	**4.64**	**13.65**

Scenario 2: Moderate CCS

Table A1- 3. Scenario 2: Costs for Low/High GHG Emitting Oil Sands Operations

		Carbon Capture		Carbon Offsets		Capture + Offsets Total	
		Low Cost CCS ($/bbl SCO)	High Cost CCS ($/bbl SCO)	Low Cost Offset ($/bbl SCO)	High Cost Offset ($/bbl SCO)	Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	M / E			0.62	1.87	0.62	1.87
	In-Situ			1.15	3.46	1.15	3.46
	Upgrading	0.47	1.37	0.83	2.50	1.30	3.87
High Emissions	M / E			0.88	2.64	0.88	2.64
	In-Situ			1.33	3.99	1.33	3.99
	Upgrading	1.39	4.09	0.83	2.50	2.22	6.59

Table A1- 4. Scenario 2: Summary of Range of Carbon Neutral Costs for Proxy Plant Operations

		Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**2.16**	**6.45**
	Total - 100% Mining + Upgrading	**1.92**	**5.74**
	Total - 100% In- Situ + Upgrading	**2.45**	**7.33**
High Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**3.31**	**9.83**
	Total - 100% Mining + Upgrading	**3.10**	**9.23**
	Total - 100% In- Situ + Upgrading	**3.55**	**10.58**

Scenario 3: Maximum Offsets

Table A1- 5. Scenario 3: Costs for Low/High GHG Emitting Oil Sands Operations

		Carbon Capture		Carbon Offsets		Capture + Offsets Total	
		Low Cost CCS ($/bbl SCO)	High Cost CCS ($/bbl SCO)	Low Cost Offset ($/bbl SCO)	High Cost Offset ($/bbl SCO)	Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	M / E			0.62	1.87	0.62	1.87
	In-Situ			1.15	3.46	1.15	3.46
	Upgrading			1.14	3.41	1.14	3.41
High Emissions	M / E			0.88	2.64	0.88	2.64
	In-Situ			1.33	3.99	1.33	3.99
	Upgrading			1.74	5.22	1.74	5.22

Table A1- 6. Scenario 3: Summary of Range of Carbon Neutral Costs for Proxy Plant Operations

		Low Total ($/bbl SCO)	High Total ($/bbl SCO)
Low Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**2.00**	**5.99**
	Total - 100% Mining + Upgrading	**1.76**	**5.28**
	Total - 100% In- Situ + Upgrading	**2.29**	**6.87**
High Emissions	**Total - 55% Mining, 45% In-Situ + Upgrading**	**2.82**	**8.46**
	Total - 100% Mining + Upgrading	**2.62**	**7.86**
	Total - 100% In- Situ + Upgrading	**3.07**	**9.21**

Appendix 2: Sensitivity Analyses

The following three figures detail cost ranges for the three sensitivity cases presented in section 4.2.

Case 1: Half Capture Costs and Full Offset Costs

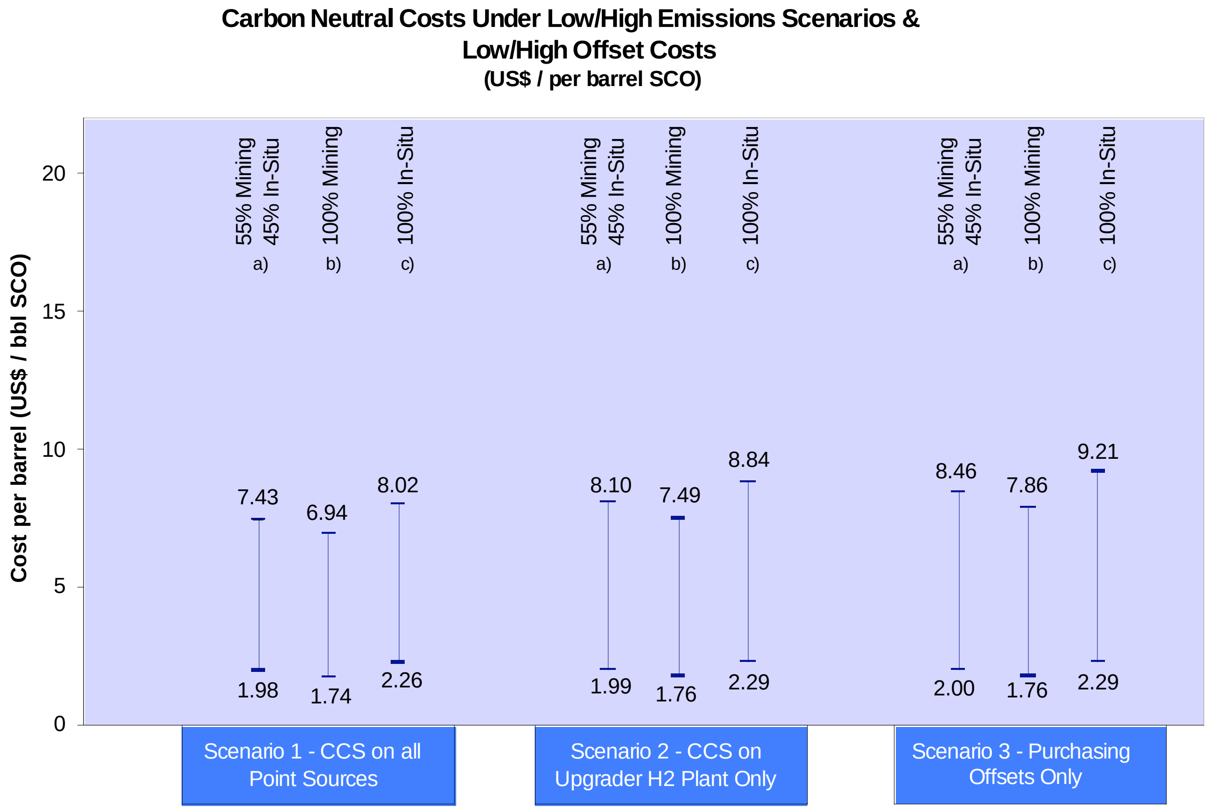

Figure A2- 1. Carbon Neutral Costs with Half CCS Costs

Case 2: Full Capture Costs and Half Offset Costs

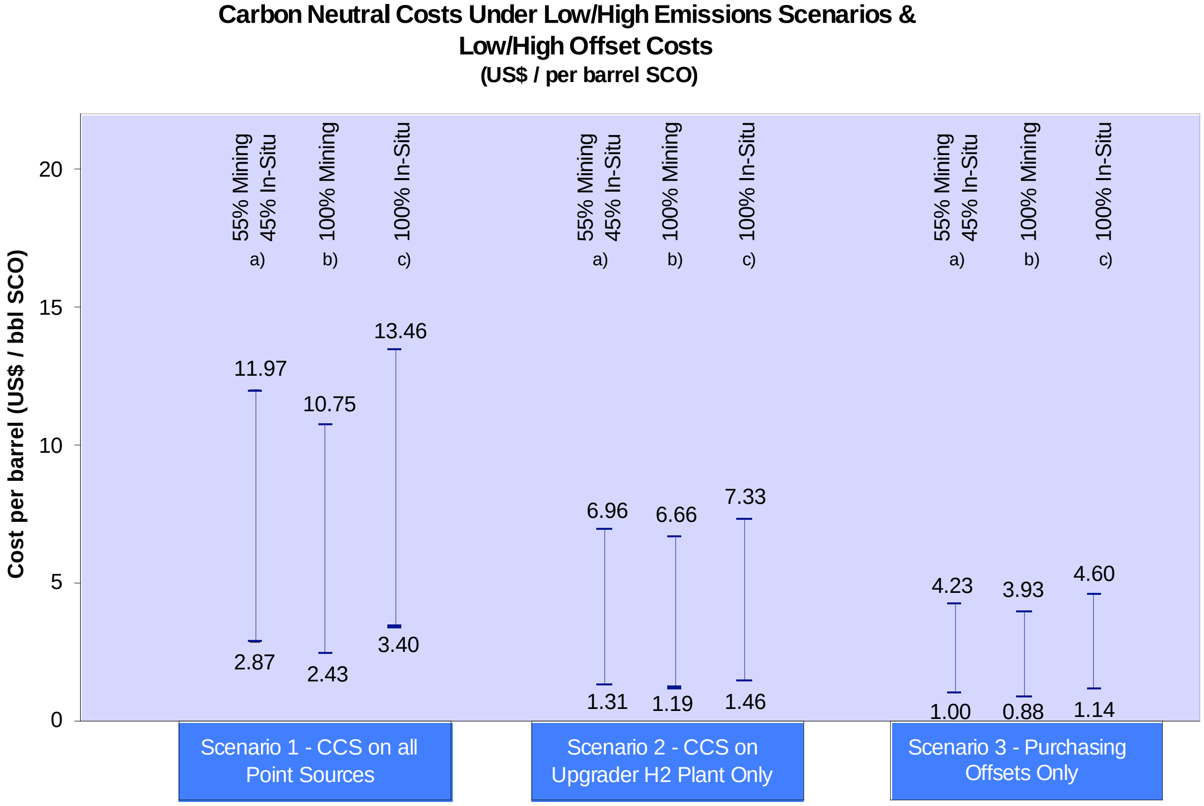

Figure A2- 2. Carbon Neutral Costs with Half Offsets Costs

Case 3: Half Capture Costs and Half Offset Costs

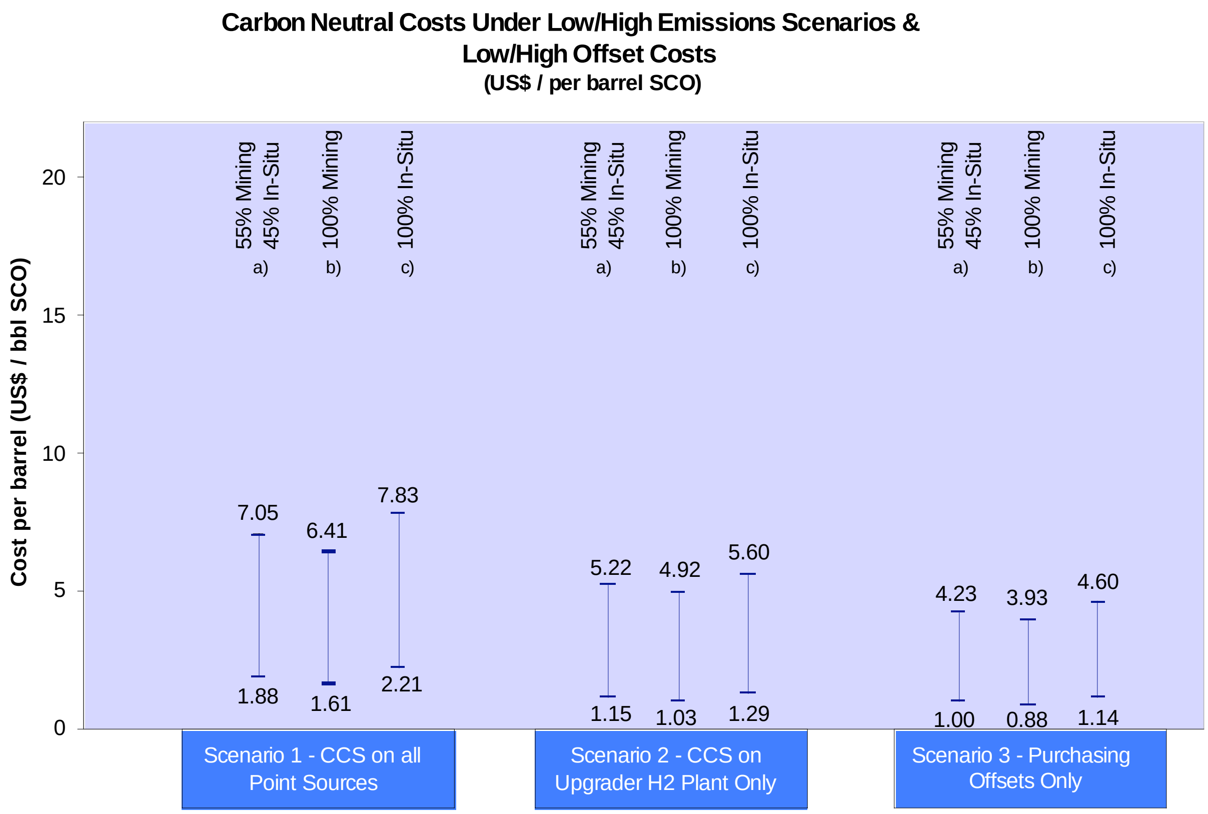

Figure A2- 3. Carbon Neutral Costs with Half CCS Costs and Half Offsets Costs