REPORT

Alberta CO₂ Capture Cost Survey and Supply Curve

prepared for the

Alberta CCS Development Council

by

Ian Murray & Company Ltd.
(“IMC”)

December 31, 2008
TABLE OF CONTENTS

1.0 Executive Summary
   1.1 Introduction
   1.2 Key Results
   1.3 Other

2.0 Situation Summary for 2020
   2.1 Introduction
   2.2 CO₂ Emissions Estimate (2020)
   2.3 CO₂ Supply Curve (2020)
   2.4 Regional CO₂ Emissions & Potential Capture (2020)

3.0 Capture Cost Methodology and Results
   3.1 Capture Costs and Unitization
   3.2 Capture Cost Survey Results and Unitization

4.0 Existing and Potential CO₂ Emissions from Large Point Sources
   4.1 Total Alberta (2006)
   4.2 Focus Sectors
   4.3 Future Volumes, Timing and Location
      4.3.1 Power Sector
      4.3.2 Oil & Gas Sector, including Oil Sands

APPENDICES

1(a) Alberta CO₂ Emissions Estimate – No Capture
1(b) Alberta CO₂ Emissions Estimate – Capture Potential
2(a) Regional CO₂ Supply Curve Estimates for Alberta (2020)
3(a) Potential Capture at Capture Cost threshold $ 80/tonne abated
3(b) Potential Capture at Capture Cost threshold $100/tonne abated
3(c) Potential Capture at Capture Cost threshold $125/tonne abated
3(d) Potential Capture at Capture Cost threshold $150/tonne abated
3(e) Potential Capture at Capture Cost threshold $175/tonne abated
3(f) Potential Capture at Capture Cost threshold $200/tonne abated
3(g) Potential Capture at Capture Cost threshold $250/tonne abated
Executive Summary
1.1 Introduction

Ian Murray & Company Ltd. ("IMC") was engaged by Alberta Energy to assist the Alberta Carbon Capture and Storage Development Council ("Council") by generating up-to-date carbon dioxide ("CO₂") supply curve estimates for capturing CO₂ at existing and prospective large emitting facilities in Alberta.

IMC's role involved gathering, analyzing and estimating volume data on CO₂ emissions up to 2020 from existing and prospective large point sources in Alberta's oil, gas, oil sands, chemical, fertilizer, refining and electric power sectors. IMC's role also involved estimating the portion of CO₂ emissions potentially available for capture in those sectors at various capture cost thresholds.

IMC's activities for the Council initially were geared to help clarify, update and expand upon varied information that is available from sources such as the Canadian Association of Petroleum Producers (CAPP), the Canadian Clean Power Coalition (CCPC), the Integrated CO₂ Network (ICO₂N) and others.

However, the Council determined that up-to-date CO₂ supply curve estimates required up-to-date capture cost inputs directly from owner/operators of existing and planned facilities in the sectors of interest.¹ The Council noted that several companies recently had responded to the Government of Alberta's request for expressions of interest regarding carbon capture and storage (CCS) and potentially could make their capture cost estimates available to the Council on a confidential, non-attributable basis. The Council believed that cost estimates from a survey of those companies and others would be more timely and accurate than cost estimates from past studies.

IMC was charged, on behalf of the Council, to approach more than 25 companies in an attempt to ascertain their projected capture costs for a number

¹ In this report, CO₂ capture costs are facility specific and are based on industrial production facility owner-operator estimates of the capital and operating costs needed to modify a production facility to capture CO₂ while maintaining the production facility's primary output.

Costs include all design, construction, owning, operating and maintenance expenditures associated with capture equipment, land and other modifications to the production facility necessary to manufacture dry, high concentration (>95% CO₂), high purity, high pressure (2200 psi), bulk CO₂ ready for injection into a pipeline system. Costs also include all expenditures necessary to make-up any decline in the production facility's primary output that is impacted by capturing CO₂. Typical profit margins for most segments of the CO₂ capture value chain also are recognized as costs, including, for example, margins for engineering suppliers, equipment suppliers, construction service suppliers, operations and maintenance service suppliers, consumables and fuel suppliers. Profit margins, if any, related to owning and operating capture facilities are assumed to be inherent in the 10% pre-tax discount rate used for calculating unitized capture costs.
of distinct CO₂ emitting point sources within their existing or prospective Alberta facilities. While 10 companies covering 20 different sources made their internal capital and operating cost estimates available to IMC, overall, for any particular industrial process (such as steam methane reforming to manufacture hydrogen or natural gas combustion to manufacture steam for in-situ oil sands production or coal combustion to manufacture electricity), the responses resulted in a relatively limited data set for comparative purposes.

In addition, no information was received with respect to numerous potential sources of CO₂ supply including, for example, (a) prospective coke gasification facilities for hydrogen production, (b) existing or prospective natural gas fired power generating facilities (including cogeneration) and (c) existing or prospective large furnaces / boilers (irrespective of fuel) at industrial complexes such as refineries, chemical plants or bitumen mines and upgraders.

For capture cost tabulation and supply curve purposes, IMC levelized all reported estimates of capital and operating costs into unitized capture costs (expressed as $ per tonne CO₂). This was done by dividing all discounted expenditures incurred to capture CO₂ over a 40 year period (without reducing the production capacity of the base facility) by all discounted CO₂ volumes captured or abated, as appropriate. At a 10% pre-tax discount rate, calculated capture costs were seen to be fairly reflective of capture costs reported to IMC.

1.2 Key Results

The Council was particularly interested in a projection of Alberta’s overall and regionalized CO₂ emissions for 2020 and the amount of those emissions potentially available for capture at or below various capture cost thresholds.

Without capture facilities, CO₂ emissions from large point sources in Alberta could reach 215 Megatonnes per year (“Mtpa”) by 2020 with additional increases thereafter.

Alberta’s large point sources cumulatively emitted 110 Mtpa in 2006. The 105 Mtpa increase in emissions by 2020 is wholly attributable to growth in Alberta’s oil sands and power sectors forecast prior to December 2008.

Subsequent to IMC’s work for the Council, in mid-December 2008, CAPP updated its long range oil production forecast. If that forecast comes to fruition, the currently estimated growth in oil sands sector CO₂ emissions up

---

2 “Abated” refers to a volume CO₂ that is lower than the captured volume of CO₂ by the amount of CO₂ emissions, if any, associated with incremental energy consumption necessary to (i) make-up any decline in a facility’s primary product output associated with the act of capturing CO₂ and (ii) operate capture equipment at a facility if not already accounted for in (i).
to 2020 could decline by 10 to 15 Mtpa. Concomitantly, power plant CO₂ emissions projected for 2020 could decline by 3 to 5 Mtpa.

Two overall Alberta CO₂ supply curves were developed for the year 2020 based on capture cost information supplied by respondents and emissions estimates prepared by IMC. The supply curves are set out in Figure 1 are expressed in 2008 Canadian $ per tonne of CO₂.

The lower supply curve depicts the relationship between capture costs as a function of the amount of CO₂ potentially available for capture, while the higher curve depicts the relationship as a function of CO₂ abated.

According to Figure 1, 35 Mtpa of emissions from large point sources in Alberta (or 16% of the total 215 Mtpa) may be available for capture at a cost of $150 per tonne CO₂ abated or less (or $110 per tonne captured).

**Figure 1**

Amalgamated CO2 Supply Curve for Alberta (2020)

Of that 35 Mtpa, 23 Mtpa (or 66%) is anticipated to be located in the Wabamun / Industrial Heartland corridor. More than half of the remaining 12 Mtpa is anticipated to be located in the North Athabasca region.

Regarding capture costs compiled for the Council IMC’s review of public and confidential capture cost projections indicates that engineering and cost estimating efforts related to industrial scale CO₂ capture in western Canada are, at best, at a Class IV “pre-FEED” level (+35%/-25%). As such, and given the

---

3 Commercially motivated industrial developments typically follow a stage gate approach where engineering and cost estimating efforts become more rigorous, costly, better defined and accurate at over time as each stage gate completed. “Pre-FEED” (pre-Front End Engineering and Design) is a relatively early stage gate. If a commercially driven development is determined to be sound at this stage based on a high level economic and technical evaluation, the development might ultimately
current materials supply and construction environment in Alberta, there appears to be significant potential for change to recent capture cost estimates, particularly considering that most were performed in early to mid 2008 when economic activity in Alberta, crude oil prices and long term growth projections were higher than today.

1.3 Other

The Council also was interested in (a) distinct CO$_2$ supply curves for key regions in Alberta, (b) directional impacts of industrial process alternatives on the prospective amount of CO$_2$ potentially available for capture and (c) practical considerations related to CO$_2$ emissions reductions in Alberta.

Materials that IMC provided the Council related to these latter interests are contained in Sections 2 and 3 of this report as well as in its Appendices.
2.0 Situation Summary for 2020

2.1 Introduction

This section of the report provides additional detail regarding materials IMC provided the Council for 2020, including results on a regional basis.

This section also highlights various implications to Alberta’s prospective 2020 CO₂ supply volume situation emanating from CAPP’s mid-December 2008 update to its oil production forecast which was issued subsequent to IMC’s work for the Council.

2.2 CO₂ Emissions Estimate (2020)

CO₂ emissions from large point sources in Alberta could reach 215 Mtpa by 2020. Chart 1 highlights the relative contribution to those emissions from Alberta’s oil sands, power, chemical, gas plant, heavy oil and “other” sectors.

Appendix 1(a) provides a breakdown of the growth in annual emissions between 2006 and 2020 by major emitting category.

CO₂ emissions from large emitters in 2020 could be 105 Mtpa higher than those reported for 2006 by Alberta Environment.

This increase in emissions likely would be wholly attributable to growth in Alberta’s oil sands and power sectors. As such, by 2020, nearly 85% of all CO₂ emissions from large point sources in Alberta are anticipated to come from these two sectors (72 Mtpa and 108 Mtpa respectively). The estimate of CO₂ emissions in 2020 is based in part on CAPP’s projection of bitumen production and upgrading contained in its June 2008 Moderate Growth Case.

Subsequent to IMC’s work for the Council, in mid-December 2008, CAPP updated its June forecast. Alberta bitumen production in 2020 in its updated forecast is not significantly different than that forecast in the June, 2008 Moderate Growth Case. However, CAPP’s updated forecast shows a significantly lower level of bitumen upgrading occurring in Alberta up to 2020.
If CAPP’s current forecast comes to fruition, oil sands related CO₂ emissions highlighted in Chart 1 could decline by 10 to 15 Mtpa. Most of this change would occur in Alberta’s Industrial Heartland region as a result of delayed, deferred or cancelled bitumen upgrading facilities originally planned for the 2012 – 2020 timeframe.

As well, should upgrading activity be delayed, deferred or cancelled, there is an increased probability that between 3 and 5 Mtpa of the estimated 21 Mtpa growth in power sector emissions will not materialize by 2020. The preponderance of any change in power generation emissions is likely to occur in the corridor between Wabamun and Alberta’s Industrial Heartland.

As long as the price for West Texas Intermediate (WTI) remains below $50 per barrel, IMC anticipates that 2009 long range forecasts of oil production and other economic activity will show further declines in the rate of growth in Alberta through 2020. As such, the growth in and regional distribution of CO₂ emissions contemplated herein could change downward significantly.

In addition, the utilization rate of available industrial production capacity can materially affect estimates of CO₂ emissions due to the fixed and variable nature of CO₂ emissions at some industrial complexes. This is particularly applicable to mining and upgrading emissions in the oil sands sector.

Currently, the utilization rate of production capacity in Alberta’s oil sands sector appears to be in the low to mid 80% range. For purposes of estimating future emissions for this sector, it was assumed that prospective capacity additions would occur at such times (in relation to CAPP’s June 2008 oil production forecast) as to maintain industry average capacity utilization rates near today’s level through 2020. However, to the extent on-stream mining and upgrading facilities increase the overall industry average capacity utilization rate over time (absent an increase in total industry bitumen production contemplated in CAPP’s June 2008 forecast), the rate of increase in CO₂ emissions for the oil sands sector will be less than that estimated herein. As well, increased capacity utilization rates could delay future capacity additions (and vice versa).

Furthermore, techno-economic choices underlying new industrial facilities that lead to increased use of carbon intensive feedstock or carbon intensive fuel to produce, for example, heat, steam, oil or electricity that otherwise could have been produced with natural gas will tend to increase the amount of CO₂ emissions identified herein. However, such choices could also lead to sizable increases in the amount of CO₂ available for capture at lower unit capture costs.
2.3 CO$_2$ Supply Curve (2020)

Two overall Alberta CO$_2$ supply curves developed for 2020 are set out in Chart 2. One supply curve depicts the relationship between capture costs as a function of the amount of CO$_2$ potentially available for capture, while the other depicts the relationship as a function of CO$_2$ abated. Results are expressed in 2008 Canadian $ per tonne of CO$_2$.

Of the total 215 Mtpa of CO$_2$ emissions from large point sources in Alberta that could materialize by 2020, the supply curve indicates that 35 Mtpa (or 16%) may be available for capture at a cost of $150 per tonne CO$_2$ abated or less.

The supply curve also suggests that little to no capture is anticipated to cost less than $50 per tonne.

Key assumptions inherent in the supply curve include:

(a) Most existing coal fired power plants are not viable capture candidates prior to 2020 due to PPA commitments or relatively short remaining lives prior to recertification. Some existing coal fired power plants are not viable capture candidates due to site and configuration limitations;

(b) All prospective coal fired power plants are viable candidates for capturing CO$_2$;

(c) All existing and prospective hydrogen manufacturing facilities are viable candidates for capturing CO$_2$;

(d) All existing and prospective coker heaters at bitumen upgraders are viable candidates for capturing CO$_2$;

(e) All existing and prospective once-through steam generators (OTSGs) at SAGD bitumen production facilities are viable candidates for capturing CO$_2$;

(f) All existing and prospective natural gas fired power plants (including simple cycle, combined cycle and cogeneration) may
be viable candidates for capturing CO$_2$ when their operating load factors are sufficiently high;

(g) All existing and prospective large furnaces / boilers at bitumen upgraders, refineries, chemical plants and other industrial facilities may be viable candidates for capturing CO$_2$; and

(h) Few other existing and prospective point sources of CO$_2$ emissions likely have capture costs within the range of the highest cost CO$_2$ from facilities identified in (b) through (f).

A significant portion of the CO$_2$ supply in 2020 that has a capture cost at or below $100 per tonne CO$_2$ abated is expected to relate to several prospective coal fired power production facilities as well as some prospective hydrogen manufacturing facilities.

Currently, there is no surety that prospective production facilities will materialize in deference to alternative production facilities which may have higher unit CO$_2$ capture costs but lower costs to produce primary products. In fact, several Council participants highlighted that decisions to design, build, own, operate, maintain, buy, sell or shut-down industrial production facilities seldomly are driven by the absolute or the unit costs to manage or mitigate CO$_2$ emissions alone, nor are such decisions driven solely by the absolute or unit costs to manage or mitigate CO$_2$ emissions relative to alternative production facilities.

There also is no surety that prospective production facilities will materialize to the extent contemplated by forecasts made in 2008.

Appendix 2 provides a breakdown of the overall Alberta CO$_2$ supply curve for four key regions in 2020: (i) Fort McMurray and area; (ii) Edmonton-Fort Saskatchewan and area; (iii) Wabamun area and (iv) Red Deer and area. That breakdown highlights that relatively small amounts of low cost supply ($50 to $75 per tonne CO$_2$ abated) may be available in each of the four aforementioned regions, but as the capture cost threshold increases, significant supplies may be available in each region other than Red Deer. As well, as the capture cost threshold increases further, very large amounts of supply could materialize in the Fort McMurray area.

As indicated earlier, CAPP recently updated its oil production forecast to 2020. Its current forecast could reduce CO$_2$ emissions estimated for 2020 by 13 Mtpa or more. At least 50% of that supply is anticipated to reduce CO$_2$ availability that falls within the $100 per tonne CO$_2$ abated threshold. Also, if WTI continues to remain below $50/bbl, revisions to Alberta’s long range oil production and power production forecasts may continue to emerge and likely
would result in additional reductions to anticipated CO₂ emissions circa 2020 as well as supplies potentially available for capture.

### 2.4 Regional CO₂ Emissions & Potential Capture (2020)

Chart 3 shows that 23 Mtpa (66%) of the 35 Mtpa of CO₂ that may be available for capture by 2020 at or below a $150 per tonne abated threshold is anticipated to be located in the Wabamun / Industrial Heartland corridor.

Of the residual 12 Mtpa (34%), 7 Mtpa is likely to be located in the North Athabasca region while the remaining 5 Mtpa is anticipated to materialize mainly in the vicinity of Cold Lake and Red Deer / Calgary.

Given CAPP’s updated oil production forecast, potential emissions for 2020 as well as emissions potentially available for capture could face downward pressure, particularly in the Wabamun / Heartland corridor.

Over the long term (post 2020), additional CO₂ emissions, including emissions potentially available for capture, are anticipated to materialize predominantly in the North and South Athabasca regions due to continued bitumen production and in the Wabamun, Edmonton, Red Deer and Calgary regions due to increased power generation and industrial activity as well as due to increased opportunities retro-fit power plants for CO₂ capture.

Appendices 3(a), (b), (c), (d), (e), (f) and (g) provide regional breakdowns of the growth in annual emissions in Alberta that may be available for capture between 2012 and 2020 at several capture cost cost thresholds ranging from $80 per tonne CO₂ abated or less to $250 per tonne CO₂ abated or less.
3.0 Capture Cost Methodology and Results

3.1 Capture Costs and Unitization

Published CO₂ capture cost estimates vary widely. Typically, capture costs are reported on a unitized and facility specific basis (i.e. a $ per quantity of CO₂ figure that is reflective of the magnitude of the capital and operating costs a subject industrial production facility would incur to physically reduce CO₂ emissions to the atmosphere.)

Much of the variance in reported unitized and facility specific capture costs can be attributed to study specifics pertaining to the host facility, site issues, capture process and capture technology. However, differing assumptions regarding technical performance, economic parameters and capture cost calculation methodologies also contribute to variances in reported costs.

Other variances result from different unitization processes as well as different reporting bases, such as (i) reporting capture costs on an “as captured” basis as opposed to an “as abated” basis and (ii) reporting capture costs on a cross-fuel or cross-technology basis rather than on a facility specific basis.

In this report, CO₂ capture costs are facility specific and are based on industrial production facility owner-operator estimates of the capital and operating costs needed to modify a production facility to capture CO₂ while maintaining the production facility’s primary output.

Such costs include all design, construction, owning, operating and maintenance expenditures associated with capture equipment, land and other modifications to the production facility necessary to manufacture dry, high concentration (>95% CO₂), high purity, high pressure (2200 psi), bulk CO₂ ready for injection into a pipeline system.

Such costs also include all expenditures necessary to make-up any decline in the production facility’s primary output that is impacted by capturing CO₂.

For purposes of this report, unitized CO₂ capture costs were calculated both on a captured basis and on an abated basis. However, this report generally refers to CO₂ capture costs on a “2008 Canadian $ per tonne of CO₂ abated” basis unless otherwise indicated.

---

4 The facility specific basis for reporting capture costs presumes that the subject industrial facility exists or will be built. Capture costs reported on a facility specific basis do not provide an indication of the economic merit of building the subject industrial facility (with or without capture). Such reported capture costs also do not provide an indication of relative economic merit of a similar industrial facility based on alternative feedstock / fuel or alternative primary production technology.
3.2 Capture Cost Survey Results and Unitization

IMC approached more than 25 companies with large CO₂ emitting facilities existing in or planned for Alberta in an attempt to secure confidential, non-attributable, current estimates regarding prospective capital and operating costs to capture CO₂ at their existing or planned facilities (i.e. facility specific costs). This was done to access cost data from recent internal company studies, notably those made in preparation for submission to the Provincial Government CCS RFP process in September 2008.

20 facility specific capital and operating cost estimates as well as their associated captured and abated CO₂ volume estimates were obtained from 10 survey participants. The information received spanned, predominantly, existing and prospective CO₂ emissions sources in the power and oil sands sectors. IMC sourced some additional data through public reports.

Analysis of industry data and public reports indicates that engineering work and cost estimating related to large scale CO₂ capture in western Canada is, at best, at a Class IV level (+35%/-25%). This level of engineering work and cost estimating is referred to as “process definition pre-Front End Engineering and Design” or “pre-FEED”. ⁵

IMC standardized some elements of the cost estimates received from industry as well as sourced from publications, such as the cost of natural gas fuel supplies at $7 per GJ in and effort to eliminate some of the variances in reported numbers.

CO₂ capture costs were calculated by facility type by discounting projections of the 40 year capital and operating cost profiles associated with CO₂ capture at a 10% pre-tax discount rate. Capture costs were unitized by dividing the calculated CO₂ capture costs by discounted captured or abated CO₂ volumes, as appropriate. This approach resulted in unitized capture costs that were fairly reflective of capture costs reported by several respondents as well as those reported in recent CCS studies, such as that performed by the CCPC.

Chart 4 summarizes calculated unit CO₂ capture costs by major facility type on a 2008 Canadian $ per tonne of CO₂ abated basis. The range of capture cost results within each major facility type are indicative of facility specific issues such as geographic location, production/operating specifics and greenfield versus retrofit/brownfield situations. The range in results also emanates from differences in owner/operator design approaches and cost estimating.

---

⁵ Commercially motivated industrial developments typically follow a stage gate approach where engineering and cost estimating efforts become more rigorous, costly, better defined and accurate over time as each stage gate is completed. Usually, a commercially motivated development starts at the conceptual design stage. If perceived to be sound from a high level economic and technical vantage point, the development could advance to the pre-FEED stage and ultimately on to more rigorous and costly FEED and EPC/M (engineering, procurement and construction / management) activities.
Chart 4

Compilation of Industry CO2 Capture Cost Estimates
Aggregated Results from Capture Cost Survey

Major facility type

- Coal / Coke / Ashph - Gasification (Proc. Stream)
- Coal - Air Combustion (Flue Stream)
- Coal - Oxygen Combustion (Flue Stream)
- Gas - Benfield (Proc. Stream)
- Gas - PSA (Proc. Stream)
- Gas - PSA (all via Flue Stream)
- Gas - SAGD Boilers (Flue Stream)

Notes:
- Based on over 20 different facilities from over 10 company interviews, plus information from other recent studies.
- Cost ranges represent geographic, technological suitability as well as greenfield versus retrofit considerations.
- $ are 2008 Cdn, based on levelizing real 2008 Capital and real 2008 Annual Operating costs discounted at 10% from year(s) incurred.
- $ / tonne abated includes cost penalties for make-up production and incremental CO2 emissions resulting from CO2 capture.
- Gasification excludes cost penalty, if any, associated with production technology choice relative to alternative(s).
- Benfield excludes cost penalty, if any, associated with production technology choice relative to alternative(s).

Both footnote 1 to this report as well as the notes below Chart 4 are important to interpreting the charted facility specific capture costs. As well, as indicated earlier, several Council participants highlighted that decisions to build industrial production facilities seldomly are driven by the absolute or the unit costs to manage or mitigate CO2 emissions alone and neither are such decisions driven solely by the absolute or unit costs to manage or mitigate CO2 emissions relative to alternative production facilities.

As such, Chart 4 alone should not be used to draw conclusions that the facility specific (and unitized) capture cost of any one facility is indicative of:

(a) the economic merit of that type of facility type versus another type of facility; or
(b) the absolute cost to mitigate CO2 emissions at that type of facility versus another type of facility; or
(c) the impact on the cost of producing a primary product at that type of facility versus another type of facility.

Predominantly, Chart 4 only indicates that once a particular type of facility exists, or is expected to exist, the cost to add and operate CO2 capture capability to such a facility likely falls within the range shown for that particular type of facility.
4.0 Existing and Potential CO₂ Emissions from Large Point Sources

4.1 Total Alberta (2006)

In 2006, CO₂ emissions from large emitters in Alberta amounted to 110 Mtpa as shown by sector in Chart 5.

![Chart 5](source – Alberta Environment)

2006 Total Reported AB CO₂ Emissions by Facility Type
110 Megatonnes (Mt)
(per July 2007 AB Environment Report on 2006 GHG Emissions, Large Emitters)

Over 65% of those emissions were attributable to power generation and oil sands production activities (51 Mtpa and 23 Mtpa respectively).

Analysis indicates that, without capture facilities, CO₂ emissions from large point sources in Alberta could reach 215 Mtpa by 2020 (Chart 1). As well, the entire growth in emissions between 2006 and 2020 is expected to result from expansion of Alberta’s power generation and oil sands sectors. By 2020, nearly 85% of all large point source emissions are anticipated to come from these two sectors (72 Mtpa and 108 Mtpa respectively).

Currently, forecasts for Alberta’s oil sands sector activity for the 2012 through 2020 timeframe are in a state of flux and likely will remain uncertain while WTI trades well below $50 per barrel. As such, estimates of CO₂ emissions associated with some existing and many prospective large point sources in

---

6 Power generation, for purposes of emissions, appears to include coal-fired power generation, large gas-fired power generation as well as large fossil fuel-fired cogeneration, particularly facilities which are “out-side the industrial fence.” This sector may include some “inside the industrial fence” facilities.
Alberta are becoming increasingly uncertain for the 2020 timeframe, and could face material downward pressure.

However, as indicated earlier, over the long term (post 2020), growth in bitumen production, upgrading, industrial development and power requirements in Alberta likely will counteract any reductions in medium term emissions projections.

4.2 Focus Sectors

As noted in Section 2.2, and as evident from Chart 1, large point source CO₂ emissions in Alberta predominantly emanate from facilities that produce Alberta’s fossil resources (oil, natural gas, bitumen and coal) as well as other industrial facilities that use significant quantities of those resources as feedstock or fuel in their resource processing, refining, upgrading or product manufacturing operations.

Charts 1 and 5 categorize emissions into 6 general sectors:

a. Heavy Oil;
b. Gas Plant;
c. Chemical;
d. Power Plant;
e. Oil Sands (including refinery based bitumen upgrading); and
f. Other (including oil refining, fertilizer, cement, lime, forest products, power, chemical, coal mining etc)

Currently, industry forecasts suggest that natural gas, conventional oil and heavy oil production in Alberta are in a relatively flat to declining environment through 2020. Analysis suggests a modest decrease can be expected in CO₂ emissions associated with those fossil resources between 2006 and 2020. In particular, emissions from the Heavy Oil sector and the Gas Plant sector each are anticipated to decline by 1 Mtpa. Some additional discussion of results for the Oil & Gas sector is provided in Section 4.3, below.

While there has been some suggestion that Alberta’s Chemical sector could expand should there be adequate availability of secure, long term, low cost feedstock, recent uncertainty surrounding when these criteria will be met supports the view that no material growth in CO₂ emissions for the Chemical sector is anticipated between 2006 and 2020.

There also has been some suggestion that Alberta’s refining, fertilizer and cement sectors could experience growth in the 2006 to 2020 time period. However, the materiality of such growth on Alberta’s overall CO₂ emissions, should such growth occur, is viewed as being relatively inconsequential with
respect to volume. As such, no change in emissions for the Other sector between 2006 and 2020 is anticipated.

While the materiality of growth in the Other sector is marginal with respect to overall CO₂ emissions in Alberta, the relatively low cost to capture CO₂ from some sources within this sector may present near to medium opportunities to initiate and develop CCS in Alberta.

Estimates regarding large scale growth in CO₂ emissions between 2006 and 2020 in the Power Sector and the Oil Sands sector are discussed in detail in Section 4.3, below.

### 4.3 Future Volumes, Timing and Location

#### 4.3.1 Power Sector

According to the ERCB’s ST98-2008, Alberta’s installed power generation capacity in 2007 was 12,143 MW, an increase of 2.5% from 2006. The ERCB forecasts installed power generation capacity to be near 16,000 MW by 2017, representing an annual average rate of capacity growth of 2.8%.

Most of the 4,000 MW increment in capacity is projected to occur by 2012/2013, mainly as a result of increasing power demands forecast for the oil sands sector. As well, over 50% of the 4,000 MW increment is expected to be new natural gas fired generating capacity (mainly in the form of on site, high utilization rate steam / power cogeneration facilities), while less than 25% (or 1,000 MW) is anticipated to be new, centralized coal fired facilities (Chart 6).

![Chart 6](source.png)
Also according to the ERCB, total annual power generation in 2007 was 66,143 gigawatt hours (GWh) and is forecast to grow by 27,000 GWh to reach approximately 93,000 GWh by 2017 (Chart 7). This represents an annual average growth rate in power production of 3.5%, significantly higher than the average growth rate in production capacity of 2.8%.

Chart 7
Source – ERCB ST98-2008 (Figure 9.2: Alberta Electricity Generation)

The oil sands sector is expected to “dominate load growth” as can be seen in the growth forecast for the category “Industrial on site” (Chart 8). Industrial on site is also meant to indicate local, site produced power, which, as noted above, is expected to be mainly in the form of high utilization rate steam / power cogeneration facilities fueled with natural gas.

Chart 8
Source – ERCB ST98-2008 (Figure 9.4: Alberta Electricity Consumption by Sector)
With the rate of load growth throughout Alberta exceeding the rate by which capacity is being added, concerns are increasing with respect to the medium and longer term adequacy of Alberta’s power generation reserve margin.

From Charts 6, 7 and 8 (as well as other public information available from the ERCB, AESO, CAPP and other publications), IMC was able to generate approximate annual capacity utilization rates, by facility type, for Alberta’s existing power generation fleet and extrapolate Charts 6 and 7 out to include the year 2020.

The extrapolated forecasts were modified to include one new coal-fired power plant in 2017 and a second new coal-fired power plant in 2020. Concomitant adjustments were made to capacity utilization rates across all facility types.

Emissions factors were applied by facility type and, with some minor modifications, by vintage to replicate reported power generation sector emissions in 2006. ERCB and CAPP data as well as other public information was used to regionalize emissions from the existing and prospective generation fleet.

As indicated earlier, key assumptions inherent in the development of the supply curve with regard to emissions potentially available for capture in the power sector include:

(a) Most existing coal fired power plants are not viable capture candidates prior to 2020 due to PPA commitments or relatively short remaining lives prior to recertification. Some existing coal fired power plants are not viable capture candidates due to site and configuration limitations;

(b) All prospective coal fired power plants are viable candidates for capturing CO₂;

(c) All existing and prospective natural gas fired power plants (including simple cycle, combined cycle and cogeneration) may be viable candidates for capturing CO₂ when their operating load factors are sufficiently high.

Information on projected CO₂ capture volumes and associated capital and operating costs for some power generating facilities were supplied to IMC. In those cases, that data was used in the development of unitized capture costs and CO₂ supply curves. As well, based on literature and industry association reports, such as a recently completed CCPC report, some volume and cost data for certain power generating facilities was estimated and used in the development of the supply curves.
4.3.2 Oil & Gas Sector, including Oil Sands

CAPP’s June 2008 crude oil production forecast indicates Alberta’s total crude production (including condensates mainly produced from natural gas) is projected to grow from 1.8 Million barrels per day in 2007 to 3.5 Million barrels per day in 2020.

Chart 9 depicts this production forecast broken down by (a) condensates, (b) conventional light and medium crude oil, (c) conventional heavy crude oil, (d) synthetic crude oil (SCO, comprised of mined bitumen upgraded as well as upgraded bitumen from in situ sources) and (e) non-upgraded bitumen from in situ sources.

Oil & Gas

Annual production rates for conventional light, medium and heavy oils inherent in CAPP’s June 2008 forecast and CO₂ emissions rates per unit of production from CAPP’s Stewardship reports and other sustainability reports, enabled a calculation of the contribution toward annual CO₂ emissions that could be attributable to each type of crude oil.

Given the flat to declining profile for production from these sources through 2020, emissions associated with conventional crude oil production, and in particular conventional heavy, were estimated to decline by 1 Mtpa from current levels.

Resultant emissions over time (absent capture facilities) for the oil and gas sector are depicted in Appendix 1(a) along with profiles for other sectors contributing to Alberta’s large point source emissions through 2020.
Oil Sands

By mid 2008, the level of new bitumen mining, bitumen upgrading and in situ bitumen production capacity proposed for the oil sands sector to 2020 far and away exceeded the level of facility additions needed to meet either CAPP’s June 2008 “Moderate Growth” forecast or the ERCB’s forecast in ST98-2008. In fact, announced projects, at capacity, amounted to the equivalent of 6.6 MMBbl/d of bitumen production and 3.3 MMBbl/d of upgrading capability.

Oil sands production capacity and facility utilization information for 2006 and 2007, as well as the publicly reported status of announced projects, was used to generate a probable profile of capacity additions related to bitumen mining, upgrading and in situ bitumen production. In doing so, a reasonable and relatively constant capacity utilization rate was used relative to the bitumen production and upgrading volumes inherent in CAPP’s June 2008 forecast.

As noted in Section 2.2, the utilization rate of available production capacity in the oil sands sector can materially affect estimates of CO₂ emissions due to the fixed and variable nature of CO₂ emissions at some industrial complexes.

To the extent the oil sands sector increases its overall average utilization rate over time, and absent an increase in the overall oil production forecast, the rate of increase in CO₂ emissions for the oil sands sector is expected to be less than that estimated herein. As well, increased capacity utilization rates in the oil sands sector, absent an increase in the overall oil production forecast, should result in (or benefit from) delay in the timing of future capacity additions.

Estimates contained herein emanate from announced mining, upgrading and in situ projects. Nearly all of the industrial complexes proposed for the oil...
sands sector up to 2020 appear to be based mainly on natural gas for feedstock (where needed) as well as natural gas for fuel or electricity for power.

Unlike a standard electricity manufacturing facility in the power sector, an integrated bitumen mining / upgrading (or in situ production / upgrading) facility in the oil sands sector has multiple locations within its product manufacturing complex where CO₂ is emitted. These include, but are not limited to, steam methane reformers, coker heaters (as applicable), large furnaces/boilers, small furnaces/boilers, froth preparation and treatment facilities, mine faces, tailings ponds, trucks, steam generators and others.

In developing estimates of the amount of CO₂ emissions potentially available for capture in the oil sands sector, attention was focused on three key point sources that, to date, have been perceived by industry to represent the most sizable, CO₂-rich emissions streams within the sector that potentially have the lowest cost to capture (i.e. steam methane reformers, coker heaters and once through steam generators).[^8]

When IMC approached companies regarding access to their internal cost estimates for CO₂ capture at their industrial complexes, IMC requested information the companies might have developed with respect to capturing CO₂ at any and all of their large point sources within their complex.

The appropriateness of focusing attention on the three key sources in the oil sands sector (steam methane reformers, coker heaters and once through steam generators) was confirmed through the related capture cost information provided by respondents. Not one respondent specifically addressed other CO₂ streams within their facilities, except to indicate their belief that capturing CO₂ from such other streams would be precipitously more difficult and expensive than capturing CO₂ from the three key sources.

In order to baseline oil sands sector emissions estimates and replicate reported 2006 emissions, emissions factors were applied by type of industrial complex with some minor modifications. ERCB and CAPP data as well as other public information was used to regionalize emissions from existing and prospective oil sands complexes. A number of other factors, based on average industry information available through sustainability reports, EIAs and other sources were used to allocate total emissions at various oil sands complexes.

[^8]: For purposes of this report, natural gas fired cogeneration facilities were considered to fall within the power plant sector. In any event, no information regarding CO2 emissions, potentially available capture volumes, nor capture costs associated with cogeneration were specifically addressed by any of the capture cost survey participants. One participant mused whether some combination of OTSGs (once through steam generators) and gas-fired cogeneration might prove more environmentally benign and economically advantageous for bitumen production using steam assisted gravity drainage, but that musing did not carry forward into any specific response.
complexes amongst the major CO$_2$ emitting point sources typically found within each complex.

As indicated earlier, key assumptions inherent in the development of the supply curve with regard to emissions potentially available for capture in the oil sands sector include:

(a) All existing and prospective hydrogen manufacturing facilities are viable candidates for capturing CO$_2$;

(b) All existing and prospective coker heaters at bitumen upgraders are viable candidates for capturing CO$_2$;

(c) All existing and prospective once-through steam generators (OTSGs) at SAGD bitumen production facilities are viable candidates for capturing CO$_2$; and

(d) All existing and prospective large furnaces / boilers at bitumen mines and upgraders may be viable candidates for capturing CO$_2$.

Ultimately, CAPP’s June 2008 “Moderate Growth” Case oil sands production forecast was translated into an estimate of CO$_2$ emissions for the oil sands sector over time. This translation is depicted in Chart 10 and a regionalized perspective is provided in Chart 11.

Subsequent to IMC’s work for the Council, in mid-December 2008, CAPP updated its June forecast. Alberta bitumen production in 2020 in its updated
CAPP’s updated forecast shows a slower rate of growth in bitumen production and upgrading in the 2012 through 2016 timeframe. Between 2016 and 2020, CAPP’s updated forecast projects fairly aggressive growth in bitumen production activity in order to recover by 2020 nearly to the bitumen production levels contemplated in its June, 2008 forecast. Similar aggressive growth is not included in CAPP’s forecast for intra-Alberta upgrading to 2020.

Information on projected CO₂ capture volumes and associated capital and operating costs for key CO₂ streams at several oil sands facilities were supplied to IMC. In those cases, that data was used in the development of unitized capture costs and CO₂ supply curves. As well, based on literature and industry association reports, some volume and cost data for a very limited number of other CO₂ streams was estimated and used in the development of the supply curves.
APPENDIX 1 (a)

Alberta CO2 Emissions Estimate – No Capture

Annual Alberta CO2 Emissions from
Crude, Power, Refining, Chemicals, Fertilizers and Other Production
(Megatonnes per year)

Year

2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

CO2(eq) in Mtpa

0.0
25.0
50.0
75.0
100.0
125.0
150.0
175.0
200.0
225.0
250.0

Other
Condensates
Conventional Light & Medium
Conventional Heavy
Gas Power
Cogen Power
Refining, Chemicals, Fertilizers
Coal Power
Upgrading
Oil Sands In-Situ
Oil Sands Mining
APPENDIX 1 (b)
Alberta CO2 Emissions Estimate – Capture Potential

Potential CO2 Supply from Alberta Large Emitters
based on $ per tonne abated

Mtpa CO2 Captured

Year

2012 2014 2016 2018 2020

below $250
below $200
below $175
below $150
below $125
below $100
below $80
$50 to $65
APPENDIX 2(a)

Regional CO2 Supply Curves for Alberta (2020)
Capturable CO2 in Large Emitting Regions
(from existing and new large emitters)

Mtpa CO2 Captured

CO2 Capture Cost (in $ CDN 2008/tonne)

- 2020 Fort Mac & area - abated basis
- 2020 Edmonton / Fort Sask & area - abated basis
- 2020 Wabumum & area - abated basis
- 2020 Red Deer & area - abated basis
APPENDIX 3 (a)
Potential Capture at Capture Cost threshold $80/tonne abated

Potential CO2 Supply from Alberta Large Emitters
At or Less Than $80 per tonne abated

Year
2012 2014 2016 2018 2020

Mtpa CO2 Captured
70.0 60.0 50.0 40.0 30.0 20.0 10.0 0.0

Red Deer & area
Wabumum & area
Fort Sas k & area
Fort Mac & area
APPENDIX 3 (b)
Potential Capture at Capture Cost threshold $100/tonne abated

Potential CO2 Supply from Alberta Large Emitters
At or Less Than $100 per tonne abated

Red Deer & area
Wabumum & area
Fort Sask & area
Fort Mac & area

Mtpa CO2 Captured

Year
APPENDIX 3 (c)
Potential Capture at Capture Cost threshold $125/tonne abated

Potential CO2 Supply from Alberta Large Emitters
At or Less Than $125 per tonne abated

- Red Deer & area
- Wabamum & area
- Fort Sask & area
- Fort Mac & area

Year
2012 2014 2016 2018 2020

Mtpa CO2 Captured
0.0 10.0 20.0 30.0 40.0 50.0 60.0 70.0

2012 2014 2016 2018 2020

Potential CO2 Supply from Alberta Large Emitters
At or Less Than $125 per tonne abated
APPENDIX 3 (d)
Potential Capture at Capture Cost threshold $150/tonne abated

Potential CO2 Supply from Alberta Large Emitters
At or Less than $150 per tonne abated

- Red Deer & area
- Wabumum & area
- Fort Sask & area
- Fort Mac & area

Year
2012 2014 2016 2018 2020
Mtpa CO2 Captured
0.0 10.0 20.0 30.0 40.0 50.0 60.0 70.0

IMC Report
Alberta CO2 Capture Cost Survey & Supply Curve
December 31, 2008
Page 31 of 34
Potential CO2 Supply from Alberta Large Emitters At or Less Than $175 per tonne abated
APPENDIX 3 (f)
Potential Capture at Capture Cost threshold $200/tonne abated

Potential CO2 Supply from Alberta Large Emitters
At or Less than $200 per tonne abated
APPENDIX 3 (g)
Potential Capture at Capture Cost threshold $250/tonne abated

Potentially Supply from Alberta Large Emitters
At or Less than $250 per tonne abated

<table>
<thead>
<tr>
<th>Year</th>
<th>Mtpa CO2 Captured</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>0.0</td>
</tr>
<tr>
<td>2014</td>
<td>0.0</td>
</tr>
<tr>
<td>2016</td>
<td>0.0</td>
</tr>
<tr>
<td>2018</td>
<td>0.0</td>
</tr>
<tr>
<td>2020</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Red Deer & area
Wabumun & area
Fort Sask & area
Fort Mac & area