

Canadian Energy Research Institute

# Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta's Oil Sands

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David McColl  
Mellisa Mei  
Dinara Millington  
Charu Kumar

Study No. 119, Part I - Introduction and Overview  
ISBN 1-896091-89-X

March 2008



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**GREEN BITUMEN: THE ROLE OF NUCLEAR, GASIFICATION, AND CCS IN ALBERTA'S  
OIL SANDS  
PART I – INTRODUCTION AND OVERVIEW**

Green Bitumen: The Role of Nuclear, Gasification and CCS in Alberta's Oil Sands  
Part I – Introduction and Overview

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ISBN 1-896091-89-X

Authors:

David McColl

Mellisa Mei

Dinara Millington

Charu Kumar

Acknowledgements: The author of this report would like to extend our thanks and gratitude to everyone involved in the production and editing of the material, including, but not limited to, Capri Gardener, Megan Murphy, Marwan Masri and Peter Howard.

CANADIAN ENERGY RESEARCH INSTITUTE  
#150, 3512 – 33 STREET NW  
CALGARY, ALBERTA  
CANADA T2L A6

TELEPHONE: (403) 282-1231

March 2008

Printed on Recycled Paper Canada

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## CHAPTER 1 INTRODUCTION

### 1.1 Background

The phrase “resources beyond belief” has often been used to describe Alberta’s oil sands. With an estimated initial volume in-place of approximately 1.7 trillion barrels (269 billion m<sup>3</sup>) of crude bitumen, Alberta’s oil sands are one of the largest hydrocarbon deposits in the world.<sup>1</sup> When the Oil and Gas Journal released its estimates of global proved petroleum reserves at the end of 2002,<sup>2</sup> it increased Canada’s proved oil reserves to 180 billion barrels (29 billion m<sup>3</sup>), compared to 4.9 billion barrels (780 million m<sup>3</sup>) the previous year. This almost forty-fold increase was the result of a methodology change by the Journal, whereby Alberta’s crude bitumen was no longer classified as “unconventional” oil. This definitional change catapulted Canada into second position for total oil reserves behind only Saudi Arabia, and cut the Organization of Petroleum Exporting Countries’ (OPEC’s) share of world oil reserves by more than 10 percent. Five years have passed since Alberta was hurled onto the global stage. Massive investment, in the order of tens of billions of dollars, has flowed into the province to assist with the development of the oil sands. Once the realm of private enterprise and the Government of Alberta, the oil sands are quickly becoming mired in political intrigue as national oil company’s set-up “shop” in the province.

Extensive development of Alberta’s oil sands already has taken place. In 2006, Alberta produced 1.25 million barrels per day (199.4 thousand m<sup>3</sup>/d) of crude bitumen, with surface mining accounting for 61 percent and in situ 39 percent. In 2002, 0.83 million barrels per day (131.8 thousand m<sup>3</sup>/d) of crude bitumen was produced, with 64 percent of that attributable to mining and 36 percent to in situ techniques.<sup>3</sup> Non-upgraded bitumen and synthetic crude oil (SCO), derived from crude bitumen, accounted for 62 percent of Alberta’s total crude oil and equivalent production in 2006, compared to 48 percent in 2002. There is considerable uncertainty related to future growth projections for bitumen production due to:

- uncertainty about future crude bitumen, synthetic crude oil and natural gas prices;
- concerns over how the province’s proposed royalty framework will impact future development and supply costs;

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<sup>1</sup>Alberta Energy and Utilities Board, *Alberta’s Reserves 2005 and Supply/Demand Outlook 2006 – 2015*, June 2006, [http://www.eub.gov.ab.ca/bbs/products/STs/st98\\_current.pdf](http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf).

<sup>2</sup>Marilyn Radler, “Worldwide Reserves Increase as Production Holds Steady,” *Oil and Gas Journal* (December 23, 2002).

<sup>3</sup>Alberta Energy and Utilities Board, *Alberta’s Reserves 2005 and Supply/Demand Outlook 2006 – 2015*, June 2006. Alberta Energy and Utilities Board, *EUB Statistical Series 2003-98: Alberta’s Reserves 2002 and Supply Demand Outlook 2003-2012* (Calgary, Alberta, 2003), [www.eub.gov.ab.ca/bbs/products/STs/st98-2003.pdf](http://www.eub.gov.ab.ca/bbs/products/STs/st98-2003.pdf).

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- concerns about the availability of natural gas and diluents to support proposed developments;
- infrastructure constraints (pipelines and electrical transmission systems);
- recent cost overruns on the construction of new projects;
- limited availability of skilled labour;
- market constraints and the possible need for new upgrading/refining capacity; and
- environmental concerns including long-term water management and long-term uncertainty over plans for reducing greenhouse gas (GHG) emissions given Alberta's new Climate Change Plan, announced in January 2008, and potential initiatives currently being reviewed by the federal government.

This study examines these uncertainties and their implications for future oil sands development.

### 1.2 Introduction

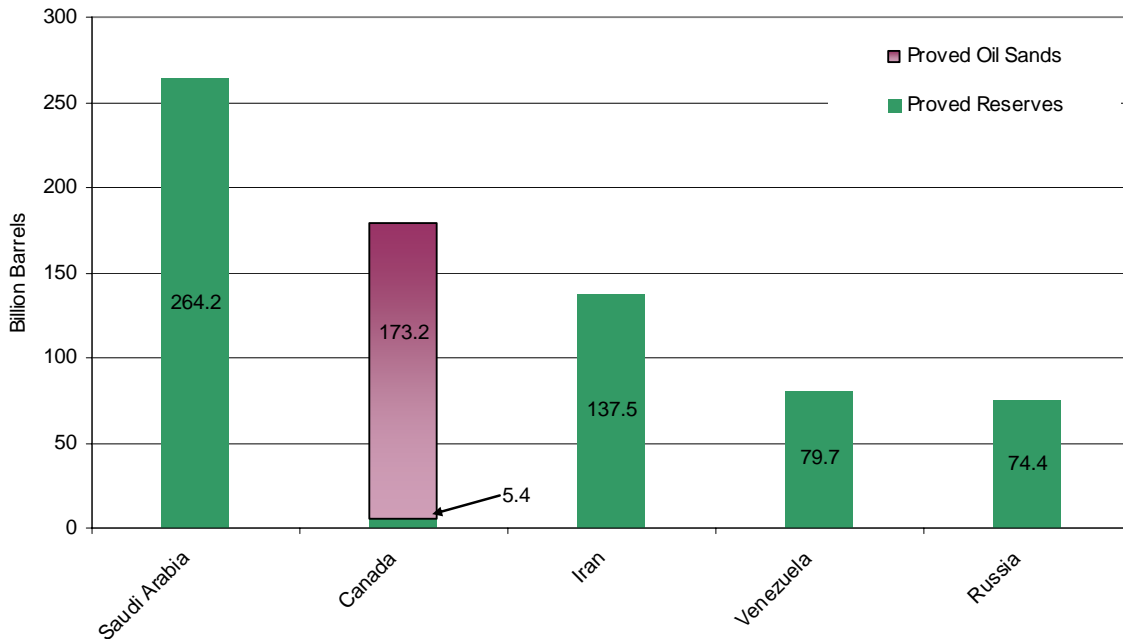
As reserves and production of conventional crude oil decline, unconventional resources have moved to centre stage in Canada, and are becoming increasingly important to the global oil industry. While not quite matching Saudi Arabia's conventional oil reserves, remaining established reserves of Canada's crude bitumen, at 173.2 billion barrels (27.53 billion m<sup>3</sup>),<sup>4</sup> places Canada in the top tier of the world's oil reserves (see Figure 1.1).<sup>5</sup>

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<sup>4</sup>Alberta Energy and Utilities Board, *Alberta's Reserves 2006 and Supply/Demand Outlook 2007 – 2016*, June 2007.

<sup>5</sup>The BP Group, *BP Statistical Review of World Energy 2003*, [www.bp.com](http://www.bp.com). Saudi Arabia's proved oil reserves at the end of 2002 stood at 261.8 billion barrels. Proved reserves are generally taken to be those quantities that geological and engineering information indicates can be recovered in the future from known reservoirs under existing economic and operating conditions with reasonable certainty.

**Figure 1.1**  
**Top Five World Proven Reserves**



SOURCES: (1) Statistical Series 2003-98, Alberta's Reserves 2005 and Supply/Demand Outlook 2006-2015, Alberta Energy and Utilities Board (EUB); and (2) BP Statistical Review of World Energy 2006.

### 1.3 Oil Sands and Crude Bitumen

Oil sands are composed of approximately 80-85 percent sand, clay and other mineral matter, 5-10 weight percent water, and anywhere from 1-18 weight percent crude bitumen. More than 12 percent bitumen content is considered rich, and less than 6 percent is poor and not usually considered economically feasible to mine, although it may be mined with a blended stock of higher grade oil.<sup>6</sup> In the Athabasca region, the oil sands are hydrophilic or "water wet". Each grain of sand is enveloped by a thin film of water, which is then surrounded by crude bitumen. The sands are unconsolidated with grain-to-grain contact. Being silica quartz, the sands are extremely abrasive, thus posing significant challenges in the mining and extraction processes. Early developers of the oil sands experienced the challenges associated with this abrasive product. Pipelines and equipment were often damaged, which resulted in alternative methods to transport the bitumen in pipelines. Such methods involve creating bitumen emulsions and adding large quantities of water into pipelines for hydro transport. These and other innovative initiatives helped turn the resource into a viable source of oil.

<sup>6</sup>Oil Sands Discovery Centre Fact Sheet.

[http://www.oilsandsdiscovery.com/oil\\_sands\\_story/pdfs/oilsands.pdf](http://www.oilsandsdiscovery.com/oil_sands_story/pdfs/oilsands.pdf).

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Crude bitumen is a thick, viscous crude oil that, at room temperature, is in a near solid state. The definition used in the industry is that crude bitumen is “a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well”.<sup>7</sup>

The term crude bitumen generally refers to petroleum with a density greater than 960 kilograms per cubic metre.<sup>8</sup> In fact, much of the bitumen in Canada's oil sands deposits has densities that exceed 1,000 kg/m<sup>3</sup> (API Gravity of less than 10 degrees). Because of its high gravity and very high viscosity, crude bitumen may be blended with a light hydrocarbon liquid (condensate) before it is shipped to markets by pipeline. Table 1.1 compares the densities of a number of crude oil types, including blended bitumen from Athabasca and Cold Lake.

**Table 1.1  
Crude Oil Densities  
(kg/m<sup>3</sup>)**

Crude Oil Type	Density
Cold Lake Crude Bitumen	1,009
Athabasca Crude Bitumen	1,015
Federated Light	826
Bow River Blend	894
Athabasca Bitumen Blend	919 <sup>a</sup>
Cold Lake Bitumen Blend	919 <sup>a</sup>
Commercial Condensate	720
West Texas Intermediate	827
Bonny Light	841
Arab Light	858
Maya	921

<sup>a</sup>Athabasca and Cold Lake Bitumen Blends are derived by adding diluent to crude bitumen to reduce viscosity prior to being transported by pipeline. The most commonly used diluent is very light natural gas liquid (C5+ or pentanes plus), which is a by-product of natural gas processing. A condensate diluent typically constitutes 24-32 percent of the bitumen blend.

SOURCES: (1) *Markets for Canadian Bitumen-Based Feedstock*, CERI Study No. 101; and (2) Alberta Research Council Open File Report 1993-25.

<sup>7</sup>Alberta, Canada, *Oil Sands Conservation Act, Section 1(1)(c)*, Alberta Statutes and Regulations. Note that more than 100 thousand b/d (16,000 m<sup>3</sup>/d) of crude bitumen from the Cold Lake and Athabasca Oil Sands Areas was produced using primary production techniques during 2002, in apparent contravention of this definition.

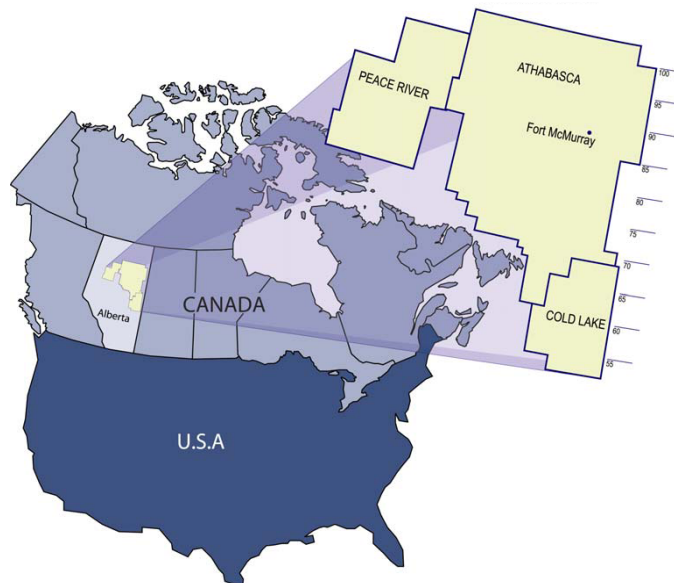
<sup>8</sup> Alberta Department of Energy, <http://www.energy.gov.ab.ca/OilSands/793.asp>, February 2008.

#### 1.4 Location of Oil Sands Deposits and Resource Base

Alberta's oil sands resources are spread across more than 140,000 square kilometres of northern Alberta in the Western Canada Sedimentary Basin (WCSB) (see Figure 1.2).<sup>9</sup> They are primarily contained in sand and carbonate formations that are located in the following areas:

- Athabasca in the northeast;
- Cold Lake in the east-central; and
- Peace River in the northwest parts of the province.

**Figure 1.2**  
**Oil Sands Areas in Alberta**



SOURCE: Alberta Department of Energy.

The Alberta Energy and Utilities Board (EUB) estimates the initial volume of crude bitumen in-place to be 270.3 billion m<sup>3</sup> (1,701 billion barrels) as of December 31, 2006. The Athabasca region alone accounts for almost 80 percent or 217.7 billion m<sup>3</sup> (1,369 billion barrels) of the total. Table 1.2 summarizes the volumetric resources by oil sands area and deposit. Oil sands areas (OSAs) define the geographical boundaries of crude bitumen occurrence, and oil sands deposits (OSDs) contain the specific geological zones declared as oil sands deposits. OSAs and OSDs are designated by the EUB.

<sup>9</sup> Oil sands deposits also exist in Saskatchewan.

**Table 1.2**  
**Initial In-Place Volumes of Crude Bitumen**

Oil Sands Area Oil Sands Deposit	Initial Volume In-Place (10 <sup>6</sup> m <sup>3</sup> )	Average Pay Thickness (m)	Average Bitumen Saturation (%)		
			Mass	Pore Volume	Average Porosity
<b>Athabasca</b>					
Grand Rapids	8,678	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	16,087	30.5	9.7	69	30
Wabiskaw-McMurray (in situ)	132,128	13.2	10.2	73	29
Nisku	10,330	8.0	5.7	63	21
Grosmont	50,500	10.4	4.7	68	16
Sub-Total	217,723				
<b>Cold Lake</b>					
Grand Rapids	17,304	5.9	9.5	66	31
Clearwater	9,422	11.8	8.9	59	31
Wabiskaw-McMurray	4,287	5.4	7.3	59	27
Sub-Total	31,013				
<b>Peace River</b>					
Bluesky-Gething	10,968	6.1	8.1	68	26
Belloy	282	8.0	7.8	64	27
Debolt	7,800	23.7	5.1	65	18
Shunda	2,510	14.0	5.3	52	23
Sub-Total	21,560				
Total	270,296				

SOURCE: Alberta Energy and Utilities Board, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007 – 2016, June 2007, [http://www.eub.gov.ab.ca/bbs/products/STs/st98\\_current.pdf](http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf)

### 1.5 Crude Bitumen Reserves

Remaining established reserves were estimated by the EUB to be 27.53 billion m<sup>3</sup> (173.2 billion barrels) as of December 31, 2006. Remaining established reserves are calculated separately for those that are likely to be recovered by mining methods and those by in situ methods using established technology and under anticipated economic conditions.

The EUB determined mineable established reserves by identifying potential mineable areas using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 weight percent, and a

minimum saturated zone thickness cutoff of 3.0 metres. The ESR criteria are fully explained in *ERCB Report 79-H, Appendix 3*.<sup>10</sup>

The EUB determined in situ established reserves for those areas considered amenable to in situ recovery methods. Reserves attributable to thermal development were determined using a minimum saturation cutoff of three weight percent crude bitumen and a minimum zone thickness of ten metres. For primary development, the same saturation cutoff of three weight percent was used, with a minimum zone thickness of three metres. Recovery factors of twenty percent for thermal development and five percent for primary development were applied to the areas within the cutoffs. The recovery factor for thermal development is lower than recoveries being achieved by some of the active in situ projects to account for the uncertainty in the recovery processes and the uncertainties inherent with developing poorer quality resource areas. While the resource base is very large, it is worth noting that many in situ recovery technologies are still in the early development stage and there is still considerable uncertainty about how much crude bitumen will ultimately be recovered.

Table 1.3 summarizes the EUB's estimates of in-place volumes and established mineable and in situ crude bitumen reserves.<sup>11</sup>

Of the remaining established reserves of 27.53 billion m<sup>3</sup>, 3.34 billion m<sup>3</sup> (21.0 billion barrels), or 12.13 percent, were under active development at year-end 2006. Significantly, more than 80 percent of remaining established reserves are estimated to be recoverable from in situ techniques.<sup>12</sup>

To process bitumen, it must first be extracted from the ground. Bitumen from the shallower oil sands deposits is extracted through open-pit mining operations. These mines expose the oil sands by stripping the overburden. The oil sand is then removed by using truck and shovel mining methods. Bitumen is separated from the sand through a process of adding warm water and agitation. Roughly two tons of sand are mined, moved and processed to produce one barrel of bitumen.

In situ means "in place", and indicates that the bitumen is extracted from the sand in the reservoir. These techniques are employed for deeper oil sands deposits (generally greater than about 75m to the top of the oil sands formation). The two main in situ processes currently being used are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). These methods inject steam into the formation to heat the bitumen, allowing it to flow and be pumped to the surface.

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<sup>10</sup>Alberta Canada, Alberta Energy Resources Conservation Board, *Alsands Fort McMurray Project, ERCB Report 79-H, 1979*.

<sup>11</sup>Alberta, Canada, Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Reserves 2006 and Supply Demand Outlook 2007-2016* (Calgary, Alberta, 2007), [http://www.eub.gov.ab.ca/bbs/products/STs/st98\\_current.pdf](http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf).

<sup>12</sup> Ibid.

**Table 1.3**  
**In-Place Volumes and Established Reserves of Crude Bitumen**  
**(10<sup>9</sup>m<sup>3</sup> as of December 31, 2006)**

Recovery Method	Initial Volume In-Place	Initial Established Reserves	Cumulative Production	Remaining Established Reserves	Remaining Established Reserves Under Active Development
Mineable	16.1	5.59	0.58	5.01	2.95
In situ	254.2	22.80	0.28	22.53	0.39
Total	270.3	28.39	0.86	27.53	3.34
	(1,701) <sup>a</sup>	(178.7) <sup>a</sup>	(5.4) <sup>a</sup>	(173.2) <sup>a</sup>	(21.0) <sup>a</sup>

<sup>a</sup>Imperial equivalent in billions of stock-tank barrels.

SOURCE: Alberta Energy and Utilities Board, *Statistical Series 2007-98, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016*.

### 1.5.1 Mineable Crude Bitumen Reserves

Oil sands mines currently comprise operations by Suncor Energy Inc., Syncrude Canada Ltd., and Albian Sands Energy Inc. The first commercial development of Alberta's oil sands began when Great Canadian Oil Sands (now Suncor) opened its mine, extraction plant and upgrader north of Fort McMurray in 1967. This was followed by development of the Syncrude mine, extraction plant and upgrader, in the same area, in the 1970s. Construction began on the Syncrude site in 1973 and, after five years of construction, Syncrude commenced production in 1978. Albian Sands operates the Muskeg River Mine located 75 kilometres north of Fort McMurray. The project reached a major milestone with start-up and first bitumen production on December 29, 2002. Albian Sands is part of the Athabasca Oil Sands Project (AOSP), a joint venture between Shell Canada Limited (60 percent), Chevron Canada Limited (20 percent) and Marathon Oil Canada Corporation (20 percent).

The EUB publishes estimates of mineable crude bitumen reserves for each of the three operators as shown in Table 1.4.

**Table 1.4**  
**Mineable Crude Bitumen Reserves**  
**(10<sup>6</sup>m<sup>3</sup> as of December 31, 2006)**

<b>Development</b>	<b>Initial Volume In-Place</b>	<b>Initial Established Reserves</b>	<b>Cumulative Production</b>	<b>Remaining Established Reserves</b>
Albian Sands	672	419	32	387
Fort Hills	699	364	0	364
Horizon	834	537	0	537
Jackpine	361	222	0	222
Suncor	990	687	220	467
Syncrude	2,071	1,306	330	976
Total	5,627	3,535	582	2,953

SOURCE: Alberta Energy and Utilities Board, *Statistical Series 2007-98, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016*.

### 1.5.2 In Situ Crude Bitumen Reserves

In situ bitumen development began in the 1960s when Imperial Oil Limited built a test project to extract bitumen from the Cold Lake deposits using the cyclic steam stimulation recovery method. During the 1970s, Shell Canada developed similar technology for producing bitumen in the Peace River area.

In the Athabasca Area, extensive efforts by government and industry led to the development of the steam assisted gravity drainage process. This approach involves two horizontal wells being drilled, one above the other. Low pressure steam is injected into the upper well to heat the reservoir and enable the bitumen to flow, and condensed steam and bitumen are produced from the lower well.

### 1.6 Resource Development Trends and Issues

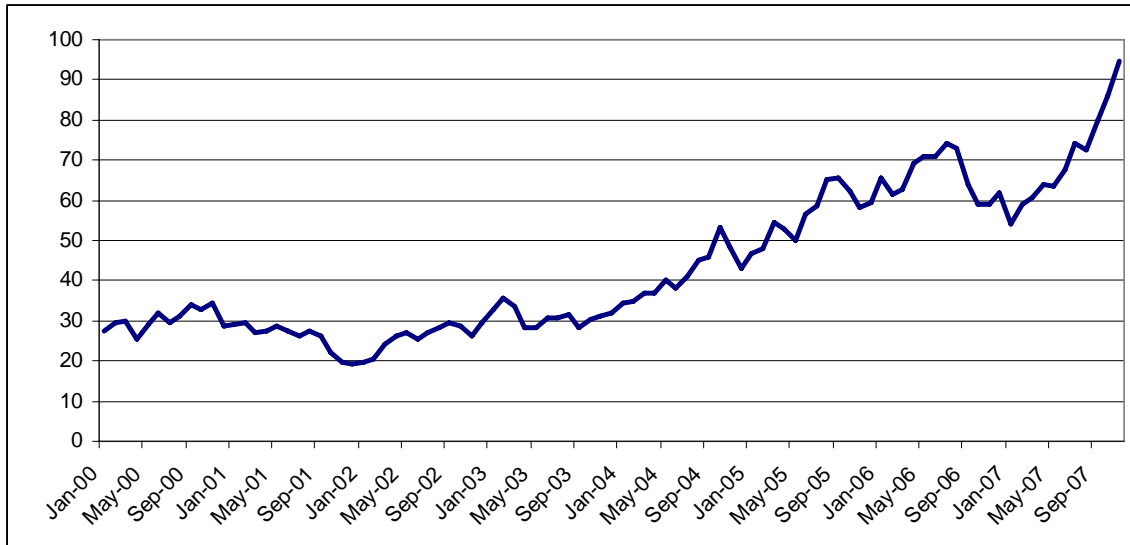
There is no doubt that Alberta's bitumen resource base is huge. What then, are the longer-term development prospects? In highlighting some of the major energy and petroleum industry trends and issues at the macro level, this section acts as a precursor to more detailed discussions of oil sands projects under development in Alberta in subsequent chapters. This report will examine opportunities and potential constraints for the oil sands industry, options to reduce air emissions, and, most importantly, the supply costs of crude bitumen and synthetic crude oil.

This prediction (essentially based on the resource scarcity argument) could be upset by a number of factors: the discovery of huge new reserves (i.e., Russia and Kazakhstan, among others); further development of oil recovery technology to extract more oil from known resources; and the credibility of reserve estimates in the Middle East. There are, however, major economic factors as well: a steep rise in oil prices would make it profitable to recover even the most stubbornly buried oil; and easing of foreign investment laws in countries with known reserves to encourage development and the use of more sophisticated technologies. As is indicated in Figure

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1.3, the market price of oil has surged since 2000, making the oil sands an attractive investment. As will be discussed in Part II, a high market price for oil today, needs to translate into a sustained high—relative to 2000 to 2005—real price of oil.

**Figure 1.3**  
**WTI Market Prices (US\$/bbl)**

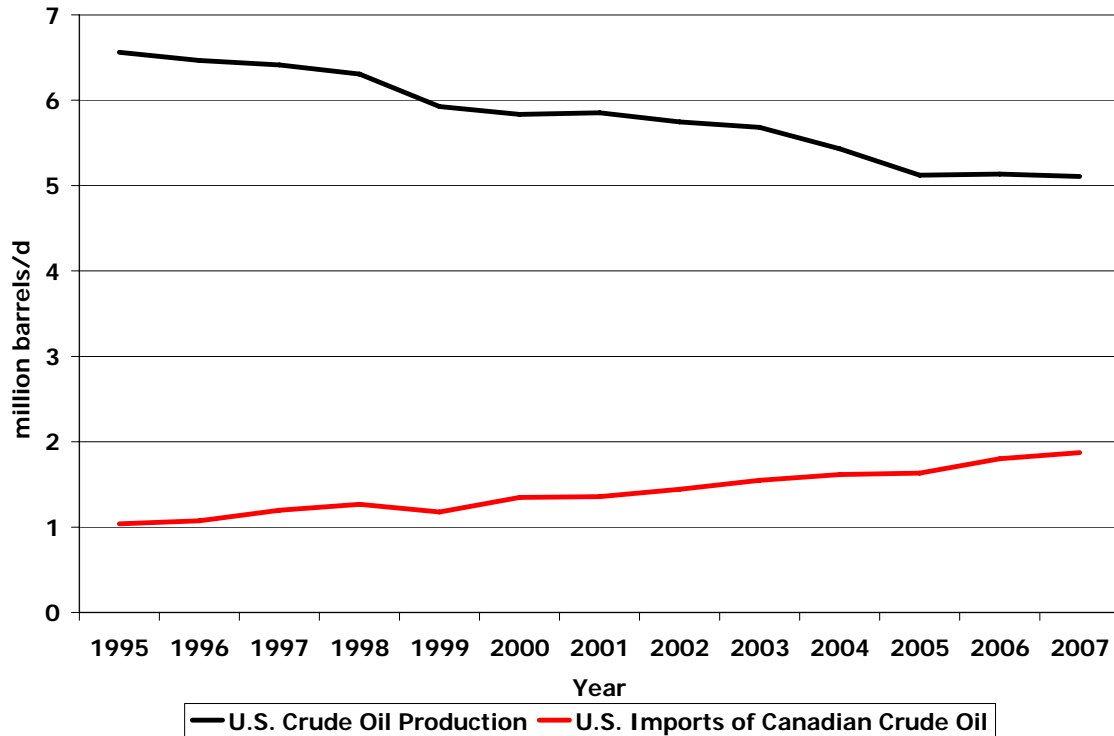


SOURCE: IEA, "Oil Market Report".

Controversy and debate continue to rage on the longer-term sustainability of global conventional oil production. Any shortfall in global conventional crude supplies would be good news for the Canadian oil sands industry, especially if such a shortfall leads to a period of sustained high prices.

In 2007, the United States was still their own largest supplier of crude oil, followed by Canada with a supply of 1.87 million barrels per day, on average through 2007 (until and including November, the last date of available data at the time of writing this report). While US field production of crude oil has declined from an average of 6.56 million barrels per day in 1995 to 5.11 million barrels per day in 2007, US imports of Canadian crude oil has been on the rise. In 1995, the volume of Canadian crude oil imported by the United States was equivalent to 16 percent of their total domestic production. This number has grown to almost 37 percent in 2007. Figure 1.4 illustrates the trends in US crude oil production and imports from Canada for the period 1995 to 2007.

**Figure 1.4**  
**US Crude Oil Production and Imports from Canada**



What about alternatives to oil that could turn the tables on what appears to be a robust outlook for fossil fuel demand? The contention is that while a looming oil shortage could trigger an increase in oil prices, curtailing demand, such price signals could have a limited effect on the availability of alternatives, at least over the next two decades. There are, however, technologies and fuel alternatives that exist today. As will be discussed in Part III, gasification, hydrocarbons and nuclear energy could play an important role in technology changes over the next two decades. Furthermore, advancements in processing of mined bitumen and knowledge of in situ reservoirs could reduce the energy demands of in situ projects. For the foreseeable future, the prospect for oil sands to become a major supplement to conventional oil is bright.

The foregoing serves to highlight some of the major issues that will affect future development of Canada's oil sands. The list is by no means exhaustive, and ensuing Parts and Chapters will address challenges as well as opportunities for the industry.

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## CHAPTER 2 RECOVERY TECHNOLOGIES

### 2.1 Introduction

Dogged determination by the pioneering developers, and dedicated research and development have paid off, judging by the innovative technologies that are being employed to recover crude bitumen from Alberta's huge oil sands resources. The result is a dynamic and commercially successful industry that effectively competes on the world stage with conventional oil and other energy sources. Continuing efforts to reduce costs through technological improvements and other operational measures, while addressing environmental concerns and new regulations, should ensure a robust future. However, unintended consequences from policy makers in Canada and around the world could impede oil sands development and curtail investment in new technologies.

### 2.2 Recovery Techniques

Two methods are employed for recovery of crude bitumen from oil sands deposits:

- In situ
- Surface mining and extraction

### 2.3 In Situ Recovery

About 90 percent of the oil sands in Alberta are buried too far below the surface (generally more than about 75 metres) to support economic surface-mining operations. Bitumen in these deeply buried deposits can only be recovered using in situ techniques. Most in situ bitumen production comes from deposits buried more than 400 metres below the surface, although some projects are operating at shallower depths. In situ bitumen production is similar to that of conventional oil production where oil is recovered through drilled wells.

In situ recovery comprises the following processes:

- Primary recovery:
  - Cold Heavy Oil Production with Sand (CHOPS)
- Thermal recovery:
  - Cyclic Steam Stimulation (CSS)
  - Steam-Assisted Gravity Drainage (SAGD)
  - Toe-to-Heal-Air-Injection (THAI)

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- Solvent-based recovery processes:
  - Vapour Recovery Extraction (VAPEX)
  
- Hybrid thermal/solvent processes:
  - Steam Assisted Gas Push (SAGP)
  - Expanding-Solvent SAGD (ES-SAGD)
  - Low-Pressure Solvent SAGD
  - Tapered Steam Solvent SAGD (TSS-SAGD)

### 2.4 Primary Recovery

There are reservoirs in the oil sands that permit primary recovery or "cold production". That is, no external energy is applied to the reservoir to induce the bitumen<sup>13</sup> to flow to the well bore. This type of production technology is commonly referred to as cold heavy oil production with sand. A significant difference between primary bitumen and conventional heavy oil production is the amount of sand that is co-produced. Sand production from primary bitumen wells tends to be two to three times greater than that from conventional heavy oil wells.

Several primary recovery projects are operating in the southern parts of the Cold Lake and Athabasca (Wabasca) Oil Sands Areas. Early production in the Cold Lake area was ridden with problems caused by extreme wear on the pumps used to bring bitumen to the surface due to the presence of sand. Beginning in the early 1990s, introduction of the progressive cavity pump represented a significant innovation, with the new equipment being better suited to handle sand. Operators found that producing sand along with the bitumen, especially early in a well's life, was conducive to higher production rates. This was because a system of preferential fluid flow paths, or "wormholes",<sup>14</sup> was formed and expanded as the sand was produced. This resulted in significantly higher production rates, lower operating costs and improved economics. Recovery factors range from three to ten percent using CHOPS in this area.

Development in the Wabasca area gained interest with the advent of horizontal well technology in the 1990s that yielded higher production rates. The reservoirs are relatively thin (five metres) and consolidated, with no significant sand production problems, and better suited to primary production by means of horizontal wells. The horizontal well technology has advanced to the stage that very long single leg and even "multi-leg" or "multilateral" producing wells can be drilled and successfully operated. Wells with up to seven legs and with a total length of 15

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<sup>13</sup>Some refer to primary production from defined oil sands areas as (very) heavy oil. However, in this report, production from primary recovery techniques within defined oil sands areas is referred to as crude bitumen.

<sup>14</sup>The Alberta Research Council (ARC) conducts ongoing research into sand production processes including investigations of the benefits of sand production in promoting wormhole growth to increase reservoir access and improve oil recovery.

[http://www.heavyoil.arc.ab.ca/Brochures/HOOS/SandProdn\\_flyer\\_Jn02.pdf](http://www.heavyoil.arc.ab.ca/Brochures/HOOS/SandProdn_flyer_Jn02.pdf)

kilometres are being drilled from a single well bore. Recovery factors are expected to be in the seven to ten percent range using primary recovery in this area.

## 2.5 Thermal Recovery

In general, the heavy, viscous nature of the bitumen means that it will not flow under normal reservoir temperature and pressure conditions. Numerous in situ technologies have been developed that apply thermal energy to heat the bitumen and reduce its viscosity thereby allowing it to flow to the well bore.

The most common thermal techniques involve steam injection into the oil sands deposit using either cyclic steam stimulation or steam-assisted gravity drainage recovery technology. Steam is injected into the oil sands zone using either vertical, deviated or horizontal wells. The steam heats the bitumen, thereby lowering its viscosity, allowing it to migrate toward producing wells where it can be brought to the surface using reservoir pressure, gas lift or downhole pumps.

### 2.5.1 Cyclic Steam Stimulation (CSS)

The CSS system was first developed by Imperial Oil in the late 1950s at Cold Lake. The technology was commercialized by 1985. Initially, innovations included recycling of produced water and application of the pad drilling concept. Each pad contains a cluster of vertical and directionally drilled wells to access the bitumen-producing reservoir. Drilling twenty or more wells from one pad has become commonplace. The pad design minimizes surface disturbance while directional wells provide access to a much larger area of the underground oil sands reservoir than would conventional wells.

The CSS or "huff and puff" system is based on producing steam in once-through-steam-generators (OTSGs) or the heat-recovery-steam-generators (HRSGs) associated with cogeneration facilities and injecting it down the well bore into the target formation at a temperature of about 300° Celsius (C) and pressures averaging 11,000 kilopascals (kPa). This pressure is sufficient to cause parting of the unconsolidated oil sands formation creating paths for fluid flow. For each individual well, periods of steaming are followed by periods of soaking and then by periods of production. Typical initial cycle times for the Imperial Cold Lake development are:

- Injection            4-6 weeks
- Soak                 4-8 weeks
- Production         3-6 months

When production rates decline, another cycle of steam injection begins. The injection-production cycle is repeated a number of times over the life of the well. The time to steam and produce the wells varies from well to well with each cycle, typically between six to eighteen months. Expected recovery factors range between about 20 to 25 percent of original bitumen in-place.

Bitumen at Cold Lake is produced from the Clearwater formation located more than 400 metres below the surface. The productive zone is 30-40 metres thick. In 2006, bitumen production before royalties at Imperial's Cold Lake Project exceeded 150 thousand b/d (24 thousand m<sup>3</sup>/d),<sup>15</sup> Dual above-ground pipelines – one delivering steam and the other carrying produced fluids back to the central processing facilities – serve multiple pads.

### 2.5.2 Steam-Assisted Gravity Drainage (SAGD)

The concept of utilizing continuous heating and production, rather than the discontinuous CSS process was developed during the late 1970s and early 1980s. SAGD evolved from work that was done at the Underground Test Facility (UTF) near Fort McMurray beginning in 1987. UTF was initially developed by the Alberta Oil Sands Technology and Research Authority (AOSTRA) with the support of several industry participants. Initial tests at the UTF involved placing pairs of horizontal wells within the oil sands deposit, at a depth of about 200 metres below the surface, through a system of vertical shafts and horizontal access tunnels completed below the oil sands formation. Each well pair consisted of a production well situated near the base of the oil sands zone and an injection well about five metres directly above the production well. Steam is injected through the upper well and heats the oil sands and bitumen. Provided there is sufficient permeability, the mobilized bitumen and condensed steam drain, by gravity, to the producing well, and are subsequently pumped to the surface.

SAGD technology offers some potential advantages over CSS in reservoirs that have high vertical permeability.<sup>16</sup> Advantages include higher recovery factors (up to 50 percent for SAGD compared to 15-20 percent for CSS),<sup>17</sup> lower steam-oil ratios,<sup>18</sup> which reduce operating costs, and the use of lower pressures that allow the exploitation of shallower reservoirs. However, these advantages are offset to some degree by SAGD's requirement for injection of saturated (100 percent quality) steam and by much higher gas-oil-ratios (associated gas production) for operations in Cold Lake compared to Athabasca.<sup>19</sup>

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<sup>15</sup> Randy L. Broiles, Senior Vice-President – Resources Division, Imperial Oil Limited, "Imperial Oil – A Leader in Canada's Oil Sands", *Raymond James Oil Sands of Canada Conference*, New York, May 7, 2007.

<sup>16</sup>SAGD has proven to work better than CSS in reservoirs that have vertical permeability greater than 1 Darcy, such as the Athabasca McMurray oil sands reservoirs. The CSS process is preferred in reservoirs that have vertical permeability of less than 1 Darcy, such as the Cold Lake Clearwater reservoirs.

<sup>17</sup>Recovery factors are quoted from a presentation made by Francois Cupcic entitled *Extra Heavy Oil and Bitumen: Impact of Technologies on the Recovery Factor, The Challenges of Enhanced Recovery*. <http://www.peakoil.net/iwood2003/ppt/CupcicPresentation.pdf>.

<sup>18</sup>Steam-Oil Ratio is the ratio of the volume of steam injected to the volume of bitumen recovered. SOR is commonly used as a measure of thermal efficiency of the SAGD process.

<sup>19</sup>CSS operations allow the injection of lower quality steam – typically 80 percent or less. Produced gases reduce offsite fuel requirements.

### 2.5.3 Toe-to-Heal-Air-Injection (THAI)

THAI is a new thermal recovery process proposed for the recovery of oil sands using in situ combustion.<sup>20</sup> THAI combines vertical air injection wells with horizontal production wells. During this process, a combustion front is created where heavy bitumen residues left on the sand grains during the production process are burned in the reservoir. This generates heat, which reduces the viscosity of bitumen, enabling it to flow, by gravity, to horizontal production wells. The combustion front sweeps the bitumen from the toe to the heel of the horizontal producing well efficiently recovering an estimated 80 percent of the bitumen in place, while partially upgrading the bitumen in situ. Other potential benefits of THAI technology include minimal natural gas and fresh water usage, partially upgraded oil quality (high-temperature oxidization of coke is left underground), lower capital and operating costs, 50 percent less GHG emissions, reduced diluent requirement for transportation, and the potential to operate in lower pressure, lower quality, thinner and deeper oil sands reservoirs than current steam-based methods.

Whitesands Insitu Ltd. (a wholly owned subsidiary of Petrobank Energy and Resources Ltd.) is carrying out the world's first field pilot test of this technology at its Whitesands Project located at Christina Lake. The project, which was approved by the AEUB in 2004, consists of three horizontal wells (500 metres long and 100 metres apart), three vertical air injection wells, and 19 vertical observation wells (17 for temperature and 2 for pressure observations). Positive results from the Whitesands Project have motivated the company to move to the commercial development stage with the multi-phase May River Project. Ultimate production capacity is anticipated to be 100,000 b/d.

In a supplemental information package provided to the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV), results from an analysis of produced fluids from 3-D cell tests were reported.<sup>21</sup> Oil produced using the THAI technology had an API gravity of 20.63 degrees, compared to 10.1 degrees for crude oil produced using SAGD, and a density level of 930.1 kg/m<sup>3</sup> compared to 999 kg/m<sup>3</sup>. Additionally, the oil produced with THAI technology had much lower viscosity at 20°C (33 cST compared to 80,000 cST), and relatively lower levels of carbon, nitrogen, sulphur, iron, nickel, vanadium, molybdenum, saturates, resins, and asphaltenes.<sup>22</sup>

The horizontal and vertical wells are steamed to facilitate air injection and bitumen flow. A combustion zone, with temperatures ranging between 400°C and 700°C, is created when the air injected ignites the oil.<sup>23</sup> The hot combustion gases coming into contact with the bitumen will cause thermal cracking and upgrading of the bitumen. The lighter oil at the combustion front and vaporized reservoir water flow into the horizontal wells while the coke remains underground and

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<sup>20</sup> THAI technology was developed by Dr. Malcolm Greaves from the University of Bath and Dr. Alex Turta from the Petroleum Recovery Institute/Alberta Research Council.

<sup>21</sup> The test was conducted by Dr. T. Xia at University of Bath, July 4, 2003, using Wolf Lake Bitumen.

<sup>22</sup> Orion Oil Canada Ltd., WHITESANDS Project Supplemental Information Requests and Responses, January 2004. [http://www.petrobank.com/webdocs/whitesands/whitesands\\_eub\\_response.pdf](http://www.petrobank.com/webdocs/whitesands/whitesands_eub_response.pdf)

<sup>23</sup> Results from early combustion operations, released in September 2006, showed that combustion zone temperatures reached a peak of over 700°C.

[http://www.petrobank.com/webdocs/news\\_2006/2006\\_09\\_12\\_WHITESANDS\\_Update.pdf](http://www.petrobank.com/webdocs/news_2006/2006_09_12_WHITESANDS_Update.pdf)

functions as a fuel source for further combustion as the combustion process moves through the formation.

## **2.6 Solvent-Based Recovery Processes (VAPEX)**

VAPEX is a recovery technique that uses gaseous solvents to increase bitumen recovery by reducing its viscosity. Vaporized hydrocarbon solvents are injected into the oil sands reservoir. The solvent mixes with the bitumen, reduces its viscosity, and causes it to drain by gravity to a horizontal production well.

Since VAPEX is a non-thermal method, it has the potential to reduce CO<sub>2</sub> and other greenhouse gas (GHG) emissions substantially – estimated to be as much as 85 percent over thermal processes. Other driving forces for VAPEX include potential for dramatically reduced water consumption compared to other extraction technologies, and related lower water-handling and surface facility costs. The technology also has significant potential economic advantages because it can be used to recover bitumen from zones that are considered too thin for traditional thermal recovery methods, and offers the potential for an upgraded and higher-value product by promoting in situ upgrading. Paraffinic solvents cause asphaltenes to be precipitated and left behind in the reservoir (i.e., partial upgrading occurs).

Like SAGD technology, the VAPEX process uses horizontal well pairs to recover the bitumen. However, the process uses a hydrocarbon solvent instead of steam. This eliminates the need to burn fuel (usually natural gas) to create the steam, resulting in reduced GHG emissions. In addition, the solvent in the VAPEX process can be reused. With the VAPEX process, vapourized solvents are injected into the reservoir via an upper horizontal well. The bitumen in the reservoir is diluted with the solvent, which reduces its viscosity and allows the bitumen-solvent mixture to drain by gravity to the production well. On the surface, the solvents are separated from the produced bitumen and recycled.

Research carried out thus far suggests that up to 90 percent of the solvent used can be recovered and recycled, offering the potential for dramatic cost savings over other extraction methods. Results have also shown the quality of produced bitumen to be superior because some of the heavier fractions are left in the ground.

## **2.7 Hybrid Thermal/Solvent Recovery Processes**

### **2.7.1 Steam Assisted Gas Push (SAGP)**

SAGP is a variation of the SAGD process involving the addition of a small amount of non-condensable gas such as natural gas or flue gas with the injected steam. Through improved energy efficiencies, the SAGP process presents opportunities for reducing steam consumption by up to 70 percent compared to SAGD.

### **2.7.2 Hybrid Steam-Solvent Processes**

The Alberta Research Council (ARC) is undertaking research into a number of hybrid steam-solvent processes combining SAGD technology with different solvent injection strategies. The new processes are aimed primarily at improving recovery and energy efficiency, and reducing water requirements. These enhanced thermal processes include Expanding-Solvent SAGD (ES-SAGD), Low-Pressure Solvent SAGD, and Tapered Steam Solvent SAGD (TSS-SAGD). Research is also under way on characterizing asphaltene behaviour with the objective of controlling and exploiting asphaltene precipitation.

## **2.8 Surface Mining and Extraction**

### **2.8.1 Introduction**

Before the oil sands can be mined, the water-laden muskeg that overlies much of the area must be drained, and the layers of muskeg, surface vegetation and tree cover removed. This is usually carried out in the winter when the muskeg is frozen. Any suitable soil materials are selectively excavated and used for reclamation. Once the muskeg is removed, the overlying overburden is removed using shovels and trucks to expose the top of the oil sands formation and prepare the site for mining operations. The overburden, consisting of a mixture of rock, clay and barren sand, is placed in previously mined-out areas, or in areas where the underlying oil sands deposits are considered uneconomic to mine. The oil sands formations beneath the overburden are typically 40 to 60 metres thick and sit on top of relatively flat limestone beds.

### **2.8.2 Surface Mining**

Over time, different techniques have been used for oil sands mining. Suncor started its operations using bucketwheel excavators that discharged their loads onto conveyor belts. The initial Syncrude operation used large draglines to remove material from the mine face and place it in windrows from which bucketwheel reclaimers loaded it onto conveyor belts. Suncor has since retired its bucketwheel excavators and two of four trains of Syncrude's dragline-based mining equipment have been retired.

Large mining trucks and power shovels in the mining operations were introduced to replace early bucketwheel and dragline based mining systems. By the early 1990s, Syncrude was moving about one-third of its ore using this method, while Suncor converted completely to a truck and shovel operation in 1993. The truck and shovel method is considerably more efficient and reliable than previous methods. Today, the oil sands ore is commonly moved to ore preparation facilities by trucks capable of hauling up to 400 tons of material.

### **2.8.3 Oil Sands Transport**

The ore (oil sands) is transported from the ore preparation facilities in the mine to the extraction plant (where bitumen is separated from the sand). Suncor and Syncrude both used long conveyor systems during their early operations. These systems have largely been replaced by

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hydrotransport. Development of hydrotransport technology began in the late 1980s. The first commercial applications occurred in the early 1990s. Truck-and-shovel operations mine the oil sands and deliver it to ore preparation facilities where crushers size the feed. The oil sands is then conveyed to a mixing operation that combines the oil sands with hot water to create a slurry that is pumped via pipeline to the extraction plant. Hydrotransport preconditions the ore for extraction of crude bitumen and improves energy efficiency and environmental performance.

The advantages of the hydrotransport include:

- the break down of large lumps of oil sands in the ore and some separation of bitumen from oil sands as the slurry moves through the pipeline;
- much more flexibility than conveyor belt systems, because pipelines can follow circuitous routing and be placed on uneven terrain; and
- low energy extraction – because of separation during hydrotransport, extraction plant operating temperatures can be reduced to 50°C, or less. The reduced energy requirements will result in lower emissions.

Suncor uses hydrotransport to bring ore across the Athabasca River from its Steepbank Mine. Syncrude uses hydrotransport to bring ore to the Mildred Lake upgrader from its North Mine. At more remote mines, primary extraction occurs at the mine site. Bitumen froth is then transported to a central site by pipeline for secondary extraction and upgrading. Syncrude has remote primary extraction at its Aurora Mine, 35 km north of the Mildred Lake upgrader. Suncor has remote primary extraction at its Millennium Mine on the east side of the Athabasca River. Some of the major challenges faced by hydrotransport operations include the effects of fine solids (clays), temperature, bitumen content (oil sand grade), and average sand grain size on the pre-conditioning process and on pipeline friction losses.

### 2.8.4 Bitumen Separation

The first commercial operations (GCOS<sup>24</sup>/Suncor and Syncrude) used the Clark Hot Water Extraction Process. Oil sands were mixed with hot water (70-80°C) and caustic in large rotating tumblers to begin separation of the bitumen from the sand. Slurry from the tumblers was fed into large primary separation vessels (PSVs) where the bitumen was separated from the sand by gravity. The bitumen floated to the surface of the PSVs as a froth; the sand settled to the bottom. The froth was subjected to further processing (froth treatment) for water and solids removal. Froth treatment is required to minimize the amount of water and solids going to the upgrader, so at this point naphtha is added as a diluent and the mixture enters a high-speed centrifuge to complete the cleaning/separation. The diluted bitumen is moved to the upgrading unit while the sand and other materials that settle during the separation process are removed as "tailings slurry" for disposal in large tailings ponds.

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<sup>24</sup>Canadian operations of Great Canadian Oil Sands Limited (GCOS) and Sun Company Inc. were amalgamated in 1979 to form Suncor Inc.

The middlings and underflow streams from the PSVs are pumped to tailings oil recovery vessels (TOR – a technology developed by Syncrude) to recover residual bitumen that is returned to the primary separation vessels. The middlings from the TOR vessels are processed in a secondary floatation plant for further bitumen recovery. Primary and secondary froth are combined, de-aerated and heated, and fed to the froth treatment plant. Froth is diluted with naphtha for separation of solids in plate settlers and/or centrifuges. A naphtha recovery unit recovers naphtha from froth treatment tailings before the tailings are sent to disposal.

In a technique that is relatively new to the oil sands industry, bitumen froth is sent to a circuit known as counter-current decantation. A solvent is added which separates the remaining solids, water and heavy asphaltenes in a three stage, dual circuit process. The process yields clean, diluted bitumen, low in contaminants, and with a viscosity that enables the bitumen to be transported by pipeline.

Recent ground-breaking work by Shell Canada has also resulted in the innovative Shell Enhance froth treatment technology that the company is using at the Athabasca Oil Sands Project's (AOSP) Muskeg River Mine. Using higher temperatures in the processing of the oil sands froth improves energy efficiency by 10 percent, resulting in a 40,000 tonne reduction in annual GHG emissions, and decrease water usage by 10 percent, compared to conventional low temperature paraffinic froth treatment processing.<sup>25</sup>

Considerable effort is underway to reduce the energy required for bitumen extraction. At its Aurora Mine, opened in 2000, Syncrude installed a low-energy extraction process that operates at approximately 35°C, and is designed to consume about one-third of the energy of the traditional 80°C process. Success in this area would result in substantial cost reductions and have considerable environmental benefits.

### **2.8.5 Tailings Management**

Tailings are a by-product of the oil sands extraction process. After bitumen is extracted from oil sands with hot water, a leftover mixture of water, sand, silt and fine clay particles is pumped into a settling basin. Tailings also contain residual bitumen that is not recovered and residual solvents used in the extraction process. It may be possible to recover the residual bitumen and solvent, however, the emissions impact from the increased energy use to recover these products will not be examined in this report. Fast-settling coarse sand particles in the tailings are used to construct mounds, dikes and other stable deposits. Fine tailings, consisting of slow-settling clay particles and water, are more problematic.

Until now, tailings have been allowed to segregate into tailings sand, and fine tailings, and then disposed of separately. Techniques for handling and re-vegetating tailings sand exist; however, tailings management is made difficult by the amount of time it takes for fine tailings to settle.

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<sup>25</sup> Shell Canada, February 2008.

[http://www.shell.com/home/content/ca-en/news\\_and\\_library/press\\_releases/2006/unindex/november21\\_shell\\_enhance.html?LN=/news\\_and\\_library/press\\_releases/2006](http://www.shell.com/home/content/ca-en/news_and_library/press_releases/2006/unindex/november21_shell_enhance.html?LN=/news_and_library/press_releases/2006),

After a few years, fine tailings tend to form a highly voluminous sludge with the consistency of runny toothpaste, but it would take a few centuries for them to further consolidate to the consistency of soft clay. The environmental challenges are therefore to manage the sheer volume of fine tailings and their fluid nature. Because of the high water content of the sludge (as much as 85 percent), it retains fluid characteristics and must be stored behind dykes with little possibility of being used as a solid substrate for plant establishment during reclamation.

Another strategy being considered for fine tailings management is Paste Technology, which rapidly dewateres the fine tailings stream to produce a paste-like material which is still pumpable. This relatively new technique requires synthetic flocculants to achieve rapid settling of dense fine solids aggregates, a deep bed thickener to promote self weight consolidation in the settled solids, and dewatering channels to relieve the excess pore pressures, to form the paste. Upon discharge, the paste deposit forms a slope and gains strength. The thickener overflow is recycled to the plant. Research is underway to determine the parameters for its application in the oil sands. The paste would be incorporated within the coarse tailings disposal sites.

Other key tailings research and development initiatives proposed for the next few years include, optimization of the composite tailings process, reclamation of tailings deposits, management of recycle water chemistry, and development of thickened tailings for oil sands application.

## **2.9 Upgrading**

In the upgrading process,<sup>26</sup> bitumen is converted from a viscous oil that is deficient in hydrogen and high in sulphur, nitrogen, oxygen and heavy metals, to a high quality "synthetic" or "upgraded" crude oil that has density and viscosity characteristics similar to conventional light sweet crude oil, but with a very low sulphur content (0.1-0.2 percent). Upgrading is achieved using coking and/or hydro-conversion processes. Coking processes improve the hydrogen-carbon ratio by "carbon removal"; hydro-conversion processes by "hydrogen addition".

### **2.9.1 Coking**

As a severe method of thermal cracking, the coking process involves sending bitumen to the coker's reactors where high temperatures cause the long bitumen molecules to thermally crack. Coking is used to upgrade heavy residuals into lighter products or distillates. Part II will present supply costs for upgrading bitumen, while Parts III and IV will consider alternative fuels for the upgrading process and how they could reduce emissions and change the supply cost. The process so completely reduces hydrogen that the residue is a form of carbon called "coke." The two most common processes in oil sands operations are delayed coking and continuous (contact or fluid) coking. With delayed coking, thermal cracking temperatures of 485-505°C are reached.

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<sup>26</sup>The National Centre for Upgrading Technology (NCUT) is leading much of the heavy oil and bitumen upgrading research for the oil sands industry. Formed in 1995 as a partnership between the Canadian federal and Alberta provincial governments, NCUT provides science and technology research that will improve energy efficiency and reduce greenhouse gas emissions in the heavy oil upgrading and refining industries.

Suncor uses delayed coking while Syncrude uses fluid coking. Produced coke is used as a fuel source for the coker burners (fluid coking at Syncrude) as well as for other heat requirements (Suncor power plant). Excess coke is stockpiled or sold for industrial applications—such as future gasification or power projects. The Scotford Upgrader of the AOSP uses hydro-conversion processes rather than coking.

#### Delayed Coking<sup>27</sup>

In delayed coking, the heated charge (typically residuum from atmospheric or vacuum distillation towers) is transferred to large coke drums that provide the long residence time needed to allow the cracking reactions to proceed to completion. After the coke reaches a predetermined level in one drum, the feed is diverted to another drum to maintain continuous operations. The full drum is steamed to strip out uncracked hydrocarbons, cooled by water injection, and decoked by mechanical or hydraulic methods.

#### Continuous Coking<sup>28</sup>

Continuous (contact or fluid) coking is a moving-bed process that operates at temperatures higher than delayed coking. In continuous coking, thermal cracking occurs by using heat transferred from hot, recycled coke particles to feedstock in a radial mixer, called a reactor.

#### Visbreaking

Visbreaking, a mild form of thermal cracking, significantly lowers the viscosity of heavy crude-oil residue without affecting the boiling point range. Residual from the atmospheric distillation tower is heated (425-480°C) at atmospheric pressure and mildly cracked in a heater. It is then quenched with cool gas oil to control overcracking, and flashed in a distillation tower. Visbreaking is not being applied at any of the commercial oil sands operations. It has been considered for partial upgrading to produce a lower viscosity material that is suitable for pipeline transportation without the addition of diluents. However, it does pose a risk of generating unstable hydrocarbon compounds (olefins) that could precipitate asphaltenes in oil pipelines—this could increase the operating and maintenance costs of pipelines and reduce the flow volume.

### **2.9.2 Hydro-conversion**

Hydro-conversion or hydro-addition is a high temperature, high pressure upgrading process that breaks up large hydrocarbon molecules into smaller hydrocarbon molecules by adding hydrogen to the bitumen in the presence of a catalyst, heat and pressure.

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<sup>27</sup>Used at Suncor's Tar Island Upgrader.

<sup>28</sup>Used at Syncrude's Mildred Lake Upgrader.

### Hydrocracking<sup>29</sup>

Hydrocracking is a two-stage process combining catalytic cracking and hydrogenation, wherein heavier hydrocarbons are cracked in the presence of hydrogen to produce more desirable products. The process employs high pressure, high temperature, a catalyst, and hydrogen. The hydrocracking process largely depends on the nature of the feedstock and the relative rates of the two competing reactions, hydrogenation and cracking. Heavy aromatic feedstock is converted into lighter products under a wide range of very high pressures (1,000-2,000 psi) and high temperatures (400-815°C), in the presence of hydrogen and special catalysts. When the feedstock has a high paraffinic content, the primary function of hydrogen is to prevent the formation of polycyclic aromatic compounds. Another important role of hydrogen in the hydrocracking process is to reduce tar formation and prevent buildup of coke on the catalyst.

### Catalytic Hydrotreating<sup>30</sup>

Catalytic hydrotreating is a hydrogenation process used to remove about 90 percent of contaminants such as nitrogen, sulphur, oxygen, and metals from liquid petroleum fractions. Hydrotreating for sulphur removal is called hydrodesulphurization. In a typical catalytic hydrodesulphurization unit, the feedstock is mixed with hydrogen, preheated in a fired heater (315-425°C) and then charged under pressure (up to 1,000 psi) through a fixed-bed catalytic reactor. Hydrotreating converts sulphur and nitrogen compounds present in the feedstock to hydrogen sulfide and ammonia.

## **2.10 Ancillary Processes and Utilities**

### **2.10.1 Hydrogen Production**<sup>31</sup>

Hydrogen is usually produced on site using natural gas as feedstock. The process of Steam Methane Reforming (SMR) involves the reaction of methane with steam over a catalyst at high temperatures.

### **2.10.2 Gas Treating and Sulphur Recovery**

Gases produced during upgrading operations contain hydrogen sulphide, carbon dioxide and ammonia. These gases are treated to remove these contaminants, and then dehydrated, making them suitable for plant fuel. The acid gases (hydrogen sulphide, carbon dioxide and ammonia) are further processed for sulphur recovery. Waste gases are incinerated and exhausted into the atmosphere.

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<sup>29</sup>Used at Syncrude's Mildred Lake Upgrader and AOSP's Scotford Upgrader.

<sup>30</sup>Suncor, Syncrude and AOSP all use catalytic hydrotreating processes in their upgrading facilities at Tar Island, Mildred Lake and Scotford, respectively.

<sup>31</sup>A more detailed discussion of hydrogen production and needs is contained in Chapter 8. Chapter 8 of what report..

### 2.10.3 Utilities

Extraction and upgrading operations are large consumers of both electricity and heat. Cogenerators are usually installed on site at upgrading facilities to help provide the electricity and heat required in a manner that is more efficient than generating both separately. The cogenerators are connected to the provincial electrical grid (Alberta Integrated Electrical System) to allow the owner of the cogeneration plant to market any surplus electricity.

## 2.11 Canadian Upgraders

### 2.11.1 Integrated Upgraders

The Suncor and Syncrude upgraders are integrated with, and located close to, the Suncor and Syncrude mining operations north of Fort McMurray.

The Scotford Upgrader, located next to Shell Canada's Scotford Refinery near Fort Saskatchewan, is integrated with the Muskeg River Mine and the Shell refinery as part of the AOSP. Diluted bitumen is delivered to the upgrader from the Muskeg River Mine through the 453 km long Corridor Pipeline. The Scotford Upgrader, constructed and now operated by Shell, employs hydro-conversion technology to provide more environmentally friendly operations and a greater yield of high quality, synthetic crude oil than coking techniques.

### 2.11.2 Standalone Upgraders

The Husky Bi-Provincial Upgrader and the Federated Co-op NewGrade Upgrader process both crude bitumen and conventional heavy oil. They are not integrated with any specific producing property. In 2000, Husky's Lloydminster Upgrader produced 60.6 thousand b/d (9.6 thousand m<sup>3</sup>/d) of synthetic crude oil and 10.8 thousand b/d (1.7 thousand m<sup>3</sup>/d) of diluent, well above its rated throughput capacity of 54 thousand b/d (8.6 thousand m<sup>3</sup>/d). Husky has been considering an expansion of capacity to 150 thousand b/d (23.8 thousand m<sup>3</sup>/d) since 1998. In 2006, Husky reaffirmed their intention to expand the upgrader through their Public Disclosure Documents.

The NewGrade Upgrader in Regina, Saskatchewan has a crude distillation capacity of 52 thousand b/d (8.3 thousand m<sup>3</sup>/d). It was recently expanded by 25 thousand b/d (4.0 thousand m<sup>3</sup>/d), with additions to vacuum distillation and hydrotreating capacity.

In end-December 2001, Petro-Canada announced it had applied to the EUB for approval to modify its Strathcona Refinery near Edmonton, to upgrade crude bitumen from its McKay River and proposed Meadow Creek in situ commercial projects. In 2007, the refinery expansion project received regulatory approval.

## 2.12 Summary

In sheer volumetric terms, Alberta's bitumen resources from oil sands rival conventional oil reserves of the world's largest producers. Commercializing the country's bitumen resource base

will continue to challenge the best technical minds, as they search for innovative technologies to extract and produce as much of the resource as possible. Increasing the proven reserves in the province is essential for the long-term success of the industry. At anticipated production rates, the oil sands could be fully produced in just over 100 years. Future research and development will focus on increasing recoverable reserves, reducing costs, improving product quality and enhancing environmental performance. Industry, government and community stakeholders will continue to undertake cooperative R&D as long as there is a perceived commercial incentive to do so. The end result will be an oil sands industry that is better equipped to withstand the vagaries of market forces.

## CHAPTER 3 HISTORICAL PRODUCTION

### 3.1 Introduction

Since the first production of oil sands from the Great Canadian Oil Sands (GCOS) project, oil sands production has witnessed numerous historical milestones. Total production has grown steadily since GCOS began operations in 1967, with rapid growth occurring over the 1990-2006 period. Total crude bitumen production, from mining and in situ, increased from 360 thousand b/d (57.2 thousand m<sup>3</sup>/d) in 1990 to 1.25 million b/d (38.1 million m<sup>3</sup>/d)<sup>32</sup> in 2006. The main contributor to total crude bitumen production has historically been, and still is, from surface mining.

#### 3.1.1 Surface Mining Operations

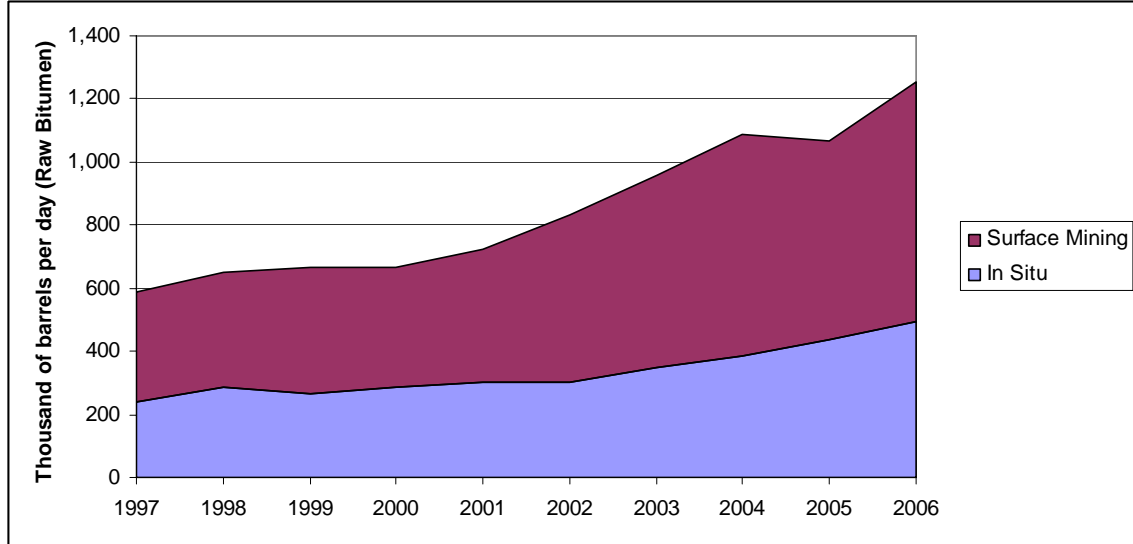
Surface mining of oil sands and extraction of crude bitumen take place exclusively in shallow parts of the Athabasca Oil Sands area – north of Fort McMurray on both sides of the Athabasca River. Most Athabasca oil sands and all Cold Lake and Peace River oil sands are too deeply buried for surface mining (generally more than about 75 metres). In 1990, mining techniques accounted for nearly 71 percent of total crude bitumen produced. This percentage grew to about 75 percent in 1995, but has since declined to 61 percent of total production as new in situ production comes on stream (see Figure 3.1).<sup>33</sup>

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<sup>32</sup>Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Energy Reserves 2006 and Supply Demand Outlook 2073-2016* (Calgary, Alberta, 2007).

<sup>33</sup>In this section, "enhanced" in situ refers to in situ production using "tertiary" recovery technique; "primary" in situ refers to in situ production using natural flow or artificial lift. Primary in situ may also be referred to as cold heavy oil production with sand (CHOPS).

Figure 3.1  
Historical Gross Crude Bitumen Production by Production Method



SOURCE: *Statistical Series ST-98*, Alberta Energy and Utilities Board.

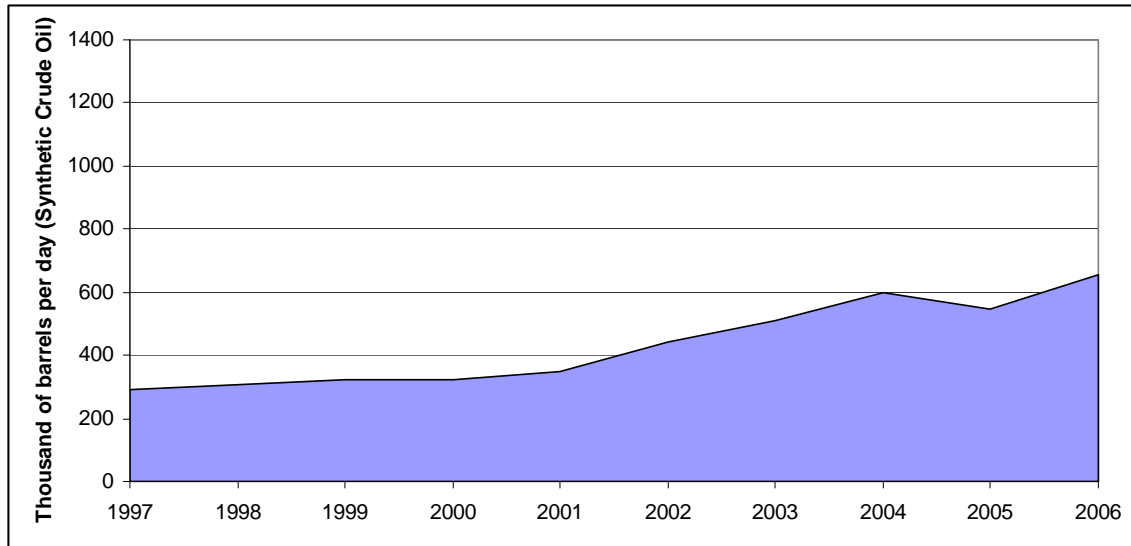
Synthetic crude oil (SCO) production reached 210 thousand b/d (33.4 thousand m<sup>3</sup>/d) in 1990 and 658 thousand b/d (104.6 thousand m<sup>3</sup>/d) in 2006. In 2006, the AEUB valued Alberta's synthetic crude oil production at \$16.3 billion.<sup>34</sup>

Bitumen that is not upgraded to synthetic crude oil is mixed with diluent and sold to refineries in Canada and the United States as bitumen blend. Traditionally, condensate has been used as the diluent. More recently, with limited condensate supplies, synthetic crude oil is increasingly being used as a diluent.

Total synthetic crude oil production is presented in Figure 3.2.

<sup>34</sup> Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Energy Reserves 2006 and Supply Demand Outlook 2073-2016* (Calgary, Alberta, 2007).

**Figure 3.2**  
**Historical Synthetic Crude Oil Production**



SOURCE: *Statistical Series ST-98*, Alberta Energy and Utilities Board.

### 3.2 Conclusion

Although commercial production from Alberta's oil sands began less than half a century ago, it has been growing rapidly and now represents over 50 percent of Canada's total oil production. As oil sands production continues to grow, they are facing an emissions constrained world that could hamper development and reduce its potential. The greenhouse gas emissions concerns will be explored in Parts II-V of this study.

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## CHAPTER 4 OBJECTIVE AND SCOPE

### 4.1 Objective and Scope

The overall objective of the project is to assess the current status of oil sands development activities and their future direction. The specific objectives are outlined as follows:

- Gain a better understanding of the current status of Canadian oil sands projects, both existing and planned. The status assessment will cover the full spectrum of activities and technologies such as in situ, mining and integrated production; facilities for upgrading crude bitumen to synthetic crude oil (SCO); transportation of crude bitumen and/or SCO to the market places.
- Explore the future direction of oil sands development including projection of investment and production; scenarios for domestic upgrading vs. export of crude bitumen; and supply cost forecasts.
- Provide an estimate of the supply cost, including costs associated with carbon emissions, for Greenfield projects consistent with in situ, mining and integrated production.

Explore the alternative fuel sources that could help reduce not only the oil sands dependency on natural gas, but reduce the air emissions associated with natural gas and alternative fuel sources.

## **4.2 Organization of the Report**

Part I provided a historical overview of the oil sands.

Part II introduces the future of the oil sands upstream activities including existing projects and future projects and forecasted productions. It also presents historical as well as future investment profiles, costs of supplying crude bitumen from oil sands activities including both surface mining and in situ operations, under the current regulatory framework for emissions.

Part III examines the supply cost of alternative fuels to natural gas for oil sands development, and how they could contribute to a reduction in greenhouse gas emissions.

Part IV will explore the existing Alberta framework and discuss Canadian and North American proposals and existing mechanisms for carbon and emissions mitigation.

Part V will wrap up the report with an examination of how changes in the carbon and emissions mitigation programs (i.e., emissions compliance costs) could impact the adoption of various technologies and the overall industry emissions profile.

## APPENDIX A TRANSPORTATION SALES AND MARKETING

Pipeline infrastructure and market requirements will have to be addressed to assist the expansion in bitumen supply. Appendix A concentrates on the major pipeline routes, including existing and proposed (as of July 2007) and various market destinations to accommodate this expansion.

### A.1 Transportation (Pipelines) Capacity

Adequate pipeline capacity is necessary to transport blended or upgraded bitumen to refineries as well as to supply diluent/condensate necessary to operate the projects. The current pipeline infrastructure in Alberta is not sufficient to transport the forecasted volumes and will need to be expanded to keep pace with growth in oil sands production.

#### A.1.1 Current Status of Transportation (Pipelines) Capacities

Capacity is needed to both transport blended or upgraded bitumen to refineries and also to supply diluent/condensate necessary to operate the projects. Currently, the capacity of regional oil pipelines that transport SCO and non-upgraded bitumen out of Cold Lake and Athabasca regions is  $1.8 \times 10^6$  bbl/d (see Table A.1).<sup>35</sup> The Cold Lake pipeline system delivers SCO and heavy oil from the Cold Lake region to Edmonton, Lloydminster and Hardisty with a capacity of  $0.7 \times 10^6$  bbl/d. The Fort McMurray pipeline system is greater than the Cold Lake system, with a capacity of  $1.1 \times 10^6$  bbl/d, delivering crude from Fort McMurray region to Hardisty and Edmonton.

Alberta has an export capacity of 2.6 million barrels a day of crude oil – using the Enbridge system, Terasen (Kinder Morgan Express and Transmountain) and several other smaller pipelines. These are listed in Table A.1. Clearly this capacity is insufficient to transport all of the production forecasted.

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<sup>35</sup> Alberta Energy and Utilities Board, (EUB), "Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015", ST98-2006, June 2006.

**Table A.1**  
**Alberta Regional and Export Pipelines**

Name	Type	Destination	Capacity (10 <sup>6</sup> bbl/d)
• Cold Lake Area pipelines			
• Cold Lake	• Heavy	• Hardisty	• 193.7
• Cold Lake	• Heavy	• Edmonton	• 117.6
• Husky Oil	• Heavy	• Hardisty	• 133.3
• Husky Oil	• Heavy	• Lloydminster	• 226.4
• Echo	• Heavy	• Hardisty	• 75.5
• <b>TOTAL</b>	•	•	• <b>746.6</b>
• Fort McMurray Area pipelines			
• Athabasca Pipeline	• Semi-processed	• Hardisty	• 300.0
• Terasen	• Diluted	• Edmonton	• 259.8
• Alberta Oil	• SCO	• Edmonton	• 388.7
• Oil Sands	• SCO	• Edmonton	• 144.7
• <b>TOTAL</b>	•	•	• <b>1093.2</b>
• Export pipelines			
• Enbridge Pipeline (includes Kinder Morgan)	• Crude oil	• Eastern Canada • US East	• 1839.8
• Milk River	• Crude oil	• US Rocky Mountains	• 281.8
• Rangeland	• Light	• US Rocky	• 118.3
• Kinder Morgan (Transmo)	• Cold	• US Rocky	• 64.8
• Kinder Morgan (Transmo)	• Crude oil & Refine	• British Columbia • US West	• 284.9
• <b>TOTAL</b>	•	•	• <b>2589.6</b>

SOURCE: Alberta Energy and Utilities Board, (AEUB), "Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015", ST98-2006, June 2006.

### A.1.2 Future Plan for Transportation Capacity Expansion

Future plans include expansion of diluent and feeder pipelines, as well as export pipelines to carry crude oil to various markets. Diluent and feeder pipelines in Alberta are expanding to transport diluent to the region and growing bitumen volumes to the major hubs of Edmonton and Hardisty. These proposed pipelines are described below.

In order to ship raw bitumen to market through feeder pipelines, the bitumen must either be blended with SCO or a diluent (such as pentanes plus) to reduce the viscosity of the oil so it can flow through pipelines. Diluent on its own is insufficient to resolve the problem of how to move the bitumen to market; feeder and export pipelines are required to bring the blended bitumen or SCO to market (refineries) where it can be refined. The expected growth in bitumen production has resulted in many proposed pipeline projects and expansions. Based upon information from

the National Energy Board (NEB), pipeline capacity leaving the oil sands region is expected to increase to around 5.8 million barrels a day by 2015.<sup>36</sup> Table A.2 summarizes the announced and potential pipeline expansions. Based upon CERI's Constrained production estimates, this capacity would be sufficient to allow bitumen, as a blend or SCO, to leave the region for refineries outside of Alberta; CERI's Unconstrained forecast indicates there could be a shortage of pipeline capacity and potential for new pipelines to move excess capacity directly to the United States, or export to Asia; this depends on each pipeline's ability to transport a bitumen blend. Under a scenario where SCO is blended with the remaining bitumen from our Unconstrained case, there appears to be sufficient pipeline capacity to meet the needs of the industry when there is 5.5 MBPD of marketable bitumen production. For visual representation, see Figures A.1 and A.2, which show the existing and proposed regional pipeline routes and existing and proposed export lines, respectively.

As seen in Table A.2, many pipelines have been proposed to carry the forecasted bitumen production volumes from Alberta to various markets. The rate of expansion will greatly depend on market conditions and regulatory approvals. In the end, producers will support the pipeline projects that will provide them with the highest netbacks for their production. Additionally, the pipeline companies might take on too much throughput risk to advance the development of their individual projects in order to provide shippers with attractive terms, thus reducing the return on the project beyond an acceptable risk-adjusted level. Hence, not all proposed projects will be completed.

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<sup>36</sup> Ibid.

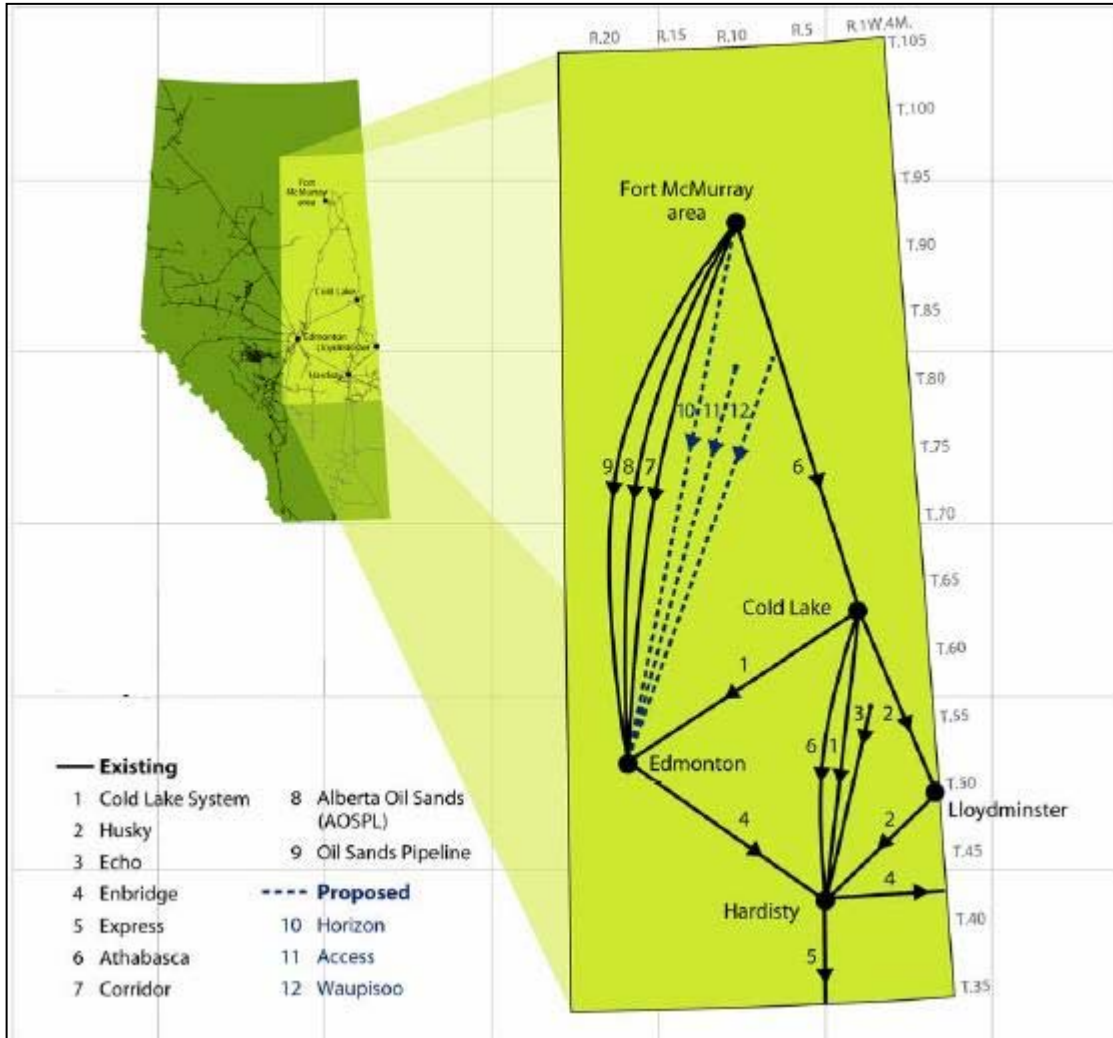
**Table A.2**  
**Potential Pipeline Expansions**

Pipeline	Type	Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Proposed Alberta Pipeline Projects					
Enbridge Waupisoo	Blended bitumen	December '05	350 (max. 600)	Mid-2008	Edmonton
	Diluent		150		Cheecham
Enbridge Gateway	diluent	June '06	150	Mid-2010	Alberta
Enbridge Southern Lights	diluent	N/A	180	1Q '09	Alberta
Kinder Morgan Corridor	dilbit	December '05	240	2009	Edmonton
Pembina Spirit	diluent	N/A	100	April '09	Alberta
Pembina Horizon	SCO	N/A	250	July '08	Alberta
Access	dilbit	December '05	150 (max. 400)	2006/2007	Edmonton
Proposed Export Pipeline Projects					
Kinder Morgan (Phase 1 TMX1)	Crude oil &RPPs	Filed July '05	75	April '07	PADD V
(Phase 2 TMX1)		Filed Jan. '06	35	November '08	Offshore/Far East
Southern Option (TMPL TMX2)	Crude oil &RPPs	1Q '07	40		PADD V
(TMPL TMX3)		N/A	700	January '10	Offshore/Far East
Northern Option (TMX)	Crude oil &RPPs	N/A	100	2011	East
			300	2011	PADD
			400		Offshore/Far East
Enbridge Gateway	Crude oil	June '06	400	2012-2014	PADD V
					Offshore/Far East
Enbridge Southern Lights Line 2 Expansion:					
Edmonton to Cromer	Crude oil	N/A		2009	PADD II
Cromer to Clearbrook			103		PADD II
Clearbrook to Superior			33		PADD II
New sour line Cromer to Clearbrook			33		PADD II
Enbridge Alberta Clipper	Crude oil	February '06	185	2010/11	Southern
			450		PADD II
Enbridge (Southern Access)	Crude oil		315		Midwest/Southern
		May '06	120	October '06 & February '07	PADD II
Phase I		N/A	148	2008/09	
Phase II		N/A	47	N/A	
Phase III					
TCPL (Keystone) Expansion & Extension	Crude oil	June '06	435	2009	Southern
			155	2010	PADD II/ PADD III
Altex Energy	Crude oil	N/A	250	4Q '10	PADD III

N/A – Not Available

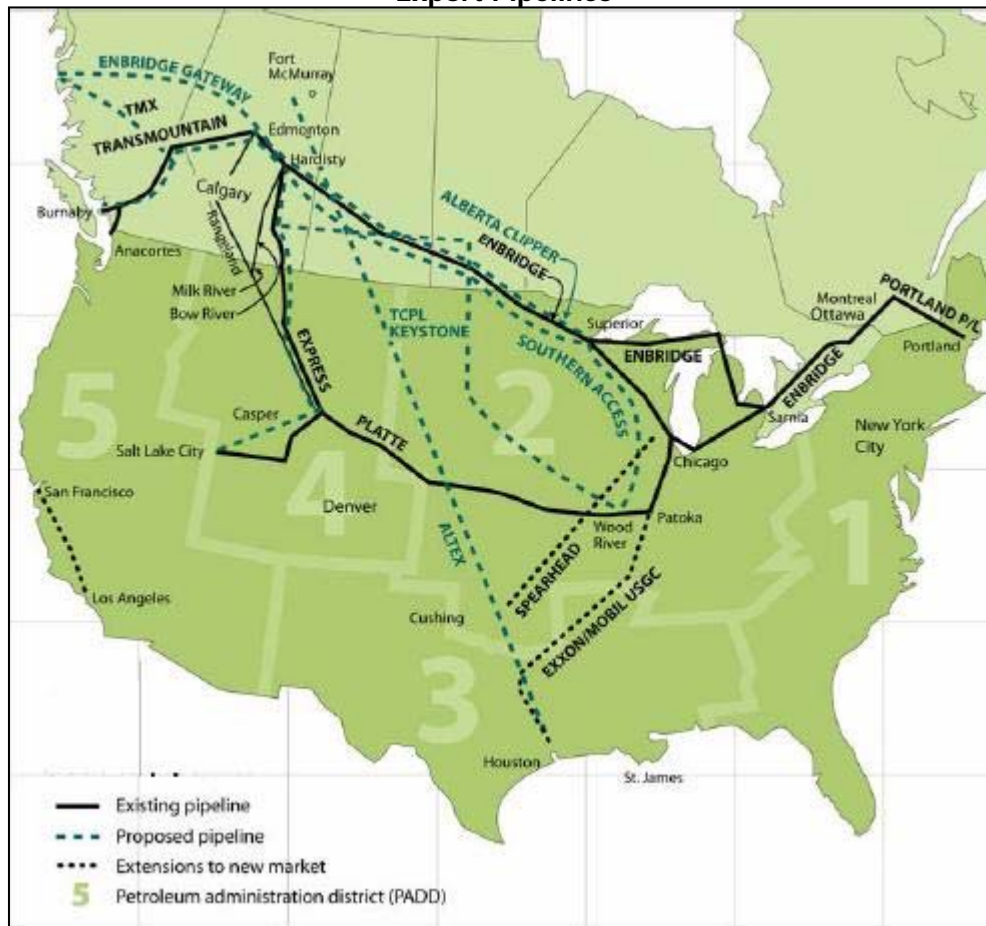
SOURCES: NEB, "Canada's Oil Sands Opportunities and Challenges to 2015: An Update", An Energy Market Assessment, June 2006. AEUB, "Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015", ST98-2006, June 2006. RBC Capital Markets, Canadian Energy Summit, March 2007.

**Figure A.1**  
**Alberta SCO and Non-upgraded Bitumen Pipelines**



SOURCE: AEUB, "Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015", ST98-2006, June 2006.

Figure A.2  
 Export Pipelines



SOURCE: AEUB, "Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015", ST98-2006, June 2006.

## A.2 Sales and Markets

The routes of the new and expanded pipelines will depend on which markets hold the greatest potential. The industry will likely take advantage of major existing markets by maximizing its volumes to western and eastern Canada, PADD<sup>37</sup> II, PADD IV and Washington State (i.e., PADD V), with the potential for further expansions to California, PADD III and markets in the Far East, such as China, Japan, Korea, and Taiwan. This section reviews the existing Canadian and export markets for crude as well as looks at the potential for new and expansion of existing markets.

<sup>37</sup> PADD stands for Petroleum Administration for Defense Districts. There are 5 PADD regions altogether and they were implemented during World War II to facilitate oil allocation. Refer to the EIA for full description:  
[http://www.eia.doe.gov/pub/oil\\_gas/petroleum/analysis\\_publications/oil\\_market\\_basics/paddmap.htm](http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/paddmap.htm)

### A.2.1 Current Status of Sales and Markets (by destination and by product)

The current market for Alberta crude encompasses western and eastern Canada, upper PADD II, PADD IV and Washington State, with smaller volumes going to PADD I and III, as shown in Table A.3.

**Table A.3**  
**Domestic Exports of Western Canadian Crude Oil in 2005 (10<sup>3</sup> bbl/d)**

Market	Refining Capacity	Refining Runs	Conventional Light <sup>1</sup>	Conventional Heavy	SCO	Blended Bitumen	Total
W.Canada	632	576	234	114	200	24	572
E.Canada – Ontario	467	404	84	12	44	44	185
E.Canada – all	1,378	1,284	84	12	44	44	185
Total Canada	2,010	1,859	319	126	245	68	757

<sup>1</sup> Includes condensates and pentanes plus.

SOURCE: NEB, "Canada's Oil Sands Opportunities and Challenges to 2015: An Update", An Energy Market Assessment, June 2006.

Canada has a relatively small refining market with 19 refineries totaling in capacity of almost 2 MMb/d (see Table A.3). In 2005, the Canadian refineries operated above 90 percent of their capacity to meet the domestic oil demand. However, they will not be able to absorb the growth of oil sands production due to the age and lack of complexity of these refineries. There are a few announced projects to either convert existing refinery to solely process oil sands derived crude oil, or to increase the refining capacity, or to construct new upgraders to process heavy bitumen. If these plans are executed, they will predominantly be developed in western Canada.

The refineries located in western Canada process exclusively western Canadian crude, including oil sands. In 2005, SCO and blended bitumen made up almost 40 percent of total refined crude. To increase the proportion of oil sands derived crude oil in western Canada, Husky, Imperial, Petro-Canada, and Shell who own refineries and produce oil sands will look at the ways to incorporate their upstream production with downstream operations.

In 2005, less than 50 percent of Ontario's crude oil demand was met by western Canada sources, and only 22 percent of that total was SCO and blended bitumen. It is believed that there is room for growth opportunities to take more western Canadian crude oil in Ontario and Quebec. Companies, such as Imperial Oil, Suncor and Shell Canada are all looking at possibilities to integrate their oil sands production with their downstream facilities in Ontario.

The United States, with a refining capacity of 2.6 million m<sup>3</sup>/d (16 MMb/d), remains Canada's largest market for crude oil and probably has the greatest potential for increased distribution of oil sands derived crude oil (see Table A.4).

**Table A.4**  
**Exports of Western Canadian Crude Oil to US in 2005 (103 bbl/d)**

Market	Refining Capacity	Refining Runs	Conventional Light <sup>1</sup>
PADD I	1,551	1,421	15
PADD II	3,553	3,307	71
PADD III	7,952	7,098	1
PADD IV	565	563	52
PADD V	2,537	2,893	55
Total US	16,113	15,458	193

<sup>1</sup>Includes condensates and pentanes plus.

SOURCE: NEB, "Canada's Oil Sands Opportunities and Challenges to 2015: An Update", An Energy Market Assessment, June 2006.

In 2005, Canada supplied almost 10 percent of the US crude oil refining needs, becoming one of the largest crude oil exporters to the US. The ongoing war and geopolitical concerns in the Middle East hamper the security of supply for the US, which drives the decision-makers in the US to look to Canada as a secure source of crude oil supply in the future.

PADD I is not considered a market with a large growth potential for Canadian oil sands. With a refining capacity of almost 1.5 MBPD, most imports into that region come from eastern Canada. On the other hand, PADD II is so far the largest market for western Canadian crude oil in the US, with capacity to refine over a half a million cubic meters a day. Seventy percent of Canadian crude oil exports went to PADD II in 2005 (see Table A.4) and SCO and blended bitumen comprised 20 percent of that total. Also, the core markets of St. Paul and Chicago in northern PADD II are predominantly heavy and medium sour refining markets, which suit the needs of oil sand producers. Producers have also been able to deliver to the southern part of PADD II, to Cushing, Oklahoma, with the recent reversal of Spearhead pipeline in March 2006.<sup>38</sup>

PADD IV in the past had been an important market for Canadian heavy crude, with refining capacity of almost 600,000 BPD. Recently however, with crude oil prices hitting record high levels, the producers of PADD IV have been drilling for oil at a greater rate. This has resulted in increased oil production, which has led to pressure from domestic producers to process this production in local refineries. Consequently, refiners in PADD IV are processing less western Canadian heavy crude supplies to facilitate the refining of available and discounted Wyoming sweet and sour crudes. This situation is assumed to continue as long as the crude oil prices remain above US\$50 per barrel.

<sup>38</sup> Ibid.

Currently, Washington State processes 11 percent of its crude requirements from Canada. This volume of supply is largely dependent on availability of Alaskan North Slope crude and capacity constraints on Kinder Morgan's Transmountain pipeline. The industry is enthusiastic about increased supply of western Canadian crude oil and this is seen through the number of cokers and refinery conversions that are being discussed in that market. ConocoPhillips, Tesoro and British Petroleum all have plans to process heavier crudes, which will include oil sands crude oil.

### A.2.1 Future Market Projections

The traditional market for Canadian crude oil has been refineries in Canada and the US northern tier. As more bitumen is produced, more upgrading will be needed either at refineries in Canada or the US. Another option is countries in the Far East: China, Japan, South Korea, and Taiwan. This section covers the future market projections in Canada and the US.

In Canada, there are a few announced plans to increase the refining capacity to assist with growing bitumen production. Petro-Canada, for example, is planning to convert its Edmonton refinery to process only oil sands feedstock. It is estimated that by 2008, 100 percent or 21,400 m<sup>3</sup>/d (135,000 b/d) of oil sands feedstock will be processed at that refinery.<sup>39</sup> In addition to upgraders, there is a publicly announced proposal for a new refinery complex in Alberta. This is currently being studied by Alberta Energy and 19 stakeholders. This project could be completed as early as 2011 with initial capacity of 47,700 m<sup>3</sup>/d (300,000 b/d), which could be expanded to 71,500 m<sup>3</sup>/d (450,000 b/d). The refinery would also include a petrochemical facility and 500 MW coal-fired power generation plant. As well, in eastern Canada, Ontario is expected to increase its use of SCO. According to one of the industry studies, Ontario's demand for SCO will be approaching 120,000 b/d by 2010 based on favorable pricing of light sweet crude substitution.<sup>40</sup>

In the US it is expected that, in the short term, the industry will exploit the existing markets of PADD II, PADD IV and Washington State to their potential with further expansions later on into California and PADD III.

The southern region of PADD II is becoming an increasingly significant market for Canadian heavy crude. The reversal of the Spearhead pipeline has helped to open up other locations that did not have access to Canadian crude before. By extending the core market of PADD II further south into areas of Wood River, Cushing and Ponca City, Canadian crude oil could compete with other foreign and US sour grades of crude and this would result in better crude prices for Canadian producers. Northern PADD II is currently the largest market for Canadian crude oil and is well positioned to run increased volumes of bitumen blends and SCO because of the complexity of the refineries. Many companies have expressed an interest in arranging some sort of "integrated" deal between their refineries and oil sands production. The list of announced projects in PADD II together with other propositions in the US is shown in Table A.5.

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<sup>39</sup> Petro-Canada, <http://www.petro-canada.ca/en/media/1886.aspx?id=576106>

<sup>40</sup> Purvin&Gertz, "Potential of US/Northern Tier and Canadian Markets to Absorb Heavy and Synthetic Crude", May 2003.

Table A.5  
Proposed Refinery Expansions

Company	Location	Capacity Increase (Mb/d)	Coker or Expansion	Date of Completion
Tesoro	Anacortes, WA	15	Coker	2Q2007
Cenex	Laurel, MT	No change	Coker (15 Mb/d)	1Q2008
Sunoco	Toledo, OH	50	Expansion	2008
Flint Hills Resources	St. Paul, MN	50	Expansion	1Q2008
Frontier Oil	El Dorado, KS	11	Expansion	2008
Frontier Oil	Cheyenne, WY	n/a	Coker	2008
Sinclair	Sinclair, WY	13	Coker	2008
United Refining	Warren, PA	5	Coker	2009
ConocoPhillips	Wood River, IL	55	Coker	2012-2015
ConocoPhillips	Borger, TX	25	Coker	2012-2015
ConocoPhillips	Ferndale, WA	25	Coker	2012-2015
ConocoPhillips	Billings, MO	n/a	Expansion	2012-2015

n/a – not available.

SOURCE: NEB, *"Canada's Oil Sands Opportunities and Challenges to 2015: An Update"*, An Energy Market Assessment, June 2006.

PADD III is of particular interest to western Canadian oil sands producers given the size and complexity of the refineries and the chance to compete with Venezuelan and Mexican imports, especially since bitumen blends have been heavily discounted in the US Midwest. Altex Energy Ltd. is proposing to build a new direct route oil pipeline, which would transport crude oil from northern Alberta to the US Gulf Coast.

PADD IV remains a marginal growth market for Canadian crude oil, in particular SCO and blended bitumen due to declining light sweet crude supply in that region. Recently, Holly Corp. announced the sale of its Montana Refining Company to Connacher Oil and Gas Ltd. This refinery will provide processing to the SAGD production from their Great Divide oil sands project and well as give some protection against wide light/heavy differential.

The California market is an attractive market option for heavier crudes because California's refineries already process predominantly sour medium and heavy crude oil and rely on two sources of supply that are in decline, namely in-state and Alaska production. However, access to California is not likely to happen in the short term and will depend on the supply from Alaskan North Slope.

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