

# Canada's Oil Sands - A World-Scale Hydrocarbon Resource

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November 2012

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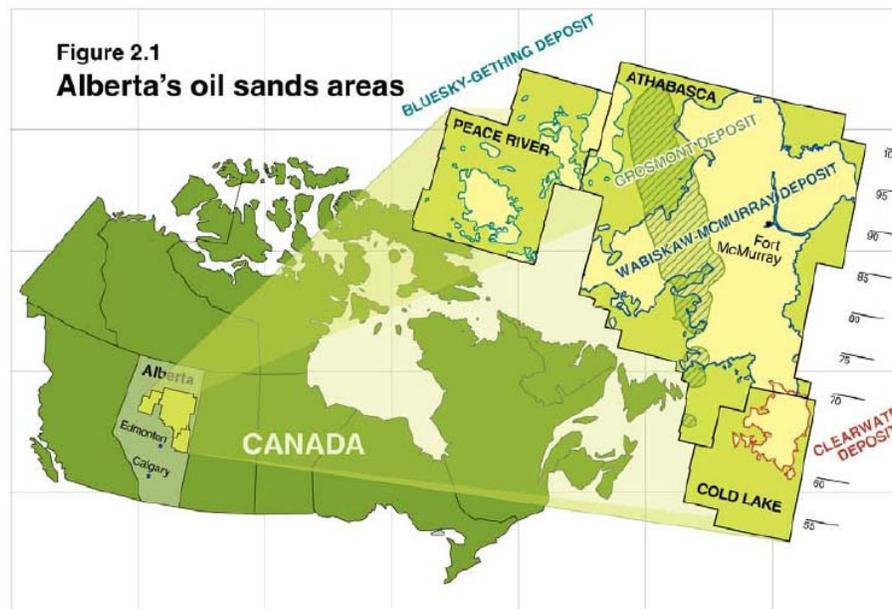
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## 1. Introduction

With an estimated initial volume in-place of approximately 1.8 trillion barrels<sup>1</sup> of crude bitumen, Canada's oil sands, located in the Province of Alberta, are one of the world's largest hydrocarbon accumulations. When the Oil and Gas Journal released its estimates of global proved petroleum reserves at year-end 2002, it increased Canada's proved oil reserves to 180 billion barrels compared to 4.9 billion barrels the previous year. This almost forty-fold increase catapulted Canada into second position for total oil reserves behind only Saudi Arabia at year-end 2002, and cut the Organization of Petroleum Exporting Countries' (OPEC's) share of world oil reserves by more than 10 percent.<sup>2</sup>

Alberta's massive crude bitumen resources are contained in sand (clastic) and carbonate formations in the three Oil Sands Areas (OSAs) in Alberta as shown in Figure 1-1. Contained within the OSAs are 15 Oil Sands Deposits (OSDs), which designate the specific geological zones containing the oil sands. Each OSA contains a number of bitumen-bearing deposits.

**Figure 1-1:  
Oil Sands Areas**



Source: Alberta Energy Resources Conservation Board

<sup>1</sup> Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012-2021; ERCB ST98-2012, June 2012

<sup>2</sup> Source: Oil & Gas Journal; Worldwide Report: Worldwide Reserves Increase as Production Holds Steady; Marilyn Radler; December 23, 2002

The known extent of the largest OSD, the Athabasca Wabiskaw-McMurray, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are shown in Figure 1-1. The bitumen in these three OSDs is contained in sand (clastic) formations. Most of the development activity to date has occurred in these three OSDs.

The bitumen in four of the 15 OSDs is contained in carbonate formations. The areal extent of the Grosmont carbonate deposit is shown on Figure 1-1. While there is no commercial production of bitumen from the carbonate deposits, several companies have acquired oil sands leases in the carbonate deposits and are developing recovery technologies.

As an indication of scale, the right-hand edge of Figure 1-1 shows township markers that are about 50 kilometres (km) (30 miles) apart. Together the three OSAs occupy an area of about 142,000 km<sup>2</sup> (54,000 square miles).

While most industry activity to date has focussed on Alberta, several companies have leased land in northwest Saskatchewan, are evaluating the extent of the Saskatchewan oil sands resources and are investigating bitumen recovery technologies. This document focuses on oil sands industry activity in Alberta.

## 2. Oil Sands Resources and Reserves

Oil sands are a mixture of sand and other rock materials that contain crude bitumen (extra-heavy non-conventional crude oil). 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.

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>3</sup>

### 2.1. Initial Volume In-Place

At year-end 2011, the Alberta Energy Resources Conservation Board (ERCB) estimated the Initial Volume In-Place of crude bitumen in Alberta's oil sands to be 1,844 billion barrels.<sup>4</sup>

The ERCB reported that 7% of the volume in-place, 131 billion barrels, is contained in shallow deposits – that are generally less than 65 m (215 feet) to the top of the oil sands zone. All of the shallow oil sands deposits are located in the Athabasca OSA. Surface mining and bitumen extraction technologies are used to recover crude bitumen from these shallow deposits.

The remaining 93% of the volume in-place, 1,714 billion barrels, is contained in deeper deposits that are present in all three OSAs. In situ recovery techniques are used to recover crude bitumen from the deeper deposits.

The ERCB's estimates of initial volume in-place are given in Table 2-1.

**Table 2-1:  
Initial Crude Bitumen Volume In-Place**

Initial Volume in Place	10 <sup>9</sup> barrels	
	10 <sup>9</sup> barrels	Percent
Mineable	131	7.1%
In Situ	1,714	92.9%
Total	1,844	100.0%

<sup>3</sup> Source: Alberta Statutes and Regulations; Oil Sands Conservation Act, Section 1(1) (c)

<sup>4</sup> Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012-2021; ERCB ST98-2012, June 2012

These figures represent the ERCB's best estimates of initial volume in-place. However, only a fraction of the volume in-place is expected to be technically and economically recoverable. The amounts estimated to be recoverable are classified as reserves and are discussed in the next section.

## 2.2. Reserves

The ERCB estimates that approximately 10% of the bitumen in-place is recoverable. Its estimates of Initial Established Reserves at year-end 2011 are given in Table 2-2.

**Table 2-2:  
Initial Established Crude Bitumen Reserves at Year-end 2011<sup>5</sup>**

<b>Initial Established Reserves</b>		
	10 <sup>9</sup> barrels	Percent
Mineable	38.8	21.9%
In Situ	138.1	78.1%
<b>Total</b>	<b>176.8</b>	<b>100.0%</b>

To year-end 2011, 4.6% of the initial established reserves had been produced. Cumulative production to year-end 2011, as reported by the ERCB, is summarized in Table 2-3.

**Table 2-3:  
Alberta Crude Bitumen Production to Year-end 2011<sup>6</sup>**

<b>Cumulative Production</b>		
	10 <sup>9</sup> barrels	Percent
Mineable	5.2	63.6%
In Situ	3.0	36.4%
<b>Total</b>	<b>8.1</b>	<b>100.0%</b>

The ERCB's estimates of Remaining Established Reserves at year-end 2011, after accounting for cumulative production, are reported in Table 2-4.

**Table 2-4:  
Remaining Established Crude Bitumen Reserves at Year-end 2011**

	10 <sup>9</sup> barrels	Percent
Mineable	33.6	19.9%
In Situ	135.0	80.1%
<b>Total</b>	<b>168.6</b>	<b>100.0%</b>

<sup>5</sup> Totals do not add due to rounding.

<sup>6</sup> Ibid

Only a fraction of these reserves are associated with active development projects. The ERCB's estimate of Remaining Established Reserves "Under Active Development" at year-end 2011 is reported in Table 2-5.

**Table 2-5:  
Remaining Established Crude Bitumen Reserves under Active Development**

	10 <sup>9</sup> barrels	Percent
Mineable	22.6	88.2%
In Situ	3.0	11.8%
Total	25.6	100.0%

### **2.3. Ultimate Potential**

The ERCB estimates the ultimate potential of crude bitumen recoverable by in situ recovery methods from Cretaceous sediments to be 33 10<sup>9</sup>m<sup>3</sup> (~210 billion barrels) and from Paleozoic carbonate sediments to be some 6 10<sup>9</sup>m<sup>3</sup> (~40 billion barrels). Nearly 11 10<sup>9</sup>m<sup>3</sup> (~70 billion barrels) is expected from within the surface-mineable boundary, with a little more than 6 10<sup>9</sup>m<sup>3</sup> (~60 billion barrels) coming from surface mining and about 0.4 10<sup>9</sup>m<sup>3</sup> (~3 billion barrels) from in situ methods. The total ultimate potential crude bitumen is therefore about 50 10<sup>9</sup>m<sup>3</sup> (~315 billion barrels).

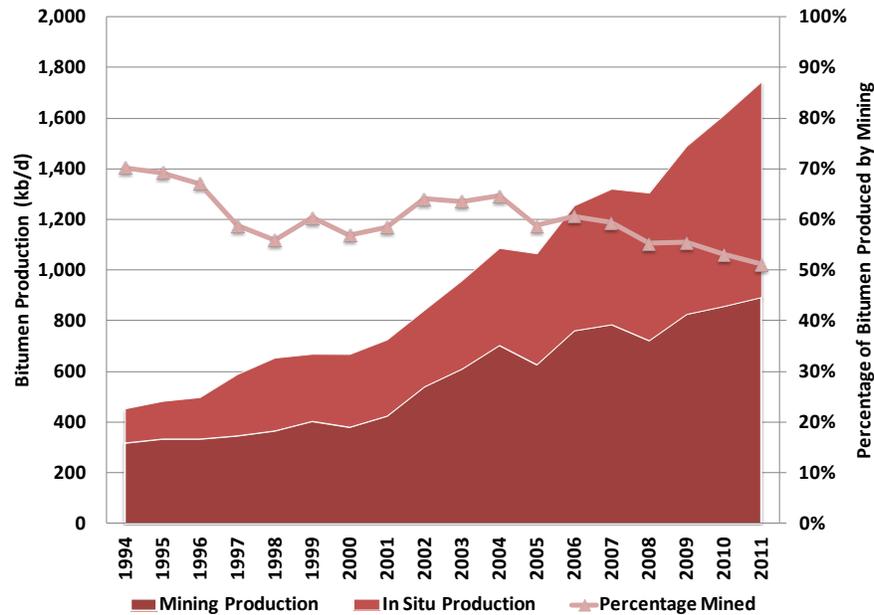
### 3. Historical Bitumen and Synthetic Crude Oil Production

Commercial operations in Canada's oil sands industry commenced with the startup of the Great Canadian Oil Sands<sup>7</sup> (GCOS) mining, extraction and upgrading project in 1967. This was followed by startup of the Syncrude mining, extraction and upgrading project in 1978. The first commercial in situ project was Imperial Oil's Cold Lake project, which commenced commercial operations in 1985.

Substantial growth has occurred since these early projects commenced operations resulting in production of 1,744 thousand barrels per day (kb/d) of crude bitumen in 2011, 892 kb/d from surface mining and 852 kb/d from in situ projects. The oil sands industry represented approximately 54% of Canada's total oil production in 2011.

Historical bitumen production since 1994 is illustrated in Figure 3-1.

**Figure 3-1:  
Historical Bitumen Production**

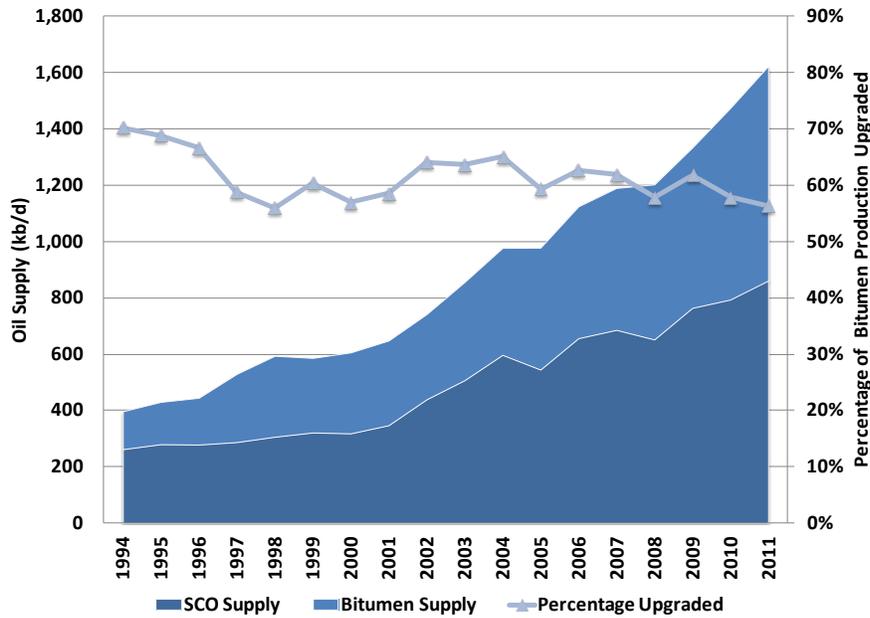


As new commercial in situ capacity has come on stream, the percentage of bitumen produced by mining projects has declined from 70% to 51% of total annual bitumen production from 1994 to 2011 as shown on Figure 3-1.

<sup>7</sup> GCOS is the predecessor to Suncor Energy's mining, extraction and upgrading operations.

A large portion of Alberta's bitumen production is upgraded to synthetic crude oil and other products. After upgrading, supply of synthetic crude oil (including other products) and non-upgraded crude bitumen totalled 1,625 kb/d in 2011 (863 kb/d of synthetic crude oil and 762 kb/d of non-upgraded crude bitumen) as illustrated in Figure 3-2.<sup>8</sup>

**Figure 3-2:  
Historical Oil Sands Supply**



Note that some volumetric loss occurs due to upgrading – i.e., total bitumen production of 1,744 kb/d resulted in the oil sands industry supplying 1,625 kb/d of synthetic crude oil and non-upgraded crude bitumen to downstream markets. Most bitumen produced at existing mining operations is upgraded; most bitumen produced at existing in situ operations is not.

<sup>8</sup> Ibid.

## 4. Bitumen Recovery and Upgrading Technologies

The hydrocarbon component of the oil sands, crude bitumen, must be separated from the sand, other mineral materials and formation water before it is delivered to downstream upgraders or refineries. Shallow oil sands deposits, generally less than about 65 m (215 feet) to the top of the oil sands zone, are exploited using surface mining to recover ore-grade oil sands, which are then delivered to an extraction plant for separation of bitumen from the sand, other minerals and water. Deep oil sands, generally greater than about 65 m (215 feet) to the top of the oil sands zone, are exploited using in situ recovery techniques, whereby the bitumen is separated from the sand in situ ("in place") and produced to the surface through wells.

### 4.1. *Oil Sands Mining and Bitumen Extraction*

Over time, different techniques have been used for oil sands mining. Suncor started its mining operations using bucketwheel excavators that discharged their loads onto conveyor belts. The initial Syncrude operation used large draglines to remove oil sands ore from the mine-face and place it in windrows from which bucketwheel reclaimers loaded it onto conveyor belts for transportation to the extraction plant. Suncor and Syncrude have since retired their bucketwheel- and dragline-based mining systems.

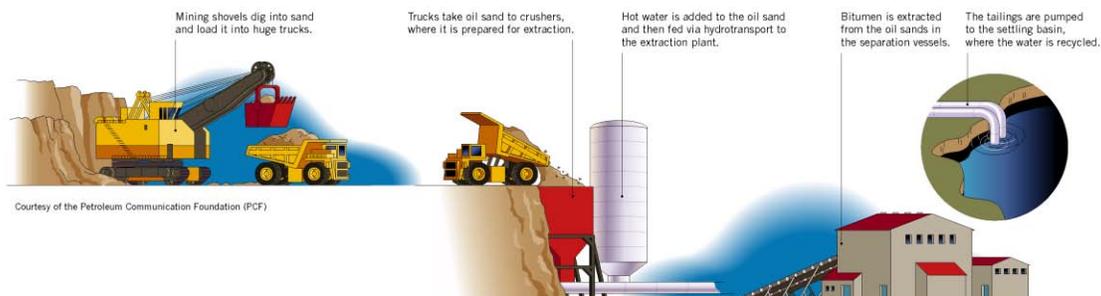
Large mining trucks and power shovels were introduced to replace these early mining systems. By the early 1990s, Syncrude was mining about one-third of its ore using trucks and shovels, while Suncor totally converted to a truck and shovel operation in 1993. Truck and shovel mining is considerably more flexible and less prone to interruption of service than the earlier systems used. In mining systems today, trucks capable of hauling up to 380 tonnes of material are loaded by electric- and hydraulic-power shovels with bucket capacities up to 44 cubic metres (m<sup>3</sup>). The trucks transport the oil sands to ore preparation facilities where the ore is crushed and prepared for transport to the extraction plant (where bitumen is separated from the sand). In their early operations, Suncor and Syncrude used long conveyor systems for ore transportation. These systems have been replaced by hydrotransport with the first commercial applications of this technology occurring in the early 1990s. For hydrotransport, the oil sands ore is mixed with heated water (and chemicals in some cases) at the ore preparation plant to create oil sands 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 compared to conveyor systems.

At the extraction plant, bitumen is separated from the sand, other minerals and connate water using variations on the hot water extraction process, developed by Dr. Karl Clark of the Alberta Research Council in the 1920s. 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, which operates at approximately 35°C. It is designed to consume about one-third of the energy of the traditional 80°C hot water extraction process.

Tailings are a byproduct of the oil sands extraction process. After bitumen extraction, the tailings, a mixture of water, sand, silt and fine clay particles, are pumped to a settling basin. Tailings also contain residual bitumen that is not recovered and residual solvents and chemicals used in the extraction process. Coarse tailings settle rapidly and can be quickly restored to a dry surface to enable reclamation. Fine tailings, consisting of slow-settling clay particles and water, are more problematic. The industry is expending considerable effort to overcome the challenges associated with tailings consolidation and ultimate site reclamation.

The overall configuration of the oil sands mining and bitumen extraction operations is shown in Figure 4-1.

**Figure 4-1:  
Oil Sands Mining and Bitumen Extraction**



At remote mines, primary extraction occurs at the mine site. After primary extraction, bitumen froth is transported to a central site by pipeline for secondary extraction and upgrading. Syncrude has remote primary extraction at its Aurora Mine, 35 km (22 miles) north of the Mildred Lake Plant. Suncor has remote primary extraction at its Millennium and North Steepbank Mines on the east side of the Athabasca River.

## 4.2. *In Situ Bitumen Recovery*

In general, the heavy, viscous nature of the bitumen means that it will not flow under normal reservoir temperature and pressure conditions. For recovery of bitumen from deep deposits, the bitumen viscosity must be reduced in situ to increase the mobility of bitumen in the reservoir. This enables flow to wellbores that bring the bitumen to the surface. Bitumen viscosity can be reduced in situ by increasing reservoir temperature or injecting solvents. Steam-based thermal recovery is the primary recovery technique used at Athabasca, Cold Lake and Peace River. The industry is also conducting field tests of other in situ recovery methods including solvent-based recovery, co-injection of steam and solvents, co-injection of steam and non-condensing hydrocarbons, in situ combustion and electric heating.

### 4.2.1. Primary Recovery

Bitumen can be produced from some oil sands reservoirs using primary recovery or "cold production"; no external energy is applied to the reservoir to mobilize the bitumen in the reservoir. The oil in these reservoirs is less bio-degraded and less viscous than the oil in other oil sands reservoirs but is still classified as crude bitumen because it is contained within ERCB designated Oil Sands Deposits.

Several primary recovery projects are operating in the Athabasca (Wabasca), Cold Lake, and Peace River Oil Sands Areas. Early primary production in the Cold Lake Oil Sands Area was riddled with problems caused by extreme wear on the pumps used to bring bitumen to the surface. Beginning in the early 1990s, introduction of the progressing 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", were formed and expanded in the reservoir as the sand was produced. This resulted in significantly higher production rates, lower operating costs and improved economics. This type of production technology is commonly referred to as cold heavy oil production with sand (CHOPS). 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 "multi-leg" or "multilateral" producing wells can be drilled and

successfully operated. Recovery factors of seven to ten percent are achieved using primary recovery in this area.

Primary production in the Peace River Oil Sands Area has also been growing rapidly.

#### **4.2.2. Secondary Recovery**

Several operators have also been having success with application of secondary recovery techniques (water and polymer flooding) in the Brintnell region of the Athabasca Oil Sands Area.

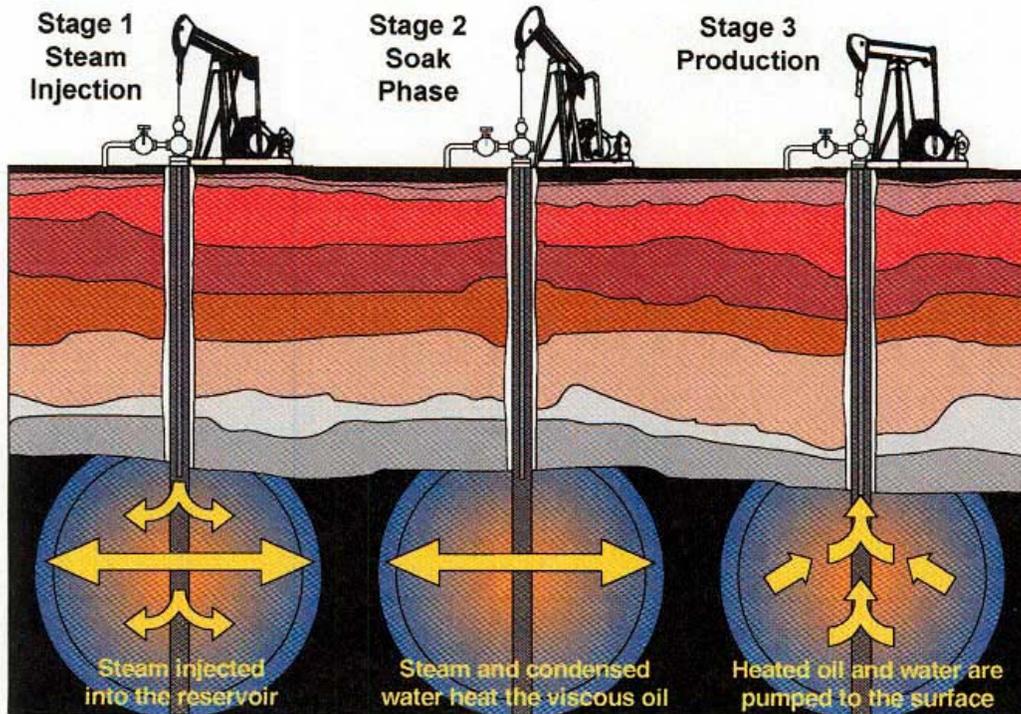
#### **4.2.3. Steam-Based Thermal In Situ Recovery**

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 recovery 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 reservoir using either cyclic steam stimulation (CSS) or steam assisted gravity drainage (SAGD). Steam is injected into the oil sands zone using vertical, deviated, horizontal or horizontal multi-lateral wells. The steam heats the bitumen, lowers its viscosity, and increases its mobility in the reservoir so it can be brought to the surface through wells using reservoir pressure, gas lift or downhole pumps.

CSS is a cyclic 3-stage process. During the initial injection cycle, steam is injected into the reservoir at high temperature and pressure. The wells then enter the soak cycle during which latent heat from the injected steam heats the bitumen and lowers its viscosity as the steam condenses. During the final production cycle, the heated bitumen and condensed steam are produced to the surface. Bitumen, water and produced gas are separated in surface production-treating facilities. During the separation process, produced bitumen is mixed with the diluent that enables pipeline transportation to upgraders or heavy-oil refineries. Produced water is treated and recycled to the maximum extent possible. Produced natural gas is used on site as fuel. CSS is effective in reservoirs with limited vertical permeability and is best suited to operations in the Cold Lake and Peace River Oil Sands Areas. The CSS process is illustrated in Figure 4-2.

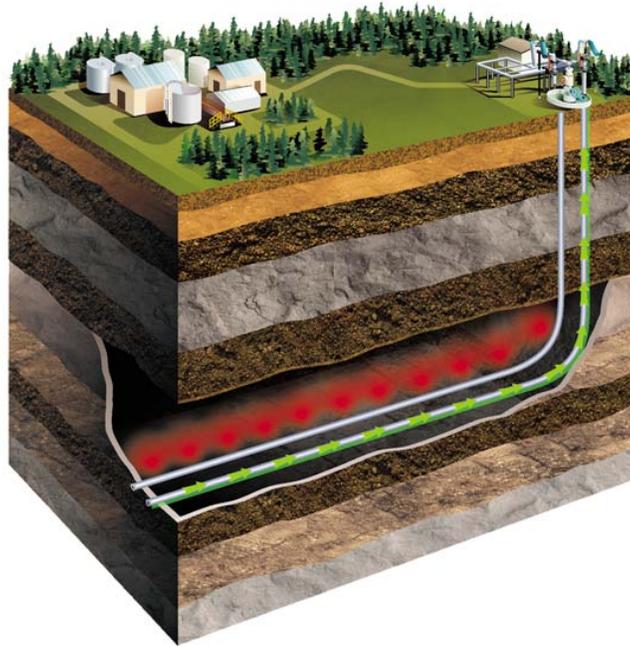
Figure 4-2:  
Cyclic Steam Stimulation Process



The concept of utilizing continuous heating and production, rather than the discontinuous CSS process, led to the development of the SAGD process during the late 1970s and early 1980s. SAGD uses horizontal well pairs, up to 1,000 m (3,300 feet) in length, which are completed near the base of the oil sands zone. The upper horizontal well is drilled and completed about 5 m (16 feet) above the lower horizontal well. Steam is injected into the upper well to heat the bitumen, reduce its viscosity and cause it to drain by gravity into the lower part of the reservoir. The bitumen and condensed steam are collected and produced to the surface through the lower well. SAGD is applied in thick reservoirs, with high vertical permeability, and is being successfully used in the Athabasca Oil Sands Area.<sup>9</sup> The SAGD process is illustrated in Figure 4-3.

<sup>9</sup> Testing of SAGD is underway, but large-scale commercial application of SAGD in the Cold Lake and Peace River Oil Sands Areas has not taken place.

**Figure 4-3:  
Steam Assisted Gravity Drainage Process**



The primary disadvantage of steam-based thermal recovery techniques is the large amount of energy and water that must be consumed for the generation of steam. A common industry rule-of-thumb is that 1,000 standard cubic feet of natural gas (~1 GJ of energy) is consumed for every barrel of bitumen produced; however, many projects are using much more.

#### **4.2.4. Other In Situ Recovery Technologies**

Because of the high energy and water consumption associated with steam-based thermal recovery techniques, the industry is conducting field trials of modified and new in situ recovery technologies. These include:

- Solvent-based processes such as VAPEX: (Vapour Extraction) which employs the injection of a vapourized hydrocarbon solvent instead of steam into the reservoir with injection and production via horizontal well-pairs
- In situ combustion processes such as THAI: (Toe to Heel Air Injection) which employs vertical air injection wells and horizontal production wells
- Hybrid processes which inject both steam and hydrocarbon solvents or gases into the reservoir

- Electrical Heating

All of the above in situ recovery techniques have been or are being tested in the field.

### **4.3. Bitumen Upgrading Technologies**

Bitumen from mining/extraction and in situ operations is either blended with a diluent (light low-viscosity hydrocarbon liquid) for shipment to market (downstream refineries) by pipeline or upgraded to a higher value synthetic crude oil or other petroleum products. Upgraders may be located on-site or off-site and may be either dedicated to a specific project or standalone facilities that process crude bitumen from many projects on a fee-for-service or other commercial basis. After upgrading, the synthetic crude oil is shipped via pipeline to downstream markets (refineries) for conversion into refined petroleum products (gasoline, diesel, jet fuel, fuel oils, etc.).

In the upgrading process, bitumen is converted from a viscous oil that is deficient in hydrogen and with high concentrations of 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).<sup>10</sup>

#### **4.3.1. Primary Separation**

Oil sands upgraders typically employ front-end primary separation processes (atmospheric and vacuum distillation) to achieve initial segregation of hydrocarbon constituents in the feedstock based on their physical properties (distillation cuts). In a typical configuration:

- Primary separation occurs in atmospheric and vacuum distillation units;
- Sour hydrocarbon gases are recovered and delivered to gas recovery and gas treating facilities where they are treated for use as plant fuel gas;
- Diluent is recovered and returned to bitumen producers for reuse as a blending agent;
- Sour distillates are delivered to secondary upgrading for further processing; and
- The residue from primary separation (atmospheric or vacuum bottoms) is delivered to primary upgrading for further processing.

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<sup>10</sup> This statement describes the normal upgrading process. In some cases, bitumen may be partially upgraded and sold as a sour synthetic crude oil or may be more completely upgraded/refined to produce refined petroleum products (i.e., ultra low sulphur diesel).

### 4.3.2. Primary Upgrading

Residue from primary separation is processed in primary upgrading to increase the hydrogen-carbon ratio of the upgrader's hydrocarbon product(s) using either carbon rejection (coking) or hydrogen addition (hydro-conversion) processes. Solvent deasphalting may also be employed for "carbon rejection". Upgraders employing coking typically achieve volumetric liquid yields (synthetic crude oil/bitumen feed) of 80 – 85%, while upgraders employing hydro-conversion can achieve volumetric liquid yields of 100% or more.

Two coking processes have been applied in the oil sands industry: delayed coking and fluid coking. With delayed coking, the heated charge (typically residue from vacuum distillation) is transferred to large coke drums that provide the long residence time needed to allow thermal 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. The Suncor Base and Millennium, CNRL Horizon, and Husky Lloydminster upgraders, and other proposed upgraders, use delayed coking for primary upgrading.

Fluid Coking is a continuous fluidized-bed process that operates at temperatures higher than delayed coking. In Fluid Coking, thermal cracking occurs through heat transfer with hot, recycled coke particles in a reactor. The Syncrude Mildred Lake upgrader uses Fluid Coking.

The coke produced via either delayed or Fluid Coking has high energy content but also contains high concentrations of sulphur and other contaminants. Suncor and Syncrude both use some of the produced coke to meet some of their energy requirements; the remainder is stockpiled.

Because of its high energy content, coke is a potential feedstock for production of fuel and hydrogen using partial oxidation (gasification). Gasification of bitumen residue (asphaltenes) takes place at the Nexen Long Lake Project and has been considered by others. Gasification technology is discussed later in this document.

Hydro-conversion is a continuous catalytic process whereby heavy feedstock (i.e., vacuum bottoms) is cracked in the presence of hydrogen to produce more desirable products. The process takes place under high pressure and high temperature conditions. The LC Fining ebullated bed hydro-conversion process is used at both the Syncrude Mildred Lake upgrader and

the AOSP Scotford upgrader. The H-Oil ebullated bed hydro-conversion process is used at the Husky Lloydminster upgrader.

#### **4.3.3. Secondary Upgrading**

Catalytic fixed-bed hydrotreating and/or fixed-bed hydrocracking is used for secondary upgrading to remove impurities and enhance the quality of the final synthetic crude oil product. In a typical catalytic hydrotreating unit, the feedstock is mixed with hydrogen, preheated in a fired heater and then charged under high pressure to a fixed-bed catalytic reactor. Hydrotreating converts sulphur and nitrogen compounds present in the feedstock to hydrogen sulphide and ammonia. Sour gases from the hydrotreater(s) are treated for use as plant fuel. Fixed-bed hydrocracking operates at higher temperatures and pressures and may be used to produce at higher quality synthetic crude oil (i.e., Nexen Long Lake Project).

#### **4.3.4. Hydrogen Production**

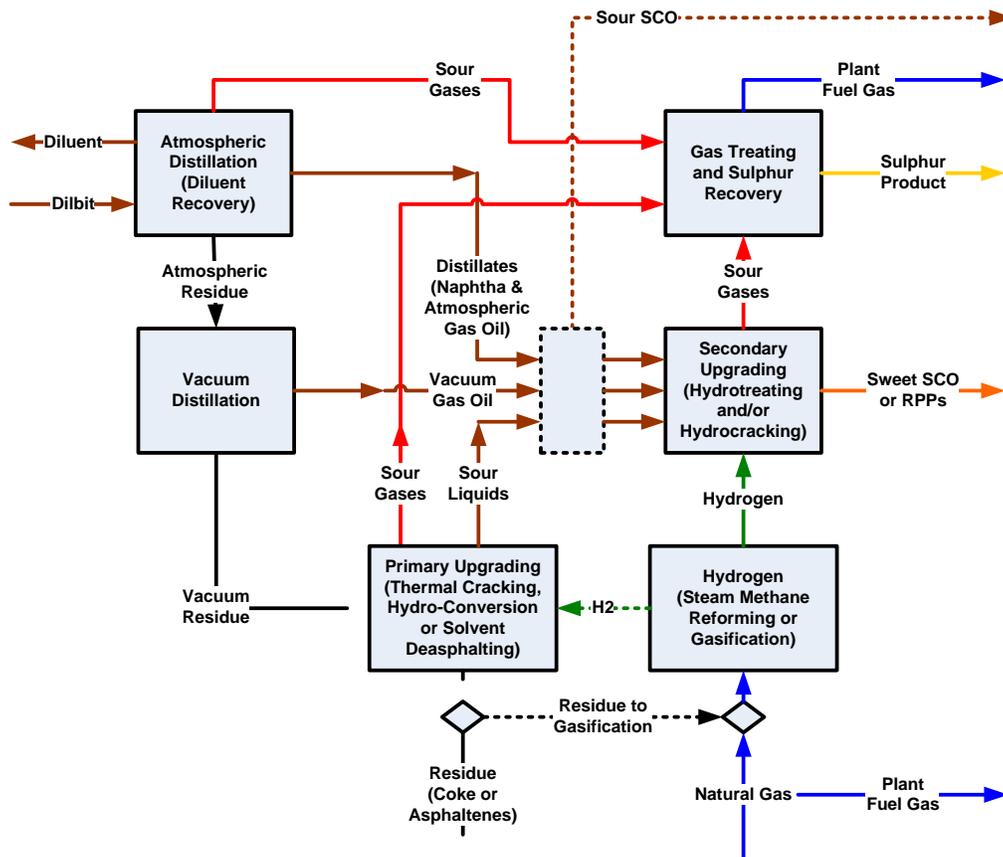
With one exception, operating oil sands upgraders are meeting their hydrogen requirements using the Steam Methane Reforming (SMR) process with natural gas used for both feedstock and fuel. However, partial oxidation (gasification) is an alternative technology for hydrogen (and synthetic fuel gas – syngas) production that has been adopted at the Nexen Long Lake Project and has been considered by others.

The Nexen Long Lake upgrader processes crude bitumen using atmospheric and vacuum distillation, followed by solvent deasphalting and a patented thermal cracking process. The asphaltene stream is gasified for the production of hydrogen and syngas. Syngas is used for the generation of steam for the Long Lake SAGD operations and for upgrader fuel. Hydrogen is used in the upgrading operations where distillates are processed in a hydrocracking unit for the production of a 39<sup>o</sup>API synthetic crude oil product. Startup of the upgrader and associated gasification facilities occurred in Q4 2008.

#### **4.3.5. Typical Upgrader Configuration**

A simplified process flow diagram for a typical oil sands upgrader is shown in Figure 4-4.

Figure 4-4:  
Simplified Upgrader Process Flow Diagram



#### 4.3.6. Utilities and Offsites

Utilities and offsites such as those listed below are not shown on Figure 4-4.

- Electricity, Steam & Hot Water
- Boiler Feedwater
- Potable Water
- Fire Water
- Surface Water Management
- Instrument & Utility Air
- Nitrogen and Oxygen
- Waste Water & Solid Waste Disposal
- Fire & Smoke Detection
- Flare & Relief
- Tankage

## 5. Industry Challenges

The oil sands industry is working hard to overcome many challenges:

- Environmental impact: air emissions including greenhouse gases and criteria air contaminants; water consumption; liquid waste disposal including tailings from mining operations; surface disturbance; and site reclamation are all serious environmental issues. The industry faces considerable uncertainty about how greenhouse gas emissions might be regulated and the economic consequences.
- Product prices: there is still considerable uncertainty about global economic growth, future global oil demand and future light oil prices. While heavy crude oil prices are strong, narrow light-heavy differentials make new upgrading investments uneconomic.
- Market access and pipeline capacity: Proposals to develop new transportation capacity to markets in the United States and Asia face strong environmental challenges.
- Energy consumption: the industry's substantial external energy requirements are currently being met using purchased natural gas. Conventional gas production in Alberta peaked in 2001 and has been declining since.
- Project costs: many projects have experienced serious cost overruns; the industry is working hard to reduce both capital and operating costs.
- Labour availability and productivity: the industry has experienced serious shortages of skilled labour for both construction and operations. Renewed industry activity may cause a recurrence of past labour availability and productivity issues.
- Limited capital availability, particularly for new industry participants, due to the 2008/2009 collapse of global capital markets.
- Other infrastructure: Northern Alberta road and rail infrastructure is inadequate.
- Diluent supply: condensate, the traditional blending agent for pipeline delivery of non-upgraded bitumen to market, is in limited supply.

## 6. Industry Outlook

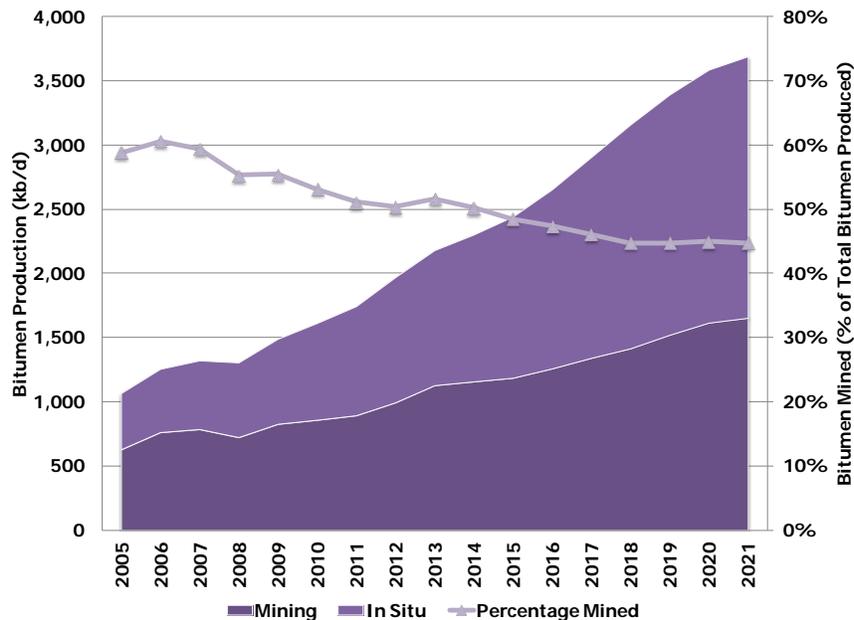
Several other organizations prepare outlooks for the Canadian oil sands industry. These include the Alberta Energy Resources Conservation Board (ERCB), the Canadian Association of Petroleum Producers (CAPP), the National Energy Board (NEB), IHS CERA, the Canadian Energy Research Institute (CERI), the Energy Information Administration (EIA) and the International Energy Agency (IEA).

The 2012 ERCB<sup>11</sup> and CAPP<sup>12</sup> outlooks project that:

- Alberta bitumen production will more than double by 2020 from 1.744 million b/d (mb/d) in 2011 to about 3.4-3.6 mb/d
- Bitumen production from in situ projects will surpass bitumen production from mining projects within the next few years
- The percentage of bitumen that is upgraded before it leaves Alberta will decline – i.e., there will be limited investment in new upgrading capacity

The most recent ERCB bitumen production outlook is provided in Figure 6-1.

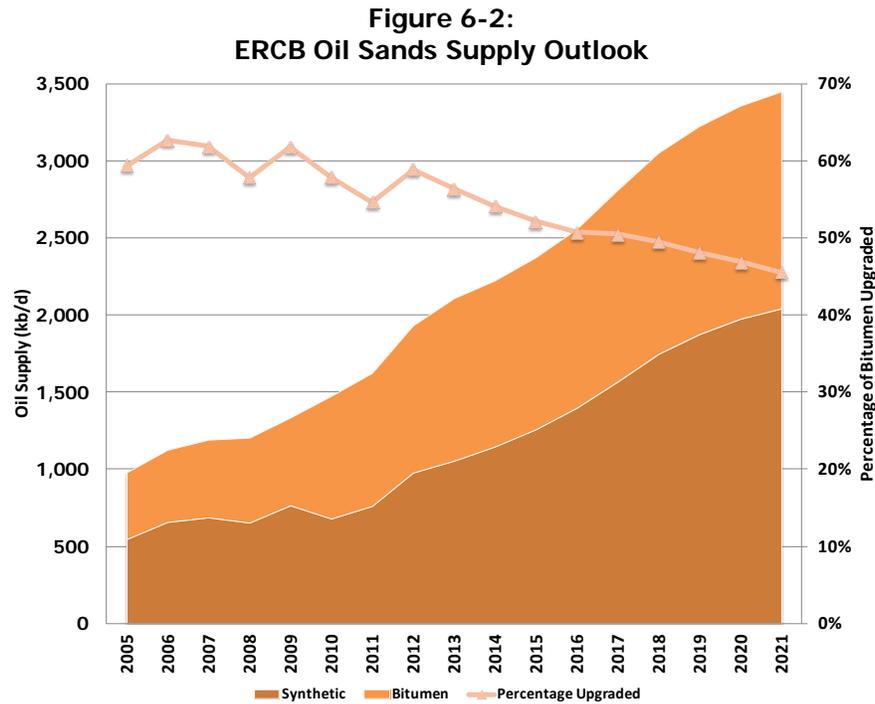
**Figure 6-1:  
ERCB Bitumen Production Outlook**



<sup>11</sup> Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012-2021; ERCB ST98-2012, June 2012

<sup>12</sup> Canadian Association of Petroleum Producers; Crude Oil Forecast, Markets & Pipelines; June 2012

The most ERCB oil sands supply outlook is provided in Figure 6-2.



Copies of the most recent ERCB and CAPP outlooks and some of the others referred to in this section may be downloaded at [www.strategywest.com](http://www.strategywest.com).

A long-term vision for the industry, released by the Alberta Chamber of Resources in 2004,<sup>13</sup> is also available for download at [www.strategywest.com](http://www.strategywest.com).

<sup>13</sup> Alberta Chamber of Resources; Oil Sands Technology Roadmap; January 30, 2004