Canada Oil Sand – A Hot Spot
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Introduction

According to the International Energy Agency, Global energy demand is expected to increase 53% by 2035 as economies in both developed and emerging countries continue to grow and standards of living improve. All sources of energy will be needed to meet growth in global demand. With conventional oil supply declining, the need for unconventional resources, like Oil sands, will increase. Canada with the “third largest oil reserves in the world” is well-positioned to help meet the global energy demands.

Canada has reported recoverable oil resources of 175 billion barrels that can be recovered economically with today’s technology. Out of the above, around 170 billion barrels are located in the oil sands. Over 97% of these reserves are located in the Alberta area with the remaining deposits being located in the Saskatchewan area.

Today, over half of Canada’s crude oil production is from the oil sands. Athabasca is considered to hold the largest oil sand resources in the world, although occurrences of the same have been reported from Venezuela, United States and Russia.

What is Oil Sand?

Oil sands are a natural complex mixture of sand, water, clay and bitumen. Bitumen is too heavy or thick to flow or be pumped without being diluted or heated. The proportion of bitumen in oil sands varies from 1 to 20%. In general, the composition of oil sand is: Sand 83%, Bitumen 10-12 %, Water 4% and Clay 3%. Most of the bitumen is deep seated, although at places, it is reported within 200 ft from the surface.

Where is it found?

Canada’s oil sands deposits are distributed in three main areas, viz. Athabasca, Peace River and Cold Lake in Alberta and Saskatchewan. Geology, geography, and the oil contents distinguish these deposits. Overall, these deposits cover ~140,000 km² surface area of the country, of which 91,000 km² or 65% area is under lease till July, 2011 (refer text figure-1). The reported in-place resources of oil sand is 1.7 trillion barrels. Almost 10% of this resource (169.3 Bbbl) is recoverable using current technology. Most of these deposits occur subsurface, but near to Fort McMurray it is immediately near to surface. The majority of the bitumen produced from these deposits has an API gravity of between 8° and 12° and a reservoir viscosity of over 10,000 cP although small volumes have higher API gravities and lower viscosities.
Additionally, Conventional heavy oil deposits in Canada are concentrated around Lloydminster in the Alberta-Saskatchewan border. The estimated area for Saskatchewan’s oil sand potential is 27,000 Km².

**How the Oil sand Formed?**

Oil generates from very fine-grained rocks known as black shale. Once the oil is formed, continued pressure from overlying rock strata as well as tectonic movements forces the oil to migrate through permeable rock layers until it is trapped in reservoirs of porous sedimentary rock such as sandstone or limestone, or until it escapes to the surface. The origins of these huge resources are believed to be a result of north-easterly migration of light crude from the Mississippian and Jurassic age sediments of southern Alberta to the present day oil sands areas driven by the same geological forces that caused the formation of the Rocky Mountains. Gradual biodegradation transformed the light oil into more viscous bitumen over time. Biodegradation occurred where microbes, carried in by oxygenated water, acted on the trapped oil. This microbial action preferentially decomposed the lighter hydrocarbon fractions, leaving the more complex heavy molecules, heavy minerals and sulphur. As a result, the specific gravity and sulphur content of the crude oil increases. It has been estimated that prior to biodegradation, the original volume of oil in the oil sands was two to three times as large as it is today. An illustrative sketch diagram is shown in text figure-2.

**Figure 1: Oil sand deposits in Alberta, Canada**

**Figure 2: Sketch showing how the oil sand formed in Alberta, Canada**
The characteristics of the bitumen and the reservoir properties of the oil sands is in large part a function of the degree of biodegradation that took place. For the Peace River deposits, the oil migrated the shortest distance and were subjected to only a moderate degree of biodegradation, while for the Athabasca and the Cold Lake deposits, the migration distance was considerably farther and therefore subjected to a greater degree of biodegradation. An East-West and North-South geological cross-section of the Alberta’s oil sand area is depicted in text figure-3.
Regional Geological framework

Most of the presently exploitable bitumen is hosted by unconsolidated Lower Cretaceous sands in the Athabasca, Cold Lake, and Peace River areas of Alberta and Saskatchewan. The Lower Cretaceous Mannville Group host sediments include: the Wabiskaw-McMurray for the Athabasca area; the Bluesky-Gething for the Peace River area; and the younger, Grand Rapids – Clearwater for the Cold Lake area. A generalized stratigraphic succession is shown in text figure-4.

Additionally, bitumen reserves are hosted within the Devonian and Mississippian carbonate reservoirs that un-conformably underlie the West Athabasca (Formerly Wabasca deposit) and Peace River oil sands area referred as “Carbonate Triangle” (refer text figure-5). Exploitation from the Carbonate Triangle is yet to start as techno-economic feasibility under current technology is yet to be ascertained. However, companies have acquired large leases there and presumably see future potential. In the Carbonate Triangle area, the primary reservoirs of bitumen are the Devonian Nisku and the Grosmont formations, which underlie the West Athabasca deposit; and the Mississippian Debolt and Shunda formations, which underlie the Peace River deposit. Other prospective carbonate bitumen reservoirs are in the Mississippian Pekisko Formation (Rundle Group) beneath the Peace River deposit. No carbonates bitumen deposits have been found beneath the Cold Lake area. Reservoir properties of all the oil sand bearing formation underlies these oil sand areas is given in text table-1.
Brief details of oil sand deposits are as under:

**Athabasca**

The Athabasca oil sands is the largest Cretaceous oil sands deposit in Alberta, covering an area of about 93,000 km² i.e. 66% of the total oil sand area and 74% area is under lease. Most of the bitumen deposits are found in the **McMurray** Formation, a layer of shale, sandstone, and oil-impregnated sands formed during the Cretaceous period by river and ocean processes. The formation is up to 150m thick and overlies strata of shale and limestone (the Devonian Waterways Formation) and capped by the **Clearwater** Formation, comprising of marine shale and sandstone (refer text figure-6).
North of Fort McMurray, the formation can be found within 75m of the surface and is exposed at the surface where the Athabasca River and its tributaries have incised into the landscape. Overall, in this area (around Fort McMurray), the oil sands are amenable to surface mining. Elsewhere, the in situ method is the common method of exploitation.

**Cold Lake**

Cold Lake, the south easternmost of the oil sand deposits covering ~ 18,000 km² i.e. 13% of the total oil sand area and has the second largest reserve of bitumen. The bitumen is present in sub-surface within 300 - 600m depth. Currently, some of these deposits are being recovered using In situ technology. As of July 2011, 50% of the area was under lease.

The deposit resources are encased within the Lower Cretaceous (Lower Albian) **Clearwater** and **Grand Rapids Formations**. The Clearwater formation, a marine deposit comprises of glauconitic sandstone at base, overlain by dark grey shale, grading up into sandstone. The formation is clearly defined in north-eastern and central Alberta, and is well exposed on lower course of the Athabasca River as well as on the banks of the Christina River (south-east of Fort McMurray). It reaches a maximum thickness of 85 m (280 ft) on the Athabasca River, thins out to 6 m (20 ft) in the Cold Lake area, and wedges out towards the south (refer text figure-6). The Clearwater formation is the dominant reservoir in this area. Grand Rapid formation is brackish water near shore deposit comprising of feldspathic sandstone and siltstone with minor shale and lignite. This may be an important reservoir towards the southern part.

**Peace River**

Peace River, the westernmost deposit covers ~ 29,000 km² i.e. 21% of the total oil sand area. These deep deposits (ranging from 300 to 770 meters below the surface) are being exploited by in-situ methods. As of July 2011, 43% of the area was under lease.
Bitumen resources in this area as encased within the **Bluesky** and **Gething** Formations overlying the locally saturated Mississippian carbonates. The stratigraphic sequence of fluvial/non-marine (Gething) to brackish bay system to a marginal marine estuarine complex (Bluesky) is similar to the McMurray Formation in the Athabasca area.

Table 1: Alberta’s oil sands Reservoir properties

<table>
<thead>
<tr>
<th>Oil sand deposits</th>
<th>Initial Volume in place ($10^6$ m$^3$)</th>
<th>Area ($10^3$ Ha)</th>
<th>Average pay Thickness (m)</th>
<th>Average Bitumen saturation</th>
<th>Average porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Mass (%)</td>
<td>Pore volume (%)</td>
</tr>
<tr>
<td><strong>Athabasca</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grand Rapids</td>
<td>8678</td>
<td>527</td>
<td>9.6</td>
<td>6.5</td>
<td>57</td>
</tr>
<tr>
<td>Wabiskaw-McMurray (mineable)</td>
<td>20823</td>
<td>375</td>
<td>25.9</td>
<td>10.1</td>
<td>76</td>
</tr>
<tr>
<td>Wabiskaw-McMurray (in-situ)</td>
<td>131609</td>
<td>4694</td>
<td>13.1</td>
<td>10.2</td>
<td>73</td>
</tr>
<tr>
<td>Nisku</td>
<td>10330</td>
<td>499</td>
<td>8.0</td>
<td>5.7</td>
<td>63</td>
</tr>
<tr>
<td>Grosmont</td>
<td>64537</td>
<td>1766</td>
<td>23.8</td>
<td>6.6</td>
<td>79</td>
</tr>
<tr>
<td><strong>Cold Lake</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Grand Rapids</td>
<td>5377</td>
<td>612</td>
<td>4.8</td>
<td>9.0</td>
<td>65</td>
</tr>
<tr>
<td>Lower Grand Rapids</td>
<td>10004</td>
<td>658</td>
<td>7.8</td>
<td>9.2</td>
<td>65</td>
</tr>
<tr>
<td>Clear water</td>
<td>9422</td>
<td>433</td>
<td>11.8</td>
<td>8.9</td>
<td>59</td>
</tr>
<tr>
<td>Wabiskaw- McMurray</td>
<td>4287</td>
<td>485</td>
<td>5.1</td>
<td>8.1</td>
<td>62</td>
</tr>
<tr>
<td><strong>Peace River</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bluesky-Gething</td>
<td>10968</td>
<td>1016</td>
<td>6.1</td>
<td>8.1</td>
<td>68</td>
</tr>
<tr>
<td>Belloy</td>
<td>282</td>
<td>26</td>
<td>8.0</td>
<td>7.8</td>
<td>64</td>
</tr>
<tr>
<td>Debolt</td>
<td>7800</td>
<td>258</td>
<td>25.3</td>
<td>5.1</td>
<td>66</td>
</tr>
<tr>
<td>Shunda</td>
<td>2510</td>
<td>143</td>
<td>14.0</td>
<td>5.3</td>
<td>52</td>
</tr>
</tbody>
</table>

(Initial in-place volumes of crude bitumen as of December 31, 2011)

*Source: ERCB ST98-2011: Alberta Energy Reserve 2010 and supply/Demand Outlook/Crude Bitumen*
Recovering the oil

Oil sand recoveries are primarily dependent in the type of overburden and depth of occurrence. In general, there are two methods for the recovery: **Open-pit mining** and **In situ**.

In places, wherever the bitumen occurs near to the surface, it is recovered by open pit mining. About 20% of the oil sands reserves in Alberta are recoverable by surface mining where the overburden is less than 75 m. For the remaining 80% of the oil sands that are buried at a depth of greater than 75 m, in-situ technologies are being widely used to extract the bitumen. Currently, majority of In situ operations uses steam-assisted gravity drainage (**SAGD**) technique. A comparison between Mining and In-situ (**SAGD**) projects is given in text Table-3.

As per Industry records, As of December 31, 2010 the total production from the oil sands was 7.5 billion barrels; 4.8 billion barrel from surface mining and 2.7 billion barrel from in-situ projects (refer text Table-2).

### Table 2: In place reserve as of December 31, 2010

<table>
<thead>
<tr>
<th>Recovery Method</th>
<th>Initial Volume in Place (Billion barrels)</th>
<th>Initial Established Reserve</th>
<th>Cumulative Production</th>
<th>Remaining Established Reserve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>1,803</td>
<td>176.7</td>
<td>7.5</td>
<td>169.3</td>
</tr>
<tr>
<td>Mining</td>
<td>130.8</td>
<td>38.7</td>
<td>4.8</td>
<td>33.9</td>
</tr>
<tr>
<td>In-situ</td>
<td>1,671.9</td>
<td>138.0</td>
<td>2.7</td>
<td>135.3</td>
</tr>
</tbody>
</table>

*Source: ERCB Report ST98-2010*

### Table 3: A comparison between Mining & In-situ (**SAGD**) project

<table>
<thead>
<tr>
<th>Factor</th>
<th>Mining</th>
<th>In-situ (<strong>SAGD</strong>)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overburden depth</td>
<td>&lt;75 m</td>
<td>&gt;150 m</td>
</tr>
<tr>
<td>Reserve (totals 170 billion bbl)</td>
<td>20%</td>
<td>80%</td>
</tr>
<tr>
<td>Crude Bitumen Production (total 1.6 million b/d- 2010)</td>
<td>53%</td>
<td>47%</td>
</tr>
<tr>
<td>Recovery</td>
<td>&gt;90%</td>
<td>&lt;60%</td>
</tr>
<tr>
<td>Fresh water demand (m³/m³ bitumen)</td>
<td>2-3</td>
<td>~0.5</td>
</tr>
<tr>
<td>Carbon Imprint (Kg CO₂e/m³ SCO)</td>
<td>820</td>
<td>1,100</td>
</tr>
<tr>
<td>Direct land Disturbance (Ha/100,000 m³)</td>
<td>5.9</td>
<td>0.88</td>
</tr>
<tr>
<td>Capital Cost</td>
<td>High</td>
<td>Moderate</td>
</tr>
</tbody>
</table>

The brief of both the methods are summarized below.
Open Pit Mining

Open-pit mining is similar to many coal mining operations – large shovels scoop the oil sand into trucks that then take it to crushers where the large clumps of earth are broken down. This mixture is then thinned out with water and transported to a plant, where the bitumen is separated from the other components and upgraded to create synthetic oil. As per independent assessments, just 20% of the oil sands underlying approximately 2.5% of the total oil sand surface area in Alberta are recoverable through open-pit mining.

The main advantage of surface mining is that nearly all of the bitumen can be extracted from the ore, whereas In-situ methods leave a substantial amount of the resource underground. A disadvantage is that a great deal of earth and ore must be moved, disturbing significant areas of landscape- an environmental hazard. The significant aspect is that to achieve better economics, the projects should have substantial resources. Each of the operating mining projects also has an Upgrader on site or is connected to an Upgrader by pipeline.

In the current projects’ lease areas, ores averages about 10 to 12% bitumen by weight. Thus, from nearly two tonnes of oil sands processing yields around 159-litre barrel of upgraded crude oil. The processed sand is then returned to the pit, and the site reclaimed as per standard practice. An illustrative sketch diagram of open pit mining project is shown in text figure-7 below.

Figure 7: Illustrative sketch diagram of Open pit Mining projects
**In Situ Technique**

As on date, 80% of oil sands reserves (which underlie approximately 97% of the total oil sands surface area) are recoverable through **in situ** technology with limited surface disturbance and environmental degradation. Major commercial in-situ projects use steam to heat and dilute the bitumen, although several other methods are being tested or deployed.

Current in-situ production technologies recover 25-50% of the bitumen from the reservoir, which in cases are significant and comparable to the recovery from a conventional reservoir. Technological improvement of this method over the years has resulted in significant recoveries in various projects.

In-situ technique uses significant amount of water to generate steam, uses less surface area and reclamation is faster after operations cease. Research and pilot operations are currently underway, which will dramatically reduce the energy and water consumption for in-situ oil sands development.

There are two principal in-situ steam injection methods used in Canada today. The majority of in-situ operations use Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Simulation (CSS) technique.

A brief review of the five In –Situ methods under application by various operators in different projects are briefed below with the most common one being the SAGD and CSS methods. The other methods are less used for commercial production, but with technology upgradation may hold the key for future. Basically, it is to be understood that these extraction methodology is entirely driven by technological advances made from time to time “What is today best may change over time as more and more projects come on line”.

**Steam Assisted Gravity Drainage (SAGD)**

SAGD technique involves the drilling of two horizontal wells, one above the other into the oil sands formation (one at the bottom of the formation and another about 5 m above it). The upper well injects steam into the reservoir. As the steam heats the oil sands formation, the bitumen melts which allows gravity to assist it to flow to the lower well and the bitumen is pumped to the surface. An illustrative diagram is shown in text figure -8.

![Figure 8: Illustrative diagram of SAGD Method](image)
SAGD is cheaper than CSS, allows very high oil production rates, and recovers up to 60% of the oil. Some of the projects where SAGD is used are Suncor’s Firebag project, Petro-Canada’s MacKay River project and EnCanas’s Foster Creek project etc.

**Cyclic steam stimulation (CSS)**

In this method, high-pressure steam is injected into the oil sands formation for several weeks or months.

The heat softens the bitumen, while the water helps to dilute and separate the bitumen from the sand grains. The pressure also creates channels and cracks through which the bitumen can flow to the well. When a portion of the reservoir is thoroughly saturated, the steam injection ceases and the reservoir "soaks" for several weeks. This is followed by the production phase, when the bitumen is pumped up the same wells to the surface. When production rates decline, another cycle of steam injection begins (refer text figure-9)

This method began to be commercially used in 1985 by Imperial Oil at Cold Lake. It is also being used at Shell Canada’s Peace River project.

**The Vapor Extraction Process (VAPEX)**

This method is similar to SAGD, but instead of steam, hydrocarbon solvents (natural gas liquids such as ethane, propane or butane) are injected into the upper well to dilute the bitumen and allow it to flow. It is much more energy efficient than steam injection and some partial upgrading of the bitumen to crude oil occurs right in the sands. This method is new and more expensive than the above but oil companies are experimenting with it.

Figure 9: Illustrative diagram of CSS method
An industry-government consortium is currently evaluating a VAPEX pilot project at the Dover lease northwest of Fort McMurray, and the technology is also being tested by several operators on their own leases.

Note that SAGD, CSS, and VAPEX are not mutually exclusive. For example some wells go through a CSS cycle to condition the formation before the SAGD production method is used. Some companies are also starting to combine VAPEX and SAGD to improve recovery rates and decrease energy costs.

Enhanced Steam-Assisted Gravity Drainage (e-SAGD)

ConocoPhillips is piloting the e-SAGD process that, compared to SAGD, reduces the amount of steam required by 15 to 35% and offers the potential to accelerate resource recovery. This also reduces the number of wells needed as well as the amount of water and natural gas required to produce a barrel of bitumen. Such innovations benefit both project economics and the environment.

In the current SAGD process, steam is injected into the bitumen reservoir to heat the bitumen, reducing its viscosity and thinning it enough to allow it to flow through the production well. In e-SAGD method, we inject a naturally occurring light hydrocarbon with the steam to thin the bitumen. By using less steam, we can reduce the resulting greenhouse gas (GHG) emissions by 15 to 35%.

Cold Flow production process

The Cold Flow production process involves the pumping out of the bitumen without heat, often using specialized pumps called progressive cavity pumps (PCP). This method only works well in areas where the bitumen is fluid enough to pump. It is most commonly used in Venezuela, but also in parts of the Athabasca region and the southern part of the Cold Lake region. This is the cheapest method but recovers only 5-6% of the bitumen. This production method is also known as CHOPS (cold heavy oil production with sand).

Toe to Heel Air Injection (THAI)

THAI is a new and experimental method where a vertical air injection well is combined with a horizontal production well. To begin the process, bitumen around the “toe” of the horizontal well is heated with steam. Once this approximately three-month heating cycle in a bitumen reservoir is complete, the steam is shut off and air is injected into the vertical well to create a combustion reaction in the reservoir. Through the controlled injection of air, an estimated two meter thick combustion front begins to move along the horizontal well at about 10 inches (25 cm) a day toward the “heel” of the horizontal well. As it heats up, the bitumen drains into the horizontal production well and brought to the surface through natural pressure. Because the combustion front heats the bitumen to 400 degrees, the oil is also partially upgraded underground. The heat causes a portion of the asphaltpine content of the oil to be left behind as coke that is the fuel for the continued combustion. An illustrative sketch diagram is shown in text figure -10.

This process has been patented by M/s Petrobank Energy and Resources. It has shown to produce more of the resource, while significantly limiting the environmental footprint. While it uses some water for the initial steaming, most of it is returned to the surface, treated and returned to the environment.
After being proven at Petrobank’s Whitesands pilot project south of Fort McMurray, the technology is poised for commercialization in other oil sands and heavy oil reserves in western Canada and around the world.

Figure 10: Sketch Diagram of THAI Method
Upgrading

Compared to conventional light crude oil, bitumen typically contains more sulphur and a much higher proportion of large, carbon-rich hydrocarbon molecules. All operating mines have integral upgraders and 100% of mineable production is upgraded within Alberta. In 2010, about 15.3% of in-situ production was upgraded in Alberta, with most of the rest being upgraded elsewhere in Canada or shipped to the US for upgrading.

The upgrading process converts bitumen into a product with a density and viscosity similar to conventional light crude oil. This is accomplished by using heat to crack the big molecules into smaller fragments. Adding high-pressure hydrogen and/or removing carbon can also create smaller hydrocarbon molecules. Most of the energy for upgrading is obtained from byproducts of the process.

Upgrading is usually a two-stage process. In the first stage, coking, hydro-processing, or both, are used to break up the molecules. Coking removes carbon, while hydro-processing adds hydrogen. In the second stage, a process called hydro-treating is used to stabilize the products and to remove impurities such as sulphur and nitrogen. The hydrogen used for hydro-processing and hydro-treating is produced from natural gas and steam. A sketch diagram of upgrading process is shown in appendix-2.

**Canadian oil sands products.**

Raw bitumen is denser than heavy oil; it’s solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid or converted into a synthetic light crude oil. The two most common products derived from oil sands are:

**Upgraded bitumen or synthetic crude oil (SCO).**

This is produced from bitumen in refinery conversion units (Upgrader) that turn very heavy hydrocarbons into lighter, more valuable fractions. SCO is typically a light sweet crude oil with no heavy fractions and API gravity typically greater than 33 degrees.

**dilbit (bitumen blend, or diluted bitumen):**

This is bitumen mixed with a diluent, typically a natural gas liquid such as condensate, to make the viscosity low enough for the dilbit to be shipped in a pipeline. Once mixed, dilbit is a heterogeneous crude oil mixture of about 22 degrees API, similar to the density and properties of other heavy crude supplies from California, Mexico, and Venezuela.
Infrastructure & Markets

Canada has well-established oil and gas infrastructure that has been built up over many years. This includes pipelines that export crude oil from western Canada to eastern Canada, the US and some offshore markets (refer text figure-11).

Most crude oil production in western Canada is delivered to two hubs located in Edmonton and Hardisty, Alberta. From these locations, crude oil and other products can be transported in segregated batches to delivery points in Canada and the United States.

The Edmonton hub has around 6.5 million barrels of storage capacity for the various types of crude oil received from the connecting feeder pipelines. Edmonton is also the only major refining centre in western Canada.

The Hardisty hub, located 220 kilometres southeast of Edmonton, connects several feeder pipelines with Express Pipeline, Enbridge Mainline and the Bow River Pipeline. Storage capacity at Hardisty is around 8.8 million barrels.

Although a majority of western Canada’s oil production is exported as crude, significant refinery capacity of around 420,000 b/d exists at the Edmonton hub.

The US is the primary export market for western Canadian crude oil supplies due to its strong demand, geographic proximity and established pipeline infrastructure. In 2010, crude oil production from western Canada was 2.7 million b/d in which 1.5 million b/d was oil sand contribution. Domestic demands for western Canadian crude oil was 828,000 b/d and the remaining supply of over 1.9 million b/d or 69% was exported to US.

Eastern PADD II (particularly, Illinois, Indiana, Michigan, Ohio and Minnesota) is the largest market for western Canadian crude oil. The other primary markets are currently: British Columbia; Alberta; Saskatchewan; Ontario; PADD IV; California and Washington in PADD V.

Fort McMurray, about 250 miles north of Edmonton in the northern part of Athabasca oil sand region is the center of Alberta’s oil industry. Canada’s crude oil pipeline system is mainly concentrated in the western provinces and largely oriented toward exports to the U.S. market.

Three Canadian companies operate the majority of export pipelines: Enbridge, Kinder Morgan, and TransCanada. There are five major pipelines operated by these companies that are directly
connected to the Canadian supply hubs at Edmonton and Hardisty, Alberta – **Enbridge Main line**, **Enbridge Alberta Clipper**, **Kinder Morgan Trans Mountain**, **Kinder Morgan Express**, and the **TransCanada Keystone pipeline**. Together, these pipelines provide a total pipeline capacity of 3.5 million b/d (refer text table-4)

Enbridge operates the largest export oil pipeline network, the **Canadian Mainline** and **Lake Head Systems**. This 3,300-mile network carries 2.1 million bbl/d of oil from Edmonton, Alberta to Quebec and the U.S. Midwest. Around 70% of Canada’s oil exports travel through this system.

Kinder Morgan operated **Express** and **Platte** Lines transport crude from Hardisty, Alberta, an emerging Canadian oil hub, to Wyoming, Colorado and Utah, connecting to pipelines bound for Illinois. With the recent startup of the TransCanada operated Keystone Pipeline to Patoka, Illinois, followed by the extension of this pipeline into Cushing, Oklahoma, crude oil supplies from western Canada into the PADD II market are expected to grow. Producers currently have limited transportation options to serve alternative markets in the U.S. Gulf Coast, which is world’s largest refining market and over half of the existing capacity can process heavy crude oil. Refineries in this market are looking to replace declining supplies historically coming from Mexico and Venezuela.

**Table 4: Capacity of major Crude Oil pipelines**

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Crude Type</th>
<th>Annual capacity (K b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enbridge</td>
<td>Light</td>
<td>1,069</td>
</tr>
<tr>
<td></td>
<td>Heavy</td>
<td>796</td>
</tr>
<tr>
<td>Express</td>
<td>Light/Heavy (35/65)</td>
<td>280</td>
</tr>
<tr>
<td>Trans Mountain</td>
<td>Light/Heavy (80/20)</td>
<td>300</td>
</tr>
<tr>
<td>Alberta clipper</td>
<td>Heavy</td>
<td>450</td>
</tr>
<tr>
<td>Keystone</td>
<td>Light/Heavy (25/75)</td>
<td>591</td>
</tr>
<tr>
<td><strong>Total Capacity (As of Dec 31, 2010)</strong></td>
<td><strong>3,486</strong></td>
<td></td>
</tr>
</tbody>
</table>

With the forecast of growing supplies, the industry is strategically looking to expand access to markets; focused on addressing the need for more capacity into the US Gulf Coast; and increasing pipeline capacity to the west coast. A number of pipeline projects are being proposed to provide both market access and additional capacity that will be needed by Canadian producers in the future. TransCanada has proposed **Keystone XL pipeline** from Cushing to the US Gulf Coast. This pipeline will carry Canadian heavy crude to refineries in the United States, and subsequently to the Gulf Coast for delivery to the international markets. New expansion proposals are on hand to expand export capacity to the west coast, providing access to new markets with strong growth potential. Existing and proposed pipeline infrastructure of Canada and US has been shown in text figure-12.
The US, after the successful development of shale gas, is trying to increase its domestic crude oil production from shale oil resources. With the increase in domestic crude oil production, the US may curtail some of its oil imports. This will affect the growth of oil sands development in Canada, unless Canada develops new export markets for its crude oil. Canada is trying to develop new exports markets for its crude oil production.

To diversify the market a new pipeline project “Northern Gateway” has been proposed. This pipeline system will carry crude oil from Edmonton, Alberta to deep water port located in Kitimat, on the western coast of British Columbia, where it will be transported to Asian markets by oil tankers (refer text figure-13). This pipeline system has been designed to provide 525,000b/d of diluted bitumen (dilbit) and synthetic crude oil (SCO) export capacity. Several firms are also assessing the feasibility of other potential terminals to facilitate exports to Asia-Pacific region.
Figure 13: New Market for Canadian Oil sand
Economies

For an oil sands producer, a project’s viability relies on many factors, such as market price for blended bitumen and SCO, exchange rate of the Canadian dollar, fiscal terms, operating expenses such as initial capital costs, natural gas price and availability, material and labour costs, and transportation cost.

Operating costs – the labour, natural gas and other goods and services needed to produce a barrel – comprise about half of the supply cost for producers. Because of unique challenges, different projects will have differing operating costs.

Operating costs in the oil sands mining projects are partly dependent on the price of natural gas used to generate steam and electricity and to produce hydrogen in associated upgrading facilities. If ways can be found to reduce or eliminate natural gas use, then costs could be reduced significantly. Wages and salaries are another major component of operating costs for mines and Upgraders as they employ large numbers of skilled workers.

Crude oil prices are the main key factors in Oil sand development which is determined by global supply and demand and change with the weather, politics and other factors. The spread between the price of heavy and light oils is called the differential.

Royalty is another dominant factor. In 2009, the Canadian government introduced a New Royalty Framework, consisting of price-sensitive royalty rates linked to the price of West Texas Intermediate crude oil in Canadian dollars. For projects that haven’t recovered capital costs incurred to construct the project, gross royalty rates start at 1% when oil is priced at $55 per barrel or less, and increase to a maximum of 9% when oil is priced at $120 per barrel or more. For projects that have recovered start-up costs, net royalty rates start at 25% when oil is priced at $55 per barrel or less, and increase to a maximum of 40% when oil is priced at $120 or more (for detail refer Appendix-1)

For Western Canadian producers, refining capacity and competition in the mid continental U.S. and Canadian markets are also key considerations.

The plant gate supply costs to produce oil sands bitumen vary considerably. In 2011, the Alberta Energy Resources Conservation Board estimated plant gate supply costs of $47 - $57 per barrel for steam-assisted gravity drainage projects, compared to $63 to $81 per barrel for stand-alone mining projects and $88- $100 per barrel for integrated mining and upgrading projects. The Canadian Energy Research Institute (Study 128) estimated the cost for new SAGD and stand-alone mining projects at $65 and $82 per barrel respectively and integrated mining and upgrading projects at

West Texas Intermediate (WTI), also known as Texas Light Sweet, is a type of crude oil used as benchmark in oil pricing and the underlying commodity of New York mercantile exchange’s oil future contracts.

WTI crude oil is of very high quality and is excellent for refining a larger portion of gasoline. Its API gravity is 39.6 degrees (making it a “light” crude oil), and it contains only about 0.24 percent of sulfur (making a “sweet” crude oil).
$91 per barrel. The supply cost comparison estimated by different Canadian agencies is given in text table -6.

Table 6: Supply Costs Comparison- WTI Equivalent Supply Costs (US$/bbl)

<table>
<thead>
<tr>
<th></th>
<th>CERI</th>
<th>ERCB</th>
<th>NEB</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAGD</td>
<td>$64.62/bbl</td>
<td>$47-57/bbl</td>
<td>$50-60/bbl</td>
</tr>
<tr>
<td>Integrated Mining &amp; Upgrading</td>
<td>$91.07/bbl</td>
<td>$88-102/bbl</td>
<td>$85-95/bbl</td>
</tr>
<tr>
<td>Stand-alone Mining</td>
<td>$81.51/bbl</td>
<td>$63-81/bbl</td>
<td>$65-75/bbl</td>
</tr>
</tbody>
</table>

(Source: CERI, ERCB, NEB)

[Supply cost is the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes and earn a specified return on investment. Supply costs is calculated using an annual discount rate of 10 % (real), which is equivalent to an annual return on investment of 12.5 percent (nominal) based on the assumed inflation rate of 2.5 percent per annum.]
Light-heavy differential

All crude oil is not valued equally. Light oil that is low in sulphur content (i.e., sweet) is more valuable to refiners than heavy oil with higher sulphur content (i.e., sour), because it is less energy intensive to refine light sweet crude, and the resulting petroleum products are of higher quality. The difference between a barrel of light sweet oil and a barrel of heavy sour oil represents the light-heavy differential.

Almost all of Canadian oil production is transported to refineries in Canada and the US and originates mostly in Alberta. The two main distribution hubs in Alberta are located near Edmonton and Hardisty – the price point for Western Canadian Select (WCS) as a crude benchmark. The WCS consists of conventional Western Canadian heavy oil, and bitumen that has been blended with sweet SCO and diluents. The table given below compares the characteristics of the WCS blend with two other heavy crude oils.

<table>
<thead>
<tr>
<th></th>
<th>WCS (Canada)</th>
<th>Maya (Mexico Heavy Oil)</th>
<th>Mars (US Blended Crude)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity (API°)</td>
<td>19-22</td>
<td>21.8</td>
<td>30.4</td>
</tr>
<tr>
<td>Carbon Residue (wt%)</td>
<td>7-9</td>
<td>13</td>
<td>5.5</td>
</tr>
<tr>
<td>Sulphur (wt%)</td>
<td>2.8-3.2</td>
<td>3.5</td>
<td>1.9</td>
</tr>
<tr>
<td>TAN (mg KOH/g)</td>
<td>0.7-1.0</td>
<td>0.3</td>
<td>0.68</td>
</tr>
</tbody>
</table>

Note: TAN – Total Acid Number, measured in mg of potassium hydroxide needed to neutralize one gram of oil.

Currently WCS prices are based on West Texas Intermediate (WTI) because WCS crude is shipped to the Cushing, Oklahoma market, for which the historical benchmark is WTI. WCS crude is sold at a discount to WTI because it is a lower quality crude, producing a positive light-heavy differential. The blend specifications for WCS meet an API gravity of 19-22°, carbon residue of 7-9 wt%, sulfur of 2.8-3.5 wt%, and a total acid number (TAN) of 0.7-1.0 mg KOH/g. The resultant crude composition for WCS compared to a standard crude West Texas Intermediate (WTI) shows that WCS has three times more residual material than WTI, 50% more Vacuum Gas Oil (VGO), half the distillate and half of the naphtha; see Figure-1 below.

The data series for WCS prices comes from Cenovus website. The Figure-2 given below illustrates the selected historical benchmark price series of WTI and WCS and the differential between the two.

As seen in Figure-2, prices have been volatile in recent years. WCS prices fell from a high of US$115/bbl in 2008 to nearly US$20/bbl in 2009. Since WCS has historically traded based on WTI, and given high correlation coefficient of 95% with WTI, it is reasonable to say that WTI prices have also exhibited periods of large fluctuation. As well, the linear trend of differential for the entire time period is observed to be decreasing from a high of US$35/bbl in 2005 to nearly US$10/bbl by the end of 2011.
Risks & Challenges

With rapid growth and prosperity in Canada’s oil sands region, the industry is also facing environment and economic challenges and working hard to overcome.

Environmental Challenge:

Air emissions including greenhouse gases and Criteria air contaminants; water consumption; liquid waste disposal including tailings from mining operations; surface disturbance, destruction of wildlife habitat and site reclamation is all serious environmental issues. The industry faces considerable uncertainty about how greenhouse gas emissions might be regulated and the economic consequences.

GHG Emission:

Oil sands require a significant amount of energy to process and upgrade the bitumen to petroleum products suitable for market. The energy intensive process results in increased air emissions. The oil sands industry currently contributes a significant amount to Canada’s national air emissions portfolio.

Criteria Air Contaminants (CACs) are the most common air pollutants released by heavy oil industry burning fossil fuels. CACs are defined as “air pollutants that affect our health and contribute to air pollution problems” and include such things as nitrogen oxides (N0x), sulphur dioxide (S02), volatile organic compounds (VOCs) and particulate matter (PM) - all of which are emitted in large volumes by oil sands operations.

GHG emissions are a major concern for Canadians. Oil sands operators have taken steps to significantly reduce the emissions intensity of their operations but total emissions have still increased due to higher production levels. 48 mega tonnes of greenhouse gases are emitted from the oil sands in 2010. This represents

- 15% of Alberta’s total greenhouse emissions
- 6.9% of Canada’s emissions
- 0.1% of the world’s total GHG emissions

GHG emissions could be reduced by developing renewable energy sources to reduce current reliance on natural gas in production processes. Several alternative “in situ” extraction methods are being developed (few of them given below) that may have potential to reduce the energy intensity and GHG emissions profile of oil sands production - although caution must be exercised to ensure that they do not create more adverse impacts than they resolve.
- Vapour extraction (VAPEX) would use solvents to make bitumen fluid, replacing steam.
- Toe-to-heel air injection (THAI™) would use underground combustion to make bitumen fluid and provide upgrading in situ.
- Other methods under development include electrical heating to make bitumen fluid without the use of steam.

Another method is Carbon Capture and Storage (CCS) technique. It may be feasible to reduce the GHG Emission, although as yet little progress has been made in implementing this strategy.

**Surface (Land) disturbance and reclamation**

The surface disturbance from mining operations and processing of bitumen includes land clearing, disturbance of surface strata and soil. These activities result in deforestation of forests and woodlands, and have a negative impact on fish and wildlife populations.

Research is made on the development of methods that will reduce the land required for open pit operations and tailings management areas. Current industry practice is to leave large areas of land to remain in a disturbed state over many years during which natural processes work to re-establish the landscape. Oil sands operators are obliged, to return the land to a sustainable landscape (reclamation).

Today, the proportion of reclaimed land in the oil sands regions is smaller compared to the surface area disturbed through surface mining and tailings ponds. The in situ process is much less harmful in terms of surface damages, and results in limited negative environmental impact to forests, wildlife and fisheries. A land disturbance due to oil sand mining project has been shown in text figure-14.
Figure 14: Land Disturbances due to oil sand mining at Suncor

**Water Consumption**

Water is extensively used in open-pit mining for oil separation and at in situ operations to make steam. Both require a significant amount of water per barrel of oil produced. Mining operation uses 3.1 barrels of fresh water for every barrel of oil produced with 80-90% recycling (2010 data), while In-situ operation uses 0.4 barrels of fresh water per barrel of oil, with 90-95% recycling (2010 data). Oil sands fresh water use in 2010 was approximately 170 million m³ (CAPP 2010).

Oil sands surface mining operations have been listed as one of the threats for Athabasca River’s integrity, because large amounts of water are withdrawn from the river for use in the extraction process. Between 2-5 barrels of water are withdrawn from the Athabasca River for each barrel of bitumen extracted. In 2010, 85% of the water withdrawn for oil sands mining was from the Athabasca River (total of 130 million m³).

Both oil sands mining and SAGD operations are impacting freshwater aquifers by lowering their levels and creating a similar decrease in water levels in streams, ponds, lakes and wetlands that are connected to groundwater. Once the mine pit is excavated, groundwater levels are often lowered in the area to prevent flooding of the pits. Because multiple mines may be pumping water from an
aquifer, the removal of groundwater from a large area of the landscape can lower the groundwater level in adjacent areas.

Oil sand industry need to ensure water use is managed responsibly. Some companies are using only non-drinkable water, such as salt water (brackish) in their operations. Developing additional sources of water supply or alternatives to the current water-intensive processes is an important challenge to the development of the industry.

**Tailing Ponds**

The tailings ponds at oil sands mining projects pose additional challenges. Surface mining operations and subsequent water-based extraction of the oil sands produce large volumes of tailings. “Tailings” are the leftover mixture of water, sand, clay and residual oil after extraction process. The tailings ponds are large engineered dam and dyke systems designed to contain and settle the tailing. In addition to acting as storage facilities, these ponds are the settling basins that enable water to be separated, recycled and used over and over. Oil sands producers recycle 80–95% of water used, reducing use of fresh water from the Athabasca River and other sources. To protect the quality of the river water, no production water can be returned instead, it is transferred to tailings ponds and then recycled into the production process.

The total area of existing tailings ponds is 170 km² (Source: ERCB) creating challenges for the industry in terms of management and liability. Without any major operational changes to separate the water from the fine tailings, tailings ponds capacity would increase to well over 1 billion cubic meters by 2014 and to 2 billion cubic meters in 2034 (compared to 900 million cubic meters today). Tailings ponds are not used in the in-situ projects.

The principle environmental threats from tailings ponds are the migration of pollutants through the groundwater system and the risk of leaks from tailings impoundments to the surrounding soil and surface water. To ensure that seepage from tailings ponds does not contaminate groundwater and surface water sources, tailings ponds are designed and constructed to guard against erosion, breaching and foundation creep over the long term. In addition, monitoring programs for groundwater and surface water are conducted to ensure the integrity of the tailings ponds.

Companies are developing new techniques to restore tailings ponds. For example, Shell Canada Limited’s Albion Sands project uses thickeners in the tailings that allow water to be recaptured from the tailings, before they are released into the pond. This reduces the size of the pond and the amount of water the company uses in production.

Another innovative practice is at Canadian Natural Resources Limited’s Horizon project. Carbon dioxide (CO2) is captured from the facility and mixed with silts in the tailings, which causes a reaction that forms a solid, and allows the silts to settle more quickly. This process has multiple benefits: the CO2 is permanently trapped in the silts, and most of the water can be recycled while it's still hot, so less energy is needed to reheat it. This results in reduced greenhouse gas emissions and smaller tailings ponds.

A number of universities and agencies are also researching new methods to speed up the separation of water and silts, faster recycling of water and new ways to return the land back to a sustainable landscape.
Economic challenge

Crude oil prices volatility

Oil sands are relatively expensive to produce; a significant drop in oil prices may lead to poor economics for many existing and potential projects. The persistence of wider than average light/heavy differentials will negatively affect project economics for those producers marketing heavy blends.

Energy consumption

Both integrated mining and thermal in situ operations are intensive users of natural gas. Natural gas is an input to three steps of the production process. It is used as a fuel to generate electricity which in turn is used to power the mining equipment, produce the steam required for in-situ production, and produce the hydrogen used in upgrading the bitumen to SCO. Finally, condensates from natural gas are used as diluents to facilitate pipeline transportation of the bitumen. Currently the natural gas used is local production from the province of Alberta. However, with Canadian natural gas production declining and the needs of the oil sands industry increasing, it will be important to either find alternative sources of natural gas or alternative sources of energy for oil sands operations, and alternative sources of hydrogen for upgrading and refining of heavy oil sands products. Over the past several years, the price of natural gas has increased substantially.

High natural gas prices have encouraged oil sands operators to use gas more efficiently and to look for alternative fuels. A potential new source of natural gas could come from the Arctic if the Mackenzie valley pipeline project under consideration goes forward. A proposed alternative to natural gas is synthetic gas (syngas), a gaseous hydrocarbon stemming from the gasification of low-value heavy bitumen residues such as coke and asphaltine. The future price of natural gas and the development of alternatives will have a material impact on supply costs and project economics.

Project costs & Labour availability

Many projects have experienced serious cost overruns. The industry is working hard to reduce both capital and operating costs. Oil sands projects, particularly those involving upgrading facilities, are very capital intensive and project economics are extremely sensitive to capital costs. Operating costs for oil sands went from $19.6/barrel of oil equivalent in 2006 to $25.5/barrel of oil equivalent in 2010. Continued escalation in raw material and labour costs will have a material impact on supply costs and project economics. The oil sand industry has serious shortages of experienced skilled labour for both construction and operations that represents one of the biggest risks to its continued robust expansion

Pipeline capacity & other infrastructure

Proposals to develop new transportation capacity to markets in the United States and Asia face strong environmental challenges. Northern Alberta road and rail infrastructure is inadequate.

Diluents supply

The viscosity of the hydrocarbons produced from the oil sands is too high to allow for their transportation to markets. In most cases, diluents are added to reduce the viscosity of the mixture
to levels which allows for pipeline transportation. Diluents need to be delivered to the production areas in order to be added to the heavy oil. The volumes required depend on the properties of the diluents and its interaction with the extra-heavy crude. The supply of the traditional blending agent, pentanes plus, flat to declining, and demand from bitumen producers increasing, therefore the prices for diluents are rising. There are pipeline proposals to import the diluents into Alberta but that could transform the problem into one of capital expenses. The future cost of blend stock will affect project economics.

**The need to break into new markets**

Currently, the US is the largest market for Canada's oil sands. But long term, as the US begins to look for more energy self-sufficiency and renewable sources of energy, it will be important for Canada to consider other sources of demand in Asia and Europe. Being dependent on a single market is a risk as it leaves the country unprepared if its largest customer turns to a new supplier or is able to use a new product instead.

**Technology Development and R&D**

In the past, technology has enabled step-wise reductions in supply costs. Technology currently under development such as mobile crushing equipment and "at-the face" slurrying for mining projects, and solvent-aided production (SAP) and low-pressure SAGD for in-situ projects, have the potential to reduce operating costs significantly. In addition, improvements in upgrading costs are anticipated as new or modified upgrading technologies are employed.

Confronting the various environmental and engineering challenges will also require new technological breakthroughs. Experimentation on alternative technological paths is already very high, indicating that companies see long-term returns in this type of investment. In many ways, investments in oil sands projects require a simultaneous investment in R&D. The role of technology is bound up with projections for the oil price and the prospects for long-term carbon regulation, which in turn will likely affect the price. The oil sands remain a high cost source, and so seem vulnerable to a falling price and any scenarios in which world demand falls.
Conclusion

The Alberta oil sands constitute the world’s largest formation of bitumen. With an estimated total potential oil reserve value of 315 billion barrels there remains a substantial opportunity for development of the three major Alberta oil sands deposits found in the Athabasca, Cold Lake and Peace River regions of Alberta. These resources represent significant long-term oil production within a politically stable country currently linked through existing infrastructure to markets in the United States. The growth of oil sands development has also prompted new proposals to expand the existing TransMountain (TMX) pipeline and to build the proposed Northern Gateway pipeline in order to facilitate the export of oil to Asia from Canada’s west coast.

In 2010, Canada was the number one exporter of oil to the US supplying an average 1.9 million barrels a day, compared with 1.2 million from Mexico and 1.1 million from Saudi Arabia. Oil production from the oil sands is expected to more than double in the next 10 years, making Alberta one of the few places in the world where oil production is increasing. Along with this growth opportunity, however, there are also environmental and social challenges that will have to be faced and overcome.

Although renewable or “green energy” is increasingly important, it is still in its early stages of development and is, in the short and medium term, likely to be only a small contributor to the world’s overall energy portfolio. To date, liquid fuels required for transportation have been difficult to replace with alternative forms of energy so that liquid hydrocarbon fuels for transportation will be required for the foreseeable future. The oil sands represent a secure source of oil, developed within a strong and transparent regulated framework that can serve as a bridge to the future use of renewable energy resources.
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Appendix
Oil Sands New Royalty Framework

The new regime introduced on January 1, 2009 maintains the basic structure of the oil sands royalty system that has existed since 1997 under the so-called “generic regime.” Under this structure, a gross royalty is imposed on gross revenue for “pre-payout” oil sands projects, while a net royalty rate is imposed on net cash flow (which allows for the deduction of costs) for “post payout” projects. “Payout” occurs when the cumulative revenues from the project exceed the cumulative costs (both operating and capital), including a return allowance.

The key difference between the previous oil sands regime and the New Royalty Framework introduced in 2009 is the determination of the gross and net royalty rates applied to pre- and post-payout projects. Under the old regime the pre-payout gross royalty was a flat 1% rate and the post payout net royalty a flat 25%; in what follows this is sometimes referred to as the old 1/25 regime.

Under the new regime both rates are price-sensitive. Specifically, the pre-payout gross royalty rate starts at a minimum of 1% and increases in a linear fashion at the rate of 0.12308% per dollar increase in the price of West Texas Intermediate (WTI) oil in excess of $55 CAD per barrel, reaching a maximum of 9% at a price of $120. The post-payout net royalty rate starts at a minimum of 25% and increases linearly at the rate of 0.23077% per dollar increase in the price of oil in excess of $55 CAD per barrel, reaching a maximum of 40% at $120. Table-1 illustrates the price-sensitive rate schedules under the New Royalty Framework.

Definition Related to Oil sand New Royalty Framework

Gross Revenue:

The gross revenue of an oil sands project is the sum of all the quantities of oil sands products produced (e.g. bitumen from a mine or synthetic crude oil from an upgrader) multiplied by their respective prices (less the cost of any diluents included in product sales). The price is adjusted to take into account all handling charges, such as pipeline tariffs, terminal charges, processing charges, etc. that are paid to move the oil sands product from the royalty calculation point to the point of sale.

Net revenue:

Net revenue is the gross revenue less all allowed costs (operating and capital). These costs are 100% credited to the project in the year in which they are incurred.

Payout:

The net royalty component only applies after a project has reached payout. Payout is the point where the developer has recovered all the allowed costs of the project, including a return allowance on those costs equal to the Government of Canada long-term bond rate - LTBR.
Table 1
New Royalty Framework
Example of Oil sand Royalty Rate

<table>
<thead>
<tr>
<th>Price WTI C$/bl</th>
<th>Royalty Rate on Gross Revenue</th>
<th>Royalty Rate on Net Revenue</th>
<th>Price WTI C$/bl</th>
<th>Royalty Rate on Gross Revenue</th>
<th>Royalty Rate on Net Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Below C$55</td>
<td>1.00%</td>
<td>25.00%</td>
<td>C$ 88</td>
<td>5.06%</td>
<td>32.62%</td>
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<td>C$ 55</td>
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<td>25.00%</td>
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Upgrading Alberta’s Oil Sands: From Bitumen to Fuel

Alberta’s oil sands, the single-largest known deposit of petroleum in the world, pose an essential problem that has transfixed petroleum engineers for decades: what is the best way to produce usable oil from the tarry bitumen-rich soil?

Bitumen is a very heavy, carbon-rich form of natural oil, and needs to undergo extensive processing before it can be pipelined and used by oil refineries, most of which were designed to refine light or medium crude oil. The most prevalent method of processing is “carbon rejection,” which typically uses a coking process and produces a great deal of solid waste as a byproduct.

An alternative method, hydrogen addition, or “hydrocracking,” is a catalytic conversion process that produces almost no solid waste at all. Bechtel and Canadian subsidiary, Bantrel, have been engaged with Shell to expand the production capacity of Shell’s Scotford Upgrader near Edmonton, Alberta, from 167,000 to 277,000 barrels per stream day (BPSD). Shell uses Chevron-Lummus “LC-Finer” hydrocracking technology with integrated hydrotreating to efficiently upgrade Athabasca bitumen into premium synthetic crude that is easy to transport and refine.

Here’s how the upgrading process works:

1. **Transporting & Separating Bitumen**
   - Bitumen is separated from sand, water, clay, and other soil deposits in the extraction facility at the mine. It is then blended with a diluent for transport via pipeline to the upgrader site. Here, the diluent is separated, treated, and piped back to the mine.

2. **Initial Distillation**
   - Bitumen is distilled to separate the lightest hydrocarbons, such as naphtha, from heavy oils. The residue is further distilled to extract oils under vacuum conditions. The vacuum residue product is then sent to the LC-Finer.

3. **Ebullated Bed Hydrocracker (LC-Finer)**
   - The core of the upgrading process is the ebullated bed hydrocracker, which uses a catalyst to remove heavy metals and “crack” large hydrocarbons in the oil residue at high temperature and pressure. The cracked hydrocarbons recombine with purified hydrogen to create products that can be further treated to yield high-quality synthetic crude oil.
   - Catalyst particles have a limited life span due to metals and coke contamination. A portion of the catalyst is replaced daily, allowing continuous operation for several years.

4. **Atmospheric Distillation**
   - The oil-hydrogen mix leaving the LC-Finer is separated and the hydrogen with lighter cracked oils is sent to the hydrotreater. Heavier oil is sent to an atmospheric distiller to separate the cracked stock from the unconverted oil.

5. **Hydrotreating & Stabilization**
   - Vacuum gas oils and LC-Finer cracked oils are now routed to the integrated hydrotreater. Here, more hydrogen is added to further upgrade the synthetic oil and improve properties, such as its smoke point.
   - Hydrotreating removes chemical impurities, such as sulphur and nitrogen. This produces a very “sweet” premium oil that is easy to refine.

6. **Blending**
   - Finally, each output is blended to produce synthetic crude blends that are ready for pipelining to the refinery.

**Sidebar: The Oil Sands Process From the Mines to the Pumps**
- MINING
- CRUSHING
- SEPARATION & EXTRACTION
- UPGRADING
- REFINERY
- GAS STATIONS

**Appendix:** Visit our website for a full array of bullet points and a comprehensive description of the process from the mines to the pumps.