

The Canadian Oil Sands in the Context of the Global Energy Demand

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SUMMARY

The Canadian Oil Sands, one of the world's largest and most challenging oil resources, have reached their potential to supply oil to world markets. This comes at a time of the peaking of conventional oil and an expansive growth in energy demand. The need to protect the environment, and reduce greenhouse gas (GHG) emissions will severely test Canada's ability to grow the energy supplies from oil sands. This presentation focuses on the current methods and emerging innovations that are applied to produce and upgrade these unconventional resources to value-added products with a decreasing impact on the environment and GHG emissions.

THE OIL SANDS AND THE GLOBAL ENERGY PICTURE

The International Energy Agency (IEA) projects that global primary energy demand will increase by 1.6% pa from 2000 to 2030, reaching an annual level of 17.8 billion m³ (112 billion barrels) of oil equivalent. The increase will be equal to over 50% of current demand. The world will remain heavily reliant on traditional forms of energy with fossil fuels expected to supply over 80% of global incremental energy demand through 2030 [1]. The IEA has also, for the first time, sounded a serious warning regarding the increasing market tightness for oil beyond 2010 and predicts that OPEC's spare capacity will decline to minimal levels by 2012 [2].

By all accounts, conventional sources are declining with the majority of oil producing countries having reached peak of oil production and, globally, reserves are not being replaced with new discoveries. However, the world has over twice as much supply of heavy oil and bitumen than it does conventional oil. Not including hydrocarbons in oil shale, it is estimated that there are 1.3–1.5 trillion cubic meters (8-9 trillion barrels) of heavy oil and bitumen in-place worldwide, of which potentially some 10% are commercially exploitable with current and emerging technology [3]. Canada alone has an estimated initial volume of crude bitumen of 260 billion cubic meters (1.6 trillion barrels) with 11% or 28 billion cubic meters (175 billion barrels) recoverable under current economic conditions [4]. Current daily oil (bitumen and synthetic crude) production has risen to 180,000 cubic meters (1.1 million barrels). This figure is expected to more than triple by 2020 based on a moderate growth case [5].

There are a number of key factors enabling the current oil sands expansion: the increase price of oil due to high demand and declining reserves of conventional oil; the favorable fiscal investment climate in Canada; the potential of this vast resource with minimal finding costs; the proximity to the largest oil market in the world; and technological innovations that have significantly reduced the supply costs of bitumen and bitumen upgraded to synthetic crude oil. Production of the oil sands is dependent, however, on finding effective solutions and the technologies to address the risks associated with sensitivity to international oil prices, increasing production costs due to labor shortages, cost and availability of energy for both the

production of the resource and upgrading to higher valued products, market limitations, and land water, air, and increasingly, greenhouse gas issues.

PRODUCING “TECHNOLOGY OIL”¹

Oil sands are composed of a mixture of sand, clay and other mineral matter (80-85 wt. %), water (2 -10 wt. %) and bitumen (3 -18 wt. %). The oil sands are spread across over 140,000 square kilometers of Northern Alberta, Canada and are contained in sand and carbonate formations divided into four sections: Athabasca oil sands, Cold Lake oil sands, Peace River oil sands and Grosmont Carbonate. The bitumen in the oil sands has a density that exceeds 1,000 kg/m³ (°API less than 10) and is virtually immobile at reservoir temperatures (viscosities of the order of 1x10⁶ centipoise).

Table 1 summarizes the major current and future development projects in the oil sands in three deposits; at the present time there are no projects in the Grosmont Carbonate deposit. A description of each of the major deposits and the current and developing technologies used to extract and upgrade the bitumen to higher valued products is described in the sections that follow.

Table 1: Oil Sands Projects in Three Deposits[6].

Athabasca – Mining Projects			
Operator	Project	Initial, bbls/day	Potential, bbls/day
Syncrude	Base Plant	300,000	600,000
Suncor	Base Plant	280,000	550,000
Albian/Shell	Muskeg/Jackpine	150,000	500,000
CNRL	Horizon (2008)	110,000	232,000
Imperial	Kearl (2010)	100,000	300,000
Petro-Canada	Fort Hills (2011)	50,000	190,000
Athabasca – In Situ Thermal			
Japan Canada	Hangingstone	10,000	30,000
Suncor	Firebag	30,000	-
ConocoPhillips	Surmont	16,000	110,000
Devon	Jackfish	35,000	70,000
Encana	Christina/Foster	30,000	400,000
Husky	Sunrise (2008)	50,000	200,000
Opti/Nexen	Long Lake (2007)	70,000	140,000
Petro-Canada	Mackay River (2009)	24,000	60,000
Synenco	Northern Lights (2010)	50,000	100,000
Total	Joslyn Creek (2007)	10,000	200,000
Cold Lake – In Situ Thermal			
Imperial	Cold Lake	150,000	180,000
CNRL	Wolf Lake/Primrose	50,000	120,000
Blackrock	Orion - Hilda Lake	500	20,000
Husky	Tucker	18,000	35,000
Peace River – In Situ Thermal			
Shell	Peace River	12,000	100,000

¹ We have coined the term “technology oil” to describe the products derived from oil sands because technology development has been the key to allow bitumen to be produced at competitive costs.

Surface Mining – Athabasca Deposit

The Athabasca is the single largest oil sands deposit, occurring from the surface to a depth of 750 m. It is the only deposit where open-pit mining operation is possible currently to a depth of about 75 m of overburden. An important feature of the oil sands deposits is that the sand grains are generally surrounded by thin water film (estimated at about 10 nm) which makes separation of the bitumen from the sand facile and reduces the energy intensity of extraction, compared to oil-wetted deposits such as the Utah Tar Sands. These projects tend to be large compared to in situ projects to achieve economies of scale.

More efficient use of shovel and truck (as large as 400 tonne) has replaced draglines and conveyer system as the main method of mining the ore. The use of slurry pipeline achieves separation of the oil from the sand matrix during flow and is designed to transport the ore from a remote mine site to the plant. More advanced mining technologies are being developed including mine face extraction. In addition research into processes that substantially reduce water use, are underway. Fresh water use in extraction processes is a major environmental concern for surface mining operations. Typically 2 to 3 units of fresh water are used to extract 1 unit of bitumen.

Oil sands mining operations are integrated with upgrading of the bitumen to synthetic crude oil which is about equivalent in value to conventional oil entering a refinery. The preferred upgrading technology is coking following by hydrogen addition. Hydrogen is produced using steam-methane reforming (SMR). Since the cost of upgrading is the single largest investment in the oil sands value chain, there is significant incentive to develop the next generation technologies to reduce the capital costs, reduce CO₂ emissions and reduce natural gas use [7].

In Situ Thermal – Athabasca Deposit

Steam assisted gravity drainage (SAGD) has emerged as the only in situ technology proven to be technically feasible and economically attractive for the thick Athabasca oil sands bitumen below about 200 meters. It is the technology currently used by all in situ operators and the acceptance of the commercialization of SAGD led to the upward revision of the established reserves estimates. SAGD is a major “breakthrough” in technology and is the culmination of aggressive public and private investments in research and development and field trials, and have led to the current major growth period for the oil sands industry.

In SAGD operations, typically, two 1000 m horizontal wells are drilled within about 5 meters of each other. Steam at about 250°C is injected from the top well which rises to form a steam chamber with bitumen and condensate draining into the production well by gravity. At steam temperature the viscosity of bitumen reaches that of water and flows readily; depending on the reservoir pressure artificial lift methods may be used to “lift” the bitumen to the surface.

In current operations, natural gas is used to produce the steam and in situ thermal operation typically uses 176 m³ of natural gas/m³ of produced bitumen (1000 scf/bbl). There is an increasing cost for natural gas which is also the fuel of choice for upgrading, heat, and power. This comes at a time when natural gas supplies have reached their peak and are declining. In addition, increasing in situ production is the major cause in raising CO₂ emissions from oil sands operations. There are a number of process development technologies that are being developed for reducing CO₂ emissions, natural gas use and water use. These include the use of solvents to enhance SAGD and reduce steam requirements, VAPEX, the solvent analogue to SAGD, combustion processes, the burning of bitumen instead of natural gas and

electrical heating. A major “game changer” that is currently being applied by Opti/Nexen and is being considered by other operators, is gasification technology that use petroleum coke or bitumen residue as feedstock. Gasification can provide not only a source of heat for in situ production or extraction, power for operating the plant H_2 for upgrading but also a potential to access cheaper sources of CO_2 for carbon capture and storage. The Opti/Nexen project is unique in situ production and integrated upgrading that is self-sufficient in energy combining solvent deasphalting, thermal cracking, hydrocracking, gasification and cogeneration to produce a high quality synthetic crude oil. In the long run the potential use of nuclear energy or deep geothermal energy (“hot rock”) could also be used to substantially reduce natural gas requirements and CO_2 emissions.

In Situ Thermal – Cold Lake Deposit

Imperial oil is the dominant player in Cold Lake and is currently the largest in situ thermal producer in Canada. Cyclic steam stimulation (CSS) has been the preferred method of production involving the injection steam from single wells at sufficiently high pressure to cause parting of the reservoir allowing the steam to penetrate in channels to heat the reservoir and mobilize the oil. Following a soak period, the well is put into production and the heated oil and condensate flow back into the well. The process is repeated over several cycles. This technology requires similar amounts of natural gas per unit of production, as SAGD. The main advantage of CSS over SAGD is the more rapid reservoir response (higher initial oil rate). The main disadvantage is the lower ultimate recovery of about 25% compared to more than double that for SAGD. CSS is considered to be the most suitable for Cold lake formations while SAGD is most suitable for Athabasca formations.

In Situ Thermal – Peace River Deposit

Shell is the major lease holder and its holding contains over 1 billion m^3 of bitumen (7 billion barrels). A variety of thermal recovery technologies and well configurations have been tested over a number of years to overcome the difficulties associated with a bottom water zone. Current operations use multilateral horizontal cyclic steam stimulation technique and this technology is the basis of the major announced expansion. The environmental issues are similar to those described above for the other in situ thermal deposits.

CONCLUSIONS

Innovation has been the key to developing the immense and complex Canadian oil sands resources. Production is expected to more than triple by 2020 reaching about 0.6 million m^3/d (3.5 million bbls/d). As production increases, more advanced upgrading will be required to meet refinery specifications and increase value by co-producing clean fuels and petrochemicals.

New recovery technologies and “game-changers” will reduce and/or replace the use of steam based processes and provide options for natural gas displacement and CO_2 mitigation over the next 20 years. Gasification of coke/asphaltenes can replace natural gas and provides integration across energy systems creating value for all the hydrocarbon assets including clean power, source of heat and hydrogen in the oil sands industry, source of future fuels and allows for capture and storage of CO_2 , enabling enhanced oil and gas recovery to be expanded

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