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Technologies, Markets and Challenges for Development of the Canadian Oil Sands Industry

by

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This paper provides an overview of the current status of development of the Canadian oil sands industry, and considers possible paths of further development. We outline the key technology alternatives, critical resource inputs and environmental challenges and strategic options both at the company and government level. We develop a model to calculate the supply cost of bitumen and synthetic crude oil using the key technologies. Using the model we evaluate the sensitivity of the supply costs to the critical model inputs.

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1. INTRODUCTION

The Canadian oil sands resource has been under development since 1967 when the mining and upgrading operations of the Great Canadian Oil Sands project (now Suncor Energy Inc.) started in the Fort McMurray region of Alberta. For many decades the resource remained promising but inconsequential. Spurred by the recent increase in the world price of oil, the industry has begun to expand rapidly. Between 1998 and 2005, production nearly doubled from 0.59 million barrels/day to 1.06 million barrels/day, and annual capital spending grew seven-fold from C$1.5 billion to C$10.4 billion (CAPP, 2007). This rapid growth now strains the capacity of the regional labor market and construction industry, as well as several other sectors. Wages in Alberta are now rising at an annual rate of 7% and estimates suggest that up to 1 percentage point will be cut from the province's GDP growth due to the labor shortage (Emery, 2006 and Hirsch, 2006). Oil sands product already occupies a significant place in the North American market, and many projections have it playing a major role on the world market.

What are the technological and economic challenges that need to be addressed for this to happen? What are the choices for the path of development? This paper provides an overview of the current state of development and identifies the key challenges and choices facing the development of this resource.

2. CURRENT STATUS

The Resource

The category of petroleum resources known as 'heavy oils' or 'non-conventional oils' are often sorted into four classes. Medium heavy oils have an API gravity of 18-25 degrees, a viscosity of 10-100 cP (centipoise), are mobile in the reservoir and therefore can be produced using conventional technologies. Lloydminster Blend is one such Canadian medium heavy oil. Extra heavy oils have an API gravity of 7-20 degrees, a viscosity of 100-10,000 cP, and are also mobile at reservoir conditions. A major source of extra heavy oils is the Orinoco region of Venezuela. Bitumen contained in Canadian oil sands rank as a third class of heavy oils, with an API gravity of 7-12 degrees and a viscosity greater than 10,000 cP. Importantly, this is not mobile at the reservoir conditions, and therefore can't be produced using conventional oil and gas engineering; it requires either direct removal through mining operations or in-situ processing that enables flow in the reservoir. The final class of heavy oil is oil shale such as can be found in Colorado, among other places. This is in the form of rock in the reservoir, an obvious candidate for mining techniques, although in situ technologies are currently under development.

The Canadian oil sands consist in a blend of sand, water, clay particles and trace minerals (fines) blended with bitumen, a heavy and degraded form of oil. The sand is enveloped in a thin film of water containing the fines, with the film of bitumen wrapping the exterior and joining the particles together. To extract the hydrocarbon content, the primary challenge is to separate the water and the fines from the bitumen film, while maximizing the recovery rate of bitumen and minimizing fines and non-organic matter concentration in the hydrocarbon product.

The Canadian oil sands are located almost entirely within the province of Alberta and are concentrated in three distinct areas – Athabasca, Cold Lake and Peace River – forming a total surface of 14 million hectares. Inside each one of these areas, oil sands are found in concentrated in deposits where bitumen averages up to 73% of volume (10.7%

of mass), and average pay thickness varies from 5.4m to 30.5m.[1] The Canadian oil sands appears to be one of the largest potential sources of oil in the world. Based on geological data, initial volume in place is estimated at around 1,700 billion barrels. Using boundary conditions based on minimum mass concentration, minimum pay thickness and maximum depth of deposit amenable for current technologies, as well as projected bitumen recovery rates estimated from current operations, the Albertan Energy and Utilities Board declares 'established reserves' of 174 billion barrels.[2] The *Oil & Gas Journal*, one of several authoritative publishers of global reserve statistics, endorsed the definition and the reported number in its 2003 reserves report. At this size, the Canadian oil sands would rank as the second largest proven oil reserve worldwide, second only to Saudi Arabia conventional giant oilfields. Among the Western Continental Sedimentary Basin (WCSB) Canadian oil reserves, oil sands dwarf the 3.1 billion barrels of remaining conventional oil established reserves. Production of convention oil in the WCSB is declining: 2005 conventional production in amounted to 1.04 million barrels/day, down from 1.32 million barrels/day in 1998. Current annual production and proved reserves levels lead to production-to-reserves ratios of 450 years for oil sands, compared to 8.2 years for conventional oil (Alberta Energy and Utilities Board, 2006).

[1] It is the concentration of the Canadian deposits that makes them potentially economic to recover. There are also large deposits in Siberia, but these appear to be widely dispersed in small pools, making the prospect of economic recovery more remote (USGS, 2003).

[2] The Alberta Energy and Utilities Board gives the following definition of 'established reserves': "those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty". Caution is required in comparing reserves of essentially different resources as the economic meanings are very different. Proved reserves of conventional oil are generally much smaller than eventual production due to the uniquely high component of cost committed to exploration and development. For the oil sands, a larger component of costs are associated with production, so that the relationship between reserves and production is different. For extensive discussion of the economic meaning of different reserve definitions, see Adelman, et al., 1983.

Extraction Technologies

There are two main approaches to extracting bitumen from the oil sands: mining and in-situ production.[3]

Mining

By mining we mean extraction of solid materials and post extraction processing to isolate the bitumen from the water, sand, clays and fines. Mining operations consist in a mining step during which ore is extracted from the ground, and two separation steps that remove water, sand and fines from bitumen.

The operations start with tree clearing and the removal of the overburden to prepare the strip-mining face. Mining shovels of up to 100 ton capacity strip the mine face and fill giant mining trucks (up to 400 tons of capacity) with overburden until the ore seam is reached. To facilitate reclamation, overburden is disposed of in formerly mined areas. Shovels then start excavating the oil sands ore and filling the trucks, which ship the material to giant separation vessels.

In the primary separation step, oil sand ore is blended in cyclofeeders with heated water and chemicals and stirred to form slurry. During this physical process, called flotation, bitumen mixes with water and air bubbles to form a froth and separates from the bulk of solid tailings and water. Tailings are disposed of in settling basins and waste water is recycled to be used in flotation. Current research efforts are focused on improving the rate of bitumen recovery, accelerating the separation of water and fines from the oil phase, and improving the energy efficiency of the flotation process.

[3] The material in this section is largely taken from Alberta Chamber of Resources, 2004.

The froth is then shipped through hydro-transport pipelines to the secondary separation vessel, where, in a second purification step, it is usually treated with naphtha solvents and processed in centrifuges and separators. New techniques developed by the Shell-Chevron-Western Oil Sands joint venture, the Athabasca Oil Sands Project (AOSP), using paraffin solvents and settler vessels result in better separation of water and solids from the bitumen froth to produce purer bitumen.

Mining operations have been employed extensively since 1967 and have historically represented the bulk of oil sands production. Mining still accounts for more than half of production today. However, as the economics of the process depends significantly on the amount of overburden to be removed before reaching the ore, it is estimated that deposits ultimately recoverable through mining are limited to reserves no deeper than 75 meters, which represent only 18% of the total remaining established reserves.

In-situ production

In-situ production refers to any method by which underground processes directly separate the bitumen in-place from the geological sand frame, usually by heating it or by injecting solvents so that it can flow into a drilling well and be brought to the surface.

Historically, in-situ technologies using hot steam as a viscosity reduction agent have proven successful. The leading in-situ technology currently in use, and the first to reach full-scale industrial development, is steam assisted gravity drainage (SAGD). SAGD employs a pair of horizontal wells separated vertically by 5 meters and running through the seam on typical lengths of 1 to 2km. Steam water is injected under controlled pressure in the upper well for a period of weeks to months before the first oil is produced.

This injection creates a vapor chamber underground above the upper well and displaces the bitumen, which starts flowing along the edges of the vapor chamber. It can then be pumped into the second well and brought to the surface. This technology has proven very successful, with recovery rates frequently over 40%. It is, however, highly energy-intensive and requires substantial amounts of water, with steam-to-oil ratios of 2 to 3 barrels of heated water for every barrel of bitumen produced.

Another steam-based technology, developed before the advent of horizontal drilling techniques, is the cyclical steam stimulation process (CSS, also called ‘huff and puff’). CSS consists in a single vertical well, in which phases of steam injection alternate with phases of extraction of the heated (hence less viscous) bitumen. Current alternative technologies use the same principle with several wells, some reserved for steam injection, some for bitumen production. Horizontal wells have also been used in combination with CSS. Though it is more mature than SAGD, the technology could have a promising future. The high steam pressure used, it is well suited to exploiting deeper reserves (more than 300m). Recovery rates typically vary from 20% to 35% of the volume in place, and steam-to-oil ratios from 3 to 4, which implies even higher energy intensity than SAGD.

Some technologies currently under experimentation would use other factors than energy and steam to reduce bitumen viscosity.

Vapor extraction (VAPEX) is based on the same well structure as SAGD, but would inject hydrocarbon solvents instead of steam in the upper well. Under ideal conditions, such a solvent would vaporize underground and create a vapor chamber on the sides of which bitumen would flow and be drawn into the production well. The main advantages of such a technology is that it is less energy intensive than SAGD, however, it still faces major challenges, especially linked to the choice of solvents and their potential environmental impact.

Toe to heal air injection (THAI) is an infant technology that aims at igniting the in-situ gasification or combustion of the bitumen seam by injecting oxygen and water underground. Ignition of the reaction and sustained pressurized injection would create a moving combustion front, where the bitumen would undergo a reaction that separates heavy residues, in the form of coke, from the lighter fraction of liquid hydrocarbons underground. The pressure from the combustion front would allow the liquid to be produced in a second well, located downstream from the front progression. This technology would represent a clear breakthrough, notably because it would produce pre-upgraded products of higher value than bitumen. However, the technology poses substantial risks. Experiments with similar technology in underground coal gasification have resulted in accidents (U.K. Department of Trade and Industry, 2003).

While experimental technologies are still in an early phase of development, steam-based in-situ production techniques have been extensively deployed since a Shell pilot plant started in 1985 and now reach nearly half of oil sands production. In-situ extraction can prove profitable on deposits too deep for mining processes to tap. Such deposits represent 82% of the remaining established reserves. As horizontal drilling also allows in-situ technologies to be used in low depth deposits where they compete with mining technologies, the outlook is that their use is likely to become widespread in the next decades.

Treatment, Transport & Upgrading Technologies

Oil sands production is an upstream industrial activity that provides refineries with crude petroleum feedstock. But in its raw form bitumen is not ready to be used directly as a refinery feedstock, as it is still too viscous and heavy to be economically shipped through long distance pipelines.[4]

The first technological solution is to blend the bitumen with lighter and less viscous hydrocarbon solvents such as condensates, or pentanes plus, to facilitate its shipping. Blending alone yields a product known as DilBit for 'diluted bitumen' (around 30% of solvent per barrel of blend depending on quality and seasonal factors) which can be processed by refineries designed for heavy crudes.

The second technological option consists in upgrading the bitumen to a lighter synthetic crude oil (SCO). In this process, the heavy fractions of the bitumen are separated from lighter hydrocarbon elements. Two main technologies are used in upgraders: coking with hydro-processing, and hydro-cracking. In both cases, hydrogen is added to the molecules to crack the heavy carbon chains and yield lighter products. Residues from the operations are coke, a form of heavy solid hydrocarbon historically used in industrial boilers, and sulfur removed from the bitumen. The SCO produced by the upgrading process is hence a light (high API density degree) sweet (low sulfur content) feedstock.

Finally, hybrid options have been used to mitigate the effect of condensate prices on bitumen netback. Condensates and pentanes plus, as light hydrocarbons, typically

[4] The material in this section is largely taken from ACR, 2004.

trade at a premium over WTI. 'SynBit' is a blend of bitumen and SCO, and 'DilSynBit' is a blend of condensate, SCO and bitumen that have been sold by oil sands producers.

These different processing options are shown graphically in Figure 1.

Currently, the major outlet for Canadian oil sands product is refineries in U.S. PADD II (roughly the Midwest), where, as of 2005, 278,000 barrels/day of SCO and 259,000 barrels/day of blended bitumen is exported. The next major outlet is western Canada, where 272,000 barrels/day of SCO and 32 thousand barrels/day of blended bitumen are consumed. Eastern Canadian refineries take 60,000 barrels/day of SCO and 60,000 barrels/day of blended bitumen. U.S. PADD IV (roughly the Rockies) takes 76,000 barrels/day of SCO and 24,000 barrels/day of blended bitumen. U.S. PADD III (the Gulf coast) takes no SCO but 67,000 barrels/day of blended bitumen. Currently the U.S. east and west coast states take *de minimus* amounts of Canadian oil sands products. Exports off the North American continent are currently limited to trial quantities to test the capacity of certain refineries to process Canadian oil sands products.

The major transport pipeline in use is Enbridge/Lakehead serving U.S. PADD II and the eastern Canada Sarnia refinery with a capacity of 2.1 million barrels/day. The Kinder Morgan Trans Mountain pipeline has a capacity of 0.26 million barrels/day for transport to British Columbia and the U.S. west coast. The Kinder Morgan Express pipeline has a capacity of 0.28 million barrels/day for transport to U.S. PADD IV and II, the Rockies and the Midwest (National Energy Board, 2006).

Industry Structure

In 2005 the industry produced an average of around 1,060,000 barrels/day of bitumen. Of this, 59% or 625,000 barrels/day was mined, while 41% or 435,000 barrels/day was extracted in-situ. All of the mining companies have historically vertically integrated their operations with upgrading facilities. Consequently, mined bitumen was entirely upgraded to SCO, yielding 600,000 barrels/day of SCO. Of the in-situ production, the majority (431,000 barrels/day) was blended and sold as non-upgraded bitumen. For reasons linked to limited supply of diluent and transportation cost of bitumen through pipelines, the share of in-situ produced bitumen being upgraded before shipment is forecast to increase significantly as in-situ technologies to reach widespread development (Alberta Energy and Utilities Board, 2006).

Major mining operations

Suncor Energy, Inc.

Launched in 1963 as a quarter million dollar investment by the Sun Company of Canada under the name “Great Canadian Oil Sands Project”, Suncor Energy Inc. is today an integrated and publicly traded energy company, with refineries in Sarnia, Ontario and Commerce City, Colorado, and a retail network in Canada, the northeastern U.S. and Colorado, in addition to its oil sands operations.

Suncor Energy Inc. operates the Steepbank mines and the Firebag in-situ production facilities, near Fort MacMurray, and upgrades the recovered bitumen as well as third-party production to two blends of SCO (light sweet and light sour), with total capacity of operations estimated at 260,000 barrels/day (2006 production average). The company markets its SCO to the U.S. and eastern Canadian markets, and integrates its production with its Sarnia and Commerce City refineries, with plans to modify them in order to accept more oil sands into their crude diet.

Suncor's Voyageur project defines the company's growth strategy for the next decade. It includes the Millenium mine project, continued growth in in-situ production, the extension of the second upgrader (capacity is planned to reach 350,000 barrels/day of SCO by 2008) and the commissioning of a third upgrader (capacity would reach 550,000 barrels/day by 2012). This third upgrader is planned to utilize coke gasification technologies and so limit the company's demand for natural gas (Suncor, 2006 and 2007).

Syncrude

Established in 1975, this private joint venture—owned 37% by Canadian Oil Sands Trust, 25% by Imperial Oil, 12% by Petro-Canada, 9% by ConocoPhilips, and 17% by other investors—started its integrated mining/upgrading operations in 1978. It currently runs truck and shovel mining operations in the Mildred Lake and Aurora mines, near Fort MacMurray, linked by hydro-transport pipelines to the Mildred Lake Plantwhere the extraction, coking and upgrading is done.

Until recently, Syncrude produced 258,000 barrels/day of Syncrude Sweet Blend (SSB), a light sweet synthetic crude oil. Debottlenecking of the upgrader having been recently completed, they forecast production of 350,000 barrels/day in 2007. Production of a higher quality SCO branded Syncrude Sweet Premium is also scheduled to start in 2007. (Market Watch, 2007)

Albian Sands, Inc.

Albian Sands Inc., a joint venture between Shell Canada (60%), Chevron (20%) and Western Oil Sands Inc. (20%), runs the Athabasca Oil Sands Project (AOSP), the latest fully integrated oil sands mining/upgrading project to start production. This operation includes the Muskeg River Mine near Fort MacMurray, and the Scotford upgrader in Fort Saskatchewan, Alberta, 493km south from the mines and next to Shell Canada's Scotford refinery. Blended bitumen produced at the mines undergoes a secondary extraction step using paraffin solvents and is blended with diluents. It is then shipped through the Corridor Pipeline (owned and operated by IPL Inter Pipeline) down to the upgrader. Premium Albian Synthetic and Albian Heavy Synthetic blends are sold to Shell's Scotford refinery and to Chevron's Salt Lake City and Burnaby refineries.

Production of SCO was estimated at 155,000 barrels/day in 2006. Plans to increase the capacity of the Scotford upgrader have been approved by the regulator, and production could increase to 200,000 barrels/day. Chevron announced its intention to acquire additional mining leases, which, due to a mutual interest agreement between the parties of the venture, would most likely be incorporated into Albian Sands operations.

CNRL Horizon project

CNRL is currently commissioning a C$10.8 billion integrated mining/upgrading project. Nominal capacity should be 232,000 barrels/day of SCO after completion of Phase 1, and is expected to produce the first oil by the end of 2008.

Major in-situ operations

Table 1 presents the major in-situ operations currently operating in Alberta. Production of crude bitumen is split evenly between CSS and SAGD technologies due to the historic role of CSS in the development of in-situ methods, but new projects are predominantly projecting to use SAGD technologies. Petrobank's Whitesands plant will, however, deploy at pilot scale the first THAI oil sands production facility, producing 1,800 barrels/day of bitumen partially upgraded underground, and this alpha plant will have a major echo on the technological choices of new entrants.

Major companies active in in-situ production of bitumen are the following.

Imperial Oil

Imperial Oil Ltd (nearly 70% owned by Exxon Mobil) is an integrated petroleum company operating primarily in Canada in exploration, production, refining and sales. The company is the major in-situ producer of oil sands, with the Cold Lake oil sands project, deploying conventional ("cold") and CSS production technologies

Canadian Natural Resources Ltd. (CNRL)

Canadian Natural Resources Ltd. is an independent Calgary-based oil and natural gas exploration and production company. The company is the major in-situ producer of oil sands, with conventional ("cold") and CSS production projects in the Cold Lake, Wolf Lake and Pelican Lake areas.

EnCana Corp.

EnCana Corporation (EnCana) is an international natural gas and oil exploration and production company. EnCana is also present in transportation and marketing, as well as in refining. EnCana is involved in oil sands operations through conventional, SAGD and CSS production facilities.

Petro-Canada

Petro-Canada is a Canadian oil and gas exploration and production company, integrated into a leading national refining and retail sales network. It is involved in oil sands through its in-situ production operations on the MacKay River lease.

Opti/Nexen Long Lake project

The Long Lake project is an integrated SAGD/upgrader project currently under construction by Opti Canada Inc. and Nexen, a global exploration and production energy company. The unique feature of the project is that it will use gasification of the heavy bitumen residue from the upgrader to provide fuel and hydrogen to the plant operations. This plant will be the first fully-integrated design of this kind. Production is expected to start by the end of 2007. The nominal capacity of the project is set at 60,000 barrels/day.

Other Major Projects

Husky Energy Lloydminster upgrader

Husky Energy Inc. is an oil and gas exploration and production company operating a stand-alone upgrader that turns crude bitumen into a light sweet blend. Lloydminster upgrader, with 80,000 barrels/day capacity, processes raw bitumen from mining and in-situ production facilities in the Athabasca area. A project to double the capacity of the upgrader to 150,000 barrels/day by 2010 is currently under consideration (Husky, 2006).

3. NEAR-TERM CHALLENGES

Several critical inputs are required in order to extract the bitumen from oil sands and process it into a product that can be sold and readily shipped to refineries. Continued expansion of the industry requires development of supply for each of these.

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. Natural gas is also the source of the hydrogen used in upgrading. Finally, condensates from natural gas are used as a diluent 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 (17.4 billion cubic feet/day peak in 2002, forecasts for 2020 around 10 million cubic feet/day), 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. 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 asphaltenes. Gasification consists in an incomplete combustion of hydrocarbons at high pressure and temperature in the presence of steam. Due to a default of oxygen in the reactor, molecular bonds are fully broken without realizing full oxidation of carbon and hydrogen. The process produces a mix of CO_2, H_2, and CO, which is shifted to syngas (CO_2 and H_2) through steam reforming. The hydrogen content of the gas can then be used as a feedstock for upgrading operations, and as a heating fuel for bitumen separation processes in mining operations or for steam production in SAGD.

If executed properly, development of this technology has the potential to provide an alternative to natural gas while utilizing low-value oil bitumen residues. Gasification processes are already being seriously examined by the electric power generation industry due to their role in innovative coal technologies, and developments in this arena are likely to benefit oil sands production. Gasification, however, is not yet deployed at industrial scale, and the difficulties inherent to the design of gasification boilers raises major reliability issues. The Long Lake Project, the first integrated upgrader/gasifier plant currently jump-started by OPTI/Nexen, will, for example, rely on three redundant boilers, using only two of them at nominal capacity.

Nuclear power is also being considered as an alternative source of electricity and for the direct production of steam for in-situ operations. The cost effectiveness of nuclear power depends on factors unrelated to the particularities of the Canadian oil sands—uncertainty on the capital costs, for example—as well as on factors that are particular to this development. One critical problem is the efficient scale of a nuclear power plant relative to the amount of steam required within the range of any location. It is too inefficient to transport the steam over long distances, so it would be necessary to identify locations with a significant concentration of bitumen reserves (Dunbar and Sloan, 2003). Alternative approaches to this problem of scale include (i) plans to utilize significant portions of the nuclear power for the generation of electricity instead of steam, and the transport of this electricity out of the province, as well as (ii) the consideration of radically different nuclear power plant designs of a significantly smaller scale. Neither alternative is an option available at the current time. Most recently, Royal Dutch Shell has reportedly been considering use of nuclear power as a means to implement a new technology for in-situ production involving electric heaters inserted into the ground (Globe and Mail, 2007). In considering the use of nuclear power, account must be taken of the fact that the province of Alberta currently lacks any nuclear regulatory authority.

Water

Water is another critical input whose supply needs to be assured, both for mining and for in-situ production operations.

Despite some marginal recycling of the water used in flotation, mining operations withdraw 2 to 4.5 barrel of water from the Athabasca River for each barrel of SCO produced, and dispose of the downstream polluted water in tailing ponds. Established oil sands mining projects are already licensed to divert 395.7 million cubic meters of water per year from the Athabasca River (Brooymans, 2007), and this is expected to grow to 529 million cubic meters a year given already planned projects (National Energy Board, 2006). Although the river has an average flow of 20 billion cubic meters per year, the flow rate is highly seasonal, with an average flow in winter months of less than 6.5 billion cubic meters per year equivalent on average. Therefore planned projects at average operating levels would be withdrawing approximately 8% of average flow; in times of low flow, the diversions would represent an even greater fraction of flow. Under the Athabasca River Water Management Framework, a new scheme defines limits on withdrawal allowances, including special limitations in periods of low flow which will constrain operations of these planned projects (Alberta Environment, 2007).

In-situ production is also based on extensive use of water, even though high recycling rates (90-95%) lead to the withdrawal of only 0.2 barrel of water from freshwater aquifers per barrel of bitumen produced. Demand for fresh water linked to in-situ production processes is however predicted to rise from 5 to 16 billion cubic meters per year from 2006 to 2015 if all announced in-situ projects reach nominal capacity on schedule. (National Energy Board, 2006)

Environmental concern may become an even more important constraint than competing uses of water. Downstream from the oil sands area, the Athabasca River feeds into Lake Athabasca through the Peace-Athabasca Delta, south of Wood Buffalo National Park. The region was designated in 1983 a UNESCO World Heritage Site for the biological diversity of the delta and the fact that it is the largest inland delta in the world. Water flow and quality are hence under close scrutiny from governmental and non-governmental groups. Developing additional sources of water supply or alternatives to the current water-intensive processes remains an important short-run challenge to the development of the industry.

<u>Labor and Capital Constraints</u>

The current rate of expansion of the industrial operations in the oil sands territories is placing great strains on the existing labor supply, construction capacity and other factors involved in major investment projects.

Labor shortages are consistently reported by the press in Alberta. Petroleum Human Resources Council estimates that 8,600 new positions will be created during the next 10 years in the oil sands industry, more than doubling the current direct employment level of 7000 jobs (Petroleum Human Resources Council, 2004). The need for very specific skilled labor in the construction and upstream oil and gas industry leads to rising wages and skills shortages. The average wage for an oil and gas industry worker in Alberta is C$29.49 per hour. In the economic region of Wood Buffalo-Cold Lake, this hourly wage is estimated at C$39.15 per hour (2005 figures, source Alberta Learning Information Service 2006), nearly twice more than Canada's average wage of C$19.61 per hour (February 2006, source Statistics Canada 2007a). Oil companies have resorted to "fly-in" policies as they organize airline transportation of workers from other parts of the nation back and forth to their monthly shifts. The pressure on wages and prices in the oil sands region has a perceivable impact on the regional economy: from January 2006 to January 2007, Alberta experienced a 3.9% Consumer Price Index inflation, compared to the national average of 1.2%. The Province's total employment grew by 3.9% compared to national growth of 2.0% since 2004. (Statistics Canada, 2007b and 2007c)

More generally, one observes a bottlenecking of the infrastructure of the entire oil sands region. Traffic on the section of Highway 63 between Fort MacMurray and Suncor increased by 200% from 4,300 daily vehicle movements in 1996 to 13,100 in 2005 (Alberta Employment Immigration and Industry, 2006). As forecasts predict that Fort MacMurray's population would increase from 56,000 residents in 2005 to 80,000 by 2010, notwithstanding 7,000 to 10,000 temporary construction workers, a stakeholder group composed of representatives of the industry and the inhabitants of the Wood Buffalo District (which includes the oil sands development areas) estimated at about C$1.2 billion the level of public expenditures needed over the 2005-2010 period. Funding needs comprise most notably of C$500 millions for highway development, C$375 millions in health, education and low income housing, and C$350 millions in municipal projects including water sanitation and road development. (Athabasca Regional Issues Working Group, 2005)

The strong pressure on the local infrastructure caused by oil sands rapid development, coupled with the high level of skilled labor utilization needed to sustain construction of the current projects, has resulted in escalating capital costs for oil sands ventures. Most current projects have experienced cost overruns or costly delays. For example, OPTI/Nexen reported that the Long Lake project may end up costing 20% more than the initial forecast of C$3.8 billion, Suncor announced a forecast cost of $7.8 billion up from an earlier estimate $5.7 billion for the completion of its step 3 extension, and the Athabasca Oil Sands Projects announced a 70% increase in the expected price of its mining extension project to up to C$12.8 billions. These important costs overruns, with the potential to seriously alter the economics of such capital-intensive projects, have led some companies to adopt an incremental development policy for their infrastructure, an approach that fits SAGD production better than mining and upgrading.

CO2

In addition to the need to secure critical inputs, the industry must also address the nature of its outputs. Prime among these is CO_2, since the production from the Canadian oil sands entails more emissions of CO_2 than conventional oils. A portion of these incremental emissions occur in the process of extraction. Mining operations emit 30 to 40 kg of CO_2 equivalent per barrel of SCO end-product, while SAGD operations emit around 60 kg of CO_2 equivalent per barrel of SCO end-product (Flint, 2004). For mined bitumen total CO_2 emissions are smaller than for bitumen extracted in situ. However, a larger fraction of the CO_2 emitted in the mining process is emitted from diffuse sources where the future prospect of capturing the CO_2 is dimmer (Pembina Institute, 2006).

A second source of the incremental CO_2 emissions occurs in the upgrading process, where 50 to 80 kg of CO_2 equivalent is emitted per barrel of SCO produced, depending on the quality of the SCO refined. It is worthwhile noting that, if the anticipated move toward residue gasification and shift to higher quality SCO (from 32 to 40 API density) occurs without adding CO_2 capture capacity after the gasification process or the coke boilers, the 80 kg of CO_2 per barrel of SCO emission profile would become widespread in the industry, and SAGD technology could emit up to 100 kg of CO_2 per barrel SCO produced (Flint, 2004).

Emissions from the production and processing of the oil are small compared to emissions from the combustion of the refined oil products. Therefore, a full wells to wheels comparison of CO_2 emissions from oil sands products versus conventionally produced oil shows a relatively smaller differential. Table 2 presents the results of an analysis done by McCann & Associates in 1999 showing that this full CO_2 emissions from oil sands products are between 12 and 16% more than from conventional light Canadian crude oil.

Nevertheless, Canada will have to concern itself with the CO_2 emissions from the production of the fuel. In 2003, the oil sands industry accounted for 3.4% of Canada's total CO_2 emissions. Under current forecasts, this could reach up to 7.5% to 8.2% of Canada's business-as-usual emissions, or 11.0% to 12.1% of Kyoto target emissions, by 2012 (Pembina Institute, 2006). The government of Alberta recently presented Bill 3 of the Climate Change and Emissions Management Amendment Act, a plan aimed at curbing the emission intensity of major carbon emissions industrial sources of the Province. Under the pending legislation, every company emitting more than 100,000 tons of CO_2 per year (a threshold corresponding to 2,000 to 4,000 barrels/day with mainstream oil sands production technologies) is required to decrease its CO_2 emissions intensity by 12% from July 1, 2007. Excess emissions above the 12% requirement will be sanctioned by a C$15 per kg CO_2 mandatory payment to the new Alberta-based climate change fund (that will invest in technology to reduce greenhouse gas emissions in the province), or to any Alberta-based, third-party certified, carbon emissions reduction project (Government of Alberta, 2007). The Federal government also recently announced its proposals for reducing greenhouse gas emissions which involve targeted reductions in carbon intensity and opportunities to trade or obtain allowances valued at C$15-20 per ton CO_2 (Canadian Ministry of the Environment, 2007).

The prospect of future and ever tightening caps on total CO_2 emissions and increasing cost of CO_2 has the potential for undermining the favorable economics behind the exploitation of the oil sands. Integrated SAGD/upgrading, which would be the most heavily impacted technology, could see its supply cost rise by up to US$5 per barrel of SCO in the face of a US$30 per ton cost for CO_2.

The development of a viable carbon capture and storage industry could play a significant role in securing the future economics of the industry. Gasification offers good prospects on this front since the syngas is produced at high pressure and high concentration of CO_2, which would facilitate capture. Carbon dioxide could also be used in enhanced oil recovery technologies for mature WCSB conventional oil fields:

Alberta's government has recently proposed to invest several million dollars in a C$1.5 billion dollars pipeline project that would ship CO_2 from oil sands projects to mature oil fields for that purpose (Ebner, 2007).

Product Markets

The bitumen produced from the Canadian oil sands is strongly weighted to a profile of heavier products. In particular, it yields a large volume of residue. Upgrading it to SCO currently involves producing a large volume of low value coke. The price of bitumen at Cold Lake, for example, averages approximately 50% of the price of WTI, with a significant seasonal effect due partly to bitumen viscosity variations with temperatures, which entail variability in the share of condensate blended with the bitumen.

New technologies that make it possible to extract higher value products from the raw bitumen may play an important role in securing the value of the oil sands resource. In particular, gasification of the residue holds the possibility of delivering both higher valued end-products, as well as relieving the shortage of local sources of natural gas. Of course, this process, too, implies significant emissions of CO_2, so that the development of a carbon capture and storage industry operating at full scale is a necessary ingredient.

Another problem in the product markets is the limited ability of geographically accessible refineries to accept oil sands crude products. Traditional heavy, medium and light refineries have been optimized to function with a specific diets of crudes that is often at odds with what the oil sands deliver. A lack of light fractions, significant sulfur concentrations and excessive share of bottoms and vacuum residues limits the potential use of bitumen blends by heavy and medium-heavy sour refineries to around 20% of inputs. Poor quality of distillates and excessive content of aromatics also significantly reduces the share of SCO most sweet light refineries can incorporate into their crude diet—rarely more than 20% (Laureshen et al., 2004).

In the near term, this limitation can be addressed by expanding the market geographically. Refinery capacity for oil sands product is already saturated in the U.S. Midwest market, PADD II, and therefore producers are looking to diversify outside this region. Kinder Morgan plans to expand its existing 225,000 barrels/day TransMountain (TMX) oil pipeline from Edmonton to refineries in Washington State, expecting to add 75,000 barrels/day capacity by 2008 and eventually reaching 700,000 barrels a day.

Longer term projects to access more distant markets are also envisioned. Enbridge is projecting the construction of the Gateway pipeline, a C$4 billion, 400,000 barrels/day transportation line that could run from Alberta to a Canadian west coast deepwater port by 2014 (Dow Jones Energy Service, 2007). From there, oil sands production could reach California, whose traditional supply from Alaska's North Slope is declining. Asian markets could also potentially become an important outlet, as Japanese and Chinese refiners have the technical ability to use more SCO in their input mix (Laureshen, at al., 2004).

There is also significant interest in extending pipeline capacity into the US Gulf Coast to allow Canadian oil sands product to be used in the Gulf Coast refinery industry. Alberta-Texas Company (Altex) has been projecting since 2005 the construction of a 250,000 barrels/day high-speed pipeline that would run from Fort McMurray through Hardisty to the Houston area. The project would be based on a confidential diluent technology that would not involve the use of condensate, the low-cost supply of which is a long run concern for the industry. The company estimates that the 3,800-kilometer project could cost between C$3 and C$4 billions, and currently seeks to finance the project by 15 to 20 years long-term agreements with shippers. Construction has been pushed back by at least one year after the original plan of 2008, and the project is currently not expected to come on line before 2011. Meanwhile, Enbridge disclosed in July 2006 that it was considering the construction of C$3.6 billions pipeline from Alberta to Texas, or could opt for the acquisition of existing assets that it would retrofit to oil sands products transportation (Dutta, 2007; Harrison, 2006; Park, 2007; Platts Commodity News, 2007). Transcanada has also announced its plans to develop the Keystone pipeline running from Hardisty, Alberta to Patoka, Illinois and possibly south near Cushing. The pipeline is projected to cost approximately US$2.1 billion and would ship 435,000 barrels of crude per day. Conoco has agreed with Transcanada to ship on the pipeline. The Keystone pipeline could be in service in 2009 (Globe and Mail, 2006).

A second long-term approach is new capital investment downstream that is suited to utilizing oil sands crude products. For example, BP announced in 2006 that it would reconfigure its Whiting, Indiana, refinery to take 350,000 bpd of Canadian heavy oil, and EnCana announced a $15-billion joint venture with ConocoPhillips to supply the 400,000 bpd of heavy oil to the latter’s refineries in Illinois and Texas (Polczer, 2006).

As North America shifts to a heavier profile of crude supplies, while simultaneously demanding higher refined product qualities and potentially limiting carbon emissions, companies will need to outline an upstream/downstream strategy that maximizes return on capital investments. Every company involved in major operations in the Canadian oil sands needs to decide whether and how to integrate the upstream production from the oil sands with downstream operations. A key aspect in this is the degree of vertical integration required—how large a presence is required both at the up- and the downstream portions of the business, and what forms of contractual and other business relations are necessary between the up- and downstream businesses. Will long-term supply contracts be necessary in order to encourage refineries to make the capital investments necessary for them to increase the share of oil sands based products in their crude diet? Companies will look to pace upstream project development together with the gradual transformation of downstream refining facilities so as to avoid margin squeezes. But what role does preemption play, and how can a company succeed in capturing a large portion of the growth in development of the oil sands, while avoiding the margin squeeze?

Finally, some within the industry have targeted the development of standardized product streams as an important tool to expand the product market and raise the value of the oil sands. A consortium of Canadian production and marketing companies (EnCana, CNRL, Petro-Canada and Talisman) have gathered to create a standardized stream of crude oil branded as West Canadian Select (WCS) and aimed at the U.S. midwestern market through Husky's Hardisty hub (EnCana, 2007).

What is the real purpose behind standardization? Why is the diversity of the product streams a problem? Is the result simply a diverse set of prices? Or does the diversity of products actually lower the total value of what is produced? Is the pursuit of a standardized product stream a valuable effort to which the major players in the region should contribute resources? From an industrial point of view, a standardized stream presents the advantage of reducing quality deterioration risks by virtue of the increased volume of the shipment, and using a SynBit blend would mitigate long-term diluent supply constraints bearing on the industry (Paterson, 2005). From a financial perspective, a recognized standard stream would increase liquidity on the spot market, thus potentially allowing the creation of a futures contract that could help the industry to thrive. Production of the WCS stream averaged 250,000 barrels/day by the end of 2006 (compared to around 350,000 barrels/day for Brent and WTI, the two widely recognized benchmarks), and producers are currently pursuing discussions about a potential futures contract on the NYMEX, TSX or ICE (Calgary Herald, 2006 & 2007).

Technology Development and R&D

Oil sands production remains a relatively high cost source of refined products. Full exploitation of the resource is likely to require repeated introduction of newer technologies over time that lower the cost of production. 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 (Alberta Chamber of Resources, 2004 and Flint, 2004). 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.

Government Actions

The main strategic questions facing the government are (i) what forms of support and enabling activities—such as infrastructure investment—will maximize the collective benefits from the resource, (ii) how to protect the long-term environmental assets of region, (iii) what role can the government usefully play in the arena of technological development, and, (iv) how to engage with an evolving international carbon regulatory system.

The government already provides critical subsidies to the industry in the form of accelerated depreciation of capital expenditures and favorable royalty regimes (Commissioner of the Environment and Sustainable Development, 2000). These supports were arguably a useful tool for bringing the resource as a whole through an infant stage. But in the present situation, where there are more projects competing for scarce capital and labor resources, and where the constraint appears to be on the rate of development, some have argued it is time to end these supports (Pembina Institute, 2006 and 2007). Indeed, as the pace of development places demands on local governments for various services, the tax funds necessary to pay for this infrastructure must come from somewhere and the argument is made it should come in no small part from the exploitation of the resources itself.

The government can also play a key role in facilitating access to new and different markets. For example, the decision on whether to develop a new pipeline route to the Canadian west coast will require both private investment and government support at various levels.

4. ESTIMATING SUPPLY COSTS IN THE OIL SANDS

Constructing a Cost Model

We constructed a discounted cash flow model to compute the supply cost of blended bitumen and SCO, i.e. the levelized price for end products that exactly covers all costs, including the required rate of return on capital. Our calculations are in real terms, i.e., constant dollars using 2005 as the base year. We model separately (i) in-situ production of bitumen using SAGD where the bitumen is blended 2:1 with condensate to yield DilBit, (ii) an integrated mining and upgrading operation producing SCO, and (iii) operation of a stand-alone upgrader. The model can be used to calculate the rate of return earned on each technology given an assumed price for end products, or alternatively can calculate the levelized product price required in order to generate a minimum return. It is this levelized price that we call the supply cost. We calculate a levelized price for bitumen—actually a netback from the price of the DilBit—and for SCO. In both cases, for reference purposes, we translate this supply cost of bitumen or SCO to an equivalent WTI crude oil price in Cushing Oklahoma using assumed product quality and transportation spreads. A copy of the spreadsheet can be downloaded from the MIT CEEPR website where this paper is found.[5] The design of the model was informed by the one discussed in the Canadian National Energy Board reports (2004 and 2006); however, those reports are not explicit about all of the details of the model.

Table 3 details the key assumptions used to model the three technologies. We are explicit about whether the input figures are denominated in Canadian or US dollars. Results are quoted in US dollars.

[5] http://web.mit.edu/ceepr/www/workingpapers.htm

For the SAGD technology, we assume a plant design producing 120,000 bbl/d of bitumen at full scale, blended 2:1 with condensate to produce 180,000 bbl/d of a DilBit. Production ramps up in four three-year steps starting from the beginning of the project: i.e., for t=1–3 bitumen output is 0, for t=4–6 it is 30,000 bbl/d, for t=7–9 it is 60,000 bbl/d, and so on. Annual capital expenditures are C$150 million per year until full scale production, i.e., for t=1–12. A constant stream of C$30 million in recurring capital expenditure is allocated to rolling-over capacity—new drilling operations to replace wells that become depleted in years t=13–42. The analysis stops in year 42 with a zero salvage value. The project has a steam oil ratio of 2.5 bbl water/bbl bitumen, steam production requires natural gas of 0.42 Mcf/bbl water. Translating from 0.975 Mmbtu/Mcf, each barrel of bitumen requires 1.02375 Mmbtu of natural gas. Other operating costs are C$3.5/bbl bitumen. Although our base case involves no cost of carbon, this can be changed, so we note that the process produces 0.05 tons of CO_2/Mcf gas, or equivalently, given our steam and gas assumptions, 0.0525 tons/bbl bitumen.

For the integrated mining and upgrading technology, we assume a plant design producing 200,000 bbl/d of light sweet synthetic crude oil. Initial capital costs are C$10 million per year for t=1-8. First oil begins in year 5 of the project at 100,000 bbl/d for t=5&6, shifting to full scale for t=7–45. Additional recurring capital expenditures are required at a rate of C$1.25/bbl produced, i.e., for t=5–45. Production requires natural gas of 0.75 Mcf/bbl or 0.73125 Mmbtu/bbl. Other operating costs total C$12/bbl. The process produces 0.117 tons of CO_2/ bbl SCO.

For the standalone upgrader technology, we assumed a plant design producing 200,000 bbl/d of SCO directly from bitumen. It is difficult to benchmark cost assumptions for a standalone upgrader since only one is currently in operation and its economic performance is blurred by the fast growth in operations over the last two years. Moreover, the many new projects being considered employ highly variant technologies. We start from the Canadian National Energy Board reports, 2004 and 2006, and incorporate an adjustment to reflect the fact that capital cost overruns have become widespread and significant in upgrading projects over the last two years. We set initial capital costs at C$7,500 million in equal increments over eight years, t=1-8. Production begins at 100,000 bbl/d in years t=5&6, shifting to full scale for t=7-45. Additional recurring capital expenditures are required at a rate of C$0.625/bbl SCO produced, i.e., for t=5–45. Production requires natural gas of 0.47 Mcf/bbl or 0.45825 Mmbtu/bbl. Other operating costs total C$5/bbl. The process produces 0.78 tons of CO_2/ bbl SCO.

These technology assumptions are complemented by a set of assumptions about market prices and other relevant economic variables as shown in Table 4. We initially assume the benchmark price of WTI for delivery at Cushing, Oklahoma, of US$50 per bbl, and calculate returns under this assumption. Later we reverse the process and calculate the required value for this benchmark crude at which each technology can earn its required rate of return. We assume the benchmark price of natural gas traded on the AECO intra-Alberta market of US$7 per Mmbtu, and the exchange rate of 0.85 US$/C$. We then assume a set of quality spreads that set the prices or netbacks for SCO, DilBit, diluent and bitumen as a function of the WTI price. We also assume a set of transportation differentials that tie together the prices of these products and the benchmark prices at various locations.

We treat the price of SCO as determined in the refinery market near Chicago in competition with WTI. Therefore we first apply a quality spread that is a constant percent which we set to zero so that the two are essentially equivalent in the Chicago crude market. We then make an adjustment for differential transportation costs from Cushing to Chicago and from Edmonton to Chicago. This sets the price for SCO in Edmonton. We then apply a transportation spread to get the price at the plant gate. Therefore, the netback on SCO at the plant gate is equal to:

WTI @ Cushing, OK	US$ 50.00
– quality spread (SCO v. WTI in % discount)	0%
– transportation spread (Cushing to Chicago v. Edmonton to Chicago)	US$ 1.00
– transportation spread (Edmonton to the plant gate)	US$ 0.60
= SCO netback @ plant gate	US$ 48.41

For bitumen the netback at the plant gate is the difference between the value of DilBit at the plant gate and the cost of the diluent required. In order to calculate this, we first need to calculate the value of DilBit at the plant gate. We treat the price of DilBit as essentially comparable to the price of Lloydminster, a conventional heavy crude oil quoted in Hardisty. The price of DilBit (Lloydminster) is also set in the refinery market near Chicago in competition with WTI. Therefore we first apply a quality spread that is a constant percent: we set this to 30%. We then make an adjustment for differential transportation costs from Cushing to Chicago and from Hardisty to Chicago. This sets the price for DilBit (Lloydminster) in Edmonton. We then apply a transportation spread to get the price at the plant gate. Therefore, the netback on DilBit at the plant gate is equal to:

WTI @ Cushing, OK	US$ 50.00
– quality spread (Lloydminster v. WTI in % discount)	30%
– transportation spread (Cushing to Chicago v. Edmonton to Chicago)	US$ 1.25
+ DilBit transportation spread (Hardisty to the plant gate)	US$ 0.98
= DilBit price @ plant gate	US$ 32.77

The price of diluent (condensate) is quoted in Edmonton where it is benchmarked against a notional WTI in Edmonton—WTI in Cushing with an adjustment for differential transportation costs from Cushing to Chicago and from Edmonton to Chicago. Therefore the price paid for diluent at the plant gate is:

WTI @ Cushing, OK	US$ 50.00
– transportation spread (Cushing to Chicago v. Edmonton to Chicago)	US$ 1.00
+ quality spread (Diluent v. WTI in % premium)	10%
+ diluent transportation spread (Edmonton to the plant gate)	US$ 0.68
= diluent price @ plant gate	US$ 54.58

Given the price of DilBit (Lloydminster) and of diluent (condensate) we can determine a netback for bitumen at the plant gate:

3/2 DilBit price @ plant gate	US$ 49.16
– 1/2 diluent price @ plant gate	US$ 27.29
= bitumen netback @ plant gate	US$ 21.87

Although we calculate the prices or netbacks for each of the products to the plant gate, in reporting results we choose to display the price at the location where it is most often quoted as a benchmark in the marketplace. Therefore, in Table 7 we report the WTI price at Cushing OK, the SCO and the diluent (condensate) prices at Edmonton, the DilBit (Lloydminster) price at Hardisty, and the bitumen netback at the plant gate.

The above calculations have been made for our base case. Keeping the quality spreads fixed in percentage terms and the transportation spreads fixed in absolute dollars, we can vary the price of WTI in Cushing and obtain a new set of prices for the other products. This is how we calculate the supply cost for each product: we vary the price of

WTI until the given technology generates a return exactly equal to the specified discount rate. The corresponding product prices are the supply cost, and these can be quoted in terms of WTI at Cushing or in terms of any of the other product prices, SCO, DilBit, diluent or bitumen.

For tax purposes, we use the current accelerated write-off provisions of the Canadian Federal income tax law; these provisions are currently under review. Under this current system, all capital expenditures can be immediately amortized against any positive operating income: if income would be negative, then the capital account must be carried forward.[6] We assume a corporate tax rate of 32.1%. Royalties paid are 25% of gross profit after capital expenditures have been fully amortized with a minimum royalty equal to 1% of revenue.

For the discount rate in our base case we use a real Weighted Average Cost of Capital (WACC) of 6% applied to unlevered project cash flows. Using a WACC implicitly accounts for the benefit of interest tax shields associated with debt financing, although our cash flows do not explicitly model the debt financing nor show any interest expenses. We also show the sensitivity of the levelized cost calculation to variations in this discount rate. We arrived at the 6% figure by the following calculations and assumptions. First, as shown in Table 5, we estimated an oil sands asset Beta (i.e., unlevered) of 0.63. We derived this by (i) determining a set of companies invested in the oil sands and their associated equity Betas and leverage ratios, (ii) unlevering each company's Beta, and (iii) averaging the unlevered Betas. The companies used are the 17 companies that constitute the Sustainable Oil Sands Sector Index, a set of major oil sands

[6] Although the calculations are shown in real terms, depreciation and some other tax related calculations are inherently nominal. We assume a 2.5% Canadian inflation rate and translate nominal values to real values.

producers that are mostly pure oil sands players, or for which oil sands represent a substantial part of their operations and which are quoted on the Toronto Stock Exchange (TSX). Two of the 17 did not have traded prices for the full five year window, and so only 15 were used. Second, we used a real risk-free rate, r_f, of 2.25%. This corresponds to the estimate generated from the yield on U.S. Treasury Inflation-Protected Securities with 30-year maturity (McCulloch, 2007). Second, we assume a market risk premium, r_p, of 5%. There is some debate about the appropriate methodology for estimating the risk premium—see the discussion in Brealey, Myers and Allen (2006, pp. 151-154) and Fama and French (2002). Our estimate lies below the traditional one calculated using the average historical realized return on stocks relative to Treasuries, but are more consistent with estimates based on fundamentals, e.g., using a dividend or earnings growth model. Third, Using the capital assets pricing model (CAPM), these three estimates combine to generate a real asset discount rate of slightly less than 6%:

$$r_a = r_f + \beta_a \, r_p = 2.25\% + (0.63)\,(6.0\%) = 5.41\%.$$

An asset discount rate can be applied to the total project cash flows (debt plus equity), which explicitly recognizes in the cash flows the interest tax shields generated by the debt. Alternatively, a WACC can be applied to the unlevered project cash flows to produce the same value. The discount rate adjustment in the WACC implicitly generates the value associated with the interest tax shield. We choose the latter method. To determine the real WACC, we need to assume a leverage ratio. Based on the observed ratios of the companies in our sample we choose a leverage ratio of 25%. We assume a Beta of debt equal to 0.25, which implies a before-tax real cost of debt of 3.5%:

$r_d = r_f + \beta_d\, r_p = 2.25\% + (0.25)\,(6.0\%) = 3.5\%$. This also implies a real cost of equity of $6.04\% = r_e = (r_a - [D/V]\, r_d)/[E/V]$. The WACC formula is then:

$$WACC = [D/V]\,(1\text{-}t)\, r_d + [E/V]\, r_e = 25\%\,(67.9\%)\,3.5\% + 75\%\,6.04\% = 5.12\%.$$

Model Results: Supply Costs and Their Sensitivity

Table 7 shows the full set of results from the model. We first calculate the profitability of each technology given our base case assumptions about the crude oil price (WTI Cushing OK) and related product spreads. We then find the supply cost for each technology, using the crude oil price as the parameter to be varied and keeping fixed all of the related product spreads.

Figures 2 through 8 show the sensitivity of the results to changing the various input parameters.

SAGD in-situ DilBit production

The base case IRR is 20.2%. As shown in Figure 2, this varies between 3% and 40% as the exchange rate and the crude oil price are varied from 0.70 US$/C$ to 1.00 US$/C$ and from US$35 to US$70 per barrel, respectively.[7] The DilBit supply cost is US$22.90 (measured at Hardisty, i.e., comparable to Lloydminster blend at Hardisty), which corresponds to a WTI Cushing price of US$34.50. This is strikingly low, which is a common result for all of the cases which follow. The corresponding netback for raw bitumen is US$14.13 per barrel. Figure 3 is a tornado diagram showing the sensitivity of

[7] In varying the exchange rate, we have assumed that all product prices remain fixed in US$, and that all capital and operating costs remain fixed in C$. Obviously, this ignores any equilibrium relationship between the exchange rate and the prices charged in either currency. The assumption is arguably accurate for crude oil and for labor, but wide of the mark for capital costs and material costs.

the supply cost of DilBit to key parameters, including the discount rate, the price of natural gas, non-fuel operating costs and capital costs. Figure 4 translates this tornado diagram into the corresponding bitumen netbacks. Compared to the other technologies, SAGD production is clearly more sensitive to the price of natural gas, as this is a central cost of the production process.

Integrated mining-upgrading SCO production

The base case internal rate of return for the integrated mining and upgrading technology is 17.3%. As shown in Figure 5, this ranges from 7% to 30% as the exchange rate and the price of WTI at Cushing vary from 0.70 US$/$C to 1.00 US$/$C and from US$35 per barrel to US$70 per barrel, respectively. Under the base case assumptions, we find a SCO supply cost of US$27.82 per barrel (measured at Edmonton). This corresponds to a bitumen netback of US$11.29. Figure 6 provides a tornado diagram showing the sensitivity of the supply cost of SCO with respect to the choice of discount rate, the price of natural gas, non-fuel operating costs and capital costs. Because of the capital intensive nature of this production process, the discount rate has a relatively more significant impact on the cost of this process as compared to the others.

Stand-alone upgrading SCO production

The base case internal rate of return for the stand-alone upgrader is 13.9%. Figure 7 shows that this ranges from 7% to 24% when exchange rate and the price of WTI at Cushing vary from 0.7 to 1 and US$35 per barrel to US$70 per barrel. The stand-alone upgrader captures the required 6% rate of return with a spread between SCO and bitumen of \$16.76. Given our assumptions on the relationships between the various prices, this occurs when the WTI price is US\$29.27, the SCO price at Edmonton is US\$28.27, and the bitumen netback is US\$11.51.

It is interesting to ask what would be the supply cost for an integrated SAGD-SCO production, i.e., production of bitumen via SAGD and upgrading to SCO at the stand-alone unit. The bitumen would be transported as DilBit, but the diluent would be recycled. We perform this calculation in 2 steps: (i) determine a netback for bitumen that earns 6% on the SAGD operation, and (ii) apply the spread for upgrading that earns a 6% return. The total supply cost for SCO is US\$30.90. This is higher but in the same ballpark as the SCO supply cost from the integrated mining and upgrading operation, US\$27.82. Figure 8 shows the sensitivity of this supply cost to changes in the discount rate, the price of natural gas, non-fuel operating costs and capital costs.

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Table 1 – In-situ production projects currently in operation or under construction

Company	Project	Technology	Production
Imperial Oil	Cold Lake	CSS	158,000 b/d (06Q3)
Canadian Natural Resources Limited (CNRL)	Cold Lake Primary Production Project	Primary ("cold" production)	75,000 b/d (06Q3)
	Primrose/Wolf Lake	CSS	75,000 b/d (06Q3)
	Pelican Lake	Primary ("cold" production)	30,000 b/d (06Q3)
EnCana	Foster Creek	SAGD and CSS	37,000 b/d (06Q3)
	Pelican Lake	Primary ("cold" production)	23,000 b/d (06Q3)
	Christina Lake	SAGD	7,000 b/d (06Q3), expected to reach 18,000 b/d by 2008
Petro-Canada	MacKay River	SAGD	25,000 b/d (06Q3)
Suncor	Firebag	SAGD	20,000 b/d (06Q3)
Japan Canada Oil Sands	Hangingstone Pilot	SAGD	8,000 to 9,000 b/d (estimate 2006)
Petrobank	Whitesands Pilot	THAI	1,000 b/d (06Q3)
Total SA	Joslyn	SAGD	Phase 1 260 b/d (06Q3), phase 2 construction completed
Husky Energy	Tucker Project	SAGD	Construction completed
Connacher O&G	Great Divide	SAGD	Under construction
ConocoPhillips	Surmont	SAGD	Under construction
Husky Energy	Tucker Project	SAGD	Construction completed
MEG Energy	Christina Lake	SAGD	Under construction
OPTI/Nexen	Long Lake	SAGD	Under construction
Shell Canada	Orion Hilda Lake	SAGD	Under construction

Source: Alberta Employment, Immigration and Industry, 2006.

Table 2 – Canadian crude oil greenhouse gas lifecycle analysis

Metric tons of CO2 equivalent per cubic meter of end-use transportation fuel

Product	Production	Transport[b]	Refining	End-use[c]	By-products[d]	Total
Canadian Light	**0.211**	0.057	0.190	2.580	0.380	**3.418**
Oil sands (1995 actual)[a]	**0.779**	0.052	0.173	2.604	0.357	**3.965**
Oil sands (2005 forecast)[a]	**0.659**	0.051	0.173	2.604	0.350	**3.837**

Source: McCann Magee, 1999.

Notes: (a) Average for combined Syncrude and Suncor Production
(b) Total to Chicago area – pipeline or marine plus pipeline
(c) Gasoline, jet fuel, diesel using U.S. EPA 1996 Greenhouse Gas Inventory N_2O
(d) Canadian Light Crude Case as reference with regard to byproduct energy contribution to economy. Other cases adjusted to same energy contribution by adding or subtracting natural gas.

Table 3 – Oil sands cost model technology assumptions

Parameters	Values	
Steam-Assisted Gravity Drainage		
Annual construction capex (initial phases)	150	Million C$ 2005
Annual recurring capex (exploitation)	30	Million C$ 2005
Bitumen production at full scale	120,000	Bbl/day
Required diluent	33.3%	% blend volume
Steam Oil Ratio (dry)	2.5	bbl water/bbl bitumen
Natural gas consumption	0.42	Mcf/bbl water
Non-gas cash operating costs	3.5	C$/bbl bitumen
CO2 production	0.05	ton C02/Mcf
Intergrated Mining/Upgrading		
Annual construction capex (initial phases)	10,000	Million C$ 2005
Annual recurring capex (exploitation)	1.25	C$/bbl SCO
SCO production at full scale	200,000	bbl/day
Natural gas consumption	0.75	Mcf/bbl SCO
CO2 production	0.117	ton C02/bbl SCO
Non-gas cash operating costs	12	C$/bbl bitumen
Stand-alone Upgrader		
Initial capex	7,500	Million C$ 2005
Recurring capex	0.625	C$/bbl SCO
SCO production at full scale	200,000	bbl.day
Natural gas consumption	0.47	Mcf/bbl SCO
CO2 production	0.78	ton C02/bbl SCO
Non-gas cash operating costs	5	C$/bbl bitumen

Table 4 – Oil sands cost model market assumptions

Category	Parameter	Value	
Prices	WTI @ Cushing	50.0	US$/bbl
	Natural gas price	7	US$/Mmbtu
	Exchange rate	0.85	US$/C$
	Inflation rate, C$	2.5%	
Spreads	WTI @ Edmonton – SCO @ Edmonton	0	%
	WTI @ Edmonton - Lloydminster @ Hardisty	30	%
	Condensate premium over WTI @ Edmonton	10	%
Transport	Light crude transportation differential to Chicago: Edmonton vs. Cushing	1.00	US$/bbl
	Heavy crude transportation differential to Chicago: Hardisty vs. Cushing	1.25	US$/bbl
	Condensate transportation to Plant	0.80	C$/bbl
	Bitumen blend transportation differential: Plant vs. Hardisty	1.15	C$/bbl
	SCO transportation differential: Plant vs. Edmonton	0.70	C$/bbl SCO
Other	Cost of Carbon emissions	0	US$/ton CO2
	Corporate tax	32.10	% of Ebit
	Royalty (minimum rate)	1	% of revenue
	Royalty (post-amortization rate)	25	% of gr. profit
	Real discount rate	6.0	%

Table 5 – Oil Sands CAPM Beta Estimation

Company	Equity Beta (v MS World Index) Raw	Equity Beta (v MS World Index) Adjusted	Leverage Ratio (D/V) 2006	2005	2004	2003	2002	Avg.	Unlev. Beta
CNRL	0.38	0.58	33%	11%	27%	32%	65%	34%	0.47
Connacher Oil	0.90	0.93	3%	0%	0%	16%	0%	4%	0.91
COST	0.68	0.79	11%	15%	28%	36%	28%	24%	0.66
EnCana	0.21	0.47	19%	18%	31%	35%	35%	28%	0.41
Enerplus Resources	0.23	0.48	11%	10%	13%	9%	16%	12%	0.46
Husky Energy	0.39	0.59	5%	8%	13%	18%	35%	16%	0.54
Imperial Oil Ltd.	0.28	0.52	4%	4%	6%	7%	9%	6%	0.50
Nexen	0.60	0.73	29%	25%	35%	52%	44%	37%	0.55
Paramount Resources	0.19	0.46	30%	17%	27%	46%	60%	36%	0.38
Petrobank Energy	1.00	1.00	2%	9%	75%	90%	38%	43%	0.68
Petro-Canada	0.22	0.48	12%	12%	16%	13%	24%	15%	0.44
Shell Canada	0.71	0.81	4%	1%	1%	5%	12%	5%	0.78
Suncor Energy	0.46	0.64	6%	9%	12%	17%	24%	14%	0.59
UTS Energy	1.74	1.50	3%	0%	0%	0%	0%	1%	1.49
Western Oil Sands	0.80	0.87	13%	14%	37%	62%	79%	41%	0.61
Average	0.59	0.72	12%	10%	21%	29%	31%	21%	0.63

Sources:
Raw Equity Betas: Bloomberg. Based on 5 years of monthly data and the MSCI All Country World Index.
Debt-to-Value Ratios: Bloomberg. The ratio is defined as Long-Term Debt + Short-Term Debt / Market Cap. of Equity.

Notes:
1. Adjusted Beta = (2/3) Raw Beta + (1/3).
2. Unlevered Beta = (1-D/V) Adjusted Beta + (D/V) (0.26). This is the standard formula, but with a positive value for the Beta of debt, in contrast to many implementations which assume a zero value for the Beta of debt. We set the debt Beta to the value 0.25, the beta reported for high grade debt from 1977 to 1989 in Cornell and Green (1991). We use the average debt-to-value ratio over the five year period.
3. Average Beta calculated as the equally weighted average.

Table 6 – Oil Sands Weighted Average Cost of Capital Calculation

Inputs:	
Risk-free Rate	2.25%
Risk Premium	5.00%
Debt Ratio	25%
Debt Beta	0.25
Return on Debt	3.50%
Tax Rate	33%

	Asset Beta Scenarios			
	Estimated	Alternative Values		
	0.63	0.75	1.00	1.25
Equity Beta	0.76	0.92	1.25	1.58
Return on Asset	5.41%	6.00%	7.25%	8.50%
Return on Equity	6.04%	6.83%	8.50%	10.17%
WACC	5.12%	5.13%	6.38%	7.63%

Notes:
1. Return on Debt = Risk-free Rate + Debt Beta * Risk Premium.
2. Equity Beta solves the equation Asset Beta = (1-D/V) Equity Beta + (D/V) Debt Beta. We set the debt Beta to the value 0.25, the beta reported for high grade debt from 1977 to 1989 in Cornell and Green (1991). We use the average debt-to-value ratio over the five year period.
3. Return on Asset = Risk-free Rate + Asset Beta * Risk Premium.
4. Return on Equity = Risk-free Rate + Equity Beta * Risk Premium.
5. WACC = (D/V) (1-tax rate) Return on Debt + (1-D/V) Return on Equity.

Table 7 – Model Output: Returns and Supply Costs

	Base Case	Supply Costs: SAGD	Supply Costs: Integrated Mining & Upgrading	Supply Costs: Standalone Upgrader
Prices (US$/bbl):				
WTI	50.00	34.50	28.82	29.27
SCO	49.00	33.50	27.82	28.27
DilBit	33.75	22.90	18.92	19.24
diluent	53.90	36.85	30.60	31.10
bitumen	21.89	14.13	11.29	11.51
Internal Rates of Return:				
SAGD	20.2%	6.0%		
Integrated Mining & Upgrading	17.3%		6.0%	
Standalone Upgrader	13.9%			6.0%

Figure 1: Bitumen Products

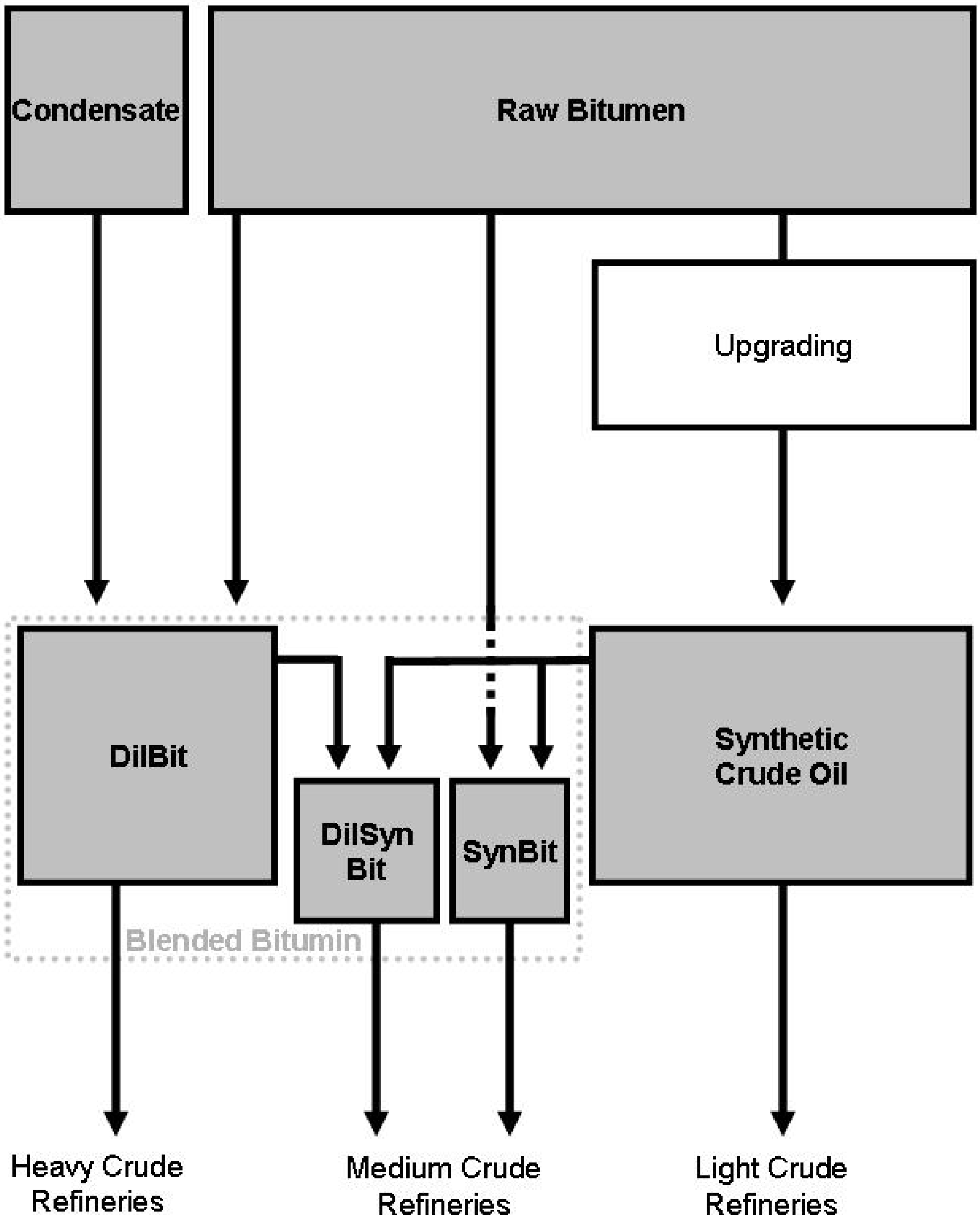

Figure 2: SAGD in-situ DilBit production
IRR sensitivity to WTI price and exchange rate

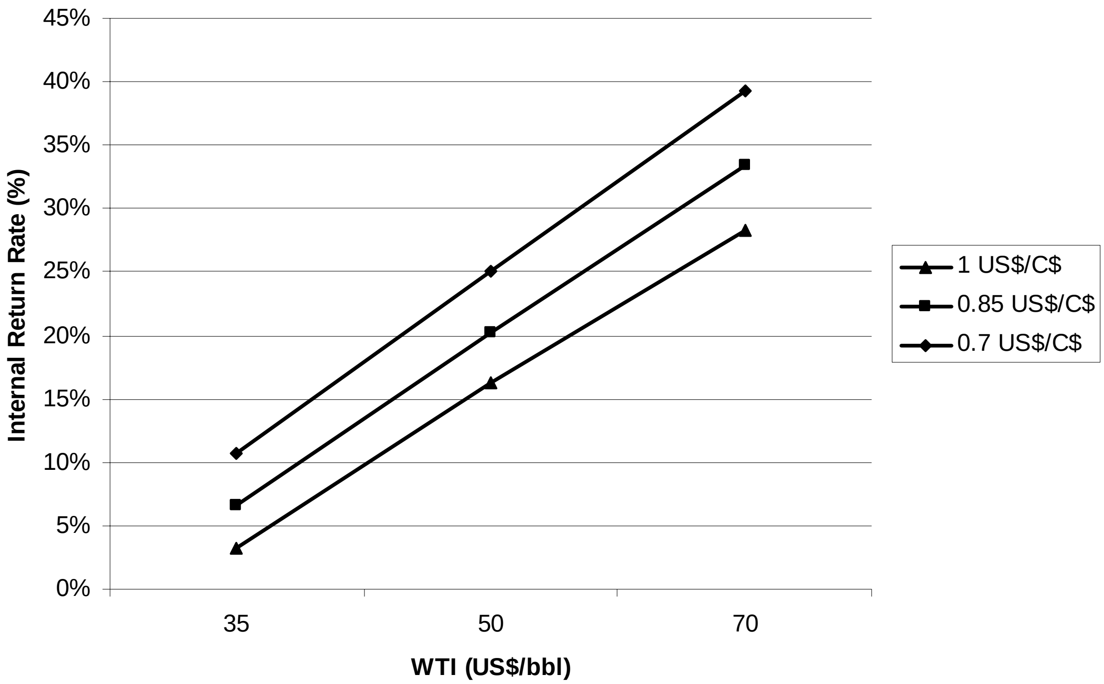

Figure 3: SAGD in-situ DilBit production
Supply cost of raw bitumen (netback) – Sensitivity analysis

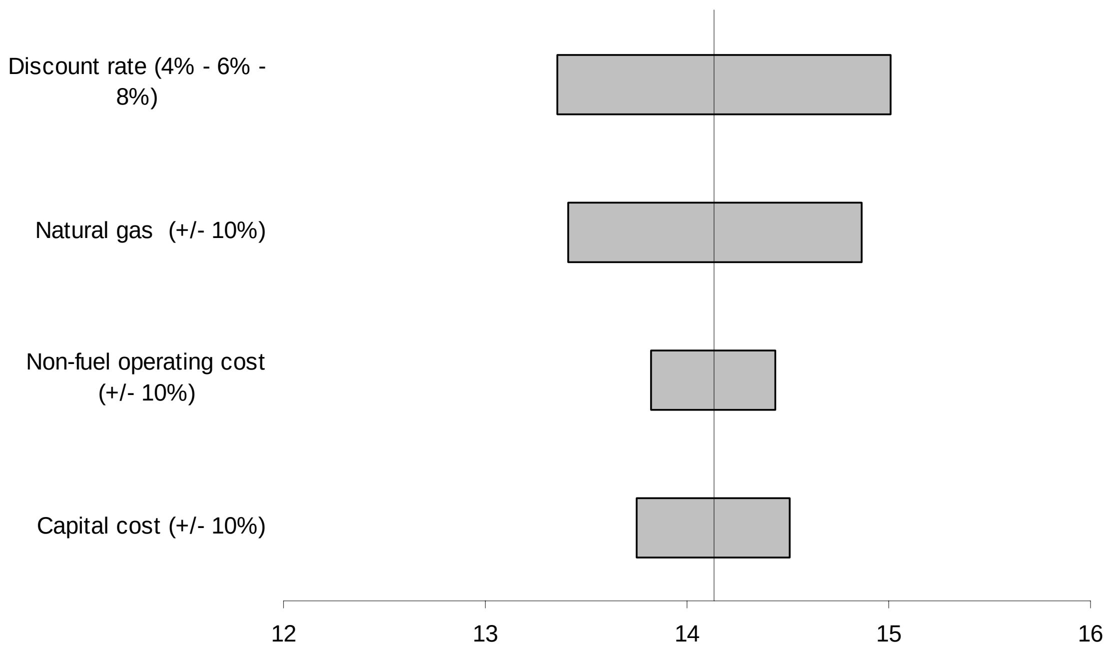

Figure 4: SAGD in-situ DilBit production
Supply cost of DilBit – Sensitivity analysis

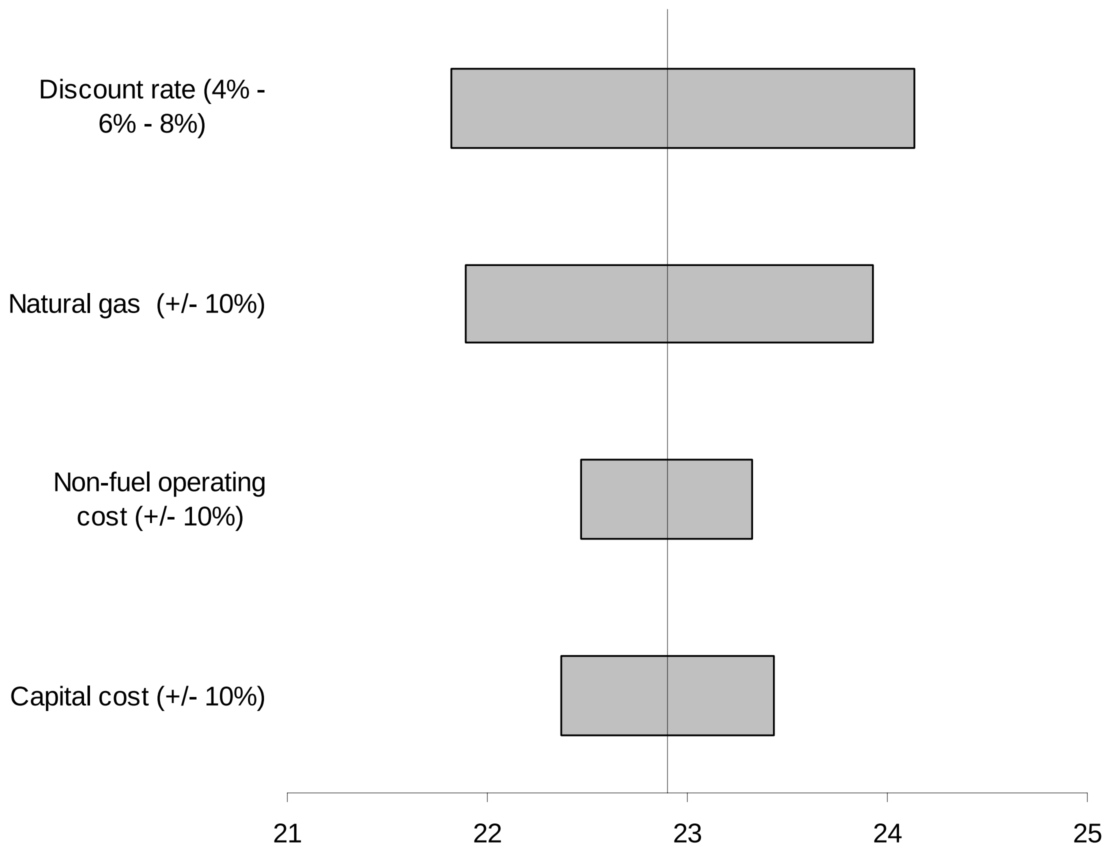

Figure 5: Integrated mining-upgrading SCO production IRR sensitivity to WTI price and exchange rate

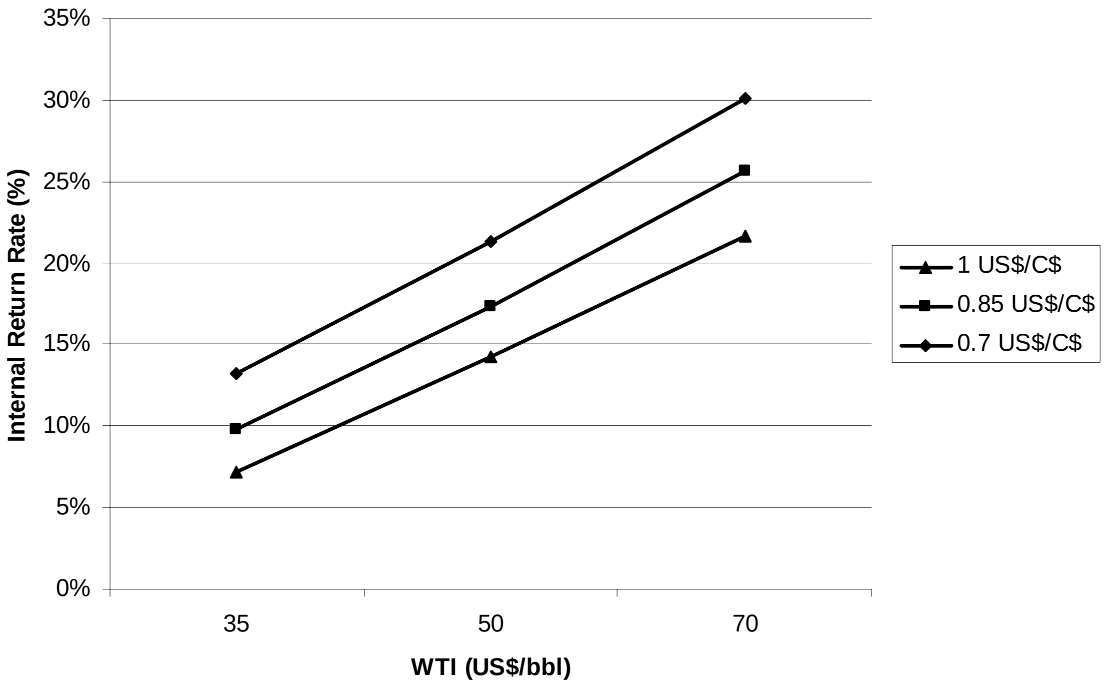

Figure 6: Integrated mining-upgrading SCO production
Supply cost of SCO – Sensitivity analysis

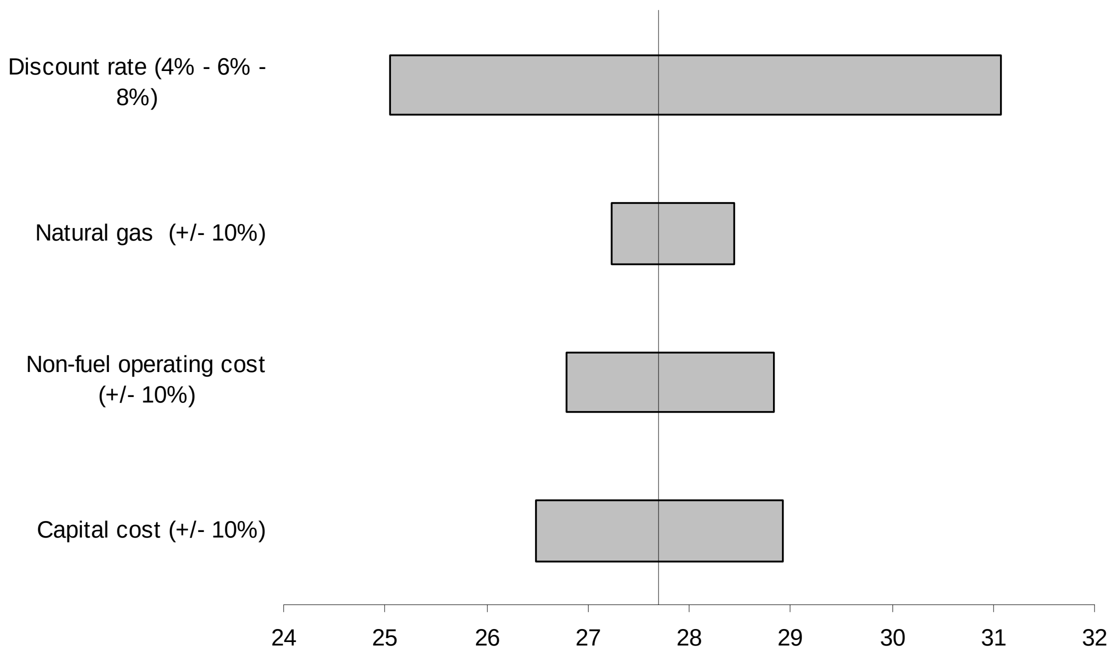

Figure 7: Standalone upgrading of in-situ produced bitumen to SCO IRR sensitivity to WTI price and exchange rate

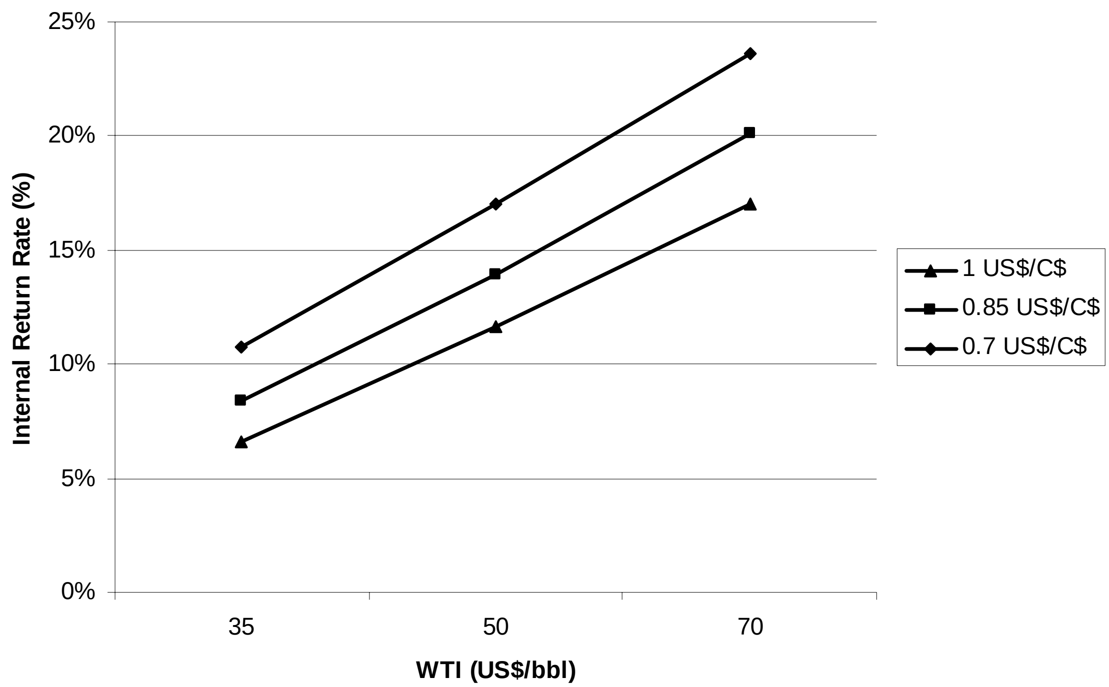

Figure 8: Standalone upgrading of in-situ produced bitumen to SCO
Supply cost of SCO – Sensitivity analysis