Treasure in the Sand

An Overview of Alberta's Oil Sands Resources

Todd Hirsch
Chief Economist

April 2005

Canada West Foundation

Front cover photo used courtesy of *Suncor Energy Inc.*

Treasure in the Sand is part of the Canada West Foundation's *Oil Sands Project.* As part of this project, the Canada West Foundation is working with *Pay Dirt Pictures* on the production of two educational documentary films on the oil sands. Funding for the *Oil Sands Project* has been provided by:

Bantrel Co.
Canadian Natural Resources Ltd.
Enbridge Inc.
Petro-Canada Inc.
Shell Canada Ltd.
TransCanada Corporation

The author would like to extend thanks to the following people for their comments and suggestions for this report:

Roslyn Kunin, Canada West Foundation Board Member
Chris Dawson, Petro-Canada Inc.
Richard Luhning, Enbridge Inc.
Mary Griffiths, Pembina Institute

The author is particularly indebted to Fraser Boyd, economics student at the University of Calgary, whose research on Alberta's oil sands royalty structure was invaluable in the preparation of this report. He is also credited with preparing *Appendix A: An Inventory of Existing and Planned Oils Sands Projects.*

Treasure in the Sand was authored by Canada West Foundation Chief Economist Todd Hirsch. The opinions expressed in this report are those of the author alone and not necessarily those of the Canada West Foundation's donors, subscribers, project funders, or Board.

ISBN 1-894825-56-X

Printed in Calgary, Alberta, Canada

CWF Report 2005-06

FOREWORD

By Robert Roach, Director of Research, Canada West Foundation

The energy sector has been the driver of the Alberta economy since *Imperial Oil* struck oil at Leduc in 1947. This discovery launched the modern oil and gas industry in the province. In the intervening years, Alberta has gone through a series of booms and busts caused by the steep ups and even steeper downs of global energy markets.

Among the province's extensive inventory of oil and gas deposits is the trillions of barrels of oil trapped in the oil sands of northern Alberta. This is the future of Alberta's energy sector and the cornerstone of its economic success in the decades ahead. As Alberta's conventional supplies of oil and gas inevitably go into decline after years of intense harvesting, it is the oil sands that will fill the gap in economic output.

Despite the fundamental importance of the oil sands to the province and, by extension, to both western Canada and the country as a whole, information about them outside the energy sector and groups directly affected by the developments taking place in the northern parts of the province, is relatively scarce.

Albertans, westerners, and Canadians need to become much more aware of this key resource, its potential, the challenges to its development, and the effects it will have on the economy, government revenues, the environment, society, Alberta's role in the federation, and Canada's role in the world. These topics could not be more important to our immediate and future economic prosperity and our long-term quality of life.

Treasure in the Sand helps move this debate forward my providing a basic primer on the oil sands and why they are important. The report answers several key questions:

- *How much oil is there?*
- *How is it recovered?*
- *What projects are underway and planned?*
- *What is the economic impact of the oil sands?*

The report also points out the need to carefully consider and debate a number of key issues. The oil trapped in the oil sands, for example, is not the same as the oil and gas that has been flowing from the Western Sedimentary Basin all these years. It is much harder to extract and, in turn, even more sensitive to market prices. This raises the spectre of another bust. Oil sands developments also raise a range of environmental concerns that highlight the need for a vigorous debate about land and water policy in the province. (This is something the Canada West Foundation is actively involved in through its *Natural Capital Project.)*

The oil sands also create social challenges related to the rapid growth of places like Fort McMurray and the impact on the Aboriginal communities on top of or near large oil sands deposits. Maintaining a sufficient supply of skilled labour and the potential royalty returns to Albertans add to this list of key issues.

As we wrestle with these public policy challenges and seek to reap the benefits of the oil sands, this report provides a handy, accessible and objective resource. If you have comments or questions, please feel free to direct them to myself *(roach@cwf.ca)* or the report's author Todd Hirsch *(hirsch@cwf.ca).*

INTRODUCTION

From humble beginnings in the 1960s, development of Alberta's oil sands has grown into a major driver of the provincial economy and a significant contributor to Canada's crude oil supply. With an estimated 2.5 trillion barrels of oil in the ground, it is one of the largest deposits of oil on earth. But there is one major problem – the oil trapped in the oil sands is much more difficult and expensive to extract than is conventional crude oil.

Nonetheless, oil companies have made tremendous headway in developing ways to extract the oil from the oil sands. Already, more than 1 million barrels of oil are produced each day from the oil sands – about a third of current total Canadian crude oil production. This figure is expected to double to 2 million barrels a day by 2010 when it will account for 57% of all oil production in the country.

To date, over $34 billion has been invested in the oil sands – more than the total annual GDP of neighbouring Saskatchewan. According to the *Canadian Association of Petroleum Producers (CAPP),* close to $38 billion in investments are planned over the next ten years – a number that changes almost daily as more and more projects are announced. These projects are having a massive impact on investment activity, exports, and employment.

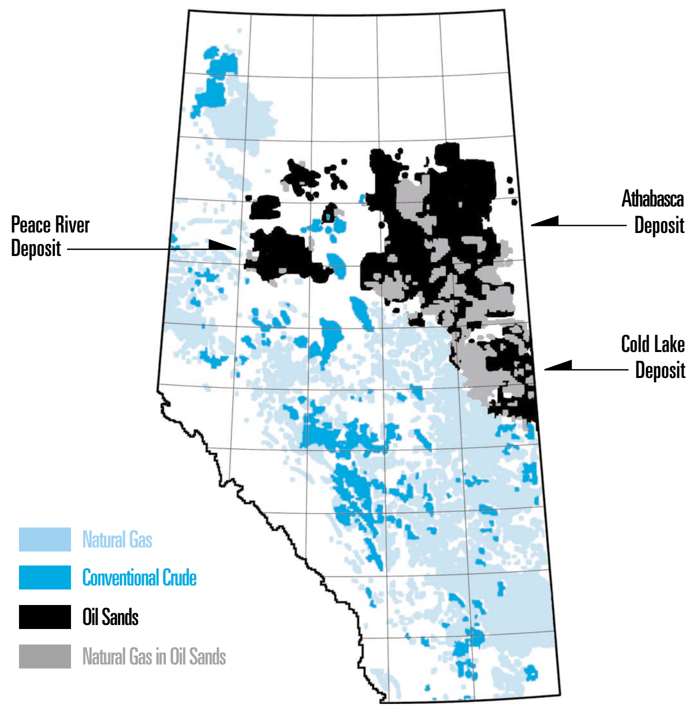
Despite the massive scope of oil sands development, few of us have taken the time to understand what it all means to Alberta and to Canada. How do we get oil from oil sands? Who owns the oil? How much oil is there? What do these projects mean for our environment, the economy and the global supply of oil?

This report seeks to provide an accessible primer on the oil sands, its importance to the economy, and the core public policy issues to which they give rise. A key goal here is to expand awareness of Alberta's oil sands outside the province and the energy sector.

HOW MUCH OIL IS UP THERE?
Location and Potential Reserves

Alberta's oil sands are divided into three geographic locations in the province: the Athabasca region, the Peace River region, and the Cold Lake region *(Figure 1).* Together these regions total approximately six million hectares (23,000 square miles), about the size of the province of New Brunswick. Almost all of Canada's bitumen resources are in Alberta (marginal amounts are found in the Arctic and on the eastern edge of the Western Canadian Sedimentary Basin).

FIGURE 1: Alberta's Oil Sands



SOURCE: Developed by the Canada West Foundation from the Alberta Department of Energy.

The oil that is mined from Alberta's oil sands is known as bitumen. In its natural form, bitumen is a very thick mixture of hydrocarbons that does not flow easily out of the ground as does conventional crude oil. It requires special processes for extraction from the sandy, tar-like soils of the oil sands, and must be thinned or heated to flow through a pipeline.

The total volume of bitumen contained in Alberta's oil sand deposits is calculated in different ways. The *National Energy Board (NEB)* adopts the estimates made by the *Alberta Energy and Utilities Board (AEUB),* which are summarized in *Figure 2.* Based on current data, the *AEUB* estimates that the initial volume of oil in place in all Alberta oil sands to be approximately 1.6 trillion barrels. But by the time all exploratory and development activity has ceased, this number is expected to rise to 2.5 trillion barrels. This measure is called the *ultimate volume in place.*

Of course, just because the oil is there in the ground does not mean that it is recoverable. Based on current technology and prices, the *AEUB* also makes estimates as to the *initial* *established reserves* and, once all exploration and development has ended, the *ultimate recoverable reserves.* It is these numbers that are most comparable to the oil reserves of other countries. Given today's data, it is estimated that Alberta holds 178 billion barrels in *reserves,* while *ultimate recoverable reserves* are pegged at 315 billion barrels. It is these two numbers – 178 billion barrels and 315 billion barrels – that are regularly quoted by the media and in presentations on Alberta's oil sands.

FIGURE 2: Bitumen Resources in Alberta
(Billions of Barrels)

MEASURE	MINEABLE	IN SITU	TOTAL
Ultimate Volume in Place	**138.4**	**2,377.6**	**2,516.0**
Initial Volume in Place	**113.2**	**1,517.1**	**1,630.4**
Ultimate Recoverable Volume	**69.2**	**245.3**	**314.5**
Initial Established Reserves	**35.2**	**142.8**	**178.0**
Cumulative Production	**2.5**	**1.3**	**3.8**
Remaining Established Reserves	**32.7**	**141.5**	**174.2**

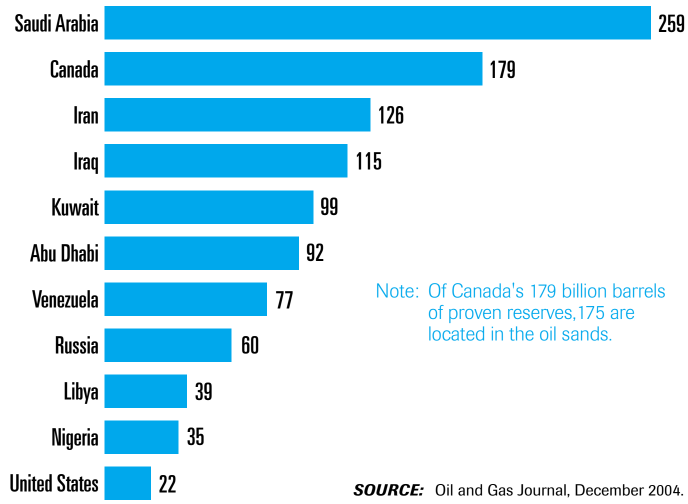
SOURCE: Alberta Energy and Utilities Board.

In the context of Canadian consumption, the 178 billion barrels of established reserves is sufficient, at current rates of consumption, to satisfy our own national demand for approximately 250 years (National Energy Board 2005).

The recent recognition of the oil reserves in Alberta's oil sands has vaulted Canada's position in international rankings. With the inclusion of the established reserves, Canada ranks second only to Saudi Arabia, and well ahead of oil-producing giants such as Iran, Iraq, the UAE and Kuwait *(Figure 3).*

It is important to keep in mind that estimates of recoverable oil reserves of all type – conventional crude, bitumen from oil sands, etc. – continues to rise over time, not diminish as one might expect. Many oil deposits around the world, including Alberta's oil sands, are not economic at low oil prices. As prices rise, more and more oil is economically recoverable. Also, technological advances add to the total recoverable reserves. Better seismic techniques, drilling and mining methods, and recovery technology make it easier and less expensive to extract oil.

FIGURE 3: Oil Reserves by Country
(Billions of Barrels as of December 2004)



SOURCE: Oil and Gas Journal, December 2004.

HISTORY OF OIL SANDS DEVELOPMENT

The usefulness of the bitumen oil sand deposits in northern Alberta had been discovered long before European settlers arrived in the area. Aboriginal people had found that the tar-like substance was useful for caulking and water-proofing their canoes.

The petroleum content of the oil sands was first recognized early in the 1900s, but there was at the time no practical method by which to extract it. It was not until much later that a number of companies started to take a closer look at the oil sands commercial potential as a source of energy. In 1964, the *Great Canadian Oil Sands Company* received approval to begin work on the first modern oil sands project involving open-pit mining and an upgrader. Ownership of the company transferred to the *Sun Oil Company* – later to become *Suncor* – and production from the world's first integrated oil sands mine and upgrading plant began in 1967.

In 1974, Alberta Premier Peter Lougheed established *AOSTRA (Alberta Oil sands Technology and Research Authority),* the purpose of which was to support and accelerate the development of oil sands technology for the future. Many of the technology advancements, including the *SAGD (steam assisted gravity drainage)* process, were financially supported or directly developed by AOSTRA.

But it was not until 1978 when *Syncrude Canada* began operations in northern Alberta that oil sands operations started to play a major role in the development of the province's energy economy. *Syncrude* – a consortium of several major oil and gas companies in Canada – participated with the provincial and federal governments in opening a large-scale mine and upgrader near Fort McMurray. The opening of the *Syncrude* facility marked the beginning of the modern oil sands operations in Alberta.

In 1983, *Imperial Oil* (which is also the majority shareholder in *Syncrude)* began commercial development of oil sands in the Cold Lake region (it had been running test pilots in the area going back to the 1960s.) This was followed in 1986 by *Shell Canada's* operations in the Peace River region.

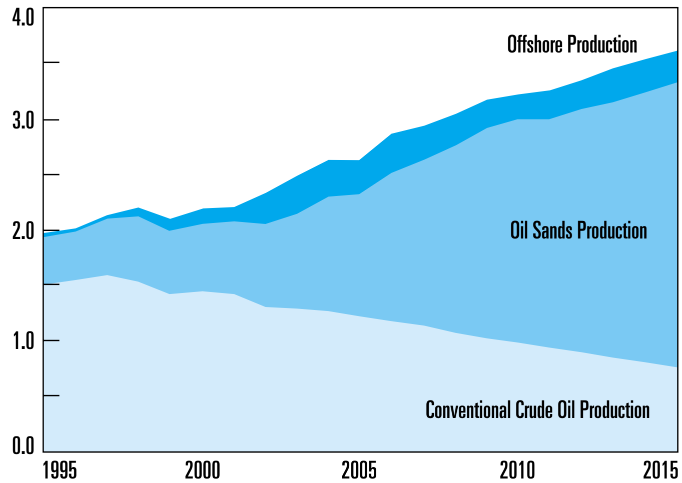
Since the mid-1990s, improvements in the oil sands extraction technology have unleashed an array of projects *(Appendix A* includes a complete inventory of existing and planned projects.) Virtually every major oil company in Canada has an existing or planned oil sands operation in northern Alberta.

OILS SANDS PRODUCTION, INVESTMENT, AND REVENUE

Since the mid-1990s, production of bitumen and synthetic crude from the oil sands has steadily increased. While there are dozens of projects and project expansions planned, there are only a few major operations producing oil from the oil sands today. The largest and currently most active is the Athabasca region. *Suncor, Syncrude,* and *Albian Sands Energy* are the major producers in the Athabasca region. *EnCana, Petro-Canada,* and a joint venture by *Conoco-Phillips, TotalFinaElf,* and *Devon Energy* are also currently producing oil from oil sands in the region. *Imperial Oil* and *Canadian Natural Resources Ltd.* are active in the Cold Lake region, while *Shell Canada* and *Blackrock Ventures* are currently active in the Peace River area.

Current production is now around 1 million barrels per day from all operations – both surface mining and in situ – in all three regions. According to *CAPP* this is forecast to grow to 2 million barrels per day by 2010, and to 2.6 million by 2015. It is expected that as production of the oil sands continues to grow, production from conventional crude oil in the *Western Canadian Sedimentary Basin (WCSB)* will gradually fall. Offshore oil production is expected to stabilize *(Figure 4).*

FIGURE 4: Annual Canadian Oil Production, 1995-2015
(Conventional, Oil Sands, and Offshore in Millions of Bbls.)



SOURCE: Oil and Gas Journal, December 2004.

Capital spending in oil sands projects has also increased steadily since the mid-1990s, reaching a peak in 2002 with a total of $6.7 billion in investments. It is estimated that $5.8 billion was spent in 2004. To date, an estimated $34 billion has been spent with another $38 billion in projects planned, awaiting approval, or already under construction *(see Appendix A).*

Revenue from oil sands production has increased dramatically since the mid-1990s. Revenue has grown from $4.0 billion in 1996 to $11.0 billion in 2003 *(Figure 5).*

FIGURE 5: Investment, Production, and Industry Revenues
(Producton in 000s of Bbls./Day and Dollar Amounts in Billions of $CDN)

	Mining Production	Bitumen Production	Capital Spending	Industry Revenues
1996	281	163	$1.3	$4.0
1997	290	238	$1.9	$4.0
1998	308	282	$1.5	$3.1
1999	324	244	$2.4	$4.9
2000	320	289	$4.2	$8.0
2001	349	310	$5.9	$6.9
2002	441	303	$6.7	$9.3
2003	429	426	$5.0	$11.0
2004	466	528	$5.8	N/A

SOURCE: Alberta Energy and Utilities Board.

EXTRACTION TECHNOLOGY

The oil found in Alberta's oil sands is called bitumen, a very thick mixture of hydrocarbons (organic compounds of hydrogen and carbon atoms that form the base of all petroleum products). In its natural state, bitumen is too thick to flow through a conventional drill pipe or pipe line *(see Discussion Box 1).* Special processes must be used to extract the bitumen from the sandy, tar-like soils of the oil sands. The extraction of bitumen from the oil sands can be divided into two primary processes – surface mining and in situ extraction.

1. Surface Mining

This is the method by which the oil sands were first mined in the 1960s, and is still used today. Basically, the soil, plant and wetlands on the ground surface – called "overburden" – are removed with truck and shovel to reveal the thick, black, sandy material that contains the bitumen. Surface mining can only be used for oil sand deposits near the surface (between 30-75 m). Giant trucks three stories in height are loaded with the oil sands and brought to a crusher and slurry operation *(Figure 6).* From this operation, the oil contained within the oil sands is separated using hot water.

When mined from the ground, the oil sands are composed of quartz sand, silt, clay, water, trace amounts of other minerals, and of course bitumen. In general, 75% to 80% of the oil sands is inorganic material (mostly quartz sand), 3% to 5% water, and 10% to 12% bitumen. It takes approximately 2 tons of oil sands deposit to produce one barrel of upgraded synthetic crude oil.

The bitumen contained in the oil sands is high density (density range is 970 kg/m^3 to 1,015 kg/m^3, or 8° to 14° API), high viscosity, and a high ratio of carbon-to-hydrogen molecules. This basically means that it is much thicker and heavier than conventional crude oil.

In order for the thick, molasses-like bitumen to be transported via pipeline, it must be "thinned out", but it may also be heated for transport over shorter distances. To be thinned out, the bitumen is blended with a diluent – usually a condensate comprised of pentanes and heavier hydrocarbons recovered as a liquid contained in natural gas, for example – to meet pipeline requirements of density and viscosity.

DISCUSSION BOX 1:
The API Scale of Oil Gravity

Conventional crude oil is oil that flows naturally or that can be pumped without being heated or diluted. Crude oil is commonly classified as light, medium or heavy, referring to its gravity as measured on the *American Petroleum Institute (API) Scale.* The API gravity is measured in degrees and is calculated using the formula (141.5/S.G.) – 131.5 = API Gravity. Light crude oil is defined as having an API gravity higher than 31.1°, medium oil as having an API gravity between 22.3° and 31.1°, and heavy oil as having an API gravity below 22.3°. Conventional heavy oil from the Lloydminster, Alberta area has an API gravity ranging from 9° to 18°.

Oil that does not flow, or cannot be pumped without being heated or diluted is called bitumen, and generally has an API gravity of less than 10°. The bitumen mined from the oil sands deposits in the Athabasca area of Alberta has an API gravity of around 8°, but is upgraded to an API gravity of 31° to 33°. This upgraded oil is known as *synthetic crude oil.*

SOURCE: Centre for Energy website (www.centreforenergy.com)

Suncor and *Syncrude* were the original pioneering companies in the surface mining techniques in the Athabasca region. A later but major addition to the surface mining operators is the *Athabasca Oil Sands Project,* a joint venture of *Shell Canada* (60%), *Chevron Canada* (20%), and *Western Oil Sands Inc.* (20%). The project created *Albian Sands Energy Inc.* specifically to operate the Muskeg River Mine on behalf of the joint venture partners.

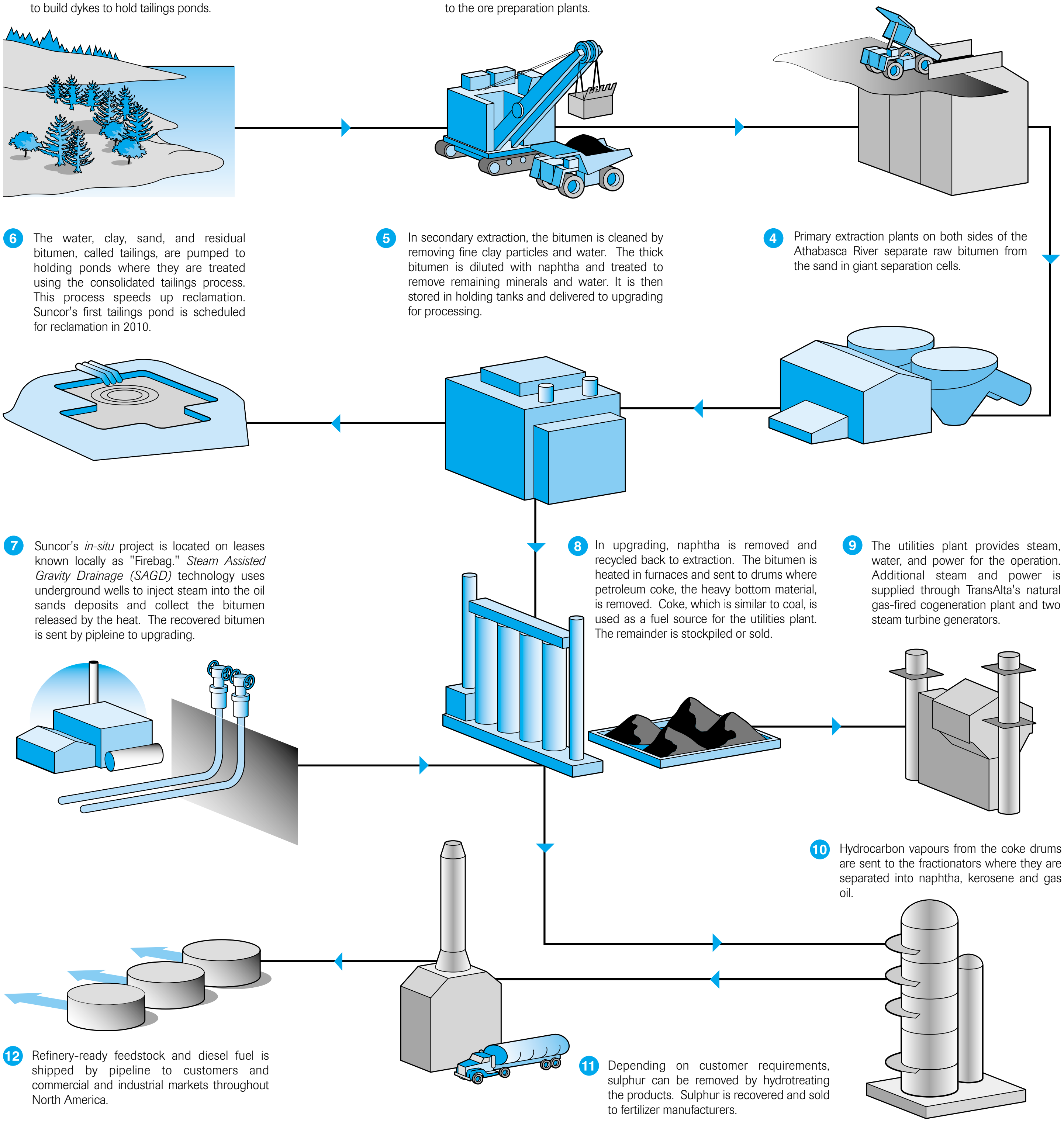
2. In Situ Extraction

Recent advancements in oil sands technology have enabled the recovery of bitumen in situ, or "in place." This has the double advantage of not requiring massive amounts of ground and tree cover to be removed (as with surface mining), and it also enables recovery of bitumen from oil sands much deeper in the earth. The basic concept of extracting bitumen in situ involves injecting steam or other solvents into the oil sands deposit to loosen the thick bitumen. This allows it to be drawn to the surface. There are a few varieties of in situ extraction techniques:

a) Cyclic Steam Stimulation (CSS): This three-stage process, also known as *"huff and puff,"* involves several weeks of steam injection into the deposit, followed by several weeks of steam and hot water "soaking," followed finally by an extraction phase

FIGURE 6: How Bitumen in the Oil Sands is Mined and Processed

(Explanation of Suncor's Oil Sands Operation)



1. Suncor leases land from the province of Alberta. Muskeg, which is water-soaked decaying plant material, is removed and saved for reclamation. Overburden, a thick layer of clay, silt and gravel, is used to build dykes to hold tailings ponds.

2. Oil sand is mined using shovels with buckets that hold 100 tonnes, loading huge 240 to 360 tonne trucks. The mine delivers about 450,000 tonnes of oil sand per day to the ore preparation plants.

3. Crushers and sizers in the ore preparation plants prepare the ore for delivery to primary extraction via hydrotransport pipelines.

4. Primary extraction plants on both sides of the Athabasca River separate raw bitumen from the sand in giant separation cells.

5. In secondary extraction, the bitumen is cleaned by removing fine clay particles and water. The thick bitumen is diluted with naphtha and treated to remove remaining minerals and water. It is then stored in holding tanks and delivered to upgrading for processing.

6. The water, clay, sand, and residual bitumen, called tailings, are pumped to holding ponds where they are treated using the consolidated tailings process. This process speeds up reclamation. Suncor's first tailings pond is scheduled for reclamation in 2010.

7. Suncor's *in-situ* project is located on leases known locally as "Firebag." *Steam Assisted Gravity Drainage (SAGD)* technology uses underground wells to inject steam into the oil sands deposits and collect the bitumen released by the heat. The recovered bitumen is sent by pipleine to upgrading.

8. In upgrading, naphtha is removed and recycled back to extraction. The bitumen is heated in furnaces and sent to drums where petroleum coke, the heavy bottom material, is removed. Coke, which is similar to coal, is used as a fuel source for the utilities plant. The remainder is stockpiled or sold.

9. The utilities plant provides steam, water, and power for the operation. Additional steam and power is supplied through TransAlta's natural gas-fired cogeneration plant and two steam turbine generators.

10. Hydrocarbon vapours from the coke drums are sent to the fractionators where they are separated into naphtha, kerosene and gas oil.

11. Depending on customer requirements, sulphur can be removed by hydrotreating the products. Sulphur is recovered and sold to fertilizer manufacturers.

12. Refinery-ready feedstock and diesel fuel is shipped by pipeline to customers and commercial and industrial markets throughout North America.

SOURCE: Adapted by the Canada West Foundation from Suncor Energy Inc.

where the oil is drawn to the surface by the same wells in which the steam and water were injected. As production declines, the injection phase is restarted. The high-pressure steam not only makes the oil more mobile, it creates cracks and channels through which the oil will flow to the drilled well.

Imperial Oil has used CSS techniques in the Cold Lake region commercially since the 1980s, and *BP* has used it since 1995 (now operated by *Canadian Natural Resources Ltd.). Shell Canada* has been operating a variation of the CSS method called *"Radial Soak"* in the Peace River region. With this method, a vertical well with four horizontal arms that extend spoke-like is drilled into the reservoir. Steam is injected into the reservoir for two months, followed by six to 18 months of reverse action during which oil is pumped to the surface through the same horizontal arms.

b) Steam Assisted Gravity Drainage (SAGD): Steam assisted gravity drainage (SAGD) involves drilling two horizontal wells – one above the other – into the oil sand deposit. Steam is continuously injected through the upper wellbore. The steam works to soften the bitumen around and above the wellbore, causing it to drain into the lower wellbore where it is pumped to the surface *(Figure 7).*

Examples of SAGD operations include the Surmont SAGD project (a joint venture of *ConocoPhillips, TotalFinaElf, and Devon Energy), EnCana's* Christina Lake project, and *Petro-Canada's* MacKay River project, all in the Athabasca region of the province.

FIGURE 7: Steam Assisted Gravity Drainage Process
(SAGD Process)

SOURCE: Diagram courtesty of Petro-Canada.

c) VAPEX: Vaporized extraction (trade mark VAPEX) refers to a process very similar to SAGD in that two parallel wells are drilled. But instead of steam, the VAPEX method injects a vaporized hydrocarbon solvent into the oil sand deposit to thin the bitumen, allowing it to be pumped to the surface.

DISCUSSION BOX 2:
How Much Oil is Recoverable?

Recovery rates vary according to the qualities of the reservoir and the recovery method used. Bitumen recovery rates at Cold Lake, where cyclic steam stimulation (CSS) technology is used, have improved from initial estimates of about 17% to more than 25% today. At the Mackay River oil sands facility, steam assisted gravity drainage (SAGD) results in recovery of more than 60% of the original oil in place. The average recoverables by oil extraction method are:

Oil sands mining (90% and higher)
In-situ oil sands (25% to 60% and higher)
Conventional light oil (average of 30%)
Conventional heavy oil (up to 20%)

SOURCE: Centre for Energy website (www.centreforenergy.com).

3. Upgrading Bitumen to Synthetic Crude

Once the bitumen is extracted from either surface mining operations or in situ processes, it must be upgraded to create synthetic crude oil that can then be refined. The synthetic crude is piped to oil refineries where it is used to produce gasoline, jet fuel, motor oil, and other hydrocarbon products. Some of the synthetic crude is also made into petrochemical products such as nylon and plastics.

The process of upgrading the heavy bitumen into synthetic crude involves breaking down the large, complex bitumen molecules into smaller ones. This is done by heating the bitumen in furnaces called cokers (to between 500° C to 925° C) to remove the carbon. This process is known as "cracking" as it cracks or splits the large bitumen molecules. The carbon molecules that are removed in the process form a solid material called coke. As a result of the heating process, gas vapours are captured in a fractionator where they cool and condense into liquids. Sulfur is removed from these liquids by adding hydrogen, and the remaining liquid is synthetic crude oil *(see Figure 6).*

The techniques and locations of upgrading vary by company and project. *Discussion Box 3* provides additional details on the upgrading of bitumen to synthetic crude.

OIL SANDS ECONOMICS

There are two primary "costs" which are commonly discussed in the context of oil sands production: *operating costs* and *supply costs. Operating costs* are only the costs of extracting the bitumen from the oil sands itself. While costs vary by company because of the different ways they are calculated, the *National Energy Board* produces a general range of costs common within the industry. The estimated operating costs are currently in the range of $4 to $14 for a barrel of bitumen depending on the process. After upgrading the bitumen to synthetic crude (so as to allow it to flow through the pipeline to refineries), the operating costs increase to $12 to $18 per barrel (National Energy Board 2005).

Supply costs include operating costs, capital costs, taxes, royalties, and the rate of return on investment. This is a more accurate price with which to compare the price of crude oil as quoted on the *NYMEX (West Texas Intermediate Crude)* or the various Alberta reference prices. Currently, supply costs depend on the process of extraction, and estimates are in the range of $10 to $19 for bitumen and $22 to $28 for synthetic crude *(Figure 8)*.

In March 2005, the price of *West Texas Intermediate Crude* was trading above $55 US per barrel, so oil sands production is clearly economically feasible. However, crude oil prices are notoriously volatile. Just as oil prices have risen suddenly and largely unexpectedly, they could just as easily fall to a range where the economics of oil sands production is less certain.

FIGURE 8: Estimated Operating and Supply Costs
(By Crude Type at the Plant Gate in 2003 $CDN/Bbl.)

Operation	Crude Type	Operating Cost	Supply Cost
Cold Production, Wabasca, Seal	Bitumen	**$4 - $7**	**$10 - $14**
Cold Heavy Oil Production with Sand (CHOPS), Cold Lake	Bitumen	**$6 - $9**	**$12 - $16**
Cyclic Steam Stimulation (CSS)	Bitumen	**$8 - $14**	**$13 - $19**
Steam Assisted Gravity Drainage (SAGD)	Bitumen	**$8 - $14**	**$11 - $17**
Mining and/or Extraction	Bitumen	**$6 - $10**	**$12 - $16**
Integrated Mining and Upgrading	Synthetic	**$12 - $18**	**$22 - $28**

SOURCE: National Energy Board (NEB).

DISCUSSION BOX 3: Upgrading Bitumen from the Oil Sands

Of the approximately 1 million barrels per day of current bitumen production, mined production makes up 65% and in situ or thermal production 35%. Essentially all of the 650,000 barrels per day of mined bitumen is upgraded. *Suncor* and *Syncrude* convert their bitumen production on-site to a light, sweet *synthetic crude oil (SCO),* and in the case of *Suncor,* other sour variants. The quality of bitumen recovered by the *Suncor* and *Syncrude* mining extraction operations has levels of water and solids that would make it currently unsuitable for shipping to conventional refineries. The *Shell*-led *Albian Sands* mining project recovers a cleaner bitumen (with more solids and water removed) and upgrades this off-site in Scotford, Alberta (near Edmonton). Products include a synthetic feedstock for the adjacent Scotford refinery, and other synthetic blends for marketing. While much of the synthetic crude is processed in Canadian refineries today, there will be increasingly larger volumes marketed in the northern tier US states as the industry expands output.

Of the 350,000 barrels per day of in situ production, some of it is upgraded to a light, sweet synthetic crude in *Husky's* Lloydminster, Saskatchewan upgrader. However, the majority is shipped with light diluent to those refineries, primarily in the US, that are suitably equipped to handle the high residue bitumen (normally in coking units), or that can use the feedstock to satisfy the seasonal demand for asphalt.

The split between end uses for mining-based and in-situ-based bitumen is historical. In situ bitumen producers will need to consider further upgrading to synthetic crude in the future.

SOURCE: Alberta Chamber of Resources, "Oil Sands Technology Roadmap."

As the extraction technology around oil sands processes has improved and expanded, the costs of production per barrel have fallen. One of the reasons why the oil sands (which were first commercially produced in the mid-1960s) has taken so many years to arrive at its current volume of production and investment is that operating and supply costs were prohibitively high. However, new technologies and methods of extraction have seen these costs per barrel fall considerably over the past few decades, improving the economic feasibility of large-scale production.

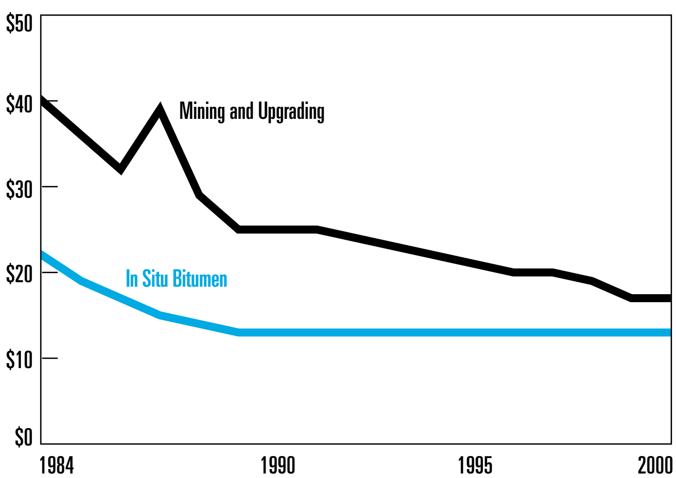
RISK

As with any expensive mega-project, there are several factors that determine if an undertaking of an oil sands operation is feasible. Projects are exposed to several risks that must be weighed and managed. Important sources of risk include commodity prices, capital costs, operating and input costs, environmental requirements, financial market support, advances in technology, market access, and the availability of skilled workers.

Primary among all of the risks is the price of crude oil itself. It is impossible to accurately forecast the price movements of crude oil, especially in the mid- to long-term. Unpredictable variables such as weather, geo-political factors, storage issues, and the price of substitutes such as natural gas can all play significant roles. More predictable factors such as the growth of consumer demand and refinery capacity constraint also affect the price of oil. While it varies from project-to-project, the price of oil is typically required to remain above $20 US per barrel for most operations to remain economically feasible. In early 2005, with current prices in a range above $50 US, there is no doubt that the existing and planned projects are feasible. However, there is never a guarantee that prices will remain at these levels indefinitely.

On the other side of the accounting ledger is the cost column. This, too, can dictate a project's economic feasibility. In the infancy of the oil sands technology, the costs of the projects were so large that few were built. But as *Figure 9* shows, the per barrel costs of these projects have come down significantly with new technological developments, making many more projects viable.

FIGURE 9: Supply Costs History
(1984-2000, $CDN/Bbl.)



SOURCE: Natural Resources Canada.

One of the largest costs involved in most projects is the price of energy inputs, especially for *SADG* projects. These operations use vast amounts of energy (often natural gas) to heat water and create steam. The natural gas requirements for the industry are projected to grow from 17 million m^3 per day in 2003 to 40 to 45 million m^3 in 2015 (National Energy Board 2005). When natural gas was plentiful and low-cost in Alberta relative to crude oil, this made sense. But with the escalation of the price of gas itself, the cost equation has been altered. Because of their smaller scale and more intensive use of natural gas, the in situ projects are more vulnerable to fluctuations in the price of gas.

The energy requirements of these oil sands projects would easily consume all of the gas potentially produced in the Arctic and shipped via the proposed Mackenzie Valley pipeline. Some question the logic of burning huge quantities of clean-burning hydrocarbons (natural gas) to create a less clean-burning fuel (crude oil).

Another cost factor is the diluent required to add to the bitumen to allow it to flow through the pipelines to the refineries in Edmonton. Diluent is a lighter hydrocarbon that is used to dilute the heavy, tar-like bitumen in preparation for pipeline transport. But diluents also cost money.

Labour costs have also become a serious problem for these projects. The construction stages and maintenance of the operations are very labour intensive, requiring massive numbers of pipe fitters, welders, electricians, project managers, engineers and other highly trained trades professionals. Western Canada's limited supply of these skilled workers has resulted in escalating wages – something that may not have been factored in when original cost estimates of projects were made. Similarly, the concurrent construction work at many facilities has driven up the price for steel, pipe and other inputs.

Cost overruns in the oil sands projects have also been common. For example, projects that were originally estimated to cost $3.5 billion have ended up costing $6 to $7 billion. Getting these costs under control has been a priority for the companies and their shareholders. Many projects have been scaled back in size. Also, companies may be coordinating amongst themselves to stagger construction or expansion plans as to avoid severe labour and input shortages.

OIL SANDS AND THE WESTERN CANADIAN ECONOMY

The magnitude of the oil sands industry is having an enormous impact on not only Alberta's economy, but on the total Canadian economy as well. The impact is being felt on many fronts.

1. Investment

Investment in fixed capital formation (such as the oil sands projects) contributes directly to the size of the economy's gross domestic product (GDP). The size of these projects is so large that one project can have a noticeable impact on Alberta's annual GDP. For example, *Canadian Natural Resources Ltd.'s* recently announced *Horizon Oil Sands* project north of Fort McMurray is currently estimated at close to $10.8 billion over several stages and years. It will be among the largest private construction projects in Canadian history.

Since 1996, actual investment spending in oil sands projects has totalled approximately $34 billion – with $6.1 billion being spent in 2004 alone. Over the next ten years, planned and projected spending is estimated at $32 billion. Relative to Alberta's total annual GDP of approximately $160 billion, it is clear that the impact of investment spending on oil sands projects will indeed have a sizable impact on total provincial GDP.

2. Production and Exports

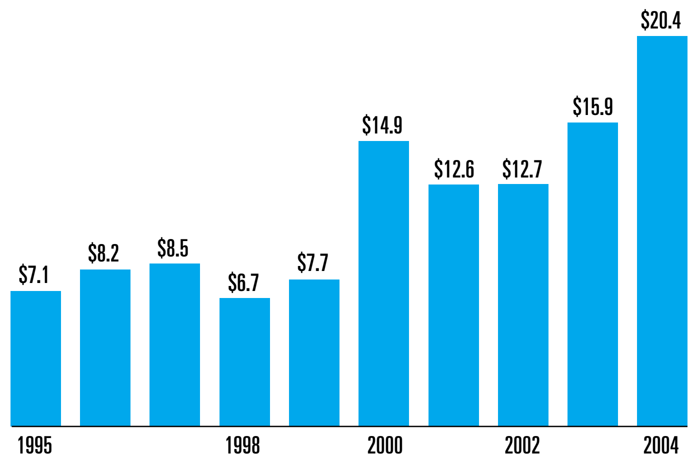
In 2003 Alberta's oil sands accounted for about 53% of the province's total crude oil and equivalent production, and about 35% of all crude oil and equivalent produced in Canada. Crude oil production is a major component of Alberta's export base. In 2004, the province's international exports of goods totaled $66.7 billion – $20.4 billion of which was crude oil *(Figure 10).* Much of that oil is upgraded synthetic crude from the oil sands.

3. Employment

It is estimated that there have been 33,000 jobs already created by oil sands development, and it is predicted that an additional 102,000 new jobs will be created by 2012 (Athabasca Regional Issues Working Group June 2004). About 40% of these jobs will be in Alberta, with the remainder elsewhere in Canada, primarily in the manufacturing sector.

Without question, the oil sands have been a positive factor in creating employment. The benefits have stretched beyond the borders of Alberta, too. There is a very vibrant, visible community of workers related to the oil sands from other parts of the country where employment opportunities are not as great, particularly Newfoundland.

FIGURE 10: Value of Crude Oil Exports From Alberta
(1995-2004, Billions of $CDN)



SOURCE: Statistics Canada.

OIL SANDS AND ALBERTA GOVERNMENT FINANCES

Natural resources in Canada belong to the citizens of the province in which they are found and extracted. The bitumen found in the oil sands, for example, belongs to the people of Alberta.

When companies purchase or lease land from the provincial government to extract the oil sands, they compensate all Albertans – who are the owners of the resource – by paying royalties. Royalties are payments made to the Crown for the use or exploitation of public land and resources. Under the Constitution, the provincial governments are responsible for collecting royalties accruing from the extraction of natural resources, including crude oil.

The royalty structure of Alberta's oil sands differs from that faced by conventional crude oil and natural gas producers in the province. Prior to the mid-1990s, the royalty structure of each oil sands project was negotiated uniquely with the province under Crown Agreements, but it was quickly recognized that unique agreements were unworkable in the long-run.

Recognizing the higher technological risk and higher capital costs faced by developers of Alberta's oil sands, the provincial government established the *National Task Force of Oil Sand Strategies (NTFOSS)* in 1993. This task force was made up of representatives from industry, as well as the provincial and federal governments. In 1995, Alberta Premier Ralph Klein announced that a new generic oil sands royalty regime will apply to all new oil sands projects. The new tax regime was passed into law in 1997.

Prior to a project's "payout" – the point at which the developer has recovered all initial capital outlay costs plus a return allowance – the applicable royalty is 1% of the project's gross revenue. Following a project's payout, the applicable royalty rate is 25% of the project's net revenue (i.e., revenue less total supply costs) or 1% of gross revenue, whichever is greater.

DISCUSSION BOX 4: Objectives of the New Royalty Regime on Oil Sands

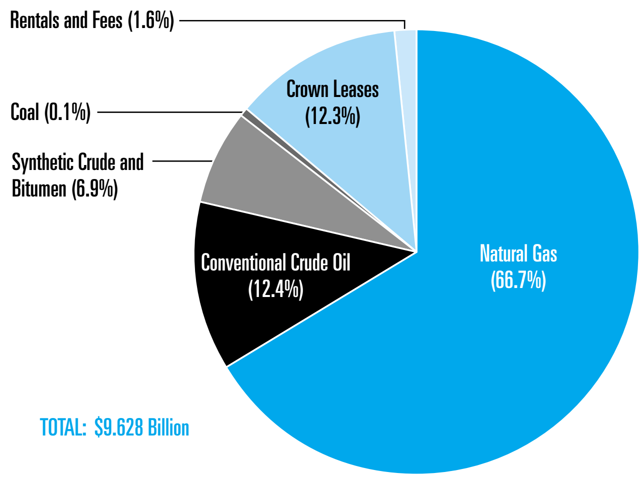
- Accelerate the development of the oil sands while ensuring a fair return to the resource owners – all Albertans.
- Facilitate development of the oil sands by private sector companies. Development must occur because businesses expect to make a reasonable profit from the venture. Alberta will not directly participate through grants, loans, loan guarantees, or any other special deals.
- Ensure that oil sands development is generally competitive with other petroleum development opportunities around the world.
- Create a standard set of royalty terms for new projects to create a clear, consistent, and stable system.

SOURCE: Alberta Energy.

Over the three fiscal years 2001 to 2004, oil sands development returned $565 million to Albertans in the form of royalties paid to the provincial government. This is expected to rise to $674 million in fiscal year 2004/05 alone due to soaring prices for crude oil. For comparison, expected royalties from natural gas are $6.5 billion, and royalties from conventional crude oil are $1.2 billion (Alberta Finance 2005).

Oil sands royalties of $674 million will account for roughly 2.3% of total provincial revenues of $28.753 billion in 2004/05. Revenue from all non-renewable resources, including bitumen from oil sands, conventional crude oil, gas, coal, and Crown land leases, is expected to be $9.6 billion or 33% of total government revenues *(Figure 11)*.

FIGURE 11: Non-Renewable Resource Royalties in Alberta
(2004/05 Estimates as of February 28,2005)



SOURCE: Alberta Finance Third Quarter Update. Total includes a royal tax credit of $107 million.

But going forward, it is difficult to predict how much royalty cash the province – and the citizens of Alberta – will accrue from the oil sands, and when it will be received.

For one thing, because of the high supply costs of oil sands relative to conventional drilling, the royalty of 25% of net revenue on oil sands production is likely to be less than the royalties paid by conventional oil producers. Royalties on conventional crude oil in Alberta are determined through a complex formula that factors in the age of the well, its productivity and the market price. Since the deposits of conventional crude oil in Alberta are in a maturing basin, there will be less conventional crude production in the future. This will affect royalties.

Secondly, the royalty structure for the new oil sands projects of 1% of gross revenues applies as long as the company is recuperating initial capital outlay costs. For projects involving many phases, this initial capital recouping period can stretch on for years. As long as there are new phases under construction, the 1% royalty applies to all oil production from that project.

For example, if an oil sands company is producing 100,000 barrels a day from a $5 billion Phase I mining operation, it pays 1% of all production until the $5 billion from Phase I (and a return on capital) is recuperated. But if the company embarks on another $5 billion Phase II of the project, adding another 100,000 barrels per day to bring production to 200,000 barrels per day, it still pays a royalty of only 1% on the total revenue from 200,000 barrels until Phase II outlay has been recuperated. In this way, as long as there are new phases under construction, the company can pay a royalty of only 1% for many years. Because of these factors, it is extremely difficult to estimate the royalties that will be collected from the oil sands, or the timing in which the royalties will be paid.

In addition to royalties, the provincial government treasury will benefit from higher corporate income tax from the profits of the oil companies and higher personal income tax from the increased employment. The *Athabasca Regional Issues Working Group* has prepared some estimates of expected royalties, corporate income tax, and personal income tax that are expected over the next 20 years. Note that in their estimation, royalties from the oil sands are expected to peak at around $1 billion per year – less than the current royalties presently flowing from conventional crude oil in the province, and only one-sixth the current royalties from natural gas.

While other estimates of oil sands royalties have been made, there is clearly no consensus. As Albertans wrestle with the current windfall revenues from natural resources – the majority of which come from a depleting supply of conventional natural gas – the less certain flow of future royalties from oil sands development should be carefully considered.

INFRASTRUCTURE ISSUES

1. Electricity Generation & Transmission

The massive amounts of electricity and steam required by oil sands operators is one of the largest costs borne by the producers. Electricity can be acquired in one of three ways: 1) purchasing off the provincial power grid; 2) stand-alone generators; or 3) cogeneration.

A cogeneration plant (also called a *Combined Heat and Power* facility, or *CHP),* offers some efficiency gains to the operator by generating both electricity and steam. The process uses a fuel, usually natural gas, to run a combustion turbine to produce electricity. In a second step, a heat recovery steam generator captures the remaining heat that would normally be wasted and uses it to produce steam or hot water. Since creating the steam and hot water is the priority end product, the electricity that is generated in the first step is considered a by-product.

Cogeneration offers the advantages of allowing operators to produce steam, create large amounts of inexpensive electricity, improve electrical reliability and efficiency, and generate additional revenues by selling surplus power. But because of inadequate transmission infrastructure, it may not be possible to sell all the surplus power back onto the provincial power grid. This is one reason why producers are not taking full advantage of the cogeneration option.

The additional electrical transmission infrastructure that is required to move all surplus electricity is an important public policy question currently being considered. Options include: 1) expanding the transmission system from Fort McMurray to Edmonton with an accompanying expansion between Edmonton and Calgary, and 2) adding a high voltage direct current (HVDC) directly from Fort McMurray to Calgary.

There is also potential for exports of surplus electricity to British Columbia or to the US Pacific Northwest. All of these options and possibilities would require massive new investment in electrical transmission. It would also take time to construct. However, if sufficient transmission capacity were in place, more oil sands operators would invest in cogeneration facilities, allowing them to reduce costs through increased efficiency and increase revenue through sales of electricity. (In some cases, a third party owns and operates the co-generation facility.)

2. Transportation Infrastructure

Aside from electricity generation and transmission, there are other infrastructure issues related to the oil sands. Transportation between Edmonton and Fort McMurray is currently strained by the single highway access offered by Highway 63. As investment in oil sands projects has increased, Highway 63 has become inadequate to carry the volume of both people and machinery.

One possible solution to the transportation bottleneck of Highway 63 is to build a rail link connecting Edmonton with Fort McMurray. A study commissioned by the *North East Alberta Transportation Corporation (NEATCOR)* was released last fall. It proposes a $2.6 billion project involving both a rail link between the two centres as well as improvements to the highway system. The private-sector led *NEATCOR* believes that most of the project costs can be covered by the private-sector. They have suggested that the provincial government contribute $300 million. However, there is not a great deal of optimism that this option is economically viable, and the provincial government has given no indication that it would contribute funds to this project.

Another aspect of transportation is the increased pipeline capacity that will ultimately be required to move the synthetic crude from northern Alberta to refineries near Edmonton and beyond. The pipeline network currently in place will be insufficient to meet the oil transportation requirements from the oil sands in the future.

The expansion of pipeline capacity is an extremely important issue because the current American market for oil sands products is becoming saturated. Aggressive actions by pipeline companies (e.g., *Enbridge Inc.)* are working to extend the pipeline infrastructure further into the southern US to the Gulf coast to compete directly with oil imports from Venezuela, Mexico and Middle East.

Another initiative currently in the planning stage is to build an oil sands products pipeline from northern Alberta to the port of Prince Rupert, BC. From there, oil sands products can be shipped on tankers across the Pacific to meet the burgeoning demand for oil in Asian economies, particularly China. Currently, much of Asia's oil supply is imported from either the Middle East or Venezuela. But, the port of Prince Rupert offers a much shorter shipping distance than either of these oil-exporting regions.

OIL SANDS & THE ENVIRONMENT

There has been considerable concern expressed as to the effects that Alberta's oil sands operations are having on the environment. This concern has grown in intensity with the rapid increase in the number of projects planned and under construction. While efforts are being made to lessen the environmental damage, the massive scope of these projects invariably leads to issues related to groundwater quality, air quality, energy consumption, and damage to the boreal forests. However, water usage and contamination has been at the forefront of the environmental concerns surrounding oil sands operations.

In the case of surface mining, muskeg drainage and overburden de-watering is required before the mine site can be stripped. Also, it is often necessary to depressurize the basal aquifer (the water-bearing sand and gravel that lies beneath the oil sands deposits) to control runoff and seepage in the mining pits. Usually this water is brackish or saline and requires special containment to prevent contamination of fresh surface water.

As well, surface mining operations require a huge amount of heated water. Approximately three barrels of water are used to produce one barrel of oil. After the hot water is used in the extraction process, some of the water can be recycled and reused for additional extraction. However, some of the water remains with the bitumen and must eventually be disposed of, along with sand and unrecoverable hydrocarbons, in tailing ponds. While there have been improvements in the handling and containment of these tailing ponds, there are concerns around the contamination of ground and surface water that these ponds may be creating.

In situ operations also use large amounts of water and steam that is pumped into the oil sand deposits to heat the bitumen. This results in some water remaining in the formation. Water can be recycled in many of these in situ processes (e.g., the Steam Assisted Gravity Drainage process can recycle an average of 90%) but large amounts of fresh water are still required to make up the losses.

There has been some movement within the industry to use less fresh water and more brackish or saline water. In addition, new methods are being developed. The VAPEX process involves injecting solvents rather than fresh water. Other methods, that also include fire-flooding, are being researched. These measures could help reduce the amount of fresh water consumed in in situ mining processes. However, more research and evaluation are required to determine if these are in fact environmentally sound alternatives.

The damage to the sensitive boreal forest is another environmental concern, particularly with respect to the surface mining operations. To mine the oil sands, all surface material such as trees, brush, and wetlands (called "overburden" within the industry) have to be cleared away. Oil sands companies are making commitments to restore the land to a usable, productive state, but returning the surface landscape to its original state is impossible. The boreal forests are extremely biologically diverse. Disruptions due to surface mining and road construction results in deforestation and the loss and fragmentation of habitat for sensitive plant, animal, and bird life.

Air quality and greenhouse gas emissions (GHGs) from the construction and operations of oil sands plants are a third area of environmental concern. Vast amounts of natural gas are consumed in the processes, particularly for heating water and creating steam, and while natural gas is considered one of the cleaner fossil fuels in terms of GHGs, the operations are contributing to emissions nonetheless. Again the question is asked if it makes sense burning a "clean" fuel (natural gas) in order to produce a "dirtier" fuel (crude oil).

The environmental concerns surrounding the oil sands operations are indeed serious. Efforts are being made by governments, environmental stewardship groups, and industry to monitor the disruption to the natural settings and to advance policies to conserve fresh water. At present there is no measure of the cumulative impacts of oil sands development on the environment, nor any measure of how much change the ecosystem can support. There is also no consensus among stakeholders as to how much damage is being sustained or how strictly environmental regulations need to be enforced. The debate over the environment is certain to grow in importance as an issue of public policy as the oil sands continue to be developed.

SOCIAL ISSUES

Aside from the effects on the natural environment, there are concerns about how the massive and rapid development of oil sands projects will affect surrounding communities. Fort McMurray is at the centre of the Athabasca oil sands region and functions as the primary centre for housing, medical services, and consumer services for the thousands of people employed in the Athabasca oil sands.

The stress on the community of the large-scale investment and construction each year in the region has taken a toll on the city of more than 50,000. Population growth and demand for housing have outpaced new residential construction. As a result, housing prices and rental rates have escalated quickly, leaving many lower income earners and new arrivals without adequate housing.

Indeed, one of the largest challenges facing the oil sands producers is the lack of skilled qualified workers. Labour shortages in many sectors have led to spiraling wages, and because of the city's remote location, it is not easy to attract labour quickly.

DISCUSSION BOX 5: Fort McMurray concerned about proposed Suncor project

(As reported on March 15, 2005 by CBC News)

EDMONTON – Community leaders in Fort McMurray say the city can't handle Suncor's proposed $10-billion expansion of its oilsands operation, because its infrastructure is already stretched to the limit.

Suncor has filed an application to build a third upgrader, and later a pipeline to feed in bitumen from the mining operation. The project, which will likely take two years to go through the approval process, would create about 4,000 construction jobs initially.

But politicians and business leaders in Fort McMurray say the city is already at capacity and needs new hospitals, roads, sewers and schools. The average house price in town is about $340,000, and there are essentially no vacancies in the city.

"Until we get our infrastructure in place, we are really not set up to handle as many people as are expected," said Jack Bonville, who owns a construction company and is vice-president of the Fort McMurray and District Chamber of Commerce.

Mayor Melissa Blake says the city is already too big for the existing services, and won't be able to function with more people. She wants the province to help out, given that the price tag on a new sewer system alone is $94 million.

"Without [provincial help], we just can't put any more development in our community," Blake said. "So that is the very harsh reality of the circumstances we are facing."

While a spokesman for Alberta Infrastructure said Fort McMurray will be treated like any other municipality in the province, Energy Minister Greg Melchin said oil sands development and the royalties it puts into the provincial economy are important enough that the city should be given special treatment.

"I would say Fort McMurray has a special case," Melchin said, citing a number of major projects proposed for the area. "So much is happening up there. For us to be able to realize the royalties and the revenue and all of that from Alberta's perspective maximizing the value, we've got to see that there's some basic infrastructure in place to accommodate it."

Outside of Fort McMurray, there are impacts on the local Aboriginal communities as well. And while the oil sands projects have indeed provided very good paying job opportunities for many Aboriginal people, there are still many who are not sharing in the wealth and opportunities. The construction of roads, plants, mines and pipelines has also been intrusive to the Aboriginal community's way of life in northern Alberta. Steps are being taken to mitigate the disruptions, but because of the size and scope of these projects it is impossible for them to have no negative impact on the Aboriginal communities.

It is not the presence of the oil sands projects that are disruptive to either Fort McMurray or the Aboriginal people, but rather the size, scope and speed at which these projects are proceeding. Indeed, both the city and the Aboriginal communities are thankful for the opportunities and wealth that the oil sands have brought. But it is extremely difficult for the social fabric of a small city or Aboriginal community to adjust to these changes so quickly. The challenge going forward will be for the communities to work with the oil companies in ensuring that developments proceed with the least negative impact on the communities as possible.

CONCLUSION

The volume of bitumen contained in northern Alberta's oil sands is enormous. It is one of the greatest hydrocarbon deposits in the world and a tremendous source of potential wealth. The impact that its development is having on the economy, the environment, and the country's supply of oil is considerable.

The mining and extraction of the bitumen oil is much more costly and difficult than is drilling for conventional crude oil, but oil companies have risen to the challenge. Over the past few decades technology has been developed that has significantly reduced operating and supply costs. Surface mining accounts for the vast majority of current bitumen recovery methods, but in situ processes are being developed and used commercially as well.

But with these opportunities come challenges *(Discussion Box 6).* Concerns regarding the environment, social impact, the timing and flow of royalty revenues, and the related shortages of skilled labour are a few such challenges. The future of the oil sands and the massive benefits they offer will depend on how Albertans and Canadians tackle the public policy issues that lie in their path. ■

DISCUSSION BOX 6: Policy Questions Raised by the Oil Sands

There are several difficult public policy questions that are posed by the oil sands developments. The public policy challenges going forward include:

- How will western Canada's regional economy be affected by the enormous demand for skilled labour? Will shortages in Alberta continue to spill over to other provinces, increasing shortages and wages elsewhere?

- What are the political implications of Alberta's wealth and economy growing at a pace disproportionate to neighbouring provinces? Will the imbalance in investment activity, employment, interprovincial migration, and provincial revenues strain relations? How will the federal government address this imbalance?

- Will new and expanded markets for oil sands products be developed to sustain the growth of the oil sands industry, thus sustaining the prosperity and future of Alberta and Canada?

- How will the environment be affected? The extraction of bitumen – and the energy requirements to extract them from the oil sands – has implications for Canada's Kyoto Protocol goals. And while energy companies are taking measures to mitigate their footprint, the massive oil sands developments are nonetheless straining the boreal forests, water resources, and wildlife habitat.

- Will the oil sands developments add undue strain to northern Aboriginal communities and towns and cities like Fort McMurray? Can these communities maintain a good quality of life with the pressures of the oil sands developments in their back yards? Should these communities have more control over the pace and scope of the projects?

- How will Alberta's economy adjust to the continued development of the oil sands? What are the implications for the government in managing the royalties that are expected to flow from oil sands production – particularly when the size and timing of those royalties are unpredictable?

- Does the province have an "exit strategy" for the time in the future when either oil prices make bitumen extraction unprofitable, or the resources are nearing depletion – as far into the future as that may be?

APPENDIX A: Inventory of Existing and Planned Oil Sands Projects

The following list describes existing and planned projects to develop the northern Alberta oil sands. Each entry in the list highlights : 1) the name of the project; 2) the companies involved; 3) the type of project; 4) the current status and/or timeline of the project; 5) production levels; 6) other pertinent details; and 7) the required investment.

A. ATHABASCA AREA: Major Oil Sands Projects

1) Muskeg River Mine: Owned and operated by *Albian Sands Energy Inc.* A mine and extraction plant. Currently operating. Production began in June 2003. Currently producing 155, 000 barrels per day. Project requires construction of a cogeneration plant, a corridor pipeline, and natural gas pipeline for gas needs of the cogeneration plant. $5.824 billion.

2) Muskeg River Mine Expansion (Phase 1): Owned and operated by *Albian Sands Energy Inc.* Mine and extraction plant. Construction expected to begin late 2005. Expected production of 70,000 barrels per day. Project requires bridge work across Muskeg River, as well as new potable water treatment system to treat Athabasca river water. $425 million.

3) Muskeg River Mine Expansion (Phase 2): Owned and operated by *Albian Sands Energy Inc.* Mine and extraction plant. Construction expected to begin in 2010. Expected production of 300,000 barrels per day. Various surface facilities will be required. $12.425 billion.

4) Jackpine Mine: Owned and operated by *Albian Sands Energy Inc.* Mine and extraction plant. *Phase 1* approved in 2004, production expected in mid 2010. *Phase 2* production expected 2010-2015. 200, 000 barrels per day expected for *Phase 1.* Additional 100,000 barrels per day expected for *Phase 2.* Includes construction of roads, power, communication systems and pipeline. $2.0 billion.

5) Scotford Upgrader: Owned and operated by *Albian Sands Energy Inc.* Upgrader. Currently operating. Production began in April 2003. Full production expected in 2005. At full capacity the upgrader will be producing more than 155,000 barrels per day. 50% of the investment for the project was spent locally in Alberta. The investment amount is included in the *Muskeg River Mine Expansion.*

6) Foster Creek Thermal Project (Phase 1): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Currently operating. Start-up was in November 2001. Currently producing 22,000 barrels per day. $290 million.

7) Foster Creek Thermal Project Expansion (Phase 1): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Construction began in 2003 and production is to begin mid-2005. Expected additional production of 13,000 barrels per day. $91 million.

8) Foster Creek Thermal Project (Phase 2): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Currently in planning stages. Construction to begin in 2005. Expected production of 40,000 barrels per day. *Phase 2* is dependent on having a dedicated upgrader market. $440 million.

9) Foster Creek Thermal Project (Phase 3): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Currently in planning stages. Construction to begin in 2007. Expected production of 30,000 barrels per day. *Phase 3* is dependent on having a dedicated upgrader market. $440 million.

10) Christina Lake (Phase 1): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Construction began in 2004. Full production levels of 10,000 barrels per day. $113 million.

11) Christina Lake (Phase 2): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Date to be determined. Production expected to be 30,000 barrels per day. $225 million.

12) Christina Lake (Phase 3): Owned and operated by *EnCana Corporation.* In-situ/SAGD. Construction to begin 2007. Production expected for 2009. Production expected to be 30,000 barrels per day. $240 million.

13) Great Divide Pilot: Owned and operated by *Connacher Oil and Gas.* In-situ/SAGD. Full production is expected for 2006. Expected production of 10,000 barrels per day. $150 million.

14) Syncrude 21 (Stage 1): Owned and operated by *Syncrude.* Mine/Upgrader. Construction began in 1996, and was completed in 1999. Production levels of 25,000 barrels per day. Development of first hydro-transport system. $470 million.

15) Syncrude 21 (Stage 2): Owned and operated by *Syncrude.* Mine/Upgrader. Construction began in 1999 and was completed in 2001. 35,000 barrels per day of added production. $1 billion.

16) Syncrude 21 (Stage 3): Owned and operated by *Syncrude.* Mine/Upgrader. Construction began in 2000 and was completed in 2004. Full production expected for 2006. 110,000 barrels per day of added production expected. $5.67 billion.

17) Syncrude 21 (Stage 4): Owned and operated by *Syncrude.* Mine/Upgrader. Start-up in 2005. Construction expected to be completed in 2010. 70,000 barrels per day of added production expected. $2.4 billion.

18) Syncrude 21 (Stage 5): Owned and operated by *Syncrude.* Mine/Upgrader. Start-up in 2010. Construction expected to be completed in 2015. 110 000 barrels per day of added production expected. $4.5 billion.

19) Kirby: Owned and operated by *Canadian Natural Resources.* In-situ/SAGD. Currently in planning stages. Application for approval submitted. Expected production levels of 30,000 barrels per day. Project on hold. $200 million.

20) Horizon (Phase 1): Owned and operated by *Canadian Natural Resources.* Mine/Upgrader. Approved in 2004. Construction to start in 2005. Expected production levels of 133,000 barrels per day. $6.1 billion.

21) Horizon (Phase 2): Owned and operated by *Canadian Natural Resources.* Mine/Upgrader. Regulatory approval in 2004. Expected start-up in 2007-2009. Expected production levels of 133,000 barrels per day. $1.7 billion.

22) Horizon (Phase 3): Owned and operated by *Canadian Natural Resources.* Mine/Upgrader. Regulatory approval in 2004. Expected start-up in 2009-2011. Expected production levels of 133,000 barrels per day. $1.4 billion.

23) Kearl Lake: Owned and operated by *Imperial Oil.* Mine/Upgrader. Public disclosure in 1997. Approval expected in 2005. Production expected for 2010. Expected production of 100,000 barrels per day. Future expansion to 200,000 barrels per day is being considered. Inclusion of an upgrader is undetermined. Use of Strathcona Refinery is being considered. $8 billion.

24) Sunrise Thermal Project at Kearl Lake (Phase 1): Owned and operated by *Husky Oil Ltd.* In-situ/SAGD. Awaiting regulatory approval. Construction expected for 2006-2008. Planned production for 2007-2008. Expected production of 50,000 barrels per day. Includes construction of access roads, water treatment and central processing facilities, and infield pipelines. $800 million.

25) Sunrise Thermal Project at Kearl Lake (Phase 2): Owned and operated by *Husky Oil Ltd.* In-situ/SAGD. Awaiting regulatory approval. Expected production of 25,000 barrels per day. $500 million.

26) Sunrise Thermal Project at Kearl Lake (Phase 3): Owned and operated by *Husky Oil Ltd.* In-situ/SAGD. Awaiting regulatory approval. Expected production of 25,000 barrels per day. Planning for extensions to increase production by 100 barrels per day. $500 million.

27) Fort Hills (Stage 1): Owned and operated by *UTS Energy and Petro-Canada.* Mine/Extraction plant. Construction expected to start in 2006. Production expected for 2009. Expected production of 95,000 barrels per day. *UTS* gained full interest in the project in 2004 from *TrueNorth Energy,* which has now been reduced to 40%. $2 billion.

28) Fort Hills (Stage 2): Owned and operated by *UTS Energy and Petro-Canada.* Mine/Extraction plant. Dates are to be determined. Expected production of 95,000 barrels per day. *Petro-Canada* gained 60% interest in March 2005. $1.3 billion.

29) Northern Lights (Phase 1): Owned and operated by *Synenco Energy.* Mine/Upgrader. Awaiting regulatory approval. Construction expected to begin 2007. Initial production expected for 2009. Expected production of 47,500 barrels per day. $1.7 billion.

30) Northern Lights (Phase 2): Owned and operated by *Synenco Energy.* Mine/Upgrader. Assuming regulatory approval, construction expected to begin in 2010. Expected production of 23,750 barrels per day. $1 billion.

31) Northern Lights (Phase 3): Owned and operated by *Synenco Energy.* Mine/Upgrader. Assuming regulatory approval, construction expected to begin 2011. Expected production of 23,750 barrels per day. $800 million.

32) Joslyn Creek (Phase 1): Operated by *Deer Creek Energy.* Owned by *Deer Creek Energy and Enerplus.* In-situ/SAGD. Construction to begin in 2004. Production in beginning of 2005. Production levels of 600 barrels per day. $40 million.

33) Joslyn Creek (Phase 2): Operated by *Deer Creek Energy.* Owned by *Deer Creek Energy and Enerplus.* In-situ/SAGD. Awaiting regulatory approval. Construction to begin 2006. Production expected for 2007. Expected production of 10,000 barrels per day. $175 million.

34) Joslyn Creek (Phase 3A): Operated by *Deer Creek Energy.* Owned by *Deer Creek Energy and Enerplus.* In-situ/SAGD. Currently planning. Construction expected to begin 2007. Production expected for 2008-2009. Expected production of 30,000 barrels per day. $325 million.

35) Joslyn Creek (Phase 3B): Operated by *Deer Creek Energy.* Owned by *Deer Creek Energy and Enerplus.* In-situ/SAGD. Currently planning. Construction to begin in 2009. Production expected for 2010. Expected production of 30,000 barrels per day. Required investment is to be determined.

36) Joslyn Creek Mine: Operated by *Deer Creek Energy.* Owned by *Deer Creek Energy and Enerplus.* Mine. Construction and production expected to begin in 2011, with expansion in 2014. Expected production of 100,000 barrels per day. Phases that would increase production by 100,000 barrels per day are being conceptualized for 2017-2020. Required investment is to be determined.

37) Long Lake (Phase 1): Owned and operated by *OPTI Canada* and *Nexen.* In-situ/SAGD. Regulatory approval in 2003. Construction began in 2004. Production expected late 2006. Upgrader start-up in 2007. Expected production of 70,000 barrels per day. Includes construction of a cogeneration plant. $3.1 billion.

38) Long Lake (Phase 2): Owned and operated by *OPTI Canada* and *Nexen.* In-situ/SAGD. Regulatory approval obtained. Construction expected to begin 2011. Expected production of 70,000 barrels per day. Expecting to process third party volumes. $2.79 billion.

39) Jackfish Project: Owned and operated by *Devon Energy Corp.* In-situ/SAGD. Approval granted in 2004. Construction began in 2005. Full production expected for 2008. Expected production of 35,000 barrels per day. No surface or potable water used in SAGD process. $450 million.

40) MacKay River (SAGD Phase 1): Owned and operated by *Petro-Canada.* In-situ/SAGD. Construction began in late 2002. Full production reached in 2003. 25 year expected lifespan. Production levels of 30,000 barrels per day. $290 million.

41) Meadow Creek (SAGD Phase 2): Owned and operated by *Petro-Canada* and *Nexen.* In-situ/SAGD. Project currently on hold. Expected production of 80,000 barrels per day. $600 million.

42) Lewis: Owned and operated by *Petro-Canada.* In-situ/SAGD. Dates of construction to be determined. Expected production of 80,000 barrels per day. $800 million.

43) Surmont (Stage 1): Owned and operated by *Conoco Phillips, TotalFinaElf,* and *Devon Energy.* In-situ/SAGD. Received approval in 2003. Construction began in 2003. Production in 2005. Production levels of 27,000 barrels per day. Surmont reserve estimates of 5 billion barrels have since been cut back. $360 million.

44) Surmont (Stage 2): Owned and operated by *Conoco Phillips, TotalFinaElf,* and *Devon Energy.* In-situ/SAGD. Dates to be determined. Expected production of 25,000 barrels per day. $360 million.

45) Surmont (Stage 3): Owned and operated by *Conoco Phillips, TotalFinaElf,* and *Devon Energy.* In-situ/SAGD. Dates to be determined. Expected production of 25,000 barrels per day. $360 million.

46) Surmont (Stage 4): Owned and operated by *Conoco Phillips, TotalFinaElf,* and *Devon Energy.* In-situ/SAGD. Dates to be determined. Expected production of 25,000 barrels per day. $360 million.

47) Hangingstone Demo Project: Operated by *JACOS.* Owned by *JACOS* and *Nexen.* In-situ/SAGD. Stage 1 production began in 1999. Stage 3 production began in 2000. Completed in 3 small phases of 2,000, 4,000, and 4,000 barrels per day. Purpose of the project was to evaluate the commercial viability of the SAGD process in the area.

48) Hangingstone Commercial Project: Operated by *JACOS.* Owned by *JACOS* and *Nexen.* In-situ/SAGD. Publicly disclosed in 2001. Construction to begin in 2006. 20 year expected lifespan. Completed in two phases of 25,000 barrels per day each. Plans to increase cumulative production to 100,000 barrels per day. $450 million.

49) Whitesands Pilot Project: Owned and operated by *Petrobank Energy and Resources.* In-situ/THAI (Toe-to-Heel-Air-Injection). EUB announced approval in 2004. Construction began early 2004. Production expected early 2005. Production to be determined. First field application of THAI. *Petrobank* owns property rights to THAI technology. $30 million.

50) Firebag (Base Operations): Owned and operated by *Suncor.* In-situ/SAGD. Construction began in 2004. Full production expected in 2005. Production expected to be 35,000 barrels per day. $1.035 billion.

51) Firebag (Expansion): Owned and operated by *Suncor.* Upgrader. Production expected for 2008. Production expected to be 105,000 barrels per day. $3.323 billion.

52) Suncor Base Operations: Owned and operated by *Suncor.* Mine/Upgrader. Construction began in 1964. Production began in 1967. Current production is 45,000 barrels per day. $240 million.

53) Steepbank Mine and Expansion of Fixed Plan: Owned and operated by *Suncor.* Mine/Upgrader. Public disclosure in 1995. AEUB approval in 1997. Completed in 1998. Current production of 17,000 barrels per day. Includes construction of the *Suncor Bridge* (391 meters in length) that crosses the Athabasca River. $600 million.

54) Steepbank Mine Extension: Owned and operated by *Suncor.* Mine/Upgrader. Regulatory approval in 2006. Assuming approval, construction expected for 2007. Expected production of 110,000 barrels per day. Required investment to be determined.

55) Millennium Production Enhancement (Phase 1): Owned and operated by *Suncor.* Mine/Upgrader. Full production was reached in 2001. Current production levels of 25,000 barrels per day. $190 million.

56) Millennium (Phase 2): Owned and operated by *Suncor.* Mine/Upgrader. Full production was reached in 2002. Current production levels of 95,000 barrels per day. Millennium is an elaboration of the Steepbank Mine. $2 billion.

57) Voyageur: Owned and operated by *Suncor.* Mine/Upgrader. Production expected to commence around 2010-2012. Production expected to be 135,000 barrels per day. Includes expansion of upgrader capacity to 450,000 barrels per day in 2008 to 550,000 barrels per day in 2010. $3 billion.

B. COLD LAKE AREA: Major Oil Sands Projects

1) Cold Lake (Phases 1-10): Owned and operated by *Imperial Oil.* In-situ. Construction completed in 1986. Production levels of 120,000 barrels per day. $1.7 billion.

2) Cold Lake (Phases 11-13): Owned and operated by *Imperial Oil.* In-situ. Obtained approval in 1999. Construction from 2000-2002. 25 year lifespan. Production levels of 30,000 barrels per day. 75% of project expenditures spent in Alberta. $650 million.

3) Nabiye (Phases 14-16 of Cold Lake): Owned and operated by *Imperial Oil.* In-situ/CSS. Granted approval in 2004. Expected completion in 2006. 30 year lifespan. Expected production of 30,000 barrels per day. Includes construction of steam generation, bitumen-processing, and water-treatment plant. $650 million.

4) Mahikan North (Extension of Phases 9 and 10 at Cold Lake): Owned and operated by *Imperial Oil.* In-situ/CSS. Currently under construction. Granted approval in 2004. Construction expected to be completed in 2006. Current production levels are maintained. Increases lifespan reserves by 125 million barrels. Includes construction of pipeline and other surface facilities. $350 million.

5) Orion EOR: Operated by *Blackrock Ventures. Blackrock* has a 75% interest in the project. In-situ/SAGD. Currently under construction. Obtained approval in 2004. Phased production. Expected production of 20,000 barrels per day upon completion of final phase. Variety of surface facilities. $300 million (two $150 million phases).

6) Primrose: Owned and operated by *Canadian Natural Resources.* In-situ/SAGD/CSS. Start-up in 1987. 53,000 barrels per day. Includes Wolf Lake Central Processing Facility (55,000 barrels per day).

7) Primrose (North): Owned and operated by *Canadian Natural Resources.* In-situ/CSS. Currently under construction. Production expected for 2007. 30,000 barrels per day. $250 million.

8) Primrose (East): Owned and operated by *Canadian Natural Resources.* In-situ/CSS. Start-up expected for 2007-2008. Application has yet to be filed. 80,000 barrels per day. Includes modification to Wolf Lake CPF to increase production to 120,000 barrels per day. $600 million.

9) Tucker Project: Owned and operated by *Husky Oil Ltd.* In-situ/SAGD. Granted approval in 2004. Construction began in 2004. Production expected for 2005-2006. Expected production of 30,000 barrels per day. $315 million.

10) Lindbergh/Elk Point/Frog Lake/Marwayne Bitumen Recovery: Owned and operated by *Petrovera Resources Ltd.* In-situ/SAGD. Currently under construction. Final phase production expected for 2010. Production to be determined. $1.2 billion.

C. PEACE RIVER AREA: Major Oil Sands Projects

1) Peace River: Owned and Operated by *Shell.* In-situ/SAGD/CSS. Currently operating. Production began in 1979. Currently producing 12,000 barrels per day.

2) Peace River Expansion: Owned and Operated by *Shell.* In-situ/SAGD/CSS. In planning stages. Construction expected for 2007. Increase production from 12,000 barrels per day to 30,000 barrels per day. Required investment to be determined.

3) Seal Project: Owned and operated by *Blackrock Ventures.* In-situ cold production. Currently operating. Currently producing 16,000 barrels per day. Heavy oil pipeline and processing facility were constructed as well.

4) Lloydminster Upgrader: Owned and operated by *Husky Oil Operations Ltd.* Upgrader. Production began in June 1992. Producing at 77,000 barrels per day. Upgrader is working at above capacity due to upgrades.

5) Strathcona Refinery Conversion: Owned and operated by *Petro-Canada.* Oil refinery conversion. Planning/early construction. Obtained approval for upgrade in December 2003. Construction expected to be completed in 2008. Expected to produce 135,000 barrels per day of heavy crude. This number is equal to the current total crude production. After conversion, production will be entirely bitumen derived upgrades. $1.2 billion.

6) Alberta Heartland Upgrader: Operated by *BA Energy Inc.* Owned by *Value Creation Group.* Bitumen upgrading facility. Three phases. Phase one is expected to start production in late 2006. Upon completion of all three phases bitumen production will be 226,000 barrels per day. $1 billion.

7) "The Upgrader" (Sturgeon County): Owned and operated by *North West Upgrading Inc.* Upgrader. Development to occur in three phases. Phase one construction to occur in 2008. Production expected for 2010. Expected production to be 150,000 barrels per day. Each phase will add 50,000 barrels per day of production. A fourth phase (50,000 barrels per day) is dependent upon market demand. $1.3 billion.

APPENDIX C: References

Alberta Chamber of Resources. 2004. Oil Sands Technology Roadmap: Unlocking the Potential.

Alberta Energy. 2003. Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories. Edmonton, AB.

Alberta Environment. 2004. Advisory Committee on Water Use Practice and Policy. Final Report. Edmonton, AB.

Alberta Finance. 2005. Third Quarter Fiscal Update. Edmonton, AB.

Alberta Environment. 2004. Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta. Edmonton, AB.

Athabasca Regional Issues Working Group. June 2004. Fact Sheet: Canada's Oil Sands.

Athabasca Regional Issues Working Group. November 2004. Update on the Oil Sands Industry.

Boyd, Fraser. 2004. Alberta Oil Sands and the Generic Royalty System. Calgary, AB.

Brethour, Partick. February 5, 2005. *TransCanada pipeline proposal fires up tension with Enbridge: Company becomes third to vie for right to transport Alberta oil sands crude.* Globe and Mail.

Brown, Michael. March 2, 2005. *Oil technologies continue to adapt to current demands.* Edmonton Sun. Edmonton, AB.

Canadian Association of Petroleum Producers. 2004. Crude Oil: Western Canada – Oil Sands – Offshore.

Canadian Association of Petroleum Producers. 2004. Canada's Oil and Gas Industry.

Canadian Natural Resources Ltd. February 10, 2005. Press Release.

Cox, James. September 12, 2004. *Oilsands abundance can't fill U.S. void: The reserves may surpass even those of Saudi Arabia, but will never be more than a drop in the bucket of U.S. Demand.* Calgary Herald.

Daly, David. 2005. Fiscal Challenges of the Canadian Oil and Gas Industry. Luncheon Presentation to the Economics Society of Calgary. Slides 1-33.

Environment Canada. 2004. Threats to Water Availability in Canada: NWRI Scientific Assessment Report Series No.3 and ACSD Science Assessment Series No. 1. National Water Research Institute.

Gray, James and Giannelia, Paul. 2004. NEATcor – The Right Answer. Presentation to the Alberta Region Alliance Fall Assembly.

Griffiths, Mary and Woynillowicz Dan. 2003. Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources. Pembina Institute for Appropriate Development.

Haavardsrud, Paul. February 14, 2005. *Heavy expectations riding on oilsands: Alberta production enters new era.* Calgary Herald. Calgary, AB.

Haggett, Scott. February 11, 2005. *Horizon gets green light: Canadian Natural Resources approves $10.8 billion project.* Calgary Herald. Calgary, AB.

Industry Canada. 2005. Trade By-product (HS) – HS Codes. *(Retrieved March 2, 2005 from http://strategis.gc.ca).*

Jaremko, Gordon. January 5, 2005. *New oilsands project interests China.* Canada.com News.

Lowey, Mark. February 3, 2005. *Oilsands projects spinning gold for Big 5: Staying in Billion-Dollar Club requires bitumen power.* Business Edge.

McCarthy, Shawn. February 9, 2005. *Syncrude chief extols oil sands to U.S. market: Reserves could account for a one-quarter of North American production by 2015.* Globe and Mail.

National Energy Board. 2004. Canada Oil Sands Opportunities and Challenges to 2015: An Energy Market Assessment.

National Energy Board. 2005. Canada Oil Sands Opportunities and Challenges to 2015: An Energy Market Assessment. Questions and Answers.

Oil Sands Discovery Centre. 2003. Professor Nositall's Fun Guide to the Oil Sands. Alberta Community Development.

Oil Sands Discovery Centre. Fact Sheets. Alberta Community Development.

Vivone, Rich. September 10, 2004. *Oil Sands is the Vehicle: Time to Build a Better Road.* Insight Into Government. Vol. 19, No.3.

Zahary, John. 2005. Issues Relating to Water in the Oil Sands. Alberta Chamber of Resources.

CanadaWest
FOUNDATION

Suite 900, 1202 Centre Street SE
Calgary, Alberta, Canada T2G 5A5
Telephone: 403.264.9535

www.cwf.ca