National Energy Board

Office national de l'énergie

Canada's Oil Sands:

Opportunities *and* Challenges *to* 2015

oil oil oil oil

An **ENERGY MARKET ASSESSMENT** • May 2004

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Acronyms and Abbreviations

ACA	Alberta Conservation Association
ACR	Advanced CANDU Reactor
AECL	Atomic Energy Canada Limited
AENV	Alberta Environment
AESO	Alberta Electric System Operator
AEUB	Alberta Energy and Utilities Board
ANS	Alaskan North Slope
AOSP	Athabasca Oil Sands Project
API	American Petroleum Institute
AOSPL	Alberta Oil Sands Pipeline
ARC	Alberta Research Council
ATC	Athabasca Tribal Council
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CANDU	Canadian Deuterium
CBM	Coal Bed Methane
CCME	Canadian Council of Ministers of the Environment
CEAA	Canadian Environmental Assessment Agency
CEMA	Cumulative Environmental Management Association
CERI	Canadian Energy Research Institute
CHOPS	Cold Heavy Oil Production with Sand
CHP	Combined Heat and Power
CFCs	Chlorofluorocarbons
CNRL	Canadian Natural Resources Limited
CONRAD	Canadian Oilsands Network for Research and Development
CSS	Cyclic Steam Stimulation
CT	Consolidated or Composite Tailings
DRU	Diluent Recovery Unit

EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EMA	Energy Market Assessment
EPEA	Environment Protection and Enhancement Act
ERCA	Energy Resources Conservation Act
FCC	Fluid Catalytic Cat-cracker
FERC	Federal Energy Regulatory Commission
GCOS	Great Canadian Oil Sands
GDP	Gross Domestic Product
GHG	Greenhouse Gases
ha	hectares
HCU	Hydrocracking Unit
HVDC	High Voltage Direct Current
IFN	Instream Flow Needs
IPS	Inclined Plate Settlers
LNG	Liquefied Natural Gas
LTBR	Long-term Bond Rate
MOU	Memorandum of Understanding
NEB	National Energy Board
NGL	Natural Gas Liquids
NO_X	Nitrogen Oxides
NRC	National Research Council of Canada
NRCan	Natural Resources Canada
NSMWG	NO_X and SO_2 Management Working Group
NYMEX	New York Mercantile Exchange
OCWE	OSLO Cold Water Extraction
OSCA	Oil Sands Conservation Act
OSEC	Oil Sands Environmental Coalition
OSLO	Other Six Lease Owners
OSWRTWG	Oil Sands Water Release Technical Working Group
PADD	Petroleum Administration for Defense District
PAH	Polycyclic Aromatic Hydrocarbons
PC	Progressive Cavity
PLA	Public Lands Act
PM	Particulate Matter
PNW	Pacific Northwest
PREP	Peace River Expansion Project

PSV	Primary Separation Vessels
RAMP	Regional Aquatics Monitoring Program
RAQCC	Regional Air Quality Coordinating Committee
RAS	Remedial Action Schemes
RGS	Regional Geological Study
RIWG	Regional Issues Working Group
RMWB	Regional Municipality of Wood Buffalo
RPP	Refined Petroleum Products
RSDS	Regional Sustainable Development Strategy
SAGD	Steam Assisted Gravity Drainage
SAP	Solvent Assisted Production
SC	Sulphur Compound
SCO	Synthetic Crude Oil
SGL	Synthetic Gas Liquids
SO_2	Suphur Dioxide
SOR	Steam-to-oil Ratio
SWWG	Surface Water Working Group
TEEM	Terrestrial Environmental Effects Monitoring
THAI	Toe-to-Heel Air Injection
TSC	Technical Solutions Committee
TOR	Tailings Oil Recovery
U/R/E	Upgrader, refinery, and ethylene complex
USGC	U.S. Gulf Coast
UTF	Underground Test Facility
VAPEX™	Vapour Extraction Process
VDU	Vacuum Distillation Unit
VOC	Volatile Organic Compound
VGO	Vacuum Gas Oil
WBEA	Wood Buffalo Environmental Association
WCSB	Western Canada Sedimentary Basin
WRA	Water Resources Act
WTI	West Texas Intermediate
WTS	West Texas Sour

FOREWORD

The National Energy Board (NEB or the Board) was created by an Act of Parliament in 1959. The Board's regulatory powers under the *National Energy Board Act* include the authorization of exports of oil, natural gas, natural gas liquids and electricity; the authorization of the construction of interprovincial and international oil, gas and commodities pipelines and international power lines; the setting of just and reasonable tolls for pipelines under federal jurisdiction; and the regulation of oil and gas activities on Canada lands in the north.

As part of its mandate, the Board is required to keep under review the outlook for the supply of all energy commodities (including oil, natural gas, natural gas liquids and electricity) and the demand for Canadian energy commodities in both domestic and export markets. The Board publishes reports, known as Energy Market Assessments (EMA), to provide analyses of the major energy commodities on either an individual or integrated basis.

In October 2000, the Board released an EMA entitled *Canada's Oil Sands: A Supply and Market Outlook to 2015*. In the course of carrying out its analyses in the 2003 report entitled *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, a number of significant issues surrounding the oil sands were identified. As a result, the Board decided to prepare this second oil sands EMA entitled, *Canada's Oil Sands: Opportunities and Challenges to 2015*. The key objectives of the report are to update the supply and demand aspects contained in the first EMA and to provide a comprehensive assessment of the opportunities and issues facing the oil sands.

In November 2003, the Board conducted an informal roundtable discussion with selected stakeholders to provide parties the opportunity to comment on the Board's identification of the key issues and opportunities surrounding the oil sands. As well, the Board conducted a series of informal meetings with a cross-section of oil sands stakeholders, including producers, refiners, marketers, pipelines, electricity and petrochemical officials, industry associations, consultants, government departments and agencies, and environmental groups. The NEB greatly appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material, as it can submit any public document. In such case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

EXECUTIVE SUMMARY

Introduction

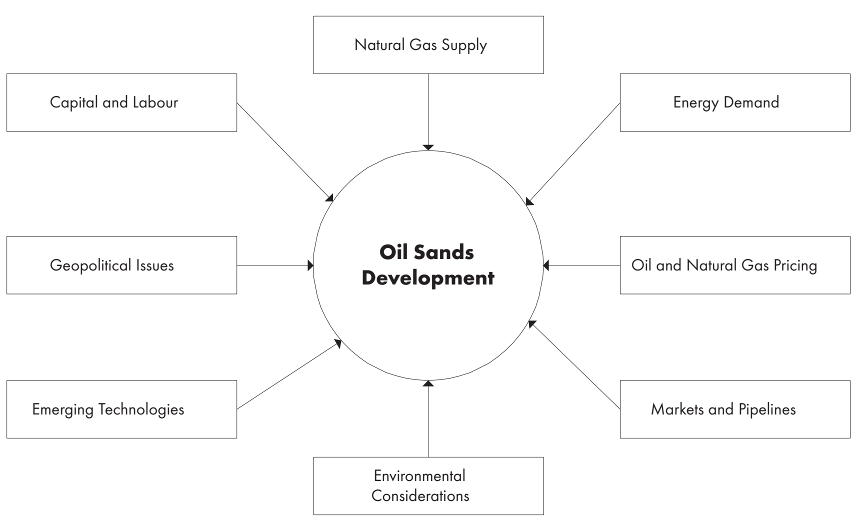
In October 2000, the Board released an Energy Market Assessment (EMA) entitled *Canada's Oil Sands: A Supply and Market Outlook to 2015*. In the course of carrying out its analyses in connection with the 2003 report entitled *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (NEB Supply and Demand Report), the Board identified a number of important opportunities and challenges facing the oil sands. As a result, the Board decided to embark on a subsequent report *Canada's Oil Sands: Opportunities and Challenges to 2015*.

The primary purpose of the report is to provide an objective assessment of the current state of the oil sands industry and of the potential for growth. In addition, it identifies and discusses the major issues and challenges associated with further development and, in this regard, the report is intended to further the public dialogue.

Canada's oil sands are one of the world's largest hydrocarbon resources. While the resource has long been known, initial production began only in 1967. In recent years, higher energy prices, together with significant strides in technology, have made this resource increasingly more economic to develop. Internationally, the economic potential of the resource has been recognized. In 2004, Canadian oil sands production will surpass 160 000 m^3/d (1.0 mmb/d); by 2015, production is expected to more than double. Growth in global oil demand indicates that markets will exist for the rising oil sands output. As industry strives to take advantage of this, significant challenges must be overcome, including sharply higher natural gas prices, capital cost overruns and environmental impacts.

The diagram to the right illustrates the major factors that will influence the pace of oil sands development.

Oil Sands Development: Driving Forces



Alberta's oil sands hold tremendous potential for all Canadians by helping to secure our energy future and by contributing to economic growth. Efficient development of the resource will require continued ingenuity and cooperation among industry stakeholders, regulatory agencies and a supportive market environment.

Key assumptions used to develop the report are as follows:

- the West Texas Intermediate (WTI) crude oil price is US$24 per barrel (2003 dollars);
- the NYMEX natural gas price is US$4.00 per MMBtu (100 percent of the crude oil price on an energy equivalent basis);
- the light/heavy crude oil price differential (Par versus Lloydminster Blend) is US$7 per barrel; and,
- the Canadian dollar is valued at US$0.75.

The report can broadly be considered as having four key components:

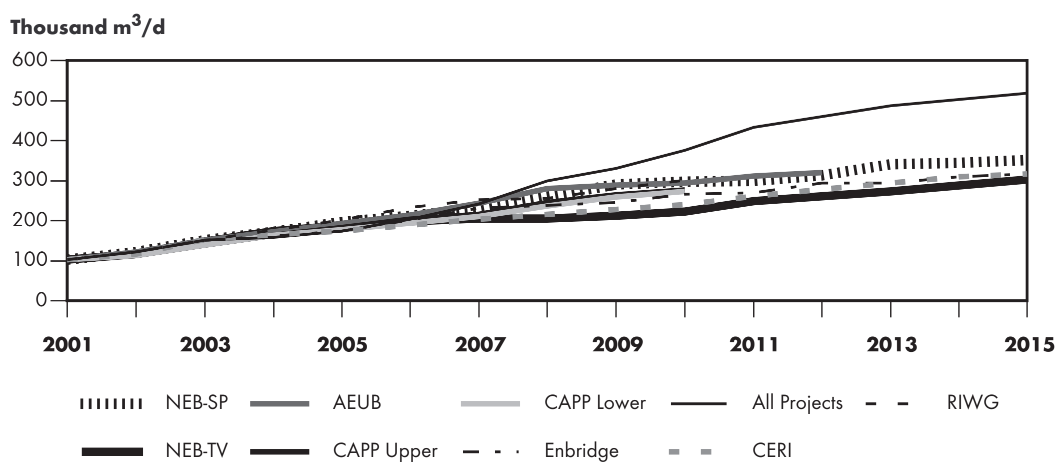
- economic potential and development of the resource base;
- markets and pipelines;
- environmental and socio-economic impacts; and,
- potential spin-off developments in the electricity and petrochemical industries.

Key Findings

Economic Potential and Development of the Resource Base

According to the Alberta Energy and Utilities Board (AEUB), the initial volume of crude bitumen in place is estimated to be approximately 260 billion cubic metres (1.6 trillion barrels), with 11 percent or 28 billion cubic metres (175 billion barrels) recoverable under current economic conditions. Continually improving economics, bolstered by recent higher crude oil prices, has resulted in the international recognition of the vast potential of Canada's oil sands.

In Situ Bitumen and Synthetic Crude Oil Supply Projections



Based on publicly announced development plans through to 2015, over C$60 billion could be invested in numerous projects to develop the oil sands (approximately C$20 billion has been invested to-date in completed projects). These announced development plans comprise more than 60 ventures, including mining and in situ projects, as well as supporting facilities and pipeline expansions. Ongoing volatility in crude oil prices is expected and suggests that it is unlikely that the entire C$60 billion in projects will be constructed within the planned timeframe. Market conditions will determine the pace of oil sands development. The previous chart shows several industry and government projections for in situ bitumen and synthetic crude oil production. As mentioned previously, compared with production of about 160 000 m^3/d (1.0 mmb/d) in 2004, output is expected to more than double by 2015.

The table illustrates estimated operating and supply costs for various types of oil sands recovery methods. Supply costs for mining/extraction and upgrading are expected to decline as technologies improve and operators gain experience. Similarly, as relatively new technologies such as Steam Assisted Gravity Drainage (SAGD) mature and as new generations of in situ processes achieve commercial viability, it is expected that in situ supply costs will exhibit a profile of comparable improvement. Project economics for mining/extraction and upgrading are highly sensitive to capital costs. The scale of development, involving a number of projects taking many years to complete and costing several billion dollars, has become a challenge. Industry is adopting several strategies to improve project management in order to avoid future cost overruns.

Estimated Operating and Supply Costs by Recovery Type

C$(2003) per barrel at the Plant Gate	**Crude Type**	**Operating Cost**	**Supply Cost**
Cold Production – Wabasca, Seal	Bitumen	4 to 7	10 to 14
Cold Heavy Oil Production with Sand (CHOPS) - Cold Lake	Bitumen	6 to 9	12 to 16
Cyclic Steam Stimulation (CSS)	Bitumen	8 to 14	13 to 19
Steam Assisted Gravity Drainage (SAGD)	Bitumen	8 to 14	11 to 17
Mining/Extraction	Bitumen	6 to 10	12 to 16
Integrated Mining/Upgrading	Synthetic	12 to 18	22 to 28

Natural gas use in oil sands operations is extensive. Gas costs can comprise up to 50 percent or more of total operating costs in a thermal in situ project. Natural gas production from the Western Canada Sedimentary Basin (WCSB) is expected to flatten and demand to increase. As well, there will continue to be volatility in gas prices, and the economics of using natural gas as the primary source of fuel will become less attractive. In this connection, companies are developing innovative technologies designed to reduce or eliminate the need for natural gas in oil sands operations. The bitumen gasification process at the proposed Nexen/OPTI Long Lake project and fuel switching capabilities at Suncor's Firebag project are prime examples. Nuclear energy appears to be a viable option from an economic viewpoint; however, major hurdles exist in terms of public and industry acceptance.

Emerging technologies such as Vapour Extraction Process (VAPEX™) and Toe-to-Heel Air Injection (THAI) have the potential to substantially reduce the energy intensity and the environmental impacts of production. In addition, in order to reduce exposure to the light/heavy differential and the rising cost of diluent, it is anticipated that some upgrading capacity will be added for in situ projects.

Markets and Pipelines

Based on broad consultation with industry and the Board's own assessment, it appears that there will be markets for increased oil sands production.

Canadian oil sands producers are creative in finding outlets for the rising output. Initiatives include, in no particular order: purchasing refineries; tailoring output quality to fit a specific refiner/buyer; upgrading to make a saleable light quality crude oil; developing long-term partnership arrangements to enable refiners to retrofit their plants to accommodate a specific grade of oil sands crude; and allowing test batches to be run by refiners to determine how a specific oil sands crude fits their crude slate. There could, however, be periods when significant price discounts are temporarily required to penetrate new or existing markets. The table below outlines a potential scenario for accessing markets for the rising oil sands supply.

Potential Markets for Oil Sands Production

Steps	Potential Markets	Timeframe	Added Production (m^3/d)
1	Washington State, PADD IV, northern PADD II, domestic markets (small volumes)	2004– 2008	65 000 – 80 000
2	eastern PADD II, southern PADD II, new cokers in PADDs I, II and IV, Edmonton		
3	PADD III		
4	California, Far East, eastern Canada	2009	65 000

The pace of pipeline capacity expansion is dependent on market conditions. Industry will not add capacity unless it is reasonably certain that supply and markets exist. Producers will be looking for the most economical markets for their production, and pipelines will, in turn, expand or be built to connect these markets. The following table summarizes the announced and proposed expansion plans of NEB regulated pipelines.

Announced and Proposed Capacity Expansions[1] by NEB Regulated Pipelines

	Capacity Increase (m^3/d)	Anticipated Completion Date
Terasen (TMPL)	4 300	Sep-04
Express	17 600	Apr-05
Terasen (TMPL TMX1)	15 900	End 2007 to Mid-2008
Terasen (TMPL TMX2)	15 900	Mid-2008
Enbridge (Mainline)	To be determined	2008 - 2010
Enbridge (Gateway)	63 600	By 2009
Terasen (TMPL TMX3)	63 600	To be determined
Overland (Hardisty to California)	47 600	To be determined

1 All expansions are subject to approval by the National Energy Board.

Environmental and Socio-economic Impacts

The cumulative environmental effects of development are beginning to be considered in a coordinated manner. Oil sands developers are taking advantage of new opportunities and technologies as well as synergies in their operations to improve environmental performance and create positive changes in nearby communities.

The economic benefits associated with development of the oil sands are considerable. If poorly managed, however, this development has the potential to impose negative socio-economic impacts on communities in the surrounding regions. Although employment opportunities have grown, the steady population growth has placed strains on the local infrastructure and services. Stakeholders have demonstrated a strong dedication to preserving the social well-being of communities and this is expected to continue.

Potential Spin-off Developments in the Electricity and Petrochemical Industries

Cogeneration of steam and electricity holds synergies for oil sands operations by lowering energy costs and improving electricity reliability. Typically, excess electricity generated above project requirements is sold into the Alberta power pool at a relatively low cost. Excess electricity, therefore, provides a potential source of revenue for producers and inexpensive energy for use in Alberta, or for export. Currently, however, electrical transmission capacity out of the Fort McMurray area is constrained. The challenge is to create an environment where producers are encouraged to maximize cogeneration capacity.

The core of Canada's petrochemical industry is located in Alberta and is based on natural gas-derived ethane. Since the late 1990s, in response to flattening natural gas production from the WCSB and rising demand, natural gas prices, and therefore ethane prices, have increased significantly. The Alberta petrochemical sector now faces a situation of tight ethane feedstock supply. The bitumen upgrading process produces off-gas from which ethane; ethylene and other light hydrocarbons could be extracted. Currently, most of this potential feedstock is not removed but is used as fuel in operations. By 2015, however, market conditions may evolve so that Alberta's huge bitumen resource base could provide a secure, substantial, and stable-priced feedstock for the petrochemical industry.

Introduction

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Canada's oil sands are a substantial resource. According to the Alberta Energy and Utilities Board (AEUB), the initial volume of crude bitumen in place is estimated to be approximately 260 billion cubic metres (1.6 trillion barrels), with 11 percent or 28 billion cubic metres (175 billion barrels) recoverable under current economic conditions.

Based on publicly announced development plans through to 2015, over C$60 billion could be invested in numerous projects to develop the oil sands (approximately C$20 billion has been invested to-date in completed projects). These announced development plans consist of more than 60 ventures, including mining and in situ projects in the Athabasca, Cold Lake and Peace River oil sands areas, as well as supporting facilities and pipeline expansions. Ongoing volatility in crude oil prices is expected, and suggests that it is unlikely that the entire C$60 billion in projects will be constructed within the planned timeframe. Market conditions will determine the pace of oil sands development.

The main reasons for the rapid pace of development in the oil sands include:

- more accessible markets due to the decline of North American conventional oil production and growth in oil demand;
- reductions in supply costs for both in situ and mining operations, and expected further improvements driven by technological innovation and operational learning; and,
- recent high crude oil prices and an optimistic price outlook for the future.

Key assumptions used to develop the report are as follows:

- the West Texas Intermediate (WTI) crude oil price is US$24 per barrel (2003 dollars);
- the NYMEX natural gas price is US$4.00 per MMBtu (100 percent of the crude oil price on an energy equivalent basis);
- the light/heavy crude oil price differential (Par versus Lloydminster Blend) is US$7 per barrel; and,
- the Canadian dollar is valued at US$0.75.

For the supply cost estimates, sensitivities around the oil price, natural gas price, exchange rate, and other cost components were carried out.

The report can broadly be considered as having four key components:

- economic potential and development of the resource base;
- markets and pipelines;
- environmental and socio-economic impacts; and,
- potential spin-off developments in the electricity and petrochemical industries.

The primary purpose of the report is to provide an objective assessment of the current state of the oil sands and of the potential for growth. In addition, it identifies and discusses the major issues and challenges associated with further development and, in this regard, the report is intended to further public dialogue.

The following summarizes the content of the report:

- Chapter 1 is an introduction to the report;
- Chapter 2 examines the size of the resource base and the reserves that are estimated to be economically recoverable;
- Chapter 3 discusses supply costs for the various types of bitumen recovery and upgrading methods;
- Chapter 4 shows supply projections to the year 2015 for synthetic crude oil and bitumen;
- Chapter 5 focuses on the market potential for the rising supply;
- Chapter 6 examines the existing pipeline network and future expansion plans to move the expected incremental supply to market;
- Chapter 7 sets out the environmental impacts of oil sands activities on water, land, and air quality, and discusses socio-economic impacts;
- Chapter 8 reviews the significance of natural gas in developing oil sands supply;
- Chapters 9 and 10 discuss the opportunities and challenges for the electricity and petrochemical industries, respectively, arising from future oil sands development; and,
- Chapter 11 provides a review of major emerging technologies that could have a substantial impact on future supply.

Oil Sands Resources

2.1 Introduction

Canada's oil sands deposits contain a vast quantity of crude bitumen (bitumen), with this resource being well delineated and defined through many years of exploration and development work. This presents a tremendous opportunity to oil sands developers because the exploration risk is low, projects have the potential to produce for 30 to 40 years with no decline in production rates, and there may be opportunities for several phases of project expansion.

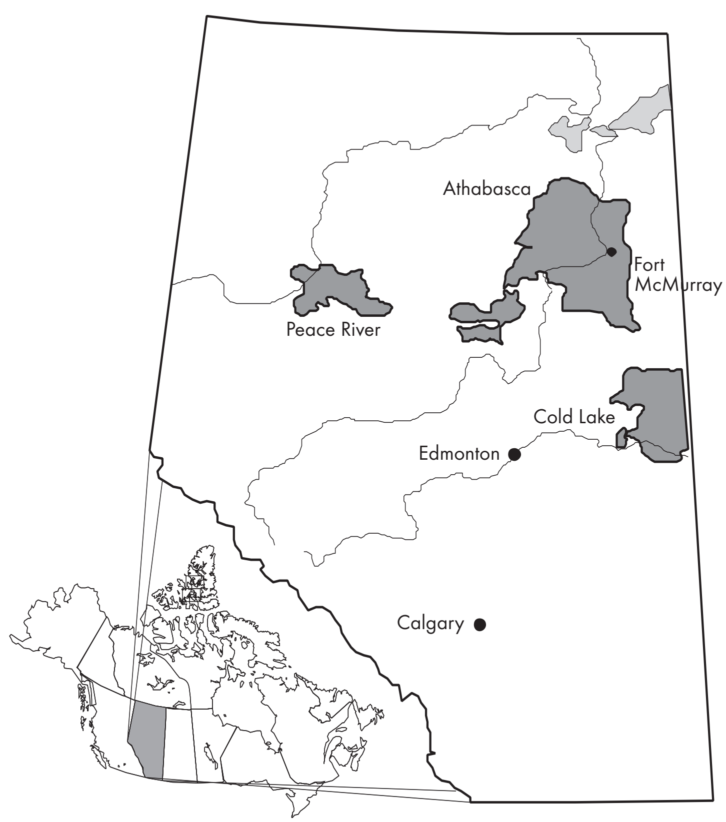
This chapter presents a brief description of the location, size and characteristics of Canada's oil sands resources.

2.2 Bitumen Resources

Canada's bitumen resources are situated almost entirely within the province of Alberta, with only minor oil sands deposits found on Melville Island in Canada's Arctic Island region, and minor showings of oil shale on the eastern edge of the Western Canada Sedimentary Basin (WCSB). Alberta's oil sands deposits are grouped on the basis of geology, geography and bitumen content, and are defined as the Peace River, Athabasca and Cold Lake Oil Sands Areas (Figure 2.1). The bitumen deposits in these three areas are found in sedimentary formations of sand and carbonate that collectively cover roughly six million hectares (ha), an area comparable in size to the province of New Brunswick, or to the countries of Scotland or Ireland.

FIGURE 2.1

Oil Sands Areas



The NEB adopts the bitumen resource estimates published by the Alberta Energy and Utilities Board (AEUB). The AEUB estimates the initial volume-in-place to be 259.2 billion cubic metres (1.6 trillion barrels), based on currently available data. The AEUB further estimates the ultimate volume in place, a value representing the volume expected to be found by the time all exploratory and development activity has ceased, to be 400 billion cubic metres (2.5 trillion barrels). Of this amount, 22 billon cubic metres (140 billion barrels) are categorized as amenable to surface mining and the remaining 378 billion cubic metres (2.4 trillion barrels) amenable to in situ recovery or underground mining methods. The division between surface mining and in situ areas is based on the thickness of the surface cover, or overburden, situated above the bitumen deposit, with mining operations generally limited to areas where the overburden thickness is 75 metres or less. Of the ultimate in-place volume, about 12 percent or some 50 billion cubic metres (315 billion barrels) is estimated to be recoverable. The estimation of the initial established reserves of bitumen takes into account current technology as well as current and anticipated economic conditions. Initial established reserves are estimated to be 28.3 billion cubic metres (178 billion barrels), made up of 5.6 billion cubic metres (35 billion barrels) in the surface-mineable areas and 22.7 billion cubic metres (143 billion barrels) for the in situ areas.

The resource and reserves estimates are summarized in Table 2.1.

2.3 World Oil and Bitumen Resources

In early 2003, the Oil & Gas Journal and Cambridge Energy Research Associates recognized AEUB's estimates for established reserves of bitumen, for the first time, in their listing of world oil reserves. Based on this listing, Canada ranks second in the world (Figure 2.2). Other groups maintain that the AEUB's evaluation methodology is not sufficiently rigorous to meet the strict definition of reserves, since large capital investments in facilities are required to develop the resources. Specifically, they would recognize reserves on a project-by- project basis, when proven by the installation of facilities and the successful operation of the project. Adherence to the stricter definition, however, makes it difficult to properly portray the realistic potential for the economic development of the oil sands resource.

TABLE 2.1

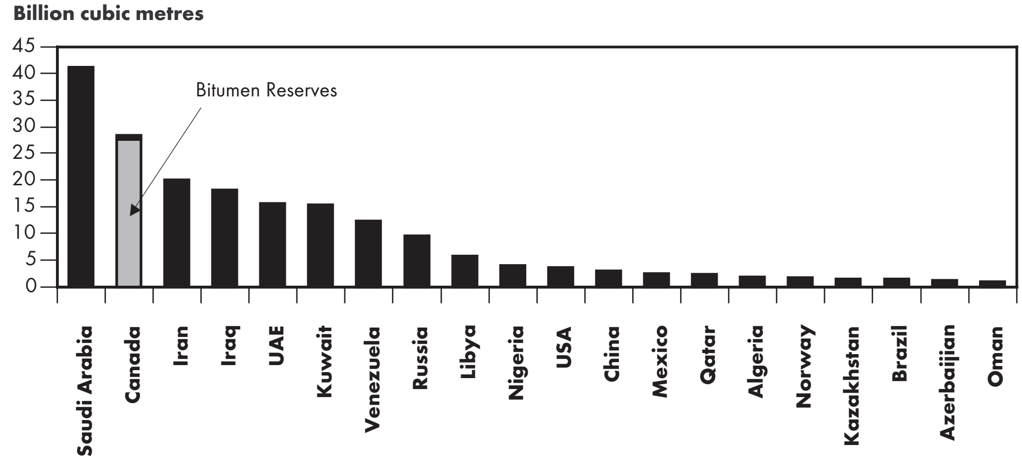
Bitumen Resources

(Billion m^3)	Ultimate Volume In Place	Initial Volume In Place	Ultimate Recoverable Volume	Initial Established Reserves	Cumulative Production	Remaining Established Reserves
Mineable						
Athabasca	22.0	18.0	11.0	5.6	0.4	5.2
In Situ						
Athabasca	n/a	188.8	n/a	n/a	n/a	n/a
Cold Lake	n/a	31.9	n/a	n/a	n/a	n/a
Peace River	n/a	20.5	n/a	n/a	n/a	n/a
Subtotal	378.0	241.2	39.0	22.7	0.2	22.5
Total	**400.0**	**259. 2**	**50.0**	**28.3**	**0.6**	**27.7**

Source: AEUB

FIGURE 2.2

World Oil Reserves - Top 20



Source: Oil and Gas Journal.

The bitumen resources contained in Alberta's oil sands constitute one of the world's largest known deposits of liquid hydrocarbons. While the current estimate of the ultimately recoverable volume represents only 12 percent of the estimated volume of bitumen in place, there is considerable potential for this percentage to increase as advances are made in recovery technology. The initial established reserves, estimated to be 28.3 billion cubic metres (178 billion barrels), would be sufficient to satisfy total domestic demand for crude oil, at current rates, for approximately 250 years.

Venezuela's Orinoco Belt also contains vast hydrocarbon resources, but these are generally referred to as heavy and extra-heavy crude oil (greater than 1 000 kg/m^3), rather than crude bitumen. These deposits are estimated to contain oil-in-place of 300 billion cubic metres (1.9 trillion barrels), ultimate recoverable reserves of 43.2 billion cubic metres (272 billion barrels)[1] and proven reserves of 12.3 billion cubic metres (77.8 billion barrels).

Canada's and Venezuela's non-conventional oil resources constitute a major part of the world's remaining oil resources and will be increasingly needed in the future.

2.4 Oil Sands and Bitumen Characteristics

The oil sands deposits are composed primarily of quartz sand, silt and clay, water and bitumen, along with minor amounts of other minerals, including titanium, zirconium, tourmaline and pyrite[2]. Although there can be considerable variation, a typical composition would be:

- 75 to 80 percent inorganic material, with this inorganic portion comprised of 90 percent quartz sand;
- 3 to 5 percent water; and,
- 10 to 12 percent bitumen, with bitumen saturation varying between zero and 18 percent by weight.

1 7th UNITAR International Conference on Heavy Crude and Tar Sands.

2 For a more complete review of oil sands, bitumen, reservoir characteristics and geological setting, please refer to the Board's earlier report *Canada's Oil Sands: A Supply and Market Outlook to 2015*, available at www.neb-one.gc.ca

The oil sands are generally unconsolidated and thus quite friable and crumble easily in the hand.

The bitumen contained in the oil sands is characterized by high densities, very high viscosities, high metal concentrations and a high ratio of carbon-to-hydrogen molecules in comparison with conventional crude oils. With a density range of 970 to 1 015 kg/m^3 (8 to 14 °API), and a viscosity at room temperature typically greater than 50 000 centipoise, bitumen is a thick, black, tar-like substance that pours extremely slowly.

Bitumen is deficient in hydrogen, when compared with typical crude oils, which contain approximately 14 percent hydrogen. Therefore, to make it an acceptable feedstock for conventional refineries, it must be upgraded through the addition of hydrogen or the rejection of carbon. In order to transport bitumen to refineries equipped to process it, bitumen must be blended with a diluent, traditionally condensate, to meet pipeline specifications for density and viscosity.

2.5 Conclusion

Alberta's oil sands collectively contain a vast bitumen resource - one of the largest known hydrocarbon deposits in the world. With established reserves estimated to be 28.3 billion cubic metres (178 million barrels), it ranks second only to Saudi Arabia in terms of reserves, a fact recognized by the Oil & Gas Journal and Cambridge Energy Research Associates for the first time in 2003.

The oil sands deposits are composed primarily of quartz sand, silt and clay, water and about 10 to 12 percent bitumen, a very heavy, viscous, tar-like substance, deficient in hydrogen. Its transportation requires blending with a diluent, and it must be upgraded to create an acceptable feedstock for conventional refineries.

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Additional Reading

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Supply Costs

3.1 Introduction

Supply costs are a significant factor in determining the economic potential of Canada's oil sands resource base. Since the commercialization of the oil sands began with the Great Canadian Oil Sands Company in 1967, supply costs have fallen dramatically, which has contributed to further development of the resource. Today, a vibrant industry exists and billions of dollars in projects are being proposed. The industry does, however, face a number of challenges, including higher natural gas costs, the costs related to meeting evolving environmental standards, and most recently, substantial capital cost overruns.

Table 3.1 provides a snapshot of current oil sands operating costs and supply costs for major recovery methods. Operating costs can generally be considered as reflecting the cash costs of operation, while supply costs include all costs associated with production, including operating costs, capital costs, taxes, royalties and a rate of return on investment. Compared with the Board's previous report, *Canada's Oil Sands: A Supply and Market Outlook to 2015*, published in October 2000, some of the costs in this table are significantly higher. The primary reasons for the changes are higher natural gas prices, and increasing capital costs for project construction.

In this report, "integrated mining" refers to surface-mining/extraction and upgrading operations, while "mining/extraction" refers to oil sands surface-mining/extraction projects that do not include an on-site upgrader. "In situ" refers to all in situ operations, including cold (non-thermal) bitumen recovery operations.

T A B L E 3 . 1

Estimated Operating and Supply Costs by Recovery Type

C$(2003) per barrel at the Plant Gate	**Crude Type**	**Operating Cost**	**Supply Cost**
Cold Production – Wabasca, Seal	Bitumen	4 to 7	10 to 14
Cold Heavy Oil Production with Sand (CHOPS) - Cold Lake	Bitumen	6 to 9	12 to 16
Cyclic Steam Stimulation (CSS)	Bitumen	8 to 14	13 to 19
Steam Assisted Gravity Drainage (SAGD)	Bitumen	8 to 14	11 to 17
Mining/Extraction	Bitumen	6 to 10	12 to 16
Integrated Mining/Upgrading	Synthetic	12 to 18	22 to 28

3.2 Methodology

3.2.1 Supply Cost Methodology

Supply costs are expressed as full cycle, which includes all costs associated with exploration, development and production. They include capital costs, operating costs, taxes and royalties and a 10 percent real rate of return (12 percent nominal) to the producer. Supply costs do not include any costs to society associated with environmental impacts that have not been mitigated. In this report, the supply costs are quoted in Canadian dollars (real 2003) per barrel unless otherwise noted.

Estimates of supply costs are based on the Board's own analysis, consideration of the announced development plans for mining and in situ projects, research of trade literature, and discussions with industry. Supply costs are stated as a range, reflecting variables such as: reservoir quality, depth of the producing formation, project size, recovery method and operating parameters.

3.2.2 Project Economic Evaluation Methodology

It is anticipated that increased oil sands supply to 2015 will be driven primarily by development in the Athabasca oil sands region using surface mining and Steam Assisted Gravity Drainage (SAGD) recovery methods. In order to promote a better understanding of the factors that determine the economic viability of oil sands development, the Board has conducted economic evaluations for representative oil sands projects employing these major recovery methods.

A discounted cash flow model was used to conduct project economic evaluations. The resulting supply cost value is the constant dollar crude oil price required over the life of the project to cover all costs, except land acquisition costs that can vary widely, and provide a rate of return on investment. The Canadian Energy Research Institute (CERI) report, *Oil Sands Supply Outlook: Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada 2003-2017*, has been referenced extensively. The model employed by CERI is similar to that applied in this report; however, there are differences in forward-looking assumptions and project scale that contribute to differing supply cost estimates.

Projects were evaluated on a stand-alone basis. In reality, some companies in a fully taxable position may benefit from the flow-through of tax losses; in such a case, supply costs would be somewhat reduced. A crude oil price of US$24 (C$32) per barrel (2003 dollars) for WTI at Cushing, Oklahoma and a NYMEX natural gas price of US$4.00 (C$5.33) per MMBtu (2003 dollars) were used in the analysis. A discount rate of 12 percent was applied. This rate is somewhat higher than the estimated cost of capital for the oil and gas industry and is intended to reflect some of the added uncertainties of oil sands development and the magnitude of investment. Historically, there have been significant improvements in operating costs and the Canadian oil sands industry is still maturing; therefore, further cost reductions are anticipated. In this connection, consideration for future improvement in operating costs was incorporated into the project economic evaluations for both SAGD and mining. Economic and market assumptions are available in Appendix 1 and major modelling assumptions are available in Appendix 2 and 3.

The supply cost estimates for SAGD, mining/extraction, and integrated mining/upgrading, presented in Table 3.1 are not directly comparable with the results of the project economic evaluations of Sections 3.3 and 3.4. Unlike Table 3.1, which provides a snapshot of current supply costs, the supply costs generated by the project economic evaluation models provide the constant dollar price that is required over the life of the project. In these models, costs in the initial years of operation are higher than costs in the final years of operation. In addition, estimates for SAGD and Mining/Extraction, presented in Table 3.1, are per barrel of bitumen, which differs from the supply cost model results of Sections 3.3 and 3.4, which provide estimates for bitumen blend at the plant gate.

3.3 Oil Sands Mining

3.3.1 Introduction

The first two integrated mining projects, Great Canadian Oil Sands Company (now Suncor), which began operations in 1967, and Syncrude, which commenced in 1978, suffered from start-up problems. It took several years for reasonably stable production operations to be established. Early supply costs are estimated to have been $35 per barrel or more (dollars of the day). Substantial reductions in costs have been achieved through continual process improvement, but more dramatically through two major innovations in the 1990s. First, there was a move towards replacing the draglines and bucketwheel reclaimers with more flexible, robust, and energy efficient trucks and power shovels. Second, hydrotransport systems were introduced to replace the conveyor belts used to transport oil sands to the processing plant. Currently, much attention is being directed toward maintaining stable production by minimizing unplanned maintenance, which can significantly reduce production capabilities and increase operating costs.

Since 1997, operating costs for Suncor and Syncrude have generally been in the range of $12 to $18 per barrel with variations largely due to natural gas price volatility, planned and unplanned maintenance turnaround costs and project start-up costs related to expansions. At the time of writing, the Athabasca Oil Sands Project (AOSP), a Shell Canada Limited (Shell), Western Oil Sands Inc., and Chevron Canada Limited (Chevron) joint venture, had not yet achieved steady-state operations. The potential exists to lower operating costs for integrated mining and upgrading to below $10 per barrel within the timeframe of this report.

Capital costs can vary widely depending on the chosen technology and the targeted quality of synthetic crude oil (SCO) that the project is designed to produce. These differences prevent meaningful comparison of projects based solely on capital costs. In addition, because of the differences in the timing of project construction, the impact of inflation should also be considered. Capital costs can also be impacted greatly by the effectiveness of project management. Industry has become increasingly aware of the importance of managing capital costs, which run in the billions of dollars. Table 3.2 displays a summary cost-per-barrel analysis of the four major operating and planned integrated mining projects.

Suncor Energy's (Suncor's) Millennium project, completed in 2001, and AOSP, completed in 2003, experienced capital cost increases of more than 60 percent above initial estimates while Syncrude

TABLE 3.2

Integrated Mining: Project Capital Costs

Project	Bitumen (b/d)	SCO (b/d)	Capital ($MM)	Unit Cost ($/SCO b/d)	Primary Upgrading Technology
Suncor Millennium (1998 – 2001)	130,000	110,000	3,400*	30,909	Delayed Coking
Syncrude Stage 3 (2000 – 2006)	125,600	112,000	7,800**	69,643	Fluid Coking
Athabasca Oil Sands Project (AOSP) (1999 – 2003)	161,290	153,225	5,700	37,200	LC-Fining
CNRL Horizon (2004 – 2011)	270,000	232,000	8,500	36,210	Delayed Coking

* Does not include third party costs for cogeneration.

** Includes capital to improve base plant and the quality of existing production.

Canada Ltd.'s (Syncrude's) Stage 3 expansion is also significantly over its initial budget. The primary reason behind these cost increases is lower productivity of labour as a result of concurrent construction phases, which put a heavy strain on a limited supply of skilled tradespersons. Another contributing factor is the massive scope and complexity of these projects, which present special challenges in project management. Recent estimates of capital costs for planned mining projects are considered to be more accurate in that project planners and evaluators have learned from the experiences of Millennium, AOSP and Syncrude's Stage 3 expansion.

The industry has adopted several strategies to help maintain capital budgets and construction schedules:

- improved project management through tighter control;
- industry-government partnerships in education to help prepare a workforce for future employment opportunities in the oil sands industry;
- earlier completion of engineering work and increased modularization of construction components that will improve labour productivity; and,
- better materials management practices that will help avoid on-site delays.

Current supply costs for integrated mining and upgrading projects are estimated to be in the range of $22 to $28 per barrel for SCO. Presently, there are no producing oil sands mining and extraction projects that do not include on-site upgrading; however, such projects have been proposed, including True North's Fort Hills (now delayed indefinitely) and Deer Creek's Joslyn Creek mine. Supply costs for mining/extraction without upgrading are estimated to be in the range of $12 to $16 per barrel of bitumen.

Section 3.3.2 and Section 3.3.3 provide economic evaluations for integrated Athabasca mining and Athabasca mining and extraction projects, respectively. A discussion of the major cost components of operations and specific industry challenges is also included.

3.3.2 Project Economic Evaluation - Integrated Mining/Extraction and Upgrading

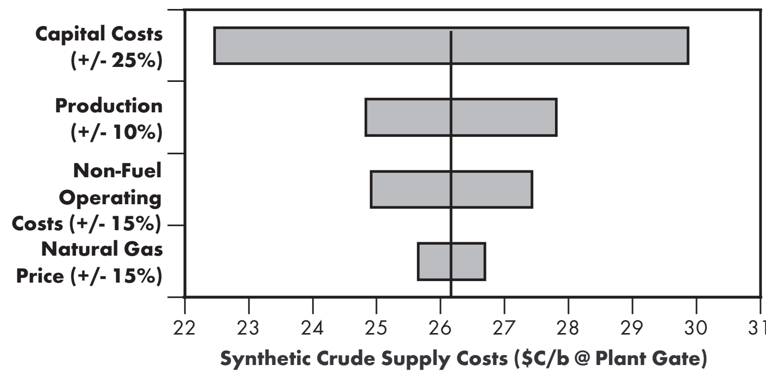
An economic evaluation for a 31 700 m^3/d (200 mb/d) mining/extraction and upgrading operation has been performed. This model is intended to emulate a greenfield project with construction beginning in 2004 and first production in 2008. The mining project evaluated is assumed to produce SCO of 36 °API and sulphur content of 0.015 percent, which would be of similar quality and assumed value to conventional light oil. The model results indicate a supply cost for SCO at the plant gate of about $26 per barrel.

Figure 3.1 shows the results of a sensitivity analysis for the factors that account for much of the volatility in the SCO supply cost. The supply cost for mining produced SCO is highly sensitive to capital costs. A 25 percent change in capital costs result in an estimated $3.70 per barrel change in supply cost. A 10 percent decrease in production, for a given capacity design, results in an increase in supply cost of approximately $1.50 per barrel.

Supply cost is also sensitive to non-fuel operating costs, which include purchased power, administration, environmental, and other direct costs. On-site cogeneration facilities limit exposure to fluctuations in electricity prices since required purchased energy is typically minimal. The implementation of more stringent environmental regulation may affect supply costs. However, Suncor's preliminary analysis of the Kyoto Accord through to 2012 predicts that the impact on supply cost will be manageable at approximately $0.20 to $0.27 per barrel.

F I G U R E 3 . 1

Supply Cost Sensitivities: 200 mb/d Athabasca Mining/Extraction and Upgrading Project



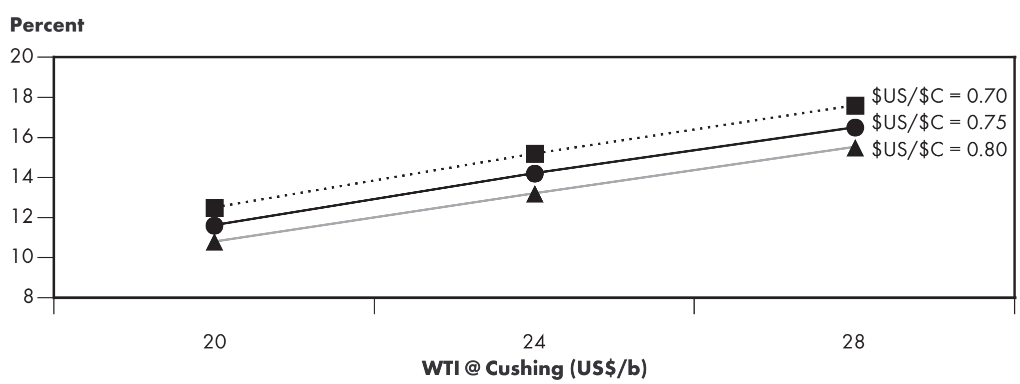
Integrated mining projects use natural gas to produce heat energy, electric power, and as a source of hydrogen for hydrotreating in the upgrading process. Natural gas is both produced and purchased by the operation. In the most commonly employed upgrading technology, the coking process, approximately 35 percent of the natural gas required is produced by the upgrader while the remaining 65 percent must be purchased externally. The required purchase of natural gas is substantial at approximately 0.75 Mcf per barrel of SCO produced. A 15 percent change in the price of natural gas results in a change of about $0.50 per barrel in SCO supply cost.

The economic performance of an integrated mining project is also very sensitive to market conditions including the world price of oil and the currency exchange rate between the United States and Canada. Figure 3.2 illustrates the economic performance of an integrated mining project for different combinations of the oil price and the exchange rate.

The exchange rate affects the rate of return mainly because oil is priced relative to WTI, which is denominated in US dollars, while most costs are paid in Canadian dollars. An appreciating Canadian dollar therefore reduces net revenue. Producers will typically employ financial instruments that serve to mitigate risk with respect to the market price of crude oil and the exchange rate. In addition, some companies may hold significant debt denominated in US dollars, which becomes less burdensome under an appreciating Canadian dollar. Also, capital equipment imported from US becomes less expensive under a more valuable Canadian dollar. Overall, however, a rising Canadian dollar vis-à-vis the US dollar, a situation that occurred in 2003, will result in a lower rate of return.

F I G U R E 3 . 2

After-tax Nominal Rate of Return: 200 mb/d Athabasca Mining/Extraction and Upgrading



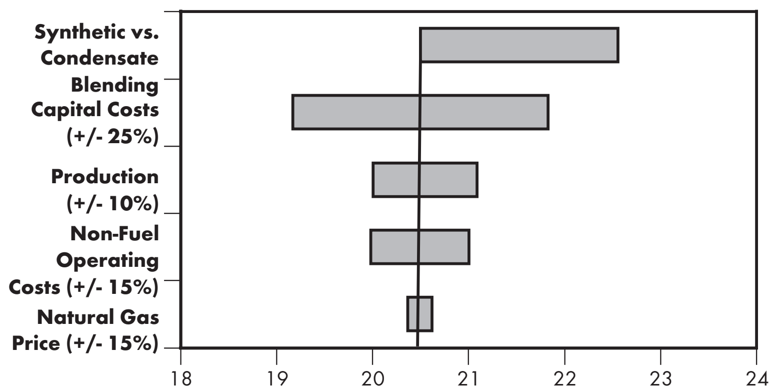
At US$24 per barrel for WTI, an integrated mining project is estimated to provide a rate of return in the low to mid-teens, which for most companies, is considered adequate to compensate for cost of capital and project risk.

3.3.3 Project Economic Evaluation - Mining/Extraction

An economic evaluation for a 15 900 m^3/d (100 mb/d) mining/extraction project without upgrading has been performed. Instead of upgrading the mined bitumen as in the previously developed case, condensate is used as a blending agent to permit transportation to market by pipeline. The project is assumed to produce a condensate-bitumen blend (DilBit), 21.5 °API and sulphur content of 3.3 percent, which is similar in quality to Lloydminster Blend. Lloydminster Blend provides a suitable comparison for DilBit pricing. The differential (the price difference between light sweet crude oil at Edmonton and Lloydminster Blend at Hardisty) is assumed to be US$7.00 per barrel at an oil price of US$24 per barrel for WTI. The results of the model indicate a supply cost for DilBit at the plant gate of about $20.50 per barrel. Figure 3.3 shows the results of a sensitivity analysis for the factors that account for much of the volatility in the supply cost.

FIGURE 3.3

Supply Cost Sensitivities: 100 mb/d Athabasca Mining/Extraction Project



As in the SCO case, the supply cost for mining produced DilBit is highly sensitive to capital cost. A 25 percent change in capital cost results in about a $1.50 per barrel change in supply costs. Production of 10 percent below capacity design results in an increase in supply cost of approximately $0.55 per barrel. Natural gas consumption is reduced considerably in the absence of the upgrading process; as a result, DilBit supply cost sensitivity to changes in the natural gas price is also reduced.

Growth in non-upgraded bitumen supply will increase the demand for diluent required to facilitate pipeline transportation to market. The Board's outlook for traditional diluent (i.e., condensate) projects little growth in supply through to 2015, while demand under current operational conditions would be expected to rise by approximately 50 000 m^3/d (315 mb/d). Additional supply could be made available by directing condensate used for other purposes to diluent usage, but the majority of the gap must be filled through the use of substitutes. Several opportunities exist for substitutes including refinery naphtha and conventional light oil; however, the most suitable solution, due to its availability, is SCO.

Table 3.3 provides a comparison of SCO versus condensate as a blending agent for bitumen at US$24 per barrel for WTI and a US/Canada exchange rate of $0.75. Generally, SCO is marginally less expensive than condensate; however, a greater proportion of it is required to achieve required pipeline specifications. Currently, marketed volumes of synthetic-bitumen blend (SynBit) are small compared with DilBit; however, greater volumes are expected as the price differential between SCO and condensate widens.

TABLE 3.3

Blending Costs: SCO versus Condensate 100 mb/d Athabasca Mining and Extraction

	Cost of Blending Agent (C$/b @ Plant Gate)	Blending Ratio (diluent: bitumen)	Bitumen Cost (C$/b bitumen blend)	Diluent Cost (C$/b bitumen blend)	Supply Cost (C$/b bitumen blend)
SCO	30.73	0.50 : 0.50	7.19	15.37	22.56
Condensate	32.92	0.33 : 0.67	9.64	10.86	20.50

Figure 3.4 illustrates the economic performance of a mining/extraction project for different combinations of the oil price and the exchange rate.

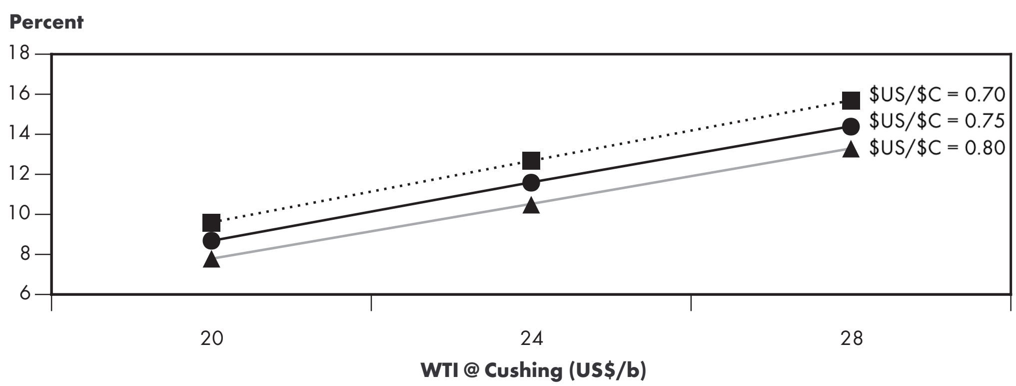
In addition to vulnerability to changes in the crude oil price and the exchange rate, producers marketing DilBit face the risk of exposure to the price differential between light and heavy crude oil, which can vary widely. For a given oil price, a higher differential results in a lower netback to heavy oil producers, but leads to increased demand for heavy crude because of the opportunity for heavy refiners to earn improved margins. Because of the large capital investment, however, the normal market mechanism of reducing supply during periods of lower prices does not necessarily follow as projects already in operation have little choice but to continue producing. In the longer term, differential risk, through its negative impact on project economics, may temper production growth.

When compared with the integrated mining case in which SCO is produced, a mining/extraction project provides a lower expected rate of return. This result, however, takes into account the entire differential risk associated with marketing large volumes of DilBit. In reality, it is unlikely that a company would complete a non-integrated mining project without the associated downstream facilities that would serve to limit this differential exposure and improve overall project economics.

At US$24 per barrel for WTI, an Athabasca mining/extraction project would provide an estimated rate of return in the low teens, which broadly speaking, would be considered adequate to compensate for cost of capital and project risk.

FIGURE 3.4

After-tax Nominal Rate of Return: 100 mb/d Athabasca Mining/Extraction Project



3.3.4 Opportunities to Reduce Supply Costs: Mining/Extraction and Upgrading

There are currently several areas of research directed towards reducing supply costs in oil sands mining, extraction and upgrading:

Continuous Improvement

- improved materials and equipment that are more durable and better suited to the oil sands industry;
- improved monitoring systems for mechanical equipment to reduce production interruptions;
- enhanced materials management systems that reduce transport and handling costs;
- decision support and information systems to improve mine management;
- reductions in bitumen loss through primary separation and reductions in the energy intensity of the extraction process; and,
- continued improvement in the performance of existing upgrading technologies including increased energy efficiency, catalyst development, and reductions in hydrogen use.

Longer-term Improvement

- tailings consolidation and dry tailings disposal technology reducing the draw on fresh water and potentially eliminating the need for overburden to be used in tailings confinement structures, thereby opening the door for new, more cost effective, overburden removal methods;
- continuous mining and extraction equipment that could significantly reduce operating and capital costs while reducing environmental impact and improving overall recovery rates; and,
- improved froth treatment processes that reduce residual water and solids providing a cleaner bitumen feedstock for upgrading.

3.4 Oil Sands In Situ

3.4.1 Introduction

In situ production has not achieved the step reductions in operating costs that mining and upgrading projects have enjoyed. Instead, reductions have been driven by technological advancements and steady improvements in energy and operating efficiency. The two most common in situ recovery types, Cyclic Steam Stimulation (CSS) and SAGD, require thermal stimulation of the reservoir to induce the flow of bitumen. There are, however, certain areas in the Athabasca (Wabasca), Peace River and Cold Lake oil sands regions that do not require thermal stimulation.

A major factor in determining the economic viability of an in situ project, particularly thermal projects, is reservoir quality. Although reservoir evaluation tools and methods are steadily improving, reservoir quality remains one of the greatest uncertainties in project evaluation. Major features that characterize a low-quality reservoir include low vertical permeability and pay thickness, high shale content and the presence of bottom water. A high-quality reservoir would be characterized by high vertical permeability and pay thickness, no bottom water and little shale.

3.4.2 Steam Assisted Gravity Drainage (SAGD)

In a SAGD operation, closely spaced horizontal well pairs are utilized with low pressure steam continuously injected into the upper well while the heated bitumen is simultaneously produced from a lower well. Lower steam injection pressure generally means that SAGD can be applied to thinner reservoirs than CSS, although good vertical permeability is essential. A major advantage of SAGD is that an estimated 40 to 60 percent of original bitumen in-place can be recovered, compared with CSS where an estimated 20 to 25 percent of the initial oil in-place is estimated to be recoverable.

Section 3.4.2.1 provides an economic evaluation for an Athabasca SAGD project with a high-quality reservoir and an Athabasca SAGD project with a low-quality reservoir. A discussion of the major cost components of a SAGD operation and specific challenges facing the industry is also included.

Current supply costs for Athabasca SAGD are estimated to be $11 to $17 per barrel of bitumen.

3.4.2.1 Project Economic Evaluation - SAGD

The Board has developed a project evaluation model for a 19 000 m^3/d (120 mb/d) Athabasca SAGD project with a high-quality reservoir, and a 4 800 m^3/d (30 mb/d) Athabasca SAGD project with a low-quality reservoir. As in the previously developed mining/extraction case, both of the evaluated SAGD projects are assumed to produce a DilBit of similar quality and value to a Lloydminster Blend.

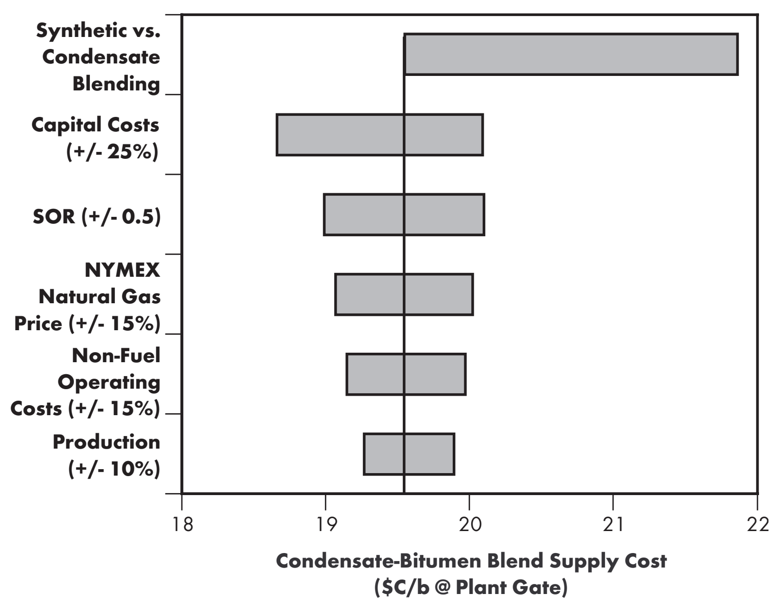
Figure 3.5 shows a sensitivity analysis for the factors that account for much of the volatility in supply cost for a SAGD operation with a high-quality reservoir. The model results indicate a supply cost of about $19.50 per barrel for DilBit at the plant gate.

SAGD supply cost is less sensitive to capital cost than mining projects since the capital investment required is far less. Historically, in situ projects have also had a better track record of staying on budget. Steam-to-oil ratio (SOR) is a measure of the quantity of steam required to produce one barrel of oil. Steam is typically produced using natural gas fuelled steam generators; therefore, a lower SOR translates into lower fuel costs. A change of 0.5 in the SOR results in approximately a $0.60 per barrel change in the supply cost. Higher SORs also result in greater volumes of produced water, which increases water handling costs; the SOR sensitivity above does not reflect these costs and is therefore likely understated.

An industry rule of thumb for SAGD projects is that the production of one

FIGURE 3.5

Supply Cost Sensitivities: 120 mb/d Athabasca SAGD Project - High-Quality Reservoir



barrel of bitumen requires approximately 1 Mcf of natural gas. While there is considerable volatility in the price of natural gas and consumption is extensive, there is over time, a linkage between natural gas and crude oil prices that serves to mitigate much of this risk. Companies are adopting innovative strategies to reduce their exposure to natural gas prices. The steam generators at Firebag, Suncor's SAGD project, are designed to burn diesel or natural gas; the company is a net producer of both and will therefore choose to use the commodity with the lowest market value. The Nexen/OPTI Long Lake SAGD project is expected to employ its proprietary gasification technology to create synthetic fuel gas and hydrogen from the low value, heaviest portion of the bitumen barrel. This process will nearly eliminate the need to purchase natural gas.

As in the case of non-upgraded bitumen blend produced by mining and extraction, in a SAGD operation, bitumen supply costs increase when SCO replaces condensate for blending. Table 3.4 provides a comparison of condensate versus SCO as a blending agent for bitumen at US$24 per barrel for WTI and a US/Canada exchange rate of $0.75.

T A B L E 3 . 4

Blending Costs: SCO versus Condensate 120 mb/d Athabasca SAGD High-Quality Reservoir

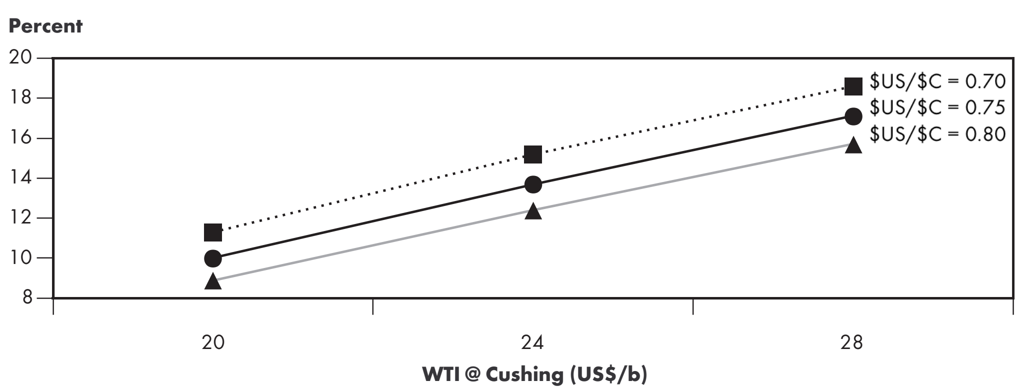
	Cost of blending agent (C$/b @ Plant Gate)	Blending Ratio (diluent:bitumen)	Bitumen Cost (C$/b bitumen blend)	Diluent Cost (C$/b bitumen blend)	Supply Cost (C$/b bitumen blend)
SCO	30.73	0.50 : 0.50	6.49	15.37	21.86
Condensate	32.92	0.33 : 0.67	8.59	10.86	19.55

It is expected that SynBit will compete with United States Gulf Coast (USGC) medium sour crude and DilBit will continue to compete with Mexican Maya crude. Currently, USGC medium sour is priced at a premium to Maya; a key point of uncertainty in the industry is whether the SynBit price premium over DilBit will be adequate to compensate for increased blending costs.

Figure 3.6 shows the economic performance of a SAGD project in a high-quality reservoir for different combinations of the oil price and the exchange rate. These factors impact SAGD project economics through similar market mechanics as in the previously developed mining case.

F I G U R E 3 . 6

After-tax Nominal Rate of Return: 120 mb/d Athabasca SAGD Project High-Quality Reservoir



At US$24 per barrel for WTI, a large-scale, Athabasca SAGD project with a high-quality reservoir is estimated to provide a rate of return in the low to mid-teens, which for most companies, is considered adequate to compensate for cost of capital and project risk.

Similar to mining/extraction projects without upgrading, in situ projects producing DilBit face exposure to the price differential between light and heavy crude oil. In order to reduce exposure to light/heavy differentials and to alleviate dependence on high-cost diluent, it is anticipated that a greater proportion of in situ produced bitumen will be upgraded into a more valuable light sweet product. Upgrading could potentially involve an integrated on-site upgrader such as the proposed Nexen/OPTI Long Lake project, or an independent upgrader such as BA Energy's proposed Heartland Upgrader. Another option is integrated producers shipping their in situ production to their downstream refinery or upgrader, such as Husky is currently doing with its Lloydminster upgrader and Suncor plans to do by sending production from its Firebag SAGD project to its adjacent upgrader.

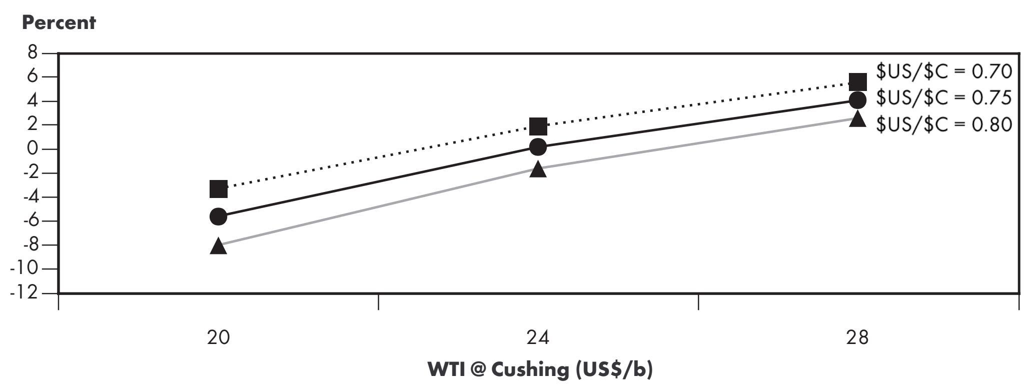
In oil sands mining, the minimum efficient scale of operation is much higher than for in situ development. Because of this difference, an in situ operation lends itself more easily to a phased approach of adding production. Many variable factors influence the operational performance of an in situ project and there exists an inherent level of risk that cannot be avoided. Through a phased approach, a company has the significant advantage of being able to reduce business risk by learning from operations and making more informed capital investment decisions as a project progresses. It is for this reason that most proposed in situ projects include plans for many phases of development contingent upon project performance.

Figure 3.7 illustrates the economic performance of a 4 800 m^3/d (30 mb/d) Athabasca SAGD project with a low-quality reservoir. Low-quality reservoirs have well production profiles that are much less prolific and SORs that are higher, which result in higher energy costs. In addition, capital costs are significantly higher as more wells must be drilled in order to maintain a stable level of production. These factors lead to poor economic performance.

At US$24 per barrel for WTI, an Athabasca SAGD project with a low-quality reservoir is unlikely to be economic.

FIGURE 3.7

After-tax Nominal Rate of Return: 30 mb/d Athabasca SAGD Project Low-Quality Reservoir

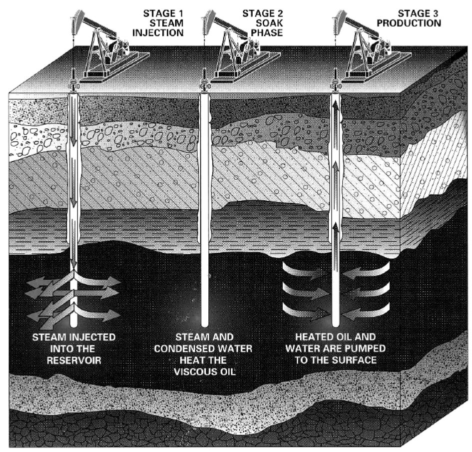


3.4.3 Cyclic Steam Stimulation (CSS)

Figure 3.8 illustrates the CSS in situ recovery process. A combination of directional and horizontal wells are used to inject high pressure steam into the Clearwater Formation, which warms the bitumen and lowers its viscosity thereby permitting it to flow into the well bore. CSS is a three-stage process: first, high pressure steam is injected through a vertical well bore for a period of time; second, the reservoir is shut in to soak; and third, the well is put into production. In addition to heating the bitumen, the high pressure steam creates fractures in the formation thereby improving fluid flow.

FIGURE 3.8

Cyclic Steam Stimulation



Source: Imperial Oil

Imperial Oil has employed the CSS technology since 1985 to recover oil sands bitumen on a commercial scale in the Cold Lake region. At Primrose, also in the Cold Lake region, Amoco (now BP) began CSS operations in 1995; Canadian Natural Resources Limited (CNRL) is the current operator of this project. Shell Canada has had success operating a variant of the CSS process 'Radial Soak' at Peace River, which it has optimized for the Bluesky Formation.

Although CSS is characterized by higher SORs than SAGD, the quality of steam used is lower and requires less energy to produce. In CSS operations in the Cold Lake area, some 15 percent of natural gas requirements are typically met through produced solution gas, whereas in a SAGD operation in the Athabasca area, these amounts are comparatively minimal. Overall, the requirement for purchased natural gas for CSS is comparable with that of SAGD at approximately 1.0 to 1.2 Mcf per barrel of production. CSS produced bitumen in the Cold Lake region has a higher API value and is less viscous; therefore, diluent costs are reduced when compared with Athabasca SAGD bitumen. In addition, the Cold Lake region is closer to market than the Athabasca region; therefore, transportation costs are typically lower when compared with SAGD.

A key focus in a CSS operation is to increase the total recovered bitumen by increasing the quantity of bitumen recovered in each cycle and/or increasing the number of cycles for which bitumen recovery is economical. SOR, and therefore gas costs for steam generation, is typically at its lowest point during early cycles, after which it begins to rise until the point at which bitumen production is no longer economic and the well is abandoned.

Imperial Oil developed pads at phases 1 to 10 on 1.6 ha well spacing, based on the performance history and technology of the day. In phases 11 to 13, the Mahkeses project, an average well spacing of 3.2 ha is used, which has contributed to reduced supply costs. When CSS production began in the Primrose area in 1995, steam was injected below fracture pressure. In 1999, CNRL acquired the property and in 2000 obtained approval to increase steam injection pressure to fracture levels on a portion of the wells in order to investigate the impact on bitumen production rates. After realizing a two-to-three fold increase in bitumen production, in 2002, CNRL received approval from the AEUB to convert all of its CSS wells to fracture pressure. This strategy has significantly improved the economics of the project.

Over the years, various recovery processes have been piloted in the Cold Lake region. Today, solvent (condensate) addition to the injected steam is being evaluated for its impact on bitumen recovery rates. The operating pilot project will be evaluated on the marginal improvement in oil recovery and the proportion of high cost injected condensate that is able to be recovered from the produced bitumen. If successful, this solvent-aided recovery process has the potential to reduce supply costs further.

CSS, like SAGD, is a thermal process and therefore supply costs are dependent on many of the same factors that affect the economics of SAGD. Current operating costs for CSS are estimated to be in the range of $8 to $14 per barrel, with supply costs estimated to be in the range of $13 to $19 per barrel. It is not anticipated that the CSS method will be widely applied outside of the Cold Lake region.

3.4.4 Cold Production

The oil sands bitumen that is amenable to cold production methods is heavier than conventional heavy oil, but lighter than the oil sands bitumen that is recovered through mining and thermal stimulation methods. Currently, there are several thousand cold production wells in the oil sands regions with production rates that vary from 3 to 45 m^3/d (19 to 284 b/d). Typically, cold bitumen recovery wells have productive lives of four to 10 years with 60 to 70 percent of total recovered bitumen being produced in the first three or four years. A significant level of ongoing drilling is required to maintain production. Low capital investment and lower operating costs, because steam generation is not required, generally mean that cold production is more profitable than thermal methods.

In the Cold Lake region, Cold Heavy Oil Production with Sand (CHOPS) occurs with vertical production wells and Progressive Cavity (PC) pumps. The CHOPS process involves the intentional co-production of sand with oil, as it has become apparent that the exclusion of sand results in uneconomic production rates. The main conditions for successful CHOPS are: continuous sand failure (unconsolidated sands); active foamy oil mechanism (sufficient gas in solution); no free water zones in the reservoir; and the use of PC pumps. The CHOPS process produces large volumes of sand and other types of fluid waste. Management of this waste is one of the major components of operating cost; therefore, successful minimization of disposal-related costs is critical to overall project economics. Compared with conventional production, well workovers in CHOPS are more frequent and comprise a greater proportion of supply cost. The operating costs for Cold Lake CHOPS are estimated to be in the range of $6 to $9 per barrel, with supply costs estimated to be in the range of $12 to $16 per barrel.

In the Wabasca area of the Athabasca region and the Seal area of the Peace River region, horizontal wells are used to achieve comparable production rates to the CHOPS process in Cold Lake, but without the production of sand on the same scale. Generally, lower viscosity is associated with lower rates of sand production. The viscosity of the bitumen in Wabasca and Seal areas is lower than in the Cold Lake region; therefore less sand is produced and handling costs are lower. The cost of drilling horizontal wells, however, is on the order of three to five times more expensive than vertical wells, and in addition, well workover costs are higher. The operating costs for cold production in the Wabasca and Seal areas are estimated to be in the range of $4 to $7 per barrel with supply costs estimated to be in the range of $10 to $14 per barrel.

It is not anticipated that there will be substantial growth in cold production or significant changes in operating costs within the timeframe of this report.

3.4.5 Opportunities to Reduce Supply Costs - In Situ

There are currently several areas of research directed towards reducing supply costs for in situ operations:

Continuous Improvement

- reduced dependence on natural gas, which can be achieved through improving efficiencies of steam generation and by implementing new, less expensive, sources of energy, which may include nuclear, bitumen combustion and gasification;
- increased electricity transmission capacity out of the Fort McMurray area, which would permit the wider incorporation of cogeneration plants and reduce the cost of steam generation and electricity;
- reservoir injection of solvent, with or without steam, to increase production rates [Vapour Extraction Process (VAPEX™), Solvent Assisted Production (SAP)] while reducing energy costs;
- advancements in drilling technology that will reduce costs and improve the accuracy of well placement within the reservoir, thereby improving reservoir performance;
- development of advanced computer simulations that will better predict reservoir performance, thereby reducing business risk; and,
- steam tracking technologies that will allow more efficient steam injection, thereby improving bitumen recovery rates and lowering energy costs.

Longer-term Improvement

- in situ combustion methods that result in partially upgraded bitumen being produced and lower fuel costs;
- injection of solvent in combination with electrical induction or microwaves to partially upgrade the bitumen and substantially reduce fuel requirements; and,
- use of catalysts in production strings (CAPRI).

Although promising, these opportunities are in the very early stages of development and have yet to be commercially proven in the field. Further discussion on these technologies is provided in Chapter 11 - Emerging Technologies.

3.5 Conclusion

Supply costs for in situ bitumen production from Canada's oil sands have been reduced significantly through a process of continual operational improvement. In the case of integrated mining, a few key technological innovations have permitted stepwise reductions in supply costs. This improvement in economics, bolstered by recent high crude oil prices, has resulted in the international recognition of the economic potential of the vast oil sands resource.

Current supply costs for integrated mining and upgrading projects are estimated to be in the range of $22 to $28 per barrel for SCO, while supply costs for mining/extraction without upgrading are estimated to be in the range of $12 to $16 per barrel of bitumen. Supply costs for mining/extraction and upgrading are expected to continue to decline as technologies improve and operators gain experience. There are no new technologies in the timeframe of this report that are expected to achieve the magnitude of supply cost reductions that the industry has achieved over the past decades.

Current supply costs for Athabasca SAGD are estimated to be in the range of $11 to $17 per barrel of bitumen, while supply costs for CSS are estimated to be in the range of $13 to $19 per barrel of bitumen. Costs for both methods are highly dependent on the quality of the reservoir and natural gas prices. The amenability to a phased-in approach of expansion reduces the risk of investment. As in the case of mining and upgrading, it is also expected that in situ processes will exhibit a profile of improvement in supply costs as relatively new technologies, such as SAGD, and new generations of in situ processes mature. Promising technologies, such as VAPEX™, have the potential to reduce energy intensity and the environmental impacts of production. In order to limit exposure to the light/heavy differential and the rising cost of diluent, steps will likely be taken to secure upgrading capacity for in situ projects.

Supply costs for cold production in the Wabasca and Seal areas are estimated to be in the range of $10 to $14 per barrel, compared with $12 to $16 per barrel for CHOPS in the Cold Lake region. It is not anticipated that there will be significant reductions in these supply costs within the timeframe of this report.

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Crude Oil Supply

4.1 Introduction

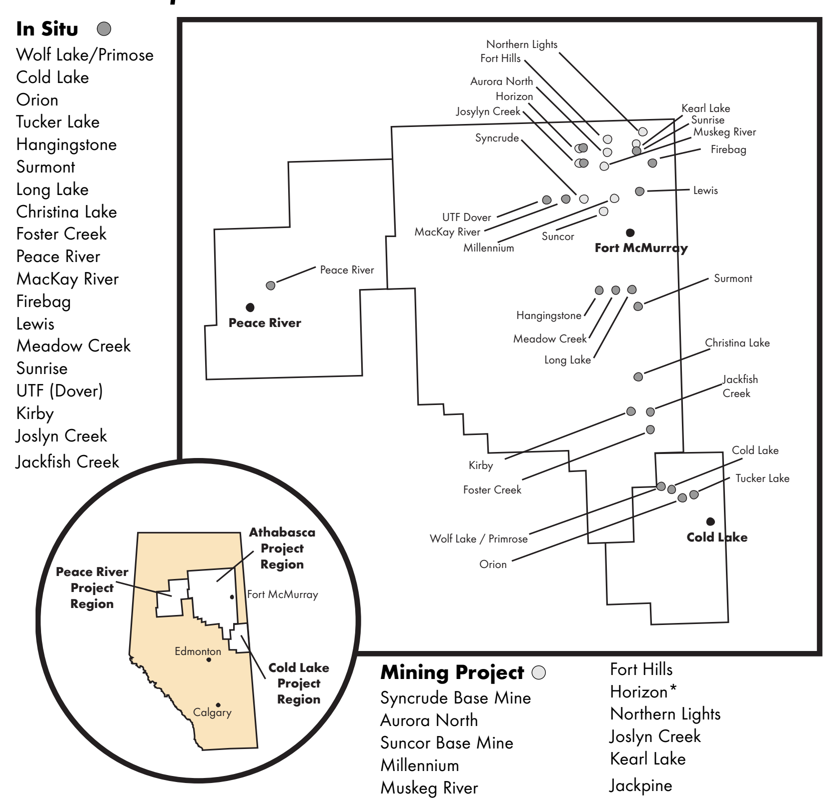
This chapter focuses on the projections of oil supply from Canada's oil sands; it is divided into two categories reflecting the method of recovery. "Oil sands mining" includes all production derived from surface mining operations, while "oil sands in situ" includes all production derived from in situ operations, including primary recovery projects. Supply projections are also expressed in terms of net available crude oil supply, a term that refers to the volumes of crude oil available to the market after upgrading and blending are taken into account. In addition, brief descriptions of the more important active projects, as well as currently planned projects, are provided.

4.2 Oil Sands Mining and In Situ Projects

Figure 4.1 shows the location of significant oil sands projects, as well as, a list of the projects by type. There are more than 40 announced projects and project expansions. Appendix 4 provides a brief discussion of the major operating and planned projects in the Athabasca, Cold Lake and Peace River oil sands areas.

F I G U R E 4 . 1

Oil Sands Project Locations



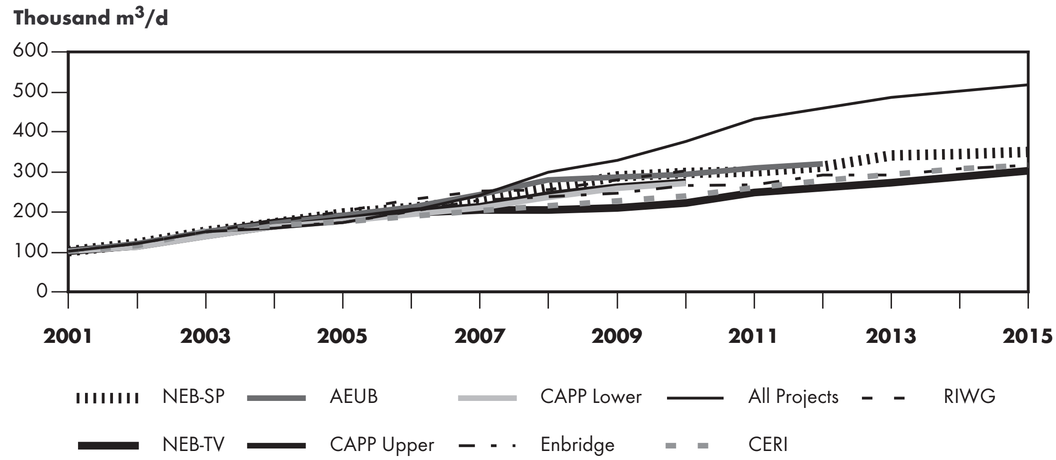
* Includes plans for both in situ and mining.

4.3 Methodology

The approach taken for this report was to review the various projections of oil sands production by various organizations, and publicly available in 2003 and early 2004, including the oil sands projections from the NEB Supply and Demand Report (Figure 4.2). In general, the major assumptions, such as oil and gas prices, upon which these outlooks are based, do not vary widely between projections.

FIGURE 4.2

In Situ Bitumen and Synthetic Crude Oil Supply Projections



A common approach in formulating a projection of oil sands growth is to include all of the announced oil sands mining and in situ projects at their nameplate capacities and start-up dates, and then "risk' or discount the projection by some means. Typically, this discounting considers the status of the approval process, with an increasing percentage of the projects' estimated future production moved into the projection as the project status goes from public disclosure to first production. Further considerations in formulating the projections may include analysis of supply costs and cash flow, and the experience and access to capital of the project proponents. The capability of the industry to construct large complex plants, often on a concurrent basis, might also be considered.

It is difficult to judge whether a project will proceed and when to schedule first production. This cannot be done with a great deal of precision, as each company has its own perspective on the future and its own set of circumstances to consider when making its investment choices.

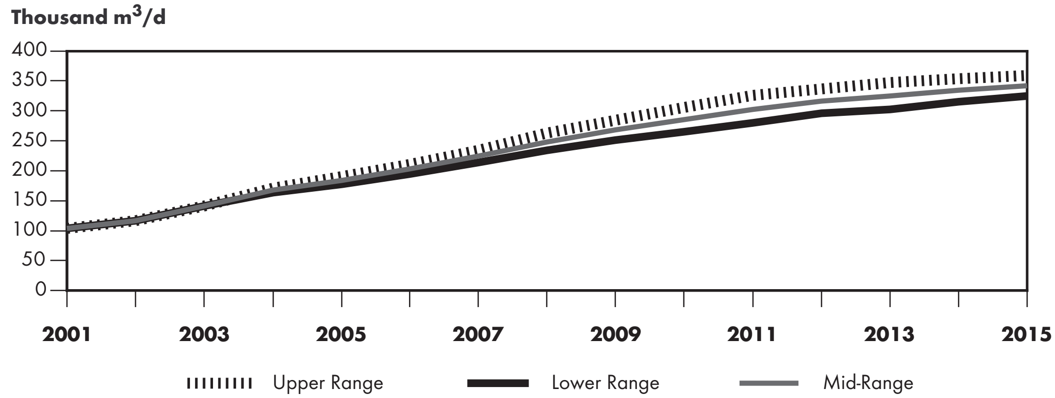
Based on the level of uncertainty inherent in these types of projections, it would seem reasonable to present the various projections shown in Figure 4.2 (except for "All Projects") as a range or band of values, defined by the "Upper Range" and "Lower Range" curves (Figure 4.3). The width of the band shown is representative of the variance between the individual curves. It is important to note that the band is intended to bracket supply outcomes that could be reasonably expected, given the assumptions inherent in the projections. For the purposes of analysis and discussion, a mid-range or average projection is shown.

The Board's approach was to test the reasonableness of the mid-range projection in a three-step process:

- First, examining the supply costs and economic assumptions related to each type of project.
- Second, matching the production profile as closely as possible, by including new projects and project expansions. A relative ranking is given to projects based on certain criteria,

F I G U R E 4 . 3

Oil Sands Supply Projections



such as: approval status; company experience and financial resources; history of technology proposed; and reservoir quality.

- Third, applying an upper limit on oil sands projects-related construction spending, recognizing the constraints that have caused cost escalation for recently completed large projects.

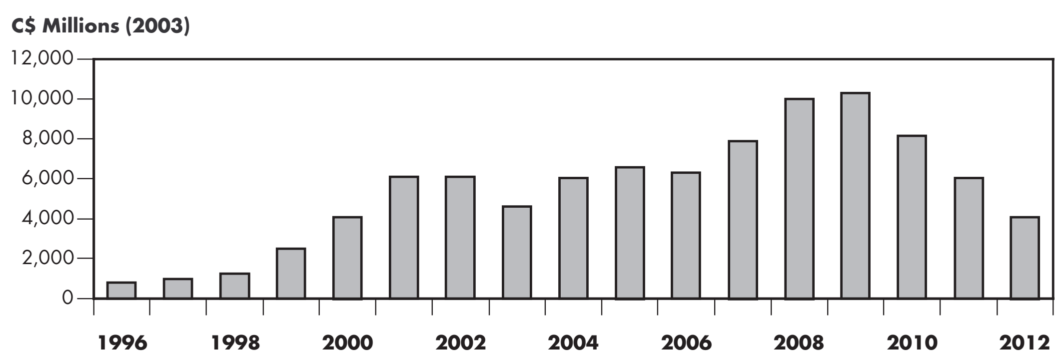
The basic economic assumptions used in the supply projections are outlined in Chapter 3 - Supply Costs, and include a US$24 per barrel price forecast for WTI and a NYMEX natural gas price of US$4.00 per MMBtu. A summary of the economic assumptions is provided in Appendix A1.1. For purposes of discussion, the supply projections for conventional light crude oil, pentanes plus and conventional heavy crude oil are taken from the Techno Vert scenario of the NEB Supply and Demand Report.

4.4 Capital Expenditures and Cost Overruns

During the period 2000 to 2003, the WTI price averaged about US$29 per barrel, and provided oil sands producers with favourable netbacks. In this regard, a renewed sense of optimism is present in the oil sands industry. As evidence of this, some 44 new bitumen recovery projects or expansion projects have been announced, 18 mining and 26 in situ, to be implemented in the 2004 to 2012 time frame. Capital expenditure of about $60 billion will be required to construct these projects (Figure 4.4). Not all of these projects are likely to proceed, as the construction spending levels appears to be beyond industry capacity.

F I G U R E 4 . 4

Total Capital Expenditures — Oil Sands Projects



Between 1999 and 2002, three major integrated mining projects or expansion projects were under construction: Suncor Millennium; Syncrude Stage 2 Expansion; and the Shell Canada led Athabasca Oil Sands Project (AOSP). The average spending level over this period was $4.8 billion per year and spending levels in 2001 and 2002 reached $6.2 billion[3]. All of these projects experienced cost overruns of 50 percent or more. Similarly, early in 2004, Syncrude announced that cost estimates for its Stage 3 expansion had risen to $7.8 billion, and that the completion date would be extended by one year, to 2006. In 2003, Syncrude had already increased its cost estimate from $4.1 billion to $5.7 billion.

The main reasons that have been cited are: insufficient front-end engineering; inadequate management control of the project; and a shortage of skilled tradespeople and experienced supervisory staff, created by constructing these very large projects concurrently. The sheer size of the projects seems to be a contributing factor, as cost overruns are commonplace in large construction projects around the world. Syncrude attributes its Stage 3 cost overrun to making modifications within a very complex setting in the midst of ongoing operations. This expansion will also allow it to create a higher quality synthetic crude oil (SCO) from its total bitumen production, not just the Stage 3 portion.

Some analysts have suggested that these should not be considered as cost overruns, but as the true cost of construction of these large complexes. It is anticipated that future cost estimates will be closer to the mark.

The in situ projects constructed to date have come in on-budget or under-budget. These are smaller projects, typically less than $500 million, with the largest completed project to-date being Imperial Oil's Cold Lake Makheses project, at $1.0 billion.

4.5 Supply Projections

4.5.1 Projections of Capital Expenditures

As indicated, there are 44 major oil sands projects planned: 18 mining and 26 in situ. For the most part, the proponents of these projects are large Canadian companies or multinational companies with considerable experience in oil sands development. In many cases, the proposed projects are expansions of projects that are being successfully operated today. These companies have access to huge amounts of oil sands resources. Also, the oil sands royalty and taxation regimes encourage project expansion. As a result, there are a number of currently planned or future projects that could be brought into production when required. However, given the recent cost overrun experiences, it would appear that the capacity of the construction industry to handle large-scale concurrent projects is constraining supply growth.

In order to develop a supply projection that is constrained by a spending limit for strategic and sustaining capital, a four-year spending profile for each project was developed. Based on historical costs for projects already constructed and estimated costs for planned projects,

TABLE 4.1

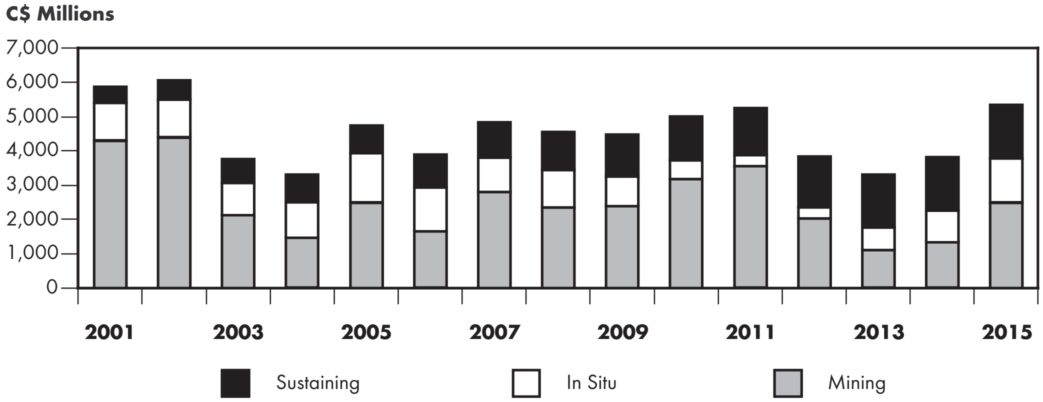
Cost per Barrel of Incremental Capacity by Project Type

Project Type	Cost per Barrel Daily Capacity ($)
CSS	18,000
SAGD	12,000
Mining and Extraction	18,000
Integrated Mining/Extraction/Upgrading	40,000

3 Canadian Association of Petroleum Producers.

FIGURE 4.5

Projected Capex — Mid-Range



costs per barrel of incremental capacity were assigned for each major project type (Table 4.1). New projects were entered into the projection at their name plate volume and start-up date, and the resultant spending totals were assessed. Using a limit of $4.5 billion as a guide for an annual spending limit, project start-ups were delayed as necessary to keep the total spending limit generally at or under this level.

The results of this exercise indicate a spending pattern that shows considerable variation, but averages about $4.4 billion over the period 2004 to 2015 (Figure 4.5), and yields a total oil sands production projection that increases to 350 000 m^3/d (2.2 mmb/d) by 2015. This is in agreement with the mid-range profile.

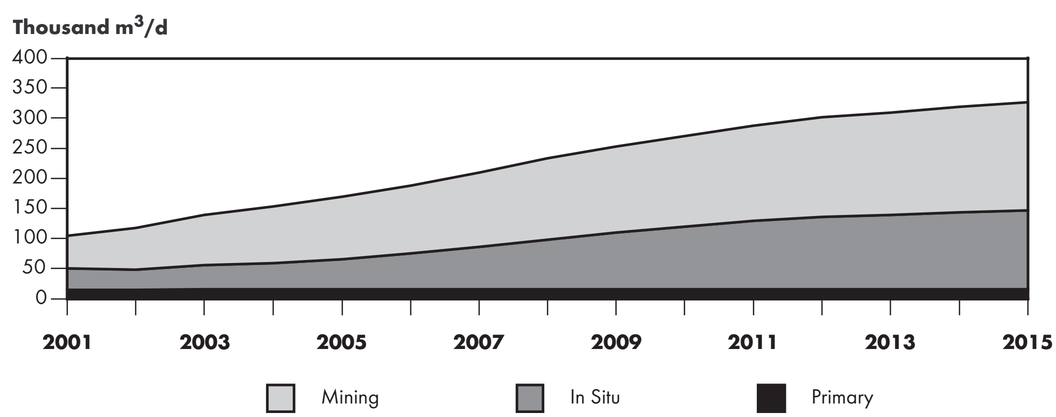
Based on the spending assumptions used, the exercise suggests that future oil sands supply levels should reasonably be expected to fall within the band or range of values previously shown in Figure 4.3.

4.5.2 Oil Sands Mining SCO and In Situ Bitumen Projections

Figure 4.6 sets out projections to 2015 for oil sands mining derived SCO and in situ bitumen based on the mid-range projections.

FIGURE 4.6

Mid-Range Supply Projections



In 2003, SCO production from integrated mining and upgrading plants averaged over 76 000 m^3/d (480 mb/d) or approximately 20 percent of the total Canadian crude oil production. By 2015, SCO from integrated mining and upgrading operations is projected to reach 180 000 m^3/d (1.1 mmb/d), a 137 percent increase.

In situ bitumen production averaged over 54 000 m^3/d (340 mb/d) in 2003. Thermal projects operated by Imperial Oil and Canadian Natural Resources Limited (CNRL) in the Cold Lake/Primrose area account for most of the bitumen production to-date, but there has also been significant production from the Lindbergh and Peace River areas.

There are currently 26 major new in situ bitumen projects or expansion phases proposed. In the mid-range supply projection, by 2015, in situ bitumen production is projected to reach 147 000 m^3/d (926 mb/d), a 172 percent increase.

Primary production [Cold Heavy Oil Production with Sand (CHOPS)] from the Cold Lake, Wabasca and Seal areas is an important component of in situ production, accounting for 26 percent of total in situ bitumen output in 2003. Moderate expansion of primary production from the Wabasca area and Seal areas is anticipated; however, this is expected to be offset by the natural decline in other areas. For the purposes of the Board's projection, primary production has been held flat at 15 000 m^3/d (95 mb/d).

4.6 Condensate Supply

Although some condensate is produced at the field level, the bulk of the supply is derived from the processing of natural gas. The projection of condensate supply is therefore directly tied to the natural gas supply outlook. It is included in this report because condensate is used primarily as a diluent to blend with heavy crude oil and bitumen to reduce density and viscosity in order to meet pipeline specifications.

The supply projections for condensate are taken directly from the NEB Supply and Demand Report - Techno Vert scenario. The supply of condensate from the WCSB is projected to gradually decrease from 2003 levels of 27 200 m^3/d (171 mb/d) to 24 000 m^3/d (151 mb/d) by 2015. If the Mackenzie Valley pipeline proceeds, another 3 000 m^3/d (19 mb/d) of condensate could be available in the 2009 to 2010 timeframe. While coal bed methane (CBM) is expected to supplement conventional natural gas supply in the WCSB, it is relatively dry gas and not a substantial source of condensate.

4.7 Diluent Requirement

The largest use of condensate is for diluent in the blending of heavy crude oil and bitumen to facilitate its transportation to market by pipeline. Typically, raw bitumen requires approximately 40 percent of diluent to be added, while conventional heavy crude oil requires about seven percent.

Two important determinants of the demand for diluent are the pace of development of bitumen projects and the amount of local upgrading installed. In the supply projections, most oil sands mining developments are assumed to include upgrading capacity; hence they require no net diluent. However, some mining and most in situ bitumen projects are assumed to include only partial or no upgrading, and will therefore require significant additional diluent. It is estimated that about 2 000 m^3/d (13 mb/d) of condensate is not currently available for use as a diluent. This amount includes the volumes that are used in miscible flood oil recovery projects, as refinery feedstock, or batched directly into light crude oil streams. It is assumed that some of these volumes would be available for use as diluent within the projection period.

At the rate of projected growth of non-upgraded bitumen, the demand for condensate will exceed available supply in the 2005 to 2006 timeframe. As a result, oil sands operators will need to develop other diluent sources. The shortfall of diluent could be alleviated by adding local upgrading capacity, which could include partial upgrading or small scale field upgrading, if these technologies prove viable. Alternatively, some of the shortfall could be offset by using heated pipelines or by using other types of diluent, such as light crude oil, SCO or naphtha. The use of SCO as diluent to produce a blend termed SynBit is gaining popularity. A combination of condensate, SCO and bitumen, termed DilSynBit is also being used. Although the industry will adjust to declining condensate supply, the potential solutions all entail additional costs.

4.8 Net Available Supply - Crude Oil

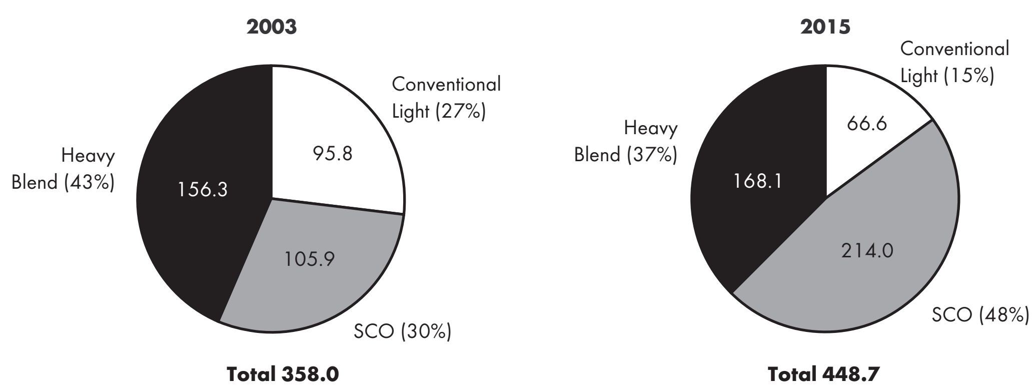
"Net available supply" refers to the volumes of crude oil available to the market after taking upgrading and blending into account. Thus, the net available Canadian crude oil supply represents the total of WCSB conventional light crude, East Coast crude, SCO, pentanes plus, blended heavy crude and blended bitumen, after local feedstock and diluent requirements have been met. Therefore, any volumes of in situ bitumen or conventional heavy that are upgraded, either in field upgraders, integrated mining and upgrading plants, or in regional upgraders, are considered to be SCO.

It is assumed that some light crude or SCO will be used as diluent. The projections of available supply take into account the diluent requirements for blending heavy oil and bitumen, recycled volumes of diluent, product losses during upgrading, and volumes of condensate not available to the downstream market. Over the course of the projection period, the total net available supply rises from 358 000 m^3/d (2.3 mmb/d) to 448 700 m^3/d (2.8 mmb/d), an increase of nearly 26 percent (Figure 4.7).

In 2003, conventional light crude oil made up about 27 percent, blended heavy oil and bitumen 43 percent, and SCO 30 percent of the total net available supply of crude oil. These proportions shift significantly over the course of the projection. By 2015, conventional light crude oil makes up about 15 percent, blended heavy oil and bitumen 37 percent, and SCO 48 percent of the total net available supply.

FIGURE 4.7

Net Available Supply of Crude Oil by Type - Thousand m^3/d



4.9 Conclusion

Relatively high oil prices since 2000 have provided favourable returns to oil sands producers. More than 40 new projects and project expansions have been announced for construction in the 2004 to 2012 period. Most of these projects are sponsored by large Canadian or multinational companies that have experience in oil sands development and sufficient financial resources to undertake them.

The analysis of supply costs, with economic assumptions of an oil price of US$24 per barrel WTI and a NYMEX gas price of US$4.00 per MMBtu, indicate that operators should be able to obtain a return on investment in the mid-teens. With adequate returns and a large number of projects to choose from, operators should be able to increase supply levels at a reasonable pace.

The Board took the view that it was not necessary to develop a new set of supply projections; however, it would re-examine the oil sands supply outlook from the NEB Supply and Demand Report, as well as those done by others and available in the public domain.

The supply projections reviewed were similar, both in their base assumptions and their results, so the approach taken was to define an average or mid-range projection. The reasonableness of this mid-range projection was then tested by determining the capital required to bring on incremental production as required, and by assuring that the $4.5 billion annual spending cap was not exceeded for an extended period.

In conclusion, the mid-range projection, shown in Figure 4.3, provides a reasonable expectation of oil sands supply to 2015.

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MARKETS

5.1 Introduction

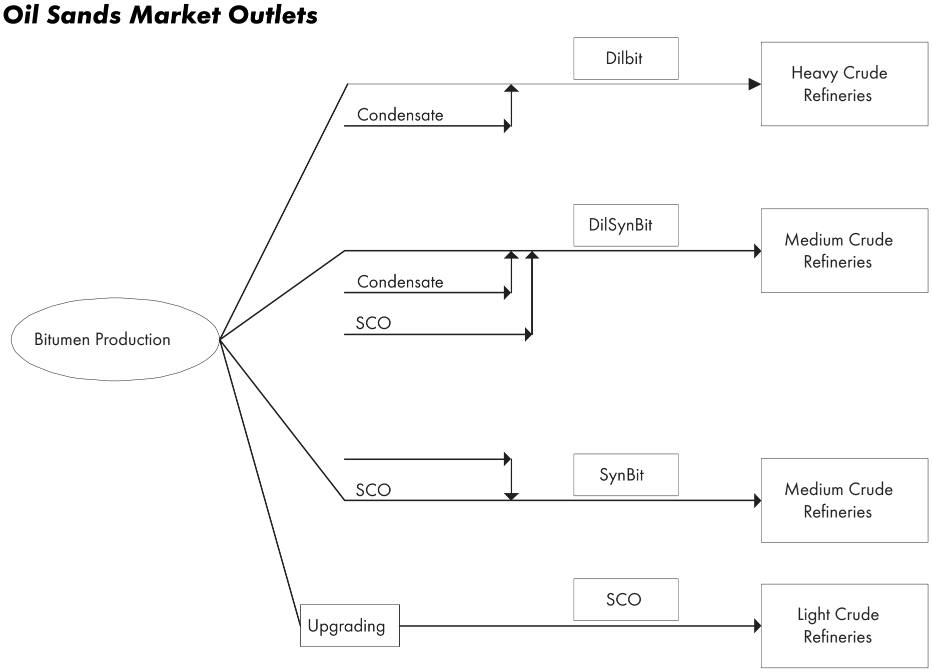
The NEB and others are projecting large increases in synthetic crude oil (SCO) and blended bitumen production, particularly in the latter part of the decade (Chapter 4 - Crude Oil Supply). Developing markets for these growing supplies will be necessary to ensure continued expansion of the oil sands resource.

Canadian oil sands producers have been creative in finding outlets for the rising output. These include, in no particular order: purchasing refineries; tailoring output quality to fit a specific refiner/buyer; upgrading to make a saleable light quality crude oil; long-term partnership arrangements to enable refiners to retrofit their plants to accommodate a specific grade of oil sands crude; and providing test batches to be used by refiners to determine how a specific oil sands crude fits their refinery configuration.

One recent example of innovation was the signing of agreements to ship DilSynBit and SynBit, which are new grades of bitumen products. It is expected that these new products will appeal to more refineries. DilSynBit is a blend of condensate, SCO and bitumen, whereas SynBit is a mixture of SCO and bitumen. Figure 5.1 provides a schematic of the different grades of bitumen products and their expected market outlets.

FIGURE 5.1

Oil Sands Market Outlets



This chapter provides a comprehensive discussion about current markets and options for additional outlets for the increasing oil sands production. It is not intended to select a specific market; rather, the objective is to encourage discussion and allow the reader to draw conclusions on which region holds the greatest potential for this growing supply.

5.1.1 Export Market

Total exports of Canadian crude oil in 2002 were approximately 231 000 m^3/d (1.5 mmb/d). Today, the majority of these volumes are shipped to PADD II (U.S. Midwest region) followed by PADD IV (Montana, Colorado, Wyoming and Utah). The NEB Supply and Demand Report, projects that by 2015 exports will be 440 000 m^3/d (2.8 mmb/d), a 90 percent increase. Existing U.S. markets will continue to be strong growth areas for Canada's oil sands; however, additional markets will be required to keep pace with oil sands expansions.

The United States' dependence on imported oil has grown in the last decade, reflecting declining domestic oil production and growing demand. In 2002, the U.S. imported 1.7 million m^3/d (10.5 mmb/d) of crude oil, and according to the U.S. Energy Information Administration's Annual Energy Outlook 2004, this is forecast to grow to 2.5 million m^3/d (15.5 mmb/d) by 2015, a 47 percent increase. Net imports accounted for 54 percent of total U.S. petroleum demand in 2002, up from 42 percent in 1990. By 2015, net imports are expected to account for 63 percent of total U.S. petroleum demand. Historically, the U.S. has absorbed virtually any increase in Canadian oil production, and it is expected that it will continue to be the major market for Canadian crude oil.

Asia has attracted global interest as an emerging market and growth is expected in the coming years, with energy demand projected to keep pace with Gross Domestic Product (GDP). Oil demand is likely to be supported by the demand for transportation fuels.

5.1.2 The North American Refining Industry

The North American refining industry is predominantly geared toward the production of motor gasoline and middle distillates. The average size of a Canadian refinery is 17 500 m^3/d (110 mb/d) while the average size of a U.S. refinery is 19 700 m^3/d (125 mb/d). At first glance, it appears that Canada and the U.S. are roughly equal with respect to refinery size; however, 20 percent of U.S. refineries are over 32 000 m^3/d (200 mb/d) with the largest being over 79 500 m^3/d (500 mb/d). In contrast, Canada only has two refineries that are over 32 000 m^3/d (200 mb/d) with the largest being 39 700 m^3/d (250 mb/d).

Refineries in North America will need to address a number of environmental considerations, including: cleaner fuels (e.g., reducing sulphur in both gasoline and diesel); the ban of MTBE in several states in the U.S.; and the addition of ethanol in gasoline. As well, the North American refining industry is under intense public pressure to reduce emissions.

With refiners investing in facilities to meet changing fuel quality specifications, some refineries are examining ways to modify their operations to enable them to convert heavy, low-value feedstocks such as vacuum gasoil (VGO - by-product of bitumen) into gasoline and distillate. There are essentially two upgrading processes in North Amercia for converting VGO to useable lighter products: carbon rejection and hydrogen addition. Coking and catalytic cracking (cat-cracking) are examples of carbon rejection technologies, whereas hydrocracking involves hydrogen addition.

Currently, the key issue for SCO is the poor distillate and gasoil product quality. This is primarily due to cracking in the absence of hydrogen, which promotes the formation of highly aromatic hydrocarbon species. For jet and diesel fuels, reduction of aromatic content is not easily remedied in the conventional refinery process and requires the addition of hydrogen.

For refineries in North America to process larger volumes of oil sands production, they will need to invest in coking or cat-cracking capacity to process blended bitumen and hydrocracking capacity for SCO.

Most of the refineries in Canada and the U.S. have a configuration that includes one or a combination of thermal cracking (e.g., coker), fluid catalytic cracking (FCC) or a catalytic hydrocracking unit (HCU). Canadian refineries generally have less upgrading capability and were designed to process light crude oils, while some U.S. refiners have been adapted specifically to run heavier crude oils from western Canada. Therefore, a large portion of heavy oil production is exported to the U.S., particularly to PADDs II and IV (Chapter 6 - Pipelines, Figure 6.2). In general, heavier grades of crude oil receive a lower price because they cost more to refine and yield a smaller proportion of higher-value transportation fuels. The U.S. refineries with higher throughput capacity and access to the large U.S. domestic market have an economy of scale advantage, and are able to reduce costs to the point where processing heavy crude oil is economic. The economy of scale aspect allows refineries to invest in complex, add-on upgrading units.

Coking is an upgrading process that involves severe thermal cracking. The feed to a coker is heated to about 540 °C (1,000 °F) and then charged to the bottom of a coke drum. The cracked lighter products rise to the top of the drum, are drawn off and sent to a fractionator. The remaining heavier product cracks to coke, a solid coal-like substance. The advantage of a coker versus other thermal cracking processes is that the coker produces no residue. However, its product slate includes 30 percent coke, which requires a market. Thermal processes produce gasoline, naphtha, and gasoils that are low in quality (e.g., relatively high aromatic content).

FCC was introduced to increase the gasoline yield from a barrel of crude oil. Cat-cracking involves subjecting straight-run heavy gasoils to heat and pressure in the presence of a catalyst to promote cracking. The temperature in this process ranges between 340°C and 590°C (650°F to 1,100°F).

The HCU is a later generation of the cat-cracker. Hydrocracking is cat-cracking in the presence of hydrogen. This combination of hydrogen and a catalyst, under certain operating conditions, permits high yields of good quality gasoline. Hydrocracking can also be used to produce light distillates (jet fuel and diesel) from heavy gas oils. Its greatest attribute is that hydrocracking produces no bottom-of-the-barrel fractions (coke, pitch, or resid). The HCU also yields up to a 25 percent gain in volume, although the gain includes some lighter products (i.e., propane and butane). Hydrocracking is more common in Canadian refineries, as it provides high quality distillates in a market where there is a balanced demand for gasoline and distillates. As well, HCUs are better able to process aromatics.

5.2 Markets - Existing and Future Opportunities

Refineries in Canada are located in four regions: Western Canada, Ontario, Quebec and the Atlantic. The Canadian refining industry utilizes both domestic and imported crude oils. Canada's refining capacity is 321 800 m^3/d (2.0 mmb/d) (Table 5.1). In 2002, Canadian refineries operated at almost 90 percent of capacity. Synthetic and blended bitumen comprise only 15 percent of total crude processed.

Refineries in western Canada process primarily conventional light sweet crude, sweet SCO and some heavy crudes. These refineries are relatively modern and among the most advanced in Canada.

TABLE 5.1

Receipts of Western Canadian Crude Oil — 2002 (m^3/d)

Market	Refining Capacity	Refinery Runs	Conventional Light[1]	Conventional Heavy	Synthetic	Blended Bitumen	Total
Canada							
Western Canada	94 400	88 896	40 790	16 873	26 958	4 275	88 896
Ontario	87 500	75 386	18 317	7 120	7 856	5 197	38 490
Eastern Canada[2]	227 400	204 121	18 317	7 120	7 856	5 197	38 490
Total	**321 800**	**293 017**	**59 107**	**23 993**	**34 814**	**9 472**	**127 386**
USA							
PADD I	252 200	244 944	3 299	4 642	725	532	9 198
PADD II	558 100	510 402	24 418	76 594	16 482	32 137	149 631
PADD III	1 258 600	1 130 171	0	0	731	6	737
PADD IV	90 800	82 593	10 572	21 583	6 468	1 272	39 895
PADD V	407 500	408 147	7 067	0	1 239	630	8 936
Total	**2 567 200**	**2 376 257**	**45 356**	**102 819**	**25 644**	**34 578**	**208 397**
Asia	2 500 000		28	0	8	388	424

Source: Statistics Canada, National Energy Board and the U.S. Energy Information Administration.

1 Includes condensate and pentanes plus.

2 Includes Ontario.

The eastern Canadian refining industry is a mix of modern and older refineries. Two refineries in the Atlantic and Quebec region have been modernized and are considered to be world class facilities; some of the refinery production is destined for export to the U.S. northeast market. The five refineries located in Ontario tend to be older and less sophisticated, and serve markets in that region.

The number of refineries in Canada has been declining for many years. This is primarily the result of industry restructuring and the continuing requirement to make very large investments to meet changing consumer demands and environmental standards.

The United States market is divided geographically into five Petroleum Administration for Defense Districts (PADDs) (Chapter 6 - Pipelines, Figure 6.2). Refineries in the U.S. are located throughout the country in PADDs I through V (Table 5.1). The largest refining center is the U.S. Gulf Coast (USGC), located in PADD III, with well over 1.2 million m^3/d (7.6 mmb/d) of refining capacity followed by PADDs II and V. In total, the United States has a refining capacity of approximately 2.6 million m^3/d (16.4 mmb/d). In 2002, U.S. refineries operated at almost 93 percent of capacity. In the U.S., Canadian synthetic and blended bitumen make up only three percent of total crude processed.

On occasion, spot shipments of blended bitumen and conventional light crude are made to Asia, specifically South Korea and China. Canadian producers are assessing this market with interest and it is expected that more shipments could move to these locations.

5.2.1 Western Canada

There are nine refineries in western Canada with a refining capacity of 94 400 m^3/d (590 mb/d) (Table 5.2): Chevron, Co-op, Husky (2), Imperial, Moose Jaw Asphalt, Parkland, Petro-Canada and Shell.

In 2002, refineries in western Canada operated at 94 percent of capacity and processed about 88 900 m^3/d (560 mb/d) of crude oil (Figure 5.2). Of this, 46 percent or 41 000 m^3/d (258 mb/d) was conventional light crude, followed by 30 percent or 27 000 m^3/d (170 mb/d) of synthetic, 19 percent or 17 000 m^3/d (107 mb/d) of heavy conventional crude oil and five percent or 4 300 m^3/d (27 mb/d) of blended bitumen. It is expected that refineries in the Edmonton area will increasingly look to oil sands to replace declining conventional production.

TABLE 5.2

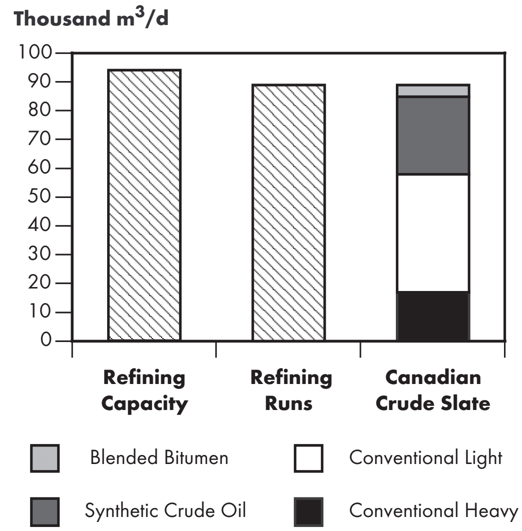
Western Canada Refinery Specifications

	m^3/d	mb/d
Refinery Capacity	**94 400**	**590**
Coking	3 000	19
FCC	21 000	132
HCU	12 000	76

Developments related to the oil sands are ongoing. A private Calgary company, BA Energy Inc., an arm of the Calgary-based Value Creation Group of Companies announced in the fourth quarter 2003 an $800 million proposal to build Canada's first independent heavy oil upgrader. It would be located in Strathcona County, within Alberta's Heartland, near feedstock sources and pipelines. The project, called the Heartland Upgrader, would be built in three phases, with the initial phase capable of processing 7 900 m^3/d (50 mb/d) of heavy oil or bitumen by 2006. Further expansion could increase the processing capability to 23 800 m^3/d (150 mb/d).

FIGURE 5.2

Western Canada Receipts of Canadian Crude Oil - 2002



As well, Petro-Canada has announced that it will upgrade its Edmonton refinery, which currently has a capacity of 21 900 m^3/d (138 mb/d), to process oil sands derived crude oil. In addition to integrating its oil sands production with the refinery, the project includes a 10-year arrangement, starting in 2008, under which Petro-Canada will buy SCO from Suncor Energy. The objective is to lower its crude oil costs and to shift from declining western Canadian conventional oil supplies.

In the first quarter 2004, Husky Oil Operations Limited, a subsidiary of Husky Energy, proposed a commercial thermal project east of Kearl Lake, about 60 kilometres northeast of Fort McMurray, Alberta. The Sunrise Thermal Project includes an expansion of Husky's heavy oil upgrader in Lloydminster.

5.2.2 Eastern Canada

There are 12 refineries located in eastern Canada; however, SCO and blended bitumen are transported only as far as the province of Ontario. There are six refineries in Ontario with a refining capacity of 87 500 m^3/d (551 mb/d) (Table 5.3), owned by Imperial (2), Nova, Petro-Canada, Shell and Sunoco.

TABLE 5.3

Ontario Refinery Specifications

	m^3/d	mb/d
Refinery Capacity	**87 500**	**551**
Coking	3 650	23
FCC	2 600	130
HCU	7 600	48

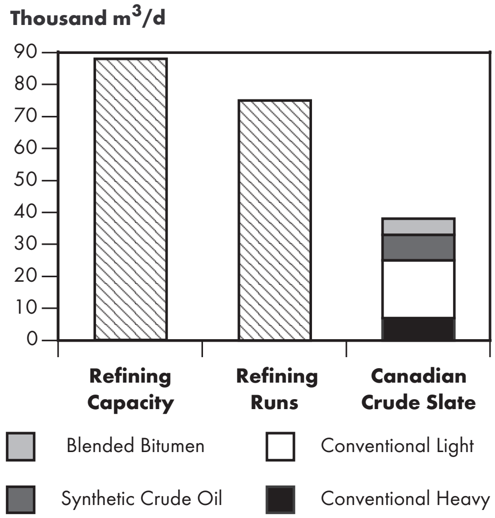
In 2002, Ontario refineries operated at 86 percent of capacity. Ontario refiners currently process ten percent or 7 856 m³/d (50 mb/d) of SCO and seven percent or 5 197 m³/d (33 mb/d) of blended bitumen. In 2002, 71 percent or 53 420 m³/d (337 mb/d) of refinery runs in Ontario were conventional light crude oil of which 66 percent was received from the Enbridge Sarnia-to-Montreal pipeline (Line 9), which was reversed in July 1998.

It is expected that equity owners of crude oil produced offshore eastern Canada will continue to take a significant portion of this production to Ontario and Quebec.

There is some potential for SCO to further penetrate the Ontario refining market, and it is expected that this could occur when refineries make the necessary investments to meet the new fuel specifications introduced by the Federal Government.

FIGURE 5.3

Ontario Receipts of Western Canadian Crude Oil[1] - 2002



1 Excludes imports of 26 378 m³/d (166 mb/d) and east coast production of 8 725 m³/d (55 mb/d)

In the Board's Reasons for Decision OH-1-2003, Trans-Northern Pipelines Inc. (TNPI), July 2003, TNPI received approval to increase the capacity on its petroleum products pipeline from Montreal, Quebec to Farran's Point near Ingleside, Ontario and to reverse the direction of flow between Farran's Point and the Clarkson Junction in Mississauga, Ontario. During the proceeding, Petro-Canada announced that it would cease operations at its Oakville refinery and serve the Ontario market from its Montreal refinery. The company indicated that the reason for this closure was the capital investment required to meet the reduction in sulphur levels for fuels that will be required by 1 January 2005 (gasoline 30 ppm) and 1 June 2006 (diesel 15 ppm).

It has been suggested by some industry stakeholders that eastern Canadian refineries could potentially be a growth market for SCO. If the conditions were favourable, synthetic could back out Line 9 shipments. Other scenarios that have been proposed are: Line 9 could be fully utilized going west (which is currently the case); Line 9 could be shut down and not utilized at all; or Line 9 could be re-reversed to flow in an easterly direction to Montreal.

Suncor (Sunoco) has indicated that it plans to spend $330 million in 2004 on Canadian operations, with the majority directed to meeting federal regulations for the reduction of sulphur in diesel fuel at its Sarnia refinery. At this time, Suncor will make modifications to its refinery to process greater quantities of oil sands production.

5.2.3 United States

PADD I

With a refining capacity of 252 000 m³/d (1.6 mmb/d) (Table 5.4), PADD I has 11 refineries: American, Ergon, Giant, Motiva, ConocoPhillips (2), Sunoco (3), United and Valero.

TABLE 5.4

PADD I Refinery Specifications

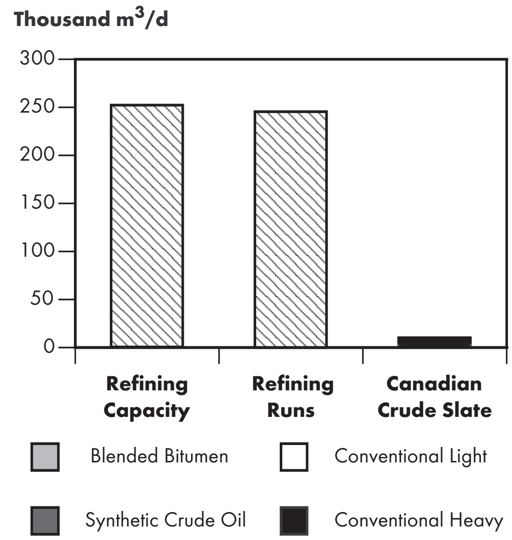
	m³/d	mb/d
Refinery Capacity	**252 000**	**1 600**
Coking	14 400	91
FCC	99 000	623
HCU	6 000	38

PADD I refineries currently process a slate from various sources. In 2002, over 190 000 m³/d (1.2 mmb/d) of its crude oil requirement was imported and, of that, western Canada provided about 9 200 m³/d (58 mb/d) or four percent (Figure 5.4). A large portion of the Canadian supply is conventional light from offshore eastern Canada.

PADD I currently processes minor amounts of synthetic and it is expected that these volumes will not increase significantly. Use of blended bitumen is growing and it is anticipated that this could continue with additional coking capacity. United Refining has received an environmental permit to construct a coker at its Warren, Pennsylvania facility. The start-up for this project could occur in January 2007. It is estimated that following the installation of the coker the refinery will run 100 percent Canadian heavy crude oil, and potentially, small volumes of synthetic.

FIGURE 5.4

PADD I Receipts of Western Canadian Crude Oil[1] - 2002



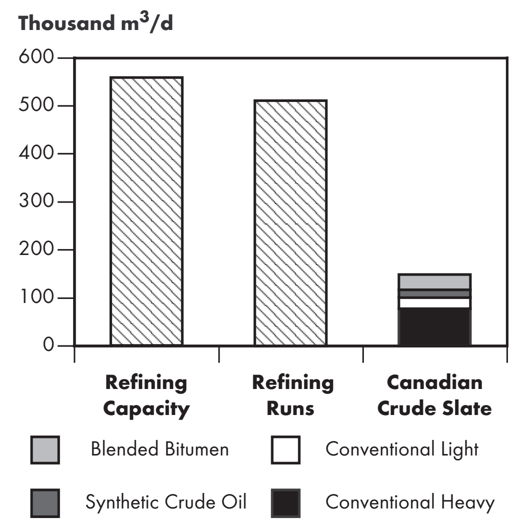
1 Excludes 14 100 m³/d (89 mb/d) of east coast production.

PADD II

PADD II is the largest U.S. market for western Canadian crude oil and has a refining capacity of 558 100 m³/d (3.5 mmb/d) (Figure 5.5). In 2002, 72 percent or 149 630 m³/d (943 mb/d) of western Canadian crude oil exports were delivered into PADD II. Of this amount, 16 480 m³/d (104 mb/d) or 11 percent is synthetic and 32 140 m³/d (203 mb/d) or 21 percent is blended bitumen. This market takes more synthetic and blended bitumen than the other four PADDs combined and is the largest processor of blended bitumen among all Canadian and U.S. markets. Refineries in PADD II are well equipped to process blended bitumen because they have the sophisticated upgrading units required to obtain maximum value from heavy crude. It is worth noting that western Canadian crude oil made up 27 percent of PADD II runs in 2002. At first glance, it would appear that new opportunities exist in this market. However, refineries in this region have many supply options and Canadian crude must be priced competitively with foreign and U.S. domestic production to penetrate the market.

FIGURE 5.5

PADD II Receipts of Western Canadian Crude Oil - 2002



PADD II is currently short about 127 000 m³/d (800 mb/d) of refined petroleum products therefore companies ship those volumes by pipeline north from PADD III. Despite the fact that it is more costly to ship refined products than crude oil, there has recently been an increase in product transfers from PADD III to PADD II. In addition, recent product pipeline expansions - Centennial and Explorer - have resulted in a push to utilize pipeline capacity. However, some PADD II refiners do not have sufficient refining capacity to meet local demand and, therefore, must transfer refined products from PADD III.

The Board's consultations with stakeholders suggest that PADD II refining capacity could increase by 31 750 m³/d (200 mb/d) by 2010. As well, there are refiners in PADD II that have indicated that they are looking at additional coker projects for their facilities. It is expected that much of these capacity increases would be supplied with oil sands production.

In the short term, it is expected that a previously owned coker purchased from Premcor will be processing approximately 2 900 to 4 800 m³/d (18 to 30 mb/d) of Canadian heavy crude in the first quarter of 2004.

For the purpose of this report, PADD II is separated into two tiers - northern and southern and, within these regions, further segregated into smaller market areas.

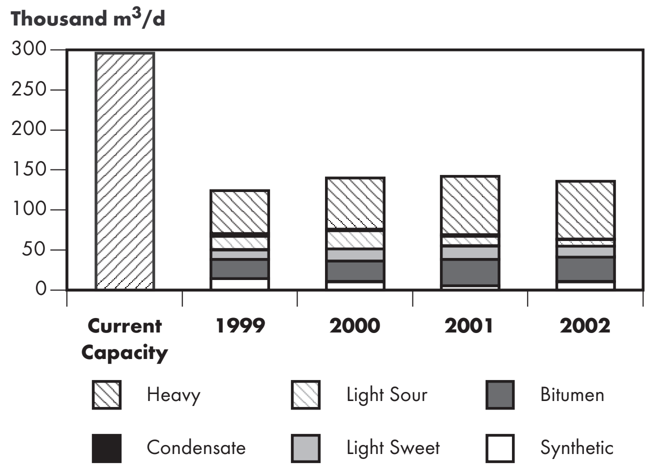
The Northern Tier

The Northern Tier includes refineries located in the states of: North Dakota (Tesoro), Minnesota (Flint Hills Resources and Marathon Ashland LLC), Michigan (Marathon Ashland LLC), Wisconsin (Murphy Oil), Ohio (BP, Marathon Ashland LLC, Sunoco and Premcor), Indiana (BP and Countrymark Cooperative) and Chicago, Illinois (CITGO and ExxonMobil).

This area has a combined refining capacity in excess of 296 000 m³/d (1.9 mmb/d). These refineries receive crude that is shipped by Enbridge and Express pipelines. They already take a significant portion of their crude oil requirements from western Canada. In 2002, 46 percent or 136 000 m³/d (860 mb/d) of the crude oil processed at these facilities was Canadian. Of this quantity, 53 percent or 72 000 m³/d (455 mb/d) was conventional heavy while SCO and blended bitumen account for 30 percent or 41 000 m³/d (260 mb/d). The remaining volumes are domestic crude oil and imports from the USGC (Figure 5.6).

FIGURE 5.6

Northern Tier PADD II Receipts of Western Canadian Crude Oil - 1999 to 2002



Industry has identified the Northern Tier as having growth potential although large volumes of Canadian crude oil are already processed in these refineries. Canadian oil receipts have remained steady or have increased slightly year-to-year. It is anticipated that with declining conventional production in Canada and the U.S. this area will continue to take increasing volumes of blended bitumen and synthetic, particularly if refining capacity increases or upgrading units are added.

Chicago

The Chicago area with a refining capacity of 128 000 m³/d (806 mb/d) (Table 5.5), includes three refineries: BP, CITGO and ExxonMobil.

TABLE 5.5

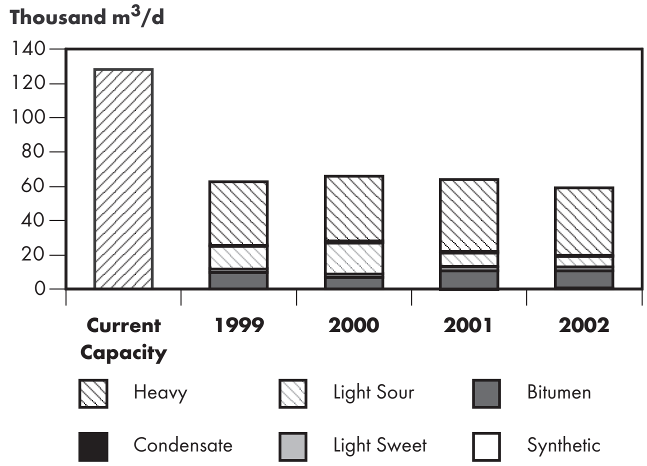
Chicago Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**128 000**	**806**
Coking	19 840	125
FCC	48 730	307
HCU	0	0

This market has, on average, refined in excess of 60 000 m³/d (378 mb/d) of Canadian crude oil or close to 50 percent of its refining capacity over the past four years (Figure 5.7). Of this amount, conventional heavy crude oil has accounted for 66 percent or 39 000 m³/d (246 mb/d), followed by blended bitumen at 17 percent or 10 000 m³/d (63 mb/d) and the remainder being light crudes. The demand for heavy crude oil is seasonal, based on the needs of the asphalt market.

FIGURE 5.7

Chicago Receipts of Western Canadian Crude Oil - 1999 to 2002



There are pipelines into Chicago that deliver domestic crude and systems that deliver from the USGC carrying both domestic and import supplies. In PADD II, particularly Chicago, Canadian crude oil must compete directly with Mars, Louisiana Light Sweet, WTI and WTS. Almost all of the 103 000 m³/d (650 mb/d) of WTS production from PADD III is processed in refineries south of Chicago.

It is expected that some small refinery expansions will occur as a result of growing demand for petroleum products in this market. This will result in increased demand for oil sands supply if priced competitively with other sources of supply.

North Dakota/Minnesota/Wisconsin

The North Dakota/Minnesota/ Wisconsin area with a refining capacity of 69 000 m³/d (436 mb/d) (Table 5.6) includes four refineries: Tesoro, Flint Hills Resources, Marathon Ashland and Murphy Oil.

TABLE 5.6

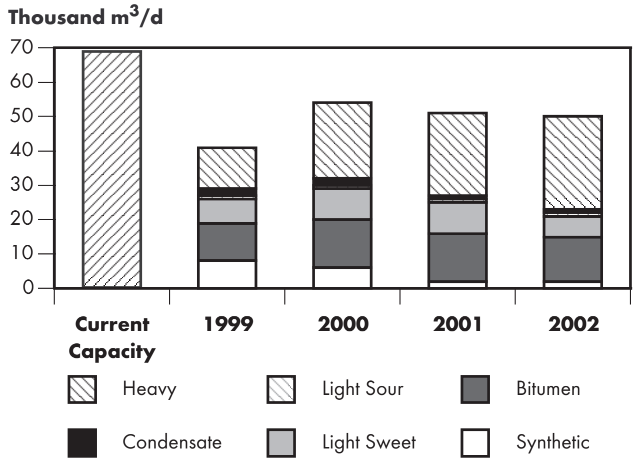
North Dakota/Minnesota/ Wisconsin Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**69 000**	**436**
Coking	9 700	61
FCC	17 800	112
HCU	0	0

The Tesoro refinery in North Dakota processes small volumes on a spot basis of Canadian crude. The three remaining refineries receive on average 85 percent or 50 000 m³/d (315 mb/d) of their crude requirements from western Canada (Figure 5.8). Of this, 53 percent or 27 000 m³/d (170 mb/d) is conventional heavy crude oil, followed by 25 percent or 13 000 m³/d (82 mb/d) of blended bitumen and five percent or 2 000 m³/d (13 mb/d) is SCO.

FIGURE 5.8

North Dakota/Minnesota/Wisconsin Receipts of Western Canadian Crude Oil - 1999 to 2002



The Minnesota refineries access Canadian crude from the Enbridge system and then the Minnesota Pipeline from Clearbrook to St. Paul, and the Express System from Wood River up the Koch Pipeline. These refineries would prefer to run exclusively Canadian crude oil; however, the Minnesota Pipeline, owned by Koch Industries and Marathon Ashland, is capacity constrained. Because of this constraint, the refiners in this area process some U.S. domestic production and foreign crudes.

If refinery expansions were to occur in this area, it is likely that an expansion of the Minnesota Pipeline would be required for these refineries to process more Canadian crude. Flint Hills Resources announced in the first quarter of 2004 that it will be constructing a 5 600 m^3/d (35 mb/d) HCU, hydrogen plant and additional storage tanks at its Rosemount (St. Paul) refinery. The project will increase its crude oil processing capacity by 8 000 m^3/d (50 mb/d).

Increased volumes of oil sands, which will displace conventional heavy, will continue to grow due to the complexity of these refineries.

Toledo/Detroit

The Toledo/Detroit market with a refining capacity of 96 000 m^3/d (604 mb/d) (Table 5.7), includes five refineries: Marathon Ashland (2), BP, Premcor and Sunoco Inc.

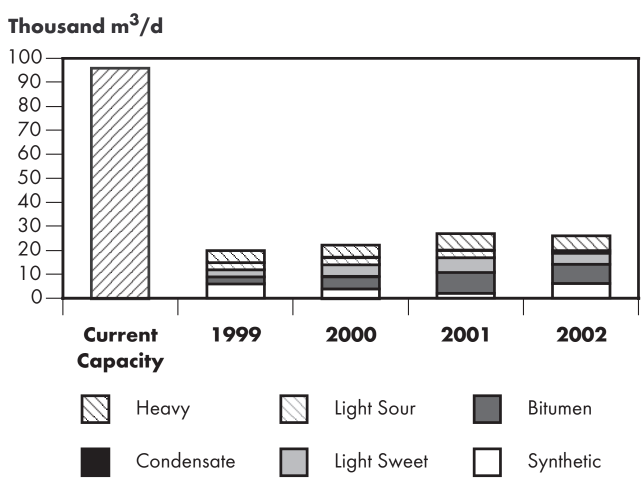
TABLE 5.7

Toledo/Detroit Refinery Specifications

	m^3/d	mb/d
Refinery Capacity	**96 000**	**604**
Coking	15 000	93
FCC	33 000	209
HCU	13 000	83

FIGURE 5.9

Toledo/Detroit Receipts of Western Canadian Crude Oil - 1999 to 2002



The Toledo/Detroit market receives about 27 percent, or 26 000 m^3/d (165 mb/d) of its crude oil requirements from western Canada (Figure 5.9). Western Canadian crude oil is transported by Enbridge and, to a lesser extent, Express Pipeline to refineries in this area. Because of its accessibility to the Capline Pipeline, the refinery located in Canton, Ohio can receive crude from the USGC economically.

One issue with respect to supplying Toledo is that Enbridge Line 17, which flows off the mainline and into

Toledo, is currently capacity constrained. It has a capacity of 15 900 m³/d (100 mb/d) and only delivers heavy crude oil. This line is currently used by BP and Marathon Ashland (MAP); however, BP has to compete with MAP to get space on the line. Enbridge, BP and MAP are assessing expansions of this line to 23 800 m³/d (150 mb/d), which could provide an additional 8 000 m³/d (50 mb/d) of Canadian heavy crude oil to this market.

The Southern Tier

The Southern Tier includes 13 refineries with a refining capacity of 261 000 m³/d (1.7 mmb/d) (Table 5.8). These are located in:

- Illinois: Wood River - ConocoPhillips, Robinson - Marathon Ashland;
- Oklahoma: ConocoPhillips, Gary Williams, Sinclair, Sunoco and Valero;
- Kansas: Farmland, Frontier and NCRA;
- Tennessee: Premcor;
- Kentucky: Marathon Ashland and Somerset.

In 2002, the refineries in this area processed only four percent or 11 000 m³/d (65 mb/d) of Canadian crude oil. Seventy-three percent of that was conventional heavy (Figure 5.10).

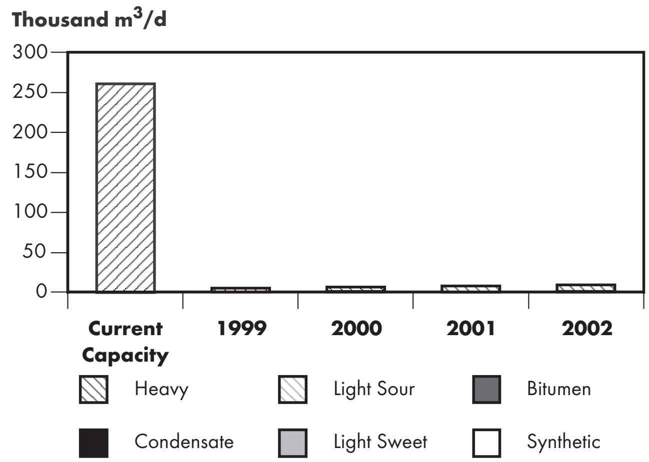
TABLE 5.8

Southern Tier Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**261 000**	**1,650**
Coking	18 400	116
FCC	75 000	472
HCU	11 000	71

FIGURE 5.10

Southern Tier Receipts of Western Canadian Crude Oil - 1999 to 2002



In the second quarter of 2003, ConocoPhillips purchased selected assets from Premcor's Hartford, Illinois refinery. The purchase included a coker, a crude unit and a catalytic cracker as well as additional assets. The acquisition was not intended to increase the refinery production at ConocoPhillips' Wood River facility; however, it would enable the refinery to process heavier, lower cost crude oil. There is an opportunity for additional volumes of blended bitumen to be processed at this refinery.

Recently, this market has been considered to be an emerging market with tremendous potential because of its upgrading capabilities. During the past several months, there has been a series of announcements by Enbridge of projects and acquisitions that would enhance its presence in the U.S. and open new potential outlets for western Canadian crude oil production (see Chapter 6 - Pipelines), including the Southern Tier.

Over the past four years the Southern Tier has increased its receipts of Canadian crude oil by 100 percent; however, this is only four percent of total refining capacity. Canadian crude oil has assumed a dominant position in northern PADD II; however, this has not been the case in the southern region due to lack of pipeline accessibility. It appears that, given the potential success of the various pipeline proposals, deliveries of Canadian crude oil to this region could increase significantly in the future.

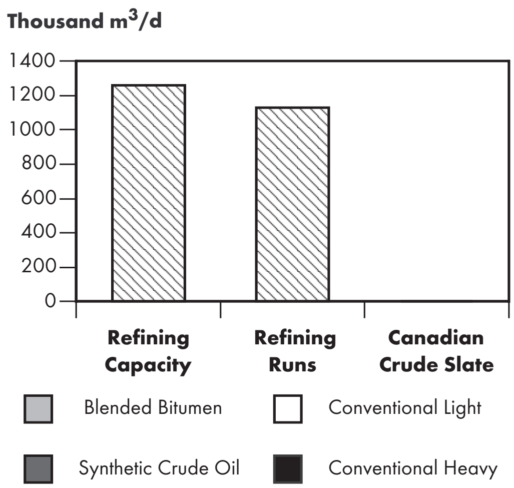
TABLE 5.9

PADD III Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**1 258 600**	**7,900**
Coking	177 000	1,100
FCC	457 000	2,900
HCU	101 000	634

FIGURE 5.11

PADD III Receipts of Western Canadian Crude Oil - 2002



PADD III

There are 53 refineries located in PADD III with a refining capacity of 1 258 600 m³/d (7.9 mmb/d) (Table 5.9).

PADD III is the largest and most complex refining centre in the world and accounts for roughly 35 percent of total North American capacity.

The crude oil slate of these refineries consists mainly of foreign imports and U.S. domestic production. PADD III occasionally takes small spot shipments of western Canadian crude oil, as well as volumes from offshore eastern Canada (Figure 5.11).

At one time, it was believed that this market was not attainable for Canadian producers because there was no access to it except by tanker, and furthermore Mexico and Venezuela dominated the market because of their geographic proximity and joint ventures with some of these refineries.

This could change as a result of the recent announcements by Enbridge to purchase various pipeline assets in PADD II (see Chapter 6 - Pipelines). The next logical step would be to reverse the ExxonMobil line that moves crude oil from Nederland, Texas via Corsicana north to Patoka. Because the Gulf Coast market is very competitive, the impact on netbacks to Canadian producers must be considered.

According to stakeholders, penetrating this market with an initial volume of 12 700 m³/d (80 mb/d) or less could enable Canadian producers to assess the economics of further sales at a later stage.

TABLE 5.10

PADD IV Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**90 800**	**572**
Coking	6 700	40
FCC	24 000	150
HCU	795	5

PADD IV

PADD IV can be divided into three market regions: Montana, Utah and Colorado/Wyoming, with a refining capacity of 90 800 m³/d (572 mb/d) (Table 5.10).

Refiners in this area are price takers because they have few alternatives for crude oil supply. Historically, these refineries have processed local production; however, ongoing annual declines have forced them to source more crude from Canada (Figure 5.12). For example, in 1995, PADD IV imported roughly 23 percent of its requirements from Canada in comparison with 48 percent in 2002. These refineries tend to be seasonally constrained and need to import refined products as well.

Canadian crude oil is transported to PADD IV via Express Pipeline, the Rangeland/Western Corridor System, the Bow River/Milk River/Cenex pipelines, and the Wascana and Eastern Corridor pipelines.

Consultations with stakeholders suggested that refining capacity could increase by up to 15 900 m^3/d (100 mb/d) by 2010, including the addition of a coker. Furthermore, it was suggested that this capacity increase would be supplied by oil sands production.

Montana

There are four refineries in Montana: Cenex, ConocoPhillips, ExxonMobil in Billings and Montana Refining in Great Falls, with a refining capacity 28 400 m^3/d (175 mb/d) (Table 5.11).

In 2002, Montana refineries processed roughly 70 percent or 20 000 m^3/d (126 mb/d) of western Canadian crude oil. Of this, 70 percent or 14 000 m^3/d (88 mb/d) was conventional heavy crude, followed by 20 percent or 4 000 m^3/d (25 mb/d) of light sour and small volumes of blended bitumen and condensate (Figure 5.13).

Historically, this has been a very good market for Canadian crude oil and is likely to continue. As well, it is expected that this market could expand marginally and possibly add some coking capacity.

FIGURE 5.12

PADD IV Receipts of Western Canadian Crude Oil - 2002

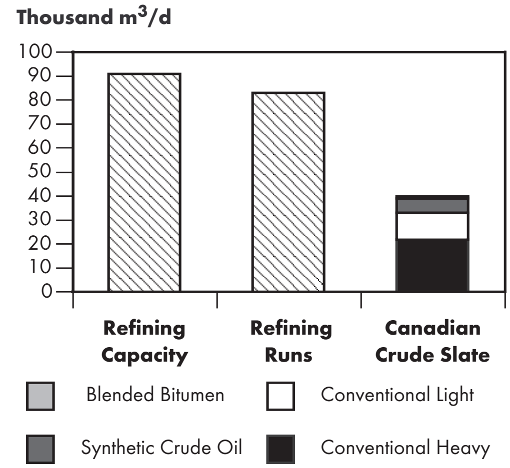


TABLE 5.11

Montana Refinery Specifications

	m^3/d	mb/d
Refinery Capacity	**28 400**	**175**
Coking	4 000	25
FCC	8 400	53
HCU	794	5

FIGURE 5.13

Montana Receipts of Western Canadian Crude Oil - 1999 to 2002

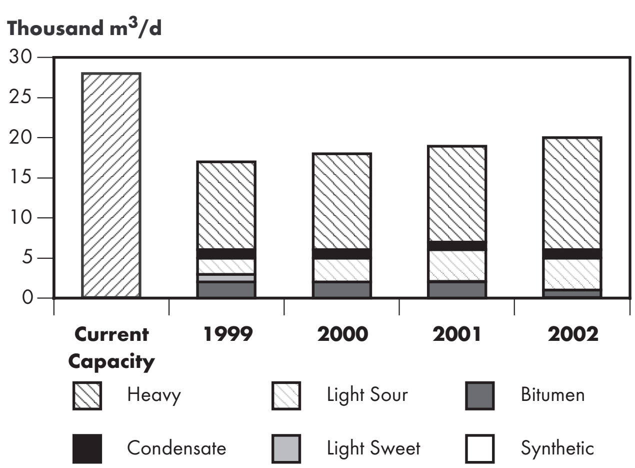


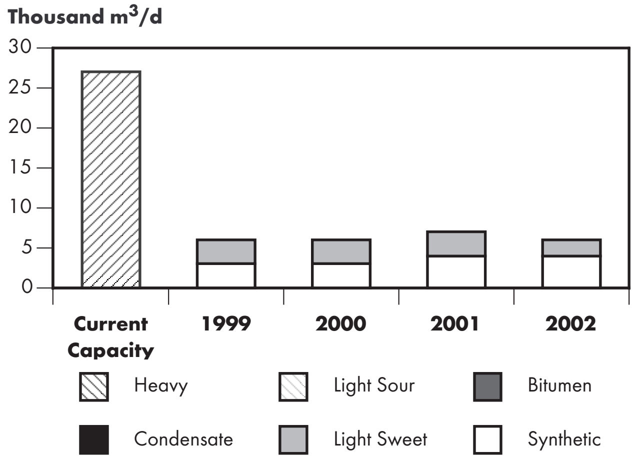
TABLE 5.12

Utah Refinery Specifications

	m^3/d	mb/d
Refinery Capacity	**26 700**	**168**
Coking	1	7
FCC	8 500	54
HCU	0	0

FIGURE 5.14

Utah Receipts of Western Canadian Crude Oil - 1999 to 2002



Utah

Utah has a combined refinery capacity of about 26 700 m^3/d (168 mb/d) (Table 5.12). There are four refineries, owned by Tesoro, ChevronTexaco, Flying J and Holly Corp.

The Utah refineries rely primarily on indigenous light crude oil supply, running only 25 percent or 6 300 m^3/d (40 mb/d) of western Canadian crude oil. These refineries process primarily light sweet crude oil. As domestic supply continues to decline, they will run more synthetic. SCO has increased its share in Utah and, in 2002, accounted for 57 percent or 4 000 m^3/d (23 mb/d) of Canadian imports (Figure 5.14).

It is unlikely that blended bitumen will be a feedstock for these refiners, given the lack of upgrading capacity.

TABLE 5.13

Colorado/Wyoming Refinery Specifications

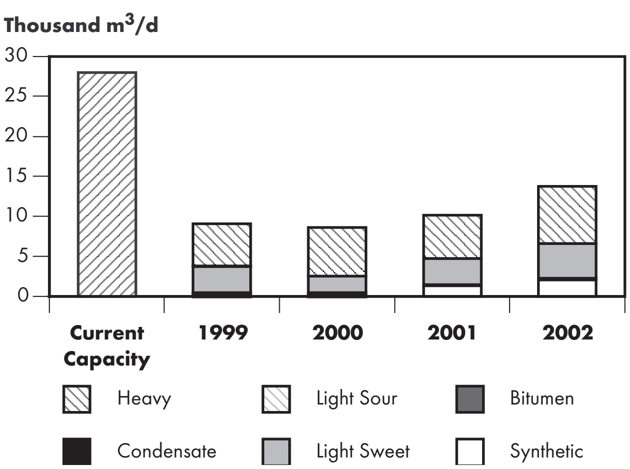
	m^3/d	mb/d
Refinery Capacity	**35 400**	**223**
Coking	2	10
FCC	11 000	69
HCU	0	0

Colorado/Wyoming

The six refineries in Colorado/Wyoming are: Suncor, Frontier, Little America, Sinclair Oil, Valero, and Wyoming Refining, and have a combined refining capacity of 35 400 m^3/d (223 mb/d) (Table 5.13).

FIGURE 5.15

Colorado/Wyoming Receipts of Western Canadian Crude Oil - 1999 to 2002



In 2002, 39 percent or 13 750 m^3/d (87 mb/d) of the total crude processed was Canadian (Figure 5.15). Slightly more than half of these volumes were conventional heavy crude oil, followed by light sweet. Synthetic has grown in popularity and it is expected that, with Suncor's purchase of the ConocoPhillips refinery in Denver, this will continue. In addition, with the expected declines in U.S. domestic production and Canadian conventional heavy, refineries in this area will run increasingly more blended bitumen.

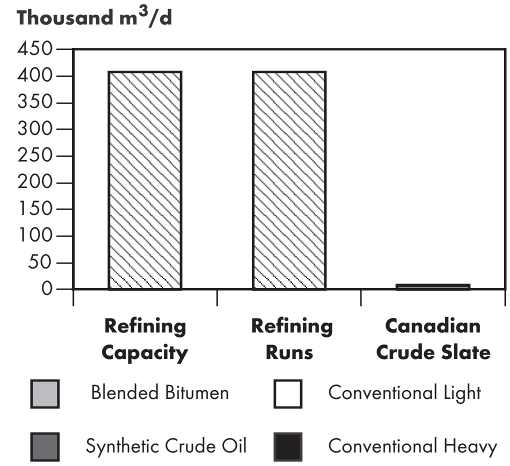
TABLE 5.14

PADD V Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**407 500**	**2,600**
Coking	87 000	550
FCC	124 000	780
HCU	66 000	420

FIGURE 5.16

PADD V Receipts of Western Canadian Crude Oil - 2002



PADD V

There are 20 refineries in PADD V: BP (2), ChevronTexaco (2), Shell Oil Products (4), ExxonMobil, Kern, Paramount, ConocoPhillips (3), San Joaquin, Tesoro, Valero (3) and U.S. Oil with a combined refining capacity of 407 500 m³/d (2.6 mmb/d) (Table 5.14).

Of the 20 refineries located in PADD V, five are located in Washington State and routinely take some Canadian crude oil (Figure 5.16). Currently, the California refineries occasionally take spot shipments if it is deemed economic and there is space on Terasen Pipelines (Trans Mountain) Inc.

There are currently three proposals to increase oil sands access to California and the Asia markets (See Chapter 6 - Pipelines, for additional details).

TABLE 5.15

Washington Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**98 400**	**620**
Coking	13 500	85
FCC	12 150	127
HCU	8 700	55

Washington

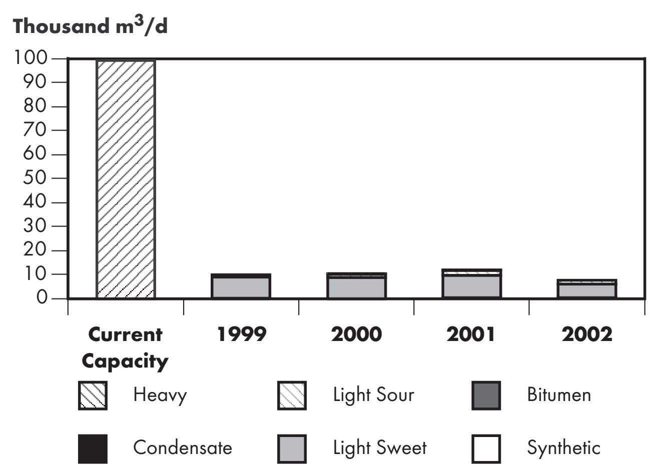
There are five refineries in Washington State, owned by BP, Shell Oil Products, Tesoro, ConocoPhillips and U.S. Oil. The total refining capacity is approximately 98 400 m³/d (620 mb/d) (Table 5.15).

The refineries in this area process about eight percent or 8 000 m³/d (50 mb/d) of Canadian light crude oil (Figure 5.17).

The Washington refineries run predominately Alaskan North Slope (ANS) crude oil. As ANS continues to decline, Canadian heavy blends and synthetic could be a replacement. As well, with minor modifications to existing refinery configurations, these facilities could run more Canadian oil sands if pipeline capacity exists.

FIGURE 5.17

Washington Receipts of Western Canadian Crude Oil - 1999 to 2002



California

There are 15 refineries located in California: BP, ChevronTexaco (2), Shell Oil Products (3), ExxonMobil, Kern, Paramount, ConocoPhillips (2), San Joaquin and Valero (3) with a refinery capacity of 302 000 m³/d (1.9 mmb/d) (Table 5.16).

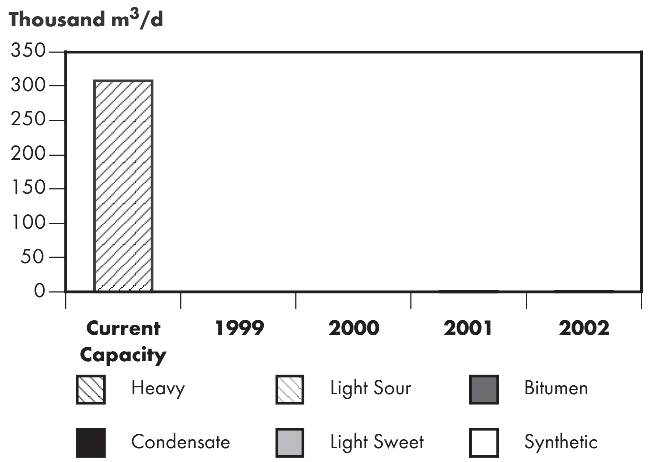
TABLE 5.16

California Refinery Specifications

	m³/d	mb/d
Refinery Capacity	**302 000**	**1,900**
Coking	74 000	463
FCC	104 000	655
HCU	58 000	363

FIGURE 5.18

California Receipts of Western Canadian Crude Oil - 1999 to 2002



Many consider California to be an emerging market for Canadian crude and one that holds great potential. Whether Canadian crude oil will penetrate this market depends on a number of factors, including production declines in California, competition with crude oil imports and the rate of decline of ANS. Industry has indicated that this market is ideally suited to synthetic and blended bitumen as the refineries currently process predominately heavy sour and medium sour crude oil. Little Canadian crude oil is currently delivered into California (Figure 5.18). It must be shipped through the Trans Mountain Pipeline to its Westridge dock facility and transported by tanker. This is costly and, in order for Canadian crude oil to be competitive, it must be priced competitively relative to other foreign crude oils.

Canadian heavy grades could be an excellent substitute for much of the decline in local heavy crude oil production and ANS, and could be competitive against the import alternatives, as well. Our consultations with stakeholders indicated that refineries in this area could be receptive to taking Canadian crude and some would consider a long-term supply contract.

Shell has announced that it will be closing its refinery in Bakersfield with a capacity of 10 300 m³/d (65 mb/d), effective 1 October 2004, as a result of declining supplies of San Joaquin Valley heavy crude oil. The refinery is the twelfth largest in California.

5.2.4 Asia

Asia has attracted global interest as an emerging market and growth is expected in the coming years, with energy demand expected to keep pace with GDP growth (Table 5.17). Oil demand is likely to be supported by demand for transportation fuels.

China will be the dominant factor in the region, with GDP growth expected to be well above the average for Asia, the United States and the rest of the world. On average during the period 2003 to 2008, oil demand is expected to increase by four percent per year (Table 5.18).

The Asian market is a potential outlet for the rising outputs from the oil sands. In the case of Japan, China and South Korea, for example, imports of crude oil totaled about 1.2 million m^3/d (7.5 mmb/d) in 2002 and this could increase to approximately 1.6 million m^3/d (10 mmb/d) by 2015.

Based on consultations with stakeholders, Asia has been identified as a destination for ongoing spot shipments of Canadian crude oil. Most recently, there has been interest in Canadian Albian and Cold Lake crude oils. In 2003, China's Unipec purchased Albian crude (20º API and 2 percent sulphur) on a spot basis to blend with lighter, sweeter grades.

TABLE 5.17

Projected GDP Growth Selected Countries — 2003 to 2010 (Percent)

Country	2003	2004	2005	2006	2007	2008	2010
China	7.4	7.0	6.5	6.4	6.3	6.2	6.0
Japan	0.7	1.5	2.0	2.0	2.0	2.0	2.0
Total Asia	2.9	3.3	3.5	3.5	3.5	3.5	3.4
USA	2.5	3.0	3.5	3.5	3.5	3.5	3.3
World	2.4	2.9	3.3	3.3	3.3	3.2	3.1

Source: PEL Market Services – April 2003 World Long Term Oil and Energy Outlook.

TABLE 5.18

Projected Oil Demand Selected Countries — 2003 to 2008 (Thousand m^3/d)

Country	2003	2004	2005	2006	2007	2008
China	817	849	887	925	963	1 000
Japan	837	830	830	829	830	830
Total Asia	3 400	3 500	3 600	3 700	3 800	3 900
USA	3 200	3 200	3 200	3 300	3 300	3 400
World	12 300	12 500	12 800	13 000	13 200	13 500

Source: PEL Market Services – April 2003 World Long Term Oil and Energy Outlook.

In the longer term, it appears that Asia is a promising term-contract outlet for Canadian crude oil. In this connection, Enbridge and Terasen (TMPL) have proposals to tap both the Far East and California markets (See Chapter 6 - Pipelines).

5.3 Conclusion

Canadian oil sands producers have been creative in finding outlets for the rising output. These include, in no particular order: purchasing refineries; tailoring output quality to fit a specific refiner/buyer; upgrading to make a saleable light quality crude oil; long-term partnership arrangements to enable refiners to retrofit their plants to accommodate a specific grade of oil sands; and providing test batches to be used by refiners to determine how a specific oil sands crude fits their refinery configuration.

Based on consultations with industry and the Board's assessment of potential markets, it appears that markets will be available for the growing oil sands production. For many years, Canadian crude oil production has successfully expanded in traditional markets (e.g., upper PADD II, PADD IV and, to a lesser extent, Washington State). During this period, Canadians have gained a solid understanding of these markets. As well, spot shipments have occurred into California, PADD III and the Far East by tanker.

It is recognized, however, that there will likely be temporary periods when substantial price discounts are required to penetrate both existing and potential new markets as new oil sands production comes onstream in large volumes and the market adjusts to the incremental supply.

The following steps outline a potential scenario for accessing markets for the growing oil sands production.

- **First Step:** Fill up existing markets including Washington State, PADD IV, northern PADD II and, perhaps, some small incremental volumes in the domestic market.
- **Second Step:** Penetrate eastern PADD II, southern PADD II, and perhaps build new cokers in PADDs I, II and IV.

  This step would also include increased usage of oil sands crude in Canada, at two refineries in Edmonton (Imperial and Petro-Canada).

TABLE 5.19

Number of Refineries and Refining Capacity in Asia and North America

Area	**# Refineries**	**Refining Capacity Thousand m^3/d**
North America	153	3 000
Asia		
China	95	719
Indonesia	8	158
Japan	33	747
Malaysia	6	82
North Korea	2	12
Philippines	3	53
Singapore	3	209
South Korea	6	404
Taiwan	0	-
Thailand	4	112
Vietnam	0	-
Subtotal	160	2 500
World	**717**	**13 000**

Source: Oil and Gas Journal Dec 22, 2003.

- **Third Step:** Penetrate PADD III. It is important to mention that the industry had mixed views on this. On the one hand, there are those who believe that any attempt to penetrate PADD III would bring on competition from other sellers in this market, resulting in a significant impact on Canadian crude oil netbacks. Others feel that, because of its size (1.3 million m^3/d, 7.9 mmb/d), Canada could, at a minimum, penetrate the market by up to 12 700 m^3/d (80 mb/d). On balance, there seemed to be support for at least testing this huge market.

  The previous three steps might result in the absorption of 63 500 m^3/d to 80 000 m^3/d (400 to 500 mb/d) of oil sands production through to 2008. After that, it appears that industry would have to branch out to find new markets, as discussed in Step 4 below.

- **Fourth Step:** There seems to be almost unanimous opinion in industry that a new or expanded pipeline to the Canadian west coast would eventually be required to serve the potentially lucrative California market. According to stakeholders, the attraction of a new or expanded line to the west coast compared with an overland pipeline to California is that the Far East market could be tapped as well.

  Another domestic market could be examined, if additional markets were required, and this would involve reducing throughputs or closing the Sarnia-to-Montreal pipeline and replacing imports into Ontario with oil sands output.

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PIPELINES

6.1 Introduction

Pipelines are the vital link in the oil sands supply chain. They are the connection between the upstream producer and the downstream refiner. Although crude oil could be transported via truck or rail, pipelines are the most practical, reliable and economic mode to ship large volumes of crude oil. This chapter focuses on the location and capacity of pipelines transporting crude oil within Canada and for export to the United States or markets served by marine transportation. The discussion will be limited to those pipelines that ship crude oil from the oil sands. Also included is a discussion on proposed pipeline projects in Canada and the U.S. that have been announced to transport the increasing outputs from the oil sands.

6.2 Alberta Hubs

Most feeder pipelines in Alberta, in particular those that transport synthetic crude oil (SCO) and blended bitumen, deliver crude oil to two hubs located in Edmonton and Hardisty, Alberta. From these locations, crude oil can be transported in segregated batches to delivery points in Canada and the United States.

The Edmonton hub has slightly more than one million cubic metres (6.5 million barrels) of storage capacity for the various types of crude oil received from the connecting feeder pipelines. Crude oil is shipped from the Edmonton hub on two main trunklines:

- Enbridge Pipeline Inc. (Enbridge) is the major carrier of crude oil to Ontario and U.S. markets; and
- Terasen Pipelines (Trans Mountain Pipe Line) Inc. (TMPL) transports crude oil to British Columbia, Washington State and to its Westridge dock for loading on tankers.

The Hardisty hub is located 220 km southeast of Edmonton and connects several feeder pipelines with Express Pipeline, Enbridge and Inter Pipeline Fund's Bow River Pipeline. In 2003, storage capacity at Hardisty increased by 476 thousand cubic metres (3 million barrels) with the addition of four salt caverns. These caverns have access to commodities delivered on Enbridge from Edmonton as well as all other volumes handled at the Hardisty terminal. The cavern partners are Enbridge (Athabasca) Inc. and CCS Income Trust, but BP Canada Energy leases the facilities. The total storage capacity at Hardisty is approximately 1.4 million cubic metres (8.8 million barrels).

With proposals for capacity expansions to the various mainline systems, it is likely that companies may also seek to build more storage tanks. This will become increasingly important to accommodate the various types of oil sands products.

One such proposal by Terasen Pipelines Inc. (Terasen) is to build and operate a new crude oil storage terminal within the Heartland Industrial Area in Strathcona Country near Edmonton. The facility would be named Terasen Heartland Terminal. Preliminary engineering design foresees it having:

- up to eight storage tanks;
- underground storage caverns;
- a metering system; and
- other associated facilities.

This terminal would also have an associated pipeline connecting to existing facilities at Edmonton. Terasen is conducting detailed engineering and design review, and preparing an application to the AEUB. It expects to submit the application by mid-2004. Pending approval, construction could begin by the spring 2005 with completion by the end of 2006.

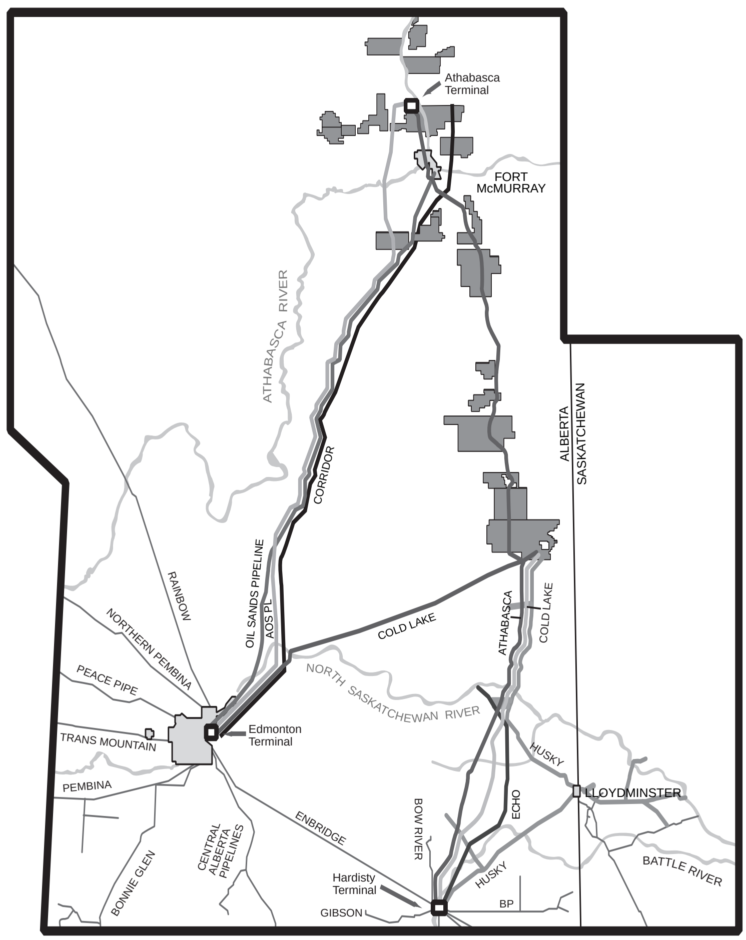
6.3 Existing Feeder Pipelines

Alberta Oil Sands Pipeline

The Alberta Oil Sands Pipeline (AOSPL), owned by Pembina Pipeline Income Fund (Pembina), transports SCO from the Fort McMurray, Alberta area to Edmonton. The AOSPL system is made up of a 434 km mainline and various facilities. The initiation point of this line is Syncrude Canada Ltd.'s production facility, and it is the exclusive transporter for Syncrude. The pipeline has expanded over the years to accommodate production increases at Syncrude. AOSPL's current capacity is 43 700 m^3/d (275 mb/d) but it will increase to 61 900 m^3/d (390 mb/d) with the completion of its Stage 3 expansion. The pipeline expansion involves the installation of 273 km of loops added to the mainline and enhancing the originating pump station. The construction of the project was completed ahead of schedule and could be in service by the second quarter 2004.

FIGURE 6.1

Feeder Pipelines



Athabasca Pipeline

The Athabasca Pipeline, owned by Enbridge Inc., is a 550 km pipeline with a current capacity of 38 200 m^3/d (240 mb/d). It transports SCO and blended bitumen. The pipeline originates at Suncor's plant north of Fort McMurray, proceeds to Cold Lake, Alberta and ultimately delivers crude oil to the Hardisty terminal. In 2002, Enbridge added laterals from the Athabasca terminal to both Petro-Canada's MacKay River and EnCana's Christina Lake bitumen projects. The lateral to MacKay River is an insulated hot bitumen line. Christina Lake, on the other hand, is comprised of two laterals, one to deliver diluent to the lease and the other to transport the diluted bitumen to the Athabasca Pipeline at Kirby Lake, Alberta.

The Athabasca Pipeline could reach a maximum capacity of 90 600 m^3/d (570 mb/d) with the addition of pump stations. Timing of any expansion is solely dependent on industry demand for capacity.

Cold Lake Pipeline

The Cold Lake Pipeline is owned by Inter Pipeline Fund and Canadian Natural Resources Limited (CNRL). There are two separate legs to this system. Cold Lake West is a 37 400 m^3/d (235 mb/d), 233 km line that transports crude oil from Cold Lake to Edmonton. This line is accompanied by a 12" diluent return line. The newest section of the system, Cold Lake South, commenced delivering blended bitumen to Hardisty in December 2001. The length of Cold Lake South is 418 km with a capacity of 31 800 m^3/d (200 mb/d).

Both lines are dedicated to the transportation of blended Cold Lake bitumen. However, through a recent commercial agreement with three shippers, there will be a new product, DilSynBit, for delivery on this system. By fourth quarter 2004, shipments of approximately 9 500 m^3/d (60 mb/d) of DilSynBit will commence.

Terasen Pipelines (Corridor) Inc.

Terasen Pipelines (Corridor) Inc. is a subsidiary of BC Gas Inc. There are two sections of the Corridor Pipeline. The first, being a dual pipeline system, consists of a 450 km pipeline connecting the Athabasca Oil Sands Project's (AOSP) Muskeg River Mine near Fort McMurray to the Scotford upgrader adjacent to Shell's refinery near Edmonton. One line transports 35 100 m^3/d (220 mb/d) of diluted bitumen to the Scotford Upgrader and a second line transports 11 300 m^3/d (71 mb/d) of diluent back to the mine.

The second system is a 43 km pipeline that is associated with the Scotford upgrader. Part of this consists of one line that ships up to 19 950 m^3/d (125 mb/d) of SCO to existing terminals at the Edmonton Hub. The other is a return line that delivers up to 6 450 m^3/d (41 mb/d) of supplementary feedstock to the upgrader.

Corridor, like other pipelines, will expand with increased production at the AOSP. Current plans see pump stations being added by the end of the decade to bring the pipeline up to its ultimate capacity 56 800 m^3/d (357 mb/d) for blended bitumen. Looking farther out, if Albian's Jackpine mine expansion occurs between 2010 and 2015, then a new pipeline would be required in the same time period, bringing total capacity to between 90 600 m^3/d (571 mb/d) and 113 300 m^3/d (714 mb/d).

ECHO Pipeline

ECHO Pipeline is owned and operated by CNRL. With an extension to CNRL's heavy oil properties in late 2001, this line now traverses 210 km from Beartrap, Alberta to the Hardisty terminal. ECHO Pipeline eliminates the necessity of condensate blending because it is a high temperature insulated pipeline. Keeping the bitumen hot allows it to flow through this line; however, once it is delivered to the Hardisty hub, it is blended with diluent in order to meet downstream pipeline specifications. The current capacity is 9 000 m^3/d (57 mb/d), but could increase to 11 900 m^3/d (75 mb/d) with minor upgrades to pump stations.

Husky Pipelines

Husky Pipelines, owned by Husky Energy, has several gathering pipelines that transport heavy conventional crude oil and bitumen from properties in Cold Lake and Lloydminster, Alberta to the Husky upgrading and refining facilities at Lloydminster. From Lloydminster, the system can ship Husky Synthetic and Lloydminster blends to the Hardisty hub.

Oil Sands Pipeline

The Oil Sands Pipeline is owned and operated by Suncor Energy Corporation. This line transports SCO 430 km from Suncor's oil sands plant north of Fort McMurray to the Edmonton hub and area refineries. The capacity varies between 14 300 m^3/d (90 mb/d) and 22 300 m^3/d (140 mb/d), depending on the quality of the crude oil. The Suncor plant produces SCO varying from light sweet to heavy sour. This line can also carry a small amount [about 2 000 m^3/d (13 mb/d)] of high-vapour pressure products, such as propane and C_3+ mix.

Rainbow Pipeline

The Rainbow Pipeline is owned by Rainbow Pipe Line Company Ltd. The mainline is 781 km, operating from Zama Lake, Alberta to Edmonton. The current mainline capacity is 42 000 m^3/d (265 mb/d) for the shipment of conventional light sweet crude oil, condensate and blended bitumen from Peace River and Wabasca. By mid-2004, there will be additional bitumen coming into the system from Black Rock Seal's project. A 7 950 m^3/d (50 mb/d) pipeline is under construction to connect to the Rainbow system at the Nipisi Terminal. At this time, there is ample capacity on the mainline to allow for this increase.

6.4 Trunklines

Enbridge Pipelines Inc.

Enbridge Pipelines Inc., owned by Enbridge Inc., is the primary transporter of crude oil from western Canada to Ontario and the United States. The mainline, consisting of Lines 1, 2, 3, 4 and 13, has a combined capacity of 292 500 m^3/d (1.8 mmb/d). It receives crude oil at Edmonton and Hardisty; Regina, Saskatchewan; and Cromer, Manitoba. Enbridge's Lakehead pipeline system serves refineries in Ontario and the Great Lakes region of the United States. This region is the largest market for all types of Canadian crude oil. Enbridge is also the primary transporter of synthetic and blended bitumen.

In addition, Enbridge ships refined petroleum products from Edmonton to Saskatchewan and Manitoba, and transports natural gas liquids from Edmonton, Kerrobert, Saskatchewan and Cromer to Sarnia, Ontario as well as various locations in the U.S. Midwest. Enbridge serves the U.S. Rocky Mountain and, to a lesser degree, the Midwest areas indirectly via its connections to Express and Bow River pipelines at Hardisty and the Wascana system at Regina.

The Lakehead system is owned by Enbridge Energy Partners, L.P., and connects to the Enbridge pipeline at the Canada/U.S. border in southern Manitoba. The Lakehead pipeline delivers crude oil from Superior, Wisconsin to Sarnia and directly south to the large Chicago, Illinois market. Through other Enbridge-owned lines, crude oil deliveries are made to refineries in:

- Toledo, Ohio;
- Detroit, Michigan;
- Superior, Wisconsin; and
- Warren, Pennsylvania.

The Lakehead system also connects to other pipelines, including the 30 percent owned Mustang Pipe Line Partners system, which delivers western Canadian crude oil into the Patoka, Illinois hub. In addition, at Clearbrook, Minnesota it connects to the Minnesota Pipeline, which ships crude oil to refineries in Twin Cities, Minnesota.

With growing oil sands production, Enbridge has undertaken various mainline expansions. Its Terrace expansion program is near completion. Phase I, completed in early 1999, added about 27 000 m^3/d (170 mb/d) of capacity. In the second quarter 2002, Phase II became operational with incremental capacity of 6 300 m^3/d (40 mb/d). The construction of Phase III is complete; however, the proposed line swaps have yet to transpire. In this phase of the project, Enbridge will convert Line 3 from light crude service to heavy crude service and Line 2 from heavy crude service to light crude service. Once the line swaps occur, Enbridge capacity will be almost 316 000 m^3/d (2 mmb/d).

Express Pipeline

Express Pipeline, operated by Terasen Pipelines Inc., the newest of the three trunklines, commenced operations in April 1997. It runs from Hardisty to Casper, Wyoming where it connects with its U.S. counterpart, Platte Pipeline. At the Casper hub, Platte transports Canadian crude oil and U.S. domestic crude oil from the ConocoPhillips and ExxonMobil pipelines in Montana to the Wood River, Illinois market. From the Casper hub, crude oil can also flow southwest to refineries in Salt Lake City, Utah via a network of smaller pipelines (Frontier and Anschutz). From the connection at Guernsey, Wyoming to the newly purchased Suncor line, crude oil can flow south to refineries in Denver, Colorado. This will benefit Suncor, a major SCO producer, because of its recent acquisition of the Commerce City, Colorado refinery from ConocoPhillips.

In July 2001, Express completed a connection from its mainline in Montana to the Glacier Pipeline to access Billings. This enables up to 4 800 m^3/d (30 mb/d) of additional crude oil to flow into the Billings market. Express expanded to another market allowing for the delivery of crude oil via Platte through a connection at Holdredge, Nebraska into the Jayhawk line. At this time, crude oil via this connection can only access the National Co-op refinery in McPherson, Kansas.

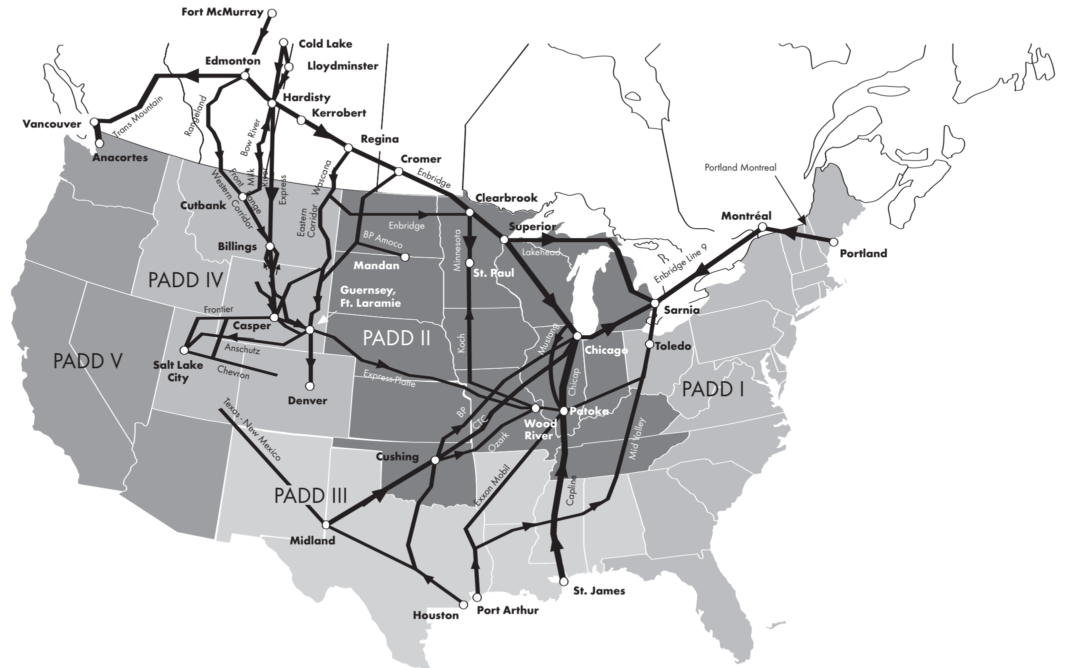
Express has filed an application to increase the current capacity of 27 300 m^3/d (172 mb/d) by 17 600 m^3/d (111 mb/d). (See section 6.6.4 - PADD IV for details).

Terasen Pipelines (Trans Mountain) Inc.

TMPL, a subsidiary of BC Gas Inc., has a light crude oil capacity of 41 300 m^3/d (260 mb/d). It delivers crude oil from the Edmonton hub and Kamloops, British Columbia to the Chevron refinery in Vancouver, British Columbia. As well, the pipeline ships refined petroleum products from the Edmonton refineries to terminals in Kamloops and Vancouver. TMPL also transports Canadian

FIGURE 6.2

Major Canadian and U.S. Crude Oil Pipelines and Markets



crude oil through its subsidiary pipeline at Sumas, Washington to Washington State refiners. Through its Westridge dock facility in the Port of Vancouver, it can load tankers with Canadian crude oil for transportation to other markets, including California and Asia.

This system is designed to transport petroleum products and light crude oil. With its current configuration, TMPL can only ship one or two heavy crude cargoes per month, which reduces the capacity to about 29 900 m^3/d (188 mb/d) from 41 300 m^3/d (260 mb/d). Terasen is seeking approval to expand the heavy capacity to 34 100 m^3/d (215 mb/d) in order to transport up to four heavy crude cargoes per month. If heavy crude oil is not shipped on the line, then the expanded capacity would be 46 000 m^3/d (290 mb/d). Further details on the application are provided in Section 6.6.5.

6.5 Other Pipelines to the Export Market

Rangeland Pipeline

Rangeland Pipeline, with a capacity of 10 300 m^3/d (65 mb/d), ships crude oil from Sundre, Alberta to Cutbank, Montana. This system includes a northern flowing section from Sundre to Rimbey, Alberta. The southern flowing mainline transports primarily conventional light crude oil and some Cold Lake bitumen to markets in Montana, Wyoming and Utah. Reaching these markets is made possible by Rangeland's connection to the Western Corridor System in Montana. The Western Corridor system is made up of the Glacier, Beartooth and Big Horn pipelines. Besides the gathering lines into Sundre, Rangeland can receive crude oil from Edmonton via a connection at Sundre to the Mid Alberta Pipeline. Pacific Energy Partners L.P. recently purchased both the Rangeland and Mid Alberta pipelines.

At Casper, crude oil can be transferred to the Frontier Pipeline, which extends to Ranch Station, Utah and connects with Pacific Energy Partner's Anschutz Ranch East Pipeline for further delivery to the Salt Lake City refining market. The Frontier system also connects with Pacific's Salt Lake City Core System at Divide Junction, Wyoming for delivery to Salt Lake City.

Bow River Pipeline

The Bow River Pipeline, owned by Inter Pipeline Fund, is both a feeder pipeline and a gathering system. It runs south from Hay River, Alberta to the Milk River Pipeline, which connects to the Front Range Pipeline in Montana.

In 2002, one of the mainline segments was reversed to allow crude oil to flow from Hardisty to the Milk River Pipeline. The company has announced plans to expand this southern flowing mainline by 2 700 m^3/d (17 mb/d) with a planned in service date of May 2004.

Milk River Pipeline

The Milk River Pipeline, owned by Plains Marketing Company (Plains), delivers crude oil mainly from the Bow River and the Manyberries pipelines into the Front Range Pipeline in northern Montana. Once delivered to this system, the crude oil can either exit at Cutbank for delivery into the Glacier Pipeline or remain in the line to Laurel, Montana.

Although this line does not currently transport oil sands derived crude oil, it has the potential to do so since the Bow River Pipeline now has access to the Hardisty hub. The current capacity is 18 800 m^3/d (118 mb/d), but could be expanded to 23 850 m^3/d (150 mb/d) with the installation of supporting facilities.

Wascana Pipeline

The Wascana Pipeline, also owned by Plains, transports crude oil from Regina to the Eastern Corridor Pipeline System in Montana. This system consists of two separate pipelines. The Poplar system has a capacity of 6 400 m^3/d (40 mb/d) and delivers crude oil from Raymond, Montana to Baker, Montana. It then connects to the Butte system, which has a capacity of 14 300 m^3/d (90 mb/d) and delivers crude oil to Guernsey. From Guernsey, crude oil can be shipped on pipelines to Salt Lake City, Denver or the Wood River market via Platte Pipeline.

The capacity on Wascana Pipeline varies depending on the quality of crude oil transported and seasonal temperatures. The design capacity for shipping only light crude oil is around 6 200 m^3/d (39 mb/d).

6.6 Proposed Pipeline Expansions to Existing and New Markets

6.6.1 Alberta

Alberta Oil Sands Pipeline (AOSPL)

Pembina is proposing to construct laterals, which would allow for the transportation of SCO for blending and return blended bitumen to the mainline. In addition, Pembina is considering splitting AOSPL into two lines. The original pipeline built in 1978 is 70 percent looped. With the completion of looping, there would be two separate lines. The plan would be to use the new looped line for Syncrude's production and the old line for the transportation of blended bitumen. As a result, capacity on the old 22" line would be 31 800 m^3/d (200 mb/d) while on the newer 24" to 30" line, it would be 61 900 m^3/d (389 mb/d). To do this, Pembina would need support from one or more SAGD projects.

The system may need further expansion sometime after 2008 depending on production levels at Syncrude. This would probably involve a de-bottlenecking of around 6 400 m^3/d (40 mb/d) by 2010.

Terasen Pipelines (Bison) Inc.

Bison Pipeline, proposed by Terasen, would transport oil sands production from the Fort McMurray area to Edmonton. It would be a 24" pipeline with the capability of shipping both SCO and blended bitumen in batches. The pipeline would have a capacity of 47 700 m^3/d (300 mb/d), but would initially transport 15 900 to 23 850 m^3/d (100 to 150 mb/d). Bison would be built to complement the growth in oil sands production in 2006 to 2008.

In conjunction with this, Terasen has an option in this proposal to construct a second pipeline around 2010 to 2012, to allow for segregation of synthetics from the blended bitumen.

Waupisoo Pipeline

Enbridge is examining the possibility of building a new pipeline from the Fort McMurray region to Edmonton that would be designed to transport bitumen. All possibilities are being assessed to determine whether it would be a hot bitumen or a blended bitumen line. Judging from industry response, it will most likely transport a SynBit. It would be a 450 km line with a capacity between 51 700 m^3/d (325 mb/d) and 95 400 m^3/d (600 mb/d) depending on the diameter of the pipe. Enbridge proposes that, if it has support to build the line, it could be in service around 2008.

6.6.2 PADD II

Enbridge Pipelines Inc.

Some stakeholders are of the opinion that with growing oil sands production, Enbridge will need to expand the mainline out of Alberta in the 2008 to 2010 timeframe. Any expansion would be dependent on market conditions, support from the Canadian Association of Petroleum Producers (CAPP), shippers and approval by the NEB.

Spearhead Pipeline

In 2003, Enbridge purchased 90 percent of BP's Cushing, Oklahoma to Chicago Pipeline. Enbridge intends to reverse this line to allow Canadian crude oil to further penetrate the Kansas and Oklahoma markets. Although it currently has a capacity of 47 700 m^3/d (300 mb/d), it will only have a throughput capability of 23 850 m^3/d (150 mb/d) once it has been reversed. The name of the pipeline will be changed from Cushing to Chicago Pipeline to Spearhead Pipeline. In late March 2004, Enbridge indicated that it has shelved the Spearhead initiative because it could not come to an agreement with producers.

Enbridge also acquired, from Shell Pipeline Company LP and Shell Oil Products US, the 27 000 m^3/d (170 mb/d) Ozark Pipeline, which extends from Cushing to Wood River. Included in this transaction is a 58.8 percent interest in the 15 900 m^3/d (100 mb/d) Osage line from Cushing to El Dorado, Kansas. If Canadian crude oil is delivered to Cushing, it will be able to penetrate the Kansas and Oklahoma refining centers, and gain access to all pipeline connections to Wood River.

Southern Access

Enbridge forecasts that by 2007, throughputs will exceed capacity at Superior. Southern Access is a proposed project by Enbridge Pipelines to build a new 1 025 km pipeline from Superior to Wood River. It would also intersect with the proposed Spearhead Pipeline to provide shippers with access north to Chicago and south to Cushing. The pipeline would have an initial capacity of 39 750 m^3/d (250 mb/d).

This proposal fits with Enbridge Energy Partners' agreement to purchase crude oil pipelines and storage facilities from Shell. As part of this arrangement, Enbridge obtained a 60 percent interest in the 49 000 m^3/d (309 mb/d) Woodpat Pipeline from Wood River to Patoka, Illinois along with 79.5 thousand cubic metres (500 thousand barrels) of storage at Patoka. This would allow producers to access new markets in southern and eastern PADD II.

Koch Pipeline

Koch Pipeline Company (KPL) is proposing to build a pipeline to Twin Cities and add capacity to Wood River through existing pipeline facilities. KPL currently operates the following two systems in this region:

- the Minnesota Pipe Line Company (MPL) from Clearbrook, Minnesota to Minneapolis/St. Paul (MSP), Minnesota; and
- the Wood River Pipeline (WRPL) from Wood River to MSP.

KPL is considering building a line from Clearbrook to MSP that would parallel the existing line and allow incremental volumes to flow to the two refineries in this region, for storage or pipeline transfer. Today, WRPL flows north; however, KPL is proposing to modify it to allow for bi-directional flow. This connection would allow transportation of incremental volumes of Canadian production to Wood River. It has been suggested that additional capacity would be added in phases along with increased storage facilities. Any incremental capacity assumes that the new volumes are heavy or blended bitumen. This proposal could be viewed as an alternative to Enbridge's Southern Access.

6.6.3 PADD III

ExxonMobil Pipeline

Access to PADD III is being contemplated through a possible reversal of ExxonMobil's pipeline from Nederland, Texas to Patoka. Currently, the section from Corsicana, Texas to Patoka is out of service. Reversal of this line, with an initial volume of 12 700 m^3/d (80 mb/d) for heavy crude oil, would allow for an additional market for Canadian crude oil. With access to foreign crude oils and domestic production, the USGC market has traditionally been unavailable to Canadian oil production by pipeline from western Canada.

6.6.4 PADD IV

Express Pipeline

In December 2003, Express submitted an application to the Board to expand its pipeline by 17 600 m^3/d (111 mb/d), thereby increasing export capacity to 44 900 m^3/d (283 mb/d). This would be accomplished by installing three intermediate pump stations on the Canadian portion of the pipeline as well as the construction of two storage tanks at the Hardisty terminal. The remaining pump stations to be added are on the U.S. portion of the system and come under the Federal Energy Regulatory Commission (FERC).

Initial expansion plans called for this increase to be completed in two stages. However, the outcome from the open season, held in December 2003, resulted in new commitments totalling 16 700 m^3/d (105 mb/d). If both regulatory bodies approve the facilities application, Express anticipates this expansion would be operational by March 2005.

6.6.5 PADD V and Asia

Gateway Pipeline

Enbridge is proposing to build a pipeline from Fort McMurray to Prince Rupert or Kitimat, British Columbia to transport increasing volumes of oil sands production to California and the Far East. This project, known as the Gateway Pipeline, would ship 63 600 m^3/d (400 mb/d) of SynBit. It is expected that this proposal would require shippers to sign long-term, ship-or-pay contracts. Enbridge is of the view that this pipeline may be needed by 2009.

Terasen Pipelines (Trans Mountain) Inc.

As mentioned previously, Terasen has filed an application with the Board for a capacity expansion of 4 300 m^3/d (27 mb/d). There are further expansion plans to transport larger volumes of heavy crude oil, namely blended bitumen and heavy synthetic grades (the TMX project), which would involve incrementally looping the TMPL system. Ultimately, there would be two lines, which would allow for improved product segregation.

The thrust of the TMX expansion would be to increase heavy throughput capacity. During the first stage, X1, the system into British Columbia would be looped to increase the capacity by 15 900 m^3/d (100 mb/d) to about 47 700 m^3/d (300 mb/d). Included in this phase is an optional leg from Hardisty to Edmonton. During the second stage, X2, a new pipeline would be added to connect with an existing loop northeast of Kamloops. This phase also adds 15 900 m^3/d (100 mb/d) of capacity. The timelines for completion of these two stages depends on whether they are constructed sequentially or concurrently. Either way, if Terasen is successful in obtaining industry support and regulatory approval, construction could begin by mid-2006 with completion by the end of 2007 or mid-2008. During the final stage, X3, the looping to Burnaby would be completed bringing capacity to 127 200 m^3/d (800 mb/d). The timing of this stage would be dependent on market conditions.

These expansions would allow for increased volumes to Washington, and to new markets in California and Asia. The key is transportation via the Westridge dock to these pipeline-disconnected markets. It is viewed that the dock can support increased volumes of up to ten vessels (Panamax or Aframax) per month. Terasen does have an existing water lot lease for another dock (dock 59). This would require permits to upgrade, but Terasen believes it could be put into service if there is a requirement. Terasen is also looking at other potential deep-water sites that could accommodate larger vessels in the event that transporting to the Asian market becomes a reality. The smaller vessels that the dock presently loads are a good fit for California ports.

Overland Pipeline to California

An option initially proposed by Terasen is the construction of a new overland pipeline from Hardisty to California with the initial proposal suggesting that it would have a capacity of 47 600 m^3/d (300 mb/d). The line would terminate in Bakersfield, California where it would have access to several trunklines to refineries in San Francisco or Los Angeles, California.

6.7 Conclusion

The table below summarizes current expansion proposals either before the Board or under consideration by industry.

The pace of pipeline capacity expansion is dependent on market conditions and the necessary regulatory approvals. Producers and pipelines companies will seek to avoid the pipeline apportionment that existed for much of the 1990s. To achieve this, timely industry and regulatory decisions will be required. In the medium term, Canadian producers will be looking beyond the traditional export markets in northern PADD II and PADD IV. This may require, for example, pipeline expansions or reversals in the U.S. In the longer term, this also may result in the need to expand pipelines in Canada, which may require financial support from shippers.

TABLE 6.1

Announced and Potential Expansions[1] by NEB Regulated Pipelines

	Capacity Increase (m^3/d)	Anticipated Completion Date
Terasen (TMPL)	4 300	Sep-04
Express	17 600	Apr-05
Terasen (TMPL TMX1)	15 900	End 2007 to Mid-2008
Terasen (TMPL TMX2)	15 900	Mid-2008
Enbridge (Mainline)	To be determined	2008 - 2010
Enbridge (Gateway)	63 600	By 2009
Terasen (TMPL TMX3)	63 600	To be determined
Overland Pipeline (California)	47 600	To be determined

1 All of these expansions are subject to approval by the NEB.

ENVIRONMENT AND SOCIO-ECONOMIC

7.1 Introduction

As oil sands development in Alberta is poised to enter a period of unprecedented growth and expansion, there are a number of issues and challenges facing operators. In recent oil sands hearings, interest in climate change and greenhouse gas (GHG) emissions were at the top of the list of environmental concerns, but the management of other emissions, boreal forest disturbance, and water conservation were also significant issues. As is the case with any large-scale development situated in a rural setting, there is some trepidation regarding the social well-being of the communities in the oil sands area. While the environmental and socio-economic impacts of individual projects are extensively monitored, the potential cumulative effects of oil sands development and operations are not well understood.

Oil sands development in Alberta is regulated by both the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV). Applications are typically integrated and contain information as required by the Energy Resources Conservation Act (ERCA) and the Oil Sands Conservation Act (OSCA). Applications to AENV are filed under the Environment Protection and Enhancement Act (EPEA), the Water Resources Act (WRA) and the Public Lands Act (PLA). Proponents are also required to meet the requirements under the Canadian Environmental Assessment Agency (CEAA) Act as required for any Federal approvals. The AEUB may request the CEAA to participate in a hearing as a joint panel or in a shared leadership role in the review of oil sands proposals.

7.2 Environment

7.2.1 Air Emissions

The reduction of air emissions is one of the most complicated and pervasive issues now facing the oil sands industry. The oil sands operations emit large amounts of carbon dioxide (CO_2) and some methane (CH_4) gas. These are among the heat-trapping "greenhouse" gases that affect the global climate. Other air emissions from the oil sands operations include:

- sulphur dioxide (SO_2);
- nitrogen oxides (NO_X);
- hydrogen sulphide (H_2S);
- carbon monoxide (CO);
- volatile organic compounds (VOCs);
- ozone (O_3);
- polycyclic aromatic hydrocarbons (PAH);

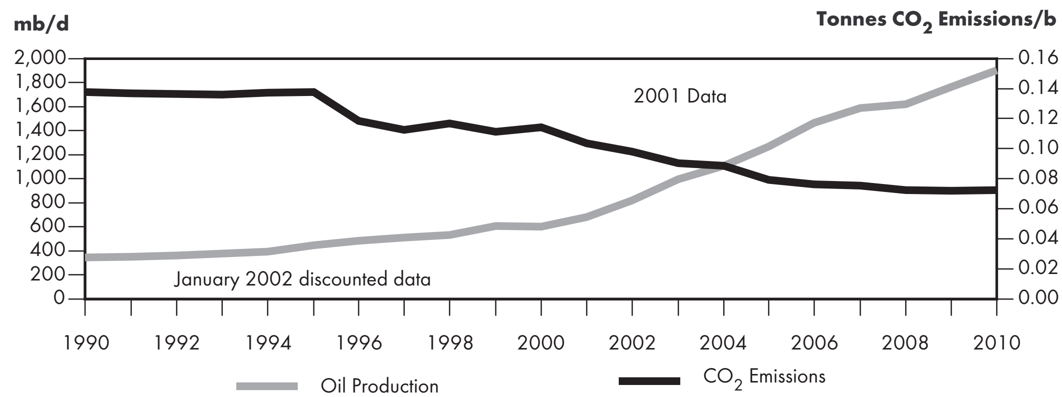
- particulate matter (PM);
- reduced sulphur compounds (SCs); and
- other trace air contaminants.

Acidification of soil and water is linked to the emissions of compounds such as SO_2 and NO_X.

The energy efficiency of oil sands operations has improved significantly in recent years. Figure 7.1 shows a 53 percent reduction in CO_2 emissions per barrel of production due to investments in new technologies despite an increase in production. In addition, Federal regulations for reducing the sulphur content in gasoline require more energy to refine the crude oil and uses more hydrogen, thereby creating more CO_2.

FIGURE 7.1

Oil Production versus Carbon Dioxide Emissions



Sources: Regional Issues Working Group and Nichols Applied Management

The Greenhouse Gas Challenge

The Government of Canada released the *Climate Change Plan for Canada* (the Plan) on 21 November 2002. In the Plan, oil sands producers are included in the Large Industrial Emitters category (companies emitting 8 000 tonnes of CO_2 equivalent or more per year). This category includes both upstream and downstream oil and gas sectors, electricity generation, and mining and manufacturing such as cement plants and iron and steel mills. Collectively, the Large Industrial Emitters are expected to produce about half of Canada's total GHG emissions by 2010[4].

The Federal Government is calling upon the oil and gas sector to continue to reduce its emissions by lowering the emissions intensity of oil and gas production and distribution. Citing examples such as reducing the leakage of methane from natural gas pipelines and reducing the use of energy in oil sands production, the Government expects the industry to reduce emissions while continuing to grow. Over the past decade, the oil sands sector was a key driver of economic growth in Canada investing \$21 billion and creating 100,000 jobs while at the same time reducing its emissions intensity by 26 percent[5].

4 Government of Canada, Climate Change Plan for Canada.

5 Ibid.

Final emission targets have yet to be determined and discussions with industry are ongoing. The Plan proposes a three-pronged approach for the category of Large Industrial Emitters including:

- targets for emissions reductions established through covenants with a regulatory or financial backstop;
- access to emissions trading, domestic offsets and international permits to provide flexibility; and
- cost-shared investments and innovative technologies to reduce emissions.

Further, a variety of international monitoring, reporting, and review requirements are planned such as the annual compilation and reporting of emissions inventories and the creation of a registry to track Canada's assigned amount of emissions permits.

The Plan's lack of specifics resulted in an outcry from industry critics and some provincial governments. With respect to the oil and gas sector, the uncertainty in the industry resulted in a letter dated 18 December 2002 from the Minister of Natural Resources Canada to the Canadian Association of Petroleum Producers (CAPP). The letter committed the Federal Government to cap the cost of CO_2 to C$15/tonne and limit the requirement for compliance to improvements in emissions intensity at a level not more than 15 percent below projected "business as usual" levels for 2010. In a subsequent letter dated 24 July 2003 to CAPP the Prime Minister of Canada further committed that targets for new projects will be locked in for the first 10 years from start-up. These concessions have increased certainty in the long-term development of the oil sands and in the implementation of Canada's climate change commitments.

In Alberta, the Provincial Government has developed its own GHG-reduction program, which has culminated in Bill 37, the Climate Change and Emissions Management Act. This Act is intended to strengthen and complement Alberta's existing legislation on environmental protection and resource management related to air emissions. Bill 37 has been passed by the Alberta Legislature but the regulations to enforce the Act are pending[6].

The goal for Alberta's GHG-reduction program is to reduce by 2020 GHGs relative to the province's Gross Domestic Product (GDP) by 50 percent from 1990 levels. This is expected to result in total emissions of 238 Mt of CO_2 in 2010, and 218 Mt of CO_2 in 2020. Alberta's GHG-reduction program includes emissions trading systems, mandatory reporting and the creation of a Climate Change and Emissions Management Fund for implementing new technologies, and programs and measures for reducing emissions and improving Alberta's ability to adapt to climate change[7].

Industry Response

Considerable effort has been made by the oil sands industry over the last several years to reduce energy consumption and thereby reduce GHG emissions. For example, Shell Canada Limited (Shell) describes the Athabasca Oil Sands Project (AOSP)[8] as being one of its greatest challenges; the project was successfully redesigned from the original plan in 1997 to reduce emissions by 64 percent when it commenced operation in 2002. Further, Shell estimated in a feasibility case in 1999 that a 50 percent

6 Pers. Comm. Val Mellesmoen, Communications, Alberta Environment. 29 Jan 2004.

7 Major Feasibility Study: A Preliminary Analysis and Discussion Document.

8 Shell Canada.

reduction in emissions from AOSP can be realized by 2010[9] by using a combination of reduced energy consumption and improved energy efficiency projects as well as domestic purchases offsets (including afforestation projects[10]), generated within Shell and partners' activities, Clean Development Mechanism projects with international partners, and feasibility studies regarding CO_2 capture. Additionally, between 1988 and 1999, Syncrude Canada Ltd. (Syncrude), the world's largest producer of crude oil from oil sands, cut CO_2 emissions per barrel of oil produced by 26 percent, and it estimates that by 2008 the total reduction will improve to 42 percent.

The oil sands industry has been actively dealing with emissions by using low NO_X burners, sour water treaters, and flue gas desulphurization to reduce emissions. Other examples of gas emission reduction opportunities include:

- improvements in cogeneration in oil sands and gas plants;
- leak detection programs for pipelines and gas plants;
- reduction in methane emissions from natural gas dehydrators;
- vent gas capture and storage;
- power generation with micro-turbines; and
- improved energy efficiency of pumps, compressors etc. in field operations.

Alternative fuels are also being considered. A switch from natural gas to other fuel sources could include low sulphur coal (although coal combustion would increase GHG emissions significantly). Coal gasification technology is being developed but has yet to become economic. Coal bed methane (CBM) and the combustion of the heavier bitumen products are also being considered as alternatives although these fuels also have high emissions. Nuclear power has also been debated and is discussed in Chapter 11 - Emerging Technology.

In addition, there have been many multi-stakeholder groups established in recent years and all are examples of industry, governments and local communities working together to create policies and programs to address GHG emissions.

- The Trace Metals and Air Contaminants Working Group of the Cumulative Environmental Management Association (CEMA) has been working to identify and prioritize emissions in the Regional Municipality of Wood Buffalo (RMWB) where the oil sands industry is the dominant source of emissions. CEMA is a regional multi-stakeholder group consisting of representatives from industry, government, local First Nations and environmental groups. Additionally, the NO_X and SO_2 Management Working Group (NSMWG) of CEMA is tasked with developing management recommendations for NO_X and SO_2 emissions related to acidification and ground-level O_3 issues in the region.
- The Wood Buffalo Environmental Association (WBEA) operates an environmental monitoring program that measures the ambient air quality at 13 stations throughout the RMWB. The WBEA also monitors environmental effects of air emissions through the Terrestrial Environmental Effects Monitoring Program, which addresses issues such as soil acidification, trace metals in foods harvested by Aboriginal communities, and vegetation stress.

9 The methodology used to estimate the GHG emissions is based on the full-cycle methodologies outlined in both the World Bank's Greenhouse Gas Assessment Handbook and the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories.

10 In association with Tree Canada Foundation, the AOSP joint venture owners provided $200,000 to plant 200,000 trees during 2002, which will yield an estimated offset of just over 90,000 tonnes of CO_2.

- The Oil Sands Environmental Coalition (OSEC) is a coalition of Alberta public interest groups with a longstanding interest in the Athabasca oil sands area. OSEC was formed in the mid-1980s to facilitate more efficient participation in the regulatory approval process for oil sands applications[11]. OSEC believes that progressive companies will need to develop an internal capacity for evaluating and purchasing GHG emission offsets as part of their corporate GHG management plans. They are calling for companies to provide comprehensive GHG management plans for new projects including emission reduction targets and strategies for continuous improvements over the life of the project. As commitments to meet Kyoto targets extend only to 2012, OSEC believes the onus is on companies to extend their emission reduction efforts beyond this period.
- The Canadian Oilsands Network for Research and Development (CONRAD) supports responsible environmental activities and continued funding of research in upstream oil and gas emission reduction opportunities.

7.2.2 Water Use and Conservation

Water Requirements

While both mining and in situ bitumen operations use large volumes of water, most of it can be recycled. Process water is the lifeblood of an oil sands operation; its quality can have significant impacts on extraction performance, tailings management and reclamation performance and plant integrity. The primary challenge for process water is that no large-scale water treatment facilities exist near the oil sands. As a result, process water is recycled, which ultimately reduces process efficiency. To supplement the operational water requirements, developers have been devising methods of using brackish water from underground aquifers.

The water requirements for oil sands projects range from 2.5 units to 4.0 units of water for each unit of bitumen produced[12]. An in situ facility requires freshwater to: generate steam and for various utility functions throughout the plant; separate the bitumen from sand and hydrotransport bitumen slurry; and upgrade the bitumen into lighter forms of oil for transport.

The in situ bitumen extraction process offers the benefit of removing the bitumen from the ground while leaving the sand in place. However, as water is used to fill the space left when oil is removed, the in situ process also has the detrimental effect of removing water permanently from the hydrologic cycle. The net permanent[13] loss for SAGD and in situ operations is estimated at one barrel of water for every barrel of oil recovered. Even though in the SAGD process an average of 90 percent of the water is recycled, the process still requires large volumes of water.

Ground water is used for two main reasons: groundwater aquifers are used as the source of process water and a normal operating procedure is the disposal of process affected water to deep aquifers. The decision to use groundwater or surface water is dependent on whether a source of surface water is available or if it is necessary to drill a well to access subsurface aquifers.

11 Includes Fort McMurray Environmental Association, the Pembina Institute and the Toxics Watch Society of Alberta.

12 Pembina Institute, *Oil and Troubled Waters*.

13 When water is used for irrigation or for industrial or domestic use, most of it eventually finds its way back to the hydrologic cycle by evaporating to the air, flowing to the surface water environment either directly or indirectly through sewage treatment plants or replenishing groundwater.

For mining operations, muskeg drainage, overburden and formation dewatering and diversion of water flow are the main concerns regarding water. The removal of water from nearby aquifers can lower the overall water level in the area and may affect other aquifers and surface water bodies, including wetlands that are dependent on groundwater recharge. In addition, depressurization of the basal[14] aquifer is done to prevent seepage water from accumulating in the mine pit. This water is usually brackish to saline and high in total dissolved solids and therefore it requires treatment before it can be used for steam generation. The prevention of seepage from ponds, pits and landfills into freshwater aquifers is another ongoing management concern. Water that remains with the oil and sand slurry after the extraction of bitumen is disposed of as mine tailings, which are usually stored in large ponds until they can be used to begin filling in the mined out pits. Generally, suspended sediments settle out before water drains into natural water bodies; however, seepage from ponds, pits and landfills into freshwater aquifers is an ongoing concern.

Initiatives in Water Use and Conservation

Water use and conservation are important issues in oil sands development and there have been several initiatives to develop new technologies and integrated approaches to water conservation. For example, oil sands mine operators in the Fort McMurray region are looking at ways to coordinate water withdrawals and to jointly manage water to minimize impacts on the Athabasca River. Suncor Energy (Suncor) is conducting a company-wide assessment of water use in all regions in which it operates to evaluate opportunities to reduce the amount of water used by its operations.

Other methods to conserve and reduce the total use of fresh water by the oil sands industry include:

- minimizing impacts to sediment and water quality conditions in receiving waters by implementing runoff containment and control measures at the plant site and well pads, such as berms, drainage ditches and retention ponds;
- developing a non-thermal in situ recovery method, using solvents, to assist in the extraction of bitumen, which could reduce the need for water;
- treating water from basal aquifers for use in the extraction process;
- re-injecting used water into basal water sands; and
- recapturing and recycling of water from the mine tailings.

Two multi-stakeholder initiatives to monitor the aquatic systems potentially affected by development in the oil sands area are: the Oil Sands Regional Aquatics Monitoring Program (RAMP) and the instream flow needs management objective for the Athabasca River, which is being developed by the Surface Water Working Group of CEMA. RAMP surveys water quality, sediment quality, benthic invertebrates, fish and wetland vegetation primarily in the Athabasca, Steepbank, and Muskeg rivers, as well as wetlands occurring near current and proposed oil sands developments and acid sensitive lakes in Northeastern Alberta. Both of these programs are being undertaken as part of AENV's Regional Sustainable Development Strategy (RSDS)[15]. In addition, in 2003, the Oil Sands Environmental Research Network created an Instrumented Watershed Research Team website to share information and describe the various other initiatives being undertaken by industry, government

14 Underlying the bitumen-saturated sands are: water-bearing sands, gravel or fractured rock, found at the bottom of a geological formation. This is referred to as the "basal aquifer".

15 The Regional Regulators Committee provides the policy and regulatory steering role for the RSDS. The committee has members from the federal government (Environment Canada, Department of Fisheries and Oceans) municipal government (Regional Municipality of Wood Buffalo) and provincial departments (Alberta Environment, Alberta Sustainable Resource Development, Alberta Energy, Alberta Energy and Utilities Board, Alberta Agriculture Food and Rural Development and the Saskatchewan Environment and Resource Management).

and multi-stakeholders. In Chapter 11 - Emerging Technologies, new extraction methods that reduce or negate the need for steam and consequently conserve water are described.

Regulatory and Policy Initiatives

Regulatory and policy initiatives are being implemented to improve the efficient industrial use of water. The requirement for oil sand operators to maximize the recycling of produced water is embodied in Alberta's *Water Recycle Guidelines* issued by AENV. Further, the Alberta Government recently released the province's new water strategy called *Water for Life: Alberta's Strategy for Sustainability*. The document presents the challenges for all of Alberta's industries operating in the face of increased demands for limited water, and identifies these major objectives:

- to actively manage water quality in the province;
- to establish goals for water quantity and quality modeling and an economic framework for decision making; and
- to improve understanding of the impacts of water quality on tailings deposition, reclamation and discharge.

There are inherent problems in the management of water in the province. AENV allocates water licenses under the *Water Act*, which came into force in 1999. Currently, licenses have a 10-year renewal period and are for volumes that are sufficient to meet routine operations (with a separate temporary license to meet additional water requirements during start-up). Under the previous WRA, however, AENV issued water licenses without expiry dates and for volumes set at the full start-up requirement. This has enabled companies to implement expansions and new projects and to increase their daily average withdrawal rates, which are substantially larger than volumes required for normal operations[16]. Further, these licenses have been "grandfathered" and continue to have an indefinite time period. This was done to recognize commitments made under earlier legislation and the fact that investments were made based on those commitments.

Additionally, Alberta's "first-in-time, first-in-right" principle allows for older licenses to have access first before newer licenses regardless of how much water is requested and what it is being used for. This provides certainty with regard to the license holder's access to water but does not encourage conservation of the water resource. The *Water for Life Strategy* addresses this by allowing water allocation transfers within river basins, which should lead to efficiencies in water use in the province.

Improving the reporting and monitoring of water usage is a specific action for the Water for Life Strategy and a system is being designed that will report actual water use, the purpose and the user. With this may come plans to implement a fee for water use, which would likely encourage water conservation and improved efficiency in water allocations. A fee could put additional financial pressures on the oil sands industry.

Other water management provisions of the *Water Act* include the following:

- AENV can impose low flow-cut-off levels as needed for licenses on the Athabasca River. (i.e., the primary source of water in the Athabasca oil sands area). The current rate imposes a 14.2 cubic metres per second passing flow on all water licenses, which is an interim limit to serve until the work of the Instream Flow Needs (IFN)[17] subgroup of CEMA is

16 Pembina Institute, *Oil and Troubled Waters*.

17 A science-based instream flow needs management objective by the IFN subgroup of the Surface Water Working Group (SWWG) is not expected until the 4th quarter 2004 according to the CEMA SWWG 2003 Workplan and Budget, February 13, 2003.

completed. The IFN is currently studying the Athabasca River to determine the in-stream flow needed to sustain aquatic habitat and water quality.

- Applicants to AENV for water licenses need to provide a hydrogeological assessment to estimate the impact that a planned drawdown will have on the aquifer and on other users. As the science of hydrology is uncertain in nature, it is recognized in the *Water for Life Strategy* that an ongoing water reporting system that reports actual water usage would contribute more to the wise management of this resource.
- The *Water Act* suggests an integrated approach to water management by proposing that water management plans be developed for seven major river basins in Alberta including the Athabasca and Slave/Peace rivers. The plans are to be developed cooperatively with all stakeholders and will impact the right to divert water.
- In 2003, Alberta's Environment Minister, initiated a committee to find ways to reduce the oil and gas industry's consumption of fresh water. As part of the province's long-term water strategy, limits may be placed on the volume of potable water that companies are allowed to use. The strategy will also call for more regulated water-use reporting requirements and a system to capture and validate the reports.

7.2.3 Tailings and By-products

Tailings Management

The current method for the recovery of bitumen from the oil sands via surface mining results in the accumulation of large volumes of fluid wastes called fine tailings. Fine tailings are a complex system of clays, minerals and organics. Because of their extremely low rate of consolidation, settling basins or tailings ponds must be constructed to last indefinitely and must be guarded against erosion, breaching and foundation creep. After about six years, the consolidated tailings, consisting of a mixture of coarse tailings, thickened tailings[18], and gypsum are deposited in mined-out pits[19]; however, there is currently no demonstrated means to reclaim fluid fine tailings. The principal environmental threats from tailings ponds are the migration of pollutants through the groundwater system and the risk of leaks to the surrounding soil and surface water.

Consequently, the management of fine tailings is one of the main challenges for the oil sands. Despite technological advances, such as the use of consolidated or composite tailings (CT) and paste technology that decrease the amount of time and increase the rate of water release from the tailings ponds, the scale of the problem is daunting and current production trends indicate that the volume of fine tailings ponds produced by Suncor and Syncrude alone, will exceed one billion cubic metres by the year 2020[20]. The current practice to impound the tailings and the problems associated with the reclamation of tailings areas have persisted despite considerable efforts to develop alternative bitumen extraction methods that do not produce fluid fine tailings. Recently, the AEUB/CEAA joint panel for Shell's Jackpine Mine Project directed AEUB staff to work with the mineable oil sands industry, AENV, and Alberta Sustainable Resources to develop tailings management performance criteria by 30 June 2005.

18 Paste deposits or thickening tailings are a result of a Thickening Tailings Disposal (TTD) system. The main advantage of thickening tailings is that water can be removed and returned to the plant or diverted which eliminates water loss evaporation or seepage in the closure landform.

19 Consolidated or Composite Tailings (CT) deposits are backfilled mine cells that have been used as receptacles for CT materials.

20 Stosur, George J., Waisley, Sandra, Reid, Thomas B., and Marchant, Leland C.

There is a high degree of cooperation among industry participants to ensure that state of the art knowledge is being applied to tailings management research. The 2001 Tailings Research Projects Information Exchange consisted of 29 reports contributed by the different CONRAD participants. An opportunity exists for an integrated approach to tailings management, which would involve the disposal of overburden and tailings across lease boundaries (i.e., a mined out pit in one operation could become the disposal area for another operation); however, the legal and liability issues need to be resolved for this to be practical to operators.

Numerous collaborative studies between industry and researchers have been undertaken to advance the knowledge of tailings disposal and reclamation options. The research is focused on the following areas to reduce the impacts of fine tailings on the environment:

- accelerating the consolidation of the fine tailings;
- detoxifying tailings pond water; and
- reprocessing of fine tailings.

There have been some technological advances for the clean-up and reclamation of fine tailings. Two methods being developed are bioremediation, in which bacteria and nutrients are used to treat the tailings ponds, and electrocoagulation, in which an electrical current is used to separate the amorphous solids from fine tailings. Further research and development will be needed to improve these methods and make them more effective and manageable. Three alternatives to tailings deposition being investigated are:

- sand stacking to provide either a sand capping or surface for earlier reclamation;
- thickening in conjunction with non-segregating tailings using CO_2 as the chemical additive; and
- compact settling basin - an in-ground thickening concept to reduce costs while still maintaining the advantages of thickening.

The National Research Council of Canada (NRC) has been actively involved in research dealing with various aspects of fine tailings. A process has been developed to treat the fine tailings and recover potentially valuable by-products such as residual bitumen, heavy metal minerals and amorphous solids that may be suitable as fertilizer. This process also improves the dewatering and consolidation behavior of fine tailings and has succeeded at recovering over 60 percent of the original water for recycling.

The use of non-segregated tailings[21] disposal methods has the advantage of reducing the footprint of the tailings ponds, which minimizes surface land disturbance. It also permits earlier reclamation and opportunities for faster water recycling for re-use in the operations of the mine.

Another avenue being investigated is the co-production of minerals and metals (aluminum, titanium and others) from fine tailings. At this time, no full-scale operations to recover minerals and metals have been initiated; however, a pilot project using mechanical concentration methods to clean and sort the tailings (by size, density, oil wettability or other physical properties) and acid leach to dissolve valuable metals has been undertaken with promising results[22].

21 Research in non-segregating tailings disposal research is being undertaken by Canadian Natural Resources Limited, Syncrude, Suncor, Albian Sands, the University of Alberta, CANMET and the Alberta Research Council.

22 Solv-Ex Corp., Solv-Ex/ AOSTRA Program for the recovery of Alumina from the Oil Sands Tailings Ponds. Aug. 1993.

By-Products

As the oil sands industry expands, the volumes of by-products produced will increase, which will result in a greater potential for environmental effects. By-products that are currently produced from oil sands operations include: elemental sulphur; coke; gypsum and ammonium sulphate from flue gas desulphurization units; and brine concentrate from water treatment facilities. There are options for the commercial sale, disposal and managed release of these by-products into the environment, all of which have various risks and benefits. Considerable research effort is being focused on these by-products, particularly the management of sulphur.

Sulphur

Bitumen contains on average 4.8 percent sulphur. Desulphurization of bitumen occurs during the upgrading process and as part of the cleaning of flue gas, but potential developments such as gasification of residues for recovery energy could see this by-product issue spread to mine and in situ sites. By 2030, sulphur recovery from the expanded oil sands region could generate as much as 10 Mt of sulphur per year. Consequently, the disposition of sulphur is a major challenge facing producers.

Currently, producers either stockpile the converted elemental sulphur or ship the by-product for use in fertilizers, road asphalt and, potentially, in concrete or other construction materials. There are also potential markets for sulphuric acid in the production of titanium oxide from tailings. In addition, the use of sulphur as an energy source and research into the injection of SO_2 into formations for bitumen extraction is underway. For all of these options, the development of environmentally acceptable long-term storage options for sulphur will be the challenge in the coming years.

A study to determine if sulphur can be safely buried underground is underway for the Alberta Sulphur Research Ltd.. The idea is to store the sulphur at a depth where the temperature is too low for sulphur-metabolizing bacteria to survive (i.e., soil temperature is less than 5ºC). Bacteria use sulphur and excrete sulphuric acid, which damages soil and prevents vegetation from growing. The project began in 1999 and further testing will determine if frozen sulphur is really inert and safe to store underground.

The use of caverns in salt deposits is also being considered for both waste sulphur and produced sand. To create space, warm water is used to wash out the caverns in salt deposits that can then be filled with the waste. The brine water is recycled to remove the brine concentrate; however, disposal of this by-product is then necessary and the entire process uses energy and increases emissions. Therefore, options and mitigation are needed for the use of salt caverns as viable means of disposal for these by-products.

Wastewater Management

Under the *Alberta EPEA*, oil sands operators must manage both operational and reclamation wastewater. Water quality issues include the effect of project-related water releases on water quality, thermal regime, dissolved oxygen levels and PAH levels in bottom sediments of the receiving surface waterbodies. Sustainability of the closure landscape and its drainage system are also key issues. For fish and fish habitat, the key issue is the relocation of large portions of the affected rivers.

Another challenge facing in situ operations is the potential for contamination of groundwater due to casing failures. Design improvements, such as the use of detection systems, greatly reduce the risk of damage to the aquifer and minimizes the release of fluid to groundwater. Monitoring and surveillance of groundwater throughout the operating life of a project is done to ensure the quality of groundwater is not affected by in situ operations.

Land Disturbance and Reclamation

Re-establishment of self-sustaining ecosystems is a major challenge in the reclamation of land disturbed by oil sands mining operations. The surface disturbance from mining operations and processing of bitumen involves land clearing, disturbance of surface strata and soil, and effects on fish and wildlife populations. The challenge for industry is to minimize the active area of disturbance, and research is focused on the development of methods that will reduce the land required for out-of-pit overburden dumps, open pit operations and tailings management areas.

Innovative approaches to tailings management need to be integrated into normal operating procedures[23]. Current industry practice is to leave large areas of land to remain in a disturbed state over many years during which natural processes work to re-establish the landscape. Through licensing, operators are committed to the creation of a landscape that has a productive capability at least equal to its condition before operations. Therefore, the onus is on operators for the long-term management of these sites.

An integrated approach requiring the coordination and joint management of mined-out pits and tailings management areas as well as the implementation of accelerated and progressive reclamation techniques could reduce the net active disturbance from oil sands operations. However, the issues of owner liability and reduced flexibility in water and solids management during operations need to be resolved. Further, a consensus is needed between all stakeholders on the use of terrestrial reclamation schemes over aquatic dominated reclamation schemes (i.e., water capping of fine tailings) although both may be acceptable for specific planning purposes.

Future opportunities for the management of overburden and tailings are being investigated by The Oil Sands Reclamation Research Network at the University of Alberta[24]. The purpose of the Network is to better integrate and enhance research in oil sands reclamation by sharing information through meetings, workshops and online forums.

Minimizing land disturbance is one of the goals of the oil sands industry. A benefit of drilling horizontal and directional wells from central pads for in situ recovery operations is the reduced surface area needed for the operation. Further, the in situ process is less complex in terms of surface activities and results in limited disruption to biophysical resources such as forests, wildlife and fisheries. It also minimizes many of the land use conflicts that occur between oil sands developments and traditional pursuits by native inhabitants of the area.

It is estimated that over the next decade, major players in the Athabasca oil sands industry will reclaim approximately 3 000 ha (30 km2) of land. To date, Suncor has reclaimed nine percent of the total land disturbed and Syncrude considers 3 290 ha of its 17 653 ha or 18 percent reclaimed (only 191 ha are "permanently reclaimed") although the Alberta Government has not issued a reclamation certificate to either of these operators[25]. Changes to Alberta's Upstream Oil and Gas Reclamation and Remediation Program have expanded the scope of industry liability for reclaimed sites. The AEUB's Directive 001 outlines the requirements for a site-specific liability assessment, which is conducted by a licensee or approval holder, to estimate the cost to suspend, abandon, or reclaim a site.

23 Alberta Chamber of Resources, *Oil Sands Technology Roadmap*.

24 A "simulated oil sands development" has been described.

25 Syncrude Canada 2002 and Suncor Energy.

Cumulative Effects Assessments

As issues of rapid industrialization and the complexity of environmental stewardship cross company boundaries, industry, public interest groups and regulators all recognize and expect past environmental standards and practices to be examined and upgraded to meet the challenges of regional sustainability.

To evaluate impacts, oil sands projects are required by AENV to conduct an Environmental Impact Assessment (EIA). EIAs are prepared in order to meet three primary objectives:

- contribute to the design and development of the proposed project so as to minimize any negative impacts the project may have on the region's cultural, social and environmental characteristics;
- provide the information required by regulators to make decisions regarding project approval including the cumulative effects of the project (as specified in the Terms of Reference for each project provided by AENV); and
- identify ongoing monitoring and management actions to monitor mitigation effectiveness and identify modifications where required. In recent oil sands hearings, there has been more emphasis on the cumulative effects assessment of the project.

To address the increasing importance of the cumulative environmental impacts, AENV's RSDS outlines a framework for managing cumulative environmental effects to ensure sustainable development in the Athabasca oil sands region. There are 14 themes identified in the RSDS (i.e., sustainable ecosystems, soil and plant diversity, effects of emissions from tailing ponds and cumulative impacts on ground water quality). For each of the themes, the objectives, options and management tools are identified.

The RSDS is being implemented in partnership with CEMA. The goal of both the RSDS and CEMA is to create a consensus-based environmental management system for the RMWB that examines the cumulative impacts of large-scale industrial development on the environment and makes recommendations to government regulators and industry on how best to manage those impacts to protect the environment.

The first CEMA Annual Report for the years 2000 and 2001 is now accessible. It outlines the various initiatives being undertaken by the five working groups and numerous subgroups working to implement the RSDS. A significant accomplishment by the CEMA members is the development of a definition of the region's environmental capacity that will form the basis for recommendations to government and industry to address other issues such as soil acidification, water usage and land disturbance.

The environmental thresholds proposed by CEMA for the Athabasca oil sands region have not yet been established and concerns have been identified by several agencies including Environment Canada, the Standing Committee on Environment and Sustainable Development and the Sierra Club of Canada. The main concern is that the number of newly proposed projects in the region and the rate of construction is potentially exceeding the ability of CEMA and the RSDS to effectively develop management systems and establish environmental thresholds.

Another study to address cumulative effects is a collaborative research project between the Alberta Conservation Association (ACA) and the Alberta Research Council. The Northern Watershed Project is a four year study that will focus on streams in Alberta's boreal forest. The project will form the basis for a road map to ecological sustainability for the successful management of the boreal forest and has three interrelated studies:

- to document how disturbances influence the forested zones adjacent to water;
- to assess the potential effects of industrial activities on fish communities; and
- to determine the cumulative impacts on fish communities of all watershed disturbances arising from forestry and oil and gas operations.

7.3 Socio-Economic

7.3.1 Impacts of Oil Sands Development

The Athabasca deposit is the largest of the three oil sands deposits in northern Alberta and has undergone the most concentrated oil sands development. Development in the Cold Lake and Peace River regions to date has been less extensive; however, this is starting to change. These regions could face similar socio-economic impacts to the Athabasca region in the future if they do not follow a proactive process that promotes the responsible and sustainable development of the resource. It will require a concerted effort from all of the stakeholders to effectively address socio-economic concerns as the oil sands enter into a period of unprecedented growth. Industry, government and local organizations are working hard to improve the social well-being of communities in the region, and these efforts must continue in order to keep pace with the increasing demands that will be placed on the existing social infrastructure.

There are numerous positive socio-economic impacts on the communities and regions associated with oil sands development, including employment, economic benefits, economic stability, government revenue, and investment in research and development. There are also negative socio-economic effects that no one company is individually responsible for, but each nonetheless contributes. These negative effects, such as a shortage of affordable housing, increased regional traffic, overworked and understaffed health care and public education systems, municipal infrastructure that lags behind population growth, drug and alcohol abuse, and increased dependence on non-profit social service providers are evidence that socio-economic impacts exist and need to be addressed. These impacts have partially contributed to the shortage of available labour, an overheated labour market, and cost overruns, which can directly influence the development of the oil sands region.

Employment and Economic Benefits

The development of oil sands projects generates economic benefits to the regional, provincial and national economies. In addition to the 33,000 currently employed by oil sands development, it is predicted that the oil sands will create a total of 102,000 new jobs across Canada by 2012, for a total of 2.7 million person-years of employment over 25 years[26]. Approximately 60 percent of these jobs will be outside Alberta, with the majority in the manufacturing sector.

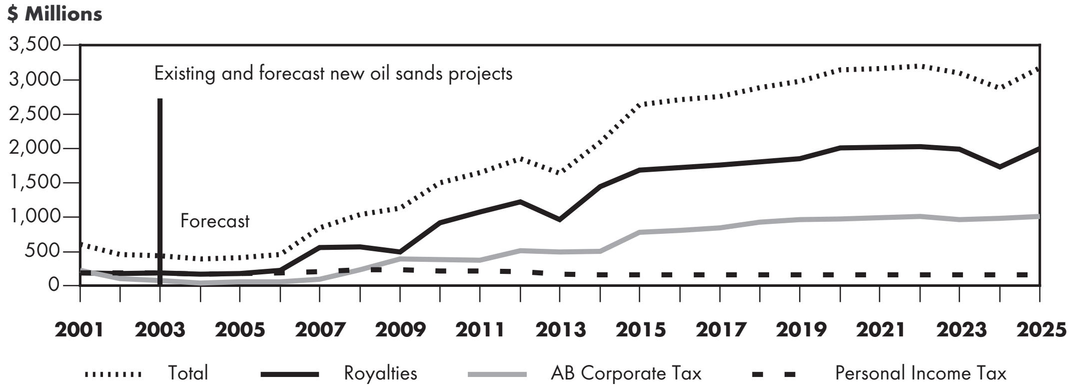
Government Revenue

Projections for new revenue to governments over the period of expansion (1997 - 2025) have been increased to $200 billion. Figure 7.2 illustrates the estimated revenues for the Alberta government generated by existing and forecast new oil sands projects.

26 Athabasca Regional Issues Working Group.

F I G U R E 7 . 2

Forecast of Alberta Government Revenues



Sources: Athabasca Regional Issues Working Group, Nichols Applied Management.

Population Growth

The population in Fort McMurray has grown steadily from 1,100 in 1961, to 6,000 in 1971, to 24,000 in 1978, and to 35,200 in 1996[27]. The latest census information indicates that the population of Fort McMurray has reached 47,240 as of 2002, and supports an additional 8,063 living in oil sands work camps[28]. This growth is forecast to continue with the population reaching 70,000 by 2010.

Workers living in camps are drawing on the services of the municipality, including health care, law enforcement and social services. This population is very difficult to include in budgets and plans because it is transient and fluctuates dramatically over short periods of time, whereas government budgets often plan in three-year cycles. Furthermore, it is difficult for governments to justify construction of infrastructure for populations that are transient and are not likely to pay municipal taxes in the future.

Housing

The growing population of Fort McMurray creates a demand for housing, resulting in high accommodation costs, low availability and a lack of subsidized housing. Roughly 3,000 families are either under-housed or paying unreasonable portions of their income for housing[29].

Homes are being built but housing costs are escalating. Currently, the average cost of a single family home is $283,357[30]. Apartment rentals are not an affordable alternative to single family housing as project developers have been "block renting" apartments, driving average rental costs for one bedroom apartments to $973 per month[31]. Figure 7.3 shows the average price for various sizes of apartments for 1999 to 2003, which illustrates that prices rose by roughly 50 percent for all apartment sizes. The Canada Mortgage and Housing Corporation confirmed that the rental rates in Fort McMurray are the highest in Canada. In February 2004, the vacancy rate was at 4.45 percent[32].

27 Statistics Canada.

28 Regional Municipality of Wood Buffalo.

29 Rubinstein, Dan.

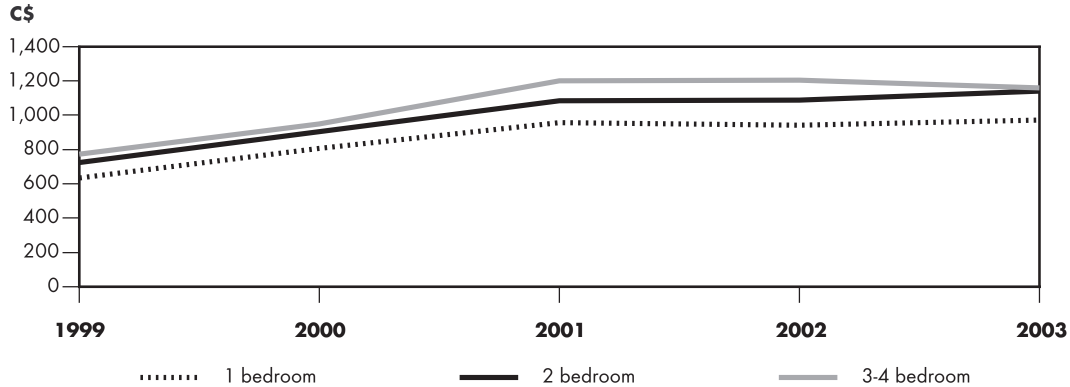
30 Fort McMurray Real Estate Board.

31 Canada Mortgage and Housing Corporation.

32 Fort McMurray Landlord and Tenant Advisory Board.

FIGURE 7.3

Average Apartment Rent in Fort McMurray



Source: Canada Mortgage and Housing Corporation.

In the past vacancy rates in Fort McMurray have fluctuated widely, from a low of 0.5 percent in 2001 to a high of 4.7 percent in 2002.

Construction of apartment buildings is taking place, but there is no certainty that rents will be affordable or that the units will not be sold as condominiums. Additionally, there are not enough apartments being built to accommodate the population and in particular, the construction of low-income (subsidized) housing cannot keep pace with waiting lists. In 2003, there were 360 families and singles waiting for subsidized housing in Fort McMurray; approximately 80 of these were considered to be high priority[33].

Local and Regional Services

As a result of the fast and somewhat unpredictable population growth, the community of Fort McMurray has experienced deficiencies in community service delivery and infrastructure development. Sewage, water treatment and waste disposal systems are nearing capacity and the current development scenario for the region will inevitably result in even greater demands in the near future. In addition, the Federal government has imposed higher standards on water and sewage treatment, so the Municipality will have to plan for both an increase in population and an increase in treatment standards. The RMWB projects that restrictions on the level of debt it can assume will limit its ability to finance capital projects during the 2004 to 2008 period[34].

Further, both non-profit and government agencies that are responsible for providing social services are being affected by the increase in demands for services, a decline in volunteerism and an inability to pay the higher wages needed to recruit and retain qualified senior staff[35].

Traffic

The volume and nature of the traffic (i.e., large construction and related vehicles) travelling from Fort McMurray to the oil sands plants has contributed to increases in congestion and the risk to public safety in the Wood Buffalo Region.

33 Homelessness Initiative Steering Committee, Broadview Applied Research Group Inc.

34 Alberta Economic Development, October 2003.

35 Alberta Economic Development, May 2003.

7.3.2 Community Initiatives

There are a number of community initiatives in place to address socio-economic impacts including the Alberta Regional Issues Working Group (RIWG), the Wood Buffalo Housing and Development Corporation and various government agencies and departments. This is not an exhaustive list as there are many non-governmental organizations (i.e., Big Brother Big Sisters of Canada, Canadian Mental Health Association), non-profit organizations (i.e., the Salvation Army, United Way) and other excellent initiatives (i.e. Alberta Alcohol and Drug Abuse Commission, Wood Buffalo HIV & AIDS Society) that provide valuable contributions towards the resolution of socio-economic issues.

RIWG is an organization that has been created by industry, and relied upon by government in part to monitor, research and coordinate responses to cumulative social effects of development. The membership of RIWG is composed almost entirely of industry members, with the RMWB as the only non-industry member. The sub-committees of RIWG have engaged over 44 different groups, representing over 450 different people from all aspects of the community. RIWG has contributed important information to planning organizations for the region, and has facilitated agreements to address social issues (i.e., day care and health care funding for the shadow population).

The Wood Buffalo Housing and Development Corporation is a non-profit organization that has been given the mandate to run existing social housing projects and to develop new social and affordable housing projects in the Fort McMurray region.

Various departments within the Alberta Government are involved in addressing socio-economic impacts. For example, Alberta Transportation has plans to improve the highway infrastructure around Fort McMurray, including twining Highway 63 between Fort McMurray and the Syncrude plant. Socio-economic issues are also addressed during the AEUB approval process as project proponents are required to conduct public consultation with stakeholders. The information gathered from stakeholder consultations is then incorporated into the project design. Companies may enter into agreements with stakeholders if they deem it beneficial in resolving issues identified during the public consultation process.

7.3.3 Company Initiatives

Oil sands companies are generally interested in improving the quality of life in the communities where they operate. In 2002, the Athabasca Regional Oil Sands Developers spent nearly $8.5 million on socio-economic environmental management initiatives[36]. Nine groups or initiatives benefited from this funding, including the WBEA, CEMA, RAMP and the RIWG.

Syncrude and Suncor were the first commercial projects in the oil sands region and both companies have made efforts to address socio-economic impacts. The Suncor Energy Foundation, a private charitable foundation fully funded by Suncor, invested over $1.8 million in the RMWB in 2003 in programs that address environmental issues, community needs and education. During 2003, Syncrude supported 358 community projects that focused on endeavours in education, environment, health and safety, science and technology, Aboriginal development, local community development, arts and culture, and recreation. Other companies have followed Syncrude's and Suncor's lead in this area such as the Athabasca Oil Sands Project, Canadian Natural Resources Limited (CNRL) and other suppliers including Finning and ATCO.

36 Athabasca Regional Issues Working Group.

7.4 Aboriginal

7.4.1 *Impacts of Oil Sands Development*

Aboriginal issues are relevant in the oil sands region because the oil sands deposits in Northern Alberta are situated in close proximity to First Nation and Métis communities. An oil sands project has the potential to impact both reserve lands and traditional territories, and how these lands are used by Aboriginal people, through extensive ground disturbance, construction activities and the operation of the facilities. In addition, there is an increasing expectation that Aboriginal groups should be involved in projects that will affect them. This involvement often includes understanding the impacts of oil sands activities, having their concerns heard, commenting on the proposed mitigation, and participating in economic opportunities generated by the project.

Employment and Economic Benefits

There are significant positive benefits for Aboriginal people living in close proximity to the oil sands deposits. Several initiatives are underway to enhance job and contracting opportunities for Aboriginal people. These include company-specific commitments to hire Aboriginal people and company-specific and co-operative initiatives to support education and training of Aboriginal people[37]. In 2002, the oil sands industry spent more than $170 million on contracts to source goods and services from businesses owned by Aboriginal people[38].

Traditional Lands

One area of concern for Aboriginal people is the impact of oil sands projects on their traditional lands. Aboriginal communities have a close connection to the land as it forms an integral component of their cultural identity. Communities are attempting to ensure that oil sands development occurs in a manner that preserves and protects the land base that supports traditional activities. Common concerns with oil sands developments include potential health risks, loss of natural habitat, impacts on wildlife, water usage, reclamation of disturbed areas, access management, cumulative effects, and air, water and land pollution.

Traditional Way of Life

Another impact on Aboriginal people is the alteration of their traditional way of life. Aboriginal people continue to participate in traditional activities (i.e., hunting, trapping and gathering), but there is an increase in the number of people who are participating, to varying degrees, in the wage economy. This transition from a traditional economy to a wage economy has the potential to affect the cultural identity of a community.

7.4.2 *Community Initiatives*

There are a number of initiatives in place that attempt to address the concerns of Aboriginal groups in the oil sands area. These initiatives have focused largely on techniques to incorporate the interests of Aboriginal people into the development process. Examples of these initiatives include the involvement of Aboriginal members in multi-stakeholder groups and the development of regional agreements between governments, developers and Aboriginal groups.

37 Alberta Economic Development, October 2003.

38 Athabasca Regional Issues Working Group.

The Athabasca Tribal Council (ATC)-All Parties Core Agreement is a key part of ensuring the responsible development of the oil sands in the Athabasca region. This three-year agreement was signed in 2002 by the ATC and the oil sands industry developers. The agreement sets out three objectives: managing the issues related to the impact of industrial development on regional First Nations; developing long-term, mutually beneficial relations between the parties; and maximizing opportunities for all parties to benefit from industrial development. The agreement also provides base funding for the community level Industrial Relations Corporations that enables First Nations to consult with industry.

A Métis-Industry Terms of Reference was signed in June 2003 with the Métis locals within the RMWB. The goals of the one-year pilot are: to determine key concerns about industrial development for each of the six Métis communities within the RMWB; to develop consultation protocols for each Métis community in the RMWB; to develop a resource centre on industrial development for the Métis people; and to participate in organizations dealing with the impacts of industrial development.

Both of these agreements are examples of how Aboriginal people and developers are striving to work together in a cooperative fashion, to address the issues that are important to Aboriginal communities. Negotiations are underway between industry, provincial and federal governments, and the First Nations in the region to develop a long-term benefits agreement, which would reduce uncertainty and provide tangible benefits to all parties involved.

7.4.3 Company Initiatives

Many companies have Aboriginal policies and programs in place to enhance benefits to Aboriginal groups. These programs may encompass the areas of education, employment, business development, community development and environmental issues, particularly the understanding of cumulative environmental effects on traditional lands. In 2002, over 1,300 Aboriginal people from the RMWB were directly employed by oil sands developers or have been engaged by contractors. This represents an increase of nearly 60 percent since 1998. Syncrude and Suncor were the first commercial projects in the oil sands region and both companies have made efforts to address Aboriginal issues. Other companies have been following the examples set by Suncor and Syncrude with respect to Aboriginal issues (i.e., Albian Sands local procurement figures in 2003 included $30 million to Aboriginal companies).

Syncrude is Canada's largest industrial employer of Aboriginal people and has conducted more than $600 million in business with Aboriginal firms over the past 12 years. In 2003, $92 million was spent on contracts with Aboriginal-owned companies. At the end of 2003, there were close to 700 Aboriginal people employed by Syncrude and its contractors, or 12.5 percent of their combined employee population. Syncrude's goal is to maintain an Aboriginal employee population that mirrors the representation of Aboriginal people in the general population of Wood Buffalo, which is about 12 percent. Syncrude's Aboriginal interests extend to employment, education, business development, community development, capacity building and environmental protection.

Suncor has stated that responsible development must take into account Aboriginal communities' needs, expectations, and concerns about the effect of industrial development on traditional land and resources, including hunting, trapping and fishing. Suncor oil sands business set a goal in 1998 of raising full-time Aboriginal employment to 12 percent of its workforce by 2002. Full-time Aboriginal employment is currently more than 10 percent and growing, compared with three percent in 1996. The operation has a business target to spend 12 percent of total contracts or $50 million, which ever is greater, on Aboriginal contracts. In 2003 that target was exceeded, with a spending of $60 million with Aboriginal contractors.

7.5 Conclusion

As pressure increases to address the environmental and socio-economic implications for new projects, oil sands developers are taking advantage of new opportunities and technologies as well as synergies in their operations to improve the environmental performance of their projects and create positive changes in nearby communities. The cumulative effects of the projects are beginning to be considered collectively and in a coordinated manner, and companies are combining their individual management strategies. There is an opportunity for developers to be leaders in the adoption of new technology and in developing cooperative approaches that address issues such as air emissions and water use to ensure the long-term sustainable development of the oil sands.

The significant investment of time and resources in the various areas of environmental research speaks to the commitment the oil sands industry has for environmentally responsible activities. Concern for climate change and in particular GHG emissions are in the forefront of management issues and the industry is striving for minimum use and maximum reuse of freshwater. Technologies exist or can be developed to cost-effectively limit the atmospheric concentration of CO_2, reduce the use of freshwater, minimize land disturbance, and to deal effectively with the by-products of bitumen extraction.

The economic benefits associated with the development of the oil sands are considerable. This growth and expansion have the potential, if poorly managed, to generate negative socio-economic impacts on both Aboriginal and non-Aboriginal communities in the region. Employment opportunities have resulted in steady population growth for the area, which places a strain on the local infrastructure and services. Stakeholders are interested in preserving the social well-being of the communities and several initiatives have been established. These efforts need to be continued and supplemented with careful planning, to ensure that no irreparable damage is done to people or the environment, and that natural resources are developed in a sustainable manner taking into account the needs of future generations.

There are many challenges facing the oil sands industry; however, continued efforts to enhance research and development activities, and to create public-private partnerships and supporting government policies and programs, will improve the future of oil sands developments. It will be necessary to overcome barriers, both technical and economic, to the implementation of new methods and technologies that will reduce the overall environmental effects from the oil sands and promote the well-being of people in supporting communities.

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Importance of Natural Gas

8.1 Introduction

This chapter presents a discussion of the oil sands industry's requirement for natural gas, and also provides a summary of the gas-over-bitumen issue.

The recovery and upgrading of bitumen from the oil sands are energy intensive endeavors, consuming large amounts of natural gas, electricity, transportation fuels and hydrogen. Historically, natural gas usage by the oil sands operators developed in an environment where gas provided an inexpensive, reliable and clean-burning source of energy, and thus came to be relied upon as the major energy source. However, a tightening North American natural gas market has resulted in higher and more volatile gas prices. Oil sands operators are thus seeking ways to reduce their exposure to natural gas, through efficiency improvements in all aspects of their operations, through greater integration of plant facilities, through the cogeneration of electricity to utilize waste heat, and through developing alternative sources of energy and hydrogen.

8.2 Gas Requirements

Oil sands operators have historically depended on natural gas as their main source of energy, and thus as oil sands based production has grown, so has the related demand for gas. At a time when oil sands based production is projected to grow substantially, gas supplies from the WCSB appear to be flattening, thereby putting pressure on the traditional source of energy for the oil sands.

A large part of the energy requirements for oil sands mining, extraction and upgrading operations, as well as for in situ operations, are met through on-site electricity generation using externally-sourced natural gas as fuel. Natural gas-fired turbines generate electricity to operate equipment and facilities, and also provide heat that is used to generate steam and provide process heat for bitumen recovery, extraction and upgrading. Natural gas also provides a source of hydrogen used in hydrocracking and hydrotreating as part of the upgrading process.

8.2.1 Mining/Extraction/Upgrading

Mining requires energy for the operation of the equipment, such as electric power shovels used to remove overburden and recover oil sands from the mine face, and the operation of the hydrotransport pipelines and facilities that move the oil sands in a water-based slurry to the bitumen extraction sites. Current extraction processes use natural gas as a source of heat in a hot water extraction process that separates the bitumen from the oil sands.

Upgrading bitumen into higher quality synthetic crude oil (SCO) utilizes natural gas as a source of heat and steam for processing, and also as a source of hydrogen for hydro-cracking and hydrotreating.

Depending on the upgrading employed, whether delayed coking, fluid cat cracking or hydrogen addition, and depending on the degree of quality improvement of the final product, varying amounts of hydrogen are required. In 2003, 55 percent of this requirement was met through the use of "off-gas" created internally as part of the upgrading process, while 45 percent was provided via externally-sourced natural gas. The most common method of producing hydrogen is by steam methane reforming, which uses about 0.4 volume units of natural gas per volume unit of hydrogen produced[39]. Upgrader operators typically produce hydrogen via steam methane reforming in their plants, but some rely on outside suppliers of hydrogen.

8.2.2 In Situ Recovery

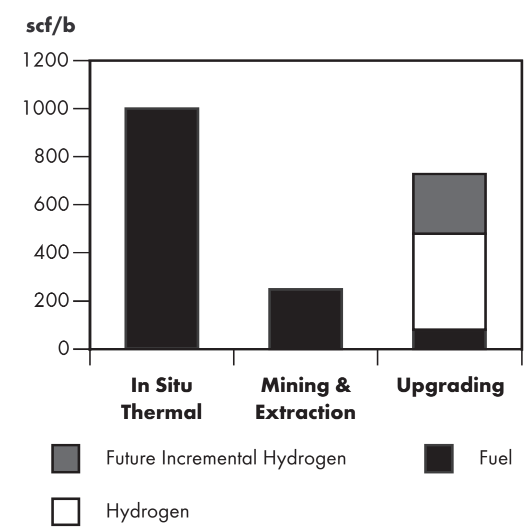
Both common in situ thermal recovery methods, Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD), are very energy intensive. These methods use natural gas to produce steam, often in conjunction with the cogeneration of electricity. The steam is injected into underground formations to induce bitumen to flow into producing wells. The CSS process is a cyclic, high pressure method compared with SAGD, which is a lower pressure continuous method. As a result, CSS typically has a higher steam-to-oil ratio (SOR) and a greater requirement for natural gas on a per barrel of production basis. However, CSS operators in the Cold Lake area typically get 15 percent of their gas needs from solution gas, thus leaving their requirement for purchased gas on par with SAGD operators. Although there is considerable variation between individual projects, an industry rule of thumb is that it takes 1 Mcf of gas to produce one barrel of bitumen.

8.2.3 Projections of Natural Gas Requirements

Figure 8.1 shows the approximate distribution of natural gas requirements for oil sands operators, and provides the basis for developing longer-term projections of natural gas demand for oil sands operations. The incremental future upgrading category is included to recognize that the demand for higher quality, cleaner SCO, and thus the demand for hydrogen in upgrading, will rise in the future.

FIGURE 8.1

Natural Gas Demand by Recovery Type



Source: Oil Sands Technology Roadmap.

The projection of natural gas usage for oil sands operations considers the current usage levels as well as certain assumptions regarding future use patterns. These include recognition that some upgrading expansions will require incremental hydrogen supply; therefore, the gas requirement per barrel of SCO is increased by one percent per year after 2006. Average gas usage of 1.2 Mcf per barrel for thermal in situ projects and 0.56 Mcf per barrel for mining and upgrading projects were applied at the beginning of the projection period.

An overall one percent per year improvement in energy efficiency is applied to in situ production, recognizing that SAGD technology is still relatively new. Also, proposed new upgrading technologies, such as the Nexen/OPTI ORcrude™ process will utilize gasification of

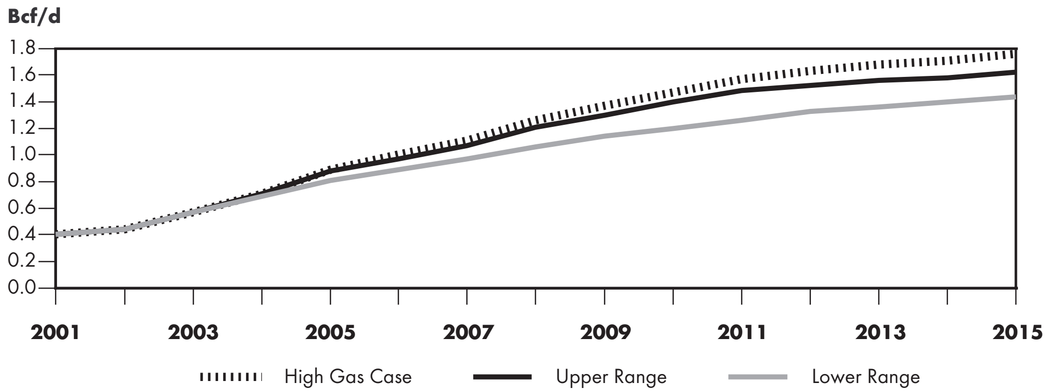
39 Alberta Chamber of Resources, *Oil Sands Technology Roadmap*.

bitumen to provide fuel, thus minimizing the need for natural gas. In situ methods, such as Vapour Extraction Process (VAPEX™), use solvent injection instead of steam injection and also reduce the need for natural gas. Similarly, a one percent per year improvement is applied to SCO production, recognizing the trend in efficiency gains of the integrated mining plants.

The application of the resultant gas-usage factors to the Lower Range and Upper Range supply projections, developed in Chapter 4 - Crude Oil Supply, indicates the total gas requirement increases to about 1.4 and 1.6 Bcf/d for the respective cases (Figure 8.2). The High Gas Case employs higher gas usage factors, representing a case where the energy efficiency improvements are not realized, and the gas usage factor for thermal in situ remains at 1.2 Mcf per barrel, while that for mining and upgrading increases marginally to 0.60 Mcf per barrel. In the High Gas Case, gas usage rises to 1.8 Bcf/d by 2015.

FIGURE 8.2

Projected Oil Sands Natural Gas Requirement

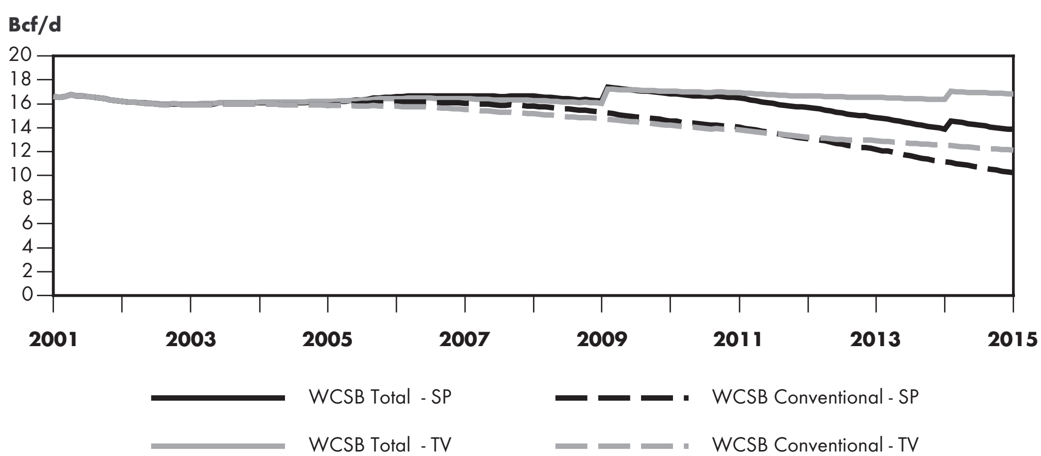


8.3 Gas Supply

Recent projections of natural gas supply indicate that total production from the WCSB is expected to stay relatively flat, in the range of 16.5 to 17.0 Bcf/d until the 2010 to 2011 timeframe (Figure 8.3). Conventional supply from the WCSB is shown to be in decline by 2006-2007, after which time

FIGURE 8.3

WCSB Natural Gas Supply Projections



incremental gas from non-traditional sources such as coalbed methane (CBM) and from new regions such as the Mackenzie Delta/Beaufort Sea area become increasingly important to western Canadian users.

Alternative sources of gas supply are postulated, such as increased CBM and imports of liquefied natural gas (LNG) and, in the 2009 to 2013 timeframe, supplies from the North via the Mackenzie Valley and Alaska pipelines. If supply from these sources develops more slowly than projected, it is possible that tight gas market conditions might prevail over the next five to six year period or longer, until alternative supply can be delivered in sufficient quantity.

Currently, the oil sands industry uses about 0.6 Bcf/d of purchased gas, or about four percent of WCSB production. By 2015, this increases to approximately 10 percent, assuming gas production stays level at 16.5 Bcf/d. Current distribution data indicates that about 9.0 Bcf/d is exported to the U.S., with 3.5 Bcf/d delivered to eastern Canada and 4.0 Bcf/d consumed in western Canada. If deliveries to the U.S. and eastern Canada are maintained at 2003 levels, oil sands related demand could account for nearly 50 percent or more of western Canadian available supply.

Natural gas prices for consumers in the oil sands areas are determined in the context of an integrated North American gas market. We have assumed for the purpose of analysis in this report, that the price of natural gas will be at parity with crude oil, on a heat-value basis. While this relationship may hold on a longer-term basis, the regional and short-term supply/demand balance for natural gas can influence gas prices in the near term.

For in situ thermal projects, natural gas costs can be as much as 60 percent of total operating costs. For integrated mining operators it is somewhat less, typically 15 percent. Thus, gas supply and its impact on gas prices is a critical issue to the oil sands industry.

In order to reduce their exposure to gas prices, oil sands operators are actively seeking to reduce their dependence on natural gas, by increasing efficiency through improved energy management, and by researching and developing alternate sources of energy.

Some examples of attempts to reduce dependence on natural gas are:

- the proposed Nexen/OPTI Long Lake Project, which is planning to use gasification of bitumen to produce a synthetic gas, that will eliminate the need for natural gas;
- the gasification of coke, coal or vacuum gas-oil;
- Suncor has built in the ability to switch to burning diesel fuel instead of natural gas at its Firebag SAGD project; and
- Atomic Energy Canada Ltd. (AECL) has studied the use of an Advanced CANDU reactor to produce electricity, steam and hydrogen.

Further discussion of alternative energy sources is provided in Chapter 11 - Emerging Technologies.

While these examples offer ways to reduce gas usage, they also increase the potential emissions of CO_2 (with the exception of the nuclear energy option), so operators have to weigh the relative costs and benefits.

8.4 Gas-Over-Bitumen Issue

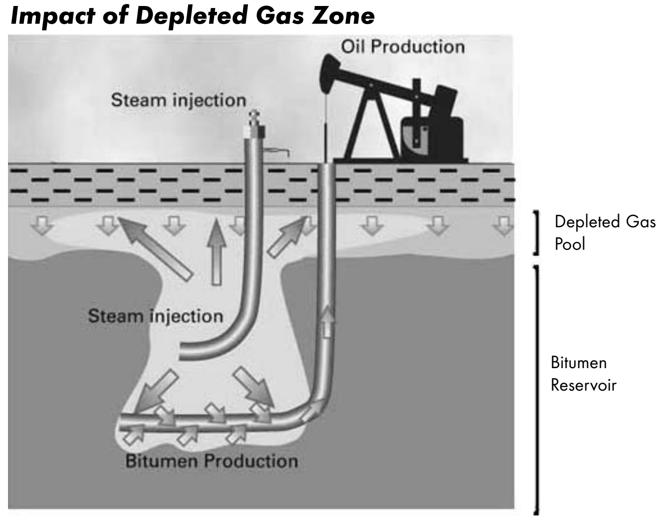
The gas-over-bitumen issue gained public attention in the mid-1990s. The question raised was whether the performance of thermal bitumen recovery schemes would be adversely affected by the depletion of gas pools that were in pressure communication with underlying bitumen reservoirs. A controversy developed regarding the Wabiskaw-McMurray geological zones in the Athabasca oil sands area, where in many cases rights had been issued to different lease holders, permitting the production of oil or natural gas from the same zone. In many cases, this pitted the interests of the gas producer against those of the bitumen producer.

In late 1996, Gulf Canada Resources Limited (now ConocoPhillips Canada) asked the Alberta Energy and Utilities Board (AEUB) to shut-in associated gas production from pools situated above its proposed Surmont SAGD project. Gulf's position was that production activities in certain Surmont area gas pools had the effect of continuously lowering the reservoir pressure at its Surmont bitumen project, and if allowed to continue would put the proposed SAGD project in jeopardy. Gulf was concerned that if pressure in the gas pool was too low, steam would escape from the bitumen production chamber into the depleted gas pool (Figure 8.4). Also, in situations where a water zone exists above the bitumen, operating at a lower pressure increases the risk of water invading the bitumen reservoir. An additional potential problem is that SAGD projects depend on artificial lift[40] systems, usually gas lift, to bring the produced bitumen to the surface, and the limit below which artificial gas lift can operate is considered to be about 400 to 600 kpa[41].

Since 1996, the AEUB has conducted numerous proceedings and studies, including two record-length hearings, in regard to the gas-over-bitumen issue. The extensive information gathered has led the AEUB to adopt measures meant to preserve the value of the bitumen resources, accepting the argument that depleting pressure puts at risk the ability to produce bitumen using SAGD. Also, over this period, the geographical area of concern has been more clearly defined, thus exempting gas producers outside this area from shut-in. The reduced area of concern includes the thickest bitumen within the Athabasca Wabiskaw-McMurray deposit and contains all of the existing and proposed SAGD projects in the Athabasca oil sands area (Figure 8.5). The bitumen outside this area is not considered to be exploitable using SAGD or other thermal technologies.

FIGURE 8.4

Impact of Depleted Gas Zone



Source: AEUB

40 Artificial lift is required when the downhole energy is insufficient to force fluids to the surface.

41 Kilopascals absolute.

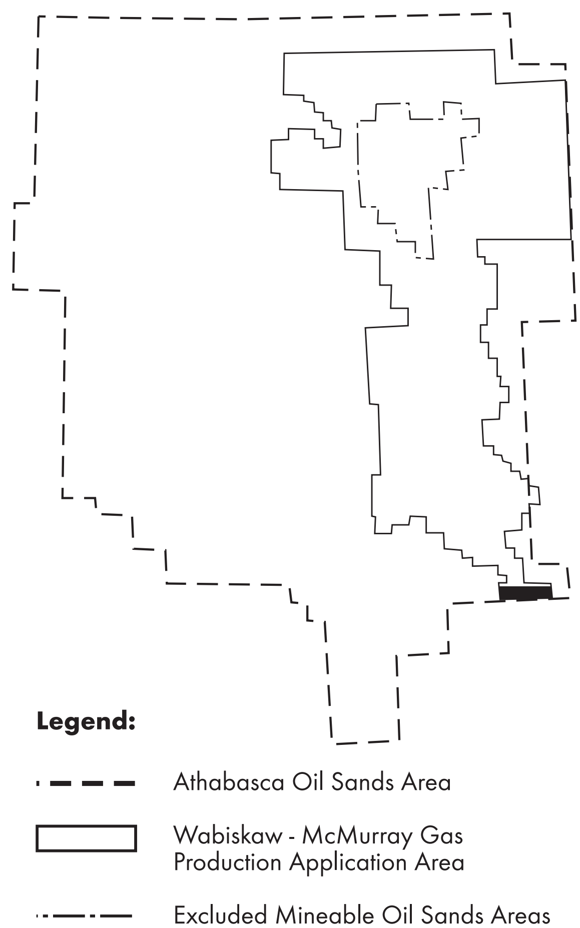
8.4.1 General Bulletin GB 2000-28

In its July 2003 decision, General Bulletin GB 2000-28, the AEUB ordered the interim shut-in of Wabiskaw-McMurray gas production in the area of concern, in order to protect the underlying bitumen and provide greater certainty for bitumen producers. In its decision, the AEUB stated the following conclusions:

- "Associated gas production presents an unacceptable risk to bitumen recovery using steam assisted gravity drainage (SAGD).
- Currently, there are no proven technologies that satisfactorily mitigate this risk.
- Within a defined area, Wabiskaw-McMurray gas production that is associated with potentially recoverable bitumen must be identified and shut in as soon as possible.
- The best available method to identify nonassociated gas production is through a regional geological study".

FIGURE 8.5

Area of Concern



Source: AEUB

The AEUB also stated that it "considers the bitumen resource within the application area to have the best potential for SAGD development. In addition, the Board is of the view that Wabiskaw-McMurray gas pools in this area are generally at an advanced stage of depletion, the depletion is ongoing, and immediate action is required to mitigate further risk to SAGD bitumen recovery".

8.4.2 Blanket Shut-In

The AEUB indicated that some 7 million m^3/d (247 MMcf/d) of gas would be subject to shut-in, but made provision for gas producers affected to apply for exemption from shut-in. Effective 1 September 2003, 2.7 million m^3/d (95 MMcf/d) of gas was ordered shut-in, with the remainder temporarily exempt. The shut-in order applied to previously grandfathered gas production that was deemed to be in communication with an underlying bitumen reservoir.

To put things into perspective, on an energy basis the bitumen reserve at risk is approximately 600 times the remaining producible gas reserves recommended for shut-in. The Wabiskaw-McMurray formation recoverable bitumen reserves are estimated to be approximately 6 billion cubic metres (100 billion barrels) (using a 20 percent recovery factor). Remaining shut-in gas reserves represent about 1 Tcf, which is equivalent to about two percent of total Alberta remaining natural gas reserves of 42 Tcf. In terms of conventional crude oil, the Wabiskaw-McMurray formation recoverable bitumen reserves represent about 60 times the remaining conventional oil reserves in Alberta.

In the fall of 2003, the AEUB commenced a detailed geological review to determine what, if any, gas should be allowed to re-commence production. In early January 2004, the AEUB released its Regional Geological Study (RGS), which focused on identifying which Wabiskaw-McMurray natural gas pools are in contact with the underlying bitumen. The study found that 464 gas pools were in contact with recoverable bitumen.

In late January 2004, based on the RGS findings, an AEUB Staff Group (operating independently from the Board) recommended the permanent shut-in of 485 Wabiskaw-McMurray natural gas wells that were producing 3.8 million m^3/d (135 MMcf/d) of gas as of 31 August 2003. Another 300 Bcf of producible gas reserves is also recommended for shut-in. The gas represents less than one percent of Alberta's remaining producible gas reserves and about 50 percent of remaining Wabiskaw-McMurray producible gas reserves.

Parties that disagreed with the Staff Group recommendations filed evidence; in addition, several gas producers disputed the July gas-over-bitumen regulatory ruling and were granted leave to appeal the AEUB decision to the Alberta Court of Appeal in late January 2004. However, prior to hearing the appeal, the Alberta court ruled that the parties must first participate in AEUB interim hearings, set to begin in March 2004.

The AEUB hearing will assess whether natural gas is associated with potentially recoverable bitumen. The hearing is designed to hear objections from affected parties about gas wells proposed for shut-in. The AEUB intends to decide the status of all exempted gas production by 1 April 2004, on an interim or final basis.

At the time of writing this report, the results of the March AEUB hearing were not available. The AEUB is anticipating an additional hearing later in 2004 to decide the final production status of wells that continue to be in dispute. The hearings are not expected to be the end of the gas-over-bitumen dispute, as the AEUB will be studying the matter as it might affect the Cold Lake and Peace River regions, as well.

The Alberta Government continues to consider royalty adjustments for companies that might be affected by permanent shut-in and a policy could be in place some time in 2004.

8.4.3 Technical Solutions

In 2001 a Technical Solutions Committee (TSC), with representation from government and industry, was set up to direct and facilitate research into the problem of gas-over-bitumen and to promote development and field-testing of appropriate solutions. Under the direction of the TSC, there are currently five technical subcommittees working on the following areas:

- lateral and vertical pressure communication;
- low pressure SAGD performance;
- shut-in data gathering and interpretation;
- fluid injection technology; and,
- artificial lift-low pressure SAGD.

Repressuring of the depleted gas pools has been postulated by some industry personnel as a viable solution to the problem. The AEUB's stated position on this option is it "continues to believe that repressuring should not be relied upon until it has proven to be feasible and practical on the basis of field tests"[42].

There are two new technologies that offer the potential to satisfactorily mitigate the risk that associated gas production represents to bitumen recovery. The first is VAPEX™, which uses vapourized solvent (i.e., propane and butane) rather than steam to decrease bitumen viscosity in situ, and can run at relatively low reservoir pressures. The second is Toe-to-Heel-Air-Injection (THAI) combustion technology for in situ bitumen recovery. The technology combines a vertical air injection well with a horizontal production well. A depleted gas reservoir is not a concern with this technology, as air is injected into a depleted well to create the combustion zone that mobilizes the oil that is produced in the horizontal well. Both of these technologies remain to be proven in the field. VAPEX™ has been pilot-tested at several locations, while the first THAI field pilot is expected to be in place in late 2004.

8.5 Conclusion

Natural gas requirements for the oil sands industry are projected to increase substantially during the projection period, rising to 1.4 to 1.8 Bcf/d, and accounting for about 10 percent of WCSB supply. In response to higher and more volatile gas prices, producers are seeking ways to reduce their dependence on natural gas as the major source of energy and hydrogen for their operations. A number of alternatives have been suggested, with gasification of bitumen likely to be the first implemented on a commercial scale.

The gas-over-bitumen issue has been a source of controversy in Alberta since the mid-1990s, in areas where gas pools overlie bitumen deposits. Bitumen producers are seeking to preserve their SAGD projects from potential damage, while gas producers are seeking to develop the full value of their gas assets. The AEUB, after conducting several hearings and numerous other proceedings, has decided that the gas production in question does indeed pose some risk to SAGD recovery operations. It therefore ordered the shut-in of nearly 500 producing gas wells, on an interim basis, pending further investigation.

The gas-over-bitumen issue is an ongoing concern for the industry and the AEUB. The Athabasca area concerns are not yet fully resolved, and the issue may extend to other oil sands areas, as well.

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42 AEUB Decision 2003-023 *Chard Area and Leismer Field, Athabasca Oil Sands Area Applications for the Production and Shut-in of Gas*, 18 March 2003.

ELECTRICITY

9.1 Introduction

This chapter discusses the potential for cogeneration development in the oil sands.

Oil sands extraction operations require significant quantities of both steam and electricity. Cogeneration offers the potential for oil sands operators to meet their steam requirements and to:

- generate large quantities of inexpensive electricity;
- improve electrical reliability and efficiency; and
- generate additional revenues.

However, oil sands producers are currently not taking full advantage of this potential because of inadequate transmission infrastructure and the perception that the Alberta market is not large enough to absorb all the potential oil sands cogeneration capacity. Transmission infrastructure and market demand are key to determining whether cogeneration capacity in the oil sands, and the associated benefits, can be maximized.

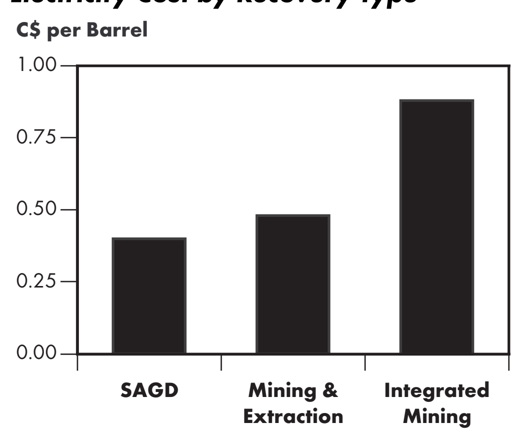
9.2 Electricity Requirements

Mining operations require electricity for a variety of functions. For example, electricity is required to operate mining equipment, such as electric mining shovels that remove overburden and recover oil sands from the mine face, and to operate hydrotransport pipelines and facilities that move oil sands in a water-based slurry to bitumen extraction sites. Electric motors are used in ore preparation equipment, such as crushers and sizers, and throughout plants to move materials through the various stages of processing. Electricity is also used to provide lighting throughout the plants.

For in situ recovery operations, electric motors and pumps are used to move materials and operate the normal electrical utilities. Since ore processing or upgrading is not required for in situ bitumen recovery, the electricity requirements are less than for mining and extraction or for fully integrated mining plants (Figure 9.1).

FIGURE 9.1

Electricity Cost by Recovery Type



Note: Assumes an electricity price of $40/MW.h.

Source: CERI

The main electricity source options available for Alberta oil sands producers are:

- the Alberta Interconnected Electric System (the grid);
- cogeneration; or
- a stand-alone electricity generator.

Currently, some producers, often the smaller ones producing less than 1 600 m^3/d (10 mb/d), will draw their electricity from the grid while others can generate their electricity onsite. If surplus electricity is generated, producers have the option to supply it to their other projects or to sell it to the market.

9.3 Cogeneration

Electricity generation and oil production involve two distinct processes that convert energy from one form to another. A cogeneration plant, also known as a combined heat and power (CHP) facility, realizes efficiency gains by combining the processes, using fuel (typically natural gas) to run a combustion turbine to turn a generator and produce electricity. A heat recovery steam generator then captures the remaining heat that would normally be wasted, and uses it to produce steam, hot water or a mixture of the two. This is then used in the oil sands production process. The electricity produced is considered a by-product because the heat used in the oil production process is viewed as the priority end product.[43]

Natural gas is the main fuel used for cogeneration, but as discussed in Chapter 11 other energy sources such as nuclear and syngas produced from bitumen are under consideration.

A continuous supply of electricity and steam is necessary to maintain oil production and avoid interruption related costs. Both mining-based and in situ methods of production are highly sensitive to unscheduled electrical outages, but each is impacted differently. Maintaining electricity supply at 100 percent reliability is the producer's primary concern, in order to avoid days or even weeks of lost production. Mining and upgrading processes are vulnerable to even brief interruptions in the electricity supply. In situ projects have more tolerance for short interruptions depending on the specifics of the project. Cogeneration, along with the grid providing back-up, assists oil sands producers to meet their electricity reliability needs.

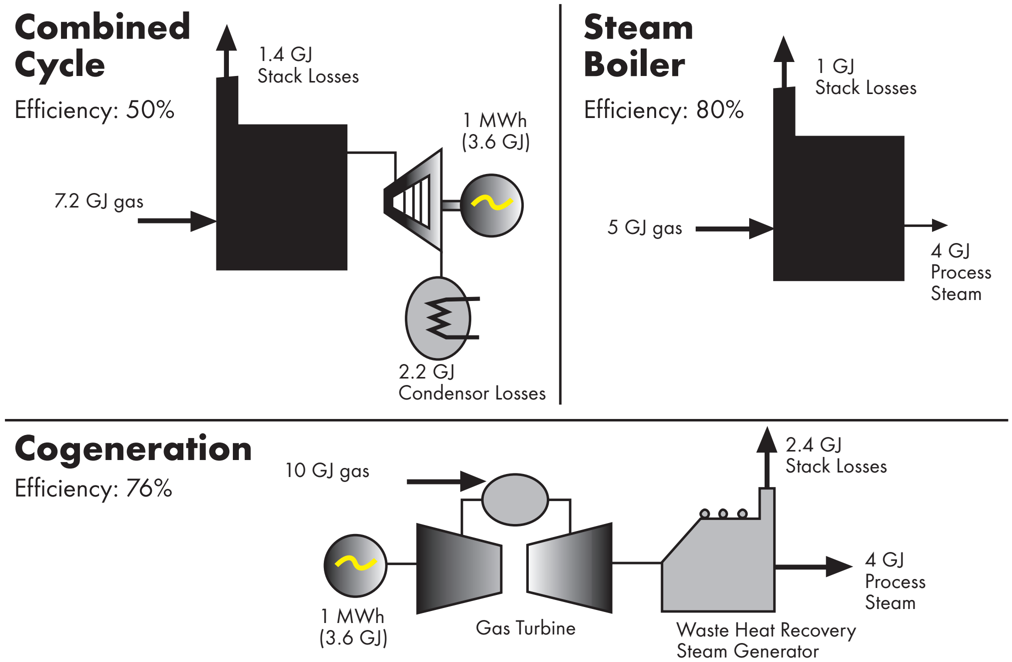
Efficiency gains are a key benefit and driver for producers installing cogeneration facilities. Natural gas is cleaner burning than coal, and compared with a stand-alone combined-cycle gas fired generation facility, a cogeneration unit can convert a higher percentage of natural gas into steam and electricity. Some cogeneration units can increase fuel conservation, translating into 10 to 20 percent fuel savings when compared with a stand-alone facility. The efficiency gains can thus be considered as environmental benefits since they reduce emissions, such as CO_2.

Based on industry estimates, a cogeneration facility costs around one million dollars per MW of installed generating capacity, or about 10 to 15 percent of an oil sands project's total cost. This cost is less than the total cost of a comparable stand-alone power plant plus steam production facility. Although it is difficult to apply a general revenue value to cogeneration facilities because of the many variables that influence how it is operated, the potential revenue stream can be up to 10 to 20 percent of an oil sands project's revenue. A producer could use the electricity revenues to partially offset

43 *Cogeneration/Transmission Sub-Committee Oil Sands Cogeneration Potential Survey Results.* Athabasca Regional Infrastructure Working Group. May 2003.

FIGURE 9.2

Efficiency Gains from Cogeneration



This diagram compares the efficiency of producing electricity in a combined cycle stand-alone power generator and steam in a dedicated boiler with a cogeneration facility that combines the two processes. Capital costs of the combined cycle and cogeneration plants are about $1,000,000 per installed MW of capacity, while the steam boiler requires an investment of about 40% of that of the corresponding cogeneration facility.

Plant Type	Capital Cost ($)	Fuel Used (GJ)	Electricity Produced (MW.h)	Steam Produced (GJ)	Efficiency (%)
Combined Cycle	1,000,000	7.2	1.0	-	50.0
Steam Generator	400,000	5.0	-	4.0	80.0
Total	1,400,000	12.2	1.0	4.0	62.3
Cogeneration	1,000,000	10.0	1.0	4.0	76.0

The benefits of a cogeneration plant are apparent. Capital cost and fuel consumption are both less than those of a stand-alone generator plus steam generator. Given a market for the electricity and a use for the steam produced, cogeneration is the logical choice.

Note: Fuel consumption and output figures are illustrative and may not correspond to the balues of any particular facility.

Source: Based on material prepared by the Electricity and Industrial Combustion Branch of Environment Canada.

increases in the price of natural gas. Revenues could also be used to recover cogeneration facility capital expenditures that are over and above those of a stand-alone steam generator.

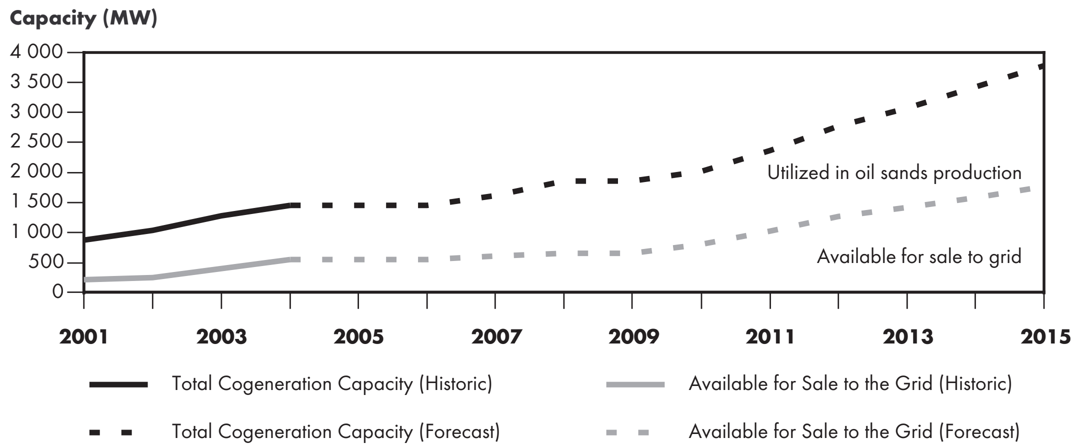
Integrated mining, extraction and upgrading projects are large consumers of electricity, while in situ projects require less electricity but greater amounts of steam. Consider a typical project with 170 MW of installed capacity, producing 4 800 m^3/d (30 mb/d) of oil. If it uses SAGD technology only 10 MW is required for onsite use, while a mining-based project would required about half the available generation for onsite consumption. Thus, the quantity available for sale may vary widely between mining and in situ types of operations.

9.4 Opportunities

The most prominent opportunity, with respect to cogeneration, reaches beyond producers' needs and has the potential to have a province wide impact on electricity supply options and electricity prices. The vastness of the oil sands and the long project lives suggest there is considerable potential for cogeneration. However, many of the oil sands producers are currently sizing cogeneration facilities to match on-site demand for electricity and are using boilers to meet the remaining demand for steam. If they could be encouraged to build beyond their immediate needs, the benefits gained from cogeneration could be increased to a much larger scale. Appendix 5 provides the existing cogeneration capacity and Figure 9.3 provides total cogeneration capacity and surplus capacity available to the grid.

FIGURE 9.3

Oil Sands Based Cogeneration Capacity



Total Alberta generating capacity, as of early 2004, is about 11 200 MW, while the all-time peak demand was 8 970 MW.[44] This indicates a capacity surplus of 2 230 MW, or about 25 percent above peak load. With the addition of the 490 MW Genesee #3 coal-fired generating plant, scheduled to come on-line in 2005 at Lake Wabamun, southwest of Edmonton, capacity should meet the reserve margin[45] of 15 percent above peak demand set by the Alberta Electric System Operator (AESO), until at least 2008.[46]

Current oil sands projects have an installed total capacity of about 1 450 MW of which 900 MW are for their own use, leaving a surplus of approximately 550 MW. It is estimated that oil sands based cogeneration could grow to 3 800 MW by 2015, and that surplus capacity could grow to 1 760 MW or more by 2015.

Increasing the surplus cogeneration capacity available to the grid can also reduce electricity prices for consumers because cogeneration could displace more expensive forms of electricity generation.

Clearly, a significant opportunity is presented by the potential to increase oil sands based cogeneration and transmit excess electricity out of the Fort McMurray area to load centres. However, a number of challenges are presented by infrastructure and market constraints, as discussed below.

44 *Key Numbers - Electricity*. www.energy.gov.ca. Alberta Energy. November, 2003.

45 An amount of capacity thought to be sufficient to meet extraordinary demand increases or generation losses. Carrying too large a surplus capacity is uneconomical.

46 CERI Oil Supply Outlook. *Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada 2003 - 2017*. Study No. 108. CERI (Canadian Energy Research Institute). March 2004.

9.5 Transmission

It is apparent the benefits of cogeneration could be substantial; however, the availability of transmission presents a challenge. The last major transmission project in the province was the Alberta-B.C. 500 kV interconnect built in the mid-1980s. Stresses and constraints on the transmission system, such as a lack of transmission capacity, are reasons producers have not maximized their potential cogeneration capacity.

Fort McMurray is currently connected to the rest of the province by two 240 kV transmission lines with a total capacity of 370 MW. While the variability of on-site bitumen production means it is unlikely the full 550 MW of surplus cogeneration capacity will be available at one time, current transmission capacity still limits the ability to deliver electricity to market. As a temporary measure, the latest cogeneration facility to enter service has been placed on a Remedial Action Scheme (RAS). This means if one of the lines from Fort McMurray trips out of service, the RAS automatically cuts off this generation to prevent the remaining line from overloading. This allows the transfer of an additional 150 MW (the net capacity of the plant in question) when both lines are in service.

When a third 240 kV line is completed (scheduled for the fall of 2004), capacity will increase to 610 MW and the need for a RAS should be eliminated. However, significant new generation additions could cause the surplus to exceed the new transmission capacity and result in the need for a new RAS for some or all of this new generation.

With oil sands surplus cogeneration capacity forecast to be around 600 MW for the next three years, it is anticipated the existing transmission capacity will not be sufficient to move any additional excess electricity to the Alberta market[47]. If producers do not perceive transmission capacity will be available to move excess electricity, they may choose to build only enough cogeneration capacity to meet their average load and pull any extra energy they need from the grid.

9.5.1 Alberta Transmission Policy

A key challenge to improving the robustness of the electricity industry to determine which assets should be committed first: transmission or generation. On average, it takes longer to build transmission than generation.

A recent regulatory change in Alberta has been implemented that recognizes that transmission should not be a barrier to generation[48]. Under the new Electric Utilities Act (the Act), released June 2003, the AESO was formed. One of the AESO's functions is transmission planning and development. Following the proclamation of the Act, Alberta Energy, the provincial body responsible for energy policy, introduced the Transmission Development Policy in December 2003. The general view is that the new policy will increase stability in the marketplace by allowing market participants to make more informed decisions with respect to building and operating transmission and generation. The policy outlines the direction of transmission operation in the province and gives the AESO the mandate to proactively plan and build transmission. The policy also directs the Alberta Energy and Utilities Board (AEUB) to provide a regulatory and approval process that is timely and efficient.

47 *Cogeneration/Transmission Sub-Committee Oil Sands Cogeneration Potential Survey Results*. Athabasca Regional Infrastructure Working Group. May 2003.

48 Transmission Development. The *Right Path for Alberta*. A Policy Paper. Alberta Energy. Electricity Business Unit. November 2003.

9.5.2 Proposals

Increased transmission capacity will be required if the full potential for cogeneration in the oil sands is to be realized. This transmission is intended to move power from Fort McMurray to load centers in the southern part of Alberta, to gain access to the U.S. market in the Pacific Northwest (PNW) and California, or some combination of these goals.

The AESO has reviewed proposals to expand provincial transmission capacity from Fort McMurray to the Calgary region, and found they fall into two broad categories:

- expand the existing transmission system from Fort McMurray to Edmonton, with an accompanying expansion of the Edmonton to Calgary connections; or
- add a High Voltage Direct Current (HVDC) line running directly from Fort McMurray to the Calgary area.

Of the two, the HVDC system is favoured by the AESO. Although it has a higher initial capital cost it is expected to be less expensive in the long run.

There also are options for increasing electricity exports:

- wheel power through British Columbia using existing transmission; or
- develop a direct link to the U.S. PNW.

Increased transmission capacity between Fort McMurray and southern Alberta would allow more use of existing links to British Columbia, but would still face transmission congestion in the PNW. A direct link will require considerable capital investment but has gained support since it avoids transmission congestion on the existing links between British Columbia and Washington State.

The NorthernLights Transmission project is an example of the latter option. It is a proposed equity partnership for a large transmission export project (up to 3 500 MW), spearheaded by TransCanada PipeLines Limited. The proposed line would be a merchant, or non-utility owned transmission facility, extending from the Fort McMurray area, south across Alberta and British Columbia to the PNW, where it would connect to the existing Pacific HVDC Intertie. According to project coordinators, the line could be in service as early as the end of the decade.

NorthernLights would allow access to both the Mid-Columbia[49] and California markets and could potentially maximize cogeneration capacity in the oil sands. The project is expected to cost $1.6 to 1.8 billion. It would likely encounter a number of challenges, including the issues of potential benefits to Albertans and right-of-way access. In addition, it would require long-term generation and load contracts that would be sufficient to obtain project financing.

The AESO and NorthernLights proposals are not necessarily exclusive. For example, an AESO-sponsored HVDC transmission line from Fort McMurray to southern Alberta might serve as the first leg of an export line, or conversely, the NorthernLights project could be connected to the Alberta grid in southern part of the province and sell long-term transmission capacity to the AESO.

The range of transmission proposals demonstrates the potential to expand energy transfers from Fort McMurray. The option chosen and implementation date will help decide the future of cogeneration in the Fort McMurray region.

49 Mid-Columbia (Mid-C) - The trading hub for bulk (wholesale) power sales in east-central Washington state.

9.6 Alberta Market

A significant impediment to maximizing cogeneration is the perception that the Alberta market is not large enough to support the full potential of surplus cogeneration capacity.

As of early 2004, there is sufficient generation capacity to meet demand in the province. The projected demand is expected to be approximately 11 500 MW in Alberta by 2013, and a supply shortage is not expected in the mid to long-term despite the retirement of older generation.[50] With excess generation capacity already in place in Alberta and with the new AESO making plans to improve transmission congestion and address capacity issues, accessing additional markets to promote cogeneration capacity growth could be a course of action.

If cogeneration capacity is maximized, Albertans could benefit from the must-run capabilities of oil sands producers. Specifically, to ensure their electricity is dispatched and they can produce the steam they need for oil production, oil sands producers would submit offers below the prevailing prices in the Alberta power pool, thus displacing higher cost production and reducing the pool price.

Given British Columbia's relative level of electricity self-sufficiency and Saskatchewan's small border interconnect with Alberta, industry participants view the PNW as a preferred market option. Considerations in reaching this market, besides transmission availability, include the economics of transporting the natural gas versus the electricity.

Should surplus electricity generated from the oil sands reach another market, most likely in the U.S., the resulting impact on electricity prices appears to be less clear.

50 Source: Alberta Electric System Operator.

Energy Prices

Low electricity prices and high gas prices can deter investors from building cogeneration. In the short run, a cogeneration facility at least recover its fuel cost from electricity sales. Ideally, the market heat rate must be higher than the plant heat rate.

While a cogeneration facility uses less fuel to generate electricity than a combined cycle gas plant, some additional fuel is required to produce electricity as well as steam. The average heat rate for electricity generation (not including fuel used to produce steam) for a cogeneration facility is typically around 5 500 GJ/GW.h (5.5 GJ/MW.h). Therefore, if gas prices are $4/GJ, a power pool price of at least $22/MW.h is required to meet fuel costs.

The Pacific Northwest (PNW) Market

Over the near term, the PNW will continue to reflect weak market fundamentals for new supply as a result of high capacity margins.[1] The high capacity margin is primarily a result of the curtailment of the majority of regional aluminum smelting loads and a significant supply increase. This is evidenced in the fact that electricity consumption from smelter operations dropped from 2,500 MW in 2000 to less than 400 MW by the end of 2003 while total supply increased by 3,600 MW from 2001 to 2003. In addition, a downturn in aerospace and technology industries has dampened overall regional year-over-year electricity demand growth.

The PNW mid-term supply/demand outlook could improve. As a result of the current oversupplied market, merchant developers are suspending or canceling the majority of current projects in the queue. Unless regional utilities develop new generation to meet integrated resource plans, very little new generation will enter the system.

1 Assuming the Columbia River system will realize normal hydro conditions.

It has been suggested that Alberta electricity prices will converge to match the prices in the new market; however, this is likely only if the transmission line has enough capacity to take all the surplus generation. If there is more oil sands electricity surplus than can be transmitted out of Alberta, prices in the province may still decline.

9.7 Conclusion

The oil sands industry uses large quantities of electricity and has made increasing use of cogeneration to supplement power taken from the Alberta grid. An opportunity exists to significantly increase the amount of cogeneration in conjunction with expanding oil sands production. The increase in cogeneration can have positive impacts on both oil sands producers and the province as a whole. The potential for reliability, efficiency and revenue gains could help producers reduce their costs. For the province, this would translate into a potential for increased corporate tax revenue, investment and job opportunities.

How much cogeneration capacity built will depend on the successful resolution, through regulatory policy and industry initiative, of the current lack of adequate transmission capacity and of uncertainties regarding demand levels in the Alberta market.

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Petrochemical Feedstocks and Transportation Fuels

10.1 Introduction

The core of Canada's petrochemical industry is located in Alberta where investments in ethane cracker and petrochemical derivative facilities currently total about $11 billion. Since the late 1990s, in response to flattening natural gas production from the WCSB and rising demand, natural gas prices, and therefore ethane prices, have increased significantly. The Alberta petrochemical sector now faces a situation of tight ethane feedstock supply. The bitumen upgrading process produces off-gas from which ethane, ethylene and other light hydrocarbons could be extracted. Currently, most of this potential feedstock is not removed but is used as fuel in operations. By 2015, however, market conditions may evolve so that Alberta's bitumen resource base could provide a secure, substantial and stable-priced feedstock for the petrochemical industry.

10.2 Background

Alberta's industry was founded in the mid-1970s and is based on ethane. Ethane is the most efficient feedstock for the production of the petrochemical "building block" ethylene, as it results in the fewest number of co-products. Considering that feedstock costs account for over 65 percent of the total cost of ethylene production, it follows that they have a strong influence on operating profitability.

Ethane, along with propane, butane and pentanes plus (collectively referred to as natural gas liquids or NGL), is a by-product of natural gas production. From the mid-1980s to mid-1990s, natural gas production from the WCSB exceeded pipeline take-away capacity, resulting in gas volumes being trapped in Alberta. The gas over-supply environment in Alberta led to reduced natural gas prices in the province compared with those in eastern Canadian and U.S. markets, which in turn, meant lower ethane prices relative to the U.S. market. Access to large quantities of low-cost ethane feedstock, in conjunction with the ethane cost recovery mechanism[51] in place at the time and the efficiency of the ethane extraction and pipeline gathering facilities, led to the expansion of the Alberta petrochemical industry on a world-scale level. The expansion investments were based on the long-term view that natural gas costs in Alberta would be discounted versus gas on the U.S. Gulf Coast (USGC). The gas cost advantage resulted in the petrochemical sector becoming an incremental market for natural gas.

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51 The infrastructure necessary for a competitive petrochemical industry is very extensive and highly capital-intensive and includes straddle plants, an ethane gathering pipeline system and ethylene and derivative plants. Therefore, prior to the construction of the initial facilities, a contract mechanism was developed in the 1970s as a means to ensure the full recovery of ethane extraction and ethylene production costs, plus a reasonable return on equity. These cost-of-service (COS) pricing contracts involved ethane sales between the straddle plant operators and the ethylene plants, and ethylene sales contracts between the ethylene and the derivative plants.

Going forward, WCSB conventional natural gas supply and subsequently ethane supply are expected to remain flat-to-declining. In addition, Alberta pipeline takeaway capacity has increased, narrowing the price advantage. With natural gas prices expected to remain high (over US$4 per MMBtu) and volatile, NGL feedstock costs are also expected to remain high. Nevertheless, the Alberta maintains a cost advantage relative to the USGC ethane/propane cracking facilities. This cost advantage is important, as the USGC, with its high concentration of petrochemical cracking and derivative infrastructure, is the primary competitor for the Alberta petrochemical sector.

One cost aspect that has changed relates to the price relationship between natural gas and oil. Natural gas historically traded at a value below crude oil, on an energy or heat content basis. By late 2002, the price of natural gas relative to crude oil had increased to about parity. Going forward, Alberta NGL-based ethylene is expected to continue to have a cost advantage over USGC NGL-based ethylene. Under the assumption of parity pricing, Gulf Coast oil-based (e.g., naphtha-based) ethylene could have an advantage. However, since about half of the ethylene produced on the Gulf Coast is NGL-based, Alberta is expected to remain competitive.

These feedstock challenges have highlighted the need to consider future ethane supply and feedstock flexibility. For example, in 2002, the ethylene plants located near Joffre, Alberta expanded their cracking capability to use small volumes of propane as feedstock - when economic to do so. Ethylene plants can accommodate up to about 10 percent propane in the feedstock slate. Cracking greater than this amount would require additional investment, which is unlikely given that propane commands a significant price premium, particularly during the heating season.

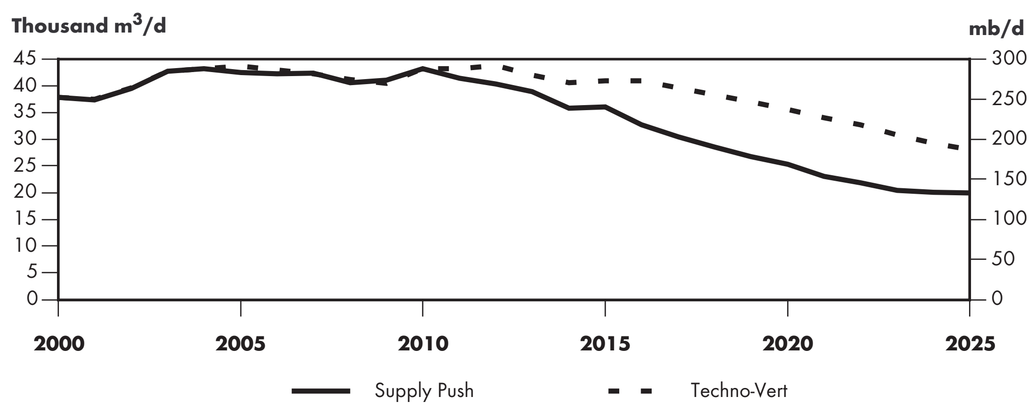
In 2003, a new straddle plant was brought online at Joffre, and the deep-cut capability of an Empress, Alberta straddle plant was also expanded to add incremental ethane supply. However, despite this additional ethane supply and propane cracking capability, as well as potential future small deep-cut expansions at Empress, an ethane supply shortfall could materialize if conventional natural gas production in the WCSB declines.

The NEB's 2003 Supply and Demand Report included a discussion about the potential outlook for ethane. As illustrated in Figure 10.1, under the Supply Push and Techno-Vert scenarios, ethane supply peaks and remains essentially flat from 2004 to about 2012, and then declines significantly.

These outlooks do not include ethane entrained in natural gas exported via the Alliance pipeline. Potential ethane volumes associated with the Mackenzie Delta are included but potential volumes associated with Alaskan natural gas are not. If a proposed northern pipeline from Alaska is approved

FIGURE 10.1

WCSB Conventional Ethane Supply Scenarios



and constructed, and if ethane entrained in the Alaskan natural gas stream is extracted in Alberta, an estimated 9 500 to 19 000 m^3/d (60 to 120 mb/d) of ethane could be available.

With North American ethylene demand forecast to grow, it is expected that by 2012 new ethylene capacity will likely be required in North America. The Alberta ethylene sector will not be able to maintain its existing utilization rates or expand without additional secure and cost competitive feedstock supply.

10.3 Potential Petrochemical Feedstock Supply

Upgrading bitumen represents potential petrochemical feedstocks from two sources:

1) synthetic gas liquids (SGL) - ethane, ethylene and propylene in particular from the upgrading process; or
2) intermediary products recovered from existing upgrader and refinery processes or from an integrated, upgrading/refining plant. The petrochemical feed could include SGL, naphtha, aromatics and vacuum gas oil (VGO).

10.3.1 Synthetic Gas Liquids Feedstock from Upgrader Off-gas

The upgrading process involves coking, catalytic cracking, or hydro-cracking of bitumen. When bitumen is upgraded to synthetic crude oil (SCO), the process also produces off-gas - a mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and olefins ethylene, propylene and butylenes[52]).

Figure 10.2 depicts a general composition of the lighter products obtained from upgrading bitumen. The paraffinic SGL components of off-gas could be a potential source of incremental feedstock supply for the existing Alberta ethylene plants, while the olefin portion could be feed for petrochemical derivative plants.

10.3.1.1 Ethane and Ethylene

Ethane and ethylene can be extracted from off-gas but are currently left in the gas stream and used as fuel for the existing upgraders. The amount of ethane and other SGL feedstock available from this source in the future will depend upon:

- the number of proposed bitumen upgrader projects that are actually built;
- the type of upgrader (i.e., coker, catalytic or hydrocracker); and
- where bitumen is upgraded (i.e., Alberta or the U.S.).

Based on production from existing and currently proposed upgrading expansions, it is estimated that by 2012, about 7 900 m^3/d (50 mb/d) of ethane/ethylene (C_2/C_2=) could be entrained in upgrader off-gas[53]. About 80 percent of the C_2/C_2= stream would be ethane[54]. This significant volume of

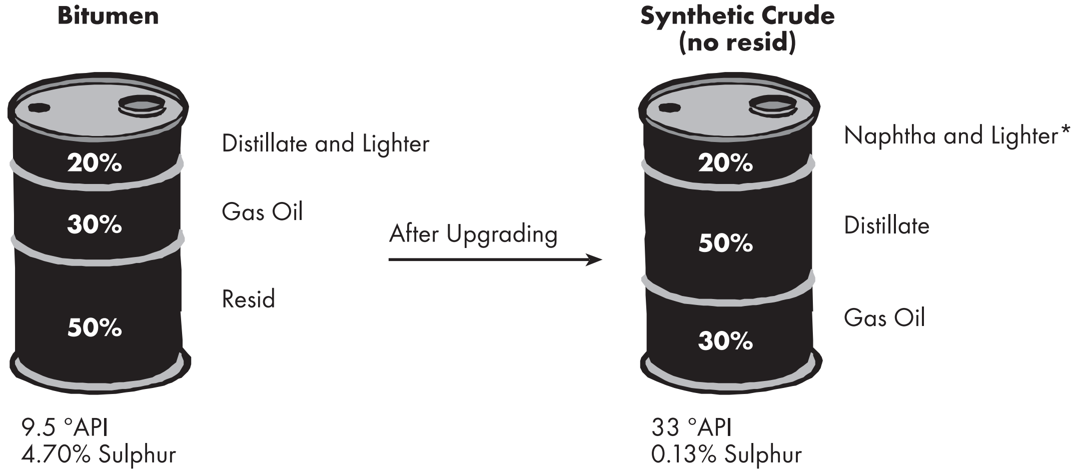
52 Olefins differ from paraffins in that they have a characteristic, reactive double carbon-to-carbon bond. Due to this reactive double bond, olefins can be either polymerized (bonding of two or more monomers) or undergo other reactions to create a wide variety of chemical derivatives. Ethylene is the most utilized olefin.

53 Purvin & Gertz Inc.

54 Ibid.

FIGURE 10.2

Bitumen and Synthetic Crude oil Composition



* Lighter refers to SGL (Ethane, Propane, Butane and various olefins contained in off-gas).

Source: Purvin & Gertz Inc.

ethane, if recovered from off-gas, could be consumed by the existing petrochemical facilities. Tying in C_2/C_2= streams from refinery processes could further increase the potential.

The extraction of SGL produced from bitumen upgrading (SGL-from-bitumen) could be a more expensive source of supply than NGL from natural gas, because initial capital and ongoing operating costs for SGL recovery are higher. The difference in ongoing operating costs can be attributed mainly to the amount of compression required in the two processes. Since SGL contains olefins, investment in paraffin/olefin separation and handling facilities would also be required.

The only company in the business of extracting SGL from bitumen upgrading today is Williams Energy (Canada), Inc. (Williams). Williams has a "keep whole" contract with Suncor Energy Inc. (Suncor) to remove SGL from off-gas produced by Suncor's upgrader (located near Fort McMurray) and to return sweet gas to the upgrader. Under this arrangement, Williams is required to replace the liquids' heat content removed with an equivalent heating value of natural gas. In March 2002, Williams brought online its olefinic C_3+ liquids compression, extraction and batching facilities near Fort McMurray, as well as an olefins fractionation plant near Redwater, Alberta. The extracted C_3+ mix is transported on Suncor's Oil Sands Pipeline (in discrete batches separated by naphtha) to Redwater, where propane, propylene, butane, butylene and olefinic condensate are produced. Williams has indicated that its SGL extraction facilities are operating close to capacity, with production approaching 2 100 m^3/d (15 mb/d) of C_3+ mix.

Propylene is the main driver behind Williams' SGL facilities, as propylene is a high value component. With some modifications, the Williams' Fort McMurray extraction facilities could extract an olefinic C_2+. Investment and operational costs related to C_2/C_2= extraction from the existing and proposed upgrading expansions will be critical, with the focus on the resulting cost of ethylene[55]. The recovery of propane/propylene and butane/butadiene could offset part of the cost of ethylene and ethane recovery but that would be dependent upon demand for propylene and butadiene.

55 If ethylene from off-gas is available in the future, the Alberta ethylene derivative plants would be able to accommodate incremental ethylene produced from this source; however, some de-bottlenecking investment may be required. The derivative plants would require certainty of supply, prior to investing in expansion capacity.

10.3.1.2 Propane and Propylene

If propylene associated with the existing upgrader, refinery and ethylene (U/R/E) plants located in the Edmonton, Fort Saskatchewan, Fort McMurray and Joffre regions were to be accumulated, it is estimated that the volume would meet the threshold requirement to support construction of a polypropylene plant in Alberta. Some parties suggest that a polypropylene plant in Alberta could be viable based on transportation cost savings. For example, if the market for polypropylene were Chicago or the Pacific Northwest, there would be cost savings due to their proximity. Others have said that the relatively low rail (tank car) costs for propylene delivered to the large USGC market may impact the competitiveness of propylene derivatives produced in Alberta. Specifically, with low rail costs, it could be more viable to deliver propylene to the Gulf Coast, as opposed to building a derivative plant in Alberta.

It is important to note that there is an opportunity to utilize propylene; the question is how to achieve this. Considering a timeline of over 10 years, many factors could change: such as feedstock availability; price certainty, and improved economic growth leading to increased propylene and propylene derivative product prices. The chemical sector continuously evaluates the feasibility of constructing a propylene derivative plant in Alberta.

The upgrader and refinery facilities that could potentially be re-tooled to tie-in the various paraffinic/olefinic liquid streams include:

- the Petro-Canada, Imperial Oil and Shell refineries located in the Edmonton area;
- the Suncor and Syncrude upgraders located near Fort McMurray and Shell's upgrading facilities in the Fort Saskatchewan area;
- the approved but not constructed CNRL Horizon and Nexen/OPTI upgrading facilities in the Fort McMurray area;
- the proposed ExxonMobil upgrader near Kearl Lake and the Synenco, BA Energy upgrading facilities in the Fort Saskatchewan region; and
- the existing Husky and Co-Op/Newgrade heavy oil upgraders located in Saskatchewan.

In addition, other parties are studying the feasibility of constructing new upgrader facilities.

10.3.2 Issues Related to Recovery of Synthetic Gas Liquids from Off-gas

In light of the recent high and volatile natural gas prices, the natural gas make-up requirement (i.e., to replace removed SGL) has been a deterrent to ethane production from off-gas. In addition, SGL-from-bitumen could be more expensive than NGL-from-natural gas, as SGL recovery could require construction of integrated extraction, separation, gathering and delivery facilities, including various segregated product pipelines.

The natural gas make-up requirement is, in effect, tying SGL recovery costs to natural gas costs. Proponents of the development of bitumen-based products are of the view that economics could be improved by tying energy make-up costs to bitumen-based fuel. They suggest that the "mind set" of replacing removed SGL products with natural gas must change. For example, rather than using natural gas as a source of fuel and hydrogen for the upgrading process, a low-value bitumen residue (e.g., upgrader bottoms - estimated to cost about US$1/MMBtu [mining and extraction costs for equity owners])[56] could be used. Any SGL recovered from off-gas in this scenario could then be made up with upgrader bottoms, resulting in lower SGL replacement costs. However, burning bitumen

56 Alberta Economic Development.

residue as fuel would be a source of potentially significant GHG emissions. In addition, re-tooling costs to convert existing upgraders to burn bitumen residue could also be significant.

While not currently feasible, there may be an opportunity to pursue recovering ethane or other SGL from off-gas within the next 10 years. The capture of light-hydrocarbon feedstock from the majority of the U/R/E off-gas sources will probably be required to achieve the economies of scale necessary for a viable operation. It has been suggested that having the Redwater fractionation facilities in place and a pipeline connection with the Fort McMurray area (to ship batches of SGL mix) increases the likelihood of adding ethane extraction from off-gas capability in the future.

As a result, there is a potential expansion opportunity for the petrochemical industry in Alberta through oil sands development. However, a significant barrier lies in the competing priorities of the essential parties including upgraders, refiners and petrochemical industry players. In the future, an advantage could come from integration, with the maximum return coming from the use of low-cost bitumen.

Opportunities from an integrated approach, if identified, could reduce total costs to the point where Alberta value-added petrochemical products can be competitive in the North American market. Perhaps piggy-backing petrochemical developments with oil sands transportation fuel development could improve economics and add flexibility for the upgrading, refining and petrochemical sectors.

10.4 Petrochemical Feedstock and Refined Petroleum Products Supply

10.4.1 Petrochemicals-from-Bitumen Study

A joint industry/Alberta Government study (2002/2003) suggested that Alberta has a synergistic opportunity to marry bitumen upgrading and refining operations with petrochemical (i.e., ethylene/derivative and propylene/derivative) developments. The study examined the feasibility of constructing an integrated complex in the Fort Saskatchewan area. The study was essentially a feasibility test to determine if it is technically and economically feasible to use VGO, a bitumen by-product produced by the upgrading and refinery processes, as petrochemical feedstock as well as refinery feed for manufacturing transportation fuels. The complex would require a unique "partnership" between oil sands mining/upgrading, refinery and petrochemical companies and would require commitments to research and development and to demonstration projects. The study estimated the internal rate of return on investment from the complex to be 15 percent (after taxes). To attract the estimated $8.5 billion investment to create the integrated complex, the study suggested that it would likely require the Alberta government to act as a facilitator.

The availability of existing infrastructure is a major advantage in this region; however, the study determined that a new pipeline may be required to deliver approximately 13 500 m^3/d (85 mb/d) of gasoline and diesel from the complex to markets in the Pacific Northwest, California or Chicago. The study also envisioned that any CO_2 produced by the complex (estimated at 4 Mt) could be transported via pipeline to depleted oil fields for sequestration, or could be used for enhanced oil recovery (EOR) or coal bed methane (CBM) recovery.

The key finding of the study - the real value attainable from an integrated approach would be achieved through the co-production of transportation fuels and petrochemical feedstock. As a result of this study, there have been ongoing initiatives and other studies to look at development options. Currently, several industry and government groups are involved in discussing whether a complex focused more on transportation fuels production would be economic.

10.4.2 Refined Products and Petrochemicals from Bitumen Study

A study was commissioned in 2003 by Alberta Energy and Economic Development (50 percent) and a group of private sector companies (50 percent) to determine whether there are economic benefits of going beyond upgrading to produce refined products and petrochemical feedstocks, rather than just SCO. The study, which was completed in early 2004, considered the potential for petrochemical developments associated with co-products from an integrated upgrader/refinery facility sized at 32 000 m^3/d (200 mb/d) of bitumen feed.

Essentially, an upgrader is not much more than the front end of a complex refinery. Adding units to produce gasoline, diesel fuel and jet fuel instead of SCO are not large step-outs. Further, recovering ethane, ethylene and propylene from an upgrader/refinery complex are additional processing steps that are common in many modern refineries. Recovery of aromatics, as wells as the addition of units to produce styrene, are also common processes. This study examined these add-on steps in an incremental manner to determine the value added from each step.

Alberta refineries are currently producing motor gasoline and diesel products made from upgraded bitumen. Some diesel fuel is also being produced at one upgrader. Historically, the western Canadian refined products market demand has been and remains in close balance with local supply. Thus, whether there will be a market for incremental Alberta supply of refined products is the issue. Consequently, the study was based on supplying refined transportation fuel products to markets in California and the U.S. Midwest - both logical markets due to their size and reasonable access by pipelines and/or tankers. Exporting transportation fuels on a sufficient scale could translate to relatively low transportation costs and provide competitive netback prices for producers. One option for reaching the California market could include expansion of Trans Mountain Pipeline (owned by Terasen). An option for moving products to the Midwest could be available in a reconfigured, and possibly expanded, Enbridge pipeline system.

A further processing step - the addition of a cracker unit to the complex - could be feasible whereby some of the bitumen, or VGO from bitumen, is used as petrochemical feedstock. Or, by modifying the existing crackers to accommodate some heavier, oil/bitumen-based feeds, the Alberta crackers could become flexi-crackers, with some ability to switch feedstock and product slates, depending upon the economics for each feed (NGL, SGL, upgrader or refinery intermediate) and product/co-product. At the same time, the upgrader/refinery plant would have the flexibility to optimize transportation fuel production. The above study did not assess the potential of adding a cracker to the complex, as it focused on refined products and readily available petrochemicals as co-products from the upgrading/refining operations (i.e., ethylene and propylene in particular).

Although the petrochemical co-product supply from an upgrader/refinery plant would be relatively small in terms of volume, the incremental value attributable to the recovery of petrochemicals is significant and could assist in a decision to go ahead in the development of such an integrated project. The industry/government task force anticipates using the market study as a tool to help determine what policy and/or strategy the government and industry should use going forward to encourage such developments.

10.5 Ethane Cost Comparisons

Ethane from WCSB natural gas is the most economic source as the existing facilities in this region associated with gas gathering, processing, extraction and transportation are over 20 years old and almost fully depreciated. It has been suggested that potential Mackenzie Delta-based ethane is expected to be cost competitive with ethane from conventional natural gas, as supply from the Delta would likely utilize the same infrastructure. Ethane from Delta gas appears to be limited in quantity.

Although the proponents of Alaska gas pipelines have not determined their final project configurations, if ethane from Alaskan natural gas is extracted in Alberta, this option would likely utilize existing Alberta infrastructure and downstream facilities. However, as suggested by some stakeholders, this relatively significant source of ethane could require investment in some new or "green-field" facilities in Alberta (e.g., decompression and recompression, de-ethanizing and heater facilities). If this is the case, Alaskan ethane could be less competitive than conventional or Delta-based ethane.

Ethane from off-gas could be more expensive than from conventional or northern ethane supply sources, as the off-gas stream may require significant compression prior to the SGL extraction process. In addition, bitumen-based SGL contains olefins that may require investment in green-field extraction, as well as olefin/paraffin handling capability (such as segregated product pipeline facilities).

Ethane-from-bitumen from an integrated U/R/E complex could be more competitive than ethane derived from U/R/E off-gas only. Specifically, ethane recovered from off-gas, on a business-as-usual, fragmented basis would not attract the benefits of integrated cost and revenue sharing.

Since 1982, essentially all ethylene derivative production in Alberta has been exported. Therefore, the key cost issue is whether ethylene-from-bitumen can be competitive with USGC product.

10.6 Conclusion

The Alberta petrochemical sector presently faces a tight ethane feedstock situation.

Until a significant, new gas supply source becomes available, natural gas costs are expected to remain high and volatile. Price volatility translates into high risk and uncertainty for the Alberta petrochemical companies that have their feedstock costs tied closely to natural gas. By 2015, market conditions may evolve so that Alberta's huge bitumen resource base could provide a secure, substantial, stable-priced feedstock for the petrochemical industry.

A significant portion of ethylene produced on the USGC is oil-based. During periods when natural gas is valued above oil, Gulf Coast oil-based ethylene could have a cost advantage relative to Alberta NGL-based ethylene. In light of this, there could be an opportunity for bitumen-based ethylene.

Possible "synergies" through integration and cooperation could yield environmental benefits and maximize total returns through shared costs and value creation. For example, shared use of infrastructure and operations, and economies of scale, could reduce total costs to the point where Alberta RPP and petrochemical products are competitive with U.S. products.

The U.S. is a net importer of refined transportation fuels and imports into the U.S. are expected to grow over the next decade. Consequently, there could be sufficient refined products demand to support the production of incremental refined petroleum products in Alberta. With bitumen production expected to expand significantly, the provincial government and U/R/E sectors will likely continue to assess the feasibility of adding the maximum value to this resource.

Emerging Technologies

11.1 Introduction

Technological innovation has been a key driving force behind the oil sands industry since its inception. All aspects of the industry, including mining, extraction, upgrading, in situ recovery and reclamation have gone through substantial change, sometimes step changes, in their evolution into today's industry. Research and the application of improved technologies have resulted in improved supply costs for integrated mining and in situ bitumen where they are roughly comparable with those for conventional crude oil. However, opportunities exist for further improvement.

The oil sands industry is a multi-billion dollar industry and research related to it has grown to involve a wide range of disciplines, including government and private research organizations, as well as academic institutions, in every province in Canada and in many places around the world.

The subject of technology in oil sands is so broad that even a cursory summary would be well beyond scope of this study. Readers are referred to the "Oil Sands Technology Roadmap", a report released in early 2004 that sets out a 50-year technological plan to optimize the oil sands potential. Additional references on technology in the oil sands are provided at the end of this chapter.

In this chapter we limit the discussion to those production and upgrading technologies that are expected to be implemented and have an effect within the time frame of our projections, that is, by 2015, and some alternative energy sources that have recently been proposed.

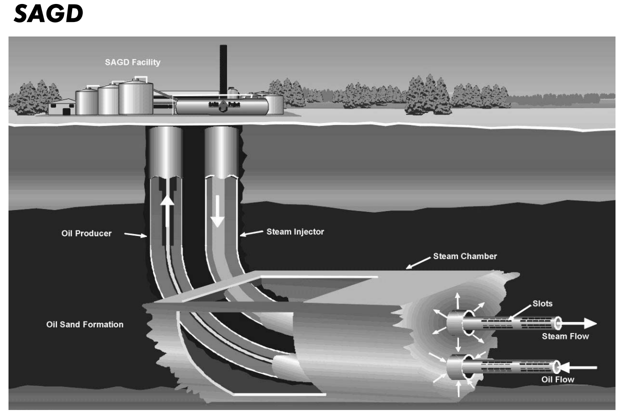
11.2 Steam Assisted Gravity Drainage (SAGD)

Although commercial SAGD projects have been in operation since 2001, it is still relatively early in the development of this recovery method, and there is considerable scope for modification and improvement, in terms of energy efficiency and recovery factors.

At its Foster Creek SAGD project, EnCana has been testing the concept of using low pressures (>2,000 kpa), low temperatures (~180 ºC), and using electrical submersible pumps instead of gas-lift for producing the bitumen to the surface. The expectation is lower steam-to-oil ratios (SORs) and improved economics.

FIGURE 11.1

SAGD



Source: EnCana

A variant of SAGD that is being tried in several projects is Solvent Aided Process (SAP), where injecting a combination of steam and solvent, typically butane, is expected to reduce the SOR and accelerate the recovery rate. The recovery of most of the injected solvent is necessary for economic feasibility.

There are a number of other hybrid thermal/solvent processes being tested. The Alberta Research Council (ARC) is leading research into a number of hybrid steam/solvent processes combining SAGD technology with solvent injections. The new processes are aimed primarily at improving recovery and energy efficiency, and reducing water requirements. These enhanced thermal processes include Expanding-Solvent SAGD (ES-SAGD), Low-Pressure Solvent SAGD, and Tapered Steam Solvent SAGD (TSS-SAGD)[57].

11.3 VAPEX™

Vapour Extraction Process, or VAPEX™, is similar in operation to SAGD, except that a solvent such as ethane, propane or butane, instead of steam, is injected into the reservoir along with a displacement gas to mobilize the hydrocarbons in the reservoir and move them toward the production well. This offers the cost advantage of not having to install steam generation facilities or purchase natural gas to produce steam. The VAPEX™ method requires no water processing or recycling, offers lower carbon dioxide (CO_2) emissions, and can be operated at reservoir temperature with almost no heat loss. The capital costs are estimated to be 75 percent of SAGD costs, while the operating costs are estimated to be 50 percent compared to SAGD[58]. Another advantage is the possibility of reduced diluent requirement, as some of the solvent diffuses into the bitumen to mobilize it. On the negative side, more wells are needed to achieve similar production rates and recovery factors.

VAPEX™ offers an alternative process to recover bitumen from reservoirs that are not amenable to thermal processes such as reservoirs with bottom water and/or high water saturation, vertical fractures, low porosity and low thermal conductivity.

Devon Canada Corporation is leading a consortium, with participation of the provincial and federal governments, in conducting field trials to develop and test vapour extraction (VAPEX™) recovery technology. The pilot is located at the Dover Underground Test Facility site in the Athabasca oil sands area near Fort McMurray. Several other smaller-scale tests are also being carried out.

In addition to evaluating the economics of this recovery method, technical problems are also addressed. Examples include testing cold-start or hot-start methods (using electrical heating or steam) to determine the best method to initiate the formation of a vapour chamber. Maximizing solvent effectiveness and recovery is also important.

11.4 THAI/CAPRI

Toe-to-Heel Air Injection, or THAI, is a proposed method of recovery that combines a vertical air injection well with a horizontal production well (Figure 11.2).

The process ignites oil in the reservoir itself, creating a vertical wall or front of burning crude (fire front) that partially upgrades the hydrocarbons in front of it and drains the crude to a producing

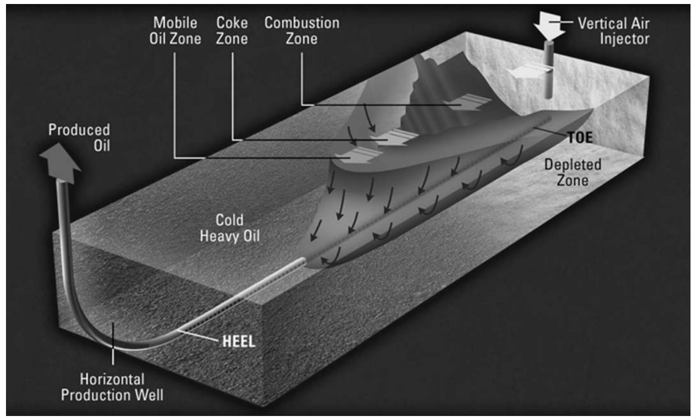
57 Alberta Research Council. http://www.arc.ab.ca/.

58 EnCana.

horizontal well. By creating heat in situ, the process negates the need for injecting steam from the surface. The process also offers some potential for upgrading the bitumen in the reservoir as the process proceeds. A THAI variant, named CAPRI, utilizes a catalyst in the horizontal well to promote the precipitation of asphaltenes and thus upgrade the bitumen in situ.

FIGURE 11.2

THAI Process



Source: Petroleum World

In situ combustion recovery methods were tried in heavy oil and oil sands settings in the 1970s and 1980s, using vertical wells, but met with little success, primarily because of an inability to control the direction of the firefront in the reservoir. This generally resulted in poor production performance and often caused damage to downhole equipment. The proponents of the THAI method believe that using a horizontal production well will offer better control of the firefront, but the concept has yet to be proven in the field.

In early 2004, Orion Oil Canada Ltd., a heavy oil business unit of Petrobank Energy and Resources, filed an application with the AEUB to test the THAI process on the Whitesands oil sands leases near Conklin, Alberta. According to plan, delineation drilling and site preparation will begin in early 2004, with startup in late 2004.

11.5 Nexen/OPTI Long Lake Project

The Long Lake SAGD project, a joint venture between Nexen Inc. and OPTI Canada Inc., received approval from the Boards of Directors of both companies early in 2004. Field construction work is expected to begin in the third quarter of 2004.

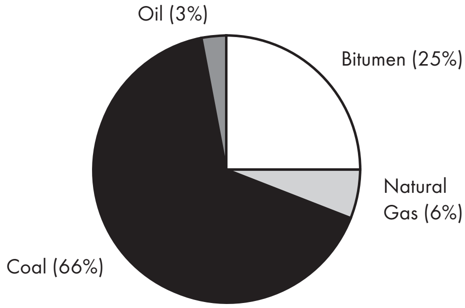
The $3.4 billion SAGD project includes an integrated upgrader that will use OPTI's proprietary ORcrude™ process along with commercially-available hydrocracking and gasification technology. Long Lake is the first oil sands project to integrate SAGD with an onsite upgrader. This unique configuration of proven processes is designed to significantly reduce the need to purchase outside fuel and thereby screen the project from the volatility of natural gas prices. The project is designed to produce a premium synthetic crude oil (SCO) with an expected gravity of 39º API and very low sulphur content, thus yielding a high quality refinery feedstock. The project proponents expect this unique configuration to result in a $5 to $10 per barrel operating cost advantage over existing integrated oil sands projects. Commercial bitumen production is scheduled to start in 2006, with 9 500 m^3/d (60 mb/d) of SCO production beginning in 2007.

11.6 Coal

There are abundant reserves of coal in Canada, with coal making up 66 percent of Canadian fossil fuel reserves (Figure 11.3). About 40 percent of these reserves are in Alberta, where coal is the most

FIGURE 11.3

Canadian Fossil Fuel Reserves



Source: Coal Association of Canada

abundant fossil-fuel resource with a reserve life index of about 1,100 years[59]. These reserves are generally of high quality, relatively low in sulphur and ash content, and are reasonably well delineated, with little further exploration required. Coal mining and infrastructure are well established in Alberta, as coal currently provides about 65 percent of electricity production in the province. Coal is as efficient as gas in terms of steam production, with an 80 percent conversion rate in modern boilers. Given the above, coal would seem to be an obvious choice to provide energy for oil sands operations.

Historically, natural gas has provided a reliable, inexpensive and relatively clean-burning source of energy, and the oil sands industry has grown dependent on it. More recently, higher and more volatile gas prices have caused oil sands producers to examine alternative energy sources.

Coal combustion, which involves the burning of pulverized coal in boilers, is a proven technology and could be considered as a near-term option. However, its use would significantly increase greenhouse gas (GHG) emissions and also require desulphurization and the removal of particulate matter and other harmful emissions (flue-gas clean-up), with the associated additional expense.

In the longer-term, coal gasification to produce synthetic gas (syngas) is postulated to provide fuel gas and hydrogen. However, its technical and economic feasibility are yet to be established.

The cost of delivering coal to the oil sands areas could be reduced by shipping a liquid-coal slurry in a pipeline system, similar to the hydrotransport systems used to move oil sands/water slurry in oil sands mining operations.

Coal has great potential to provide a stable long-term source of fuel for oil sands developers, but a number of hurdles remain to be crossed. It must be shown to be both economic and environmentally acceptable.

11.7 Nuclear Energy

11.7.1 History

Use of CANDU nuclear reactors in the oil sands was first discussed in the aftermath of the 1973 Arab oil embargo. Studies were carried out in the late seventies and early eighties but economic factors such as the availability of cheap natural gas and high interest rates led to natural gas-fired cogeneration being the technology of choice.

11.7.2 Recent Developments

While the last CANDU reactor in Canada was commissioned in 1993, international sales led to continual improvement in construction techniques and encouraged Atomic Energy Canada Limited (AECL) to proceed with the design of the new Advanced CANDU Reactor (ACR).

59 Sherritt International Corporation- Presentation to Canadian Heavy Oil Association, November 2003.

AECL has set targets for the ACR of US$1,000/MW for capital cost and four years for regulatory approval and construction. The capital cost target is significantly less than current CANDU reactors (US$1,500/MW). Cost savings are anticipated from the use of slightly enriched uranium instead of the natural uranium in the older CANDUs, and new construction techniques. Using slightly enriched uranium allows for a more efficient reactor design, which reduces the amount of heavy water required and the associated capital costs. The new construction techniques use a combination of pre-approved standardized designs and modular construction to reduce the time it takes to build a power plant, and have been successfully tested in the construction of CANDU reactors in Korea and China.

In light of these significant improvements, AECL and the Canadian Energy Research Institute (CERI) carried out a study of the economics of CANDU-based cogeneration for oil sands applications. Based on their assumptions, nuclear energy for oil sands use is cost competitive with a conventional cogeneration plant using natural gas with plantgate natural gas price of C$4.25/GJ (NYMEX US$3.50 per MMBtu)[60].

Some major issues raised were that the ACR would require a minimum SAGD project size of 25 400 m^3/d (160 mb/d) and the difficulty in transporting steam long distances would require the ACR to be built in close proximity to a bitumen deposit with sufficient reserves to support a project of that size. However, a portion of the ACR output could be dedicated to additional electricity generation to produce hydrogen for upgrading, reducing both dependence on natural gas and the size of the SAGD facility.

The following comparison highlights the opportunities and challenges facing the use of the ACR in oil sands development.

Opportunities

- Low operating costs make the ACR competitive with natural gas given current gas prices.
- Does not emit CO2 so the ACR is not affected by environmental initiatives designed to reduce greenhouse gas emissions (Kyoto).
- Provides protection against natural gas shortages and price spikes.
- 24/7 operation of oil sands facilities fits well with the base load characteristics of nuclear power.
- The ACR can also be used to produce hydrogen for use in upgraders.

Challenges

- Oil sands producers are unfamiliar with nuclear technology.
- ACR is still under development so it lacks a proven track record.
- Public concern about nuclear safety and terrorism.
- The price of steam from an ACR is very sensitive to construction costs.
- The ACR has two technical issues that need to be addressed:
    - an ACR facility is large compared to the typical SAGD project.
    - it is difficult to economically ship steam long distances.

In the short term the prospects for nuclear energy in the oil sands appear to be constrained by:

- the lack of a proven track record for the ACR;
- oil sands producers lack experience with the technology; and
- public concerns about safety and the disposal of nuclear waste.

60 *Comparative Economics of Nuclear and Gas-Fired Steam Generation for SAGD Applications* CERI (Canadian Energy Research Institute). May 2003. More information on this study can be found on the CERI website at: http://www.ceri.ca/

In the longer term, as the ACR technology matures and if oil sands producers are concerned about natural gas price volatility, nuclear energy could look increasingly attractive. Concerns about minimizing GHG and other harmful emissions would also favour the use of nuclear energy. If an entity with nuclear experience were willing to assume responsibility for the permitting, construction and operation of such a plant, selling steam to oil sands producers and electricity to the Alberta market, nuclear energy could prove to be a viable option in the oil sands.

11.8 Conclusion

The oil sands industry relies heavily on technological innovation to provide more efficient and economic operations. Modifications to SAGD to allow it to run at lower pressures and temperatures, and thus lower gas-to-oil ratios and demand for gas, has some potential in reservoirs suited to low pressure operations.

VAPEX™ is a promising recovery technology that involves the injection of solvents, instead of steam, into the reservoir to reduce the viscosity of the bitumen and allow it to flow to the well bore. The advantage of this process is that natural gas is not required to produce steam thus providing a savings on energy usage. A disadvantage is that the process has lower production rates. Several pilot projects are in operation, but no commercial project has yet been announced.

The proposed THAI process is designed with a vertical injection well and a horizontal producing well, with air injected into the reservoir to support combustion of the bitumen in situ. The heat generated reduces the viscosity of the bitumen allowing it to be produced. This concept needs to be proven in the field, and a pilot project is planned for fall 2004 by PetroBank at Whitesands.

The proposed Nexen/OPTI project at Long Lake is designed to produce a synthetic gas through a process that gasifies the heavy bottoms, or asphaltenes contained in the bitumen, thus eliminating the need for natural gas.

While coal has the potential to provide a long-term, stable source of fuel and hydrogen, the economics and acceptable environmental performance of its application in the oil sands remain to be demonstrated.

Although the economics of using the ACR to produce steam and electricity for oil sands operations appears to be economically viable, it faces resistance from the public because of safety concerns. It is highly unlikely that such a facility would be built before 2015.

These processes hold promise in reducing the oil industry's dependence on natural gas as the major energy source.

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Petroleum Technology Research Centre: http://www.ptrc.ca/

Nickle's New Technology Magazine: http://www.ntm.nickles.com/

Petroleum Alliance of Canada: http://www.PTAC.org

GLOSSARY

Advanced CANDU Reactor	The latest version of the CANDU reactor. The ACR uses slightly enriched uranium (instead of the natural uranium) to reduce the amount of heavy water required, and a combination of pre-approved standardized designs and new modular construction techniques, to reduce costs.
Apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
Aquifer	An underground geological formation, or group of formations, that contain water.
Aromatics	A term referring to compounds containing one or more six-carbon rings, with alternating (or resonating) carbon-hydrogen double bonds. Benzene, toluene and xylene are examples of common aromatic hydrocarbons.
Associated Gas	Natural gas that overlies and is in contact with crude oil in the reservoir.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 Imperial gallons.
Biodiversity	The variety of living components in an ecosystem.
Bitumen or Crude Bitumen	A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Blended Bitumen	Bitumen to which light oil fractions have been added in order to reduce its viscosity and density to meet pipeline specifications.
C_2	Ethane.
C_2=	Ethylene.
C_2/ C_2=	Ethane/Ethylene Stream.
C_2+	Ethane plus refers to a mixture of natural gas liquids consisting of ethane and heavier hydrocarbons.

C_3	Propane.
C_3+	Propane plus refers to a mixture of natural gas liquids consisting of propane and heavier hydrocarbons.
C_3/ C_3=	Propane/Propylene Stream.
Catalyst	A substance that increases the rate of chemical or biochemical reaction without undergoing any permanent chemical change to itself.
Catalytic-cracking	The process of breaking down larger, heavier more complex hydrocarbon molecules into smaller, lighter molecules through the use of heat in conjunction with a catalyst.
Cetane Number	A number for designating the percentage of pure cetane in a blend of cetane and alphamethylnapthalene that matches the ignition quality of a diesel fuel sample. This number, specified for middle distillate fuels, is synonymous with the octane number of gasolines.
Cogeneration	A facility that produces process heat and electricity. Also known as Combined Heat and Power (CHP) facility.
CH_4	Methane.
CO	Carbon monoxide.
CO_2	Carbon dioxide.
Coke	A solid black carbon residue remaining after valuable hydrocarbons are extracted from bitumen.
Coker	A vessel in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil. The lighter fractions, primarily naphtha and gas oils, become the main ingredients of the final blend.
Composite Tails (CT)	Also known as consolidated tails. This technology combines fine tailings with gypsum and sand as tailings are deposited. The mixture causes the tailings to settle faster, enabling final reclamation to occur sooner.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed.
Conventional Crude Oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.

Cracking	The process of breaking down larger, heavier more complex hydrocarbon molecules into smaller, lighter molecules.
Cyclic Steam Stimulation (CSS)	A method of recovering bitumen from a reservoir using steam injection to heat the reservoir to reduce the viscosity of the oil and provide pressure support for production. Oil production occurs in cycles, each of which begins with a period of steam injection followed by the same well being used as a producer.
Deep-Cut Plant	Refers to a plant that extracts ethane and heavier hydrocarbons from natural gas streams.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Distillate	Fraction of crude oil; a term generally used for naphthas, diesel, kerosene and fuel oils.
DilSynBit	A newly introduced blend of bitumen, condensate and synthetic crude oil that has similar properties to medium sour crude. It is currently offered in the Cold Lake system.
Ecosystem	A biological community of interacting organisms and their physical environment.
Enhanced Oil Recovery	Any method for enhancing oil recovery from a pool over what would be obtained through natural depletion.
Ethane	The simplest straight-chain hydrocarbon structure with two carbon atoms.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from the oil sands.
Fossil Fuels	Hydrocarbon-based fuel sources such as coal, natural gas, natural gas liquids and crude oil.
Greenhouse Effect	A naturally occurring phenomenon in the earth's atmosphere in which incoming solar short-wave radiation passes relatively unimpeded, but long-wave radiation emitted from the warm surface of the earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperature.
H_2S	Hydrogen Sulphide.
Heat Rate	The amount of input energy used to generate electricity, commonly expressed in gigajoules per gigawatt hour (GJ/GW.h).

Heavy Crude Oil	Generally, a crude oil having a density greater than 900 kg/m^3.
Horizontal Well	A well that deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.
Hydrocarbons	Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, gaseous or solid.
Hydrocracking	The breaking of hydrocarbon chains into smaller molecules in the presence of hydrogen and a catalyst such as platinum. The end result is a high quality gasoline and other light hydrocarbons.
Hydrotreating	A process used to saturate olefins and improve hydrocarbon stream quality by removing unwanted materials such as nitrogen, sulphur, and metals utilizing a selected catalyst in a hydrogen environment.
Integrated Mining Plant	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
In Situ Recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Light Crude Oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.
Mid-Columbia (Mid-C)	The trading hub for bulk (wholesale) power sales in east-central Washington State.
Muskeg	A water-soaked layer of decaying plant material, one to three metres thick, found on top of the overburden. Muskeg supports the growth of shallow root trees such as black spruce and tamarack.
Natural Gas Liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, and pentanes plus.
NO_X	Oxides of nitrogen.
O_3	Ozone.
Off-gas	A mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and olefins ethylene, propylene and butylenes) produced when bitumen is upgraded to produce synthetic crude oil.

Oil Sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Olefins	Refers to any open-chain hydrocarbon such as ethylene, propylene and butylenes, having the general formula CnH_2n with a carbon-to-carbon double bond.
Overburden	The layers of sand, gravel and shale that overlie the oil sand and must be removed before mining can begin. Overburden underlies the muskeg in many places.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Paraffin	A straight-chain hydrocarbon without double bonds; also called an alkane.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Real Price	The price of a commodity after adjusting for inflation. In this report most real energy prices are expressed in 2003 dollars.
Reclamation	Returning disturbed land to a stable, biologically-productive state.
Recovery - Improved	Improved or enhanced recovery is the extraction of additional crude oil from reservoirs through a production process other than primary recovery.
Recovery - Primary	The extraction of crude oil from reservoirs utilizing the natural energy available in the reservoirs and pumping techniques.
Remedial Action Scheme	A system to prevent a cascading blackout of a power system by taking generation out of service if part of the transmission system fails.
Reserves - Established	The sum of the proven reserves and half probable reserves.
Reserves - Initial Established	Established reserves prior to deduction of any production.
Reserves - Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves - Remaining	Initial reserves less cumulative production at a given time.
Reservoir	A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil that is confined by impermeable rock or water barriers.

Residual oils	Refers to asphalt, tar, coke and heavy fuel oils.
Resources - In Place	The gross volume of crude oil estimated to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.
Resources - Recoverable	That portion of the ultimate resources potential recoverable under expected economic and technical conditions.
Resources - Ultimate Potential	An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology.
SAGD	Steam-Assisted Gravity Drainage is a steam stimulation technique using horizontal wells in which the bitumen drains, by gravity, into the producing wellbore. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Smoke Point	A test measuring the burning quality of jet fuels, kerosene, and illuminating oils. It is defined as the height of the flame in millimeters beyond which smoking takes place.
Stand Alone Upgrader	An upgrading facility that is not associated with a mining plant or a refinery.
Straddle Plant	A reprocessing plant located on a gas pipeline. It extracts natural gas liquids from previously processed gas before the gas leaves or is consumed within the province.
SO_2	Sulphur dioxide.
Supply Cost	Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude.
Synthetic Gas Liquids	Refers to the liquids (ethane, ethylene and propylene in particular) produced from upgrading bitumen to synthetic crude oil.
Synthetic Crude Oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Unconventional Crude Oil	Crude oil that is not classified as conventional crude oil (e.g., bitumen).

Upgraded Crude Oil	Generally refers to crude bitumen and heavy crude oil that have undergone some degree of upgrading, but is commonly synonymous with synthetic crude oil.
Upgrading	The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
VAPEX™	Vaporized Extraction is a process similar to SAGD but using a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
Viscosity	The measure of the resistance of a fluid to flow. The lower the viscosity, the more easily a liquid will flow.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

Economic and Market Assumptions for Supply Cost Models

TABLE A1.1

Economic Assumptions

Rate of Return	10 percent real, 12 percent nominal
Royalty	Alberta Oil Sands regime
Federal Taxes	Current Oil Sands terms
Provincial Taxes	Current Alberta rates
Inflation - constant (percent)	2.00
Exchange Rate $US/$C	0.75

TABLE A1.2

Market Pricing Assumptions

Natural gas NYMEX (US$ per MMBtu)	4.00
Natural gas AECO (C$/GJ)	4.66
NYMEX – AECO Natural Gas (US$ per MMBtu)	0.50
WTI @ Cushing, Oklahoma (US$ per barrel)	24.00
Condensate premium over MSW @ Edmonton (percent)	5.00
WTI quality @ Edmonton - Syncrude @ Edmonton (US$ per barrel)	0.00
WTI quality @ Edmonton – Lloydminster Blend @ Hardisty (US$ per barrel)	7.00
Heavy crude transportation differential to Chicago: Hardisty vs. Cushing (US$ per barrel)	0.95
Light crude transportation differential to Chicago: Edmonton vs. Cushing (US$ per barrel)	0.80

ASSUMPTIONS FOR ATHABASCA SAGD MODELS

TABLE A2.1

Project Assumptions
(costs in per barrel of bitumen produced)

	Low-Quality	High-Quality
Steam Oil Ratio (dry)	3.50	2.50
Natural gas consumption (Mcf/b)	1.47	1.05
Non-gas cash operating costs[a] (C$ per barrel)	5.00	5.00
Reduction in operating costs (percent per year)	2.00	2.00
Required diluent – percent of blend volume	33.30	33.30
Project start date	2004	2004
Project end date	2036	2045
Kyoto compliance cost (C$ per barrel)	0.00	0.00
Capital expenditures to first oil (millions C$ 2004)	470.00	310.00
Capital expenditures over project life (millions C$ 2004)	1,600	1,900
Condensate transportation to Plant (C$ per barrel)	0.65	0.65
Bitumen blend transportation differential: Plant vs. Hardisty (C$ per barrel)	1.15	1.15

a Other non gas cash operating costs include pruchased power, administration, environmental and other direct costs associated with the operation.

TABLE A2.2

Development Schedule: SAGD Low-Quality Reservoir

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2007	4 800	30,000

TABLE A2.3

Development Schedule: SAGD High-Quality Reservoir

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2007	4 800	30,000
Phase 2	2010	9 600	60,000
Phase 3	2013	14 400	90,000
Phase 4	2016	19 200	120,000

TABLE A2.4

Reservoir Assumptions - SAGD

	Low-Quality	High-Quality
Oil Sands Area	Athabasca	Athabasca
Oil Sands Deposit	McMurray	McMurray
API°	8.0	8.0
Continuous Pay Thickness (m)	15.0	35.0
Porosity (percent)	31.0	35.0
Effective Vertical Permeability (Darcies)	2.5	5.0

ASSUMPTIONS FOR ATHABASCA MINING/EXTRACTION AND UPGRADING MODEL

TABLE A3.1

Project Assumptions

	Mining/ Extraction	Mining/Extraction & Upgrading
External natural gas consumption (Mcf/b)	0.27	0.75
Non-gas cash operating costs[a] (C$ per barrel)	6.00	10.00
Reduction in operating costs (percent per year)	2.00	2.00
Kyoto compliance cost (C$ per barrel)	0.00	0.00
Capital maintenance cost (C$ per barrel)	0.50	1.00
Capital expenditure excluding maintenance capital (billions C$)	1.80	7.30
Project start date	2004	2004
Project end date	2046	2048
Transportation differential: Plant versus Edmonton (C$ per barrel)	1.15	0.70

a Other non gas cash operating costs include pruchased power, administration, environmental and other direct costs associated with the operation.

TABLE A3.2

Development Schedule Mining/Extraction

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2008	15 873	100,000

TABLE A3.3

Development Schedule Mining/Extraction and Upgrading

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2008	15 873	100,000
Phase 2	2010	31 746	200,000

TABLE A3.4

Reservoir Assumptions - Mining

Oil Sands Area	Athabasca
Oil Sands Deposit	McMurray
API°	8
Bitumen grade – weight percent	11

Oil Sands Projects

The following presents a brief discussion of the major operating and planned projects in the Athabasca, Cold Lake and Peace River oil sands areas. The information is a summary of publicly available information, up to the end of the first quarter 2004.

Athabasca Oil Sands Area Mining Projects

Suncor - Millennium and Voyageur

Suncor has operated a surface mining, extraction and upgrading project at Ruth Lake since 1967. The Millennium expansion project was completed between 1999 and 2002 at a cost of $3.4 billion, and increased capacity to 35 800 m^3/d (225 mb/d). This expansion included a second processing plant, a second upgrader train, and expansion of the mining area. The operation has the ability to "tailor" its products to meet consumer needs, and thus produces a variety of refinery feedstocks, diesel fuel and by-products.

In 2001, Suncor outlined a growth strategy, dubbed "Voyageur", that set out a multi-phased plan to increase its oil sands production capacity to the 79 400 m^3/d to 87 300 m^3/d (500 to 550 mb/d) range by 2010 to 2012. In early 2003, Suncor announced plans for the first phase of Voyageur, designed to increase upgrader capacity to 52 400 m^3/d (330 mb/d) by 2007. This includes the installation of an additional vacuum unit to increase capacity to 41 300 m^3/d (260 mb/d) by 2005, and then to 52 400 m^3/d (330 mb/d) by 2007. This upgrader expansion is estimated to cost $1.5 billion, and is designed to accommodate bitumen delivered from Suncor's Firebag SAGD operations. Suncor plans to spend an additional $1.5 billion to expand the Firebag project in four phases, each producing about 5 560 m^3/d (35 mb/d) of bitumen. The first phase of Firebag is expected to be fully operational in 2005.

The third segment of the Voyageur plan is to build a third upgrader in the 2010 to 2012 timeframe, bringing overall production capacity to 79 400 m^3/d to 87 300 m^3/d (500 to 550 mb/d). Suncor is considering further expansion of Firebag and/or mining facilities to supply the third upgrader.

Syncrude - Syncrude 21

The Syncrude Project is a joint venture operated by Syncrude Canada Ltd. and owned by Canadian Oil Sands Limited Partnership, Canadian Oil Sands Limited, ConocoPhillips Oil Sands Partnership II, Imperial Oil Resources, Mocal Energy Limited, Murphy Oil Company Ltd., Nexen Inc., and Petro-Canada Oil and Gas.

In its "Syncrude 21" strategy, Syncrude plans to increase capacity through the completion of five stages of expansion between 1996 and 2015. Stages 1 and 2 were completed in 2001, at a cost of $1 billon, and increased Syncrude's production capacity to 39 100 m^3/d (246 mb/d) of high quality

SCO, Syncrude Sweet Blend (SSB). These first two stages featured the development of two new mining areas, the North Mine and Aurora. Large-scale truck and shovel mining, and new technologies, such as hydro-transport and low-temperature extraction, were also introduced. Two processing trains were introduced at North Mine. The Aurora expansion included a processing train and further de-bottlenecking of the Mildred Lake upgrader. The Aurora Mine is located 35 km northeast of the main Syncrude plant, and extraction takes place at the mine site with bitumen froth moved via hydrotransport to the base plant for upgrading.

Stage three is scheduled for completion by 2006, and calls for a 15 900 m^3/d (100 mb/d) expansion at a cost of $7.8 billion. A second mining and extraction train will be added at Aurora, and an expansion of the Mildred Lake upgrader will be implemented, featuring an additional upgrading train. The mining train was commissioned in late 2003, while the upgrader expansion (UE-1) is expected to be completed in 2006, allowing Syncrude to further improve the quality of its SCO.

Stage four includes the startup of a third mining train at Aurora as well as another stage of expansion of the Mildred Lake upgrader (UE-2). This expansion will increase total production to about 64 100 m^3/d (400 mb/d) by 2011. This stage will add further improvements to crude oil quality, and also features full implementation of energy efficiency and environmental mitigation technologies.

Stage five calls for the installation of a fourth mining train at Aurora and further expansion of the Mildred Lake Upgrader (UE-3). This expansion phase is scheduled to take place between 2010 and 2015, and will increase total production to about 84 000 m^3/d (530 mb/d).

Athabasca Oil Sands Project

This project is a joint venture, with Shell retaining a 60 percent interest and Chevron Canada Resources Limited and Western Oil Sands Inc. each holding a 20 percent interest. The project consists of two components, the Muskeg River Mine, located 70 km north of Fort McMurray, and the Scotford upgrader, situated adjacent to Shell's existing Scotford refinery near Edmonton. Albian Sands Energy Inc., a company created to operate the Muskeg River Mine on behalf of its joint venture owners, began mining and extractions operations in late 2002. After extraction at the mine site, diluted bitumen is shipped to Scotford via the Corridor Pipeline. At Scotford, the upgrader uses hydrogen addition technology to process the bitumen into high quality SCO. Capital costs for the mine and upgrader were $5.7 billion. Shell also invested approximately $400 million to modify its existing Scotford refinery to utilize the new SCO produced by the Scotford upgrader.

As well, other companies constructed new facilities to serve the needs of the Athabasca Oil Sands Project under long-term agreements. The Corridor Pipeline transports the diluted bitumen from the mine to the upgrader. ATCO Power built a 170 megawatt cogeneration facility to provide steam and electricity to meet the requirements of the mine, as well as additional electricity to the Alberta grid. ATCO Pipelines constructed a pipeline to transport natural gas to the cogeneration facility.

The project owners have proposed a debottlenecking and expansion project that would increase capacity by 11 100 m^3/d (70 mb/d) by 2008, at a capital cost of $750 million.

Further expansion is planned through the development of the Jackpine mine, with Phase 1 calling for a new stand-alone mining and extraction facility with a capacity of approximately 31 800 m^3/d (200 mb/d) of bitumen production. Jackpine Phase 2 could be mined to extend the life of the overall development and allow for future production growth of approximately 15 900 m^3/d (100 mb/d). If all these projects are built, it would result in combined production from Muskeg River and Jackpine of 84 000 m^3/d (525 mb/d).

Fort Hills

The Fort Hills project is owned by TrueNorth Energy L.P. with a 78 percent share and UTS Energy holding the remaining 22 percent. The project design calls for truck and shovel mining with hot water extraction techniques to produce 15 100 m^3/d (95 mb/d) of bitumen for each of two phases. The bitumen would be shipped as a blended bitumen to markets in Canada or the U.S. Project plans included an 80 MW cogeneration unit. Total estimated costs are $3.5 billion for the first phase.

Although the project received approval from the Alberta Government, TrueNorth, in early 2003, decided to indefinitely defer development of the project, citing escalating capital costs, lack of additional partners and the uncertainty about the economic impact of the Kyoto Accord. The project remains on hold while the project sponsors consider their options, including evaluating a range of potential development scenarios.

Imperial Oil/ExxonMobil - Kearl Oil Sands

In 2002, Imperial consolidated its Kearl holdings by swapping leases with Husky Energy Inc. Imperial became the sole owner of surface-mineable portions of leases 87 and 6, while Husky gained a 100 percent stake in Kearl leases where it is now considering its own in situ oil sands project.

Kearl Oil Sands, a potential joint oil sands mining project proposed by ExxonMobil Canada and Imperial Oil on their Athabasca oil sands leases, is located about 70 km north of Fort McMurray. A resource delineation drilling program, currently underway, will help determine project design. The company has started a public consultation process with stakeholders in the region and held two open houses in Fort McMurray. Filing an application for regulatory approval is scheduled for 2005, while regulatory review and approval are expected in 2005-06.

The Kearl project is slated to consist of oil sands mining and possibly on-site bitumen upgrading, with integration with Imperial's Edmonton refinery or upgrading at the ExxonMobil refinery at Joliet, Illinois. The company indicates a phased approach as the most likely scenario, with an initial phase of 15 900 m^3/d (100 mb/d), potentially growing to 31 800 m^3/d (200 mb/d) by 2012, with an estimated cost of $5 to $8 billion.

CNRL - Horizon

Canadian Natural Resources Limited (CNRL) received government approval for its Horizon oil sands project in late 2003, and has delayed making the final go-ahead decision till the fall of 2004 to allow additional time to do detailed engineering work. Horizon is slated to feature surface mining and bitumen processing, in situ operations, an upgrader and associated infrastructure. The proposed project includes an open pit, truck and shovel mine, four bitumen processing trains, three upgrading trains, associated utilities and infrastructure, water and tailing management plans, and an integrated development and reclamation plan.

The execution strategy phases in production from the project over a five-year period. First oil is expected in the first half of 2008 at a production rate of 17 500 m^3/d (110 mb/d) of light SCO. The second phase of production is expected in 2010, with an incremental 7 100 m^3/d (45 mb/d) of SCO. The third and final phase of development is expected in 2012 bringing total production to 37 000 m^3/d (233 mb/d) of SCO. Total project cost is estimated to be $8.4 billion.

Other Mining Projects

The Joslyn Creek Mining project is being proposed by Deer Creek Energy Inc. This project was announced along with the announcement of the Joslyn Creek in situ project. Potential production capacity of the Joslyn Mine is 15 900 m^3/d (100 mb/d). The project would use truck and shovel mining and hot water extraction technologies, with no on-site upgrading. The decision on whether to proceed with the project will likely depend on the success of the Joslyn Creek in situ project.

Synenco Energy Inc. is proposing to build its Northern Lights project, an integrated oil sands mining, bitumen extraction and upgrading facility with a capacity of 7 900 m^3/d (50 mb/d) of 40 °API SCO. The company plans to use bitumen gasification technology to provide heat and hydrogen for processing and upgrading, thus reducing the need for natural gas. According to a company announcement, the project is scheduled to come on stream in 2008. Later stages of development in 2009 and 2010 would increase production by 27 800 m^3/d (175 mb/d), with a total project cost of $4 billion.

Synenco is seeking joint venture partners, and if successful expects to file in 2005 for AEUB approval.

Athabasca In Situ Projects

Surmont

The Surmont SAGD project, located about 60 km southeast of Fort McMurray, is a joint venture between ConocoPhillips Canada (43.5%), TotalFinaElf (43.5%) and Devon Energy (13%), and will be operated by ConocoPhillips. The project received AEUB approval in May 2003 and company board approvals in November 2003.

The $1.1 billion project calls for four phases, with initial production to begin in 2006 and to increase to 15 900 m^3/d (100 mb/d) by 2012.

The oil sands formation is between 300 and 400 metres below the surface, with thickness varying from zero to 60 metres. In-place bitumen is estimated at 3.2 billion cubic metres (20 billion barrels), with potential recovery of 25 to 50 percent. Each phase will have its own central facility consisting of steam generators, water recycling facilities, emulsion treating and storage tanks for diluent and blended bitumen. Each phase of the development will be connected by pipeline to allow water, diluent and bitumen to be shipped between any of the locations.

EnCana - Christina Lake

EnCana is using the SAGD method at the Christina Lake project located approximately 170 km south of Fort McMurray. This lease covers 35 sections that contain an estimated 475 million cubic metres (3 billion barrels) of bitumen. Three phases are planned, with total production scheduled to reach 11 000 m^3/d (69 mb/d). Each of the three phases will have its own plant facility consisting of water treatment, steam generation, production separation, heat recovery, water de-oiling, water disposal and oil handling facilities. The project began production in the second quarter of 2002, and in 2003 the project produced 840 m^3/d (5 mb/d) from three SAGD well pairs.

At the Christina Lake project, there are gas-over-bitumen issues, but EnCana and Devon Canada Corporation have agreed to cooperatively develop their respective bitumen and natural gas assets.

Petro-Canada - MacKay River

This 100 percent Petro-Canada owned project is located about 60 km northwest of Fort McMurray, two km east of the Underground Test Facility that is now known as the Dover project. This is Petro-Canada's lead SAGD project in its plans to develop its substantial lease holdings in the area. Due to the success of the Dover project, Petro-Canada took the project directly to commercial development without having a pilot project. Production began in 2002, and in 2003 reached close to its target capacity of 4 770 m^3/d (30 mb/d). MacKay River has a projected recovery of an estimated 37 to 48 million cubic metres (233 to 302 million barrels) of bitumen over a 25-year project life span.

There is a 165 MW cogeneration plant on-site, built and operated by TransCanada Pipelines.

Suncor - Firebag

Suncor will use the SAGD technique at its in situ oil sands leases located approximately 40 km northeast of the company's oil sands plant. Suncor's combined oil sands leases have an in situ recovery potential of 800 million cubic metres (5 billion barrels) of bitumen. The oil sands deposits in this area lie about 250 metres beneath the surface in the McMurray Formation. Raw production from Suncor's open-pit mine and from the proposed in situ project can be combined and sold directly to market or used as a feedstock in the oil sands upgrading facility. To give Suncor the capability to process the additional bitumen, the company plans to expand its upgrading facility by adding a vacuum tower complex by 2004 to coincide with production from the in situ facility.

Firebag development plans call for four phases of 5 560 m^3/d (35 mb/d), with the first phase to be operational in 2004, and all four phases by 2010. The Firebag facilities are connected to Suncor's Tar Island upgrader via a utility corridor that contains four buried pipelines, a power line and a fibre-optic cable. The pipelines will carry fuel-gas, diluent, and water to Firebag, while diluted bitumen will be delivered to the Tar Island upgrader.

Suncor has added the capability to burn diesel fuel instead of natural gas to produce steam, and is considering a cogeneration plant for stages 2 to 4 of the project.

Petro-Canada - Meadow Creek

The Meadow Creek project, located 45 km southwest of Anzac, Alberta would be operated by Petro-Canada. An application was made to the AEUB in November 2001, with production slated to begin in 2006. The capacity of the project would be 12 700 m^3/d (80 mb/d) of bitumen, with the product shipped to Petro-Canada's Strathcona refinery. A cogeneration facility is proposed. The capital cost for this project is estimated to be $800 million. Petro-Canada recently announced it is retrenching its oil sands production plans, resurrecting its upgrader in a slimmed-down form and delaying its plans at Meadow Creek, until at least the end of the decade. It is possible that Petro-Canada will proceed with the Meadow Creek project sooner, but at a reduced scale.

Petro-Canada - Lewis

Petro-Canada's proposed Lewis project is located 40 km northeast of Fort McMurray. SAGD would be used to produce the bitumen at a rate of 12 700 m^3/d (80 mb/d). A preliminary disclosure for the Lewis project has been released. The capital cost for the project is estimated to be $800 million. There would be no on-site upgrading and the production startup date has yet to be determined. In view of Petro-Canada's announcement that it was delaying its plans to proceed with the Meadow Creek project; the Lewis project is not likely to proceed before the end of this decade.

Devon - Jackfish

The proposed Jackfish project would be operated by Devon Canada Corporation. The project would be located 15 km south of Fort McMurray. It would produce bitumen using SAGD technology at a rate of 5 600 m^3/d (35 mb/d), starting in 2007. The estimated capital cost for this project is $400 to $450 million. A preliminary disclosure was issued in 2002; in November 2003, Devon filed its application with the AEUB.

CNRL - Kirby

The Kirby project was originally operated by Rio Alto Exploration., which was acquired by CNRL in July 2002. The project will use SAGD to produce bitumen and is located 85 km northeast of Lac La Biche. The application, filed with the AEUB in April 2002, is still under review. Each phase of the project (two phases applied for) would produce 2 400 m^3/d (15 mb/d) of bitumen, with Phase 1 production starting in 2006 and Phase 2 in 2010. Four phases are ultimately planned, with the goal of maintaining production at 4 800 m^3/d (30 mb/d). The project does not include a dedicated upgrader. The capital cost is estimated to be $500 million for the two phases. CNRL is currently soliciting proposals for purchase of the Kirby project.

Deer Creek - Joslyn Creek

Deer Creek Energy Ltd. is the operator of the Joslyn Creek in situ project. This is a multi-phased project, the first commercial phase of which was approved in January 2003. It is located 65 km north of Fort McMurray and will use dual well-pair SAGD technology. The first two phases were built on a previous test pilot. The intent is to expand the test project to maintain production at 1 590 m^3/d (10 mb/d). Interestingly, the planned facilities include a small steam generator to test the feasibility of using bitumen instead of natural gas as a fuel source.

The application for Phase 2 was filed with the AEUB in July 2003 and is currently under regulatory review. Phase 2 of the project has an estimated capital cost of $170 million.

Phases 3 and 4 of the Joslyn Creek project were announced along with Phases 1 and 2, each producing 4 800 m^3/d (30 mb/d) with startup around 2010.

JACOS - Hangingstone

The Hangingstone project is 75 percent owned by Japan Canada Oil Sands (JACOS) and 25 percent by Nexen Inc., and is located 50 km south of Fort McMurray. A three-stage demonstration project was designed to evaluate the viability of a commercial SAGD project. It began operations in 1999 and achieved production of 1 110 m^3/d (7 mb/d) in 2003.

Commercial development plans have been released in a public disclosure. Plans call for construction of facilities to begin in 2005, with first production in 2007. Each of the two phases of the commercial project is designed to produce 3 975 m^3/d (25 mb/d), with the second phase scheduled for start-up in 2010, bringing the total expected production for the Hangingstone project to 9 540 m^3/d (60 mb/d).

Nexen/OPTI Long Lake

The Long Lake project is a 50/50 joint venture between Nexen and OPTI Canada, and is located 40 km southeast of Fort McMurray. The commercial portion of the Long Lake project was approved in August 2003. Construction is expected to commence in 2004, with production slated for 2006, and an upgrader expected in 2007. The first phase of the project is expected to produce 11 100 m^3/d (70 mb/d) of bitumen using SAGD. The bitumen would be upgraded using a dedicated on-site upgrader and a patented ORcrudeTM process to produce a premium quality SCO. The process uses gasification of bitumen to provide fuel gas and hydrogen for the upgrader. The capital cost for the commercial project is estimated at $3 billion.

OPTI plans to add an additional 11 100 m^3/d (70 mb/d) of bitumen upgrading capacity to process third party bitumen on a fee-for-service basis.

Orion Oil - Whitesands

Orion Oil Canada Ltd. (a 100 percent owned subsidiary of Petrobank Energy and Resources Ltd.) is the operator of the proposed Whitesands pilot project. The project is located 120 km south of Fort McMurray. The pilot project will test Orion's proprietary Toe-to-Heel Air Injection (THAI) technology. The application for this project was filed in October 2003 and, if approved, will begin production in late 2004. The production rate would be 300 m^3/d (2 mb/d) for the five-year life of the project. THAI employs in situ combustion and is expected to use much less water and natural gas than the SAGD process.

Dover VAPEX Project (DOVAP)

Devon Canada Corporation is leading a consortium, with participation of the provincial and federal governments, which is conducting field trials to develop and test vapour extraction (VAPEX™) recovery technology. The pilot is located at the Dover Underground Test Facility site in the Athabasca oil sands area near Fort McMurray. This research project will consist of two horizontal well pairs and some associated monitoring wells. One well pair will test a cold start-up process and the other well pair will potentially test a hot start-up steam stimulation of the VAPEX™ process. The facilities and operations are integrated with the existing Dover infrastructure to reduce costs.

Operations began in 2003 and are expected to continue to 2008.

Cold Lake In Situ Projects

Imperial - Cold Lake

Cold Lake is owned and operated by Imperial Oil Limited. Laboratory and field research projects over the past 30 years led to this phased commercial production project. Since the oil sands at Cold Lake are buried too deeply within the Clearwater Formation for surface mining, Imperial applies Cyclic Steam Stimulation (CSS). Imperial currently operates Phases 1 through 13 of the facility. In 2003, Imperial's Cold Lake production averaged 20 700 m^3/d (130 mb/d) accounting for almost half of the bitumen produced in Alberta. Production from the Makheses project (Phases 11 to 13) started in June 2003 and is expected to reach 22 200 m^3/d (140 mb/d). Imperial has also installed a 170 MW steam cogeneration and electrical power facility at Cold Lake. Imperial expects to use about 60 percent of the power, and will make the surplus power available to the Alberta Power Pool.

The Nabiye project (Phases 14 to 16) will be an extension of the Cold Lake project, and is designed to increase capacity by 4 770 m^3/d (30 mb/d). Pending approvals, production is scheduled for 2006.

EnCana - Foster Creek

EnCana's Foster Creek project is located north of Wolf Lake in the middle of the Primrose Military Range. After testing its SAGD extraction method for four years at its 300 m^3/d (2 mb/d) pilot project, EnCana proceeded to build Foster Creek Phase 1, with 24 well pairs, a water treatment plant, an oil treatment unit, a testing centre and steam generators. Production began in 2002 and averaged 2 900 m^3/d (18 mb/d) in 2003. Production is to be expanded to 4 770 m^3/d (30 mb/d) by 2004. EnCana has long-range plans for Foster Creek to be producing 15 900 m^3/d (100 mb/d) by 2007.

An experimental VAPEX™ scheme is also being tested at the Foster Creek site.

CNRL - Primrose and Wolf Lake

CNRL's Primrose and Wolf Lake thermal heavy oil projects are located approximately 55 km north of Bonnyville in northeastern Alberta. These properties, which CNRL purchased from BP Canada Energy Company (BP) in 1999, have been operating commercially since the 1980s. Production in 2003 was about 6 400 m^3/d (40 mb/d).

CNRL uses both CSS and SAGD recovery techniques. CSS is used to target the Clearwater Formation's higher-clay content sands, while SAGD is used in the Grand Rapids zone, which has fewer clay impurities. The CSS process involves drilling horizontal wells rather than vertical or slant wells and injecting steam at a rate above the required reservoir parting pressure. The higher pressure will allow steam to penetrate farther into the oil sands allowing for fewer wells, reduced number of cycles and increased production. By drilling horizontally through the deposit, CNRL will be able to minimize both cost and surface disturbance by substituting a single well for between five and ten conventional wells.

Expansion plans were approved by the AEUB in 2002 and call for facility optimization and construction that will increase production in two phases to 9 500 m^3/d (60 mb/d) by 2006.

Husky - Tucker Lake

Husky Energy Inc. is the operator of the proposed Tucker project in Cold Lake. It is located 30 km west of Cold Lake, and would use SAGD to extract the bitumen. The application for the project was filed in February 2003 and pending approval, production would begin in 2006. The design capacity of the project is 4 800 m^3/d (30 mb/d). The estimated capital cost for the project is $400 million.

Black Rock Orion

The Orion project, operated by BlackRock Ventures Inc., is located 30 km northwest of Cold Lake. The application for this project was filed in July 2001. The Hilda Lake experimental project (precursor to the Orion project) has been in operation since 1997. The Orion project will use SAGD technology to produce bitumen at a rate of 1 600 m^3/d (10 mb/d) for each of the two phases. The estimated capital cost for both phases is $270 million ($150 million for Phase 1 and $120 million for Phase 2).

Peace River In Situ Projects

Shell - Peace River

The Peace River project is owned by Shell Canada Limited. This site has an estimated 1.6 billion cubic metres (10 billion barrels) of bitumen in place. Shell operated a pilot project at this site from 1979 to 1992, which was considered a technical success. More recently, Shell has used both CSS with multi-lateral wells and SAGD. Shell plans to expand this "radial-soak" technique. In 2002, the project achieved its design capacity of 2 000 m^3/d (13 mb/d). The technology that is driving the efficient recovery of bitumen will create the opportunity for future expansions at this large resource base.

The company has approved a plan to increase production to 2 540 m^3/d (16 mb/d) by debottlcnecking the plant and drilling additional wells. This expansion and subsequent growth are contingent upon regulatory approvals and ongoing satisfactory operating performance.

Cogeneration Facilities

Project Owner	Cogen Facility Owner	Project Name	Capacity (MW)	Description
Cold Lake and Area				
Canadian Natural Resources Limited	Canadian Natural Resources Limited/ATCO Power	Primrose	85	Project commissioned 1998. In situ CSS technology.
EnCana	EnCana	Foster Creek	80	Cogen commissioned 2003. SAGD technology.
Imperial Oil Ltd.	Imperial Oil Ltd.	Mahkeses	170	Cogen commissioned 2003. In situ CSS technology.
Fort McMurray and Area				
Athabasca Oil Sands Project	ATCO Power	Muskeg River Mine	170	Oil sands project commissioned 2003. Mine technology.
Petro-Canada	TransCanada Pipelines Limited.	MacKay River	165	Cogen commissioned 2004. SAGD technology.
Suncor Energy	TransAlta Energy Corporation	Suncor Plant	420	Cogen commissioned 2001. Mine technology.
Syncrude Canada Ltd.	Syncrude Canada Ltd.	Mildred Lake	280	Oil sands project operating since 1978. Mine technology.
Syncrude Canada Ltd.	Syncrude Canada Ltd.	Aurora	80	Oil sands project operating since 1999. Mine technology.

Conversion Factors and Greenhouse Gas Emissions Intensities

Abbreviation Table

Prefixes		Equivalent
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Imperial/Metric Conversion Table

Physical Units		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil, LPG)
		35.3 cubic feet (gas)
L	litre	0.22 imperial gallon
b	barrel (oil, LPG)	0.159 m^3

Energy Content Table

Energy Measures		Energy content
GJ	gigajoule	0.95 million BTU
Electricity		**Energy content**
MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ
Natural Gas		**Energy content**
Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ

Energy Content Table

Natural Gas Liquids		Energy content
m^3	Ethane	18.36 GJ
m^3	Propane	25.53 GJ
m^3	Butanes	28.62 GJ
Crude Oil		**Energy content**
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ

Greenhouse Gas Emissions Intensities

	Oil Sands Production (kg/m^3)	
Emission Type	In Situ	Mining/Extraction/Upgrading
CO_2	439.2	741.2
CH_4	25.04	42.47
N_2O	2.45	8.56

Source: Natural Resources Canada - Canada's Emissions Outlook: An Update, 1999.

ORGANIZATIONS CONSULTED

Alberta Economic Development
Alberta Electric System Operator (AESO)
Alberta Department of Energy
Alberta Energy and Utilities Board (AEUB)
Alberta Energy Research Institute (AERI)
Alberta Environment (AENV)
Alberta Innovation and Science
ATCO Electric
ATCO Power
BP Products North America Group
BP Canada Energy Trading Company
Canadian Association of Petroleum Producers (CAPP)
Canadian Energy Research Institute (CERI)
Canadian Natural Resources Limited (CNRL)
Chesterman Consulting Inc.
CHS Inc.
Climate Change Central
ConocoPhillips Canada
Cumulative Environmental Management Association (CEMA)
Dow Chemical Canada Inc.
Enbridge Pipelines Inc.
EnCana
Flint Hills Resources Ltd.
Big West Oil LLC
Frontier Refining Inc.
Gibson Petroleum Company Ltd.
Golder Associates Ltd.
Husky Energy Inc.
Imperial Oil Ltd.

Imperial Oil Resources

Inter Pipeline Fund

IPPSA/Mercury Energy Corporation

Marathon Ashland Petroleum Canada, Ltd.

Natural Resources Canada (NRCan)

Nexen Canada Ltd.

Nova Chemicals Corporation

Pembina Pipeline Income Fund

Petro-Canada

Plains Marketing Canada, L.P.

Purvin & Gertz Inc.

Rainbow Pipe Line Company, Ltd.

Regional Issues Working Group (RIWG)

Shell Canada Limited

Shell Chemicals Canada Ltd.

Sherritt International Ltd.

Suncor Energy

Syncrude Canada Ltd.

Terasen Pipelines

Tidal Energy Marketing Inc.

TransCanada PipeLines Ltd. & NorthernLights Transmission

United Refining Company

Western Oil Sands Inc.

Williams Energy (Canada), Inc.

Wood Buffalo Environmental Association (WBEA)