National Energy Board

Office national de l'énergie

Short-term Outlook for Canadian **Crude Oil** *to 2006*

oil oil oil oil

An **ENERGY MARKET ASSESSMENT** • September 2005

Canada

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ANS	Alaskan North Slope
AOSP	Athabasca Oil Sands Project
API	American Petroleum Institute
CHOPS	Cold Heavy Oil Production with Sand
CNRL	Canadian Natural Resources Limited
CSS	Cyclic Steam Stimulation
EEP	Ethanol Expansion Program
EIA	Energy Information Agency
EOR	Enhanced Oil Recovery
EMA	Energy Market Assessment
EUB	Alberta Energy and Utilities Board
F&D	Finding and Development
FSU	Former Soviet Union
GDP	Gross Domestic Product
GHG	Greenhouse Gases
IEA	International Energy Agency
LLB	Lloydminster Blend
LPG	Liquefied Petroleum Gas
MMcf/d	Million Cubic Feet per Day
MOU	Memorandum of Understanding
MSW	Mixed Sweet Blend
NEB	National Energy Board
NGL	Natural Gas Liquids
NRCan	Natural Resources Canada
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
RPP	Refined Petroleum Products
SAGD	Steam Assisted Gravity Drainage
SARS	Severe Acute Respiratory Syndrome
SCO	Synthetic Crude Oil
SEC	U.S. Securities and Exchange Commission
SSP	Syncrude Sweet Premium crude oil
TAN	Total Acid Number
TPTM	Terasen Pipelines (Trans Mountain) Inc.
USGC	U.S. Gulf Coast
VAPEX™	Vapour Extraction Process
WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

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's 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 addition, the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA, entitled *Short-term Outlook for Canadian Crude Oil to 2006*, was undertaken to expand the effectiveness of the Board's monitoring activities by providing short-term analysis on recent developments and emerging issues in the Canadian oil industry. The EMA presents the NEB's 18-month outlook on prices, supply and markets for Canadian crude oil and petroleum products. Where foreseen opportunities and challenges exist, these are identified.

During the preparation of the report, the Board conducted a series of informal meetings with a cross-section of stakeholders, including producers, refiners, marketers, pipeline companies, industry associations, government departments and agencies. 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

This EMA, entitled *Short-term Outlook for Canadian Crude Oil to 2006*, was undertaken to expand the effectiveness of the Board's monitoring activities by providing short-term analysis on recent developments and emerging issues in the Canadian oil industry. The EMA provides the NEB's 18-month outlook on prices, supply and markets for Canadian crude oil and petroleum products. Where foreseen opportunities and challenges exist, these are identified.

Since late 2002, the world has experienced very strong oil markets. As benchmark crudes around the world flirt with record high prices, global oil demand is surging and demonstrating remarkable resilience. In this environment, Canada is in an enviable position as the holder of the world's second largest reserves and as one of few countries outside of the Organization of Petroleum Exporting Countries (OPEC) with significant prospects for production growth.

The high price environment has translated into record profits for the Canadian oil and gas industry and has spurred billions of dollars in investment, with Alberta's oil sands being a primary beneficiary. At the same time, consumers and industries have faced sharply higher prices for energy and petroleum products.

International and Domestic Oil Prices

The following are some key drivers that are likely to underpin the global oil market through 2006:

- Crude demand growth will continue to be strong, led by China. Most of this growth will be in transportation fuels.
- Non-OPEC supply growth is expected to be almost 1.0 MMb/d in 2005 and 1.3 MMb/d in 2006.
- The resulting call on OPEC is expected to be 29.5 MMb/d in 2005 and 30.0 MMb/d in 2006.
- OPEC's spare capacity is expected to be limited to only about 1.0 MMb/d over the next two years.
- Transportation bottlenecks and the lack of spare refining capacity worldwide were issues in 2004 and are expected to be problematic in 2005 and 2006.
- Geopolitical risks will continue to be a concern.

Against this background, most industry experts believe that West Texas Intermediate (WTI) prices are likely to trade in the area of US$50 per barrel. The oil market seems to perceive the downside to be limited to about US$40 to $45 per barrel while the upside is not limited.

Overall, it is expected that higher international oil prices will continue to drive attractive returns for Canadian producers of light crude oil through 2006. Wider-than-average light/heavy oil differentials are expected to endure but narrow somewhat from those experienced since late 2004. Bitumen and extra heavy oil producers requiring substantial quantities of light hydrocarbons for blending will likely face a significant challenge in maintaining profitable operations, particularly in winter months.

Drilling, Exploration and Production

Although overshadowed to some extent by the record breaking number of gas wells being drilled in western Canada, oil-directed activity is responding to higher oil prices. This response is most evident in the oil sands, in the Newfoundland and Labrador offshore, and in Saskatchewan and Manitoba. The conventional oil areas of the Western Canada Sedimentary Basin (WCSB) are relatively mature from an oil exploration and development standpoint. However, with only 22 percent of the oil-in-place projected to be recovered overall, the remaining oil represents a large target for exploitation. In order to further encourage enhanced oil recovery (EOR), governments have recently introduced several measures, including modifying fiscal terms and increasing support for EOR research.

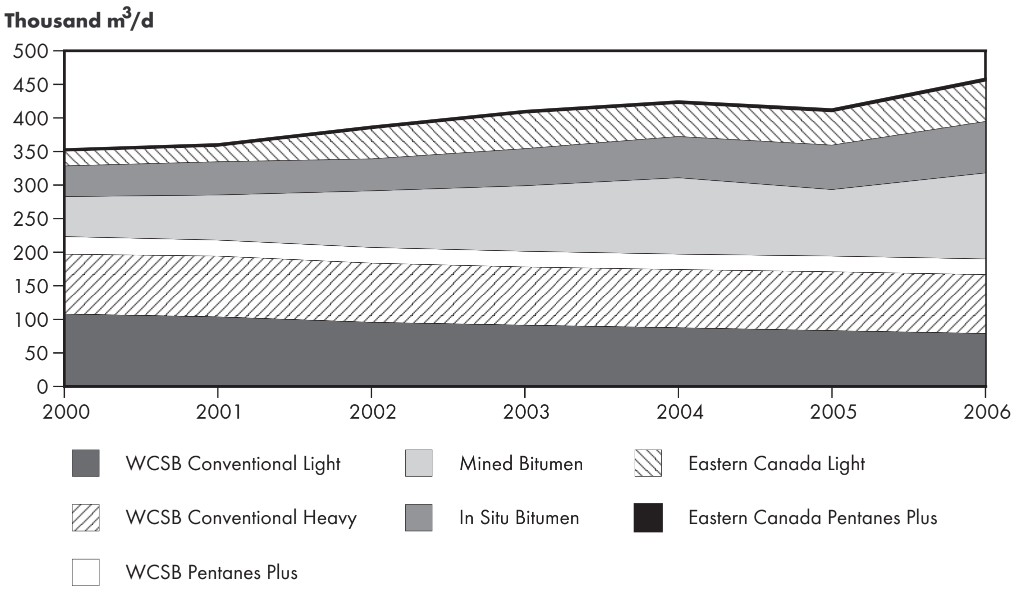
On the east coast offshore, activity continues at a modest pace. Activity is concentrated on the Newfoundland offshore, but there is also some activity on the island of Newfoundland and on the Nova Scotia deepwater shelf. In Canada's north, recent oil exploration activity has taken place in four areas of the Yukon and Northwest Territories. In Ontario and Québec, oil-directed drilling and exploration activity has increased modestly.

Overall, WCSB conventional production is in decline, but this is more than offset by production gains from the east coast offshore and the oil sands.

In 2005, total production is projected to be about three percent below 2004 levels primarily due to operational problems experienced at all three integrated oil sands mining and upgrading plants.

FIGURE I

Total Canada Crude Oil Production



By year-end 2006, however, total Canadian production is projected to increase substantially to 458 000 m^3/d (2.9 MMb/d) as mined bitumen, in situ bitumen and east coast offshore production expand.

Markets and Pipelines

New markets will be required to accommodate growth in oil sands production. In response, industry applied for and received NEB approval in June 2005 for two proposals to access new markets for Canadian crude oil, particularly bitumen blends. The Spearhead and ExxonMobil 20" reversal pipeline projects will provide access to southern PADD II (Cushing, Oklahoma) and the U.S. Gulf Coast (USGC), respectively. These initiatives will provide additional outlets for Canadian crude oil and should have a moderating effect on the light/heavy price differential and result in improved heavy oil netbacks.

Other major issues facing industry include: insufficient supply of diluent to transport heavy crudes to market; lack of heavy pipeline capacity out of the WCSB; price volatility; and lack of coking capacity for the growing supply of oil sands derived crude.

Industry is working together to develop transportation solutions to handle growing oil sands production. In this connection, it is conceivable that by the end of 2006 a major pipeline application could be filed with the Board.

Petroleum Products

It is expected that strong economic growth and the associated demand for petroleum products will keep refinery utilization rates in Canada very high at approximately 90 percent. There are no major refinery expansion projects planned within the timeframe of this report.

Since 2003, domestic demand for gasoline and diesel does not appear to have been materially affected by higher prices; however, this could change as we move forward particularly if oil prices remain high. Demand growth for both fuels is predicted to rise moderately in 2005 and 2006.

The net economic impact of higher oil prices for Canada as a whole is unclear. Although high oil prices enrich producing provinces, they represent a reduction in real income for consumers and pose a significant business challenge for many Canadian industries. Persistent high energy prices can be expected to spur investment in energy saving technologies in the longer term.

Introduction

This Energy Market Assessment (EMA) is the National Energy Board's (NEB) first report presenting a short-term analysis and outlook for Canadian crude oil. The EMA provides the NEB's 18-month outlook on supply, prices and markets for Canadian crude oil and petroleum products. Where foreseen opportunities and challenges facing the industry exist, these have been identified. This analysis was undertaken to expand the effectiveness of the Board's monitoring activities by providing a short-term examination of recent developments and emerging issues in the Canadian oil industry.

Since late 2002, the world has experienced very strong oil markets. As benchmark crudes around the world flirt with record high prices, global oil demand is surging and demonstrating remarkable resilience. In this environment, Canada is in an enviable position as the holder of the world's second largest reserves and as one of few countries outside of OPEC with significant prospects for production growth. Growth in oil sands production is resulting in the development of new and existing markets and the need to expand pipeline infrastructure.

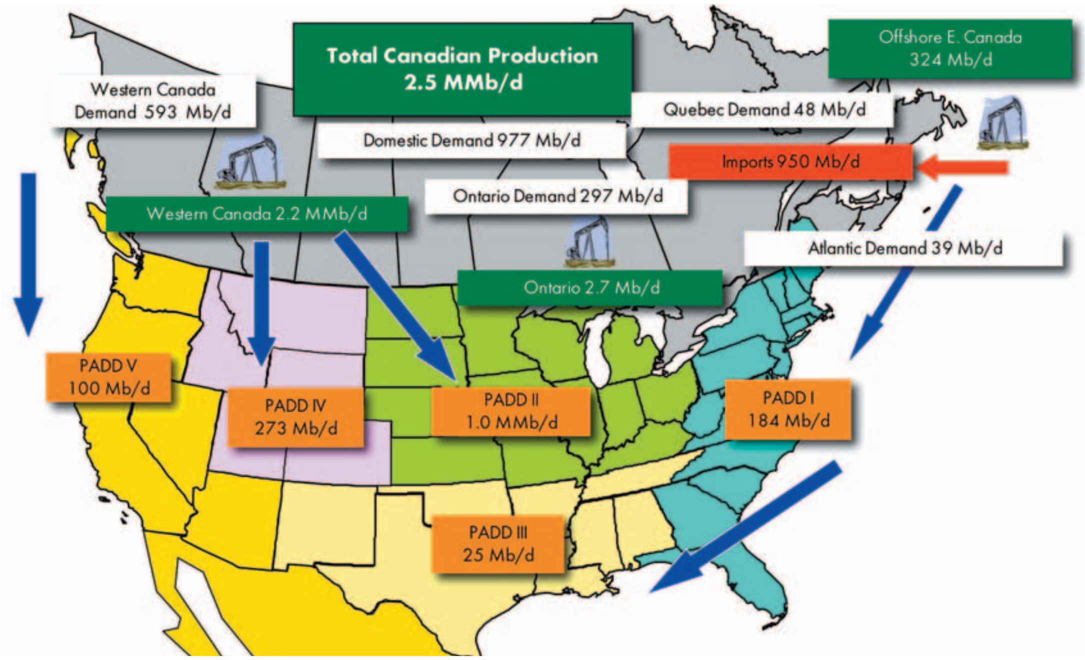
The high price environment has translated into record profits for the Canadian oil and gas industry and has spurred billions of dollars in investment, with Alberta's oil sands being a primary beneficiary. At the same time, consumers and industries have faced sharply higher prices for energy and petroleum products.

Figure 1.1 and the following text provide an overview of the Canadian oil industry:

- Currently, there are two major oil-producing areas in Canada, the Western Canada Sedimentary Basin (WCSB), including the oil sands, and offshore eastern Canada.
- Conventional oil production, both light and heavy in the WCSB is declining; development focus has shifted to the oil sands and eastern Canada offshore.
- There has been development of three major oil fields offshore Newfoundland and Labrador (Hibernia, Terra Nova and White Rose).
- In 2004, Canada produced almost 400 000 m^3/d (2.5 MMb/d) of crude oil of which almost 350 000 m^3/d (2.2 MMb/d) came from the WCSB.
- In western Canada, crude oil is transported by pipeline to the United States, southern Ontario, British Columbia, and by tanker to offshore markets. Production from offshore eastern Canada is shipped by tanker to Canadian and U.S. refineries and pipeline terminals.
- In 2004, Canada consumed 155 000 m^3/d (977 Mb/d) of domestically produced crude oil and imported 150 000 m^3/d (950 Mb/d).
- In 2004, Canada exported almost 251 000 m^3/d (1.6 MMb/d) of crude oil to the U.S. Overall, Canada is a net exporter of about 100 000 m^3/d (630 Mb/d).

FIGURE 1.1

The Canadian Oil Industry in 2004



- There are 19 refineries in Canada with a total refining capacity of almost 320 000 m^3/d (2.0 MMb/d).
- Largely because of strong demand for transportation fuels, refineries in Canada have been operating at about 90 percent of capacity for the last several years.

This report includes the following chapters:

- Chapter 1 is an introduction to the report
- Chapter 2 provides an outlook for international and domestic crude oil prices
- Chapter 3 discusses drilling and exploration activity
- Chapter 4 shows Canadian oil supply projections
- Chapter 5 focuses on Canada's crude oil trade balance and markets for Canadian crude
- Chapter 6 examines the existing export pipeline networks as well as project expansion plans
- Chapter 7 discusses the Canadian petroleum products industry and the impact of higher prices
- Chapter 8 concludes the report

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Crude Oil Prices

2.1 International Crude Oil Prices

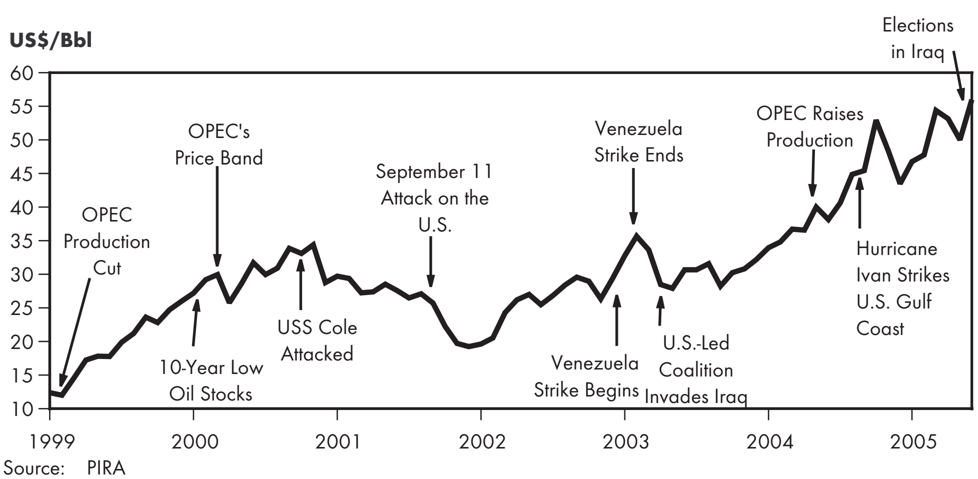
The years 1997 and 1998 were watershed years for the global oil market. In 1997, the U.S. and European oil markets were experiencing slow but steady growth, while the Asian Tigers were experiencing explosive growth. Iraq had negotiated the Oil-for-Food program with the United Nations to sell limited quantities of its crude oil on the open market in order to buy humanitarian aid supplies. Despite this added supply, the Organization of Petroleum Exporting Countries (OPEC) was in the driver's seat and, at its meeting in November 1997, decided to raise production significantly to take advantage of strengthening Asian demand. What OPEC did not realize, however, was that the Asian economies were over-extended. First, the Thai Baht collapsed, sending shockwaves around the world. Soon thereafter, other Asian economies faltered. As a consequence, the demand for oil was materially affected.

In 1998, oil prices fell rapidly and the world was experiencing a glut of crude oil. Prices fell to levels not seen since 1986 when the benchmarks dropped below US$10 per barrel. Iraqi volumes continued to grow despite price weakness, being outside the OPEC quota system. Very low prices caused high cost producers to shut in wells and a wave of consolidations began in the industry.

In response to the price collapse, OPEC reduced production drastically in a bid to reverse the market's direction. The process culminated with OPEC crude oil production cuts in early 1999, which forced crude and products stocks down sharply. The effort was successful and substantially higher prices prevailed by late 1999. Figure 2.1 provides a review of West Texas Intermediate (WTI) prices from 1999 to 2005.

FIGURE 2.1

1999-2005 WTI Prices



Source: PIRA

2000 – The Stage is set with Low Crude Inventories and Establishment of the Target Price Band

At the beginning of 2000, crude prices had rebounded from 1998/early 1999 monthly average lows of US$10 to 12 per barrel for benchmark WTI to US$27 per barrel.

During OPEC's March 2000 meeting, Venezuela was able to persuade the other ministers to agree in principle to a price band of US$22 to $28 per barrel for the OPEC basket - equivalent to about US$24 to $30 per barrel at the time for WTI. OPEC would adjust its output after consultation if the price fell below or rose above this range. OPEC decided to meet quarterly to make adjustments to output based on where prices were relative to the price band.

TABLE 2.1

2000 in Review

	Growth vs. Prior Year
Global Oil Demand	0.8%
Non-OPEC Production	3.1%
OPEC Production	5.2%
Global GDP	4.7%
	2000 Levels
WTI 12/31/2000	US$26.74
OPEC Spare Capacity	2.0 MMb/d

Source: PIRA

In 2000, the role of speculators in setting oil prices became important. Large speculative positions were made in the trading of WTI and Brent contracts, effectively tightening balances and pushing up light, sweet crude prices. The strength in crude oil prices that began in February 1999 was dissipating by the end of 2000. Demand growth had been weak as economic growth slowed and production in the Former Soviet Union (FSU) exceeded expectations. The stage was set for lower prices since commercial oil inventories began to build in the winter, as compared with the previous winter's massive stock decline. Table 2.1 provides a snapshot of the 2000 oil market.

2001 – September 11 Changes Everything

The U.S., the world's largest economy, entered into recession in the second quarter of 2001 and, as a result, global oil demand growth weakened. In order to maintain oil prices in this demand environment, OPEC instituted a series of production cuts and through September 2001, OPEC was able to maintain prices within its band. The September 11 terrorist attacks, however, dealt a severe blow to the U.S. economy as well as international air travel. Economic activity abroad was also reduced because of declines in foreign equity markets, reduced consumer confidence and expected lower U.S. imports. The worldwide economic decline became broader and deeper, and oil demand prospects deteriorated. Adding to oil market woes were relatively high world onshore commercial inventories. OPEC cut output three times in 2001 and prices were recovering but the negative impact of the terrorist attacks required additional cuts and OPEC was unwilling to reduce production again without the cooperation of key non-OPEC producers such as Russia, Norway and Mexico. Initially, that cooperation was not forthcoming and this proved to be the only time that crude oil prices dipped below OPEC's target range. By the end of the year, however, key non-OPEC countries agreed to make significant supply contributions to OPEC's market stabilization effort, resulting in the largest-ever OPEC and non-OPEC output cuts, which reduced world crude supplies by 1.5 MMb/d in the first half of 2002. The cooperation produced a substantial recovery in oil prices. Table 2.2 provides a snapshot of the 2001 oil market.

TABLE 2.2

2001 in Review

	Growth vs. Prior Year
Global Oil Demand	1.0%
Non-OPEC Production	5.0%
OPEC Production	(1.3%)
Global GDP	2.7%
	2001 Levels
WTI 12/31/2001	US$19.83
OPEC Spare Capacity	2.7 MMb/d

Source: PIRA

2002 – Strong Economic Growth and a Strike in Venezuela

In 2002, the beginnings of economic recovery were evident but oil demand growth remained weak. However, OPEC production in the first quarter of 2002 was nearly 3.0 MMb/d lower than the prior year. The excess of commercial oil inventories relative to 2001 was substantially narrowed. The third quarter 2002 draw in commercial stocks was the largest in over ten years as the U.S. economy strengthened which, in turn, boosted oil consumption. This was followed by substantial further inventory declines in the fourth quarter as a result of the huge unexpected production losses from the Venezuelan oil workers strike and Gulf of Mexico hurricane damage. As well, there were growing fears of war with Iraq. Commercial onshore stocks in the three major Organization for Economic Cooperation and Development (OECD) markets ended the year at the lowest level in over ten years. Low stocks and geopolitical events were a powerful combination for high oil prices, and WTI soared to almost US$30 per barrel in December 2002. Table 2.3 provides a snapshot of the 2002 oil market.

TABLE 2.3

2002 in Review

	Growth vs. Prior Year
Global Oil Demand	0.9%
Non-OPEC Production	3.4%
OPEC Production	(6.8%)
Global GDP	2.8%
	2002 Levels
WTI 12/31/2002	US$31.24
OPEC Spare Capacity	3.5 MMb/d

Source: PIRA

Concern over Iraq grew in the latter part of 2002 and boosted the demand for inventory. In August 2002, the United Nations Security Council passed a strong U.S./U.K. sponsored resolution demanding the disarmament of Iraq, and the U.S. Congress authorized the use of armed forces to force disarmament.

While the odds of war with Iraq grew, trouble was developing in Venezuela. On 2 December 2002, a large percentage of Petroleos de Venezuela's work force went on strike to force a referendum on the rule of the leader of the country, Hugo Chavez. The standoff caused a near shutdown of the oil industry and has had a lasting negative impact on Venezuela's crude oil productive capacity. The loss of Venezuelan oil exports in late 2002/early 2003 caused a sharp decline in reported U.S. inventories and forced prices upward. If it were not for other exporters expanding production, particularly Saudi Arabia and Mexico, oil prices would likely have skyrocketed. Prices were nevertheless strong, moving into the US$30 to $36 per barrel range for WTI.

2003 – War with Iraq

After five years of relatively weak demand growth, there was a return to historical (2 percent+) rates of global demand growth in 2003. With the U.S. economic rebound in place and China beginning to surge, global demand grew by over 2.0 MMb/d in the first half of 2003. At the same time, the Iraqi war commenced and shut down production in that country. Commercial crude and product stocks were at the lowest absolute levels in over ten years during 2003. With record high oil demand, a crippled Venezuelan oil industry and the war with Iraq, oil prices set new post-Gulf war highs. Saudi Arabia attempted to balance oil markets by satisfying customer requirements, which were somewhat tempered by a warmer winter. Venezuelan production gradually returned and Iraq oil exports resumed in June but the recovery was slower than originally expected.

With very low oil inventories at the start of the year and a heightened risk to supply from the likely war with Iraq, Asian countries built oil stocks in the first quarter and planned large volume purchases for the second quarter. These large volume purchases were occurring while economic activity was slowing because of weakness in the Atlantic Basin industrialized countries, largely because of the spread of the Severe Acute Respiratory Syndrome (SARS) virus in Asia. As a consequence, Asia built oil inventories at a much greater rate than planned. However, after several months of rebalancing, Asia had a renewed thirst for oil and its almost eight percent annual real gross domestic product (GDP) growth and resulting strong oil demand tightened oil market balances. Oil prices fell to US$28 per barrel immediately after major combat was declared in Iraq and Iraqi oil fields were unharmed. Prices, however, quickly moved higher as inventories remained low and strong Asian demand reappeared in the latter part of the year.

TABLE 2.4

2003 in Review

	Growth vs. Prior Year
Global Oil Demand	2.4%
Non-OPEC Production	1.9%
OPEC Production	4.7%
Global GDP	3.9%
	2003 Levels
WTI 12/31/2003	US$32.46
OPEC Spare Capacity	1.5 MMb/d

Source: PIRA

One of the important consequences of the lost Venezuelan production capacity (after the oil workers strike) and reduced Iraq capacity (because of extensive looting after the war) was a substantial reduction in overall OPEC spare capacity. Spare capacity dropped from a 3.5 MMb/d average in 2002 to just 1.5 MMb/d in 2003. Nearly 60 percent of this low level of spare capacity resided in Saudi Arabia. Table 2.4 provides a review of the 2003 oil market.

2004 – An Inflection Point?

In 2004, defending the price band became increasingly irrelevant for OPEC with global GDP growth of over five percent and global oil demand growth over 3.5 percent. Growth in China's oil demand alone was close to 0.9 MMb/d in 2004. This demand growth strongly outpaced non-OPEC supply increases, enabling OPEC to raise production. This caused OPEC's spare capacity to drop to a very low level. Table 2.5 provides a snapshot of the 2004 oil market.

The strong demand growth absorbed much of the world's spare oil producing, refining and transportation capacity. This encouraged financial players to make investments in commodities, including oil, which contributed to higher oil prices. In many respects, 2004 represents an inflection point. Oil prices well above the average of the last decade seemed to be required to satisfy robust demand growth in an environment of relatively modest increases in non-OPEC supply. With OPEC required to supply more oil in an environment of supply risks related to geopolitical events, it is not surprising that oil prices have risen significantly. With the world oil market having very limited spare capacity, with many non-OPEC countries past their peak production, and with finding and development costs substantially rising, higher prices were required to bring forth new investments in OPEC and non-OPEC countries and to slow the rate of oil demand growth.

TABLE 2.5

2004 in Review

	Growth vs. Prior Year
Global Oil Demand	3.5%
Non-OPEC Production	2.3%
OPEC Production	6.2%
Global GDP	5.0%
	2004 Levels
WTI 12/31/2004	US$43.38
OPEC Spare Capacity	1.3 MMb/d

Source: PIRA

The lack of spare refining capacity in 2004 in the face of strong light product demand growth caused refinery margins to soar. In turn, this caused the price spread between light and heavy crude and products to widen to historic levels.

2005 - Very Strong Oil Markets

The strong oil markets experienced in 2004 continued into 2005 in the face of limited OPEC spare production capacity, tight transportation and refinery capacity throughout the world and ongoing risks to supply due to geopolitical events. In an effort to curb rising oil prices, OPEC increased its quotas in the first quarter 2005 but WTI still rose to nearly US$56 per barrel, reflecting cold weather in Europe and the U.S. northeast, a tight worldwide supply and demand balance and heavy buying of futures contracts by hedge funds.

In the second quarter 2005, OPEC again tried to curb world oil prices with another hike in quotas. However, the market largely discounted the increase on the grounds that the extremely limited available spare production capacity was largely medium and heavy sour crude oil, not the quality of feedstock needed to meet rising light petroleum product demand. By early July, WTI rose to a record, closing at slightly over US$61.00 per barrel.

It is expected that the market environment prevailing at mid-year 2005 will continue for the balance of 2005 and 2006.

2.2 Domestic Crude Oil Prices

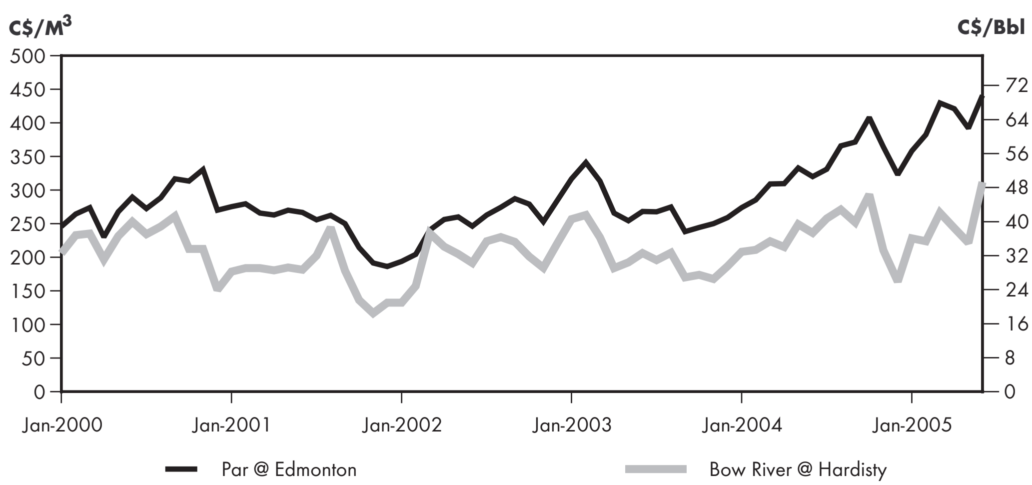
Crude oil is traded in a global marketplace and although Canada is the eighth largest oil producer in the world, it does not influence the world price of oil – Canada is essentially a price taker.

For all practical purposes, the relevant benchmark for Canada is WTI at Cushing, Oklahoma. The U.S. is the world's largest market for crude oil and traditionally it has been Canada's exclusive export market. Figure 2.2 shows the price for Canada's two major benchmark crudes: Bow River (heavy) and Edmonton Par (light). Broadly speaking, these prices reflect supply/demand fundamentals and refining values in the U.S. upper Midwest (PADD II, see Figure 6.2), adjusted for quality and transportation costs from Hardisty or Edmonton.

Although prices for Canadian crude oils are mainly determined in the global marketplace, light/heavy oil differentials and the U.S./Canada exchange rate are two significant factors that also affect the prices that Canadian producers receive. A widening of light/heavy differentials leads to poorer

FIGURE 2.2

Canadian Benchmark Crude Prices



netbacks for heavy oil producers – a factor of particular concern for the growing in situ oil sands sector. In general, higher values for the Canadian dollar versus the U.S. dollar lead to lower crude oil netbacks for all Canadian producers. These issues are discussed below.

2.2.1 Light/Heavy Oil Differentials

All crude oil is not valued equally. Light oil that is low in sulphur is considered to be the most valuable to refiners because it yields larger volumes of high-value transportation fuels. On the other hand, heavy oil with higher sulphur content requires more extensive processing. Typically, discounts are applied to heavier crude oils with lower API (American Petroleum Institute) values and higher sulphur content. Table 2.6 shows average 2004 prices for selected Canadian crude types.

Canadian producers market a wide slate of crude oils ranging from heavy sour bitumen blends derived from oil sands to pentanes plus (C5+) primarily derived from natural gas. The future of Canadian oil supply will be derived primarily from the oil sands. This means that Canada will be producing an ever-increasing volume of heavy sour oil. This supply will require either upstream or downstream upgrading.

In order to achieve pipeline specifications for viscosity and density, bitumen blend typically comprises 30-50 percent light hydrocarbons. Figure 2.3 shows that in the winter of 2005, the price premium relative to Mixed Sweet Blend (MSW) for the traditional blending agent, C5+, has been substantially

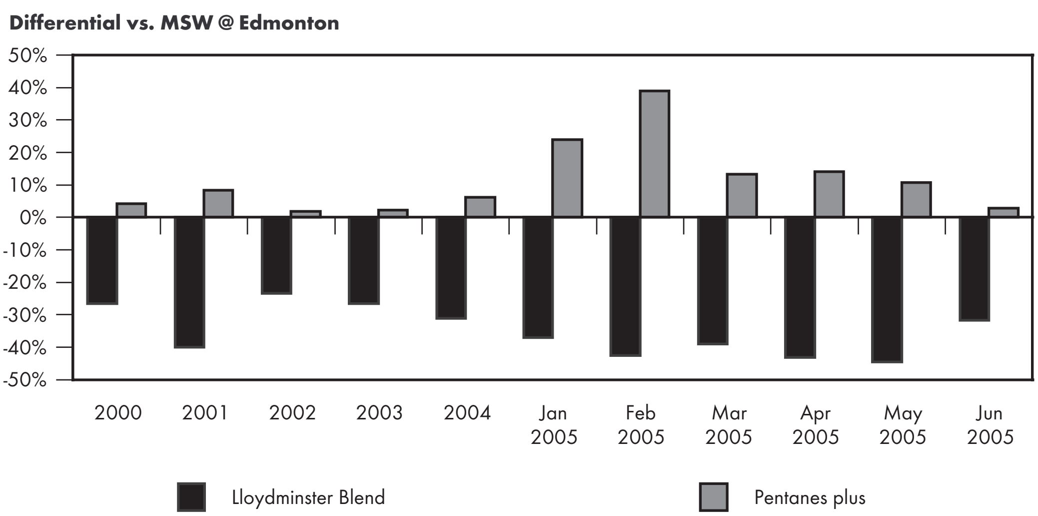
TABLE 2.6

Selected 2004 Canadian Oil Prices

Crude Type	API Gravity	Sulphur (% by wt.)	2004 Avg. Price (C$/b)
Mixed Sweet (Edmonton)	39.5	0.39	52.54
Syncrude Sweet (Edmonton)	31.9	0.12	52.96
Bow River (Hardisty)	24.9	2.48	37.60
Lloydminister Blend (Hardisty)	21.0	3.34	36.18

FIGURE 2.3

Widening Light/Heavy Differentials



higher than the historical average of about five percent. Through most of the first half of 2005, the price discount of Lloydminster Blend (LLB), which serves as a proxy for bitumen blend, has been substantially greater than its historical value of about 28 percent below MSW. Higher blending costs that are not accompanied by higher heavy oil prices result in reduced producer netbacks and, at times, even negative cash flow. Because of wide light/heavy differentials on 31 December 2004, U.S. Securities and Exchange Commission (SEC) guidelines forced many Canadian companies to de-book proved bitumen reserves even though WTI was trading at US$43.45 per barrel.

The international market primarily determines the relative value of heavy and light crude oil. High growth in oil demand since 2003, primarily driven by demand for light petroleum products, has been met mainly with OPEC heavy sour grades. This has resulted in a greater premium placed on light sweet crude relative to heavy grades. This price differential has widened recently because of limited global refining capacity to process heavy crudes.

Light/heavy differentials are further determined based on local market conditions. In the first quarter of 2005, unplanned production disruptions at all three oil sands mining plants reduced light synthetic supplies which contributed to price premiums for Canadian light oil.

Canada's primary export market for heavy crude, upper PADD II, is currently a captive market that is becoming increasingly saturated as a result of growth in oil sands production. In response, industry applied for and received NEB approval in June 2005 for two proposals to access new markets for Canadian crude oil, particularly bitumen blends. The Spearhead and Mobil 20" reversal pipeline projects will provide access to southern PADD II (Cushing, Oklahoma) and the U.S. Gulf Coast (USGC), respectively. Further details on these pipeline reversals are contained in Chapter 6: Major Oil Pipelines.

Determinants of Light/Heavy Differentials

• Quantity and quality of world oil production
 	
• Local supply/demand
    • Market options
 	
• Bottoms content of crude
    • Demand for residual fuel oil and asphalt
 	
• Demand for light products
    • Conversion equipment availability
 	
• Total Acid Number (TAN) discount (Canadian bitumen blends)

It is expected that through 2006, the marginal barrel on the world market will continue to be heavy sour. A worldwide shortage of heavy refining capacity is an issue that is unlikely to be resolved within the timeframe of this report. These factors, combined with strength in light product demand, are expected to keep light/heavy differentials wide around the world. Canadian producers will continue to face wider-than-average differentials. However, expanded heavy refining capacity in PADD II and market expansion into southern PADD II and the USGC are expected to improve heavy oil prices in 2006. Price spikes for Western Canada Sedimentary Basin (WCSB) C5+ are likely to reoccur, particularly in winter, since supply is declining and demand from bitumen producers is on the rise. Globally, C5+ is in abundance and its value is significantly below recent prices seen in western Canada; however, import pipeline infrastructure does not exist.

2.2.2 *The United States/Canada Currency Exchange Rate*

The Canada/U.S. exchange rate affects producer netbacks mainly because oil production is priced relative to WTI which is denominated in U.S. dollars while most costs are paid in Canadian dollars. An appreciating Canadian dollar therefore reduces net revenue. However, it does minimize the impact of high oil prices on the Canadian economy.

FIGURE 2.4

United States / Canada Curency Exchange Rate

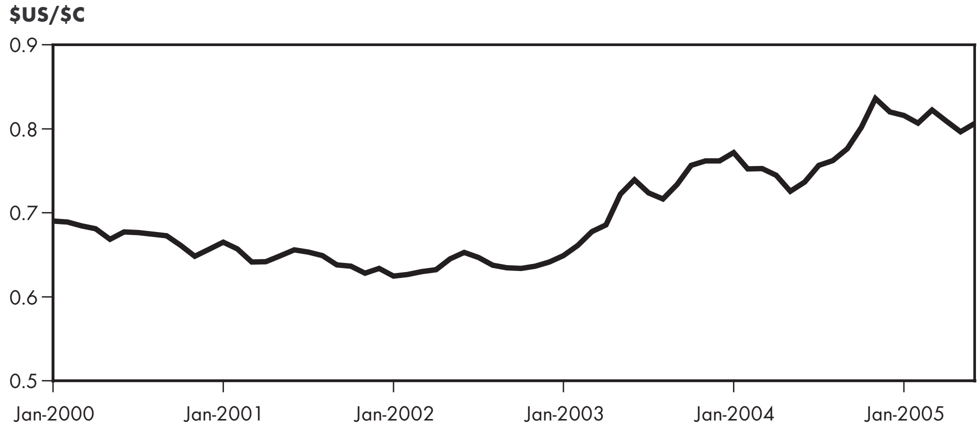


Figure 2.4 shows that the Canadian dollar has risen substantially (21 percent) since January 2003, mainly as a result of the fall in the value of the U.S. dollar relative to many of the world's dominant currencies. At the time of writing, the consensus outlook through 2006 for the Canadian dollar relative to the U.S. dollar is flat to moderate appreciation (under one cent). The Canadian dollar forward strip to the end of 2006 is consistent with this outlook.

2.3 Outlook

The following are some key factors that are likely to underpin the oil market for the balance of 2005 and 2006:

- Crude oil demand is expected to grow by 2.2 percent annually, led by China at seven percent in 2005 and 6.5 percent in 2006. Most of this growth will be transportation fuels - gasoline, diesel and jet fuel.
- Non-OPEC supply growth, primarily from the FSU and North America, is expected to be 1.0 MMb/d in 2005 and 1.3 MMb/d in 2006.
- The resulting call on OPEC is expected to be 29.5 MMb/d in 2005 and 30.0 MMb/d in 2006.
- OPEC's spare capacity is expected to be limited to about 1.0 MMb/d over the next two years.
- Transportation bottlenecks and the lack of spare production and refining capacity were issues in 2004 and are expected to be apparent in the period through 2006 as well.

Against this background, most industry experts believe that WTI prices are likely to trade in the area of US$50 per barrel. The oil market seems to perceive the downside to be limited to about US$40 to $45 per barrel while the upside is not. Product shortages, a crude supply interruption, or unexpected refinery outages could quickly propel oil prices higher while slower economic growth would be required to undermine OPEC and drive prices below US$40 per barrel. Geopolitical risks continue to be a concern, especially in Iran, Iraq and Nigeria. Petroleum product tightness is likely since oil demand growth is expected to be greater than refinery capacity additions through 2006.

OPEC will meet in September 2005 and there is speculation that it may introduce a new pricing mechanism. It could entail the implementation of a new price floor that the producer group would defend.

It is expected that high international oil prices will continue to drive attractive returns for Canadian producers of light crude oil through 2006. Wider-than-average light/heavy oil differentials are expected to endure but narrow somewhat from those experienced since late 2004. Bitumen and extra heavy oil producers requiring substantial quantities of light hydrocarbons for blending will likely face a significant challenge in maintaining profitable operations. This will be particularly so when the MSW/LLB differential is greater than 40 percent and C5+ premiums exceed historical levels. The rapid appreciation of the Canadian dollar relative to the U.S. dollar over the past two years has somewhat dampened the gains from high oil prices for Canadian producers. The outlook through the end of 2006 generally predicts flat-to-moderate appreciation (under one cent).

ON THE WEB

The Organization of Petroleum Exporting Countries
http://www.opec.org/home/

International Energy Agency
http://www.iea.org/

DRILLING AND EXPLORATION ACTIVITY

3.1 Introduction

Although overshadowed to some extent by the record–breaking number of gas wells being drilled in western Canada, oil-directed activity is nonetheless responding to higher oil prices. This response is most evident in the oil sands, in the Newfoundland and Labrador offshore, and in the provinces of Saskatchewan and Manitoba, where gas potential is not as great. The conventional oil areas of the WCSB are relatively mature from an oil exploration and development standpoint. However, with only 22 percent of the oil-in-place projected to be recovered overall, the remaining oil represents a large target for exploitation. In order to further encourage enhanced oil recovery (EOR), governments have recently introduced several measures, including modifying fiscal terms and increasing support for EOR research.

In eastern Canada, while still relatively small in scope, oil-directed drilling and exploration activity has increased its pace in Ontario and Québec. On the east coast offshore, activity continues at a modest pace, concentrated on the Newfoundland offshore, but with some activity onshore Newfoundland and in the Nova Scotia deepwater slope.

3.2 Western Canada Sedimentary Basin (WCSB)

In general, industry views WCSB conventional oil as mature, and in spite of recent higher oil prices, development drilling and exploration activity has favoured natural gas targets and oil sands areas. This is the case in British Columbia where the gas potential is still quite good and in Alberta where both good gas potential and excellent oil sands opportunities exist. In Saskatchewan and Manitoba where gas potential is not as great, drilling directed towards conventional oil has been more responsive. Figure 3.1 shows the number of development and exploratory oil wells drilled in conventional areas within the WCSB over the past five years, with projected well counts for 2005 and 2006.

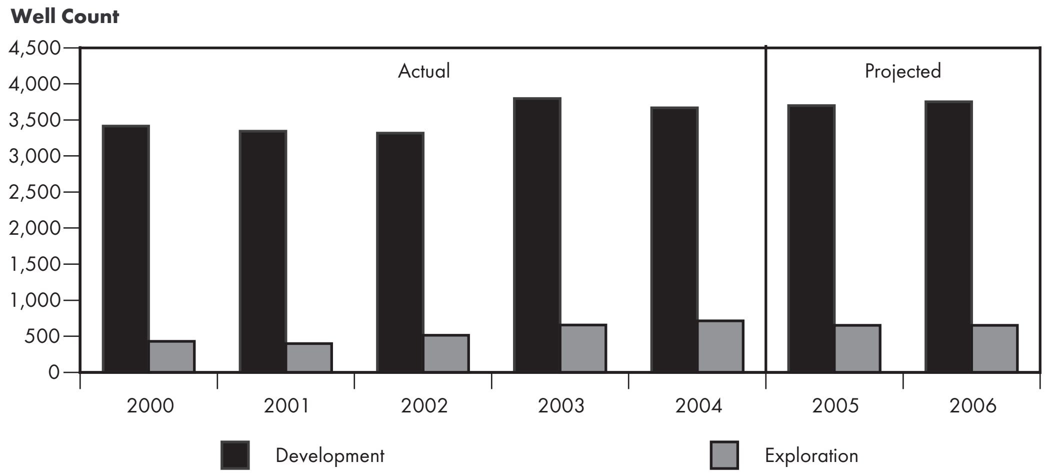
In the WCSB, conventional oil potential should be viewed as having two components, light and heavy, as they are different targets with different costs involved, receive different prices and have different development strategies. Conventional light oil is generally seen as a mature industry with production exhibiting a long-term decline of three to four percent per year. Conventional heavy oil is thought to be approaching or already at its peak production level with a future of long-term decline.

Both the provincial governments in western Canada and the federal government recognize the potential for EOR in conventional light and heavy oil fields in the WCSB. Over the last two to three years, several initiatives to support research and encourage additional oil production have been announced. These include:

- changes to fiscal terms to further encourage EOR;

FIGURE 3.1

WCSB Conventional Oil Drilling



- greater financial support for research; and,
- a co-operative approach to subsurface geoscience research, including the collection and dissemination of geoscience data.

For conventional light oil, industry strategy is to develop the remaining small undiscovered pools in selected areas of the basin, re-visit the existing larger pools to implement EOR schemes, or infill drill to a smaller spacing size. These schemes include waterfloods and miscible floods including the use of carbon dioxide. Currently, light oil has a net recovery of 27 percent, leaving a substantial volume available to be targeted by improved recovery techniques.

For conventional heavy oil, industry is exploring new zones in undrilled portions of the basin to exploit remaining small undiscovered pools in more developed areas or to apply EOR schemes. Enhanced oil recovery schemes include water floods, application of thermal energy and miscible floods such as the Vapour Extraction Process (VAPEX) technology. Currently, only 15 percent of the heavy oil is being recovered, leaving a large volume for future recovery techniques. Some recent examples of these strategies are highlighted below:

There is an emerging Bakken-formation oil play in southeastern Saskatchewan and southwestern Manitoba, covering an area of about 640 square kilometres (250 square miles). The oil from this play is reported to be light sweet (40º to 43º API) and drilling depths are relatively shallow, varying from 1 000 metres (3,280 feet) in Manitoba to 1 700 metres (5,576 feet) in Saskatchewan. Oil production from this play generates attractive netbacks, and it is estimated that 80 wells have been drilled since late 2003.

In southeast Saskatchewan, EnCana Corporation (EnCana) implemented a scheme in the large Weyburn oil field using carbon dioxide imported by pipeline from a North Dakota syn-fuels plant. The Weyburn field contains light to medium gravity oil in the Carboniferous-aged Midale Formation. This project will extend the life of the field by 50 years and will increase the amount of oil recovered to 60 percent. As a result of this success, others have announced plans to implement similar schemes in Saskatchewan and Alberta.

For conventional heavy oil, BlackRock Ventures Inc. (BlackRock) has been a leader in finding and developing pools in the Cretaceous-aged Bluesky Formation in the Seal Field of northwestern

Alberta, using a combination of vertical and horizontal wells. More recently, BlackRock and Talisman Energy Inc. (Talisman) have announced a heavy oil discovery in the Mississippian-aged Pekisko Formation in the Chipmunk Field in northwestern Alberta. This is the first field in WCSB to successfully produce heavy oil from a carbonate formation using a cold primary production scheme.

3.3 Eastern Canada

East Coast

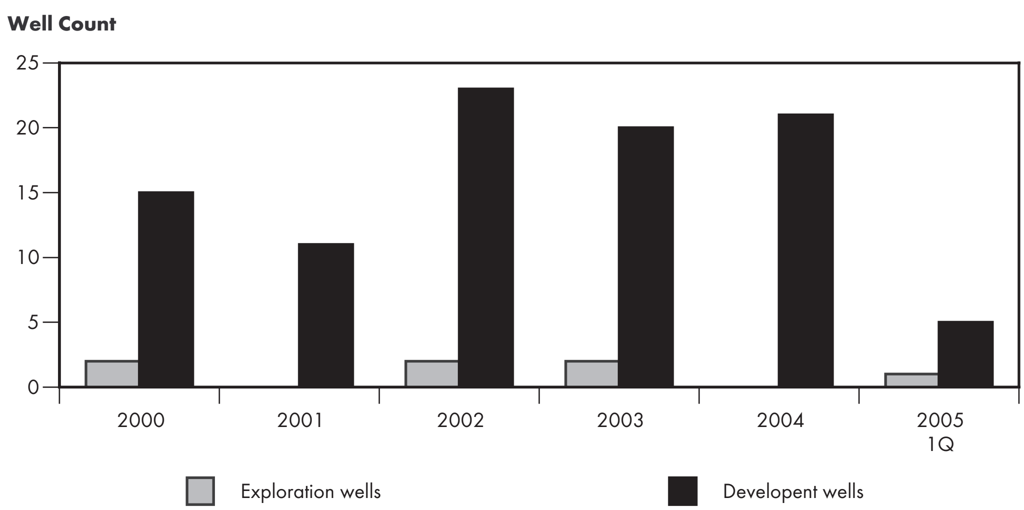
Oil activity in the east coast can be sub-divided into three areas: offshore Newfoundland, onshore Newfoundland and offshore Nova Scotia. Targets and players are different for each area. Figure 3.2 summarizes the exploration and development drilling activity occurring in these areas for the period 2000 through the first quarter of 2005.

Offshore Newfoundland currently has two fields in production, Hibernia and Terra Nova, with a third field, White Rose, expected to start production late in 2005. Both Hibernia and Terra Nova are already enhancing oil recovery with downdip waterflooding and updip gas injection for pressure maintenance. There is also the potential for a miscible flood component at Hibernia. Operators continue to drill development wells at all three projects and exploration for new fields is also ongoing.

Figure 3.3 shows the major basins of the eastern Canada offshore. In 2005, Chevron Canada Limited (Chevron) plans to conduct a seismic program in the Orphan Basin with drilling to follow in 2006 or 2007. Husky Energy Inc. (Husky) is drilling an exploratory well in the South Whale Basin and at least one delineation well at White Rose. As well, Husky plans to shoot seismic in the Jeanne D'Arc Sub-basin. ConocoPhillips Canada Resources Corp. (ConocoPhillips) is planning to shoot seismic in the Laurentian Basin, although that could be gas-directed. There are also plans for two non-exclusive seismic programs offshore Labrador, which could be considered gas-directed although there is a potential deep-water oil play. In April 2005, Chevron signed a Joint Operating Agreement with the companies involved in the already discovered Hebron-Ben Nevis-West Ben Nevis fields. These heavier oil deposits were previously considered to be uneconomic, but under this agreement Chevron and its partners are moving forward with a re-evaluation of these fields. In December 2005,

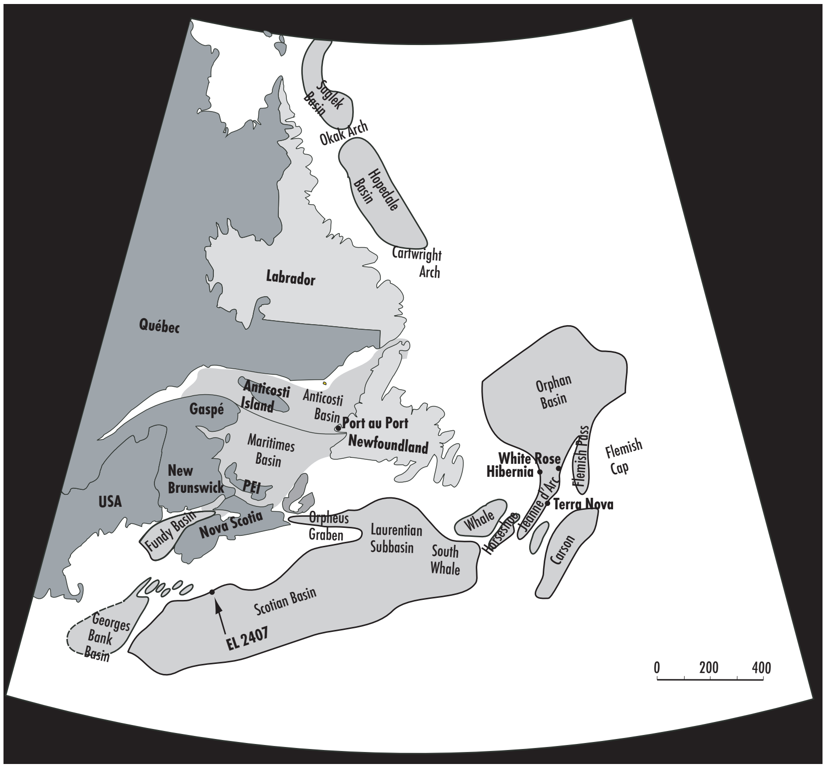
FIGURE 3.2

East Coast Drilling



F I G U R E 3 . 3

Eastern Canada Offshore Basins



there will be a land sale with four parcels being offered in the offshore region along the west coast of Newfoundland.

Onshore Newfoundland, there is potential for oil activity in four areas along the west coast. This activity will involve a number of small companies including local companies. In the Flat Bay area, Vulcan Minerals Inc. is considering drilling up to two wells this year. In the Port au Port area, Canadian Imperial Ventures Corporation in partnership with Alliance Energy Inc. is considering a 3-D seismic program near the pool discovered by PanCanadian Petroleum Limited and Hunt Oil Company of Canada Inc. in 1994. This program would be designed to image porous sections of the generally tight carbonate reservoir. Further north, in the Parson's Pond area, seismic is being considered for deeper targets. In the Deer Lake Basin, there is some consideration for re-testing a well drilled in 2003 that had indications of gas.

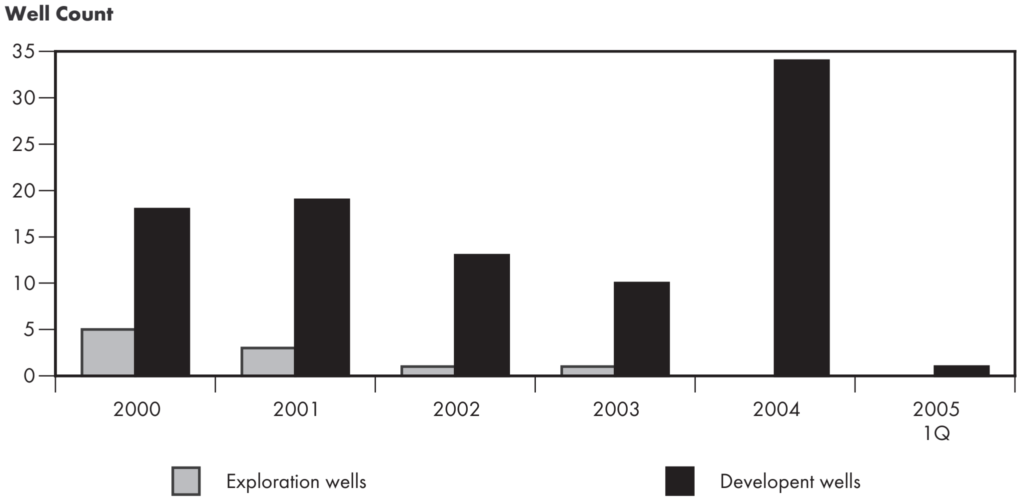
Offshore Nova Scotia, the only oil producing field, Cohasset, ceased operation in 1999. This, and a number of drilling disappointments, has meant that oil-directed exploration and development activity has been relatively quiet. However, in May 2005, BEPCo. Canada Company (BEPCo), whose general partner is Bass Enterprises Production Co., announced plans to conduct exploration drilling on its Nova Scotia offshore license, EL 2407 (Figure 3.3). This prospect is situated about 70 km (44 miles) south-southeast of Halifax. BEPCo currently proposes to drill one exploratory well per year from 2005 to 2007. The first well is planned for the second or third quarter of 2005, subject to necessary approvals and rig availability. The initial well has a reported target depth of 3 200 metres (10,500 feet) and will be drilled in approximately 1 450 metres (4,760 feet) of water.

Ontario

Southern Ontario was the first region in Canada to produce oil in the mid-1850s at Oil Springs. In spite of the very mature nature of the basin exploration and development continues today, although at a low level with only 25 wells drilled annually over the past five years (Figure 3.4). Wells are targeting the remaining potential in selected geological plays. Those plays range in age from Devonian to Cambrian and are among the older rocks developed for petroleum in Canada. Targets require extensive geological and geophysical reviews to locate the small target sizes and 3-D seismic is critical

FIGURE 3.4

Ontario Drilling



for success. Target sizes are in the order of 10 000 cubic metres (63 thousand barrels) and wells produce at rates of up to 16 m^3/d (100 b/d). Despite the relatively small target size, costs to drill, in the order of C$200,000, still allow for economic development.

Québec

In the Gaspé region of Québec, Junex Inc. and its partner Gestion Berard Lemaire report that the Galt #3 well, located approximately 20 km (13 miles) west of Gaspé, has flowed 48º API crude oil on test. Based on preliminary results, the company believes Galt #3 could become the first oil well to be put into commercial production in the history of Québec. On Anticosti Island, Corridor Resources Inc., in partnership with Hydro-Québec, commenced drilling operations at the Chaloupe well in May 2005 to evaluate the potential for light crude oil in the Trenton/Black River Formation. The Chaloupe structure is reported to have potential to contain in excess of 16.7 million cubic metres (105 million barrels) of recoverable light oil.

3.4 North of 60˚

Recent oil-related activity has taken place in four areas of the Yukon and Northwest Territories: Eagle Plains, Colville Hills, Norman Wells and Cameron Hills (Figure 3.5). In Eagle Plains, Devon Canada Corporation (Devon) drilled a well this past winter with the expectation that gas or oil would be found, similar to discoveries like Chance found in the 1960s. The well has been announced as a dry hole, but will allow Devon to continue to hold the land for another four years.

In the Colville Hills area, Apache Canada Ltd. and Paramount Resources Ltd. (Paramount) drilled two wells, and Canadian Natural Resources Limited (CNRL) drilled two wells, testing the basal Cambrian Mount Clarke sands primarily for gas; however, there is some oil potential as well. No announcements have been made on the results of these wells. Depending on the results of this year’s drilling, further drilling is possible over the next few winter seasons. Near Norman Wells, Northrock Resources Ltd. with partners Husky, EOG Resources Inc. and others announced that their Summit Creek well drilled in 2004 tested 476 m^3/d (3 Mb/d) of oil and 283 000 m^3/d (10 MMcf/d) of gas from each of two unidentified zones. This is the first successful oil test in this area since the original Norman

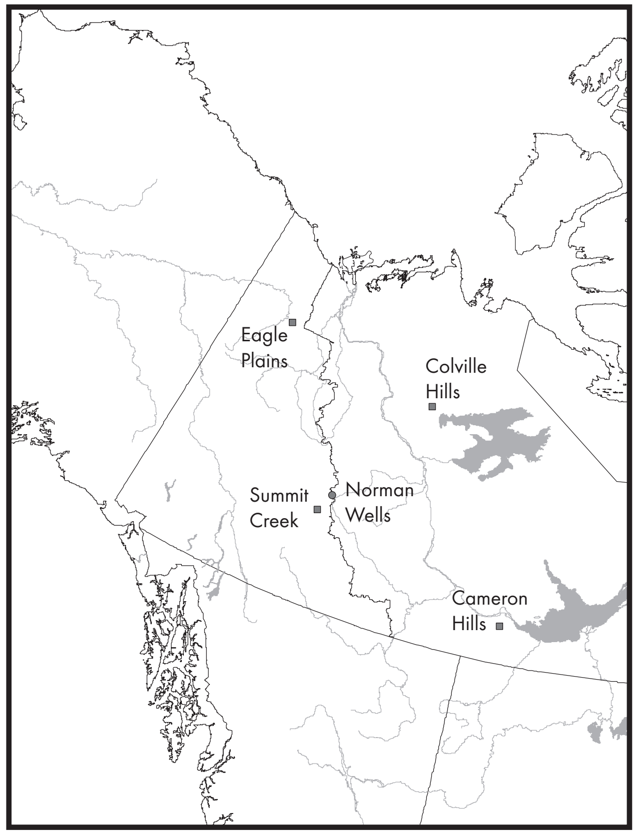
Wells discovery in 1920 and is very promising for future activity. Access to the Norman Wells Pipeline is only 61 km (38 miles) from this discovery.

In the Cameron Hills area, near the Alberta border, Paramount is producing oil from the Devonian Sulphur Point Formation. Four development wells were drilled this past winter to sustain production and more are expected in the next few winter seasons. The produced oil is pipelined to Paramount's Bistcho Lake gas plant for delivery into the Alberta system.

While there is oil potential in the Mackenzie Delta and Beaufort Sea with ultimate recoverable oil resources estimated to be 1 066 million cubic metres (6.7 billion barrels), most of the recent activity is gas directed in anticipation of a pipeline being built to connect the large gas fields to infrastructure in the rest of North America.

FIGURE 3.5

NWT and Yukon Oil Exploration and Development



3.5 Finding and Development Costs

Operating costs for the oil and gas industry have clearly been rising over the last few years, a fact which is reflected in rising finding and development (F&D) costs within the WCSB conventional oil areas. F&D costs measure the amount of capital required to add an incremental unit of reserve. Many factors can influence F&D costs such as day-rates for drilling and cost of materials.

The WCSB can be characterized as a maturely explored basin, with diminishing finding rates and relatively high F&D costs. Most of the larger pools have been discovered, and smaller fields are increasingly difficult and costly to find. Reserves can be added through EOR developments, but this is relatively expensive.

As measured by the three year average reserves replacement cost between 1997 and 2000 F&D costs were relatively stable (Figure 3.6). This was perhaps related to advances in oilfield technology that tend to lower F&D costs. For 2001 and 2002, however, F&D costs increased by about 15 percent per year. This may be explained, in large part, by higher prices for inputs such as steel, concrete and fuel. However, sustained higher oil prices after 2001 may have resulted in the phenomenon of reduced fiscal prudence in times when cash flows and profitability are enhanced.

Rising F&D costs for Canadian conventional oil production mirror the situation in most of the world. Average worldwide F&D costs for oil have been rising steadily since the mid-1990s (Figure 3.7).

FIGURE 3.6

F & D Costs – WCSB Conventional Oil

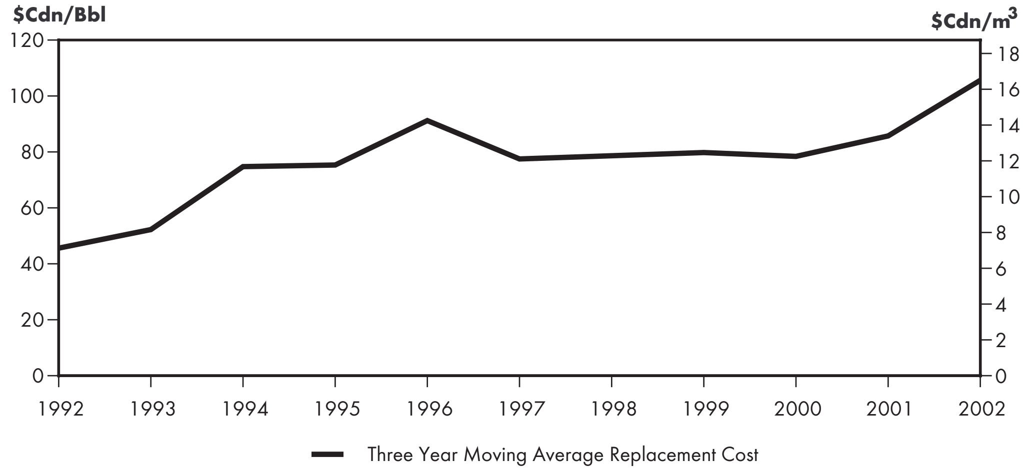
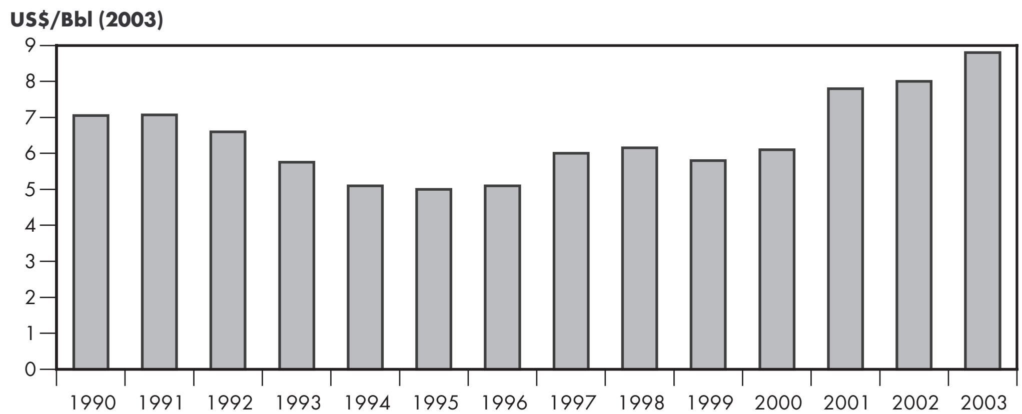


FIGURE 3.7

F & D Costs – Worldwide



Source: PIRA

3.6 Outlook

In spite of sustained higher oil prices since 2001, exploration and development in WCSB conventional oil areas has actually decreased, with the focus shifting to oil sands and natural gas. While the WCSB is considered to be maturely explored for oil, average recovery factors in conventional oil pools are still relatively low (27 percent for light and 15 percent for heavy). Thus, a greater emphasis on research and development of enhanced oil recovery has emerged.

In Ontario and Québec, the pace of development is picking up. In 2004 there were 34 development wells drilled in Ontario, about double previous year levels. An oil play in the Gaspé region of Québec is developing, with the possibility of commercial production in 2005.

Operators at the three major oil fields offshore Newfoundland and Labrador (Hibernia, Terra Nova and White Rose) continue with development drilling. Active exploration is concentrated in the Orphan Basin, South Whale Basin and off the Labrador coast. There is also land-based exploration and development activity in the Port au Port and Deer Lake Basin areas. However, capital intensive offshore developments tend to require long lead times from discovery to first production.

In Canada's north, recent oil exploration activity has taken place in four areas of the Yukon and Northwest Territories: Eagle Plains, Colville Hills, Norman Wells and Cameron Hills.

Finding and development costs have been increasing since 2000, due to the effect of higher input costs for equipment and material, and the effect of higher oil prices.

ON THE WEB

Canadian Association of Petroleum Producers
http://www.capp.ca

Canadian Association of Oilwell Drilling Contractors
http://www.caodc.ca

Petroleum Services Association of Canada
http://www.psac.ca/index.html

Indian and Northern Affairs Canada
http://www.ainc-inac.gc.ca

The Canada-Newfoundland and Labrador Offshore Petroleum Board
http://www.cnlopb.nl.ca/

Canada-Nova Scotia Offshore Petroleum Board
http://www.cnsopb.ns.ca

Domestic Production

4.1 Introduction

Alberta's vast oil sands reserves, combined with sustained higher oil prices since 2001, have presented oil sands operators and investors with opportunities to make attractive returns on existing production operations and encouraged them to develop additional oil sands projects. Bitumen production from mining and in situ operations is expected to reach 205 000 m^3/d (1.3 MMb/d) in 2006, or 20 percent above 2004 levels. However, all has not been smooth sailing, with all three integrated mining and upgrading plants suffering unplanned outages in 2005.

Conventional light crude oil in the WCSB continues its decline, having peaked in 1973, while conventional heavy crude is expected to increase slightly, based primarily on increased drilling activity in heavy oil pools in Saskatchewan. Flat-to-declining WCSB natural gas production has resulted in declining C5+ availability at a time when demand for blending from bitumen producers has been on the rise.

In eastern Canada, while increasing production in Ontario is noteworthy, the major item of interest is the expected start-up of the White Rose field offshore Newfoundland in late 2005, which has a target production of 15 800 m^3/d (100 Mb/d) in 2006.

4.2 Oil Sands

Figure 4.1 is a reference map that provides the location of the major oil sands mining and in situ projects that will be discussed in this chapter.

4.2.1 Mined Bitumen

Over the last five years, production from oil sands integrated mining, extraction and upgrading plants has doubled, with synthetic crude oil production reaching a level of 103 000 m^3/d (650 Mb/d) in 2004. This was made possible through several expansions of mining and upgrading facilities at the Suncor Energy Inc. (Suncor) and Syncrude Canada Ltd. (Syncrude) operations, as well as the start-up of a third major project, the Athabasca Oil Sands Project (AOSP), in 2002.

The Syncrude operations were expanded with the opening of the Aurora Mine in 2000, which concluded the second phase of an expansion program that began in 1996. A second bitumen production and mine train at Aurora was added in 2003. Construction is about 75 percent complete on Syncrude's Stage 3 upgrader expansion, known as UE1, which is scheduled for start-up in mid-2006. These expansions will bring Syncrude's capacity to 55 600 m^3/d (350 Mb/d) of high quality crude oil, Syncrude Sweet Premium (SSP).

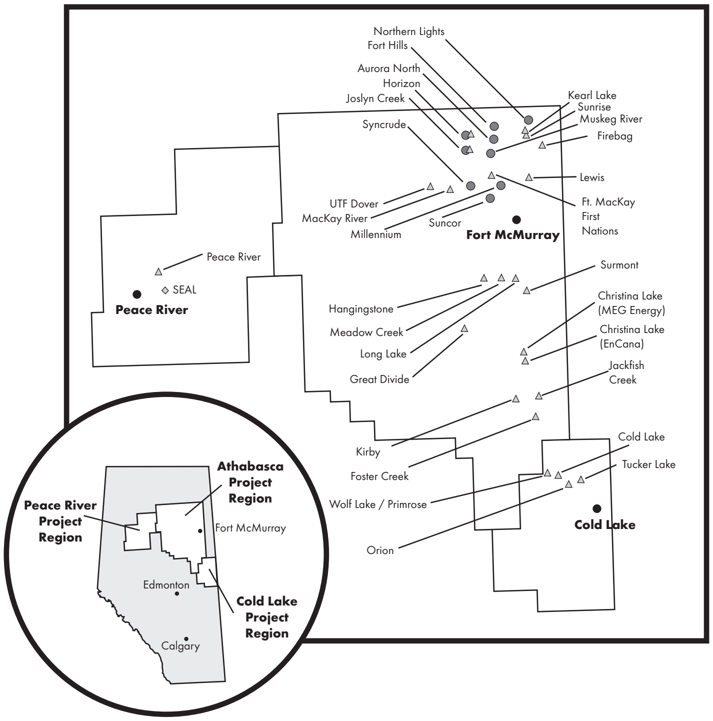
FIGURE 4.1

Major Oil Sands Project Locations

LEGEND

In Situ Projects △	*Operator*
Wolf Lake/Primrose	Canadian Natural Resources
Cold Lake	Imperial Oil
Orion	BlackRock Ventures
Tucker Lake	Husky Energy
Hangingstone	Japan Oil Sands/Nexen
Surmont	Conoco/Devon/Total
Long Lake	Nexen/OPTI Canada
Christina Lake	Encana
Foster Creek	Encana
Peace River	Shell Canada
MacKay River	Petro-Canada
Firebag	Suncor Energy
Lewis	Petro-Canada
Meadow Creek	Petro-Canada/Nexen
UTF (Dover)	Devon Energy
Kirby	Canadian Natural Resources
Joslyn	Deer Creek Energy
Jackfish	Devon Energy
Ft. MacKay First Nations	
Great Divide	Connacher Oil and Gas
Christina Lake	MEG Energy Corporation
Mining Projects ●	
Syncrude Base Mine	Syncrude Joint Venture
Aurora North	Syncrude Joint Venture
Suncor Base Mine	Suncor Energy
Millennium	Suncor Energy
Muskeg River	Shell/Chevron/Western Oil Sands
Fort Hills	PetroCanada/UTS Energy
Horizon*	Canadian Natural Resources
Northern Lights	Synenco
Kearl Lake	Imperial Oil
Sunrise	Husky
Joslyn	Deer Creek Energy
Primary Projects ◇	
SEAL	BlackRock Ventures

* Includes plans for both in situ and mining



Suncor completed the commissioning of its Millennium Project expansion in 2001, essentially doubling its capacity to 35 700 m^3/d (225 Mb/d) from the 2000 average production of 18 100 m^3/d (114 Mb/d). In mid-2001, Suncor began construction of the Millennium Vacuum Unit, a major component of the company's plan to increase production capacity to 41 300 m^3/d (260 Mb/d) in 2005. The incremental feedstock required will come from the first phase of Suncor's Firebag steam assisted gravity drainage (SAGD) project.

AOSP is a joint venture (60 percent Shell Canada, 20 percent Chevron, 20 percent Western Oil Sands). The project consists of mining and extraction facilities situated at Muskeg River, and the Scotford Upgrader located next to the Scotford refinery near Edmonton. The project has a rated mining capacity of 24 600 m^3/d (155 Mb/d) with an upgrading capacity of 31 750 m^3/d (200 Mb/d). It started producing bitumen in late 2002 and achieved fully integrated operations between the mine and the Scotford Upgrader in April 2003. While the project has met or exceeded design capacities in some months, it has not been able to meet capacities on a sustained basis. Average output of the Scotford Upgrader in 2004 was 28 700 m^3/d (181 Mb/d).

These mining, extraction and upgrading plants are large, very complex facilities, situated in northern locales where extremely cold winters are normal. Over the years, operational reliability has increased dramatically, but some unscheduled outages still occur. Outages in cold weather are often exacerbated by freeze damage, increasing repair time and delaying start-up. In late 2004-early 2005, a series of outages affecting all three oil sands plants resulted in lost production. At Suncor, a 4 January 2005 fire reduced production by 50 percent for an estimated eight-month period. At the Scotford Upgrader, throughput was reduced to 65 percent of capacity from October 2004 to January 2005 due to operational issues at both the Muskeg River mine extraction facilities and at the Scotford Upgrader. At Syncrude, the unsuccessful start-up of Hydrogen Plant 9-3 in early February 2005 resulted from tube failure after an instantaneous over pressure of the tubes in the plant. Downtime was minimized by advancing the scheduled maintenance turnaround of Coker 8-2, with both plants back in operation by the end of the first quarter 2005. Targeted annual production for Syncrude has been reduced marginally to 36 000 m^3/d (227 Mb/d).

As a result of these operational problems, the projected synthetic crude oil (SCO) production for 2005 is 91 300 m^3/d (575 Mb/d), or about 10 percent below 2004 levels. In 2006, the Syncrude Stage 3 expansion, the Suncor MillenniumVacuum Unit start-up, and improved production at AOSP are expected to ramp up SCO production to 115 000 m^3/d (725 Mb/d).

Figure 4.2 shows production levels of mined bitumen and represents the volumes of bitumen extracted before upgrading. The upgraded bitumen represents a range of upgraded products, the bulk of which is SCO. Some of the upgrader feedstock could have been sourced from in situ projects.

4.2.2 *In Situ Bitumen*

Over the period 2000–2004, bitumen production from in situ operations has increased by 34 percent to 61 300 m^3/d (386 Mb/d), with most of that increase occurring in 2003 and 2004. Thermal cyclic steam stimulation (CSS) projects operated by Imperial Oil Ltd. (Imperial) 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 commercial SAGD projects in the Athabasca area initiated by EnCana, Petro-Canada, and Suncor.

Table 4.1 sets out the commercial scale projects or project expansions that were primarily responsible for this increase, and also identifies projects that are scheduled to start-up in the 2005–2007 timeframe. Actual production may be different from the design capacities listed for the projects. Further information on these projects is provided in Appendix 1: Bitumen Projects.

Non-thermal production in the Cold Lake, Wabasca and Seal areas is an important component of in situ production, averaging about 16 600 m^3/d (105 Mb/d) between 2000 and 2004 and accounting for 27 percent of total in situ bitumen output in 2004. Moderate expansion of primary production from the Wabasca and Seal areas is anticipated. In the Pelican Lake/Britnell area some success is reported in improving recovery through the implementation of waterflooding and polymer flooding

F I G U R E 4 . 2

Bitumen Production

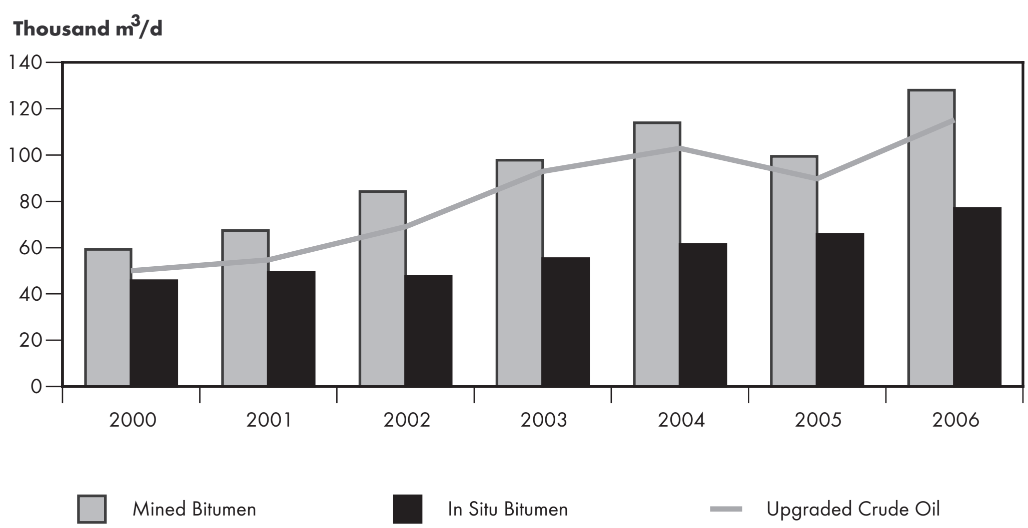


TABLE 4.1

Major In Situ Bitumen Projects 2000-2006

Project	Start-Up Date	Design Capacity (m^3/d)
Imperial Oil – Cold Lake – Makheses (Phases 11-13)	2003	4 770
Imperial Oil – Cold Lake – Nabiye (Phases 14-16)	2007	4 770
CNRL - Primrose/Wolf Lake – Phase 1B (Primrose South/Wolf Lake)	2005	500
CNRL - Primrose/Wolf Lake – Phase 2 (Primrose North)	2006	4 770
EnCana – Foster Creek SAGD – Phase 1	2002	4 770
EnCana – Foster Creek SAGD – Phase 2A	2004	1 600
EnCana – Foster Creek SAGD – Phase 2B	2006	3 200
EnCana – Christina Lake SAGD – Phase 2B	2002	3 670
Petro-Canada - Mackay River SAGD – Phase 1	2002	4 770
Suncor - Firebag SAGD – Phase 1	2004	5 560
Suncor - Firebag SAGD – Phase 2	2006	5 560
Suncor - Firebag SAGD – Phase 3	2007	5 560
Deer Creek – Joslyn Creek SAGD – Phase 1	2007	5 560
Husky – Tucker Lake SAGD – Phase 1	2006	4 770
Shell - Peace River Radial Soak – Production Expansion	2006	600
ConocoPhillips – Surmont SAGD – Phase 1	2006	4 000

techniques. For the purposes of the Board's projection, non-thermal production increases by two percent for 2005 and 2006, reaching 17 300 m^3/d (109 Mb/d) in 2006.

4.3 WCSB – Conventional Light Oil

Conventional light and medium crude oil production in Alberta has been declining since 1975 as the larger oil pools have peaked and have set into decline. Various secondary and tertiary enhanced recovery schemes implemented over the years have served to soften the rate of decline. Production has declined at a fairly consistent rate of about 5.5 percent over the last decade and this is expected to continue. The projection of this trend yields production of 56 000 m^3/d (353 Mb/d) in 2006.

In British Columbia, several large pools contribute the bulk of production and with these pools in decline, the province overall has exhibited a decline of about six percent per year. On this basis, 2006 production levels are projected to be 5 400 m^3/d (34 Mb/d).

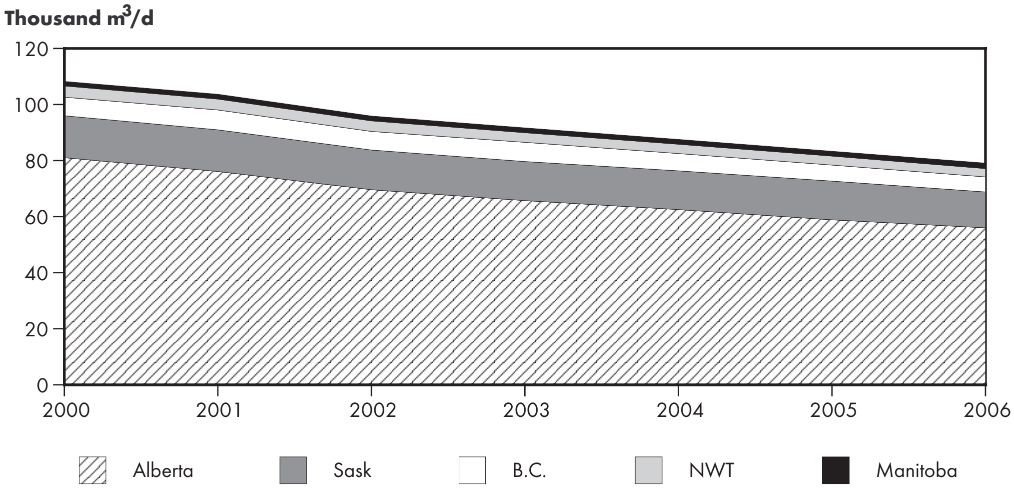
Saskatchewan production has had a long period of decline, but at relatively shallow rates of about 1.5 percent per year over the past five years. The extrapolation of this trend yields a production level of 13 600 m^3/d (86 Mb/d).

In Manitoba, production has been essentially flat at 1 750 m^3/d (11 Mb/d) and production is expected to be maintained at this level for 2005 and 2006.

In the Northwest Territories, Norman Wells is the only major producing field. Production was expanded in the mid-1980s through the installation of a waterflood recovery scheme. This field has been in decline since 1992 at about five percent per year, and this trend is expected to continue.

FIGURE 4.3

WCSB Conventional Light Crude Oil Production



Production levels in 2006 are projected to be 2 950 m^3/d (19 Mb/d). Production at Cameron Hills is projected to be 140 m^3/d (900 b/d) in 2006.

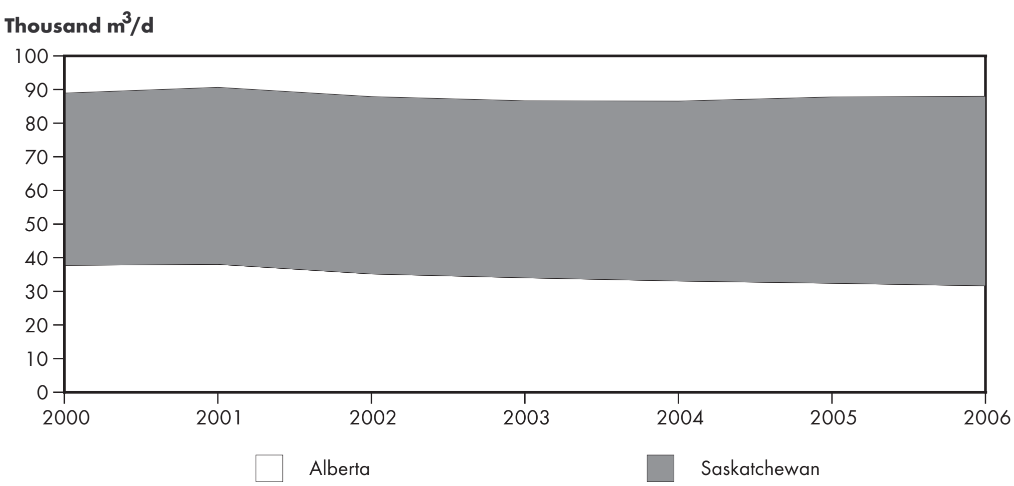
4.4 WCSB – Conventional Heavy Oil

Conventional heavy oil production in Alberta has exhibited an average decline of about three percent per year since 1997. In spite of higher oil prices in recent years, the primary focus of the industry has been on natural gas drilling, with oil-directed drilling up only marginally in 2004. The projection for 2005 and 2006 shows a decline of two percent per year, yielding production of 31 600 m^3/d (199 Mb/d) in 2006 (Figure 4.4).

In Saskatchewan, production has been relatively flat at about 52 700 m^3/d (332 Mb/d) over the period 2000 to 2003. Being less gas-prone than Alberta, higher oil prices did result in increased oil-directed

FIGURE 4.4

WCSB Conventional Heavy Oil Production



drilling, with drilling counts increasing by about six percent per year from 2002 through 2004. As a result, production began a two percent per year uptrend in 2004 that is projected to continue, at least out to 2006. Projected production in 2006 is estimated at 56 400 m^3/d (355 Mb/d).

4.5 WCSB - Pentanes Plus

The viscous nature of heavy oil and bitumen makes it difficult to transport by pipeline. In order to meet pipeline specifications for viscosity and density, dilution with a lighter hydrocarbon, such as condensate is required. Condensate is a by-product of natural gas, and historically, the availability and price of condensate has made it the diluent of choice. In recent years, natural gas production in the WCSB has leveled off, as has condensate production, while bitumen production has continued to grow. As a result, shortages of condensate have developed, to the extent that condensate commands a price premium of about 25 percent above light crude oil (See Chapter 2: Crude Oil Prices - Figure 2.8). Thus, heavy oil producers are seeking ways to maximize condensate availability and to use alternative sources of diluent. As examples, Deer Creek Energy Limited (Deer Creek) announced the execution of a letter of intent with a major oil sands producer outlining the terms of an agreement whereby Deer Creek will purchase light density diluent for its SAGD bitumen and sell the resultant blended bitumen to the major oil sands producer. Also, Enbridge Inc. (Enbridge) recently announced it will conduct an open season to confirm shipper support for the development of a condensate import pipeline in conjunction with its proposed Gateway crude oil export pipeline project to the West Coast.

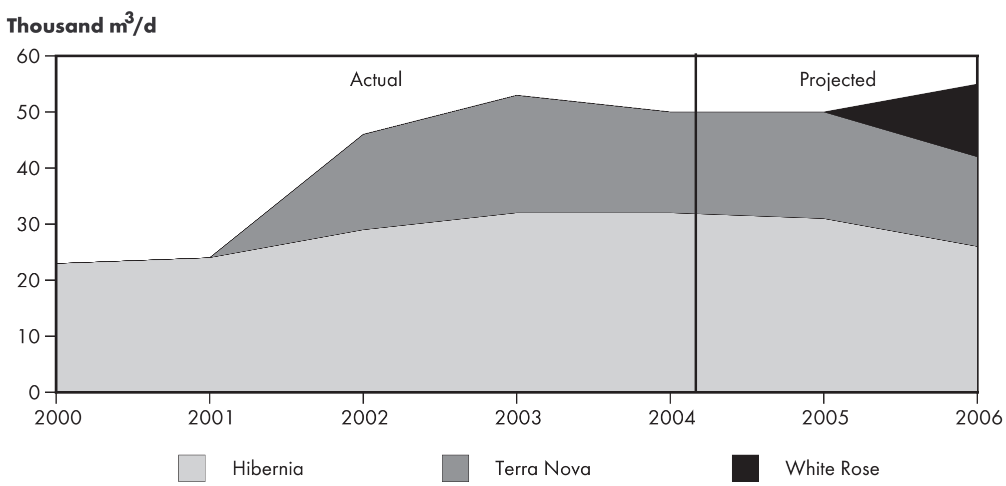
4.6 Eastern Canada

In Ontario, increased development drilling in 2004 (34 wells versus 10 wells in 2003) will help to offset a long–term decline trend and should translate into higher production levels for 2005 and 2006, with projected production rates of 425 m^3/d (3 Mb/d) for 2005 and 2006.

Offshore Newfoundland, the Hibernia Field started up in 1997 and was joined by a second field, Terra Nova, in January 2002. In 2003, the first full year of production for Terra Nova, total offshore production averaged 53 500 m^3/d (337 Mb/d). Production in 2004 was reduced by about six percent because of an oil spill incident at Terra Nova late in the year that resulted in the suspension of operations for approximately one month. The White Rose Field, with a rated capacity of 15 800 m^3/d

FIGURE 4.5

East Coast Oil Production



(100 Mb/d), is expected to begin production in late 2005. Although both Hibernia and Terra Nova are in decline by 2006, due to natural depletion, the total from these three fields is projected to raise average annual production in 2006 to 57 200 m^3/d (360 Mb/d) (Figure 4.5).

4.7 Total Canadian Crude Oil Production

The WCSB conventional production is in decline, but this is more than offset by production from the east coast and by rapidly increasing oil sands production.

Figure 4.6 shows total Canadian crude oil production. Between 2000 and 2004, total Canadian production increased by nearly 30 percent. In 2005, total production is projected to fall by about three percent due to operational problems experienced to some degree at all three integrated mining and upgrading plants. By year-end 2006, production is projected to increase substantially, to 458 000 m^3/d (2.9 MMb/d) as mined and in situ bitumen, and east coast production expand. Note that the source or "raw" production is represented here. The mined bitumen volumes are those extracted at the mine site before any blending or upgrading. Likewise, the in situ bitumen volumes are those produced at the wellhead before any blending or upgrading.

4.8 Net Available Supply

Net available supply refers to the volumes of crude oil available to the market after accounting for upgrading and blending. Thus, the net available Canadian crude oil supply represents the total of WCSB conventional light crude, east coast crude, synthetic, C5+, 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, through integrated mining and upgrading plants, or in regional upgraders, are considered to be synthetic. These volumes are subtracted from the heavy oil and in situ bitumen production totals, to avoid double counting.

FIGURE 4.6

Canadian Crude Oil Production

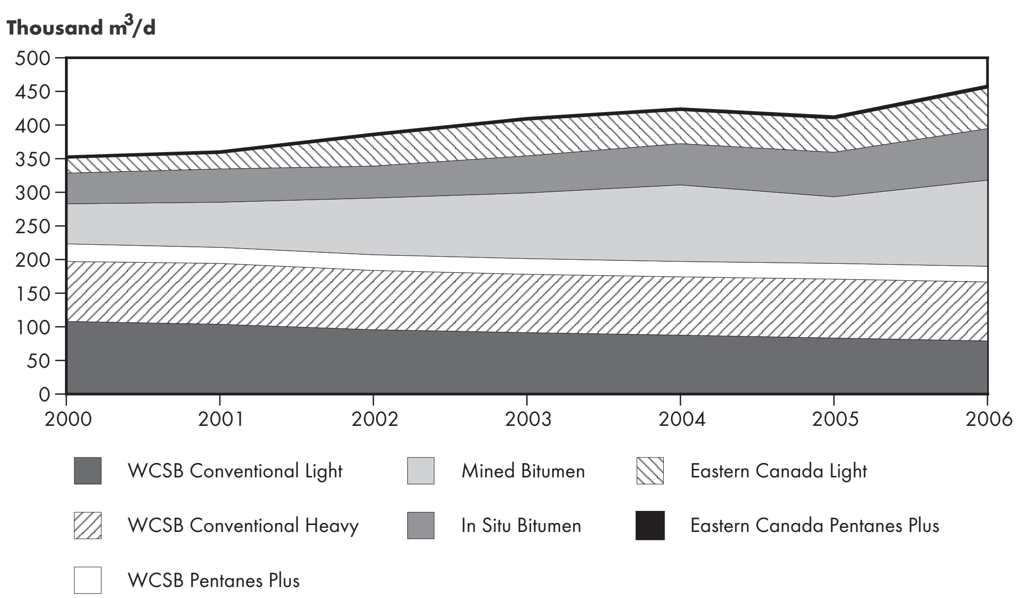
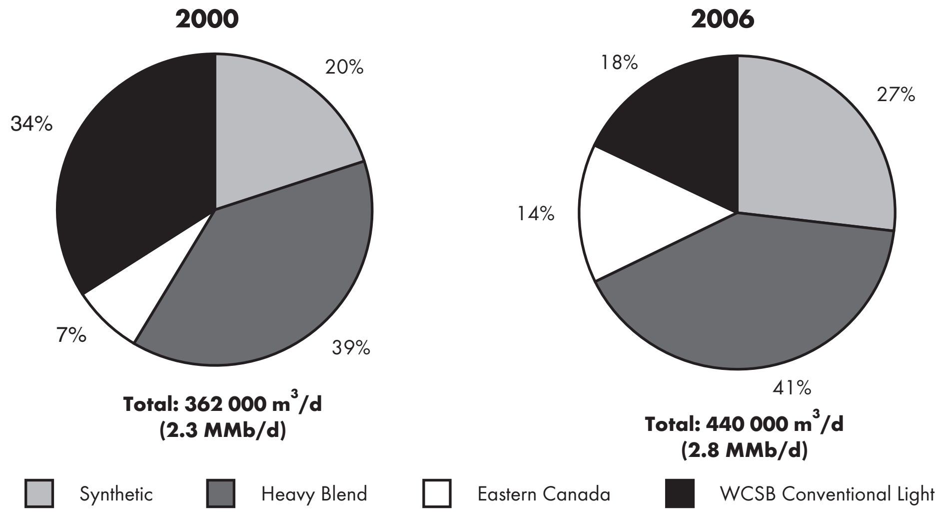


FIGURE 4.7

Net Available Supply by Type (thousand m^3/d)



It is assumed that some light or synthetic 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 be used as diluent. Between 2000 and 2006, the total net available supply is expected to rise from 362 000 m^3/d (2.3 MMb/d) to 440 000 m^3/d (2.8 MMb/d), an increase of about 24 percent.

Figure 4.7 shows that the proportions of the components of Canadian supply shift significantly over the time period of 2000 to 2006. It also shows that WCSB conventional light declines 16 percent, while eastern Canada and synthetic supply rise by seven percent.

4.9 Outlook

WCSB conventional crude oil production is in long-term decline; however, this decline is more than offset by expanding east coast and oil sands production.

Through aggressive expansion over the last five years, production from oil sands integrated mining, extraction and upgrading plants has doubled, with synthetic crude oil production reaching a level of 103 000 m^3/d (649 Mb/d) in 2004. Additional expansion and debottlenecking of facilities is projected to take capacity to 115 000 m^3/d (725 Mb/d) by the end of 2006.

Because of operational problems at all three integrated oil sands plants in late 2004 and early 2005, total synthetic crude oil production in 2005 will be reduced by about 12 percent below 2004 levels. Recovery to full capacity is projected for late 2005.

In situ bitumen production has also been expanded aggressively, with production in 2004 up 34 percent from 2000 levels. Production from an additional eight phases of expansion in existing or new thermal recovery projects is projected to increase production to 76 900 m^3/d (484 Mb/d) by the end of 2006.

Primary bitumen recovery also plays an important role, with production levels projected to increase by two percent per year, reaching 17 340 m^3/d (109 Mb/d) by the end of 2006.

In contrast to the overall declining trend for WCSB conventional crude oil, heavy oil in Saskatchewan is projected to increase by two percent per year in 2005 and 2006.

East coast total production is projected to reach 61 000 m^3/d (384 Mb/d) by the end of 2006, with White Rose starting up in late 2005.

The total net available supply which includes upgrading and blending, is projected to reach 440 000 m^3/d (2.8 MMb/d) in 2006, representing an increase of about 24 percent over 2000 levels.

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Canadian Association of Petroleum Producers
http://www.capp.ca/

Alberta Department of Energy
http://www.energy.gov.ab.ca/

Manitoba Industry Economic Development and Mines
http://www.gov.mb.ca/iedm/petroleum/index.html

Ontario Ministry of Energy
http://www.energy.gov.on.ca/

Canada-Nova Scotia Offshore Board
http://www.cnsopb.ns.ca/

Northwest Territories Resources Wildlife and Economic Development
http://www.iti.gov.nt.ca/mog/index.htm

Canada-Newfoundland and Labrador Offshore Board
http://www.cnlopb.nl.ca/

Canada's Crude Oil Trade Balance

5.1 Introduction

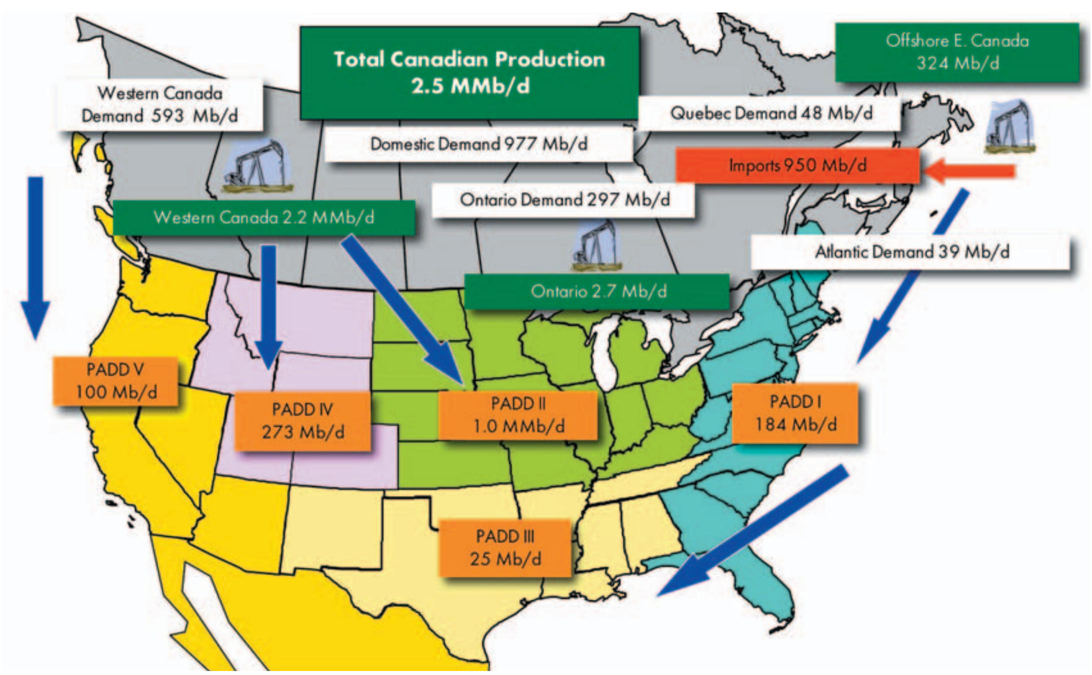
Figure 5.1 illustrates Canadian crude oil production and disposition. In 2004, Canada produced about 400 000 m³/d (2.5 MMb/d) of crude oil, of which almost 350 000 m³/d (2.2 MMb/d) or 90 percent, came from western Canada. Domestic demand for Canadian crude was 155 000 m³/d (997 Mb/d).

Sixty-five percent of all crude oil produced in Canada is exported to the U.S. The major market for western Canadian crude oil is the U.S. Midwest – including Chicago, Toledo and the Twin Cities area; the Prairie provinces – most notably, Alberta and Saskatchewan; PADD IV – which includes Billings, Salt Lake City and Denver; refineries located in southern Ontario; and British Columbia and Washington State. Canada imported 150 000 m³/d (950 Mb/d) to meet the needs of eastern refineries, including Québec and Ontario. Overall, Canada is a net exporter of about 100 000 m³/d (630 Mb/d).

Eastern Canadian crude oil is primarily refined in PADD I and some volumes are processed in eastern Canada (Montreal, St. Romuald, Come By Chance, Halifax and Saint John) and southern Ontario. Periodically, small volumes move into the USGC and offshore markets.

FIGURE 5.1

Canadian Crude Oil Supply and Disposition – 2004



5.2 Canadian Refinery Crude Oil Receipts

Refineries in Canada process a combination of domestic and imported crude oil depending on the location of the facilities. The type of crude oil processed in a refinery is determined by a number of factors including crude type availability and quality, refinery configuration and price structure. Figure 5.2 illustrates the four refining regions in Canada and the actual crude receipts for the years 2000 to 2004. Forecasted volumes are provided for 2005 and 2006.

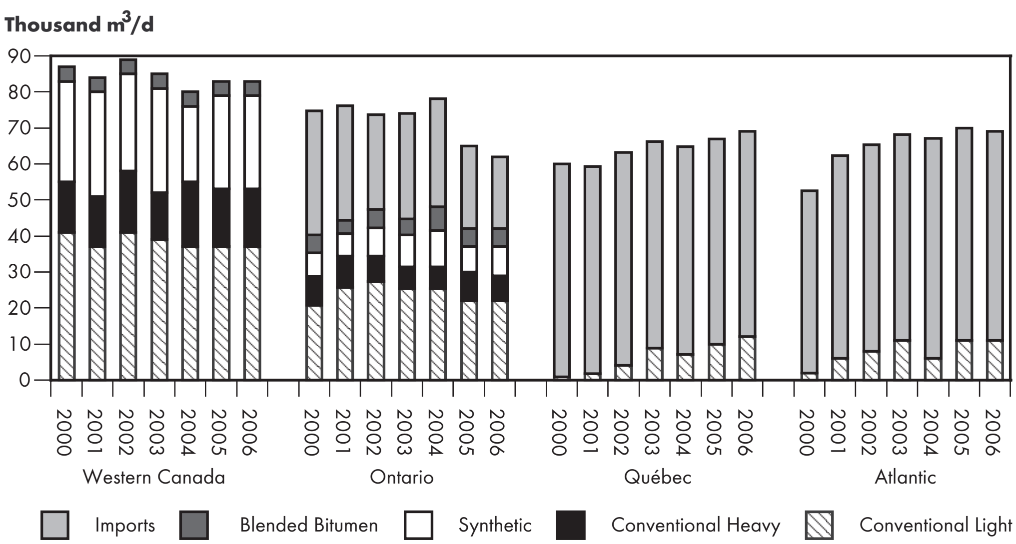
Total Canadian demand for crude oil increased by a considerable 16 200 m^3/d (102 Mb/d) to 290 300 m^3/d (1.8 MMb/d) during the period 2000 to 2004. Much of this increase was driven by capacity expansion at refineries located in Atlantic Canada and Québec that coincided with investments to meet the reduction in sulphur in transportation fuels. As well, high utilization rates in all refineries across Canada have been a contributing factor. During 2000 to 2004, there were two refinery closures: the Parkland refinery located in Alberta and, more recently, Petro-Canada's refinery in Ontario.

Refineries in western Canada typically process light conventional crude oil, some light synthetic and small volumes of heavy conventional and bitumen blends. In Ontario, refineries process a mix of Canadian and imported oil depending on availability and price. It is expected that refineries located in Atlantic Canada and Québec will continue to process primarily imported crude due to their proximity to waterborne supplies, and east coast production depending on price. In western Canada, it is expected that refineries will make the necessary modifications to process increased volumes of oil sands derived crude. In this regard, there have been a number of publicly announced expansions and retooling of refineries in western Canada. They include the following:

- In December 2003, Petro-Canada announced that through an agreement with Suncor, it will process 8 400 m^3/d (53 Mb/d) of bitumen at its Edmonton refinery. This agreement will take effect in 2008.
- In July 2005, the AEUB approved all three phases of the proposed Heartland upgrader. It will have an ultimate capacity of 41 300 m^3/d (260 Mb/d) and will be located in the

FIGURE 5.2

Refinery Crude Oil Receipts



Source: Statistics Canada 2000 to 2004

Fort Saskatchewan area near Edmonton, Alberta. Construction will begin in the third quarter 2005 on the first phase which will be 12 000 m^3/d (75 Mb/d) and start-up is scheduled for fourth quarter 2007.

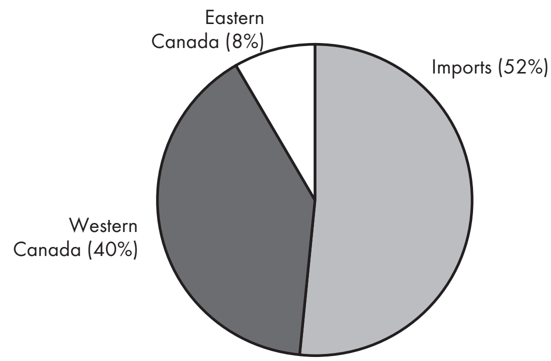
While the refining industry in Canada is not expected to add capacity in the timeframe of this report, there will likely be opportunities to increase western Canadian heavy crude oil receipts. In particular, with the especially wide light/heavy differential, refineries will try to maximize their runs of cheaper heavier crude. In addition, declining light conventional production and the need for refineries to make the necessary investments to process greater volumes of bitumen and SCO will exist; however, this will be in the longer term.

5.3 Imports

Figure 5.3 illustrates that Canada imports about half of its crude oil requirements. In March 2005, 42 percent of imports came from OPEC countries such as Algeria, Saudi Arabia and Venezuela, while the remaining came from non-OPEC countries, mainly the United Kingdom and Norway (Figure 5.4). In 2004, refineries located in Atlantic Canada and Québec imported 90 percent of all crude processed in their refineries. Because of the proximity to waterborne supplies, it is likely that refineries located in these regions will continue to process imported crudes.

FIGURE 5.3

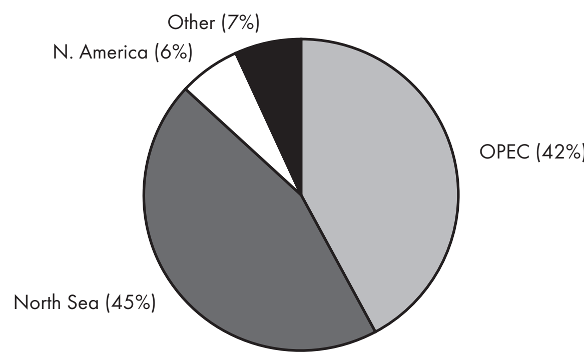
Refinery Supplies of Crude Oil – March 2005



Source: Statistics Canada

FIGURE 5.4

Imports of Crude by Source – March 2005



Source: Statistics Canada

5.4 Exports

Canada's major export market continues to be the U.S. In 2004, 65 percent or 270 000 m^3/d (1.7 MMb/d) of all crude oil produced in Canada was exported to the U.S., making Canada its largest foreign supplier. Exports were particularly strong in 2004 because of higher oil production in Canada, and strong oil demand in the U.S. during the summer months.

As identified in Chapter 4, oil sands production is projected to continue growing. In this context, Canadian producers, particularly heavy conventional and oil sands producers need to find additional markets for their production. In an effort to simplify marketing and improve the appeal of Canadian heavy crude to refiners, in the fourth quarter 2004, Talisman, EnCana, CNRL and Petro-Canada introduced Western Canadian Select (WCS). WCS is a new crude stream that includes 19 Canadian heavy blends. The objective is to move growing volumes into PADDs II and IV and promote the development of a paper trading market for WCS similar to the existing WTI contract market. It is anticipated that WCS will improve stream liquidity and enhance price discovery and transparency; the price target for WCS is Bow River. According to industry, the response to this new stream has been favourable.

5.4.1 PADD I

PADD I extends from the U.S. northeast to the state of Florida and is the blue area of Figure 5.1. It has 11 refineries with a refining capacity of 250 000 m^3/d (1.6 MMb/d). A significant portion of Hibernia and Terra Nova production is shipped to refineries in the U.S. northeast. Shipments from western Canada are processed at the United refinery, located in Warren, Pennsylvania, the largest importer of Canadian crude in PADD I. During the past five years, volumes of Canadian crude have increased by a modest six percent to average 29 000 m^3/d (183 Mb/d) (Figure 5.5).

It is expected that shipments of western Canadian crude oil will rise stemming from the recently announced heavy crude oil supply agreement between Nexen and United Refining for its coker project. The in-service date for the supply agreement is January 2008.

5.4.2 PADD II

The U.S. Midwest or PADD II is the largest market for Canadian crude oil and is the green area in Figure 5.1. In 2004, slightly over 50 percent of all crude oil exports to the U.S. were destined for markets in the Midwest- primarily Chicago, Twin Cities and Toledo.

PADD II has 24 refineries with a refining capacity of 555 000 m^3/d (3.5 MMb/d). Over 70 percent of the exports into the Midwest are heavier grades such as bitumen, heavy synthetic, synbit and heavy conventional. In this regard, this market holds tremendous growth opportunities for Canadian oil sands producers. During the past five years, volumes of Canadian crude have increased by almost nine percent to average 154 000 m^3/d (970 Mb/d) (Figure 5.5). In this market Canadian crude competes with imports and some indigenous production.

With the especially wide light/heavy differentials in the fourth quarter 2004 and first quarter 2005, there has been much impetus by companies to either consider adding coking capacity or expanding existing facilities to process additional heavy crude. In addition, companies are investing capital to meet ultra low sulphur diesel regulations that come into effect January 2006, and are at the same time, looking for opportunities to add capacity to process increased volumes of western Canadian crude oil. Publicly announced projects are listed in Table 5.1.

FIGURE 5.5

Exports of Canadian Crude Oil by PADD

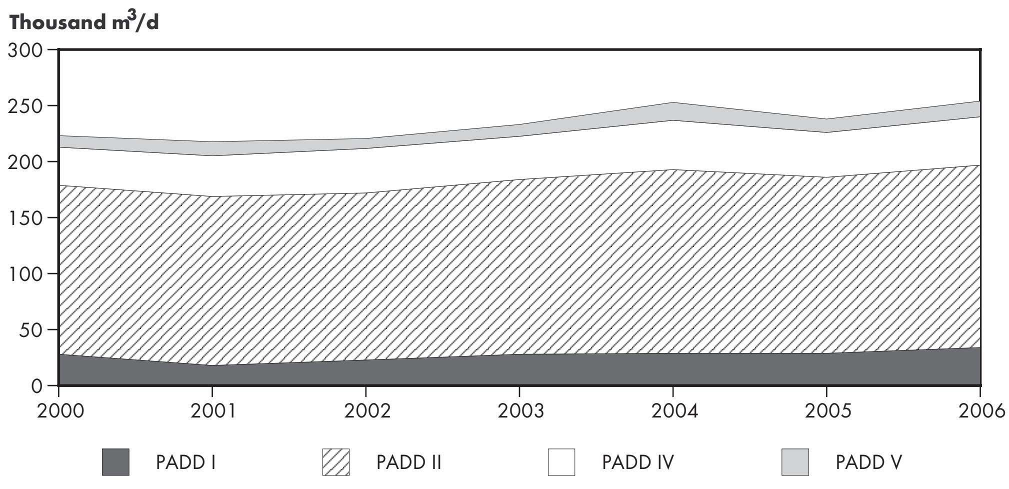


TABLE 5.1

Refinery Expansion Plans

Company	Location	Project	Volume (Mb/d)	In-Service
Suncor	Chicago, Illinois	Suncor has shown interest in this Citgo facility	167 capacity	N/A
BP	Whiting, Indiana	Upgrade of existing facilities to process more sour crude	400 capacity	2010
BP	Toledo, Ohio	Upgrade of existing facilities to process more sour crude	155 capacity	2010
Marathon Ashland	Detroit, Michigan	Crude capacity increase	75 - 100	4Q05
Frontier Refining	El Dorado, Kansas	Increase volumes of Lloydminster/Syncrude off the Spearhead pipeline Vacuum Tower	35 40	September 2007 N/A
Flint Hills	Pine Bend, Minnesota	Crude capacity increase Coker expansion	50 incremental 330 capacity	2008
Sunoco	Toledo, Ohio Tulsa, Oklahoma	Crude expansion – will likely process more Syncrude May take Canadian crude	100 capacity 20-30 incremental 85 capacity	
EnCana/ Premcor	Lima, Ohio	MOU to upgrade Premcor facility to process EnCana heavy oil under long-term agreement	200	2008

With the reversal of the Enbridge Spearhead pipeline in January 2006, and commitments to ship 9 540 m^3/d (60 Mb/d), increasing volumes of western Canadian crude oil will penetrate the Cushing, Oklahoma market. During the course of the NEB proceeding in April 2005, proponents of the project reiterated that access to this market would provide benefits for shippers and western Canadian producers now and in the future.

5.4.3 PADD III

PADD III includes most of the States on the USGC and is the light yellow area in Figure 5.1. It is the largest and most sophisticated refining region in North America. It has a refining capacity of almost 1 100 000 m^3/d (7 MMb/d). It imports some offshore eastern Canadian production and has periodically taken some western Canadian production off the Westridge Dock via Terasen Pipelines (Trans Mountain) Inc. (TPTM). In 2004, Canada exported almost 4 000 m^3/d (25 Mb/d) of offshore eastern Canadian crude to refineries located in PADD III (Figure 5.5).

In early 2005, Mobil Pipeline Company announced its intentions to reverse its 20” line from Patoka, Illinois into the Beaumont/Nederland, Texas area. This would allow western Canadian crude oil to penetrate this market. The in-service date is targeted to be the fourth quarter of 2005. This project is primarily producer driven and shipper support of 8 000 m^3/d (50 Mb/d) has been secured. It is expected that heavier crudes will flow through this reversed line.

5.4.4 PADD IV

PADD IV includes the Rocky Mountain States and is the pink area in Figure 5.1. There are fourteen refineries in this market with a refining capacity of almost 92 000 m^3/d (578 Mb/d). Western Canadian crude oil exports have risen steadily (30 percent) over the past five years (Figure 5.5). In 2004, exports into PADD IV were about 44 000 m^3/d (277 Mb/d) of which roughly 50 percent was heavy conventional with the remaining being primarily light synthetic and conventional light.

There is potential for increasing volumes of western Canadian crude in this market. However, because of high oil prices, there has been an increase in drilling activity in PADD IV, resulting in the stabilization of local light conventional production. Therefore, refineries have been processing more indigenous crudes. Unfortunately, there is not a significant amount of coking capacity in this region so it is unlikely that refineries will process increasing volumes of oil sands derived crude oil in the short term. In the longer term, Suncor's addition of a hydrogen desulphurization reactor at its Commerce City, Colorado refinery will allow it to process its high sulphur oil sands production.

In June 2005, Suncor Energy Inc. announced that its U.S. subsidiary Suncor Energy (U.S.A.) purchased the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero. The 4 800 m^3/d (30 Mb/d) refinery is located next to Suncor's existing refinery in Commerce City. Suncor intends to fully integrate these facilities, providing a combined refining capacity of approximately 14 300 m^3/d (90 Mb/d). The refinery is expected to continue processing indigenous supplies of condensate and light sweet conventional crude. In the longer term, however, Suncor intends to process additional volumes of synthetic in both facilities.

In addition, Holly Corporation, located in Woods Cross, Utah is also looking to process sour western Canadian crude. However, it is limited by its location and the type of crude refineries in the area. It is intending, however, to install equipment that would allow it to run more heavy crude if incremental volumes are available.

5.4.5 PADD V

PADD V is the region west of the Rockies and is indicated by the darker yellow area in Figure 5.1. It has 20 refineries with a refining capacity of 403 000 m^3/d (2.5 MMb/d). Although western Canadian crude is a very small percentage of total crude imported by these refineries, it has risen 56 percent over the past five years (Figure 5.5). In 2004, total western Canadian crude oil exports into PADD V were approximately 16 000 m^3/d (100 Mb/d) of which 65 percent, was light conventional. Most of these volumes were processed in refineries located in Washington State.

This market has potential for additional shipments of Canadian crude oil but in the medium and longer term. Two publicly announced proposals, one by Enbridge called the Gateway project, and another by Terasen Pipelines (Trans Mountain) Inc. called TMX would entail expansion or construction of new pipelines which would likely see increased volumes of western Canadian crude be exported to the California market. Indigenous California crude is declining and Alaska North Slope (ANS) crude though it has stabilized, is expected to decline as early as 2006. Therefore, western Canadian heavy sour crudes should be able to compete effectively with other waterborne alternatives in this market.

Tesoro Corp. recently announced that it plans to add a 2 400 m^3/d (15 Mb/d) coker at its refinery in Anacortes, Washington. This has the potential to increase Tesoro's volumes of bitumen blends. It is expected that the coker will be operational by April 2007.

As well, BP recently indicated that it is considering repositioning its Cherry Point, Washington refinery to handle western Canadian heavy crude by 2010 and increasing this ability through 2015.

5.4.6 Offshore

In 2004, Canada exported approximately 3 300 m^3/d (20 Mb/d) of light crude oil to offshore locations such as Puerto Rico and the Caribbean. In the past, Canadian crude has also been shipped to Korea, Europe and China. There are ongoing discussions between pipeline companies and Chinese officials concerning the possible involvement by China in Enbridge's Gateway pipeline.

Chinese companies are also looking to invest in Canada's oil sands. In April 2005, offshore producer CNOOC purchased almost 17 percent of the common shares of MEG. MEG, formerly McCaffrey Energy Group, has a pilot project in the oil sands that could grow to a 15 000 m^3/d (95 Mb/d) commercial operation.

In addition, Chinese oil giant Sinopec Group announced that it purchased a 40 percent interest in Synenco Energy Inc.'s proposed Northern Lights oil sands mining project northeast of Fort McMurray. The $4.5 billion mining and upgrading project is designed to produce 16 000 m^3/d (100 Mb/d) of synthetic crude oil.

Although not in the timeframe of this report, China and other Asian countries are potential markets for Canadian crude oil in the longer-term, likely near the end of the decade.

5.5 Outlook

Through consultations with industry and the Board's own analysis, a number of short-term market issues have been identified:

- There is insufficient supply of diluent to move heavy crudes to market. To address this concern in the longer term, it has been suggested that a return pipeline from the west coast be constructed in parallel with a new pipeline from Edmonton (Gateway or TMX northern option) to the west coast to provide for imports of diluent. Enbridge has also suggested that it might ship diluent on its mainline from Chicago back to Edmonton and Hardisty.
- Synthetic crude, while it can be used as a replacement for traditional diluent, is currently trading at a premium and not fully recoverable in heavy blends particularly when the price of light crude is high.
- The impact of the wide light/heavy differential will continue to have severe consequences for heavy crude oil producers. Heavy crude oil prices have not kept pace with WTI. Most of the run-up in the WTI price reflects the strength in light petroleum products due to strong demand growth.
- Lack of heavy pipeline capacity could also impact the light/heavy differential by causing a disconnect of prices from the global price. A line swap by Enbridge will take place between October and November 2005 to address this issue. However, this will have to be well timed so as not to impact prices and the market.
- As a result of disruptions in SCO supplies that plagued producers in the fourth quarter 2004 and first quarter 2005, reliability of supply could become more of an issue as conventional light production declines. As well, upgrader outages could lead to future discounts after production levels are restored to compensate refiners for the risk of potential unreliable supply.

- Ongoing oil sands quality concerns that could cause refinery process issues continue to be addressed (e.g., WCS).
- Which new markets to access? In the short-term, this has been resolved with the upcoming reversals of the Spearhead and Mobil pipelines. However, decisions will need to be made in the near term to prepare for the long-term growth of oil sands output.
- Lack of coking capacity in traditional markets.

While these issues will remain through the outlook period, industry is working together to develop solutions. It is expected that by the middle or the end of 2006, a major pipeline application will be filed with the Board and at this time a clear understanding on the next step for market expansion will emerge.

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National Energy Board
http://www.neb.gc.ca/

Natural Resources Canada
http://www.nrcan-rncan.gc.ca/inter/index.html

U.S. Department of Energy- Energy Information Administration
http://www.eia.doe.gov/

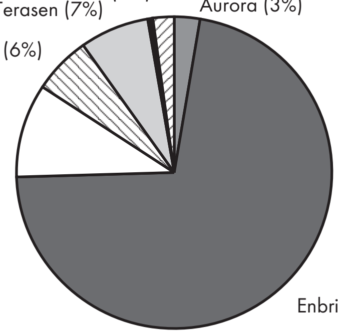
Major Oil Pipelines

6.1 Introduction

In 2004, about 270 000 m³/d (1.7 MMb/d) of crude oil was transported from western Canada to Ontario and the U.S. Figure 6.1 shows crude oil shipments for the seven pipelines exiting western Canada. In 2004, the three major trunklines, Enbridge, Terasen (Trans Mountain) and Express, comprised 88 percent of total deliveries. This chapter will focus on these systems.

FIGURE 6.1

Western Canadian Crude Oil Shipments



Chapter 4 illustrated that oil sands production is expected to increase. Any increases in production results in the growth of throughput volumes on the major export pipeline systems.

Domestic crude oil demand is not forecast to increase significantly through 2006; it is therefore expected that new production in this time frame will be exported to markets in the U.S. In this connection, capacity additions for all three major trunklines have recently been completed or will be completed by the end of 2006. In addition, long-term oil sands growth has spurred proposals from Enbridge Pipelines, Terasen Pipelines (Trans Mountain) Inc. and TransCanada for major expansions to existing systems or new pipelines.

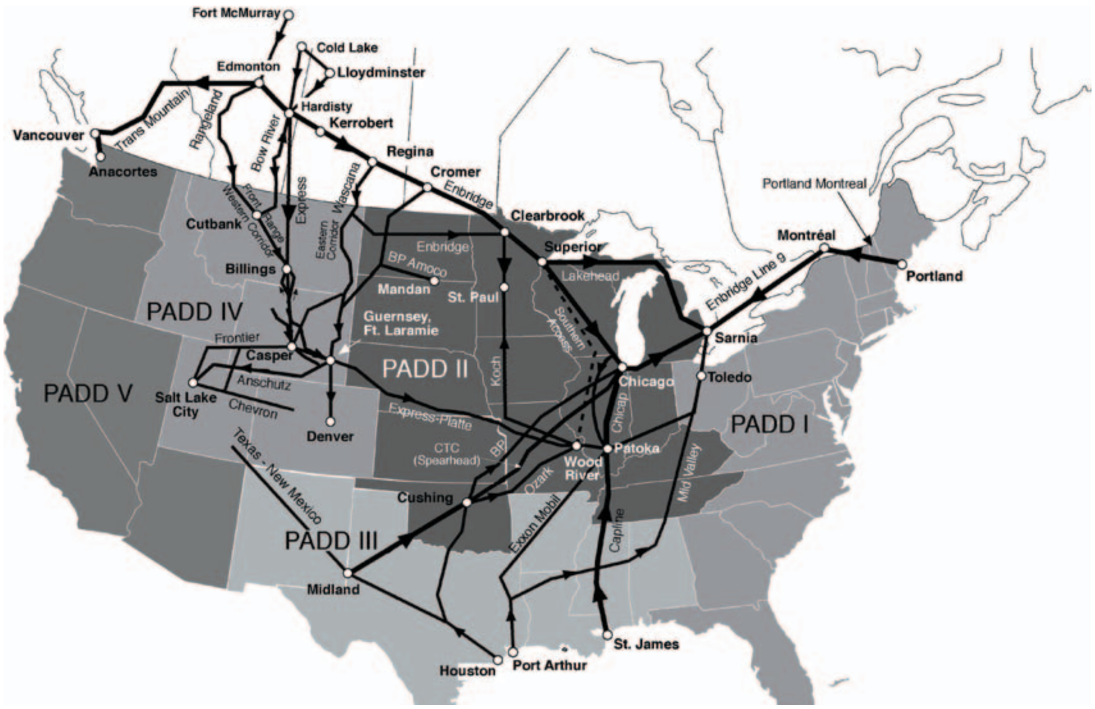
6.2 Major Trunklines

Figure 6.2 shows the major Canadian and U.S. crude oil pipelines and markets including the three Canadian trunklines:

- Enbridge's mainline originates at Edmonton with major terminals at Hardisty and Regina and delivers into Ontario and PADD II via the Lakehead system
- Terasen's Trans Mountain system originates at Edmonton for delivery to Burnaby, B.C., the Westridge Dock and PADD V
- Terasen's Express system originates at Hardisty and delivers into PADD IV and connects to the Platte system at Casper, Wyoming for delivery into southern PADD II

FIGURE 6.2

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



6.2.1 *Enbridge Pipelines*

Enbridge is Canada's largest pipeline and together with the Lakehead pipeline in the U.S. is the longest oil pipeline system in the world. It consists of multiple lines with a total capacity of about 292 500 m^3/d (1.8 MMb/d). In addition to deliveries of crude oil from western Canada, Enbridge also delivers foreign and eastern Canadian crude oil to Sarnia, Ontario from Montreal via its Line 9 from the Portland-Montreal Pipeline.

Figure 6.3 sets out Enbridge export volumes by crude type. Since 2000, there has been steady growth in oil sands heavy (bitumen and heavy synthetic) and oil sands light (light synthetic).

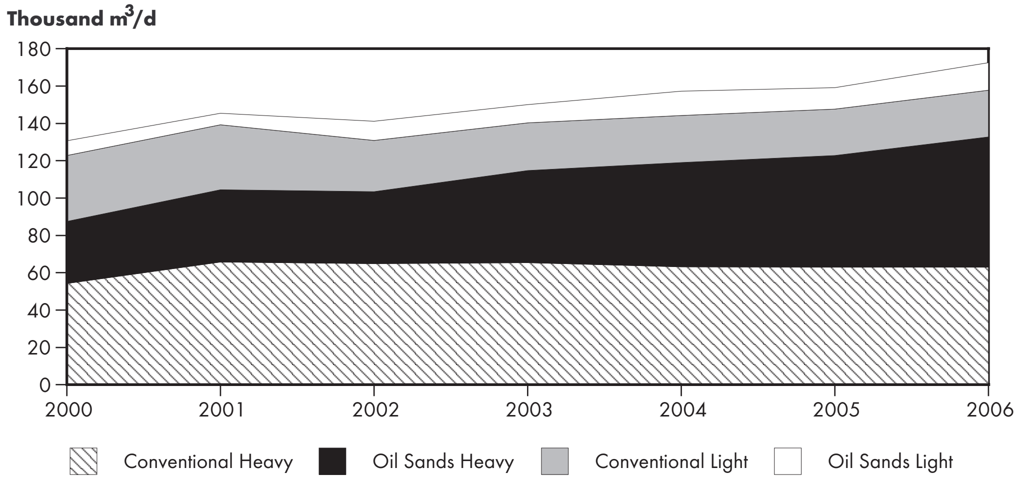
Reduced shipments of conventional light have been replaced by increased heavy shipments resulting, at times, in periods of apportionment. The Terrace Phase III expansion project will expand heavy oil capacity by 39 000 m^3/d (246 Mb/d) by converting Line 3 from light service to heavy and converting Line 2 from heavy to light. It is estimated that this line swap will occur between October and November 2005.

The Spearhead and Mobil 20" reversal pipeline projects will provide market access to southern PADD II and the USGC, respectively. Heavy crude oil shipments are expected to increase on Enbridge with combined commitments for both lines at 17 480 m^3/d (110 Mb/d). Mobil anticipates the completion of the reversal by the fourth quarter 2005 while Enbridge expects that Spearhead will be operational in January 2006.

Line 9 is currently operating at capacity and has experienced periods of apportionment. It is expected that Line 9 will remain at capacity through 2006 even though Petro-Canada's Oakville, Ontario refinery closed in April 2005.

FIGURE 6.3

Enbridge Mainline Export Volumes



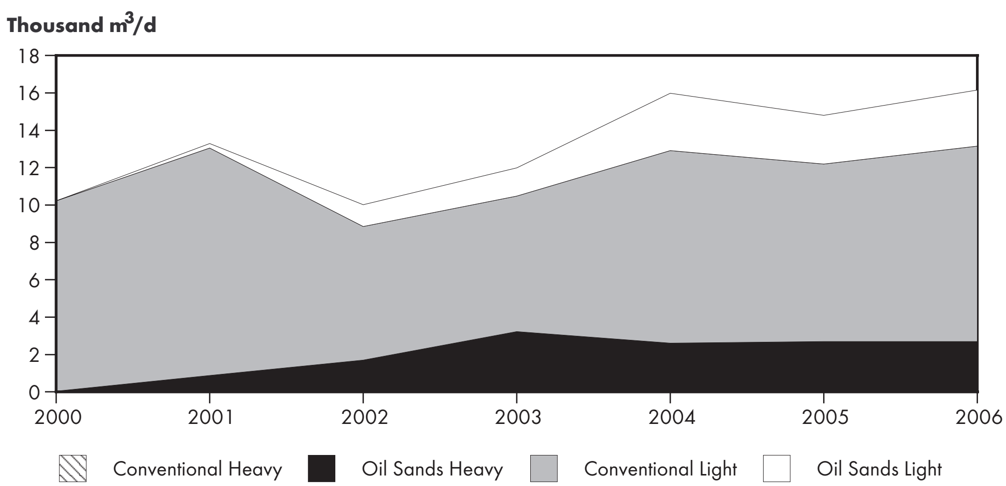
6.2.2 Terasen Pipelines (Trans Mountain) Inc. (TPTM)

TPTM is a single line system that transports crude oil, alkylates and refined petroleum products. The majority of the crude oil enters the system at Edmonton, but it does have the capability to receive volumes of B.C.-produced crude oil at Kamloops. TPTM recently completed a small expansion, which increased its throughput capacity by 4 300 m^3/d (27 Mb/d). This capacity increase is mainly for light crude oil.

Figure 6.4 shows that, historically, volumes transported on TPTM have been conventional light. However, over the past five years, increasing volumes of blended bitumen have been shipped. These volumes are being delivered primarily to the Westridge marine terminal for tanker transportation to California, Asia or the USGC.

FIGURE 6.4

Terasen Pipelines (Trans Mountain) Export Volumes



Increased demand by Washington refineries for light crude together with growing shipments of heavy grades resulted in apportionment over the past year and a half. It is anticipated that TPTM will continue to operate at capacity through 2006.

The first phase of Terasen Pipelines Inc.'s Trans Mountain Expansion Project (TMX) project will increase capacity by 5 560 m^3/d (35 Mb/d) with an in-service date of April 2007.

6.2.3 *Express Pipeline*

The Express system was built in 1997 to expand markets for western Canadian crude by increasing access into PADD IV and southern PADD II. Express differs from Enbridge and TPTM in that 85 percent of its capacity is contract carriage.

The maturation of the WCSB has resulted in reduced shipments of conventional heavy and light on Express while shipments of oil sands derived crudes have grown.

Originally Express had a capacity of 27 320 m^3/d (172 Mb/d) and in April 2005, it was expanded to 44 800 m^3/d (282 Mb/d). Prior to the expansion, the pipeline was operating at capacity. Forecasts indicate it will operate around 90 percent capacity for the remainder of 2005. At this time, there are no publicly announced plans for further expansion.

6.3 Outlook

Short-term capacity pipeline expansion projects to transport western Canadian crude oil include:

- the Express expansion completed in April 2005 to 44 800 m^3/d (282 Mb/d);
- the Enbridge Spearhead and Mobil 20" reversal pipeline projects to southern PADD II and the USGC, respectively. Mobil anticipates the completion of the line reversal by fourth quarter 2005 while Enbridge expects that Spearhead will be in operation by January 2006; and
- Terasen's Trans Mountain Expansion Project (TMX1) to expand capacity by 5 560 m^3/d (35 Mb/d) possibly by April 2007.

FIGURE 6.5

Express Export Volumes

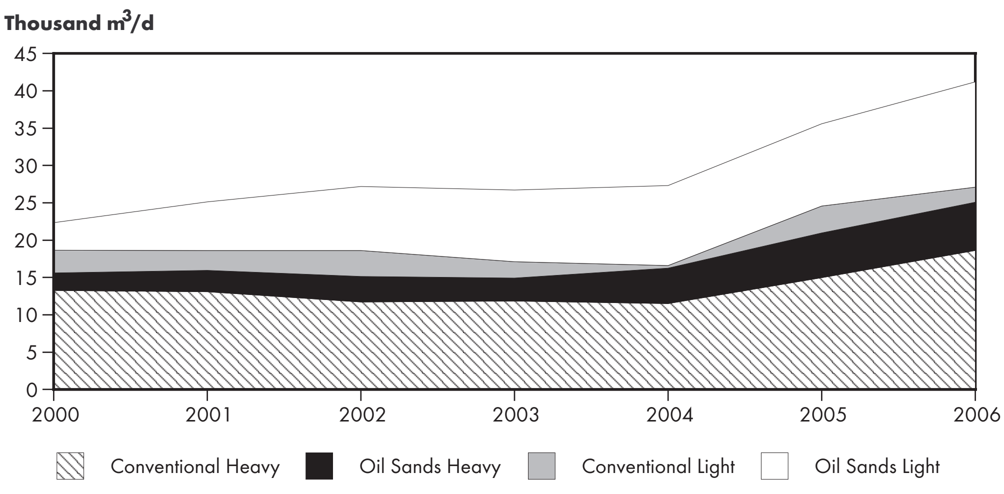


TABLE 6.1

Major Export Pipeline Proposals

		Incremental Capacity (m^3/d)	Anticipated Completion Date
Terasen (TPTM TMX1)	Phase 1	5 560	End 2006
	Phase 2	6 340	Mid-2008
Terasen (TPTM TMX2 Southern Option)		15 900	2009
Terasen (TPTM TMX3 Southern Option)		63 500	2010
Terasen (TPTM Northern Option)		87 400	2010
Enbridge (Gateway)		63 600	Mid-2010
Enbridge (Mainline)	Phase I	19 000	Mid-2008
TransCanada Pipeline (Keystone)		63 500	2008 to 2009

Table 6.1 provides a snapshot of major export pipeline proposals.

Industry has indicated that growth in oil sands production will require a major expansion to existing systems or construction of new pipelines by 2010.

Enbridge Pipelines Inc. proposes to construct the Gateway Pipeline from Edmonton to a deepwater port in Kitimat or Prince Rupert, B.C. This new 30-inch line would have a design capacity of 63 500 m^3/d (400 Mb/d). Enbridge has entered into a Memorandum of Understanding (MOU) with PetroChina International Company Limited concerning the development of the Gateway Pipeline. Enbridge will assist by aggregating long-term crude oil supplies for the Chinese company.

Enbridge has announced that the Canadian mainline will need to be expanded under its proposed Southern Access Program. The Program is proposing a four-phase approach that would include an expansion of its mainline as early as mid-2008 for Phase I. Phase I would include debottlenecking Lines 3 and 4 with a capacity expansion of 19 000 m^3/d (120 Mb/d). In addition, a four-staged approach is proposed ex-Superior, Line 14 would be looped and pump stations would be added on Line 6 increasing capacity by 20 000 m^3/d (125 Mb/d). Total new capacity under this Program in Canada would approximate 50 000 m^3/d (315 Mb/d) and about 62 500 m^3/d (395 Mb/d) ex-Superior.

The two-phase approach to Terasen's TMX1 project would add a total of 11 900 m^3/d (75 Mb/d) by 2008. The company is proposing two optional routes for further expansion. Both of these routes require the completion of TMX 1. The Southern Option proposed in TMX2 and TMX3 would expand the entire system to Burnaby, B.C. This option would essentially loop the entire system allowing for the segregation of products on one of the lines. The Northern Option would incorporate the construction of a new line near Valemount, B.C. to the port of Kitimat or Prince Rupert, B.C. The total proposed capacity for the project would be 127 000 m^3/d (850 Mb/d) regardless of the chosen option.

TransCanada Corporation announced its proposed Keystone Pipeline project in February 2005, aimed at transporting 63 500 m^3/d (400 Mb/d) of heavy crude oil from Hardisty, Alberta to Wood River/Patoka, Illinois. The company proposes to convert an existing natural gas pipeline in Canada to oil service and construct a new pipeline from the Canada/United States border to Wood River/Patoka, Illinois.

ON THE WEB

Canadian Energy Pipeline Association
http://www.cepa.com/Index.aspx?page_guid=3B002ED5-4E32-4F00-8EBE-2BC89C01D5B6

Enbridge Inc.
http://www.enbridge.com/

Terasen Inc.
http://www.terasen.com/Inc/Default.htm

TransCanada PipeLines Inc.
http://www.transcanada.com/

Petroleum Products

7.1 Introduction

There are 19 refineries operating in Canada. Two of these produce either asphalt or petrochemicals while the remaining 17 produce a broad range of refined petroleum products. Figure 7.1 shows the locations of Canada's refineries. Generally, refineries were built to supply regional markets; however, inter-provincial and international trade also occurs.

Figure 7.2 shows that Canadian refining capacity has grown moderately in recent years and capacity utilization has been relatively high.

In 2005 and 2006 there are no major refinery expansions planned. Over this forecast period, "capacity creep" is assumed to add one percent per year to capacity, and refinery utilization is expected to remain above 90 percent.

Refiners are planning an estimated $5.3 billion in investments through 2010 to meet Environment Canada's regulations for the reduction of sulphur in fuels (Table 7.1).

FIGURE 7.1

Canadian Refineries (thousand m^3/d)

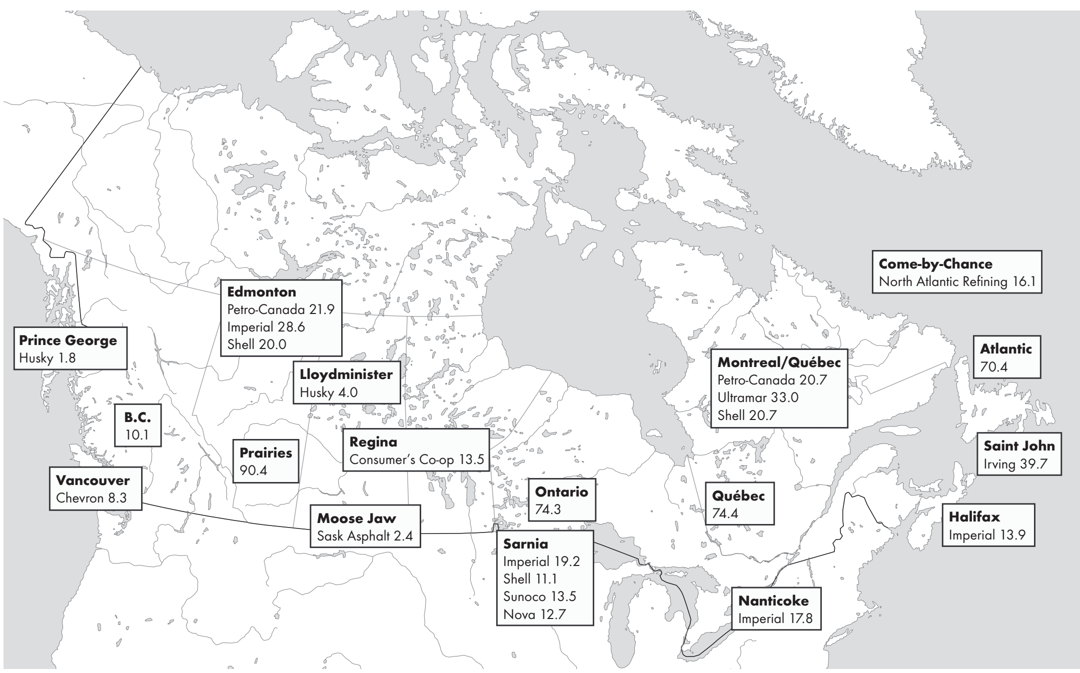


FIGURE 7.2

Canadian Refining Capacity and Utilization

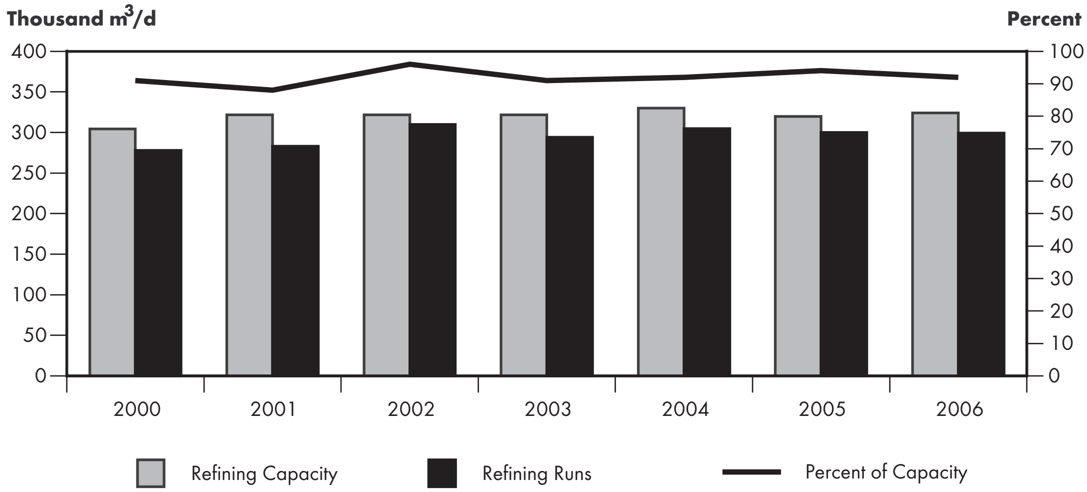


TABLE 7.1

Low Sulphur Fuel Targets

Gasoline	30 ppm	2005
On-road Diesel	15 ppm	2006
Off-road Diesel	500 ppm	2007
Off-road Diesel	15 ppm	2010
Furnance Fuel Oil	1000 ppm	2010

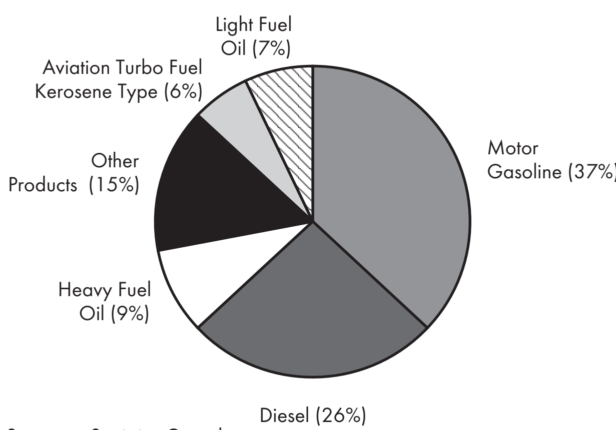
7.2 Petroleum Product Domestic Demand Trends

When crude oil is processed, the hydrocarbons are sorted, split apart and reassembled and blended at refineries and petrochemical plants before they can be used in a multitude of products ranging from gasoline to synthetic rubber. Figure 7.3 shows domestic sales of refined petroleum products. Almost 70 percent of domestic sales are transportation fuels, including aviation turbo fuel, gasoline and diesel. These percentages may vary by season. In the summer, refineries increase their output of gasoline and asphalt, while in the winter they produce more heating fuel or light fuel oil.

Figure 7.4 shows gasoline, diesel and jet fuel sales for the period 2000 to 2004 and an outlook to 2006. Gasoline sales for the period 2000 to 2004 have increased over seven percent, while diesel sales have increased almost eight percent. Jet fuel demand was reduced following the terrorist attacks in September 2001 and the SARS outbreak in Asia and in Canada.

FIGURE 7.3

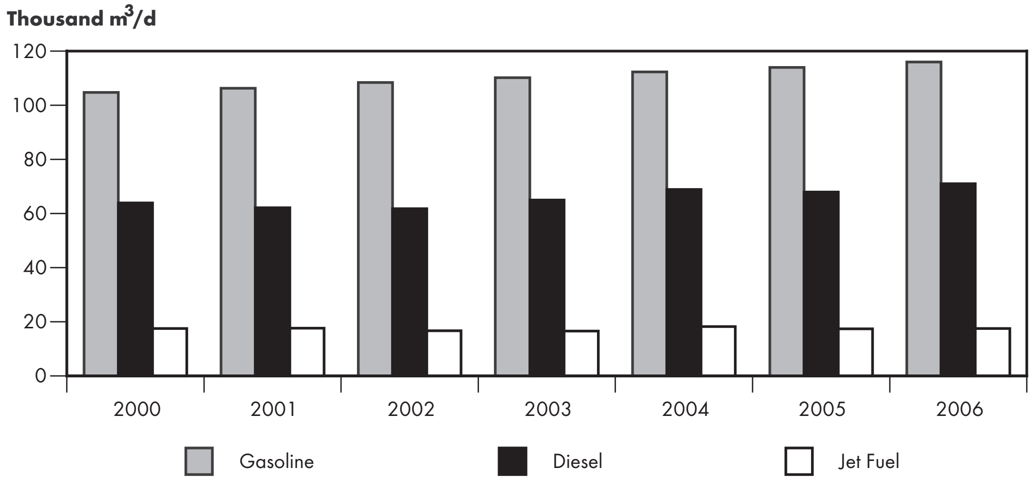
Domestic Sales of Refined Petroleum Products – March 2005



Source: Statistics Canada

FIGURE 7.4

Domestic Sales of Gasoline, Diesel and Jet Fuel



Source: Statistics Canada

Strong demand for transportation fuels reflects robust economic growth, increases in personal disposable income and, in the case of gasoline and diesel, continued consumer preference for SUVs. During this period, there have been no changes in fuel economy levels. To date, demand growth for diesel and gasoline supports the view that prices have not yet reached the level required to significantly alter driving behaviors, although there are signals that this may be changing.

The increasing number and size of vehicles is contributing to the problem of air pollution. In response, federal and provincial governments have supported or mandated the use of ethanol in gasoline to reduce greenhouse gas (GHG) emissions. There are five ethanol plants in Canada and they produce approximately 190 million litres per year of anhydrous ethanol suitable for blending with gasoline. In 2003, estimated consumption of ethanol was 280 million litres. The Ethanol Expansion Program (EEP) announced on 12 August 2003 by the Federal Government, is intended to expand ethanol production and use in Canada. The first round of the program totals $78 million in contributions.

To date, eleven projects have been approved with production estimated to be 1.2 billion litres of ethanol per year by the end of 2007. Under its climate change plan, the federal government is targeting 35 percent of all gasoline to contain a blend of ethanol by 2010. Saskatchewan, Manitoba and Ontario have proposed legislation to increase ethanol in the gasoline pool. In addition, Ontario is also proposing legislation to mandate biodiesel volumes.

Crude oil accounts for about half of the retail price of gasoline. Figure 7.5 shows, as expected, that wholesale and retail gasoline prices track closely the price of crude oil. On average, between 2000 and 2005 retail prices were almost 75 cents/litre and wholesale prices were almost 40 cents/litre. Gasoline prices are typically unregulated and rise and fall with market conditions;

What are Biofuels?

- Biofuels are made from biological products.
- Ethanol is a commercial alcohol made from grain and cellulose fibres.
- During its production and use ethanol can reduce GHG emissions by 40 percent for grain and 80 percent for cellulose fibres.
- Biodiesel is a diesel fuel substitute made from vegetable oils and animal fats.
- Both ethanol and biodiesel can be blended with gasoline and diesel, respectively.

Four Key Components of Retail Gasoline Prices
1. Cost of crude oil purchased by the refinery.
2. Refining margin: the gasoline rack price less the cost of crude oil. This margin would cover all fixed and variable costs associated with operating a refinery.
3. Marketing margin: the Ex-Tax pump price less the rack price. The revenue is used for product sales (all costs associated with operating a gas station, supply costs and profit for the dealer and the supplier) and freight.
4. Federal and provincial taxes.

however, Prince Edward Island and Newfoundland regulate the price of gasoline at the pump. While there is no evidence to suggest that prices are lower in regulated markets, it does appear to reduce price volatility.

With a crude oil outlook of above US$50 per barrel for WTI, it is expected that Canadian gasoline prices will remain high averaging above 80 cents/litre through 2006.

Figure 7.6 shows the domestic sales of refined petroleum products for 2000 to 2004 and an outlook to 2006. Generally, demand for all refined products has increased reflecting strong economic growth in Canada and this trend is expected to continue through 2006.

Light fuel oil is used primarily for heating in Ontario and eastern Canada in areas where there is limited access to natural gas. During the past five years, temperatures have generally been normal or above normal resulting in flat sales volumes. Through to 2006, no growth in heating oil sales is expected.

Heavy fuel oil is typically used in heavy industries in the provinces of British Columbia, Québec and Ontario and for electricity generation in New Brunswick and Nova Scotia. Some industrial users have fuel-switching capability that results in increased demand when natural gas prices rise, particularly during the heating season. The environmental benefits of natural gas continue to limit the demand growth for heavy fuel oil. Other products include: petrochemical feedstock, asphalt, coke, Liquefied Petroleum Gases (LPGs), lube oil and greases. Petrochemical demand represents the largest component of this category. Strong economic growth has increased petrochemical demand. Refer to the Board's October 2005 EMA, *Short-Term Outlook for Natural Gas and Natural Gas Liquids to 2006*, for a detailed analysis of natural gas and natural gas liquids (NGL) supply, prices and markets. Through 2006, demand is expected to remain flat for the other category.

FIGURE 7.5

Edmonton Par Price versus Average Canadian Wholesale and Retail Gasoline Prices

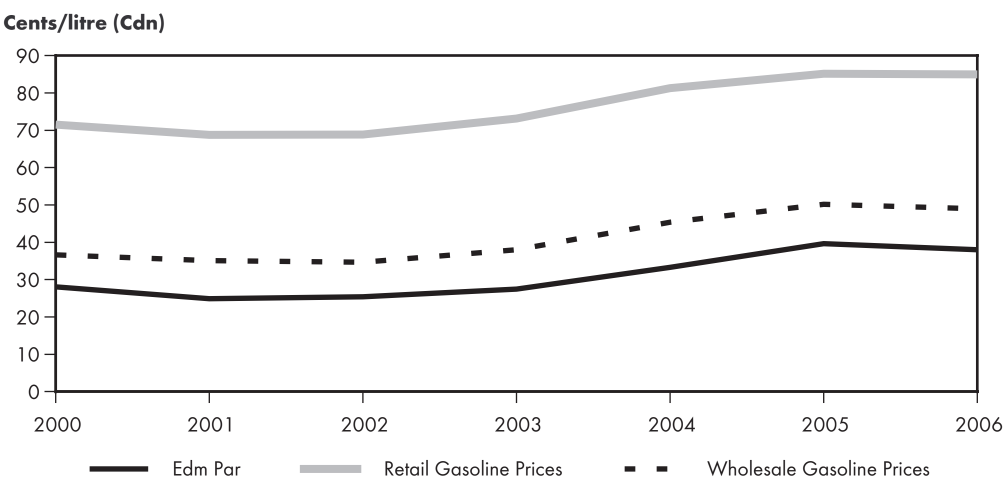
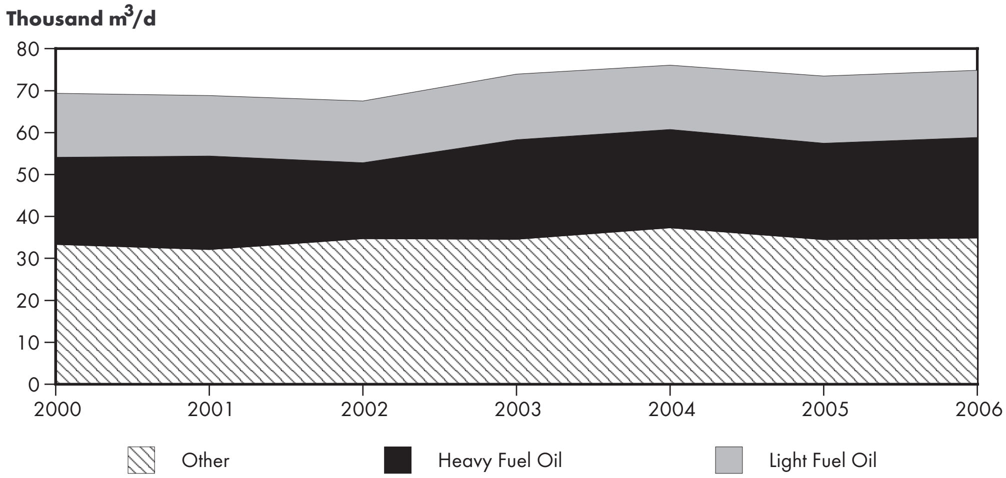


FIGURE 7.6

Domestic Sales of Light and Heavy Fuel Oil and Other Petroleum Products



Source: Statistics Canada

7.3 Impact of High Oil Prices

Oil markets are driven by the global demand for petroleum products. Today, oil is at the centre of the entire energy complex and higher oil prices generally lead to higher natural gas and electricity prices. Rising oil prices therefore raise both the cost of energy and the cost of petroleum as an input into production. In this connection, high energy costs contribute to inflation and unemployment and are a potential threat to economic growth.

Generally, the economies of developed countries, such as Canada and the U.S., are less sensitive to oil prices today than in the past since the energy consumption per unit of Gross Domestic Product (GDP) has declined. Figure 7.7 shows that Canadian energy consumption per dollar of GDP has fallen by about 35 percent since 1973. Over the same time period, personal expenditures on energy in Canada (residential energy and motor fuels) as a percentage of total consumer expenditures have exhibited a similar profile of decline.

FIGURE 7.7

Energy Consumption per Dollar of Canadian GDP

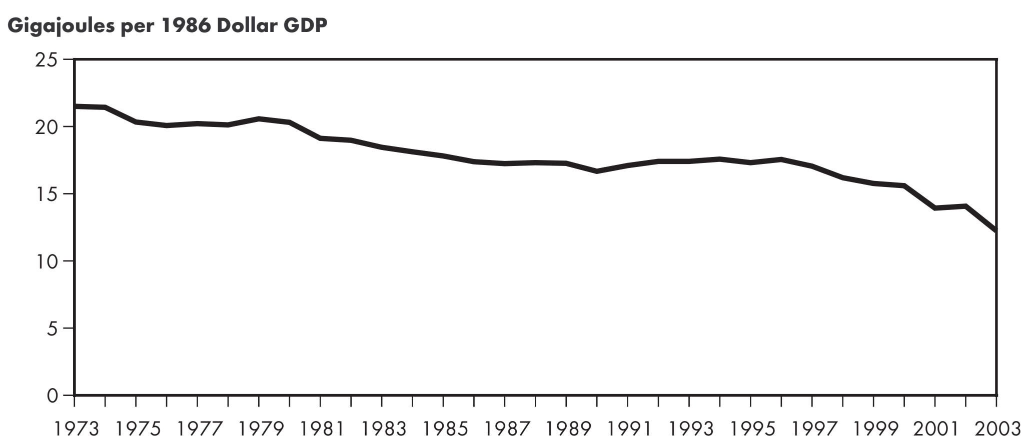
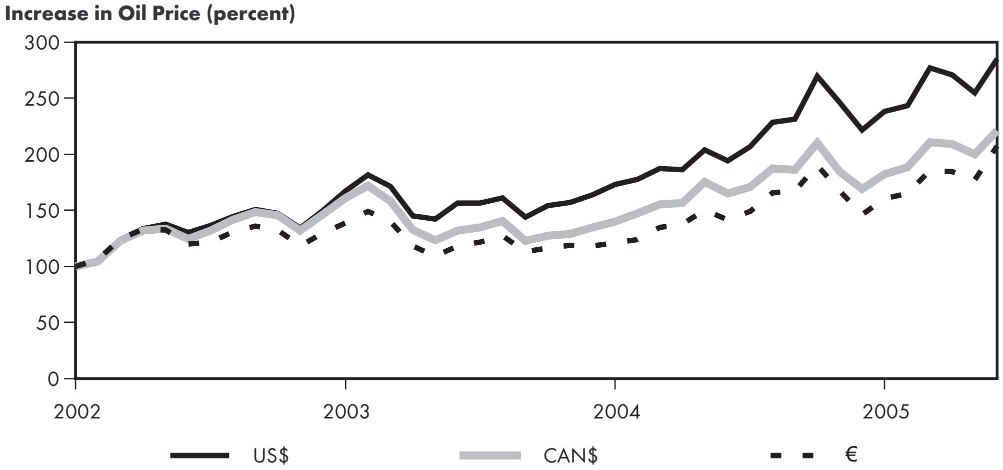


FIGURE 7.8

Currency Effect on WTI Prices



Economists are divided on whether, as a net exporter of oil, Canada as a whole is benefiting from the rapid rise in oil prices. A rise in energy prices represents a transfer of wealth from importing nations to exporting nations, and this effect is becoming more pronounced in Canada as oil production increases and net energy exports rise in-step. The debate is whether economic gains in the oil producing provinces of Alberta, Saskatchewan and Newfoundland are sufficient to offset the reduction in disposable income of citizens and the increased costs to energy intensive industries such as manufacturing and exporting in central Canada.

From the standpoint of the manufacturing industry, high energy prices are squeezing profits and putting pressure on company cash flow, which could result in under-investment and reduce future productive capacity. Canadian companies generally face the same high energy prices as their competitors around the world but, because of the appreciating Canadian dollar, energy prices domestically have not risen as much as prices in the U.S. Therefore, Canadian exporters to the U.S. may actually have a cost advantage. Figure 7.8 shows the WTI price at Cushing, Oklahoma adjusted for appreciation in the value of the Canadian dollar and Euro versus the U.S. dollar. Since January 2002, WTI in Canadian dollars has increased by 220 percent versus an increase of nearly 285 percent in the U.S.

Over the long-term, persistent high oil prices will encourage industries and consumers to invest in energy-saving technologies.

7.4 Outlook

It is expected that strong economic growth and the associated demand for petroleum products will keep refinery utilization rates very high at approximately 90 percent. There is no major refinery expansion projects planned within the timeframe of this report.

Since 2003, domestic demand for gasoline and diesel does not appear to have been affected by higher prices. Demand growth for both fuels is predicted to rise moderately in 2005 and 2006.

The net economic impact of higher oil prices for Canada as a whole is unclear. Although high oil prices enrich producing provinces, they represent a reduction in real income for consumers and a significant business challenge for many Canadian industries. Persistent high energy prices can be expected to spur investment in energy saving technologies in the longer term.

ON THE WEB

Canadian Petroleum Products Institute
http://www.cppi.ca/

Centre for Energy
http://www.centreforenergy.com/silos/ET-CanEn01.asp

Canadian Renewable Fuels Association
http://www.greenfuels.org/index.htm

Government of Canada Office of Climate Change
http://www.climatechange.gc.ca/english/

Environment Canada
http://www.ec.gc.ca

Conclusions

Strong global economic growth and the associated demand for crude oil is expected to continue to drive oil markets through 2006 keeping oil prices in the area of US$50 per barrel. Product shortages, weather or a crude supply interruption could quickly propel oil prices significantly higher while there would need to be a substantial decline in demand to drive prices below US$40 per barrel.

Canada is the world's eighth largest producer of crude oil and production is growing as a result of strong oil markets spurring investment in the oil sands and the Newfoundland offshore. By year-end 2006, total Canadian production is projected to exceed 2004 levels by 13 percent reaching 458 000 m^3/d (2.9 MMb/d). Industry is working together to address the need for new markets and expanded pipeline capacity to handle growing oil sands production. It is conceivable that by the end of 2006 a major export pipeline application could be filed with the Board.

Since 2003, domestic demand for gasoline and diesel does not appear to have been materially affected by higher prices. Demand for both fuels is predicted to rise moderately in 2005 and 2006, despite the expectation that higher pump prices will endure.

Recommendation

The net economic impact of higher oil prices for Canada as a whole is unclear. Although high oil prices enrich producing provinces, they represent a reduction in real income for consumers and pose a significant business challenge for many Canadian industries. In this connection, the NEB recommends that all levels of government continue to collaborate to enhance public and industry access to high-quality data and analysis.

GLOSSARY

Apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
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.
Asian Tigers	Refers to the countries of India, Malaysia, Indonesia, Hong Kong, Japan, Korea and Thailand and are located in eastern Asia.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 imperial gallons.
Benchmark Crudes	West Texas Intermediate (WTI), Dubai (Middle East) and Brent (U.K.).
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.
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.
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.
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.
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 C5+, 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 naphtha, 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.
Enhanced Oil Recovery	Any method for enhancing oil recovery from a pool over what would be obtained through natural depletion.
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.
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 C5+.
Miscible	Phases that can mix and form a homogeneous mixture. Hydrocarbon gases and liquids are commonly miscible.
Miscible flood	A general term for injection processes that introduce miscible gases into the reservoir to improve oil recovery.
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.
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.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Real Price	The price of a commodity after adjusting for inflation. In this report most real energy prices are expressed in 2003 dollars.
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.
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.
Stand Alone Upgrader	An upgrading facility that is not associated with a mining plant or a refinery.
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 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).

Updip, downdip	Located up the slope of a dipping plane or surface. In a dipping (not flat-lying) hydrocarbon reservoir that contains gas, oil and water, the gas is updip, the gas-oil contact is downdip from the gas, and the oil-water contact is still farther downdip.
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.

IN SITU BITUMEN PROJECTS

The two major types of bitumen recovery from the oil sands include mining and in situ. In a mining operation, oil sand is taken by truck to a crusher that sizes the ore so that it can be transported to the extraction plant as slurry. During extraction, the bitumen is separated from water, sands and other materials in preparation for upgrading. Upgrading is the final stage of the process whereby tar-like bitumen is converted into refinery-ready synthetic crude oil and, in some cases, petroleum products.

Steam-Assisted Gravity Drainage (SAGD) is becoming the dominant in situ technology used today to access oil sands deposits that are too deep to be surface mined. The SAGD process uses a pair of closely spaced horizontal wells in which the producer well is positioned near the bottom of the reservoir and the steam injection well is positioned directly above. Steam is continuously injected into the upper well to melt the bitumen and allow it to drain into the production well where it is pumped to the surface.

- At Imperial's Cold Lake CSS project, the commissioning of Phases 11 to 13, also known as Makheses, in late 2002, raised capacity to about 21 000 m^3/d (130 Mb/d), consistent with its plan to increase production by about five percent per year. Plans are to put Phases 14-16 (Nabiye) into production in 2007.
- EnCana began operation of its SAGD project at Christina Lake in the second quarter of 2002, and in 2003 the project produced 840 m^3/d (5 Mb/d) from three SAGD well pairs.
- EnCana's Foster Creek SAGD project 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.
- Petro-Canada's Mackay River SAGD project began production in 2002, and in 2003 reached close to its target capacity of 4 770 m^3/d (30 Mb/d). There are currently no plans for expansion.
- Suncor's Firebag SAGD project is designed to provide additional feedstock to Suncor's upgrading facilities, but can also be sold directly to market. 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 late 2005. Firebag development plans call for four phases of 5 560 m^3/d (35 Mb/d) to be in place by 2010. Phase 1 was completed in 2004, with Phase 2 scheduled to be completed in 2006.
- CNRL has been expanding its operations at Wolf Lake and Primrose projects. Phase 2A is a 500 m^3/d (3 Mb/d) expansion at Primrose South/Wolf Lake, scheduled for 2005. Phase 2B is a 4 770 m^3/d (30 Mb/d) expansion at Primrose North, scheduled for start-up in 2006.
- ConocoPhillips' SAGD project at Surmont is scheduled to come on stream in 2006 with Phase 1 design capacity of 4 000 m^3/d (25 Mb/d).

- Deer Creek Energy is building a SAGD project at Joslyn Creek, scheduled to begin commercial-scale production in 2007, with a design capacity of 5 560 m^3/d (35 Mb/d).
- Husky's SAGD project at Tucker Lake has a design capacity of 4 770 m^3/d (30 Mb/d) and is scheduled to come on stream in 2006.
- Shell's Peace River project is being expanded to increase production to its current plant capacity of 1 900 m^3/d (12 Mb/d). Drilling of additional wells is expected to begin in 2005 with production scheduled to come on stream in 2006.

CONVERSION FACTORS

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 or Bbl	barrel (oil, LPG)	0.159 m^3

Crude Oil		**Energy Content**
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ