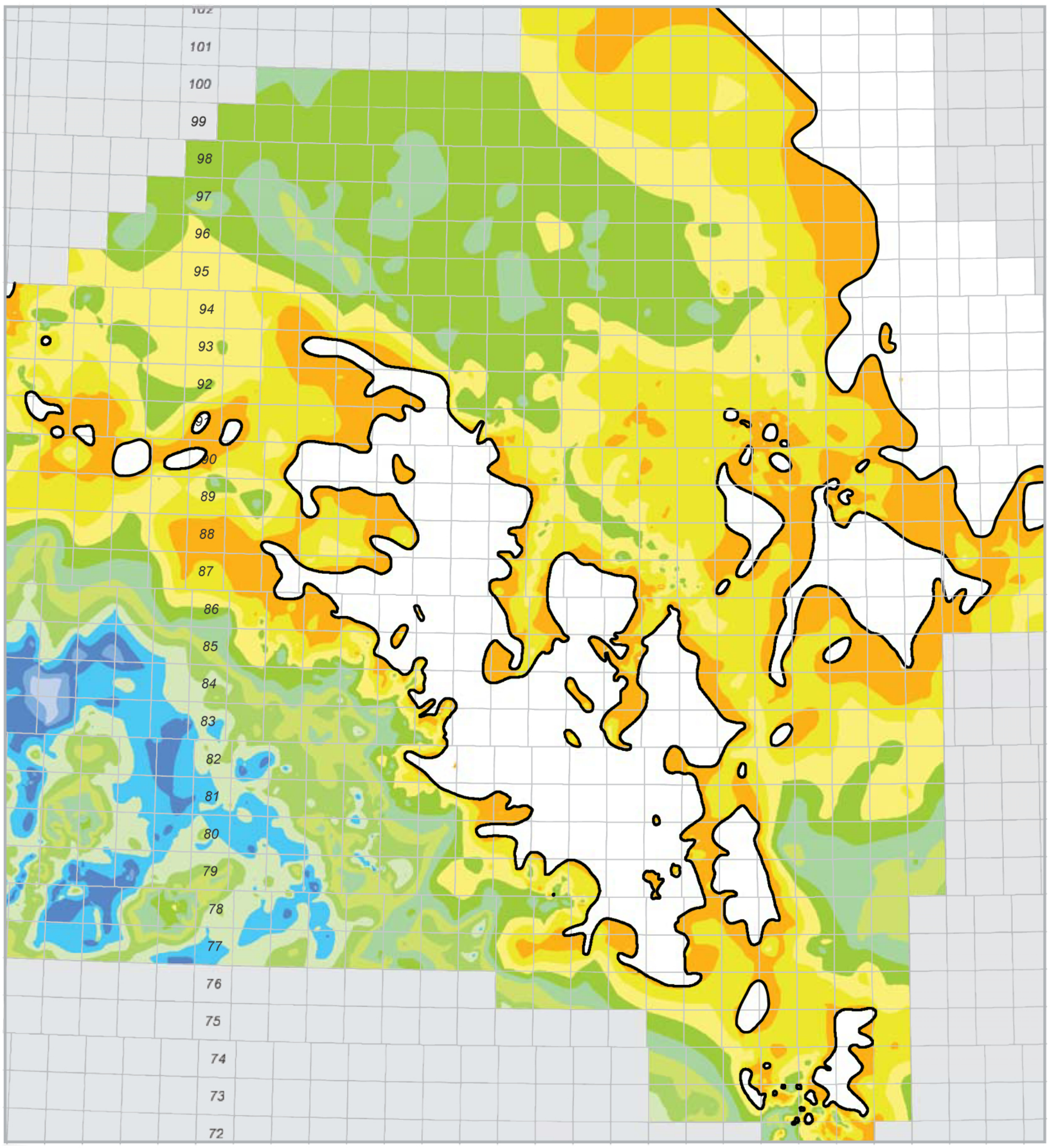
ST98-2007

Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016



Alberta Energy and Utilities Board

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Errata—June 15, 2007

The following changes have been incorporated into the print and Web versions of *ST98-2007*:

Section	Old	New
Overview, page 10, Figure 7 legend	~~SCO~~ price	Bitumen price
2.2.2, page 2-19, first paragraph	~~2005~~	2006
Table 4.1, page 4-1, change in Initial established reserves	~~5.0~~	4.8

Contents

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Overview

The Alberta Energy and Utilities Board (EUB) is an independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources and utilities services take place in a manner that is fair, responsible, and in the public interest. As part of its legislated mandate, the EUB provides for the appraisal of the reserves and their productive capacity and the requirements for energy resources and energy in Alberta.

Providing information to support good decision-making is a key service of the EUB. Making energy resource data available to everyone involved—the EUB, landowners, communities, industry, government, and interested groups—results in better decisions that affect the development of Alberta's resources.

Every year the EUB issues a report providing stakeholders with one of the most reliable sources of information on the state of reserves, supply, and demand for Alberta's diverse energy resources—crude bitumen, crude oil, natural gas, natural gas liquids, coal, and sulphur. This year's *Alberta Energy Reserves 2006 and Supply/Demand Outlook 2007-2016* includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (includes reserves that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources.

In this year's report, the EUB has added a new section on Alberta's electricity outlook. As well, some historical trends on selected commodities are provided for better understanding of supply and price relationships.

Energy Prices and Alberta's Economy

For world energy markets, 2006 will be remembered as a year dominated by geopolitics and the inventory fluctuation in the United States, the world's largest oil-consuming nation. A major decline in Nigeria's production due to political unrest and the escalation of tension in the Middle East due to the war between Israel and Lebanon during the summer months were among the geopolitical events in 2006. These factors caused world crude oil prices to skyrocket to their highest levels yet. In the Unites States, warmer-than-usual weather and a calm hurricane season allowed crude oil inventories to increase and eased the tension in the market. As a result, crude oil prices dropped during the last quarter of the year.

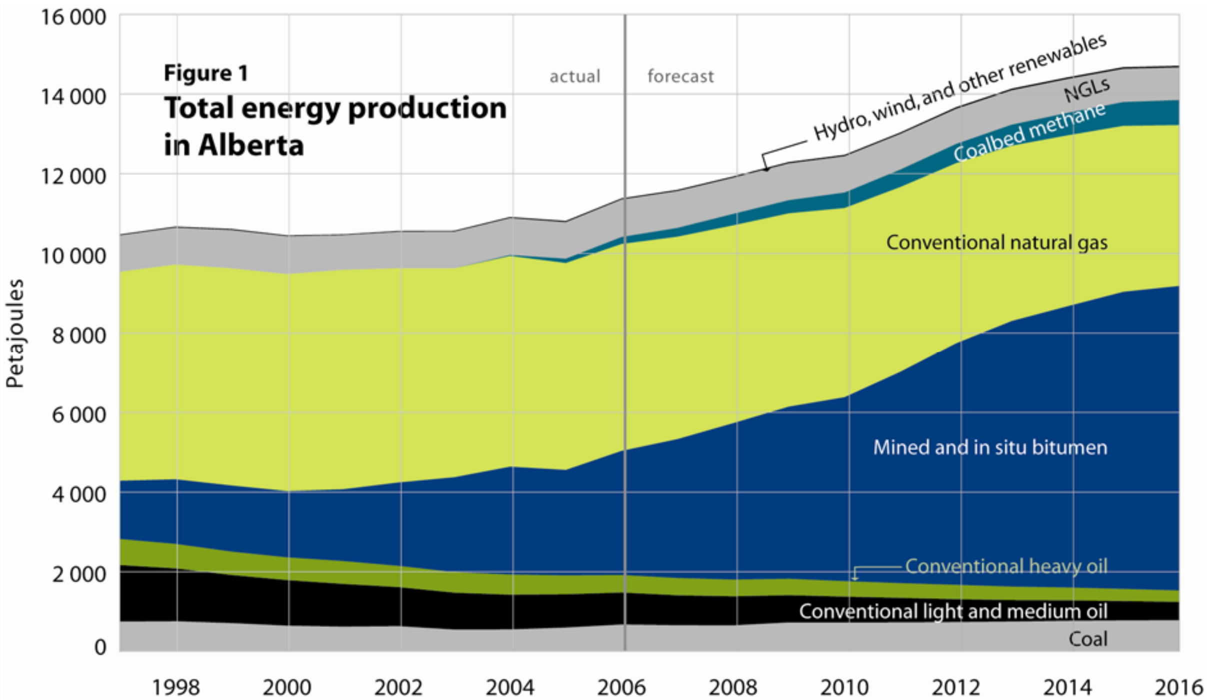
The growth in world oil demand also slowed, as demand in the United States, Europe, and some Pacific countries declined. World oil supply grew more than demand, leading to somewhat larger spare capacity in the Organization of Petroleum Exporting Countries (OPEC), particularly Saudi Arabia.

The EUB is basing its analysis on the expectations that the crude oil price in North America, measured by West Texas Intermediate (WTI) crude oil, will average US$62 per barrel in 2007 and rise steadily to an average of US$69 per barrel by 2016.

North American natural gas prices and drilling activity were also impacted by warmer-than-usual weather in 2006. Natural gas storage levels in North America remained well above their five-year average. As a result, natural gas prices declined compared with 2005. The Alberta price of natural gas at the plant gate is expected to average Cdn$7.25 per gigajoule in 2007 and then rise steadily to Cdn$8.35 per gigajoule by 2016.

Energy Production in Alberta

While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy is also produced from renewable energy sources. In 2006, Alberta produced 11 378 petajoules of energy from all sources, including renewable sources such as hydro and wind power. This is equivalent to 5.1 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by these energy sources is illustrated in **Figure 1**.



The remainder of this report focuses on nonrenewable energy resources. This section provides an overview of the reserves and production from these sources.

Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to extract bitumen. Raw bitumen production surpassed conventional crude oil production in 2001 for the first time. Production of bitumen has continued its growth, accounting for 70 per cent of Alberta's total crude oil and raw bitumen production in 2006. The value-added process of upgrading raw bitumen to synthetic crude oil (SCO) was expanded in 2006.[1] Bitumen production at in situ projects increased by 13 per cent in 2006, while production at mining projects increased by 21 per cent. As a result, overall raw bitumen production increased by some 18 per cent compared with 2005.

Conventional natural gas production in Alberta held onto 2005 levels in 2006. The EUB has concluded that natural gas production in the province peaked in 2001. Natural gas production in 2007 is expected to decline by 2.2 per cent compared with 2006. High levels of drilling in the past four years have prevented a sharp decline in production.

[1] The upgrading process produces a variety of lighter products that are collectively referred to as SCO in this report. Naphtha, diesel fuel, and a crude similar to light crude oil in quality are the common products in the upgrading process.

Gas production from coalbed methane (CBM) development activity continued to increase in 2006. CBM wells produced 0.17 trillion cubic feet (tcf) of commingled natural gas, an increase of 62 per cent over 2005. CBM contributed 3.4 per cent of the provincial total natural gas production. The EUB anticipates that CBM development activity will continue to increase. The growing amount of information available from high CBM drilling activity has led EUB estimates of established CBM reserves to increase compared with last year.

The following table summarizes Alberta's energy reserves at the end of 2006.

Reserves and production summary, 2006

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in place	270 296	1 701	10 400	65.4	8 516	292	94	103
Initial established	28 392	179	2 704	17.0	4 827	171	35	38
Cumulative production	864	5.4	2 481	15.6	3 687	131	1.30	1.43
Remaining established	27 528	173	250	1.6	1 140[b]	40.5[b]	34	37
Annual production	72.8	0.458	31.5	0.198	138	4.9	0.033	0.036
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Includes CBM, except for Initial in place with no estimate at this time. Expressed as "as is" gas.
[b] Measured at field gate (or 38 trillion cubic feet downstream of straddle plant).
[c] Does not include CBM.

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves for crude bitumen are 27.5 billion cubic metres (m^3) (173 billion barrels), which is slightly less than 2005 due to production. Only 3.0 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

In 2006, Alberta produced 44.1 million m^3 (278 million barrels) from the mineable area and 28.7 million m^3 (180 million barrels) from the in situ area, totalling 72.8 million m^3 (458 million barrels). This is equivalent to199 thousand m^3/day (1.25 million barrels per day). Bitumen produced from mining was upgraded, yielding 38.1 million m^3 (240 million barrels) of SCO. In situ production was mainly marketed as nonupgraded crude bitumen.

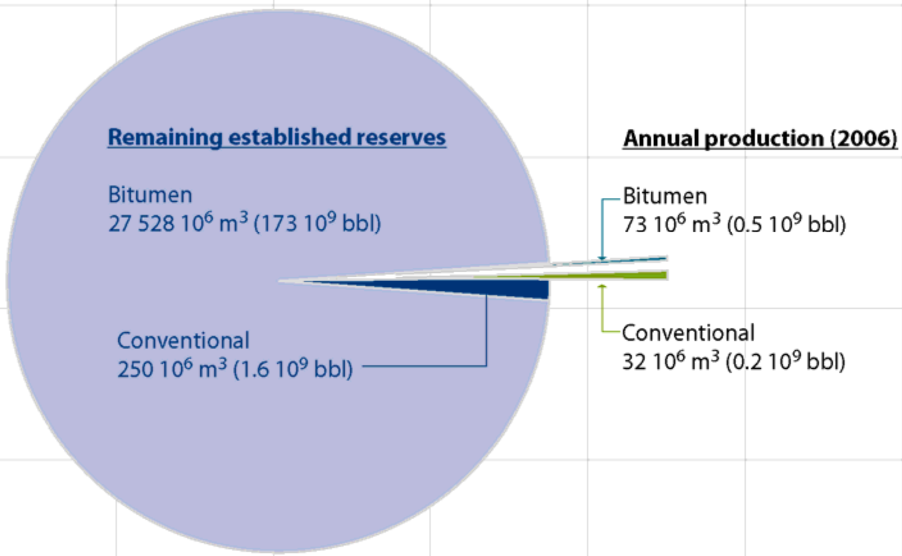
Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 250 million m^3 (1.6 billion barrels), a 2 per cent decrease from 2005. Of the 27.1 million m^3 (171 million barrels) added to the initial established reserves, 24.9 million m^3 (157 million barrels) was due to exploratory and development drilling, as well as new enhanced recovery schemes. This replaced 79 per cent of the 2006 production. Positive revisions accounted for the remaining 2.2 million m^3 (14 million barrels).

Based on its 1988 study, the EUB estimates the ultimate potential recoverable reserves of crude oil at 3130 million m^3 (19.7 billion barrels). The EUB believes that this estimate of ultimate potential is still reasonable. Future improvements in technology could improve the current average recovery efficiency of 26 per cent.

Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 2**.

Figure 2
Alberta oil reserves



Crude Oil Production and Drilling

Alberta's production of conventional crude oil totalled 31.5 million m^3 (198 million barrels) in 2006. This equates to 86 400 m^3/day (543 700 barrels/day).

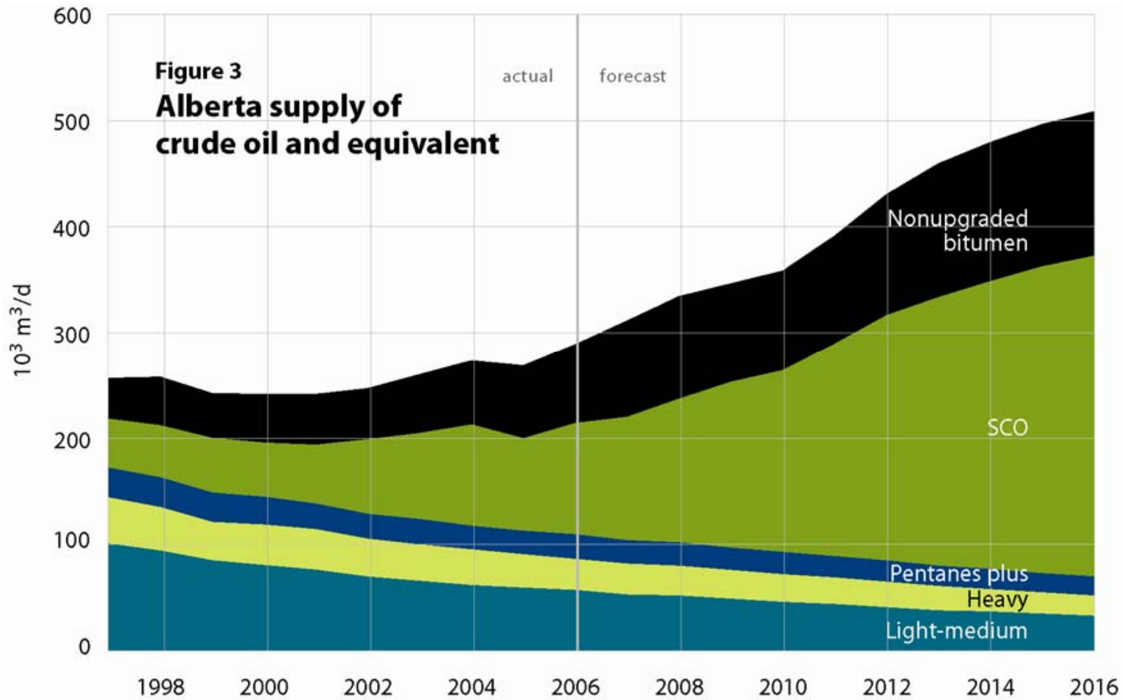
The number of oil wells placed on production increased by 4 per cent to 1956 in 2006 from 1881 in 2005. With the expectation that crude oil prices will remain strong, the EUB estimates that the number of new wells placed on production will increase to 2000 wells in 2007 and remain at this level over the forecast period.

Total Oil Supply and Demand

Alberta's 2006 production from conventional oil, oil sands, and pentanes plus was 289 000 m^3/day (1.82 million barrels/day), a 7 per cent increase compared with 2005. Production is forecast to reach 507 000 m^3/day (3.2 million barrels/day) by 2016.

A comparison of conventional oil and bitumen production, as illustrated in **Figure 3**, over the last 10 years clearly shows the increasing contribution of bitumen to Alberta's oil production. This ability to shift from conventional oil to bitumen is unique to Alberta, allowing the province to offset the continued decline in conventional oil with bitumen production.

The EUB estimates that bitumen production will more than double by 2016. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 62 per cent in 2006 to 86 per cent by 2016.



Natural Gas

Natural gas is produced from two main sources in Alberta at this time. While natural gas production from conventional sources accounts for the majority, natural gas production from coal, CBM, has grown rapidly in the past few years. Natural gas production from other sources, such as shale gas, may prove to be an additional source in the near future.

Coalbed Methane Reserves

CBM has been recognized as a commercial supply of natural gas in Alberta for only the past few years. Activity in CBM has increased dramatically from a few test wells in 2001 to over 6000 wells connected to pipelines in 2006. The growth in CBM data collection and gas production has increased confidence in publication of CBM reserves estimates, despite continuing uncertainty in recovery factors and production accounting.

At the end of 2006, the remaining established reserves of CBM in Alberta is estimated to be 24.7 billion m^3 (877 billion cubic feet). This is limited mainly to the "dry CBM" trend of central Alberta, as other CBM resource development has currently shown commercial producibility in only two fields.

Conventional Natural Gas Reserves

At the end of 2006, Alberta's remaining established reserves of natural gas stood at 1115 billion m^3 (40 tcf) at the field gate. This reserve includes some liquids that are subsequently removed at straddle plants. Reserves from new drilling replaced 68 per cent of production in 2006. This compares with 63 per cent replacement in 2005.

In March 2005, the EUB and the National Energy Board (NEB) jointly released *Report 2005-A*: *Alberta's Ultimate Potential for Conventional Natural Gas*, an updated estimate of the ultimate potential for conventional natural gas. The Boards adopted the medium case, representing an ultimate potential of 6276 billion m^3, or 223 tcf (6528 billion m^3, or 232 tcf, at 37.4 megajoules per m^3). The estimate, which does not include unconventional gas, such as CBM, updates the 5600 billion m^3 stated in the Energy Resources Conservation Board (now EUB) *Report 92-A: Ultimate Potential and Supply of Natural Gas in Alberta*. The primary reason for this increase is a better understanding of the geology of the province as a result of significant increased drilling since 1992.

Natural Gas Production and Drilling

Several major factors have an impact on natural gas production, including natural gas prices, drilling activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. Alberta produced 138.3 billion m^3 (4.9 tcf) of marketable natural gas in 2006, of which 1.2 billion m^3 (0.04 tcf) was CBM.

There were 12 062 successful conventional natural gas wells drilled in Alberta in 2006, a 9 per cent decrease from the 13 271 gas wells drilled in 2005. The EUB expects strong drilling over the forecast period, estimating 12 000 successful wells in 2007, and increasing to 13 000 successful wells per year thereafter.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta, which contains over half of the province's producing gas wells but only 20 per cent of the 2006 natural gas production. The EUB anticipates that shallow drilling will continue to account for a large share of the activity in the province over the next few years.

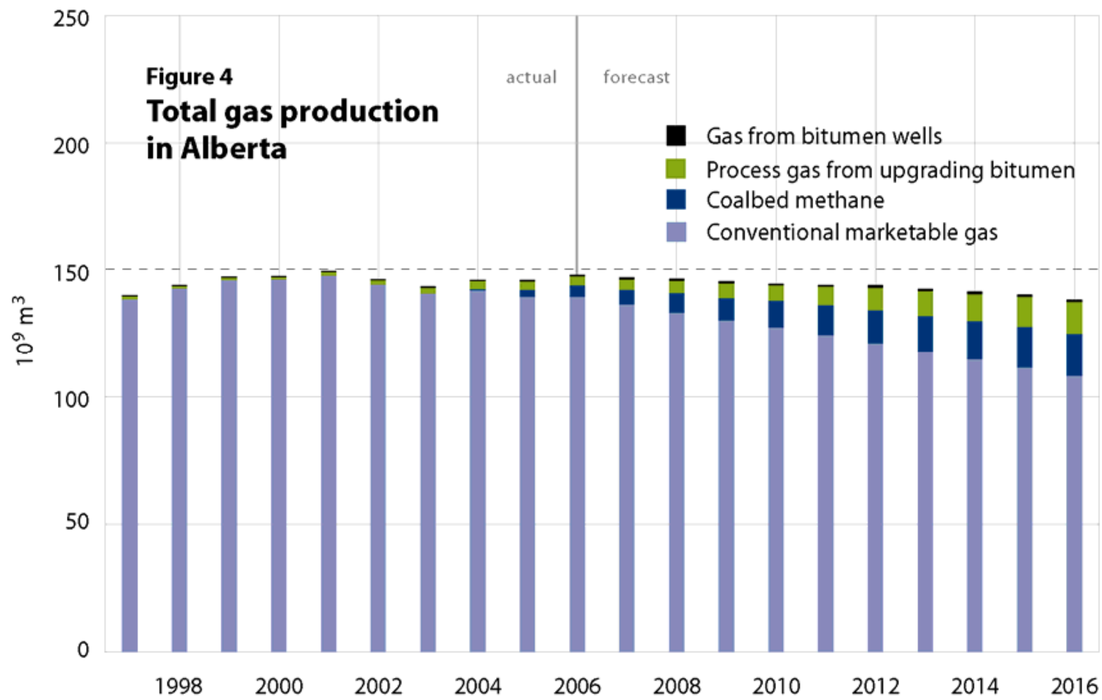
CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 2434 successful CBM well connections in Alberta in 2006. The EUB expects CBM well drilling to decline in 2007 to 1900 wells. The commodity price declines that took place in late 2006 are responsible for a slowdown in CBM and shallow conventional gas drilling, which is expected to continue well into 2007. In 2008 and 2009, some 2400 wells are forecast to be connected annually, increasing to 2500 wells in 2010 and thereafter for the remainder of the forecast period.

Natural Gas Supply and Demand

The EUB expects conventional gas production to decline by an average of 2.5 per cent per year over the forecast period. New pools are smaller, and new wells drilled today are exhibiting lower initial production rates and steeper decline rates. Factoring this in, the EUB believes that new wells drilled will not be able to sustain production levels over the forecast period. CBM production commingled with conventional gas is forecast to supplement the supply of conventional gas in the province. It is expected to increase from 4.7 billion m^3 in 2006 to 16.8 billion m^3 in 2016.

Although natural gas supply from conventional sources is declining, sufficient supply exists to easily meet Alberta's demand. If the EUB's demand forecast is realized, Alberta's natural gas requirement will be 44 per cent of total Alberta production by the end of the forecast period.

As Alberta requirements increase and production declines over time, the volumes available for removal from the province will decline. The EUB's mandate requires that the natural gas requirements for Alberta's core market (defined as residential, commercial, and institutional gas consumers) are met over the long term before any new gas removal permits are approved. **Figure 4** depicts Alberta's marketable gas production and disposition.



Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 125 million m^3 (787 million barrels) as of year-end 2006. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

In 2006, the production of specification ethane increased slightly to 40.6 thousand m^3/day (255 thousand barrels/day) from the 2005 level of 40.1 thousand m^3/day (252 thousand barrels/day). The majority of ethane was used as feedstock for Alberta's petrochemical industry. The supply of ethane is expected to meet demand over the forecast period.

The remaining established reserves of other natural gas liquids (NGLs)—propane, butanes, and pentanes plus—increased to 171 million m^3 (1.1 billion barrels) in 2006. The supply of propane and butanes is expected to meet demand over the forecast period. However, a shortage of pentanes plus as a diluent for heavy oil and nonupgraded bitumen is expected by 2007. Alternative sources of diluent will be required.

The remaining established reserves of sulphur increased in 2006 by 70 million tonnes to 159 million tonnes. Sulphur is recovered from the processing of natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is expected to remain at 2006 levels, and Alberta's sulphur inventory is expected to grow over the forecast period.

Coal

The current estimate for remaining established reserves of all types of coal is about 34 billion tonnes (37 billion tons). Most of this massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 63 per cent of the province's electricity generation in 2006. Alberta's total coal production in 2006 was 32.5 million tonnes of marketable coal, most of which was subbituminous coal destined for mine mouth power plants. Alberta's coal reserves represent over a thousand years of supply at current production levels. Subbituminous coal production is expected to increase over the forecast period to meet demand for additional domestic electrical generating capacity.

The small portion of Alberta coal production that was exported from the province can be separated into thermal coal exports and metallurgical coal exports. Due to continued high oil prices, there has been improved economics in the coal markets, and hence thermal coal production at the Coal Valley mine more than doubled in 2006.

Electricity

Electricity generating capacity within Alberta totalled 11 760 megawatts (MW) in 2006. The decommissioning of units at the Cloverbar natural gas-fired generating station, increases to natural gas-fired generation capacity at Syncrude's oil sands operation, and the commissioning of new wind turbines resulted in a net decrease to capacity of 330 MW compared to 2005. Over the next 10 years, as much as 3550 MW of capacity may be added to the power grid. Total capacity could reach 15 030 MW by 2016.

In 2006, the total electricity generated within Alberta reached 65 280 gigawatt hours (GWh), an increase of nearly 4 per cent from 2005. Alberta's net imports of electricity were 1214 GWh in 2006. Total imports were comparable to 2005 at 1704 GWh, but exports decreased by 53 per cent to 490 GWh. Over the forecast period, electricity generation is expected to grow by an average of 4 per cent per year, or a total of 25 terawatt hours.

As electricity demand is expected to grow at roughly the same rate as supply, the electricity market will continue to exhibit a tightness that will result in elevated electricity prices comparable to the 2006 average. In Alberta, total electricity demand (retail sales and industrial on-site use) in Alberta increased 4 per cent from 2005. Growth in industrial electricity demand, through both retail sales and on-site generation, was between 3 and 4 per cent. Electricity demand in the oil sands sector grew by 23 per cent in 2006, accounting for 19 per cent of total industrial demand.

Energy Trends

Crude Oil and Bitumen

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 5**. Production from the Turner Valley field, first discovered in 1914, accounted for 99 per cent of production in 1938 and 89 per cent of production in 1946. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with peak production of 227.4 thousand m^3/day. Major events that affected Alberta's crude oil production and crude oil prices are also noted on the figure. Factors affecting current crude oil prices and the forecast are found in Section 1: Economics.

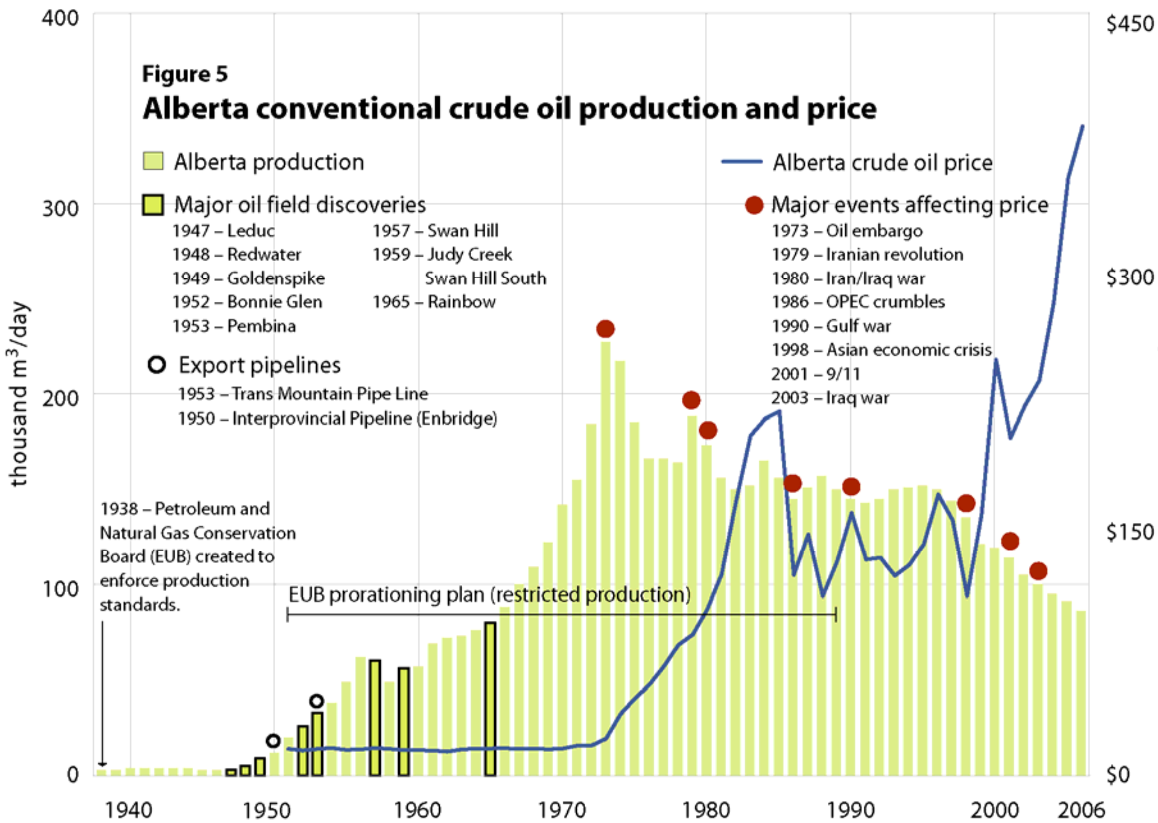
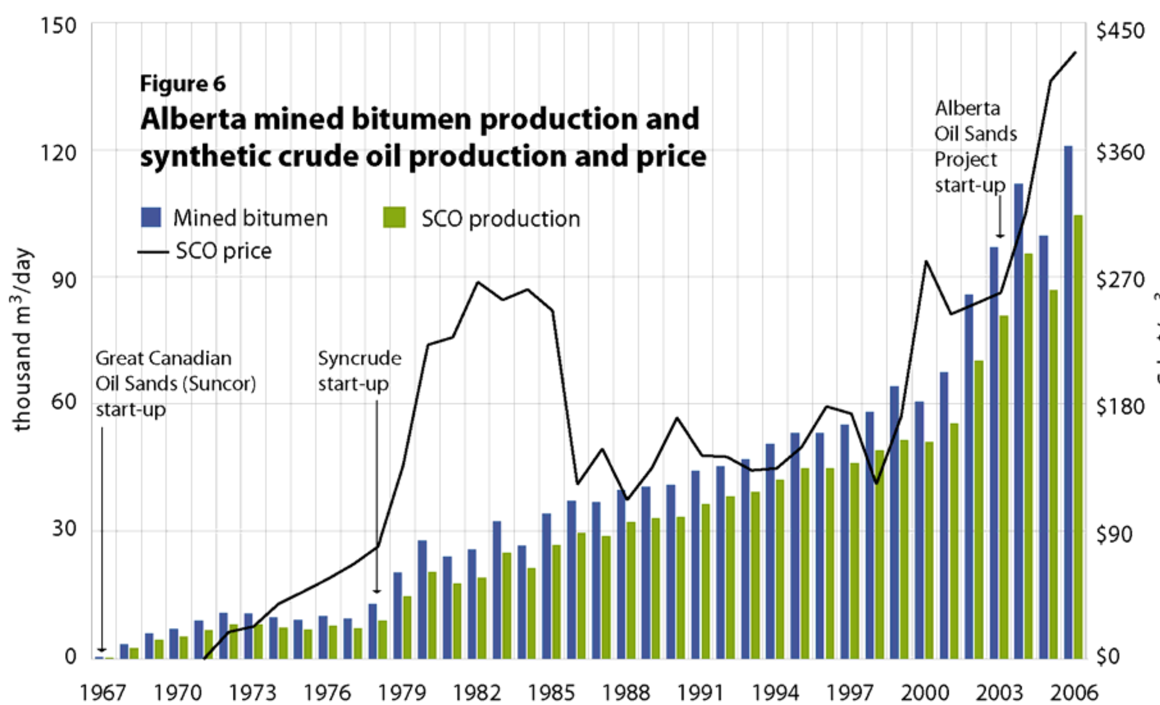
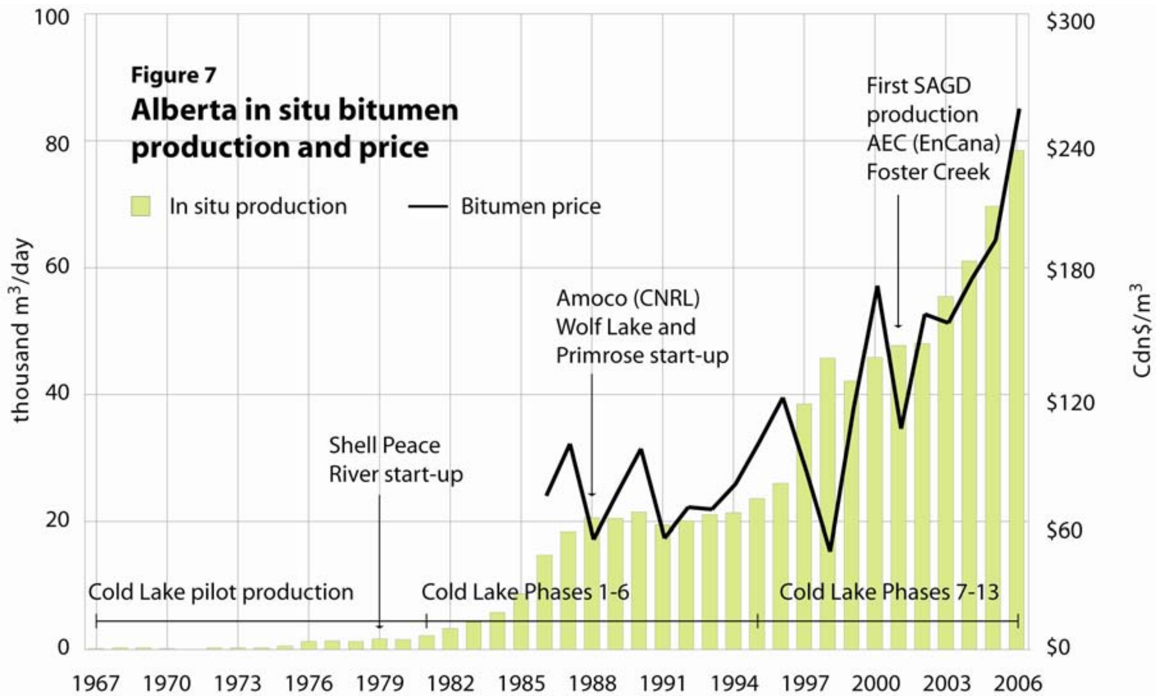


Figure 6 shows the historical mined bitumen and SCO production commencing with the start-up of Great Canadian Oil Sands (Suncor) in 1967. This was followed by Syncrude in 1978 and the Alberta Oils Sands Project (Albian Sands and Shell Scotford Upgrader) in 2003. Also shown in the figure is the price of SCO from 1971. The price of SCO generally runs at a premium to light crude oil.



Historical production and price of in situ bitumen are shown in **Figure 7**. Imperial's Cold Lake, which uses the cyclic steam stimulation recovery method, has historically accounted for the major portion of in situ production. The price of bitumen generally follows the light crude oil price but at a discount of between 50 and 60 per cent.



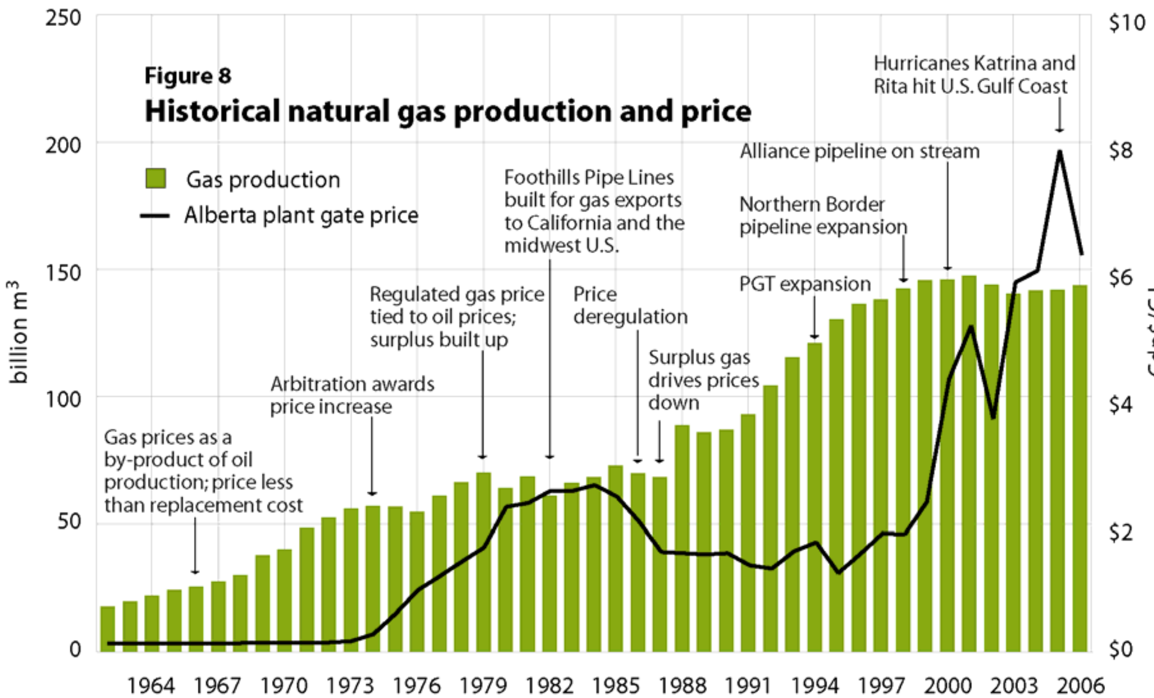
Natural Gas

Natural gas as a commodity has an interesting past, as seen in **Figure 8,** which shows historical gas production and price. In the 1950s and 1960s it was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when OPEC increased crude oil prices, western Canadian producers started asking for higher prices. The federal government at the time objected to higher gas prices, as it believed that would have a negative impact on the Canadian economy. The disagreements were resolved through arbitration and natural gas prices started to increase.

In 1980, through the National Energy Program, the federal government imposed regulated gas prices tied to crude oil prices based on their relative calorific values. High gas prices in the 1980s brought on a vibrant gas industry, which resulted in a significant oversupply of reserves.

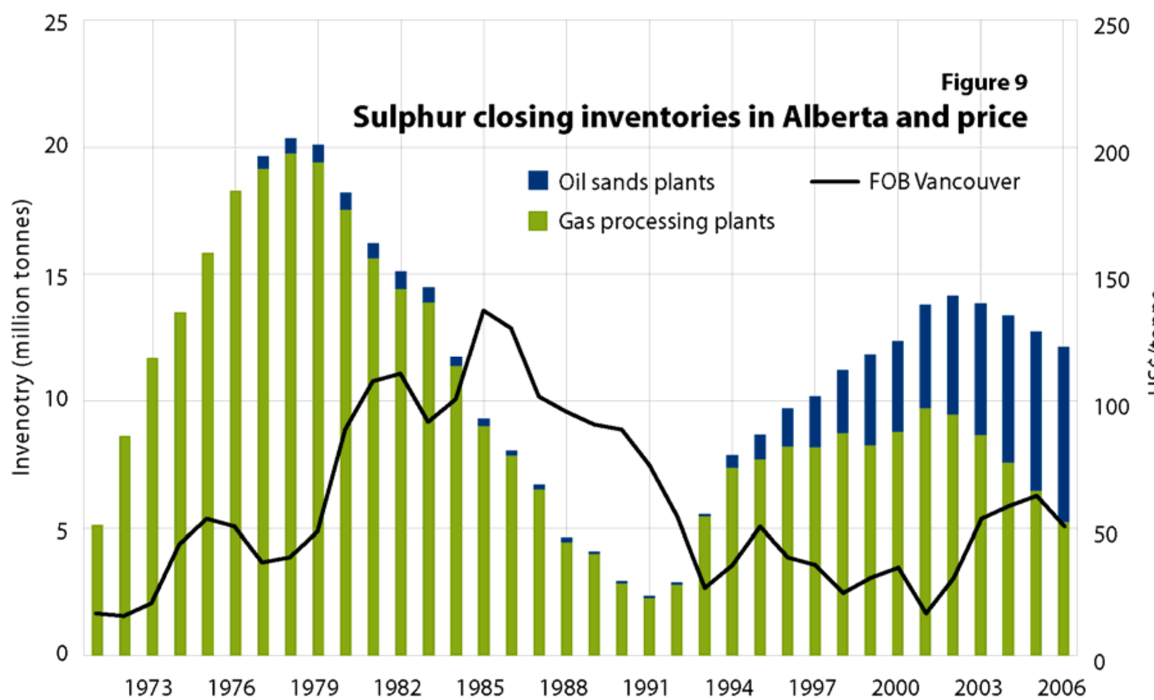
In 1985, natural gas prices were deregulated in Canada. The removal of set prices, the oversupply of reserves, and the drop in demand due to recession resulted in the decline of natural gas prices for the rest of the decade.

In the early 1990s natural gas prices became more market responsive. Development of trading points in Chicago, New York, and the Henry Hub in the United States in the late 1980s and AECO "C" in the early 1990s facilitated natural gas being traded as a true commodity. The development of new export pipelines and expansions to existing pipelines to the United States has allowed Alberta gas to be fully integrated into the North American gas marketplace.



Sulphur

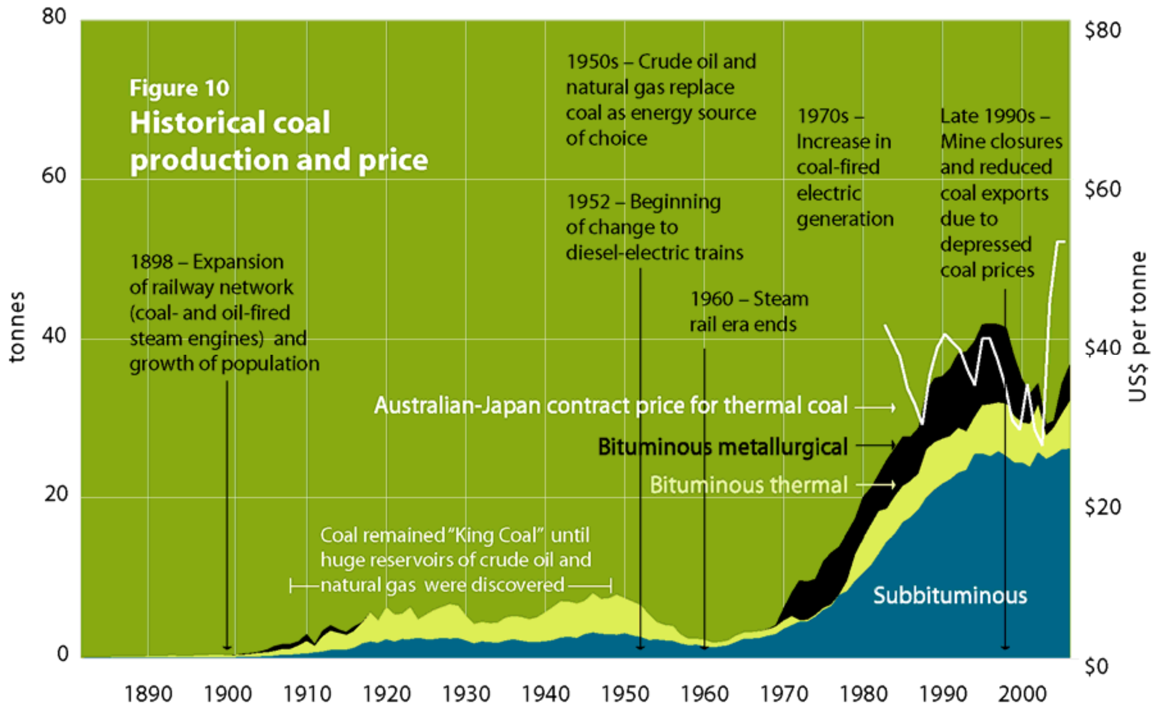
Figure 9 illustrates sulphur closing inventories at processing plants and oil sands operations from 1971 to 2006. Sulphur prices in this period are also shown, adding insight into understanding how prices affect the growth or decline in sulphur inventories. Because of the logistics costs, Canadian sulphur producers do not remelt and remove inventories unless they are assured a "good price." When international demand is high



and international prices follow, Alberta remelts block and adds to the supply. This is usually sufficient to bring things back into balance, reduce prices, and stop the remelting of inventories. The cycle has been repeated several times in the last 35 years. **Figure 9** depicts the trends in Alberta sulphur market.

Coal

The price for coal, as indicated in **Figure 10**, is based on thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and is used as a benchmark in this report. Australia is the world's largest exporter of coal.



1 Energy Prices and Economic Performance

This section discusses major forecast assumptions that affect Alberta's energy supply and demand. Energy production is generally affected by energy prices, demand, and other factors. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. Furthermore, the activity in Alberta's energy sector is heavily influenced by demand and supply conditions and economic activity in the United States, the largest importer of Alberta's fossil fuels.

This section introduces some of the main variables impacting energy requirements and sets the stage for supply and demand discussions in the report. Alberta crude oil prices are determined globally and relate to West Texas Intermediate (WTI) and the Organization of Petroleum Exporting Countries (OPEC) reference basket price. The section begins with a discussion of the current global oil demand and supply picture, with projections for 2007 and 2008 based on research conducted by the International Energy Agency (IEA).

A review of the OPEC crude oil basket reference price and summary of factors that will play a key role in influencing benchmark oil prices in the years to come are included. A discussion of North American energy prices is presented, including natural gas and electricity. The section concludes with a summary of Canada's recent economic performance, along with the EUB's outlook on Alberta's economic growth.

1.1 Global Oil Market

For world energy markets, 2006 will be remembered as a year dominated by geopolitics and the inventory situation in the United States, the world's largest oil-consuming nation.

1.1.1 Global Crude Oil Supply

Following severe supply shocks of oil, natural gas, and gasoline production from the U.S. Gulf of Mexico in the third and fourth quarters of 2005, stocks of those products were quickly rebuilt in early 2006. By March 2006, crude oil stocks in the United States reached a record 16 per cent above their five-year average. Furthermore, distillate stocks (including diesel fuels and gasoline) were well above five-year averages heading into the automobile driving season.

Hurricanes Katrina and Rita caused damage to refineries, pipelines, and storage in the U.S. Gulf Coast, and for months the United States was forced to draw on crude from its Strategic Petroleum Reserve (SPR). Additions to the SPR stopped in May after some of the strategic inventory was rebuilt. Given the good supply situation in the first two quarters of the year and the relatively low demand that came about due to a relatively warm winter and spring, prices of crude oil and petroleum products should have been falling from their record highs in 2005. Instead, geopolitics once again took centre stage.

Political unrest during the spring in Nigeria, Africa's largest oil producer, and one of OPEC's largest exporters caused output in that country to fall by a quarter of its normal production levels.

1.1.2 Global Crude Oil Reference Price

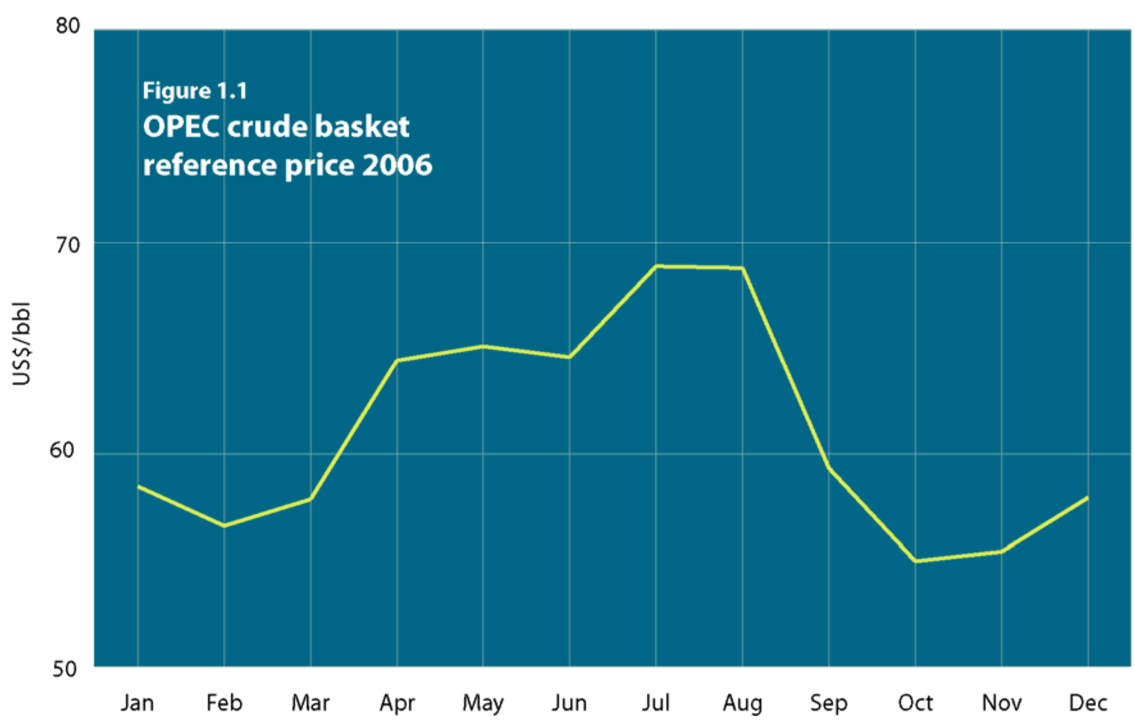
The political events noted above caused significant upheaval in world energy markets, and the OPEC reference price of crude oil jumped well beyond US$60 per barrel in April, remaining there for a number of months.

Tensions between Israel and Lebanon escalated to war in July. Although neither of these countries has significant oil producing or exporting capacity, traders were worried that the conflict spreading through the Middle East had the potential to cause production, transportation, and export disruptions. By the last half of July and first half of August, the OPEC reference price rose even further, averaging US$68.89 per barrel in July and US$68.81 per barrel in August. These were record average monthly prices since trading began in the early 1970s.

Soon after the conflict between Israel and Lebanon subsided and the forecast of a devastating hurricane season in the United States did not materialize, world crude oil prices tumbled. OPEC was then quick to announce production cuts to quotas totalling 1.7 million barrels per day (bbl/d) to take place between November 2006 and February 2007. This first production cut announced by OPEC since April 2004 helped to prop up prices in December.

OPEC has stated that it would like to keep its reference price between US$55 and US$60 per barrel. Maintaining such a level will depend largely on the demand situation in the United States and its effect on inventories as the driving season commences and another hurricane season gets under way.

Figure 1.1 depicts the monthly average OPEC crude oil basket reference price for 2006. OPEC adopted a new reference crude oil basket on June 15, 2005, consisting of eleven crude oils. It is a better reflection of the average quality of the main crudes exported from OPEC member countries.



The original OPEC reference basket consisted of seven crude oils, including Saudi Arabia Arab Light, Nigeria Bonny Light, Dubai Fateh, Mexico Isthmus (non-OPEC), Indonesia Minas, Algeria Saharan Blend, and Venezuela Tia Juana (T.J. Light). The new OPEC reference basket consists of Arab Light, Bonny Light, Minas, and Saharan Blend, plus Iran Heavy, Iraq Basra Light, Kuwait Export, Libya Es Sider, Qatar Marine, United Arab Emirates Murban, and Venezuela BCF 17. The new OPEC reference crude is heavier, with an American Petroleum Institute (API) gravity of 32.7°, compared to 34.6° for the previous basket. It is also more sour, with an average sulphur content of 1.77 per cent, compared to a previous average sulphur content of 1.44 per cent. When it was adopted in June 2005, the original OPEC reference price averaged US$52.72 per barrel for the month, while the new OPEC reference price averaged US$50.92 per barrel. The move to this new OPEC crude oil basket is a reflection of average crude quality. The member countries are producing from reservoirs with heavier and more sour crudes to augment the rapidly declining production from the higher quality reservoirs.

In 2006, the OPEC reference price averaged US$61.08 per barrel, a 20.6 per cent year-over-year increase from 2005. During the last quarter of 2006, OPEC suggested that crude oil supplies were in excess to demand and caused destabilization to the market. OPEC subsequently reacted by announcing a number of cuts to production to balance supply and demand. OPEC production (including Iraq) averaged 29.6 million bbl/d in 2006, but production was cut to 25.8 million bbl/d effective February 1, 2007.

At its meeting in March 2007, OPEC stated that it is unlikely to cut quotas any further as long as current prices hold. These quota cuts mean that spare capacity will grow and provide more of a cushion for the markets. OPEC has the potential to produce about 30.2 million bbl/d of crude oil, excluding production from Angola and Iraq. Angola joined OPEC in January 2007; with Angola and Iraq production, OPEC capacity is estimated at 34.2 million bbl/d. With a better cushion of spare capacity, large fluctuations in the OPEC reference price could be minimized.

OPEC members still have a number of issues that the markets will be wary of: Venezuela nationalizing its energy industry, the threat of continued militant attacks in upstream oil infrastructure in Nigeria, and the potential for conflict to erupt between Iran and the United States. With the continuing conflict in Iraq, it is unlikely that its oil production potential will be reached in the short term. Venezuela, Nigeria, Iran, and Iraq accounted for 10.6 million bbl/d, or 36 per cent, of OPEC's crude oil production in 2006.

1.1.3 Global Crude Oil Demand

In the short run, the price of oil is inelastic, meaning reduced production or increased consumption will provoke an immediate response of sending oil prices higher. High energy prices, however, can create a drag on economic growth, especially for major oil importers whose currencies depreciate, making it more costly to import other goods and services, which may result in slower growth in the global demand for crude oil.

Growth in global oil demand slowed somewhat in 2006, from 1.3 to 0.8 million bbl/d. China's economy is still very strong, and its oil demand increased by 7 per cent in 2006. Chinese demand is expected to grow by 0.5 million bbl/d in 2007, as China's economy continues to post economic growth of between 7 and 10 per cent per year in the short term.

Economic growth, in particular that of Asia, will play a key role in the continued strength of crude oil prices going forward. In both the Middle East and India, oil demand is growing at a good pace and will continue to do so over the short term. India's economic growth may rival that of China's in future years, while only some of the economies of the Middle East have robust outlooks.

Demand weakness was most evident in the United States and Europe in 2006. In the United States demand averaged 20.7 million bbl/d for 2006, 0.1 million bbl/d less than in 2005. Milder weather, ample storage, and weaker economic growth all contributed to the drop in oil demand. Demand is expected to grow by 0.4 million bbl/d in 2007. Economic growth in the United States is expected to remain moderate in 2007, as the economy makes a "soft landing" following the deceleration that began in 2006. Some analysts believe the uncertainty in the U.S. housing market, inflationary pressures, and low employment gains may have passed. In Europe, crude oil demand remained stagnant at 16.2 million bbl/d in 2006 and is expected to remain at that level for 2007.

Total world oil demand reached 84.3 million bbl/d in 2006, up 0.9 per cent or 0.8 million bbl/d from 2005. Demand is expected to grow by 1.8 per cent, or almost 1.5 million bbl/d in 2007. **Figure 1.2** illustrates growth in oil demand across the globe between 2005 and 2007.

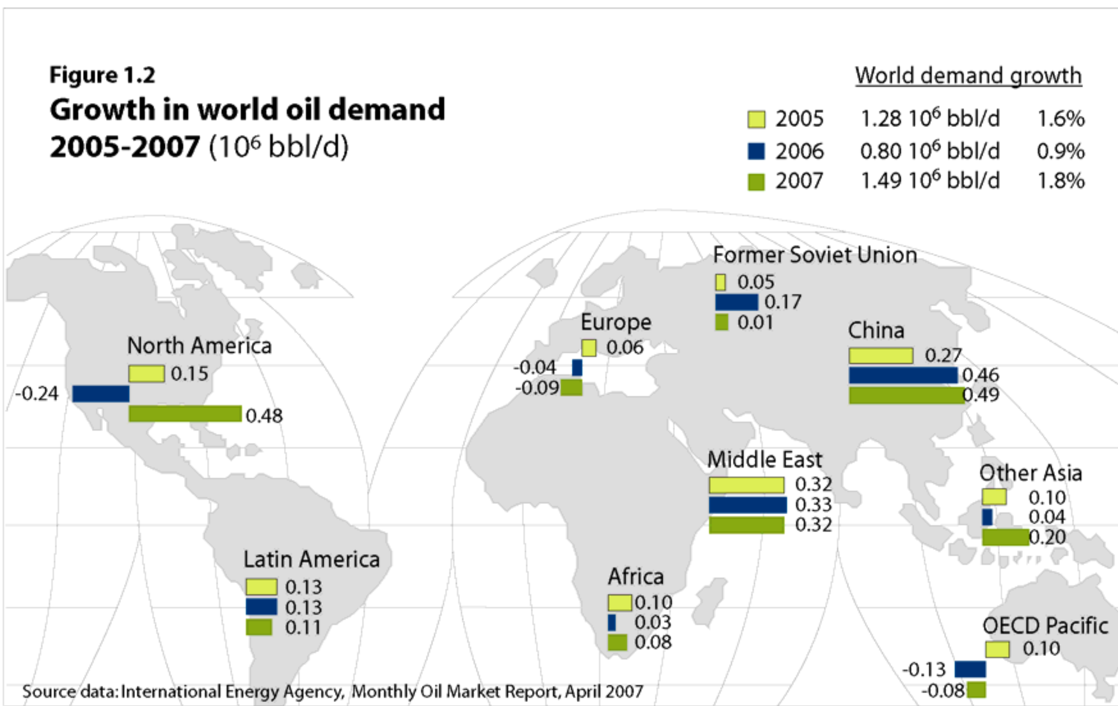


Figure 1.2
Growth in world oil demand 2005-2007 (10^6 bbl/d)

Global oil supply exceeded demand in 2006 by an estimated 0.9 million bbl/d, but this had little effect on stabilizing prices. Supply reached 85.2 million bbl/d, with 29.7 million bbl/d of crude being produced by OPEC members, a share of 35 per cent. OPEC members are expected to supply an increasingly larger share of crude oil, as significant investment is going into oil production in countries such as Saudi Arabia. Supply from non-OPEC countries has fallen off in recent years, as it is becoming increasingly difficult and expensive to find and produce large sources of crude. With more crude oil originating from politically unstable nations in the short to medium term, the OPEC reference price of oil is expected to remain well above US$50 per barrel.

The EUB expects an average growth rate for global demand for crude oil to be in the 1 per cent range over the forecast period. However, it is expected that fluctuations will occur around this average rate within this time period.

1.2 North American Energy Prices

1.2.1 North American Crude Oil Prices

North American crude oil prices are determined by international market forces and are most directly related to the reference price of WTI. WTI is a reference crude with an API of 40° and sulphur content of less than 0.5 per cent. The WTI crude oil price is set in Chicago and ranges between US$6 to $7 higher than the OPEC reference price, reflecting quality differences and the cost of shipping to the Chicago market.

The EUB uses the WTI crude price as its benchmark for world oil prices, as Alberta crude oil reference prices are based on WTI netbacks to the Alberta wellhead. Netbacks are calculated from the price of WTI at Chicago less transportation and other charges from the wellhead to Chicago and are adjusted for the exchange rate, as well as crude quality. Edmonton Par is priced at an API of 40° with a sulphur content of 0.5 per cent.

The WTI price of crude oil was influenced by many of the same factors affecting the OPEC reference price during 2006. Following the supply shocks of the second half of 2005, when an active hurricane season caused a substantial reduction in oil production and refining capacity in the U.S. Gulf Coast, the WTI price of oil surpassed US$60 per barrel. Political risk surrounding Nigeria and Venezuela, combined with escalating civil violence in Iraq, caused WTI spot price at Cushing, Oklahoma, to hit a daily record US$74.62 in May. A warm winter decreased heating demand from its normal level and caused inventories of crude oil and products to swell well beyond five-year averages; however, this did little to deflate prices.

With the events of the 2005 hurricane season still fresh in the minds of traders, markets became wary of the ensuing hurricane season. The probable risk of a second consecutive destructive hurricane season was quickly priced into WTI in the early spring of 2006. Ironically, the 2006 hurricane season started late in the summer and barely made the headlines. Inventories of crude oil and most petroleum products grew accordingly. This also gave refineries on the U.S. Gulf Coast a chance to complete repair work necessitated by the 2005 hurricane season. With bulging inventories, docile weather, and low demand growth caused by a decelerating U.S. economy, oil prices should have been falling quickly. Once again, in mid July geopolitics overwhelmed the stable demand-supply conditions due to the Israel-Lebanon conflict. Hence WTI averaged US$75.70 in July and US$74.31 in August. Another daily record spot price of US$76.29 was reached on August 8.

From mid-August, WTI fell significantly, but it still exhibited wide daily swings. From September to the end of 2006, supply and demand fundamentals were successful at influencing prices. The key heating oil consuming regions of North America experienced a mild autumn and beginning to the winter season, which allowed inventories of crude oil and products to be built even more and to remain at record levels. The WTI price of oil sank quickly and approached US$50 per barrel in January 2007.

The EUB expects WTI to range between US$55 and US$69 per barrel, with an average price of US$62 per barrel for 2007. The forecast range is lower than last year’s and is indicative of the expectations for crude supply and demand in the United States, as well as shrinkage in the risk premium set by geopolitical tensions. Over the longer term, the top end of the range assumes a nominal average annual growth rate of 3 per cent. This rate takes into account a 1 per cent growth in global crude demand and an average annual inflation rate of 2 per cent. The bottom end of the price range of WTI is an extension of the current average lows experienced in the market. Most of the risks to this forecast are upward and include a longer than expected heating season, which could reduce the inventories, more demand than anticipated for gasoline during the driving season, a particularly active hurricane season, further cuts to OPEC quotas, and renewed geopolitical upheavals. Downside risks include lower than anticipated economic performance in the United States, which could quell oil demand. Weak economic performance in the United States could impact the global economy and further weaken demand for oil.

Figure 1.3 illustrates the EUB forecast of WTI at Chicago. **Figure 1.4** shows the forecast for the wellhead price of crude oil in Alberta based on WTI netbacks from Chicago.

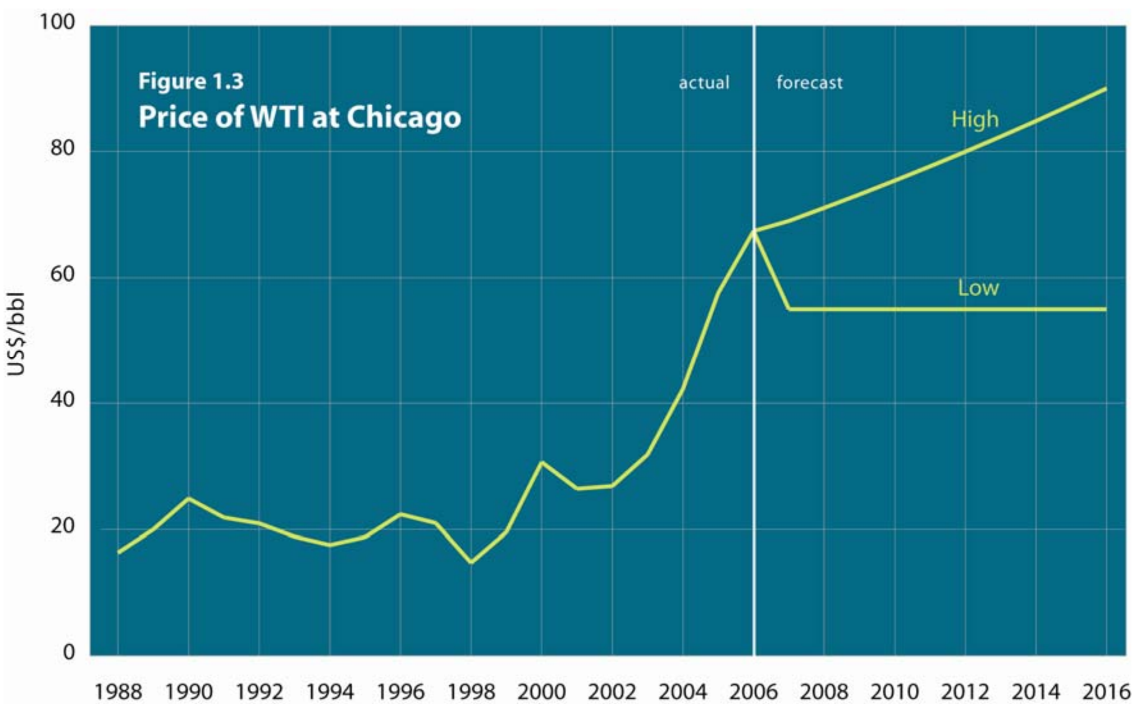
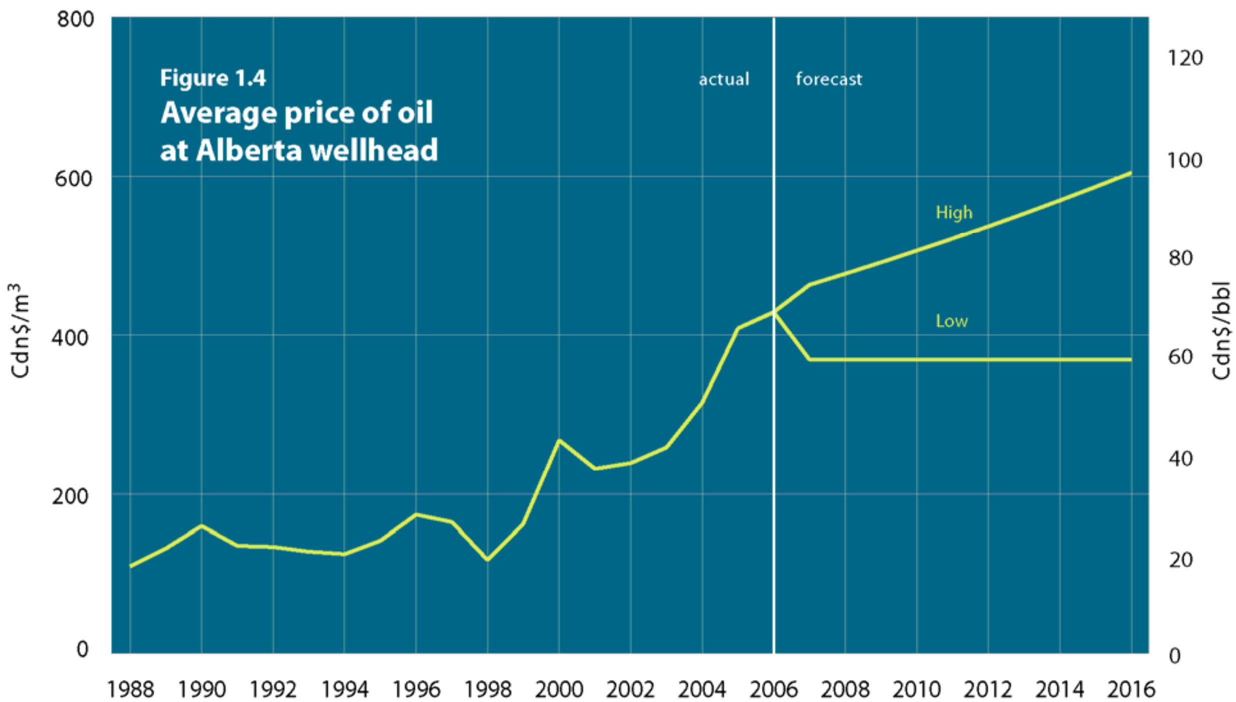
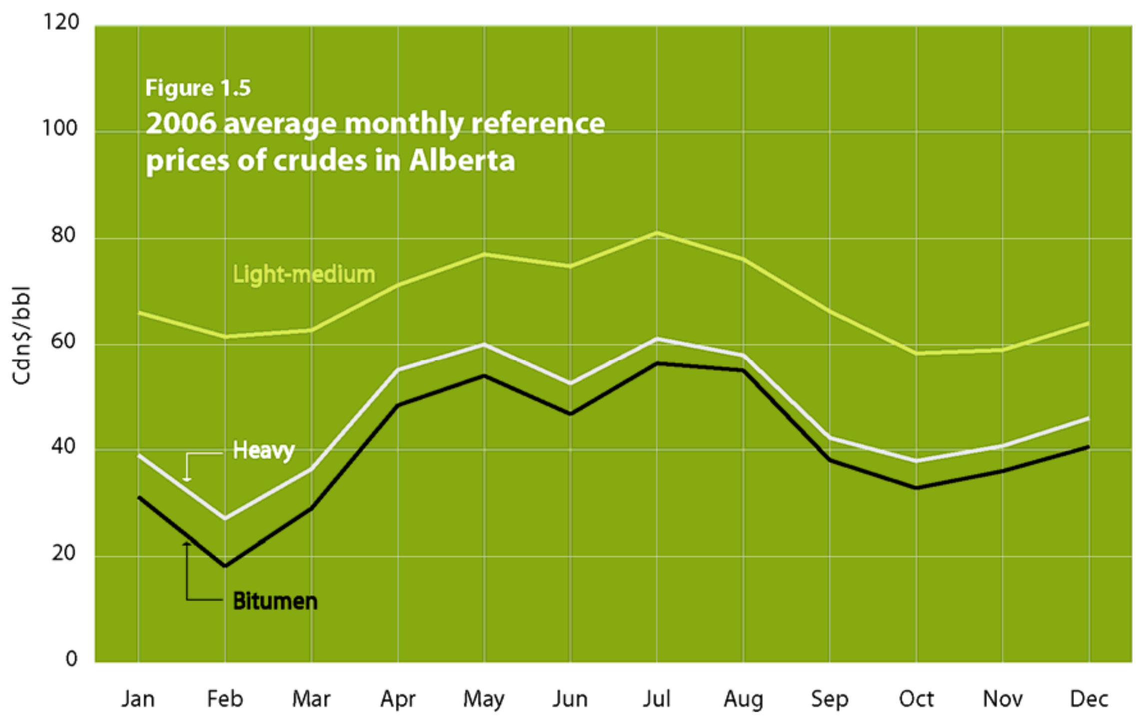


Figure 1.5 illustrates the monthly average price of Alberta light-medium crude, heavy crude, and neat bitumen. In 2006, heavy crude and bitumen prices averaged Cdn$46.36 and Cdn$40.53 per barrel respectively, while the Alberta light-medium reference price averaged Cdn$68.16 per barrel. In 2004 and 2005, the heavy/light differential widened as light crude prices increased at a faster pace than heavy crude. However, in 2006 the opposite occurred, and the price of heavier crudes in Alberta increased at a faster rate relative to light and medium crude, leading to a narrowing of the premium of heavy versus light from 60 per cent to 68 per cent. Similarly, the bitumen/light-medium differential narrowed from 47 to 59 per cent.





The EUB focuses on the forecast of WTI rather than bitumen, as the majority of bitumen is upgraded to a synthetic crude oil (SCO) product of similar quality to WTI. Forecasts for the price of heavy crude and bitumen can be estimated by applying the appropriate average differentials to the netback price of WTI at the Alberta wellhead. The EUB expects the bitumen/light-medium differential to average 56 per cent over the forecast period. Wider differentials are noticeable incentives for investment in additional upgrading capacity in North America. The heavy/light-medium differential is expected to remain near the five-year trend, at 68 per cent.

Wider differentials between bitumen and Alberta light-medium are due to imbalances in supply and demand. Increases in the supply of bitumen without an increase to the refinery capacity that can process this crude can lead to a wider spread in the short term. Diluent prices also play a role in determining bitumen prices, as more expensive diluent will result in lower bitumen prices. While seasonal variations have always existed, the bitumen/light-medium spread may be wider than heavy/light-medium for quite some time.

Further expansion of upgrading capacity, refinery conversions, and more pipeline access to new markets should help stabilize these differentials over the longer term. There are currently three bitumen upgrading sites in Alberta, with ten additional upgraders and a number of debottlenecking and expansion projects planned during the forecast period. As a result, upgraded bitumen product is expected to increase over threefold, from 105 thousand cubic metres per day (10^3 m^3/d) (661 10^3 bbl/d) in 2006 to 302 10^3 m^3/d (1898 10^3 bbl/d) by 2016. Details on markets for Alberta bitumen are discussed in more detail in Section 2.

After meeting Alberta and Canadian refinery demand, the Petroleum Administration for Defense Districts (PADD) 2 and 4 in the United States are the largest importers of Alberta heavy crude and bitumen, with total refinery capacity of 664 10^3 m^3/d (4180 10^3 bbl/d) combined. The expansion at the Flint Hills upgrader, the ConocoPhillips refinery conversion, and other refinery conversions will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta's heavier crudes. However, it is expected that the small-sized expansions and conversions will open up capacity only over the short term, as the growth in Alberta production could quickly fill the gaps. Refinery capacity in the United States has increased somewhat from the early 1990s, but only due to increases in existing capacity. No new refineries have been built since the 1970s. At the same time, product demand has increased significantly and has resulted in refineries in the United States operating at 90 per cent of capacity or more since 1993.

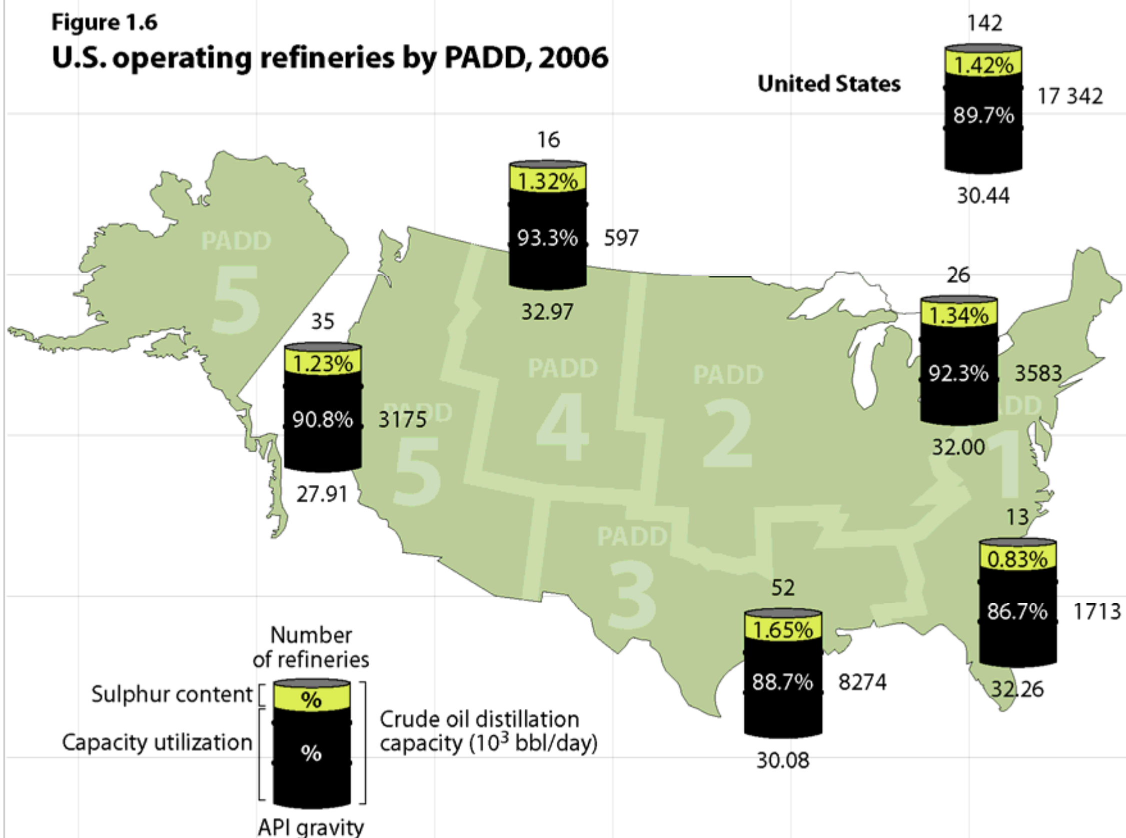
Additional pipeline infrastructure will provide an avenue for Alberta heavy crude to extend to larger markets in the United States and East Asia. With expected increases in both non-upgraded and upgraded bitumen over the forecast period, adequate incremental pipeline capacity is essential to market greater volumes of Alberta production. During the past few years, pipeline companies have made strides towards completing existing projects, as well as moving ahead with the necessary steps involved with planning and executing new projects.

In summary, twelve proposed new pipelines and pipeline expansions indicate an overall increase in crude oil pipeline capacity of 158 10^3 m^3/d (990 10^3 bbl/d) to the Alberta market and 329 10^3 m^3/d (2070 10^3 bbl/d) for the export market, some with the potential to reach PADD 3, PADD 5, and East Asia. This represents an increase of 50 per cent in Alberta SCO and non-upgraded bitumen pipeline capacity and an 80 per cent increase in export pipeline capacity.

If production follows our current forecast, additional Alberta crude oil pipeline capacity will be required in the 2010 to 2012 time frame. The proposed Alberta pipeline projects include built-in capacity for future increases in deliveries as production grows in the Athabasca region. In addition to increased crude oil pipeline capacity, three new pipelines will be dedicated to moving 68 $10^3 m^3/d$ of condensate (diluent) from the U.S. midwest and from the B.C. west coast to the Edmonton area.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the United States, with 52 operating refineries and net crude oil distillation capacity of 1315 10^3 m^3/d (8.3 million bbl/d), plus the existing capability of refining heavier crudes. PADD 3 was not always viewed as the most likely market for Alberta because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude production. Traditional crude inputs to PADD 3 have been on the decline, suggesting a more tangible opportunity for Alberta heavy crude producers while plans to increase pipeline capacity to the area are under way.

Figure 1.6
U.S. operating refineries by PADD, 2006

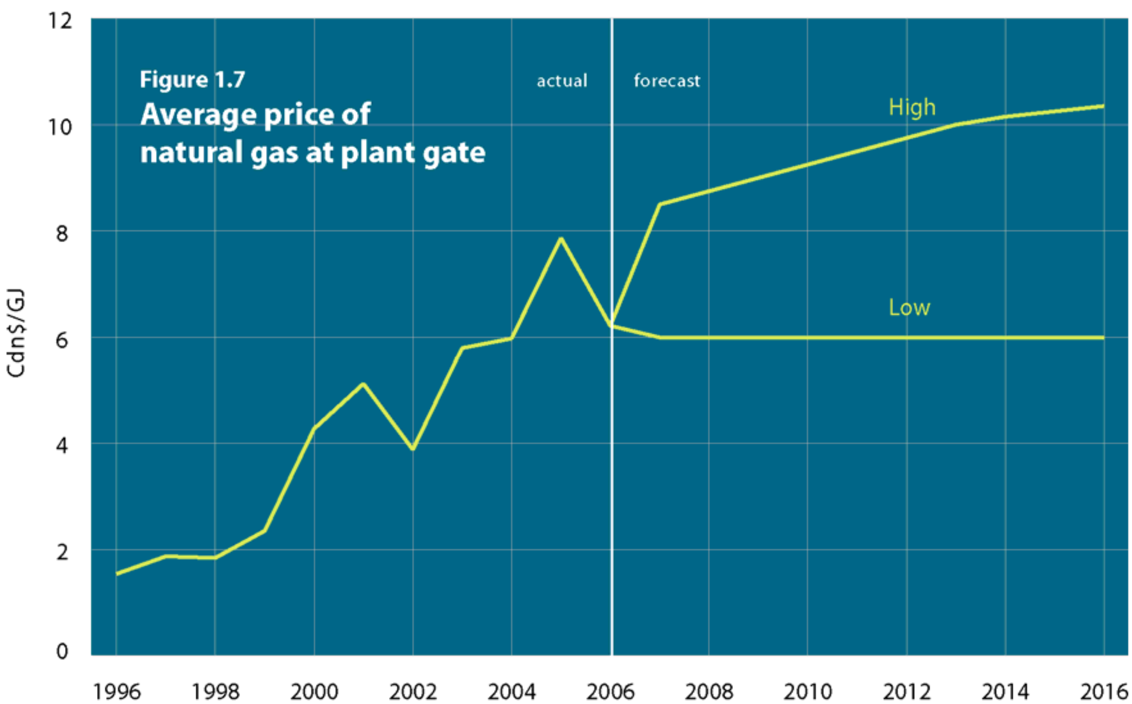


Source data: U.S. Energy Information Agency
Number of operable refineries as of January 1, 2006.
Data for the year 2006. Sulphur content and API gravity are weighted averages.

1.2.2 North American Natural Gas Prices

While crude oil prices are determined globally, natural gas prices are set in the North American market with little global gas market influence. Alberta natural gas prices are heavily influenced by events in the United States, the largest importer of Alberta natural gas. Natural gas prices are impacted to some extent by crude oil prices, as some substitution does occur due to the price differential between the two commodities. About 10 per cent of industrial users in the United States can switch between oil and natural gas for power production. **Figure 1.7** shows historical data and the EUB forecasts of natural gas prices at the plant gate from 1996 to 2016.

Alberta gas prices trended almost consistently downward in 2006, from a high of $9.52 per gigajoule (GJ) in January to a low of $4.40 in October. A warm winter season in the U.S. northeast early in the year allowed storage levels of natural gas to reach record levels. The hurricane season turned out to be mild, and natural gas producers returned to their full capacity in the Gulf of Mexico. Since then prices have slowly moved upward, as winter finally greeted the U.S. northeast and eastern Canada. But as the 2007 winter heating season comes to a close in early March in the United States, storage levels will likely remain above their five-year average going into the summer cooling season. This will keep prices tempered to an average range of $6.00- $8.00 per gigajoule (GJ) in 2007. Some upside risks to the forecast exist if another shock were to occur—for example, if the hurricane season starts early in the United States and leads to production disruptions in the Gulf of Mexico, or if the summer is particularly hot and cooling requirements soar. The EUB assumes a normal hurricane season combined with normal cooling requirements for both the United States and Canada.



The Alberta gas-to-light-medium-oil price parity on an energy content basis was only 0.56 for 2006, as the price of natural gas fell more quickly than oil and remained much lower until the end of 2006. During the 2001 to 2005 period, the parity averaged 0.76.

Over the forecast period, the price of natural gas is expected to increase slowly to reach an average of $8.35 by 2016, while the top end of this range could surpass $10.00/GJ. The gas-to-oil price parity is expected to average 0.66 over the forecast period.

A gas-to-oil discount is likely to remain in the short to long term for a number of reasons. As mentioned earlier, oil is a world price, while natural gas prices are regional. Oil prices respond instantaneously to global events, such as demand or supply shocks in various nations or geopolitics, while natural gas responds mainly to regional supply and demand conditions. Most important, demand for oil globally is particularly inelastic in the key transportation sector. This means that consumers will pay for it no matter what the cost, because there is no short-term substitute for refined products, such as gasoline, diesel, jet fuel, and heating. Furthermore, as more consumers become wealthier in the rapidly developing economies of China and India, they too will demand more transportation goods and services.

Natural gas, on the other hand, does not have the wide-ranging demand of crude oil or refined petroleum products. It may, however, have the potential to become a global commodity if the trade in liquefied natural gas (LNG) is developed globally, but only over the longer term. There are plans for LNG to be transported throughout the world, but the location and construction of LNG liquefaction facilities remain highly contentious issues. Even then, natural gas will likely never become a dominant fuel in the important transportation sector. Despite the impact that intercontinental trade in liquefied natural gas (LNG) could have on gas prices in North America, the EUB believes that LNG will not capture a high market share in North America over the forecast period, primarily due to the risk and regulatory requirements for construction of gasification terminals. Furthermore, while there are substantial natural gas reserves worldwide that can be tapped into for liquefaction purposes, lining up supply for specific projects is proving to be more difficult than expected.

The LNG landed price on the U.S. east coast is in the US$6.00 to $8.00/GJ range and is competitive with gas prices set at the Henry Hub pricing point. It is expected that LNG suppliers will not price their gas at their marginal cost, but rather at a level that the market can bear in order to maximize their revenue.

Similar to the 2006 forecast, the EUB believes the current forecast for natural gas prices will be more a reflection of future supply and demand conditions in both the United States and Canada. Coalbed methane (CBM) is expected to provide an increasing share of Alberta’s total natural gas production, but the industry is still relatively new, and exploration and production in the province are greeted with significant landowner opposition. CBM is also not likely to offset the downward trend in conventional gas production.

1.2.3 Electricity Pool Prices in Alberta

The electricity price paid by consumers consists of a wholesale market price determined in the power pool, transmission and distribution costs, and a fixed monthly billing charge. Since deregulation, the wholesale or pool price of electricity in Alberta has been determined by the balance between electricity supply and demand.

Table 1.1 shows the average pool prices and electricity load, along with hourly minimums and maximums experienced during each month in 2006. The 2005 average is included for comparison.

Corresponding with declining Alberta spot prices for natural gas, over the first four months of 2006 the monthly average pool price continued to slide from the average high reached last November ($125/megawatt-hour [MWh]). The average pool price reached a low of $43/MWh in April.

Electricity prices turned around in late spring and early summer, despite a continuing decline in the spot price of natural gas. The monthly average pool price was elevated to $128/MWh in July, due to a tightening of electricity supply and demand caused by planned maintenance and outages at some coal-fired units and increased loads for cooling requirements. An untimely series of unique events on July 24, 2006, exasperated the already narrow margin between supply and demand by causing additional coal-fired units

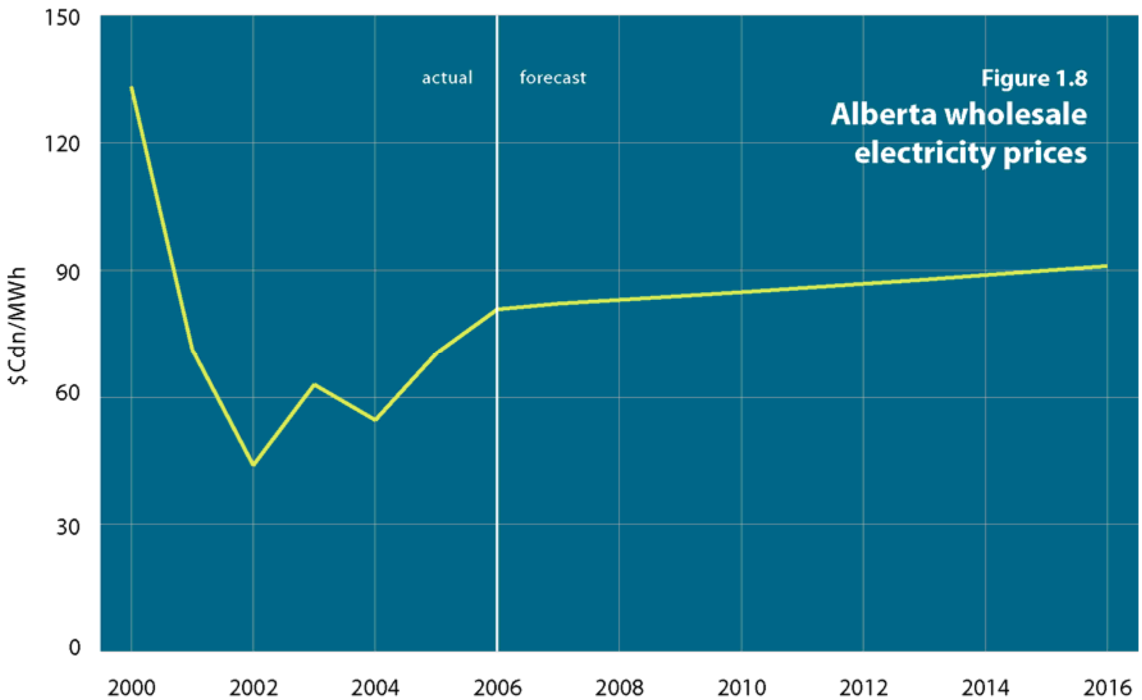
Table 1.1. Monthly pool prices and electricity load

2006	Price ($/MWh) Average	Min	Max	Load (MW) Average	Min	Max
Jan	72.12	6.22	623.56	8174	7112	9238
Feb	54.07	7.30	341.85	8160	7059	9306
Mar	44.08	6.22	328.74	8006	7022	8938
Apr	42.87	6.10	477.30	7549	6648	8325
May	56.26	6.22	897.58	7453	6351	8718
Jun	61.64	5.42	998.78	7567	6357	8906
Jul	128.23	5.47	999.99	7920	6627	8966
Aug	73.46	7.81	999.99	7933	6797	9050
Sep	82.53	11.33	999.98	7788	6754	8793
Oct	174.09	15.46	999.99	7939	6889	8966
Nov	105.47	10.06	999.98	8286	7070	9661
Dec	70.88	9.58	892.78	8260	7102	9534
2005	70.36	4.66	999.99	7564	6104	9580
2006	80.79	5.42	999.99	7920	6351	9661

to trip off line, along with the B.C.-Alberta inter-tie. As a result, on July 24, the pool price was sustained at its price ceiling of $999.99/MWh for nine consecutive hours.

The monthly average pool price remained above $70/MWh for the remainder of the year. The average pool price in October was the highest observed since December 2000, despite a continuing lull in natural gas prices. In October a large amount of coal-fired generating capacity was off line. Even though generation owners normally plan maintenance on these units in the fall, when seasonal loads are low, unplanned outages of additional coal-fired capacity resulted in supply shortages that required the dispatch of more costly electricity generating units. Electricity prices in November and December improved, reflecting a movement out of the maintenance period.

Figure 1.8 illustrates the historical pool price of electricity in Alberta from 2000 to 2006, as well as the EUB's forecast of average annual pool prices to 2016. The average hourly pool price of electricity in 2006 was $80.79/MWh, which is an increase of 15 per cent from $70.36/MWh in 2005. The EUB is anticipating that the power pool price will remain elevated in 2007. From 2007, the average annual pool price is expected to grow, a reflection of the narrow margin between electricity supply-demand in the province and the EUB's outlook on natural gas prices.



1.3 Oil and Gas Production Costs in Alberta

Drilling and completion cost estimates for typical oil and natural gas wells are shown in **Figure 1.9** by Petroleum Services Association of Canada (PSAC) area for 2006 and 2007. **Table 1.2** outlines the median well depth for each area, a major factor contributing to the drilling costs. Many other factors influence well costs, including surface conditions, sweet versus sour production, and completion method.

Table 1.2. Alberta median well depths by PSAC area, 2006 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3420	2368	706	630	888	467	914
Oil wells	3228	2015	1222	725	1560	NA	1673

NA – Not applicable.

In the four PSAC areas where oil wells were drilled, all areas exhibited a mild increase in the median cost to drill a well, with the exception of Area 3, which showed a decrease of 2.2 per cent (**Figure 1.9**). The cost decrease can be attributed to a decrease in the rig drilling and standby costs on a per day/unit basis.

Costs to drill an oil well do not vary substantially across the province, the way they do for natural gas wells. They range from as low as $749 000 in East Central Alberta (Area 4) to as high as $1 397 000 in Central Alberta (Area 5).

Costs to drill and complete a well for natural gas production in Alberta have also risen with time. Gas well drilling and completion costs have risen in all areas of the province from 2006 to 2007, albeit at a fairly tame pace. On average, drilling and completing costs have risen by only 1.9 per cent across the seven PSAC areas. This is probably due to the fact that drilling costs in most areas escalated significantly over the 2004 to 2006 period.

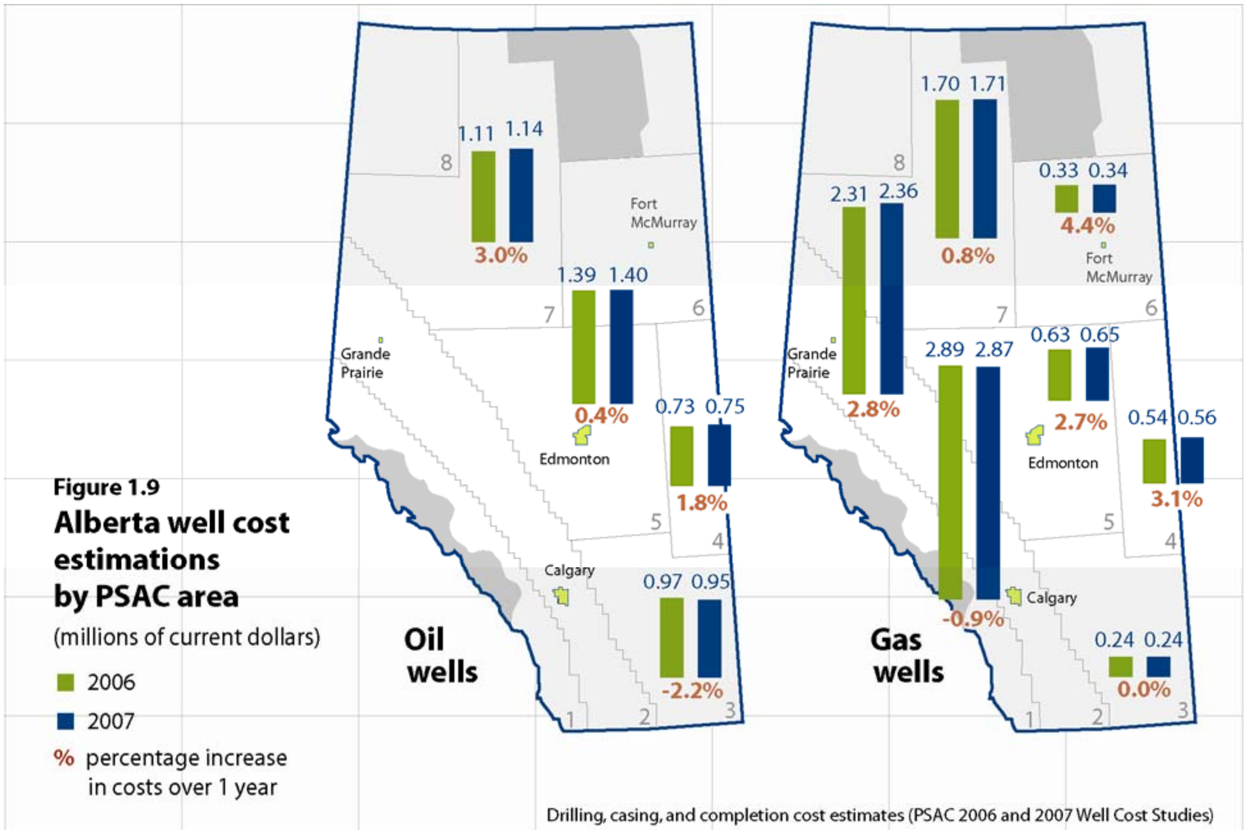


Figure 1.9
Alberta well cost estimations by PSAC area
(millions of current dollars)

Recent costs to drill and complete a typical gas well are highest in the Foothills area, at close to $3 million, but could range significantly higher for deeper wells. In Southeastern Alberta (Area 3), a typical gas well could cost around $240 000 to drill and complete.

1.4 Canadian Economic Performance

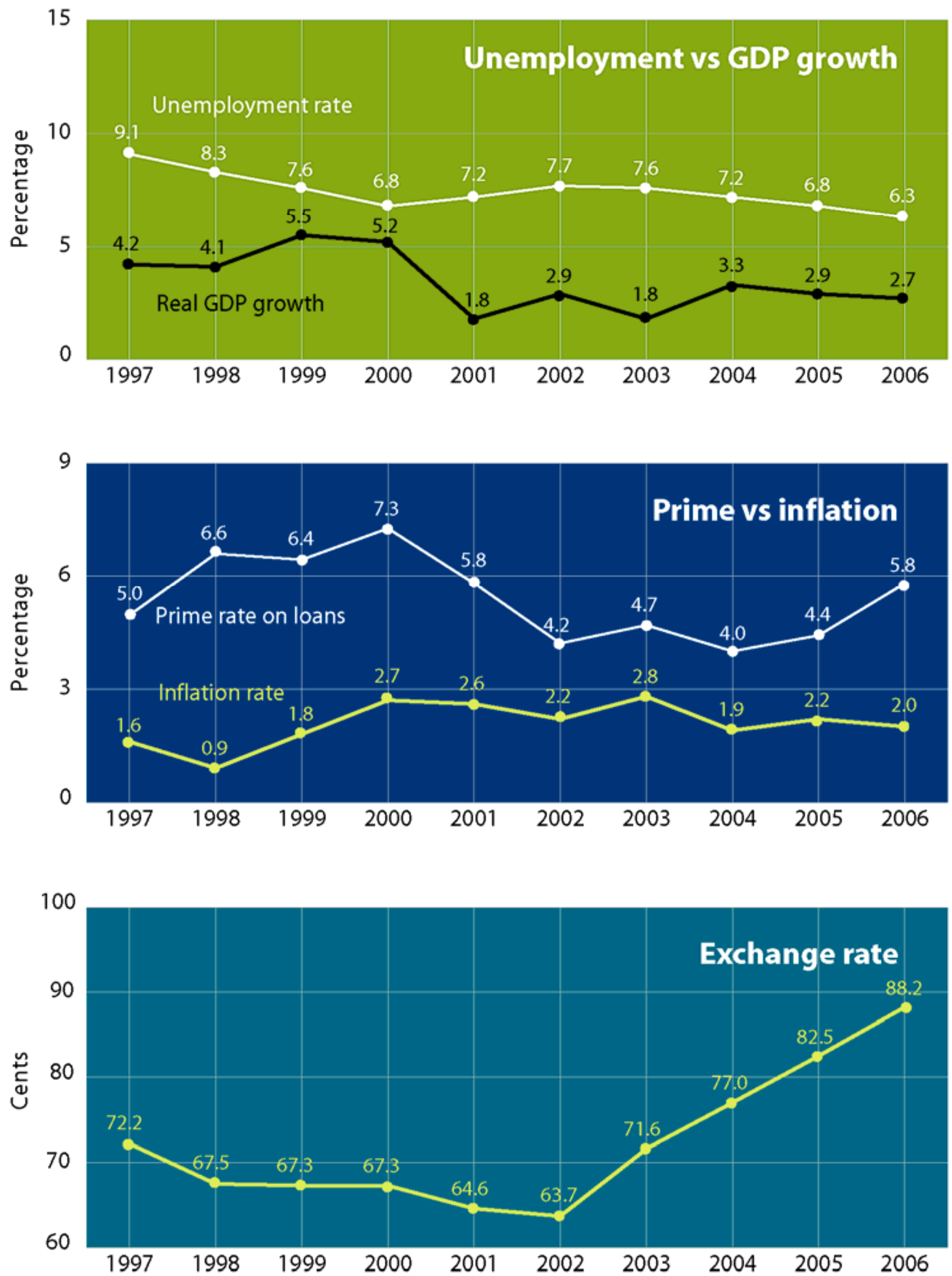
Canadian economic growth, interest rates, inflation, unemployment rate, and currency exchange rates (particularly vis-à-vis the U.S. dollar) are key indicators that affect Alberta's economy but are beyond the province's control. The Canadian performance of the above economic indicators between 1997 and 2006 are depicted in **Figure 1.10**. Canada's most recent annual performance of these indicators and the forecast to 2016 are presented in **Table 1.3**.

Table 1.3. Major Canadian economic indicators, 2006-2016

	2006[a]	2007	2008	2009-2016[b]
Real GDP growth	2.7%	2.4%	3.0%	2.8%
Prime rate on loans	5.8%	5.6%	5.5%	5.5%
Inflation rate	2.0%	2.1%	2.0%	2.0%
Exchange rate (US/Cdn$)	0.88	0.88	0.89	0.88
Unemployment rate	6.8%	6.6%	6.6%	6.6%

[a] Actual.
[b] Averaged over 2009-2016.

Figure 1.10
Canadian economic indicators



Economic growth, the percentage change of gross domestic product (GDP) between two points in time, usually a year or a quarter, measures the rate of expansion (or contraction) of an economy and its capacity to produce goods and services. In 2006, despite numerous hurdles, such as the continued appreciation of the Canadian dollar against the U.S. dollar and its effect on exports and the impact of higher energy prices on Canadian industries and consumers, Canada achieved a real GDP growth rate of 2.7 per cent. This was somewhat weaker than the 2.9 per cent growth in 2005, as central Canada's manufacturing sector, in particular the auto and auto parts and wood-related industries, continued to struggle against a strong Canadian dollar and weakening demand for new automobiles in the United States.

A driving force of Canada's economic growth in 2006 included significant gains to real gross fixed capital formation, including strong investment in both the private and public sectors. On the business side, nonresidential investment far outpaced residential investment, which grew by a mere 2.4 per cent. This was a big change from recent years, when low interest rates enticed consumers to invest heavily in new housing. On the nonresidential side, building investment advanced by 7.5 per cent and machinery and equipment investment grew by 8.7 per cent. Much of the nonresidential building construction can be explained by the billions invested in Alberta's energy sector. The strong Canadian dollar has made it cheaper for Canadian business to purchase new machinery and equipment from abroad. In total, business investment rose by 6.0 per cent in 2006.

Government investment rose by 6.4 per cent, as numerous infrastructure projects across Canada are under way. Canada's enviable fiscal situation, with successive years of budget surpluses and growing tax revenues, has allowed the federal government to make significant transfer payments to the provinces to help finance infrastructure projects in the key transportation, education, and health care sectors.

Nominal wages and salaries growth of 6.0 also paint a healthy, albeit skewed, picture of the Canadian economy. Income growth has recently been more pronounced in Canada's western provinces (Alberta, British Columbia, and Saskatchewan) compared with central and eastern Canada. Nonetheless, this has boosted overall real consumer expenditures in the country by 3.8 per cent in 2006. Imports of goods and services (4.9 per cent) from abroad have also benefited from strong consumer spending and a strong Canadian dollar.

Canada's exchange rate appreciated by an average of $0.056 in 2006, with much of the appreciation being triggered by demand for Canada's raw commodities, such as crude oil, natural gas, coal, and other minerals. Canada's energy sector, especially activity in Alberta's oil sands, combined with stable politics and a business-friendly environment, has made Canada a target of foreign investment and has helped to keep upward pressure on demand for the Canadian dollar.

The value of real export growth in Canada increased by only 1.0 percentage point in 2006, as demand for Canadian goods, especially raw commodities, surged. The appreciated Canadian dollar, however, has kept a damper on real export growth, as it has become more expensive to import goods and services from Canada. This is particularly true of the country's manufacturing sector, in which some key industries have suffered appreciably due to the strong Canadian dollar and escalating energy costs. Real output in the manufacturing sector actually declined by 0.4 per cent in 2006, with much of the weakness originating in the key autos and parts, wood, and paper products sectors. Good gains were made in the machinery and transportation manufacturing sectors, as demand for these goods in the energy sector soared.

Canada's economic growth is expected grow at a good pace over the forecast horizon to average 2.8 per cent per year between 2007 and 2016. The exchange rate is expected to remain close to current appreciated levels and average US$0.88 in 2007 and throughout the remainder of the forecast period.

In addition to investment, consumption, and manufacturing gains, economic growth typically implies growth in the labour force and possibly a reduction in the unemployment rate. Canada's unemployment rate in 2006 fell 0.5 percentage points to 6.3 per cent but is expected to increase by 0.3 percentage points in 2007, as more people enter the labour force. Employment in the country grew by 2.0 per cent in 2006, the highest growth rate since 2003.

In some cases growth can be so strong that it can create inflationary pressures within the economy as it operates at or close to capacity. The inflation rate is used to monitor changes in the cost of living in a society, as it measures the rate at which the price of goods and services is increasing. Low inflation enables an economy to function more effectively by allowing individuals to be more confident in their spending and investment decisions. It also encourages longer-term investments, sustained job creation, and higher productivity, which result in improvements in the standard of living.

Inflation is expressed in terms of changes in the total consumer price index (CPI) or the core CPI. The core CPI, a variation on the total CPI, excludes the eight components from the total CPI reference basket that exhibit the most price volatility (fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, intercity transportation, and tobacco products), as well as the effect of changes in indirect taxes on the remaining components.

The Bank of Canada keeps Canada's inflation under control by influencing short-term interest rates (monetary policy) to achieve a level of economic stimulus consistent with the inflation-control target range, which is between 1 and 3 per cent. The Bank of Canada's policy aims to keep inflation at the midpoint of this range, at 2 per cent.

The average annual interest rate on prime business loans was 5.8 per cent in 2006, an increase of 1.4 percentage points over the 2005 average rate. The rise in interest rates comes about from the Bank of Canada's decision to increase the target overnight rate a full percentage point during the first half of 2006 in an effort to keep the level of inflation in Canada within the target range. The rate of inflation in 2006 reached 2.0 per cent, a 0.2 percentage point drop from the previous year.

It is expected that the Canadian economy in 2007 will operate close to its productive capacity, albeit at a somewhat slower pace than seen over the past three years. This is due in large part to a weaker central Canadian economy compared with the roaring economy of western Canada. Therefore, further increases to the interest rate in 2007 are not expected, as employment growth, consumption, and inflationary pressure for Canada as a whole will likely remain tame due to economic deceleration in central Canada. In fact, if key economic variables in the Canadian economy exhibit weakness in the coming months, the Bank of Canada may decrease interest rates two quarters of a percentage point. As a result, the interest rate on prime business loans is expected to average 5.6 per cent and total inflation will reach 2.1 per cent in 2007. In 2008 and beyond, the EUB outlook assumes that monetary policy will remain unchanged, with the prime rate at 5.5 per cent and inflation around the midpoint of the target range.

1.5 Alberta Economic Outlook

Alberta real economic growth averaged 4.0 per cent per year between 1997 and 2005. Real GDP growth reached 6.8 per cent in 2006 and is expected to grow by a further 5.0 per cent in 2007. Alberta has the highest GDP per capita among the provinces, averaging $39 900 per person over the last five years, which is 16 per cent higher than the GDP per capita of the second-highest province, Ontario.

The EUB forecast of Alberta's real GDP and other economic indicators is given in **Table 1.4**. Real GDP growth is set to average 5.5 per cent in the near term and 3.0 per cent over the remainder of the forecast. Alberta's inflation was measured at 3.9 per cent in 2006, quite a bit above the national average of 2.0 per cent. The province is dealing with exceptional economic growth and strong population growth, which are feeding cost increases throughout the province. In the near term it is expected that prosperous economic growth will continue and inflation to remain above the national average. The positive economic outlook, however, will continue to contribute to excellent job prospects, low levels of unemployment, real increases in average employment earnings, and growth in personal disposable income.

Table 1.4. Major Alberta economic indicators, 2006-2016 (%)

	2006[a]	2007	2008	2009-2016[b]
Real GDP growth	6.8	5.0	4.7	3.0
Real personal disposable income growth	8.0	6.0	5.5	3.2
Inflation rate	3.9	3.4	2.7	2.1
Employment growth	4.8	1.9	2.2	2.4
Population growth	3.0	1.6	1.7	1.9
Unemployment rate	3.5	3.2	3.0	3.3

[a] Actual.
[b] Averaged over 2009-2016.

One caveat is that the province is strained to fill all the vacant employment positions, which has caused inflationary pressures in key areas of the economy. Over the near to long term, the province will need to attract a large number of workers from outside of the province, including from abroad, for economic growth to continue at the pace anticipated.

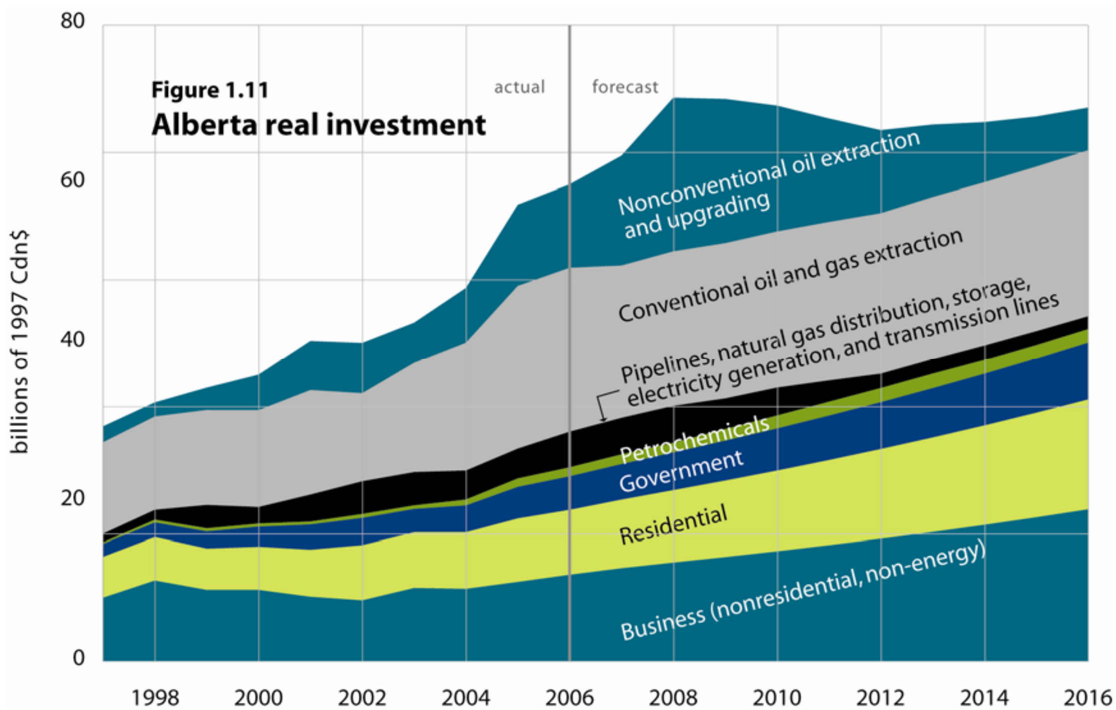
The main contributors to Alberta's current and future economic growth are large gains in investment expenditure, particularly in the oil sands sector, relatively high energy prices, and a steady rate of growth in personal consumption. The spin-offs from increased investment and consumption will mean increased output in many of Alberta's major sectors, including nonconventional energy resources, petroleum, coal, and chemical product manufacturing, as well as retail and wholesale trade and service industries. Much of Alberta's additional mineral fuel and refined product production will be destined for the export market.

Investment in construction and machinery and equipment in the province has been defying most expectations over the past few years, and the bulk of expenditure, particularly in the province's energy sector, is yet to come. Since the early part of the decade, global oil and North American natural gas prices have skyrocketed due to increasing demand, dwindling spare capacity, and geopolitics (in the case of crude oil). Many analysts expected prices to drop more in range with historical levels, but they remained stubbornly high. This has caused exploration, drilling, and extraction to surge in Alberta. It has also made previously uneconomic unconventional oil extraction become profitable. In fact, the oil sands sector has become the target of interest for investors worldwide and has contributed to massive investment in the sector.

Most of the investment in the oil sands sector has recently been focused on surface mining projects. Syncrude Canada Ltd. and Suncor Energy Inc. have been extracting bitumen from surface mined oil sands for decades, while Shell Canada Ltd. has developed the third surface mining project. Much of the future oils sands related investment, however, will be geared toward in situ type extraction methods and bitumen upgrading. In addition, investment in much-needed pipeline infrastructure to move the product to new and existing markets is also anticipated.

From 2007 until 2016 the EUB expects total real investment expenditure related to oil sands (surface mining, upgrading, in situ, and support services) to reach about $118 billion. Real investment in commercial services (pipelines, transmission lines, electricity generation, natural gas distribution, and oil and natural gas storage) will reach $28 billion, while investment in petrochemical manufacturing and refining is thus far slated to receive $16 billion in investment.

Figure 1.11 illustrates the profile of real investment in Alberta's energy, business, residential, and government sectors from 1997 until 2016. Historically, much of the volatility in Alberta's investment was strongly influenced by resource prices, interest rates and, of course, economic performance. While this trend is expected to continue, investment in the oil sands will become a major contributor to overall growth in investment well into the long term.



Total real investment expenditure is expected to grow by an average of 7.5 per cent over 2006 to 2008, before decelerating significantly. Growth will contract by an average of 1.1 per cent over the 2009 to 2016 period. In the event that oil sands projects are delayed or as new oil sands projects are announced, investment growth may become more pronounced towards the end of the forecast period.

The EUB expects the deflator related to construction investment to continue exhibiting inflationary pressure well above the CPI as capital, labour, and material are priced at a premium in the province. Construction-related costs have escalated sharply in the province over the past few years, and not only for construction related to the energy sector. Material and labour costs for infrastructure projects in transportation, education, and health care have also grown significantly.

Almost all areas of the Alberta economy are feeling the pinch from not being able to hire as many workers as necessary to accommodate the needs of rapidly growing economy. The unemployment rate in the province has fallen almost steadily from its peak of 9.6 per cent in 1993 to 3.5 per cent in 2006. The economy is operating well below full employment (usually defined as the non-accelerating inflation rate of unemployment and thought to be about 6.0 per cent or less for Canada as a whole) and has been operating at that level for a number of years.

Employment grew by 4.8 per cent in 2006, but it is unlikely that it will grow at the same pace in the near term as migration slows. Over the forecast period, employment growth will average 2.2 per cent, a pace that is stronger than the national rate. The labour force participation rate will remain fairly consistent, at between 80 to 81 per cent.

With tight labour supply and growing labour demand comes excellent earning potential. Average real wages and salaries per employee have grown at the fastest pace in the country and will continue at a good pace until labour supply and demand are in equilibrium. High salaries, combined with the lowest personal taxes in the country, have also made real personal disposable income the highest in Canada. Real personal disposable income grew by 8.0 per cent in 2006. Over the rest of the forecast period, its growth will average 3.4 per cent.

The increase in earnings will continue to propel consumer expenditures, which have also been expanding at a fast pace in the province recently. In 2005 real consumer expenditures surged by 6.7 per cent, and 2006 growth is expected to near 5.7 per cent. As inflationary pressures continue, real consumption will be somewhat eroded and spending will advance by 4.0 per cent in 2007. Over the remainder of the forecast, real consumption growth will average 4.2 per cent.

Real provincial exports, net of inflation, which include interprovincial transactions of goods, grew by 5.2 per cent in 2006 and are set to grow by 5.5 per cent in 2007. Over the remainder of the forecast, real export growth will average 3.7 per cent. Canada’s strong exchange rate further out in the forecast period implies that export growth will be weaker compared with the near term.

As disposable income and prospects for high-paid employment grow over the forecast period, consumers will continue to demand more goods and services with many of these originating from abroad. Real import growth expanded by 6.7 per cent in 2006, following 8.3 per cent in 2005. Much of the import growth can be attributed to a strong Canadian dollar, which has made these goods cheaper for Canadians. As the EUB expects the exchange rate to remain around US$0.86 over the forecast, high by historical standards, Albertans will continue to demand imported goods. In addition, businesses will find it cheaper to purchase new machinery and equipment from abroad. Investment in machinery and equipment has been strong over the past couple of years, as the price of these imported goods has fallen.

Today’s energy prices are the driving force fuelling the current pace of exploration and development activity. The assumption of prices remaining high by historical standards will increase the likelihood of further investment in upstream and downstream oil and gas infrastructure. If current prices are sustained, the effect could provide long-term stability to the current level of economic activity in Alberta, thus adding to its economic potential and standard of living.

Conventional gas wells connected and oil wells placed on production in Alberta have remained at stable levels over the past few years. In 2005, 12 458 conventional gas wells and 1881 conventional oil wells were connected and placed on production in Alberta. An additional 13 009 conventional gas wells were connected and 1956 conventional oil wells were placed on production in 2006. Also in 2005, some 2307 CBM (unconventional gas wells) were placed on production. In 2006, this number increased to 2434 wells. The EUB price forecast supports the current pace of activity going forward. In 2007, an additional 12 000 conventional gas wells, 2000 conventional oil wells, and 1900 CBM wells are expected to be tied into production.

Energy prices are also providing greater incentives to commercially develop Alberta's unconventional energy resources, such as CBM and crude bitumen. Production rates from unconventional resources are expected to increase significantly over the coming decade. As a result, the total economic value of Alberta's produced unconventional resources (shown in **Table 1.5**), in particular crude bitumen and SCO derived from the oil sands, will more than offset the decline of conventional resource production.

Table 1.5. Value of Alberta energy resource production (millions of current dollars)

	2006	2007[a]	2008[a]	2009-2016[a,b]
Conventional crude oil	12 064	11 001	10 950	9 499
Crude bitumen	6 926	8 328	9 163	12 167
Synthetic crude oil	16 377	17 648	21 157	41 016
Marketable gas	33 510	38 581	38 745	38 963
Natural gas liquids	8 964	9 400	9 385	9 269
Sulphur	122	122	122	122
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	78 752	85 875	90 648	110 004

[a] Values calculated from the EUB's annual average price and production forecasts.
[b] Annual average over 2009-2016.

CBM production accounted for 3 per cent of marketable natural gas production in 2006. By 2016, gas production from CBM wells will increase to 13 per cent of marketable gas production. However, the additional marketable gas production from unconventional sources will fall short of offsetting the decline in conventional natural gas production.

Investment in refineries and upgraders within Alberta will enable increased volumes of crude bitumen to be upgraded into higher valued SCO product, further providing long-term stability for GDP growth and employment. As well, investments in pipeline infrastructure will improve access to markets outside of Alberta. As a result, exports of Alberta's SCO product will increase from 63 per cent of the total SCO production in 2006 to 83 per cent of SCO production by 2016.

Higher energy prices are leading to increased revenues at oil and gas companies and higher operating expenditures. Today in Alberta, companies are competing with each other for skilled workers, drilling contracts, and support services. Equipment and labour are increasingly scarce and have driven costs up significantly, especially during periods of high seasonal demand. Many of these limitations are acknowledged by industry, and in some cases, when supply cannot respond to the increasing demands, unique solutions are being applied. For instance, companies are responding to the tight labour market by sponsoring training and apprenticeships, by luring migrants from within Canada and internationally, and even by providing air transportation to draw workers from other regions of the province and country.

Alberta's current and future economic growth will continue to provide a strong push for Canada's future economic growth. The province is leading many other provinces in terms of employment, population and income growth. As well, Alberta has achieved a considerably low unemployment rate. The EUB forecast for Alberta's economic growth is attainable; however, strong growth will imply a tight labour market, inflationary pressure, and significant labour and material costs. While population growth is helping to deal with the labour shortage, it could perpetuate the negative aspects of rapid economic growth by increasing the demand for essential services, such as housing, health, education, and public transportation.

2 Crude Bitumen

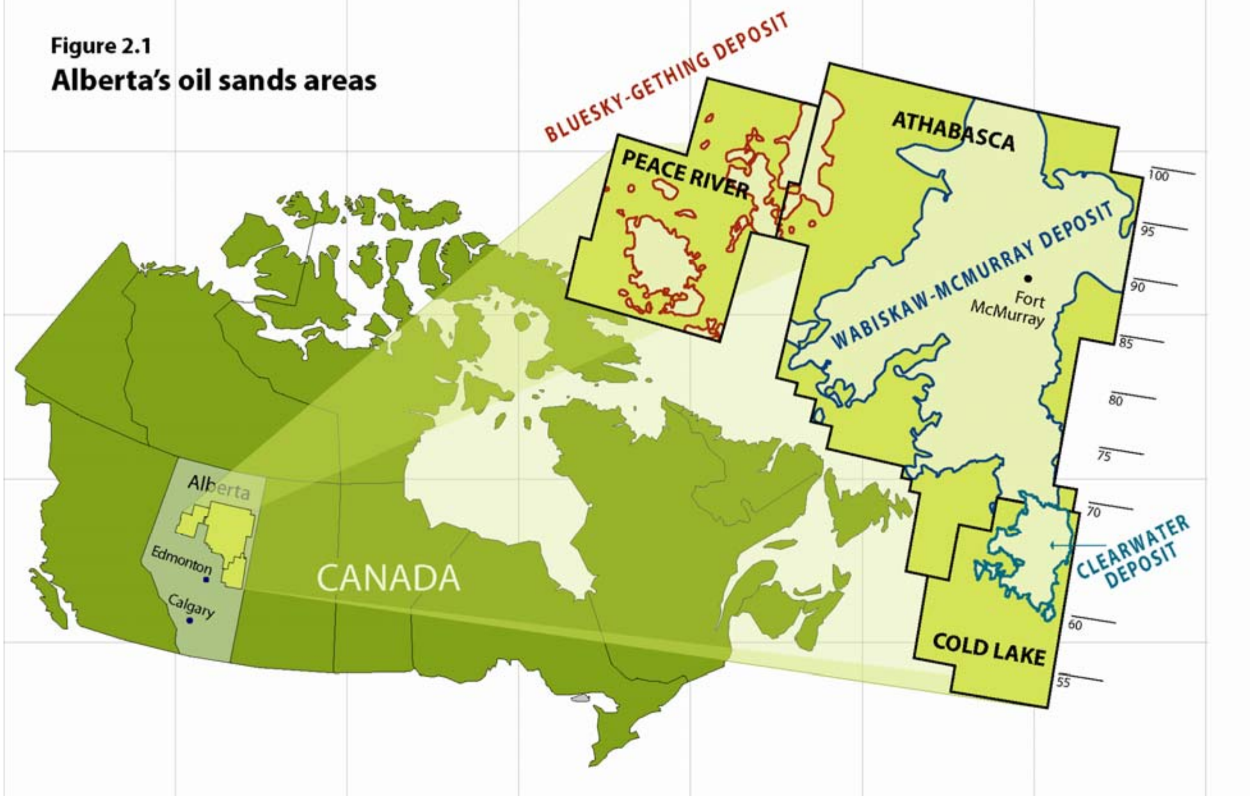
Crude bitumen, a type of heavy oil, is a viscous mixture of hydrocarbons that in its natural state does not flow to a well. In Alberta, crude bitumen occurs in sand (clastic) and carbonate formations in the northern part of the province. The crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands.

Other heavy oil is deemed to be oil sands if it is located within an oil sands area. Since these deemed oil sands will flow to a well, they are amenable to primary development and are considered to be primary crude bitumen in this report.

North of Fort McMurray, crude bitumen occurs near the surface and is recovered by open pit mining. The oil sands are excavated and the bitumen is extracted from the mined material in large facilities. At greater depths, the bitumen is recovered in situ. In situ recovery takes place both by primary development and by enhanced development, whereby steam, water, or other solvents are injected into the reservoir to mobilize the bitumen and bring it to a vertical or horizontal wellbore.

The three designated oil sands areas (OSAs) in Alberta, as of the end of 2006, are shown in **Figure 2.1**. Each oil sands area contains a number of bitumen-bearing deposits. The known extent of the largest deposit, the Athabasca Wabiskaw-McMurray, as well as the significant Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 kilometres (km) (30 miles) apart.

Figure 2.1
Alberta's oil sands areas



2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

Over the past few years, the EUB has been working towards updating Alberta's resources and reserves of crude bitumen. This initiative continues and will likely be ongoing for some years, as rapid development of the resource continues. The initial step in this review is to update the in-place resources for the most significant of the province's 15 oil sands deposits, those currently with production and consequently containing established reserves. To date, three of the most important deposits have been updated. The largest deposit, the Athabasca Wabiskaw-McMurray (AWM), was significantly updated for year-end 2004 and revised slightly last year. The AWM has the largest cumulative and annual production. The deposit with the second largest production, the Cold Lake Clearwater (CLC), was updated last year, as was the northern portion of the Cold Lake Wabiskaw-McMurray (CLWM) deposit. For year-end 2006, the Peace River Bluesky-Gething (PRBG) deposit has been updated and is shown to be more areally extensive than previously published. These four deposits contain over 60 per cent of the total initial in-place bitumen resource and about 86 per cent of the in-place resource found in clastics.

Once the in-place resources have been determined, the EUB will review Alberta's established reserves on both a project and deposit basis. This work is anticipated to take some time to complete. (See Section 2.1.6 for more on the ongoing review.) As a result, there are no significant changes to the estimate of the established reserves of crude bitumen for this year's report and, therefore, the remaining established reserves of crude bitumen at December 31, 2006, are 27.53 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.07 10^9 m^3.

Of the total 27.53 10^9 m^3 remaining established reserves, 22.53 10^9 m^3, or about 82 per cent, is considered recoverable by in situ methods and 5.01 10^9 m^3 recoverable by surface mining methods. Of the in situ and mineable totals, 3.34 10^9 m^3 is within active development areas. **Table 2.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

Table 2.1. In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	16.1	5.59	0.58	5.01	2.95
In situ	254.2	22.80	0.28	22.53	0.39
Total	270.3 (1 701)[a]	28.39 (178.7)[a]	0.86 (5.4)[a]	27.53 (173.2)[a]	3.34 (21.0)[a]

[a] Imperial equivalent in billions of barrels.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative production for 2006 are shown in **Table 2.2**. The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown in **Tables 2.4** and **2.5** respectively.

Table 2.2. Reserve change highlights (10^6 m^3)

	2006	2005	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 802	22 802	0
Total	28 392 (178 668)[b]	28 392 (178 668)[b]	0
Cumulative production			
Mineable	582	538	+44
In situ[a]	282	253	+29
Total	864	791	+73
Remaining established reserves			
Mineable	5 008	5 052	-44
In situ	22 520	22 549	-29
Total[a]	27 528 (173 231)[b]	27 601 (173 687)[b]	-73

[a] Differences are due to rounding.
[b] Imperial equivalent in millions of barrels.

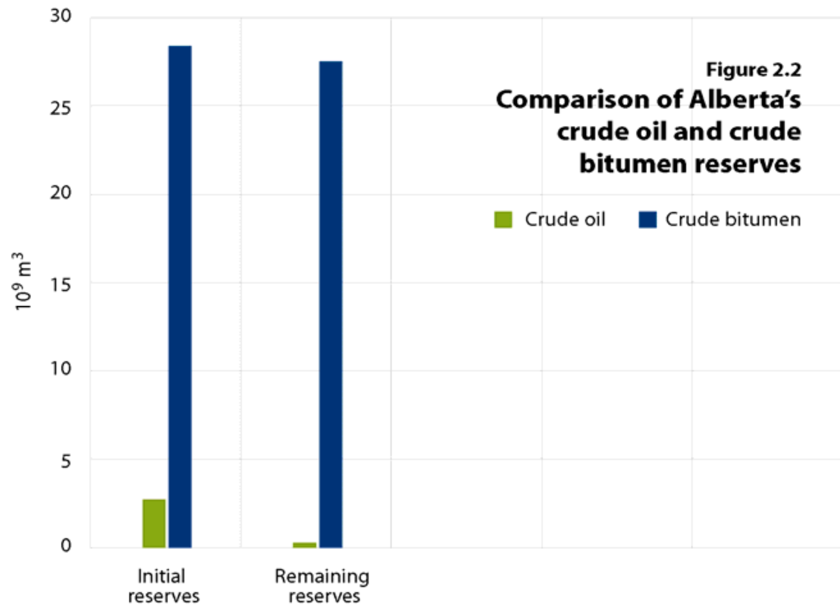
Crude bitumen production in 2006 totalled 72.8 10^6 m^3, with 28.7 10^6 m^3 coming from in situ operations. Production from the three current surface mining projects amounted to 44.1 10^6 m^3 in 2006, with 18.0 10^6 m^3 from the Syncrude Canada Ltd. project, 17.6 10^6 m^3 from the Suncor Energy Inc. project, and 8.5 10^6 m^3 from the Albian Sands Energy Inc. project.

Figure 2.2 compares the relative size of Alberta's initial and remaining established crude oil and crude bitumen reserves. While most of Alberta's known conventional crude oil reserves have been produced, most of the crude bitumen has yet to be tapped.

2.1.2 Initial in-Place Volumes of Crude Bitumen

Alberta's massive crude bitumen resources are contained in sand (clastic) and carbonate formations in the three OSAs: Athabasca, Cold Lake, and Peace River, as shown in **Figure 2.1**. Contained within the OSAs are the 15 oil sands deposits, which designate the specific geological zones containing the oil sands. Together the three OSAs occupy an area of about 140 000 km^2 (54 000 square miles).

The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation can vary significantly within a reservoir, decreasing as the reservoir shale or clay content increases or as the porosity decreases. Increasing water volume within the pore space of the rock also decreases bitumen saturation. Bitumen saturation is expressed as mass per cent in sands (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water) and per cent pore volume in carbonates (the percentage of the volume of pore spaces that contain bitumen). The selection of appropriate saturation and thickness cutoffs varies, depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.



Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data, including geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, cutoffs were increased to 6 mass per cent and 3.0 m for areas amenable to surface mining. In the two previous reports, the AWM and CLC deposits, as well as a portion of the CLWM deposit, were estimated at a 6 mass per cent saturation cutoff. This year's report also uses 6 mass per cent with the update of the PRBG deposit. The crude bitumen within the carbonate deposits was determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent.

The EUB believes that the oil sands quality cutoff of 6 mass per cent more accurately reflects the volumes from which bitumen can be reasonably expected to be recovered; consequently, deposits that are updated in the future will likely be at this level. Based solely on a change from 3 to 6 mass per cent (other factors held constant), the estimated impact on the bitumen resource in place would be a decrease of about 20 per cent for the AWM, about 35 per cent for the CLC, and more than 50 per cent for the PRBG. However, work on these deposits has shown that some or all of this reduction is offset by increases due to new drilling since the previous estimate. This year's reassessment of the PRBG, for example, shows a small increase in the initial in-place volume due to additional drilling, which has expanded the known extent of the deposit, particularly to the northeast.

In 2003, the EUB completed a regional geological study of part of the Wabiskaw-McMurray deposit of the Athabasca OSA.[1] The purpose of that study was to identify where gas pools are associated with recoverable bitumen. To support both that study and the reassessment of the AWM, geologic information from over 13 000 wells and bitumen content evaluations conducted on over 9000 wells were used. The stratigraphic framework developed for the regional geological study was used to define 21 stratigraphic intervals, which were subsequently combined into 12 zones within the AWM. In 2005, nearly 700 new wells were added to the reassessment and the volumes and maps were revised.

[1] EUB, 2003, *Report 2003-A: Athabasca Wabiskaw-McMurray Regional Geological Study*.

Figure 2.3 is a bitumen pay thickness map, revised for year-end 2005, for the AWM deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval.

For year-end 2005, the EUB completed its reassessment of the CLC deposit. This deposit contains the first commercial in situ bitumen development at Imperial's Cold Lake project, which commenced production in 1985. In its review, the EUB used stratigraphic information from more than 8000 wells and detailed petrophysical evaluations from almost 2600 wells to define the regional stratigraphy and estimate the in-place resources for the CLC.

Figure 2.4 is a bitumen pay thickness map for the CLC deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the CLC does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

For year-end 2006, the PRBG deposit was reassessed. This deposit contains the in situ bitumen development at Shell Canada's Peace River project, started in 1979. To complete its review, the EUB used stratigraphic information from more than 6500 wells and detailed petrophysical evaluations from almost 1800 wells. The relatively large number of stratigraphic wells was needed to fully define the deposit and the related palaeography because of the series of highlands that existed in the area at the time of deposition.

Figure 2.5 is a map of the reconstructed sub-Cretaceous unconformity beneath the Gething Formation at the time of the deposition of the Bluesky-Gething sediments. The relative elevations for this erosional surface were created by first flattening the top of the Bluesky Formation and then applying those adjustments to the current unconformity surface. Due to the general lack of drilling information in many areas, the location and extent of the various highlands shown in the figure are considered preliminary and subject to change.

Figure 2.6 is a bitumen pay thickness map for the PRBG deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Even though the PRBG does not contain regionally mappable internal seals, the Gething Formation does contain shale layers and is generally a poorer reservoir than the overlying Bluesky. However, consistent with **Figure 2.3**, the PRBG is mapped as a single bitumen zone so that the full extent of the deposit can be shown. The deposit is now mapped beyond the current boundaries of the Peace River OSA; as a result, the EUB will both expand the OSA and adjust the common boundary with the Athabasca OSA. The boundary shown in **Figure 2.6** is as of year-end 2006. The expanded boundary will be released when new OSA orders are issued by the EUB and will be shown in next year's report. Within the area assessed, the saturation cutoff was changed from 3 mass per cent to 6 mass per cent, as previously mentioned. The net change to the initial in-place resources was an increase of 1.04 10^9 m^3, from 9.93 10^9 m^3 to 10.97 10^9 m^3, mainly due to new drilling in areas previously undrilled at the time of the last estimate.

Also shown in **Figure 2.3** is the extent of the Surface Mineable Area (SMA). The SMA is an EUB-defined area of 37 townships north of Fort McMurray covering that part of the AWM deposit where the total overburden generally does not exceed 75 m. As such, it is presumed that the main recovery method will be surface mining, unlike the rest of Alberta's crude bitumen area, where recovery will be through in situ methods.

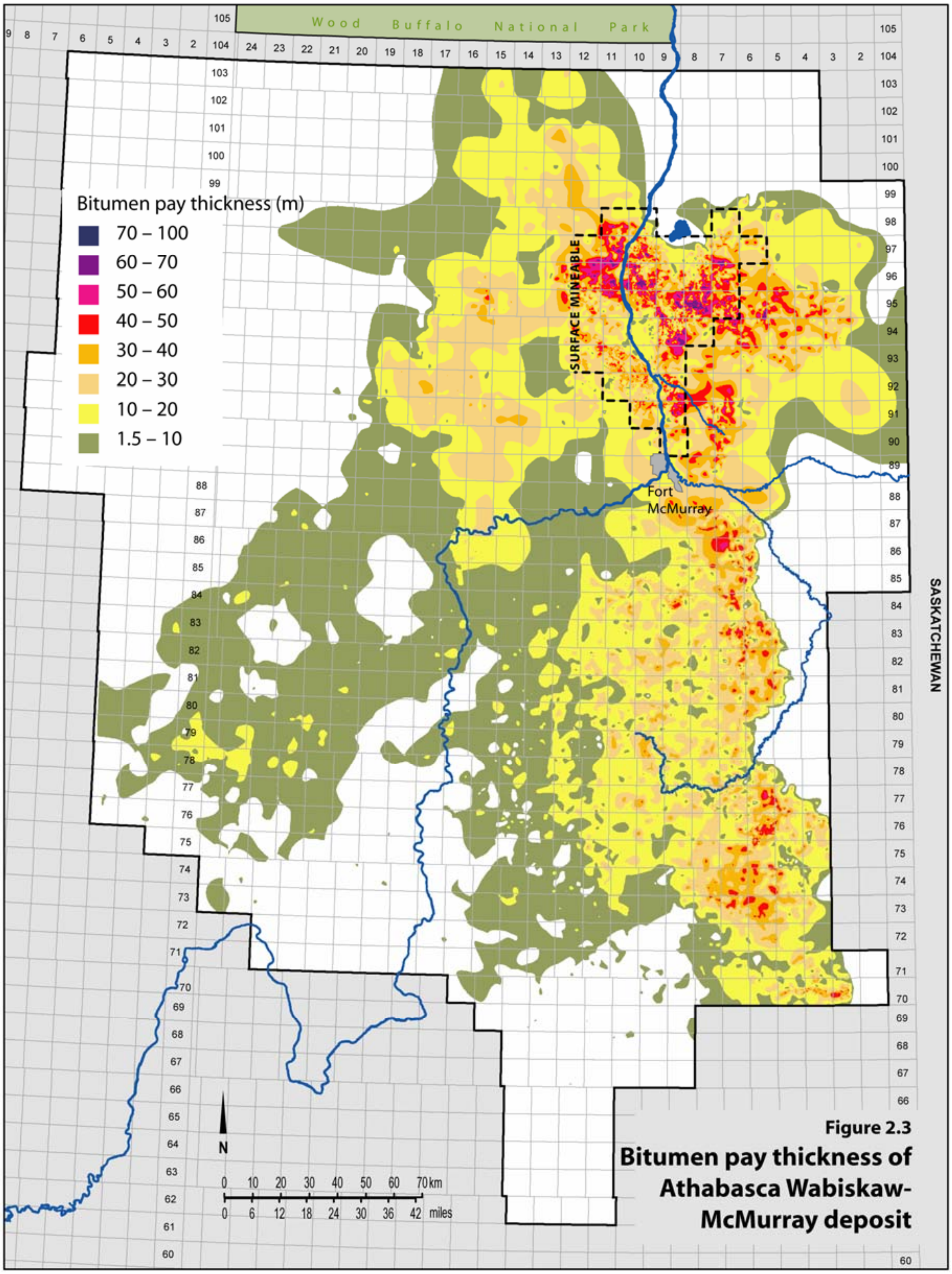
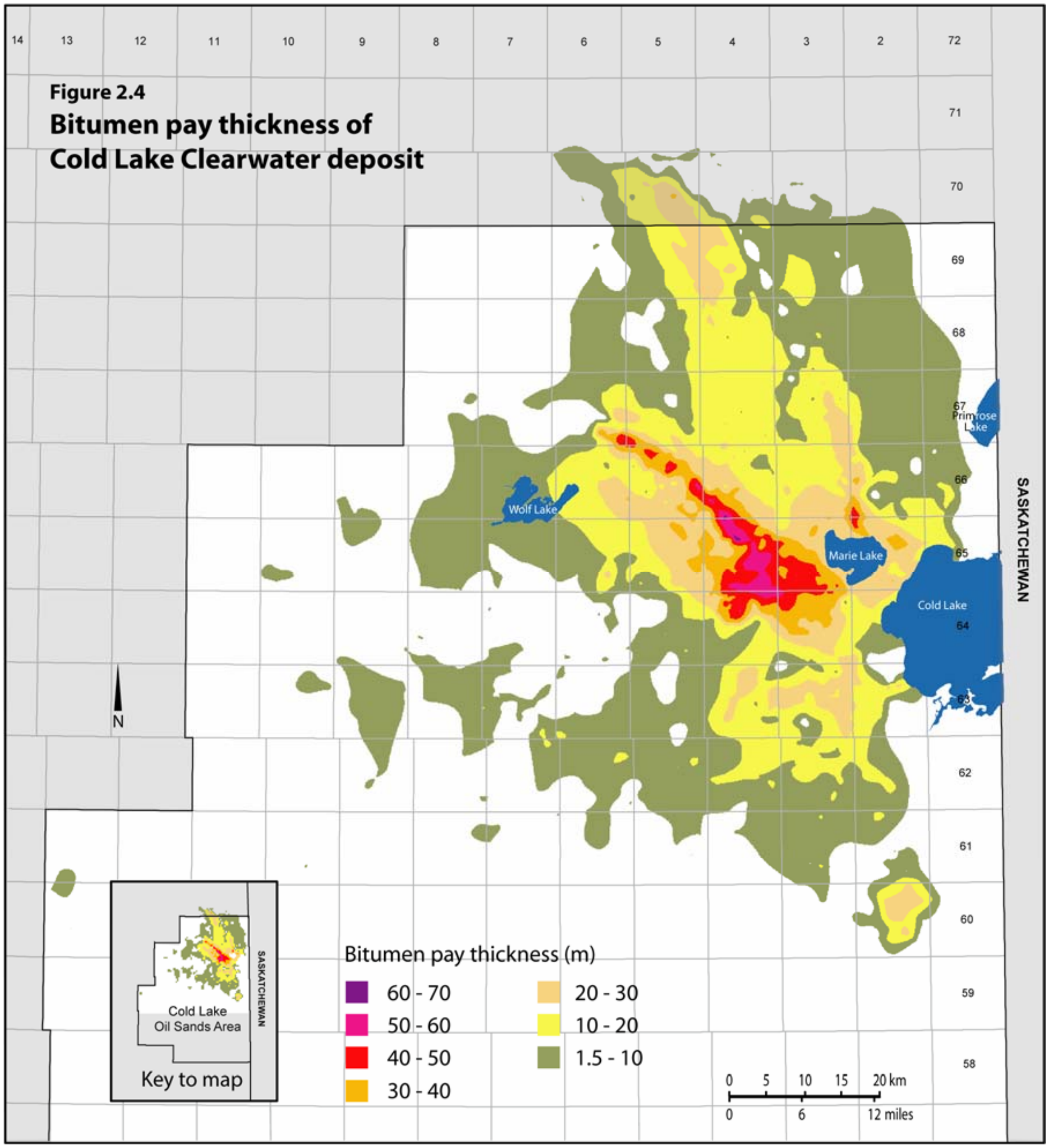


Figure 2.3
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit



Because the boundary of the SMA was originally defined using complete townships, it incorporates a few areas of deeper bitumen resources that are more amenable to in situ recovery. With last year's report, the in-place resources in those areas below 80 m in depth (1.39 10^9 m^3) were removed from the mineable total and incorporated into the in situ total. This change does not affect the established mineable reserves because no quantity of resource economically amenable to mining exists beyond 80 m in depth. Presently there are a few areas between 40 and 80 m of depth that are being developed or considered for in situ extraction. There are likely other areas where in situ extraction may be the most appropriate recovery method. When fully evaluated, these quantities will also be excluded from the mineable total.

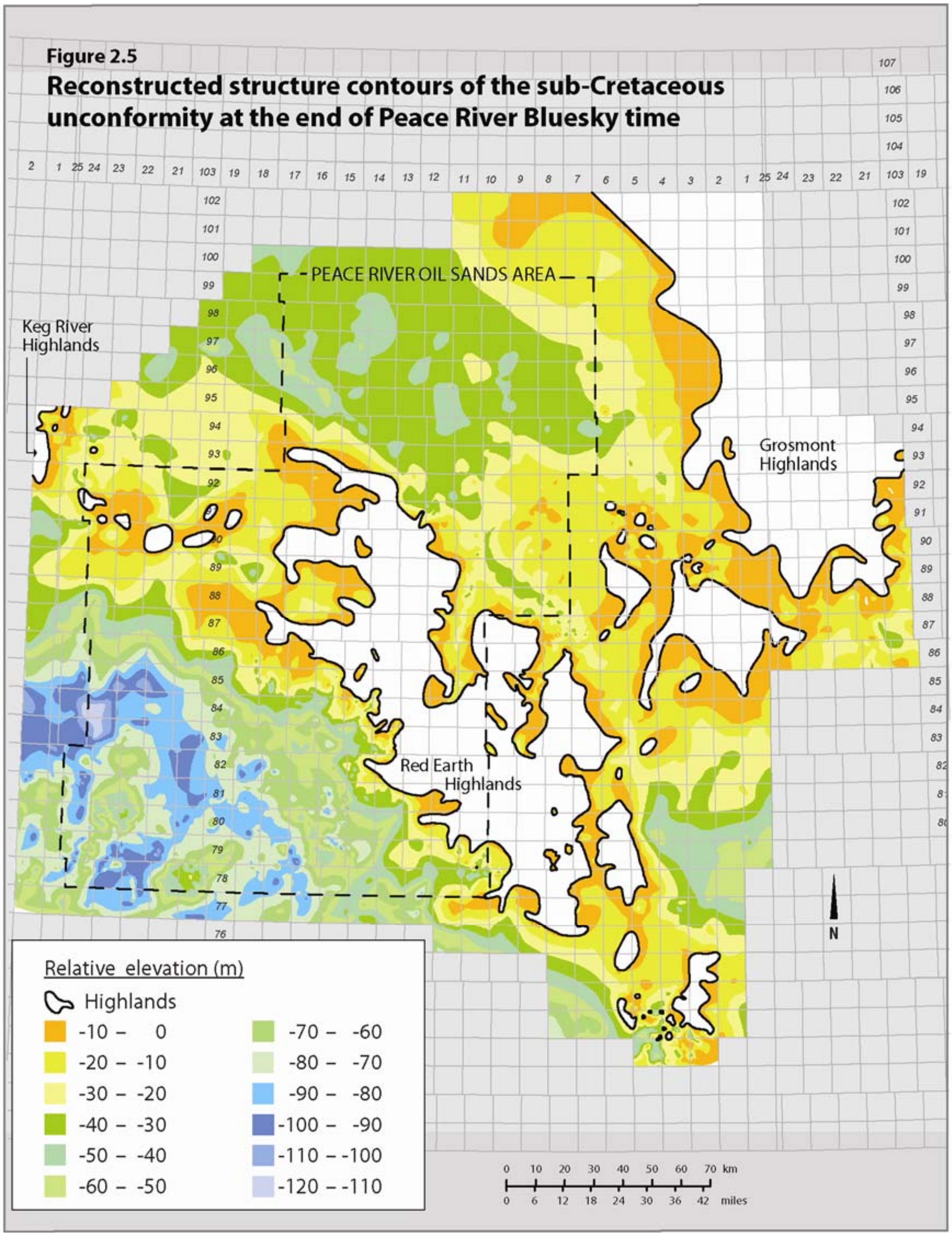


Figure 2.5
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Peace River Bluesky time

The estimate of the initial volume in place of crude bitumen within the SMA was therefore reduced to 16.1 10^9 m^3, to exclude the bitumen resource beyond 80 m in depth. Notwithstanding this reduction, more than 40 per cent of the above volume has been estimated to be beyond the economic range of current commercial mining. However, it is believed that significant portions of this amount will be subjected to future recovery operations, either by in situ technology or by mining methods operating under enhanced economic conditions.

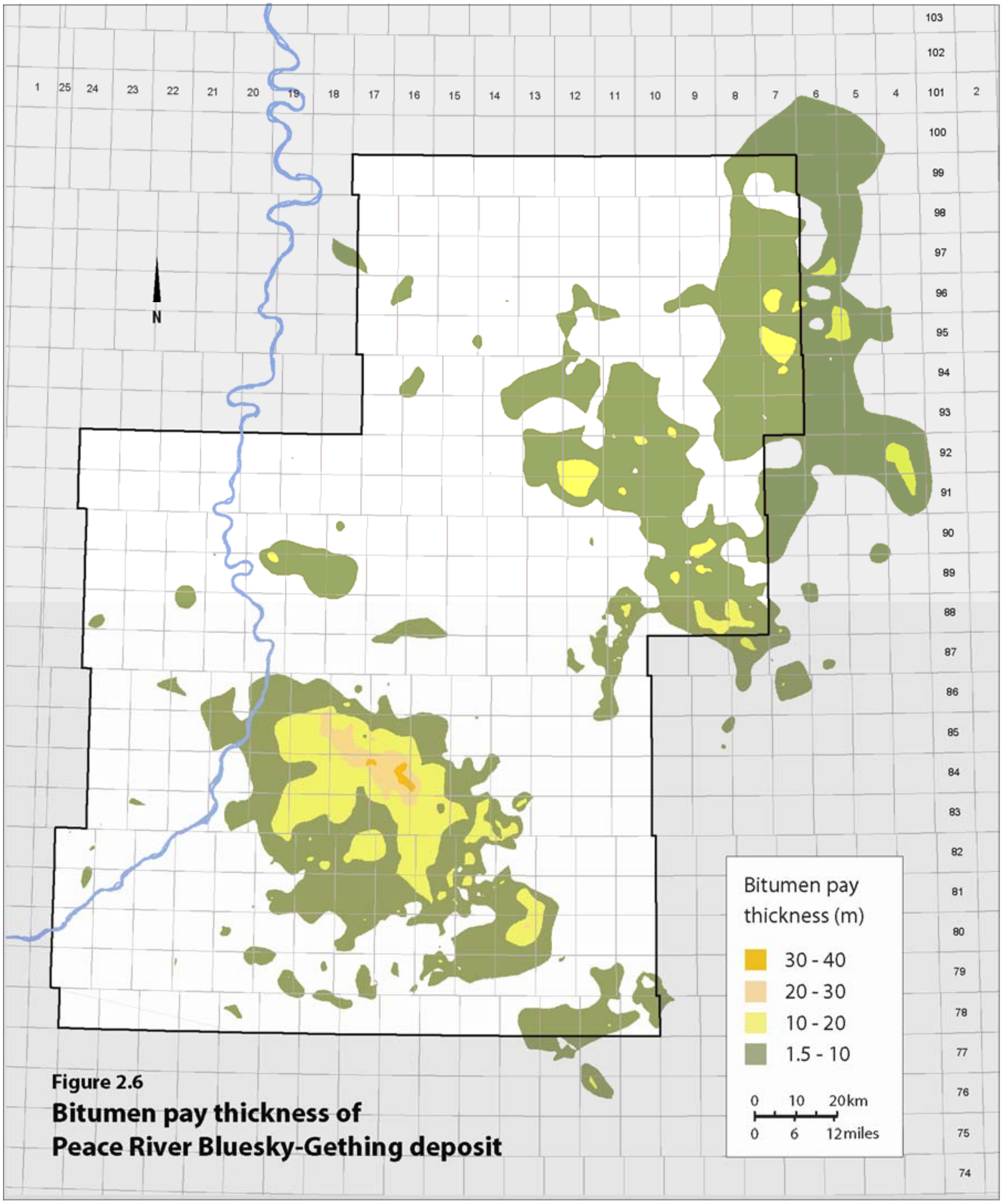


Figure 2.6
Bitumen pay thickness of Peace River Bluesky-Gething deposit

Drilling in recent years north of the SMA boundary has better identified in-place bitumen resources that are potentially recoverable by surface mining methods. The EUB is considering some expansion of the SMA, but no changes were made in 2006. Expansion of the SMA boundary in the future would have the impact of transferring some in-place volumes from in situ to mineable categories and increasing the established mineable reserves. No in situ recoverable volumes have been identified in this area, so expansion would have no impact on the established in situ reserves.

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Tables B.1** and **B.2** respectively in Appendix B and are summarized by formation in **Table 2.3**. Individual maps to year-end 1995 are shown in EUB *Statistical Series 96-38: Crude Bitumen Reserves Atlas* (1996). The latest maps for the AWM, CLC, and PRBG will be available separately.

Table 2.3. Initial in-place volumes of crude bitumen

Oil sands area Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Average bitumen saturation: Mass (%)	Average bitumen saturation: Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	16 087	256	30.5	9.7	69	30
Wabiskaw-McMurray (in situ)	132 128	4 665	13.2	10.2	73	29
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	50 500	4 167	10.4	4.7	68	16
Subtotal	217 723					
Cold Lake						
Grand Rapids	17 304	1 709	5.9	9.5	66	31
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.4	7.3	59	27
Subtotal	31 013					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	302	23.7	5.1	65	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	21 560					
Total	270 296					

2.1.3 Surface-Mineable Crude Bitumen Reserves

Potential mineable areas within the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[2] This method reduces the initial volume in place of 16.1 10^9 m^3 to 9.4 10^9 m^3 as of December 31, 2006. This latter volume is classified as the initial mineable volume in place.

Factors were applied to this initial mineable volume in place to determine the established reserves. A series of area reduction factors was applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total area, and therefore each factor is set at 90 per cent. A combined mining/extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by the mining operations and the extraction facilities. The resulting initial established reserve of crude bitumen is estimated to be 5.59 10^9 m^3, unchanged from December 31, 2005.

[2] Energy Resources Conservation Board, 1979, *ERCB Report 79-H: Alsands Fort McMurray Project.*

The remaining established mineable crude bitumen reserve as of December 31, 2006, is 5.01 10^9 m^3, slightly lower than last year's estimate due to the production of 44.1 10^6 m^3 in 2006.

As of the end of 2006, nearly two-thirds of the initial established reserves were under active development. This large change from year-end 2005 results from updated estimates for the producing mines and the inclusion of projects approved in recent years. Currently, Suncor, Syncrude, and Albian Sands are the only producers in the SMA, and the cumulative bitumen production from these projects is 582 10^6 m^3. However, the Fort Hills mine project (owned by Petro-Canada, UTS Energy, and Teck Cominco), the Canadian Natural Resources Ltd. (CNRL) Horizon, and the Shell Canada Ltd. Jackpine projects are considered to be under active development and have been added to **Table 2.4**. The recently approved Kearl Mine (Imperial Oil/ExxonMobil) is not yet under active development but will be included when it reaches active status.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2006, are presented in **Table 2.4**.

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2006

Development	Project area[a] (ha)	Initial mineable volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
Albian Sands	13 581	672	419	32	387
Fort Hills	18 976	699	364	0	364
Horizon	28 482	834	537	0	537
Jackpine	7 958	361	222	0	222
Suncor	19 155	990	687	220	467
Syncrude	44 037	2 071	1 306	330	976
Total	132 189	5 627	3 535	582	2 953

[a]The project areas correspond to the areas defined in the project approval.

2.1.4 In Situ Crude Bitumen Reserves

The EUB has determined an in situ initial established reserve for those areas considered amenable to in situ recovery methods. Reserves are estimated using cutoffs appropriate to the type of development and differences in reservoir characteristics. Areas amenable to thermal development were determined using a minimum zone thickness of 10.0 m in all deposits except the AWM, where 15.0 m was used for the Wabiskaw zones. For primary development, a minimum zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. A minimum saturation cutoff of 3 mass per cent was used in all deposits. Future reserves estimates will likely be based on values higher than the 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to the areas meeting the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the active project recovery factors to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas. These overall recovery factors are currently under review.

In 2006, the in situ bitumen production was 28.7 10^6 m^3, an increase from 25.3 10^6 m^3 in 2005. Cumulative production within the in situ areas now totals 282 10^6 m^3, of which 221 10^6 m^3 is from the Cold Lake OSA. Due to production, the remaining established reserves of crude bitumen from in situ areas decreased to 22.52 10^9 m^3.

The EUB's 2006 estimate of the established in situ crude bitumen reserves under active development is shown in **Table 2.5**.

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2006

Development	Initial volume in place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	55.8	40	22.3	8.9	13.4
Primary recovery schemes	120.6	5	6.0	2.7	3.3
Subtotal	176.4		28.4	11.6	16.7
Athabasca Oil Sands Area					
Thermal commercial projects	155.6	50	77.8	18.7	59.1
Primary recovery schemes	628.6	5	31.4	18.20	13.2
Enhanced recovery schemes[c]	(136.7)[d]	5	6.8	5.6	1.2
Subtotal	784.2		116.1	42.5	73.5
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25	200.7	158.7	42.0
Primary production within projects	601.1	5	30.1	13.3	16.7
Primary recovery schemes	4 347.1	5	217.4	43.0	174.4
Lindbergh primary production	1 309.3	5	65.5	6.3	59.1
Subtotal	7 060.3		513.6	221.4	292.2
Experimental Schemes (all areas)					
Active	8.1	15[e]	1.2	1.1[f]	0.1
Terminated	87.4	10[e]	9.1	5.4	3.7
Subtotal	95.5		10.3	6.4	3.9
Total	8 116.4		668.3	282.0	386.3

[a] Thermal reserves for this table are assigned only for lands approved for thermal recovery and having completed drilling development.
[b] Cumulative production to December 31, 2006, includes amendments to production reports.
[c] Schemes currently on waterflood in the Brintnell-Pelican area. Previous primary production is included under primary schemes.
[d] The in-place number is that part of the primary number above that will see incremental production due to waterflooding.
[e] Averaged values.
[f] Production from the Athabasca OSA is 0.86 10^6 m^3 and from the Cold Lake OSA is 0.20 10^6 m^3.

The EUB has assigned initial volumes in place and initial and remaining established reserves for commercial projects, primary recovery schemes, and active experimental schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is shown for all active experimental schemes, as well as an estimate of initial volumes in place and cumulative production. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. The initial established reserves under primary development are based on a 5 per cent average recovery factor. The recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake areas respectively reflect the application of various steaming strategies and project designs.

That part of the total remaining established reserves of crude bitumen from within active in situ project areas is estimated to be 386.3 10^6 m^3. This decrease is the result of production of 28.7 10^6 m^3 in 2006. New projects and expansions to existing commercial thermal projects and primary recovery schemes in the Athabasca and Cold Lake OSAs were not assessed in 2006. It is anticipated that as these projects and schemes are added or updated and as approved or announced projects become active, the established reserves totals in **Table 2.5** will increase significantly.

2.1.5 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ recovery methods from Cretaceous sediments is estimated to be 33 10^9 m^3 and from Paleozoic carbonate sediments to be 6 10^9 m^3. Nearly 11 10^9 m^3 is expected from within the surface-mineable boundary. The total ultimate potential crude bitumen is therefore unchanged at 50 10^9 m^3.

2.1.6 Ongoing Review of In Situ Resources and Reserves

In 2003, the EUB initiated a project to update its resource and reserves numbers for in situ bitumen. There are a number of components to this project, including

- updating the geological framework for each deposit,
- reviewing established mass per cent bitumen and thickness cutoffs,
- re-evaluating all wells to provide data on a detailed incremental thickness basis and storing these evaluations in a new database,
- evaluating all recent drilling,
- remapping deposits and recalculating in-place resource volumes, and
- reviewing recovery factors, changing them where appropriate, and calculating new established reserves volumes.

The EUB held a series of bitumen conservation proceedings from 1997 to 2005 to determine the need to shut in gas production to protect potentially recoverable bitumen. As a result of the proceedings, the EUB has accepted that bitumen exceeding 6 mass per cent and 10 m thickness is potentially recoverable. This removes much of the poorer quality component of the bitumen resource (with low potential for recoverability) from the reserve category.

Given the relatively early stage of steam-assisted gravity drainage (SAGD) development, it is not yet possible to refine the current deposit-wide recovery factor of 20 per cent with any greater degree of certainty. Furthermore, the impact of the uncertainty in the deposit-wide recovery factor is noteworthy because a minor change in the recovery factor on a resource of this magnitude has a significant impact on the recoverable component. While a great deal of study and effort have gone into updating the resources of the AWM, the CLC, and now the PRBG, the EUB has not completed its review of recovery factors that should be applied on a deposit-wide basis. The EUB will therefore retain the existing established reserves figure for the province, except for adjustments due to production, until a geological reassessment of other deposits is complete and until further work provides refinement of deposit-wide recovery factors for those deposits with commercial production. The EUB is also considering providing a low, best, and high estimate for established bitumen reserves volumes in future updates to take into account uncertainty in some variables, such as the recovery factor. A range in estimates would take into account the relative early stage of development of a very large resource and the long time frames associated with full development.

In parallel with this work, the EUB is also continuing with the review of its resource/reserve categories, terminology, and definitions. This is particularly relevant for bitumen, considering the high level of interest in the resource, both nationally and globally, in recent years.

2.2 Supply of and Demand for Crude Bitumen

This section discusses production and disposition of crude bitumen. It includes crude bitumen production by surface mining and in situ methods, upgrading of bitumen to various grades of synthetic crude oil (SCO), and disposition of both SCO and nonupgraded bitumen. The nonupgraded bitumen refers to the portion of crude bitumen production that is not upgraded but blended with diluent and sent to markets by pipeline. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to SCO and is primarily used by refineries as feedstock.

Upgrading is the term given to a process that converts bitumen and heavy crude oil into SCO. Upgraders chemically add hydrogen to bitumen, subtract carbon from it, or both. In upgrading processes, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. Most oil sands coke is stockpiled, with some burned in small quantities to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Two methods are used for recovery of bitumen, depending on the depth of the deposit. The shallow-depth deposits in Athabasca (Fort McMurray) are currently recovered by surface mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted using hot water.

Unlike the mineable area of Athabasca, other oil sands deposits are located deeper below the surface. For these deposits, in situ methods have been proven technically and economically feasible. These methods typically use heat from injected steam to reduce the viscosity of the bitumen, allowing it to be separated from the sand and pumped to the surface. A number of these deeper deposits can also be put on production with primary recovery, similar to conventional crude oil production.

Bitumen crude must be diluted with some lighter viscosity product (referred to as a diluent) in order to be transported in pipelines. Pentanes plus are generally used in Alberta as diluent and represent about 30 per cent of the blend volumes. Diluent used to transport bitumen to Alberta destinations is usually recycled. However, the volumes used to dilute bitumen for transport to markets outside Alberta are generally not returned to the province.

SCO is also used as diluent. However, a blend volume of about 50 per cent SCO is required, as the SCO has a higher viscosity and density than pentanes plus. Other products, such as naptha and light crude oil, can also be used as diluent to allow bitumen to meet pipeline specifications. Use of heated and insulated pipelines can decrease the amount of required diluent.

The forecast of crude bitumen production and SCO production relies heavily on information provided by project sponsors. Project viability depends largely on the cost of producing and transporting the products and on the market price for bitumen and SCO. Other factors that bear on project economics are refining capacity to handle bitumen or SCO and competition with other supply sources in U.S. and Canadian markets. The forecasts include production from existing projects, expansion to existing projects, and development of new projects. Demand for SCO and nonupgraded bitumen in Alberta is based on refinery demand and SCO used for transportation needs. Alberta SCO and nonupgraded bitumen supply in excess of Alberta demand are removed from the province.

2.2.1 Crude Bitumen Production

Surface mining and in situ production for 2006 are shown graphically by oil sands area in **Figure 2.7.** In 2006, Alberta produced 199.4 thousand (10^3) m^3/d of crude bitumen from all three regions, with surface mining accounting for 61 per cent and in situ for 39 per cent. **Figure 2.8** shows combined nonupgraded bitumen and SCO production as a percentage of Alberta's total crude oil and equivalent production. Combined SCO and nonupgraded bitumen production volumes have increased from 33 per cent of all production in 1997 to 62 per cent in 2006.

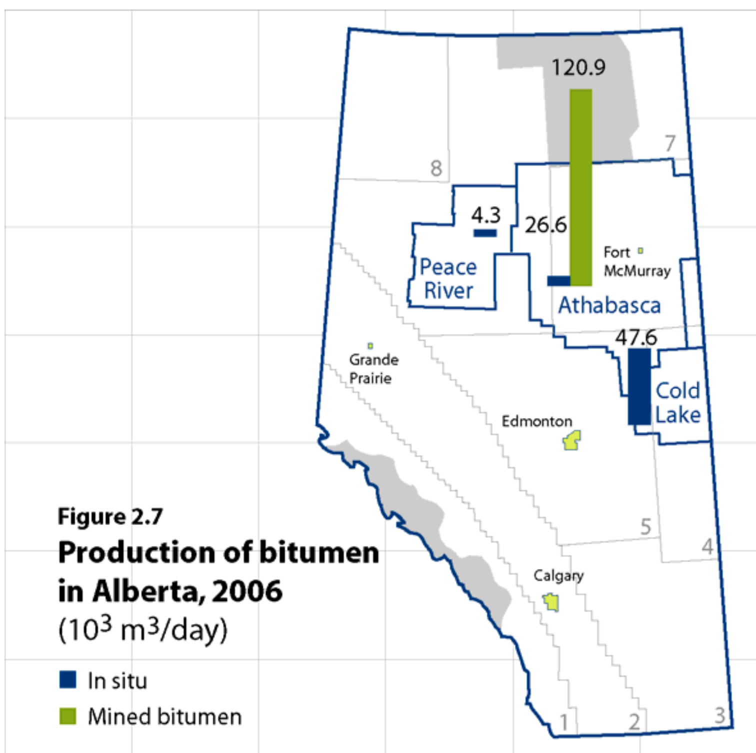
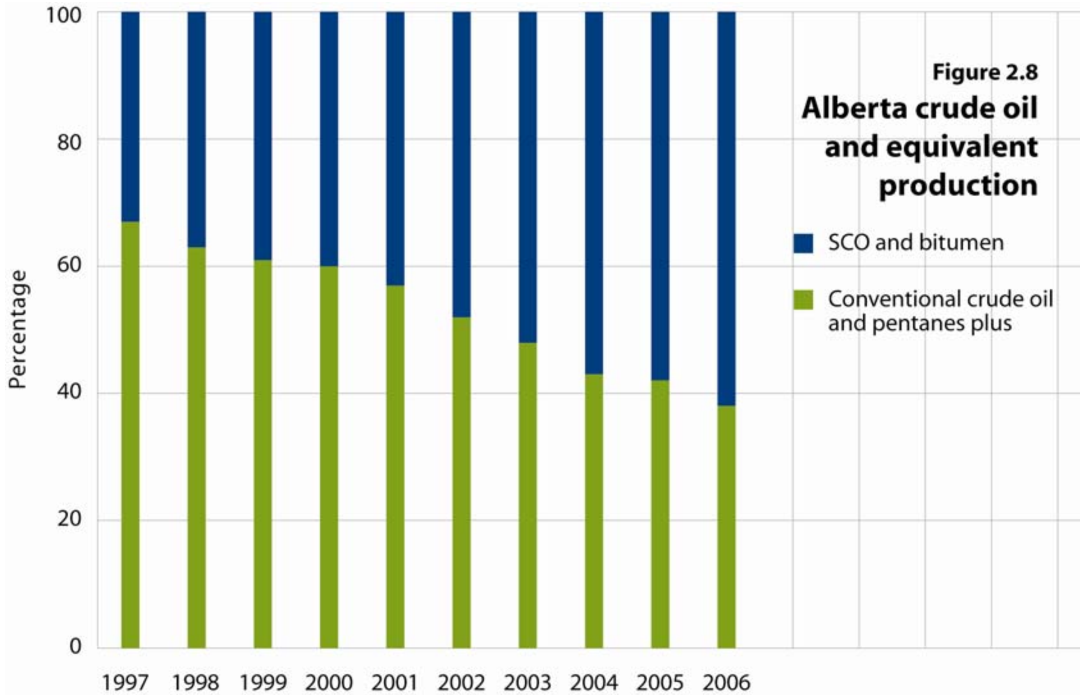


Figure 2.7
Production of bitumen in Alberta, 2006
(10^3 m^3/day)



2.2.1.1 Mined Crude Bitumen

Currently, all mined bitumen in Alberta feeds upgraders producing SCO. In 2006, mined crude bitumen production increased by 21 per cent over the past year, to a level of 120.9 10^3 m^3/d, with Syncrude, Suncor, and Albian Sands accounting for 41, 40, and 19 per cent respectively.

After the January fire that damaged one of two upgraders, Suncor experienced significantly higher oil sands production following the return to normal operations in September 2005 and the subsequent expansion of SCO production capacity to 41.3 10^3 m^3/d. Suncor's average production in 2006 increased by some 55 per cent, compared with 2005 average production, to 48.3 10^3 m^3/d.

Syncrude increased production by 19 per cent to 49.4 10^3 m^3/d with the start-up of stage three in August 2006, the largest expansion in Syncrude's history. The stage three expansion, which includes a second train at the Aurora Mine and a new coker at the upgrading facilities, increases Syncrude's SCO capacity to 55.6 10^3 m^3/d from 39.7 10^3 m^3/d.

Albian Sands produced 23.2 10^3 m^3/d in 2006, a decrease of 14 per cent compared with 2005 volumes. In February 2006, operations were reduced to a single train at both the mine and the upgrader due to a tear in the conveyor belt that carries ore from the crushers in the mine to the bitumen extraction plant. This was followed by a planned turnaround at the Muskeg Mine and Scotford Upgrader in May 2006, which was extended through late June 2006.

In projecting the future supply of bitumen from mining, the EUB considered potential production from existing facilities and supply from future projects. The forecast includes

- the existing production and expected expansions of Suncor, including the Voyageur and Voyageur South projects;

- the existing and expected expansions of Syncrude, including stage three with start-up in 2006 and the stage three debottleneck of the four-stage project that began in 1996;
- the existing Albian Sands project and its debottlenecking projects and expansion (approved by the EUB in November 2006) scheduled for completion by year-end 2010;
- the CNRL Horizon project (approved by the EUB in January 2004), with proposed production beginning in 2008;
- the Shell Canada Jackpine Mine (approved by the EUB in February 2004), with production expected two years after the Muskeg Mine expansion (late 2010);
- the Petro-Canada/UTS Energy/Teck Cominco Fort Hills project (originally TrueNorth Energy's Fort Hills Oil Sands Project, approved by the EUB in October 2002), with production proposed by 2011;
- the proposed Imperial Oil/ExxonMobil Kearl Mine (approved by the EUB in February 2007), a multiphased project with start-up expected by late 2010 (current plans do not include any on-site upgrading facilities);
- the Deer Creek (Total E&P Canada) Joslyn North Mine Project, a proposed multistaged development, with production expected in 2013; and
- the Synenco Energy/SinoCanada Petroleum Northern Lights Mining and Extraction Project, proposed as a two-staged project with initial start-up in late 2010.

In projecting total mined bitumen over the forecast period, the EUB assumed that potential market restrictions, cost overruns, construction delays, and availability of suitable refinery capacity on a timely basis may affect the timing of production schedules for these projects. Considering these factors, the EUB assumed that total mined bitumen production will increase from 120.9 10^3 m^3/d in 2006 to about 280 10^3 m^3/d by 2016.

Total mined bitumen production over the forecast period is illustrated in **Figure 2.9.**

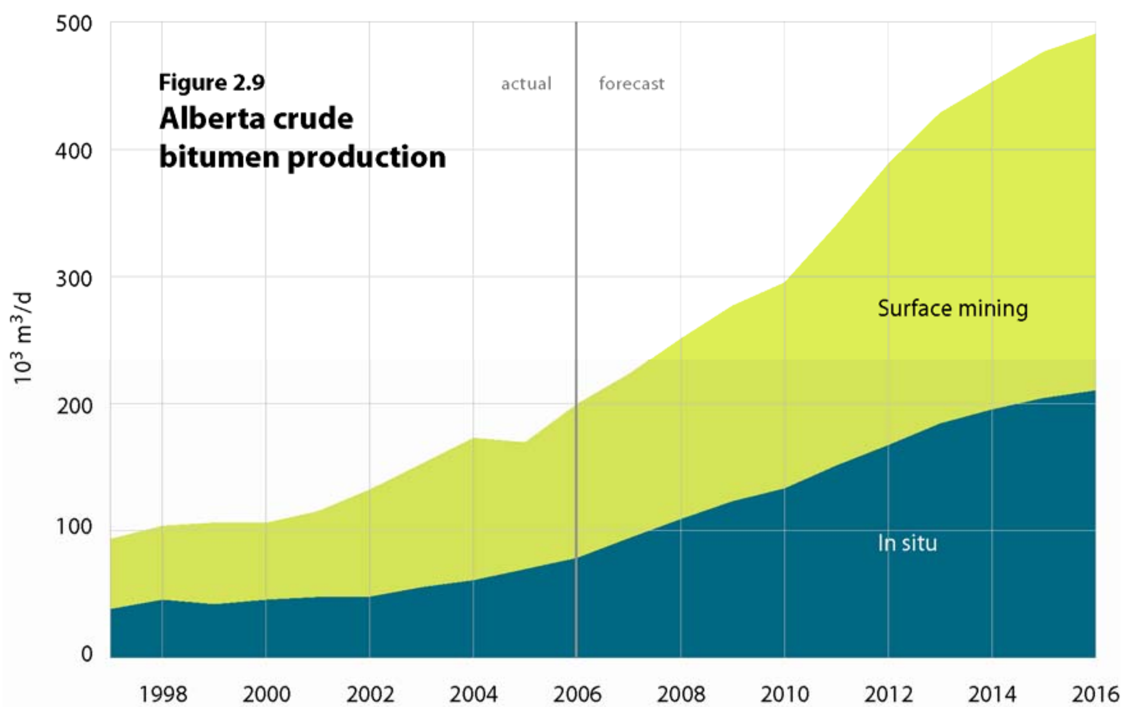
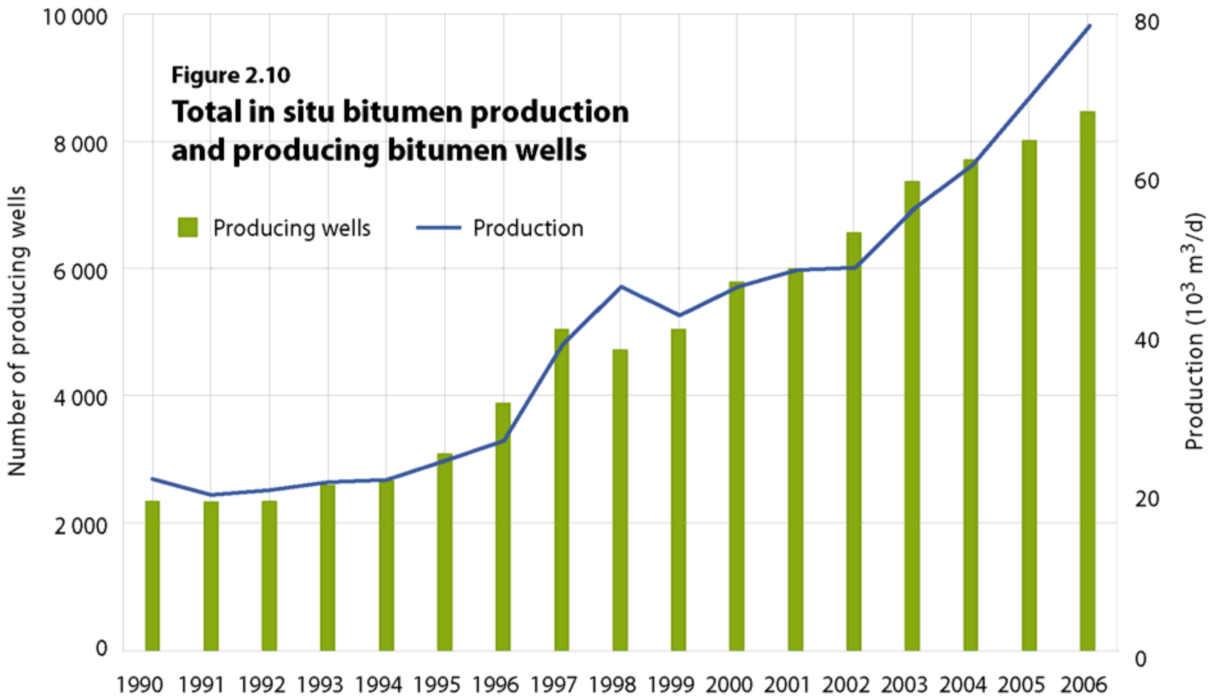


Figure 2.9
Alberta crude bitumen production

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 21.5 10^3 m^3/d in 1990 to 78.5 10^3 m^3/d in 2006. Production of in situ bitumen, along with the number of bitumen wells on production in each year, is shown in **Figure 2.10**. Corresponding to the increase in production, the number of producing bitumen wells has also increased from 2300 wells to about 8500 wells over the same period. The average well productivity of in situ bitumen wells in 2006 averaged 9.7 m^3/d.



The majority of in situ bitumen, 91 per cent, was marketed in nonupgraded form outside of Alberta, and the remaining 9 per cent was used in Alberta by refineries and upgraders.

Similar to surface mining, the future supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects.

In projecting the production from existing and future schemes, the EUB considered all approved projects, projects currently before the EUB, and projects for which it expects applications within the year. For the purposes of this report, it assumed that the existing projects would continue producing at their current production levels over the forecast period. To this projection the EUB has added production of crude bitumen from new and expanded schemes. The assumed production from future crude bitumen projects takes into account past experiences, project modifications, natural gas prices, pipeline availability, and the ability of North American markets to absorb the increased volumes. The EUB also realizes that key forecast factors, such as diluent requirements, gas prices, and light crude and bitumen price differentials, may delay some new projects and affect existing ones.

As illustrated in **Figure 2.9,** the EUB's in situ crude bitumen production is expected to increase to 210 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period, about 43 per cent of in situ bitumen production will be used as feedstock for SCO production within the province.

2.2.2 Synthetic Crude Oil Production

A large portion of Alberta's bitumen production is upgraded to SCO. The three major upgraders, Suncor, Syncrude, and Shell Canada, produced 41.0 10^3 m^3/d, 41.3 10^3 m^3/d, and 22.3 10^3 m^3/d of SCO respectively in 2006.

Currently, Alberta's three upgraders produce a variety of synthetic products: Suncor produces light sweet and medium sour crudes plus diesel, Syncrude produces light sweet synthetic crude, and the Shell upgrader produces intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy SCO. Production from new upgraders is expected to align in response to specific refinery product requirements.

The existing Suncor and Syncrude plants use different technologies for the conversion of crude bitumen to SCO. Therefore, the SCO yield through upgrading can vary depending on the type of technology, the use of products as fuel in the upgrading, the extent of gas liquids recovery, and the extent of residue upgrading. The overall liquid yield factor for the current Suncor delayed coking operation is about 0.81, while that for the current fluid coking/hydrocracking operation at Syncrude is 0.85. The overall liquid yield factor for the Albian Sands project, via the Shell upgrader hydrocracking process, is at or above 1.00. The OPTI/Nexen Long Lake Project will use a new upgrading technology that will have a liquid yield factor of about 0.85. CNRL will use delayed coking with a liquid yield factor of about 0.86.

To project SCO production over the forecast period, the EUB included existing production from Suncor, Syncrude, and Shell Canada, plus their planned expansions and the new production expected from projects listed below. Production from future SCO projects takes into account the high engineering and project material cost and the substantial amount of skilled labour associated with expansions and new projects in the industry. The EUB also recognizes that key factors, such as the length of the construction period and the market penetration of new synthetic volumes, may affect project timing.

The EUB expects significant increases in SCO production over the forecast period based on the following projects.

Suncor

- the continued operation and future expansions of the Firebag In Situ Oil Sands Operation
- expansion of the existing upgrader (the construction of a pair of coke drums, a sulphur recovery plant, and other crude oil processing equipment) by 2008
- Voyageur Phase One—establishment of a third upgrader by 2010 and further development of the oil sands mining facilities
- Voyageur Phase Two—expansion of the third oil sands upgrader by 2012
- Voyageur South – an expanded mining operation located directly south of the proposed Voyageur upgrader

Syncrude

- stage three, including the upgrader expansion and a second train of production at Aurora, which commenced late August 2006
- stage three debottleneck estimated to be on stream 2013

Shell

- the debottlenecking projects to increase bitumen processing capacity at the Scotford Upgrader
- an expansion to the upgrader to correspond with the expansion of the Muskeg Mine by late 2010
- upgrading of crude bitumen from the Jackpine Mine

OPTI/Nexen Long Lake Project

- an in situ bitumen recovery and field upgrading facility located about 40 km southeast of Fort McMurray
- Phase I expected to commence in the fourth quarter of 2007
- Phase 2 scheduled for start-up in 2011, followed by Phases 3 and 4 in approximate two-year intervals
- at year-end 2006, upgrader construction is about 80 per cent complete

Horizon Project

- located within the Municipality of Wood Buffalo, about 70 km north of Fort McMurray
- five-phase project expected to begin operation in the third quarter of 2008
- at year-end 2006, 57 per cent of project construction completed

Fort Hills

- plans include a mine and extraction facility, with an associated upgrader to be built in the Alberta Industrial Heartland Area of Sturgeon County by 2011

Joslyn Project

- upgrader to be constructed in Strathcona County in association with the mine and extraction project, with start-up expected in 2013

Northern Lights Upgrader

- a fully integrated oil sands project that involves a two-staged development, with start-up expected by 2010
- proposed upgrader to be located in Sturgeon County

BA Energy Heartland Upgrader

- a merchant upgrader located near Fort Saskatchewan capable of processing bitumen blends from the Athabasca oil sands mining and in situ operations
- designed to be built in three phases, with start-up in 2008
- approved by the EUB in July 2005

NorthWest Upgrader

- a merchant upgrader, located within the Industrial Heartland Area of Sturgeon County, to process bitumen produced by oil sands in situ and mining operations

- development of upgrader to be done in three phases, with the first phase expected to come on stream in 2010

Peace River Oil Bluesky Project

- Bluesky plant located in the south-central quadrant of the Peace River Arch
- proposed upgrader to be built in phases, with the first phase expected to come on stream in 2011

North American Oil Sands Corporation Upgrader Project

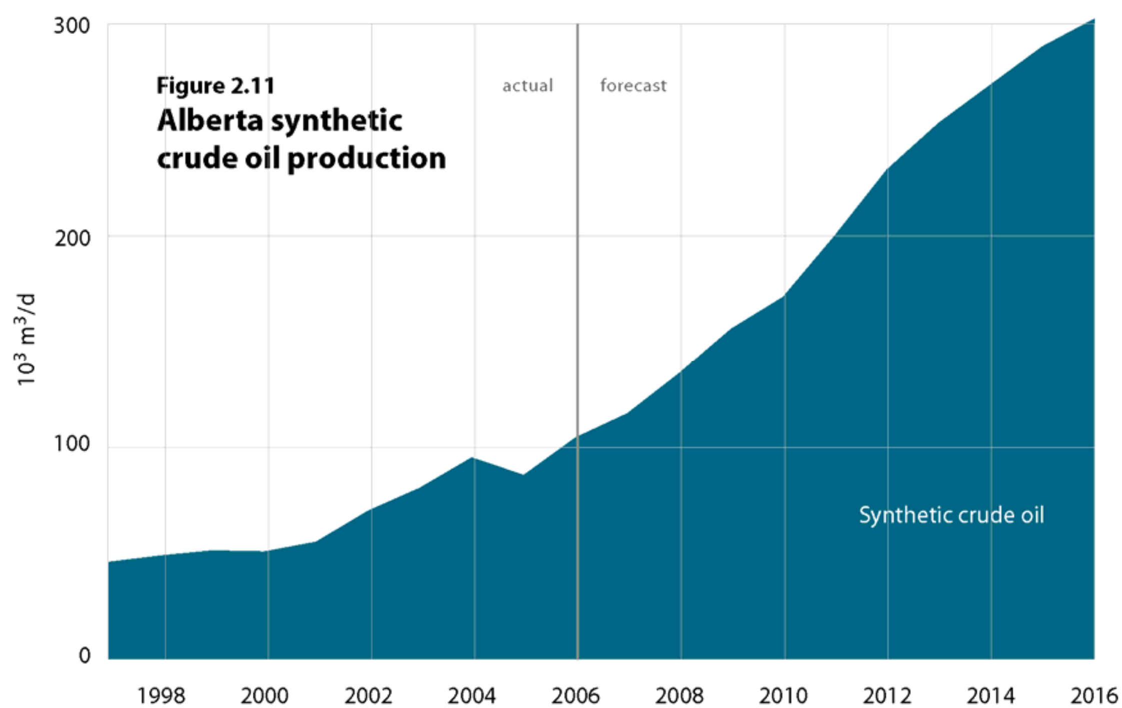
- plans include an upgrader to be built in Strathcona County in association with the Kai Kos Dehseh Project, a SAGD project located near Conklin, Alberta
- start-up expected in 2012

Value Creation Inc. Terre de Grace

- an in situ bitumen recovery and field upgrading facility located about 90 km northwest of Fort McMurray
- designed to be built in stages, with startup of phase 1 in 2011

Due to uncertainties regarding timing and project scope, some projects recently or soon to be announced have not been considered in this forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

Figure 2.11 shows the EUB projection of SCO production. SCO production is expected to increase from 104.6 10^3 m^3/d in 2006 to 302 10^3 m^3/d by 2016.



2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, adequate incremental pipeline capacity is essential to market greater volumes of product. Throughout 2006, pipeline companies made strides towards completing existing projects, as well as moving ahead with the necessary steps involved in planning and executing new projects. The current pipeline systems in the Cold Lake and Athabasca areas are described in **Table 2.6**. **Figure 2.12** shows the current pipelines and proposed crude pipeline projects within the Athabasca and Cold Lake regions. Numerals in parentheses refer to the legend on the map.

Table 2.6. Alberta SCO and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty	30.8
Cold Lake Heavy Oil Pipeline	Edmonton	18.7
Husky Oil Pipeline	Hardisty	21.2
Husky Oil Pipeline	Lloydminster	36.0
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	47.7
Terasen Pipelines (Corridor)	Edmonton	44.2
Alberta Oil Sands Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0

2.2.3.1 Existing Alberta Pipelines

- The Cold Lake pipeline system (1) is capable of delivering heavy crude from the Cold Lake area to Hardisty and Edmonton.
- The Husky pipeline (2) moves Cold Lake crude to Husky's heavy oil operations in Lloydminster. Heavy and synthetic crude is then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge (4) or the Express pipeline (5) systems.
- The Echo pipeline system (3) is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending. This pipeline delivers Cold Lake crude to Hardisty.
- The Enbridge Pipeline (4), described below, is an existing export pipeline.
- The Kinder Morgan Express Pipeline (5), described below, is an existing export pipeline.
- The Athabasca pipeline (6) delivers semiprocessed product and bitumen blends to Hardisty and has the potential to carry 90.6 10^3 m^3/d.
- The Kinder Morgan Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford upgrader. An expansion of the Corridor pipeline was completed in 2006, increasing capacity to 44.2 10^3 m^3/d by upgrading existing pump station facilities

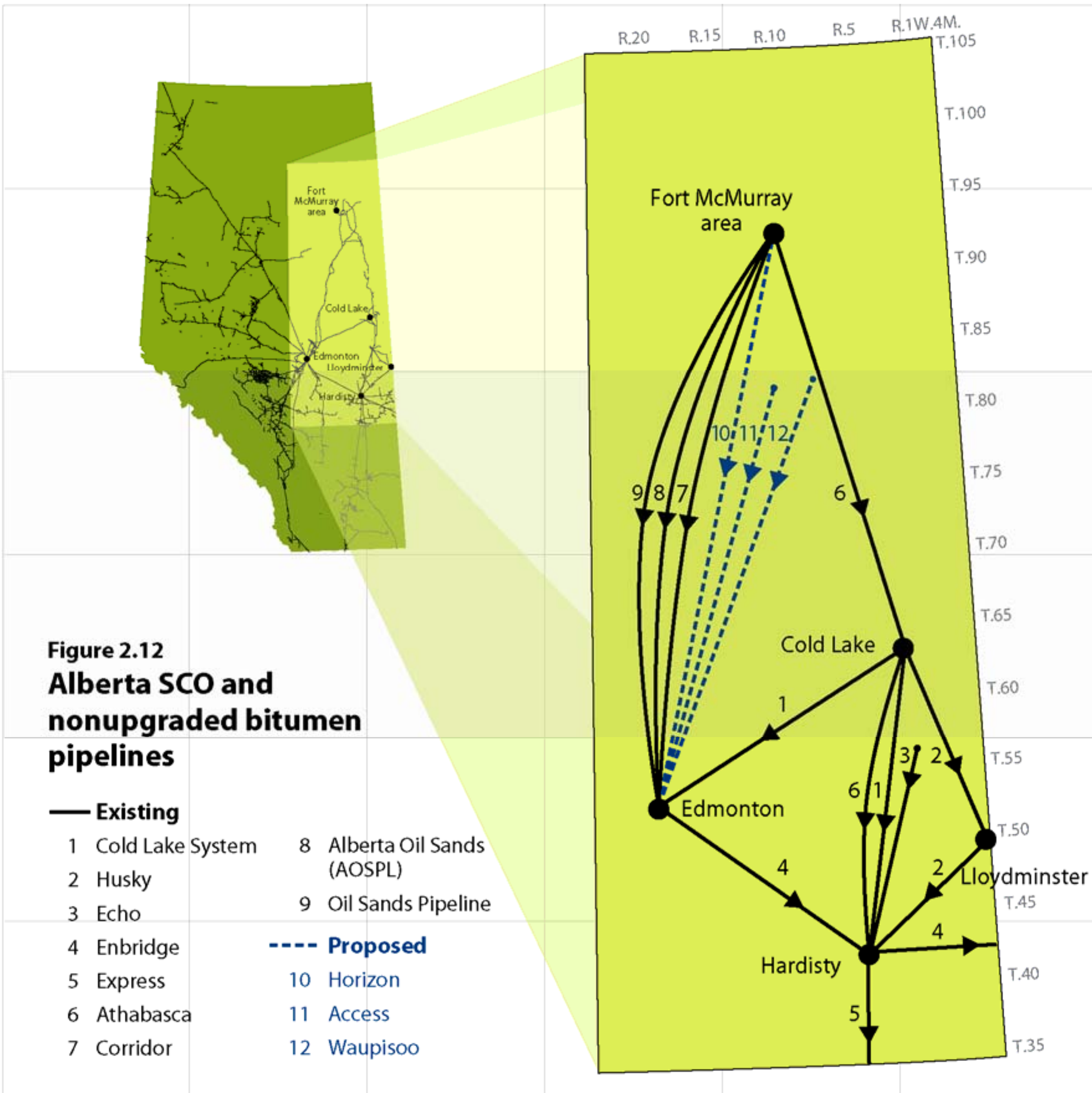


Figure 2.12
Alberta SCO and nonupgraded bitumen pipelines

- The Alberta Oil Sands Pipeline (AOSPL) (8) is the exclusive transporter for Syncrude; an expansion to increase capacity to 61.8 10^3 m^3/d was completed in 2004.

- The Oil Sands Pipeline (9) transports Suncor synthetic oil to the Edmonton area.

2.2.3.2 Proposed Alberta Pipeline Projects

- The Kinder Morgan Corridor pipeline (7) expansion project includes construction of a 42-inch diluted bitumen line, a new 20-inch products pipeline, tankage, and upgrading existing pump stations along the existing pipeline from the Muskeg River mine to the Edmonton region. The expansion will increase diluted bitumen capacity to about 73.1 10^3 m^3/d by 2009 and will support further expansions beyond 2009 by adding intermediate pump stations.

- Construction of the Horizon Pipeline (10) began in November 2006 and is expected to be in service mid-2008, with an initial capacity of 39.7 10^3 m^3/d. Pembina Pipeline Corporation will complete the twinning of the existing AOSPL (8), resulting in two parallel, commercially segregated lines, one dedicated to Syncrude and the other to CNRL's new Horizon oil sands development. Also included is the construction of a new 48 km 20-inch pipeline from the Horizon site, 70 km north of Fort McMurray, to the AOSPL terminal.

- The Access Pipeline project (11) will transport diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Access obtained approval from the EUB in December 2005. Initial capacity of the pipeline will be 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d. Construction of the pipeline is 99 per cent complete and start-up is expected early in 2007.

- Enbridge plans to construct the 390 km Waupisoo Pipeline (12) to move blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. Waupisoo is scheduled to be in service in mid-2008, with an initial capacity of 55.6 10^3 m^3/d, expandable to 95.3 10^3 m^3/d.

2.2.3.3 Existing Export Pipelines

- The Enbridge Pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the U.S. midwest.

- The Kinder Morgan Express pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends into Wood River, Illinois. The pipeline capacity was increased to 44.8 10^3 m^3/d in early 2005 with an expansion that added new pump stations in Canada and the United States and new tankage facilities at Hardisty.

- The Kinder Morgan Trans Mountain pipeline system transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State. Trans Mountain's current capacity is 35.8 10^3 m^3/d, assuming some shipments of heavy oil. Receipts of heavy crude at Edmonton have averaged some 20 per cent over the past two years. Pipeline capacity increases to 45.3 10^3 m^3/d, without heavy oil.

- Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake Blend to Montana refineries.

- Milk River Pipeline delivers Bow River heavy and Manyberries light oil primarily into Montana refineries.

Figure 2.13 shows the existing export pipelines leaving Alberta, in addition to the proposed expansions and new pipeline projects expected to transport the increased SCO and nonupgraded bitumen production to established and expanded markets.

Table 2.7 lists the export pipelines, with their corresponding destinations and capacities.

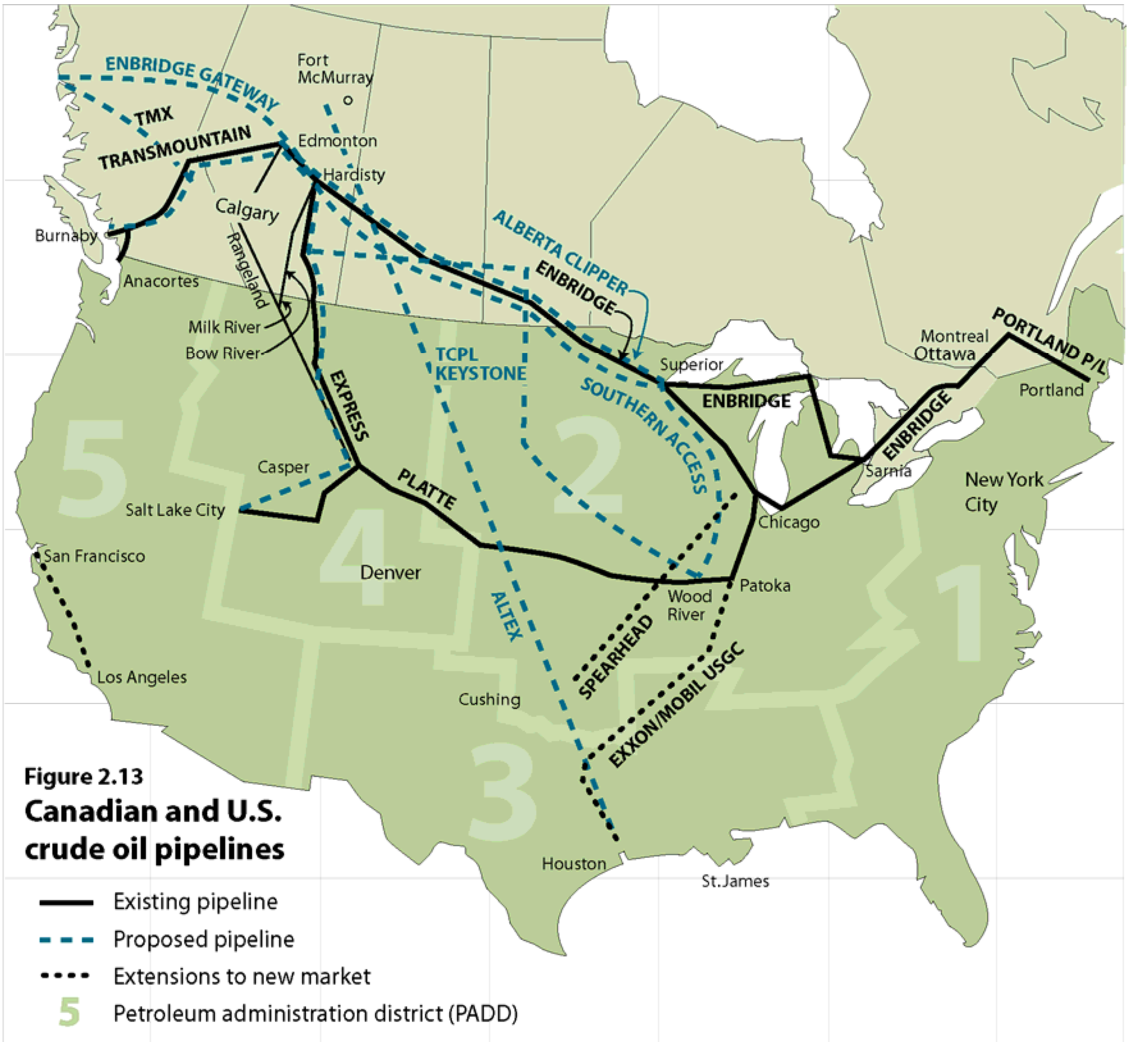


Figure 2.13
Canadian and U.S. crude oil pipelines

Table 2.7. Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Pipeline	Eastern Canada U.S. east coast U.S. midwest	301.9
Kinder Morgan (Express)	U.S. Rocky Mountains U.S. midwest	44.5
Milk River Pipeline	U.S. Rocky Mountains	18.8
Rangeland Pipeline	U.S. Rocky Mountains	13.5
Kinder Morgan (Trans Mountain)	British Columbia U.S. west coast Offshore	35.8
Total		414.5

2.2.3.4 Proposed Export Pipeline Projects

- Enbridge's Gateway Pipeline will consist of a 1150 km petroleum export line transporting 63.6 10^3 m^3/d of oil or blended bitumen and a 23.8 10^3 m^3/d condensate import line in the same right-of-way between Strathcona County and Kitimat, British Columbia. The proposed pipeline will provide access to the California and Asian markets and is expected to be in service in the 2012 to 2014 time frame.

- Kinder Morgan's Trans Mountain Expansion (TMX) project is proposed as a staged expansion of the existing Trans Mountain system between Edmonton and Burnaby (Vancouver) and/or Prince Rupert/Kitimat, British Columbia. The existing pipeline will be looped in stages to eventually create a dual pipeline system with an initial incremental capacity of 11.9 10^3 m^3/d, increasing to 99.3 10^3 m^3/d. The TMX1 Pump Station expansion is currently under construction and is expected to increase capacity by 5.6 10^3 m^3/d between Edmonton and Burnaby. The installation of new pump stations and the upgrading of existing facilities between Edmonton and Burnaby is expected to be completed by April 2007. The TMX1 Anchor Loop expansion involves looping a 160 kilometre section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the system's capacity will increase to 47.7 10^3 m^3/d by the end of 2008.

- TransCanada PipeLine's Keystone Project proposes to convert a natural gas pipeline to crude oil service. The 1300 km of pipe to be converted originates near Hardisty, Alberta, and terminates at Oak Bluff, Manitoba. The project also includes construction of a 70 km pipeline to connect the Hardisty terminal with existing pipe, and an additional 1700 km will be built to connect Oak Bluff to Patoka, Illinois. The total length of proposed pipeline is 3000 km from Hardisty to Wood River and could be in service by 2010, with a capacity of 69.1 10^3 m^3/d.

- Enbridge's Southern Access Program includes an expansion component on the Canadian mainline and on the U.S. Lakehead System, which will result in increased capacity of 64 10^3 m^3/d. The Canadian expansion from Hardisty to the international border involves pump modification and tankage construction. Downstream of Superior, Wisconsin, the expansion includes optimization of existing facilities and a 42-inch pipeline to Flanagan, Illinois, built in two stages scheduled to be in service in 2008 and 2009 respectively.

- Altex, a newly formed Canadian company, intends to design, build, own, and operate the Altex Pipeline system. It will be a direct-route, standalone pipeline system from northern Alberta to the Gulf Coast, the largest oil refining market in North America. The pipeline will have an initial capacity of 39.7 10^3 m^3/d, expandable to 119.2 10^3 m^3/d, and could be in service by 2010.

- Enbridge recently announced the Alberta Clipper Pipeline, a proposed new 36-inch pipeline from Hardisty to Superior, where it will connect to the existing mainline system for deliveries into the U.S. midwest. This pipeline would be in addition to the Southern Access Program and have an initial capacity of 72 10^3 m^3/d, with start-up in late 2009 or 2010.

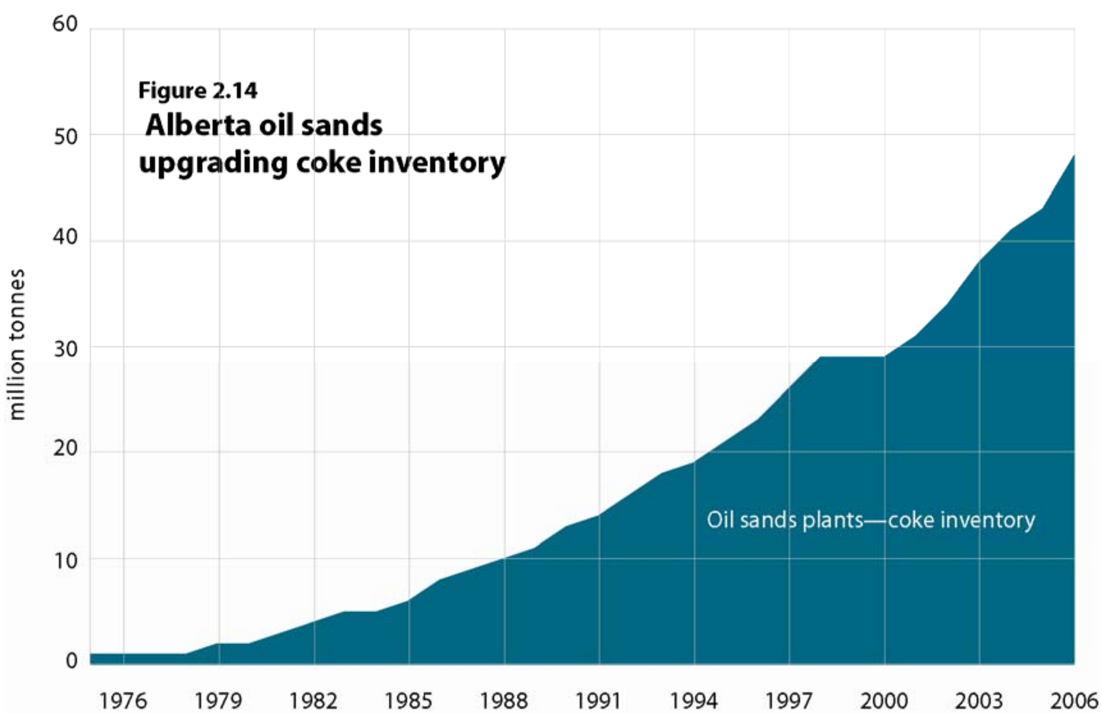
2.2.4 Petroleum Coke

Petroleum coke is a by-product of the oil sands upgrading process that is currently being stockpiled in huge amounts in Alberta. Petroleum coke produced in the delayed coking operation is considered a potential source of energy. It contains high sulphur but has lower ash than conventional fuel coke. It has the potential of becoming a future energy resource through a process called gasification and could possibly reduce the demand for natural gas.

Suncor Energy Inc. and Syncrude Canada Ltd. operate Alberta's two largest oil sands mines near Fort McMurray. Complete with on-site extraction and upgrading capabilities, Syncrude and Suncor both produce coke but through different processes, which results in coke deposits with different ranges of particle size. Syncrude's coke is like coarse sand, while Suncor's is the size of gravel (or larger).

Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke usage as a site fuel. Suncor has also been delivering small volumes of petroleum coke to Asian markets since 1997, mostly Japan, through its Energy Marketing Group. Syncrude began using coke as a site fuel in 1995 and accounts for a lower share of the total coke usage as a site fuel. Syncrude is looking for alternative uses for its coke surplus and is looking into way of using coke as a reclamation material.

Statistics of petroleum coke inventories reported in the yearly *ST43: Mineable Oil Sands Annual Statistics* show consistent increases in the total closing inventories, except for a leveling in 1999 and 2000 due to oil sands operations, reaching 48 million tonnes in 2006, as shown in **Figure 2.14**.



2.2.5 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

Light sweet SCO has two principal advantages over light crude: it has very low sulphur content, and it produces very little heavy fuel oil. The latter property is particularly desirable in Alberta, where there is virtually no local market for heavy fuel oil. Among the disadvantages of SCO in conventional refineries are the low quality of distillate output, the need to limit SCO intake to a fraction of total crude requirements, and the high level of aromatics (benzene) that must be recovered.

Overall demand for Alberta SCO and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, expansion of refineries currently processing SCO and blended bitumen, altering the configuration of current light crude oil refineries, and the availability and price of diluent for shipping blended bitumen.

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. In 2006, five Alberta refineries, with a total capacity of 75.5 10^3 m^3/d, used 32.7 10^3 m^3/d of SCO and 3.2 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand represents 31 per cent of Alberta SCO production and 4 per cent of nonupgraded bitumen production.

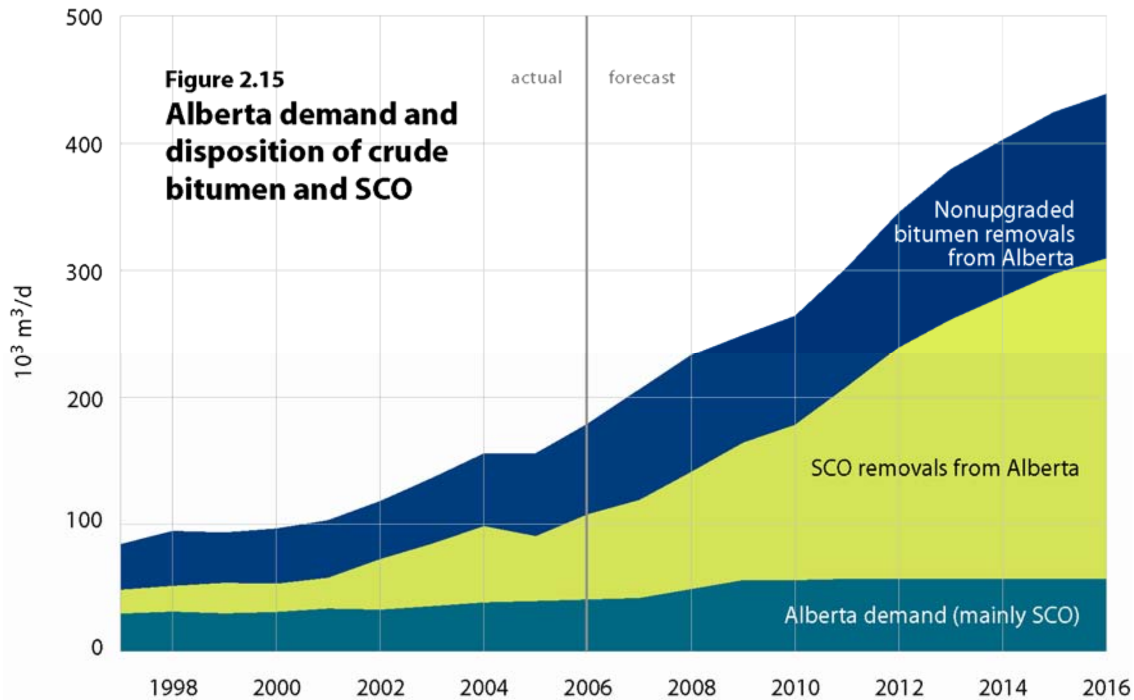
Petro-Canada, in addition to the announced joint venture with UTS and Teck Cominco in the Fort Hills project, continues to reconfigure its Edmonton refinery to fully replace light-medium crude oil with SCO and nonupgraded bitumen by 2008.

SCO is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor also operates a Suncor Energy-branded “cardlock” station selling diesel fuel supplied from its oil sands operation. The station is located on Highway 63 north of Fort McMurray. In 2006, the sale of SCO as diesel fuel oil accounted for about 13 per cent of Alberta SCO demand.

Figure 2.15 shows that in 2016 Alberta demand for SCO and nonupgraded bitumen will increase to about 58 10^3 m^3/d. It is projected that SCO will account for 87 per cent of total Alberta demand and nonupgraded bitumen will account for 13 per cent.

Given the current quality of SCO, western Canada’s nine refineries, with a total capacity of 91.4 10^3 m^3/d, are able to blend up to 35 per cent SCO and a further 4 per cent of blended bitumen with crude oil. These refineries receive SCO from both Alberta and Saskatchewan. In eastern Canada, the four Sarnia-area refineries, with a combined total capacity of 56.5 10^3 m^3/d, are the sole ex-Alberta Canadian market for Alberta SCO.

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, as well as increased markets for the future growth of refined products. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with a refining capacity of 569 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 95 10^3 m^3/d. The refineries in these areas are capable of absorbing a substantial increase in supplies of SCO and nonupgraded bitumen from Alberta. Other potential market regions could be the U.S. east coast, with a refining capacity of 272 10^3 m^3/d, the U.S. Gulf Coast, with a refining capacity of 1315 10^3 m^3/d, the U.S. west coast, with a refining capacity of 504 10^3 m^3/d, and Asia.



The traditional markets for Alberta SCO and nonupgraded bitumen are expanding. These include western Canada, Ontario, the U.S. midwest, the northern Rocky Mountain region, and the U.S. west coast (Washington State). In March 2006, Enbridge announced that the first western Canadian crude oil was delivered through its Spearhead pipeline to Cushing, Oklahoma. The oil being delivered to Cushing travels through the Enbridge mainline system from Edmonton to Chicago, 2519 km, before entering Spearhead for the final 1046 km to Cushing. Shipments on the 20 10^3 m^3/d capacity pipeline have increased steadily, with nominations exceeding capacity in the fourth quarter of 2006. Enbridge is currently in the process of evaluating the potential to expand the Spearhead pipeline by 10 10^3 m^3/d.

Markets were further expanded in April 2006 with the reversal of an ExxonMobil Corporation pipeline that moves oil from Patoka, Illinois, to Beaumont/Nederland, Texas. Canadian crude can access the line via the Enbridge mainline and Lakehead systems and then the Mustang Pipeline or the Kinder Morgan Express-Platte Pipeline system. ExxonMobil expects the pipeline will operate at its estimated capacity of 10.5 10^3 m^3/d in heavy crude service. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure 2.13**.

As illustrated in **Figure 2.15,** over the forecast period SCO removals from Alberta will increase from 65.6 10^3 m^3/d to 251 10^3 m^3/d, and the removals of nonupgraded bitumen will increase from 71.2 10^3 m^3/d to 129 10^3 m^3/d.

3 Crude Oil

3.1 Reserves of Crude Oil

3.1.1 Provincial Summary

The EUB estimates the remaining established reserves of conventional crude oil in Alberta to be 250.1 million cubic metres (10^6 m^3) at December 31, 2006. This is a net decrease of 4.8 10^6 m^3, or 1.9 per cent, from December 31, 2005, resulting from all reserve adjustments and production, as well as additions that occurred during 2006. The changes in reserves and cumulative production for light-medium and heavy crude oil to December 31, 2006, are shown in **Table 3.1**. **Figure 3.1** shows that compared to 1990, the province's remaining conventional oil reserves have declined by more than half. Remaining reserves now stand at 20 per cent of the peak reserves of 1223 10^6 m^3 reported in 1969.

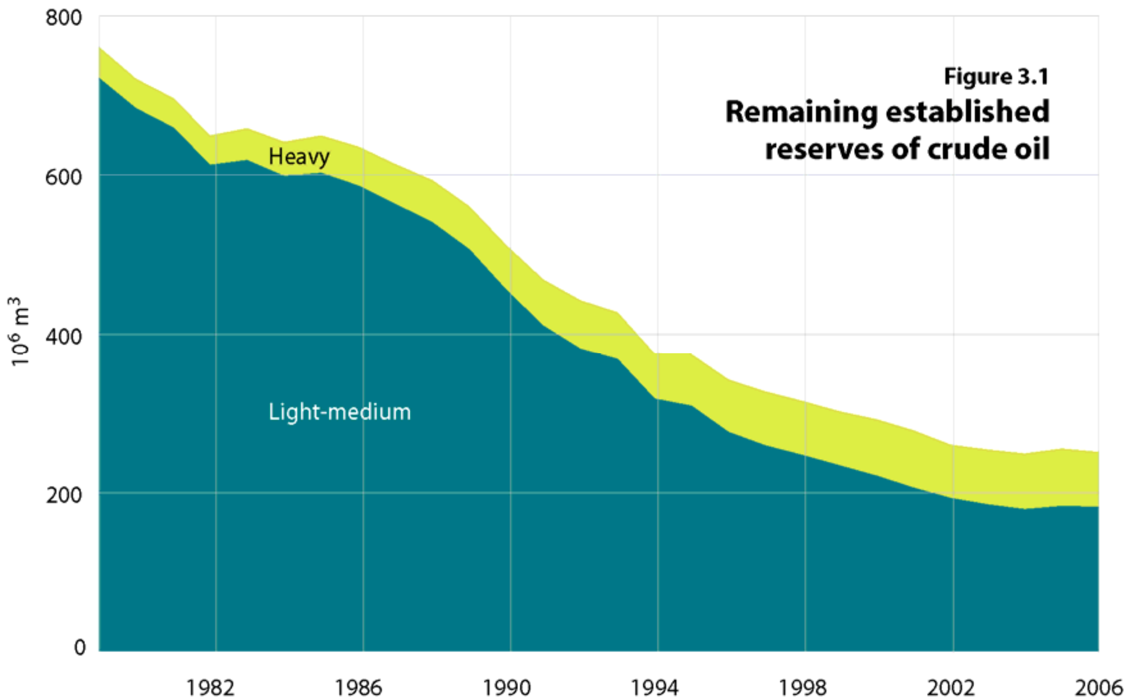
Table 3.1. Reserve change highlights (10^6 m^3)

	2006	2005	Change
Initial established reserves[a]			
Light-medium	2 329.6	2 310.2	+19.4
Heavy	401.2	393.5	+7.7
Total	2 730.8	2 703.7	+27.1
Cumulative production[a]			
Light-medium	2 148.0	2 127.5	+20.5[b]
Heavy	332.7	321.4	+11.3[b]
Total	2 480.7	2 448.9	+31.8[b] (200 10^6 bbls)
Remaining established reserves[a]			
Light-medium	181.6	182.7	-1.1
Heavy	68.5	72.2	-3.7
Total	250.1 (1 573 10^6 bbls)	254.8	-4.8

[a] Discrepancies are due to rounding.
[b] May differ from annual production.

3.1.2 Reserves Growth

A detailed pool-by-pool listing of reservoir parameters and reserves data is available on CD (see Appendix C). **Table 3.2** gives a detailed breakdown of this year's reserves changes, including additions, revisions, and enhanced recovery, while **Figure 3.2** gives a history of these changes back to 1990. The initial established reserves attributed to the 495 new oil pools booked in 2006 totaled 8.2 10^6 m^3 (an average of 16 thousand [10^3] m^3 per pool), up from 5.5 10^6 m^3 in 2004. Reserve additions from new waterfloods increased from 1.2 10^6 m^3 to 1.6 10^6 m^3 **(Figure 3.3)**. Net reserve revisions totalled 2.2 10^6 m^3. The resulting total increase in initial established reserves for 2006 amounted to 27.1 10^6 m^3, compared to last year's 38.8 10^6 m^3. **Table B.3** in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.



Reserve additions resulting from drilling and new enhanced recovery schemes amounted to 24.9 10^6 m^3, up from 19.9 10^6 m^3 the year before. These additions replaced 79 per cent of Alberta's 2006 conventional crude oil production of 31.5 10^6 m^3, significantly up from last year's 60 per cent replacement.

Table 3.2. Breakdown of changes in crude oil initial established reserves[a] (10^6 m^3)

	Light-medium	Heavy	Total
New discoveries	7.1	1.1	8.2
Development of existing pools	9.7	5.1	14.8
Enhanced recovery (new/expansion)	1.4	0.5	1.9
Revisions	+1.2	+1.0	+2.2
Total[a]	+19.4	+7.7	+27.1

[a] Discrepancies are due to rounding.

3.1.3 Oil Pool Size

At December 31, 2006, oil reserves were assigned to 9166 light-medium and 2697 heavy crude oil pools in the province, most of which consist of a single well.
The distribution of reserves by pool size shown in **Figure 3.4** indicates that some 63 per cent of the province's remaining oil reserves is contained in the largest 3 per cent of pools, and 95 per cent of those reserves were discovered before 1980. By contrast, the smallest 74 per cent of pools contain only 6 per cent of its remaining reserves. **Figure 3.5** illustrates the historical trends in the size of oil pools.

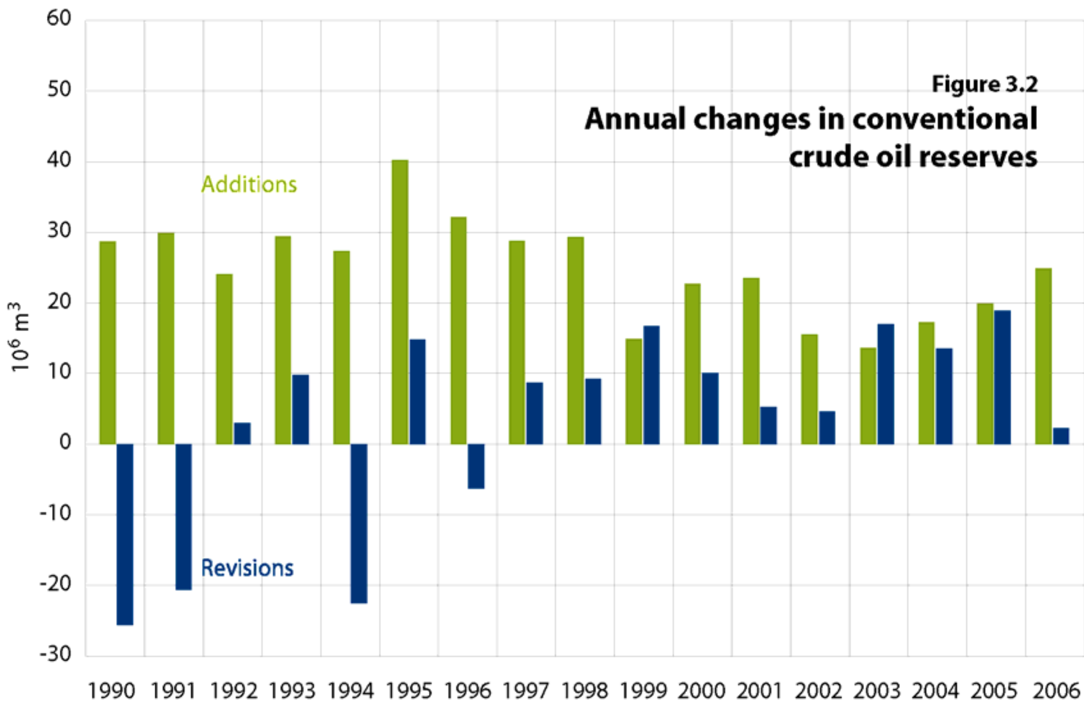


Figure 3.2
Annual changes in conventional crude oil reserves
Additions
Revisions
10^6 m^3
60
50
40
30
20
10
0
-10
-20
-30
1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006

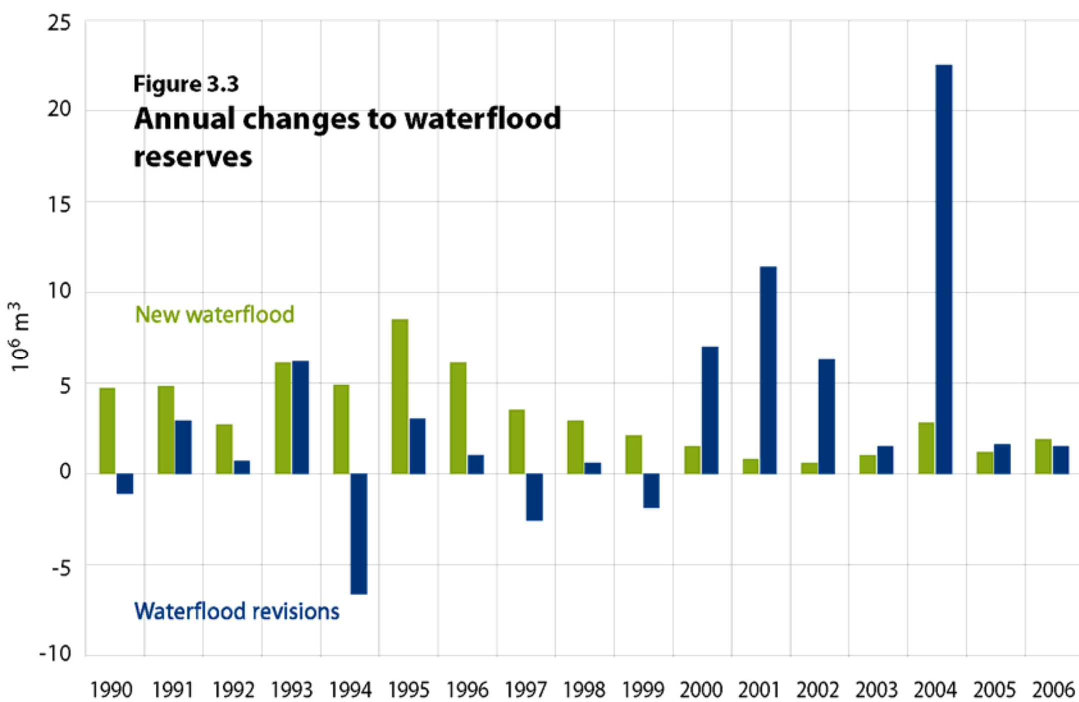
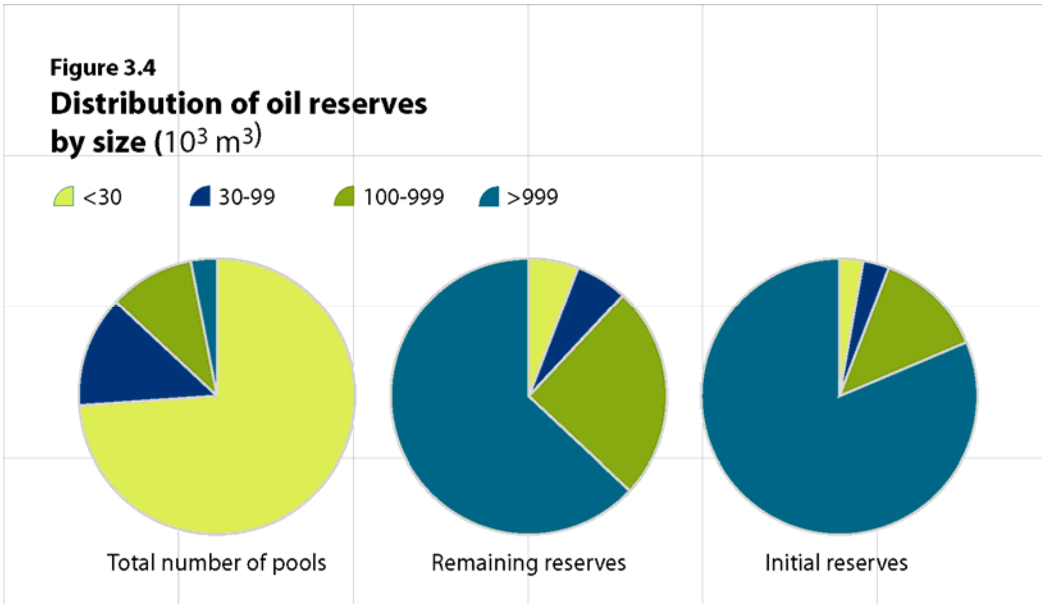
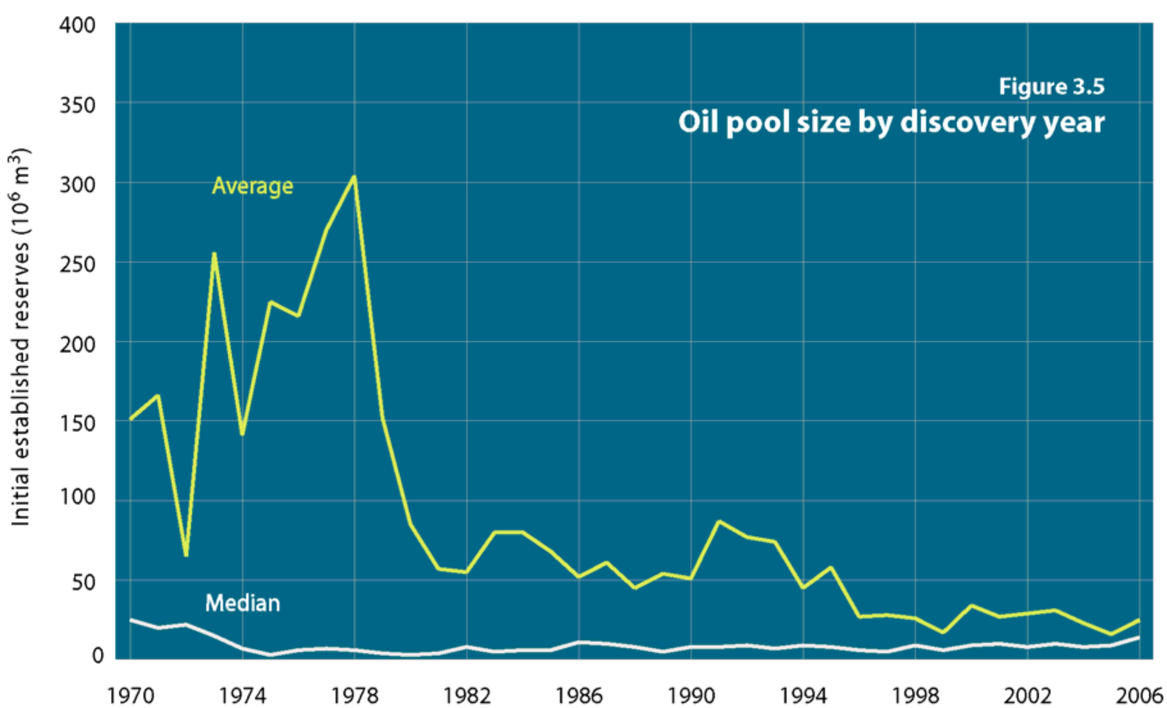


Figure 3.3
Annual changes to waterflood reserves
New waterflood
Waterflood revisions
10^6 m^3
25
20
15
10
5
0
-5
-10
1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006



While the median pool size has remained fairly constant over time (below 10 10^3 m^3 initial established reserves per pool), the average has declined from 150 10^3 m^3 in 1970 to about 30 10^3 m^3 over the last few years. The Valhalla Doe Creek I and Dunvegan B Pool discovered in 1977 is the last major (over 10 10^6 m^3) oil discovery in Alberta. Its initial established reserve is estimated at 12 090 10^3 m^3.



3.1.4 Pools with Largest Reserve Changes

Some 1900 oil pools had their reserves changed over the past year, for a net total revision of plus 2.2 10^6 m^3. **Table 3.3** lists those pools having the largest reserve changes in 2006. Pool development in the Turner Valley Rundle Pool saw a significant increase of 4270 10^3 m^3. Reassessment of the primary reserves in the Hayter Dina B and Suffield Upper Mannville A Pool resulted in an increase of 1524 and 1394 10^3 m^3 respectively. Review of the Simonette Beaverhill Lake A waterflood resulted in a reserve write-down of 770 10^3 m^3. Continued exploration in the Pembina area since 1994 has resulted in the discovery of many off-reef Nisku pools. In 2006, initial established reserves in the play area totalled about 5000 10^3 m^3, the largest being the Pembina Nisku II Pool, with initial reserves of 1244 10^3 m^3.

3.1.5 Distribution by Recovery Mechanism

The distribution of conventional crude oil reserves by recovery mechanism is illustrated in **Figure 3.6**. It shows that waterflooding has increased recovery in light-medium pools by an average 13 per cent. **Table 3.4** shows reserves broken down by recovery mechanism. Primary recovery for heavy crude pools has increased from 8 per cent in 1990 to 12 per cent in 2006 due to improvements in water handling, horizontal wells, and increased drilling density. Incremental recovery from all waterflood projects represents about 26 per cent of the province's initial established reserves. Pools under solvent flood added another 4 per cent to the province's reserves and on average realized a 24 per cent improvement in recovery efficiency over primary. This year saw the first tertiary scheme in a heavy crude pool, a polymer flood in the Taber South Mannville B Pool. It is expected to contribute 290 10^3 m^3 (incremental 5 per cent recovery factor) for a total initial established reserve of 3019 10^3 m^3.

Figure 3.6
Initial established crude oil reserves based on recovery mechanisms
(10^9 m^3)

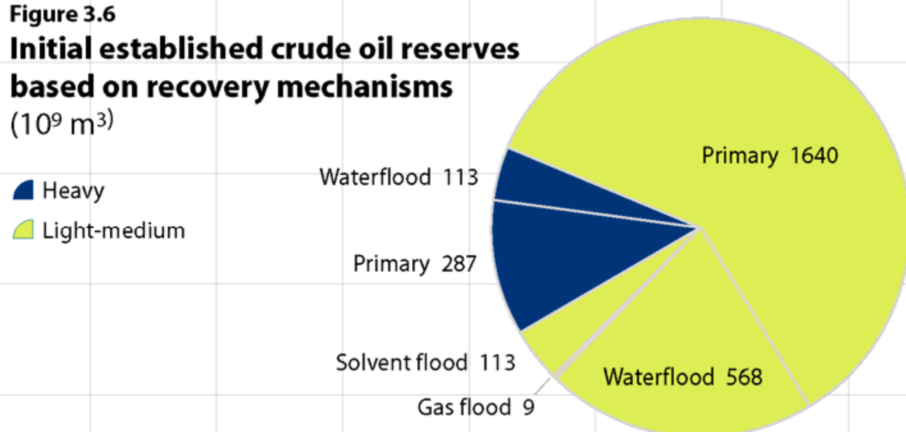


Table 3.3. Major oil reserve changes, 2006

Pool	Initial established reserves (10^3 m^3) 2006	Change	Main reason for change
Bow Island Sawtooth D	1 093	+570	Pool development
Caroline Rundle A	10 860	+740	Pool development and reassessment of waterflood
Cordel Cardium B	663	- 253	Reassessment of primary reserves
Dixonville Montney C	1 008	+577	Pool development
Ferrier Belly R Q, Cardium G & L	19 070	-330	Reassessment of waterflood reserves
Gift Slave Point A	2 312	+344	Reassessment of waterflood reserves
Hayter Dina B	11 500	+1 524	Reassessment of primary reserves
Joarcan Viking	21 640	+1 050	Reassessment of primary reserves
Kavbob Beaverhill Lake A	21 240	+1 370	Reassessment of waterflood reserves
Kleskun Beaverhill Lake A	621	+617	Pool development
Little Bow Upper Mannville I	2 099	+659	Reassessment of waterflood reserves
Lloydminster Lloydminster F	411	+381	Pool development
Loon Slave Point G	1 350	+324	Reassessment of reserves
Morgan Spky A, Lloyd A Rex A & Dina B	7 638	+729	Pool development
Pouce Coupe South Boundary B	2 469	+713	Reassessment of waterflood reserves
Progress Halfway B	1 146	+436	Reassessment of primary reserves
Provost Upper Mannville T8T	1 380	-592	Reassessment of primary reserves
Simonette Beaverhill Lake A	4 270	-770	Reassessment of reserves
Suffield Upper Mannville A	8 155	+1 394	Reassessment of primary reserves
Swan Hills South Beaverhill Lake A & B	64 070	+1 860	Reassessment of primary reserves
Taber South Mannville B	3 019	+303	Recognition of tertiary scheme
Turner Valley Rundle	29 210	+4 270	Pool development
Valhalla Doe Creek I& Dunvegan B	12 630	-1 189	Reassessment of waterflood reserves
Wildmere Lloydminster C	2 323	+445	Pool development
Willesden Green BR, Card, Vik MU#1	26 410	+2 380	Reassessment of waterflood reserves

Table 3.4. Conventional crude oil reserves by recovery mechanism as of December 31, 2006

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Waterflood/ gas flood	Solvent flood	Total	Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	3 794	855	0	0	855	23	-	-	23
Waterflood	3 254	491	400	0	891	15	12	-	27
Solvent flood	962	260	168	113	541	27	17	11	56
Gas flood	116	34	9	0	43	29	8	-	37
Heavy									
Primary depletion	1 597	199	0	0	199	12	-	-	12
Waterflood	678	87	114	0	201	13	17	-	30
Total	10 400	1 927	690	113	2 730	19			26
Percentage of total initial established reserves		71%	25%	4%	100%				

3.1.6 Distribution by Geological Formation

The distribution of reserves by geological period and PSAC area is depicted graphically in **Figure 3.7** and **Figure 3.8** respectively. About 37 per cent of remaining established reserves are expected to come from formations within the Lower Cretaceous, 21 per cent from the Upper Devonian, and 18 per cent from Upper Cretaceous. This contrasts with 1990, when 30 per cent of remaining reserves were expected to be recovered from the Upper Devonian and only 16 per cent from the Lower Cretaceous. The shallower zones of the Lower Cretaceous are important as a source of future conventional oil. A detailed breakdown of reserves by geological period and formation is presented in tabular form in Appendix B, **Tables B.4** and **B.5**.

3.1.7 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the EUB in 1994 at 3130 10^6 m^3, reflecting its estimate of geological prospects. **Figure 3.9** illustrates the historical relationship between remaining reserves and cumulative oil production. Extrapolation of the decline seems to suggest that the EUB's estimate of ultimate potential may be slightly low. However, a few more years of data are needed to better define the trend before initiating a new update to the ultimate potential. **Figure 3.10** shows Alberta's historical and forecast growth of initial established reserves. About 79 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2006. Known discoveries represent 87 per cent of the ultimate potential, leaving 13 per cent (399 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves means that 649 10^6 m^3 of conventional crude oil is available for future production.

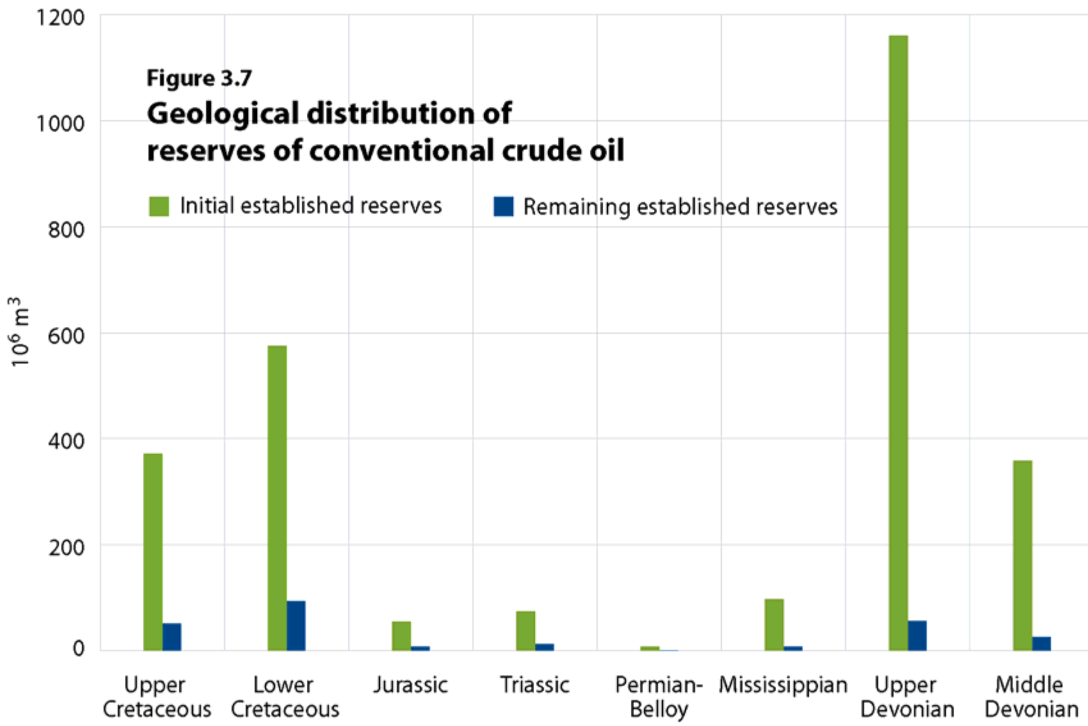


Figure 3.7
Geological distribution of reserves of conventional crude oil
Initial established reserves
Remaining established reserves
1200
1000
800
600
400
200
0
10^6 m^3
Upper Cretaceous
Lower Cretaceous
Jurassic
Triassic
Permian-Belloy
Mississippian
Upper Devonian
Middle Devonian

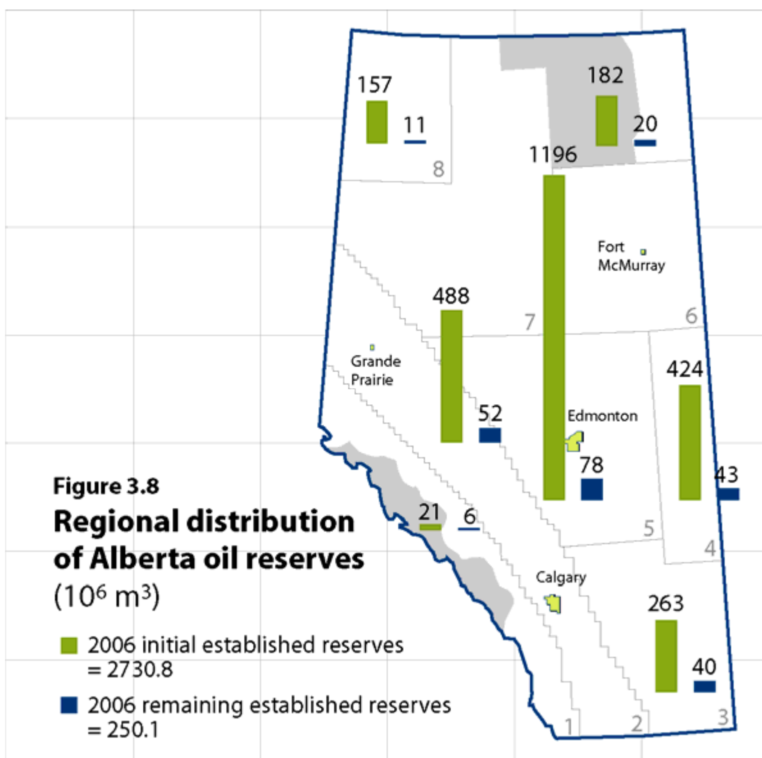
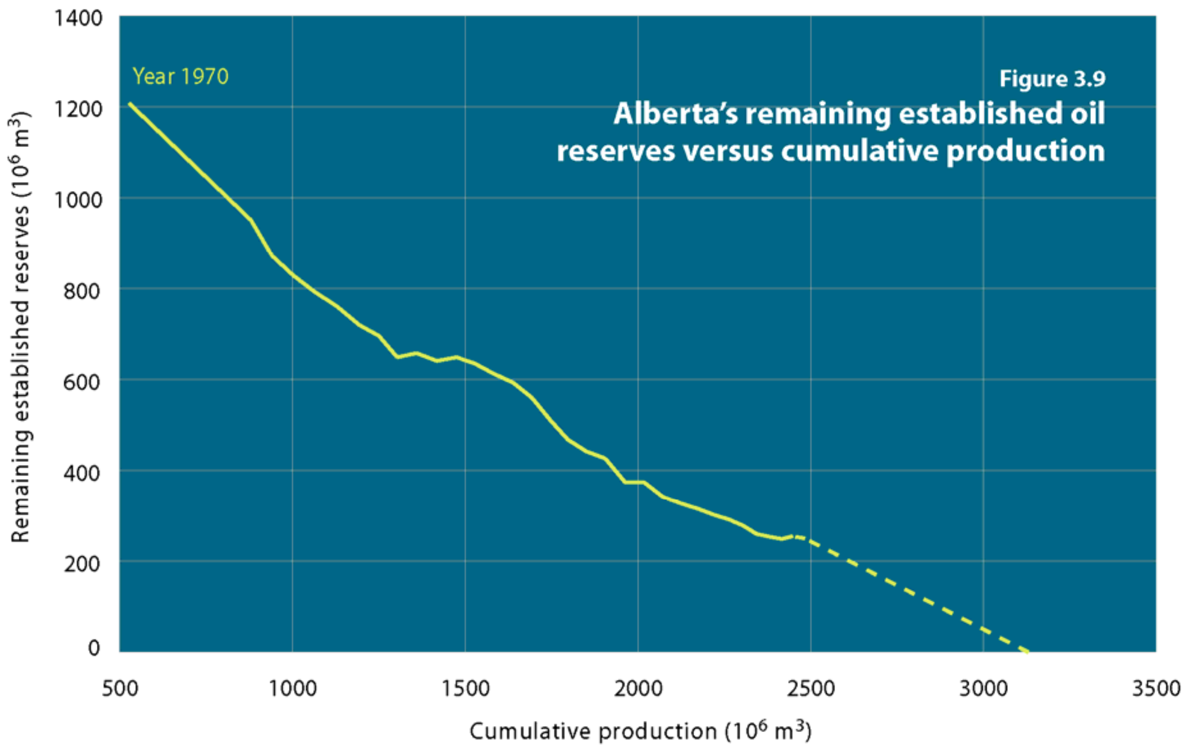
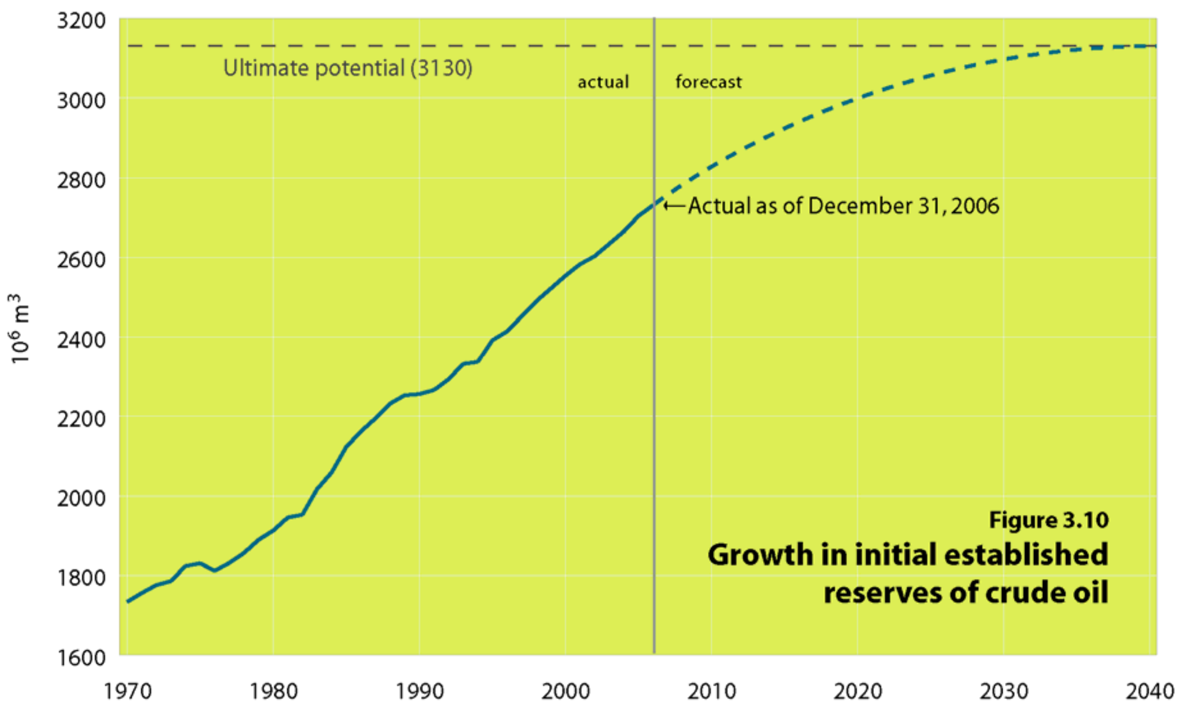


Figure 3.8
Regional distribution of Alberta oil reserves (10^6 m^3)
2006 initial established reserves = 2730.8
2006 remaining established reserves = 250.1
157
11
8
182
20
1196
Fort McMurray
488
7
6
Grande Prairie
424
52
Edmonton
78
43
21
6
5
4
Calgary
263
40
1
2
3





While remaining reserves and production of crude oil continue to decline, there are 399 10^6 m^3 yet to be discovered, which at the five-year average growth rate of 18.3 10^3 m^3 per year will take over 22 years to find. The discovery of new pools and development of existing pools will continue to bring on new reserves and associated production each year.

Any future decline in conventional crude oil production will be more than offset by increases in crude bitumen and synthetic production (see Section 2.2).

3.2 Supply of and Demand for Crude Oil

In projecting crude oil production, the EUB considers two components: expected crude oil production from existing wells at year-end and expected production from new wells. Total production of crude oil is the sum of these two components. Demand for crude oil in Alberta is based on refinery capacity and utilization. Alberta crude oil supply in excess of Alberta demand is removed from the province.

3.2.1 Crude Oil Supply

Since the early 1970s, production of Alberta light-medium and heavy crude oils has been on a downward trend. In 2006, total crude oil production declined to 86.4 10^3 m^3/day. Light-medium crude oil production declined by about 4 per cent to 57.2 10^3 m^3/d from its 2005 level, while heavy crude oil production experienced a decline of about 7 per cent to 29.2 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 5 per cent from 2005 to 2006 and is consistent with the decline from 2004 to 2005.

In 2006, 2146 successful oil wells were drilled, a decrease of some 1 per cent over 2005. **Figure 3.11** shows the number of successful oil wells drilled in Alberta in 2005 and 2006 by geographical area (modified PSAC area). The majority of oil drilling in 2006, nearly 72 per cent, was development drilling. As shown in the figure, major changes in drilling levels were seen in PSAC 4 (East Central Alberta), with an increase of 27 per cent, and PSAC 3 (Southeastern Alberta), with a decrease of 19 per cent.

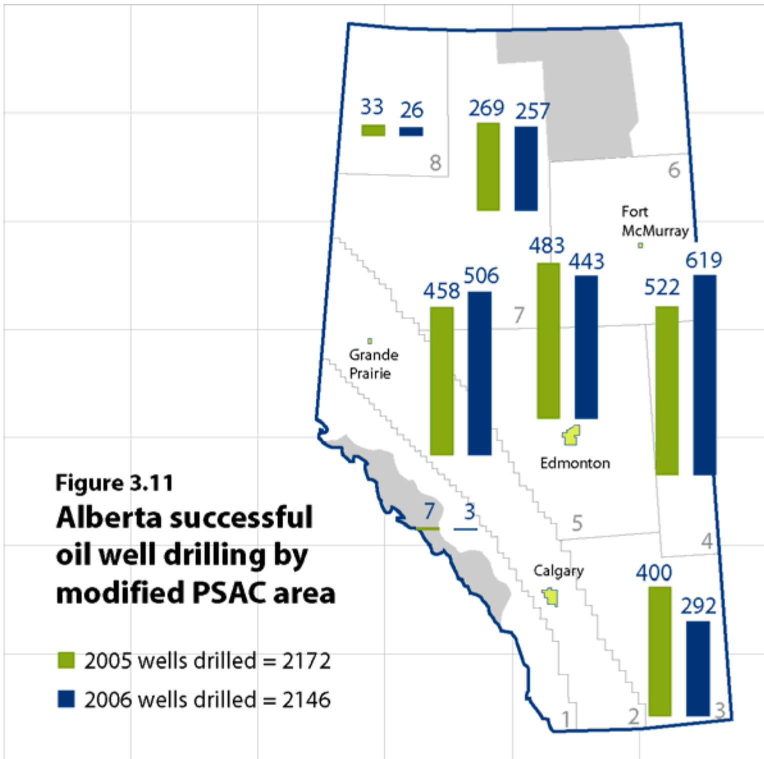


Figure 3.11
Alberta successful oil well drilling by modified PSAC area

Figure 3.12 depicts the distribution of new crude oil wells placed on production and **Figure 3.13** shows the initial operating day rates of new wells in 2006. In the past few years the number of oil wells placed on production in a given year has tended to be lower than crude oil well drilling activity. Oil well drilling statistics are based on the predicted well status from the well licence. Once the well goes on production, the company submits a fluid status for the specific producing event, which may differ from the predicted code, causing the oil well connections to be consistently less than the oil well drilling activity. The majority of these changes occur in moving from a predicted well status of oil to a producing event of gas. In 2006, actual wells placed on production increased by 4 per cent over 2005 levels.

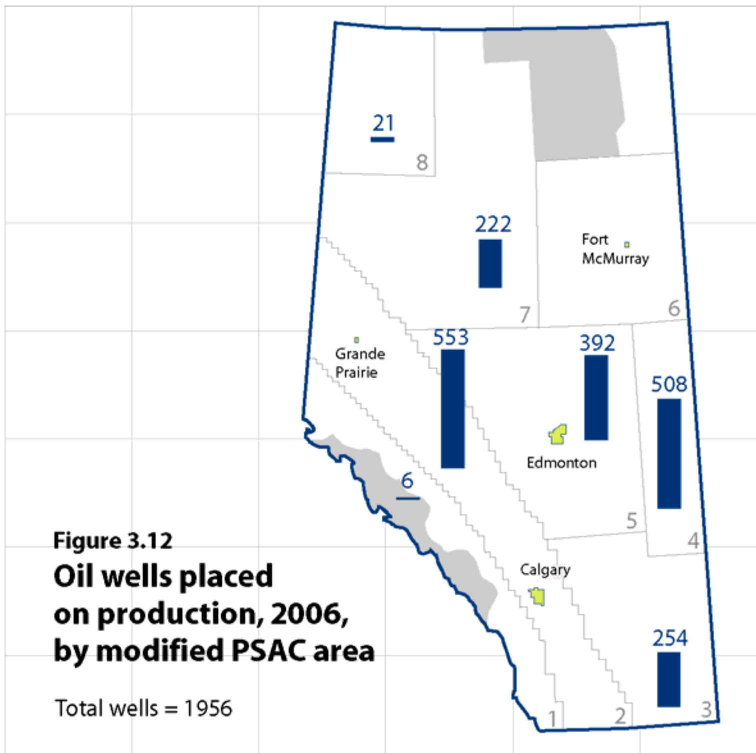


Figure 3.12
Oil wells placed on production, 2006, by modified PSAC area
Total wells = 1956

Historical oil production by geographical area is illustrated in **Figure 3.14**. Most areas experienced declines in production, ranging from 4.0 per cent in PSAC 8 (Northwest Alberta) to 9.4 per cent in PSAC 3 (Southeastern Alberta). The two exceptions were PSAC 1 (Foothills), with an increase in production of 29.5 per cent, and PSAC 2 (Foothills Front), with the production level consistent with that of 2005.

Annual EUB drilling statistics indicate that except for 1999 and 2002, the number of crude oil producing wells has increased over time. In contrast, crude oil production has been on decline since its peak of 227.4 103 m3 /d in 1973. **Figure 3.15** shows total crude oil production and the number of crude oil producing wells since 1973. As it illustrates, while the total number of producing wells has increased from 9900 in 1973 to 38 000 in 2006, crude oil production has been on decline. Of the 38 000 wells producing oil in 2006, about 2700 were classified as gas wells. Although these gas wells represented 7 per cent of wells that produced oil, they produced at an average rate of only 0.3 m3/d and accounted for less than 1 per cent of the total production.

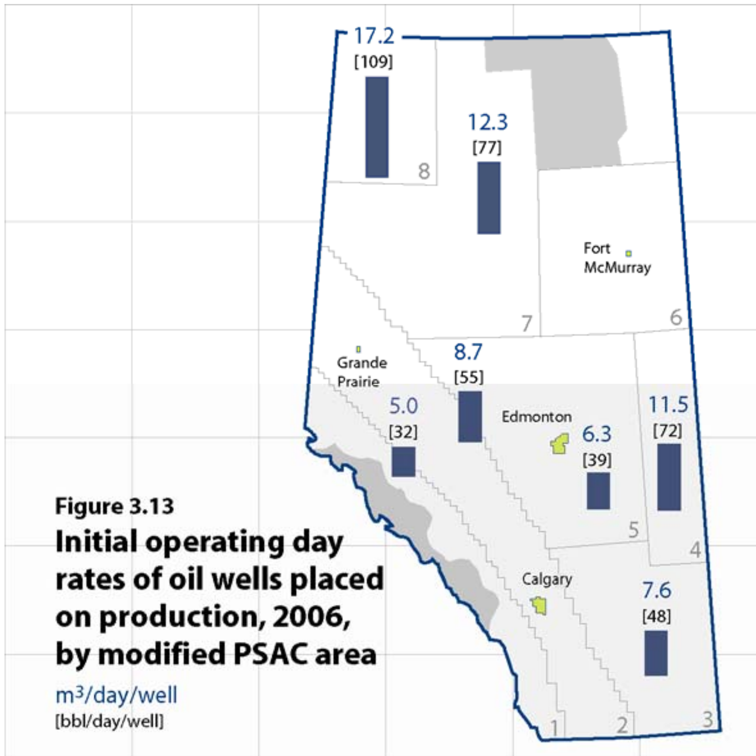


Figure 3.13
Initial operating day rates of oil wells placed on production, 2006, by modified PSAC area

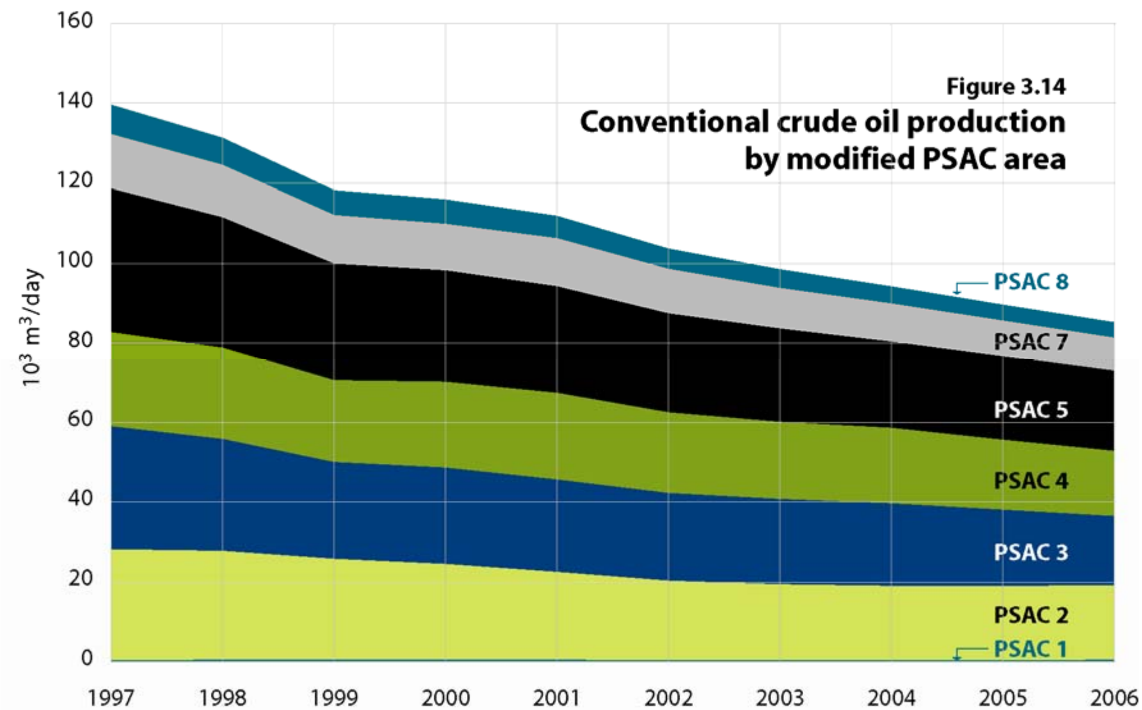
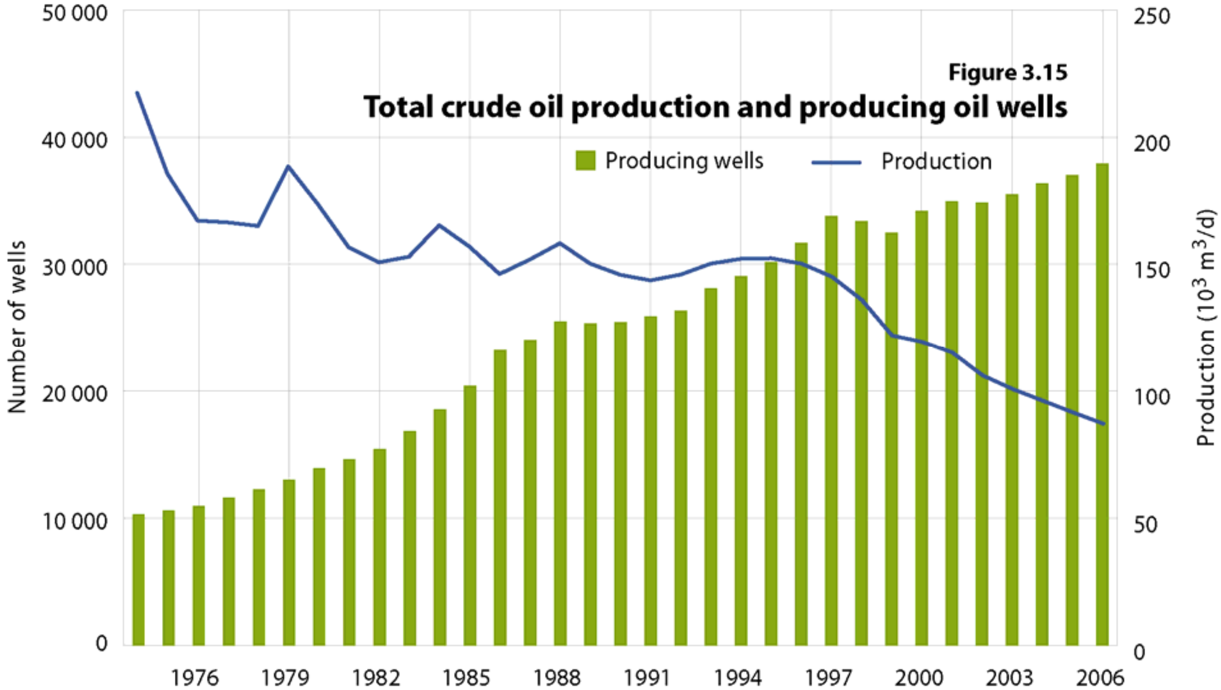
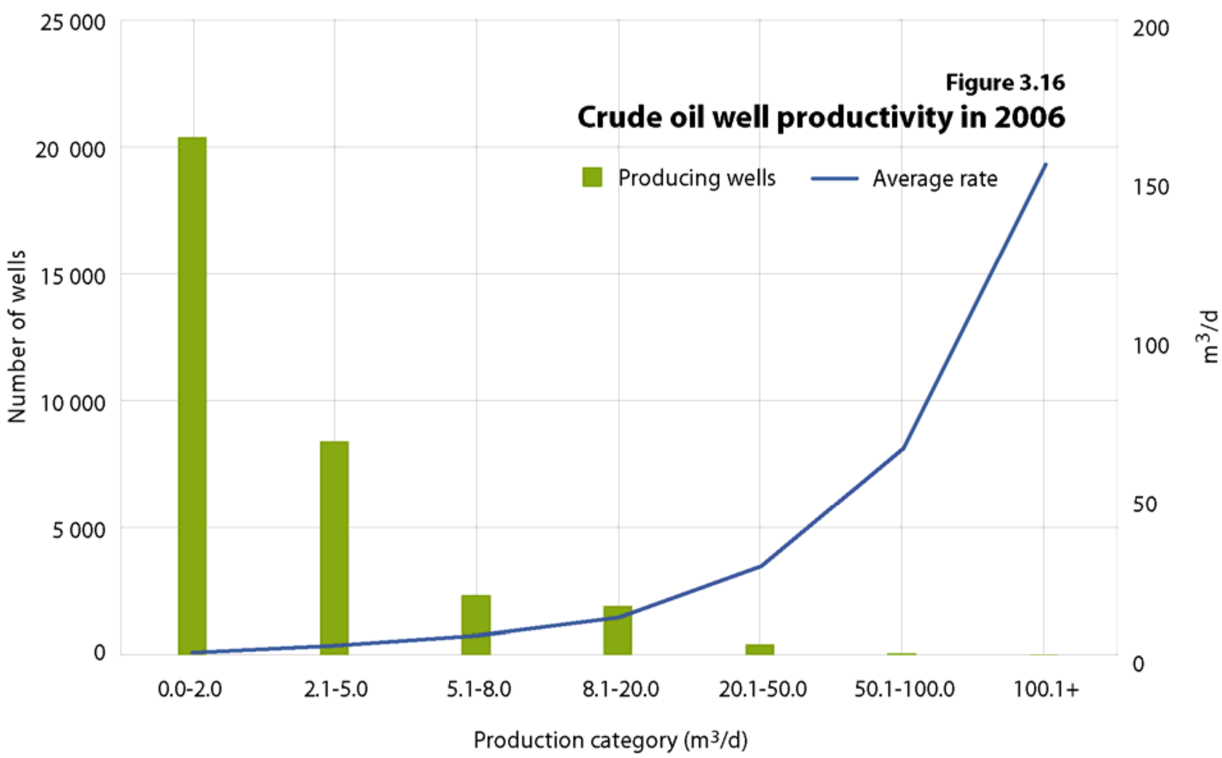


Figure 3.14
Conventional crude oil production by modified PSAC area



The average well productivity of crude oil producing wells in 2006 was 2.3 m^3/d. The majority of crude oil wells in Alberta, about 61 per cent, produced less than 2 m^3/d per well. In 2006, the 20 400 oil wells in this category operated at an average rate of 1 m^3/d and accounted for only 20 per cent of the total crude oil produced. **Figure 3.16** depicts the distribution of crude oil producing wells based on their average production rates in 2006.



In 2006, some 295 horizontal wells were brought on production, an 8 per cent decrease from 2005, raising the total to 3650 producing horizontal oil wells in Alberta. Horizontal wells accounted for 10 per cent of producing oil wells and about 17 per cent of the total crude oil production. Production from horizontal wells drilled in the past ten years peaked in 1999 at an average rate of 13.0 m^3/d. The current production rate of new horizontal wells averaged about 7.3 m^3/d.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2006 year-end and expected production from new wells. Total production of crude oil is the sum of these two components.

To project crude oil production from the wells drilled prior to 2007, the EUB considered the following assumptions:

- Production from existing wells in 2007 will be 74.6 10^3 m^3/d.
- Production from existing wells will decline at a rate of about 16 per cent per year.

Crude oil production from existing wells by year placed on production over the period 1997-2006 is depicted in **Figure 3.17**. This figure illustrates that about 35 per cent of crude oil production in 2006 resulted from wells placed on production in the last five years. Over the forecast period, production of crude oil from existing wells is expected to decline to 16 10^3 m^3/d by 2016.

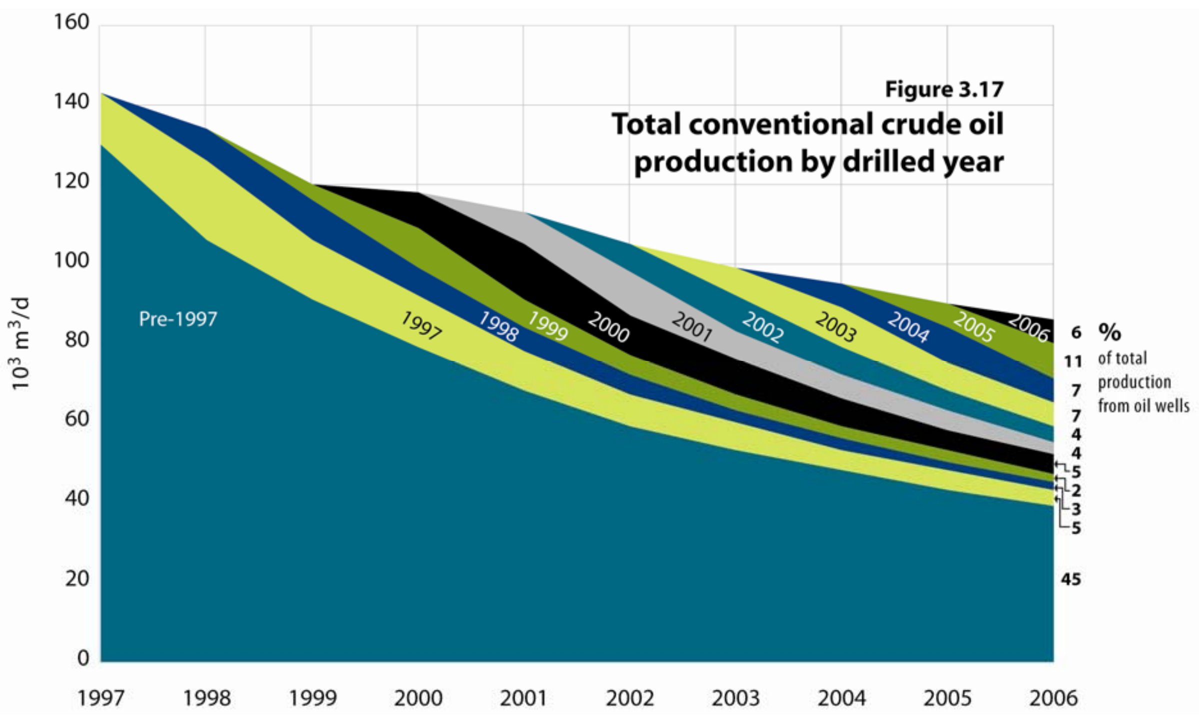
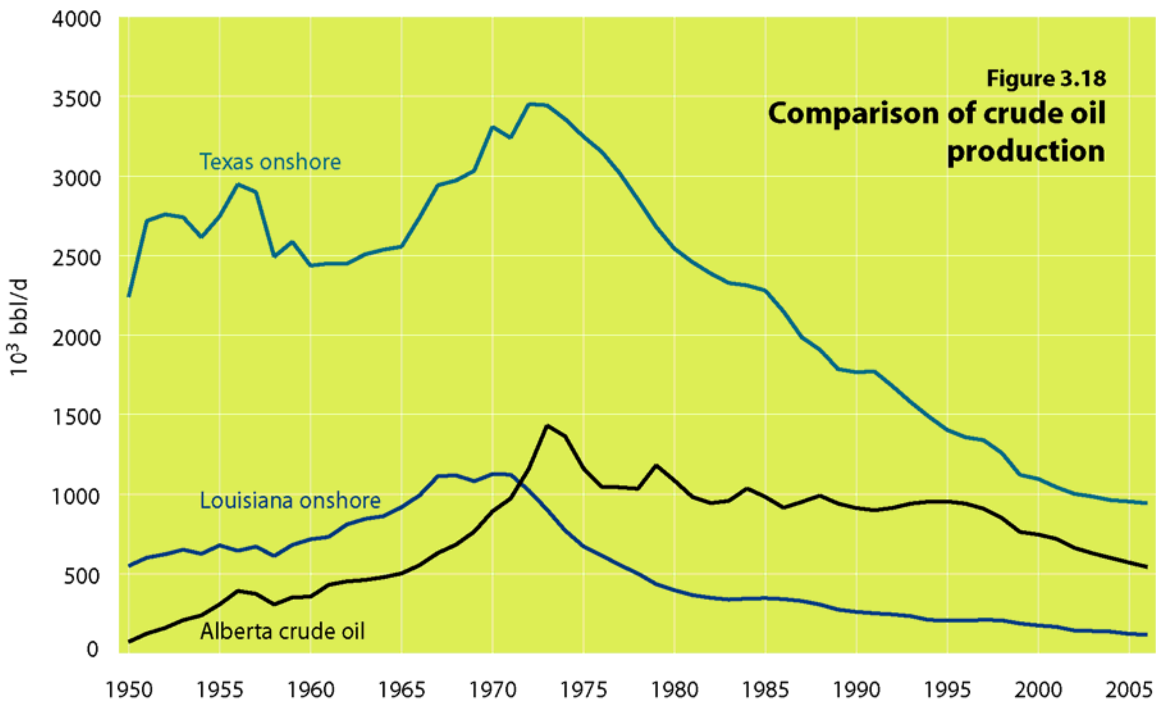


Figure 3.18 compares Alberta crude oil production with crude oil production from Texas onshore and Louisiana onshore from 1950 through 2006. Louisiana onshore production peaked in 1970, while Texas onshore production peaked in 1972 and Alberta production peaked in 1973. The figure shows that Alberta did not experience the same steep decline rates after reaching peak production as did Texas and Louisiana. This difference may be attributed in part to the crude oil prorationing system that existed in Alberta from the

early 1950s through the mid-1980s. Within this period, due to lack of sufficient markets for Alberta crude oil, production was curtailed to levels below the production capacity, which in turn resulted in a slower decline after its peak in 1973.



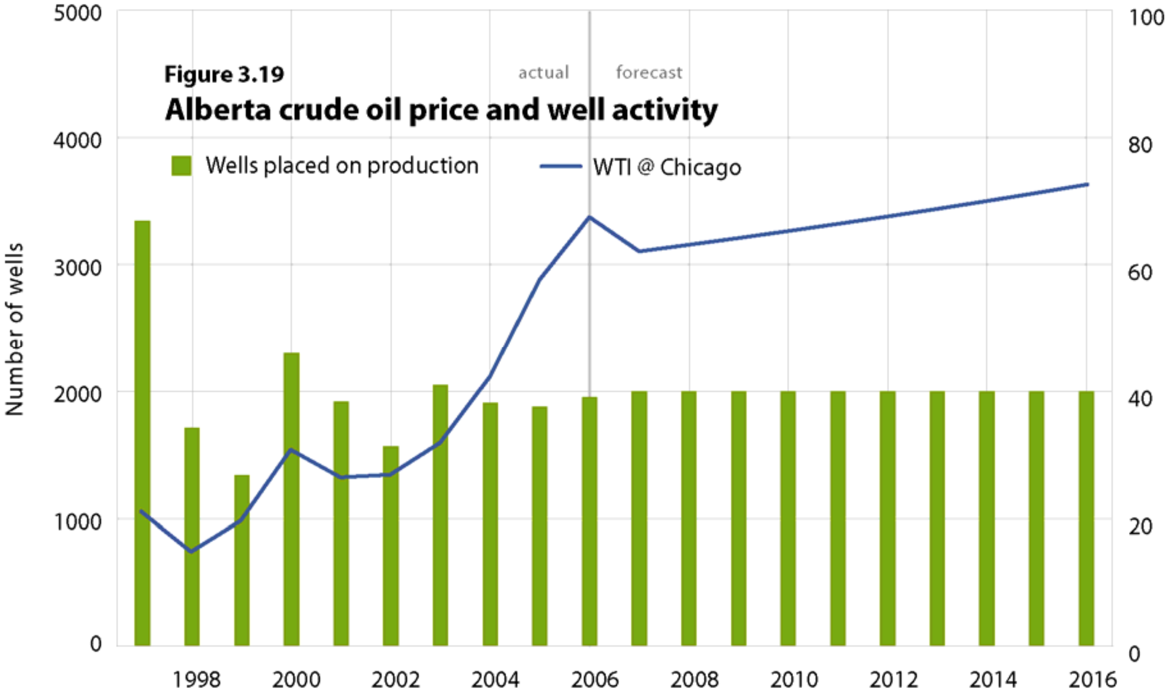
Total production from new wells is a function of the number of new wells that will be drilled successfully, initial production rate, and the decline rate for these new wells. The EUB projects that global crude oil prices will play a role in drilling activity over the forecast period. As discussed in Section 1, the EUB expects that crude oil prices will remain above historic levels. However, crude oil drilling is not expected to return to the record highs of the mid-1990s, because of the mature nature of conventional oil development in the province. Industry has turned its focus to natural gas drilling and oil sands development.

To project crude oil production from new wells, the EUB considered the following assumptions:

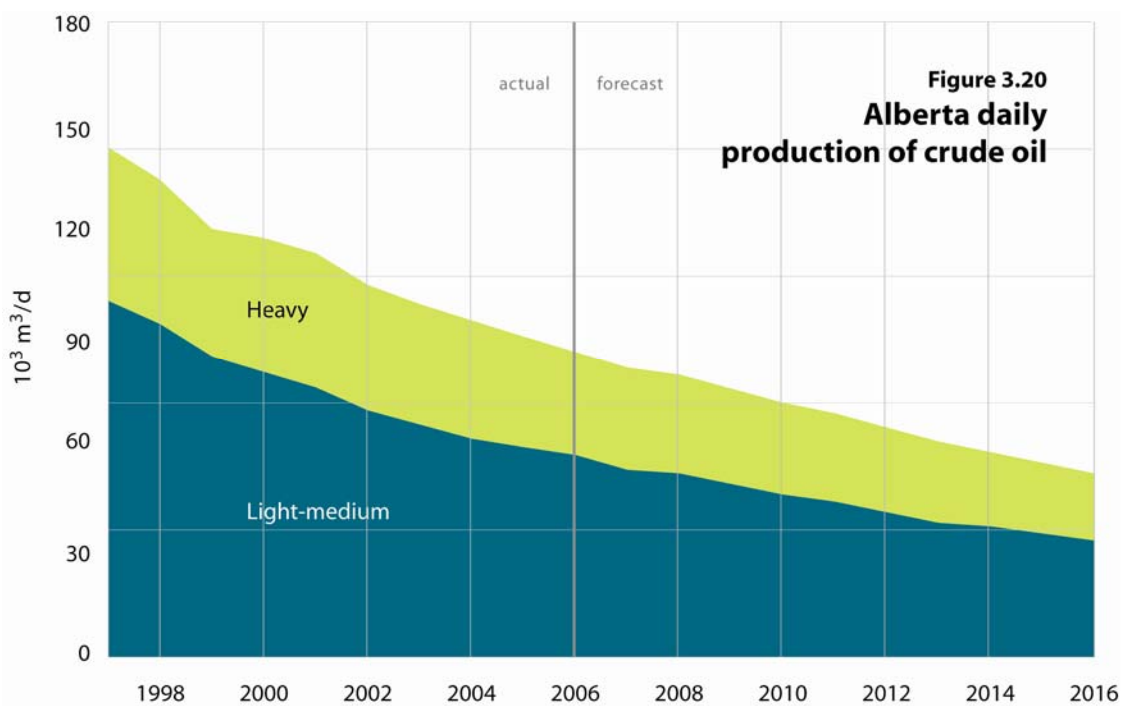
- The number of new oil wells placed on production is projected to increase to 2000 wells in 2007 and remain at this level over the forecast period. **Figure 3.19** illustrates the EUB’s forecast for wells placed on production for the period 2007 to 2016.

- New well productivities have declined over time and averaged 8.0 m^3/d/well in the mid-1990s. Based on recent history, it is expected that the average initial production rate for new wells will be 5 m^3/d/well and will decrease to 3.5 m^3/d/well by the end of the forecast period.

- Production from new wells will decline at a rate of 28 per cent the first year, 24 per cent the second and third year, 20 per cent the fourth year, 17 per cent for the remaining forecast period.



The projection of the above two components, production from existing wells and production from new oil wells, is illustrated in **Figure 3.20.** Light-medium crude oil production is expected to decline from 57.2 10^3 m^3/d in 2006 to 33 10^3 m^3/d in 2016.



Although crude oil wells placed on production are expected to continue at about 2000 wells per year, light-medium crude oil production will continue to decline by almost 5 per cent per year, due to the failure of new well production to offset declining production from existing wells. New drilling has been finding smaller reserves over time, as would be expected in a mature basin.

Over the forecast period, heavy crude production is also expected to decrease, from 29.2 10^3 m^3/d in 2006 to 19 10^3 m^3/d by the end of the forecast period. **Figure 3.20** illustrates that by 2016, heavy crude oil production will constitute a greater portion of total production compared to 2006.

The combined EUB forecasts from existing and future wells indicate that total crude oil production will decline from 86.4 10^3 m^3/d in 2006 to 52 10^3 m^3/d in 2016. By 2016, if crude oil production follows the projection, Alberta will have produced about 87 per cent of the estimated ultimate potential of 3130 10^6 m^3.

3.2.2 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with synthetic crude oil (SCO), bitumen, and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta refineries are domestic demand for RPPs, shipments to other western Canadian provinces, exports to the United States, and competition from other feedstocks. Since Alberta is a “swing” supplier of RPPs within western Canada, a refinery closure or expansion in this market may have a significant impact on the demand for Alberta RPPs and, hence, on Alberta crude oil feedstock requirements.

In 2006, Alberta refineries, with total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 29.9 10^3 m^3/d of crude oil. SCO, bitumen, and pentanes plus constituted the remaining feedstock. Crude oil accounted for roughly 45 per cent of the total crude oil and equivalent feedstock (see Section 2.2.4). **Figure 3.21** illustrates the capacity and location of Alberta refineries. It is expected that no new crude oil refining capacity will be added over the forecast period. Refinery utilization for 2006 was about 89 per cent and is expected to remain at or above this level, as demand for refined petroleum products increases in western Canada. Total crude oil use will reach 34 10^3 m^3/d in 2007, declining to 28 10^3 m^3/d in 2008, with a further decline to 21 10^3 m^3/d for the remainder of the forecast period. This decline is the result of the Petro-Canada Refinery Conversion project set to fully replace light-medium crude oil with SCO and nonupgraded bitumen by 2008.

Shipments of crude oil outside of Alberta, depicted in **Figure 3.22**, amounted to 65 per cent of total production in 2006. With the decline in demand for light-medium crude in Alberta, the EUB expects that by 2016 about 59 per cent of production will be removed from the province.

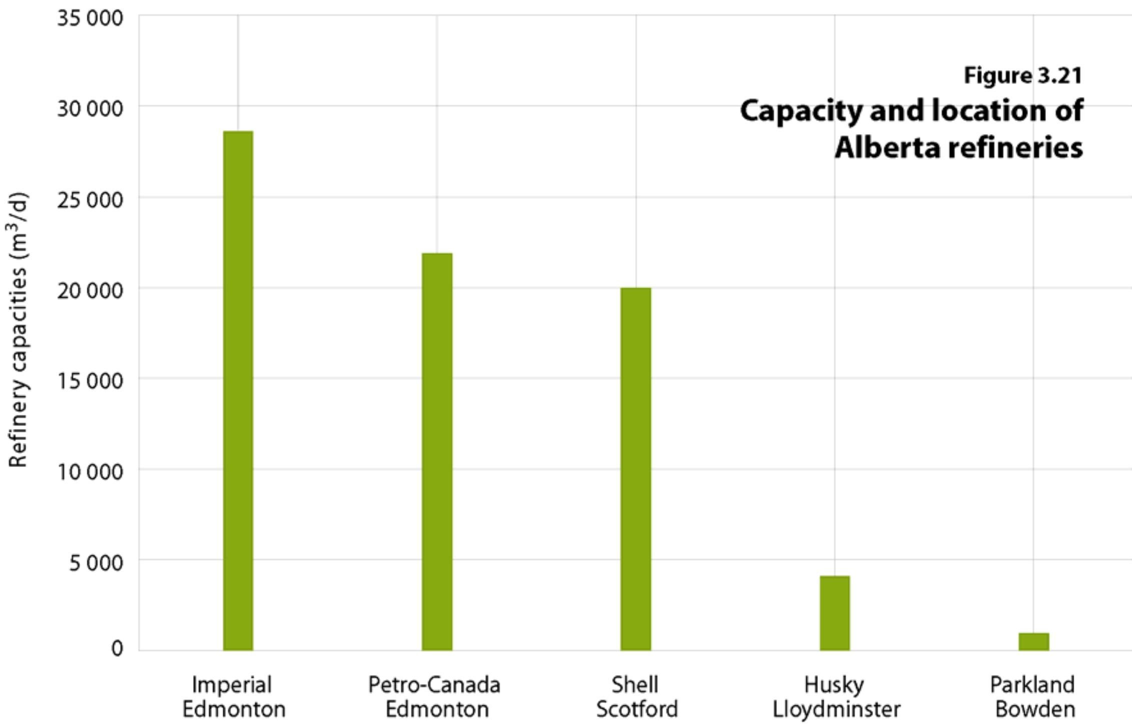
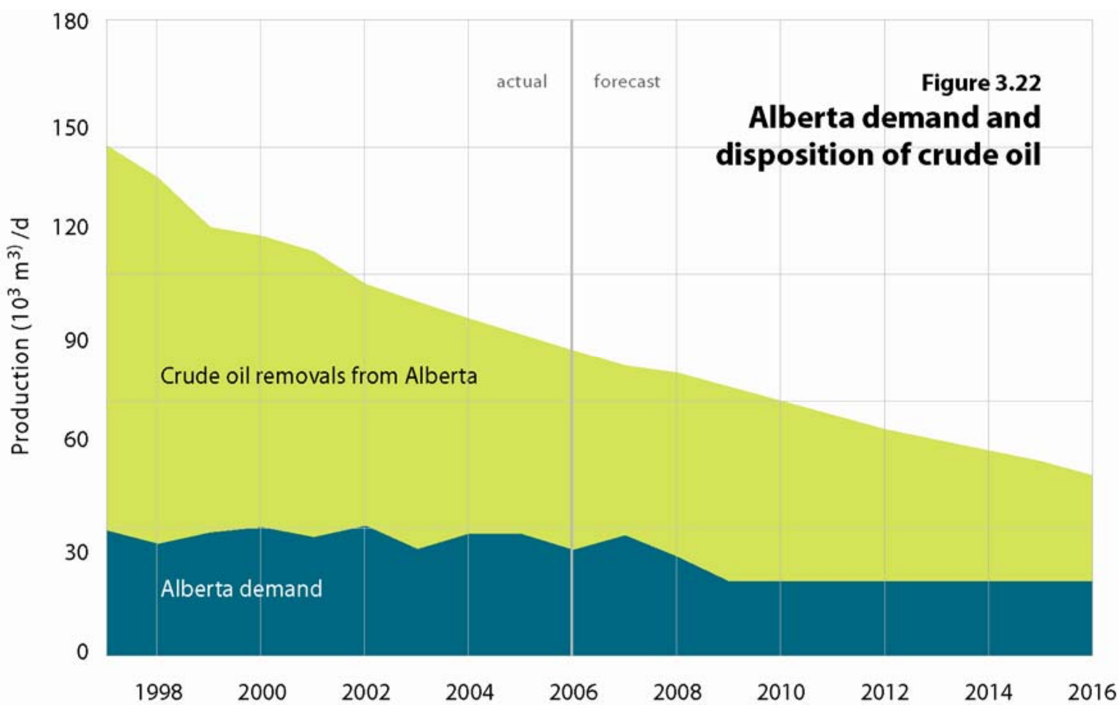
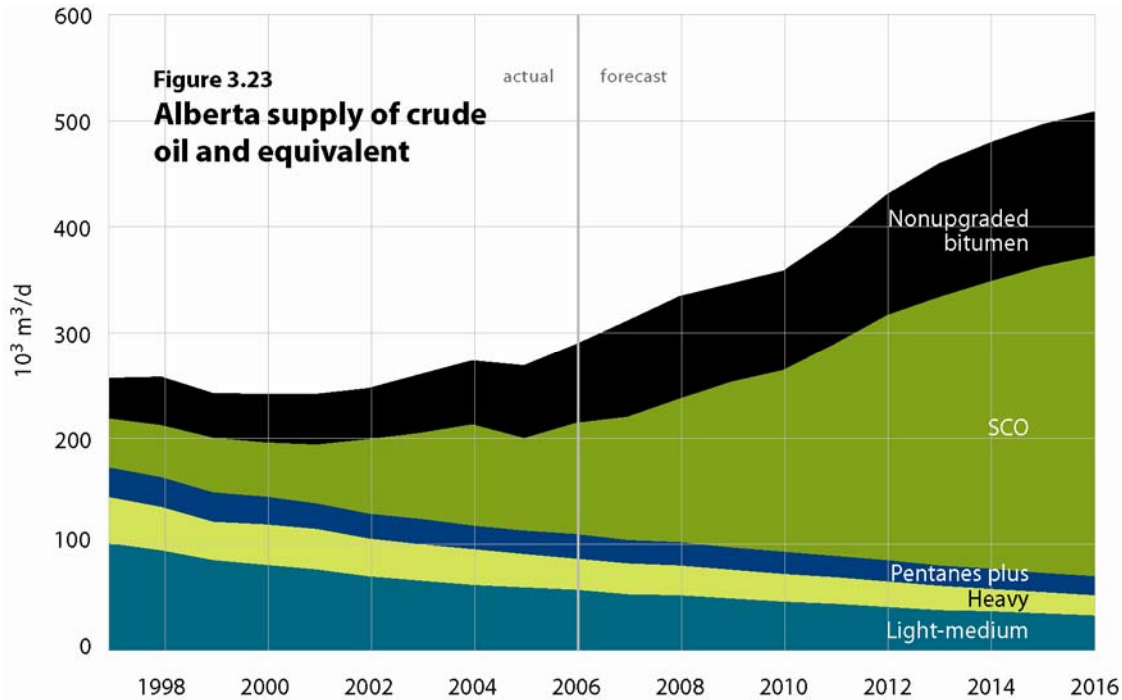


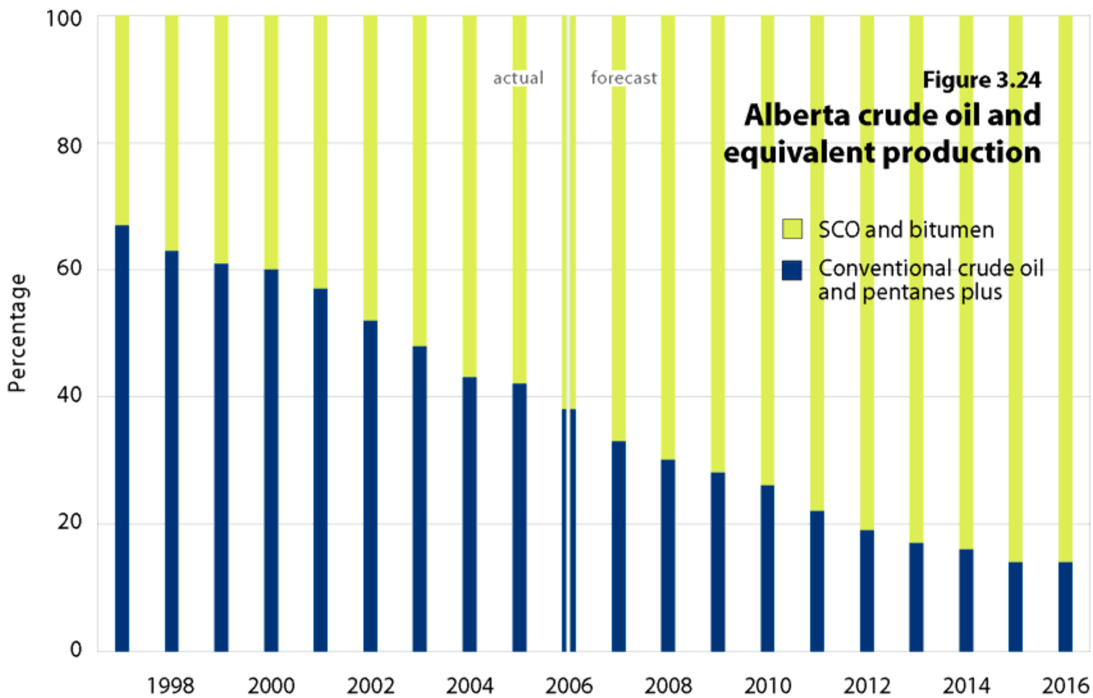
Figure 3.21
Capacity and location of Alberta refineries
Refinery capacities (m³/d)
35 000
30 000
25 000
20 000
15 000
10 000
5 000
0
Imperial Edmonton
Petro-Canada Edmonton
Shell Scotford
Husky Lloydminster
Parkland Bowden


actual
forecast
Figure 3.22
Alberta demand and disposition of crude oil
Production (10³ m³)/d
180
150
120
90
60
30
0
Crude oil removals from Alberta
Alberta demand
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016

3.2.3 Crude Oil and Equivalent Supply

Figure 3.23 shows crude oil and equivalent supply. It illustrates that total Alberta crude oil and equivalent is expected to increase from 288.6 10^3 m^3/d in 2006 to 507 10^3 m^3/d in 2016. Over the forecast period, as illustrated in **Figure 3.24**, the growth in production of nonupgraded bitumen and SCO is expected to significantly offset the decline in conventional crude oil. The share of SCO and nonupgraded bitumen will account for some 86 per cent of total production by 2016.





4 Coalbed Methane

Coalbed methane (CBM), also known as natural gas from coal (NGC), is the methane gas found in coal, both as adsorbed gas and as free gas. All coal seams contain CBM to some extent and each individual seam is potentially capable of producing some quantity of CBM. For this reason, coal and CBM have a fundamental relationship.

Coal is known, from thousands of coalholes and oil and gas wells, to underlie most of central and southern Alberta. Individual coal seams are grouped into coal zones, which can be correlated very well over regional distances.

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the EUB until 1995. Significant development with commercial production commenced in early 2002. Interest in CBM development in Alberta continues to grow, with ongoing high numbers of CBM completions. The actual CBM production to date continues to remain uncertain because of the current inability to differentiate CBM from conventional gas production where commingled production occurs. New regulations were implemented on October 31, 2006, to assist in appropriate data collection for CBM. As additional data through these requirements become available, the accuracy of CBM production estimates is expected to improve.

CBM zones are known to be laterally extensive over regional distances, but the values of reservoir parameters are generally limited to a more localized scale. CBM pools consist of several individual producing coal seams considered as one pool for administrative purposes. The current definition of a CBM pool is that of a CBM zone constrained within a gas field boundary. A CBM zone is defined as all coals within a formation unless separated by more than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool.

4.1 Reserves of CBM

4.1.1 Provincial Summary

The EUB estimates the remaining established reserves of CBM to be 24.7 billion cubic metres (10^9 m^3) as of December 31, 2006, in areas of Alberta where commercial production is occurring. The gas produced from coals in Alberta consists primarily of methane (usually about 95 per cent), with very little natural gas liquids. The heating value of CBM is usually about 37 megajoules/m^3. A summary of reserves is shown in **Table 4.1**. In 2006, the annual production from all wells listed as CBM (see EUB *Bulletin 2007-05*) was 4.7 10^9 m^3, but this includes some wells marked as CBM that do not have completions in coal or recompleted wells with no production separation by event. The production of CBM only from these wells is considered to be 1.2 10^9 m^3, slightly more than 25 per cent of the commingled flow.

Table 4.1. Changes in CBM reserves, 2006 (10^9 m^3)

	2006	2005	Change
Initial established reserves	27.8	23.0	4.8
Cumulative production	3.3	2.1	1.2
Remaining established reserves	24.7	20.9	3.8

4.1.2 Detail of CBM Reserves

Exploration and development drilling is being conducted for CBM across wide areas of Alberta and in many different horizons. The first commercial production and reserves estimates were for the Horseshoe Canyon coals, which are mainly gas-charged, with little or no pumping of water required. This remains the main focus of industry and currently has the highest established reserves. Additional data have been collected under new regulations (implemented October 2006), which has resulted in a more accurate production split of commingled wells. For some fields, this reassessed production split resulted in lower production in 2006 than in previous years. The production split was not reassessed for previous years.

Production of CBM from the Ardley coals is limited but is anticipated to increase in coming years. In 2005, the first commercial success was announced for Mannville CBM production in the Corbett/Thunder and Doris fields. In these fields, CBM production requires the disposal of saline water. Mannville CBM reserves were reported for the first time in 2005 and are now included in this report in Appendix B, **Table B.6**. Remaining reserves for all formations have been calculated using a deposit block model method. This yields a remaining established reserve of 24.7 10^9 m^3, as shown in **Table B.6**.

The Mannville CBM play has increased in activity, but there are no indications of large-scale development at this time. For this reason, there have been additional fields added to Appendix B, **Table B.7**, but no additional reserves have been determined. Current industry practice suggests that long-term CBM production from the Mannville and Ardley will be project-style developments combining recompletions of existing conventional wells with the drilling of new CBM wells. In other regions of the province, active exploration and pilot programs of various sizes are currently testing CBM production, but these have no commercial gas production. **Table B.7** lists production from these areas, but reserves have not been booked pending commercial production.

Note that many fields are still at initial stages of exploration, and there are very few data to calculate CBM reserves. Once more data are collected, the reserves should increase.

The 287.1 10^9 m^3 initial in-place volume (**Table B.6**) encompasses the areas of commercial CBM production. This volume is expected to increase with further evaluation to include areas of known resources drilled but not yet producing. The remaining established reserves is set at 24.7 10^9 m^3, based on **Table B.6**.

4.1.3 Commingling of CBM with Conventional Gas

Commingling is the unsegregated production of gas from more than one interval in a wellbore. In the case of CBM, this includes CBM/CBM and CBM/conventional gas. The former case does not affect the calculation of CBM reserves, but the latter case does complicate the calculation of remaining reserves. In several areas, CBM production has been commingled with conventional gas.

CBM production from the generally “wet CBM” formations of the Scollard, Mannville, and Kootenay coal-bearing formations is not currently being approved for commingling with gas from other lithologies because of the potential negative impact of water production on CBM recovery and mixing of water between aquifers.

As the Horseshoe Canyon and Belly River CBM pools are generally “dry CBM,” with little or no pumping of water required, the commingling of CBM and other conventional gas pools is becoming fairly common (CBM/conventional commingling). Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. As changes to the commingling requirements were implemented in 2006, there is now an area of central Alberta called Development Entity #1 that is approved for this type of production (see **Figure 4.1**). In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

However, CBM/conventional commingling creates lack of segregated data, thereby affecting reserves calculations. Many wells report only large CBM production, even though analysis of the well indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints in this report, the following analysis was completed on wells with commingled production:

- The completions were checked for most wells, and ones found to be only in coal were assigned as CBM-only production.
- CBM production from commingled CBM/sandstone wells is interpolated from CBM control wells. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was not included. In future, these wells will be subject to a reporting audit.

This process resulted in the contribution of CBM production being reduced in a few fields, as summarized in **Table B.6**. The *Oil and Gas Conservation Regulations* now stipulate data submission requirements for control wells to capture information on CBM-only production characteristics. Future submission of these test results will allow for more complete analysis to improve allocation of production in commingled wells.

4.1.4 Distribution of Production by Geologic Strata

The following horizons have CBM potential in the Alberta plains:

Ardley Coals of the Scollard Formation – This is the upper set of coals, which are generally the shallowest, with varying gas contents and quantities of water. These coals continue to the west, outcropping in the Alberta Foothills, where they are referred to as the Coalspur coals. Where water is present, it is usually nonsaline or marginally saline, and thus water production and disposal must comply with the *Water Act*.

Coals of the Horseshoe Canyon Formation and Belly River Group – This is the middle set of coals, which generally have low gas content and low water volumes, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, the main set of coals to have CBM reserves booked at this time.

Coals of the Mannville Group – This is the lower set of coals, primarily in the Upper Mannville Formation(s). These generally have high gas content and high volumes of saline water, which require extensive pumping and water disposal. These coals continue to the west to outcrop near the Rocky Mountains, where they are referred to as the Luscar coals. Mannville coals are the focus of a number of pilot projects, one of which declared commercial success. This successful pilot expanded into two gas fields. A few of the pilots have been abandoned (e.g., Fenn Big Valley). The initial reserves for other areas within the Mannville have been set at cumulative production.

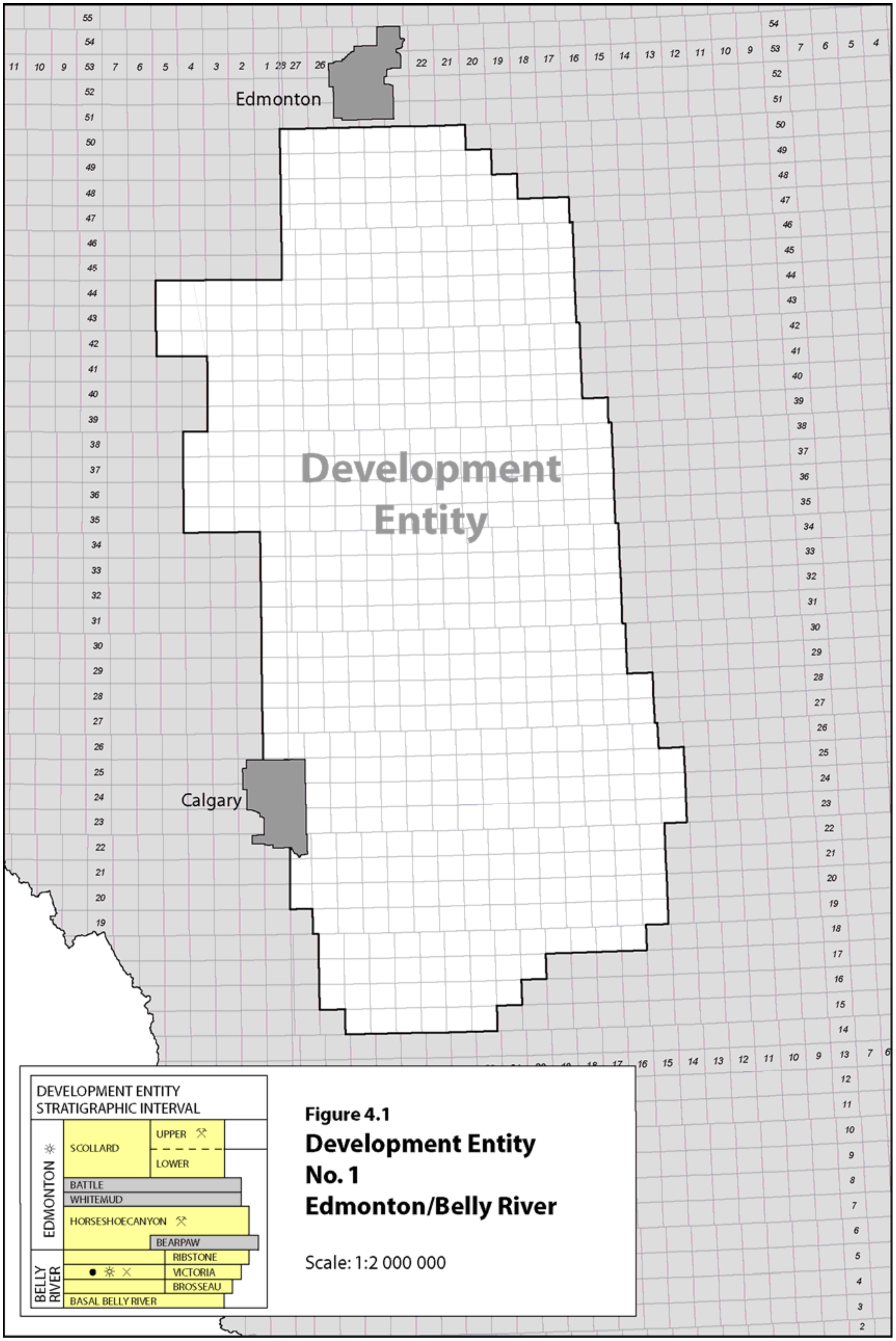


Figure 4.1
Development Entity No. 1 Edmonton/Belly River

Scale: 1:2 000 000

Kootenay Coals of the Mist Mountain Formation – These coals are only present in the foothills of southwestern Alberta. They have varying gas content and quantities of water, but production of gas is very low due to tectonic disruption. No reserves have been calculated.

4.1.5 Hydrogen Sulphide Content

Hydrogen sulphide (H_2S) is not normally considered to be an issue with respect to CBM, as the coal adsorption coefficient for H_2S is far greater than for methane. However, commingling CBM production with conventional sandstone gas from the Upper Cretaceous may result in trace amounts of H_2S being produced.

4.1.6 Reserves Determination Method

All calculations for this report used a three-dimensional deposit block model. CBM exists as deposits (similar to coal and bitumen) of disseminated gas, with gas content and reserve values that can be calculated using a deposit model. As CBM is natural gas, it is regulated and administered as if it existed in pools, but the pool resource and reserve calculation method is not directly applicable.

Analysis of the Upper Cretaceous "dry CBM" trend, where most CBM pools are geologically distinct and show different pressure gradients, concludes that it is more appropriate to use separate gas content formulas for each CBM pool. Where block modelling has been done, information on the gas content of coals, while still quite limited, does indicate that a reliable relationship exists among gas content, formation pressure, depth from surface, and ash content of the coal. The CBM deposit block models were constructed by developing a three-dimensional gridded seam model, with subsequent application of measured gas content and recovery factors to each coal block.

Production flow logs and other criteria indicate that the individual block recovery factors need to be assigned on a different basis for each coal seam. Coals shown not to produce any gas have their recovery factor set to zero. The results are highly varied from gas field to gas field, and some areas have no or limited useful data, while other fields have good information.

CBM data are available on two systems at the EUB: summarized pool style net pay data on the *Basic Well Database* and individual coal seam thickness picks on the Coal Hole Database. For further information, contact EUB Information Services.

4.1.7 Ultimate Potential

As the thickness and correlatability of coal as a host rock can be determined from the large number of available oil and gas wells, the EUB believes that a regional estimation of CBM resources can be established with some degree of confidence. In 2003, the Alberta Geological Survey, in *Earth Sciences Bulletin 2003-03*, estimated that there are some 14 trillion m^3 (500 trillion cubic feet) of gas in place within all of the coal in Alberta, as summarized in **Table 4.2**. Only a very small portion of that coal resource has been studied in detail for this report. The geographic distribution of these resources is shown in **Figure 4.2**.

Table 4.2. CBM resources gas-in-place summary—constrained potential (depth and thickness restrictions)* (10^6 m^3)

	10^{12} m^3	TCF
Upper Cretaceous/ Tertiary - Plains	4.16	147
Mannville coals	9.06	320
Foothills / Mountains	0.88	31
Total	14	500

*AGS *Earth Sciences Bulletin 2003-03*.

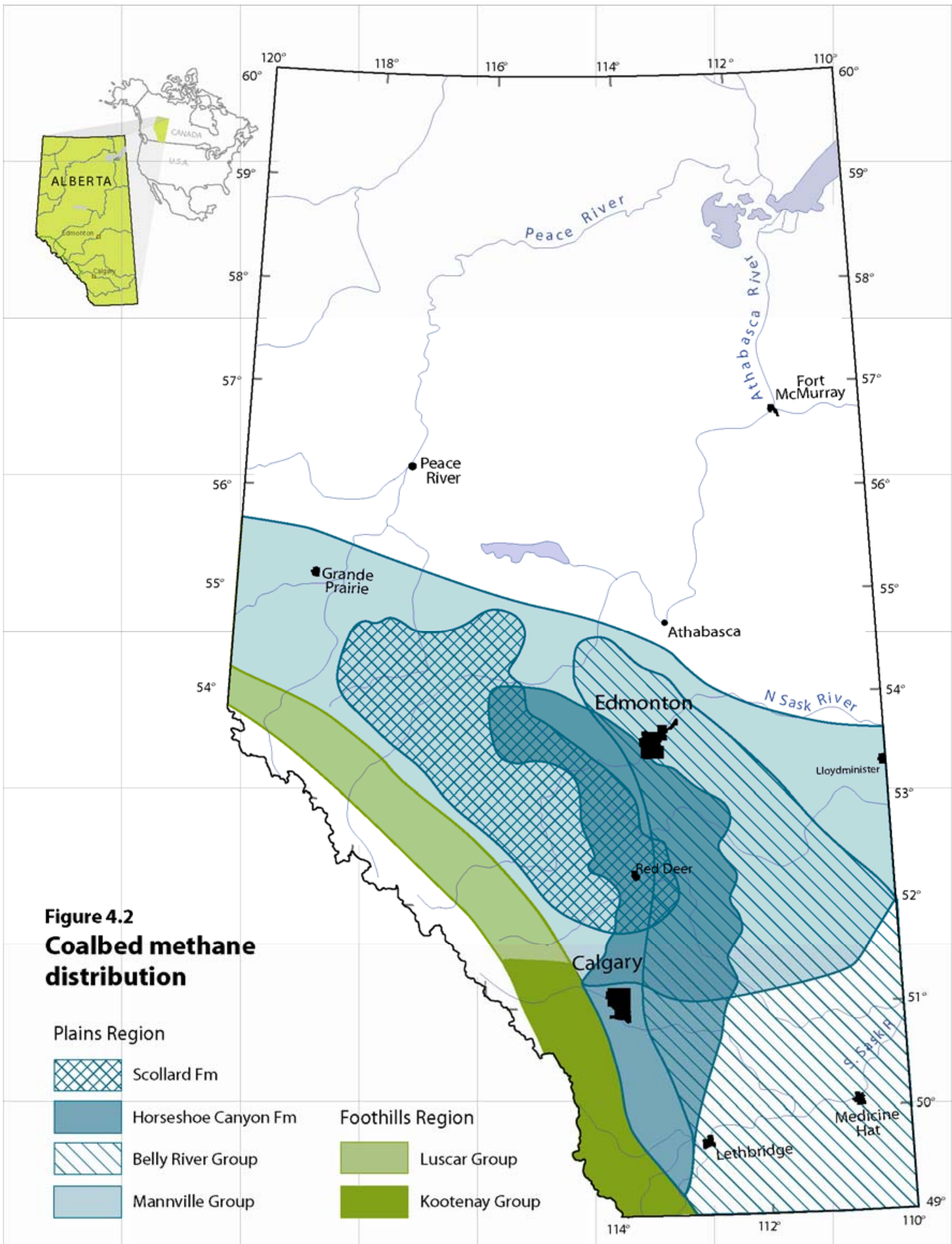


Figure 4.2
Coalbed methane distribution

4.2 Supply of and Demand for Coalbed Methane

As mentioned previously, commercial production of CBM in Alberta began in 2002, with small volumes recovered to date. In 2006, 4.7 10^9 m^3 was produced, mostly from the CBM wells of the dry coals and commingled sandstones of the Horseshoe Canyon Formation. Commercial production from the Mannville Group is in its infancy, and much of the success to date has come as a result of horizontal drilling. CBM has the potential to become a significant supply source in Alberta over the next 10 years.

In 2006, 2434 wells, similar to the revised well count for 2005, were connected for CBM production in the province. Roughly 25 per cent of the wells were classified by the operators as conventional gas wells but were deemed to be CBM producing wells by the EUB.

Figure 4.3 illustrates the location of CBM wells by geographical area. A large portion of the well connections have been in Central Alberta (PSAC Area 5) and Southeastern Alberta (PSAC Area 3), accounting for 47 and 42 per cent respectively of all CBM wells connected in 2006.

Future drilling and CBM connections are expected to continue to be significant in the Horseshoe Canyon Formation in areas of Southeastern and Central Alberta. Conventional supply will be commingled with CBM production in the same wellbore where deemed appropriate.

In projecting CBM production, the EUB considered expected production from existing wells and expected production from new well connections.

Limited historical production data suggest that CBM production does not behave in the same manner as conventional production in that CBM production declines more slowly.

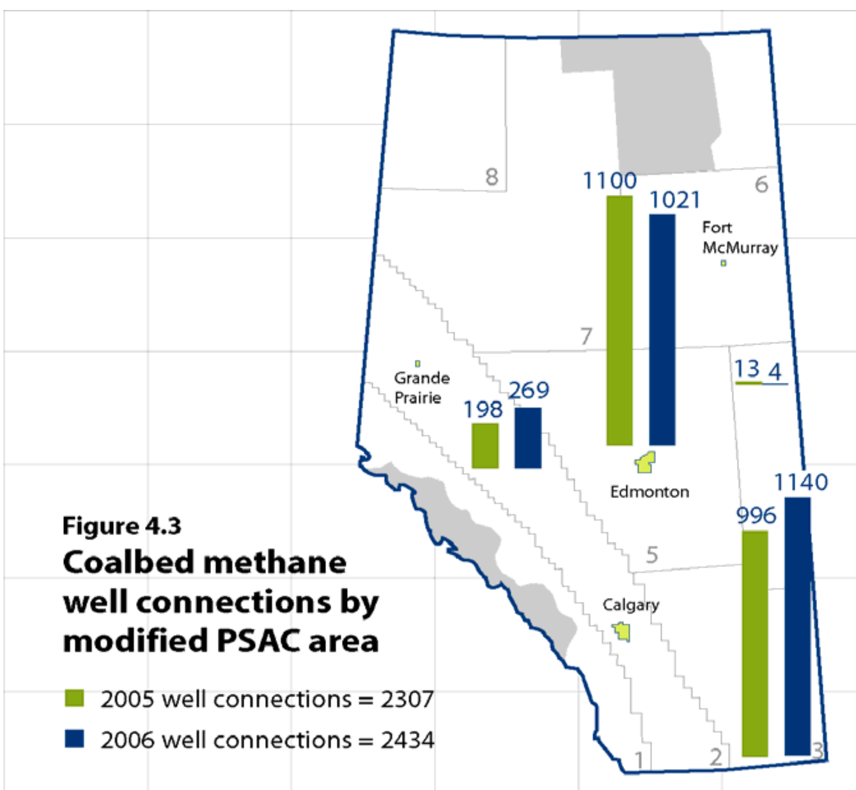


Figure 4.3
Coalbed methane well connections by modified PSAC area

To project production from new CBM well connections, the EUB considered the following assumptions:

- The average initial productivity of new CBM connections will be 2.8 10^3 m^3/d.
- Production from new well connections will decline by 15 per cent after the first full year of production and then decline by 10 per cent per year.

CBM well connections are expected to decline in 2007 to 1900 wells. The commodity price declines that took place in late 2006 are responsible for a slowdown in CBM and shallow conventional gas drilling, which is expected to continue well into 2007. In 2008 and 2009, some 2400 wells are forecast to be connected annually, increasing to 2500 wells in 2010 and thereafter for the remainder of the forecast period. The well connection numbers are lower than last year's forecast due to lower than expected economic return for CBM.

Based on the assumptions described above, the EUB generated the forecast of CBM production to 2016, as shown in **Figure 4.4**. The production of CBM is expected to increase from 4.7 10^9 m^3 in 2006 to 16.8 10^9 m^3 in 2016. This represents an increase from 3 per cent in 2006 to about 13 per cent in 2016 of total Alberta marketable gas production. Gas production from CBM may be higher than that forecast if commercial production of gas from the Mannville coal seams is accelerated.

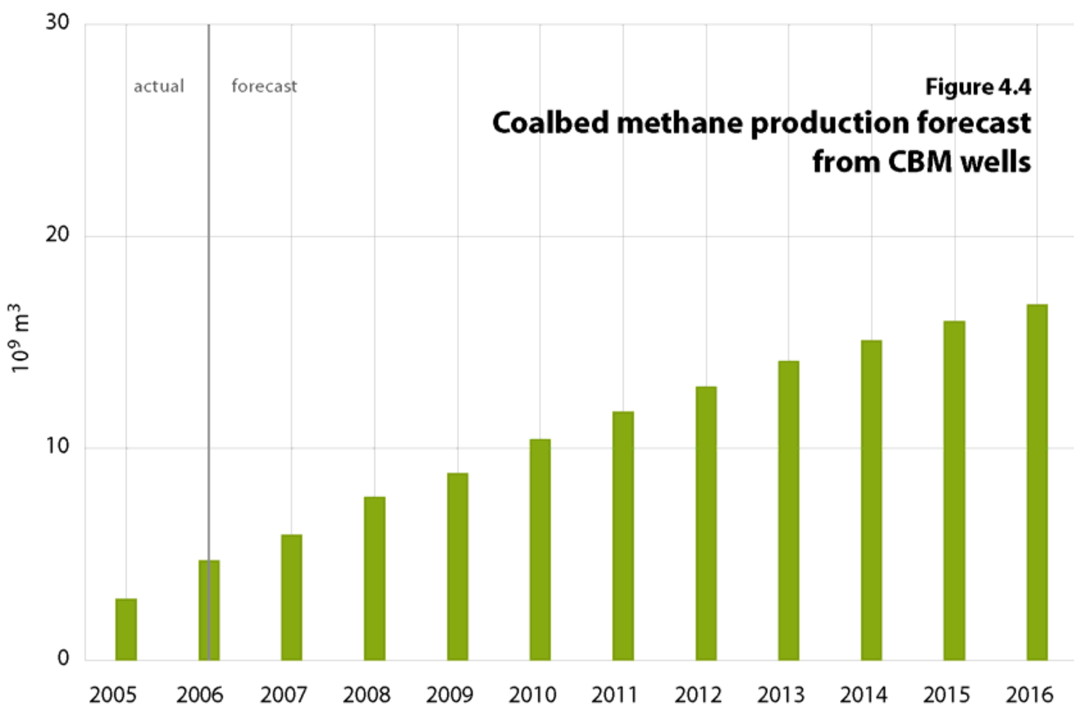


Figure 4.4
Coalbed methane production forecast from CBM wells

See Section 5 for a further discussion of Alberta natural gas supply and demand.

5 Conventional Natural Gas

Raw natural gas consists mostly of methane and other hydrocarbon gases, but also contains other nonhydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide. These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component after removal of impurities is about 91 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Ethane and higher paraffin hydrocarbon components, which condense into liquid at different temperature and pressure, are classified as natural gas liquids (NGLs) in this report.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

At December 31, 2006, the EUB estimates the remaining established reserves of marketable gas in Alberta to be 1079.6 billion cubic metres (10^9 m^3), having a total energy content of 40.2 exajoules. This decrease of 6.4 10^9 m^3 since December 31, 2005, is the result of all reserves additions less production that occurred during 2006. These reserves exclude 35.4 million 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants, as discussed in Section 5.1.7. Removal of NGLs results in a 4.4 per cent reduction in average heating value from 39 megajoules (MJ)/m^3 to 37.3 MJ/m^3 for gas downstream of straddle plants. Details of the changes in remaining reserves during 2006 are shown in **Table 5.1**. Total provincial gas in place and raw producible gas for 2006 is 8229 10^9 m^3 and 5665 10^9 m^3 respectively. This gives an average provincial recovery factor of 69 per cent. An average provincial surface loss of 15.3 per cent is applied to the raw producible gas to yield initial established marketable reserves of 4798.7 10^9 m^3, as shown in **Table 5.1**. This surface loss estimation is discussed in Section 5.1.7.

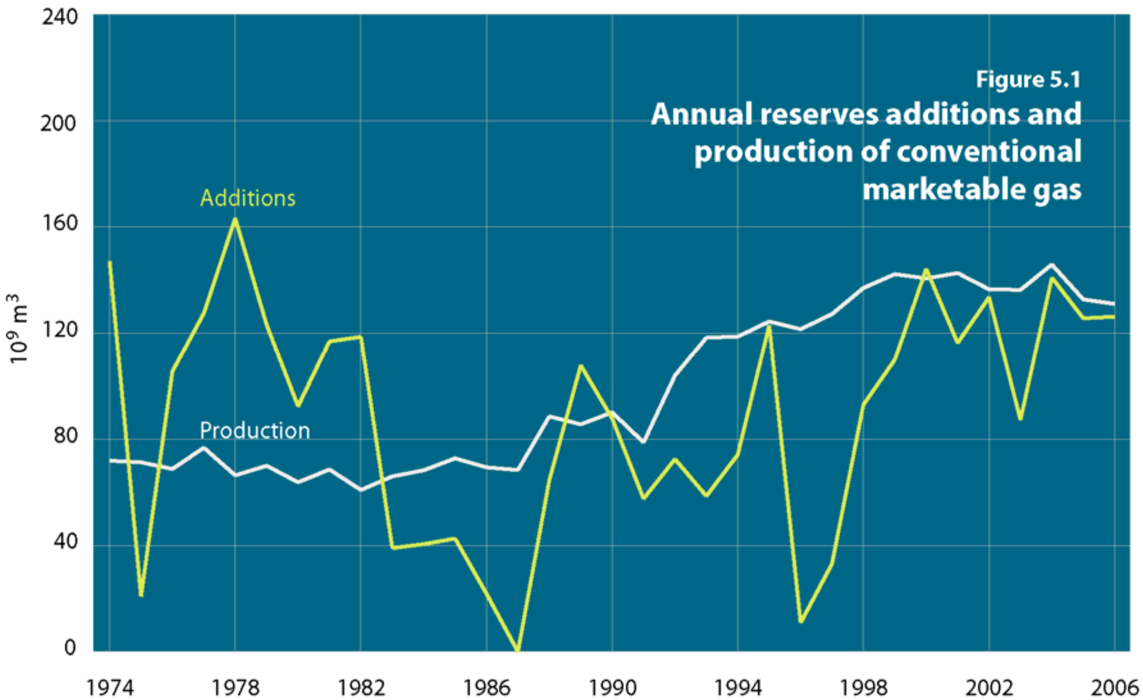
Detailed pool-by-pool reserves data are available on CD. See Appendix C.

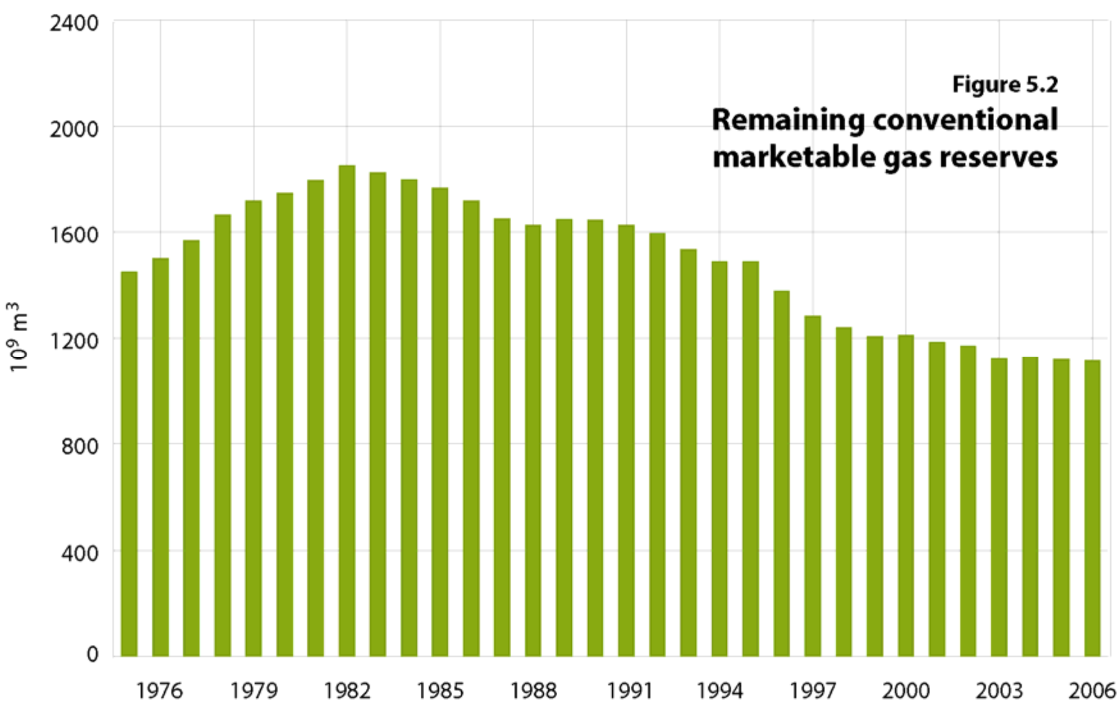
Table 5.1. Highlights of marketable gas reserve changes (10^9 m^3)

	Gross heating value (MJ/m^3)	2006 volume	2005 volume	Change
Initial established reserves		4 798.7	4 672.4	+126.3
Cumulative production		3 683.5	3 552.4	+ 131.1[a]
Remaining established reserves downstream of field plants				
“as is”	39.0	1 115.2	1 120.0	-4.8
at standard gross heating value	37.4	1 136.3	1 164.0	
Minus liquids removed at straddle plants		35.4	34.0	+1.4
Remaining established reserves “as is”	37.3	1 079.6 (38.3 tcf)[b]	1 086.0 (38.4 tcf)[b]	-6.4
at standard gross heating value	37.3	1 075.7	1 081.0	

[a] May differ from actual annual production and also contains minor volumes of coalbed methane production.
[b] tcf – trillion cubic feet.

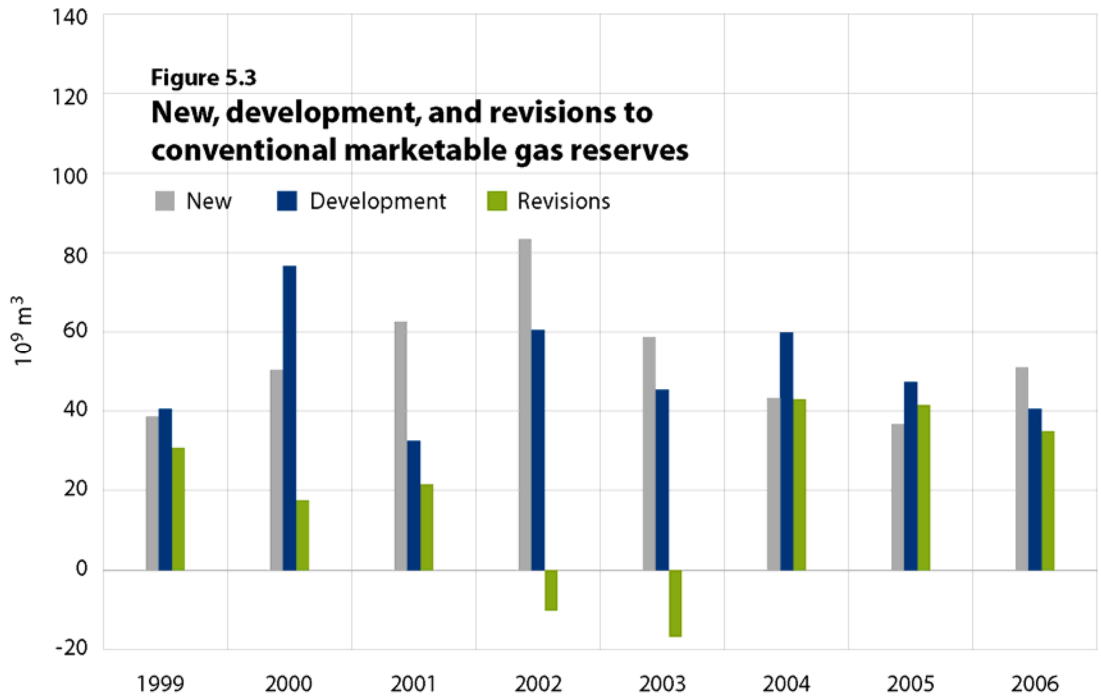
Annual reserves additions and production of natural gas since 1974 are depicted in **Figure 5.1**. It shows that total reserves additions have failed to keep pace with production, which has increased significantly since 1992. As illustrated in **Figure 5.2**, Alberta's remaining established reserves of marketable gas decreased by about 40 per cent since 1982, but has remained constant since 2003.





5.1.2 Annual Change in Marketable Gas Reserves

Figure 5.3 shows the breakdown of annual reserves additions into new, development, and reassessment from 1999 to 2006. Initial established reserves increased by 126.3 10^9 m^3 from year-end 2005. This increase includes the addition of 51.0 10^9 m^3 attributed to new pools booked in 2006, 40.5 10^9 m^3 from development of existing pools, and a positive net reassessment of 34.8 10^9 m^3. Reserves added through drilling alone totalled 91.5 10^9 m^3, replacing 68 per cent of Alberta's 2006 production of 133.7 10^9 m^3. These breakdowns are not available prior to 1999. Historical reserves growth and production data since 1966 are shown in Appendix B, Table B.8.



During 2006, EUB staff carried out a number of projects to review pools that had not been re-evaluated for some time or appeared to have reserves under- or overbooked based on their reserve life index. The projects that resulted in large reserve changes are summarized below, and pools with major changes are listed in **Table 5.2**.

- Review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in reserves reduction of 29.8 10^9 m^3. This reduction is due to the re-evaluation of reserves by production decline and adjustment of recovery factors. Over the past six years, some 205 10^9 m^3 of reserves were added to Southeastern Alberta Gas System due to continued drilling and development in the area. In 2006, a detailed review of pools within this area by production decline analysis shows that most of the larger and older pools are in decline, resulting in the downward adjustment of reserves. Some of the larger pools are listed in **Table 5.2**.

- About 425 producing pools that showed reserves-to-production ratios over 25 years were evaluated, and reserves were reduced for these pools by 26.3 10^9 m^3.

- Some 1356 producing pools with reserves-to-production ratios of less than two years were evaluated and reserves were increased by 15.7 10^9 m^3. Production decline analysis was used in estimating reserves for these pools.

- Other pools with significant changes that are listed in **Table 5.2** are Blackstone Beaverhill Lake A Pool, with a decrease of 3.0 10^9 m^3, the Provost Viking, Belly River MU#1 Pool, with a decreases of 4.0 10^9 m^3, the Rainbow Bluesky A and Banff G Pool, with an increase of 2.1 10^9 m^3, and the Wild River Cardium, Dunvegan, Fort St. John, and Bullhead MU#1 Pool, with an increase of 2.6 10^9 m^3.

- The 36 pools listed in **Table 5.2** account for reserve additions of 23 10^9 m^3, or 18.2 per cent of all additions for 2006.

Figure 5.4 illustrates a comparison in marketable gas reserves growth between 2006 and 2005 by modified PSAC areas. The most significant growth was in Area 2, which accounted for 66 per cent of the total annual change for 2006. Some pools within PSAC Area 2 that contributed to this increase in reserves are the Rundle A, B, C, Q, and R Pool, Limestone Wabamun A Pool, Ricinus Cardium A Pool, and Wild River Cardium, Dunvegan, Fort St. John, and Bullhead MU#1 Pool, for a total of 8.0 10^9 m^3.

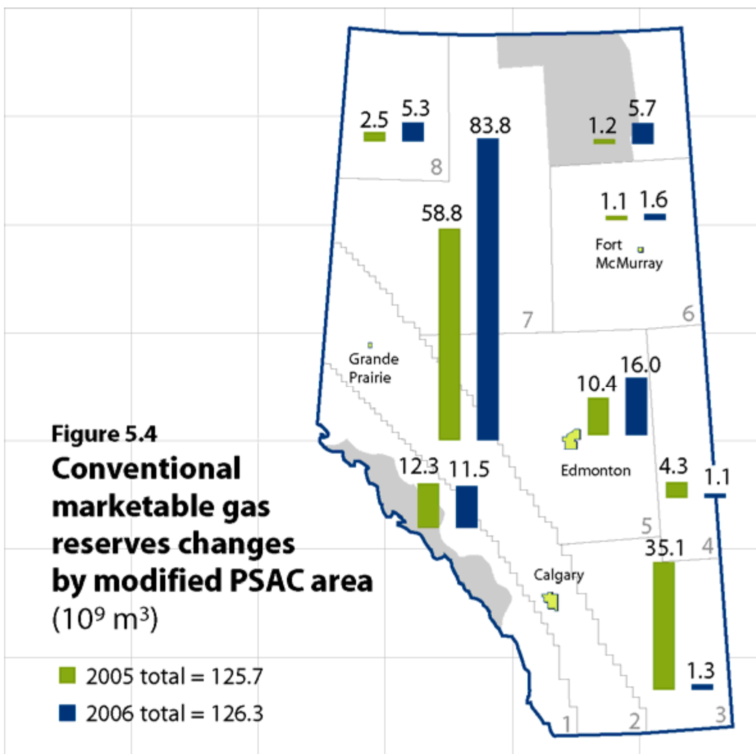


Figure 5.4
Conventional marketable gas reserves changes by modified PSAC area
(10^9 m^3)

Table 5.2. Major natural gas reserve changes, 2006

Pool	Initial established reserves (10^6 m^3) 2006	Change	Main reasons for change
Atlee-Buffalo Southeastern Alberta Gas System (MU)	9 890	-2 135	Re-evaluation of initial volume in place
Bantry Southeastern Alberta Gas System (MU)	32 675	-2 067	Re-evaluation of initial volume in place
Benjamin Rundle A, B, C,Q & R	11 530	+2 310	Re-evaluation of initial volume in place and recovery factor
Bighorn Turner Valley C	2 515	+1 075	Re-evaluation of initial volume in place
Blackstone Beaverhill Lake A	18 029	-3 044	Re-evaluation of initial volume in place
Brazeau River Viking, Mannville & Jurassic Mu #1	190	-654	Re-evaluation of initial volume in place
Brazeau River Elkton-Shunda A	30 680	-1 080	Re-evaluation of initial volume in place
Brown Creek Turner Valley A, B, C & D	2 205	+573	Re-evaluation of initial volume in place
Cessford Southeastern Alberta Gas System (MU)	18 191	-3 940	Re-evaluation of initial volume in place
Chickadee Upper Mannville A, D, E, F, G & Gething D	3 640	+1 390	Re-evaluation of initial volume in place
Chime Second White Specks A and Dunvagen C & E	18	-576	Re-evaluation of initial volume in place
Coleman Rundle A & Palliser B	7 370	-1 340	Re-evaluation of initial volume in place
Enchant Basal Belly River B and Second White Specks B	896	+532	Addition of new pool, development and re-evaluation of initial volume in place
Gadsby Edmonton, Belly River and Mannville MU #1	1 603	-707	Re-evaluation of initial volume in place
Hanna Second White Specks E	1 112	-656	Re-evaluation of initial volume in place
Jumping Pound West Rundle A & B	38 800	+1 600	Re-evaluation of initial volume in place
Knopcik Halfway N and Montney A	5 950	-1 016	Re-evaluation of initial volume in place
Leland Cadotte A & C and Cadomin A	4 038	+927	Re-evaluation of initial volume in place and recovery factor
Limestone Rundle A & B and Leduc C	16 720	+933	Re-evaluation of initial volume in place

(continued)

Table 5.2. Major natural gas reserve changes, 2006 (concluded)

Pool	Initial established reserves (10^6 m^3) 2006	Change	Main reasons for change
Limestone Wabamun A	8 652	+1 400	Re-evaluation of initial volume in place
Limestone Nisku A and Leduc A	1 995	-931	Re-evaluation of initial volume in place and recovery factor
Marsh Leduc A	1 160	+813	Re-evaluation of initial volume in place
Medicine Hat Southeastern Alberta Gas System (MU)	15 609	-1 340	Re-evaluation of initial volume in place
Medicine River Mannville and Jurassic MU#1	6 026	+1 332	Re-evaluation of initial volume in place
Nevis Edmonton and Belly River MU#1	2 620	+1 133	Re-evaluation of initial volume in place and recovery factor
Provost Viking, Belly River and Mannville MU#1	49 171	-3 952	Re-evaluation of initial volume in place and recovery factor
Rainbow Bluesky A and Banff G	10 450	+2090	Addition of new pool and re-evaluation of initial volume in place
Retlaw Basal Belly River I, K and Second White Specks B	699	-688	Re-evaluation of initial volume in place
Ricinus Cardium A	10 775	+1 678	Re-evaluation of initial volume in place
Stolberg Rundle A, B, C & D	8 888	+965	Addition of new pool and re-evaluation of initial volume in place
Sundance Smokey, Dunvagen, Fort St. John & Bullhead MU#1	47	-1263	Re-evaluation of initial volume in place
Verger Southeastern Alberta Gas System (MU)	15 976	-2 859	Re-evaluation of initial volume in place and recovery factor
Westrose South Belly River, Mannville and Rundle MU#1	23 508	+1 456	Re-evaluation of initial volume in place
Wild River Cardium, Dunvagen, Fort St. John & Bullhead MU#1	25 500	+2 598	Addition of new pools and re-evaluation of initial volume in place
Wintering Hills Southeastern Alberta Gas System (MU)	4 857	-1 874	Re-evaluation of initial volume in place
Wizard Lake D-3A	6 700	+1 964	Re-evaluation of initial volume in place

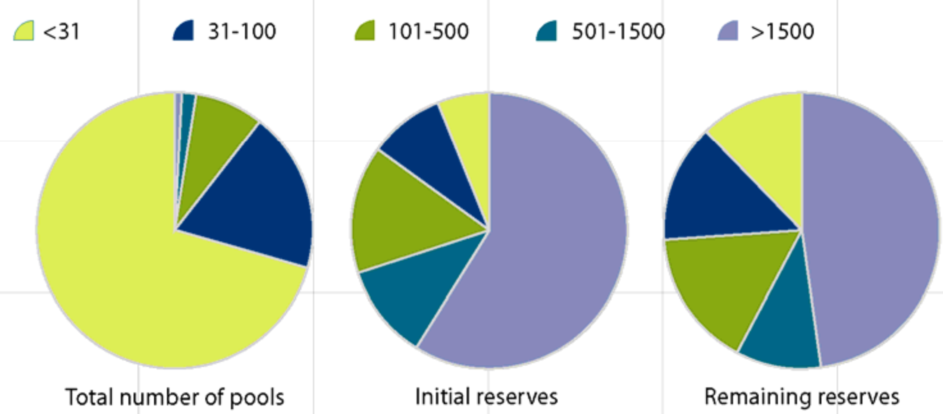
5.1.3 Distribution of Natural Gas Reserves by Pool Size

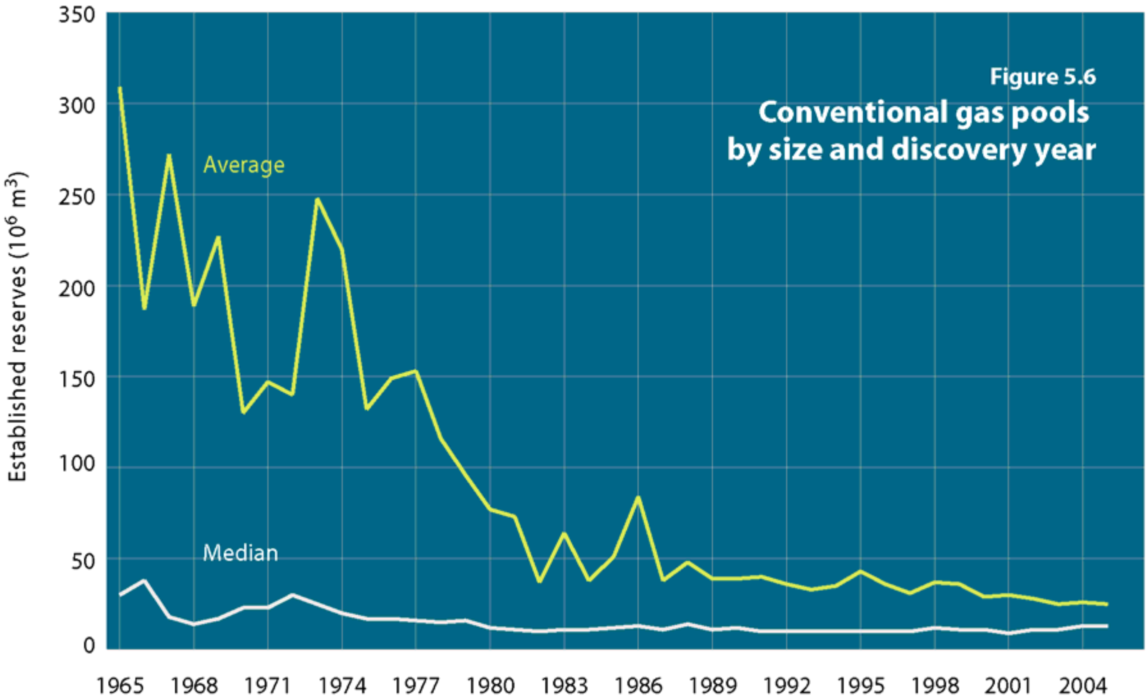
The distribution of marketable gas reserves by pool size is shown in **Table 5.3**. For the purposes of this table, commingled pools are considered as one pool and multifield pools are considered on a field basis. The data show that pools with reserves of 30 million (10^6) m^3 or less, while representing 70.5 per cent of all pools, contain only 12 per cent of the province's remaining marketable reserves. Similarly, the largest pools, while representing only 1 per cent of all pools, contain 48 per cent of the remaining reserves. **Figure 5.5** shows by percentage and by size distribution the total number of pools, initial reserves, and remaining reserves, as listed in **Table 5.3**. **Figure 5.6** depicts natural gas pool size by discovery year since 1965 and illustrates that the median pool size has remained fairly constant at about 16 10^6 m^3 for many years, while the average size declined from about 300 10^6 m^3 in 1965 to 45 10^6 m^3 in 1987 and has since declined further to about 24 10^6 m^3 in 2006.

Table 5. 3. Distribution of natural gas reserves by pool size, 2006

Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
3000+	198	0.5	2 493	52	467	42
1501-3000	160	0.4	339	7	71	6
1001-1500	167	0.4	204	4	41	4
501-1000	518	1.2	356	7	67	6
101-500	3 469	8.3	713	15	179	16
31-100	7 870	18.7	417	9	158	14
Less than 31	29 071	70.5	277	6	132	12
Total	42 071	100.0	4 799	100	1 115	100

Figure 5.5
Distribution of conventional gas reserves by size (10^6 m^6)





5.1.4 Geological Distribution of Reserves

The distribution of reserves by geological period is shown graphically in **Figure 5.7**, and a detailed breakdown of gas in place and marketable gas reserves by formation is given in Appendix B, **Table B.9**. The Upper and Lower Cretaceous period accounts for some 70.5 per cent of the province's remaining established reserves of marketable gas and is important as a source of future natural gas. The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 26.1 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 18.3 per cent, and the Mississippian Rundle, with 8.0 per cent. Together, these strata contain 52.4 per cent of the province's remaining established reserves. The percentages of remaining reserves in these geological strata have remained fairly constant over the last five years.

5.1.5 Reserves of Natural Gas Containing Hydrogen Sulphide

Natural gas that contains greater than 0.01 per cent hydrogen sulphide (H_2S) is referred to as sour in this report. As of December 31, 2006, sour gas accounts for some 21 per cent (234 10^9 m^3) of the province's total remaining established reserves and about 33 per cent of natural gas marketed in 2006. This 33 per cent is similar to previous years. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2006 is 8.9 per cent.

The distribution of reserves for sweet and sour gas (**Table 5.4**) shows that 172 10^9 m^3, or about 74 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 5.8** indicates that the proportion of remaining marketable reserves of sour to sweet gas since 1984 has remained fairly constant, between 20 and 25 per cent of the total. The distribution of sour gas reserves by H_2S content is shown in **Table 5.5** and indicates that 51 10^9 m^3, or 22 per cent, of sour gas contains H_2S concentrations greater than 10 per cent, while 47 per cent (111 10^9 m^3) contains concentration of less than 2 per cent.

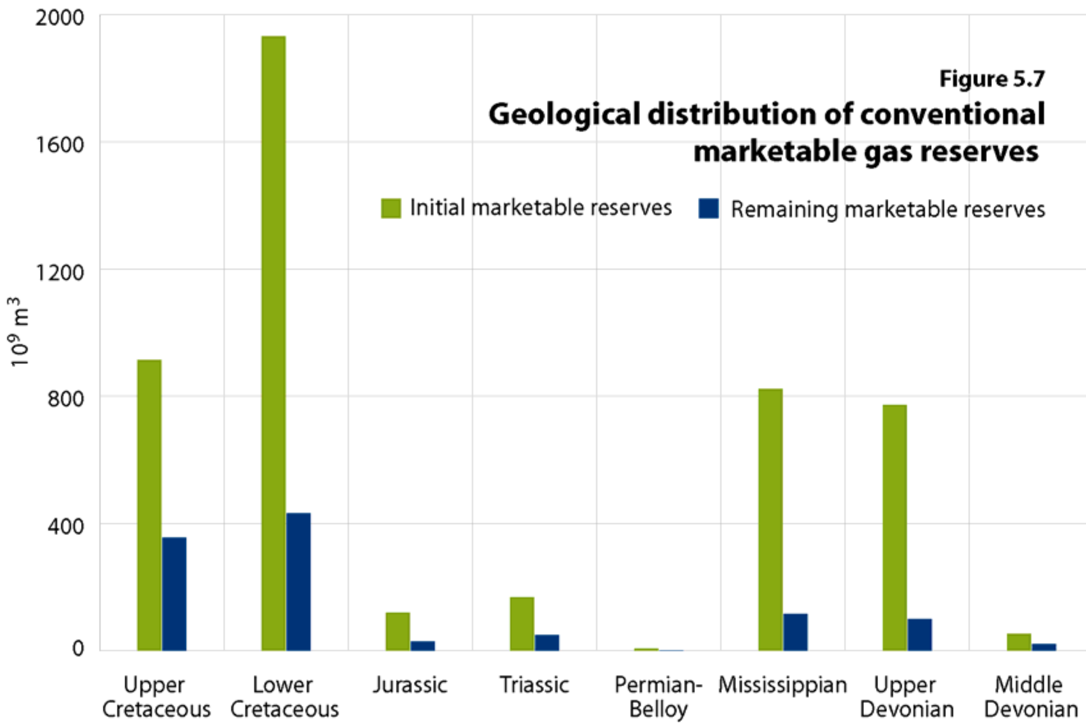


Table 5. 4. Distribution of sweet and sour gas reserves, 2006

Type of gas	Marketable gas (10^9 m^3) Initial established reserves	Cumulative production	Remaining established reserves	Percentage Initial established reserves	Remaining established reserves
Sweet					
Associated & solution	607	473	134	13	12
Nonassociated	2 623	1 876	747	54	67
Subtotal	3 230	2 349	881	67	79
Sour					
Associated & solution	429	366	62	9	6
Nonassociated	1 140	968	172	24	15
Subtotal	1569	1 334	234	33	21
Total	4 799 (170)[b]	3 683 (131)[b]	1 115[a] (39.6)[b]	100	100

[a] Reserves estimated at field plants.
[b] Imperial equivalent in trillions of cubic feet at 14.65 pounds per square inch absolute and 60˚F.

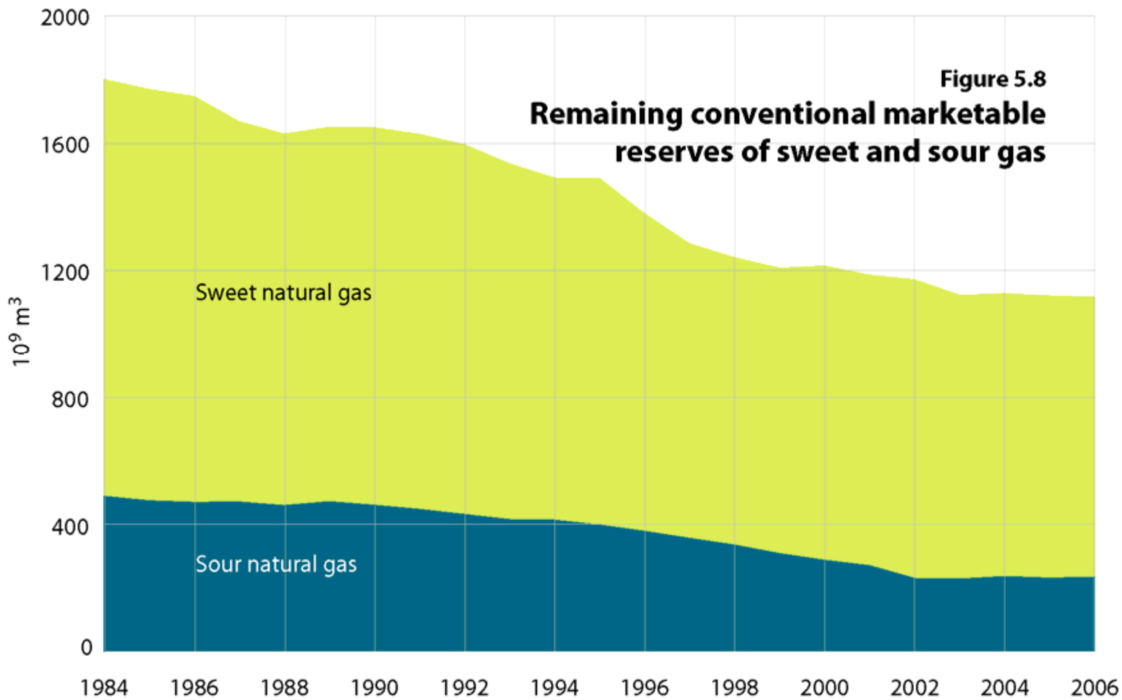


Table 5.5. Distribution of sour gas reserves by H_2S content, 2006

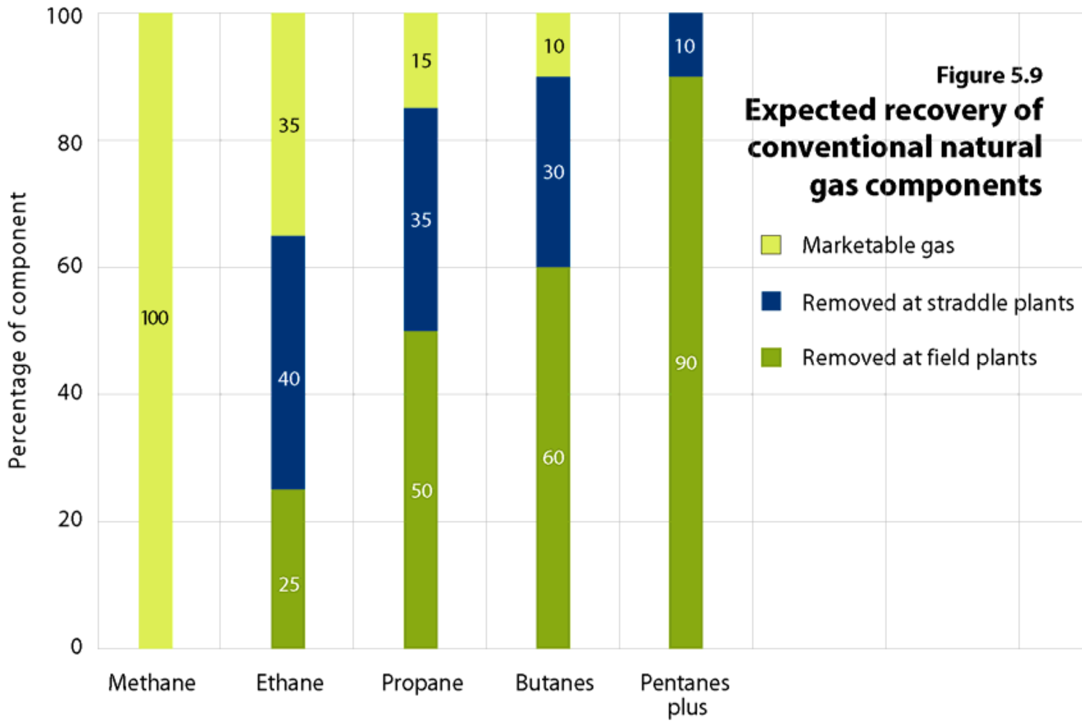
H_2S content in raw gas	Initial established reserves ($10^9\ m^3$) Associated & solution	Nonassociated	Remaining established reserves ($10^9\ m^3$) Associated & solution	Nonassociated	Total	%
Less than 2	300	399	46	65	111	47
2.00-9.99	88	385	11	61	72	31
10.00-19.99	29	204	4	24	28	12
20.00-29.99	11	50	1	10	11	5
Over 30	0	102	0	12	12	5
Total	429	1 140	62	172	234	100
Percentage	27	73	26	74		

5.1.6 Reserves of Retrograde Condensate Pools

Retrograde gas pools are pools rich in liquids that reinject dry gas to maintain reservoir pressure and maximize liquid recovery. Reserves of major retrograde condensate pools are tabulated on both energy content and a volumetric basis. The initial energy in place, recovery factor, and surface loss factor (both factors on an energy basis), as well as the initial marketable energy for each pool, are listed in Appendix B, Table B.10. The table also lists raw and marketable gas heating values used to convert from a volumetric to an energy basis. The volumetric reserves of these pools are included in the Gas Reserves and Basic Data table, which is on the companion CD to this report (see Appendix C).

5.1.7 Reserves Accounting Methods

The EUB, in its Gas Reserves Data file, books remaining marketable gas reserves on a pool-by-pool basis initially on volumetric determination of in-place resources and application of recovery efficiency and surface loss. Subsequent reassessment of reserves is made as new information becomes available using additional geological data, material balance, and production decline analysis. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids at field plants, as shown in **Figure 5.9.** A minimum 5 per cent is added to account for loss due to lease fuel (4 per cent) and flaring. Therefore, marketable gas reserves of individual pools on the EUB's gas reserves database reflect expected recovery after processing at field plants.



For about 80 per cent of Alberta's marketable gas (notable exceptions being Alliance Pipeline and some of the mostly dry Southeastern Alberta gas), additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. As the removal of these liquids cannot be tracked back to individual pools, a gross adjustment for these liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These reserves therefore represent the volume and average heating content of gas available for sale after removal of liquids from both field and straddle plants.

It is expected that some 35.4 10^9 m^3 of liquid-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 1115.2 10^9 m^3 to 1079.6 10^9 m^3 and the thermal energy content from 43.4 to 40.2 exajoules.

Figure 5.9 also shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants. Therefore, the EUB estimates reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in Section 6.

5.1.8 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in Appendix B, **Table B.11**. Each multifield pool shows the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool.

5.1.9 Ultimate Potential

In March 2005, the EUB and the National Energy Board (NEB) jointly released *Report 2005-A*: *Alberta's Ultimate Potential for Conventional Natural Gas* (EUB/NEB 2005 Report), an updated estimate of the ultimate potential for conventional natural gas. The Boards adopted the medium case representing an ultimate potential of 6276 10^9 m^3 (223 trillion cubic feet). This estimate does not include unconventional gas, such as CBM. **Figure 5.10** shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth to 2006 equals 4.9 trillion (10^{12}) m^3. **Figure 5.11** plots production and remaining established reserves of marketable gas compared to the estimate of ultimate potential.

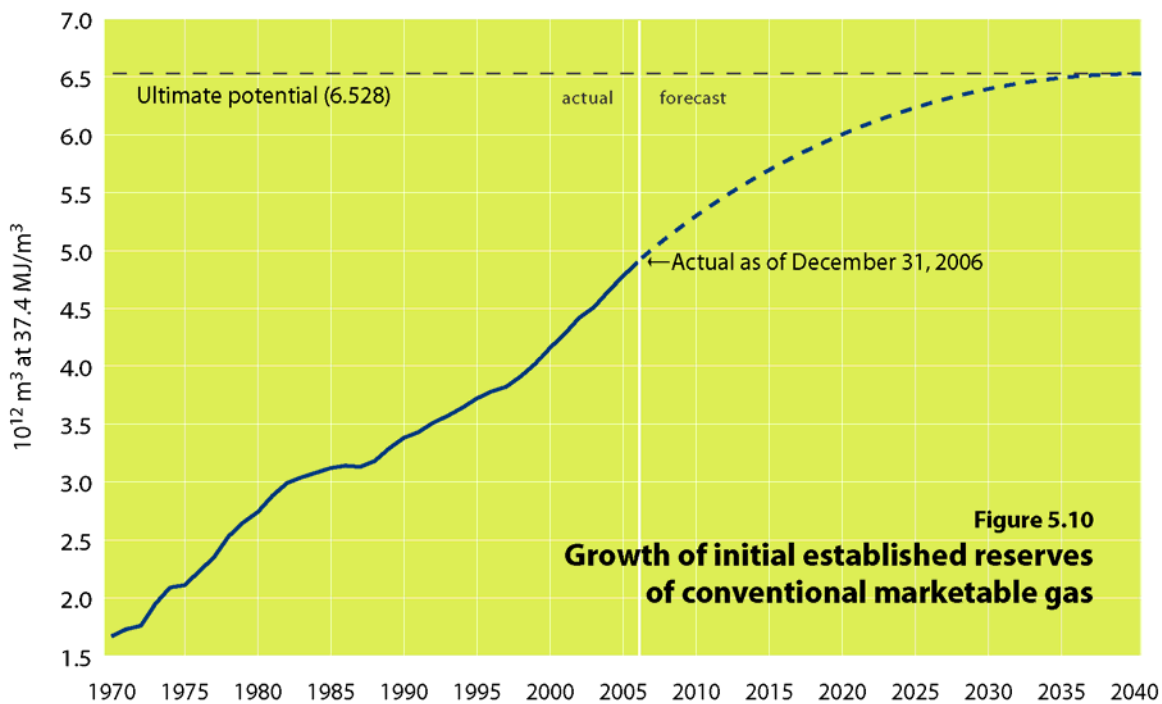


Figure 5.10
Growth of initial established reserves of conventional marketable gas

Table 5.6 provides details on the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 4799 10^9 m^3, or 76.5 per cent of the ultimate potential of 6276 10^9 m^3, has been discovered as of year-end 2006. This leaves 1477 10^9 m^3, or 23.5 per cent, as yet-to-be-discovered reserves. Cumulative production of 3683 10^9 m^3 at year-end 2006 represents 58.6 per cent of the ultimate potential, leaving 2592 10^9 m^3, or 41 per cent, available for future use.

Table 5.6. Remaining ultimate potential of marketable gas, 2006 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	@ 37.4 MJ/m^3
Yet to be established		
Ultimate potential	6 276	6 528
Minus initial established	-4 798	-4 991
	1 478	1 536
Remaining established		
Initial established	4 798	4 990
Minus cumulative production	-3 683	-3 831
	1 115	1 159
Remaining ultimate potential		
Yet to be established	1 478	1 536
Plus remaining established	+1 115	+1 159
	2593	2 695

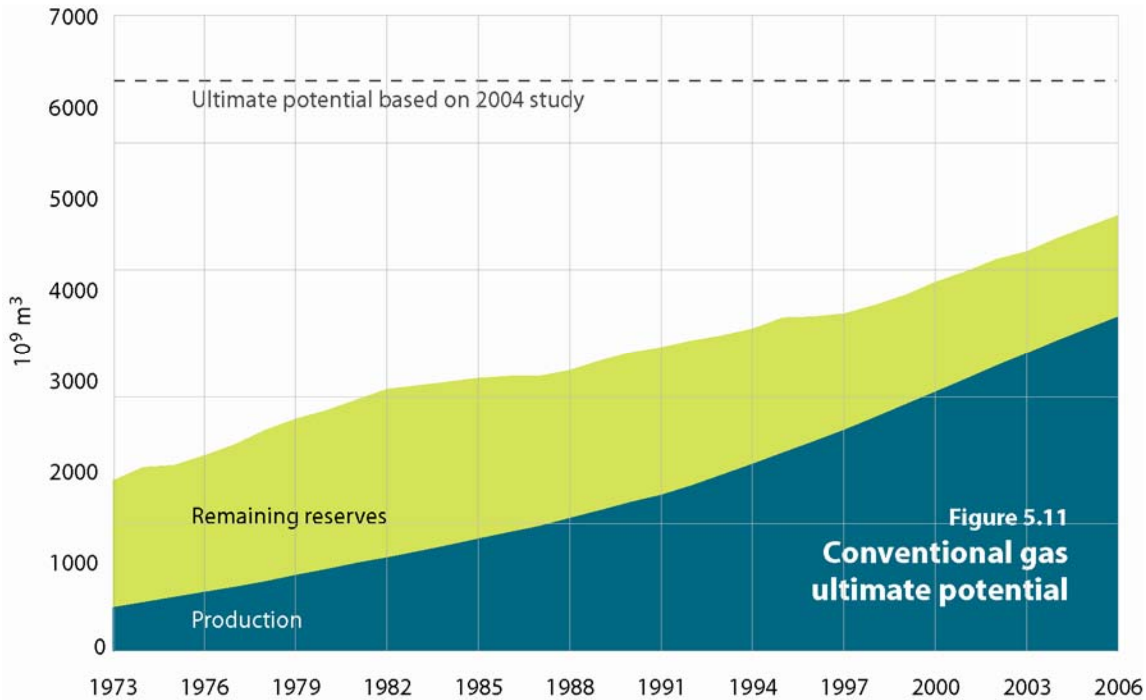


Figure 5.11
Conventional gas ultimate potential

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure 5.12**. It shows that the Western Plains (Area 2) contains about 38 per cent of both the remaining established reserves and the yet-to-be-established reserves. Although the majority of gas wells are being drilled in the Southern Plains (Areas 3, 4, and 5), **Figure 5.12** shows that based on the EUB/NEB 2005 Report, Alberta natural gas supplies will continue to depend on significant new discoveries in the Western Plains.

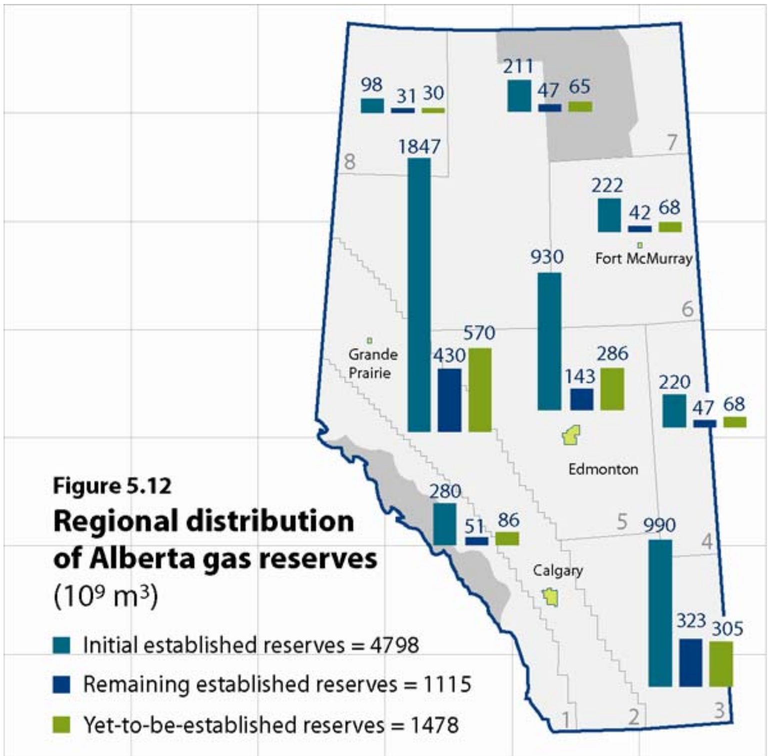
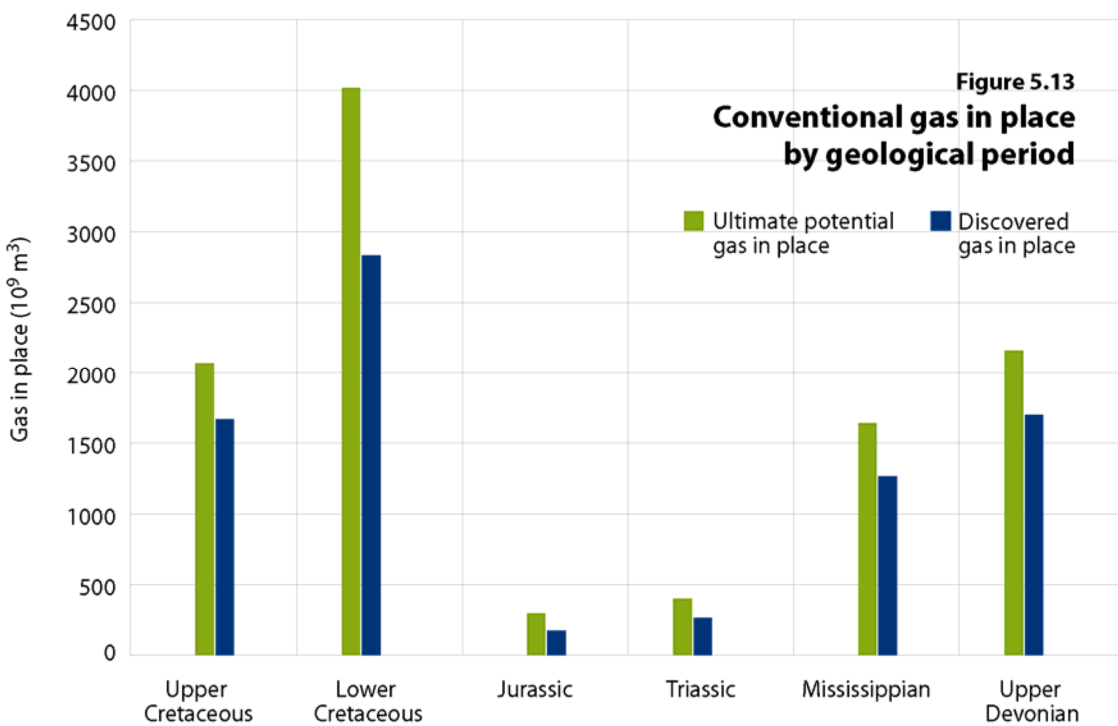


Figure 5.13 shows by geological period the discovered and ultimate potential gas in place for year-end 2005 (EUB/NEB 2005 Report). It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous.



5.2 Supply of and Demand for Conventional Natural Gas

In projecting natural gas production, the EUB considers three components: expected production from existing gas wells, expected production from new gas well connections, and gas production from oil wells. The EUB also takes into account its estimates of the remaining established and yet-to-be-established reserves of natural gas in the province.

The EUB reviews the projected demand for Alberta natural gas annually. The focus of these reviews is on intra-Alberta natural gas use, and a detailed analysis is undertaken of many factors, such as population growth, industrial activity, alternative energy sources, and environmental factors that influence natural gas consumption in the province.

5.2.1 Natural Gas Supply

Alberta produced 139.2 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its conventional gas and oil wells in 2006, similar to the previous year's volumes. As noted in Section 4, Alberta also produced 4.7 10^9 m^3 of coalbed methane (CBM). The CBM volume includes some production of conventional gas, as the coals are often interbedded with conventional gas reservoirs. In 2006, total natural gas production increased to 143.9 10^9 m^3, an increase of 1.3 per cent, compared to 142.1 10^9 m^3 in 2005.[1]

Natural gas prices and their volatility, drilling activity, the location of Alberta's reserves, the production characteristics of today's wells, and market demand are the major factors affecting Alberta natural gas production.

Market forces are driving record levels of drilling, and industry is challenged to replace production from existing wells. The high decline rate of production from existing wells and the lower initial productivities of new gas wells are having an impact on current production levels.

The drilling focus in recent years has been heavily weighted towards the shallow gas plays of Southeastern Alberta. This region has seen an increasing number of natural gas wells over the last 10 years due to the lower risk, lower cost of drilling, and quick tie-in times. The conventional marketable natural gas production volumes for 2006 stated in **Table 5.7** have been calculated based on "Supply and Disposition of Marketable Gas" in *ST3: Alberta Energy Resource Industries Monthly Statistics.*

High demand for Alberta natural gas in recent years has led to a considerable increase in the level of drilling in the province. Producers are using strategies such as infill drilling to maximize production levels. The number of successful gas wells drilled in Alberta in the last two years is shown by geographical area (modified PSAC area) in **Figure 5.14**.

In 2006, some 12 062 conventional natural gas wells were drilled in the province, a decrease of 9 per cent from 2005 levels. A large portion of gas drilling has taken place in Southeastern Alberta, representing 44 per cent of all conventional natural gas wells drilled in 2006. The commodity price declines that took place in late 2006 are responsible for a slowdown in gas drilling, which is expected to continue well into 2007.

[1] Natural gas produced in Alberta has an average heating value of about 38.9 MJ/m^3.

Table 5.7. Marketable natural gas volumes (10^6 m^3)

Marketable gas production	2006
Total gas production	167 385.1
Minus CBM production	-4 658.3
Total conventional gas production	162 726.8
Minus storage withdrawals	3 629.4
Raw gas production	159 097.4
Minus injection total	-5100.1
Net raw gas production	153 997.0
Minus processing shrinkage – raw	-10 059.3
Minus flared – raw	-648.9
Minus vented – raw	-351.0
Minus fuel – raw	-11 690.7
Plus storage injections	6 068.6
Calculated marketable gas production at as-is conditions	133 691.3
Calculated marketable gas production @37.4 MJ/m^3	139 225.7

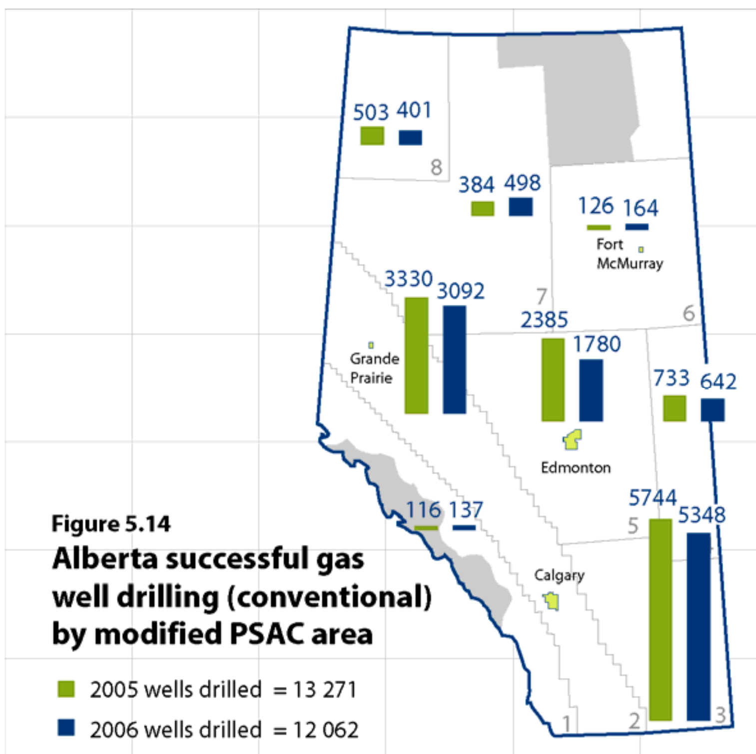


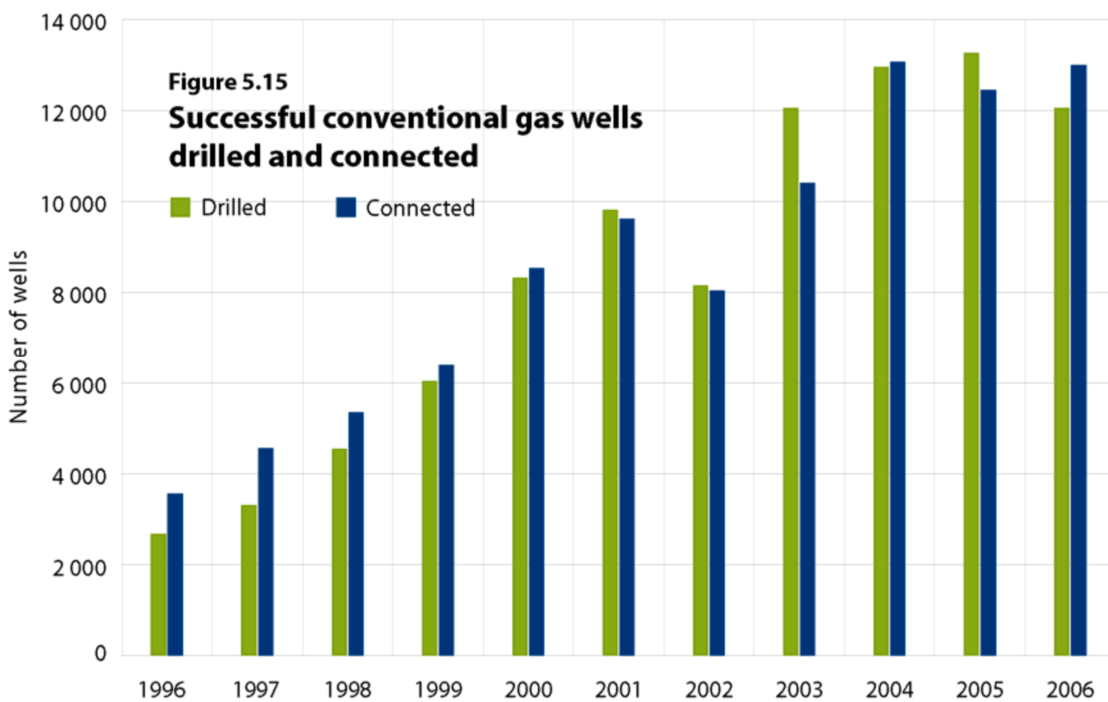
Figure 5.14
Alberta successful gas well drilling (conventional) by modified PSAC area

Drilling levels were down in all other areas of the province, with the exception of Area 1 (Foothills), Area 6 (Northeastern Alberta), and Area 7 (Northwestern Alberta). Note that the gas well drilling numbers represent wellbores that contain one or more geological occurrence capable of producing natural gas.

The number of successful natural gas wells drilled in Alberta from 1997 to 2006 is shown in **Figure 5.15**, along with the number of wells connected (placed on production) in each year. Both of these numbers are used as indicators of industry activity and future production. The definition of a gas well connection differs from that of a drilled well. While gas well drilling levels represent wellbores, well connections refer to geological (producing) occurrences within a well, and there may be more than one per well.

The number of natural gas wells connected in a given year historically tends to follow natural gas well drilling activity, indicating that most natural gas wells are connected shortly after being drilled. However, in the period 1994-2000, a much larger number of natural gas wells were connected than drilled. Alberta had a large inventory of nonassociated gas wells that had been drilled in previous years and were left shut in. Many of these wells were placed on production during the 1990s.

In 2006 the number of new wells connected was greater than the number of gas wells drilled. This was due to the time delay in bringing gas wells drilled in the previous year on production. As well, drilling activity levels fell in 2006 to levels last seen in 2003. The distribution of natural gas well connections and the initial operating day rates of the connected wells in the year 2006 are illustrated in **Figures 5.16** and **5.17** respectively.



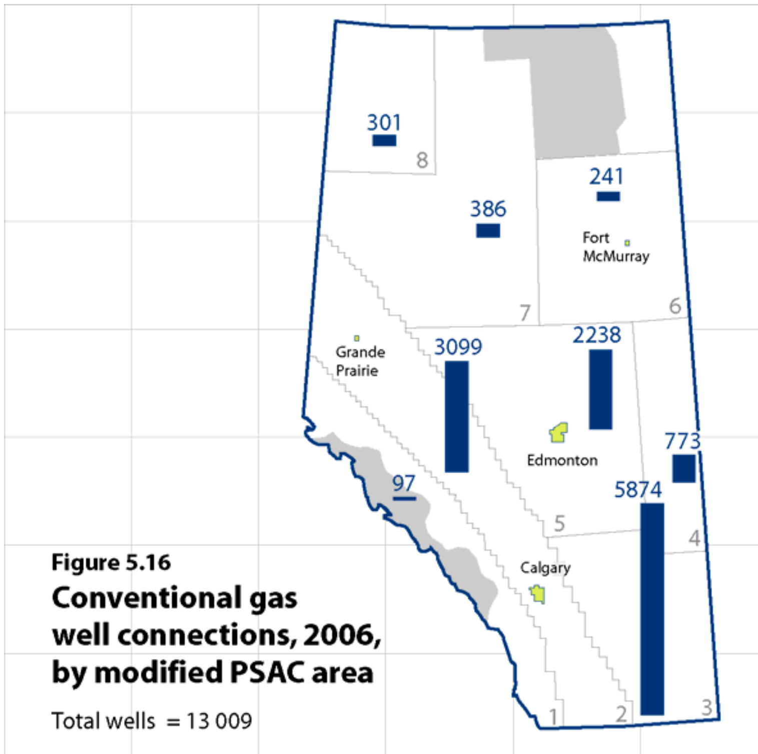


Figure 5.16
Conventional gas well connections, 2006, by modified PSAC area
Total wells = 13 009

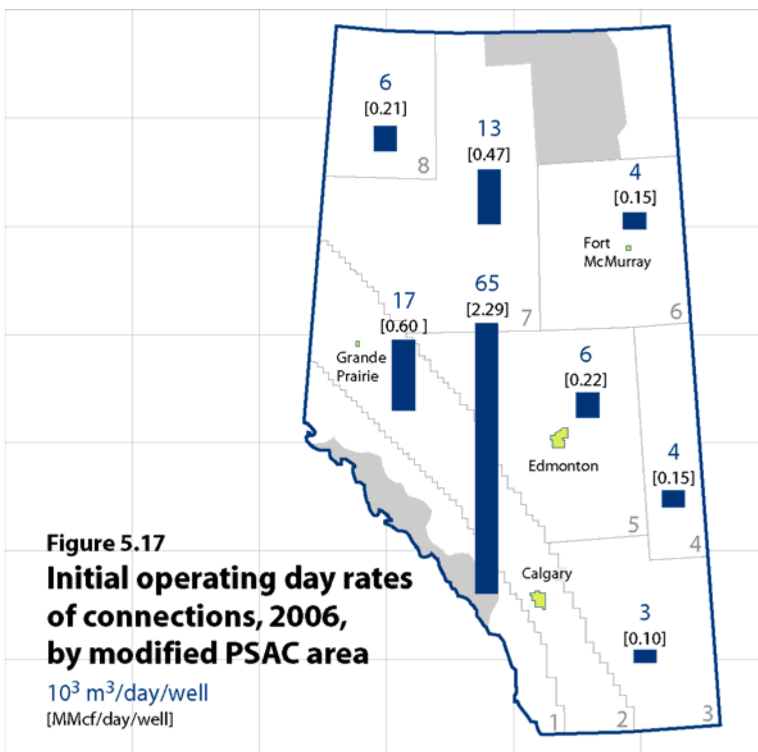
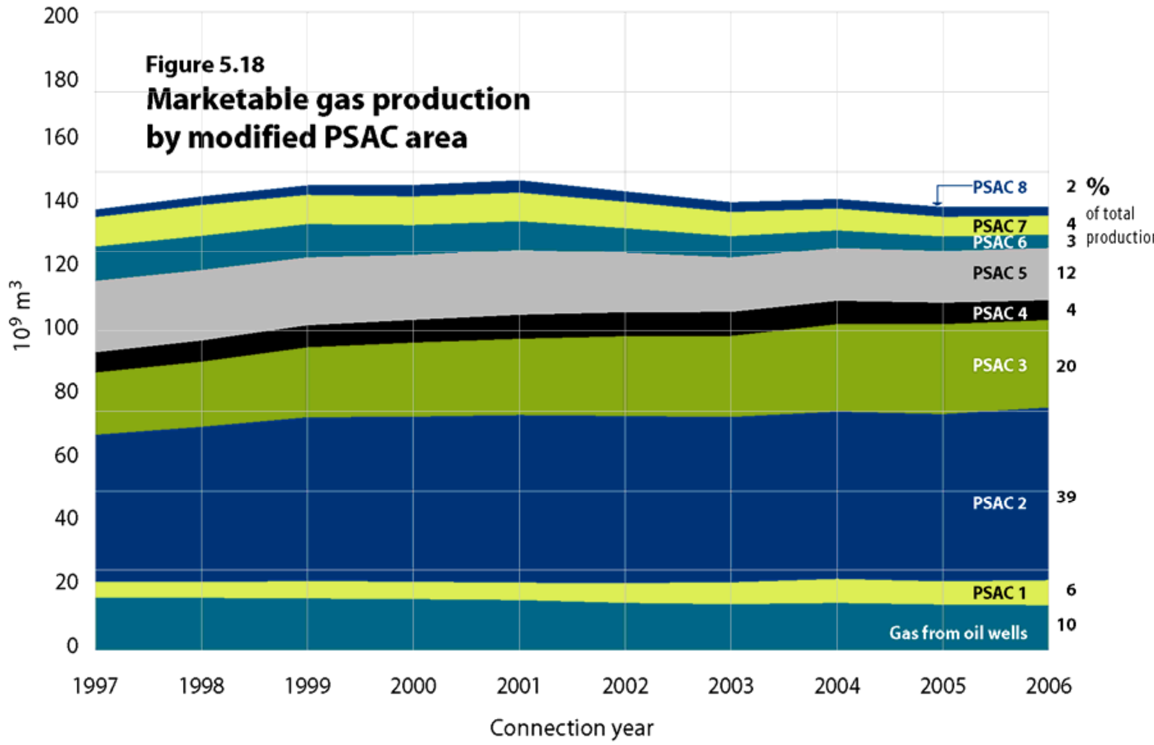


Figure 5.17
Initial operating day rates of connections, 2006, by modified PSAC area
10^3 m^3/day/well
[MMcf/day/well]

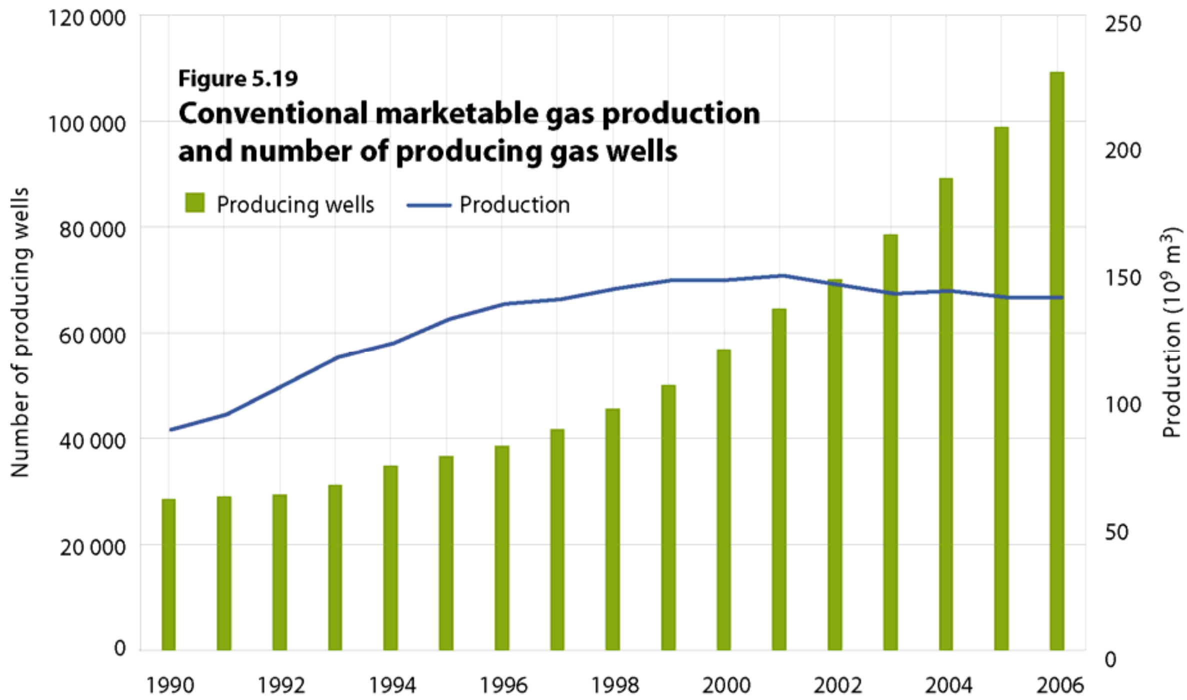
Figure 5.18 illustrates historical gas production from gas wells by geographical area. Area 1 (Foothills), Area 2 (Western Plains), and Area 5 (Central Alberta) experienced increases in production in 2006.

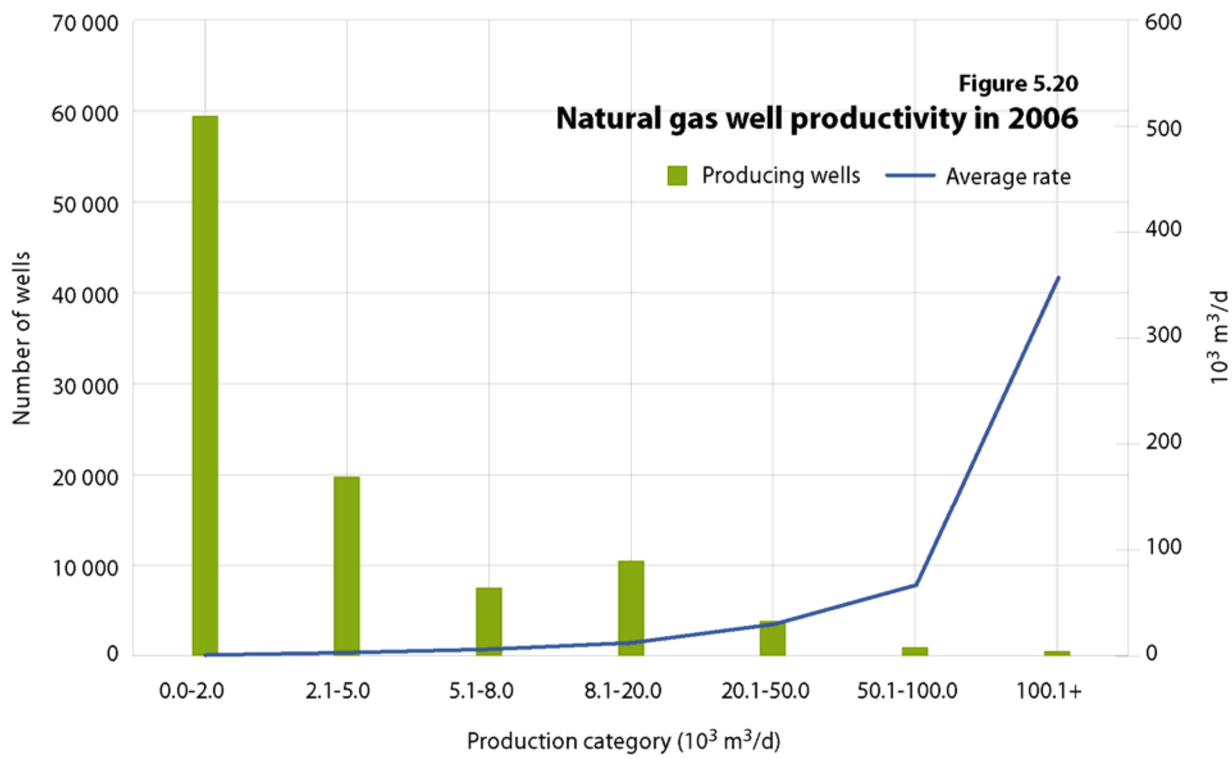


Conventional marketable gas production in Alberta from 1990 to 2006 is shown in **Figure 5.19**, along with the number of gas wells on production in each year. The number of producing gas wells has increased significantly year over year, while gas production has stabilized after reaching its peak in 2001. By 2006, the total number of producing gas wells increased to 109 300, from 28 500 wells in 1990. It now takes an increasing number of new gas wells each year to offset production declines in existing wells.

Average gas well productivity has been declining over time. As shown in **Figure 5.20**, about 62 per cent of the operating gas wells produce less than 2 thousand (10^3) m^3/d. In 2006, these 64 000 gas wells operated at an average rate of 0.8 10^3 m^3/d per well and produced less than 12 per cent of the total gas production. Less than 1 per cent of the total gas wells produced at rates over 100 10^3 m^3/d but contributed 16 per cent of the total production.

The historical raw gas production by connection year in Alberta is presented in **Figure 5.21**. Generally, a surface loss factor of around 13 per cent can be applied to raw gas production to yield marketable gas production. The bottom band in **Figure 5.21** represents gas production from oil wells. Each band above represents production from new gas well connections by year. The percentages on the right-hand side of the figure represent the share of that band's production to the total production from gas wells in 2006. For example, 12 per cent of gas production in 2006 came from wells connected in that year. The figure shows that in 2006, 55 per cent of gas production came from gas wells connected in the last five years.





Decline rates in natural gas production from new gas well connections from 1995 to 2004 have been evaluated after the wells drilled in a given year completed a full year of production.

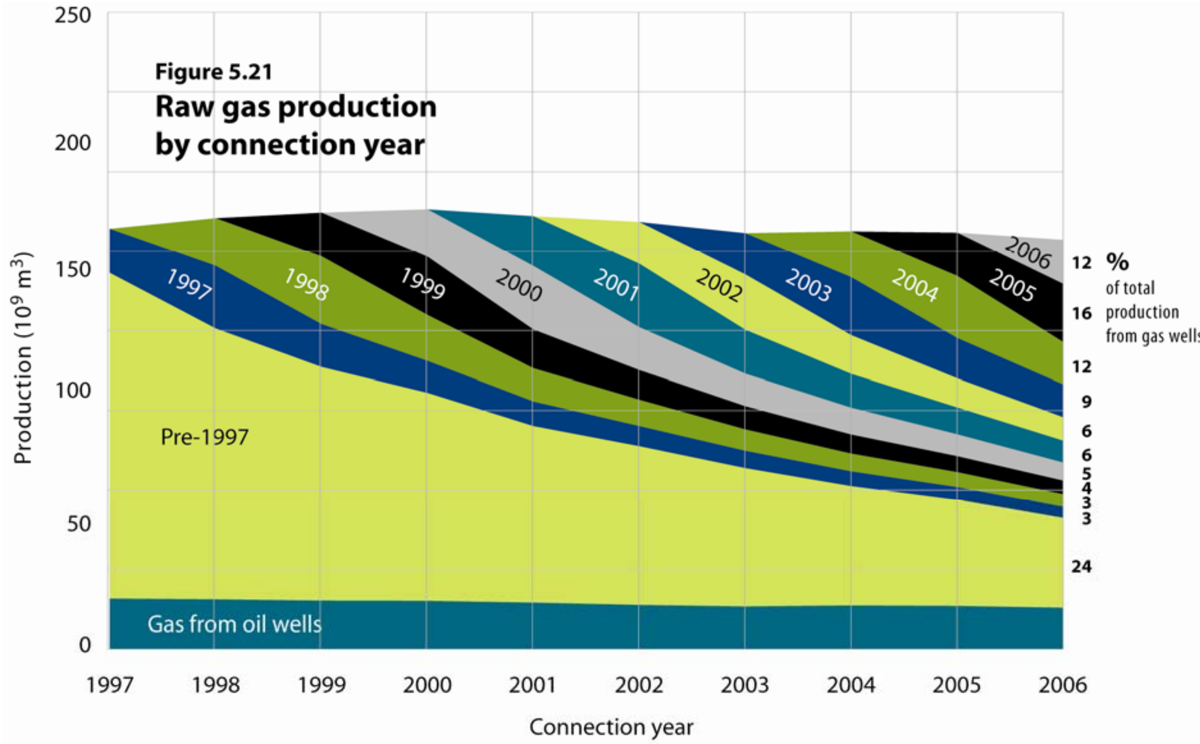


Figure 5.22 presents a comparison of raw natural gas production in Alberta to both Texas and Louisiana onshore over the past 40-year period. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta appears to be at that stage today. It is interesting to note that for both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production. However, over time production rates have been maintained at significant levels.

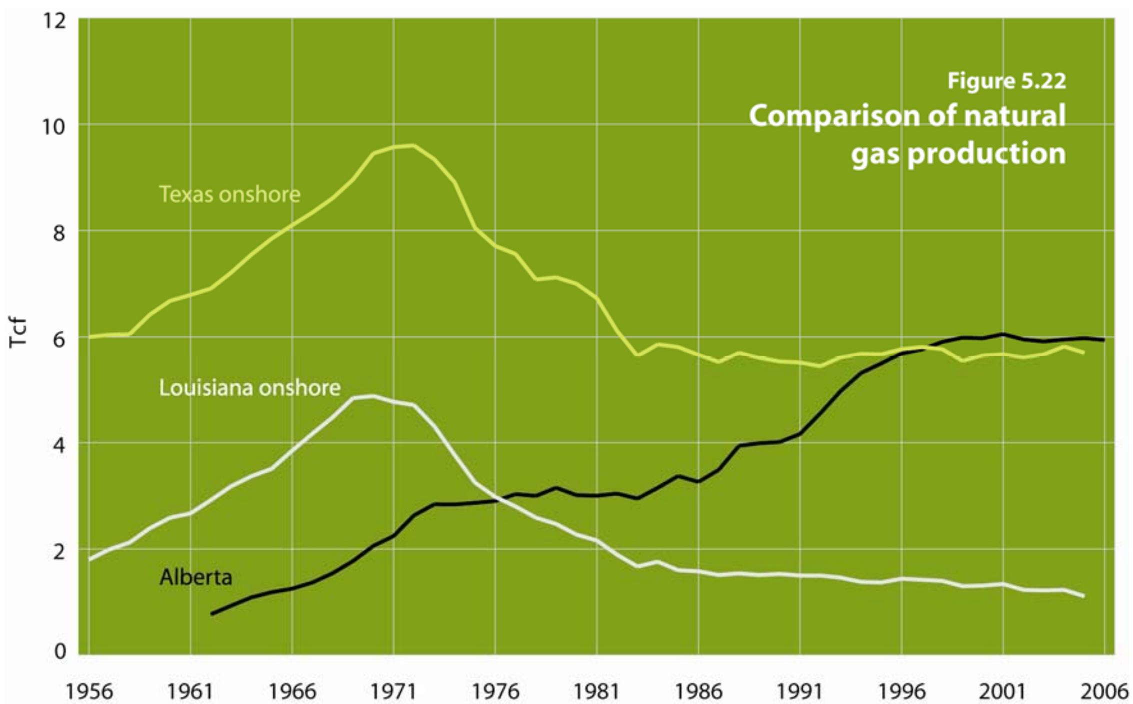
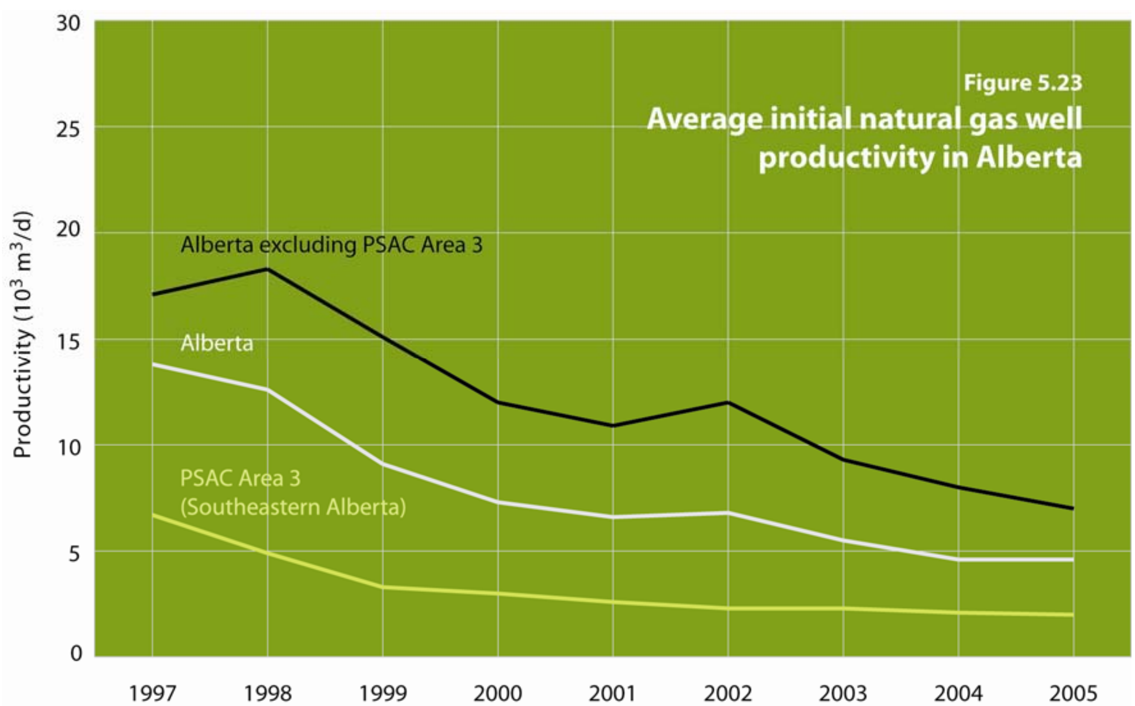


Table 5.8 shows decline rates for gas wells connected from 1995 to 2004 with respect to the first, second, third, and fourth year of decline. Wells connected from the mid-1990s forward exhibit steeper declines in production in the first three years compared to wells connected in the earlier years. However, by the fourth year of production the decline rates have not changed significantly over time. The decline rates tend to stabilize at about 18 per cent from the fourth year forward.

Table 5.8. Production decline rates for new well connections (%)

Year wells connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1995	30	25	23	19
1996	32	26	21	19
1997	32	25	24	18
1998	32	29	21	19
1999	34	24	21	17
2000	33	24	17	18
2001	31	23	21	18
2002	30	25	19	
2003	31	19		
2004	32			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 5.23** shows the average initial productivity (peak rate) of new wells by connection year for the province and for wells in Southeastern Alberta (Area 3). Average initial productivities for new wells excluding Southeastern Alberta are also shown in the figure. This chart shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average.



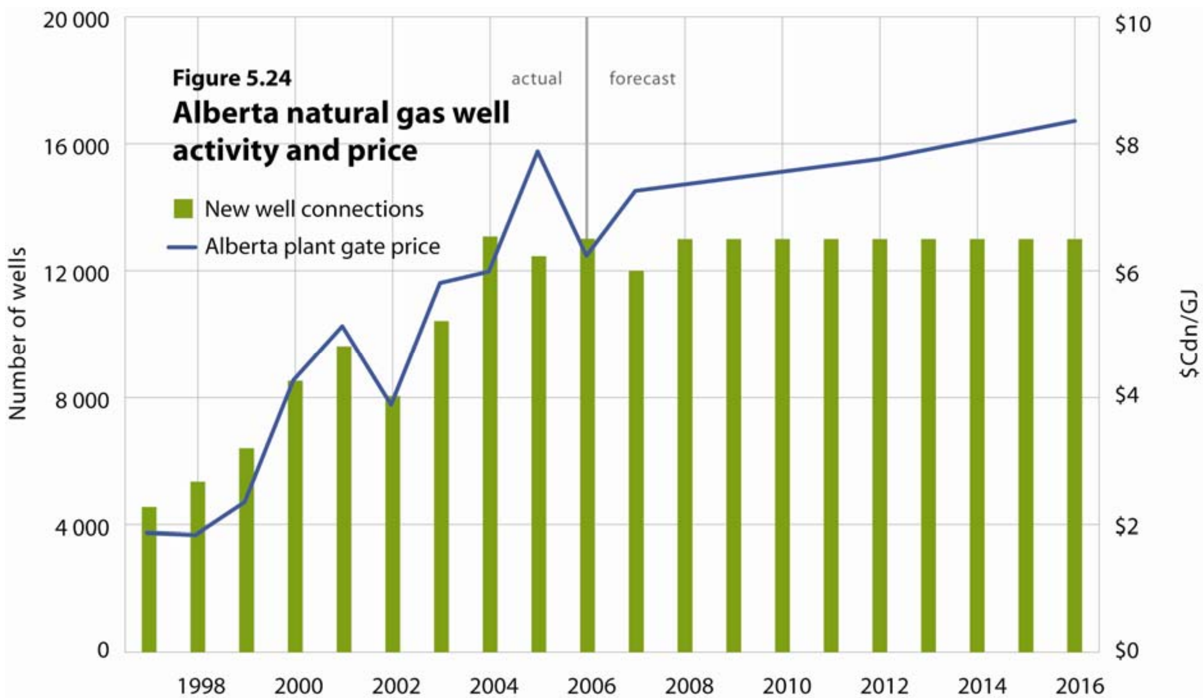
Based on the projection of natural gas prices provided in Section 1.2 and current estimates of reserves, the EUB expects that the number of new gas well connections in the province will remain high, at 12 000 wells per year in 2007 and then 13 000 per year for each year to 2016. Drilling activity in the southeastern part of Alberta is expected to remain strong throughout the forecast period. EUB spacing requirements have been amended to allow for reduced baseline well densities in areas east of the 5th Meridian and south of Township 53. New requirements allow for two gas wells per section in the Mannville Group and four gas wells per section in formations above the Mannville. **Figure 5.24** illustrates historical and forecast new well connections and plant gate prices.

In projecting natural gas production, the EUB considered three components: expected production from existing gas wells, expected production from new gas well connections, and gas production from oil wells.

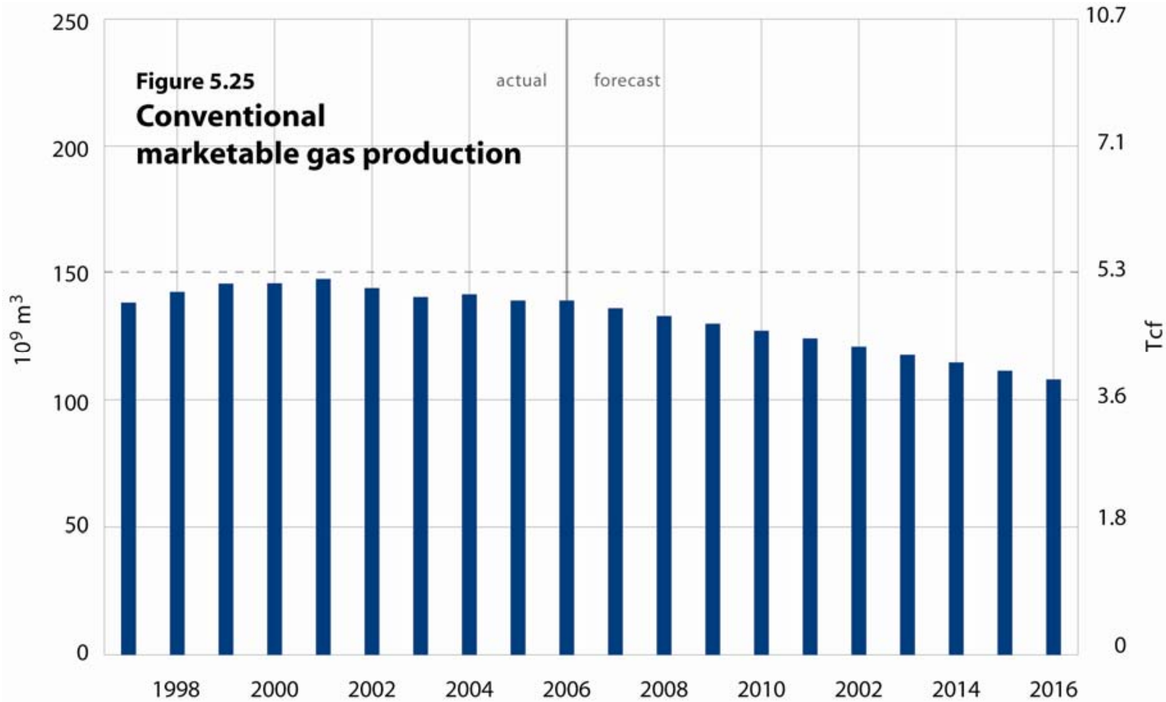
Based on observed performance, gas production from existing gas wells at year-end 2006 is assumed to decline by 18 per cent per year initially and move to 16 per cent by the second half of the forecast period.

To project production from new gas well connections, the EUB considered the following assumptions:

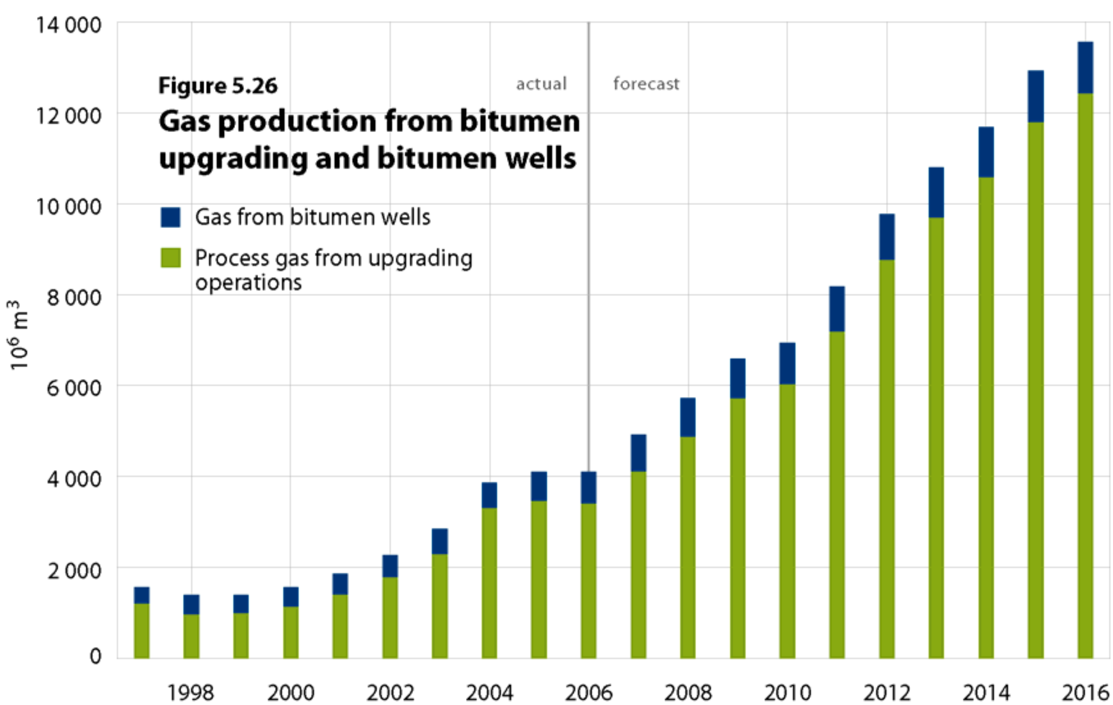
- The average initial productivity of new natural gas wells in Southeastern Alberta will be 2.0 $10^3 m^3/d$ in 2007 and will decrease to 1.5 $10^3 m^3/d$ by 2016.
- The average initial productivity of new natural gas wells in the rest of the province will be 6.5 $10^3 m^3/d$ in 2007 and will decrease to 5.0 $10^3 m^3/d$ by 2016.
- Production from new wells will decline at a rate of 31 per cent the first year, 22 per cent the second year, 19 per cent the third year, and 18 per cent the fourth year and thereafter.
- Gas production from oil wells will decline by 2 per cent per year.



Based on the remaining established and yet-to-be-established reserves and the assumptions described above, the EUB generated the forecast of natural gas production to 2016, as shown in **Figure 5.25**. The production of natural gas from conventional reserves is expected to decrease from 139.2 $10^9 m^3$ to 108.4 $10^9 m^3$ by the end of the forecast period. If conventional natural gas production rates follow the projection, Alberta will have recovered 77 per cent of the 6276 10^9 m^3 ultimate potential by 2016.

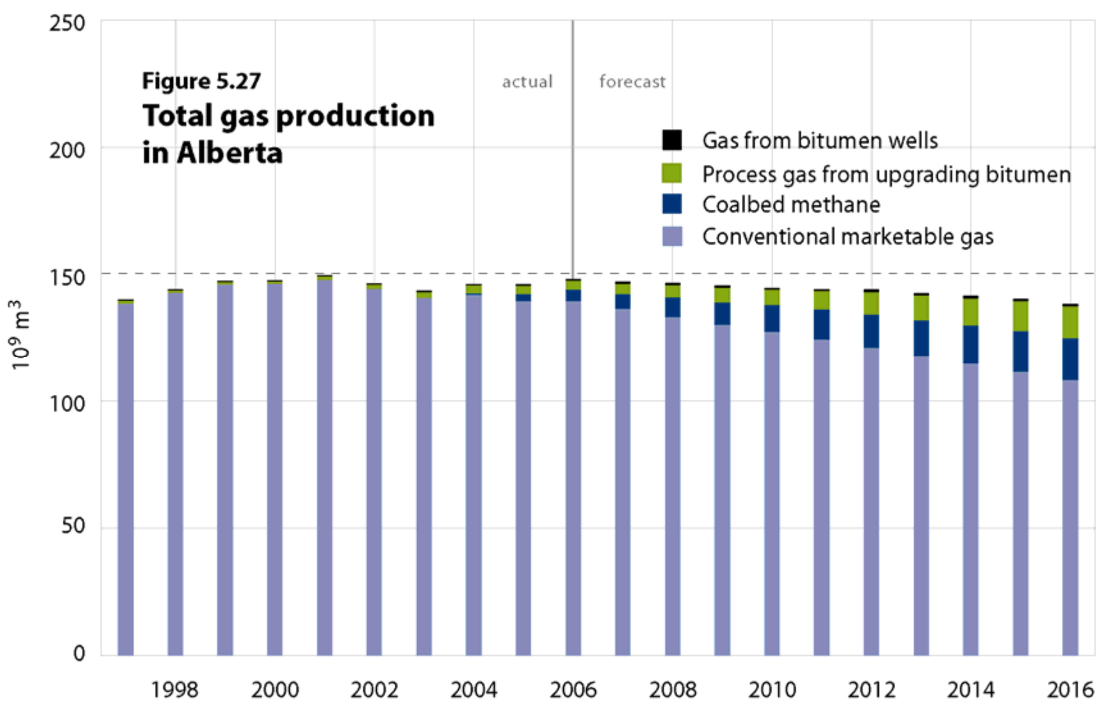


Gas production from sources other than conventional gas and oil wells includes processed gas from bitumen upgrading operations (including synthetic gas), natural gas from bitumen wells, and CBM. **Figure 5.26** shows the production from the first two categories.



In 2006, some 3.4 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 12.4 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells and use in primary and thermal schemes was 0.7 10^9 m^3 in 2006 and is forecast to increase to 1.1 10^9 m^3 by 2016. This gas was used mainly as fuel to create steam for its in situ operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.

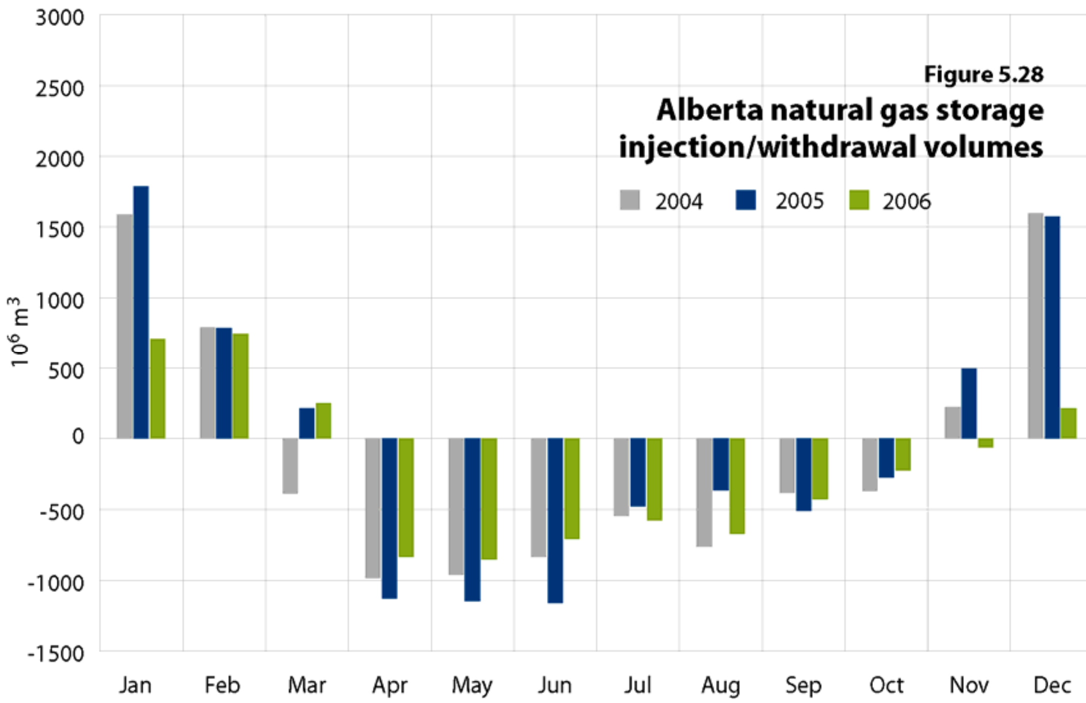
Figure 5.27 shows the forecast of conventional natural gas production, along with gas production from other sources. While the production of conventional gas in Alberta is expected to decline over the forecast period by about 2.5 per cent per year, CBM production is expected to grow over time and offset a part of the decline.



5.2.2 Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability and is not used in the EUB's long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; it allows marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Natural gas from many sources may be stored at these facilities under fee-for-service, buy-sell, or other contractual arrangements.

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas supply rises, injection slows or ends, and production generally begins at high withdrawal rates. **Figure 5.28** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province.



Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table 5.9**. **Figure 5.29** presents the location of these facilities on the Alberta pipeline systems. EnCana Corporation ceased commercial storage operations at the Sinclair Gething D and Paddy C Pools as of May 2006. A new commercial gas storage scheme has been developed by TransCanada Pipelines Ltd. using the Edson Viking D pool. This depleted gas reservoir has working gas capacity of 1775 10^6 m^3.

Table 5.9. Commercial natural gas storage pools as of December 31, 2006

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2006 (10^6 m^3)	Withdrawal volumes, 2006 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	609	457
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	817	23 950	1 089	1 173
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	1 283	265
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	682	70
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	172	145
McLeod Cardium A	PPM Corp Energy Canada Ltd.	986	16 900	659	572
McLeod Cardium D	PPM Corp Energy Canada Ltd.	282	4 230	170	89
Sinclair Gething D & Paddy C	EnCana Corporation	282	5 634	0	138
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 395	50 715	1 405	719

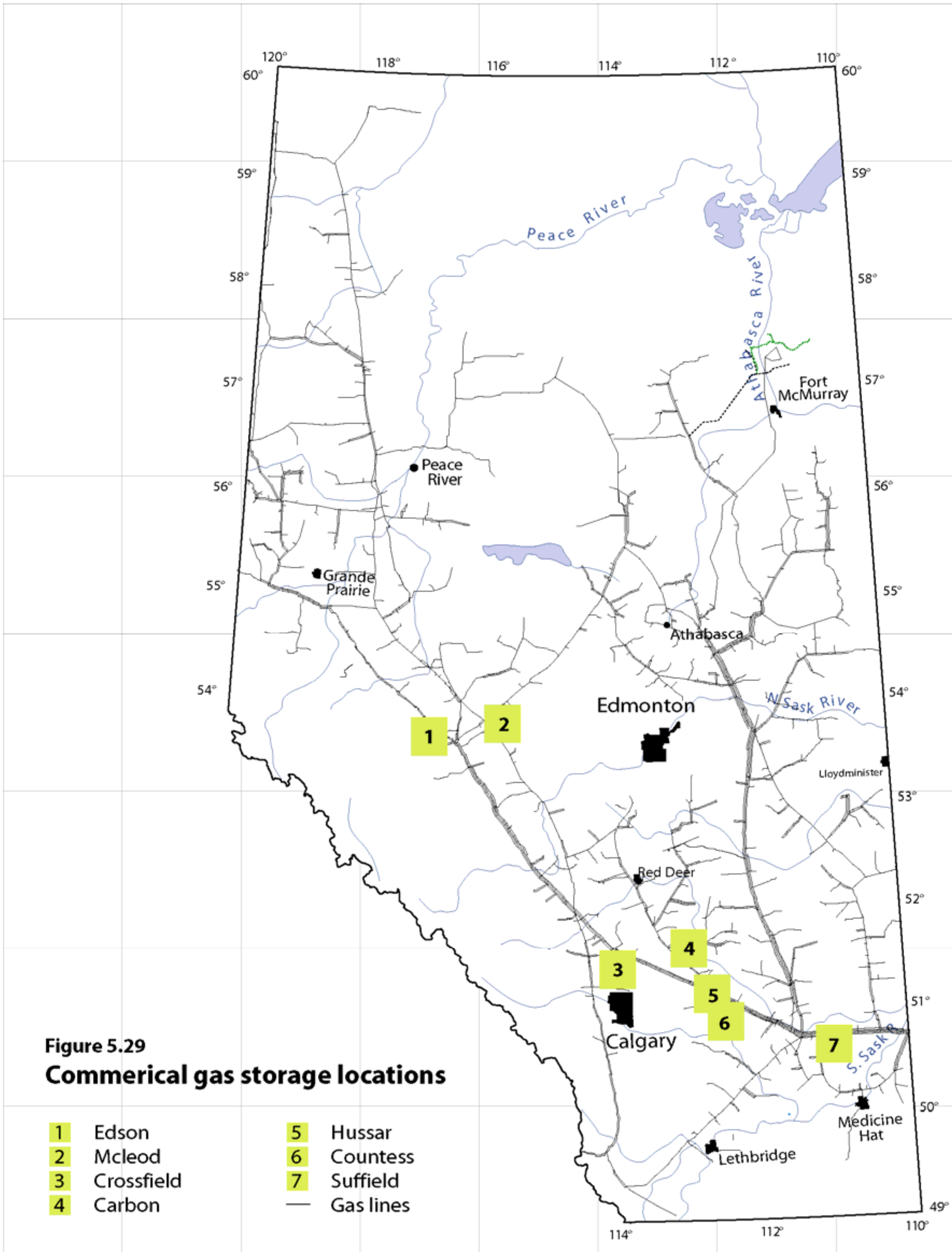


Figure 5.29
Commerical gas storage locations

In 2006, natural gas injections for all storage schemes exceeded withdrawals by 2439 10^6 m^3. Marketable gas production volumes determined for 2006 were adjusted to account for the small imbalance in injection and withdrawal volumes to these storage pools. For the purpose of projecting future natural gas production, the EUB assumes that injections and withdrawals are balanced for each year during the forecast period.

5.2.3 Alberta Natural Gas Demand

The EUB reviews the projected demand for Alberta natural gas periodically. The focus of these reviews is on intra-Alberta natural gas use, and a detailed analysis is undertaken of many factors, such as population, economic activity, and environmental issues that influence natural gas consumption in the province. Forecasting demand for Alberta natural gas in markets outside the province is done on a less rigorous basis. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets and the recent historical trends in meeting that demand. Excess pipeline capacity to the United States. allows for gas to move to areas of the United States that provide for the highest netback to the producer. The major natural gas pipelines in Canada with removal points identified that move Alberta gas to market are illustrated in **Figure 5.30**.

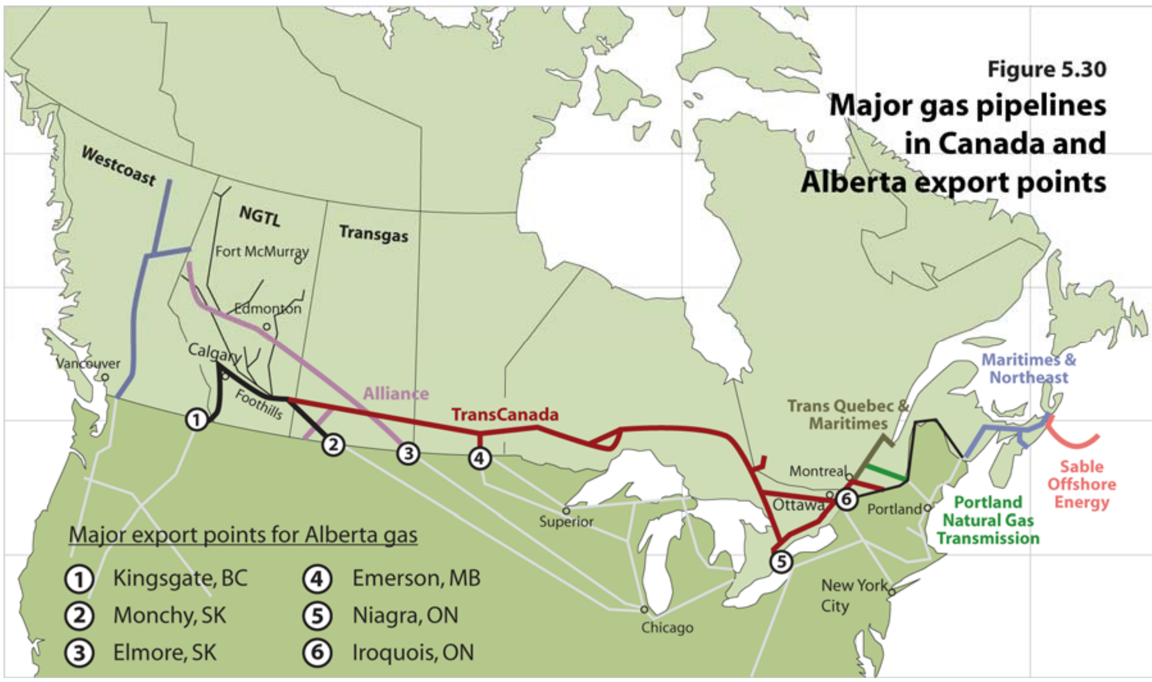
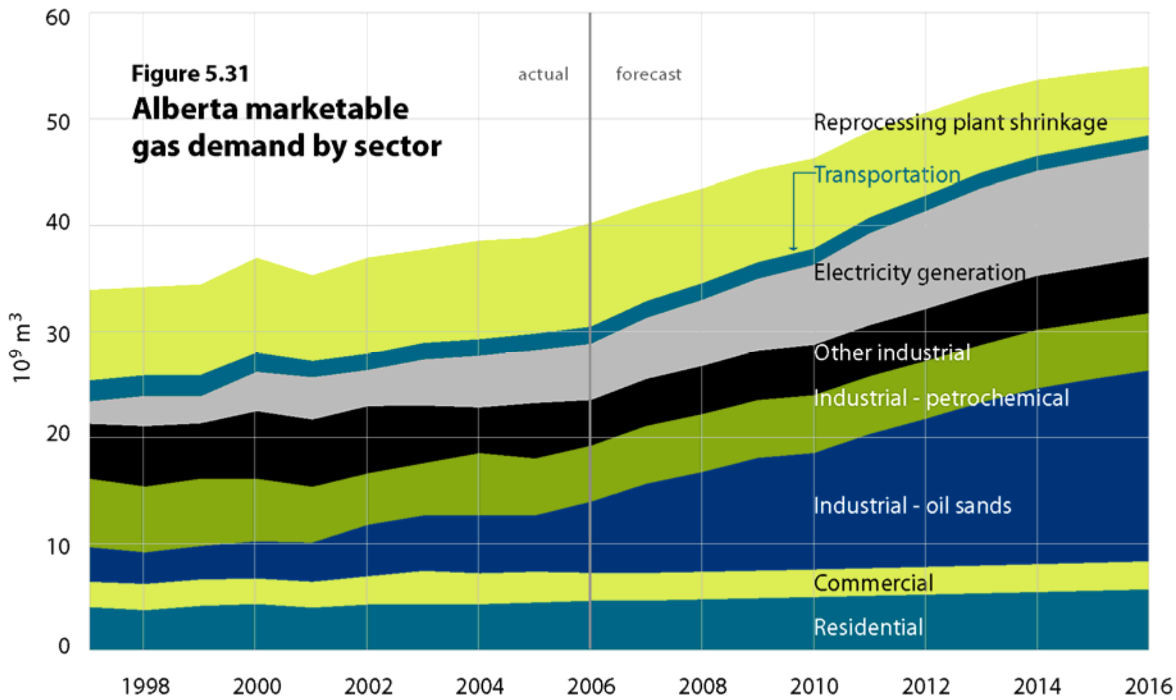


Figure 5.31 illustrates the breakdown of marketable natural gas demand in Alberta by sector. By the end of forecast period, domestic demand will reach 55.0 10^9 m^3, compared to 40.6 10^9 m^3 in 2006, representing 44 per cent of total natural gas production.

The Alberta *Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the EUB for a permit authorizing the removal. Exports of gas from Alberta are only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.



The calculation in **Table 5.10** is performed on an annual basis to determine what volume of gas is available for exports after accounting for Alberta's future requirements. There is currently 243 10^9 m^3 of surplus natural gas calculated using the 2006 remaining established reserves number. This represents a 7 per cent decrease in surplus over the year 2005. **Figure 5.32** illustrates historical "available for permitting" volumes from 1997 to 2006.

Table 5.10. Estimate of gas reserves available for inclusion in permits as at December 31, 2006

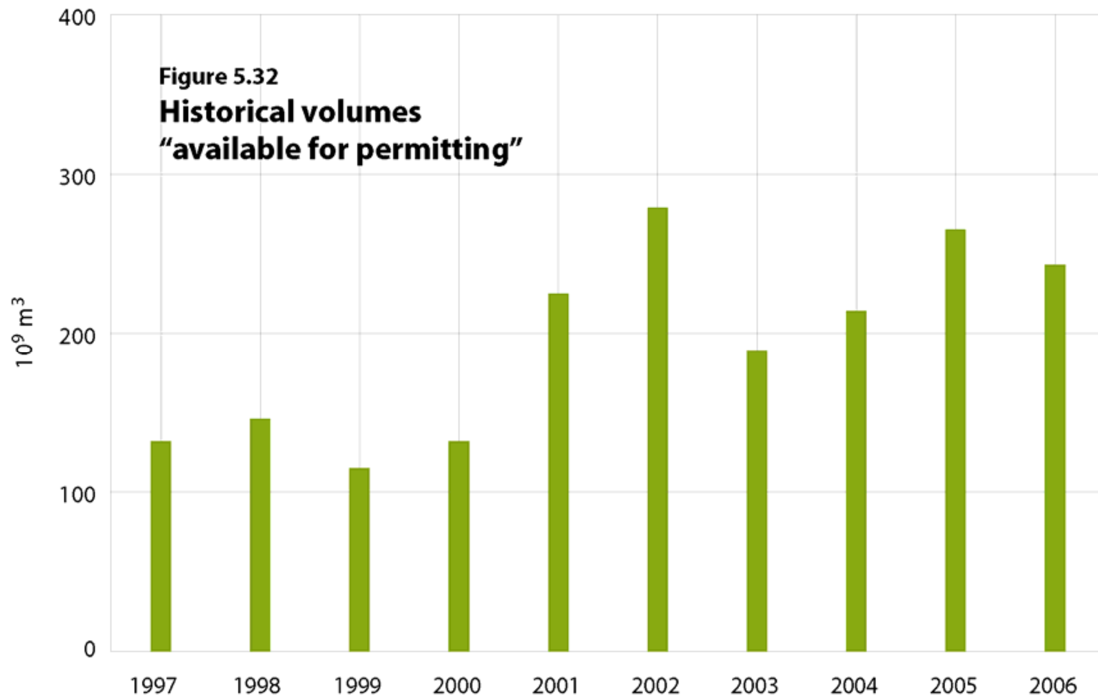
	10^9 m^3 at 37.4 MJ/m^3
Reserves (as at year-end 2006)	
1. Total remaining established reserves[a]	1 136
Alberta Requirements	
2. Core market requirements[b]	109
3. Contracted for non-core markets[b]	109
4. Permit-related fuel and shrinkage	61
Permit Requirements	
5. Remaining permit commitments[c]	614
6. Total requirements	893
Available	
7. Available for permits	243

[a] Previous estimates of gas available for permitting have included gas in the Beyond Economic Reach and Deferred categories that would become available over the next 20 years. However, in 1999 the EUB discontinued estimating reserves in these categories on the basis that the methods used did not result in accurate volumes and the effort did not add significant reserves to the total volume of reserves.

[b] For these estimates, 15 years of core market requirements and 5 years of non-core requirements were used.

[c] The remaining permit commitments are split approximately 37 per cent under short-term permits and 63 per cent under long-term permits.

Residential gas requirements are expected to grow moderately over the forecast period, at an average annual rate of 2 per cent. The key variables that affect residential gas demand are natural gas prices, population, the number of households, energy efficiencies, and the weather. Energy efficiency improvements prevent energy use per household from rising



significantly. Commercial gas demand in Alberta has fluctuated over the past 10 years and is expected to remain flat over the forecast period. This is largely due to gains in energy efficiencies and a shift to electricity.

The significant increase in Alberta demand is due to increased development in the industrial sector. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil, shown in **Figure 5.33**, are expected to increase annually from 7.1 10^9 m^3 in 2006 to 18.0 10^9 m^3 by 2016. **Table 5.11** outlines the average purchased gas use rates for oil sands operations.

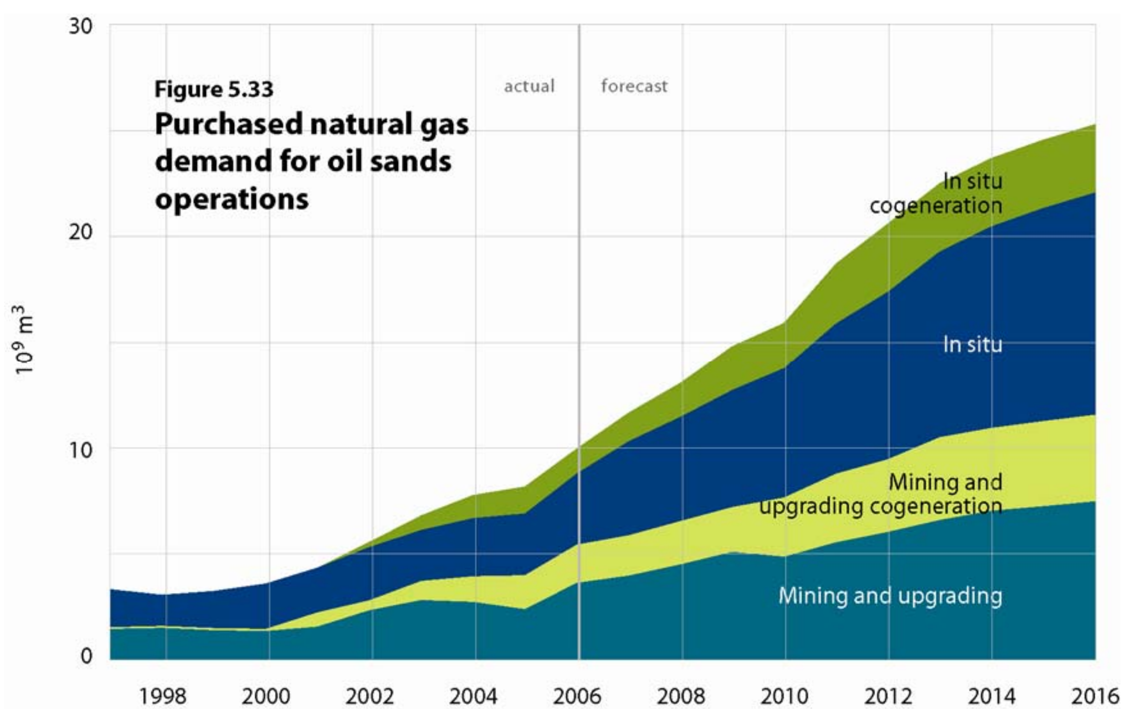
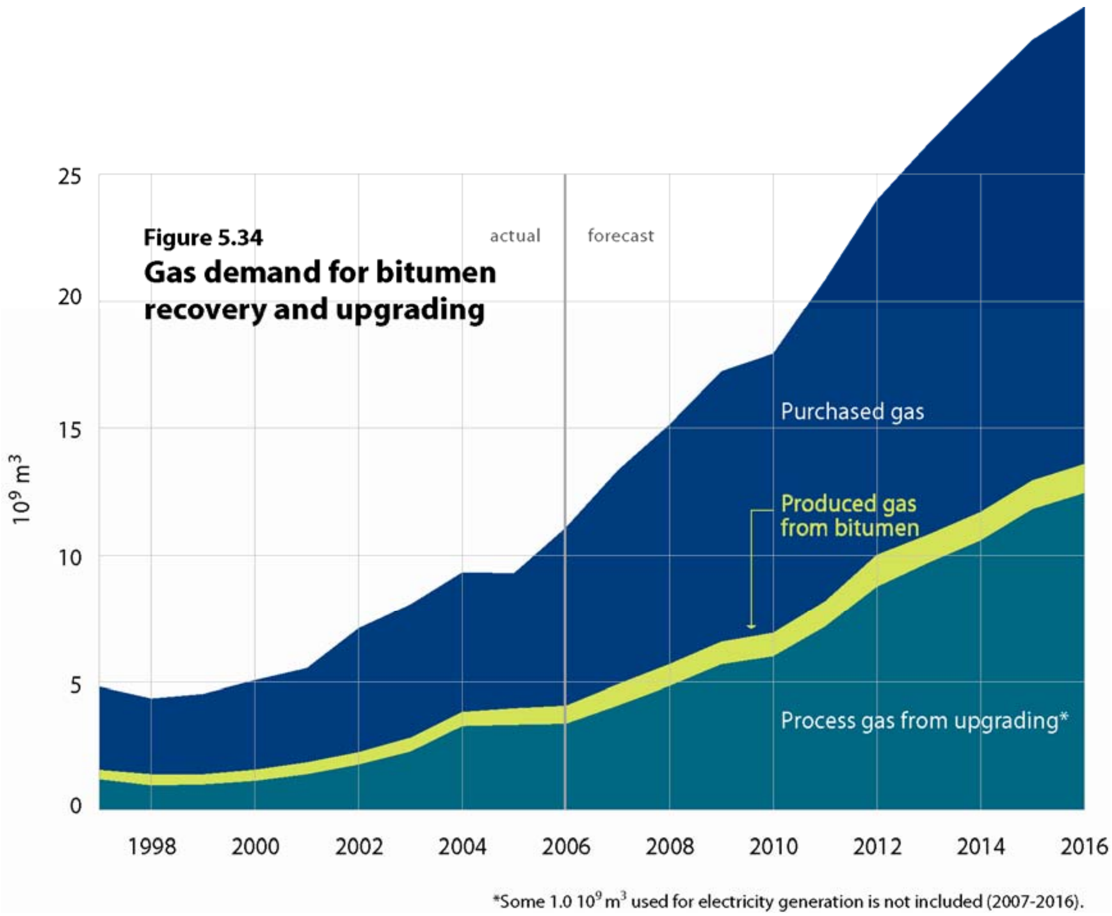


Table 5.11. 2006 oil sands average purchased gas use rates*

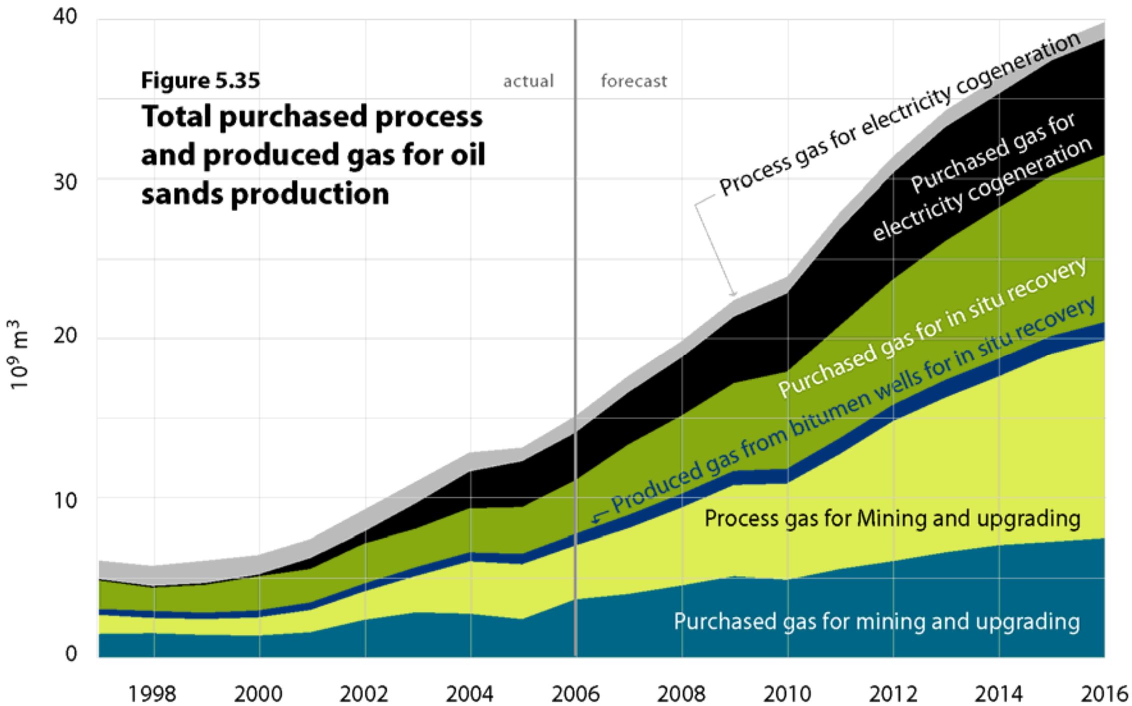
Extraction Method	Excluding purchased gas for electricity generation (m³/m³)	(mcf/bbl)	Including purchased gas for electricity generation (m³/m³)	(mcf/bbl)
In situ - SAGD	150	0.85	235	1.33
- CSS	168	0.95	220	1.24
Mining	15	0.08	67	0.38
Upgrading	30	0.17	50	0.28
Mining with upgrading	84	0.47	125	0.71

*Expressed as cubic metres of natural gas per cubic metre of bitumen/synthetic crude oil production.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. Therefore, total gas demand in this sector is the sum of purchased gas, process gas, and solution gas produced at bitumen wells, as illustrated in **Figure 5.34.** Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, is shown in **Figure 5.35.**



The potential high usage of natural gas in bitumen production and upgrading has exposed the companies involved in the business to the risk of volatile gas prices. The Opti Canada Inc./Nexen Inc. Long Lake Project will be employing technology that will produce synthetic gas by burning ashphaltines in its new bitumen upgrader expected to start up in late 2007. Other companies are now exploring the option of self-sufficiency for their gas requirements. The existing bitumen gasification technology is one attractive alternative being pursued. If implemented, natural gas requirements for this sector could decrease substantially.



The electricity generating industry will also require increased volumes of natural gas to fuel some of the new plants expected to come on stream over the next few years. Natural gas requirements for electricity generation are expected to increase over the forecast period, from some 5.4 10^9 m^3 in 2006 to 10.1 10^9 m^3 by 2016. Electricity demand can be met from existing electricity plants and plants announced to be built over the forecast period.

Figure 5.36 shows Alberta natural gas demand and production. Gas removals from the province represent the difference between natural gas production from conventional reserves and coal seams and Alberta demand. In 2006, some 28 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the United States. By the end of forecast period, domestic demand represents 44 per cent of total natural gas production.

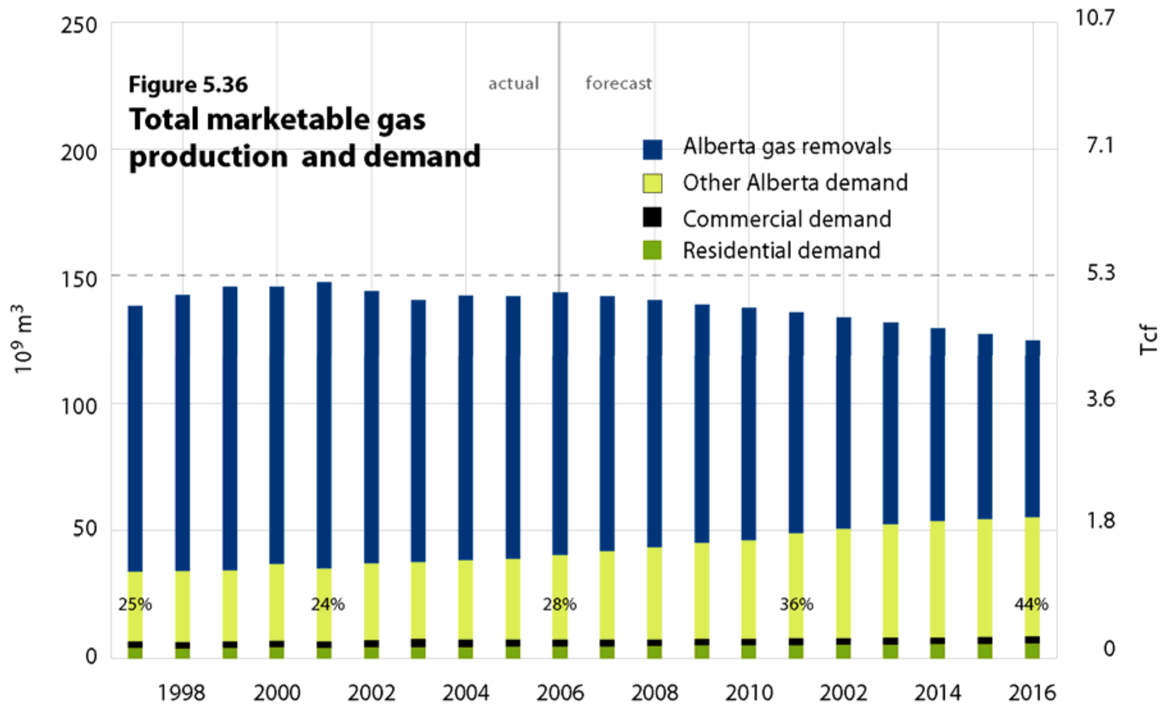


Figure 5.36
Total marketable gas production and demand

Gas production in Alberta may be higher than that forecast if commercial production of gas from the Mannville coal seams is accelerated. Mannville CBM production is largely at the pilot project stage to date, although companies have announced encouraging results.

6 Natural Gas Liquids

The EUB estimates remaining reserves of natural gas liquids (NGLs) based on volumes that are expected to be recovered from raw natural gas using existing technology and market conditions. The liquids reserves expected not to be removed from natural gas are included as part of the province's gas reserves discussed in Section 5.1. The EUB's projections on the overall recovery of each NGL component are explained in Section 5.1.7 and shown graphically in Figure 5.9.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2006 are summarized in **Tables 6.1** and **6.2**. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2006 production. Total remaining reserves of extractable NGLs have increased by 2.3 per cent since 2005. Fields that have contributed significantly to this increase are Cecilia, Countess, and Rainbow, which are listed in Appendix B, **Tables B.12** and **B.13**. It should be noted that minor adjustments were made to 2005 cumulative net production values because of revisions to the production values for years 2000 to 2005.

Table 6.1. Established reserves and production of extractable NGLs as of December 31, 2006 (10^6 m^3 liquid)

	2006	2005	Change
Cumulative net production[a]			
Ethane	239.9	225.1	+14.8
Propane	252.7	243.1	+9.6[b]
Butanes	145.0	139.9	+5.1[b]
Pentanes plus	320.6	312.1	+8.5[b]
Total	958.2	920.2	+38.0
Remaining (expected to be extracted)			
Ethane	125.1	120.7	+4.4
Propane	72.0	69.4	+2.6
Butanes	40.9	40.1	+0.8
Pentanes plus	58.1	59.3	-1.2
Total	296.1	289.5	+6.6

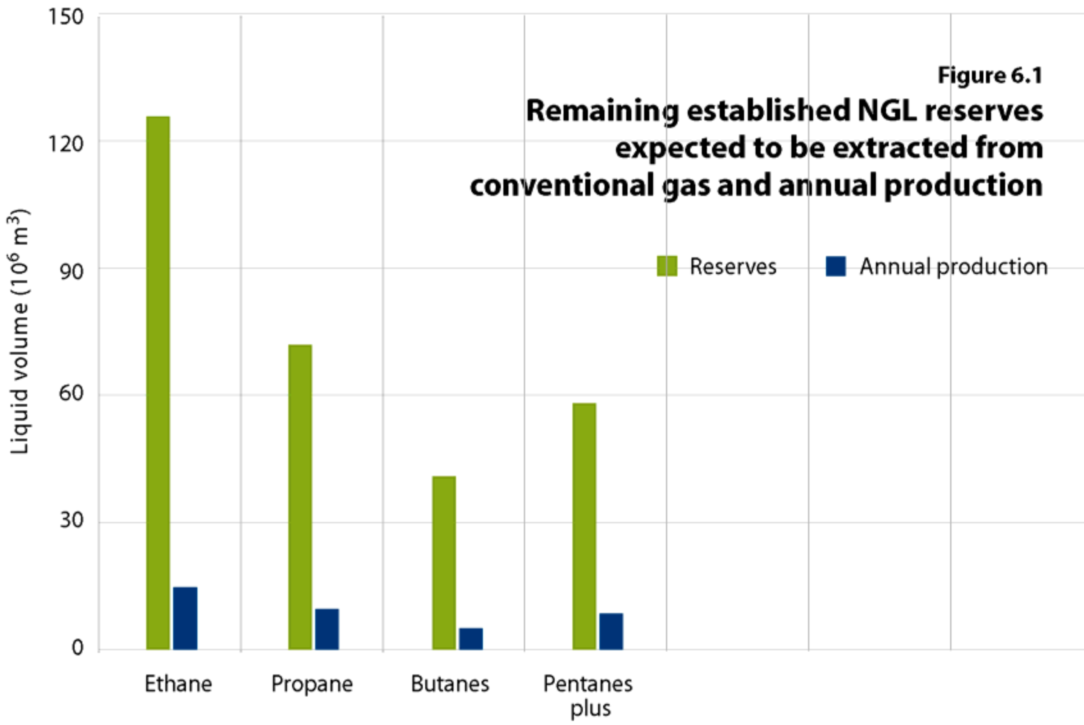
[a] Production minus those volumes returned to the formation or injected to enhance the recovery of oil.
[b] May differ slightly with actual production as reported in *ST3: Oil and Gas Monthly Statistics*.

6.1.2 Ethane

As of December 31, 2006, the EUB estimates remaining established reserves of extractable ethane to be 125.1 million cubic metres (10^6 m^3) in liquefied form. This estimate includes 5.2 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. In 2006, the ethane volume remaining in solvent floods represented about 4.1 per cent of the total ethane reserves, slightly lower than the previous year. At the end of 2006, only six pools were still actively injecting solvent, the largest being the Rainbow Keg River F and Judy Creek Beaverhill Lake A pools.

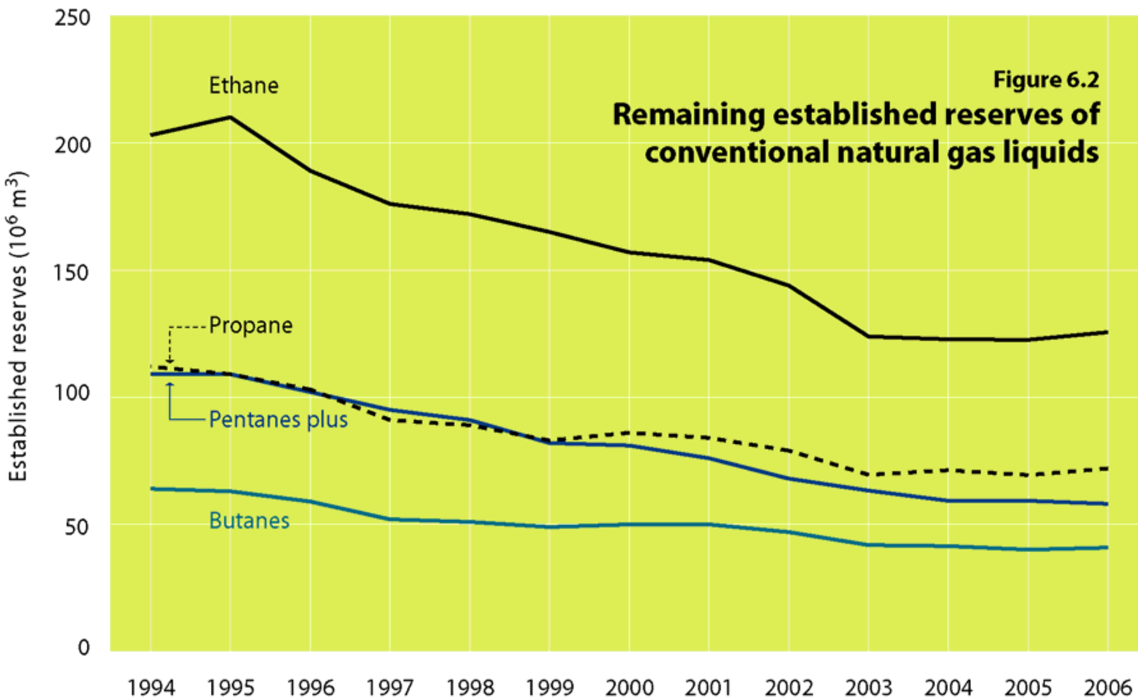
Table 6.2. Reserves of NGLs as of December 31, 2006 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	189.6	84.5	45.1	58.1	378.0
Liquids expected to remain in dry marketable gas	64.5	12.5	4.4	0	81.3
Remaining established recoverable from					
Field plants	36.9	41.5	26.6	51.9	156.9
Straddle plants	83.0	29.1	13.3	5.8	131.2
Solvent floods	5.2	1.4	1.0	0.4	8.0
Total	125.1	72.0	409	58.1	296.1



As shown in **Table 6.2**, an additional 64.5 10^6 m^3 (liquid) of ethane is estimated to remain in the marketable gas stream and available for potential recovery. **Figure 6.2** shows the remaining established reserves of ethane declining from 1995 to 2003 and then levelling off over the last three years. During 2006, the extraction of specification ethane was 14.8 10^6 m^3, compared to 14.6 10^6 m^3 in 2005.

For individual gas pools, the ethane content of gas in Alberta falls within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in Appendix B, Table B.12, the volume-weighted average ethane content of all remaining raw gas was 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves and from solvent floods. The six largest fields—Caroline, Ferrier, Pembina, Wild River, Willesden Green, and Wapiti—account for 16.7 per cent of total ethane reserves but only 8.5 per cent of remaining established marketable gas reserves.



6.1.3 Other Natural Gas Liquids

As of December 31, 2006, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 72.0 10^6 m^3, 40.9 10^6 m^3, and 58.1 10^6 m^3 respectively. The breakdown in the liquids reserves during the past year are shown in **Table 6.2**. Appendix B, **Table B.13**, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The nine largest fields—Ansell, Brazeau River, Caroline, Ferrier, Kaybob South, Pembina, Rainbow, Wild River, and Willesden Green—account for about 24.1 per cent of the total liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table. During 2006, propane and butanes recovery at crude oil refineries was 0.4 10^6 m^3 and 1.3 10^6 m^3 respectively, while accounting for 10.8 per cent of remaining established marketable gas reserves.

6.1.4 Ultimate Potential

The remaining ultimate potential for liquid ethane is considered to be those reserves that could reasonably be recovered as liquid from the remaining ultimate potential of natural gas. Historically, only a fraction of the ethane that could be extracted had been recovered. However, the recovery has increased over time to 58 per cent. The EUB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on remaining ultimate potential for ethane gas of 165.6 10^9 m^3, the EUB estimates remaining ultimate potential of liquid ethane to be 413 10^6 m^3. The other 30 per cent, or 49.9 10^9 m^3, of ethane gas is expected to be sold for its heating value as part of the marketable gas.

For liquid propane, butanes, and pentanes plus together, the remaining ultimate potential reserves are 494 10^6 m^3. This assumes that remaining ultimate potential as a percentage of initial ultimate potential is 41.3 percent, similar to that of marketable gas.

6.2 Supply of and Demand for Natural Gas Liquids

For the purpose of forecasting ethane and other NGLs, the richness and production volumes from established and future reserves of conventional natural gas have an impact on future production. For ethane, demand also plays a major role in future extraction. The NGL content from new gas reserves is assumed to be similar to existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will play a role in supplementing supplies from conventional gas production.

6.2.1 Supply of Ethane and Other Natural Gas Liquids

Ethane and other NGLs are recovered mainly from the processing of natural gas. Gas processing plants in the field extract ethane, propane, butanes, and pentanes plus as products or recover an NGL mix from raw gas production. NGL mixes are sent from these field plants to fractionation plants for the recovery of individual NGL specification products. Straddle plants (on NOVA Gas Transmission Lines and ATCO systems) recover NGL products from gas processed in the field. To compensate for the liquids removed, lean make-up gas volumes are purchased by the straddle plants and added to the marketable gas stream leaving the plants. Although some pentanes plus is recovered as condensate at the field level, the majority of the supply is recovered from the processing of natural gas. The other source of NGL supply is from crude oil refineries, where small volumes of propane and butanes are recovered. **Figure 6.3** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Ethane and other NGL production volumes are a function of raw gas production, liquid content, gas plant recovery efficiencies, and prices. High gas prices relative to NGL prices may cause gas processors to reduce liquid recovery.

In 2006, ethane volumes extracted at Alberta processing facilities increased to 40.6 10^3 m^3/d from 2005 levels of 40.2 10^3 m^3/d. About 58 per cent of total ethane in the gas stream was extracted, while the remainder was left in the gas stream and sold for its heating value. **Table 6.3** shows the volumes of specification ethane extracted at the three types of processing facilities during 2006.

Table 6.3. Ethane extraction volumes at gas plants in Alberta, 2006

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	1.1	7
Fractionation plants	2.8	19
Straddle plants	10.9	74
Total	14.8	100

Table 6.4 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2006. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butanes volumes recovered at crude oil refineries were 0.8 10^3 m^3/d and 2.1 10^3 m^3/d respectively.

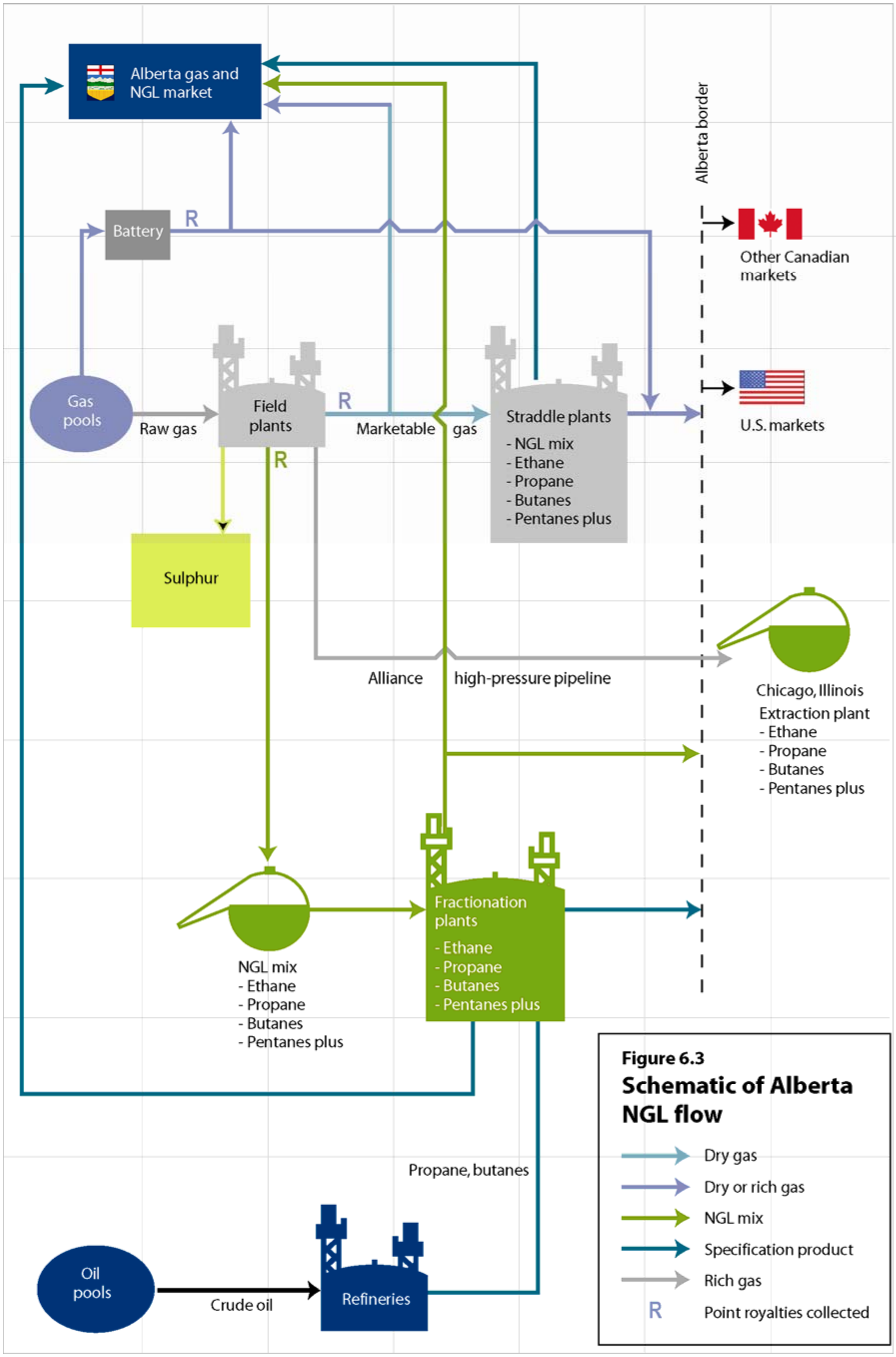


Figure 6.3
Schematic of Alberta NGL flow

Table 6.4. Liquid production at ethane extraction plants in Alberta, 2006 and 2016

Gas Liquid	2006 Yearly production (10^6 m^3)	2006 Daily production (10^3 m^3/d)	2006 Liquid/ gas ratio ($m^3/10^6$ m^3)	2016 Yearly production (10^6 m^3)	2016 Daily production (10^3 m^3/d)	2016 Liquid/ gas ratio ($m^3/10^6$ m^3)
Ethane	14.8	40.6	106	16.4	45.0	152
Propane	9.6	26.2	69	7.4	20.4	69
Butanes	5.1	14.1	37	4.0	10.9	37
Pentanes plus	8.5	23.2	61	6.5	17.7	61

As conventional gas production declines, less ethane will be available for use by the petrochemical sector. In response to the forecast decline in economically recoverable ethane, the provincial government announced a new policy to encourage the development of new supplies of cost-competitive ethane. The Incremental Ethane Extraction Policy (IEEP), announced in late September 2006, will provide incentives for petrochemical producers that use ethane as feedstock in order to sustain or expand Alberta's existing industry. These incentives are designed to allow for a significant reinvestment in the current ethane supply infrastructure and provide potential petrochemical growth opportunities. The policy focuses on supporting increased ethane extraction through the provision of consumption credits. The credits that are available to both conventional natural gas and oil sands projects would apply only to ethane used by producers over their current consumption, up to a maximum of $35 million per year in royalties collected. More details on the policy will be released later this year. Since the new policy announcement, several projects have come forward, as follows:

- NOVA Chemicals Corp. (NOVA) and Aux Sable Canada (Aux Sable) have recently announced plans to build a new ethane extraction facility near Edmonton that will provide NOVA with 6350 m^3/d of ethane feedstock. Natural gas carrying the ethane will be supplied from the Alliance pipeline, which runs from northeast British Columbia to Chicago. It is expected to be in service by mid-2010, and the ethane will be moved via pipeline to NOVA's Joffre site.

- Inter Pipeline Fund has planned investments to increase ethane production at its Empress straddle plant in southern Alberta. Upon completion, facility enhancements will allow the extraction of 1106 m^3/d of additional ethane. Initial production of incremental ethane is anticipated in the second quarter of 2008.

- Also announced is a proposed project to increase ethane recovery capacity at the Cochrane straddle plant operated by Inter Pipeline Extraction. The application is for increased ethane recovery of 2433 m^3/d from the current design capacity of 10 268 m^3/d. The ethane recovery project is expected to be operational by the fourth quarter 2008.

Off-gas from bitumen upgraders has the potential to bring on a large, long-term, and stable source of ethane feedstock. Off-gas is a mixture of hydrogen and light gases, including ethane, ethylene, and other light hydrocarbons. The majority of the off-gas produced from oil sands upgraders is presently being used as fuel for oil sands operations. Currently some natural gas liquids (C3+) are being extracted from Suncor's process gas volumes and sent for fractionation into specification products at Redwater, Alberta.

Aux Sable has recently announced plans to build the first phase of a plant to process off-gas from the BA Energy upgrader located north of Fort Saskatchewan. The plant located next to the BA Energy site will start up in mid- to late 2008, to coincide with the start-up of the upgrader. The plant will recover natural gas liquids, including an ethane/ethylene stream that will be sold to the petrochemical industry.

It is expected that recovered ethane volumes will remain at 2006 levels of 40.6 10^3 m^3/d in 2007 and 2008. In 2009, ethane production will further increase to 45.0 10^3 m^3/d and hold there for the remainder of the forecast period, as shown in **Figure 6.4.** The figure also refers to ethane supply as potential, as it indicates the volumes of ethane that could be recovered from Alberta natural gas. The supply volumes are calculated based on the volume-weighted ethane content of conventional gas production in Alberta of 0.05 mol/mol and assume that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is some 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast. Based on the historical ethane content of marketable gas in Alberta, adequate volumes of ethane are available to meet the forecast demand.

Over the forecast period, the ratios of propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas are expected to remain constant, as shown in **Table 6.4**. **Figures 6.4** to **6.7** show forecast production volumes to 2016 for ethane, propane, butanes, and pentanes plus respectively. As conventional gas production declines, so too will the natural gas liquid volumes. No attempt has been made to include ethane and other NGL production from the solvent flood banks injected into pools throughout the province to enhance oil recovery.

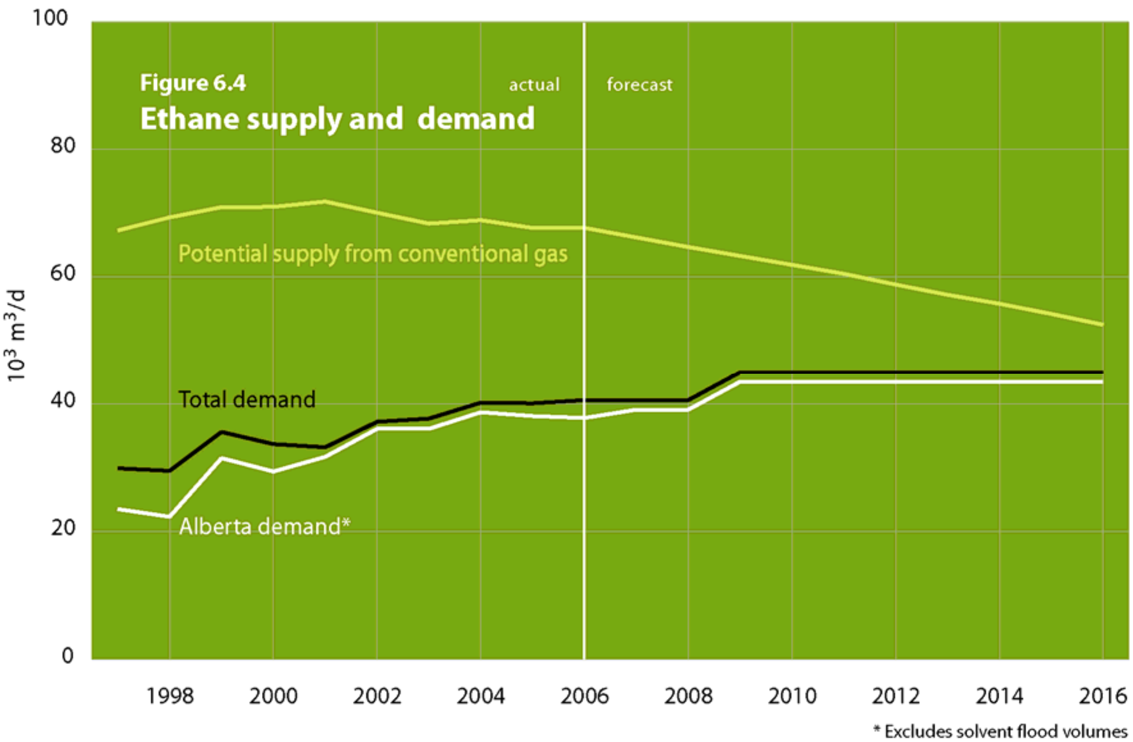
6.2.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in 2006, about 93 per cent was used in Alberta as feedstock. Some 4 per cent was removed from the province under export permits. The remaining volume is an inventory/reporting adjustment. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas in the province, with four plants using ethane as feedstock for the production of ethylene. The industry adds value to natural gas liquids by upgrading them to be used in the manufacture of products such as plastic, rope, and building materials.

The petrochemical industry in North America has been challenged in the last few years by high and volatile energy prices. Since ethane prices follow natural gas prices, feedstock costs fluctuate throughout the years. Nonetheless, the Alberta ethylene industry has maintained its historical cost advantage for ethylene production compared to a typical ethane/propane cracker in the U.S. Gulf Coast. With global economics strengthening, demand for petrochemical products is growing rapidly. Even with robust industry prospects for new growth opportunities, global capacity growth is likely to lag behind demand.

As shown in **Figure 6.4**, Alberta demand for ethane is projected to be 39.1 10^3 m^3/d for 2007 and 2008. In 2009, ethane demand will increase to 43.5 10^3 m^3/d and remain at this level over the forecast period, with all four ethylene plants running at 90 per cent of capacity. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue through the forecast period. For purposes of this forecast, it was assumed that no new ethylene plants requiring Alberta ethane as feedstock will be built during the forecast period.

To acquire ethane, the petrochemical industry pays a fee to NGL processing facility owners to extract and deliver ethane from natural gas streams processed at their facilities. In the second half of 2005, construction of the new Joffre feedstock pipeline was completed. It allows for a range of feedstocks to be transported from Fort Saskatchewan to Joffre. These feedstocks supplement the ethane supplies now used at the petrochemical plants at Joffre,



where three of the four ethylene plants are located. The fourth is located in Fort Saskatchewan.

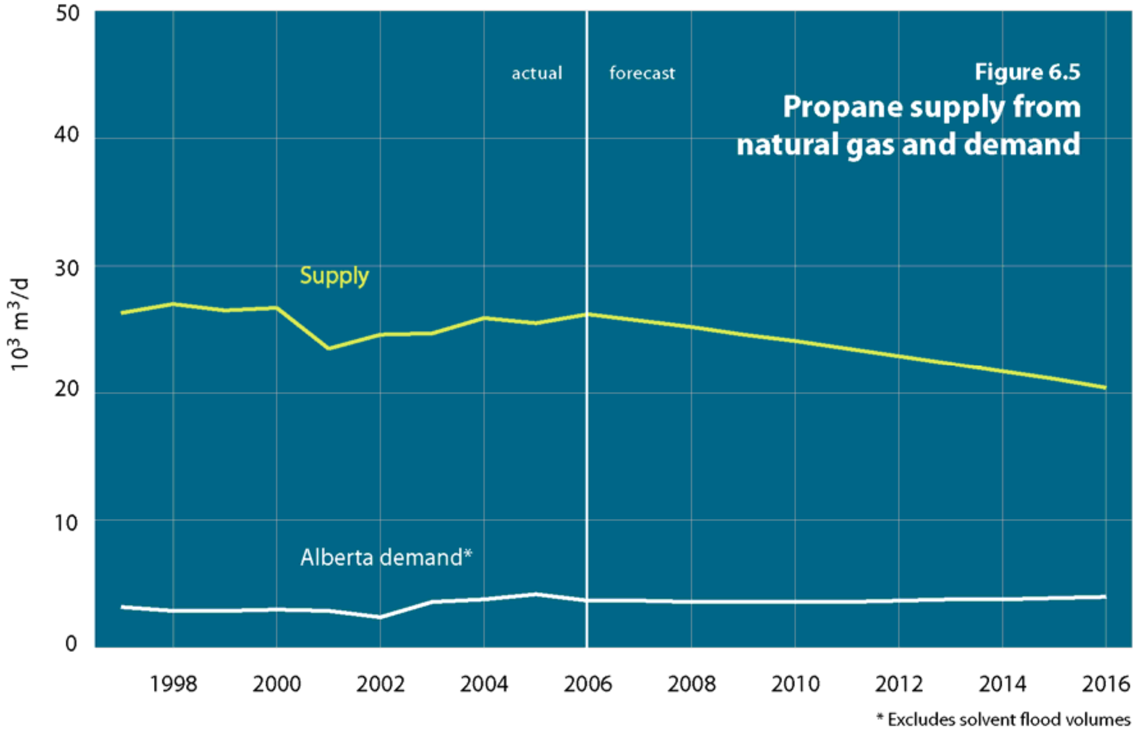
Figure 6.5 shows Alberta demand for propane compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue throughout the forecast period.

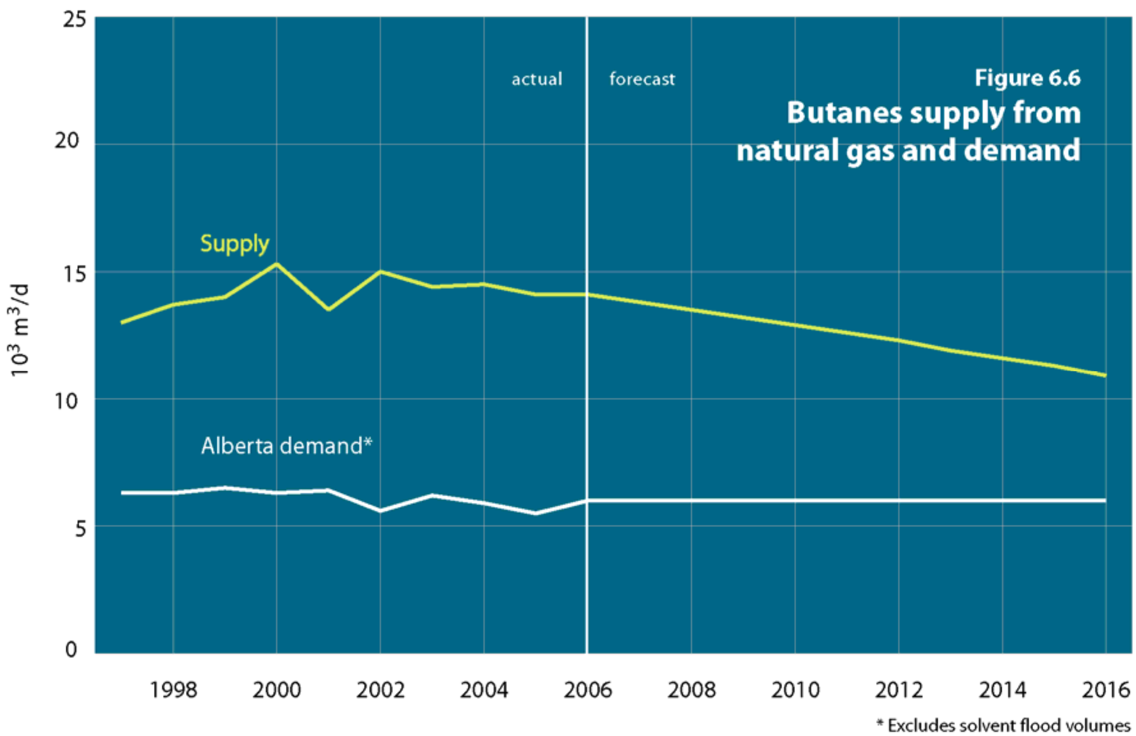
Figure 6.6 shows Alberta demand for butanes compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta demand for butanes will increase as refinery requirements grow. Butanes are used in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

Figure 6.7 shows Alberta demand for pentanes plus compared to the total available supply. The largest use of Alberta pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate the transportation to market by pipeline. Diluent increases the API gravity and reduces the viscosity of heavy crude oil and bitumen. Typically, heavy crude oil requires 5.5 per cent of diluent to be added for Bow River and 17 per cent for Lloydminster heavy crudes respectively.

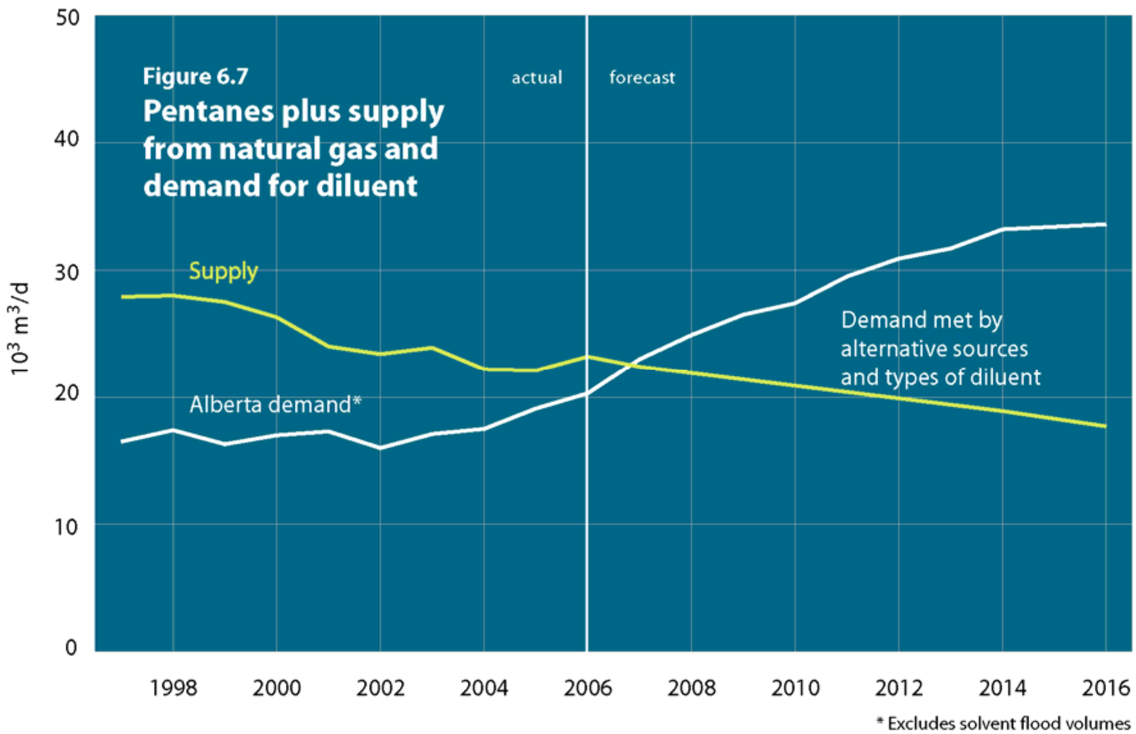
The required diluent for bitumen varies from a low of 17 per cent to as high as 31.6 per cent, depending on the producing regions of the province.

Over the forecast period, pentanes plus demand as diluent is expected to increase from 22.1 10^3 m^3/d to 33.6 10^3 m^3/d. This increased demand is largely in response to an anticipated





13.3 10^3 m^3/d increase in diluent required for bitumen transport, rising to 32.7 10^3 m^3/d in 2016 from 15.6 10^3 m^3/d in 2006. Conversely, the diluent requirement for transport of heavy crude is expected to decline from 2.5 10^3 m^3/d in 2006 to 1.6 10^3 m^3/d by the end of the forecast period, due to declining crude oil production. However, despite the reduced heavy crude diluent requirement, shortages of Alberta pentanes plus as diluent are forecast to occur in 2007. Industry has been preparing for the tight supply of available diluent from Alberta by using and assessing alternative sources and types of diluent and/or by seeking to reduce the demand.



- EnCana Corporation imports up to 4.0 10^3 m^3/d of offshore condensate to help transport its growing oil sands production to U.S. markets. With access to the Kitimat, B.C., terminal facility, EnCana imports diluent and transports it by rail to an Alberta pipeline connection that feeds its oil sands operation.

- Enbridge Inc. has announced plans to proceed with the Southern Lights Pipeline, which will transport diluent from Chicago to Edmonton through a 28.6 10^3 m^3/d, 20 inch diameter pipeline. The pipeline is expected to be in service by mid-2010.

- Pembina Pipeline Corporation is proposing a pipeline system designed to transport 15 10^3 m^3/d of condensate from Kitimat to Edmonton.

- Enbridge has shipper support for a proposed condensate pipeline capable of initially transporting 23.8 10^3 m^3/d from Kitimat to Edmonton. The Gateway Condensate Import Pipeline is expected to be in service sometime between 2012 and 2014.

- Small volumes of pentanes plus from the United States are being brought into the province by rail for use as diluent.

- Several new bitumen upgraders, similar to OPTI/Nexen's Long Lake project, will be located in the field or in the Edmonton area, where they will upgrade in situ bitumen to synthetic crude oil. These projects will reduce Alberta's requirements for pentanes plus as diluent.

- The use of light crude oil, synthetic crude oil, or naphtha as diluent is an attractive alternative for moving in situ bitumen from the field to upgrading facilities.

7 Sulphur

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The EUB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2006, to be 158.6 million tonnes (10^6 t), an increase of 78 per cent since 2005. This increase is due to an increase in reserves of bitumen under active development with the addition of Shell Jackpine, CNRL Horizon, and Petro-Canada/UTS Energy/Tech Cominco Fort Hills projects to the existing Suncor, Syncrude, and Albian Sands operations. The changes in sulphur reserves during the past year are shown in **Table 7.1**.

Table 7.1. Reserves of sulphur as of December 31, 2006 (10^6 t)

	2006	2005	Change
Initial established reserves from			
Natural gas	264.6	261.9	+2.7
Crude bitumen[a]	143.1	67.7	+ 75.4
Total	407.7	329.6	+ 78.1
Cumulative net production from			
Natural gas	230.8	223.7	+7.1
Crude bitumen[b]	18.3	16.9	+1.4
Total	249.1	240.6	+8.5
Remaining established reserves from			
Natural gas	33.8	38.2	-4.4
Crude bitumen[a]	124.8	50.8	+74.0
Total	158.6	89.0	69.6

[a] Reserves of elemental sulphur from bitumen under active development as of December 31, 2006. Reserves from the entire surface mineable area are larger.
[b] Production from surface mineable area only.

7.1.2 Sulphur from Natural Gas

The EUB recognizes 33.8 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2006, a decrease of 12 per cent from 2005. This decrease was due mainly to downward revisions of gas reserves in the Caroline Crossfield and Crossfield East fields. Remaining established sulphur reserves has been calculated using a provincial recovery factor of 97 per cent, which was determined taking into account plant efficiency, acid gas flaring at plants, acid gas injection, and flaring of solution gas. The EUB estimates the ultimate potential for sulphur from natural gas to be 354.8 10^6 t, with an additional 40 10^6 t from ultra-high hydrogen sulphide (H_2S) pools. Based on the initial established reserves of 264.6 10^6 t, this leaves 130.2 10^6 t yet to be established reserves from future discoveries of conventional gas.

The EUB's sulphur reserves estimates from natural gas are shown in **Table 7.2**. Fields containing the largest recoverable sulphur reserves are listed individually and those containing less are grouped under "All other fields." Fields with significant volumes of sulphur reserves in 2006 are Caroline, Crossfield East, Okotoks, and Waterton, which together accounted for 12.4 10^6 t (36.6 per cent) of remaining established reserves from natural gas.

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2006

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[a] (%)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Benjamin	4 943	5.1	300	406
Bighorn	3 958	8.0	385	523
Blackstone	2 761	10.5	384	521
Brazeau River	10 894	6.5	912	1237
Burnt Timber	2 539	15.9	581	787
Caroline	8 381	21.1	3 240	4 393
Cecilia	9 482	1.4	151	205
Coleman	1 679	27.3	684	928
Crossfield	3 289	8.1	355	481
Crossfield East	3 957	27.4	1 867	2 531
Elmworth	12 239	3.3	483	654
Garrington	3 728	5.4	260	353
Hanlan	5 493	8.8	635	861
Jumping Pound West	5 896	6.5	483	655
Kaybob South	10 133	2.9	366	497
La Glace	2 211	6.5	169	230
Lambert	758	14.9	156	211
Limestone	7 824	10.1	989	1 342
Marsh	1 283	18.6	340	461
Moose	3 791	13.9	707	959
Okotoks	2 864	28.6	1 479	2 006
Pembina	19 714	1.6	412	559
Pine Creek	4 912	5.3	325	441
Quirk Creek		9.6	163	222
Rainbow	10 716	1.7	229	311
Rainbow South	3 648	5.6	302	410
Ricinus West	1 992	33.3	1 193	1 618
Waterton	6 220	24.4	2 549	3 456
Wildcat Hills	5 400	3.0	183	249
Windfall	2 525	12.5	443	600
Subtotal	164 507	9.4	20 727	28 107
All other fields	950 457	0.4	4 178	5 685
Total		2.0	24 905	33 792

[a] Volume-weighted average.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current upgrading operations in which bitumen is converted to synthetic crude oil (SCO), an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in products including coke.

It is currently estimated that some 208 10^6 t of elemental sulphur will be recoverable from the 5.0 10^9 m^3 of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by multiplying the remaining established reserves of crude bitumen by a factor of 40.5 t/1000 m^3 of crude bitumen. This ratio was revised from previous estimates to reflect both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology yields a higher elemental sulphur production than does an alternative carbon-rejection technology, since a larger percentage of the sulphur in the bitumen remains in upgrading residues, as opposed to being converted to H_2S.

If less of the mineable crude bitumen reserves is upgraded with the hydrogen-addition technology than currently estimated or if less of the mineable reserves is upgraded in Alberta, as has been announced, then the total sulphur reserves will be less. However, if some of the in situ crude bitumen reserves are upgraded in Alberta, as is currently planned, the sulphur reserves will be higher. The EUB is reviewing these future development scenarios and will report the changes in a future edition of this report.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only a portion of the surface-mineable established crude bitumen reserves is under active development at the Suncor, Syncrude, Albian Sands, Shell Jackpine, CNRL Horizon, and Petro-Canada/UTS Energy/Tech Cominco Fort Hills projects. The EUB has estimated the initial established sulphur reserves from these active projects to be 143.1 10^6 t, or 69 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. A total of 18.3 10^6 t of elemental sulphur has been produced from these projects, leaving remaining established reserves of 124.8 10^6 t. During 2006, 1.8 10^6 t of elemental sulphur was produced from the six active projects.

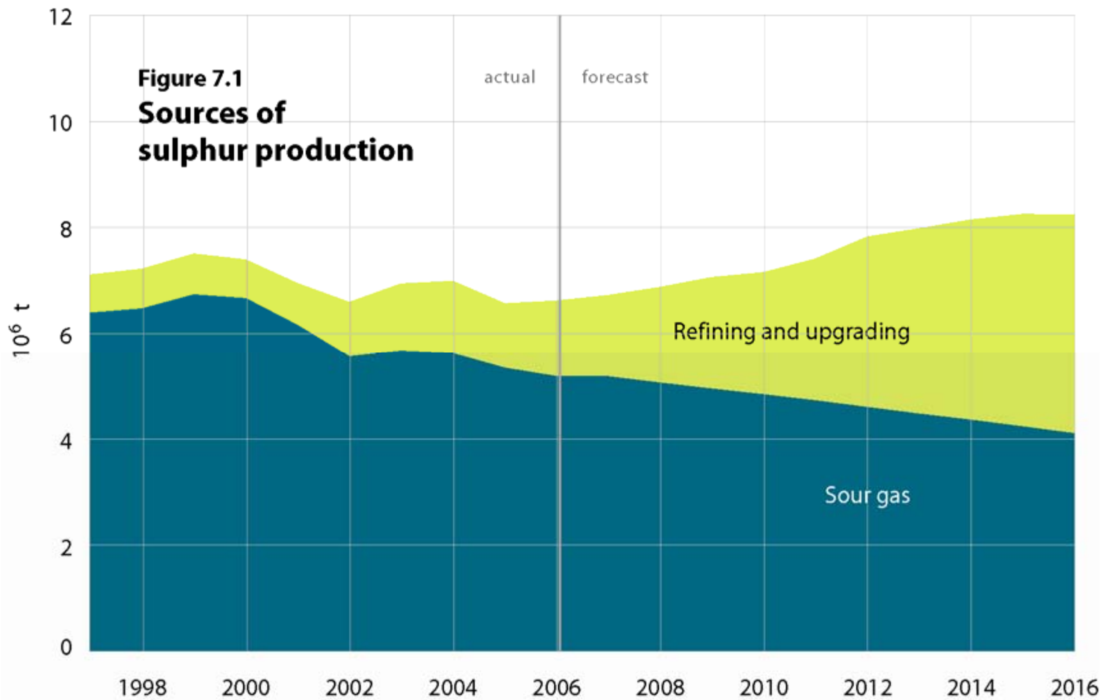
7.2 Supply of and Demand for Sulphur

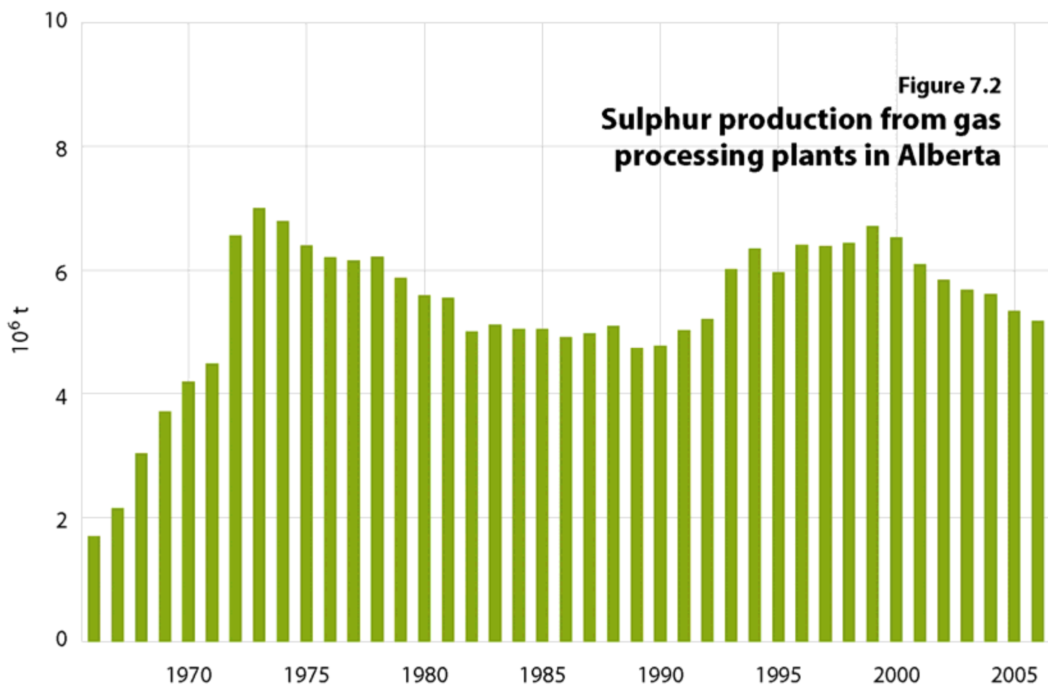
7.2.1 Sulphur Supply

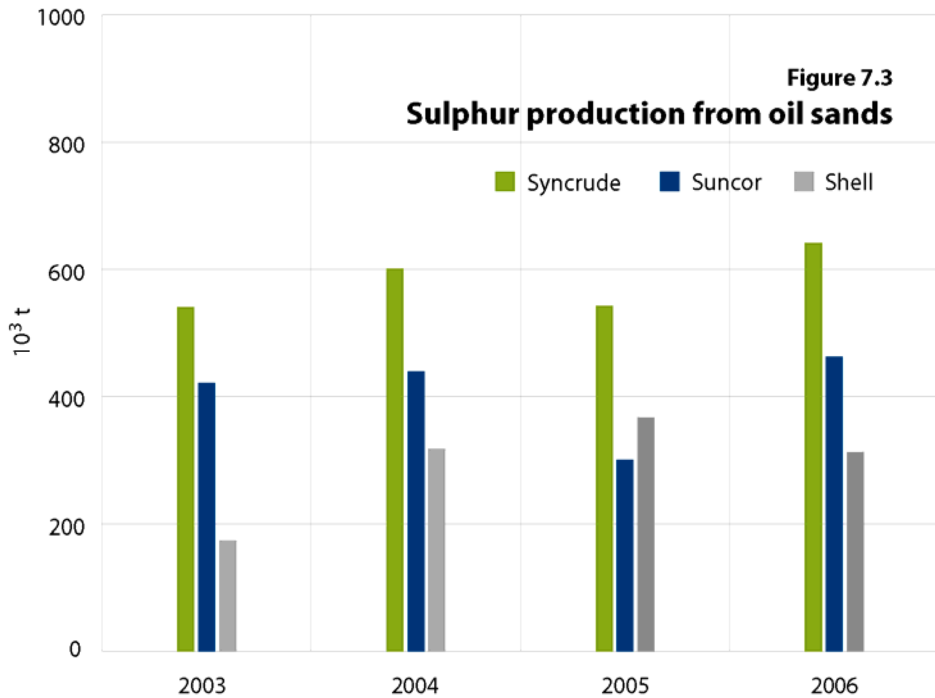
There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to SCO, and refining of crude oil into refined petroleum products. In 2006, Alberta produced 6.6 10^6 t of sulphur, of which 5.1 10^6 t was derived from sour gas, 1.4 10^6 t from upgrading of bitumen to SCO, and just 11 thousand (10^3) t from oil refining. Sulphur production from these sources is depicted in **Figure 7.1**.

While sulphur production from sour gas is expected to decrease from 5.2 10^6 t in 2006 to 4.1 10^6 t, or some 20 per cent, sulphur recovery in the bitumen upgrading industry is expected to increase to 4.1 10^6 t from 1.4 10^6 t by the end of the forecast period. **Figure 7.2** shows sulphur production from gas processing plants from 1966 forward. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional gas declines, less sulphur will be recovered from gas processing plants. Sulphur production from the three existing oil sands upgrader operations is shown in **Figure 7.3** for the period 2003-2006.

The Alberta refineries are expected to replace conventional crude and synthetic crude with bitumen, as integration of bitumen upgrading and refining takes place in this forecast period. With this integration, the sulphur recovery will increase from 11 10^3 t in 2006 to 56 10^3 t by 2016. Total sulphur production is expected to reach 8.3 10^6 t by the end of forecast period.







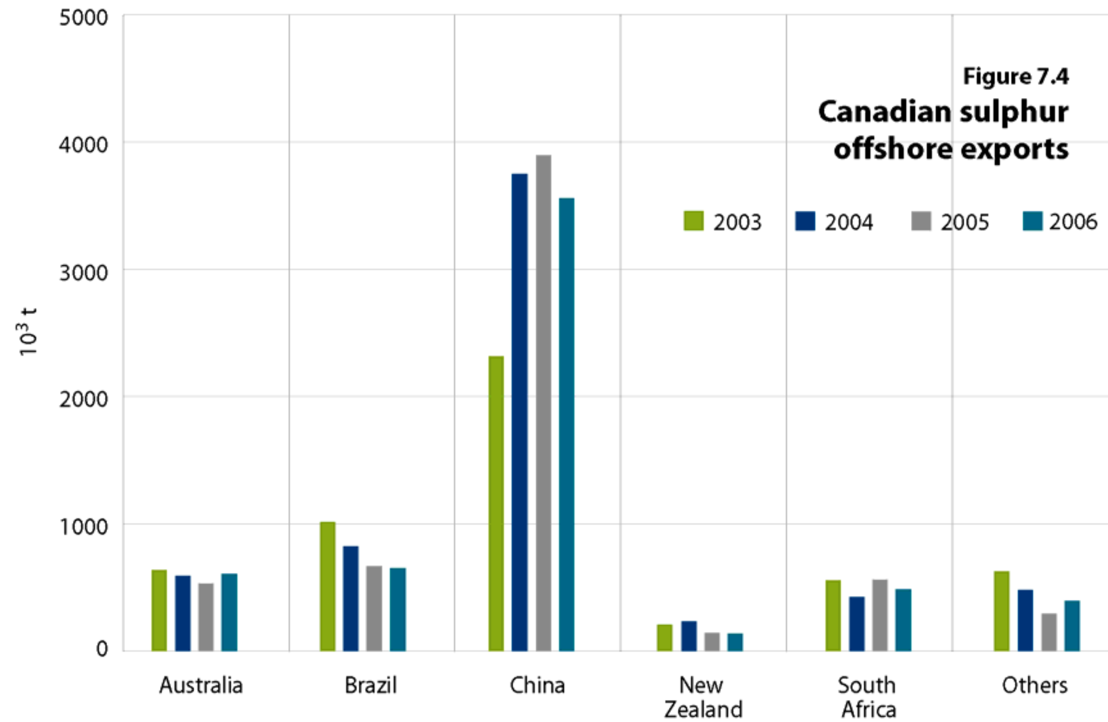
7.2.2 Sulphur Demand

Demand for sulphur within the province in 2006 was about 220 10^3 t, similar to that in 2005. It was used in production of phosphate fertilizer and kraft pulp and in other chemical operations. Some 97 per cent of the sulphur marketed by Alberta producers was shipped outside the province, primarily to United States and China.

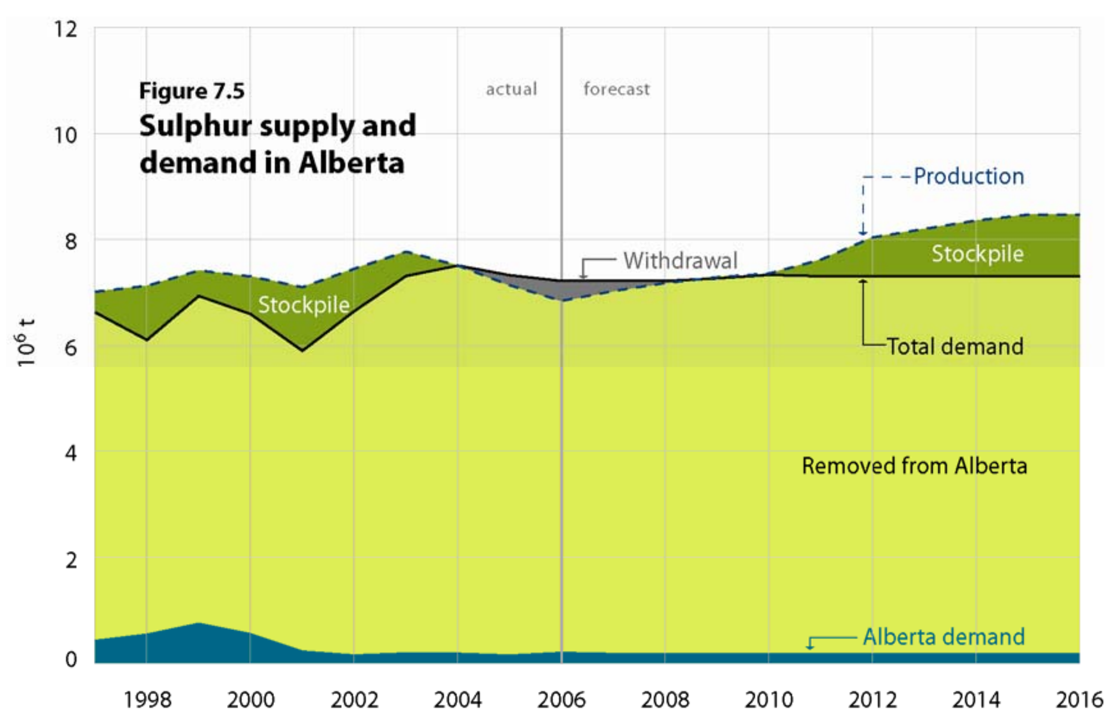
In the early 1990s, a number of traditionally sulphur-importing countries installed sulphur-recovery equipment in oil refineries and other sulphur-emitting facilities, largely for environmental reasons. Consequently, many of these countries became self-sufficient in sulphur and the price declined significantly. Under such low price conditions, many of Alberta's competitors ceased production of sulphur, enabling Alberta's market share to rise throughout the late 1990s. China's imports of sulphur have soared since 1995 and imports from Canada have increased substantially. China is now the world's largest importer of sulphur, which is used there primarily for making sulphuric acid to produce phosphate fertilizers. **Figure 7.4** shows the export volumes sent to markets outside of North America in the last four years. Clearly, China accounts for the majority of Canadian exports to foreign countries.

Increased global demand for sulphur resulted in a major price change, from US$16/t in 2001 to US$50/t in 2006 (FOB Vancouver)**.**

Because elemental sulphur (in contrast to sulphuric acid) is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles.



In the past few years, supply and demand have been in balance and are forecast to remain so until 2011. Sulphur stockpiles thereafter are expected to grow. Changes to the sulphur inventory are illustrated in **Figure 7.5** as the difference between total supply and total demand.



8 Coal

Production of coal is from mines and is called raw coal. Some coal, particularly coal from the mountain and foothills regions of Alberta, needs to be processed prior to marketing; this processed coal is called clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are termed marketable coal. Reserves within this report refer to raw coal unless otherwise noted.

The following information summarizes and marginally updates the material found in EUB *Statistical Series 2000-31: Reserves of Coal*. Those seeking more detailed information or a greater understanding of the parameters and procedures used to calculate established coal reserves are referred to that report.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The EUB estimates the remaining established reserves of all types of coal in Alberta at December 31, 2006, to be 33.5 gigatonnes (Gt). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods, 10.8 Gt is recoverable by surface mining methods, and 1.16 Gt is within permit boundaries of mines active in 2006. **Table 8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

Table 8.1. Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2006[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.226	0.585
Underground	5.06	0.738	0.107	0.631
Subtotal	6.83[c]	1.56[c]	0.333[d]	1.227[c]
High-volatile bituminous				
Surface	2.56	1.89	0.152	1.738
Underground	3.30	0.962	0.047	0.915
Subtotal	5.90[c]	2.88[c]	0.199[d]	2.681[c]
Subbituminous[e]				
Surface	13.6	8.99	0.703	8.287
Underground	67.0	21.2	0.068	21.132
Subtotal	80.7[c]	30.3[c]	0.771	29.529[c]
Total[c]	93.7[c]	34.8[c]	1.303	33.5[c]

[a] Tonnages have been rounded to three significant figures.
[b] Includes minor amounts of semi-anthracite.
[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.
[d] Difference due to rounding.
[e] Includes minor lignite.

Minor changes in remaining established reserves from December 31, 2005, to December 31, 2006, resulted from increases in cumulative production. During 2006, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.004 Gt, 0.006 Gt, and 0.026 Gt respectively.

8.1.2 Initial in-Place Resources

Several techniques, in particular the block kriging, grid, polygon, and cross-section methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground-mineable coal.

In general, shallow coal is mined more cheaply by surface than by underground methods; such coal is therefore classified as surface-mineable. At some stage of increasing depth and strip ratio, the advantage passes to underground mining; this coal is considered underground-mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio, designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

8.1.3 Established Reserves

Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reasons and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal, as well as the thicker underground classes.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been allowed for where, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region, 70 per cent in the foothills, and 90 per cent in the plains (the three regions designated by the EUB within Alberta where coals of similar quality and mineability are recovered).

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 metres [m]) and thick (> 3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Any developer wishing to mine coal in Alberta must first obtain a permit and licence from the EUB. An application for a permit must include extensive information on such matters as coal reserves, proposed mining methods, and marketing of coal. Coal reserves within the applied-for mine area must be at least sufficient to meet the marketing plans of the applicant.

Table 8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2006.

Table 8.2. Established resources and reserves of raw coal under active development as of December 31, 2006

Rank Mine	Permit area (ha)	Initial in-place resources (Mt)[a]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[c] (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	12	142
Grande Cache	4 250	199	85	23	62
Subtotal	11 705	445	239	35	204
High-volatile bituminous					
Coal Valley	17 865	572	331	114	217
Subtotal	17 865	572	331	114	217
Subbituminous					
Vesta	2 410	69	54	42	12
Paintearth	2 710	94	67	42	25
Sheerness	7 000	196	150	70	80
Dodds	425	2	2	1	1
Burtonsville Island[b]	150	0.5	0.5	0.06	0.4
Whitewood	3 300	193	120	77	43
Highvale	12 140	1 021	764	338	426
Genesee	7 320	250	176	59	117
Subtotal[c]	35 455	1 826	1 334	629	704
Total	65 025	2 843	1 904	778	1 125

[a] Mt = megatonnes; mega = 10^6.
[b] Formerly known as Keephills mine.
[c] Differences are due to rounding.

8.1.4 Ultimate Potential

A combination of two methods has been used to estimate ultimate potentials. The first, the volume method, gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the second method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

A large degree of uncertainty is inevitably associated with estimation of an ultimate potential. New data could substantially alter results derived from the current best fit. To avoid large fluctuations of ultimate potentials from year to year, the EUB has adopted the policy of using the figures published in *Statistical Series 2000-31: Reserves of Coal* and adjusting them slightly to reflect the most recent trends. **Table 8.3** gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potentials. No change to ultimate potential has been made for 2006.

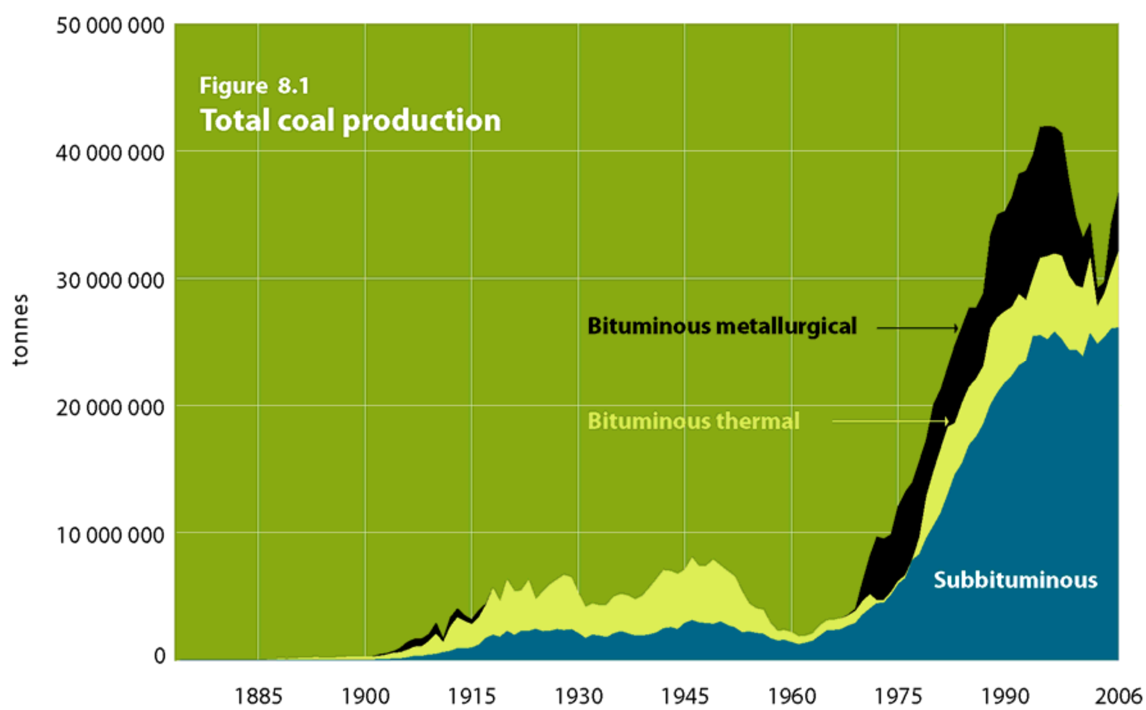
Table 8.3. Ultimate in-place resources and ultimate potentials[a] (Gt)

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	21	3.2
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	500	160
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	1 500	470
Total	2 000[b]	620

[a] Tonnages have been rounded to two significant figures, and totals are not arithmetic sums but are the result of separate determinations.
[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

8.2 Supply of and Demand for Marketable Coal

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical coal production by type is illustrated in **Figure 8.1**.



Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used for electricity generation in Alberta. Metallurgical bituminous coal is exported and used for industrial applications, such as steel making. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of bituminous thermal coal makes it possible to economically transport the coal over long distances. While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. Subbituminous raw coal and clean bituminous coal are collectively known as marketable coal.

8.2.1 Coal Supply

The location of coal mine sites in Alberta is shown in **Figure 8.2**. In 2006, eleven mine sites supplied coal in Alberta, as shown in **Table 8.4**. Excluded from this is the Obed mine, which was suspended in 2003. The operating mines produced 32.5 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 80.3 per cent of the total, bituminous metallurgical 8.6 per cent, and bituminous thermal coal the remaining 11.1 per cent. Continuing high crude oil prices have resulted in improved economics in the coal markets; hence, thermal coal production capacity at the Coal Valley mine more than doubled in 2006.

Figure 8.2
Producing coal mines in Alberta

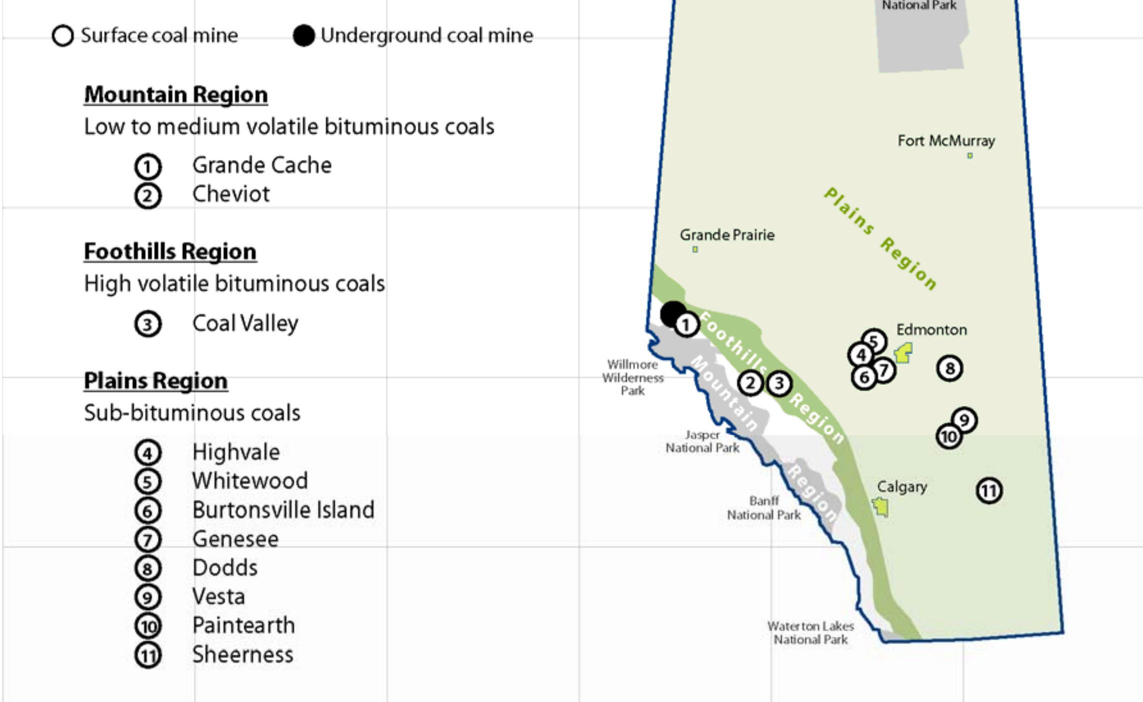


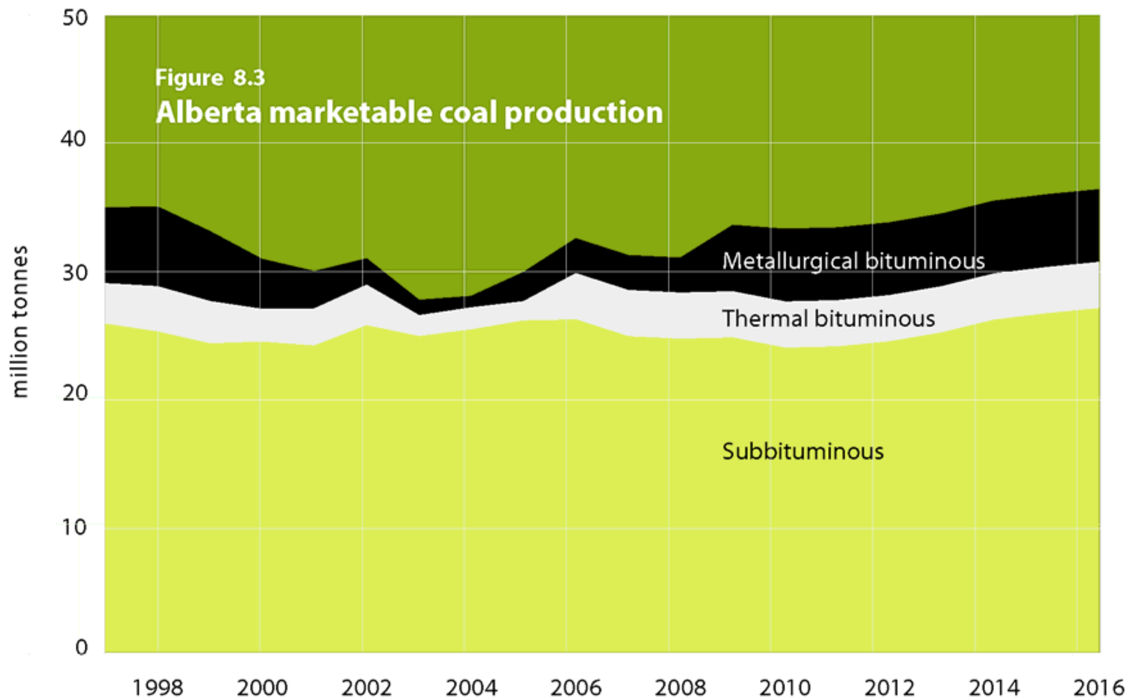
Table 8.4. Alberta coal mines and marketable coal production in 2006

Operator/owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Luscar Ltd. / EPCOR Generation	Genesee	Genesee	6.6
Luscar Ltd.	Sheerness	Sheerness	3.6
	Paintearth	Halkirk	1.5
	Vesta	Cordel	1.5
Luscar Ltd./TransAlta Utilities Corp.	Highvale	Wabamun	12.5
	Whitewood	Wabamun	1.3
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.113
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.019
Bituminous metallurgical coal			
Cardinal River Coals Ltd./Elk Valley	Cheviot	Mountain Park	1.7
Grande Cache	Grande Cache	Grande Cache	1.1
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	3.6
Total			32.5

Six large mines and two small mines produce subbituminous coal. The large mines serve nearby electric power plants, while the small mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the reserves have been dedicated to the power plants.

Two surface mines and one underground mine produce the provincial metallurgical grade coal. Although metallurgical grade coal underlies much of the mountain region, few areas have sufficient economical recoverable reserves at current prices.

Forecast Alberta production for each of the three types of marketable coal is shown in **Figure 8.3**.



8.2.2 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electric generation plants, and their production ties in with electricity generation.

One power generation unit at the Keephills plant site with a capacity of 450 megawatts (MW) is planned to be in service in 2011, with the potential for an additional plant fuelled by subbituminous coal within the forecast period.

Alberta's metallurgical coal primarily serves the Asian steel industry, mainly Japan, but export coal producers have the competitive disadvantage of long distances from mine to port. Currently export markets are expected to remain relatively strong over the next few years due to the high natural gas/crude oil prices, high levels of steel consumption, and a continuing strong demand in the Pacific Rim countries.

9 Electricity

The EUB regulates investor-owned natural gas, electric, and water utilities and certain municipally owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates. This regulatory role is currently in a state of evolution due to the ongoing deregulation of the natural gas and electric industries. Staff also respond to customer inquiries and complaints respecting utility matters. In addition, the EUB ensures that electric facilities are built, operated, and decommissioned in an efficient and environmentally responsible way.

The *Electric Utilities Act* of January 1, 1996, its subsequent amendments, and its supporting regulations establish the framework for the future of Alberta's electric industry. This framework was set to facilitate the transition of Alberta's electric industry from a vertically integrated and heavily regulated utility structure to one that features competition in the generation and retail market with consumer choice. The transmission and distribution components of the electric industry in Alberta remain regulated natural monopolies.

The competitive wholesale market is facilitated by the Alberta Electric System Operator (AESO) and monitored by the Market Surveillance Administrator (MSA). The AESO's main responsibilities include the planning and operation of Alberta's transmission system and ensuring that electricity generating and distribution companies, along with large industrial consumers, receive fair and open transmission access to the power grid. The MSA monitors Alberta's electricity market for fairness and balance in the public interest by ensuring that the market operates fairly, efficiently, and in an openly competitive manner.

Along with the AESO and the MSA, the Balancing Pool was established in 1999 in order to help manage the financial accounts arising from the transition to a competitive generation market on behalf of electricity consumers and to meet any obligations and responsibilities associated with both sold and unsold Power Purchase Arrangements (PPAs).

In 2000, in order to introduce competition to Alberta's electricity market, electricity generation from utility plants built during the era of full regulation (before 1996) were auctioned off as PPAs. These PPAs provided successful buyers with the long-term rights to sell power generated at these units directly to customers or through the power pool. Electricity generating units built after January 1, 1996, are not subject to PPAs and their generation can be bought or sold directly to the market.

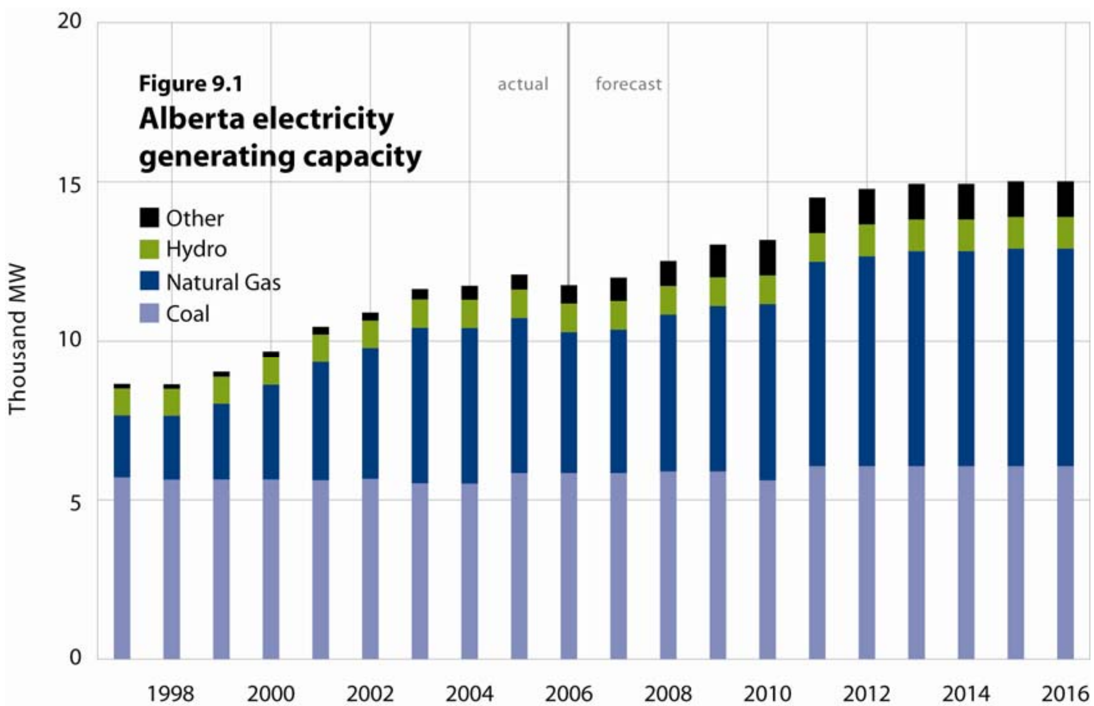
9.1 Electricity Generating Capacity

9.1.1 Provincial Summary

Capacity refers to the maximum potential supply of electricity, often expressed in megawatts (MW), that can be produced each hour. Alberta's fuel mix of available electricity generating capacity is composed of coal, natural gas, hydroelectric, and renewable energy, such as wind and biomass. A relatively small amount of capacity is obtained from diesel and fuel oil-fired generators, which are used as a source of backup power for industrial use.

A large majority of the natural gas-fired capacity in the province is classified as cogeneration. Cogeneration is the combined production of electricity and thermal energy using natural gas as a fuel source. Thermal energy is often used in manufacturing processes or for heating buildings, as such cogeneration plants are often sited alongside an industrial facility.

As illustrated in **Figure 9.1**, the structure of Alberta's electricity industry has changed since the years prior to deregulation. In 1997, Alberta's electric generating capacity was slightly more than 8600 MW, with coal-fired facilities accounting for 66 per cent. Between 1997 and 2006, electricity generating capacity increased by 3120 MW to total 11 760 MW. About 80 per cent of the incremental generating capacity was natural gas-fired. In 2006, coal-fired facilities accounted for 50 per cent of Alberta's total electric generating capacity, and natural gas-fired facilities accounted for 38 per cent.



Changes to Alberta's electricity generating capacity in 2006 resulted in a net loss of 330 MW. The decommissioning of EPCOR Power Development Corporation's Cloverbar gas-fired units triggered the removal of 630 MW from the EUB's estimate of Alberta's natural gas-fired generating capacity. While the entire 630 MW was accounted for in 2005, only one of the four units at Cloverbar was operating. A portion of the gross loss to capacity from the shutdown of Cloverbar was offset by capacity additions at Syncrude Canada Ltd.'s Aurora and Mildred Lake gas-fired cogenerators in the Fort McMurray area, as well as additional capacity from wind turbines.

The electricity generating capacity forecast includes power generation projects that are summarized by fuel source in **Table 9.1**. From this potential list as much as 3550 MW of capacity may be added to the provincial power grid by 2016. By the end of the forecast period, the EUB expects electricity generating capacity in Alberta to be 15 030 MW.

New natural gas-fired cogeneration facilities will offer the largest contribution to electricity generating capacity over the forecast period. The commissioning of new natural gas-fired cogeneration plants will coincide with the development of Alberta's oil sands resources. By 2016, electricity generation from natural gas-fired power and cogeneration units could total 6850 MW, accounting for 46 per cent of Alberta's total available capacity.

Table 9.1. Proposed electricity generating capacity additions, 2007-2016

Company	Fuel / type	Proposed capacity (MW)
2007		
Suncor	Natural gas[1]	85
ENMAX	Wind	80
Benign Energy Canada	Wind	54
Wind Power Inc/PH Wind	Wind	14
Alberta Wind Energy	Wind	4
2008		
TransAlta	Coal	53
OPTI/Nexen	Natural gas[1,2]	170
Canadian Natural Resources	Natural gas[2]	100
Meg Energy	Natural gas[1]	85
EPCOR	Natural gas	43
Shell	Natural gas	22
TransAlta (VisionQuest)	Wind	52
2009		
Suncor	Natural gas[1]	170
EPCOR	Natural gas	100
Alberta Wind Energy	Wind	47
West Windeau	Wind	100
Windrise Power	Wind	100
2010 – 2016		
TransAlta/EPCOR	Coal	450
Shell	Natural gas[1]	185
Suncor (multiple phases)	Natural gas[1]	170
Imperial Oil (multiple phases)	Natural gas[2]	170
Synenco	Natural gas[2]	170
UTS/PetroCanada/Teck Com.	Natural gas[2]	170
PetroCanada	Natural gas[1]	165
Shell	Natural gas[2]	160
EPCOR	Natural gas	100
Canadian Natural Resources	Natural gas[2]	86
Canadian Natural Resources	Natural gas[1]	85
Total E&P Canada (Deer Creek)	Natural gas[2]	85
OPTI/Nexen	Natural gas[1,2]	85
Sundance Forest Industries	Biomass	10
Glacier Power (Canadian Hydro)	Hydro	100
Benign Energy Canada	Wind	77
Total proposed generation (2007-2016)		3547

[1] Cogeneration for in situ bitumen project.
[2] Cogeneration for bitumen mine or upgrader project.

9.1.2 Electricity Generating Capacity by Fuel

Coal

In 2006, coal-fired generating units accounted for 50 per cent of Alberta's generating capacity. The current capacity of Alberta's coal generation is 5840 MW. There are proposals to develop an additional 500 MW of coal-fired electricity capacity over the next decade. With the decommissioning of TransAlta Corporation's Wabamum Unit 4, total coal-fired capacity may reach 6060 MW by 2016 and account for 40 per cent of Alberta's total generation capacity.

In May 2006, TransAlta applied to the EUB to complete an uprate to capacity at one of the generating units at its Sundance coal-fired plant. Using existing infrastructure, Sundance Unit 4 will be retrofitted with a new turbine, and modifications to the boiler and electrostatic precipitators will be made in order to achieve higher operating efficiencies. At project completion, Unit 4 will be able to produce an additional 53 MW of electricity but will use less fuel on a per MW basis. A similar project was completed on Sundance Unit 6 in 2001. Work on the Unit 4 uprate project is expected to proceed in 2007 and is forecast to be completed in 2008.

In 2001, TransAlta applied to the EUB to expand its Keephills coal-fired power plant to include two additional 450 MW units. This Centennial Project was approved by the EUB in 2002. However, in June 2006 TransAlta filed an amendment to the original planned expansion at Keephills. The Centennial Project, now referred to as the Keephills 3 project, proposes the construction of one 450 MW coal-fired unit that will incorporate supercritical boiler technology, featuring higher boiler temperatures and pressures. Combined with a high efficiency turbine, the unit will require less fuel and air emissions will be lower on a per MW basis. TransAlta and EPCOR have equal ownership in the Keephills 3 plant. EPCOR is responsible for the construction and TransAlta will run the facility. In February 2007, TransAlta announced that it expects to commission Keephills 3 by the end of the first quarter of 2011.

Natural Gas

Natural gas-fired generating capacity accounts for 38 per cent of Alberta's current total electricity capacity. The current capacity of Alberta's natural gas-fired generation is 4440 MW. Over the next 10 years, Alberta's natural gas-fired electric capacity is expected to increase by 2410 MW and will account for 46 per cent of Alberta's total generating capacity.

New natural gas-fired cogeneration power plants account for about 2160 MW, or about 90 per cent of the increase in natural gas-fired capacity over the next decade. The regulatory applications that are expected to be filed with the EUB for approvals to construct and operate cogeneration facilities coincide with the development of Alberta's oil sands resources, which require large quantities of electricity and thermal energy to extract the bitumen.

The forecast includes the construction and operation of cogeneration facilities for the following in situ oil sands operations: Suncor Energy Inc.'s Firebag project, Meg Energy Corporation's Christina Lake project, Shell Canada Ltd.'s Carmon Creek project, Canadian Natural Resources Ltd.'s (CNRL) Primrose East expansion, and PetroCanada's MacKay River expansion. Cogeneration facilities that are considered part of an oil sands mine or bitumen upgrading operation include the OPTI Canada Inc. and Nexen Inc.'s Long Lake projects, the CNRL Horizon project, Shell Canada's Jackpine project, the Synenco Energy Inc.'s Northern Lights project, the Fort Hills joint venture (Petro-

Canada, UTS Energy Corporation and Teck Cominco Ltd.), the Imperial Oil Ltd.'s Kearl Lake project, and the Total E&P Canada (Deer Creek) Joslyn project.

In August 2006, EPCOR filed a regulatory application with the EUB that proposed the installation of new natural gas-fired turbines at its existing Cloverbar power plant. The Cloverbar generating station was built in the late 1960s and the first unit became operational in 1970. The natural gas-fired units at Cloverbar had a generating capacity of 630 MW but have since been decommissioned when the Balancing Pool of Alberta terminated the PPA for the output of the plant.

EPCOR is proposing to install three natural gas-fired units at Cloverbar. The first unit, with a capacity of 43 MW, is expected to be operational by winter 2007/08. The second and third units, with capacities of 100 MW each, are planned to be operational by winter 2008/09 and winter 2010/11.

Hydro

Electricity from hydro sources accounted for almost 8 per cent of total capacity in 2006. The current capacity of Alberta's hydroelectric generation is approximately 900 MW. About 800 MW of this capacity is owned by TransAlta, operating 26 generating units along the Bow and North Saskatchewan Rivers.

In 2006, Glacier Power, a subsidiary of Canadian Hydro Developers Inc., filed a regulatory application with the EUB to construct and operate a 100 MW hydroelectric power plant on the Peace River. Subject to regulatory approval, the Dunvegan plant could be operational in 2011.

Renewable Power

About 5 per cent of Alberta's current electricity capacity is classified as renewable power that includes biomass and wind. Biomass electricity is derived from plant or animal material, such as wood, straw, peat, or manure. In Alberta, the most common fuel for biomass generation is waste wood. Forestry industries typically burn waste wood as a fuel source to generate electricity and thermal energy. In 2006, Alberta biomass capacity amounted to 184 MW, less than 2 per cent of Alberta's total capacity. Sundance Forest Industries is expected to commission a 10 MW biomass-fuelled power plant within three to five years.

Alberta's wind farms and turbines currently have the potential to supply a maximum of 387 MW of electricity to the grid. The electricity generating capacity from wind turbines has increased by about 110 MW since 2005. Three new wind projects were connected to the Alberta electricity grid in 2006. GW Power Corporation and Nexen's Soderglen joint project has a rated capacity of 70 MW. The Chin Chute joint project and Kettle Hills, first in a suite of projects, added 30 MW and 9 MW respectively.

Wind power has its benefits as a renewable, non-emission generating source of power supply; however the variability of wind can cause supply uncertainties on the Alberta electricity grid. Solutions are available to mitigate the risk of supply and demand imbalances that can occur from wind power. Developing wind power forecasting techniques and the siting of wind turbines and wind farms may help. Having geographically dispersed wind turbines may provide some relief, because while wind might not be blowing in one area to create electricity, it could be blowing in another area.

Another method that could be used to help balance electricity demand and supply from within Alberta would be to rely on the transmission interties between Alberta and other jurisdictions. The intertie could manage a supply and demand imbalance by flowing the imbalance to neighbouring provinces. However, Alberta complies with an international set of standards stipulating how frequently interties may be used for this purpose; as well, Alberta’s interties have limited transfer capabilities.

Constraining the amount of wind power development within the province is a short-term solution to balancing the supply and demand while further research specific to Alberta’s market can be completed. In 2006, after consulting with industry stakeholders and studying the impacts of wind power on the Alberta electricity grid, the AESO curtailed the amount of wind power development in the province to 900 MW.

A number of regulatory applications have been submitted to the EUB to construct wind turbines and wind farms within Alberta. Most recently, a number of the proposals received at the EUB did not disclose commissioning dates, citing unavailable transmission requirements, the AESO cap on wind power development in Alberta, and longer lead times on machinery and equipment. These latter projects have not been considered as part of the EUB forecast. Overall, it is expected that total wind power capacity will near 900 MW early on in the forecast.

9.2 Supply and Demand of Electricity

This section discusses the supply and demand of electricity within Alberta. On the supply side, the stock of electricity or capacity is measured in watts, while the flow of electricity or generation is measured in watt hours. Electricity demand, in this report, is defined as the average annual load in Alberta measured in gigawatt hours.

Electricity generation is the amount of electricity produced within a certain time period. For instance, if an electricity plant with a rated capacity of 100 MW operated at its maximum potential for one day it would supply 2.4 gigawatt hours (GWh) of electricity. Alternatively, if the same plant only supplied 1.8 GWh of electricity on a given day, the plant would be using 75 per cent of its potential capacity.

In order to forecast electricity generation, the EUB uses a defined list of existing and proposed electricity generating units, electricity generating capacities, expected operating characteristics, a merit or stacking order, hourly customer load profiles, and expected electricity demand. The proposed generating units and generating capacities are discussed in the previous section. The electricity generation forecast does not incorporate PPAs that are currently known to expire within the forecast time frame, such as the December 31, 2013, expiration of EPCOR’s PPA for Battle River units 3 and 4. Further, it is assumed that the province is import/export neutral.

The expected operating capacity of an existing electricity generating unit is determined using its historical operating parameters, such as outage and capacity utilization rates. For instance, depending on location, the effective electricity capacity of a wind turbine can be roughly 20 to 30 per cent of its installed capacity. In the oil sands sector, the forecast of electricity generation from new generation is ramped up in a phased approach that corresponds with the expected on-site load at certain phases of bitumen or SCO production.

The stacking order of electricity generation refers to the order in which electricity from each generating unit is offered in or sold to the electricity grid. The lowest marginal cost producers are expected to offer in electricity generation first. The lowest marginal cost producers include wind turbines, hydroelectric dams, and an amount of base coal-fired generation. Higher marginal cost producers, such as electricity from natural gas-fired turbines (under a regime of high natural gas prices), offer electricity into the grid at times of peak demand.

A more realistic electricity generation forecast is obtained by incorporating hourly load profiles and the EUB forecast of electricity demand for each year. For each year there is an 8760 hour load profile that corresponds with the expected total load. By incorporating hourly loads, generating units are dispatched hourly, which accounts for periods of high load and low load throughout each year.

The EUB defines Alberta's total electricity demand as the electricity sales reported by utilities to agricultural, residential, commercial, and industrial customers, as well as the on-site use of electricity generated by industrial consumers. The EUB's definition of total electricity demand excludes transmission losses and power generation from isolated plants. As such, the EUB forecast may not match the AESO's Alberta Interconnected Electric System (AIES) forecast or its Alberta Internal Load (AIL) forecast. However, the expected growth in overall demand of the AESO AIL and EUB forecast may be comparable.

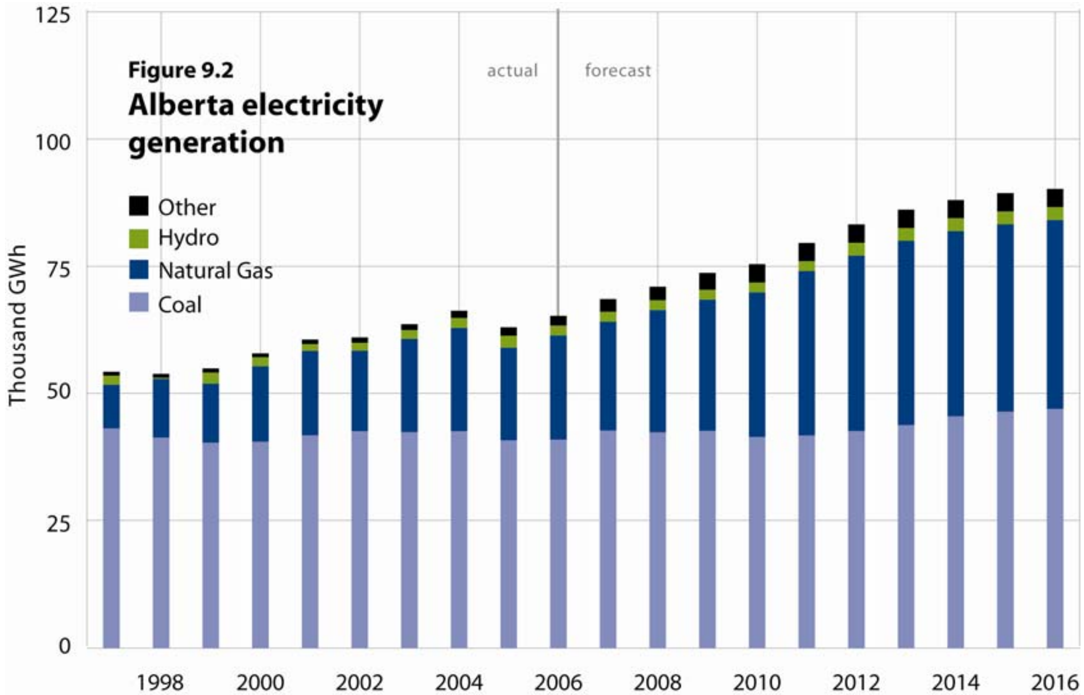
The EUB uses these customer segments and econometric modelling to forecast total electricity demand. The industrial end-use customers are further categorized into the forest product, petrochemical, refinery, and oil sands sectors in order to adequately account for electricity demand growth or contraction within these industries. The key drivers of electricity demand include components of Alberta's economy represented by its gross domestic product, heating degree days, housing stock, and household income. Within the oil sands sector, expectations for bitumen and SCO production are also important drivers.

9.2.1 Electricity Generation

Alberta installed capacity in 2006 was 11 760 MW, enough to supply over 100 000 GWh of electricity if it operated at full capacity. However, total electricity generating capacity is not continuously available to meet demand. Generating units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, technical limitations (for instance, wind turbines), or economic reasons.

Figure 9.2 illustrates total electricity generation in Alberta by fuel type, including electricity from cogeneration plants that is not sold into the Alberta Interconnected System. In 2006, total electricity generation reached 65 280 GWh. Between 1997 and 2006, electricity generation in Alberta grew by 11 060 GWh or, on average, 2 per cent per year.

In 2006, coal-fired power plants generated 63 per cent of the province's electricity, while natural gas and hydro accounted for 31 and 3 per cent respectively. The remaining 3 per cent of electricity was generated by wind and other renewable sources. Natural gas cogeneration plants designated to the oil sands sector generated 11 480 GWh of electricity. Within the oil sands, almost 6800 GWh (59 per cent) of the electricity generated was used on site, whereas the remaining was sold into the power pool.



Wind turbines contributed 922 GWh, or about 1 per cent, of total electricity generation in 2006. The generation from wind turbines is accounted for in the "other" category in **Figure 9.2**. Wind generation constituted 48 per cent of the electricity generated in the "other" category, with electricity generation from biofuel accounting for most of the remaining generation in this category.

The capacity additions discussed in the previous section, as well as the decommissioning of 280 MW (unit 4) at TransAlta's Wabamun coal-fired power plant in 2010 and apparent electricity demand from residential, commercial, and industrial sectors, suggest that electricity generation in Alberta will grow by an additional 25 Terawatt hours (TWh) over the next ten years, or an average of 4 per cent per year.

9.2.2 Electricity Transfers

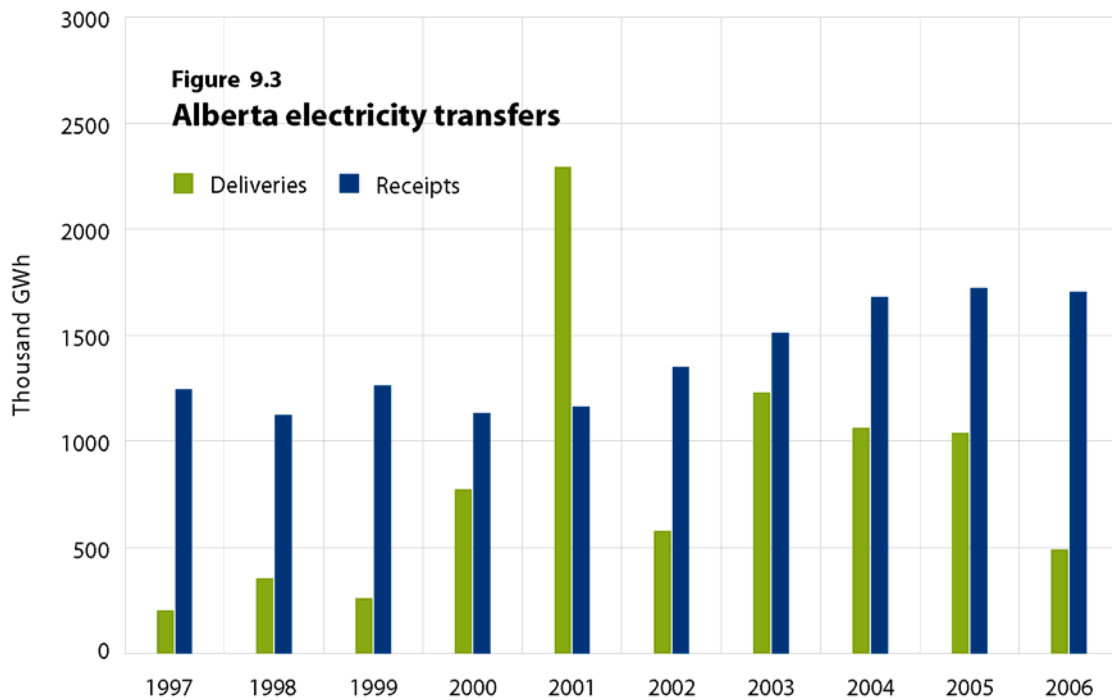
Alberta's transmission lines are connected with British Columbia (B.C.) and Saskatchewan. Alberta is interconnected with the B.C. transmission system through a 500 kilovolt (kV) line between Langdon, Alberta, and Cranbrook, B.C., and two 138 kV lines between Pocaterra and Coleman, Alberta, and Natal, B.C. Since B.C. is connected with the U.S. Pacific Northwest, the Alberta-B.C. intertie allows Alberta to indirectly trade electricity with the U.S. The 230 kV direct current electrical tie with Saskatchewan enables Alberta to import or export about 150 MW.

The Alberta-B.C. interconnection was designed to operate at transfer capacities of 1200 MW from B.C. to Alberta and 1000 MW from Alberta to B.C. Current operations on the Alberta-B.C. intertie are below these capacities and range between 0 and 750 MW, depending on system load and real-time operation conditions.

In addition to the transmission ties, a natural gas-fired electricity generation unit in Fort Nelson (northern B.C.) supplies power to its surrounding communities and sells surplus electricity generation into the Alberta grid.

Over the last decade, Alberta has generally been a net importer of electricity. However, in 2001 the electricity price differentials between Alberta and the Pacific Northwest favoured Alberta and resulted in net exports for the year. Net imports of electricity into Alberta for other years were relatively small, at about 2 per cent of Alberta generation in 2006. As a result, the electricity supply forecast assumes that the intertie contributions are neutral.

Figure 9.3 shows Alberta's electricity transfers from 1997 to 2006. In 2006, Alberta imported 1704 GWh of electricity, a decrease of 1 per cent or 18 GWh from 2005. Electricity exports decreased 53 per cent, or 546 GWh, to 489 GWh in 2006. As a result, Alberta's net imports of electricity were about 1214 GWh in 2006.



Source: EUB

In 2006, Montana Alberta Tie Ltd. (MATL) filed regulatory applications to build a 230 kV merchant electric transmission line between Lethbridge, Alberta, and Great Falls, Montana. The transmission line would provide new and direct import and export opportunities between Alberta and Montana. The proposed MATL system is capable of transferring 300 MW of electricity in each direction. Although the MATL project has acquired certain regulatory approvals from the National Energy Board, MATL is seeking EUB approval for the construction and operation of the transmission line and related facilities within Alberta and the connection to the Alberta Interconnected Electric System. An EUB decision will be rendered following the EUB scheduled hearing.

MATL held two open seasons, one in 2005 and one in 2006, that resulted in long-term, firm commitments by four shippers. The entire 300 MW capacity in each direction was awarded to Great Plains Wind Energy, Energy Logics (USA) Inc., Invenergy Wind Montana, and Wind Hunter LLC.

9.2.3 Electricity Demand in Alberta

Electricity distribution companies report their annual retail sales of electricity to the EUB. Electricity distribution companies that report to the EUB include ATCO Electric, ENMAX Corporation, EPCOR, Fortis Alberta Inc., the cities of Lethbridge, Medicine Hat, Red Deer, Cardston, Fort Macleod, Ponoka, and the municipality of Crowsnest Pass.[1]

In 2006, Alberta's electricity consumption from sales reported by electricity distributors reached 51 980 GWh. This is an increase of 2.7 per cent from 50 609 GWh in 2005. From these sales, about 56 per cent of the electricity consumed is sold to industrial customers, while commercial customers demand 25 per cent. The remaining 16 per cent and 3 per cent of sales volumes from electricity distribution companies were attributable to the residential and agricultural sectors respectively.

Residential customers consumed 8254 GWh of electricity in 2006. The electricity distribution companies have accounted for almost 1.2 million residential customers in Alberta, which translates to an electricity intensity of 6.9 MWh per residential customer. The electricity usage of the average commercial customer was 89.9 MWh in 2006.

Retail sales by electricity distribution companies make up a large component of the total electricity demand within the province. However, in addition to sales from electricity distribution companies, electricity may be self-generated and served "behind the fence." Many large consumers of electricity operate electricity generating units in this manner to take advantage of the associated economic benefits. They initially serve their on-site requirements and may opt to generate and sell additional electricity to the power pool. As outlined in the *Hydro and Electric Energy Act* (Alberta Regulation 409/83), electricity generation units with a capacity equal to or above 500 kW are required to report the unit's electricity generation, fuel use, and operating characteristics to the EUB.

In 2006, almost 41 000 GWh, or 64 per cent, of total electricity demand in Alberta was used by industrial consumers. As much as 11 800 GWh of the electricity requirements for industrial customers was served behind the fence; the remaining 29 200 GWh was sold to industrial customers by electricity distribution companies over the AIES.

Figure 9.4 illustrates Alberta's electricity consumption by sector. Behind the fence load (industrial on site) for industrial processes is accounted for, in addition to the retail sales from electricity distribution companies. Including on-site electricity generation and use, total electricity demand (excluding transmission and distribution losses) in the province amounted to 63 751 GWh in 2006. Compared to 2005, this is an increase of 2586 GWh, or 4 per cent.

Both total electricity generation and demand in Alberta are expected to grow at average rates of 4 per cent a year over the next decade. Over the next year, very little will be added to Alberta's generation capacity, while demand is expected to increase by 3 per cent. This means that Alberta's electricity generating units will have to operate closer to capacity, and the tightening of the supply/demand balance is the underlying premise for the elevated electricity price forecast discussed in the Economics section.

[1] The AESO reports retail sales from distribution companies as a component to its AIES sales, which also include transmission and distribution losses and exclude Medicine Hat sales, as well as isolated electricity loads.

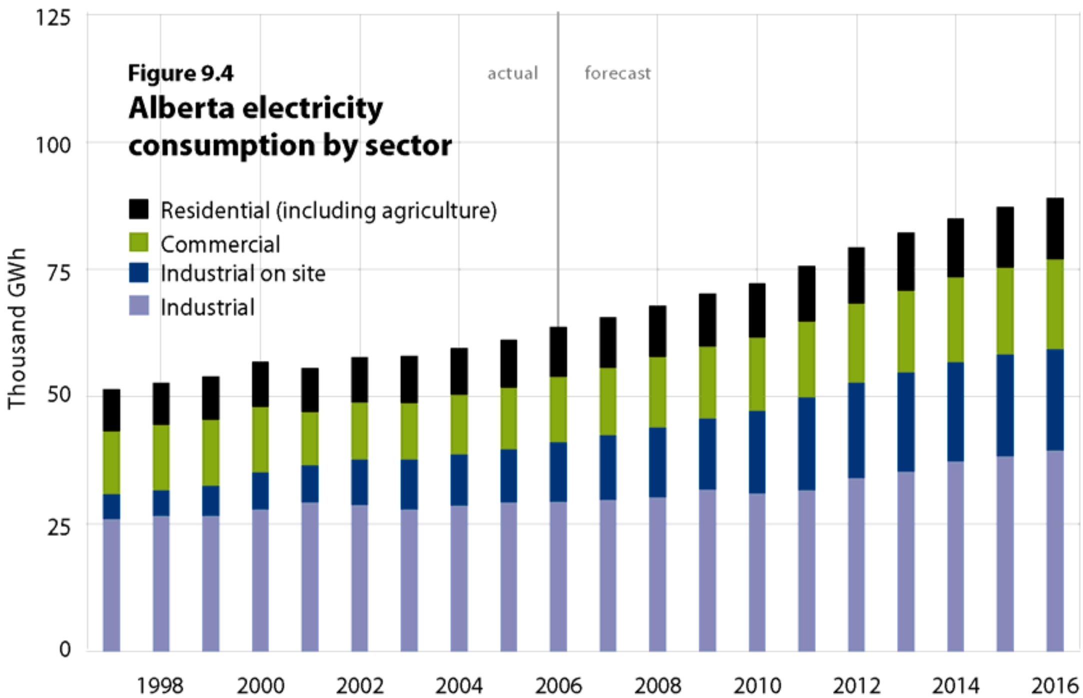


Figure 9.4
Alberta electricity consumption by sector

Over the next ten years, residential (including agriculture) electricity demand will see an average growth of 2 per cent per year. The forecast for residential electricity demand mirrors the historical average growth in this sector. Electricity demand in the commercial sector will continue its recent course, at about 4 per cent per year, as Alberta's forecast of economic growth continues to be impressive.

By the end of the forecast period, electricity demand from the industrial consumers is expected to account for 67 per cent of total electricity demand, while the commercial and residential sectors will account for the remaining 20 per cent and 14 per cent respectively.

The industrial sector will be the largest source of electricity load growth, averaging almost 5 per cent per year. The oil sands sector is expected to account for 76 per cent of the load growth within the industrial sector.

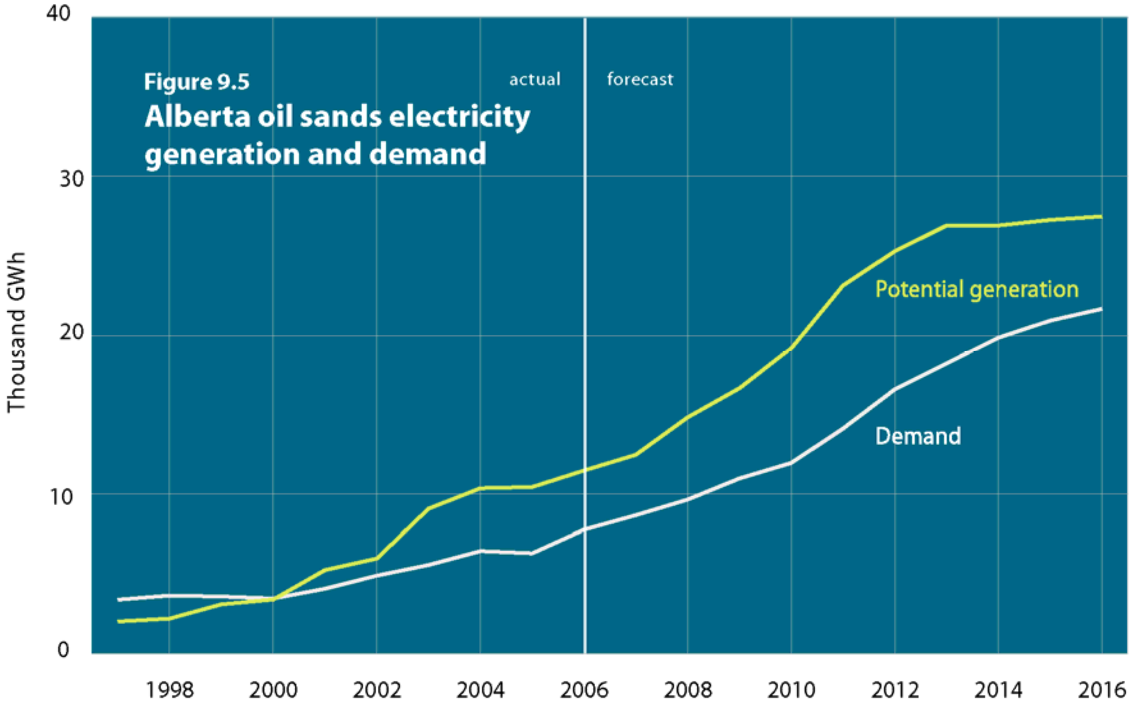
9.3 Imbalances Between Electricity Supply and Demand

9.3.1 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the balance between electricity supply and demand[2] within Alberta's oil sands sector. Electricity generation from the oil sands was forecast by applying the historical operating parameters of existing electricity cogeneration units to the proposed capacities of all current and future cogeneration units. Electricity demand is based on existing electricity intensities, electricity intensities outlined in regulatory applications, and the EUB supply forecast of bitumen and SCO.

A dedicated and reliable source of electricity and thermal energy is important to oil sands operators. While both mining and thermal in situ operators require electricity, the mining and upgrading operations can be much more intensive users of electricity.

[2] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kWh/bbl.



Electricity generating units in mining and upgrading operations are initially designed to meet the electricity demand at target bitumen or SCO production capacities, as additional thermal requirements could be provided through the use of boilers. From operational start-up until target production rates are achieved, surplus electricity may be generated and sold to the power pool. Currently, operators retain between 65 to 95 per cent of the total electricity generated for on-site use. While some operations are ramping up to target production rates, others are adding incremental electricity capacity to feed growing electricity demands.

Thermal in situ operators have lower requirements for electricity but are more intense users of steam. Large thermal requirements and the potential to further enhance the economics of a project via increased revenues from electricity sales have led many in situ oil sands operators to install cogeneration plants. However, in the initial phases of production, there may be fewer wellbores to steam and lower total steam requirements. Therefore, investments in a cogeneration facility at a thermal in situ project site may be postponed until secondary phases, when the production of bitumen has had some time to ramp up. In this case, the alternative to the cogeneration of electricity and thermal energy is to source the thermal energy requirements from steam generators and boilers and the electricity from the provincial power grid.

Currently, four thermal in situ oil sands producers are obtaining steam from on-site cogeneration facilities. The installed electricity generation capacity at each of these thermal operations ranges between 80 and 170 MW. On average, thermal in situ cogeneration facilities are operating at 85 per cent of their installed capacity. Depending of the size of the thermal in situ oil sands operation, anywhere from 10 to 50 per cent of the electricity generated is used on site, and the remainder is available to be sold to the power pool.

9.3.2 Regional Electricity Supply and Demand

The narrow margin between the supply and demand of electricity will continue in future years and will place upward pressure on electricity prices. The total available electricity supply to Alberta consumers, which would include the assumption of continuing trends in net import levels, as well as factoring normal loss factors from transmission and distribution lines, may not be reasonably adequate to supply the current forecast of Alberta demand.

Several options exist to fill a potential shortfall between electricity supply and demand within the province: new natural gas-fired generation could be added to the provincial power grid, additional upgrades could be made at existing coal-fired units, and additional large coal-fired generation could come into play towards the very end of the forecast period. The addition of lower marginal cost generating units may also dampen the electricity price.

Figure 9.6 depicts the EUB's estimates of electricity supply from Alberta generation sources (including behind the fence generation and load) and electricity demand by region. Electricity generation was allocated according to the geographical location of each electricity generation unit.

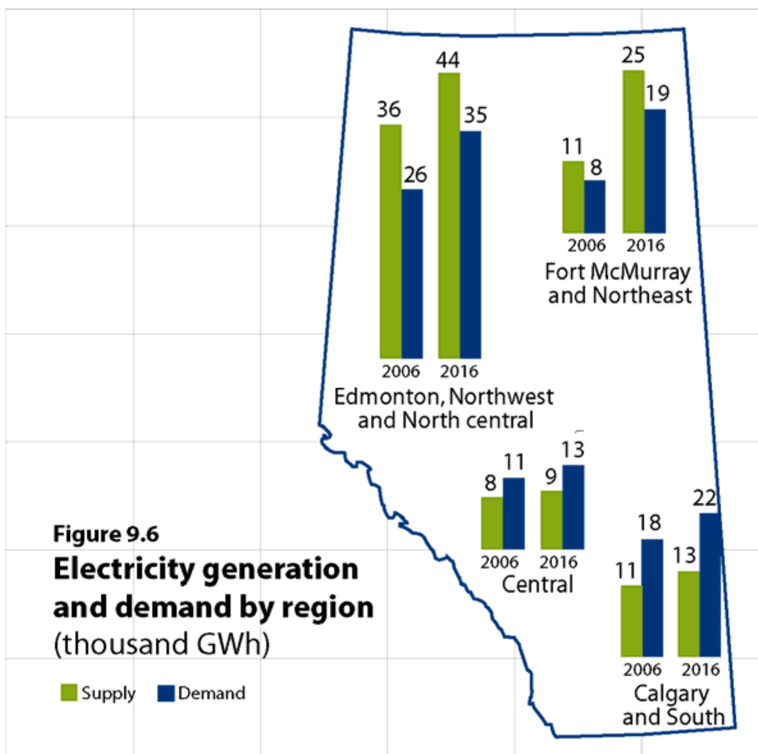


Figure 9.6
Electricity generation and demand by region
(thousand GWh)

Historical data from the AESO on Alberta's internal load by region was analyzed to allocate the EUB electricity demand forecast by region. The underlying growth in electricity demand in each region of the province is expected to be similar, with the exception of demand related to the oil sands. The electricity demand in the oil sands was externalized and added into the regional forecast on a project basis to appropriately account for stronger demand growth in the northern (Edmonton corridor and Sturgeon County) and northeastern regions.

The regional forecast generally depicts that the assumed additions to electricity generating capacity and underlying demand growth will continue to play out the current scenario of an oversupply of electricity in the northern regions of Alberta and supply deficiencies in the central and southern regions. It is currently estimated that an excess electricity generation of 11 500 GWh in the northern regions would be directed to alleviate supply shortages in the central and southern regions. By 2016, the oversupply of electricity in the northern regions will grow to 14 400 GWh, approximately echoing the undersupply of electricity in the central and southern regions.

Appendix A Terminology, Abbreviations, and Conversion Factors

1.1 Terminology

Term	Definition
API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Area	The area used to determine the bulk rock volume of the oil-, crude bitumen-, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.
Burner-tip	The location where a fuel is used by a consumer.
Butanes	In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, Section 1(1)(c.1)).
Coalbed Methane	The naturally occurring dry, predominantly methane gas produced during the transformation of organic matter into coal.
Compressibility Factor	A correction factor for nonideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(d.1)).
Cogeneration Gas Plant	Gas-fired plant used to generate both electricity and steam.
Connected Wells	Gas wells that are tied into facilities through a pipeline.
Crude Bitumen	A naturally occurring viscous mixture mainly of hydrocarbons heavier than pentane that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well (*Oil Sands Conservation Act*, Section 1(1)(f)).
Crude Oil (Conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen (*Oil and Gas Conservation Act*, Section 1(1)(f.1)).

Crude Oil (Heavy)	Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater, but the EUB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchaser's classification.
Crude Oil (Light-Medium)	Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3, but the EUB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchaser's classification.
Crude Oil (Synthetic)	A mixture mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds and is derived from crude bitumen. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, Section 1(1)(t.1)).
Datum Depth	The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.
Decline Rate	The annual rate of decline in well productivity.
Deep-cut Facilities	A gas plant adjacent to or within gas field plants that can extract ethane and other natural gas liquids using a turboexpander.
Density	The mass or amount of matter per unit volume.
Density, Relative (Raw Gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.
Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).

Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).
Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.
Frontier Gas	In this report this refers to gas produced from areas of northern and offshore Canada.
Gas	Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).
Gas (Associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (Marketable)	A mixture mainly of methane originating from raw gas or, if necessary, from the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).
Gas (Marketable at 101.325 kPa and 15°C)	The equivalent volume of marketable gas at standard conditions.
Gas (Nonassociated)	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
Gas (Raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(s.1)).
Gas (Solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas-Oil Ratio (Initial Solution) The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Good Production Practice (GPP) Production from oil pools at a rate
(i) not governed by a base allowable, but
(ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain its share of the production (*Oil and Gas Conservation Regulations* 1.020(2)9).

This practice is authorized by the EUB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.

Gross Heating Value (of Dry Gas) The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Initial Established Reserves Established reserves prior to the deduction of any production.

Initial Volume in Place The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.

Maximum Day Rate The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.

Maximum Recoverable Thickness The assumed maximum operational reach of underground coal mining equipment in a single seam.

Mean Formation Depth The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.

Methane In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, Section 1(1)(m.1)).

Natural Gas Liquids Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

Netback Crude oil netbacks are calculated from the price of WTI at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate as well as crude quality differences.

Off-gas Natural gas that is produced from bitumen production in the oil sands. This gas is typically rich in natural gas liquids and olefins.

Oil Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(n.1)).

Oil Sands
(i) sands and other rock materials containing crude bitumen,
(ii) the crude bitumen contained in those sands and other rock materials, and
(iii) any other mineral substances other than natural gas in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (*Oil Sands Conservation Act*, Section l(l)(o)).

Oil Sands Deposit A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(o.1)).

Overburden In this report overburden is a mining term related to the thickness of material above a mineable occurrence of coal or bitumen.

Pay Thickness (Average) The bulk rock volume of a reservoir of oil, oil sands, or gas divided by its area.

Pentanes Plus A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate, or crude oil (*Oil and Gas Conservation Act*, Section 1(1)(p)).

Pool A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(q)).

Porosity The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.

Pressure (Initial) The reservoir pressure at the reference elevation of a pool upon discovery.

Propane In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, Section 1(1)(s)).

Recovery (Enhanced)	The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. The artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of (i) aiding in the lifting of fluids in the well, or (ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means (*Oil and Gas Conservation Act*, Section 1(1)(h)).
Recovery (Pool)	In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.
Recovery (Primary)	Recovery of oil by natural depletion processes only measured as a volume thus recovered or as a fraction of the in-place oil.
Refined Petroleum Products	End products in the refining process.
Refinery Light Ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reprocessing Facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Retrograde Condensate Pools	Gas pools that have a dew point such that natural gas liquids will condense out of solution with a drop in reservoir pressure. To limit liquid dropout in the reservoir, dry gas is reinjected to maintain reservoir pressure.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (Gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (Water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.

Shrinkage Factor (Initial) The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.

Solvent A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.

Specification Product A crude oil or refined petroleum product with defined properties.

Sterilization The rendering of otherwise definable economic ore as unrecoverable.

Straddle Plants These are reprocessing plants on major natural gas transmission lines that process marketable gas by extracting natural gas liquids. This results in gas for export having a lower heat content than the marketable gas flowing within the province.

Successful Wells Drilled Wells drilled for gas or oil that are cased and not abandoned at the time of drilling. Less than 5 per cent of wells drilled in 2003 were abandoned at the time of drilling.

Surface Loss A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.

Synthetic Crude Oil A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.

Temperature The initial reservoir temperature upon discovery at the reference elevation of a pool.

Ultimate Potential An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple equation: Ultimate potential = initial established reserves + additions to existing pools + future discoveries.

Upgrading The process that converts bitumen and heavy crude oil into a product with a density and viscosity similar to light crude oil.

Zone Any stratum or sequence of strata that is designated by the EUB as a zone (*Oil and Gas Conservation Act*, Section 1(1)(z)).

1.2 Abbreviations

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
DISC YEAR	discovery year
EOR	enhanced oil recovery
FRAC	fraction
GC	gas cycling
GIP	gas in place
GOR	gas-oil ratio
GPP	good production practice
ha	hectare
INJ	injected
I.S.	integrated scheme
KB	kelly bushing
LF	load factor
LOC EX PROJECT	local experimental project
LOC U	local utility
MB	material balance
MFD	mean formation depth
MOP	maximum operating pressure
MU	commingling order
NGL	natural gas liquids
NO	number
NON-ASSOC	nonassociated gas
PE	performance estimate
PD	production decline
RF	recovery factor
RGE	range
RPP	refined petroleum production
SA	strike area
SATN	saturation
SCO	synthetic crude oil
SF	solvent flood
SG	gas saturation
SL	surface loss
SOLN	solution gas
STP	standard temperature and pressure
SUSP	suspended
SW	water saturation
TEMP	temperature
TOT	total
TR	total record
TVD	true vertical depth
TWP	township
VO	volumetric reserve determination
VOL	volume
WF	waterflood
WM	west of [a certain] meridian
WTR DISP	water disposal
WTR INJ	water injection

1.3 Symbols

International System of Units (SI)

°C	degree Celsius	M	mega
d	day	m	metre
EJ	exajoule	MJ	megajoule
ha	hectare	mol	mole
J	joule	T	tera
kg	kilogram	t	tonne
kPa	kilopascal	TJ	terajoule

Imperial

bbl	barrel	°F	degree Fahrenheit
Btu	British thermal unit	psia	pounds per square inch absolute
cf	cubic foot	psig	pounds per square inch gauge
d	day		

1.4 Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric		Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	=	35.49373 cubic feet of gas (14.65 psia and 60°F)
1 m^3 of ethane (equilibrium pressure and 15°C)	=	6.33 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	=	6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	=	6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	=	6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	=	6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	=	0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	=	1.102311 short tons (2000 pounds)
1 kilojoule	=	0.9482133 British thermal units (Btu as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.
[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4*
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Synthetic crude oil	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Hydroelectricity (per megawatt-hour of output)	10.5**
Nuclear electricity (per megawatt-hour of output)	10.5**

* Based on the heating value at 1000 Btu/cf.

**Based on the thermal efficiency of coal generation.

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Coalbed Methane, and Natural Gas Reserves

Table B.1. Initial in-place resources of crude bitumen by deposit

Oil Sands Area Oil sands deposit	Depth / region / zone (m)	Resource determination method	Initial volume in place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150 - 450+	Building block	5 274
Middle Grand Rapids	150 - 450+	Building block	2 354
Lower Grand Rapids	150 - 450+	Building block	1 050
Wabiskaw-McMurray	0 - 750+	Isopach	148 215
Nisku	200 - 800+	Isopach	10 330
Grosmont	All zones	Isopach	50 500
Subtotal			217 723
Cold Lake			
Upper Grand Rapids	300 – 600	Building block	6 186
Upper Grand Rapids	All zones	Isopach	534
Lower Grand Rapids	300 – 600	Building block	8 933
Lower Grand Rapids	All zones	Isopach	1 651
Clearwater	350 – 625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			31 013
Peace River			
Bluesky-Gething	300 - 800+	Isopach	10 968
Belloy	675 - 700	Building block	282
Upper Debolt	500 - 800	Building block	1 830
Lower Debolt	500 - 800	Building block	5 970
Shunda	500 - 800	Building block	2 510
Subtotal			21 565
Total			270 296

Table B.2. Basic data of crude bitumen deposits

Oil Sands Area / Oil sands deposit / Depth / region / zone / Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150 - 450+	Building Block	5274.00	334.00	9.0	0.062	0.55	0.30	0.45
Middle Grand Rapids								
150 - 450+	Building Block	2354.00	182.00	5.0	0.077	0.68	0.30	0.32
Lower Grand Rapids								
150 - 450+	Building Block	1050.00	173.00	6.0	0.051	0.45	0.30	0.55
Wabiskaw-McMurray								
0 - 20	3-D Model	4953.00	75.00	32.1	0.097			
20 - 40	3-D Model	5283.00	82.00	31.3	0.097			
40 - 80	3-D Model	5851.00	99.00	28.7	0.096			
50 - 750+	Isopach	132128.00	4665.00	13.2	0.102	0.73	0.29	0.27
Nisku								
200 - 800+	Isopach	10330.00	499.00	8.0	0.057	0.63	0.21	0.37
Grosmont								
D	Isopach	19890.00	1063.00	16.0	0.058	0.67	0.20	0.33
C	Isopach	15390.00	1189.00	10.0	0.050	0.75	0.16	0.25
B	Isopach	5380.00	976.00	5.0	0.043	0.69	0.15	0.31
A	Isopach	9840.00	939.00	10.0	0.035	0.60	0.14	0.40
Cold Lake								
Upper Grand Rapids								
300 - 600	Building Block	6186.40	812.00	6.0	0.081	0.58	0.30	0.42
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
300 – 600	Building Block	8932.70	708.00	6.0	0.106	0.73	0.31	0.27
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Mann Lake/Seibert Lk A	Isopach	6.61	5.50	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake Oo	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake Qq	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh Vv	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh Ww	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh Aa	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh Bb	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh Cc	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh Oo	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh Xx	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh Yy	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake Nn	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake Pp	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh Dd	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh Ee	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh Ff	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh Gg	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh Hh	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh Ii	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh Jj	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh Kk	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh Mm	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh Nn	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh Pp	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh Qq	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh Rr	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh Ss	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh Uu	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh Zz	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh Eee	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh Fff	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh Ggg	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh Hhh	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh Jjj	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27
Lower Grand Rapids 5								
Lindbergh Aaa	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh Bbb	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh Ccc	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh/St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350 – 625	Isopach	9422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300 - 800+	Isopach	10968.16	1015.75	6.1	0.081	0.68	0.26	0.32
Belloy								
675 – 700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500 – 800	Building Block	1830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500 – 800	Building Block	5970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500 - 800	Building Block	2510.00	143.00	14.0	0.053	0.52	0.23	0.48

Table B.3. Conventional crude oil reserves as of each year-end (10^6 m^3)

Year	Initial established: New discoveries	EOR additions	Development	Net revisions	Net total additions	Cumulative production	Remaining established
1968	62.0				119.8	430.3	1 212.8
1969	40.5				54.5	474.7	1 222.8
1970	8.4				36.7	526.5	1 207.9
1971	14.0				22.1	582.9	1 173.6
1972	10.8				20.0	650.0	1 126.0
1973	5.1				9.2	733.7	1 052.0
1974	4.3				38.5	812.7	1 011.5
1975	1.6				7.0	880.2	950.9
1976	2.5				-18.6	941.2	871.3
1977	4.8				19.1	1 001.6	830.0
1978	24.9				24.4	1 061.6	794.5
1979	19.2				34.3	1 130.1	760.2
1980	9.0				22.8	1 193.3	719.9
1981	15.0	7.2			32.6	1 249.8	696.0
1982	16.8	6.6			6.9	1 303.4	649.4
1983	21.4	17.9			64.1	1 359.0	657.8
1984	29.1	24.1			42.0	1 418.2	640.7
1985	32.7	21.6			64.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 480.7	250.1

Table B.4. Conventional crude oil reserves by geological period as of December 31, 2006

Geological period	Initial volume in-place (10^6 m^3)		Initial established reserves (10^6 m^3)		Remaining established reserves (10^6 m^3)		Average recovery (%)	
	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy
Cretaceous								
Upper	2 088	0	352	0	46	-	17	-
Lower	1 395	2 029	256	351	28	62	18	17
Jurassic	104	105	20	35	3	3	19	33
Triassic	399	29	74	3	14	1	19	10
Permian	14	0	8	0	0	-	56	
Mississippian	509	70	94	9	10	2	18	13
Devonian								
Upper	2 568	29	1 162	3	53	1	45	10
Middle	974	0	357	0	23	0	37	-
Other	76	11	7	0	4		9	
Total	8 125	2 275	2310	401	181	69	29	18

Table B.5. Distribution of conventional crude oil reserves by formation as of December 31, 2006

Geological formation	Initial volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)	Remaining established reserves (10^6 m^3)	Initial volume in-place (%)	Initial established reserves (%)	Remaining established reserves (%)
Upper Cretaceous						
Belly River	288	45	10	3	2	4
Chinook	6	1	0	0	0	0
Cardium	1 704	294	33	16	11	13
Second White Specks	36	4	1	0	0	0
Doe Creek	35	7	2	0	0	1
Dunvegan	19	2	0	0	0	0
Lower Cretaceous						
Viking	346	68	5	3	2	2
Upper Mannville	2 004	317	57	19	12	23
Lower Mannville	1075	219	30	10	8	12
Jurassic	209	56	6	2	2	2
Triassic	428	77	14	4	3	5
Permian-Belloy	14	8	0	0	0	0
Mississippian						
Rundle	338	74	8	4	3	3
Pekisko	92	15	2	1	1	1
Banff	104	13	2	1	0	1
Upper Devonian						
Wabamun	67	7	1	1	0	0
Nisku	469	211	11	5	8	4
Leduc	826	504	8	8	18	3
Beaverhill Lake	1 062	408	26	10	15	10
Slave Point	173	35	7	2	1	3
Middle Devonian						
Gilwood	309	134	7	3	5	3
Sulphur Point	9	2	0	0	0	0
Muskeg	61	10	1	1	0	0
Keg River	496	179	12	5	7	5
Keg River SS	43	18	1	0	1	0
Granite Wash	56	14	2	1	1	1

Table B.6. Upper Cretaceous and Mannville CBM in-place and established reserves, 2006 (10^6 m^3), deposit block model method

Field/strike area	Block model area (ha)	Average coal thickness (m)	Coal reservoir volume (10^6 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas In place (10^6 m^3)	Adjusted average recovery factor	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Corbett / Thunder	12611	10	1301	12.80	16647	16%	2597	271	2326	1350
Doris	4226	10	418	12.80	5346	16%	834	176	658	391
Aerial	1664	7	251	0.68	279	4%	11	0	11	0
Ardenode	13108	9	1384	2.46	3231	4%	139	2	137	0
Bashaw	72175	10	7401	0.99	8927	24%	2125	171	1954	0
Bittern Lake	20374	16	1296.81	2.01	5244	7%	341	1	339	1
Blackfoot	2093	5	400	0.86	332	7%	23	1	22	0
Brant	278	5	56	no data	50	4%	2	1	1	0
Buffalo Lake	8422	10	624	2.23	2533	4%	101	7	95	0
Carbon	25537	11	2314	1.17	2599	12%	301	24	277	0
Cavalier	21901	12	1823	0.95	2059	5%	101	6	95	0
Centron	34558	15	2291	2.18	4914	6%	275	10	265	0
Chain	17936	35	512.42	1.03	2636	9%	248	6	242	0
Chigwell	38352	12	3094	1.79	5537	13%	709	35	674	0
Clive-Alix	19205	10	1832	1.86	3237	27%	887	91	796	0
Countess	517	5	106	no data	95	4%	4	3	1	0
Craigmyle	2480	7	356	0.71	274	7%	20	18	3	0
Crossfield	1375	11	125	no data	275	4%	11	0	11	0
Davey	1375	11	125	no data	300	4%	12	1	11	0
Delia	28207	12	2296	0.92	2119	7%	153	36	117	0
Donalda	6060	11	146	1.91	517	7%	37	1	37	0
Dorenlee	2177	11	198	no data	475	4%	19	4	15	0
Drumheller/ W	3719	7	531	no data	1275	4%	51	9	42	0
Elnora	24395	9	2699	1.24	3196	12%	396	71	325	0
Entice	69650	11	6115	1.96	11611	26%	3065	337	2729	1
Erskine	20930	14	1218	2.20	4988	7%	359	26	333	0
Ewing Lake	10765	16	657	3.19	3336	8%	267	13	254	0
Fenn West	5132	6	855	no data	1625	4%	65	14	51	0
Fenn BV	43182	16	2718	0.84	2180	17%	374	80	294	0
Ferintosh	10596	11	592	3.81	2145	10%	205	32	173	0
Ferrybank	17321	11	816	3.74	6157	4%	246	15	231	0
Foster	12636	9	1438	4.22	6143	5%	332	5	327	0
Gadsby	5893	11	536	no data	1125	4%	45	10	35	0
Gayford	19448	7	2766	1.61	4846	11%	523	99	424	0
Ghostpine	79931	10	8038	1.12	8614	5%	457	50	406	0
Herronton	38314	6	1770	2.74	8562	5%	462	3	459	0
Hussar	13594	6	2266	no data	1813	8%	145	8	137	0
Huxley	7500	6	1250	no data	2375	4%	95	37	58	0
Irricana	19411	7	2823	2.47	6778	20%	1352	152	1200	1
Joffre	3993	10	386	1.76	650	13%	87	25	62	0
Lacombe	8125	11	739	no data	1625	4%	65	21	44	0
Lone Pine	3553	6	592	no data	1125	4%	45	7	38	0
Malmo	20964	14	2002	4.11	7730	10%	756	44	712	0
Manito	7106	6	475	3.25	1496	8%	120	7	112	0
Michichi	395	6	66	no data	125	8%	10	7	3	0
Mikwan	62724	13	4805	1.23	5799	4%	249	37	212	0
Morningside	395	6	66	no data	125	8%	10	4	6	0
Nevis	51662	9	5962	1.12	6444	25%	1585	156	1429	1
New Norway	10786	14	1035	1.85	3871	7%	252	5	247	0
Oberlin	6042	12	516	2.56	2300	7%	166	26	139	0
Parflesh	19219	8	2346	1.14	2651	6%	170	10	159	0

(continued)

Field/strike area	Block model area (ha)	Average coal thickness (m)	Coal reservoir volume (10^6 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas In place (10^6 m^3)	Adjusted average recovery factor	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Penhold	14583	14	1042	no data	2500	4%	100	5	95	0
Redland	15822	9	1821	1.09	1846	21%	395	52	343	0
Rich	19191	9	2132	no data	3625	4%	145	74	71	0
Rockyford	37804	8	4746	1.09	4713	12%	575	139	436	1
Rowley	28726	11	2515	0.92	2235	4%	96	57	39	0
Rumsey	4864	9	567	0.98	558	11%	64	42	22	0
Stettler/N	13185	6	510	2.62	2278	8%	182	10	172	0
Stewart	197	6	33	no data	63	8%	5	1	4	0
Strathmore	73934	10	7230	2.16	16304	8%	1353	55	1298	0
Swalwell	4454	17	265	2.45	661	12%	82	34	48	0
Thorsby	938	6	156	no data	125	4%	5	4	1	0
Three H Ck	54425	15	3707	1.97	7155	4%	308	97	210	0
Trochu	12630	9	1423	1.05	1439	24%	351	118	234	0
Twining	98609	10	9418	2.09	24542	7%	1767	166	1601	0
Vulcan	938	6	156	no data	125	4%	5	1	4	0
Wayne	5625	9	625	no data	750	4%	30	17	13	0
Westrose / S	18464	5	3768	no data	3014	4%	121	4	117	0
Wetaskiwin	1310	11	119	no data	250	4%	10	1	9	1
Wimborne	35512	10	3387	2.28	7654	8%	643	69	574	0
Wood River	5722	11	525	2.71	2277	8%	178	6	172	0
Workman	9495	12	788	4.35	3528	5%	462	1	461	0
Total	1388440	10	129358		263979		27780	3130	24650	1756

Table B.7. Noncommercial CBM production, 2006 (10^6 m^3), production extrapolation method—other CBM areas

Field/strike area	Coal zone	Initial gas In place (10^6 m^3)	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Canmore	Mist Mtn	not calc	not recorded	not recorded	0	not recorded
Fenn BV / W	Upper Mann	not calc	11	11	0	75
Coleman / Livingstone	Mist Mtn	not calc	0	0	0	0.0
Redwater	Upper Mann	not calc	not recorded	not recorded	0	not recorded
Pine Creek / Brazeau	Ardley	not calc	not recorded	not recorded	0	not recorded
Pembina	Ardley	not calc	21	21	0	13.0
Manola/ Mellow	Upper Mann	not calc	15	15	0	10
Drumheller	Upper Mann	not calc	0	0	0	0.0
Norris	Upper Mann	not calc	6	6	0	77
Strome	Upper Mann	not calc	1	1	0	15
Battle South	Upper Mann	not calc	0	0	0	5
Kelsey	Upper Mann	not calc	3	3	0	224
Swan Hills / Swan Hills S	Upper Mann	not calc	10	10	0	39
Provost	Upper Mann	not calc	12	12	0	174
Neerlandia	Upper Mann	not calc	33	33	0	169
Miscellaneous	any	not calc	70	70	0	107
Total			181	181	0	907

Table B.8. Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

Year	Initial established: New discoveries	Development	Revisions	Net additions	Cumulative	Cumulative production	Remaining actual[a]	Remaining @ 37.4 MJ/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2[a]	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	58.6	45.3	-16.7	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	43.2	59.8	42.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	36.6	47.2	41.9	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	51.0	40.5	34.8	126.3	4 798.7	3 683.5	1 115.2	1 136.3

[a] At field plant.

Table B.9. Geological distribution of established natural gas reserves, 2006

Geological period	Gas in place Initial volume (10^9 m^3)	Marketable gas Initial established reserves (10^9 m^3)	Marketable gas Remaining established reserves (10^9 m^3)	Gas in Place Initial volume (%)	Marketable gas Initial established reserves (%)	Marketable gas Remaining established reserves (%)
Upper Cretaceous						
Belly River	168	98	39	2.0	2.0	3.5
Milk River & Med Hat	982	521	204	11.9	10.9	18.3
Cardium	297	107	38	3.6	2.2	3.4
Second White Specks	38	19	13	0.5	0.4	1.2
Other	308	170	61	3.7	3.5	5.5
Subtotal	1 793	915	355	21.7	19.0	31.9
Lower Cretaceous						
Viking	441	291	54	5.4	6.1	4.8
Basal Colorado	33	27	2	0.4	0.6	0.2
Mannville	1 974	1310	291	24.0	27.3	26.1
Other	546	305	84	6.6	6.4	7.5
Subtotal	2 994	1 933	431	36.4	40.3	38.6
Jurassic						
Jurassic	70	43	12	0.9	0.9	1.1
Other	126	76	17	1.6	1.6	1.5
Subtotal	196	119	29	2.5	2.5	2.6
Triassic						
Triassic	241	146	46	2.9	3.0	4.1
Other	32	21	3	0.4	0.4	0.3
Subtotal	273	167	49	3.3	3.0	4.4
Permian						
Belloy	9	6	1	0.1	0.1	0.1
Subtotal	9	6	1	0.1	0.1	0.1
Mississippian						
Rundle	943	587	89	12.2	12.2	8.0
Other	347	235	27	4.2	4.9	2.4
Subtotal	1290	822	116	15.7	17.1	10.4
Upper Devonian						
Wabamun	249	124	22	3.0	2.6	1.9
Nisku	129	63	16	1.6	1.3	1.4
Leduc	470	247	15	5.7	5.1	1.3
Beaverhill Lake	498	227	33	6.1	4.7	3.0
Other	184	110	14	2.2	2.3	1.3
Subtotal	1530	771	100	18.6	16.0	8.9
Middle Devonian						
Sulphur Point	15	9	3	0.2	0.2	0.3
Muskeg	7	2	1	0.1	0.0	0.1
Keg River	68	26	14	0.8	0.6	1.3
Other	35	15	3	0.4	0.3	0.3
Subtotal	125	52	21	1.5	1.1	2.0
Confidential						
Subtotal	18	13	12	0.1	0.3	1.1
Total	8229 (292)[a]	4799 (170)[a]	1115 (40)[a]	100.0	100.0	100.0

[a] Imperial equivalent in trillions of cubic feet at 14.65 pounds per square inch absolute and 60°F.

Table B.10. Natural gas reserves of retrograde pools, 2006

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas (10^6 m^3)
Brazeau River Nisku J	557	74.44	41	0.75	0.50	16	41.01	380	15
Brazeau River Nisku K	1 360	74.17	101	0.75	0.60	30	42.15	718	26
Brazeau River Nisku M	1 945	76.22	148	0.75	0.60	44	43.33	1 076	59
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435	1 307
Brazeau River Nisku S	1921	54.64	105	0.80	0.57	36	41.38	873	42
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200	247
Caroline Beaverhill Lake A	61 977	49.95	3 096	0.84	0.76	621	36.51	17 000	2 623
Carson Creek Beaverhill Lake B	11 350	55.68	632	0.90	0.39	342	41.09	8 330	29
Harmattan East Rundle	44 912	50.26	2 257	0.79	0.26	1 319	41.60	31 703	6 636
Harmattan-Elkton Rundle C	37 757	46.96	1 773	0.86	0.27	1 526	58.19	26 226	3 707
Kakwa A Cardium A	4 069	55.40	225	0.85	0.32	130	52.63	2470	1 677
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 639	39.68	41 300	1 038
Ricinus Cardium A	13 295	58.59	779	0.85	0.32	450	42.0	10 775	1477
Valhalla Halfway B	6 331	53.89	341	0.80	0.33	183	40.00	4 572	2 936
Waterton Rundle-Wabamun A	86 670	48.74[a]	4 224	0.95	0.35	2 100	39.23	53 519	725
Wembley Halfway B	10 183	53.89	549	0.67	0.33	246	42.41	5 800	4 460

(continued)

Table B.10. Natural gas reserves of retrograde pools 2006 (concluded)

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas (10^6 m^3)
Westerose D-3	10 771	51.55	555	0.90	0.25	375	50.15	7 478	50
Westpem Nisku E	1 160	66.05	77	0.90	0.54	32	44.76	709	160
Windfall D-3 A	25 790	53.42	1 338	0.60	0.53	425	44.92	9 462	1 065

[a] Producible raw gas gross heating value is 40.65 MJ/m^3.

Table B.11. Natural gas reserves of multifield pools, 2006

Multifield pool / Field and pool	Remaining established reserves ($10^6 m^3$)
Belly River Pool No. 1	
Bashaw Edmonton & Belly River MU#1	448
Nevis Edmonton & Belly River MU#1	165
Total	613
Belly River Pool No. 6	
Aerial Belly River III & Basal Belly River E	39
Ardenode Edmonton & Belly River MU#1	1 581
Brant Edmonton & Belly River MU#1	360
Centron Edmonton & Belly River MU#1	927
Cessford Belly River III & Basal Belly River C & K	21
Crossfield Belly River III	55
Dalmead Lower Edmonton & Belly River III	64
Entice Edmonton & Belly River MU#1	734
Gayford Edmonton & Belly River MU# 2	157
Ghost Pine Belly River III	737
Gladys Edmonton & Belly River MU#1	509
Herronton Edmonton & Belly River MU#1	594
Irricana Belly River III	184
Lomond Belly River III & Basal Belly River A	139
Majorville Belly River MU#1	10
Matziwin Belly River III	20
Michichi Edmonton, Belly River & Mannville MU#1	80
Milo Belly River III & Basal Belly River A,B & C	26
Okotoks Belly River III	93
Parflesh Edmonton, Belly River & Mannville MU#1	701
Queenstown Belly River III	15
Redland Edmonton Belly River, Viking & Mannville MU#1	435
Rockyford Edmonton, Belly River, Colorado & Mannville MU#1	579
Rowley Belly River III	11
Seiu Lake Belly River III & Viking C	99
Strathmore Edmonton & Belly River MU#1	1 681
Swalwell Belly River III & Basal Belly River A	14
Twining Belly River III	33
Vulcan Belly River III	40
Wayne-Rosedale Belly River III	119
West Drumheller Belly River III, Basal Belly River B & C	10
Total	10 067
Basal Belly River Pool No. 1	
Belly River M & A2A & Basal Belly River B	126
Holmberg Basal Belly River B	6
Total	132
Basal Belly River Pool No. 2	
Fenn West Basal River B	9
Fee-Big Valley Edmonton & Mannville MU#1	88
Gadsby Edmonton, Belly River & Mannville MU#1	259
Total	356
Basal Belly River Pool No.4	
Cavalier Basal Belly River RR	245
Hussar	746
Total	991
Cardium Pool No. 1	
Ansell Belly River, Cardium, Viking, & Mannville MU#1	7 687
Sundance Belly River, Cardium, Viking, & Mannville MU#1	4 692
Total	12 379
Southeastern Alberta Gas System (MU)	
Alderson Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River and Colorado	23 203
Armada Milk River, Medicine Hat and Belly River	1 081
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River and Basal Belly River	5 159
Bantry Milk River, Medicine Hat, Fish Scale, Second White Specks, First White Specks, Belly River, Basal Belly River / and Colorado	14 000
Berry Medicine Hat	85
Bindloss Milk River and Medicine Hat	853
Blackfoot Medicine Hat, Belly River and Basal Belly River	802
Bow Island Milk River, Medicine Hat, Second White Specks and Colorado	1 695
Brooks Milk River, Medicine Hat, Second White Specks and Basal Belly River	357
Cavalier Belly River and Viking	253
Cessford Milk River, Medicine Hat, Second White Specks and First White Specks	9 561
Connorsville Milk River, Medicine Hat, Belly River, Colorado and First White Specks	2 458
Countess Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River, Colorado, Fish Scale, Bow Island, Viking, Basal Colodaro, Mannville and Pekisko	31 541
Drumheller Medicine Hat, Belly River, Basal Belly River Viking Basal Colorado Mannville and Pekisko	1 589
Elkwater Medicine Hat	921
Enchant Second White Specks	165
Eyremore Milk River, Medicine Hat, Second White Specks, and Colorado	2 708
Farrow, Milk River, Medicine Hat, Belly River and Basal Belly River	970
GleichenMedicine Hat and Belly River	728
Hussar Milk River, Medicine Hat, Belly River, Basal Belly River, Edmonton, Viking, Glauconitic and Second White Specks	2 381
Jenner Milk River, Medicine Hat, Second White Specks and Colorado	3 174
Johnson Milk River, Medicine Hat and Second White Specks	350
Jumpbush Belly River & Medicine Hat	171
Kitsim Milk River, Medicine Hat and Second White Specks	508
Lathom Milk River , First White Specks, Medicine Hat, Fish Scale, Second White Specks and Belly River	1 686

(continued)

Table B.11. Natural gas reserves of multifield pools, 2006 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Leckie Milk River, Medicine Hat, Belly River, and Second White Specks	780
Long Coulee Medicine Hat	67
Majorville Milk River and Medicine Hat	1 695
Matziwin Milk River, Medicine Hat, First White Specks, Fish Scale and Second White Specks	1 088
McGregor Milk River and Medicine Hat	384
Medicine Hat Milk River, Medicine Hat, Fish Scale, Second White Specks, Belly River, and Colorado	45 601
Newell Milk River, Medicine Hat and Second White Specks	1 113
Pollockville Milk River and Medicine Hat	28
Princess Milk River, Medicine Hat, Second White Specks, and Colorado	11 865
Rainier Milk River, Medicine Hat and Second White Specks	336
Ronalane Second White Specks	124
Seiu Lake Medicine Hat	507
Shouldice Medicine Hat and Belly River and Basakl Belly River	725
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	17 831
Verger Milk River, Medicine Hat, Fish Scale, Belly River, Basal Belly river Second White Specks and Colorado	5 742
Wayne-Rosedale Medicine Hat, Milk River, First White Specks, Belly River and Basal Belly River	1 468
Wintering Hills Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River and Colorado	2 211
Total	197 964
Second White Specks Pool No. 2	
Craigmyle Second White Specks E	1
Dowling Lake Second White Specks E	7
Garden Plains Second White Specks E	1463
Hanna Second White Specks E	673
Provost Second White Specks E	47
Richdale Second White Specks E	142
Sullivan Lake Second White Specks E	182
Watts Medicine Hat B & C and Second White Specks E	17
Total	2 531
Second White Specks Pool No. 3	
Conrad Second White Specks J, & Barons A & F	335
Pendant D'Oreille Medicine Hat E & Second White Specks J	460
Smith Coulee Medicine Hat A & Second White Specks J	413
Total	1 208
Second White Specks Pool No. 4	
Enchant Basal Belly River B and Second White Specks B	669
Retlaw Basal Belly River I & K and Second White Specks B	528
Vauxhall Second White Specks B	39
Total	1 236
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	84
Peavey Upper Viking A	2
Redwater Viking and Mannnville MU#1	417
Westlock Middle Viking B	202
Total	705
Viking Pool No. 2	
Albers Upper & Middle Viking A & Colony A	14
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	243
Bellshill Lake Upper and Middle Viking A	17
Birch Upper and Middle Viking A	2
Bruce Viking & Mannvillie MU#1	997
Dinant Upper & Middle Viking A	19
Fort Saskatchewan Upper and Middle Viking A	22
Holmberg Upper and Middle Viking A	3
Killam Colony, Viking & Mannville MU#1	140
Killam North Viking Mannville & Nisku MU#1	251
Mannville Viking & Mannville MU#1	520
Sedgewick Upper and Middle Viking A	1
Viking-Kinsella Viking, Colony, Mannville & Wabamun MU#1	7 099
Wainwright Colony, Viking & Mannville MU#1	385
Total	10 213
Viking Pool No. 3	
Carbon Belly River, Viking, Mannville & Rundle MU #1	139
Ghost Pine Viking D	20
Total	159
Viking Pool No. 5	
Hudson Viking A	136
Sedalia Viking A & F, Upper Mannville D & AA, and Lower Mannville B	179
Total	315
Viking Pool No. 6	
Hairy Hill Viking A & U	55
Willingdon Viking & Mannville MU#1	5
Total	60

(continued)

Table B.11. Natural gas reserves of multifield pools, 2006 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Viking Pool No. 7	
Inland Viking and Upper Mannville MU#1	94
Royal Upper Viking C and Lower Viking A	34
Total	128
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	103
Ferrybank Viking C, Glauconitic A, & Lower Mannville W	246
Total	349
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	367
Pembina Glauconitic I & D and Ostracod C	344
Total	711
Glauconitic Pool No. 6	
Hussar Viking L, Glauconitic III, and Ostracod OO	219
Wintering Hills Upper Mannville I, Glauconitic III & Lower Mannville I	34
Total	253
Bluesky Pool No.1	
Rainbow Bluesky C	235
Sousa Bluesky C	327
Total	562
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	279
Hotchkiss Bluesky-Detrital-Debolt A	268
Total	547
Gething Pool No. 1	
Fox Creek Viking, Upper Mannville & Gething MU#1	840
Kaybob South Notikewin , Bluesky ,and Gething MU#1	213
Total	1053
Ellerslie Pool No. 1	
Connorsville Colorado, Glauconitic and Ellerslie MU#1	607
Wintering Hills Upper Mannville A, EEE & NNN and Ellerslie A	179
Total	786
Cadomin Pool No. 1	
Elmworth Doe Creek, Dunvegan , Fort St John & Bullhead MU#1	6 479
Sinclair Doe Creek, Fort St John & Bullhead MU#1	841
Total	7 320
Halfway Pool No. 1	
Valhalla Halfway B	2 936
Wembley Halfway B	4 460
Total	7 396
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	1 137
Valhalla Halfway N	. 39
Total	1 176
Banff Pool No. 1	
Haro Banff E	132
Rainbow Banff E	16
Rainbw South Banff E	34
Total	182

Table B.12. Remaining raw ethane reserves as of December 31, 2006

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Ansell	12 764	0.078	1101	3915
Bonnie Glen	2 210	0.103	307	1 090
Brazeau River	10 894	0.065	912	3 242
Caroline	8 381	0.084	1 291	4 588
Carrot Creek	2 866	0.088	287	1 021
Cecilia	9 482	0.058	632	2 247
Countess	41 629	0.023	1 016	3 612
Dunvegan	12 221	0.044	600	2 132
Edson	5 030	0.068	395	1 404
Elmworth	12 239	0.054	795	2 828
Ferrier	12 675	0.085	1 209	4 296
Fir	5 240	0.062	360	1 278
Garrington	3 728	0.070	338	1 201
Gilby	5 457	0.70	440	1 563
Gold Creek	3 327	0.074	282	1 004
Harmattan East	7 104	0.083	663	2 356
Harmattan-Elkton	4 267	0.075	400	1 423
Hussar	9 071	0.030	290	1 030
Judy Creek	2 985	0.144	531	1 886
Kaybob South	10 133	0.076	956	3 399
Karr	5 138	0.083	473	1 681
Kakwa	6 331	0.088	631	2 245
Leland	4 079	0.073	320	1 139
Leduc-Woodbend	3 165	0.108	405	1 439
Medicine Lodge	3 919	0.075	326	1 160
Medicine River	4 560	0.082	452	1 606
Pembina	19 714	0.085	2 143	7 619
Pine Creek	4 912	0.071	432	1 537
Pouce Coupe South	5 757	0.050	321	1 140
Provost	17 093	0.027	506	1 798
Rainbow	10 716	0.076	1 017	3 617
Rainbow South	3 648	0.109	592	2 104
Ricinus	5 860	0.080	525	1 867
Sundance	7 409	0.073	615	2 171
Swan Hills South	2 577	0.174	641	2 280
Sylvan Lake		0.060	379	1 346
Valhalla	8 960	0.074	804	2 858
Virginia Hills	1 607	0.165	322	1 146
Westpem	3 632	0.108	492	1 750
Westerose South	7 840	0.077	672	2 391

(continued)

Table B.12. Remaining raw ethane reserves as of December 31, 2006 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Wembley	5 582	0.094	635	2 257
Wapiti	18 496	0.053	1 135	4 035
Wild River	23 908	0.070	1 799	6 394
Willesden Green	11 996	0.088	1 351	4 801
Wilson Creek	3 506	0.071	298	1 060
Subtotal	382 022	0.068	30 465	108 311
All other fields	732 942	0.029	20 760	75 750
Solvent floods			1 649	5 765
Total	1 114 964	0.052[a]	52 874	189 576

[a] Volume weighted average.

Table B.13. Remaining established reserves of natural gas liquids as of December 31, 2006

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ante Creek North	1 613	304	167	580	1 051
Ansell	12 764	1 709	888	2 078	4 674
Bonnie Glen	2 210	491	272	427	1 189
Brazeau River	10 894	1 497	943	2 292	4 732
Caroline	8 381	1 955	1 589	3 857	7 400
Carrot Creek	2 866	513	234	185	932
Cecilia	9 482	785	321	1 094	2 200
Countess	41 629	1 515	822	667	3 004
Crossfield East	3 957	326	153	921	1 400
Dunvegan	12 221	1 037	599	1 007	2 643
Edson	5 030	535	257	279	1 071
Elmworth	12 239	934	435	524	1 892
Ferrier	12 675	2 190	1 121	885	4 197
Fir	5 240	528	239	239	1 007
Garrington	3 728	530	284	395	1 209
Gilby	5 457	710	356	385	1 451
Gold Creek	3 327	395	205	352	951
Harmattan East	7 104	860	553	966	2 379
Harmattan -Elkton	4 267	548	279	281	1 108
Hussar	9 071	447	247	250	845
Judy Creek	2 985	1 271	527	306	2 104
Jumping Pound West	5 896	236	203	367	806
Kaybob	2 972	449	214	299	961
Kaybob South	10 133	1 535	824	1 390	3 748
Karr	5 138	740	316	317	1 372
Kakwa	6 331	1 110	546	644	2 300
Knopcik	3 628	361	183	278	822
Leduc-Woodbend	3 165	1 113	638	386	2 136
McLeod	2 787	494	228	255	977
Medicine Lodge	3 919	441	222	283	946
Medicine River	4 560	736	362	386	1 483
Moose	3 791	318	229	525	1 071
Peco	1 992	355	193	409	958
Pembina	19 714	4 228	2 037	1 678	7 942
Pine Creek	4 912	707	327	386	1 420
Pouce Coupe South	5 757	452	257	291	999
Provost	17 093	1 069	680	497	2 247
Rainbow	10 716	1 632	1 037	1 359	4 028
Rainbow South	3 648	1 204	581	802	2 587
Red Rock	3 331	261	119	437	817
Redwater	1 959	508	319	129	956
Ricinus	5 860	928	478	972	2 378
Smoky	4 503	611	278	196	1 085

(continued)

Table B.13. Remaining established reserves of natural gas liquids as of December 31, 2005 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Sundance	7 409	824	361	401	1 586
Swan Hills	1 277	722	396	328	1 446
Swan Hills South	2 577	1 568	718	299	2585
Sylvan Lake	5 411	273	273	250	1 095
Valhalla	8 960	1 383	741	1 073	3 197
Virginia Hills	1 607	748	247	101	1 069
Waterton	6 220	251	219	1 060	1 531
Wayne-Rosedale	5 459	435	239	231	905
Westpem	3 632	841	453	517	1 810
Westerose South	7 840	1 263	619	620	2 502
Wembley	5 582	1 233	733	1 679	3 645
Wapiti	18 496	1 137	493	511	2 141
Wild River	23 908	1 915	795	1 289	3 999
Willesden Green	11 996	2 328	1 095	1 106	4 529
Wilson Creek	3 506	510	271	329	1 110
Windfall	3 105	391	314	218	823
Zama	3 105	391	214	218	823
Subtotal	425 930	54 692	28 627	40 260	123 578
All other fields	689 043	28 406	15 437	17 425	61328
Solvent floods		1 390	1 001	415	2806
Total	1114 973	84 548	45 065	58 100	187 713

Appendix C CD—Basic Data Tables

EUB staff developed the databases used to prepare this reserves report and CD. Input was also obtained from the National Energy Board (NEB) through an ongoing process of crude oil, natural gas, and crude bitumen studies. The crude oil and natural gas reserves data tables present the official reserve estimates of both the EUB and NEB for the province of Alberta.

Basic Data Tables

The conventional oil and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2006 on the CD that accompanies this report (available for $500 from EUB Information Services). The individual oil and gas pool values are presented on the first worksheet of each spreadsheet. Oilfield, and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet is similar to the data table in last year's report and contains all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are presented in separate columns. The total record contains the summation of the multi-mechanism pool reserves data. These data appear in the pool column, which can be used for determining field and provincial totals. The mechanism type is displayed with the names.

Provincial totals for light-medium and heavy oil pools are presented separately on the provincial total worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet in this report is similar to last year's report and contains all nonconfidential pools in Alberta.

Basic reserves data are split into two columns: pools (individual, undefined, and total records) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total record contains a summation of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Abbreviations Used in the Reserves and Basic Data Files

The abbreviations are divided into two groups (General Abbreviations and Abbreviations of Company Names) for easy reference.

General Abbreviations

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
BDY	boundary
BELL	Belloy
BER	beyond economic reach
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
COMP	compressibility
DBLT	Debolt
DETR	Detrital
DISC YEAR	discovery year
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton
ERSO	enhanced-recovery scheme is in operation but no additional established reserves are attributed
FALH	Falher
FRAC	fraction
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GOR	gas-oil ratio
GRD RAP or GRD RP	Grand Rapids
GROSS HEAT VALUE	gross heating value
GSMT	Grosmont
ha	hectare
HFWY	Halfway
INJ	injected
I.S.	integrated scheme
JUR or J	Jurassic
KB	kelly bushing

KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LF	load factor
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOC EX PROJECT	local experimental project
LOC U	local utility
LOW or L	lower
LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MOP	maximum operating pressure
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NO.	number
NON-ASSOC	nonassociated gas
NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
PM-PN SYS	Permo-Penn System
RF	recovery factor
RK CK	Rock Creek
RUND or RUN	Rundle
SA	strike area
SATN	saturation
SD	sandstone
SE ALTA GAS SYS (MU)	Southeastern Alberta Gas System - commingled
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth

UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS OR 1WS	First White Specks
2WS	Second White Specks

Abbreviations of Company Names

AEC	Alberta Energy Company Ltd.
AEL	Anderson Exploration Ltd.
ALTAGAS	AltaGas Marketing Inc.
ALTROAN	Altana Exploration Company/Roan Resources Ltd.
AMOCO	Amoco Canada Petroleum Company Ltd.
APACHE	Apache Canada Ltd.
BARRING	Barrington Petroleum Ltd.
BEAU	Beau Canada Exploration Ltd.
BLUERGE	Blue Range Resource Corporation
CAN88	Canadian 88 Energy Corp.
CANOR	Canor Energy Ltd.
CANOXY	Canadian Occidental Petroleum Ltd.
CANST	Canstates Gas Marketing
CDNFRST	Canadian Forest Oil Ltd.
CENTRA	Centra Gas Alberta Inc.
CGGS	Canadian Gas Gathering Systems Inc.
CHEL	Canadian Hunter Exploration Ltd.
CHEVRON	Chevron Canada Resources
CMG	Canadian-Montana Gas Company Limited
CNRL	Canadian Natural Resources Limited
CNWE	Canada Northwest Energy Limited
CONOCO	Conoco Canada Limited
CRESTAR	Crestar Energy Inc.
CTYMEDH	City of Medicine Hat
CWNG	Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited
DART	Dartmouth Power Associates Limited Partnership
DIRECT	Direct Energy Marketing Limited
DUKE	Duke Energy Marketing Limited Partnership
DYNALTA	Dynalta Energy Corporation
ENCAL	Encal Energy Ltd.
ENGAGE	Engage Energy Canada, L.P.
ENRMARK	EnerMark Inc.
GARDNER	Gardiner Oil and Gas Limited
GULF	Gulf Canada Resources Limited
HUSKY	Husky Oil Ltd.

IOL	Imperial Oil Resources Limited
LOMALTA	Lomalta Petroleums Ltd.
MARTHON	Marathon International Petroleum Canada, Ltd.
METGAZ	Metro Gaz Marketing
MOBIL	Mobil Oil Canada
NOVERGZ	Novergaz
NRTHSTR	Northstar Energy Corporation
PANALTA	Pan-Alberta Gas Ltd.
PANCDN	PanCanadian Petroleum Limited
PARAMNT	Paramount Resources Ltd.
PAWTUCK	Pawtucket Power Associates Limited Partnership
PCOG	Petro-Canada Oil and Gas
PENWEST	Penn West Petroleum Ltd.
PETRMET	Petromet
PIONEER	Pioneer Natural Resources Canada Ltd.
POCO	Poco Petroleums Ltd.
PROGAS	ProGas Limited
QUEBEC	3091-9070 Quebec
RANGER	Ranger Oil Limited
RENENER	Renaissance Energy Ltd.
RIFE	Rife Resources Ltd.
RIOALTO	Rio Alta Exploration Ltd.
SASKEN	SaskEnergy Incorporated
SHELL	Shell Canada Limited
SHERRIT	Sherritt Inc.
SIMPLOT	Simplot Canada Limited
SUMMIT	Summit Resources Limited
SUNCOR	Suncor Energy Inc. (Oil Sands Group)
SYNCRUDE	Syncrude Canada Ltd.
TALISMA	Talisman Energy Inc.
TCPL	TransCanada PipeLines Limited
ULSTER	Ulster Petroleums Ltd.
UNPACF	Union Pacific Resources Inc.
WAINOCO	Wainoco Oil Corporation
WASCANA	Wascana Energy Inc.

Appendix D Drilling Activity in Alberta

Table D.1. Development and exploratory wells, 1972-2006, number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total	Successful oil	Crude bitumen	Gas	Total[a]
1972	438	**	*	672	1 468	69	*	318	1 208	507	*	990	2 676
1973	472	**	*	898	1 837	109	*	476	1 676	581	*	1 374	3 513
1974	553	**	*	1 222	2 101	82	*	446	1 388	635	*	1 668	3 489
1975	583	**	*	1 367	2 266	81	*	504	1 380	664	*	1 871	3 646
1976	440	**	*	2 044	2 887	112	*	1 057	2 154	552	*	3 101	5 041
1977	524	**	*	1 928	2 778	178	*	1 024	2 352	702	*	2 952	5 130
1978	708	**	*	2 091	3 186	236	*	999	2 387	944	*	3 090	5 573
1979	953	**	*	2 237	3 686	297	*	940	2 094	1 250	*	3 177	5 780
1980	1 229	**	*	2 674	4 425	377	*	1 221	2 623	1 606	*	3 895	7 048
1981	1 044	**	*	2 012	3 504	381	*	1 044	2 337	1 425	*	3 056	5 841
1982	1 149	**	*	1 791	3 353	414	*	620	1 773	1 563	*	2 411	5 126
1983	1 823	**	*	791	2 993	419	*	300	1 373	2 242	*	1 091	4 366
1984	2 255	**	*	911	3 724	582	*	361	1 951	2 837	*	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5 473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298

[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.
* Not available.
** Included in Oil.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST-17).
2000 - 2006 - Alberta Drilling Activity Monthly Statistics (ST-59).

Table D.2. Development and exploratory wells, 1972-2006, kilometres drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total	Successful oil	Crude bitumen	Gas	Total[a]
1972	608	**	*	461	1 503	99	*	350	1 569	707	*	811	3 072
1973	659	**	*	635	2 053	127	*	465	1 802	786	*	1 100	3 855
1974	708	**	*	816	2 076	115	*	465	1 580	823	*	1 281	3 656
1975	686	**	*	1 020	2 192	107	*	494	1 457	793	*	1 514	3 649
1976	564	**	*	1 468	2 910	147	*	897	1 965	711	*	2 365	4 875
1977	668	**	*	1 299	2 926	188	*	1 029	2 324	856	*	2 328	5 250
1978	934	**	*	1 463	3 298	333	*	1 267	2 828	1 267	*	2 730	6 126
1979	1 387	**	*	1 713	3 840	507	*	1 411	3 073	1 894	*	3 124	6 913
1980	1 666	**	*	2 134	4 716	614	*	1 828	3 703	2 280	*	3 962	8 419
1981	1 270	**	*	1 601	3 598	573	*	1 442	3 172	1 843	*	3 043	6 770
1982	1 570	**	*	1 280	3 601	670	*	747	2 305	2 240	*	2 027	5 906
1983	2 249	**	*	758	3 834	610	*	407	1 819	2 859	*	1 165	5 653
1984	2 768	**	*	776	4 823	774	*	464	2 407	3 542	*	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 472	834	4	6 848	1 0840	603	253	3 219	4 857	3 075	1 091	10 067	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026

[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production .
* Not available.
** Included in Oil.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST-17).
2000 - 2006 - Alberta Drilling Activity Monthly Statistics (ST-59).