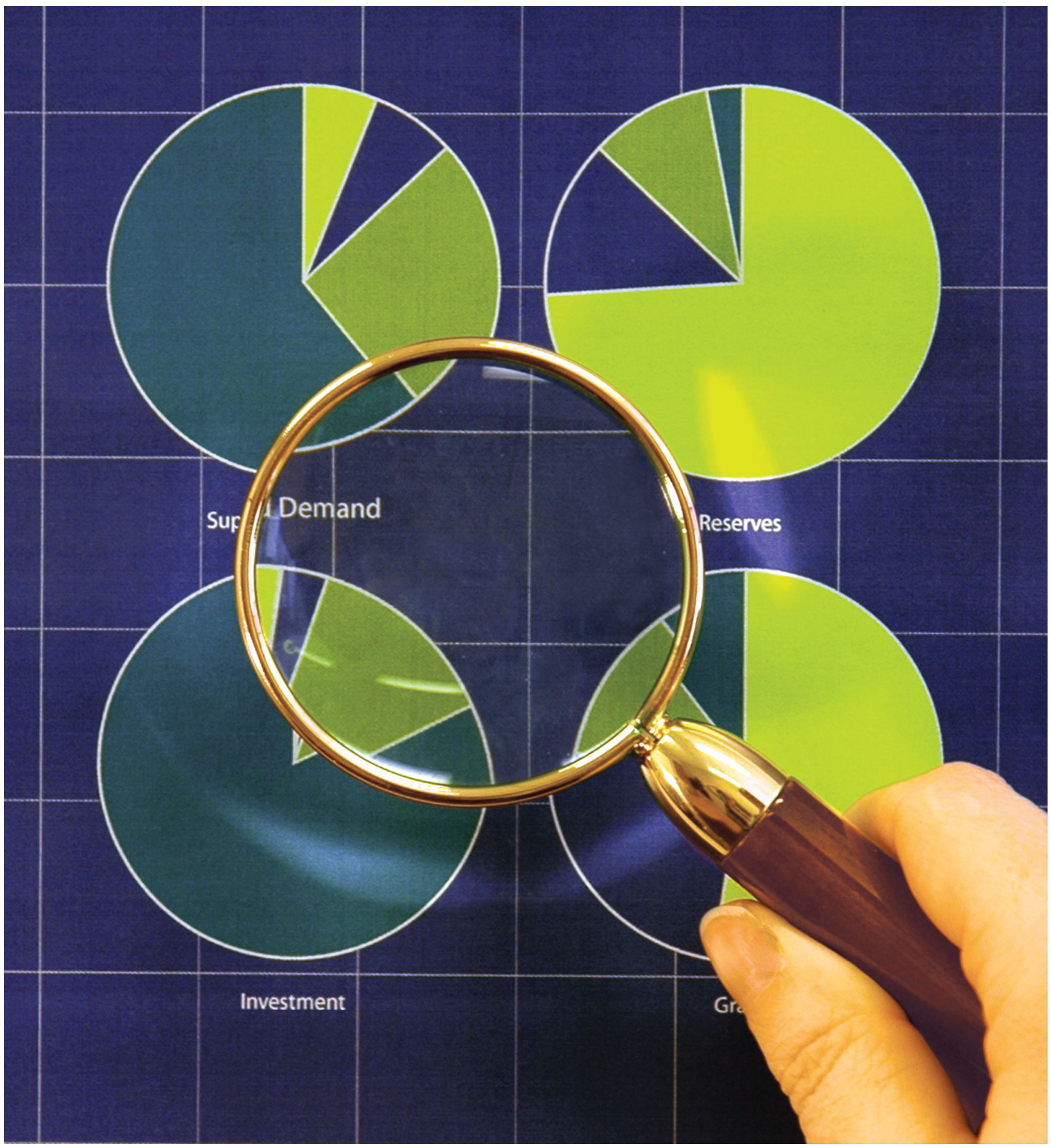
ST98-2006

Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015



Alberta Energy and Utilities Board

ACKNOWLEDGEMENTS

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ERRATA (June 27, 2006)
Corrections have been made in this edition of the report to

- Overview, page 2, Reserves and Production Summary 2005 table, numbers for Natural gas
- Overview, page 5, Conventional Natural Gas Reserves, third sentence now reads **"Reserves** from new drilling replaced 63 per cent of production in 2005."
- Section 1: Energy Prices and Economic Performance, page 1-11, Figure 1.8: data are for years 2004 and 2006

The graphs and data for each graph in this report are available for download in a separate PowerPoint file.
Download PowerPoint file.
Open the PowerPoint file. To access the dataset behind the graph, click on the graph, and a separate window showing the dataset will open.

ALBERTA ENERGY AND UTILITIES BOARD
ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015

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The CD containing the detailed data tables is available for $500
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Overview

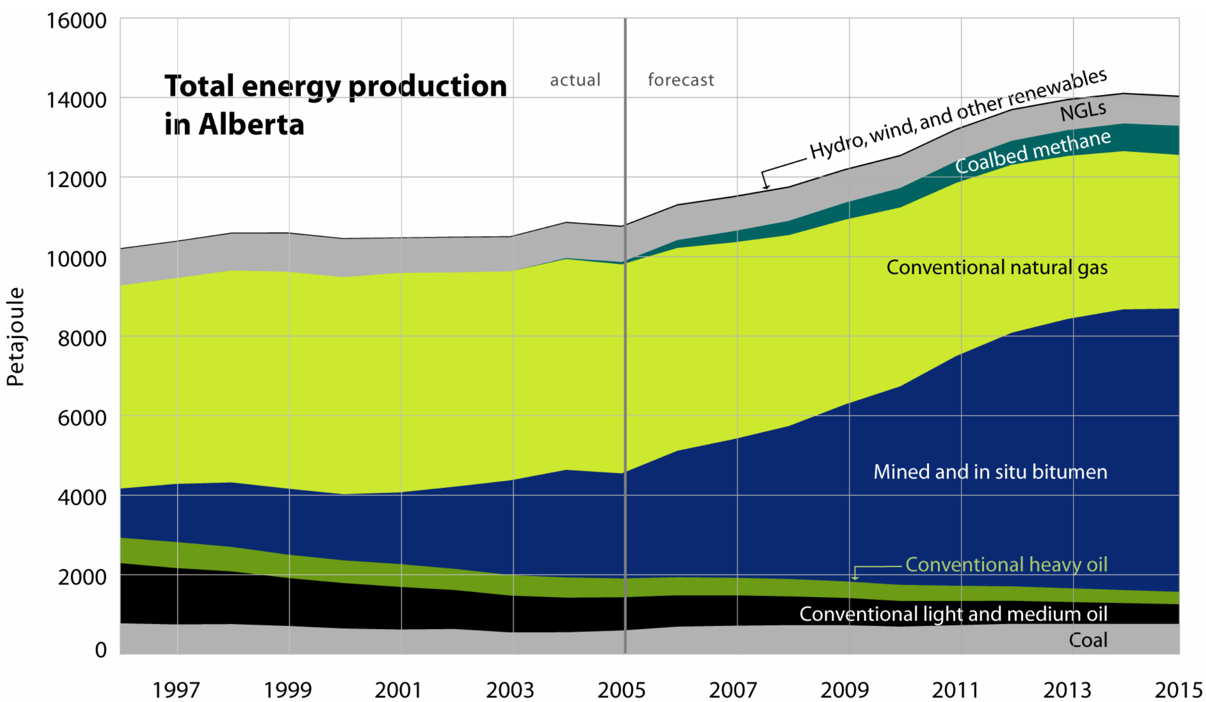
The Alberta Energy and Utilities Board (EUB) is an independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources and utilities services take place in a manner that is fair, responsible, and in the 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 2005 and Supply/Demand Outlook 2006-2015* 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.

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 2005, Alberta produced 10 794 petajoules of energy from all sources, including renewable sources such as hydro and wind power. This is equivalent to 4.8 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by these energy sources is illustrated in the following figure.



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 60 per cent of Alberta's total crude oil and raw bitumen production in 2005. The value-added process of upgrading raw bitumen to synthetic crude oil (SCO, a product similar to light crude oil) was expanded in 2005. While bitumen production at in situ projects increased by 14 per cent in 2005, production at mining projects declined due to a major fire at an upgrader. This resulted in an overall raw bitumen production decline of some 2 per cent compared with 2004. The upgrader resumed production in late 2005.

Conventional natural gas production in Alberta declined by 2 per cent in 2005 compared with 2004. The EUB has concluded that natural gas production in the province peaked in 2001. Natural gas production in 2006 is expected to have a similar decline to that in 2005. High levels of drilling in the past three years have prevented a sharp decline in production.

Coalbed methane (CBM) development activity continued to increase significantly in 2005, with CBM production doubling compared with 2004. It contributed to 2 per cent of the provincial total natural gas production and offset the decline in conventional gas production. The EUB anticipates that CBM development activity will continue to increase. The increasing 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 2005.

Reserves and production summary 2005

	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	269 254	1 694	10 278	64.7	7 849	279	94	103
Initial established	28 392	179	2 704	17.0	4 695	167	35	38
Cumulative production	791	5.0	2 449	15.4	3 554	126	1.27	1.39
Remaining established	27 601	174	255	1.6	1 141	41[b]	34	37
Annual production	61.7	0.388	33	0.209	137	4.9	0.033	0.036
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276	223	620	683

[a] Includes CBM.
[b] Measured at field gate (or 38 tcf downstream of straddle plant).

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves for crude bitumen are 27.6 billion cubic metres (m^3) (174 billion barrels), which is similar to the 2004 value . Only 2.8 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

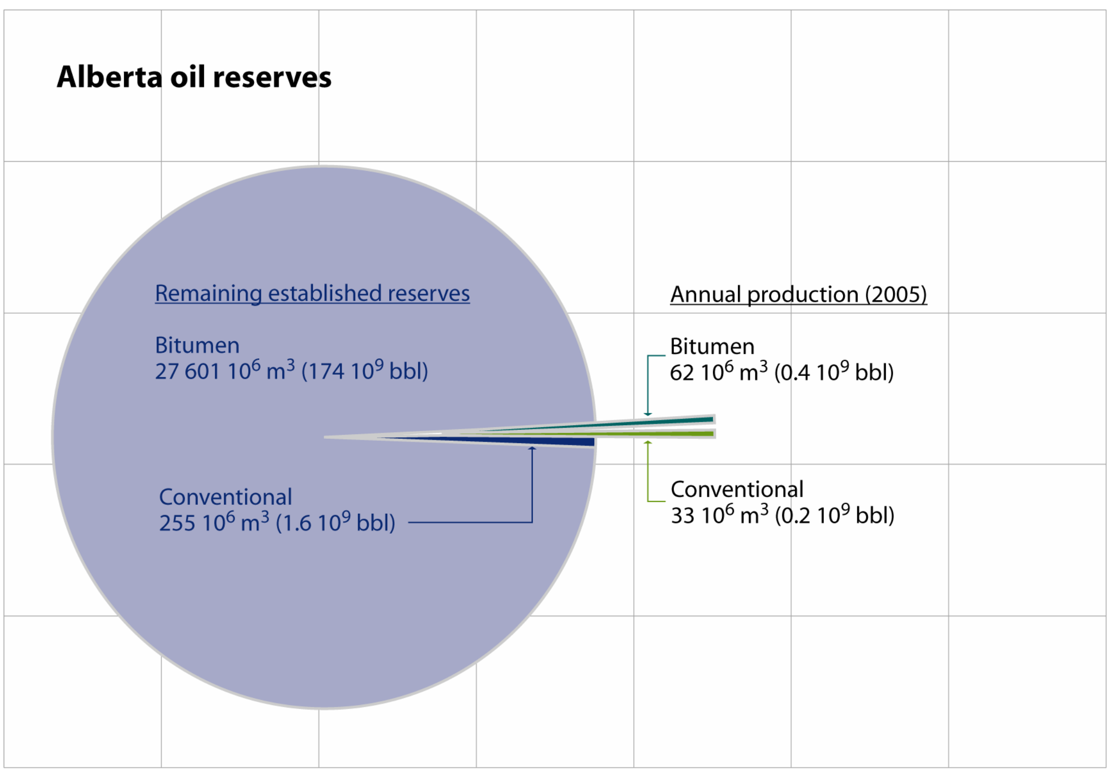
In 2005, Alberta produced 36.3 million m^3 (228 million barrels) from the mineable area and 25.4 million m^3 (160 million barrels) from the in situ area, totalling 61.7 million m^3 (388 million barrels). This is equivalent to 169 thousand m^3/day (1.06 million barrels per day). Bitumen produced from mining was upgraded, yielding 31.7 million m^3 (200 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 255 million m^3 (1.6 billion barrels), a 2 per cent increase from 2004. Of the 38.8 million m^3 (244 million barrels) added to the initial established reserves, 19.9 million m^3 (125 million barrels) was due to exploratory and development drilling, as well as new enhanced recovery schemes. This replaced 60 per cent of the 2005 production. Positive revisions accounted for the remaining 18.9 million m^3 (119 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 the following figure.



Crude Oil Production and Drilling

Alberta's production of conventional crude oil totaled 33.1 million m^3 (209 million barrels) in 2005. This equates to 90 800 m^3/day (571 400 barrels/day).

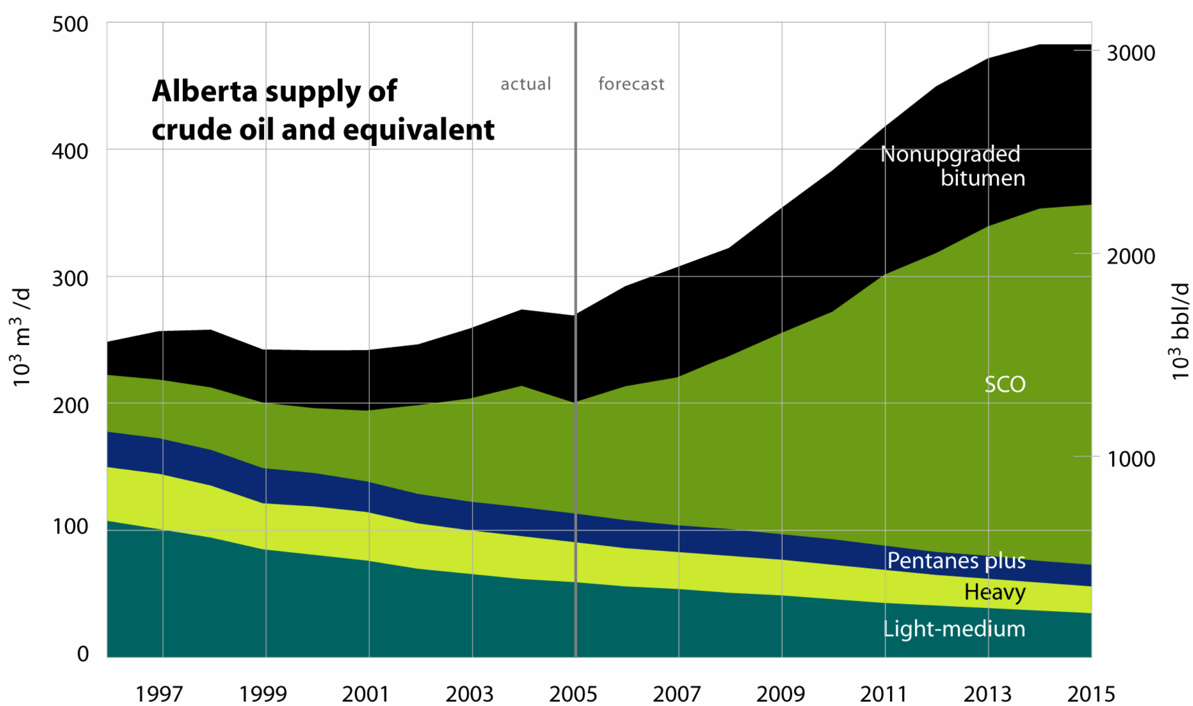
Despite high crude oil prices, the number of oil wells placed on production declined by 2 per cent to 1881 in 2005 from 1910 in 2004, mainly due to industry's emphasis on gas drilling. With the expectation that crude oil prices will remain strong, the EUB estimates that 2000 successful oil wells will be drilled in 2006 and further projects that a similar level of successful oil wells per year will be drilled over the remainder of the forecast period.

Total Oil Supply and Demand

Alberta's 2005 production from conventional oil, oil sands, and pentanes plus was 269 000 m^3/day (1.69 million barrels/day), a 1.7 per cent decline compared to 2004. Production is forecast to reach 482 000 m^3/day (3.0 million barrels/day) by 2015.

A comparison of conventional oil and bitumen production 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 2015. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 58 per cent in 2005 to 85 per cent by 2015.



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 two 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 3000 wells connected to pipelines in 2005. The increase 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 2005, the remaining established reserves of CBM in Alberta is estimated to be 20.9 billion m^3 (741 billion cubic feet). This is limited mainly to the "dry CBM" trend of central Alberta, as other CBM resource development has shown commercial producibility in only two locations new to this report.

Conventional Natural Gas Reserves

At the end of 2005, Alberta's remaining established reserves of natural gas stood at 1120 billion m^3 (40 trillion cubic feet [tcf]) at the field gate. This reserve includes some liquids that are subsequently removed at straddle plants. Reserves from new drilling replaced 63 per cent of production in 2005. This compares with 75 per cent replacement in 2004.

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 and 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 137 billion m^3 (4.9 tcf) of marketable natural gas in 2005, of which 1.3 billion m^3 (0.05 tcf) is from CBM.

There were 13 248 successful conventional natural gas wells drilled in Alberta in 2005, a 2 per cent increase from the 12 995 gas wells drilled in 2004. The EUB expects strong drilling over the forecast period, estimating 12 000 successful wells per year.

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 2005 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.

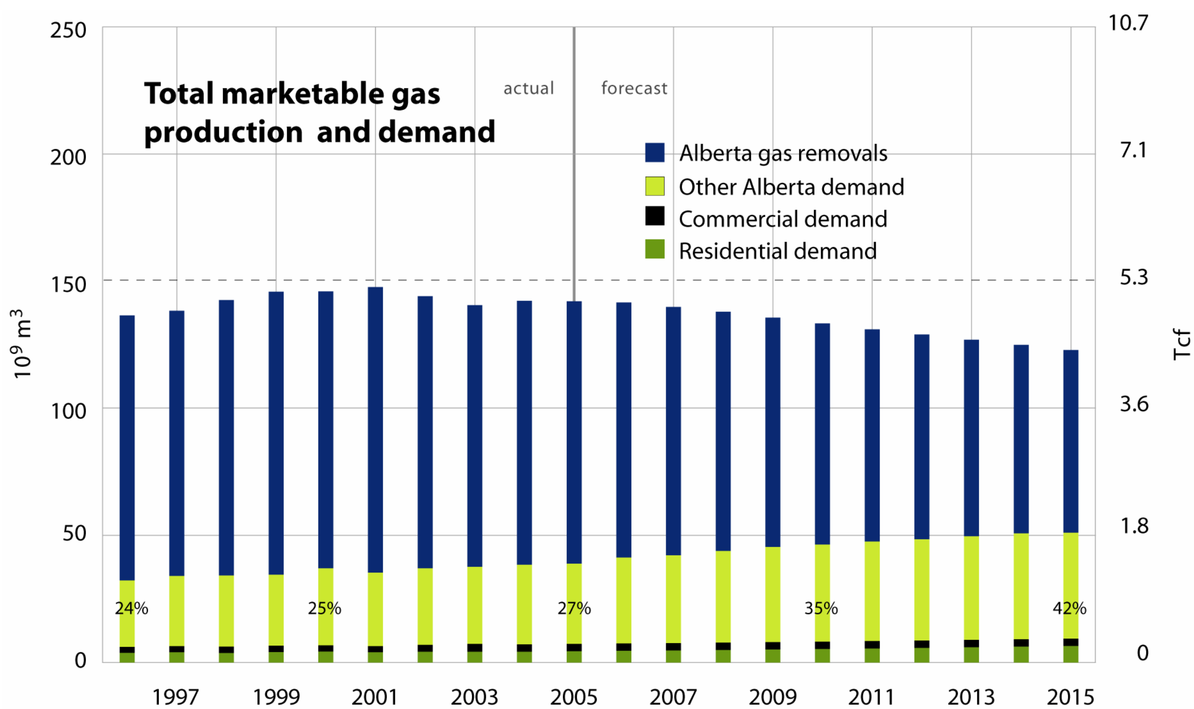
CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 3189 successful CBM well connections in Alberta in 2005. The EUB expects strong drilling of CBM wells over the forecast period, estimating 3000 well connections annually over the forecast period.

Natural Gas Supply and Demand

The EUB expects conventional gas production to decline by 2 per cent in 2006 and decline by an average of 3 per cent per year over the remainder of 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 is forecast to supplement the supply of conventional gas in the province. It is expected to increase from 2.9 billion m^3 in 2005 to 19.6 billion m^3 in 2015.

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 42 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.



Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 121 million m^3 (761 million barrels) as of year-end 2005. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

In 2005, the production of specification ethane remained similar to the 2004 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—decreased to 169 million m^3 (1.1 billion barrels) in 2005. 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 are 89 million tonnes from natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is not expected to increase significantly, and Alberta's sulphur inventory will continue 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 65 per cent of the province's electricity generation in 2005. Alberta's total coal production in 2005 was 30 million tonnes of marketable coal, most of which was sub-bituminous coal destined for mine mouth power plants. Alberta's coal reserves represent over a thousand years of supply at current production levels. Sub-bituminous 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. The thermal coal market in early 2003 saw declining prices, which influenced the closure of the Obed mine and reduced operations at the remaining mine at Coal Valley. Since that time thermal coal prices have grown to such a level that the Coal Valley mine is projected to increase production significantly in 2006.

Similarly, low market prices for metallurgical coal had influenced the closure of two mines and reduced coal production at the remaining Cardinal River mine, which was nearing its reserves limits. With the international market seeing prices almost double metallurgical coal, the mine at Grande Cache has reopened under new ownership. The Cardinal River Coals' Cheviot mine site that was opened in late 2004 will also add coal supply to Cardinal River production. This will stabilize production over the forecast period.

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.

This section introduces some of the main variables impacting energy requirements and sets the stage for supply and demand discussions in the report. It begins with a discussion of the current global oil demand and supply picture, with projections for 2006 based on research conducted by the International Energy Agency (IEA).

A review of the Organization of Petroleum Exporting Countries (OPEC) crude oil basket reference price (reference price) and summary of factors that will play a key role in influencing oil prices in the years to come are included. A discussion of North American energy prices is presented, with a focus on potential markets for Alberta crude. This section concludes with a summary of Canada's economic performance, along with the EUB's outlook on Alberta's economic growth.

1.1 Global Oil Market

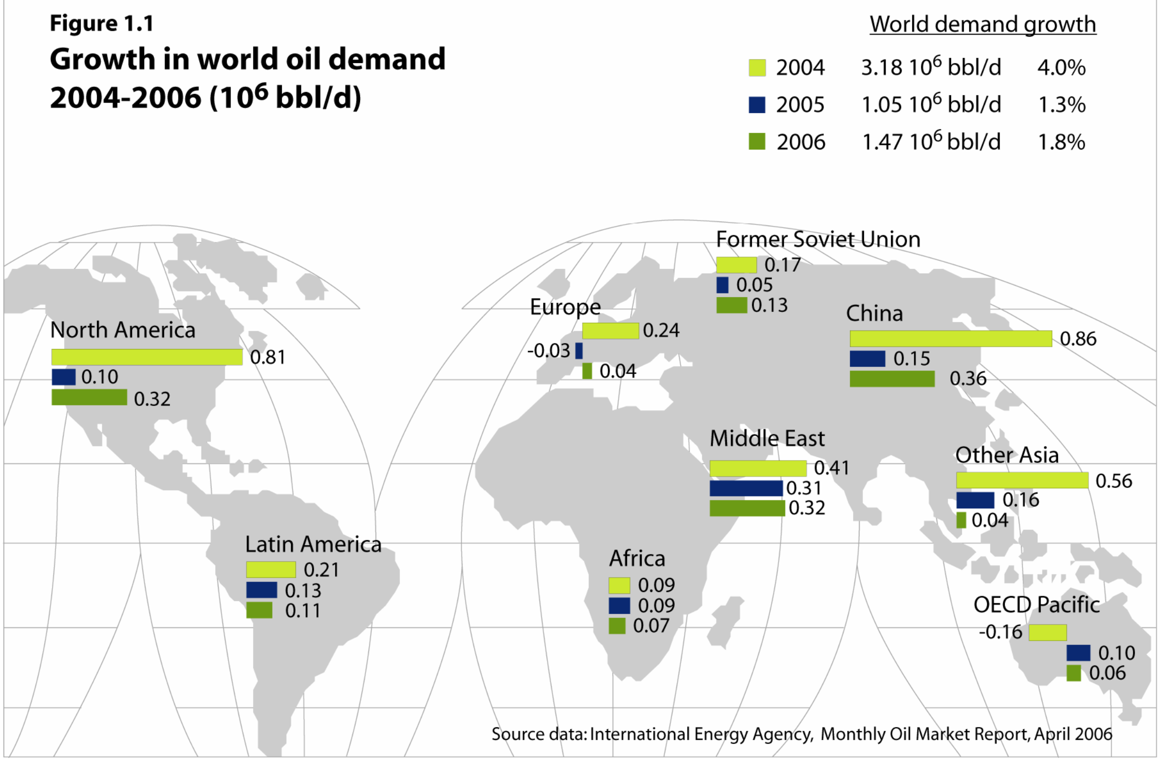
In 2005, the market continued to play out the scenario of a tighter world oil supply and demand balance. The oil market was characterized by extremely high real prices not seen in over twenty years. Fears of supply shortages continued through escalating unrest in the Middle East and Nigeria, labour disputes in Venezuela and Ecuador, and a prolonged and intense hurricane season in the Gulf of Mexico. Combined with continued economic growth in developing countries, such as China, as well as healthy economic growth in the United States (U.S.), with annual economic growth above 8 and 3 per cent respectively, the margin between the global supply and demand for crude oil remained narrow and fuelled fiery prices throughout the year.

Figure 1.1 illustrates growth in oil demand across the globe between 2004 and 2006. Growth in world demand for crude oil in 2004 doubled that of the previous year. Recorded at 82.5 million barrels per day in 2004, an additional 3.2 million barrels was required to support world economic growth compared to 2003.

As noted above, while the economic growth in China and other Asian countries, as well as the U.S., was healthy by any standards, these countries experienced lower growth rates in 2005 compared to 2004. As a result, world oil demand reached 83.6 million barrels per day, an annual change of only 1.3 per cent, compared with 4.0 per cent in 2004. Key factors leading to more moderate growth in world oil demand in 2005 included a sharp price increase and a stalling European economy.

In 2006 world oil demand is expected to reach 85.1 million barrels per day, implying an annual growth of about 1.5 million barrels a day, or 1.8 per cent. Growth is expected in all major regions across the globe, with most of the uptake in demand occurring in North America, China, and the Middle East. Growth in crude oil demand within Europe is not expected to be significant in 2006.

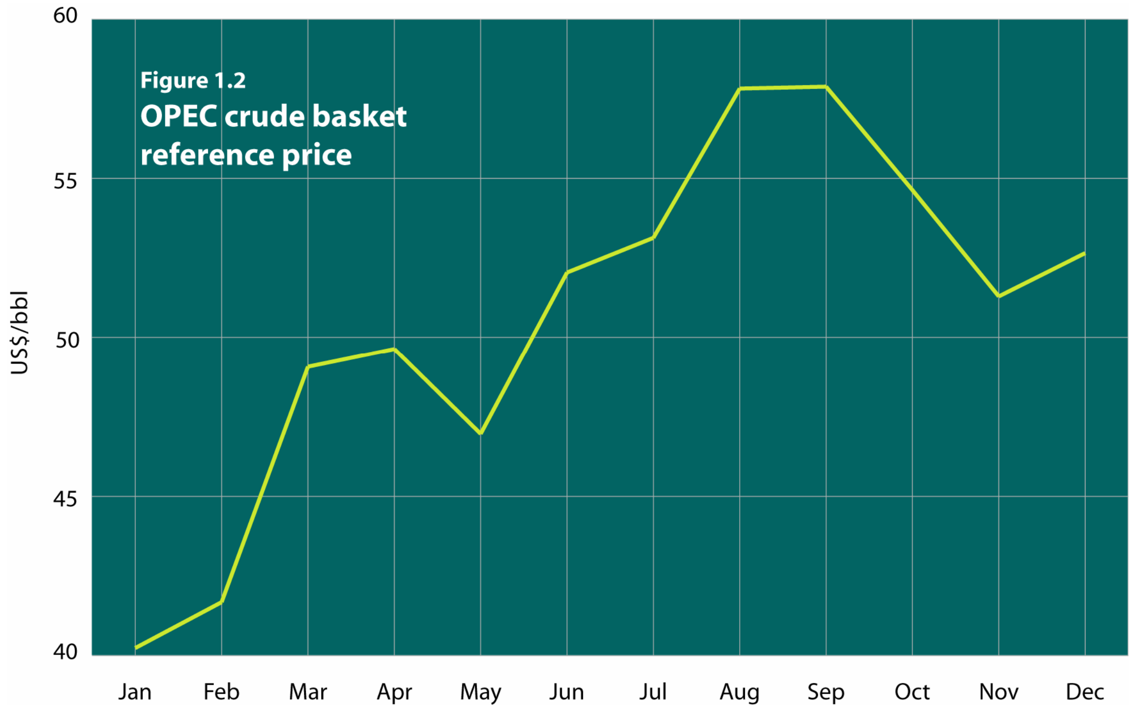
Figure 1.1
Growth in world oil demand 2004-2006 (10^6 bbl/d)



North America will account for 22 per cent of the projected growth in global oil demand in 2006, at about 1.3 per cent year over year. The Chinese economy is expected to pick up speed, which could translate into 5.5 per cent growth in its crude oil demand, or an additional 360 thousand barrels per day, about 25 per cent of growth in world oil demand in 2006. Countries in the Middle East will continue to increase their demand for oil, accounting for 22 per cent of world growth or 320 thousand barrels per day.

Figure 1.2 depicts the monthly average OPEC crude oil basket reference price (reference price) for 2005. OPEC adopted a new reference crude oil basket on June 15, 2005, consisting of eleven crude oils and better reflecting 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 OPEC reference price averaged US$40.24 per barrel in January 2005 due to continued unrest in Iraq, labour disputes in Venezuela, and a long cold period in the northern hemisphere. In March, the OPEC reference price jumped 18 per cent from the average price reported in February to US$49.07 per barrel, due to rising world oil demand and a period of colder weather.

The price began to moderate in April and May. In May, the OPEC reference price averaged US$46.96 per barrel, representing a downward movement of US$2.67 per barrel from April. A steep contango market, a condition where futures prices are higher in distant delivery months, and the recognition of ample OPEC supplies supported inventory buildup in the U.S. and eased supply worries.

In June, the OPEC reference price took a sharp swing, rising 11 per cent above the previous month as fears of future supply shortfalls took hold. The U.S. Gulf Coast hurricane season was off to an early start, with the first named tropical storm (tropical storm Arlene) recognized on June 9. In 2004, the first named tropical storm (hurricane Alex) began tracking on July 31. A longer hurricane season in 2005 meant a greater number of evacuations of Gulf rigs and platforms, damage, and supply disruptions. Unexpected refinery outages and a security alert in Nigeria also created fears of supply shortages for the summer season.

OPEC's reference price averaged US$57.82 per barrel in August, an increase of US$4.69 over the July average. Geopolitical tensions rose due to the death of the King of Saudi Arabia and speculation surrounding Iran's nuclear program. The temporary shutdown of a North Sea facility and a strike in Ecuador also reduced crude output in August.

At the end of August, hurricane Katrina made landfall on the Louisiana shore, shutting in significant volumes of production and refining capacity into the future. However, emergency response supplies from member countries of the IEA, support from OPEC, and reduced consumer demand in the face of high product prices eased fears and moderated the OPEC reference basket price going into September.

In November and December, the OPEC reference price returned to prices observed at the onset of summer. Speculation that Chinese economic growth was weakening, significant progress in returning U.S. Gulf Coast production, and a warmer winter forecast eased bullish sentiments. The year 2005 exited with the OPEC reference basket price averaging US$52.65 per barrel in December.

Overall, in 2005 the OPEC's reference price averaged US$50.64 per barrel, US$14.59 per barrel over the average price recorded for 2004. This represents a year-over-year increase in price of 40.5 per cent. Going forward, the sustainable crude oil production capacity of OPEC is expected to increase to about 33.5 million barrels per day in 2006, while the demand for OPEC crude is expected to average around 28.5 million barrels per day, which should provide a cushion to the risk of uncertain events and minimize large fluctuations in the OPEC reference price.

However, OPEC member countries have a number of difficulties that if left unaddressed could curtail crude oil supplies and push crude prices upward. These range from continued political instability and labour unrest in Venezuela to militant attacks on the upstream oil infrastructure in Nigeria, Iran's nuclear program, and sluggish growth in Iraq's crude oil production. Combined, these countries accounted for just under 10.8 million barrels per day of crude oil production, or about 36 per cent of total OPEC supply in 2005.

Several other factors on the demand side, such as global economic growth, in particular that of the emerging economies, will play a key role in the continued strength of crude oil prices going forward.

Analysts will be focused on the economic growth of Asian countries and their demand for oil over the next few years. China's strong economic performance is expected to continue: its economy may grow at a rate between 7 and 8 per cent per year over the next two years. India's emerging middle-class could become a major influence on crude demand and, hence, prices. Other Asian countries are continuing to exhibit strong demand growth.

In the U.S. the unemployment rate is around 5 per cent and employment earnings are increasing, which could result in an uptake in consumer spending. In 2006, growth in real gross domestic product in the U.S. is expected to remain above 3 per cent. However, there is some uncertainty here, as the average American is facing heavy personal debt, which will chip away at any real increase in consumer spending. In addition, it appears that the housing boom could end with the realization of higher commodity prices.

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.

Over the long run, high energy prices increase potential profits in the sector that induces investment. However, increased global crude production through investment in new resource extraction technologies will have a limited impact on prices in the immediate future. As well, demand-related investment that results in using oil and refined petroleum products more efficiently and the emergence of alternative energies should dampen price increases over the very long term.

1.2 North American Energy Prices

North American Crude Oil Prices

The price of Alberta crude oil is determined by international market forces and is most directly related to the reference price of West Texas Intermediate (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.

The EUB expects the price of WTI to range between US$60 and US$72 per barrel in 2006. Uncertainty increases farther out in the forecast period, but as prices are expected to remain in this range or could move a degree higher, the top end of the forecast price range reaches $88 per barrel by 2015. Several factors, such as global economic growth, in particular that of the emerging economies, and political instability within the major oil producing nations will have the greatest impact on the price of crude oil within the forecast period. **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.

In 2005, the monthly average price of WTI crude oil at Chicago began the year at US$47.75 per barrel. It climbed to over US$55 per barrel by March, then dipped down to US$50 per barrel in May. WTI surpassed US$60 by July and held in strong until September, when the daily spot price at Cushing, Oklahoma, narrowly missed US$70 per barrel and Chicago prices averaged US$66.65 per barrel, as hurricanes Katrina and then Rita swept the U.S. Gulf Coast. WTI ended the year at US$60.54 and averaged US$57.56 for the year.

Hurricanes Katrina and Rita placed significant pressure on oil prices. Timed only a few weeks apart, in the peak of their aftermath 100 per cent of normal daily oil production in the U.S. Gulf Coast was shut in. The shut-in oil was equivalent to nearly 30 per cent of total U.S. daily oil production. Although normal U.S. Gulf volumes account for only 2 per cent of world oil supply, the lost production during a period of tight supply was immediately reflected on WTI, as well as the OPEC reference basket price.

Figure 1.5 illustrates the monthly average price of Alberta light-medium crude, heavy crude, and bitumen. In 2005, heavy crude and bitumen prices averaged Cdn$39.18 and

Cdn$37.67 per barrel respectively, while the Alberta light-medium reference price averaged Cdn$64.92 per barrel. This resulted in the heavy/light-medium differential widening further, from 66 per cent in 2004 to 60 per cent in 2005. Similarly, the bitumen/light-medium differential widened from 65 per cent to 58 per cent.

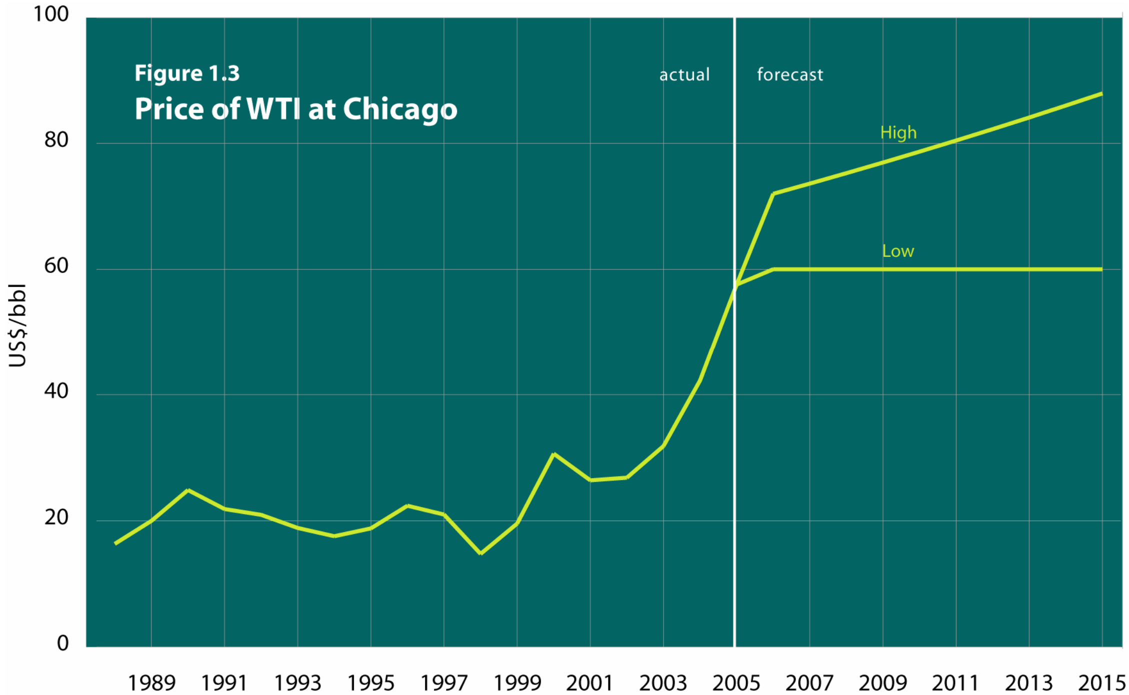


Figure 1.3
Price of WTI at Chicago

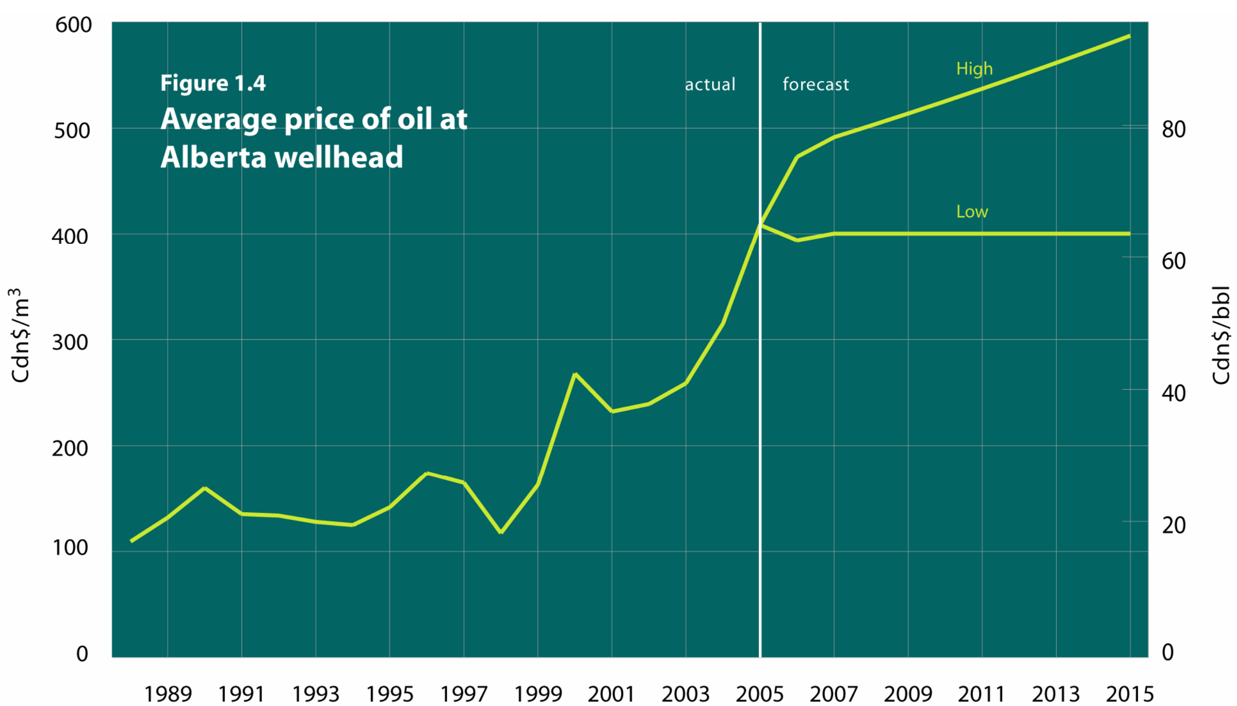
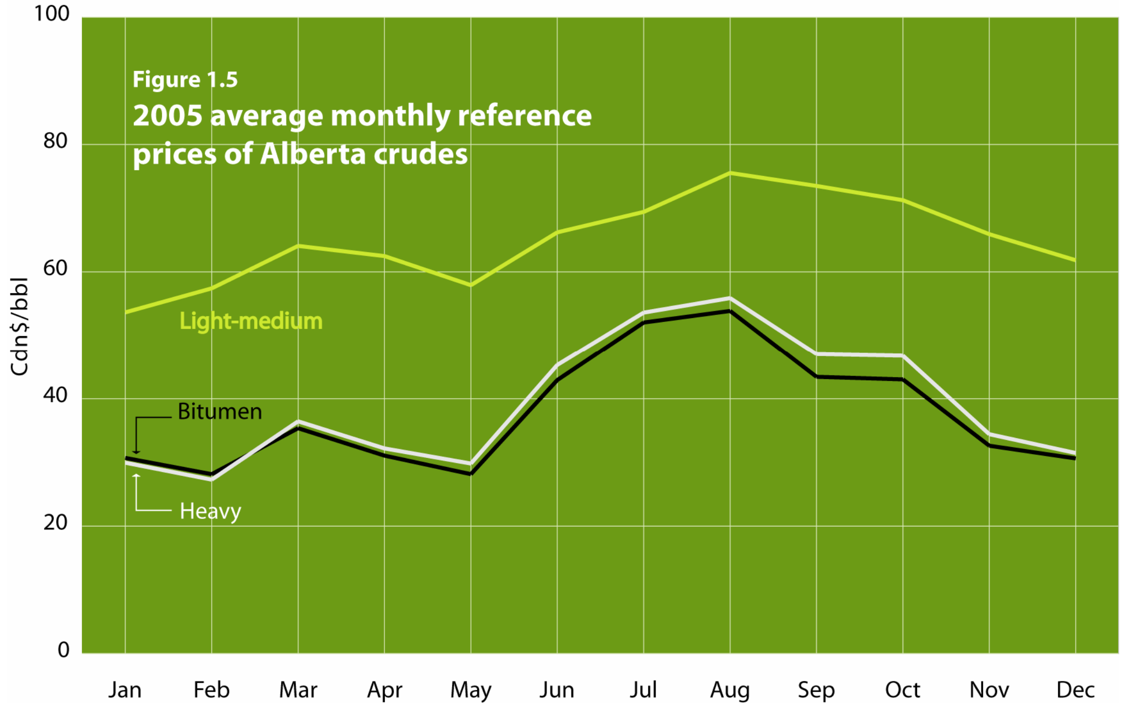


Figure 1.4
Average price of oil at Alberta wellhead



The growth in the differential of heavy crude and bitumen versus Alberta light-medium is due to imbalances in supply and demand. Recent increases in the supply of heavy crude and bitumen compared to the traditional refinery capacity that can process these crudes in the short term (without major changes in the processing capabilities) have resulted in an overall wide spread between light and heavier crudes. Diluent prices also play a role in determining the heavy crude and bitumen prices, as more expensive diluent will result in lower heavy crude and bitumen prices. While seasonal variations have always existed, the wider spread may last for some time.

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 differentials to the price of WTI. Heavy crude price differentials are expected to remain within the trend between 2006 and 2015. The forecast calls for conventional heavy to average 65 per cent of the light-medium price and bitumen to revert to 60 per cent of the light medium price. Wider differentials are becoming noticeable incentives for investment in additional upgrading capacity in North America.

Further expansion of upgrading capacity, refinery conversions, and pipeline access to new markets, which are all economically driven, should help stabilize these differentials over the longer term. In Alberta, there are currently three bitumen upgrading sites, with eight additional upgraders and a number of debottlenecking and expansion projects planned within the forecast period. As a result, upgraded bitumen product is expected to increase over threefold, from 87 thousand cubic metres per day (10^3 m^3/d) (547 thousand barrels per day) in 2005 to 283 10^3 m^3/day (1782 thousand barrels per day) by 2015.

After meeting Alberta refinery demand, the Petroleum Administration for Defense Districts (PADD) 2 and 4 in the United States are the largest importers of Alberta heavy crude, with total refinery capacity of 661 10^3 m^3/d (4157 thousand barrels per day) combined. The expansion at the Flint Hills upgrader and other refinery conversions will increase PADD 2 and 4 capability to take on increasing amounts of Alberta heavy crude. 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.

Additional pipeline infrastructure will provide an avenue for Alberta heavy crude to extend to larger markets in the U.S. and the Far East. 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. Throughout 2005, pipeline companies made strides towards completing existing projects, as well as moving ahead with the necessary steps involved with planning and executing new projects.

In summary, ten proposed new pipelines and pipeline expansions indicate an overall increase in crude oil pipeline capacity of 157.3 10^3 m^3/d (990 thousand barrels per day) to the Alberta market and 394.2 10^3 m^3/d (2480 thousand barrels per day) for the export market, some with the potential to reach PADD 3 and 5 and Asia. This represents an increase of 54 per cent in Alberta upgraded and non-upgraded bitumen pipeline capacity and a 96 per cent increase in export pipeline capacity.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the U.S., with 53 operating refineries and net crude oil distillation capacity of 1283 10^3 m^3/d (8.1 million barrels per day), plus the existing capability of refining heavier crudes. PADD 3 was not always viewed as the most likely market for Alberta because of inadequate transportation infrastructure and the proximately 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.

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. Nevertheless, natural gas prices are impacted to some extent by crude oil prices, as substitution could occur due to the price differential between the two commodities. **Figure 1.7** shows both the historical and the EUB forecast of natural gas prices at the plant gate from 1995 to 2015.

Alberta gas prices followed the upward trend of oil prices throughout 2005. Alberta plant gate natural gas prices were at their lowest in February, at $5.94 per gigajoule (GJ), as winter temperatures in the east eased. Natural gas prices remained steady until the start of a hot summer, which increased natural gas demand at power generation facilities to meet cooling requirements.

Increased demand for natural gas over the hot summer was augmented by declines in supply due to increased hurricane activity in the U.S. Gulf Coast. By September, hurricanes Katrina and Rita had shut in 80 per cent of normal daily gas production in the U.S. Gulf Coast, an equivalent of nearly 15 per cent of total U.S. daily gas production. As of March 2006, 14 per cent (1.4 billion cubic feet per day) of normal daily gas production

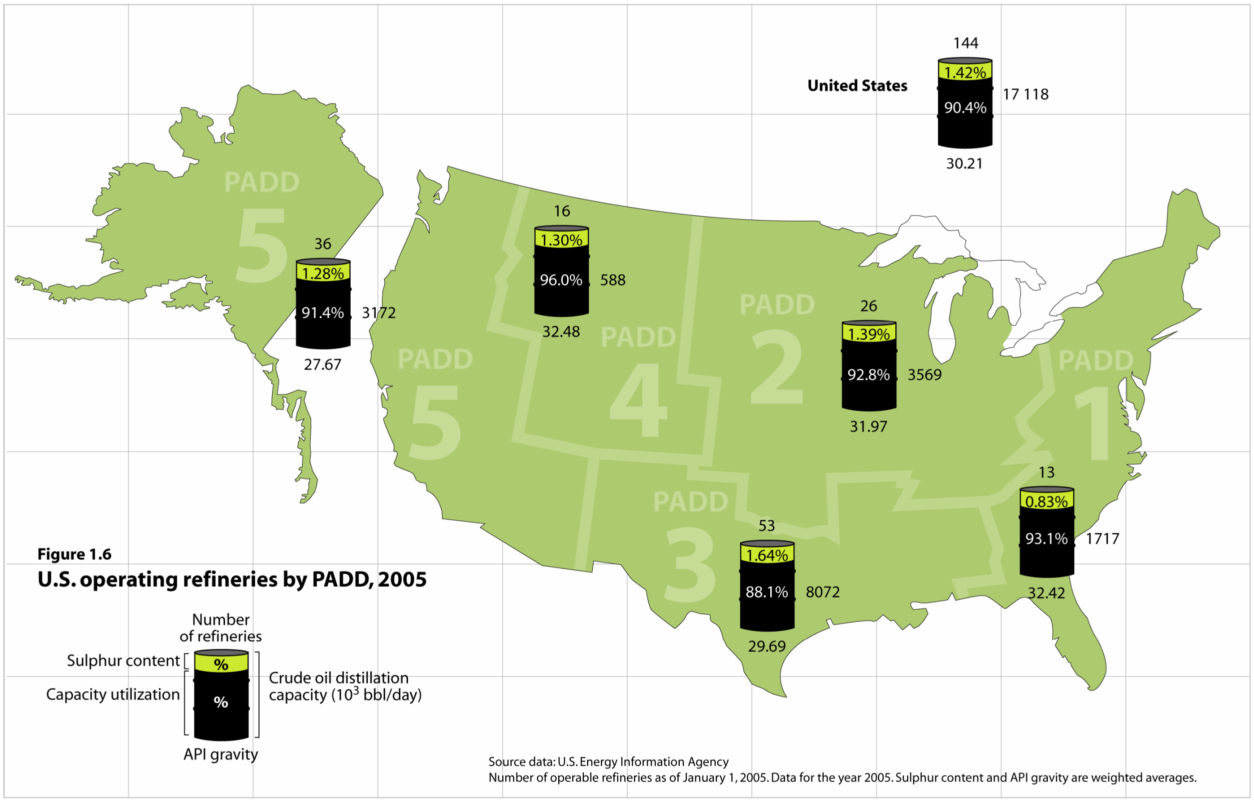


Figure 1.6
U.S. operating refineries by PADD, 2005

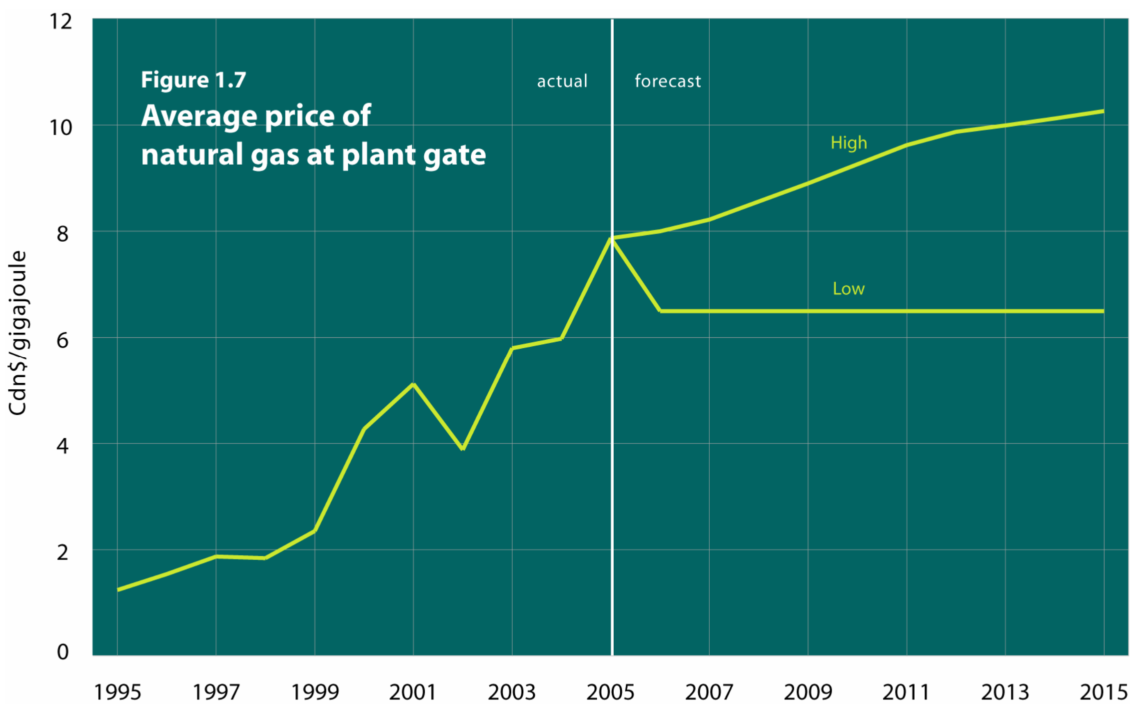


Figure 1.7
Average price of natural gas at plant gate

in the U.S. Gulf Coast still remained off-line. Destroyed and damaged rigs and pipelines were not the only carnage. The hurricanes caused significant damage to onshore infrastructure, which further delayed the resumption of normal gas and oil production rates in the U.S. Gulf of Mexico.

Increased demand for natural gas over the summer and the unusual circumstances surrounding the supply disruption caused by hurricane activity pushed prices higher late in the summer, when U.S. natural gas storage injection activities begin. Alberta plant gate natural gas prices peaked at $11.38/GJ in October. With warmer temperatures expected in the fourth quarter of 2005, natural gas prices began to ease from this peak and closed the year averaging $10.54/GJ in December and $7.87/GJ for the year.

The Alberta gas-to-light-medium-oil price parity on an energy basis was close to 0.70 for Alberta gas at the start of the year, but fluctuated downward to just under 0.60 by June. By late October the gas-to-oil parity had moved towards par and ended the year at 1.04 in December, averaging 0.74 for the year.

Natural gas prices are estimated to range between $6.50 and $8.00/GJ in 2006. Over the forecast period, the top end of the range increases to about $10.00/GJ. The gas-to-oil price parity is expected to average around 0.65 in 2006, increase to 0.70 in 2007, and remain at that level over the forecast period.

Factors supporting high future gas prices include high oil prices, increased demand for electricity generation, and tight gas supply. The rise in demand in the United States will also put pressure on the North American market, which will result in strong prices in 2006. Until significant new supply from other sources, such as Mackenzie Delta/Beaufort and Alaska, is available, prices will continue to experience volatility.

Despite the debate on the impact of intercontinental trade in liquefied natural gas (LNG) 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 requirement 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 cost at the gasification plant gate on the U.S. east coast is in the US$4.00 to $5.00/GJ range, but its small market share will not drastically affect rising natural gas prices in North America. It is also possible 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 intercontinental crude oil trades).

1.3 Production Costs in Alberta

Drilling and completion cost estimates for typical oil and natural gas wells are shown in **Figure 1.8** by Petroleum Services Association of Canada (PSAC) area for 2004 and 2006. Table 1.1 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.

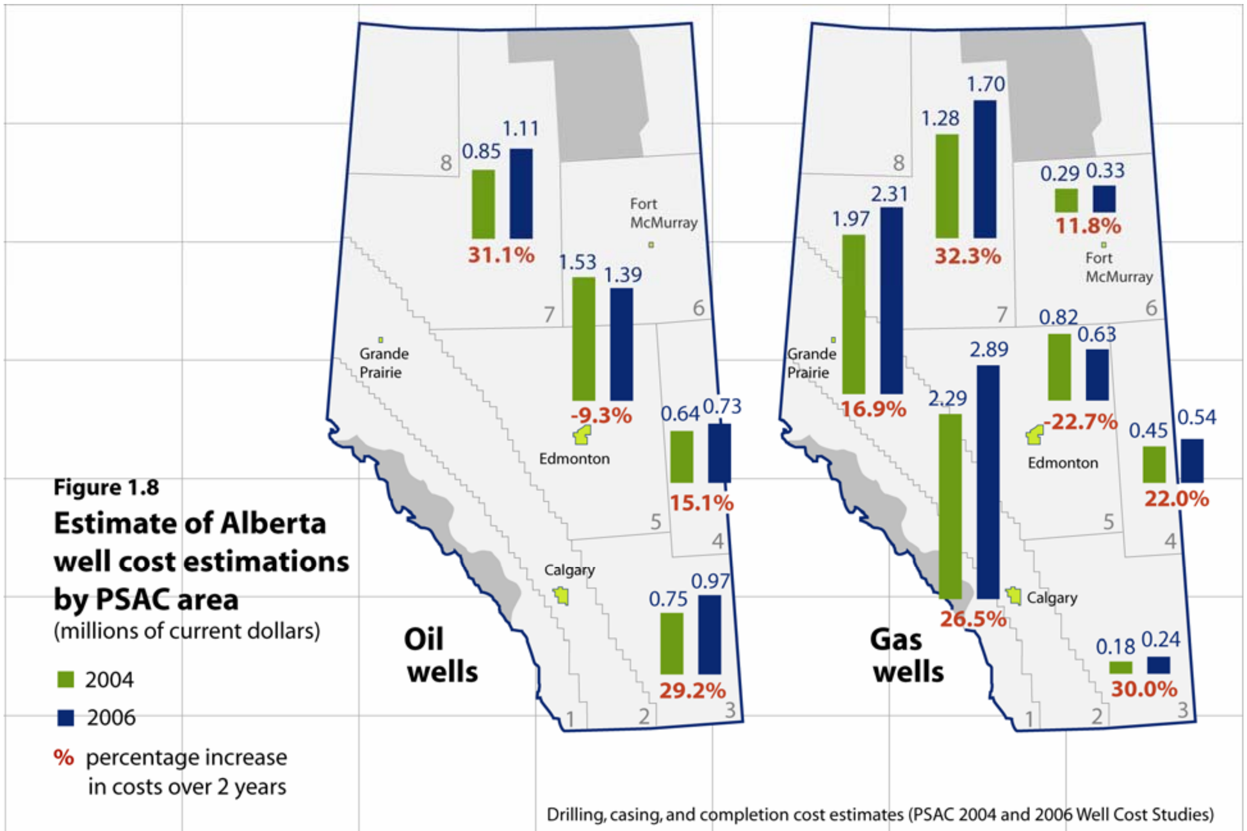


Figure 1.8
Estimate of Alberta well cost estimations by PSAC area
(millions of current dollars)

Table 1.1. Alberta median well depths by PSAC area, 2004-2005 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3 104	2 237	738	743	936	436	881
Oil wells	NA	NA	1 195	712	1 480	NA	1 528

NA – Not applicable.

With the exception of Central Alberta (Area 5), between 2004 and 2006 the expected cost to drill and complete the typical oil well increased by 15.1 to 31.1 per cent (**Figure 1.8)**. Within Area 5, the overall cost to drill and complete a typical oil well decreased 9.3 per cent, even though the completion portion of the total cost increased and other costs, such as rig in/tear out and day work, on a per day/unit basis increased. Most of the decline in overall costs to drill and complete a typical oil well in Area 5 can be explained by the amount of time required for rig work; about half the time is expected to be required in 2006 compared to 2004.

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 $730 000 in East Central Alberta (Area 4) to as high as $1 390 000 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 over the two-year period in all areas of the province, with the exception of Central Alberta (Area 5), where drilling costs for the typical vertical depth of a gas well have declined by 22.7 per cent. Despite increased costs on a per day/unit basis, the costs to drill and complete a typical gas well in Area 5 decreased as the days/units required for rig contract operations and services and other services, such as drillstem tests and core cuts, decreased.

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.

Examining the drilling and completion costs of the average oil or gas well located in different areas of the province is an acceptable method that summarizes the average cost of developing Alberta's conventional oil and gas resources. However, the EUB uses supply cost analysis as an alternate approach when evaluating the cost of bitumen production. Supply cost is defined as the revenue required per unit of output to recover capital, all operating costs, and a pre-set rate of return on capital over the life of the project. In other words, the discounted gross revenue calculated at the supply cost should be equivalent to the discounted value of all expenditures, including a return on equity.

Oil sands projects, in particular projects with bitumen upgrading facilities, are highly labour and capital intensive. Skilled labour can be a major bottleneck for a particular project, especially where multiple projects are in progress simultaneously.

The supply costs of mined bitumen and SCO production, as well as cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) bitumen extraction methods are illustrated in Table 1.2. The numbers are based on a 10 per cent after-tax real rate of return. In Alberta, that would provide a nominal before-tax rate of about 18 to 20 per cent. A fixed gas price of $7.50/GJ (constant 2003) dollars is also assumed. All other costs, such as capital costs and operating costs, are the average costs of a number of existing and future projects. While this latter assumption may underestimate the supply cost of future projects, it can be used as a benchmark to compare the relative economics of different recovery methods.

Table 1.2. Average bitumen and synthetic crude oil supply cost (constant 2003 Cdn$/m^3)

	Mined bitumen upgraded to SCO	CSS bitumen	SAGD bitumen
Average capacity (10^3 m^3/d)	62.6	13.8	9.2
Costs ($)			
Royalties	10.28	6.22	5.08
Taxes	16.28	10.84	8.32
Total variable	73.83	12.19	16.44
Natural gas	31.59	72.64	54.99
Electricity	13.33	6.89	4.04
Capital	78.63	44.51	34.27
Abandonment	0.25	0.22	0.17
Subtotal	224.18	153.51	123.30
Credits ($)			
Electricity credit	13.61	10.32	6.18
Total Supply Cost			
SCO or bitumen (Cdn$/m^3)	210.57	143.19	117.11
WTI equivalent (US$/bbl)[a]	30.32	33.28	27.22

[a] Conversion factors to calculate WTI equivalent are different for SCO and bitumen products.

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 variables that affect Alberta's economy but are beyond the province's control. The Canadian performance of the above economic indicators between 1996 and 2005 are depicted in **Figure 1.9**. Canada's most recent annual performance of these indicators and the forecast to 2015 are presented in **Table 1.3**.

Table 1.3. Major Canadian economic indicators, 2005-2015

	2005[a]	2006	2007	2008-2015[b]
Real GDP growth	2.9%	2.9%	2.9%	2.9%
Prime rate on loans	4.4%	5.5%	5.2%	5.2%
Inflation rate	2.2%	2.0%	1.8%	2.0%
Exchange rate (US/Cdn$)	0.83	0.87	0.86	0.86
Unemployment rate	6.8%	6.6%	6.6%	6.6%

[a] Actual.
[b] Averaged over 2008-2015.

The most frequently referenced indicator of a country's prosperity is the real gross domestic product (GDP). For 2005, Canada's real GDP adjusted for inflation was estimated at over $1100 billion (1997) dollars. Goods-producing industries account for less than one third of Canada's GDP, while the output of services-producing industries account for more than two-thirds.

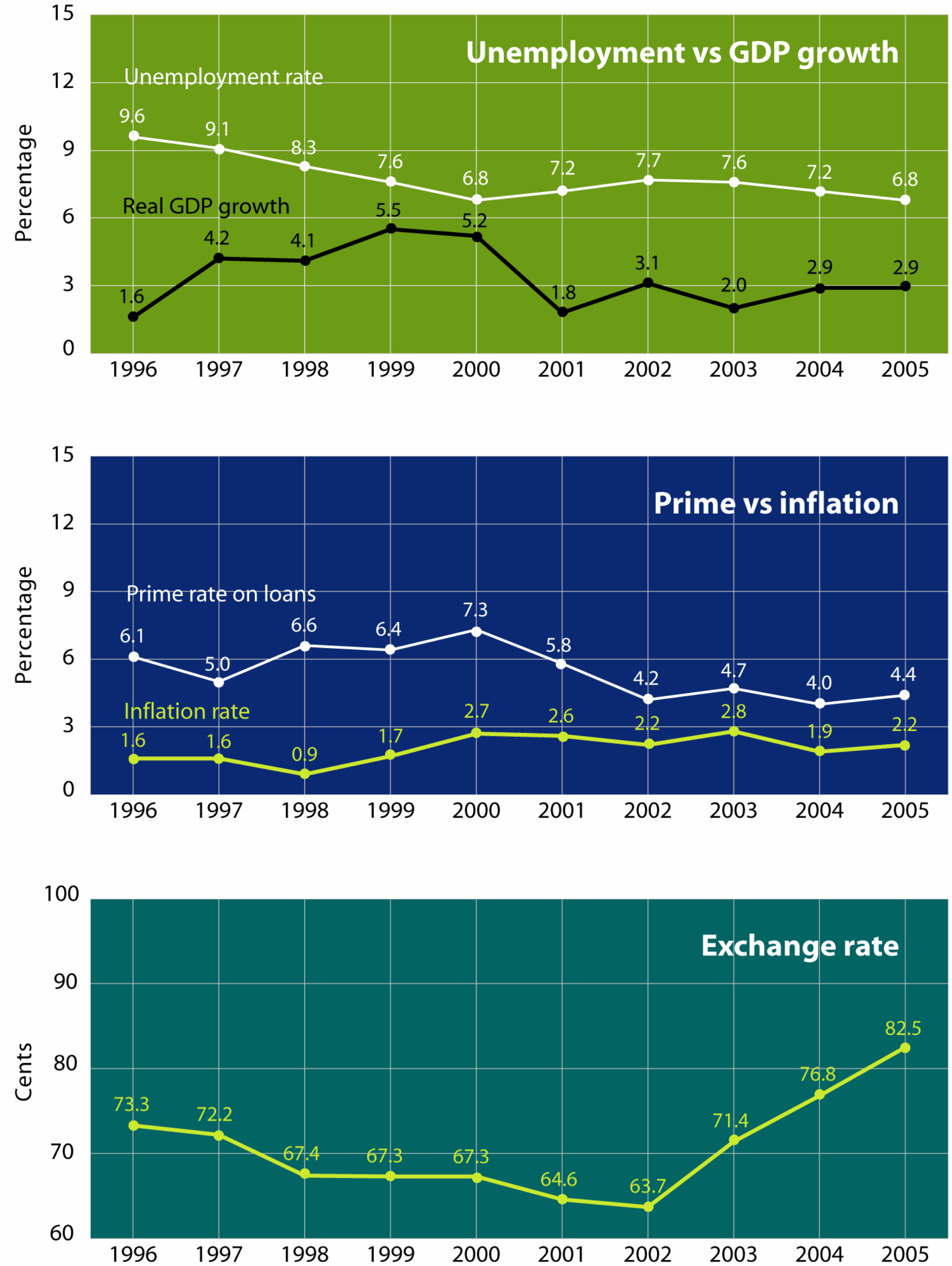
Economic growth, the percentage change of GDP between two points in time, usually a year or a quarter, measures the rate of expansion (or contraction) of an economy and its capacity to produce goods and services. Between 2004 and 2005, despite numerous hurdles, such as the continued appreciation of the 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 in line with the previous year at 2.9 per cent.

The driving forces of Canada's economic growth in 2005 were investment and personal consumption expenditures. Real investment increased 6.6 per cent in 2005, remaining at a level of growth consistent with 2004. In contrast to previous years when a booming housing sector was at the forefront of investment growth, the annual growth of investment in residential structures slowed to 3.3 per cent. Most of the uptake in investment in 2005 came through additions to machinery and equipment (10.7 per cent growth) and non-residential structures (6.8 per cent growth).

In 2005 the annual growth in wages and salaries, 5.4 per cent, reflected positively on growth in personal consumption expenditures and the performance of Canada's retail and wholesale trade industries. Personal expenditures on consumer goods and services increased 4.0 per cent in 2005, 0.6 percentage points above the 2004 annual growth rate. The retail trade industry increased 2005 output by 4.5 per cent and wholesale trades increased output by 8.1 per cent.

Figure 1.9

Canadian economic indicators



Some of the increase in consumer demand was filled by imported goods and services, which grew at a rate of 7.0 per cent in 2005; the Canadian dollar exchange rate climbed to US86.1 cents by December, making imported products increasingly attractive to Canadian consumers. The growth in imported goods and services kept Canada's economic growth below 3 per cent in 2005.

Real growth in Canadian exports declined 2.7 percentage points from 2004 to a growth rate of 2.3 per cent in 2005. The output of Canada's goods-producing industries, particularly the manufacturing sector, is suffering as the appreciation of the Canadian dollar and high energy costs cycle their way through the economy. Manufacturing output increased a mere 2.2 per cent in 2005, significantly lower than the 4.6 per cent growth rate recorded in 2004. While durable goods manufacturing grew at a modest rate of 4.0 per cent in 2005, non-durable goods manufacturing industries, which are more sensitive to international competition, exhibited a contraction of 0.4 per cent.

Canada's economic growth is expected to follow its current trend over the forecast period and to average 2.9 per cent per year between 2006 and 2015. The exchange rate is expected to average US87 cents in 2006 and remain at US86 cents throughout the remainder of the forecast period.

In addition to growth in investment and consumption, economic growth typically implies growth in the labour force and possibly a reduction in the unemployment rate. Canada's unemployment rate in 2005 fell 0.4 percentage points to 6.8 per cent. It is expected to fall a further 0.2 percentage points in 2006.

In some cases growth can be so strong that it presses the economy to the limits of its capacity, which may result in inflation. 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 are 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 aims to keep inflation at the midpoint of this range, at 2 per cent.

The average annual interest rate on prime business loans was 4.4 per cent in 2005, an increase of 0.4 percentage points over the 2004 average rate. The rise in interest rates arose from the Bank of Canada's decision to increase the target overnight rate a quarter of a percentage point over the last three consecutive fixed announcement dates in 2005 in an effort to keep the level of inflation in Canada within the target range. The inflation rate in 2005 was 2.2 per cent.

It is expected that the Canadian economy in 2006 will continue to operate at its productive capacity. Therefore further increases to the interest rate are expected, as the Bank of Canada will be focused primarily on keeping inflation within the target range. As a result, the interest rate on prime business loans is expected to average 5.5 per cent and total inflation will return to 2.0 per cent in 2006. In 2007 and beyond, an easing of monetary policy is expected, the prime rate is expected to fall to an average of 5.2 per cent, as inflation hovers around the midpoint of the target range.

1.5 Alberta Economic Outlook

Alberta real economic growth has averaged 3.6 per cent per year over the past ten years. Real GDP surpassed $135 billion in 2004, and the EUB expects the official figures to climb to over $140 billion in 2005. Alberta has the highest GDP per capita among the provinces, averaging $39 222 per person over the last five years, which is 13 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 annual economic growth in Alberta for 2005 was 4.5 per cent. Real GDP is set to grow a further 4.4 per cent in 2006, 3.3 per cent in 2007, and an average of 3.1 per cent per year over the remainder of the forecast period. Alberta's inflation was measured at 2.1 per cent in 2005, less than the Canadian average inflation rate. Prosperous economic growth and acceptable levels of inflation in future years imply job growth, relatively low levels of unemployment, real increases in average employment earnings, and growth in personal disposable income.

Table 1.4. Major Alberta economic indicators, 2005-2015 (%)

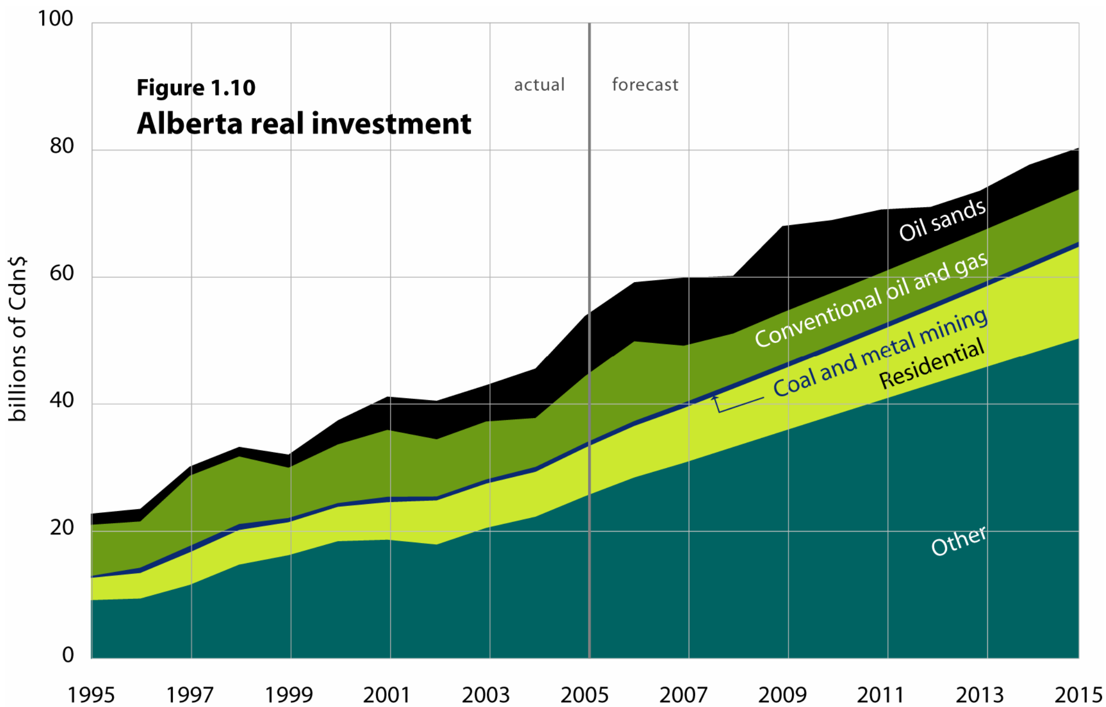
	2005	2006	2007	2008-2015[b]
Real GDP growth	4.5[a]	4.4	3.3	3.1
Real personal disposable income growth	2.5	3.5	3.6	2.5
Inflation rate	2.1[a]	2.3	2.1	2.3
Employment growth	1.5[a]	3.4	3.1	2.1
Population growth	1.6[a]	1.8	1.9	1.7
Unemployment rate	3.9[a]	3.6	3.4	3.4

[a] Actual
[b] Averaged over 2008-2015.

The main factors for Alberta's current and future economic growth are investment, particularly in the oil sands sector, relatively high energy prices, and steady rate of growth in personal consumption. The spinoffs 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 trades and service industries. Much of Alberta's additional production will be destined for the export market.

In December 2005, Alberta Economic Development published an inventory of 1148 major projects with a total market value of $123.1 billion (current dollars) that are recently completed, under construction, or proposed to start construction by 2007. The 48 projects related to the oil sands sector account for almost 60 per cent of the total value of investment. Conventional oil and gas and related pipeline infrastructure investments account for an additional 54 projects with a market value of over $10 billion.

Figure 1.10 illustrates the profile of real investment within the oil sands, conventional oil and gas, coal and metal mining, and residential sectors between 1995 and 2015. Historically, much of the volatility in Alberta's investment was strongly influenced by resource prices, interest rates and, of course, economic recession. While this trend is



expected to continue, investment in the oil sands will become a major contributor to overall growth in investment.

Over the forecast period, total real investment expenditures are expected to grow at an average rate of 4 per cent per year at minimum. About two-thirds into the forecast, oil sands investment falls to a base annual increment due to the lack of information on oil sands projects in the outlying years. As time passes, the void toward the latter part of the forecast period will likely be filled by investment from future, while currently unknown, oil sands projects.

The Alberta unemployment rate has gradually declined from its peak of 9.6 per cent in 1993. In 2005, Alberta had the lowest unemployment rate in Canada, at 3.9 per cent, down from 4.6 per cent in 2004. In addition, the unemployment rate for individuals unemployed for three months or more fell from 1 per cent in 2004 to 0.7 per cent in 2005. Alberta's unemployment rate has so far continued its downward trend, falling to a low of 3.1 per cent in February 2006.

The EUB forecasts Alberta's employment demand to grow at a rate of 3.4 per cent in 2006, 3.1 per cent in 2007, and an average of 2.1 per cent per year throughout the remainder of the forecast period. The labour force participation rate is expected to grow at roughly the same rates, influenced by positive net migration, population growth, and people re-entering the labour market. As a result, the unemployment rate is expected to fall marginally to 3.6 per cent in 2006 and remain within a tight range between 3 and 4 per cent over the forecast period.

Growth in employee earnings and personal disposable income will cause a spark for the economy in consumption expenditures. Alberta has the highest average personal disposable income of all provinces in Canada. Between 2004 and 2005, real growth in personal disposable income is estimated at 2.5 per cent, and it is expected to grow at an annual average rate of 2.7 per cent over the forecast period. As a result, real consumption expenditures in Alberta are predicted to increase on average more than 3 per cent per year between 2005 and 2015.

Real provincial exports, net of inflation, which include interprovincial transactions of goods, will grow on average between 3 and 5 per cent per year over the forecast period. However, strong growth in real imports will dampen the effect of growth in real exports on Alberta's overall economic performance. Real imports are forecast to grow at a rate just above that of export growth, especially during the periods when investment in the oil sands is highest, when more materials and equipment will be required.

Today's energy prices are the predominant factors influencing the current pace of exploration and development activity and increasing 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 2004, 12 850 conventional gas wells and 1920 conventional oil wells were connected and placed on production in Alberta. An additional 11 848 conventional gas wells were connected and 1882 conventional oil wells were placed on production in 2005. The EUB price forecast supports the current pace of activity; going forward, an additional 12 000 conventional gas wells and 2000 conventional oil wells are expected to be tied into production each year.

Energy prices are also providing greater incentives to commercially develop Alberta's unconventional energy resources, such as coalbed methane (CBM) and crude bitumen. Production rates from unconventional resources are expected to increase substantially 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)

	2005	2006[a]	2007[a]	2008-2015[a,b]
Conventional crude oil	11 684	12 326	11 936	10 100
Crude bitumen	5 953	7 745	8 495	12 028
Synthetic crude oil	12 959	17 162	18 942	37 773
Marketable gas	41 898	39 788	42 478	41 818
NGLs	8 331	8 672	8 614	8 080
Sulphur	174	183	183	205
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	80 999	85 875	90 648	110 004

[a] Values calculated from the EUB's annual average price and production forecasts.
[b] Annual average over 2008-2015.

CBM production accounted for 1 per cent of marketable natural gas production in 2005. By 2015, the gas production from CBM wells will increase to 16 per cent of marketable gas production. However, the additional marketable gas production from unconventional sources will fall short to offset 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 59 per cent of the total SCO production in 2005 to 82 per cent of SCO production by 2015.

Oil and gas companies are experiencing increased revenues as a result of higher energy prices, but on the other hand, operating expenditures are also increasing. As companies are competing against each other to acquire drilling contracts and support services, both equipment and labour are becoming increasingly scarce and driving up costs, certainly during seasonal periods of high 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 light labour market by applying a variety of solutions, such as industry-sponsored training and apprenticeships, employer-driven immigration, and even providing air transportation to draw workers from other regions.

Solid economic growth, job gains, reduced unemployment rates, and rising employee earnings provide a positive outlook for Alberta's economy. However, Alberta's economy will be affected if labour productivity growth remains relatively flat and rising labour and material costs negatively affect corporate bottom lines. Along with rising wages and salaries, the noticeable tight labour market and skilled labour shortage resulting from rapid investment expenditures in major projects could also constrain Alberta from growing at its full potential in the future.

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 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 to bring it to a vertical or horizontal wellbore.

The three designated oil sands areas (OSAs) in Alberta 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, and the significant Cold Lake Clearwater deposit 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, the two most important deposits have been updated. The largest deposit, the Athabasca Wabiskaw-McMurray (AWM), was updated last year and has been revised slightly this year due to the incorporation of new drilling. Currently the AWM has the largest cumulative and annual production. The deposit with the second largest production, the Cold Lake Clearwater (CLC), has been updated for this report, as has been the northern portion of the Cold Lake Wabiskaw-McMurray (CLWM) deposit. The deposit with the third most production, the Peace River Bluesky-Gething, together with one or two other smaller deposits, will be updated for year-end 2006.

Once the in-place resources have been determined, the EUB intends to 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, 2005, are 27.60 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.06 10^9 m^3.

Of the total 27.60 10^9 m^3 remaining established reserves, 22.55 10^9 m^3, or about 82 per cent, is considered recoverable by in situ methods and 5.05 10^9 m^3 recoverable by surface mining methods. Of the in situ and mineable totals, 1.62 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	0.54	5.05	1.20
In situ	253.2	22.80	0.25	22.55	0.42
Total	269.3	28.39	0.79	27.60	1.62
	(1 694)[a]	(178.7)[a]	(5.0)[a]	(173.7)[a]	(10.2)[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 2005 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)

	2005	2004	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	538	502	+36
In situ[a]	253	228	+25
Total	791	730	+62
Remaining established reserves			
Mineable	5 052	5 088	-36
In situ	22 549	22 574	-25
Total[a]	27 601 (173 687)[b]	27 662 (174 074)[b]	-62

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

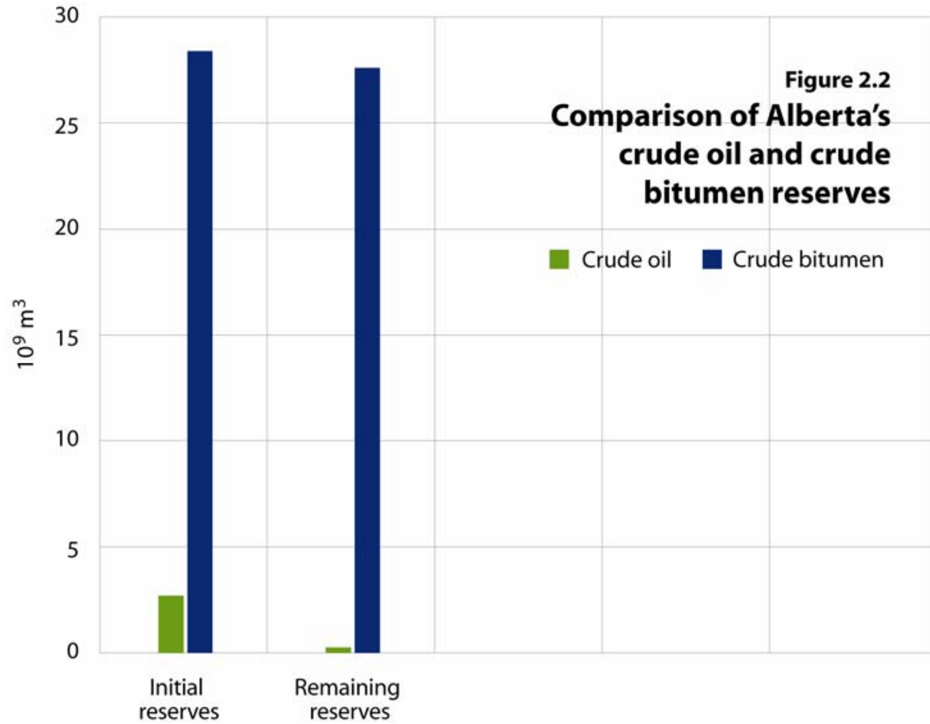
Crude bitumen production in 2005 totalled 61.7 10^6 m^3, with 25.3 10^6 m^3 coming from in situ operations. Production from the three current surface mining projects amounted to 36.3 10^6 m^3 in 2005, with 15.2 10^6 m^3 from the Syncrude Canada Ltd. project, 11.2 10^6 m^3 from the Suncor Energy Inc. project, and 9.8 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 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. With last year's report, the entire AWM deposit is now estimated using 6 mass per cent, with 1.5 m retained for in situ and 3.0 m used for surface mineable. With this year's report, the CLC and a portion of the CLWM are also now estimated at a 6 mass per cent saturation cutoff. 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 for the AWM and the CLC more accurately reflects the volumes from which bitumen can be reasonably expected to be recovered. 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 and about 35 per cent for the CLC. However, last year's review of the AWM saw an actual increase due to new drilling, and this year's reassessment of the CLC only reduced the initial in-place volume 15 per cent, from 11.1 10^9 m^3 to 9.4 10^9 m^3. This smaller reduction in the CLC is also due to additional drilling (since 1990, the last regional update), which has expanded the known extent of the deposit, particularly to the north.

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

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

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.

Figure 2.3 is a bitumen pay thickness map, revised for 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. The resultant change in initial in-place resources was minor.

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.

Figure 2.5 is a map of the reconstructed Paleozoic surface beneath the Clearwater Formation at the time of the deposition of the Clearwater sediments. The relative elevations for this erosional surface were created by first flattening the Wabiskaw shale at the top of the Wabiskaw-McMurray deposit and then applying those adjustments to the current Paleozoic surface.

Also for year-end 2005, the EUB reassessed the northern portion of the CLWM. In this area the CLWM is simply the southern continuation of the AWM sediments. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure 2.6** is a bitumen pay thickness map for the CLWM deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Similar to the AWM, the CLWM contains some regionally mappable internal seals and therefore contains several bitumen zones. However, consistent with **Figure 2.3**, the CLWM is mapped as a single bitumen zone so that the full extent of the deposit can be shown. Within the area assessed, the saturation cutoff was changed from 3 mass per cent to 6 mass per cent, as previously mentioned, and the estimation method changed from building block to isopach. The net change to the initial in-place resources was an increase of 0.7 10^9 m^3, mainly due to new drilling in areas previously undrilled at the time of the last estimate in 1995.

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.

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 this year's report, the in-place resources in those areas below 80 m in

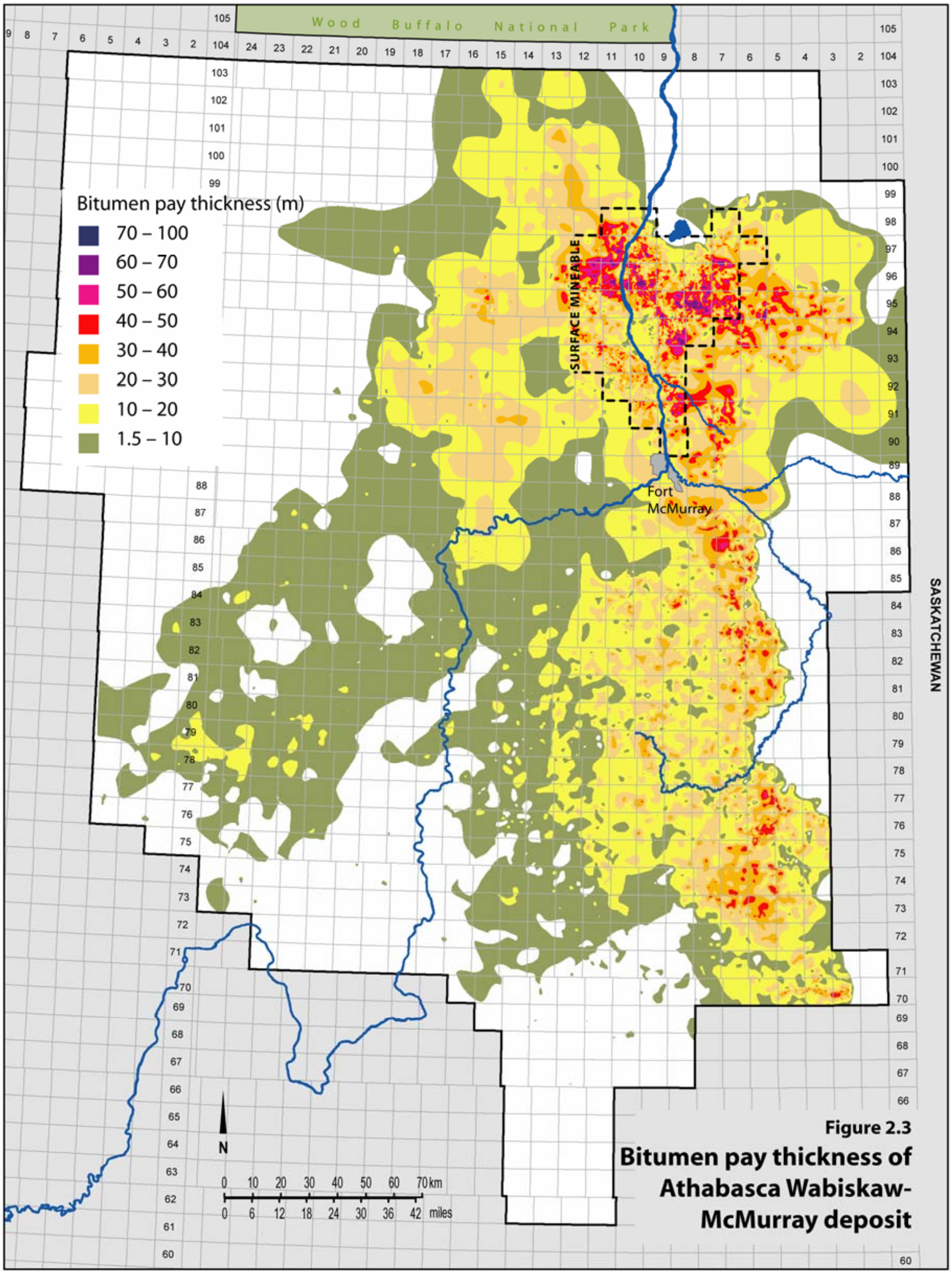


Figure 2.3
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

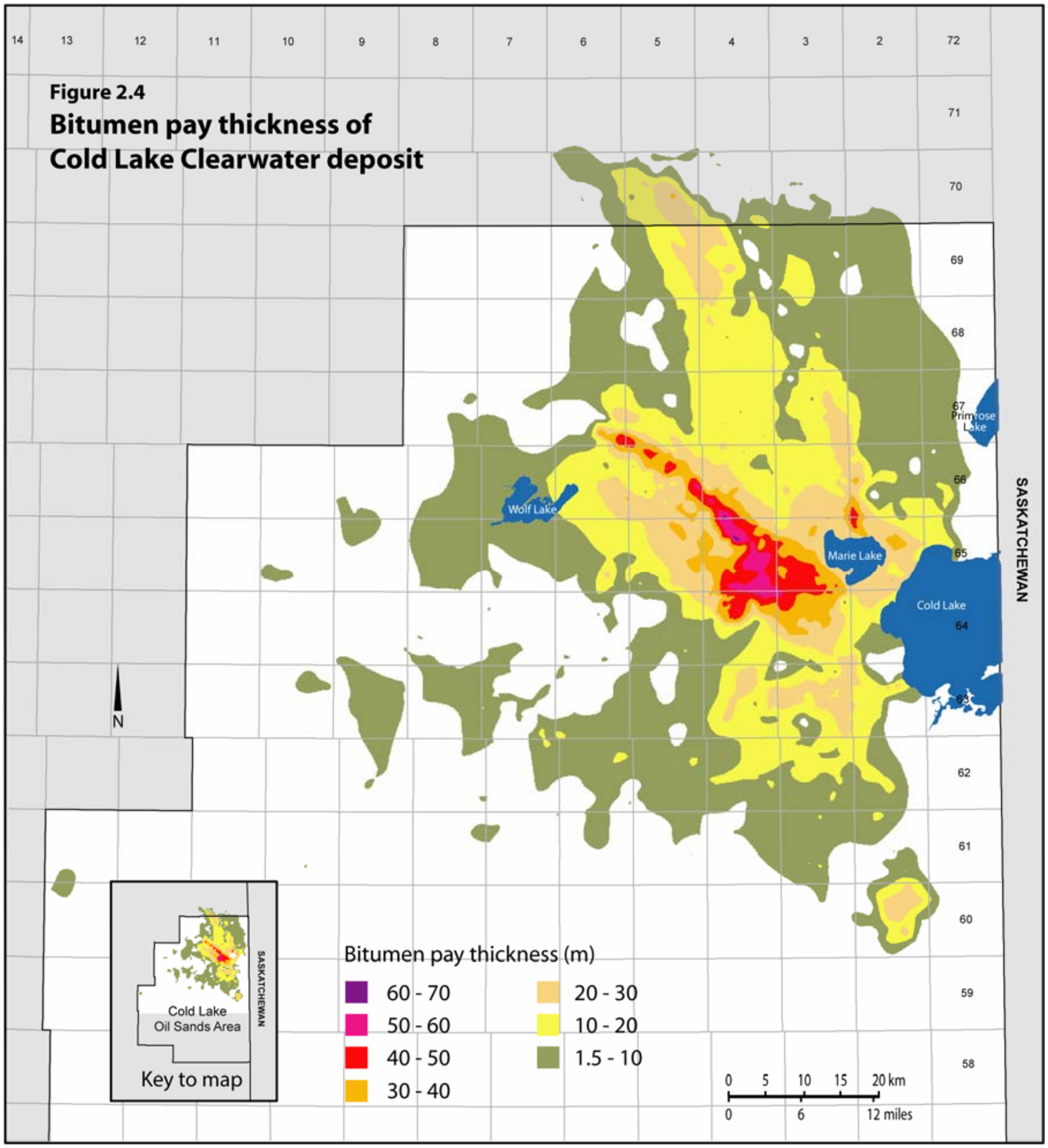


Figure 2.4
Bitumen pay thickness of Cold Lake Clearwater deposit

depth (1.39 10^9 m^3) are removed from the mineable total and incorporated into the in situ total. This change does not impact 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.

The estimate of the initial volume in place of crude bitumen within the SMA is 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

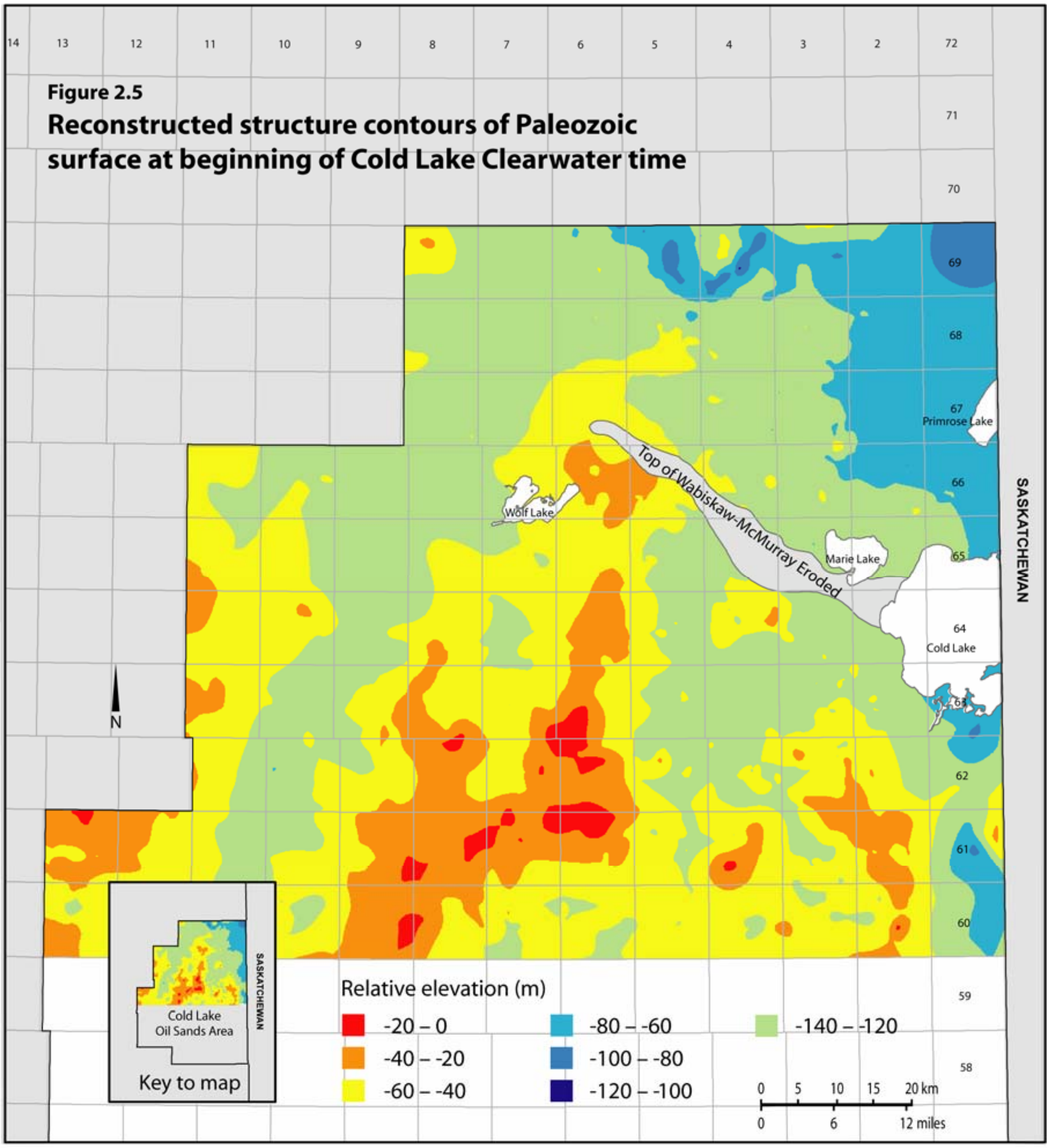


Figure 2.5
Reconstructed structure contours of Paleozoic surface at beginning of Cold Lake Clearwater time

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.

The crude bitumen resource volumes are presented on a deposit basis in the table Crude Bitumen Resources and Basic Data, provided on CD (see Appendix C) and 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 AWN and CLC will be available separately.

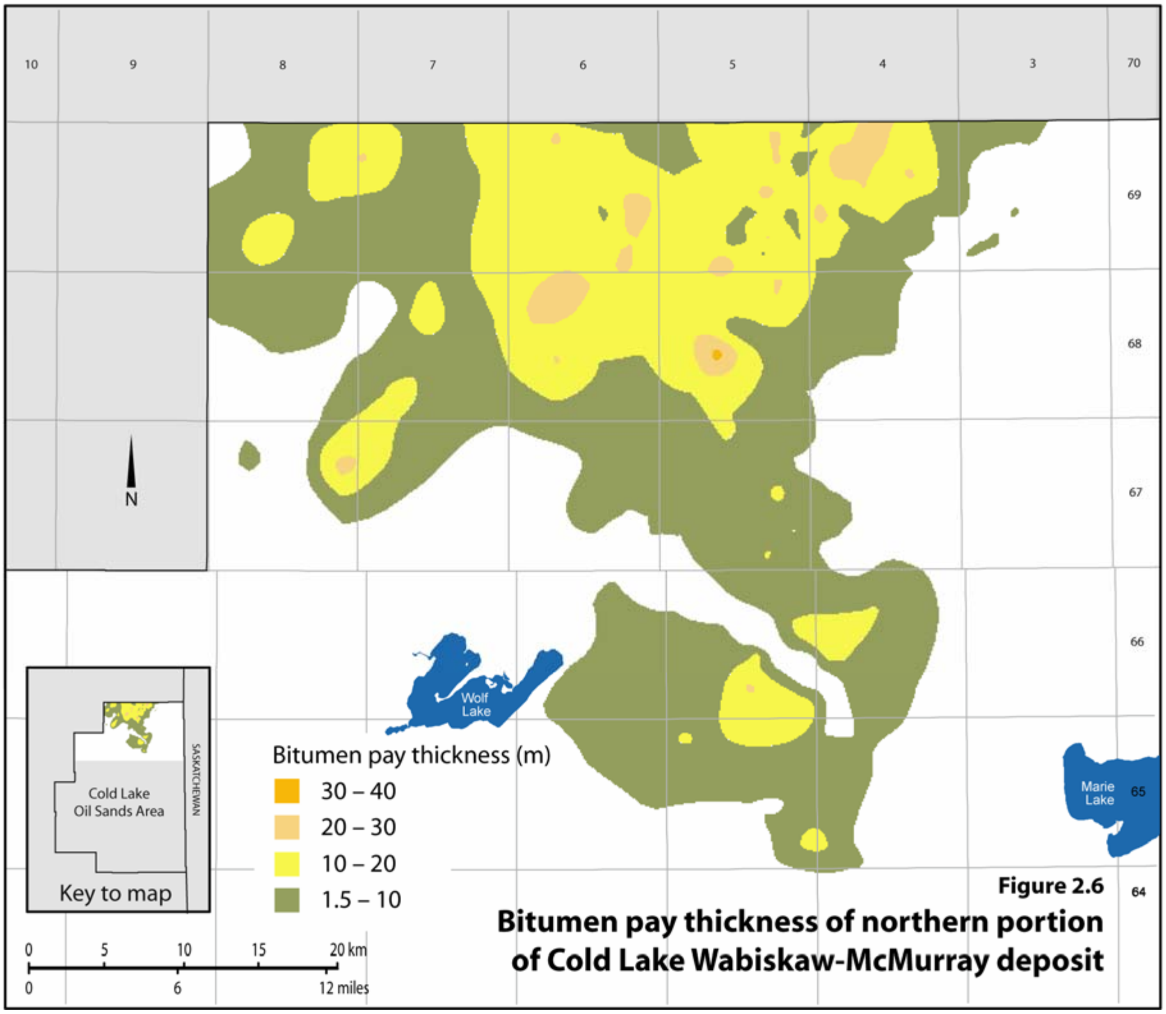


Figure 2.6
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

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 in place of 16.1 10^9 m^3 to 9.4 10^9 m^3 as of December 31, 2005. 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 were 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

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

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	9 926	1 254	8.7	6.4	60	23
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	20 518					
Total	269 254					

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, 2004.

The remaining established mineable crude bitumen reserve as of December 31, 2005, is 5.05 10^9 m^3, slightly lower than last year's estimate due to the production of 36.3 10^6 m^3 in 2005.

About a quarter of the initial established reserves are under active development. Currently, Suncor, Syncrude, and Albian Sands are the only producers in the SMA, and the cumulative bitumen production from these projects is 538 10^6 m^3. The Fort Hills mine project, currently owned by Petro-Canada, UTS Energy, and Teck Cominco, received EUB approval in late 2002 but is not yet under active development (either producing or under the final stages of construction), and as a result established reserves for this project, totalling about 400 10^6 m^3 initial reserves, are not yet included in Table 2.3. The Canadian Natural Resources Ltd. (CNRL) Horizon and Shell Canada Ltd. Jackpine projects were approved in early 2004 and CNRL's project is currently under construction. The reserves for this project will likely be included in next year's report.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2005, are presented in Table 2.4.

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2005

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	10 096	574	178	23	155
Suncor	15 370	878	604	202	402
Syncrude	21 672	1 433	959	313	646
Total	47 138	2 885	1 741	538	1 203

[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 except for the AWM and CLC, where 6 mass per cent was used. Future reserves estimates for other deposits 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 2005, the in situ bitumen production was 25.3 10^6 m^3, an increase from 22.5 10^6 m^3 in 2004. Cumulative production within the in situ areas now totals 253 10^6 m^3, of which 204 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 22.55 10^9 m^3.

The EUB's 2005 estimate of the established in situ crude bitumen reserves under active development is shown in Table 2.5.

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

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2005

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	8.5	13.8
Primary recovery schemes	120.6	5	6.0	1.6	4.4
Subtotal	176.4		28.4	10.1	18.3
Athabasca Oil Sands Area					
Thermal commercial projects	155.6	50	77.8	12.7	65.1
Primary recovery schemes	628.6	5	31.4	17.0	14.4
Enhanced recovery schemes[c]	(136.7)[d]	5	6.8	3.6	3.2
Subtotal	784.2		116.1	33.3	82.8
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25	200.7	146.3	54.4
Primary production within projects	601.1	5	30.1	13.0	17.1
Primary recovery schemes	4 347.1	5	217.4	38.4	179.0
Lindbergh primary production	1 309.3	5	65.5	5.9	69.6
Subtotal	7 060.3		513.6	203.6	310.0
Experimental Schemes (all areas)					
Active	8.1	15[e]	1.2	1.0[f]	0.2
Terminated	87.4	10[e]	9.1	5.3	3.8
Subtotal	95.5		10.3	6.3	4.0
Total	8 116.4		668.3	253.3	415.0

[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, 2005, 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 0.84 10^6 m^3 and from the Cold Lake OSA is 0.20 10^6 m^3.

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 415.0 10^6 m^3. This decrease of 7.0 10^6 m^3 from 2004 is the result of 25.3 10^6 m^3 production and of 18.4 10^6 m^3 cumulative increase due to assessing expansions to Shell's thermal project and several primary schemes in the Peace River OSA. Expansions to the commercial thermal projects and the primary recovery schemes in the Athabasca and Cold Lake OSAs were not assessed in 2005.

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, with a little more than 10 10^9 m^3 coming from surface mining and about 0.4

10^9 m^3 from in situ methods. 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. The EUB has accepted that bitumen exceeding 6 mass per cent and 10 m thickness is potentially recoverable. The EUB has adopted these cutoffs for the AWM and the CLC and will likely use the same for future updates of other deposits, rather than the 3 mass per cent cutoff previously used. 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 and the CLC, the EUB has not yet completed its review of recovery factors that should be applied on a deposit-wide basis. The EUB has therefore decided to 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.

2.2.1 Crude Bitumen Production

Surface mining and in situ production for 2005 are shown graphically by oil sands area in **Figure 2.7.** In 2005, Alberta produced 169.1 thousand (10^3) m^3/d of crude bitumen from all three regions, with surface mining accounting for 59 per cent and in situ for 41 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 29 per cent of all production in 1996 to 58 per cent in 2005.

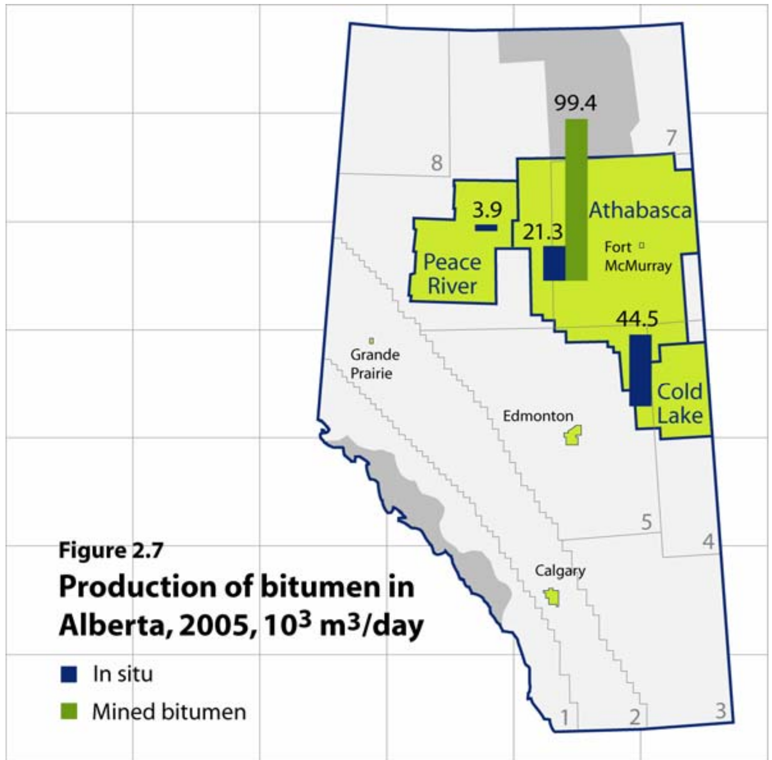


Figure 2.7
Production of bitumen in Alberta, 2005, 10^3 m^3/day

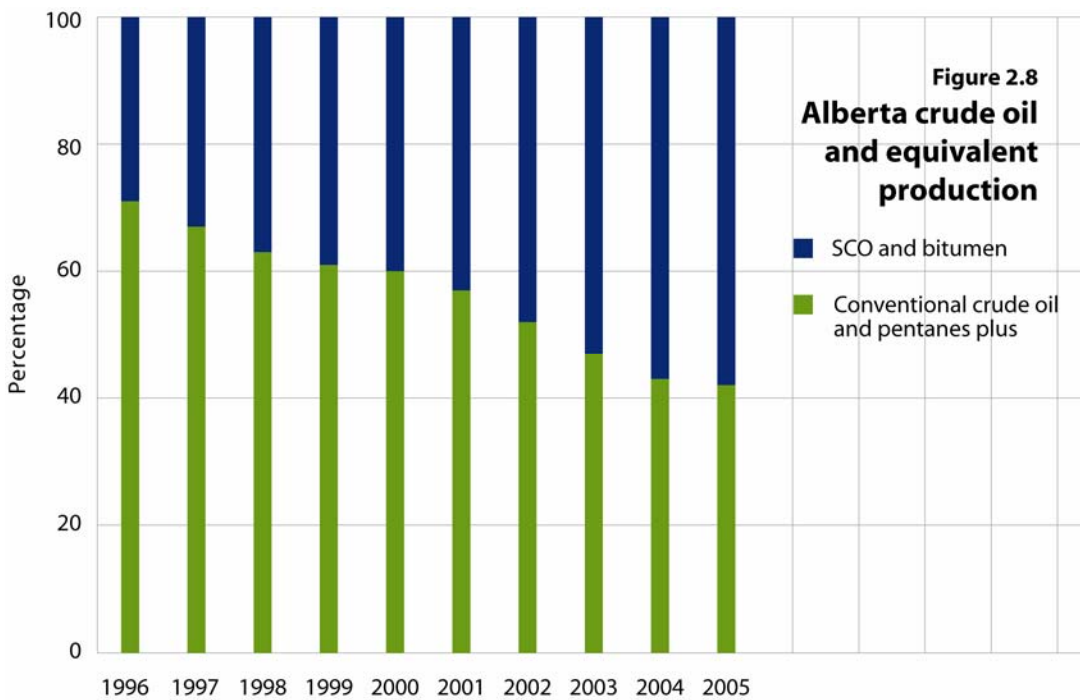


Figure 2.8
Alberta crude oil and equivalent production

The forecast of crude bitumen 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 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.

2.2.1.1 Mined Crude Bitumen

Currently, all mined bitumen in Alberta feeds upgraders producing SCO. In 2005, demand for mined bitumen feedstock was reduced as a result of operational problems and maintenance programs at Suncor, Syncrude, and Shell Canada's upgrading facilities (for Albian Sands production). Consequently, mined crude bitumen production decreased by 11 per cent over the past year, to a level of 99.4 10^3 m^3/d with Syncrude, Suncor, and Albian Sands accounting for 42, 31 and 27 per cent respectively.

The primary reason for reduced production in 2005 was the fire at Suncor's upgrading facility that damaged and shut down one of two upgraders for about nine months. Suncor returned to normal operations and production levels of about 35.8 10^3 m^3/d in September 2005. In October, it commissioned an expansion that increased production to 41.3 10^3 m^3/d. However, Suncor's average production in 2005 declined to 31 10^3 m^3/d, a decrease of about 28 per cent compared with 2004 average production.

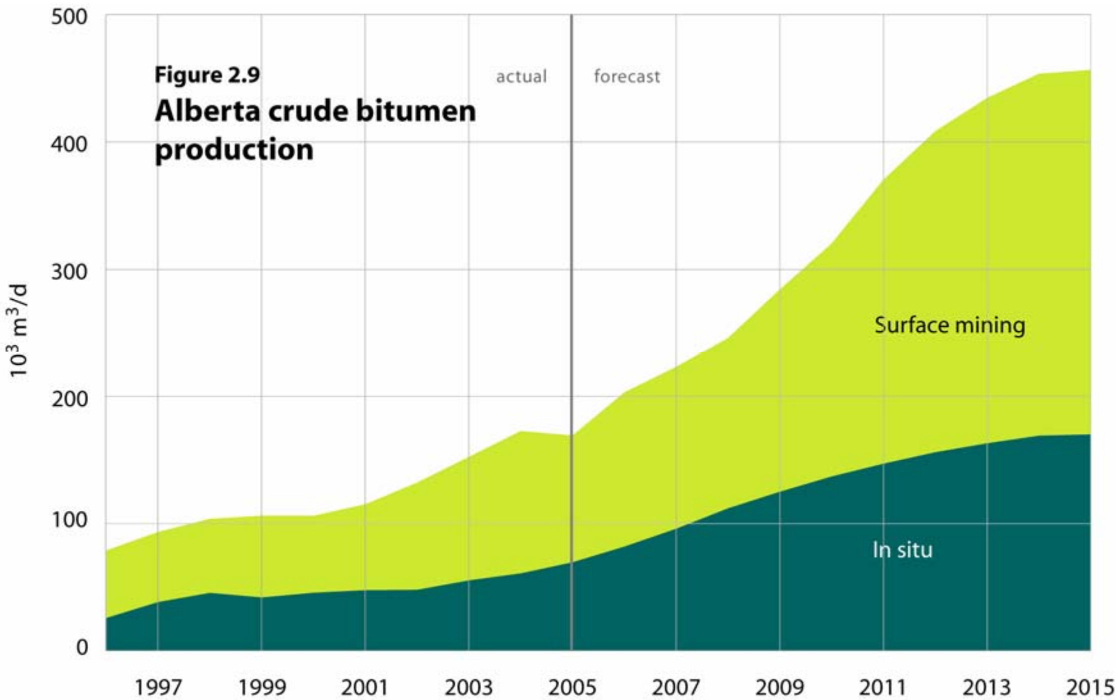
Syncrude's production for 2005 was down 9 per cent, to a level of 41.7 10^3 m^3/d, compared with the 2004 production level. Lower production rates reflect the impact of the largest turnaround in Syncrude's history, which reduced production throughout the first half of 2005. At Albian Sands, 2005 production increased to 26.8 10^3 m^3/d, an increase of 16 per cent over 2004. Production increased, despite first-quarter operational problems experienced by the Shell upgrader, due to three subsequent quarters of record production.

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 projects;
- the existing and expected expansions of Syncrude, including stage three 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 scheduled for completion by 2011;
- the CNRL Horizon Project (approved by the EUB in January 2004), with proposed production beginning in 2008;
- the Shell Canada Jackpine Mine Phase One (approved by the EUB in February 2004), with production expected two years after the Muskeg Mine expansion (2011);
- 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, 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 2010; 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 99.4 10^3 m^3/d in 2005 to about 286 10^3 m^3/d by 2015.

Figure 2.9 illustrates total mined bitumen production over the forecast period.



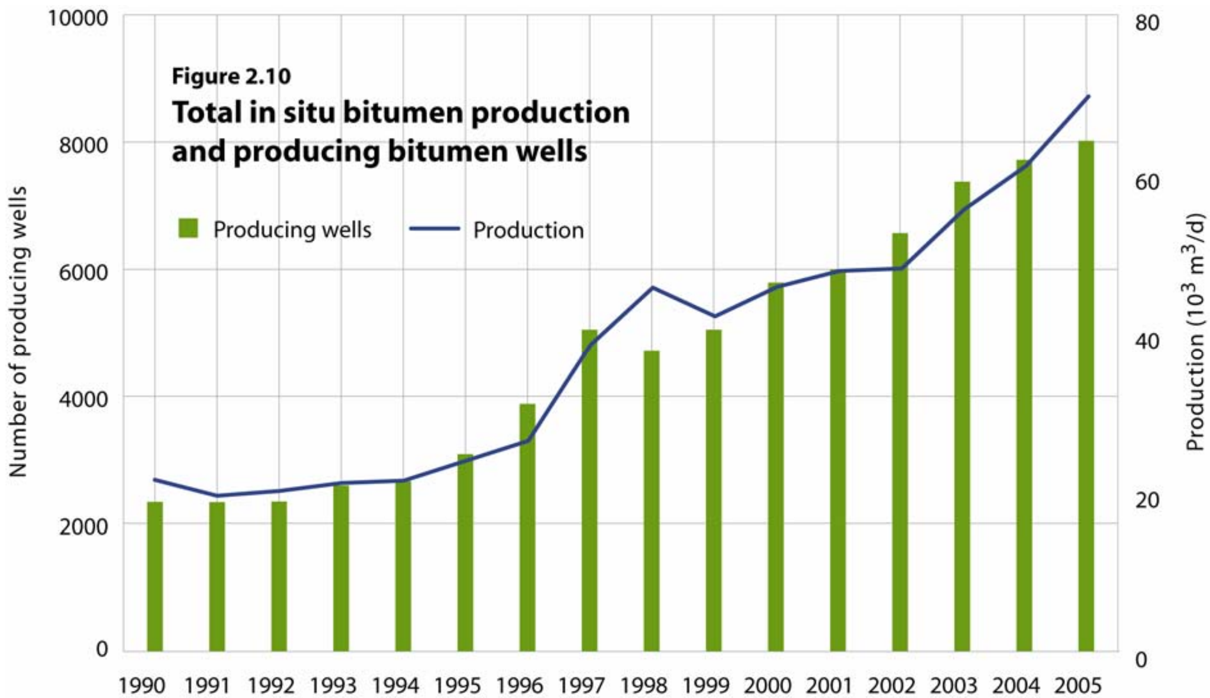
2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 21.5 10^3 m^3/d in 1990 to 69.7 10^3 m^3/d in 2005. 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 8000 wells over the same period. The average well productivity of in situ bitumen wells in 2005 averaged 9.1 m^3/d.

The majority of in situ bitumen, 94 per cent, was marketed in nonupgraded form outside of Alberta, and the remaining 6 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 or impact the existing ones.

As illustrated in **Figure 2.9,** the EUB's in situ crude bitumen production is expected to increase to 170 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period, about 34 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 25.7 10^3 m^3/d, 35.2 10^3 m^3/d, and 26.0 10^3 m^3/d of SCO respectively in 2005.

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 approximately 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
- modification of the upgrader (the addition of a vacuum tower) to increase SCO production capacity that started late in 2005
- 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

Syncrude

- stage three, including the upgrader expansion and a second train of production at Aurora in 2006
- stage three debottleneck estimated to be on stream 2012

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 2011
- 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 2007
- Phase 2 scheduled for start-up in 2011, followed by Phases 3 and 4 in two-year intervals

Horizon Project

- located within the Municipality of Wood Buffalo, about 70 km north of Fort McMurray
- five-phase project expected to begin operation in 2008
- at year-end 2005, 19 per cent of project construction completed, including a 737-capable airstrip completed in September 2005

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, will 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 early 2010

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. It is expected that the SCO production will increase from 86.9 10^3 m^3/d in 2005 to 283 10^3 m^3/d by 2015.

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 2005, 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

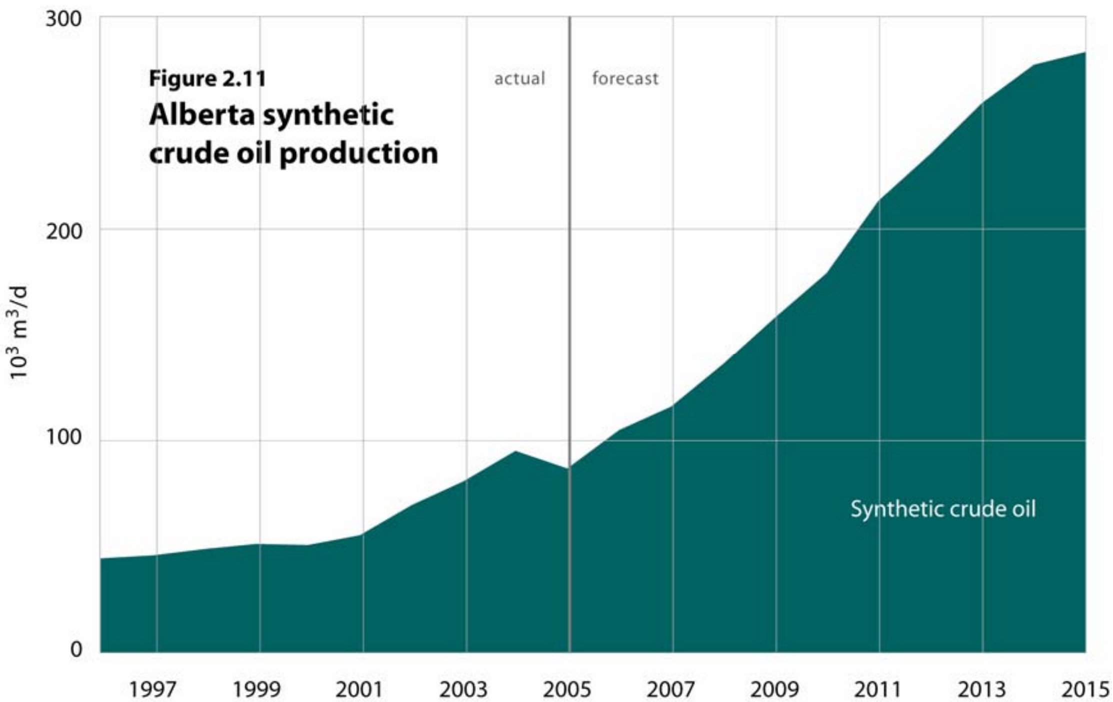


Figure 2.11
Alberta synthetic crude oil production

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	41.3
Alberta Oil Sands Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0

crude pipeline projects within the Athabasca and Cold Lake regions. Numerals in parentheses refer to the legend on the map.

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.

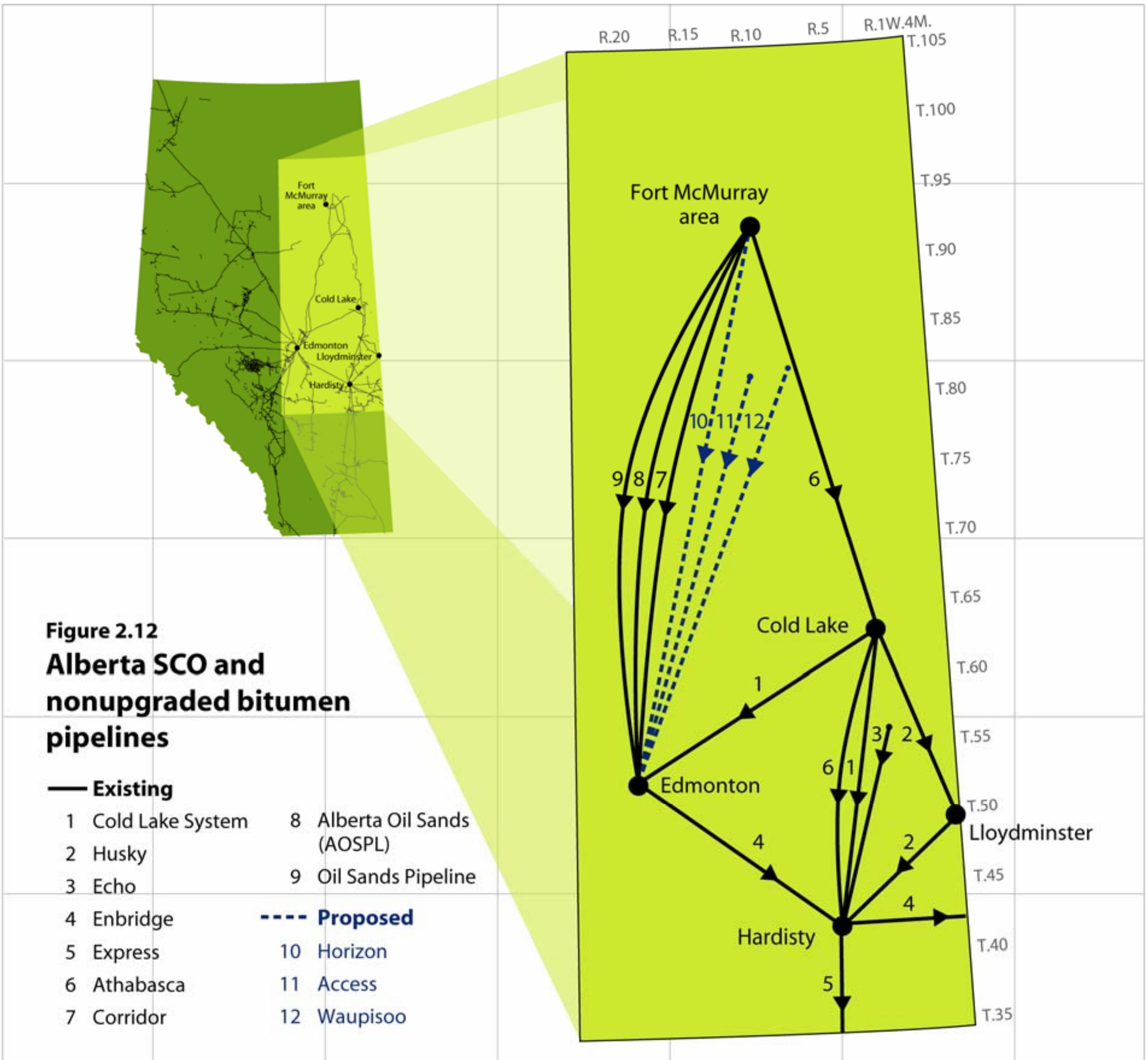


Figure 2.12
Alberta SCO and nonupgraded bitumen pipelines

- 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.
- 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.

Proposed Alberta Pipeline Projects

- The Kinder Morgan Corridor pipeline (7) expansion project includes construction of a 42-inch line 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 79.5 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) is expected to begin in 2006 and 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. The pipeline is currently under construction and is expected to be in service by mid-2006. Initial capacity of the pipeline will be 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d.

- 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 2008, with an initial capacity of 55.6 10^3 m^3/d, expandable to 95.3 10^3 m^3/d.

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 United States 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 U.S. 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. Prior to the Kinder Morgan acquisition, Terasen completed the expansion of the Trans Mountain pipeline in 2004, adding 4.3 10^3 m^3/d of additional capacity.

- 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.

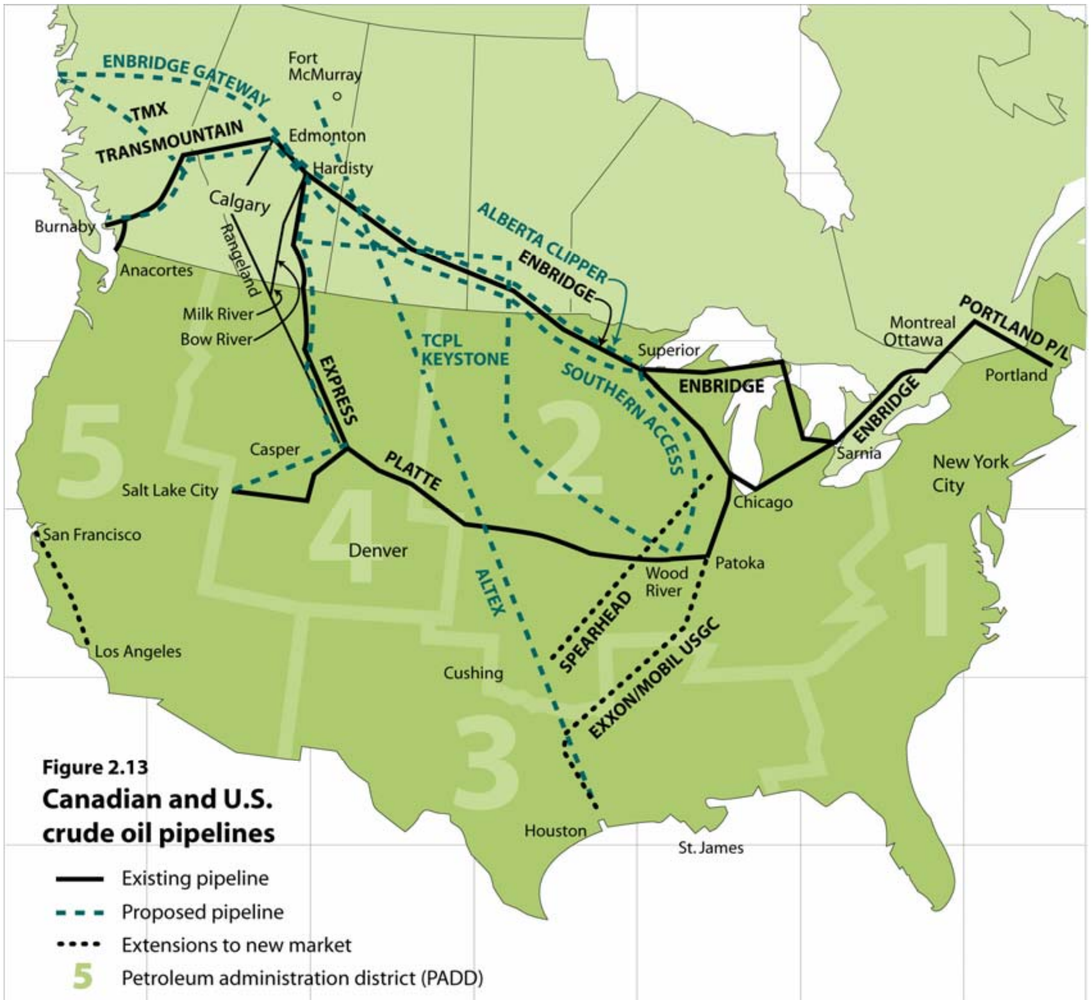


Figure 2.13
Canadian and U.S. crude oil pipelines

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 2010.

- 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 first stage could be in service by late 2006, with the final stage completed by 2010.

Table 2.7. Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Pipeline (includes Terrace Expansion)	Eastern Canada U.S. east coast U.S. midwest	292.5
Kinder Morgan (Express)	U.S. Rocky Mountains U.S. midwest	44.8
Milk River Pipeline	U.S. Rocky Mountains	18.8
Rangeland Pipeline	U.S. Rocky Mountains	10.3
Kinder Morgan (Trans Mountain)	British Columbia U.S. west coast Offshore	45.3
Total		411.7

- 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 2009, with a capacity of 63.6 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 that 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 30-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 64 10^3 m^3/d, with a start-up date as early as 2010.

2.2.4 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 2005, five Alberta refineries, with a total capacity of 75.5 10^3 m^3/d, used 31.4 10^3 m^3/d of SCO and 3.6 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand represents 36 per cent of Alberta SCO production and 5 per cent of nonupgraded bitumen production.

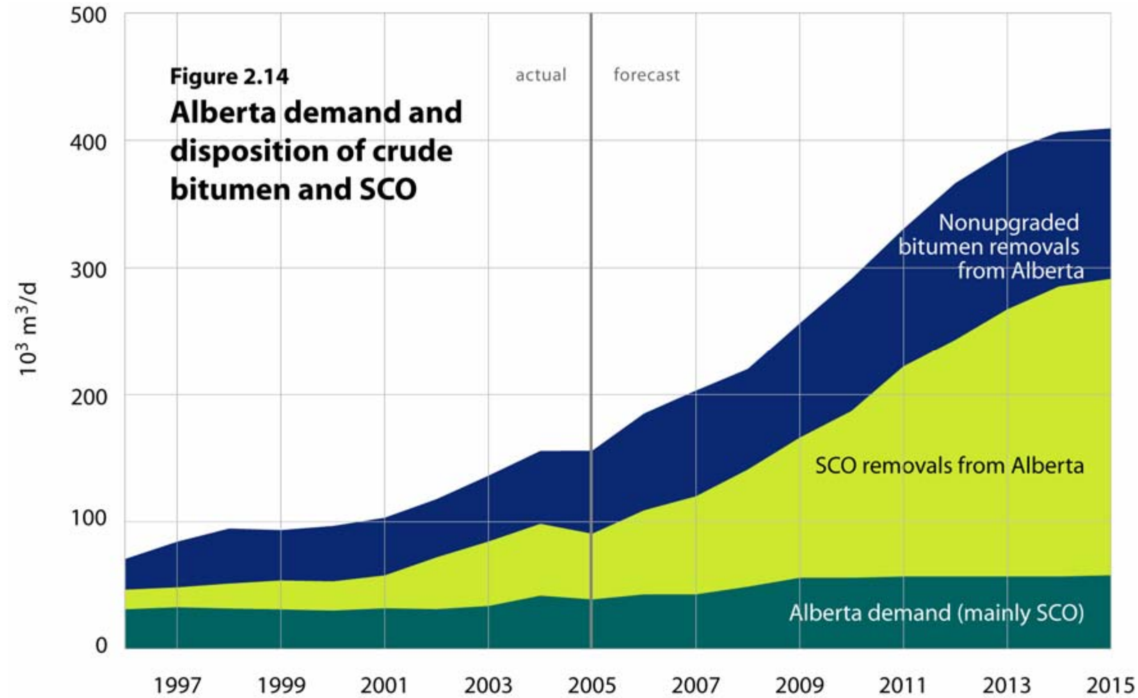
Petro-Canada, in addition to the announced joint venture with UTS and Teck Cominco in the Fort Hills project, continues to reconfigure its Edmonton refinery to fully replace light-medium crude oil with SCO and nonupgraded bitumen by 2008.

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. In January 2006, Suncor announced the opening of 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 2005, the sale of SCO as diesel fuel oil accounted for about 7 per cent of Alberta SCO demand.

Figure 2.14 shows that in 2015 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 86 per cent of total Alberta demand and nonupgraded bitumen will account for 14 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 30 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 567 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 93 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 273 10^3 m^3/d, the U.S. gulf coast, with a refining capacity of 1283 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, and the northern Rocky Mountain region. In March 2006, Enbridge announced that the first western Canadian crude oil was delivered through its Spearhead pipeline to Cushing, Oklahoma. The Spearhead pipeline has historically operated in south-to-north service, but recently had been largely inactive. Reversing the pipeline provides Canadian crude oil producers and shippers access to markets in the mid-continent and southern United States. 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. The transit time from Edmonton to Cushing averages 47 days.

Markets will be further expanded later this year with the reversal of an ExxonMobil Corporation pipeline that will move 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. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure 2.13**.

As illustrated in **Figure 2.14,** over the forecast period SCO removals from Alberta will increase from 51.6 10^3 m^3/d to 233 10^3 m^3/d, and the removals of nonupgraded bitumen will increase from 65.2 10^3 m^3/d to 118 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 254.8 million cubic metres (10^6 m^3) at December 31, 2005. This is a net increase of 5.6 10^6 m^3 from December 31, 2004, resulting from all reserve revisions, production, and additions from new drilling that occurred during 2005. The changes in reserves and cumulative production for light-medium and heavy crude oil to December 31, 2005, are shown in Table 3.1. **Figure 3.1** shows that the province's remaining conventional oil reserves have declined by half since 1990.

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

	2005	2004	Change
Initial established reserves[a]			
Light-medium	2 310.2	2 284.4	+25.9
Heavy	393.5	380.6	+12.9
Total	2 703.7	2 664.9	+38.8
Cumulative production[a]			
Light-medium	2 127.5	2 105.4	+22.1[b]
Heavy	321.4	310.3	+11.1[b]
Total	2 448.9	2 415.7	+33.2[b] (209 10^6 bbls)
Remaining established reserves[a]			
Light-medium	182.7	179.0	+3.7
Heavy	72.2	70.2	+1.9
Total	254.8 (1 603 10^6 bbls)	249.2	+5.6

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

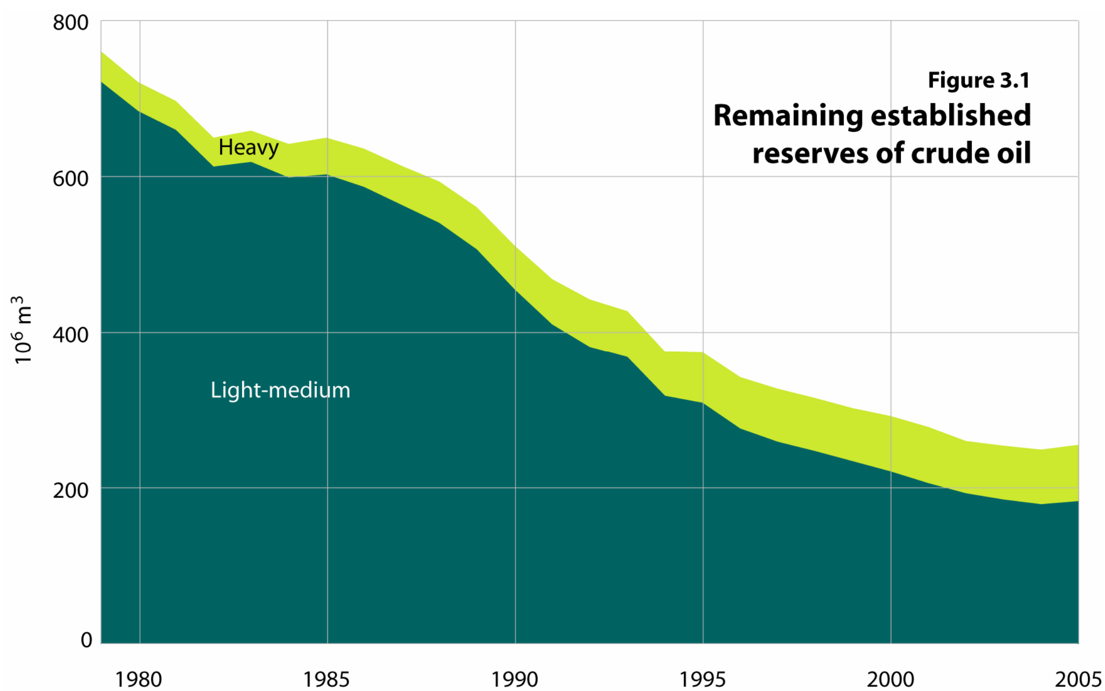


Figure 3.1
Remaining established reserves of crude oil

3.1.2 Reserves Growth

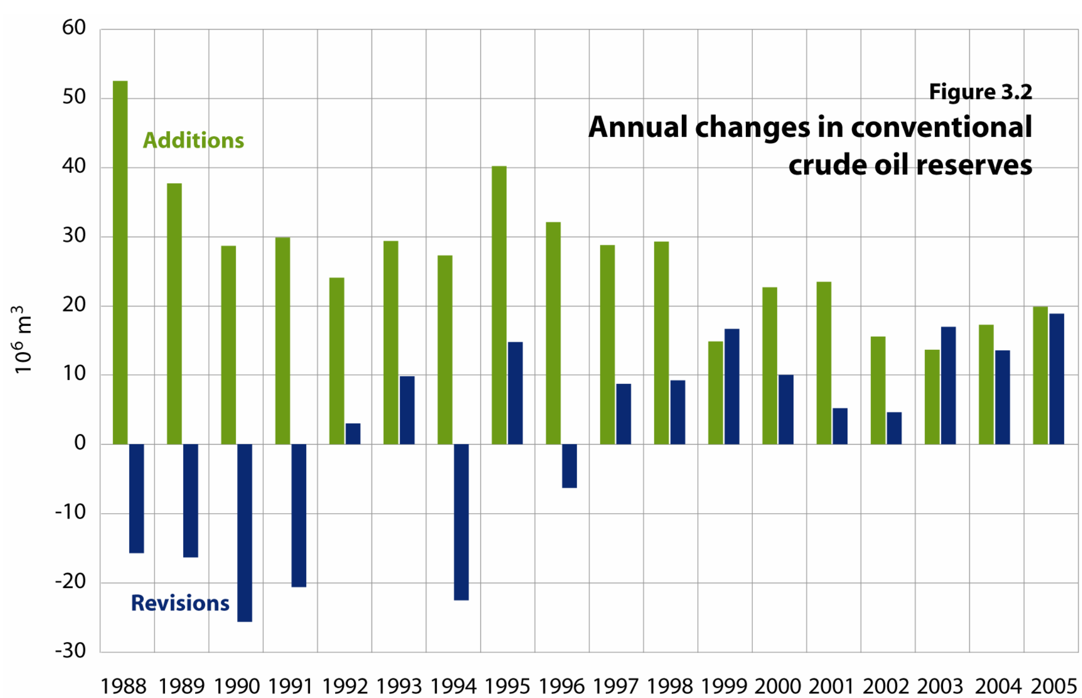
A detailed pool-by-pool list of reservoir parameters and reserves data is available on CD (see Appendix C). Table 3.2 gives a detailed breakdown of this year's reserves changes, including additions, revisions, and enhanced recovery, while **Figure 3.2** gives a history of these changes back to 1988. The initial established reserves attributed to the 390 new oil pools booked in 2005 totalled 5.5 10^6 m^3 (an average of 14 thousand [10^3] m^3 per pool), down slightly from 6.1 10^6 m^3 in 2004. Reserve additions from new waterfloods decreased from 3.2 10^6 m^3 to 1.2 10^6 m^3 (**Figure 3.3**). Net reserve revisions totalled 18.9 10^6 m^3, mostly due to positive revisions to light-medium pools under primary depletion and heavy crude pools under waterflood. The resulting total increase in initial established reserves for 2005 amounted to 38.8 10^6 m^3, compared to last year's 30.8 10^6 m^3. Table B.1 in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.

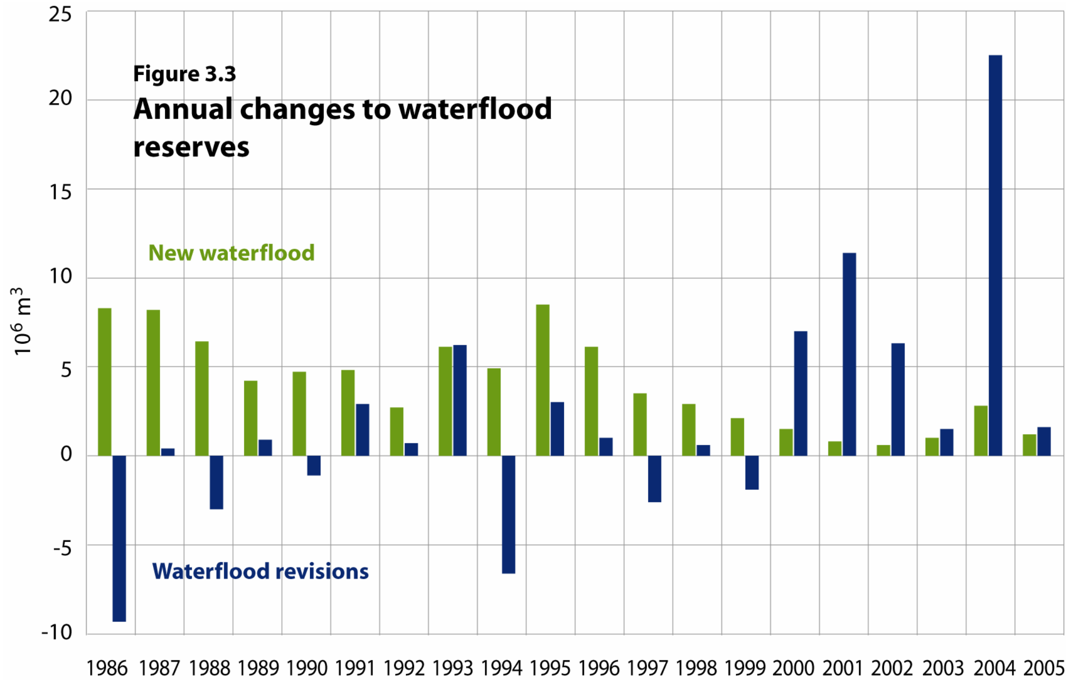
Reserve additions resulting from drilling and new enhanced recovery schemes amounted to 19.9 10^6 m^3, up from 17.3 10^6 m^3 in last year's report. These additions replaced 60 per cent of Alberta's 2005 conventional crude oil production of 33.1 10^6 m^3.

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

	Light-medium	Heavy	Total
New discoveries	4.6	0.8	5.5
Development of existing pools	7.7	5.5	13.2
Enhanced recovery (new/expansion)	0.9	0.3	1.2
Reassessment	+12.6	+6.3	+18.9
Total[a]	+25.9	+12.9	+38.8

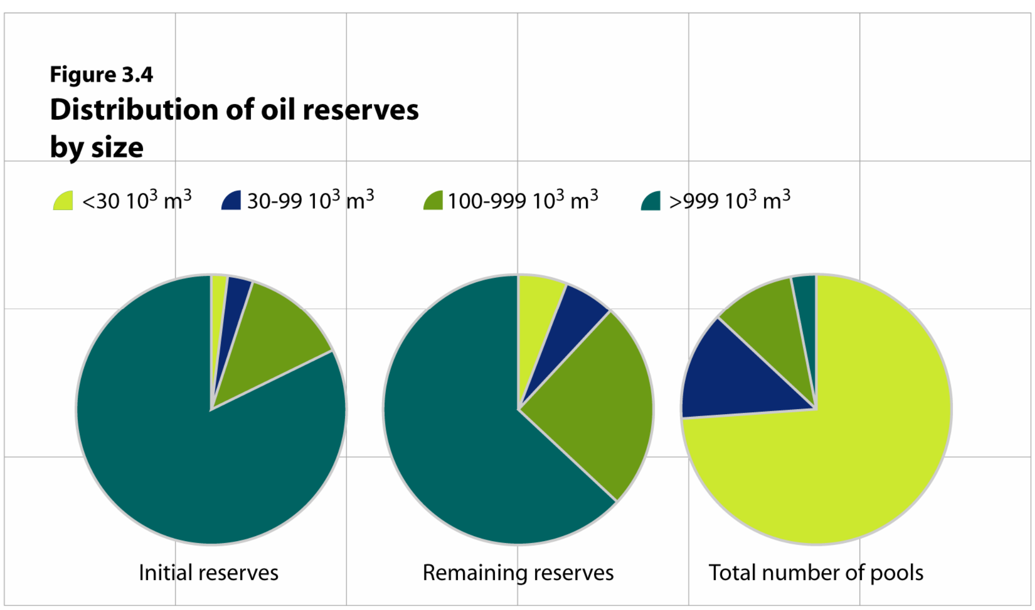
[a] Discrepancies are due to rounding.

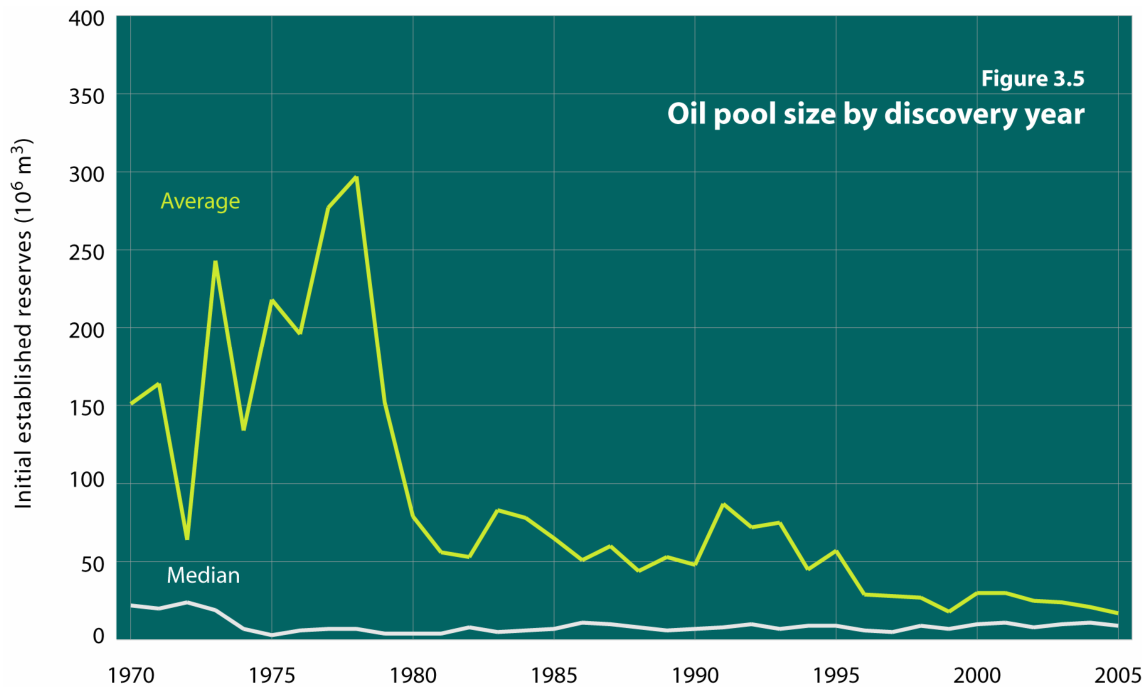




3.1.3 Oil Pool Size

At December 31, 2005, oil reserves were assigned to 8833 light-medium and 2624 heavy crude oil pools in the province, about 60 per cent of which are single-well pools. 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.





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 Pool discovered in 1977 is the last major oil discovery (over 10 10^6 m^3) in Alberta. Its initial established reserve is estimated at 13 820 10^3 m^3.

3.1.4 Pools with Largest Reserve Changes

Some 2000 oil pools were re-evaluated over the past year, resulting in positive revisions totalling 65.9 10^6 m^3 and negative revisions totalling 47.0 10^6 m^3, for a net positive revision of 18.9 10^6 m^3. Table 3.3 lists those pools having the largest reserve changes in 2005. Intensive exploration in the Pembina area since 1994 has resulted in the discovery of several Nisku pools with total initial established reserves of almost 4000 10^3 m^3. Reserves in the Swan Hills Beaverhill Lake A and B Pool saw a significant increase of 8793 10^3 m^3 due to reassessment of the solvent flood portion of the pool. Enhanced reserves were also revised upward by 2980 10^3 m^3 in the Mitsue Gilwood A Pool. A new waterflood in the Horsefly Lake Mannville Pool boosted reserves by 308 10^3 m^3. Continued rapid development of the Wildmere Lloydminster C Pool resulted in a reserve increase of 1010 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**. The average overall incremental waterflood recovery for heavy oil pools now stands at 17 per cent, compared to 13 per cent for light-medium pools. 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 today due to improvements in water handling, horizontal wells, and increased drilling density. Incremental recovery from all waterflood projects represents 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 29 per cent improvement in recovery efficiency over primary recovery.

Table 3.3. Major oil reserve changes, 2005

Pool	Initial established reserves (10^3 m^3) 2005	Change	Main reason for change
Cecil Charlie Lake JJ	721	+301	Reassessment of reserves
Cessford Mannville C	5 477	+530	Reassessment of waterflood reserves
Chauvin South Mannville MU#1	16 080	+1 341	Reassessment of waterflood reserves
Cordel Cardium B	916	+613	Pool development
Dixonville Montney C	431	+344	Reassessment of primary reserves
Enchant Arcs FF and GG	1 089	-353	Reassessment of waterflood reserves
Garrington Card, Vik, Mann MU#1	6 898	+738	Reassessment of waterflood reserves
Hayter Dina Q	709	+355	Reassessment of reserves
Horsefly Lake Mannville	2540	+308	New waterflood
Jenner upper Mannville O	2 849	+430	Reassessment of waterflood reserves
Lloydminster Sparky G	2 387	+748	Reassessment of reserves
Lloydminster Sparky ZZZ	462	-462	Reassessment of reserves
Morgan Spky, Rex, Lloyd, Dina A	6 909	-665	Reassessment of reserves
Mitsue Gilwood A	64 420	+2 980	Reassessment of enhanced reserves
Moose Rundle C	157	-443	Reassessment of reserves
Pembina Nisku II	1 061	+580	Pool development
Progress Doe Creek A	1 710	+296	Reassessment of waterflood reserves
Provost Basal Quartz C	4 273	+529	Reassessment of reserves
Red Earth Sl Pt A,Gr Wh A & VV	7 548	+568	Reassessment of waterflood reserves
Suffield Upper Manville J2J	645	+401	Reassessment of reserves
Swan Hills Beaverhill Lake A & B	149 800	+8 793	Reassessment of solvent flood reserves
Viking-Kinsella Wainwright B	8 595	+1 273	Reassessment of waterflood reserves
Wildmere Lloyd A & Sparky E	7 301	+1 371	Reassessment of waterflood reserves
Wildmere Lloydminster C	1 878	+1 010	Pool development
Worsley Charlie Lake H & J	1 419	+547	Reassessment of waterflood reserves

Figure 3.6
Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)

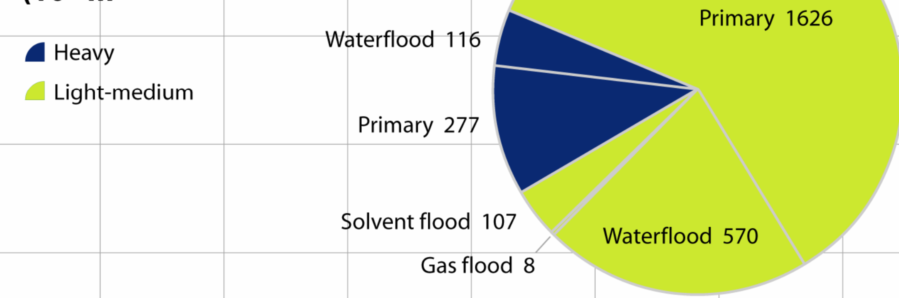


Table 3.4. Conventional crude oil reserves by recovery mechanism as of December 31, 2005

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	3 839	855	0	0	855	22	-	-	22
Waterflood	3 149	479	397	0	876	15	13	-	28
Solvent flood	939	258	173	107	538	27	18	11	57
Gas flood	117	34	8	0	42	29	7	-	36
Heavy									
Primary depletion	1 570	195	0	0	195	12	-	-	12
Waterflood	664	83	115	0	198	13	17	-	30
Total	10 278	1 904	693	107	2 704	19			26
Percentage of total initial established reserves		70%	26%	4%	100%				

3.1.6 Distribution by Geological Formation

The distribution of reserves by geological period and Petroleum Services Association of Canada (PSAC) area is depicted graphically in **Figure 3.7** and **Figure 3.8** respectively. Thirty six per cent of remaining established reserves are expected to come from formations within the Lower Cretaceous and about 20 per cent each from the Upper Devonian and 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.2 and B.3.

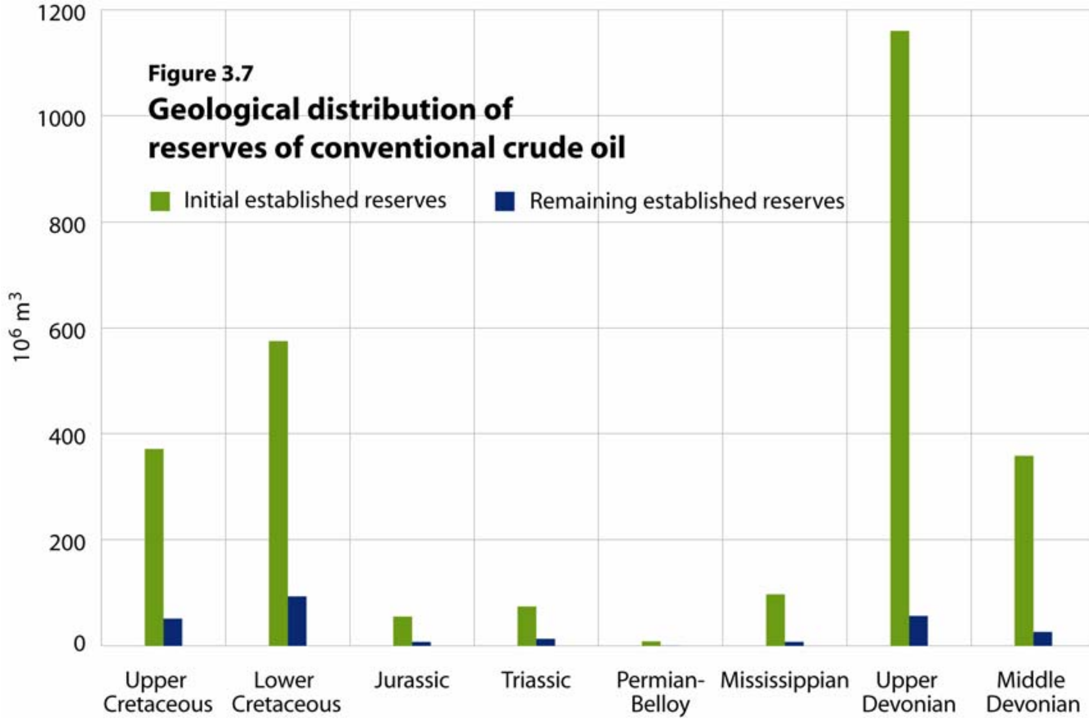


Figure 3.7
Geological distribution of
reserves of conventional crude oil
Initial established reserves
Remaining established reserves
1200
1000
800
600
400
200
0
10^6 m^3
Upper Cretaceous
Lower Cretaceous
Jurassic
Triassic
Permian-Belloy
Mississippian
Upper Devonian
Middle Devonian

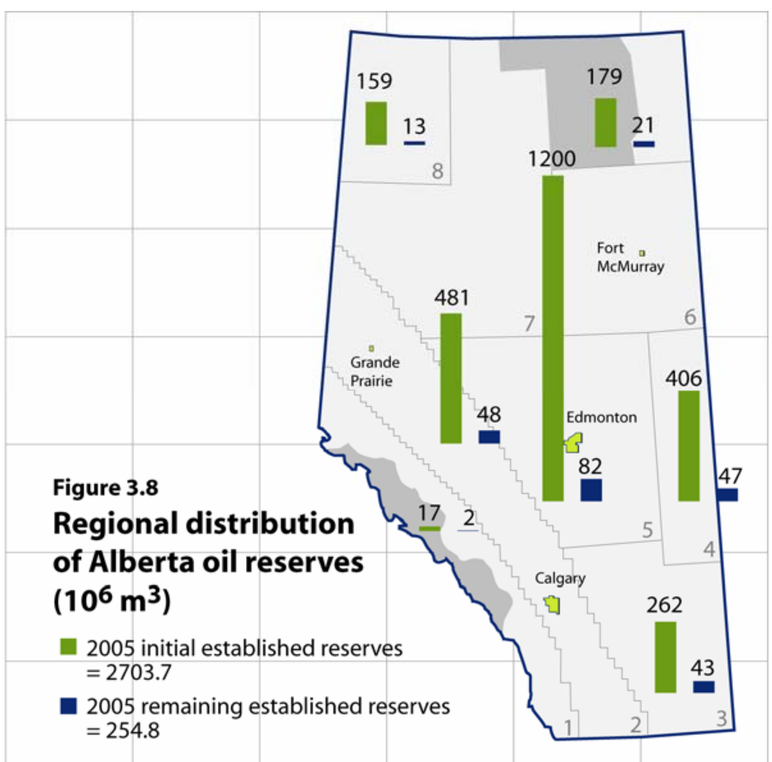
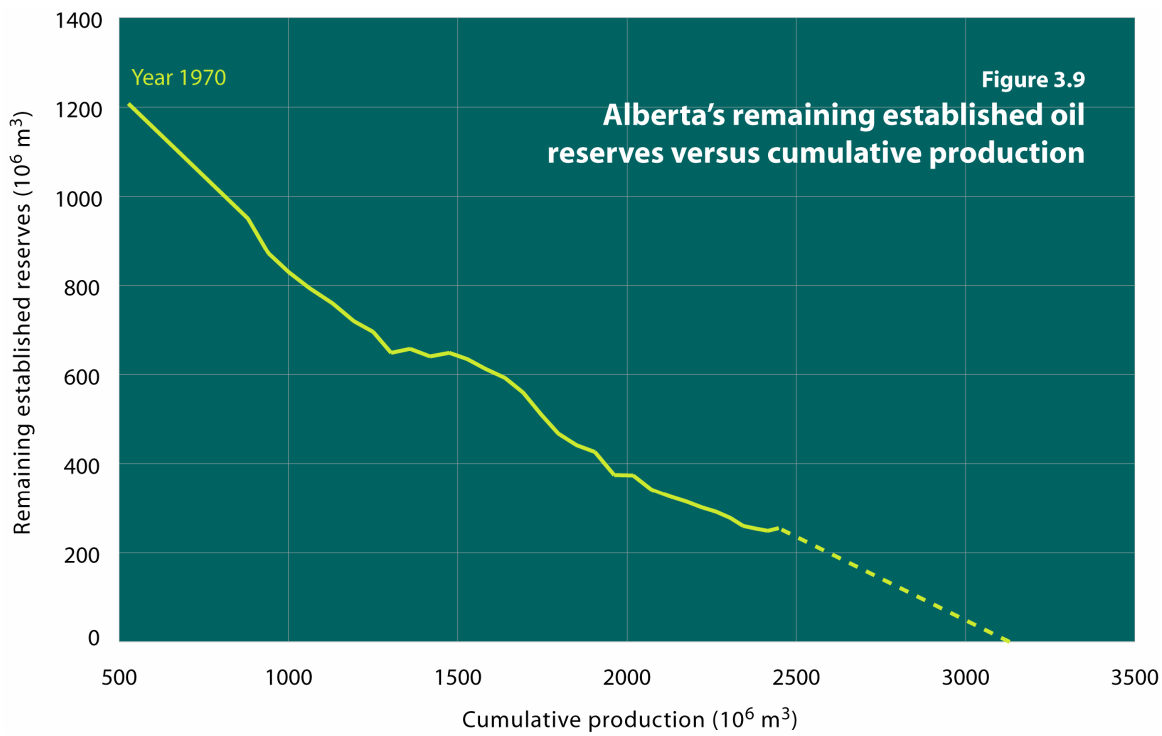


Figure 3.8
Regional distribution
of Alberta oil reserves
(10^6 m^3)
2005 initial established reserves
= 2703.7
2005 remaining established reserves
= 254.8
159
13
8
179
21
1200
Fort McMurray
481
7
6
Grande Prairie
48
Edmonton
406
82
47
17
2
5
4
Calgary
262
43
1
2
3

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. As extrapolation of the decline suggests that the EUB's estimate of ultimate potential is still reasonable, there are no immediate plans for an update. **Figure 3.10** shows Alberta's historical and forecast growth of initial established reserves. About 78 per cent of the estimated ultimate potential for conventional crude oil has been produced by December 31, 2005. Known discoveries represent 86 per cent of the ultimate potential, leaving 14 per cent (426 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves means that 681 10^6 m^3 of conventional crude oil is available for future production.



In 2005, the remaining established reserves increased marginally, while the annual production of crude oil continued to decline. However, 426 10^6 m^3 of crude oil is yet to be discovered, which at the current rate of annual reserve additions will take over 25 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).

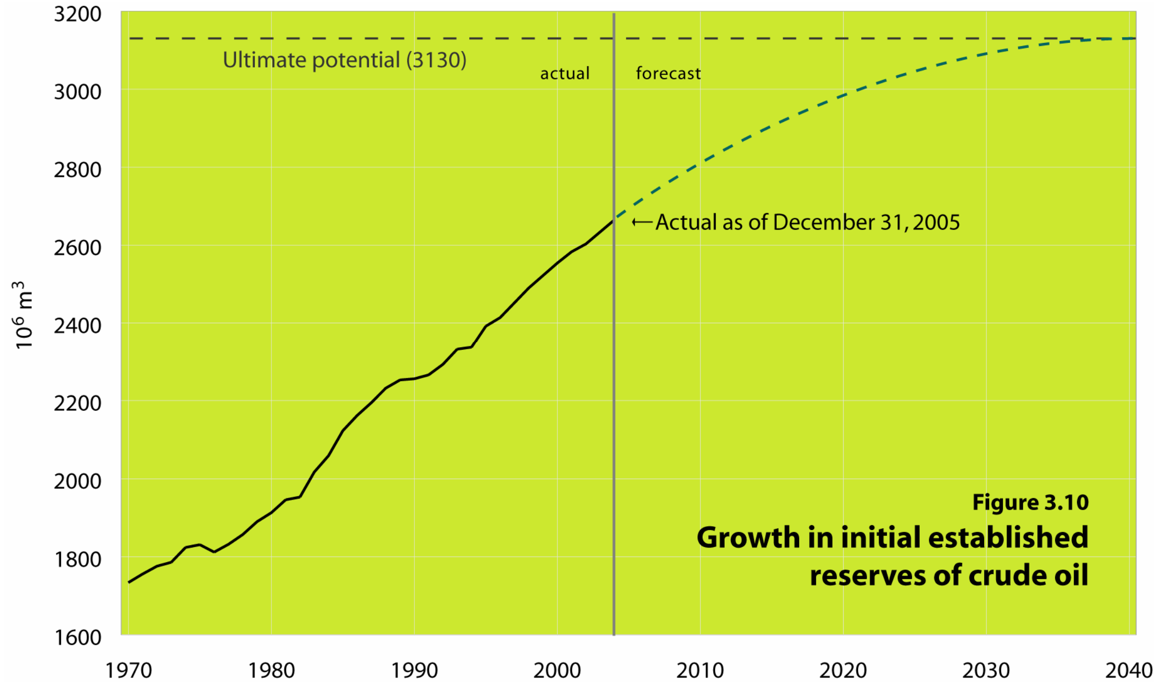


Figure 3.10
Growth in initial established reserves of crude oil

3.2 Supply of and Demand for Crude Oil

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 2005, total crude oil production declined to 90.8 10^3 m^3/day. Light-medium crude oil production declined by about 4 per cent to 59.4 10^3 m^3/d from its 2004 level, while heavy crude oil production experienced a decline of about 7 per cent to 31.4 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 5 per cent from 2004 to 2005 and is consistent with the decline from 2003 to 2004.

In 2005, 2171 successful oil wells were drilled, an increase of some 12 per cent over 2004. **Figure 3.11** shows the number of successful oil wells drilled in Alberta in 2004 and 2005 by geographical area (modified PSAC area). The majority of oil drilling in 2005, nearly 79 per cent, was development drilling. As shown in the figure, drilling levels increased in PSAC 7 (Northwestern Alberta), PSAC 5 (Central Alberta), PSAC 2 (Foothills Front), and PSAC 3 (Southeastern Alberta) by 49 per cent, 46 per cent, 44 per cent, and less than 1 per cent respectively. Only PSAC 4 (East Central Alberta) suffered a significant reduction in the number of wells drilled, while drilling levels in PSAC 1 (Foothills) and PSAC 8 (Northwest Alberta) declined negligibly.

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 2005. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are placed on production within a short time after being drilled. In 2005, oil drilling activity did not pick up until the fourth quarter, and as a result actual wells placed on production were down by 2 per cent over 2004 levels.

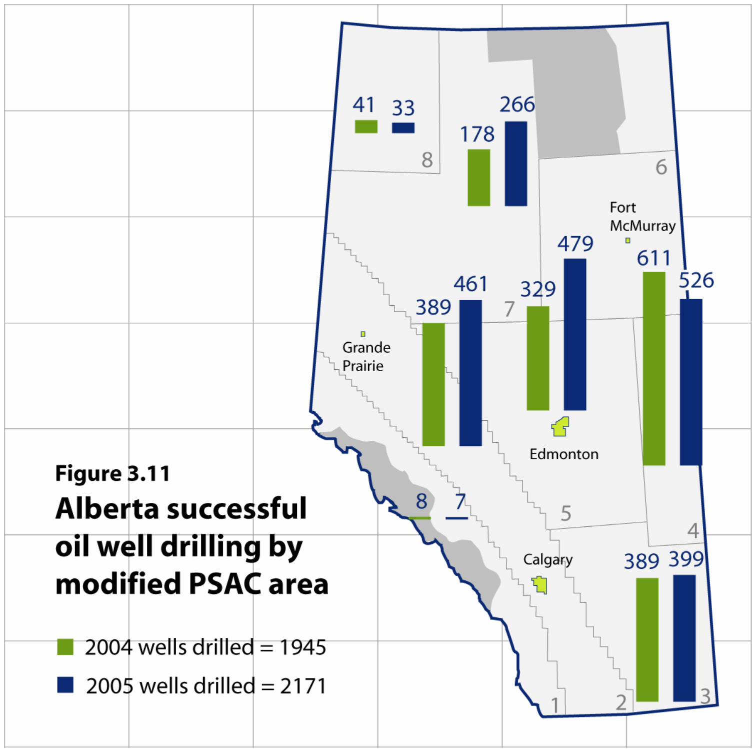


Figure 3.11
Alberta successful oil well drilling by modified PSAC area

2004 wells drilled = 1945
2005 wells drilled = 2171

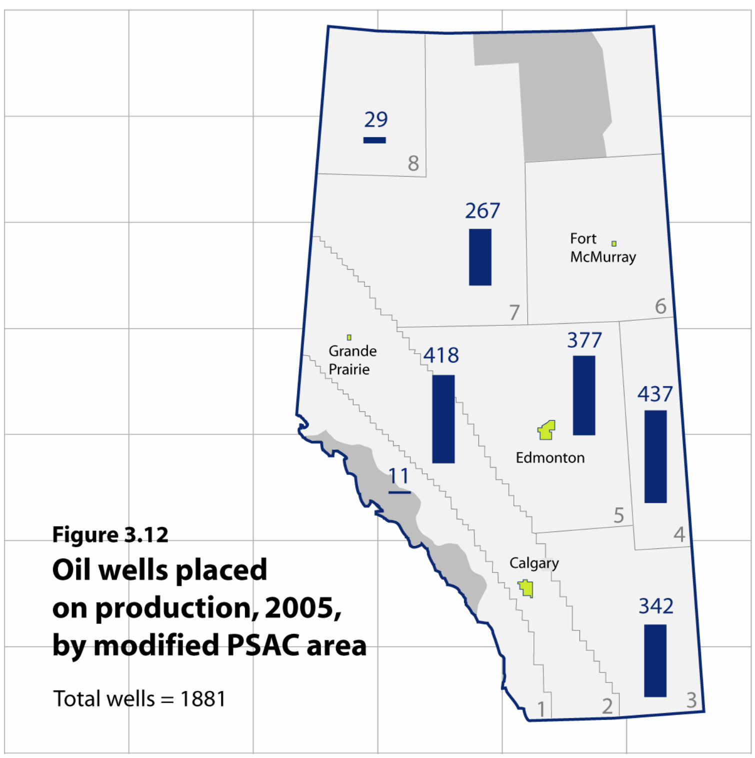


Figure 3.12
Oil wells placed on production, 2005, by modified PSAC area

Total wells = 1881

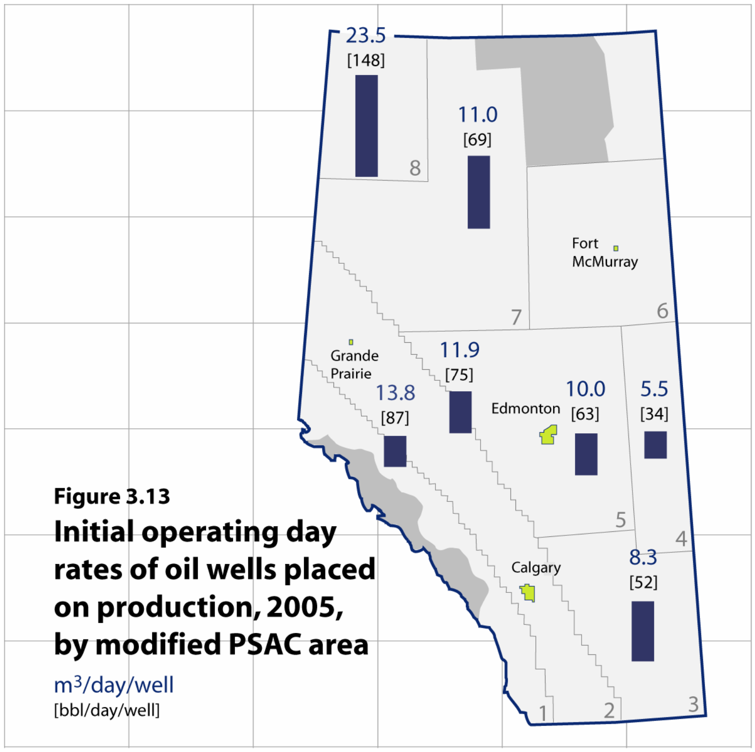


Figure 3.13
Initial operating day rates of oil wells placed on production, 2005, by modified PSAC area
m³/day/well
[bbl/day/well]

Historical oil production by geographical area is illustrated in **Figure 3.14**. Most areas experienced declines in production, ranging from 3.1 per cent in PSAC 5 (Central Alberta) to 7.5 per cent in PSAC 4 (East Central Alberta). The two exceptions were PSAC 2 (Foothills Front) and PSAC 1 (Foothills), which had increases of 1 per cent and 20 per cent respectively.

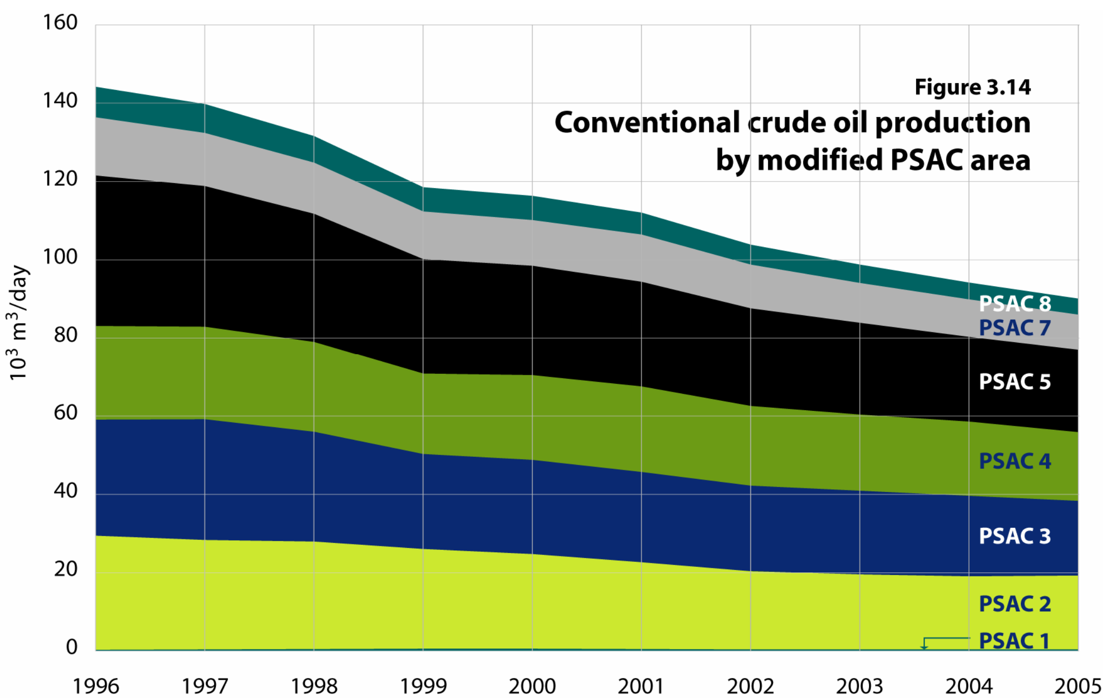
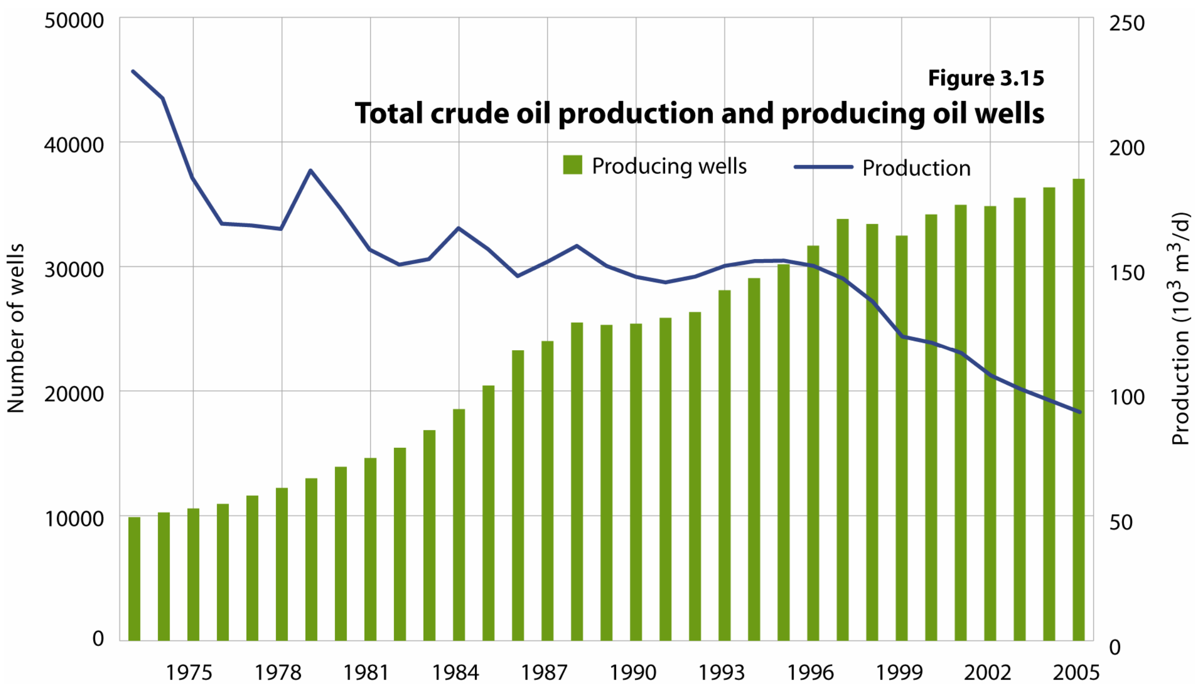


Figure 3.14
Conventional crude oil production by modified PSAC area

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 10^3 m^3/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 37 000 in 2005, crude oil production has been on decline. Of the 37 000 wells producing oil in 2005, about 2600 were classified as gas wells. Although these gas wells represent 7 per cent of wells that produce oil, they produce at an average rate of only 0.3 m^3/d and account for less than 1 per cent of the total production.



The average well productivity of crude oil producing wells in 2005 was 2.5 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 2005, the 20 900 oil wells in this category operated at an average rate of 1 m^3/d and produced 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 2005.

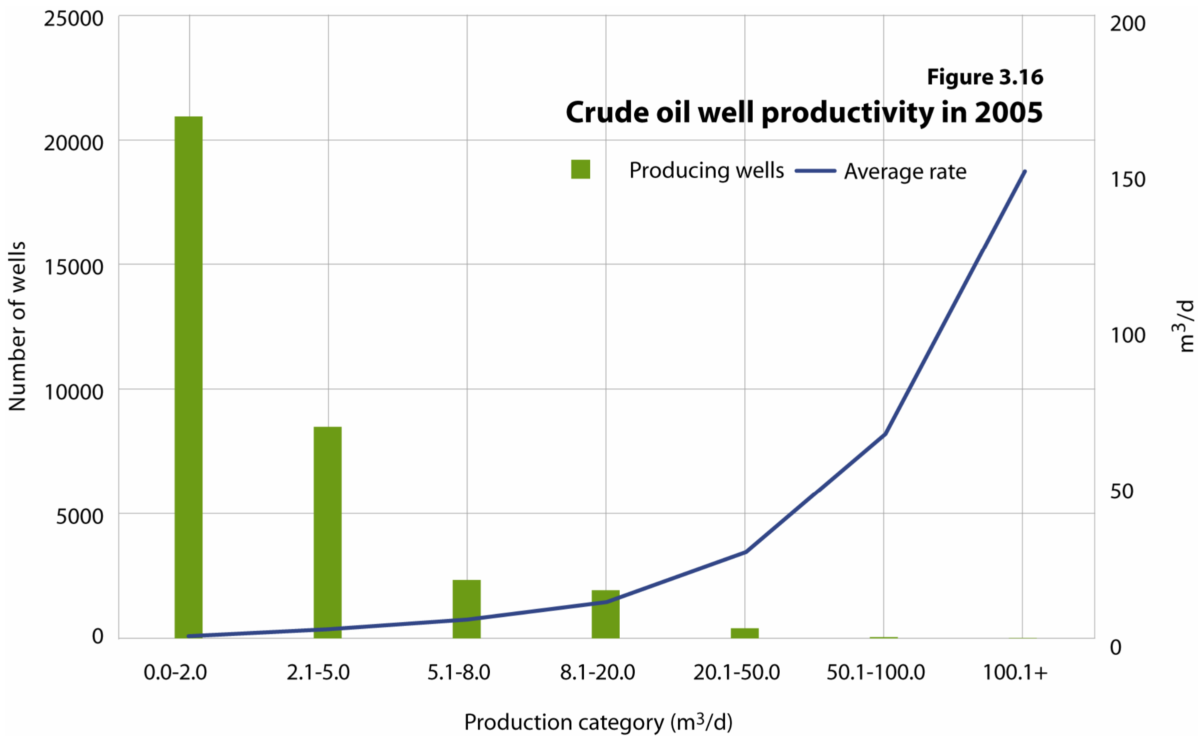
In 2005, some 321 horizontal wells were brought on production, a 12 per cent increase from 2004, raising the total to 3450 producing horizontal wells in Alberta. Horizontal wells account for 9 per cent of producing oil wells and about 18 per cent of the total crude oil production. Production from horizontal wells drilled in the past ten years peaked in 1996 at an average rate of 13.8 m^3/d. The production rate of new horizontal wells averaged about 8.7 m^3/d in 2005.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2005 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 2006, the EUB considered the following assumptions:

- Production from existing wells in 2006 will be 78.6 10^3 m^3/d.
- Production from existing wells will decline at a rate of about 15 per cent per year.

Crude oil production from existing wells by year placed on production over the period 1996-2005 is depicted in **Figure 3.17**. This figure illustrates that about 35 per cent of crude oil production in 2005 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 18 10^3 m^3/d by 2015.



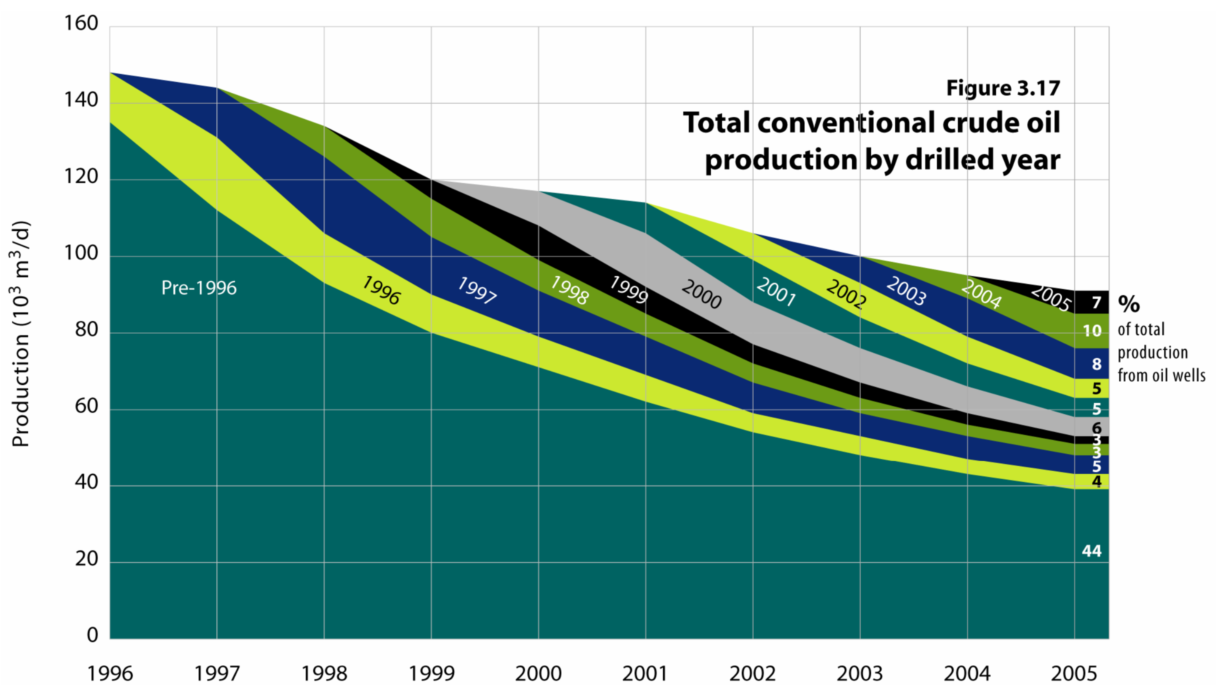
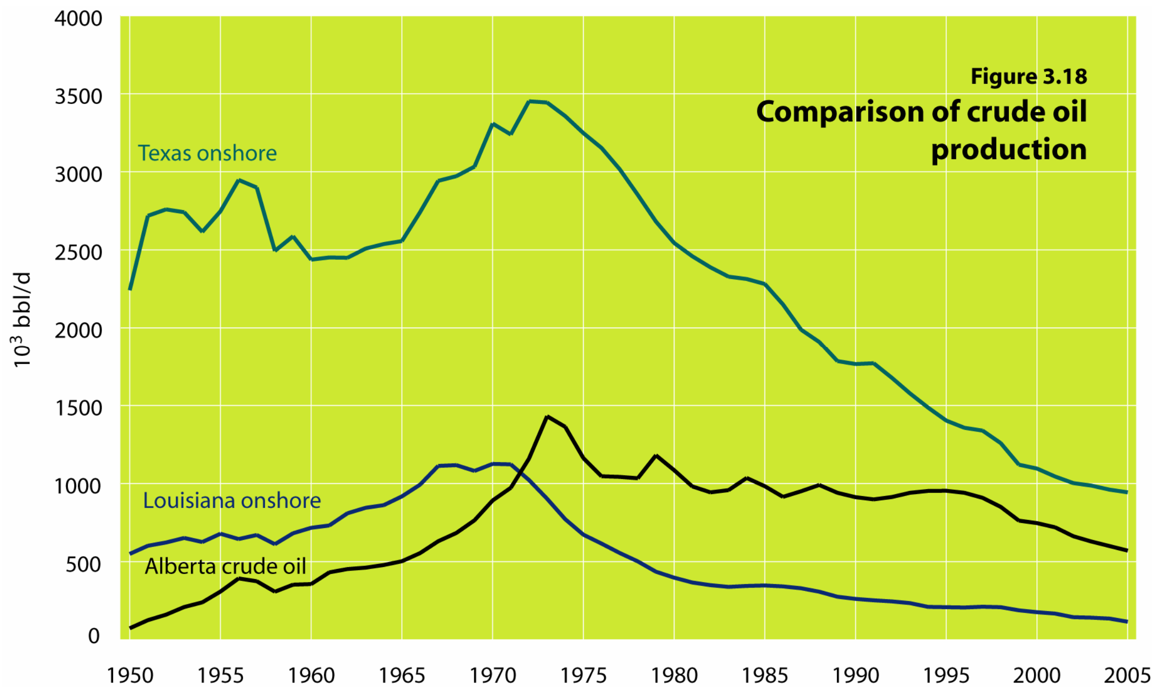


Figure 3.18 compares Alberta crude oil production with crude oil production from Texas onshore and Louisiana onshore from 1950 through 2005. Louisiana onshore production peaked in 1970, while Texas onshore production peaked in 1972 and Alberta production peaked in 1973. The figure shows that Alberta 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.

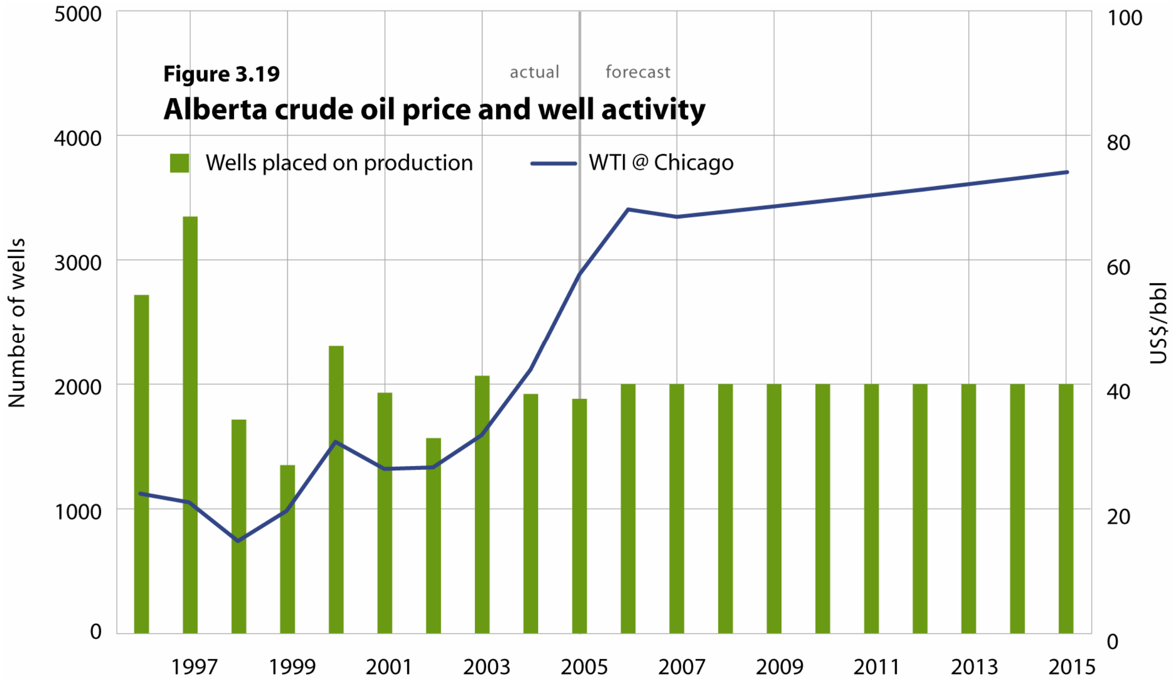


Total production from new wells is a function of the number of new wells that will be drilled successfully, initial production rate, and the decline rate for these new wells. The EUB projects that global crude oil prices will play a role in drilling activity over the forecast period. As discussed in 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, as 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:

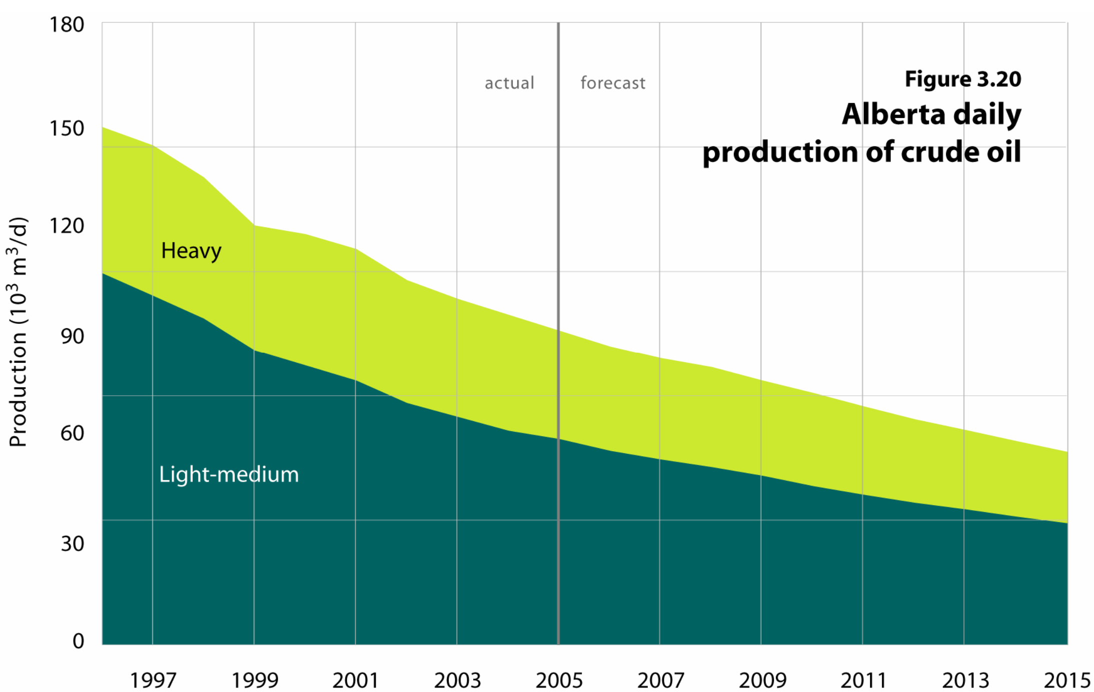
- The number of new oil wells placed on production is projected to increase to 2000 wells in 2006 and remain at this level over the forecast period. **Figure 3.19** illustrates the EUB's forecast for wells placed on production for the period 2006 to 2015.

- 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 27 per cent the first year, 23 per cent the second and third year, 18 per cent the fourth year, 17 per cent the fifth year, and 15 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 59.4 10^3 m^3/d in 2005 to 35 10^3 m^3/d in 2015.



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 31.4 10^3 m^3/d in 2005 to 21 10^3 m^3/d by the end of the forecast period. **Figure 3.20** illustrates that by 2015, heavy crude oil production will constitute a greater portion of total production compared to 2005.

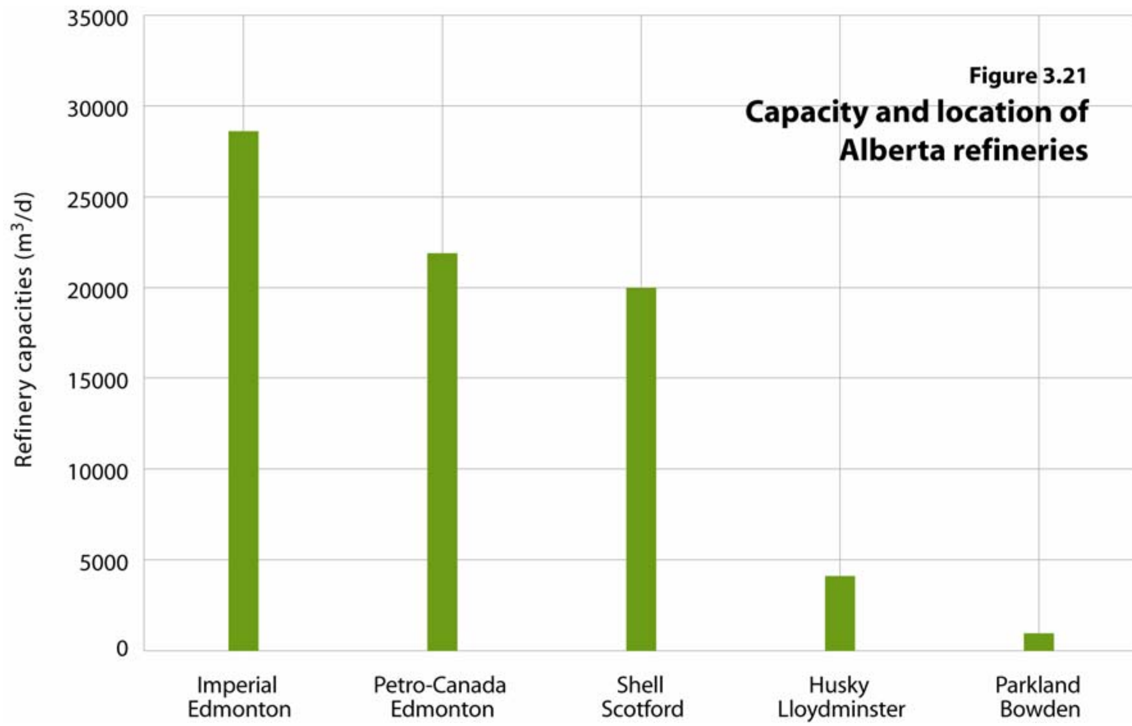
The combined EUB forecasts from existing and future wells indicate that total crude oil production will decline from 90.8 10^3 m^3/d in 2005 to 56 10^3 m^3/d in 2015. By 2015, if crude oil production follows the projection, Alberta will have produced about 87 per cent of the estimated ultimate potential of 3130 10^6 m^3.

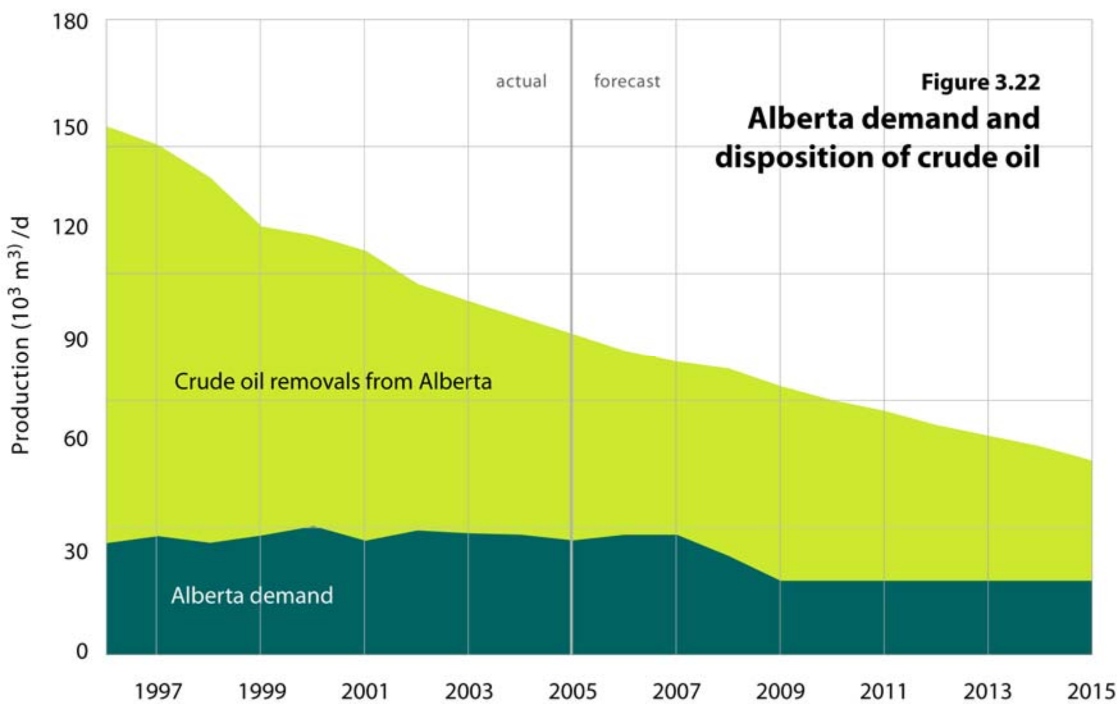
3.2.2 Crude Oil Demand

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 2005, Alberta refineries, with total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 32.4 10^3 m^3/d of crude oil. Synthetic crude oil, bitumen, and pentanes plus constituted the remaining feedstock. Crude oil accounts for roughly 48 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 2005 was about 90 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.

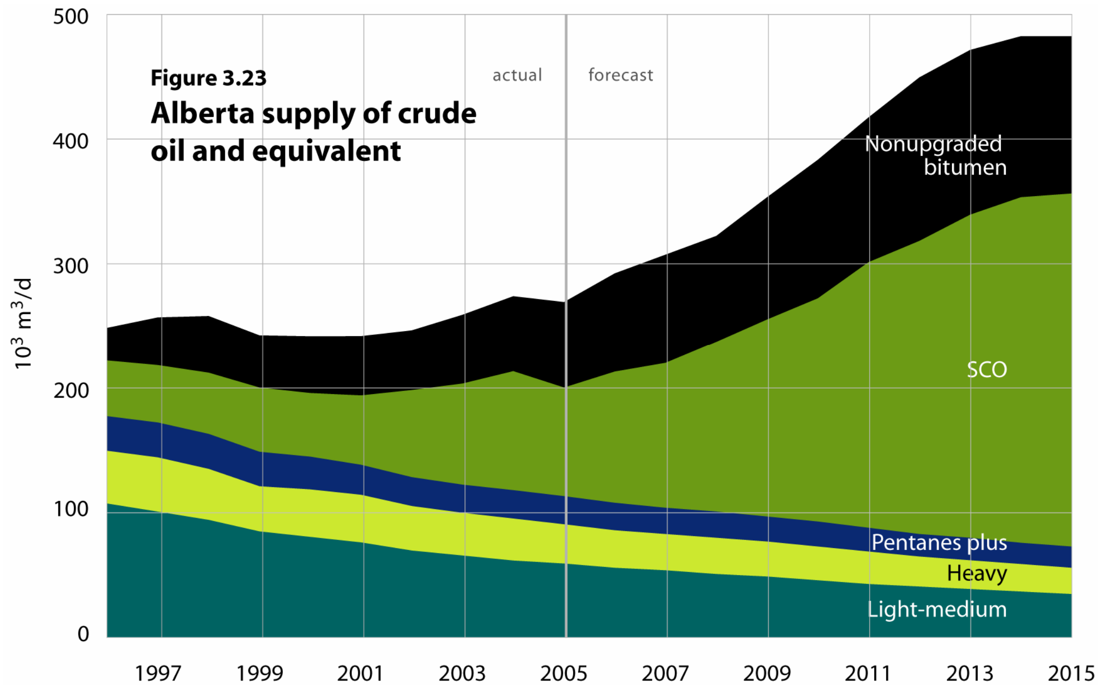
Shipments of crude oil outside of Alberta, depicted in **Figure 3.22**, amounted to 64 per cent of total production in 2005. With the decline in demand for light-medium crude in Alberta, the EUB expects that by 2015 about 62 per cent of production will be removed from the province.

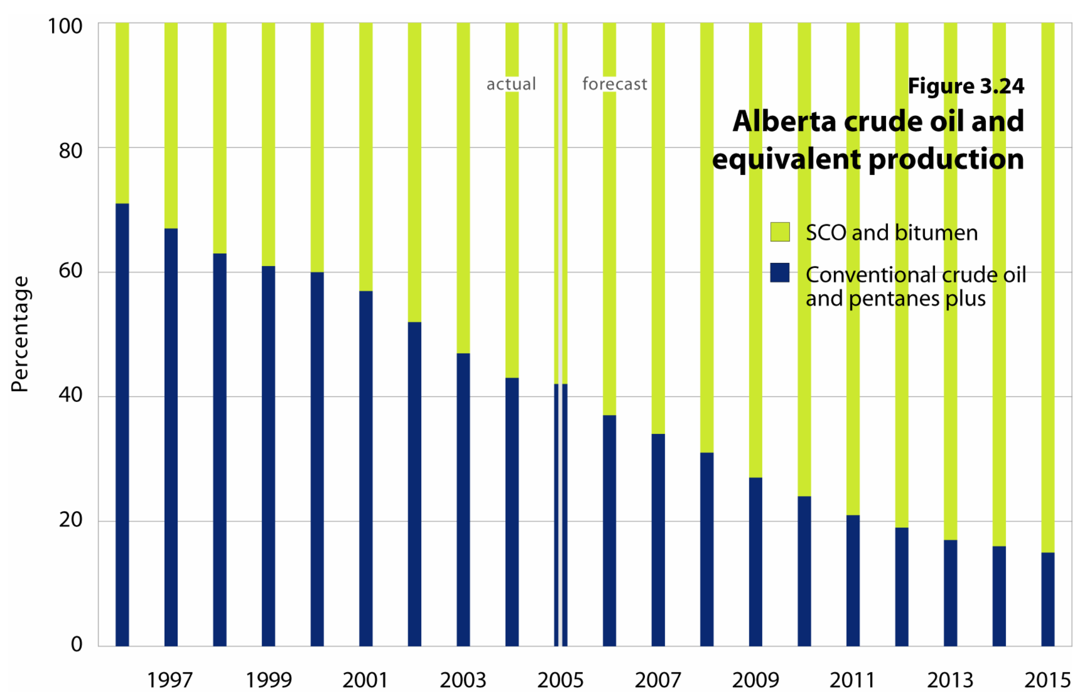




3.2.3 Crude Oil and Equivalent Supply

Figure 3.23 shows crude oil and equivalent supply. It illustrates that total Alberta crude oil and equivalent is expected to increase from 269.0 10^3 m^3/day in 2005 to 482 10^3 m^3/d in 2015. 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 85 per cent of total production by 2015.





4 Coalbed Methane

Coalbed methane (CBM), also known as natural gas from coal, 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 2005 having a higher number of CBM completions than 2004. The actual CBM production to date continues to remain uncertain because of the current inability to completely differentiate CBM from conventional gas production. However, the production accounting change to new CBM-specific codes required by EUB *Bulletin 2004-21* will allow for better segregation from conventional gas volumes.

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 metres (m) of non-coal-bearing strata or separated by a previously defined conventional gas pool.

4.1 Reserves of Coalbed Methane

4.1.1 Provincial Summary

The EUB estimates the remaining established reserves of CBM to be 20.9 billion cubic metres (10^9 m^3) as of December 31, 2005, in areas of Alberta where commercial production is occurring. The gas that is usually 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 per cubic metre. A summary of reserves is shown in Table 4.1. In 2005, the total production from all wells with completion in coal seams is 2.9 10^9 m^3. The production of CBM only from these wells is considered to be 1.3 10^9 m^3, slightly less than 45 per cent.

Table 4.1. Changes in coalbed methane reserves, 2005 (10^6 m^3)

	2005	2004	Change
Initial established reserves	22 960	8 176	14 784
Cumulative production	2 089	755	1 334
Remaining established reserves	20 872	7 421	13 451

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. There were 1649 CBM wells drilled in the province in 2005. Prior to 2005, commercial production was limited to coals that are mainly gas charged, with little or no pumping of water required. In 2005 the first commercial success was announced for one area of Mannville CBM production, which involves the disposal of saline water. Mannville CBM reserves are reported for the first time, as shown in Table 4.2 for Corbett/thunder and Doris. However, the main focus of industry activity and therefore the largest reserves continue to be the "dry CBM" portion of the Upper Cretaceous Horseshoe Canyon and Belly River coals of central and southern Alberta, which produce minimal amounts of water (Table 4.2). Remaining reserves have been calculated using a deposit block model method (see Section 4.1.6). This yields a remaining established reserve of 20.9 10^9 m^3, as shown in Table 4.2.

The 23 10^9 m^3 initial in-place volume (Table 4.2) 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 20.9 10^9 m^3, based on Table 4.2.

Current industry practice suggests that long-term CBM production will be from 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 4.3 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 with which to calculate CBM reserves. Once more data are collected, the reserves should increase dramatically. Larger reserves for fields such as Entice and Irricana are due to higher-density infill drilling.

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). Since 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. 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.

Table 4.2. Upper Cretaceous and Mannville CBM in-place and established reserves, 2005, 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	12 611	10	1 301	12.80	16 647	16%	2 597	62	2 535	580.0
Doris	4 226	10	418	12.80	5 346	16%	834	7	827	54.8
Aerial	1 664	7	251	0.68	171	4%	7	0	6	0.0
Ardenode	13 108	9	1 384	2.46	3 231	4%	139	3	136	0.0
Bashaw	72 175	10	7 401	0.99	6 927	24%	1 649	217	1 432	1.7
Beiseker	10 986	6	1 972	2.53	4 767	11%	539	7	531	0.3
Blackfoot	2 093	5	400	0.86	332	7%	23	1	21	0.0
Brant	278	5	56	no data	50	4%	2	1	1	0.0
Buffalo Lake	1 111	10	111	no data	200	4%	8	7	1	0.1
Carbon	25 537	11	2 314	1.17	2 599	12%	301	21	281	0.2
Cavalier	21 901	12	1 823	0.95	2 059	5%	101	8	93	0.1
Centron	34 558	15	2 291	2.18	4 914	6%	275	7	268	0.0
Chigwell	38 352	12	3 094	1.79	5 537	13%	709	33	676	0.3
ChigwellN	See Chigwell above for all data									
Clive-Alix	19 205	10	1 832	1.86	3 237	27%	887	86	801	0.3
Craigmyle	2 480	7	356	0.71	274	7%	20	10	11	0.1
Crossfield	1 375	11	125	no data	275	4%	11	2	9	0.0
Davey	1 375	11	125	no data	300	4%	12	2	10	0.1
Delia	28 207	12	2 296	0.92	2 119	7%	153	12	141	0.0
Donalda	1 375	11	125	no data	300	4%	12	2	10	0.0
Dorenlee	2 177	11	198	no data	475	4%	19	5	14	0.0
Drumheller	3 719	7	531	no data	1 275	4%	51	7	44	0.4
Elnora	24 395	9	2 699	1.24	3 196	12%	396	31	365	0.2
Entice	69 650	11	6 115	1.96	11 611	26%	3 065	272	2 793	1.6
Erskine	13 125	14	938	no data	2 250	4%	90	17	73	0.1
Fenn West	5 132	6	855	no data	1 625	4%	65	6	59	0.0
Fenn BV	43 182	16	2 718	0.84	2 180	17%	374	54	319	0.6
Ferintosh	16 778	11	1 525	no data	3 203	6%	205	39	166	0.1
Ferrybank	7 857	11	714	no data	1 500	4%	60	15	45	0.3
Gadsby	5 893	11	536	no data	1 125	4%	45	9	36	0.0
Gayford	19 448	7	2 766	1.61	4 846	11%	523	67	456	0.3
Ghostpine	79 931	10	8 038	1.12	8 614	5%	457	30	427	0.0
Herron	938	6	156	no data	125	4%	5	0	5	0.0
Hussar	13 594	6	2 266	no data	1 813	8%	145	36	109	0.1

(continued)

Table 4.2. Upper Cretaceous and Mannville CBM in-place and established reserves, 2005, deposit block model method (concluded)

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 ($10^3 m^3$)
Huxley	7 500	6	1 250	no data	2 375	4%	95	25	70	0.0
Irricana	8 425	10	851	2.40	2 011	29%	575	80	495	1.0
Joffre	3 993	10	386	1.76	650	13%	87	25	63	0.3
Lacombe	8 125	11	739	no data	1 625	4%	65	18	47	0.2
Lone Pine	3 553	6	592	no data	1 125	4%	45	2	43	0.1
Malmo	20 417	14	1 458	no data	3 500	4%	140	46	94	0.1
Manito	2 171	6	362	no data	688	8%	55	9	46	0.0
Michi	395	6	66	no data	125	8%	10	4	6	0.0
Mikwan	62 724	13	4 805	1.23	5 799	4%	249	35	215	0.2
Morningside	395	6	66	no data	125	8%	10	3	7	0.0
Nevis	51 662	9	5 962	1.12	6 444	25%	1 585	152	1 434	0.5
New Norway	10 938	14	781	no data	1 875	4%	75	7	68	1.0
Parflesh	19 219	8	2 346	1.14	2 651	6%	170	26	144	0.1
Penhold	7 292	14	521	no data	1 250	4%	50	4	46	0.0
Redland	15 822	9	1 821	1.09	1 846	21%	395	81	314	0.3
Rich	12 574	9	1 397	no data	2 375	4%	95	18	77	0.4
Rockyford	23 637	8	2 975	1.09	3 297	18%	607	98	508	1.1
Rowley	28 726	11	2 515	0.92	2 235	4%	96	24	72	0.1
Rumsey	4 864	9	567	0.98	558	11%	64	17	47	0.0
Standard	14 167	8	1 771	no data	1 417	6%	85	10	75	0.3
Stettler	2 763	6	461	no data	875	8%	70	8	62	0.0
Stewart	197	6	33	no data	63	8%	5	1	4	0.0
Strathmore	73 934	10	7 230	2.16	16 304	8%	1 353	48	1 305	0.5
Swalwell	4 454	17	265	2.45	661	12%	82	22	60	0.2
Thorsby	938	6	156	no data	125	4%	5	1	4	0.0
Three H Ck	54 425	15	3 707	1.97	7 155	4%	308	57	251	0.3
Trochu	12 630	9	1 423	1.05	1 439	24%	351	28	323	0.1
Twining	98 609	10	9 418	2.09	24 542	7%	1 767	122	1 645	0.3
Vulcan	938	6	156	no data	125	4%	5	0	5	0.0
Wayne	5 625	9	625	no data	750	4%	30	19	11	0.1
Wetwin	1 310	11	119	no data	250	4%	10	1	9	1.2
Wimborne	35 512	10	3 387	2.28	7 654	8%	643	26	617	0.2
Total	1 196 368		115 938		205 035		22 960	2 089	20 871	650.4

Table 4.3. Noncommercial CBM production, 2005 (10^6 m^3), production extrapolation method—other CBM areas

Field/strike area	Coal zone	Initial gas in place	Initial established reserves	Gas, cumulative production	Remaining established reserves	Water, cumulative production
Canmore	Mist Mtn	Not calc	Not recorded	Not recorded	0	Not recorded
Fenn BV	Upper Mann	Not calc	27	27	0	0.0641
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	2	2	0	0.013
Manola/Mellow	Upper Mann	Not calc	0	0	0	0.0001
Drumheller	Upper Mann	Not calc	0	0	0	0.0
Norris	Upper Mann	Not calc	2	2	0	0.0644
Strome	Upper Mann	Not calc	0	0	0	0.0045
Battle South	Upper Mann	Not calc	0	0	0	0.0036
Kelsey	Upper Mann	Not calc	1	1	0	0.1526
Swan Hills/ Swan Hills S	Upper Mann	Not calc	0	0	0	0.0152
Miscellaneous	Any	Not calc	89	89	0	0.1674
Total		Not calc	121	121	0	0.4849

However, CBM/conventional commingling creates a 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:

- The commingled CBM/conventional wells showing production trends that more resemble sandstone gas reservoir decline rates had a small percentage of production assigned as CBM.
- The commingled CBM/conventional wells showing production trends that more resemble CBM had all production assigned as CBM.
- Wells that were recompleted to CBM after conventional production and reported as one production occurrence were limited to production only since the latest completion date, as the sandstone contribution is generally far larger than the CBM production.

To further resolve these issues, commingling approvals now stipulate data submission requirements as follows:

- submission of initial segregated pressures for each CBM zone;
- submission of some initial flow meter data or logs to show individual seam CBM contributions and relative conventional contributions;
- desorption data gathered preferentially from core wells, with future possibilities of using core-supported cuttings data, but with no less than one data point per 36 sections of development;
- ongoing annual segregated pressure testing and flow meter analysis on "control wells" (flowing CBM-only observation wells), with each control well representing production from four sections of CBM development.

Future submission of these test results will allow for more complete analysis to resolve the issues described above.

4.1.4 Distribution of Production by Geologic Strata

Ardley Coals of the Scollard Formation – This is the upper set of coals that 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, that generally have low gas contents and low water volumes, with production referred to as "dry CBM." As the first commercial production of CBM in Alberta was from these coals, it is the main class 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 contents and high volumes of saline water, requiring extensive pumping and water disposal. These coals continue to the west, outcropping 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 has 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.

Kootenay Coals of the Mist Mountain Formation – These coals are only present in the foothills of southwestern Alberta. They have varying gas contents 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

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.

All calculations for this report used a three-dimensional deposit block model. The CBM deposit block models were constructed by developing a three-dimensional gridded seam model, with subsequent application of measured gas contents and recovery factors to each coal intersection.

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 was 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.

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 had 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.

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 (*Earth Sciences Bulletin 2003-03*) estimated that there are some 14 trillion m^3 of gas in place within all of the coal in Alberta, which is summarized in Table 4.4. 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 4.1**.

Table 4.4. 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	14.00	500

*AGS *Earth Sciences Bulletin 2003-03.*

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 2005, 2.9 10^9 m^3 was produced, mostly from the CBM wells of the dry coals and commingled sand 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 2005, 3189 wells were connected for CBM production in the province. Roughly 25 per cent of the wells were classified by the operators as gas wells, but were deemed to be CBM producing wells by the EUB. **Figure 4.2** illustrates the location of these 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 43 per cent respectively of all CBM wells connected in 2005.

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 it is deemed appropriate.

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

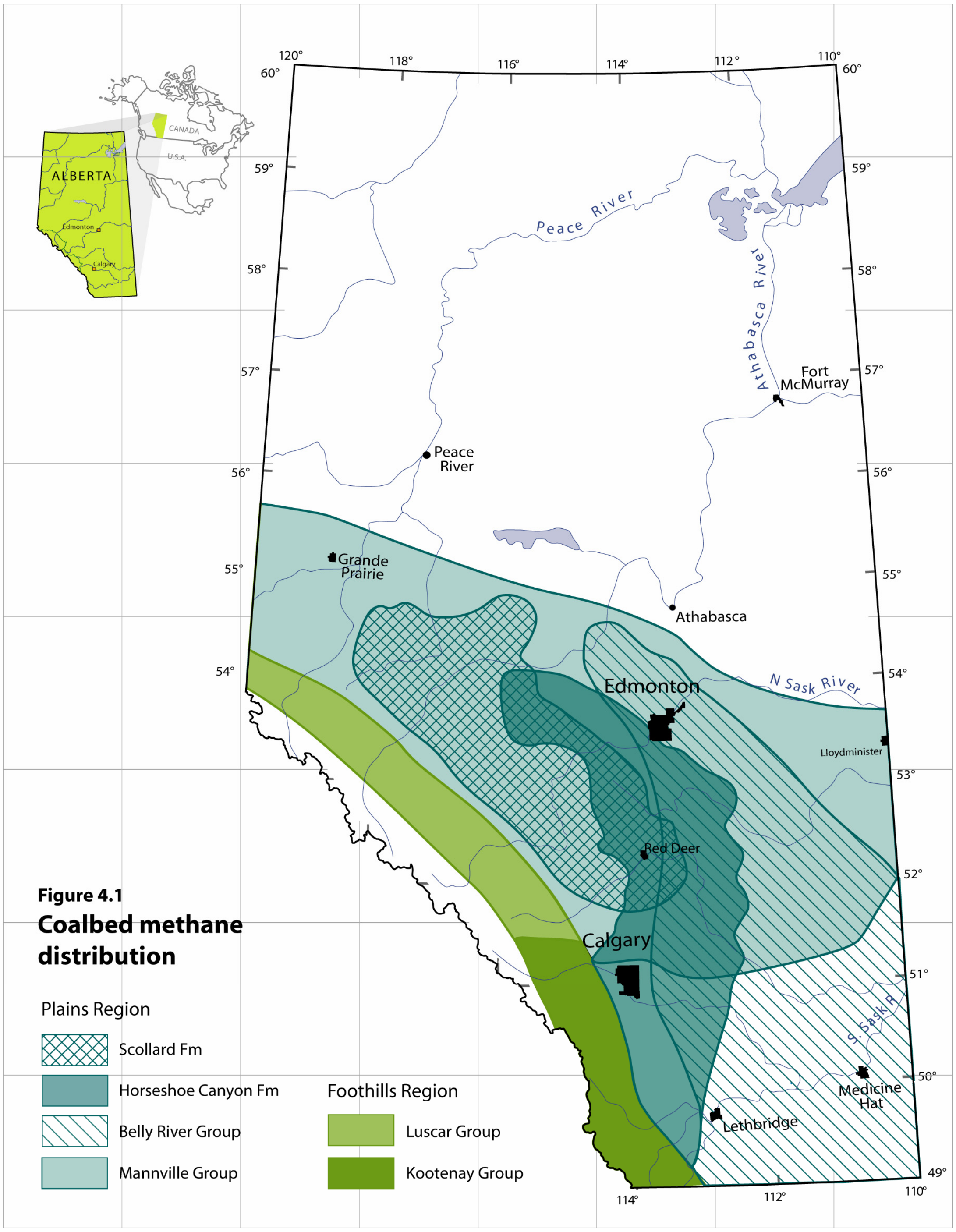


Figure 4.1
Coalbed methane distribution

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. Therefore, an initial decline rate of 15 per cent was applied to production, followed by an annual decline rate of 10 per cent.

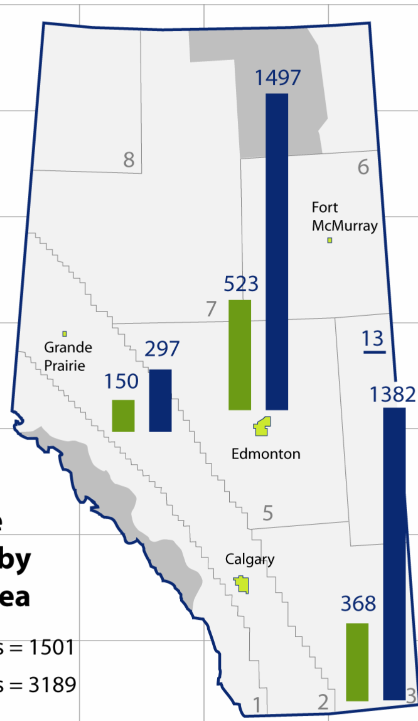


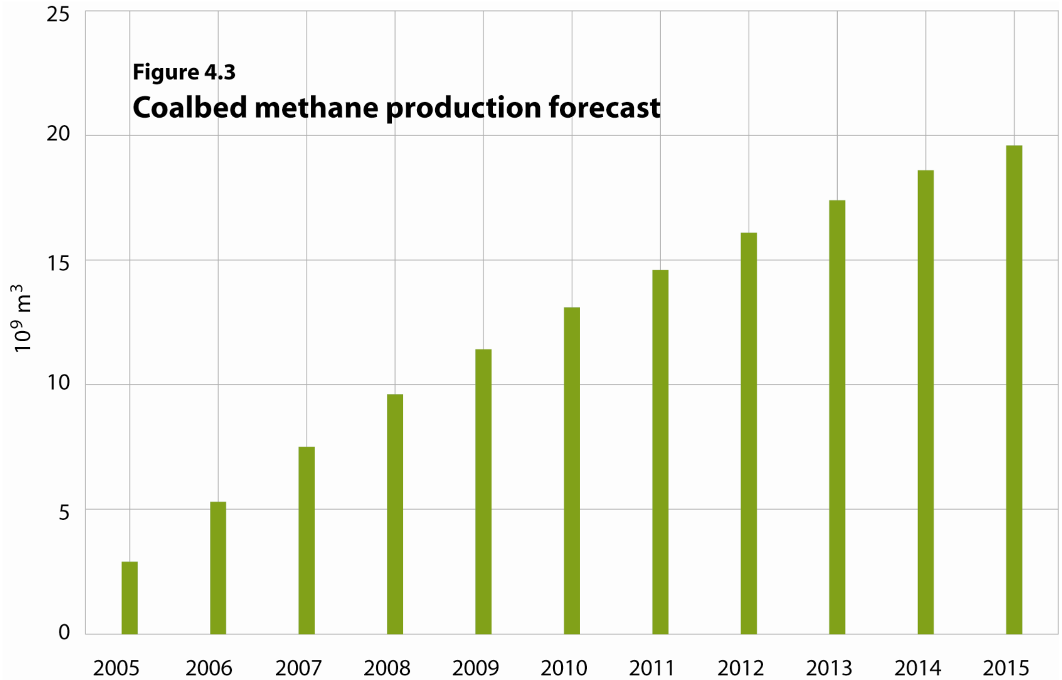
Figure 4.2
Coalbed methane well connections by modified PSAC area

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 thereafter.
- About 3000 CBM well connections are expected to occur annually.

Based on the assumptions described above, the EUB generated the forecast of CBM production to 2015, as shown in **Figure 4.3**. The production of CBM is expected to increase from 2.9 10^9 m^3 in 2005 to 19.6 10^9 m^3 in 2015. This represents an increase from less than 2 per cent in 2005 to about 16 per cent in 2015 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. At this time, with Mannville CBM production largely at the pilot project stage, companies have announced encouraging results.



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, 2005, the EUB estimates the remaining established reserves of marketable gas in Alberta to be 1086 billion cubic metres (10^9 m^3), having a total energy content of 40.4 exajoules. This is a decrease of 6.3 10^9 m^3 since December 31, 2004, and is the result of all reserves additions less production that occurred during 2005. These reserves exclude 34 million 10^9 m^3 of ethane and other natural gas liquids, which are present in marketable gas leaving the field plant and are subsequently recovered at reprocessing plants, as discussed in Section 5.1.7. Removal of natural gas liquids results in a 4.4 per cent reduction in heating value from 38.9 megajoules (MJ)/m^3 to 37.2 MJ/m^3 for gas downstream of straddle plants. Details of the changes in remaining reserves during 2005 are shown in Table 5.1. Total provincial gas in place and raw gas producible for 2005 is 7849 10^9 m^3 and 5524 10^9 m^3 respectively. This gives an average provincial recovery factor of 70 per cent. An average provincial surface loss of 15.5 per cent is applied to the raw producible gas to yield initial established marketable reserves of 4672 10^9 m^3. This surface loss estimation is discussed in Section 5.1.7.

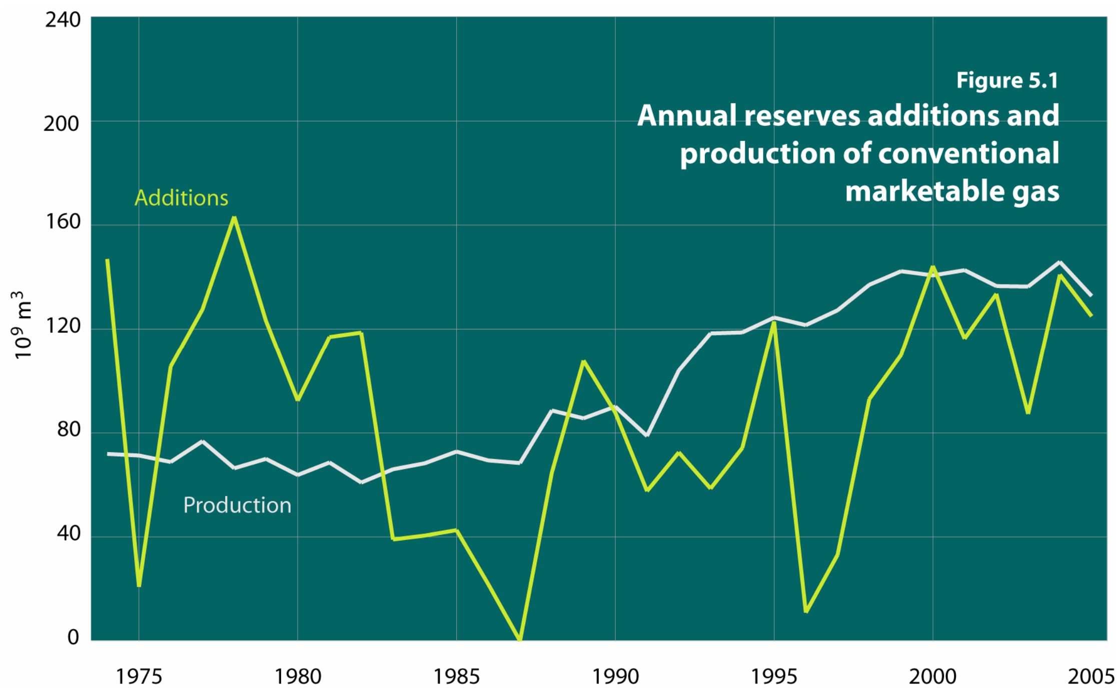
Detailed pool-by-pool reserves data are available on CD. See Appendix C.

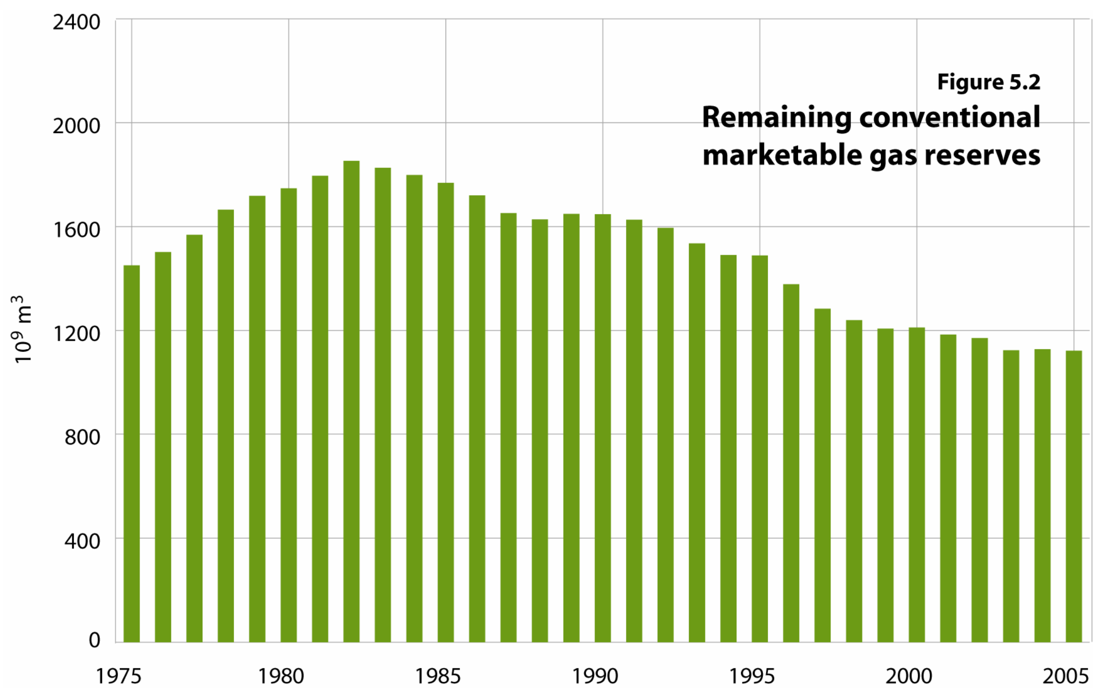
Table 5.1. Highlights of marketable gas reserve changes (10^9 m^3)

	Gross heating value (MJ/m^3)	2005 volume	2004 volume	Change
Initial established reserves		4 672.4	4 546.7	+ 125.7
Cumulative production		3 552.4	3 419.6	+ 132.8[a]
Remaining established reserves downstream of field plants				
“as is”	38.9	1 120.0	1 127.0	-7.0
at standard gross heating value	37.4	1 164.0	1 172.3	
Minus liquids removed at straddle plants		34.0	34.7	-0.7
Remaining established reserves “as is”	37.2	1 086.0 (38.4 tcf)[b]	1 092.3 (38.8 tcf)	-6.3
at standard gross heating value	37.4	1 081.0	1 087.6	

[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 has decreased by about 40 per cent since 1982.





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 2005. Initial established reserves increased by 125.7 10^9 m^3 from year-end 2004. This increase includes the addition of 36.6 10^9 m^3 attributed to new pools booked in 2005, 47.2 10^9 m^3 from development of existing pools, and a positive net reassessment of 41.9 10^9 m^3. Reserves added through drilling alone totalled 83.8 10^9 m^3, replacing 63 per cent of Alberta's 2005 production of 133.8 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.4.

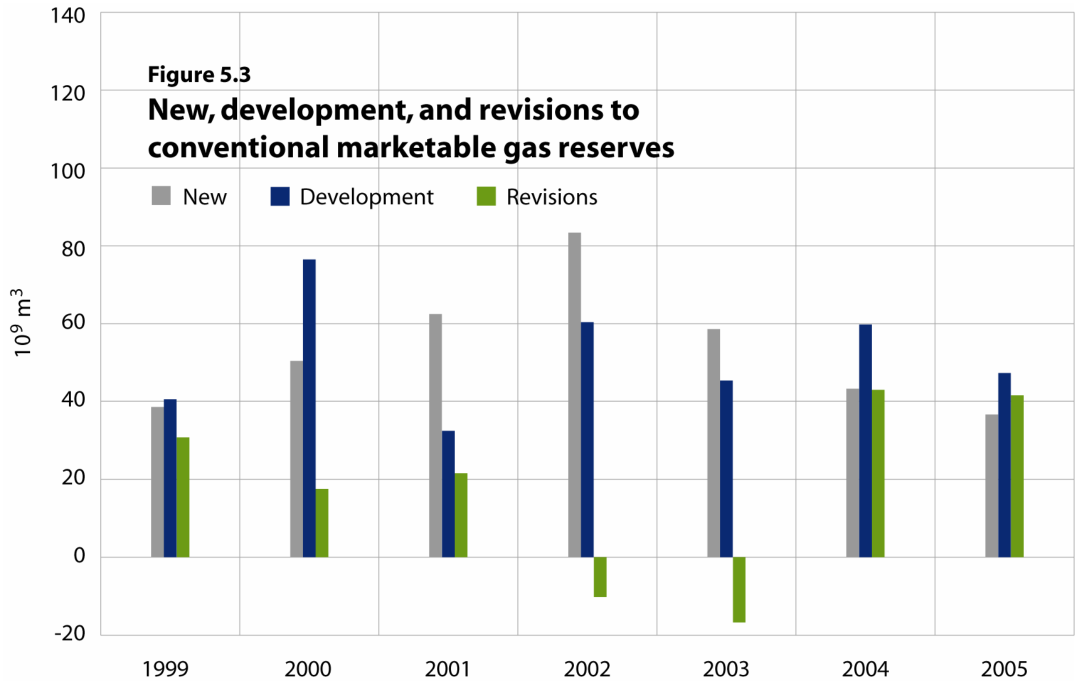


Figure 5.3
New, development, and revisions to conventional marketable gas reserves

During 2005, 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, as well as nonproducing pools discovered prior to 1995. This resulted in total positive net revisions of 31 10^9 m^3, arrived at from positive reassessments totalling 112.0 10^9 m^3 and negative reassessments totalling 81 10^9 m^3. The projects that resulted in large reserve changes are summarized below:

- Review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in reserves additions of 20.5 10^9 m^3, equivalent to 1.8 per cent of Alberta's remaining reserves. This addition was due mainly to continued aggressive development, re-evaluation of existing pools, and further development of reserves from horizons previously thought to be uneconomic.

- About 300 producing pools that showed reserves-to-production ratios over 25 years were evaluated and reserves were reduced for these pools by 23.8 10^9 m^3.

- Some 1567 producing pools with reserves-to-production ratios of less than two years were evaluated and reserves were increased by 80.7 10^9 m^3. Production decline analysis was used in estimating reserves for these pools.

- Recognition of some 370 previously unbooked gas wells drilled prior to July 2004, many of which have now been placed on production, resulted in a positive reassessment of 6.7 10^9 m^3.

- The review of 1200 single-well pools in PSAC Area 2 resulted in a reserves reduction of 12.3 10^9 m^3. Reserves were estimated using production decline.

- Reserves from about 2000 pools with finished drilling dates prior to 1995 and that showed no production were removed from the reserves category, resulting in a reserves reduction of 10.5 10^9 m^3.

Figure 5.4 depicts the changes in marketable gas reserves for 2005 by modified PSAC areas. All areas, with the exception of Area 7, showed decreased reserves growth when compared to 2004. Significant changes were made in the following areas:

- Area 2, the Western Plains area, added 58.8 10^9 m^3, compared to 71 10^9 m^3 last year. This accounts for about 47 per cent of the total annual change for 2005.

- Area 3 added a net 35.1 10^9 m^3, compared to 40.1 10^9 m^3 in 2004. This is due mainly to further development of existing pools and exploration of previously undeveloped horizons in the Cretaceous.

- Area 7 saw marginal growth of 1.2 10^9 m^3.

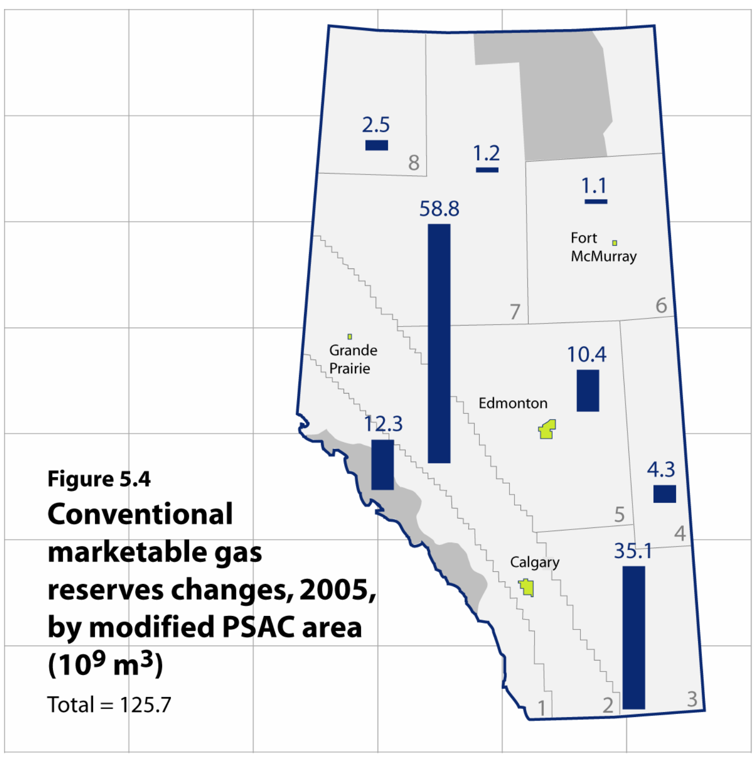


Figure 5.4
Conventional marketable gas reserves changes, 2005, by modified PSAC area (10^9 m^3)
Total = 125.7

Pools with major changes in reserves are listed in Table 5.2. Of particular interest are a number of fields in the Southeastern Alberta Gas System (MU), where reserves were revised upward in 2005, such as in the Alderson and Majorville fields, where reserves of 2.6 10^9 m^3 and 2.3 10^9 m^3 respectively were added. It should be noted that fields in the Southeastern Alberta Gas System (MU) continue after many years to have significant reserves additions due to increased drilling in the area. Other pools with significant reserves changes include the Crossfield East Wabamun Pool, with an increase of 3.3 10^9 m^3, and the Wild River Cardium, Dunvagen, Fort St. John, and Bullhead MU#1 Pool, with an increase of 3.5 10^9 m^3. The pools listed in Table 5.2 accounted for reserves additions of 38.3 10^9 m^3, or 30.5 per cent of all additions for 2005.

Table 5.2. Major natural gas reserve changes, 2005

	Initial established reserves (10^6 m^3)		
Pool	**2005**	**Change**	**Main reasons for change**
Alderson Southeastern Alberta Gas System (MU)	62 422	+2 569	New pools, development of existing pools, and re-evaluation of initial volume in place
Armada Southeastern Alberta Gas System (MU)	2 166	+1 510	New pools, development of existing pools, and re-evaluation of initial volume in place
Atlee-Buffalo Southeastern Alberta Gas System (MU)	12 029	+1 362	New pools, development of existing pools, and re-evaluation of initial volume in place
Bantry Southeastern Alberta Gas System (MU)	34 742	+1 378	New pools, development of existing pools, and re-evaluation of initial volume in place
Benjamin Rundle D&H	2 382	+839	Re-evaluation of initial volume in place
Burnt Timber Wabamun A	3 250	+550	Re-evaluation of initial volume in place
Caroline Beaverhill Lake A	17 000	+640	Re-evaluation of initial volume in place
Caroline Beaverhill Lake B	899	+739	Re-evaluation of initial volume in place
Cecilia Smokey, Dunvagen, Fort St. John and Bullhead MU#1	7 547	+2 128	Development and re-evaluation of initial volume in place
Cessford Southeastern Alberta Gas System (MU)	22 131	+991	Development and re-evaluation of initial volume in place
Crossfield Basal Quartz M	2 340	+529	Re-evaluation of initial volume in place
Crossfield East Wabamun A	20 000	+3 293	Re-evaluation of initial volume in place
Dunvagen Debolt and Elkton MU#1	36 197	-796	Re-evaluation of initial volume in place
Elkwater Milk River I	2 684	+2 442	Development and re-evaluation of initial volume in place
Elkwater Second White Specks F	1 847	+1 397	Development and re-evaluation of initial volume in place
Elmworth Halfway A	1 546	+938	Re-evaluation of initial volume in place

(continued)

Table 5.2. Major natural gas reserve changes, 2005 (concluded)

Pool	Initial established reserves (10^6 m^3) 2005	Change	Main reasons for change
Entice Edmonton & Belly River Mu#1	4 845	-772	Re-evaluation of initial volume in place
Fenn-Big Valley Edmonton & Belly River MU#1	2 003	+501	Re-evaluation of initial volume in place
Garrington Cardium, Viking & Mannville MU#1	5 487	+1 159	Re-evaluation of initial volume in place
Garrington Mannville & Rundle MU#1	4 290	+972	Re-evaluation of initial volume in place
Hamburg Slave Point HH	146	-797	Re-evaluation of initial volume in place
Hanlan Beaverhill Lake A	28 200	+1 425	Re-evaluation of initial volume in place
High River Cutbank A	3 714	+1 239	Re-evaluation of initial volume in place
Leaman Upper Mannville C & Nordegg B	1 297	-579	Re-evaluation of initial volume in place
Majorville Southeastern Alberta Gas System (MU)	3 613	+2 318	Development and re-evaluation of initial volume in place
Medicine River Glauconitic R	22	-2 714	Re-evaluation of initial volume in place
Pembina Cardium	20 996	+1 235	Re-evaluation of initial volume in place
Pendent D'Oreille Medicine Hat D	1 533	+963	Re-evaluation of initial volume in place
Pincher Creek Mannville MU#1	6 375	+1 653	Re-evaluation of initial volume in place
Princess Colorado D	1 297	+1 297	New pool
Retlaw Medicine Hat A	570	+570	New pool
Ricinus West D-3 B	2 299	+2 299	New pool
Rycroft Debolt D & C	155	-779	Re-evaluation of initial volume in place
Waterton Rundle C	2 200	+550	Development and re-evaluation of initial volume in place
Wayne Rosedale	8 100	+687	Development
Westerose South Mannville & Rundle MU#1	2 1625	+1 194	Development
Westpem Viking, Mannville & Jurassic MU#1	4 134	+1 646	Re-evaluation of initial volume in place
Wild River Cardium, Dunvagen, Fort St. John and Bullhead MU#1	22 902	+3 487	Development and 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 73.2 per cent of all pools, contain only 10 per cent of the province's remaining marketable reserves. Similarly, the largest 1 per cent of pools contains 53 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 has 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 2005.

Figure 5.5
Distribution of conventional gas reserves by size

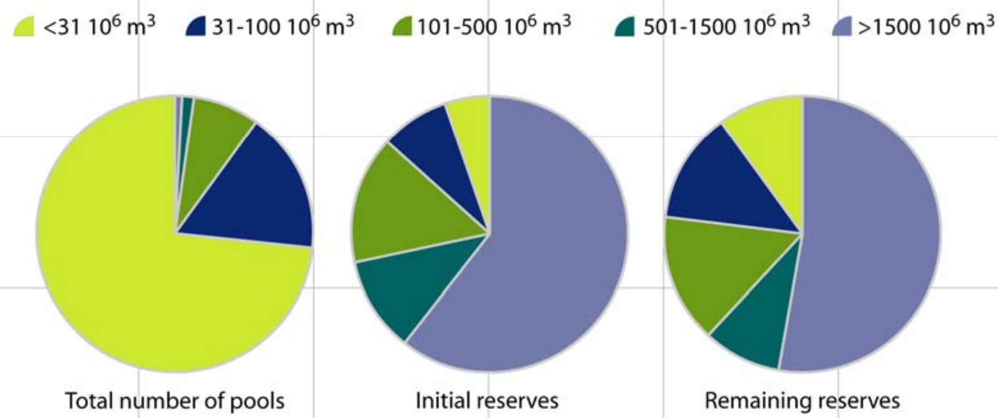
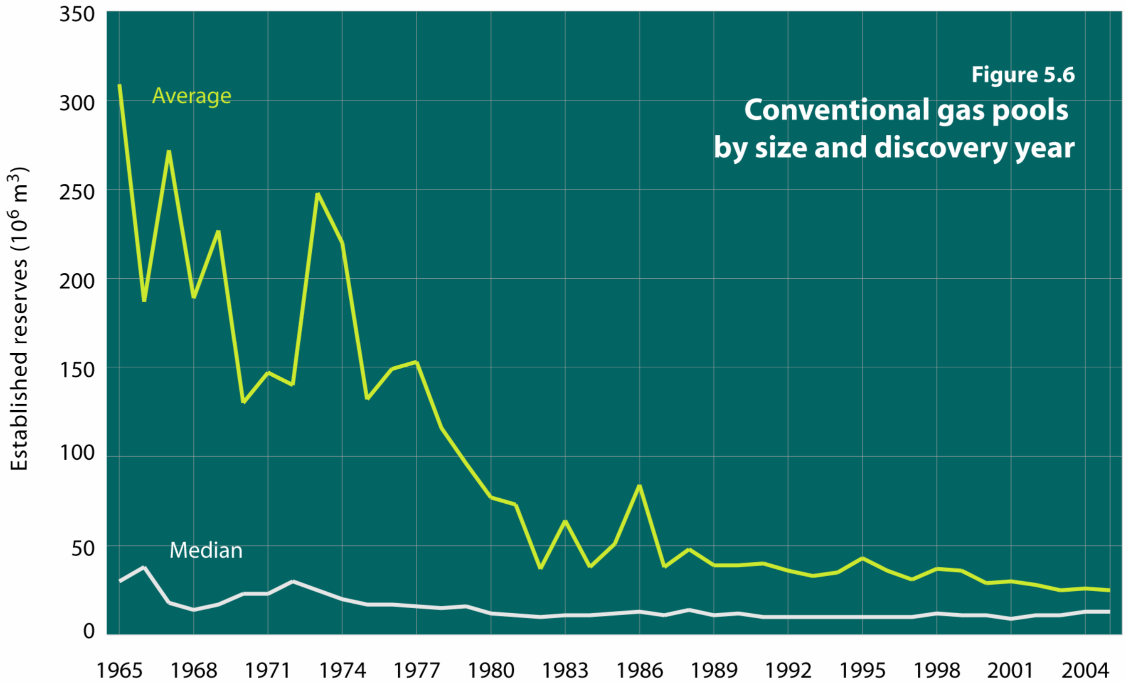


Table 5.3. Distribution of natural gas reserves by pool size, 2005

Reserve range (10^6 m^3)	Pools #	Pools %	Initial established marketable reserves 10^9 m^3	Initial established marketable reserves %	Remaining established marketable reserves 10^9 m^3	Remaining established marketable reserves %
3000+	195	0.5	2 474	53	518	46
1500-3000	162	0.4	343	7	80	7
1000-1500	153	0.4	186		36	3
500-1000	500	1.1	345	7	63	6
100-500	3 303	7.6	684	15	166	15
30-100	7 332	16.8	390	8	143	13
Less than 30	31 941	73.2	250	5	114	10
Total	43 586	100.0	4 672	100	1 120	100



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.5. The Upper and Lower Cretaceous period accounts for some 71.5 per cent of the province's remaining established reserves of marketable gas and are important as a source of future natural gas. The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 25.6 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 21.3 per cent, and the Mississippian Rundle, with 7.7 per cent. Together, these strata contain 54.6 per cent of the province's remaining established reserves.

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, 2005, sour gas accounts for some 21 per cent (237 10^9 m^3) of the province's total remaining established reserves and about 33 per cent of natural gas marketed in 2005. 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 2005 is 9.1 per cent.

The distribution of reserves for sweet and sour gas (Table 5.4) shows that 170 10^9 m^3, or about 73 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 58 10^9 m^3, or 25 per cent, of sour gas contains H_2S concentrations greater than 10 per cent.

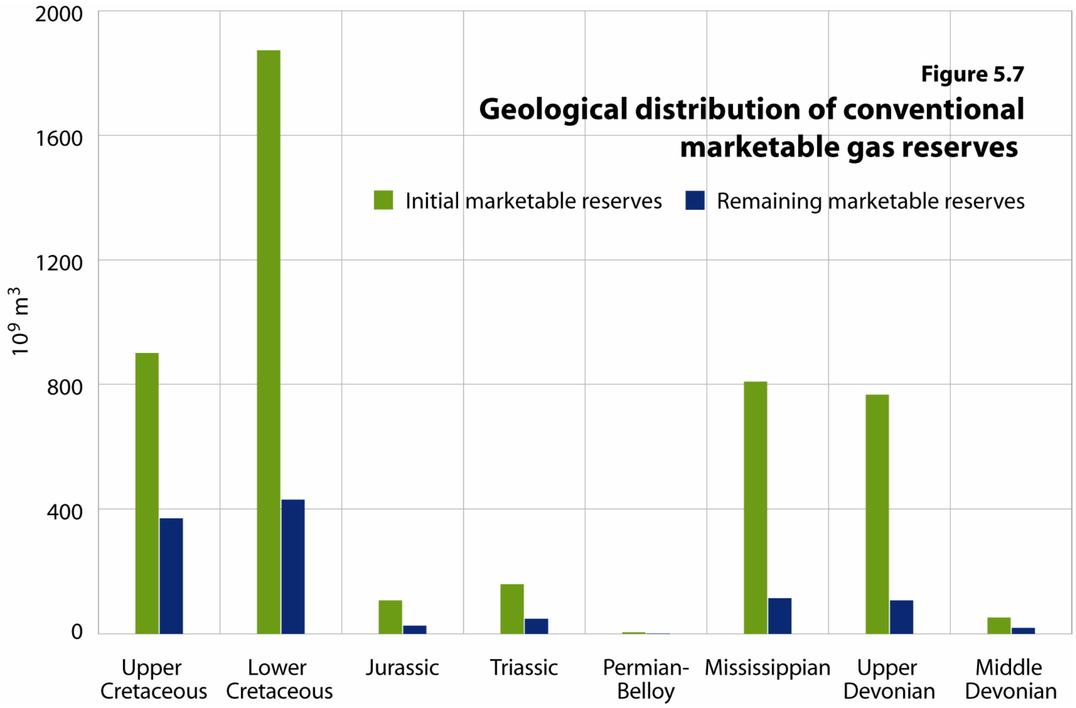


Table 5.4. Distribution of sweet and sour gas reserves, 2005

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	Initial established reserves	Cumulative production	Remaining established reserves	Initial established reserves	Remaining established reserves
Sweet					
Associated & solution	604	461	143	13	13
Nonassociated	2555	1810	745	55	66
Subtotal	3159	2271	888	68	79
Sour					
Associated & solution	410	349	62	9	6
Nonassociated	1103	933	170	23	15
Subtotal	1513	1282	232	32	21
Total	4672 (167)[b]	3553 (126)[b]	1120[a] (40)[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.

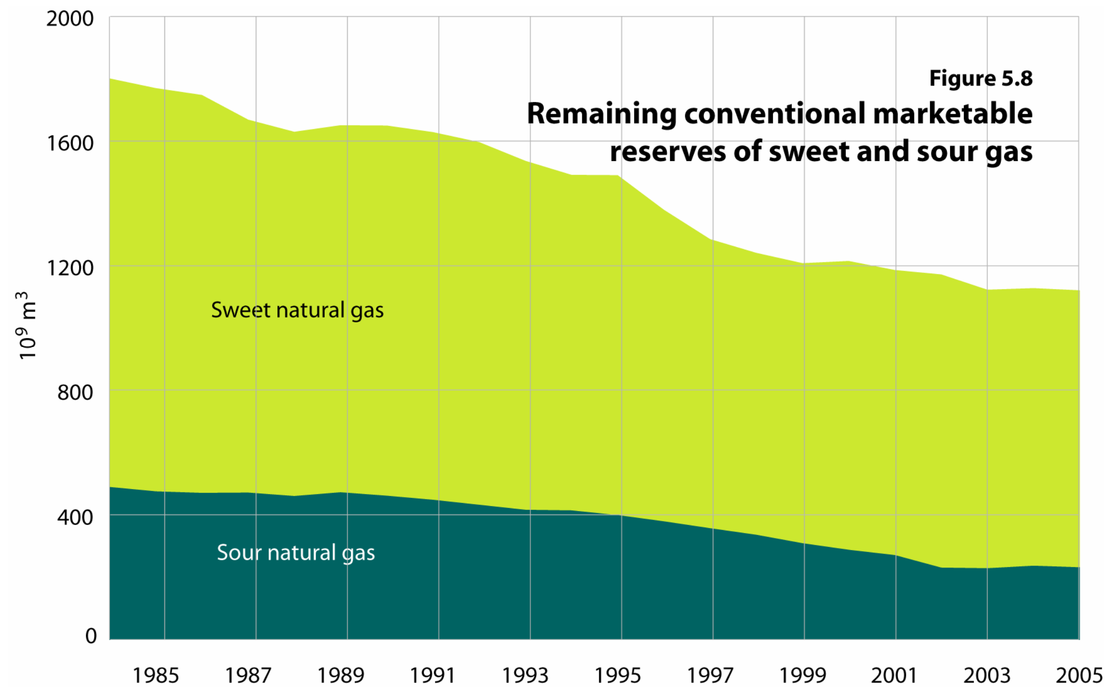


Table 5.5. Distribution of sour gas reserves by H_2S content, 2005

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	282	377	45	62	107	46
2.00-9.99	91	372	11	56	67	29
10.00-19.99	26	204	4	26	30	13
20.00-29.99	11	46	2	9	11	5
Over 30	0	104	0	17	17	7
Total	410	1 103	62	170	232	100
Percentage	27	73	27	73		

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.6. 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 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.

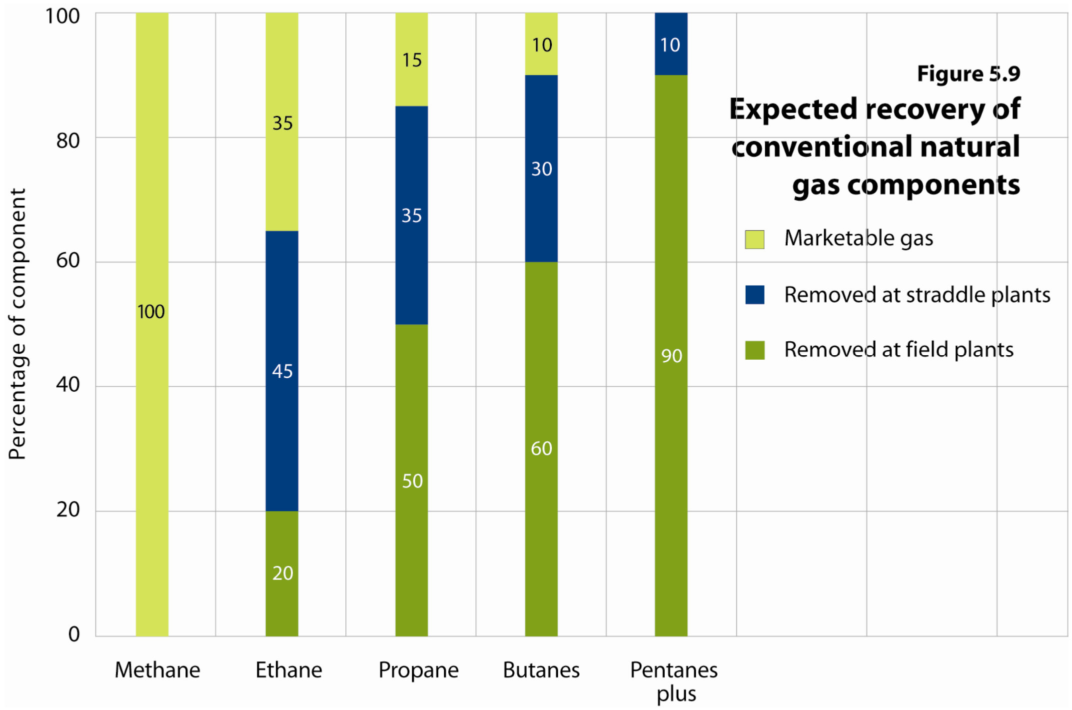


Figure 5.9
Expected recovery of conventional natural gas components

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 34.0 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 1120 10^9 m^3 to 1086 10^9 m^3 and the thermal energy content from 43.5 to 40.4 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 20 per cent is expected to be removed at field plants and an additional 45 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.7. 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 tcf). 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. **Figure 5.11** plots production and remaining established reserves of marketable gas compared to the estimate of ultimate potential.

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 4672 10^9 m^3, or 74 per cent of the ultimate potential of 6276 10^9 m^3, has been discovered as of year-end 2005. This leaves 1604 10^9 m^3, or 26 per cent, yet to be discovered. Cumulative production of 3552 10^9 m^3 at year-end 2005 represents 56.6 per cent of the ultimate potential, leaving 2724 10^9 m^3, or 43 per cent, available for future use.

Table 5.6. Remaining ultimate potential of marketable gas, 2005 (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	-4672	-4859
	1604	1669
Remaining established		
Initial established	4672	4859
Minus cumulative production	-3552	-3694
	1120	1165
Remaining ultimate potential		
Yet to be established	1604	1669
Plus remaining established	+1120	+1165
	2724	2838

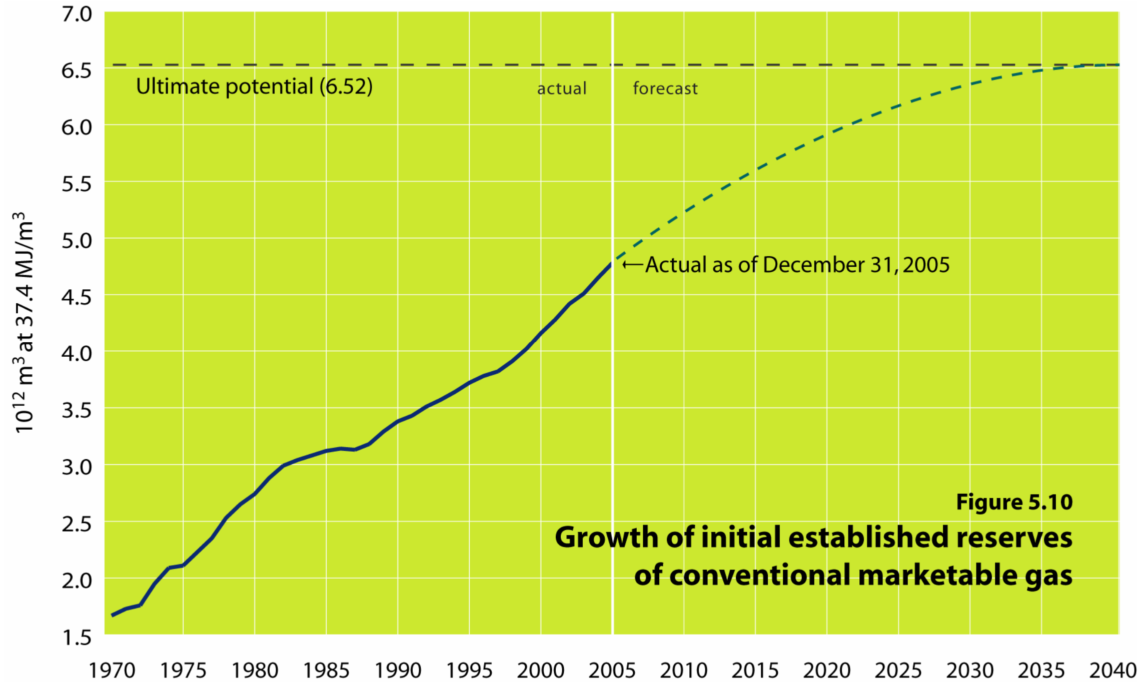


Figure 5.10
Growth of initial established reserves of conventional marketable gas

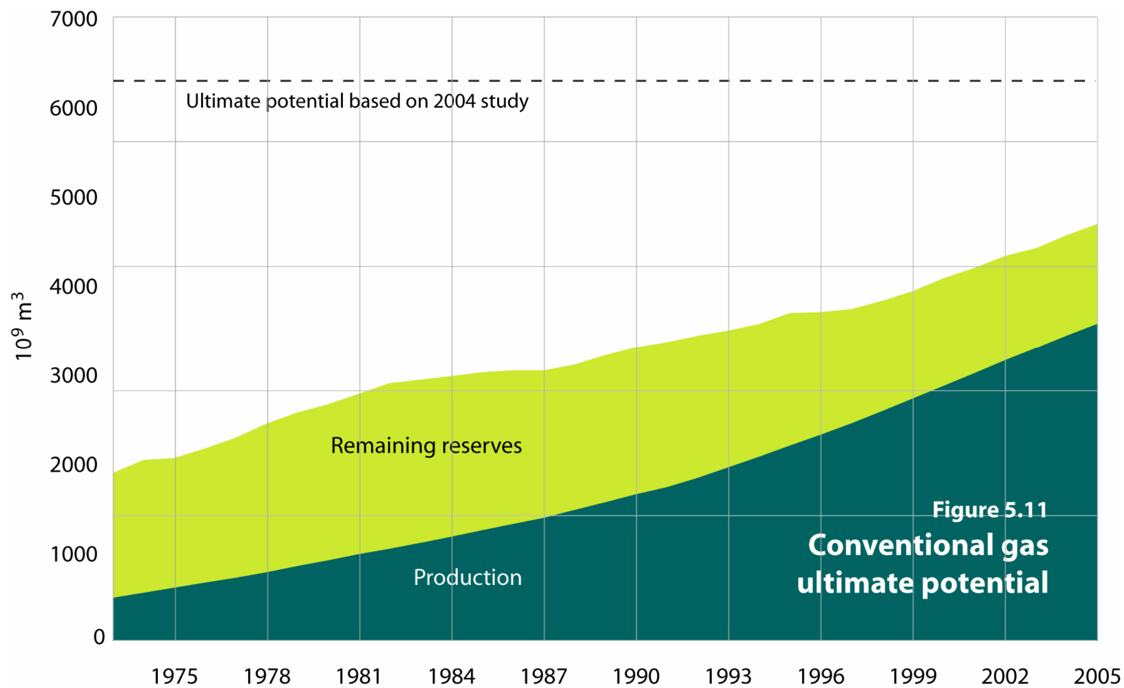


Figure 5.11
Conventional gas ultimate potential

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 36 per cent of the remaining established reserves and 37 per cent of 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 depend on significant new discoveries in the Western Plains.

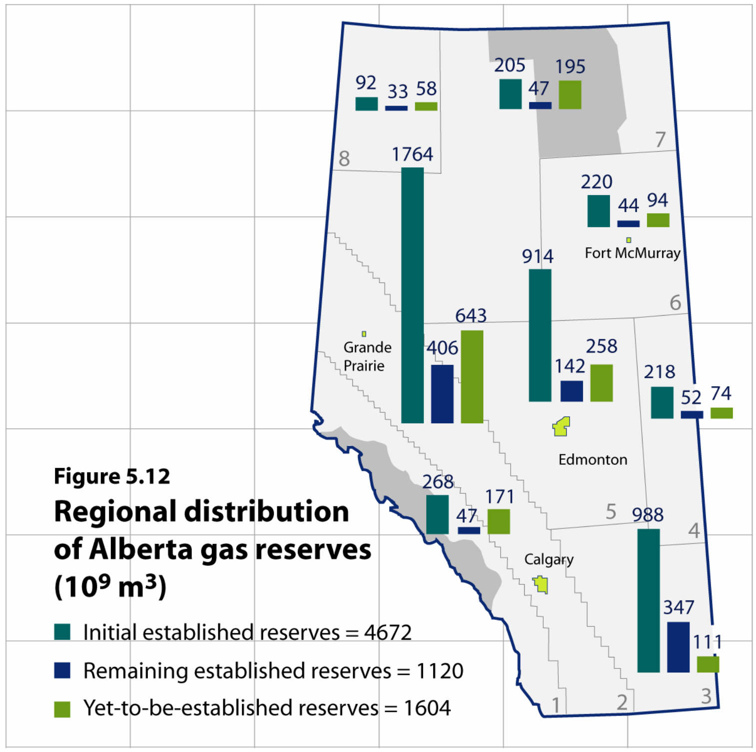
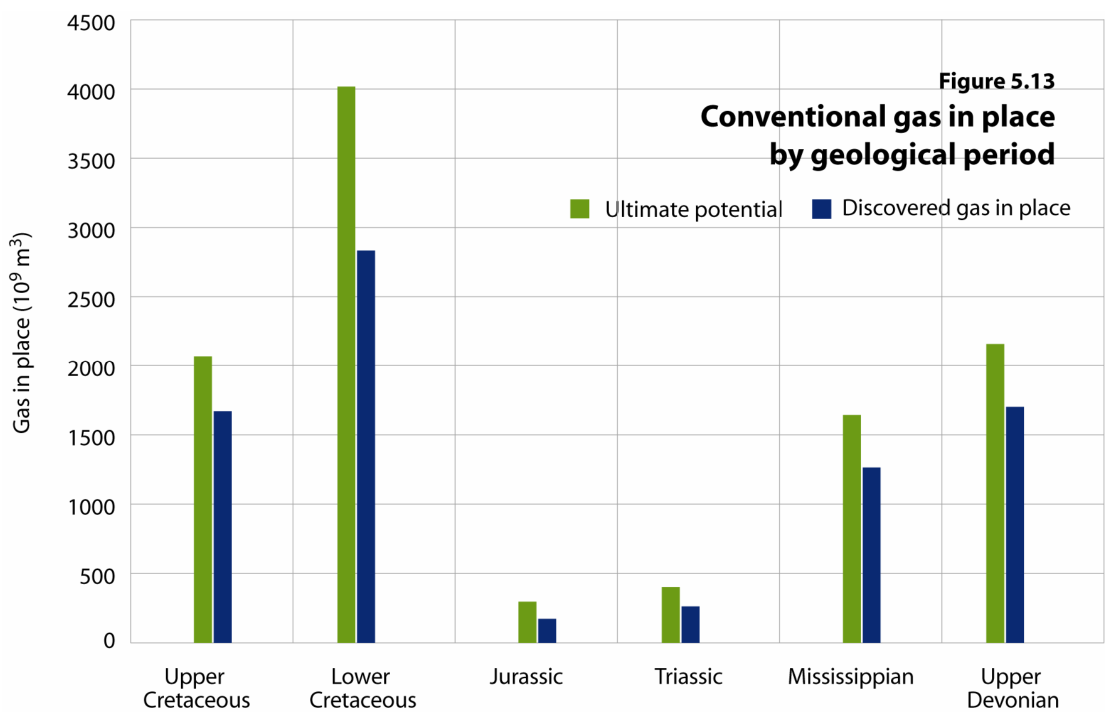


Figure 5.13 shows by geological period the discovered and ultimate potential (EUB/NEB 2005 Report) gas in place for year-end 2005. It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous.



5.2 Supply of and Demand for Conventional Natural Gas

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 2005. As noted in Section 4, Alberta also produced 2.9 10^9 m^3 of coalbed methane (CBM). This volume includes some production of conventional gas, as the coals are often interbedded with conventional gas reservoirs. Total natural gas production remained essentially flat at 142.1 10^9 m^3 in 2005 compared to 142.3 10^9 m^3 in 2004.[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, low cost of drilling, and quick tie-in times.

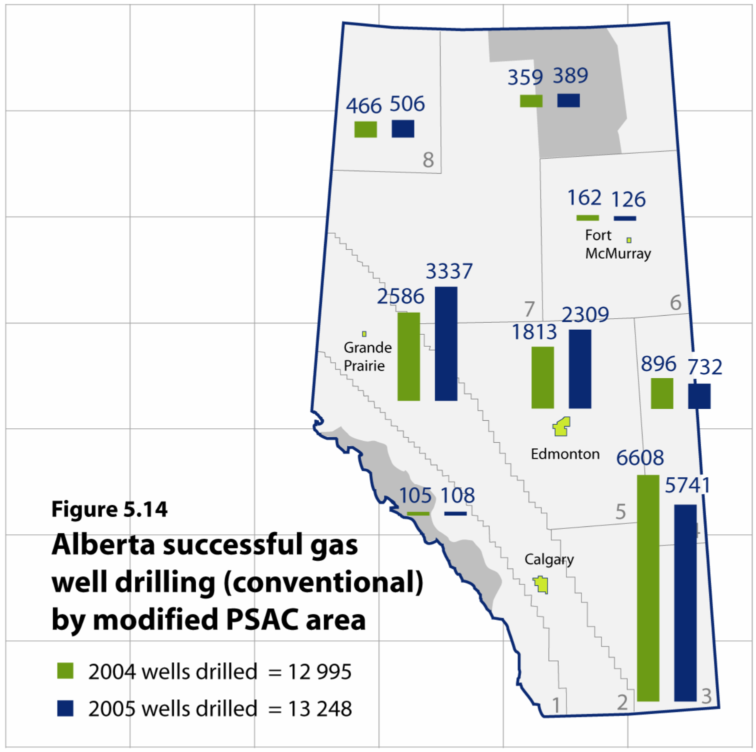
The conventional marketable natural gas production volumes for 2005 stated in Table 5.7 have been calculated based on "Supply and Disposition of Marketable Gas" in *ST3: Alberta Energy Resource Industries Monthly Statistics.*

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

Marketable gas production	2005
Total gas production	168 350.3
Minus CBM production	-2 890.0
Total conventional gas production	165 460.3
Minus storage withdrawals	5 694.4
Raw gas production	159 765.9
Minus injection total	-8 498.1
Net raw gas production	151 267.8
Minus processing shrinkage – raw	-10 625.4
Minus flared – raw	-620.9
Minus vented – raw	-332.6
Minus fuel – raw	-11 744.5
Plus storage injections	5 903.6
Calculated marketable gas production at as-is conditions	133 848.0
Calculated marketable gas production @37.4 MJ/m^3	139 201.9

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**.

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



In 2005, some 13 248 conventional natural gas wells were drilled in the province, an increase of 27 per cent from 2004 levels and an all-time high. A large portion of gas drilling has taken place in Southeastern Alberta, representing 43 per cent of all conventional natural gas wells drilled in 2005.

Drilling levels were up in all other areas of the province, with the exception of Area 4 (East Central Alberta), Area 6 (Northeastern Alberta), and Area 8 (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 1996 to 2005 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 the years 2003-2005 the number of new wells connected was less than the number of gas wells drilled. This was due primarily to the time delay in bringing gas wells drilled onto production. Also, some wells whose status was initially classified as conventional gas intent were later determined to be CBM wells. The distribution of natural gas well connections and the initial operating day rates of the connected wells in the year 2005 are illustrated in **Figures 5.16** and **5.17** respectively.

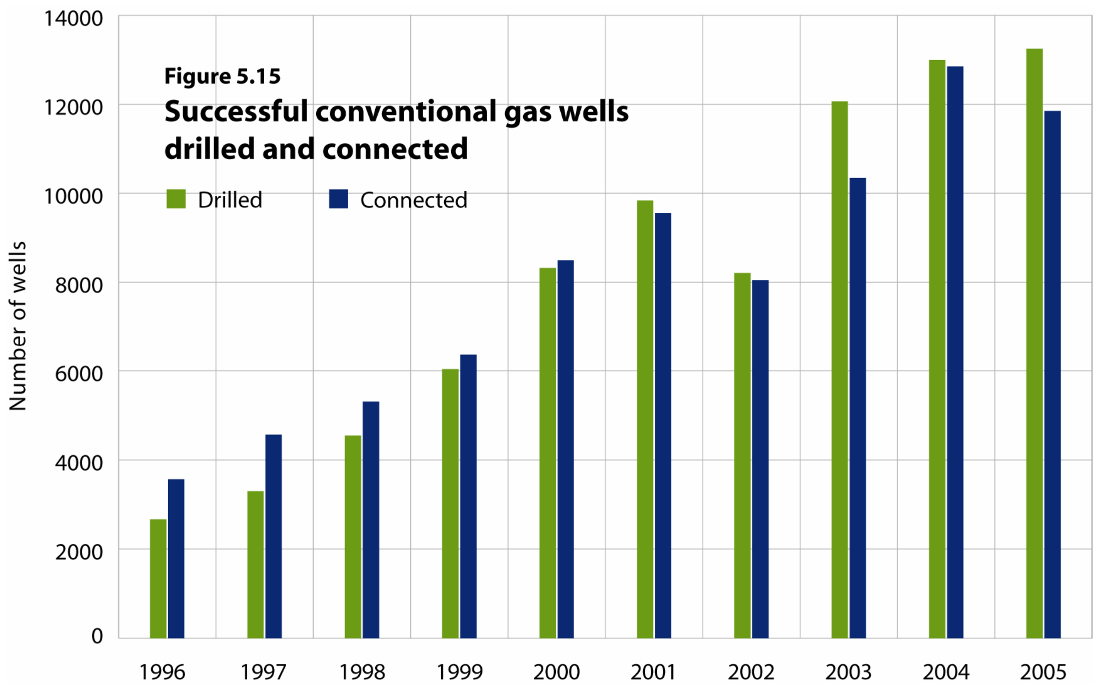


Figure 5.15
Successful conventional gas wells drilled and connected

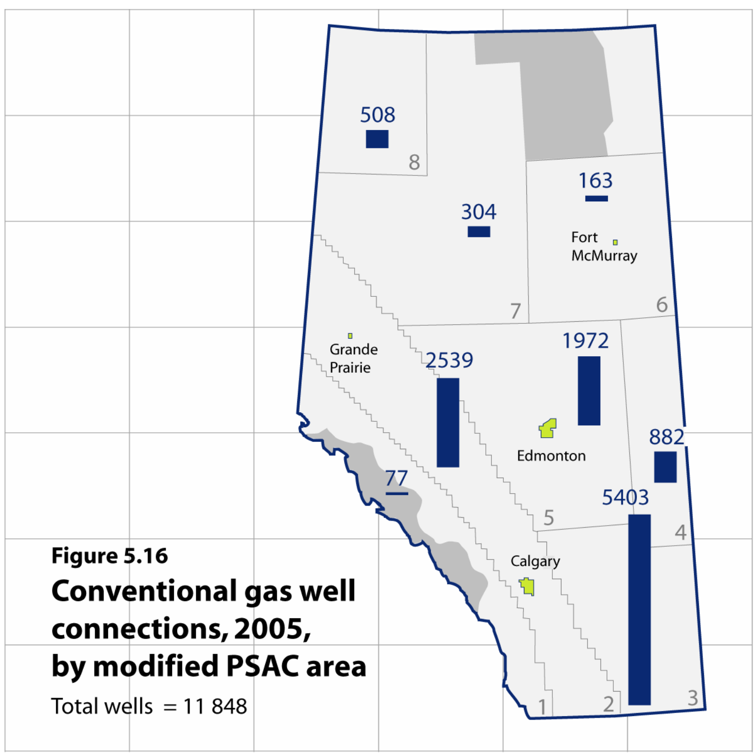


Figure 5.16
Conventional gas well connections, 2005, by modified PSAC area
Total wells = 11 848

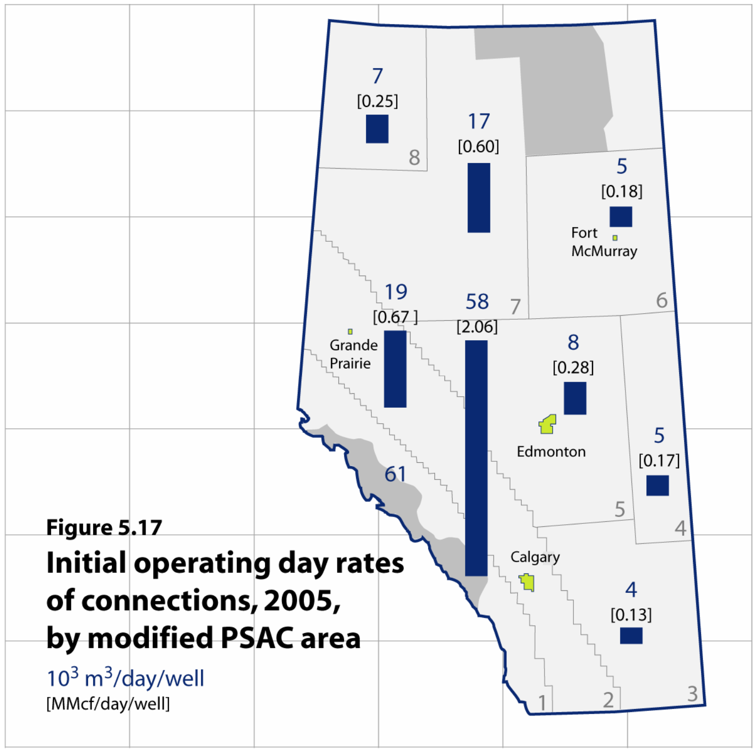
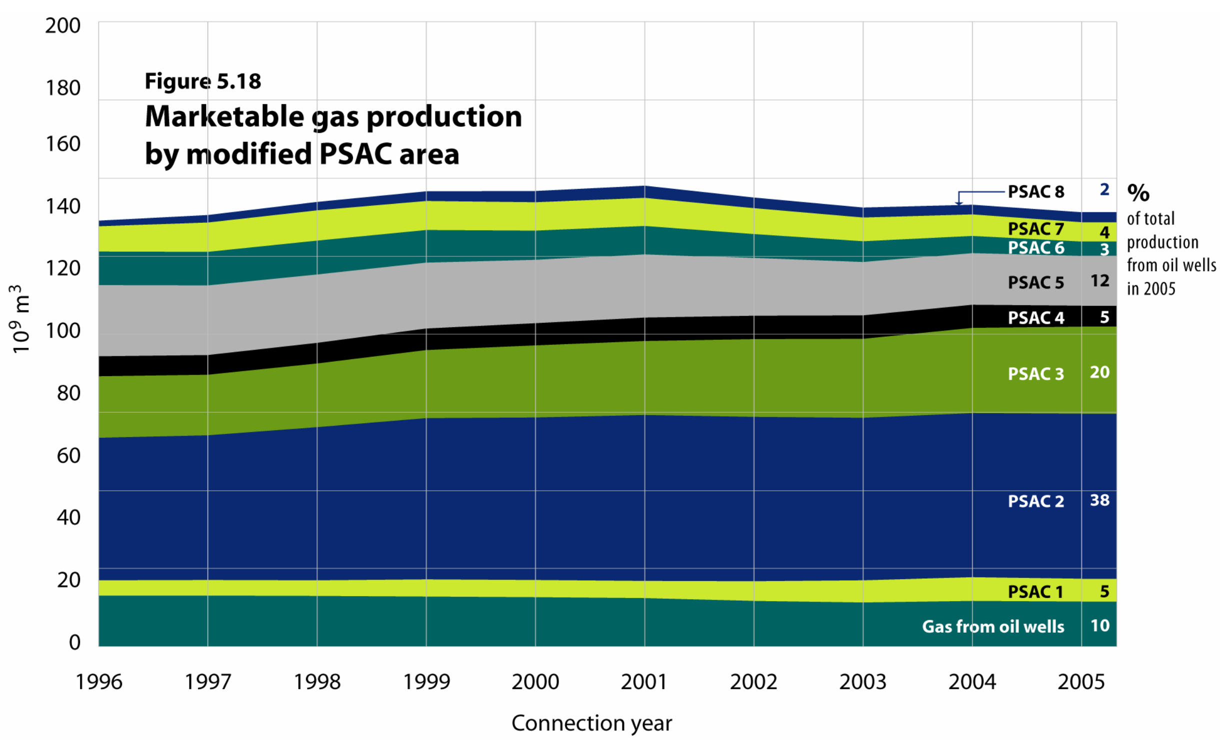
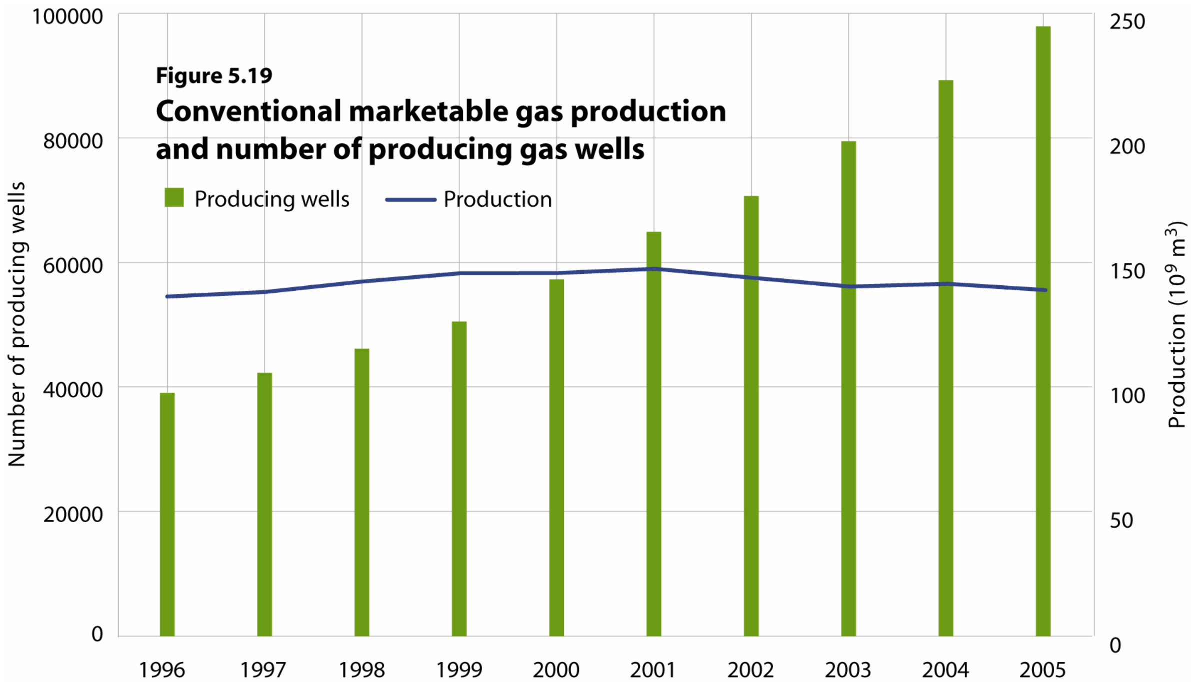


Figure 5.18 illustrates historical gas production from gas wells by geographical area. Area 1 (Foothills), Area 2 (Western Plains), Area 3 (Southeastern Alberta), and Area 8 (Northwest Alberta) experienced increases in production in 2005.



Conventional marketable gas production in Alberta from 1996 to 2005 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 2005, the total number of producing gas wells increased to 97 900, from 39 000 wells in 1996. It now takes an increasing number of new gas wells each year to offset production declines in existing wells. A large number of new wells are drilled in southeastern Alberta, where well productivity is low.



Average gas well productivity has been declining over time. As shown in **Figure 5.20**, about 60 per cent of the operating gas wells produce less than 1 thousand (10^3) m^3/d. In 2005, these 64 000 gas wells operated at an average rate of 0.8 10^3 m^3/d per well and produced less than 11 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 17 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 2005. For example, 12 per cent of gas production in 2005 came from wells connected in that year. The figure shows that in 2005, almost 54 per cent of gas production came from gas wells connected in the last five years.

Declines in natural gas production from new gas well connections from 1996 to 2003 have been evaluated after the wells drilled in a given year completed a full year of production.

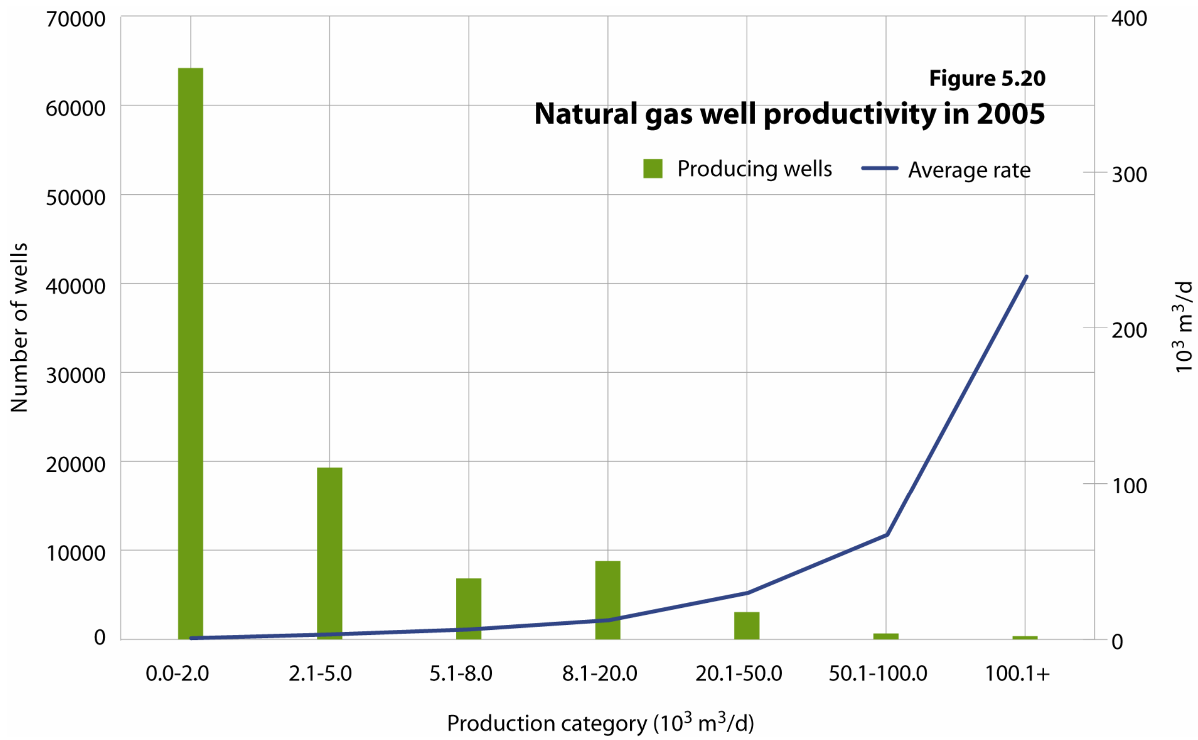


Figure 5.20
Natural gas well productivity in 2005
Producing wells
Average rate
Number of wells
70000
60000
50000
40000
30000
20000
10000
0
400
300
200
100
0
10^3 m^3/d
0.0-2.0
2.1-5.0
5.1-8.0
8.1-20.0
20.1-50.0
50.1-100.0
100.1+
Production category (10^3 m^3/d)

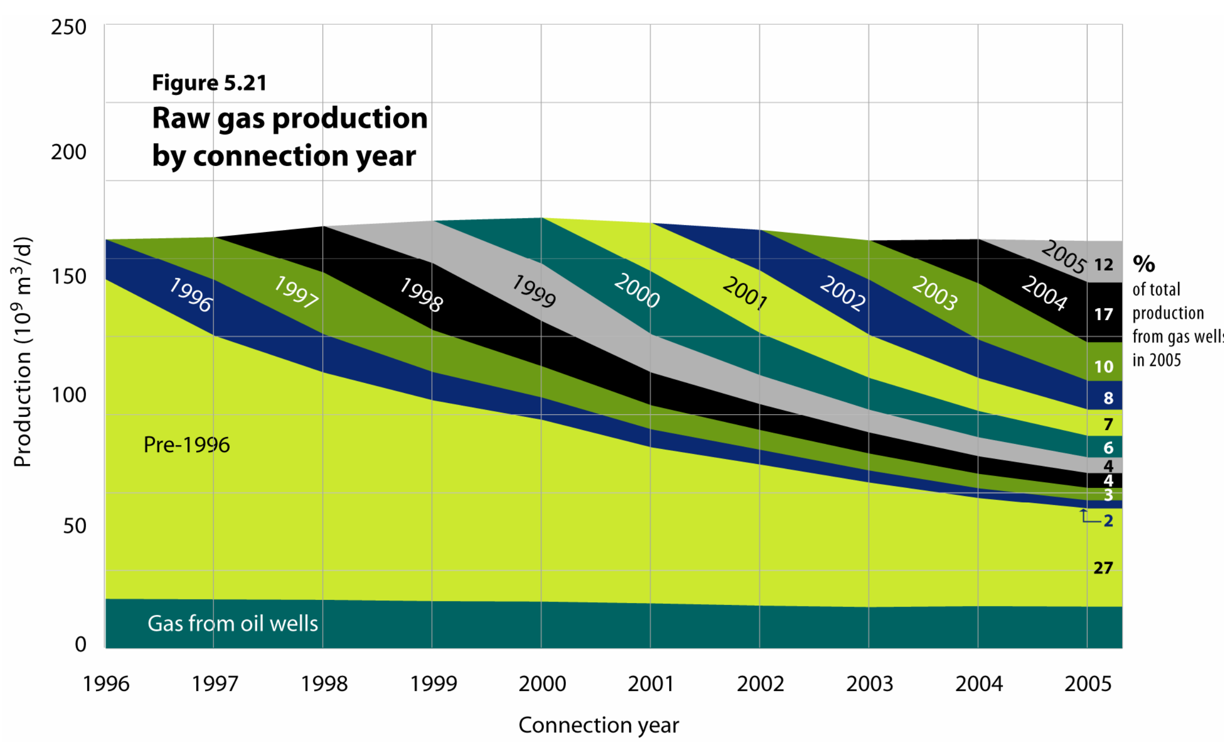


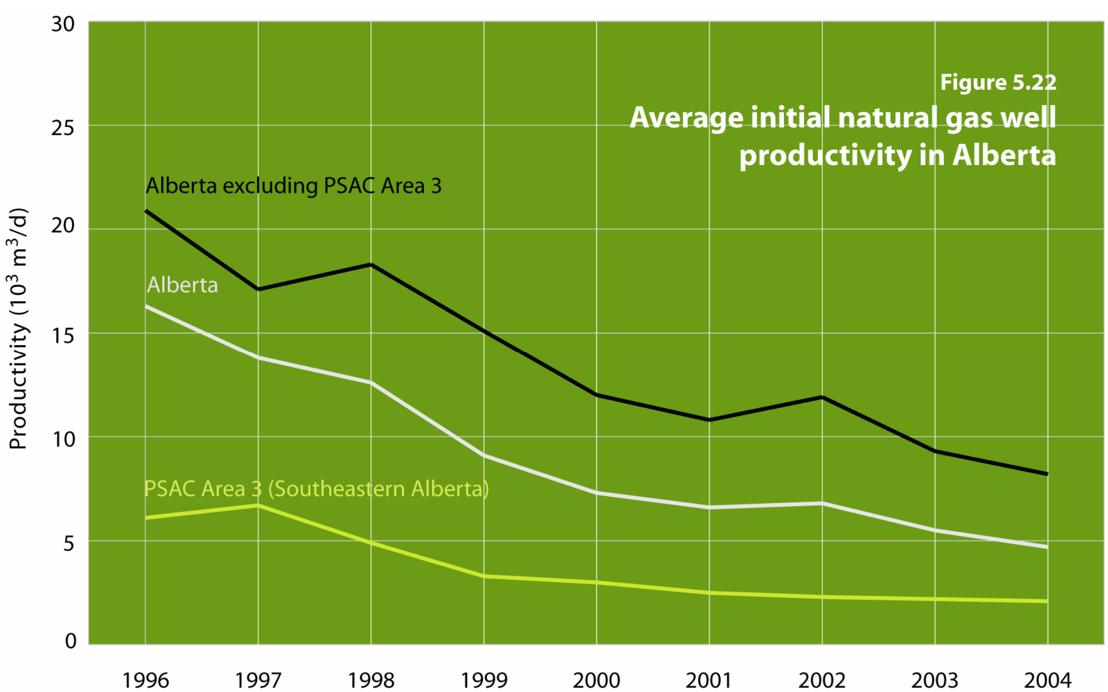
Figure 5.21
Raw gas production
by connection year
Production (10^9 m^3/d)
250
200
150
100
50
0
Pre-1996
Gas from oil wells
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
% of total production from gas wells in 2005
12
17
10
8
7
6
4
4
3
2
27
Connection year

Table 5.8 shows decline rates for gas wells connected from 1996 to 2003 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 about18 per cent from the fourth year forward.

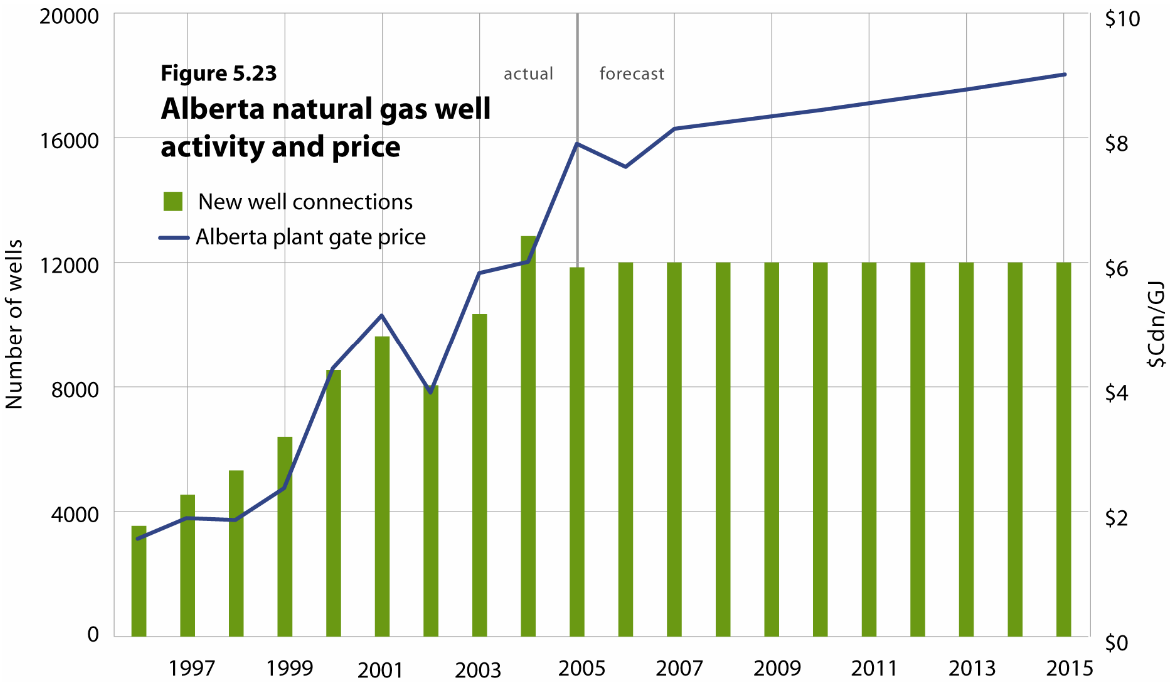
Table 5.8. Production decline rates for new well connections (%)

Year wells connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1995	30	25	23	19
1996	31	27	21	18
1997	32	28	23	19
1998	32	28	24	18
1999	34	25	21	17
2000	34	25	17	18
2001	32	25	20	
2002	30	25		
2003	33			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 5.22** 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. Drilling activity in the southeastern part of Alberta is expected to remain strong throughout the forecast period. EUB spacing requirements are being amended to allow for reduced baseline well densities in areas east of the 5th Meridian and south of Township 53. New requirements will allow for two gas wells per section in the Mannville Group and four gas wells per section in formations above the Mannville. **Figure 5.23** illustrates historical and forecast new well connections and mid-point 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 2005 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 2006 and will decrease to 1.5 10^3 m^3/d by 2015.
- The average initial productivity of new natural gas wells in the rest of the province will be 7.0 10^3 m^3/d in 2006 and will decrease to 5.5 10^3 m^3/d by 2015.
- Production from new wells will decline at a rate of 32 per cent the first year, 25 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 2015, as shown in **Figure 5.24**. The production of natural gas from conventional reserves is expected to decrease from 139.2 10^9 m^3 to 103.4 10^9 m^3 by the end of the forecast period. If conventional natural gas production rates follow the projection, Alberta will have recovered about 75 per cent of the 6276 10^9 m^3 ultimate potential by 2015.

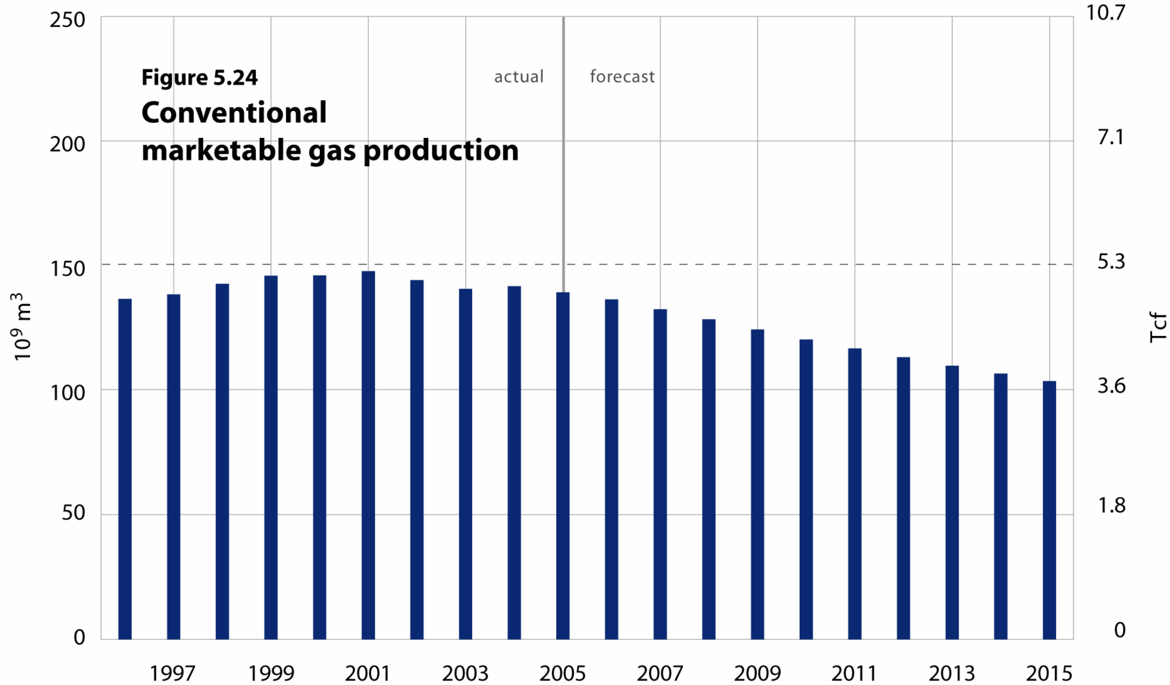
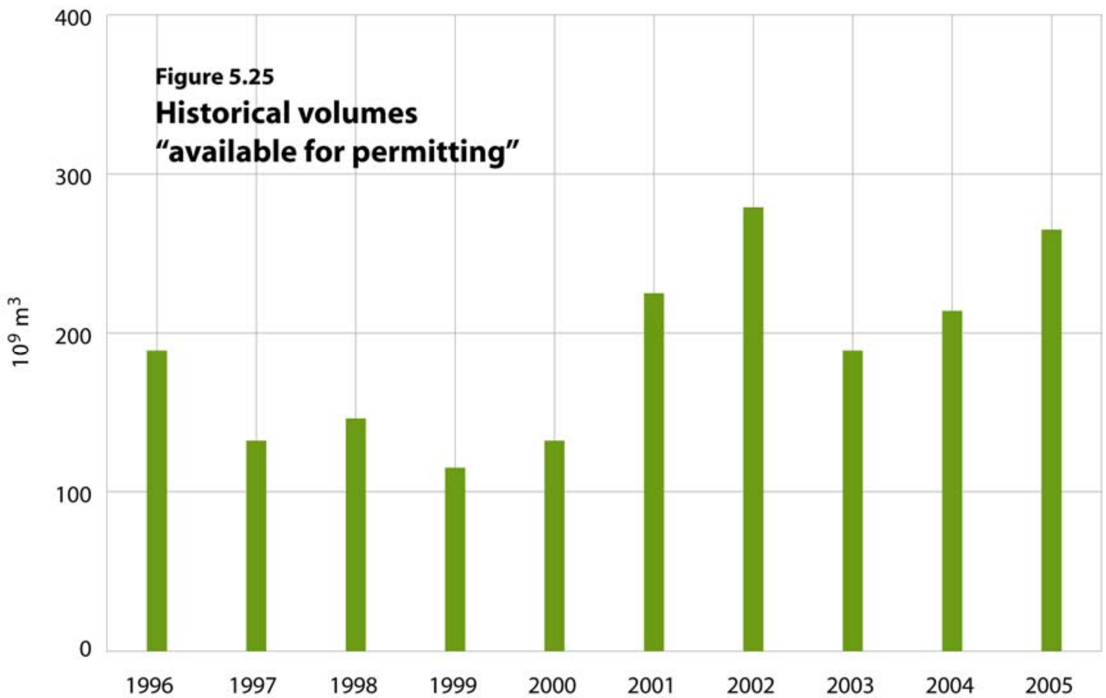


Figure 5.25 presents a comparison of raw natural gas production in Alberta to both Texas and Louisiana onshore over the past 40-year period. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta appears to be at that stage today. It is interesting to note 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.

Gas production from sources other than conventional gas and oil wells includes processed gas from bitumen upgrading operations, natural gas from bitumen wells, and CBM. **Figure 5.26** shows the historical and forecast volumes of production from the first two categories. In 2005, some 4.2 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 11.9 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells in thermal schemes was 0.5 10^9 m^3 in 2005 and is forecast to increase to 0.9 10^9 m^3 by 2015. This gas was used as fuel to create steam for its in situ operations.



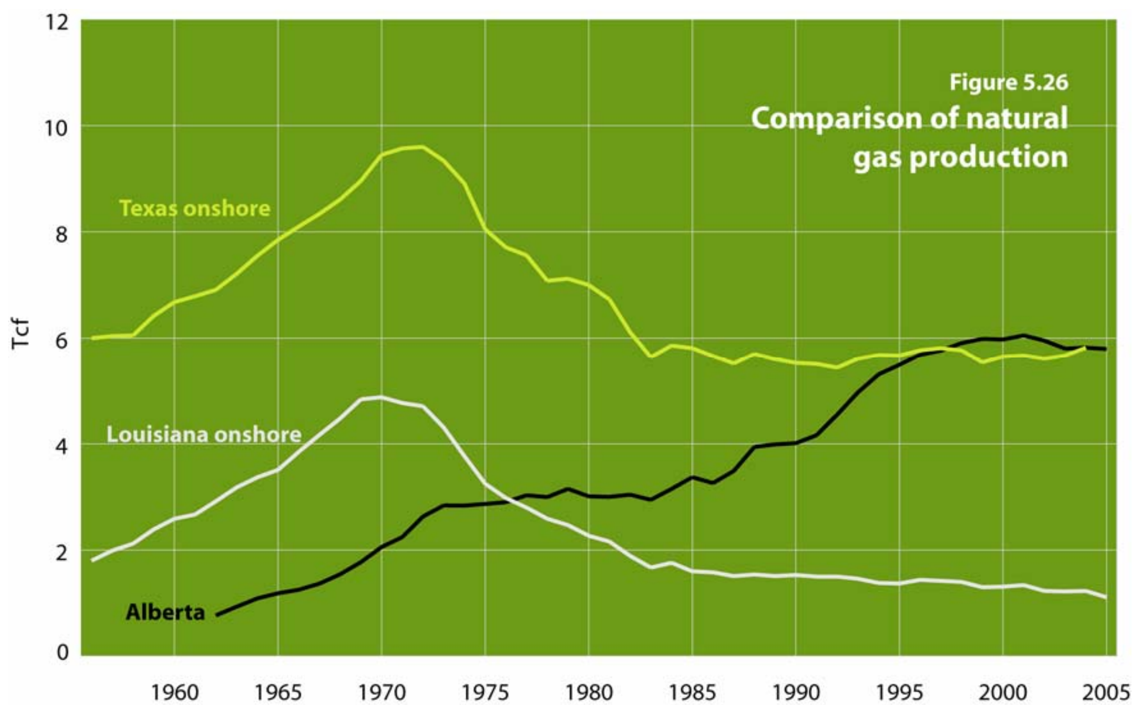
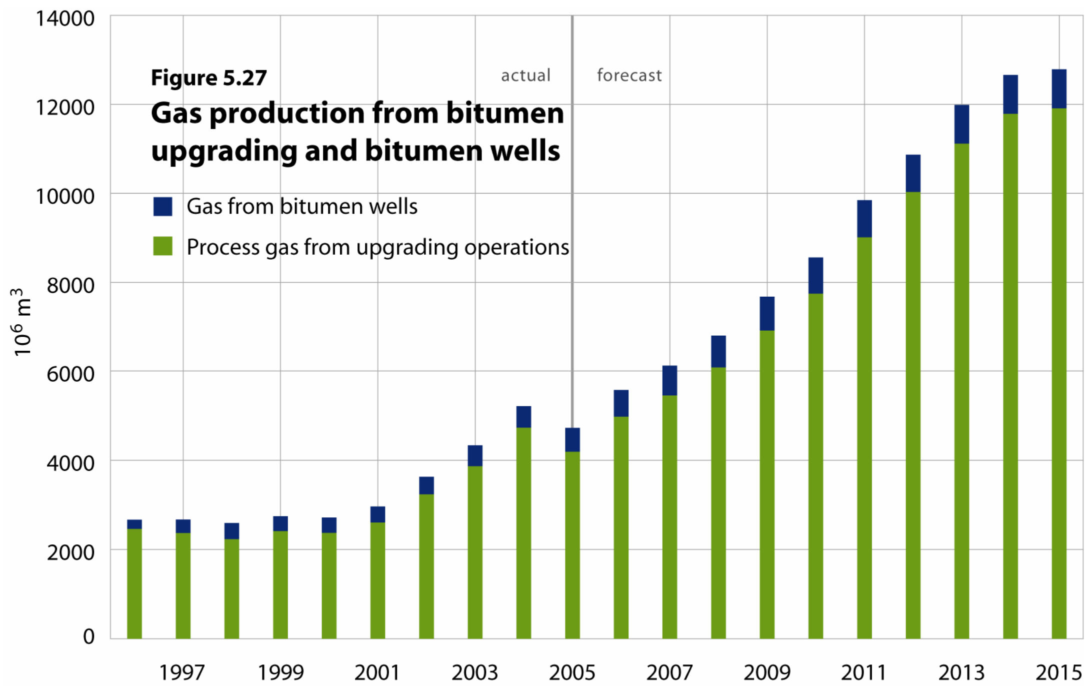


Figure 5.27 shows the forecast of conventional natural gas production, along with gas production from other sources. While the production of conventional gas in Alberta is expected to decline over the forecast period by about 3 per cent per year, CBM production is expected to grow significantly over time and offset a large 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. EnCana temporarily ceased commercial storage operations at the Sinclair Gething D and Paddy C Pools as of April 1, 2004. A new commercial gas storage scheme is being developed by TransCanada Pipelines using the Edson Viking D pool. This depleted gas reservoir is expected to have a working gas capacity of 1400 10^6 m^3 when fully operational.

In 2005, natural gas injections for all storage schemes exceeded withdrawals by 209.2 10^6 m^3. Marketable gas production volumes determined for 2005 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.

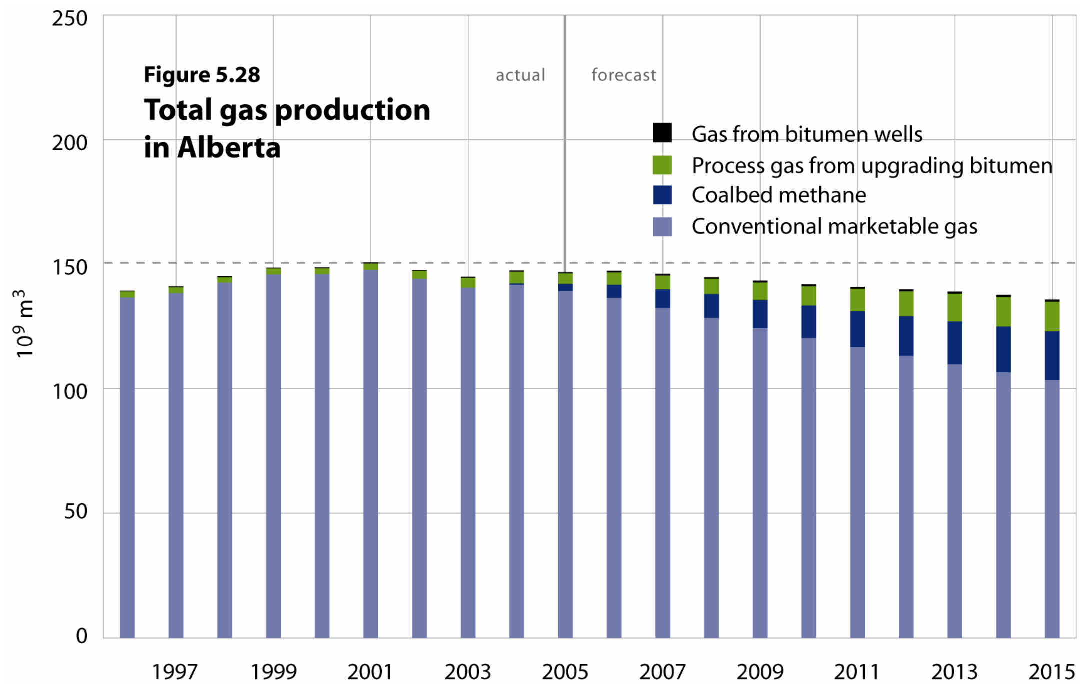


Figure 5.28
Total gas production in Alberta

Table 5.9. Commercial natural gas storage pools as of December 31, 2005

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2005 (10^6 m^3)	Withdrawal volumes, 2005 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	980	957
Countess Bow Island N & Upper Mannville M5M	EnCana Gas Storage	817	23 950	783	583
Crossfield East Elkton A & D	CrossAlta Gas Storage & Services Ltd.	1 197	14 790	923	1 031
Hussar Glauconitic R	Husky Energy	423	5 635	179	197
McLeod Cardium A	Pacific Corp Energy Canada Ltd.	986	16 900	559	608
McLeod Cardium D	Pacific Corp Energy Canada Ltd.	282	4 230	207	197
Sinclair Gething D & Paddy C	EnCana Gas Storage	282	5 634	309	258
Suffield Upper Mannville I & K, and Bow Island N & BB & GG	EnCana Gas Storage	2 395	50 715	1 964	1 863

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 U.S. allows for gas to move to areas of the U.S. 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 5.29**.

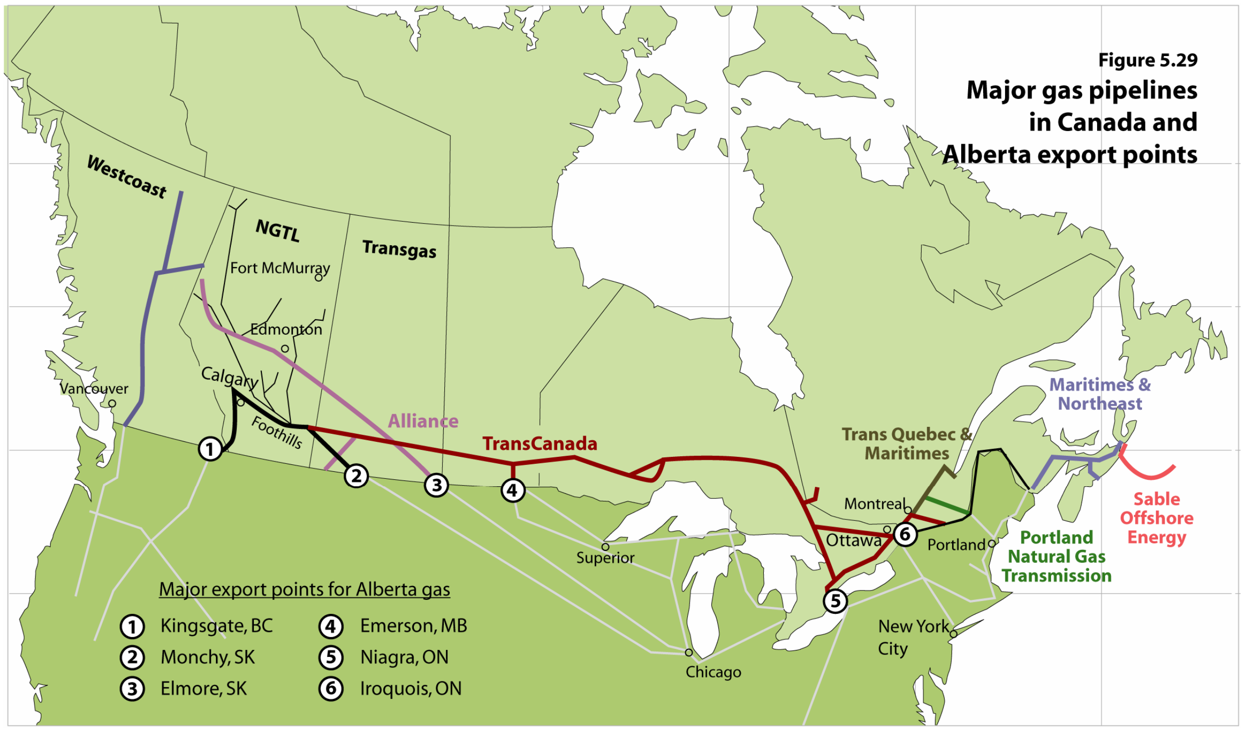


Figure 5.30 illustrates the breakdown of marketable natural gas demand in Alberta by sector. By the end of forecast period, domestic demand will reach 51.0 10^9 m^3, compared to 38.8 10^9 m^3 in 2005, representing 42 per cent of total natural gas production.

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 following 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 263 10^9 m^3 of surplus natural gas calculated using the 2005 remaining established reserves number. This represents a 23 per cent increase in surplus over the year 2004. The increase in surplus is attributed to a decline in the remaining permit commitments by 7.5 per cent. **Figure 5.31** illustrates historical "available for permitting" volumes from 1996 to 2005.

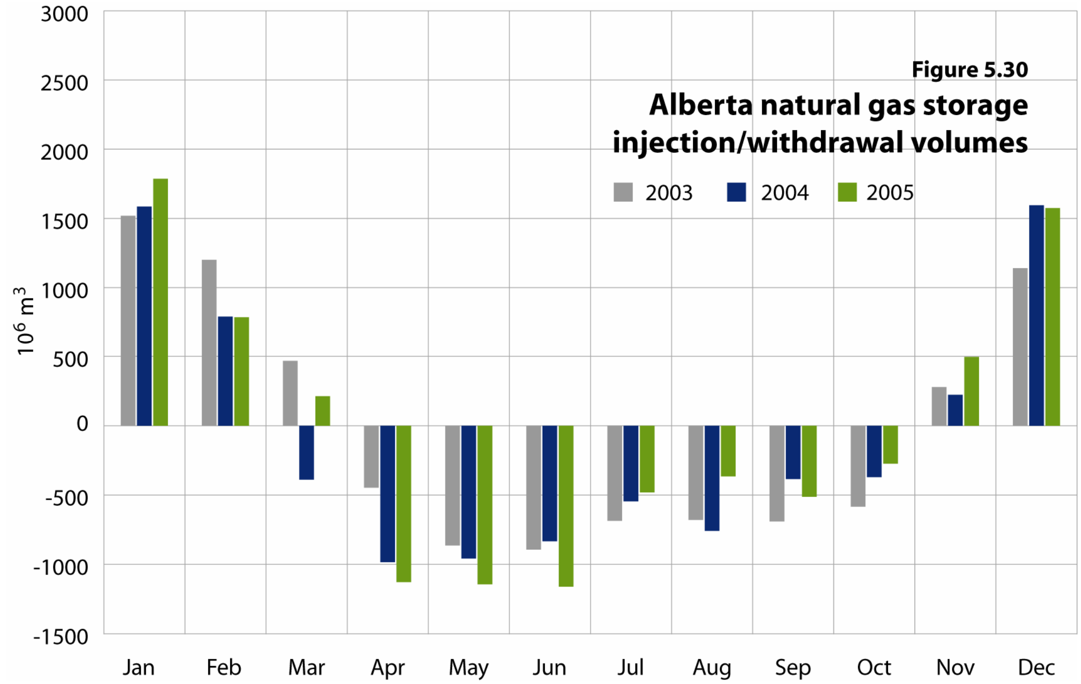


Figure 5.30
Alberta natural gas storage injection/withdrawal volumes

Table 5.10. Estimate of gas reserves available for inclusion in permits as at December 31, 2005

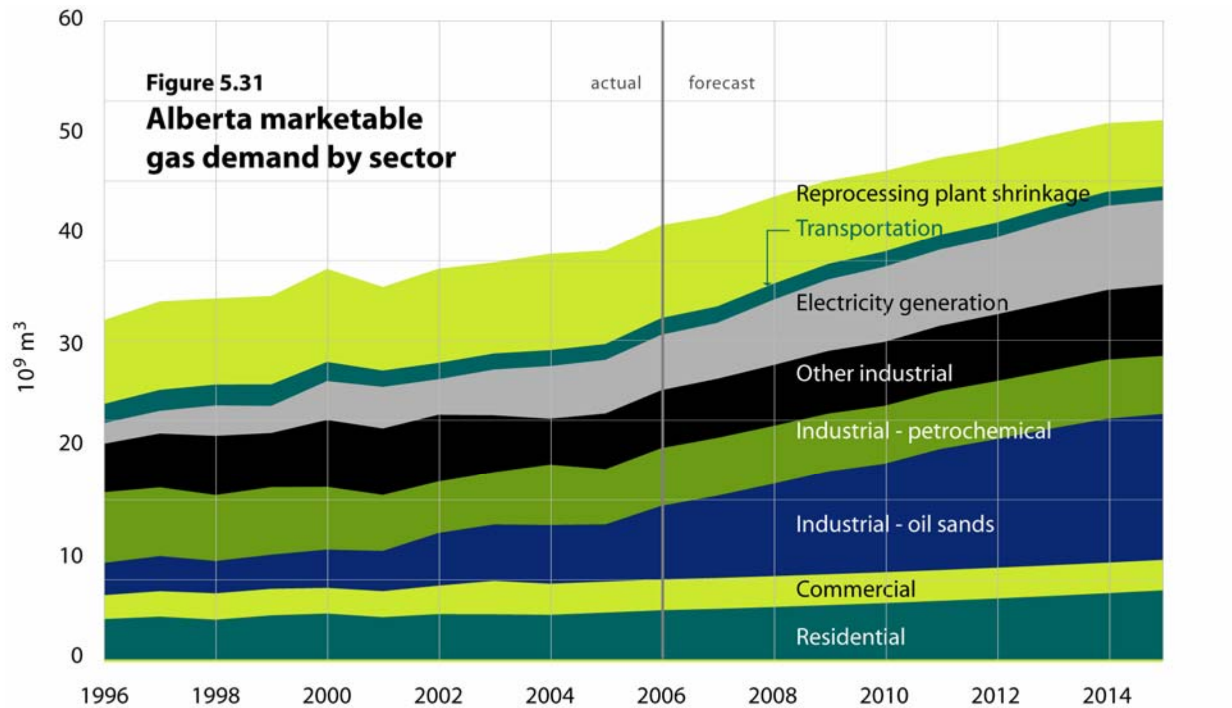
	10^9 m^3 at 37.4 MJ/m^3
Reserves (as at year-end 2005)	
1. Total remaining established reserves[a]	1 164
Alberta Requirements	
2. Core market requirements[b]	102
3. Contracted for non-core markets[b]	105
4. Permit-related fuel and shrinkage	63
Permit Requirements	
5. Remaining permit commitments[c]	631
6. Total requirements	901
Available	
7. Available for permits	263

[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 36.2 per cent under short-term permits and 63.8 per cent under long-term permits.

Residential gas requirements are expected to grow moderately over the forecast period at an average annual rate of 4.0 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.

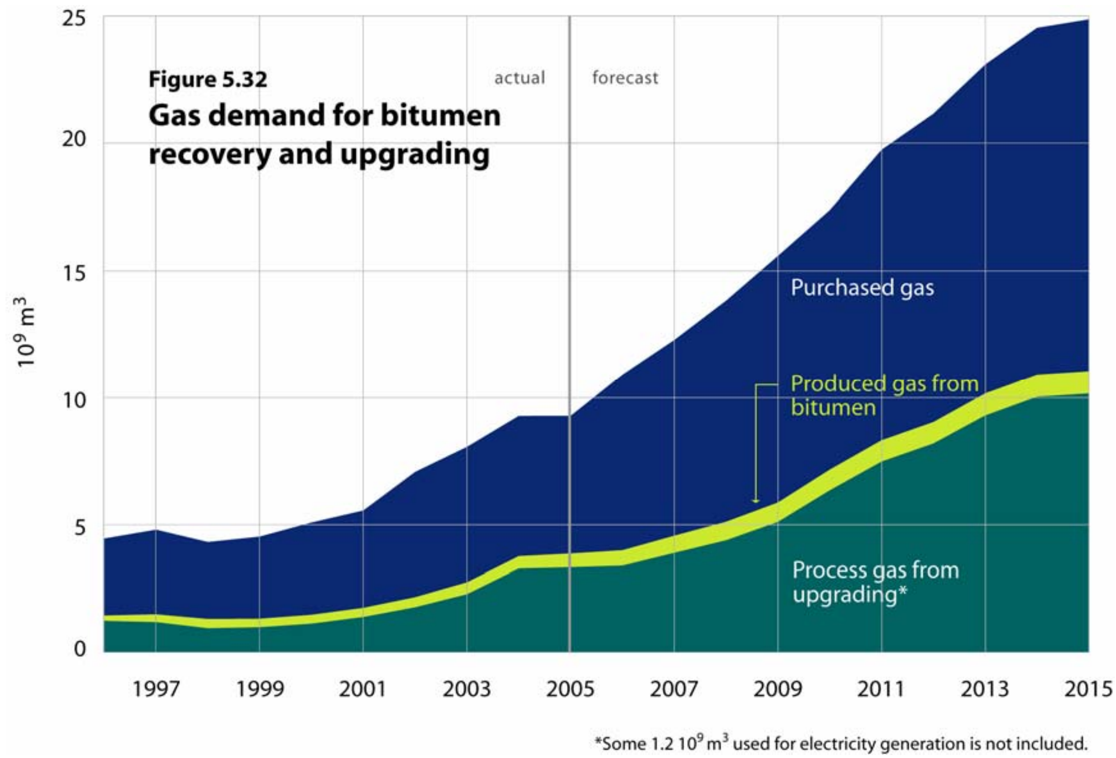


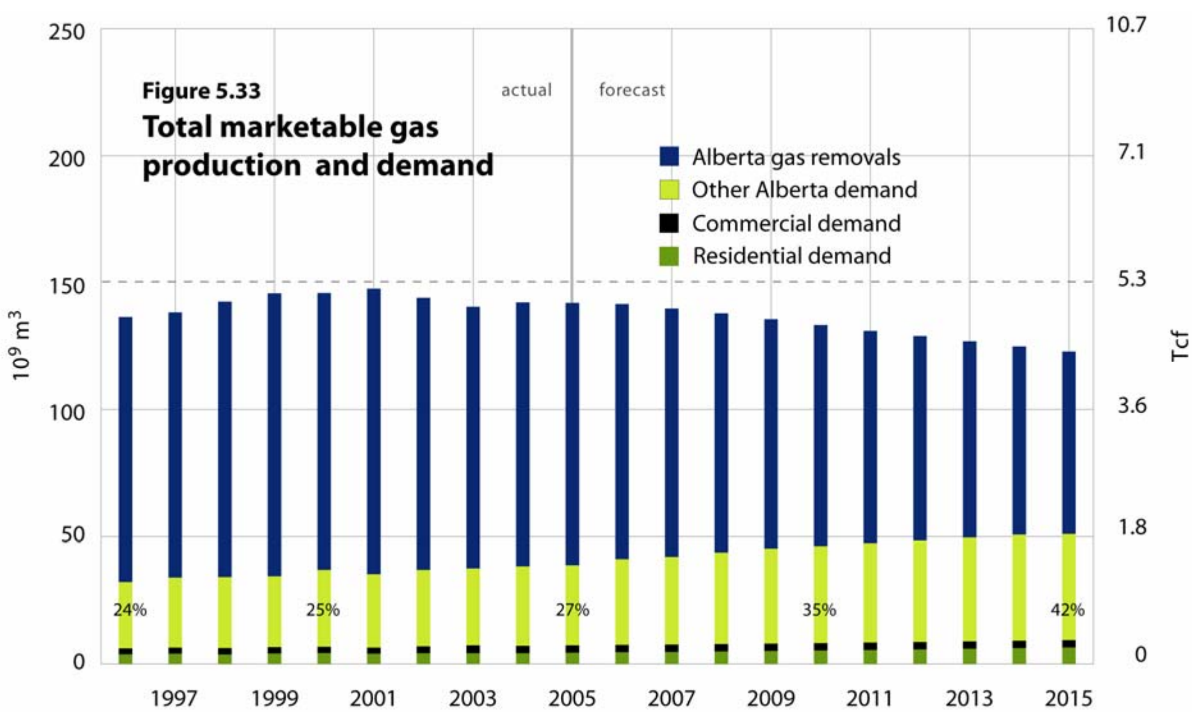
The significant increase in Alberta demand is due to increased development in the industrial sector. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil, shown in **Figure 5.32**, are expected to increase annually from 5.4 10^9 m^3 in 2005 to 13.8 10^9 m^3 by 2015. 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 5.32.** Some 1.2 10^9 m^3 of additional process gas is used by an electricity cogeneration unit to produce electricity and steam for oil sands operations.

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. Opti/Nexen will be employing technology that will produce synthetic gas by burning ashphaltines in its new bitumen upgrader expected to start up in 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 5.1 10^9 m^3 in 2005 to 8.0 10^9 m^3 by 2015. Electricity demand can be met from existing electricity plants and plants announced to be built over the forecast period.

Figure 5.33 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 2005, some 27 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 42 per cent of total natural gas production.





Gas production in Alberta may be higher than that forecast should commercial production of gas from the Mannville coal seams be accelerated. At this time, Mannville CBM production is largely at the pilot project stage, 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 2005 are summarized in Tables 6.1 and 6.2. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2005 production.

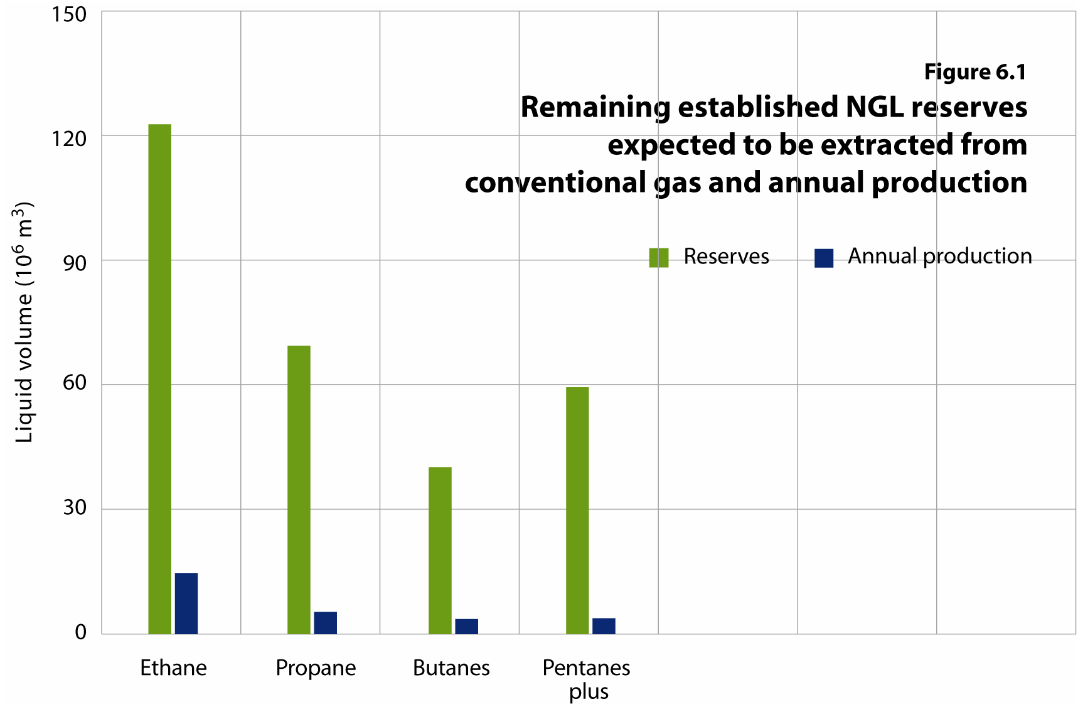
Table 6.1. Established reserves and production of extractable NGLs as of December 31, 2005 (10^6 m^3 liquid)

	2005	2004	Change
Cumulative net production[a]			
Ethane	225.7	211.1	+14.6
Propane	239.9	231.2	+8.7[b]
Butanes	138.0	132.4	+5.6[b]
Pentanes plus	312.4	303.6	+8.8[b]
Total	916.0	878.3	+37.3
Remaining (expected to be extracted)			
Ethane	120.7	122.9	-2.2
Propane	69.4	71.3	-1.9
Butanes	40.1	41.5	-1.4
Pentanes plus	59.3	59.3	0.0
Total	289.5	295.0	-5.5

[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*.

Table 6.2. Reserves of NGLs as of December 31, 2005 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	182.4	81.4	44.4	59.3	367.5
Liquids expected to remain in dry marketable gas	61.7	12..0	4.3	0	78.0
Remaining established recoverable from					
Field plants	35.3	39.9	26.1	52.9	154.2
Straddle plants	79.3	27.9	13.0	5.9	126.1
Solvent floods	6.1	1.6	1.0	0.5	9.2
Total	120.7	69.4	40.1	59.3	289.5

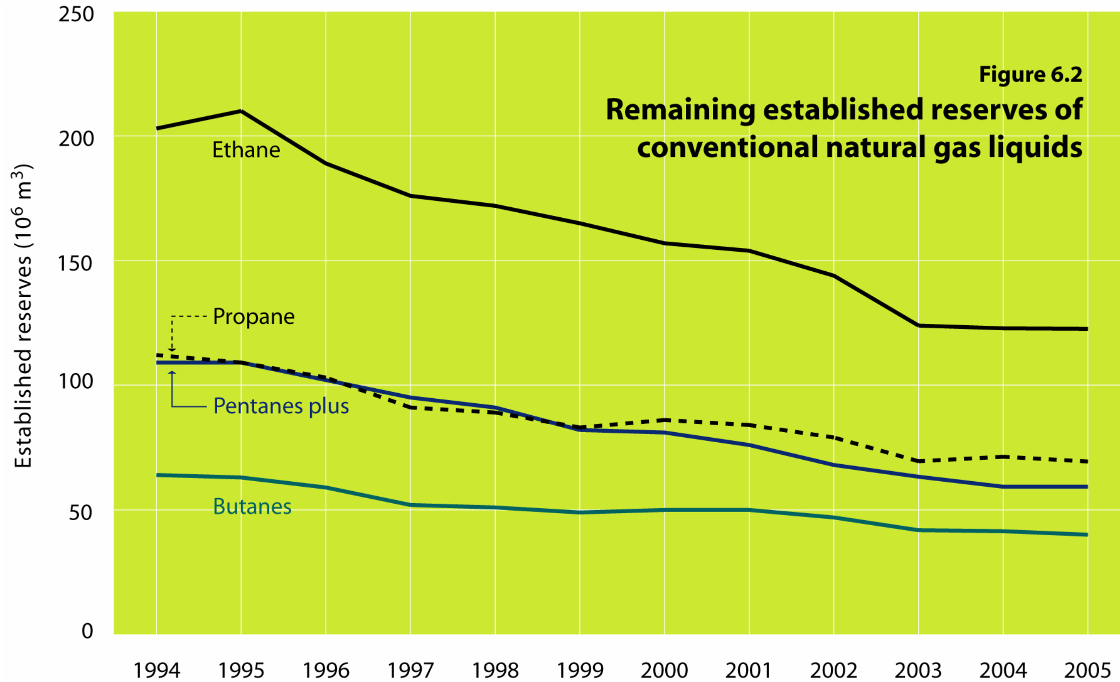


6.1.2 Ethane

As of December 31, 2005, the EUB estimates remaining established reserves of extractable ethane to be 120.7 million cubic metres (10^6 m^3) in liquefied form. This estimate includes 6.1 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. This year the ethane volume remaining in solvent floods represents about 5.0 per cent of the total ethane reserves, which is the same as last year. Presently there are only six pools that are still actively injecting solvent, the largest being the Rainbow Keg River F and Judy Creek Beaverhill Lake A pools.

As shown in Table 6.2, there is an additional 61.7 10^6 m^3 (liquid) of ethane 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 2005, the extraction of specification ethane was 14.6 10^6 m^3, compared to 14.7 10^6 m^3 in 2004. Although the EUB believes that ethane extraction at crude oil refineries and at plants producing synthetic crude oil might become viable in the future, it has not attempted to estimate the prospective reserves from those sources.

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.8, 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 five largest fields, Caroline, Ferrier, Pembina, Wild River, and Willesden Green, account for 15.6 per cent of total ethane reserves.



6.1.3 Other Natural Gas Liquids

As of December 31, 2005, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 69.4 10^6 m^3, 40.1 10^6 m^3, and 59.3 10^6 m^3 respectively. The overall changes in the reserves during the past year are shown in Table 6.2. Appendix B, Table B.9, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The seven largest fields—Ansell, Brazeau River, Caroline, Ferrier, Kaybob South, Pembina, and Willesden Green—account for about 32.5 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 2005, propane and butanes recovery at crude oil refineries was 0.4 10^6 m^3 and 1.3 10^6 m^3 respectively.

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 about 50 per cent currently due to increased market demand. 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 182.6 billion (10^9) m^3, the EUB estimates remaining ultimate potential of liquid ethane to be 434 10^6 m^3. The other 30 per cent, or 52.3 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 502 10^6 m^3. This assumes that remaining ultimate potential as a percentage of initial ultimate potential is similar to that of marketable gas, which currently stands at 43.5 per cent.

6.2 Supply of and Demand for Natural Gas Liquids

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.

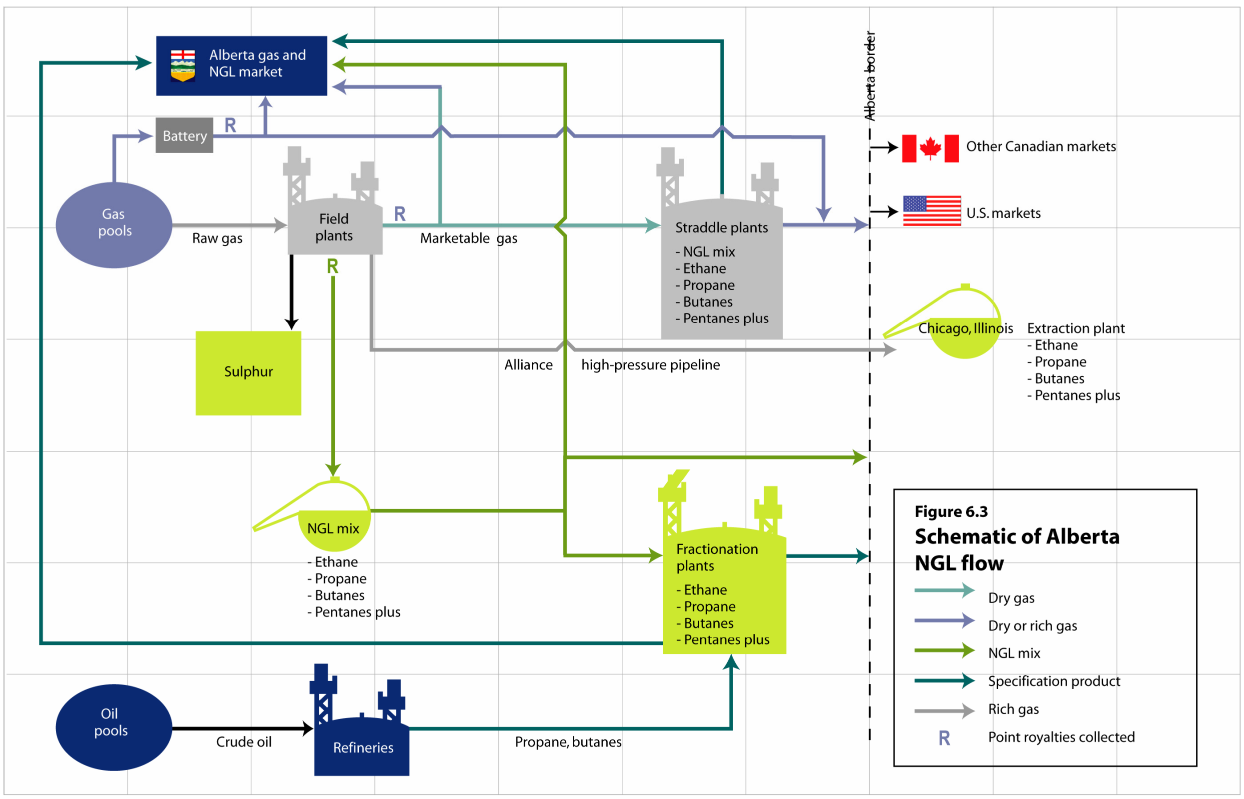


Figure 6.3
Schematic of Alberta NGL flow

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.

Table 6.3 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2005. 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 0.4 10^6 m^3 (1.0 10^3 m^3/d) and 1.2 10^6 m^3 (3.4 10^3 m^3/d) respectively.

Table 6.3. Ethane extraction volumes at gas plants in Alberta, 2005

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	1.1	8
Fractionation plants	3.1	21
Straddle plants	10.4	71
Total	14.6	100

For the purpose of forecasting ethane and other NGLs, the richness and gas production volumes from established and new reserves 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 2005, ethane volumes extracted at Alberta processing facilities remained at 2004 levels of 40.1 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 6.4 shows the volumes of specification ethane extracted at the three types of processing facilities during 2005.

It is expected that recovered ethane volumes will increase slightly to 41.6 thousand (10^3) m^3/d in 2006 and hold there for the remainder of the forecast period, as shown in **Figure 6.4**. Current processing plant capacity for ethane in Alberta 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, 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 2015 for ethane, propane, butanes, and pentanes plus respectively. 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.

Table 6.4. Liquid production at gas plants in Alberta, 2005 and 2015

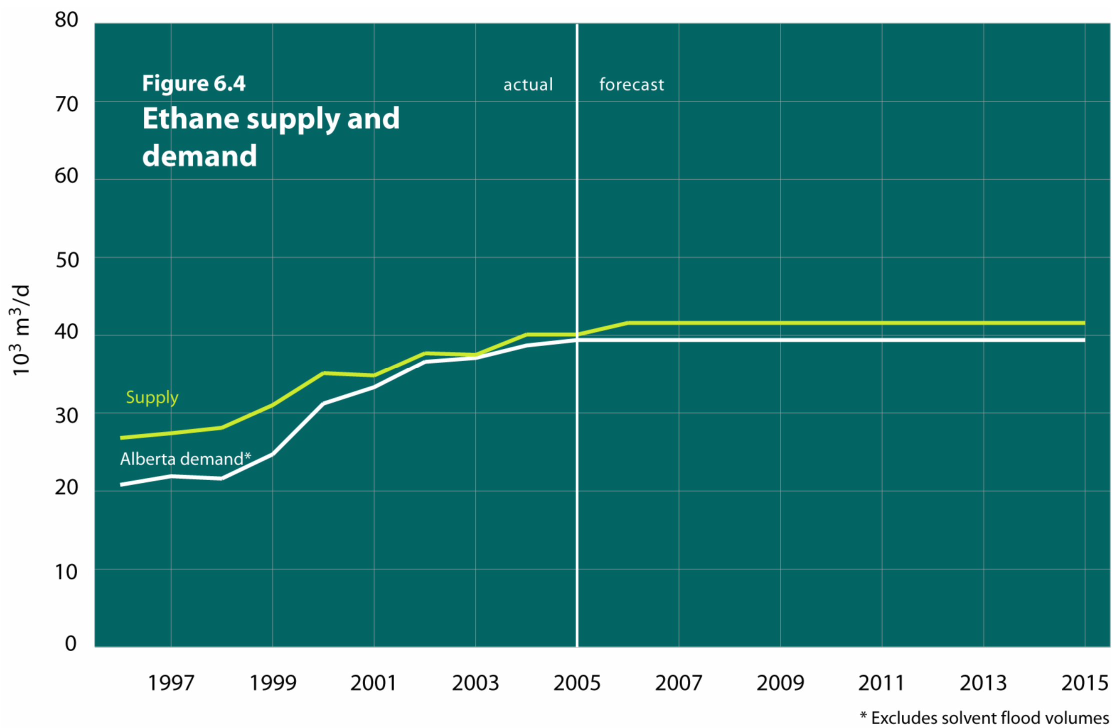
	2005			2015		
Gas Liquid	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)
Ethane	14.6	40.1	105	14.8	40.6	143
Propane	8.3	22.7	59	6.6	18.1	59
Butanes	4.6	12.6	32	3.6	9.9	32
Pentanes plus	8.2	22.5	59	6.1	16.78	59

6.2.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in 2005, about 96 per cent was used in Alberta as feedstock, while the remainder was removed from the province. 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. Small volumes of ethane are exported from the province by the Cochin pipeline under ethane removal permits.

The petrochemical industry in North America was challenged in 2005 by high and extremely volatile energy prices. Since ethane prices follow natural gas prices, feedstock costs fluctuated wildly throughout the year. Nonetheless, the Alberta ethylene industry 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 39.4 10^3 m^3/d for 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, such as propane, 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.

As conventional gas production declines, the Alberta petrochemical sector faces a tight ethane feedstock supply. Market conditions may evolve so that the petrochemical industry may consider an additional source of ethane from process gas at Fort McMurray oil sands upgraders. The majority of the process gas produced from oil sands upgraders is presently being used as fuel for oil sands operations. Process gas contains ethane, ethylene, and other light hydrocarbons. 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.

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.

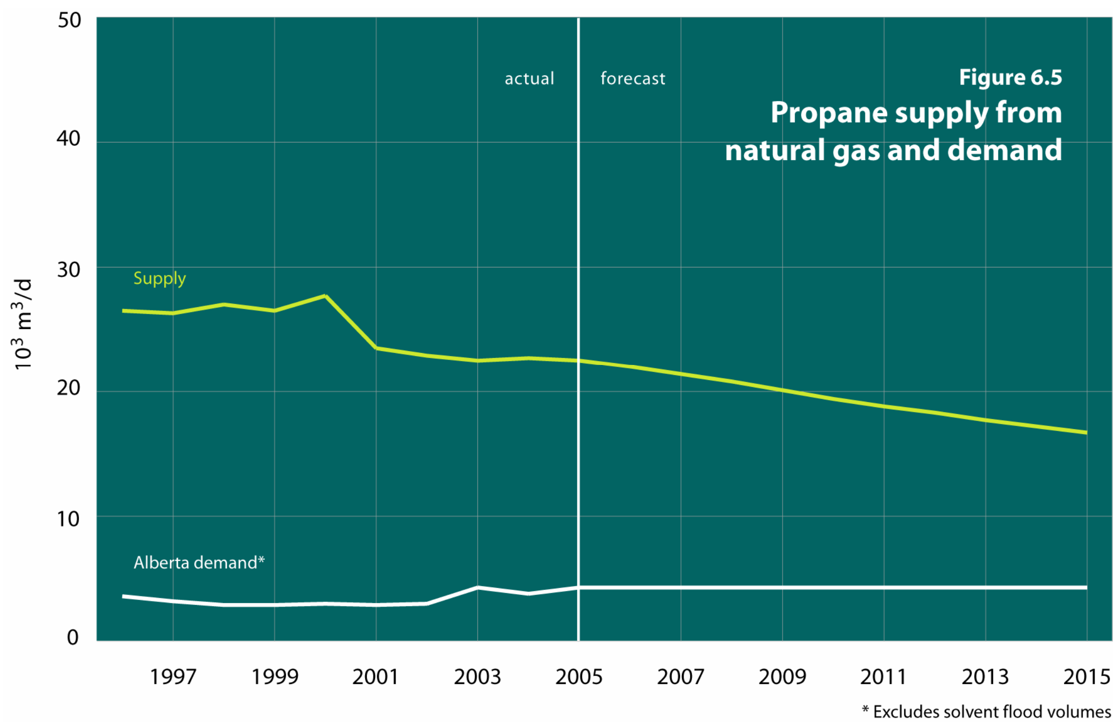
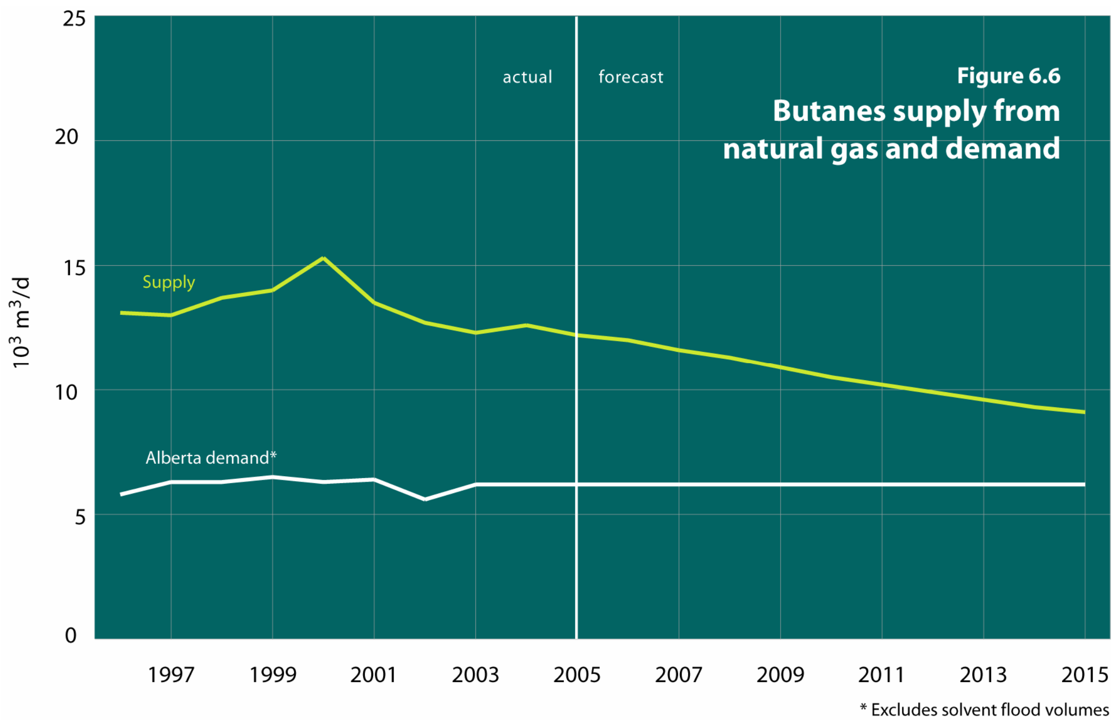
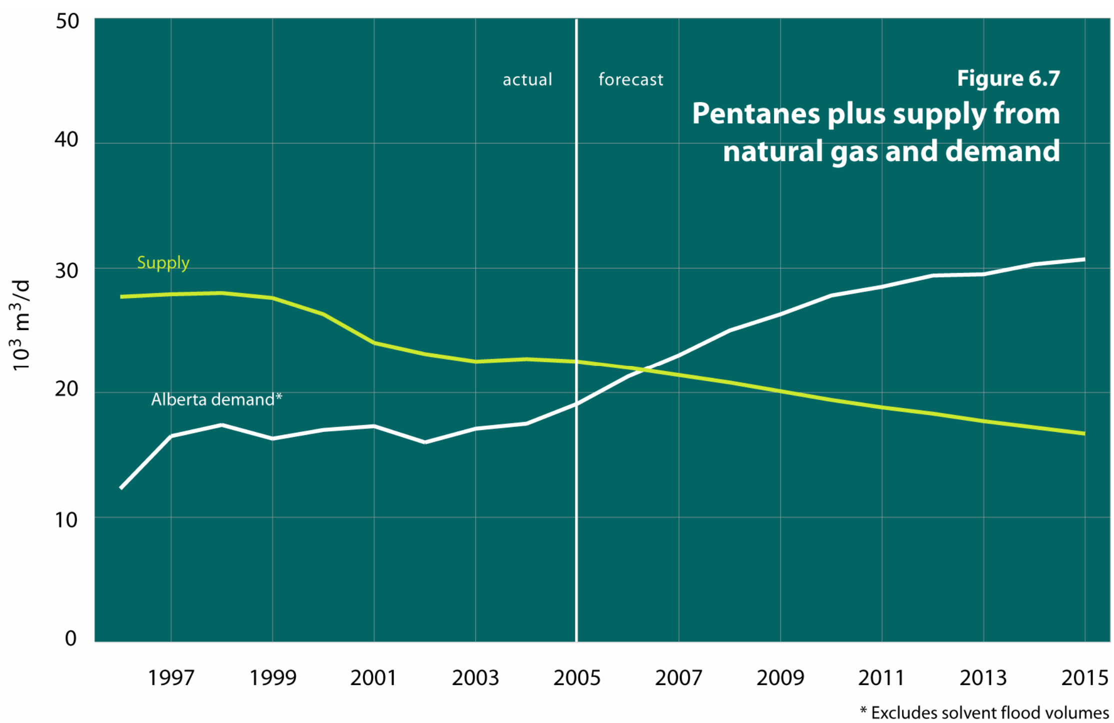


Figure 6.6 shows Alberta demand for butanes compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta demand for butanes will increase as refinery requirements grow. Butanes are 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 19.1 10^3 m^3/d to 30.7 10^3 m^3/d. This increased demand results largely in response to an anticipated 12.5 10^3 m^3/d increase in diluent required for bitumen transport, rising to 28.1 10^3 m^3/d in 2015 from 15.6 10^3 m^3/d in 2005. Conversely, the diluent requirement for transport of heavy crude is expected to decline from 2.7 10^3 m^3/d in 2005 to 1.8 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 as early as 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. Specifically,

- EnCana Corporation plans to import up to 4.0 10^3 m^3/d of offshore condensate by early 2006 to help transport its growing oil sands production to U.S. markets. With access to the Kitimat, British Columbia, terminal facility, EnCana expects to import diluent and transport it by rail to an Alberta pipeline connection that feeds its oil sands operation.

- Enbridge Inc. 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 commence construction by 2008 and begin service by 2010.

- Kinder Morgan Canada Inc. (formerly Teresen Pipelines Inc.) and Pembina Pipeline Corporation have also announced plans to develop and construct a new pipeline system designed to transport 15.9 10^3 m^3/d of condensate from Kitimat to Edmonton. The Spirit Pipeline is expected to make extensive use of existing infrastructure and be ready for service by early 2009.

- Small volumes of pentanes plus from the U.S. 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 naptha 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, 2005, to be some 89.0 million tonnes (10^6 t). 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, 2005 (10^6 t)

	2005	2004	
Initial established reserves from			
Natural gas	261.9	251.5	+10.4
Crude bitumen[a]	67.7	67.7	0.0
Total	329.6	319.2	+10.4
Cumulative net production from			
Natural gas	223.7	218.4	+ 5.3
Crude bitumen[b]	16.9	15.7	+1.2
Total	240.6	234.1	+6.5
Remaining established reserves from			
Natural gas	38.2	33.1	+5.1
Crude bitumen[a]	50.8	52.0	-1.2
Total	89.0	85.1	+3.9

[a] Reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2005. 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 38.2 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2005. This estimate 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 261.9 10^6 t, this leaves 132.4 10^6 t yet to be established 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 the most notable change in sulphur reserves over the past year are Caroline, Crossfield East, and Ricinus West, which together added 5.3 10^6 t as a result of positive revisions to the Caroline and Crossfield East fields and the addition of Ricinus West (Tay River area).

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2005

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	3 210	5.9	223	302
Bighorn	3 048	6.6	241	327
Blackstone	6 243	10.7	887	1 202
Brazeau River	10 518	5.4	734	995
Burnt Timber	2 268	17.2	576	781
Caroline	13 525	17.9	4 035	5 471
Coleman	3 251	27.3	1 324	1 796
Crossfield	4 204	13.7	843	1 143
Crossfield East	6 021	32.7	3 738	5 069
Elmworth	11 124	2.3	302	410
Garrington	3 680	6.0	288	391
Hanlan	6 055	8.9	712	966
Jumping Pound West	4 893	6.6	411	557
Kaybob South	10 306	3.3	423	574
La Glace	2 312	6.5	177	240
Lambert	738	18.1	195	265
Limestone	6 632	10.2	887	1 203
Lone Pine Creek	1 754	6.9	151	205
Moose	3 015	12.5	497	674
Okotoks	2 427	32.2	1 540	2 088
Pembina	17 459	0.9	210	284
Pine Creek	5 755	5.4	385	523
Quirk Creek	1 384	9.6	177	240
Rainbow	6 902	1.9	172	233
Rainbow South	3 801	5.2	290	394
Ricinus West	2 673	33.0	1 575	2 136
Waterton	6 372	22.9	2 421	3 284
Wildcat Hills	5 924	3.0	202	274
Windfall	2 568	12.7	460	624
Subtotal	158 062	11.0	24 079	32 652
All other fields	961 699	0.4	4 080	5 552
Total		2.2	28 159	38 204

[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 5.1 billion cubic metres (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, then 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, and Albian Sands projects. The EUB has estimated the initial established sulphur reserves from these projects to be 67.7 10^6 t. A total of 16.9 10^6 t of elemental sulphur has been produced from these projects, leaving remaining established reserves of 50.8 10^6 t. During 2005, 1.2 10^6 t of elemental sulphur was produced from the three 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 2005, Alberta produced 6.6 10^6 t of sulphur, of which 5.3 10^6 t was derived from sour gas, 1.2 10^6 t from upgrading of bitumen to SCO, and just 12 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 5.3 10^6 t in 2005 to 4.0 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 1.2 10^6 t by the end of the forecast period. **Figure 7.2** shows sulphur production from oil sands upgrader operations for 2003, 2004, and 2005. The Alberta refineries are also 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 12 10^3 t in 2005 to 54 10^3 t by 2015. Total sulphur production is expected to reach 8.2 10^6 t by the end of forecast period.

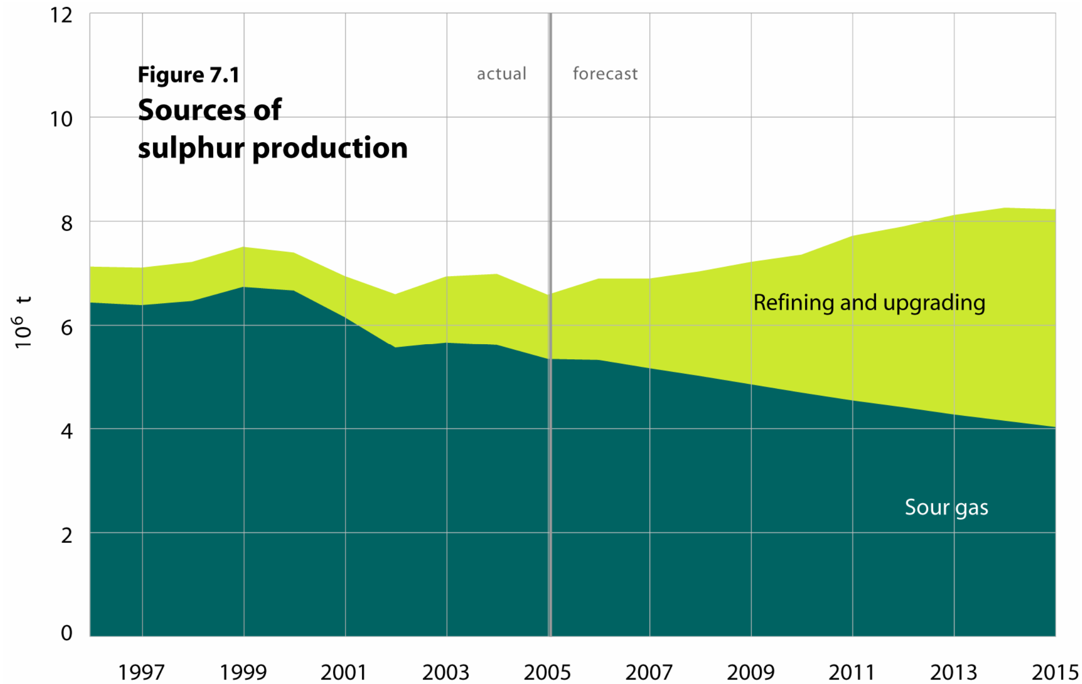


Figure 7.1
Sources of sulphur production
actual
forecast
Refining and upgrading
Sour gas
10^6 t
12
10
8
6
4
2
0
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015

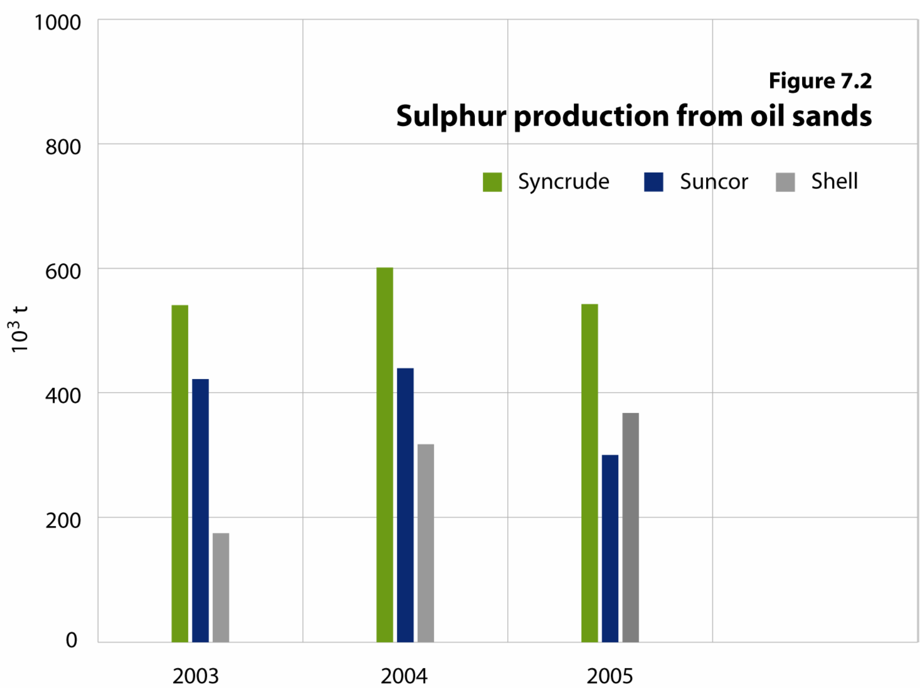


Figure 7.2
Sulphur production from oil sands
Syncrude
Suncor
Shell
10^3 t
1000
800
600
400
200
0
2003
2004
2005

7.2.2 Sulphur Demand

Demand for sulphur within the province in 2005 was similar to 2004 at about 250 10^3 t. 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. In the last four years, China has increased its sulphur imports from Canada substantially. **Figure 7.3** outlines the export volumes sent to markets outside of North America in the last three years. Clearly, China accounts for the majority of Canadian exports to foreign countries.

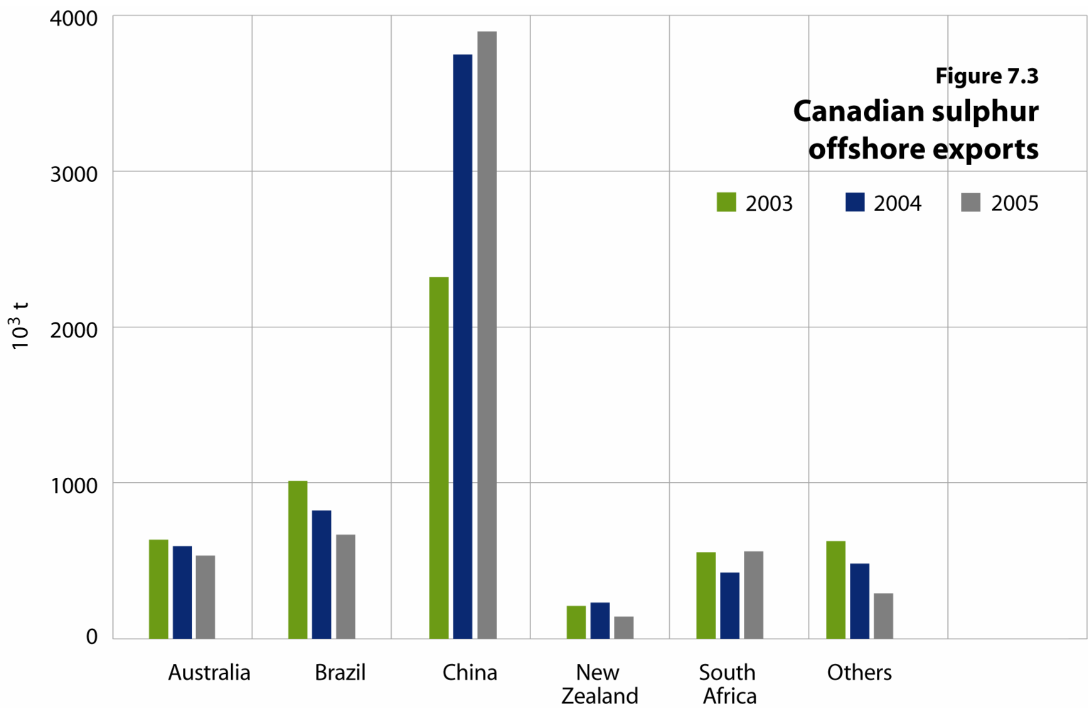
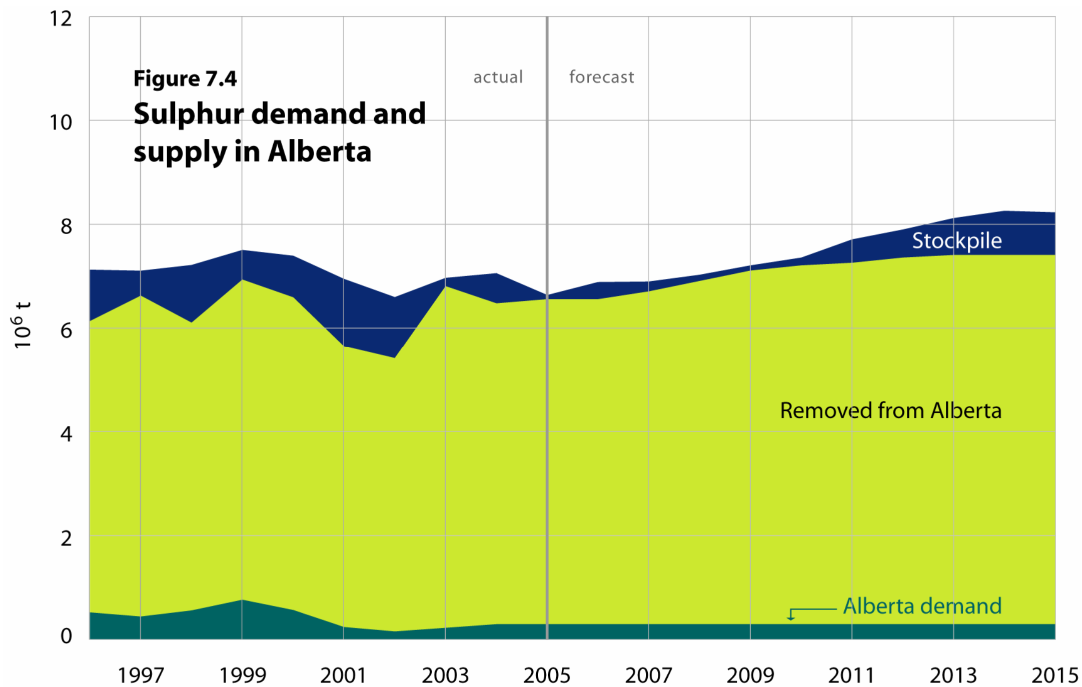


Figure 7.3
Canadian sulphur offshore exports

Increased global demand for sulphur resulted in a major price change, from Cdn$16/t in 2001 to $40/t in 2005. The export demand for sulphur is expected to continue to increase over the next few years. Demand for Alberta sulphur is expected to rise slowly, reaching 7.4 10^6 t per year by the end of the forecast period. **Figure 7.4** depicts the Alberta demand and sulphur removal.



7.2.3 Imbalances between Sulphur Supply and Demand

Because elemental sulphur (in contrast to sulphuric acid and the energy resources described in this document) 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, as was the case over the period 1985-1991, sulphur is withdrawn from stockpiles; if supply exceeds demand, as has been the case since 1992, sulphur is added to stockpiles. Sulphur stockpiles are expected to grow until markets recover from the current glut. Changes to the sulphur inventory are illustrated in **Figure 7.4** 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, 2005, to be 33.5 gigatonnes (Gt).[1] 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 2005. 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, 2005[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	0.222	0.589
Underground	5.06	0.738	0.106	0.632
Subtotal	6.83[c]	1.56[c]	0.328[d]	1.24[c]
High-volatile bituminous				
Surface	2.56	1.89	0.146	1.74
Underground	3.30	0.962	0.047	0.915
Subtotal	5.90[c]	2.88[c]	0.193[d]	2.69[c]
Subbituminous[e]				
Surface	13.6	8.99	0.677	8.31
Underground	67.0	21.2	0.068	21.1
Subtotal	80.7[c]	30.3[c]	0.745	29.6[c]
Total[c]	93.7[c]	34.8[c]	1.266	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.

[1] Giga = 10^9; 1 tonne = 1000 kilograms.

Minor changes in remaining established reserves from December 31, 2004, to December 31, 2005, resulted from increases in cumulative production. During 2005, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.004 Gt, 0.004 Gt, and 0.025 Gt respectively, a decrease for all three coal ranks from 2004.

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 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 2005.

Table 8.2. Established resources and reserves of raw coal under active development as of December 31, 2005

Rank Mine	Permit area (ha)	Initial in-place resources (Mt)[a]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[b] (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	9	145
Grande Cache	4 250	199	85	21	64
Subtotal	11 705	445	239	30	209
High-volatile bituminous					
Coal Valley	17 695	572	331	108	223
Subtotal	17 695	572	331	108	223
Subbituminous					
Vesta	2 410	69	54	41	13
Paintearth	2 710	94	67	40	27
Sheerness	7 000	196	150	66	84
Dodds	140	2	2	1	1
Keephills	150	0.5	0.5	0.04	0.5
Whitewood	3 300	193	120	76	44
Highvale	12 140	1 021	764	326	438
Genesee	7 320	250	176	53	123
Subtotal[b]	35 170	1 826	1 334	603	731
Total	64570	2843	1904	741	1 163

[a] Mt = megatonnes; mega = 10^6.
[b] 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.

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. **Figure 8.1** illustrates Alberta coal production history.

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 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 2005, eleven mine sites supplied coal in Alberta, as shown in Table 8.4. Together they produced 29.8 Mt of marketable coal. Subbituminous coal accounted for 87.3 per cent of the total, bituminous metallurgical 7.7 per cent, and bituminous thermal coal the remaining 5.0 per cent. The increase in coal production is mainly due to a substantial increase in subbituminous coal production at the Genesee mine.

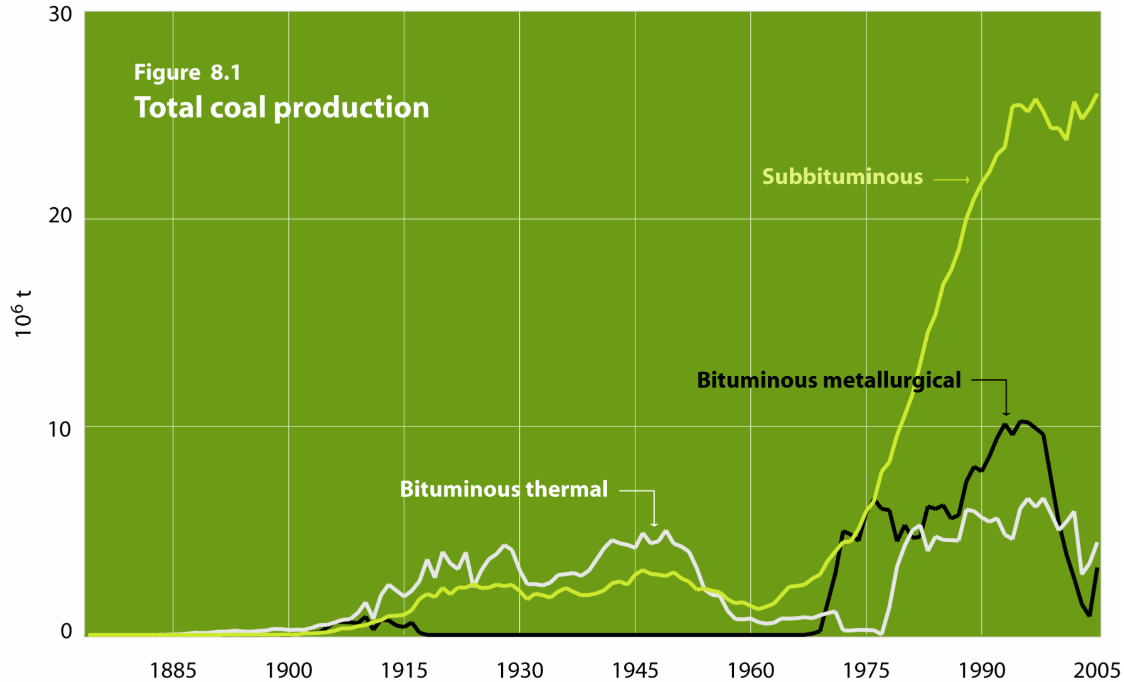


Figure 8.1
Total coal production
30
20
10
0
10^6 t
1885
1900
1915
1930
1945
1960
1975
1990
2005
Subbituminous
Bituminous metallurgical
Bituminous thermal

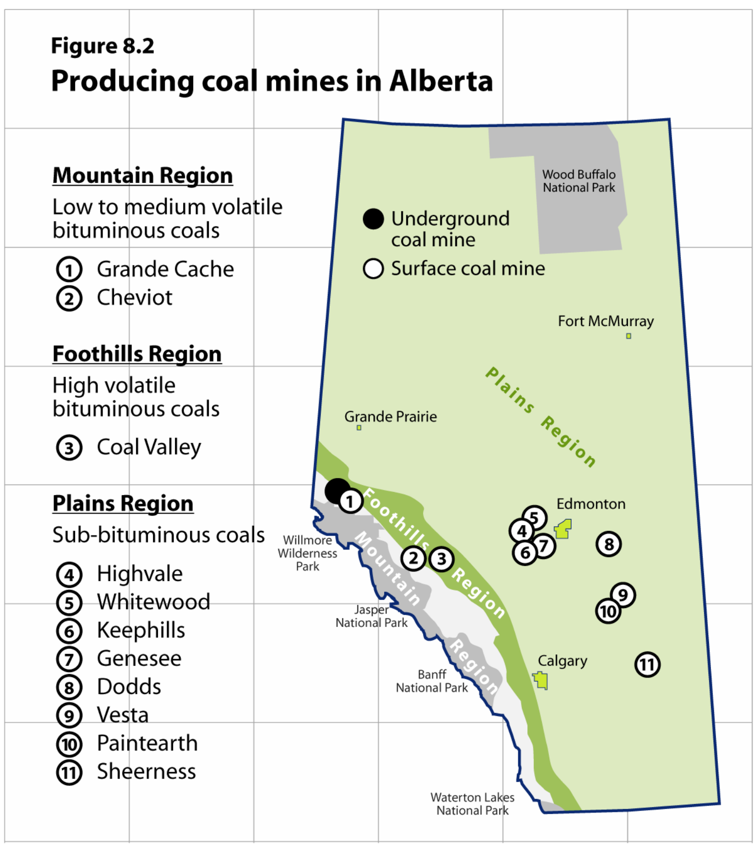


Figure 8.2
Producing coal mines in Alberta
Mountain Region
Low to medium volatile bituminous coals
1 Grande Cache
2 Cheviot
Foothills Region
High volatile bituminous coals
3 Coal Valley
Plains Region
Sub-bituminous coals
4 Highvale
5 Whitewood
6 Keephills
7 Genesee
8 Dodds
9 Vesta
10 Paintearth
11 Sheerness
Underground coal mine
Surface coal mine
Wood Buffalo National Park
Fort McMurray
Plains Region
Grande Prairie
Edmonton
Foothills Region
Mountain Region
Willmore Wilderness Park
Jasper National Park
Banff National Park
Calgary
Waterton Lakes National Park

Table 8.4. Alberta coal mines and marketable coal production in 2005

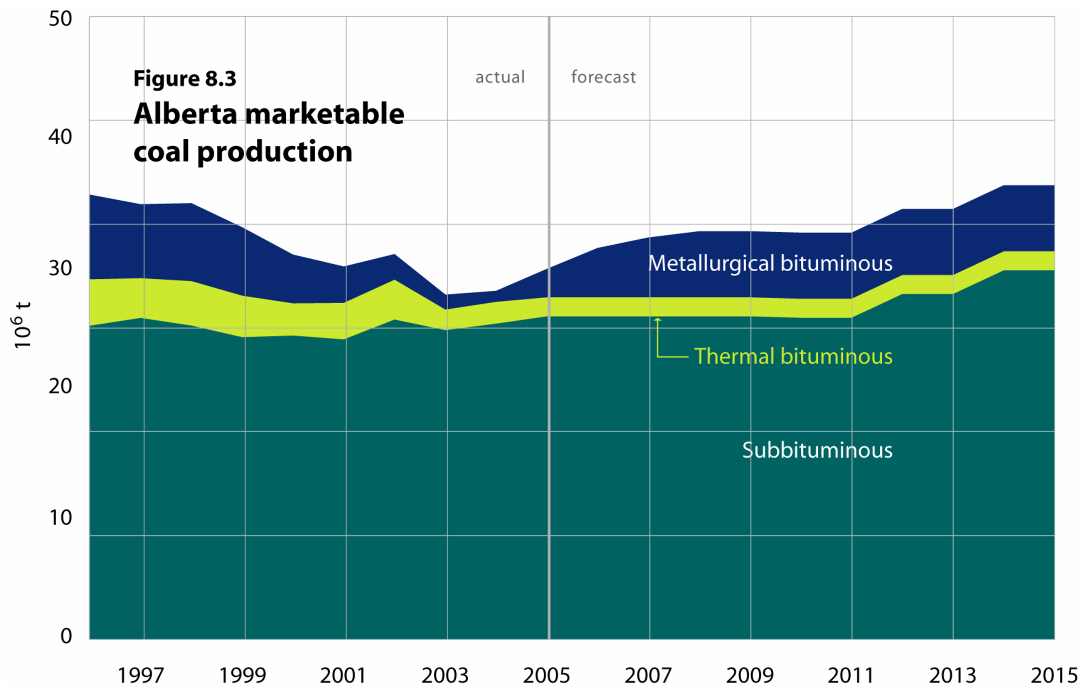
Operator/owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Luscar Ltd. / EPCOR Generation	Genesee	Genesee	5.4
Luscar Ltd.	Sheerness	Sheerness	3.7
	Paintearth	Halkirk	1.2
	Vesta	Cordel	1.9
Luscar Ltd./TransAlta Utilities Corp.	Highvale	Wabamun	12.5
	Whitewood	Wabamun	1.2
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.08
Keephills Aggregate Ltd.	Gravel pit	Burtonsville	0.03
Bituminous metallurgical coal			
Cardinal River Coals Ltd./Elk Valley	Cheviot	Mountain Park	1.5
Grande Cache	Grande Cache	Grande Cache	0.8
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.5
Total			29.8

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. In 2005, subbituminous coal production increased due to the commissioning of the Genesee 3 power generation plant, with 450 megawatt (MW) capacity. Two smaller power generation units at Wabamun were decommissioned at the end of 2004, which somewhat offset the above increase.

Three power generation units, each with 450 to 500 MW capacity, are planned to be in service within the forecast period. All of these units will be fuelled by subbituminous coal.

Although metallurgical grade coal underlies much of the mountain region, very few areas have been sufficiently explored to identify economically recoverable reserves at current prices. It is unlikely that any additional mines will come on stream over the next decade.

In early 2003 Alberta's two producing thermal bituminous coal mines, Luscar and Coal Valley mines, were negatively impacted by declining export thermal coal prices. However, recent record high crude oil prices have resulted in improved economics in the coal markets; hence, thermal coal production capacity at the Coal Valley mine is expected to double by mid-2006. The Luscar mine at Obed continues to be suspended. Historical and 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. In March 2005, the Genesee Generating Station (Phase 3) started commercial operations, requiring additional subbituminous coal mining capacity at the adjacent Genesee mine. This new generation unit is considered the most advanced coal-fired plant ever built in Canada, equipped with clean air technologies that will offset carbon dioxide emissions to the level of a natural gas combined-cycle plant.

Subbituminous coal production is expected to increase over the forecast period, with potentially three units to be commissioned in the second half of the period to meet the demand for additional electrical generating capacity. Beyond that, it is expected that the demand for subbituminous coal will level off, barring strong increases in electricity demand.

Although the North American steel industry has been going through reorganization and production declines, Asian steel production has been steady in recent years. Alberta’s metallurgical coal primarily serves the latter market, 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, rising steel consumption, and a strong demand in the Pacific Rim countries.

Appendix A Terminology, Abbreviations, and Conversion Factors

1.1 Terminology

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 of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in a reservoir before any volume 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.

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 Conventional Crude Oil and Natural Gas Reserves

Table B.1. Conventional crude oil reserves as of each year-end (10^6 m^3)

	Initial established						
Year	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

Table B.2. Conventional crude oil reserves by geological period as of December 31, 2005

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	2 236	0	378	0	51	-	17	-
Lower	1 250	1 994	230	345	28	65	18	17
Jurassic	106	107	20	35	3	4	19	33
Triassic	378	28	71	3	12	1	19	11
Permian	14	0	8	0	0	-	56	
Mississippian	466	68	89	8	6	1	19	12
Devonian								
Upper	2 545	29	1 157	3	55	1	45	10
Middle	981	1	358	0	26	-	36	-
Other	64	11	6	0	2		9	
Total	8 040	2 238	2310	394	183	72	29	18

Table B.3. Distribution of conventional crude oil reserves by formation as of December 31, 2005

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	293	46	10	3	2	4
Chinook	6	1	0	0	0	0
Cardium	1 800	298	34	18	11	13
Second White Specks	35	4	1	0	0	0
Doe Creek	84	20	5	1	1	2
Dunvegan	18	2	0	0	0	0
Lower Cretaceous						
Viking	340	67	5	3	2	2
Upper Mannville	2 043	317	57	20	12	22
Lower Mannville	861	191	31	8	7	12
Jurassic	213	55	7	2	2	3
Triassic	406	74	13	4	3	5
Permian-Belloy	14	8	0	0	0	0
Mississippian						
Rundle	334	69	3	3	3	1
Pekisko	91	15	2	1	1	1
Banff	109	13	2	1	0	1
Upper Devonian						
Wabamun	68	7	1	1	0	0
Nisku	473	210	12	5	8	5
Leduc	828	504	10	8	19	4
Beaverhill Lake	1 032	404	25	10	15	10
Slave Point	173	35	8	2	1	3
Middle Devonian						
Gilwood	310	134	8	3	5	3
Sulphur Point	9	1	0	0	0	0
Muskeg	61	10	1	1	0	0
Keg River	502	180	14	5	7	5
Keg River SS	44	18	1	0	1	0
Granite Wash	56	14	2	1	1	1

Table B.4. 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/m³
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

[a] At field plant.

Table B.5. Geological distribution of established natural gas reserves, 2005

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	155	90	32	20	1.9	2.9
Milk River & Med Hat	919	538	238	11.7	11.5	21.3
Cardium	282	96	34	3.6	2.1	3.0
Second White Specks	29	17	11	0.4	0.4	1.0
Other	281	159	55	3.6	3.4	4.9
Subtotal	1669	900	370	21.3	19.3	33.1
Lower Cretaceous						
Viking	414	282	56	5.3	6.0	5.0
Basal Colorado	33	27	2	0.4	0.6	0.2
Mannville	1936	1275	287	24.7	27.3	25.6
Other	449	288	85	5.7	6.2	7.6
Subtotal	2833	1873	430	36.1	40.1	38.4
Jurassic						
Jurassic	67	41	10	0.9	0.9	0.9
Other	106	65	13	1.4	1.4	1.2
Subtotal	173	107	26	2.2	2.3	2.1
Triassic						
Triassic	216	128	43	2.7	2.7	3.8
Other	46	31	5	0.6	0.7	0.4
Subtotal	262	159	48	3.3	3.4	4.2
Permian						
Belloy	8	5	1	0.1	0.1	0.1
Subtotal	8	5	1	0.1	0.1	0.1
Mississippian						
Rundle	926	579	86	11.8	12.4	7.7
Other	338	228	28	4.3	4.9	2.5
Subtotal	1264	808	114	16.1	17.3	10.2
Upper Devonian						
Wabamun	253	124	24	3.2	2.7	2.1
Nisku	122	59	15	1.6	1.3	1.3
Leduc	464	244	15	5.9	5.2	1.3
Beaverhill Lake	493	229	38	6.3	4.9	3.4
Other	185	110	15	2.4	2.4	1.3
Subtotal	1581	766	107	19.3	16.4	9.4
Middle Devonian						
Sulphur Point	15	9	3	0.2	0.2	0.3
Muskeg	6	2	1	0.1	0.0	0.1
Keg River	65	26	12	0.8	0.6	1.1
Other	31	14	3	0.4	0.3	0.3
Subtotal	120	51	19	1.5	1.1	1.8
Confidential						
Subtotal	2	2	2	0.0	0.0	0.0
Total	7849 (279)[a]	4672 (166)[a]	1120 (40)[a]	100.00	100.00	100.00

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

Table B.6. Natural gas reserves of retrograde pools, 2005

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	35
Brazeau River Nisku M	1 832	76.22	140	0.75	0.60	42	41.36	1 013	10
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435	1 561
Brazeau River Nisku S	1921	54.64	105	0.80	0.57	36	41.38	873	58
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200	272
Caroline Beaverhill Lake A	61 977	49.95	3 096	0.84	0.76	621	36.51	17 000	3 295
Carson Creek Beaverhill Lake B	11 350	55.68	632	0.90	0.39	342	41.09	8 330	64
Harmattan East Rundle	44 912	50.26	2 257	0.79	0.26	1 319	41.60	31 703	6 752
Harmattan-Elkton Rundle C	37 757	46.96	1 773	0.86	0.27	1 526	58.19	26 226	3 853
Kakwa A Cardium A	4 069	55.40	225	0.85	0.32	130	52.63	2470	1 816
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 639	39.68	41 300	1 205
Ricinus Cardium A	10 969	58.59	643	0.85	0.32	372	42.0	8 867	382
Valhalla Halfway B	6 331	53.89	341	0.80	0.33	183	40.00	4 572	3 031
Waterton Rundle-Wabamun A	86 670	48.74[a]	4 224	0.95	0.35	2 100	39.23	53 519	1 022
Wembley Halfway B	10 183	53.89	549	0.67	0.33	246	42.41	5 800	4 538

(continued)

Table B.6. Natural gas reserves of retrograde pools, 2005 (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	26
Westpem Nisku E	1 160	66.05	77	0.90	0.54	32	44.76	709	161
Windfall D-3 A	25 790	53.42	1 338	0.60	0.53	425	44.92	9 462	1 100

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

Table B.7. Natural gas reserves of multifield pools, 2005

Multifield pool / Field and pool	Remaining established reserves (10^6 m^3)
Belly River Pool No. 1	
Bashaw Edmonton & Belly River MU#1	155
Nevis Belly River C,O & Z	166
Total	321
Belly River Pool No. 6	
Aerial Belly River III	19
Ardenode Edmonton & Belly River MU#1	1 667
Brant Edmonton & Belly River MU#1	578
Centron Edmonton & Belly River MU#1	943
Cessford Belly River III	170
Crossfield Belly River III	69
Dalmead Edmonton & Belly River III	67
Entice Edmonton & Belly River MU#1	962
Gayford Edmonton & Belly River MU# 2	214
Ghost Pine Belly River III	263
Gladys Belly River III & Basal Belly River G	621
Herronton Edmonton & Belly River MU#1	778
Irricana Belly River III	188
Lomond Belly River III & Basal Belly River A	141
Majorville Belly River III	120
Matziwin Belly River III	85
Michichi Belly River III &Basal Belly River A, J, P & Upper Mannville J	108
Milo Belly RiverIII & Basal Belly River A,B & C	40
Okotoks Belly River III	113
Parflesh Belly River, Upper & Lower Mannville MU#1	695
Queenstown Belly River III	119
Redland Edmonton Belly River, Viking & Mannville MU#1	513
Rockyford Edmonton, Belly River, Colorado & Mannville MU#1	737
Rowley Belly River III	51
Seiu Lake Belly River III & Viking C	92
Strathmore Edmonton & Belly River MU#1	1 881
Swalwell Belly River III & Basal Belly River A	177
Vulcan Belly River III	42
Wayne-Rosedale Belly River III	408
West Drumheller Belly River III	39
Total	11 961
Cardium Pool No. 1	
Ansell Cardium, Viking, & Mannville MU#1	8 706
Sundance Belly River, Cardium, Viking, & Mannville MU#1	4 698
Total	13 404
Southeastern Alberta Gas System (MU)	
Alderson Milk River, Medicine Hat, Second White Specks, Belly River and Colorado	25 050
Armada Milk River, Medicine Hat and Belly River	2 138
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River	7434
Bantry Milk River, Medicine Hat, Fish Scale, Second White Specks, First White Specks, Belly River and Colorado	17 190
Berry Medicine Hat	58
Bindloss Milk River and Medicine Hat	1 943
Blackfoot Medicine Hat and Belly River	558
Bow Island Milk River, Medicine Hat, Second White Specks and Colorado	1 488
Brooks Milk River, Medicine Hat and Second White Specks	114
Cavalier Belly River and Viking	62
Cessford Milk River, Medicine Hat, Second White Specks and First White Specks	14 186
Connorsville Milk River, Medicine Hat, Belly River, Colorado and First White Specks	1 924
Countess Milk River, Medicine Hat, Second White Specks, Belly River, Colorado, Fish Scale, Bow Island, Viking, Basal Colodaro, and Mannville & Pekisko	30 122
Drumheller Medicine Hat, Belly River, Viking Basal Colorado, Upper Mannville, Lower Mannville and Pekisko	320
Enchant Second White Specks	348
Eyremore Milk River, Medicine Hat, Second White Specks, and Colorado	3 622
Farrow, Milk River, Medicine Hat and Belly River	1 676
Gleichen Milk River, Medicine Hat and Belly River	1 217
Hussar Milk River, Medicine Hat, Belly River, Edmonton, Viking, Glauconitic and Second White Specks	2 936
Jenner Milk River, Medicine Hat, Second White Specks and Colorado	4 068
Johnson Milk River, Medicine Hat and Second White Specks	758
Jumpbush Belly River & Medicine Hat	221
Kitsim Milk River, Medicine Hat and Second White Specks	1 072
Lathom Milk River , First White Specks, Medicine Hat, Fish Scale, Second White Specks and Belly River	2 878
Leckie Milk River, Medicine Hat, Belly River, and Second White Specks	1 451
Majorville Milk River, Medicine Hat and Belly River	3 563
Matziwin Milk River, Medicine Hat, First White Specks, Fish Scale, Second White Specks and Belly River	1 043
McGregor Milk River and Medicine Hat	1 165
Medicine Hat Milk River, Medicine Hat, Fish Scale, Second White Specks, Belly River, and Colorado	49 794
Newell Milk River, Medicine Hat and Second White Specks	1 459
Pollockville Milk River and Medicine Hat	47
Princess Milk River, Medicine Hat, Second White Specks, and Colorado	12 365
Rainier Milk River, Medicine Hat and Second White Specks	368

(continued)

Table B.7. Natural gas reserves of multifield pools, 2005 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Ronalane Second White Specks	161
Seiu Lake Medicine Hat	770
Shouldice Medicine Hat and Belly River	1 415
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	20 218
Verger Milk River, Medicine Hat, Fish Scale, Belly River, Second White Specks and Colorado	9 032
Wayne-Rosedale Medicine Hat, Milk River, First White Specks and Belly River	2 249
Wintering Hills Milk River, Medicine Hat, Second White Specks, Belly River, and Colorado	4 399
Total	230 882
Second White Specks Pool No. 2	
Dowling Lake Second White Specks E	9
Garden Plains Second White Specks E	1 526
Hanna Second White Specks E	1 383
Provost Second White Specks E	55
Richdale Second White Specks E	157
Sullivan Lake Second White Specks E	142
Watts Medicine Hat B & C and Second White Specks E	20
Total	3 292
Second White Specks Pool No. 3	
Conrad Second White Specks J, & Barons A & F	297
Pendant D'Oreille Medicine Hat E & Second White Specks J	508
Smith Coulee Medicine Hat A & Second White Specks J	502
Total	1 307
Second White Specks Pool No. 4	
Enchant Second White Specks B	106
Retlaw Second White Specks B	18
Vauxhall Second White Specks B	43
Total	167
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	99
Peavey Upper Viking A	3
Redwater Upper Viking A, Middle Viking A, and Lower Viking A	543
Westlock Middle Viking B	204
Total	849
Viking Pool No. 2	
Albers Upper & Middle Viking A & Colony A	3
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	177
Bellshill Lake Upper and Middle Viking A	20
Birch Upper and Middle Viking A	3
Bruce Viking & Mannvillie MU#1	1 078

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Dinant Upper & Middle Viking A	19
Fort Saskatchewan Upper and Middle Viking A	47
Holmberg Upper and Middle Viking A	4
Killam Colony, Viking & Mannville MU#1	104
Killam North Viking Mannville & Nisku MU#1	275
Mannville Viking & Mannville MU#1	509
Sedgewick Upper and Middle Viking A	5
Viking-Kinsella Viking, Colony, Mannville & Wabamun MU#1	7 879
Wainwright Colony B & F, Viking & Mannville MU#1	90
Total	10 213
Viking Pool No. 3	
Carbon Belly River, Mannville & Rundle MU #1	161
Ghost Pine Viking D	28
Total	189
Viking Pool No. 5	
Hudson Viking A	22
Sedalia Viking A & F, Upper Mannville D, and Lower Mannville B	114
Total	136
Viking Pool No. 6	
Hairy Hill Viking A	55
Willingdon Viking A & J and Mannville MMM & X2X	8
Total	63
Viking Pool No. 7	
Inland Viking and Upper Mannville MU#1	93
Royal Upper Viking C and Lower Viking A	34
Total	127
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	117
Ferrybank Viking C, Glauconitic A, & Lower Mannville W	29
Total	146
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	106
Pembina Glauconitic I & D and Ostracod C	423
Total	529

(continued)

Table B.7. Natural gas reserves of multifield pools, 2005 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Glauconitic Pool No. 6	
Hussar Viking L, Glauconitic III, and Ostracod OO	260
Wintering Hills Upper Mannville I, Glauconitic III & Lower Mannville I	36
Total	296
Bluesky Pool No.1	
Rainbow Bluesky C	94
Sousa Bluesky C	246
Total	340
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	103
Hotchkiss Bluesky-Detrital-Debolt A	325
Total	428
Gething Pool No. 1	
Fox Creek Viking, Upper Mannville & Gething MU#1	961
Kaybob South Notikewin , Bluesky ,and Gething MU#1	48
Total	1 009
Ellerslie Pool No. 1	
Connorsville Colorado, Glauconitic and Ellerslie MU#1	625
Wintering Hills Upper Mannville A, EEE & NNN and Ellerslie A	140
Total	765

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Cadomin Pool No. 1	
Elmworth Dunvegan , Fort St John & Bullhead MU#1	6 679
Sinclair Doe Creek, Fort St John & Bullhead MU#1	1 277
Total	7 956
Halfway Pool No. 1	
Valhalla Halfway B	3 031
Wembley Halfway B	4 538
Total	7 569
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	2 323
Valhalla Halfway N	44
Total	2 367
Banff Pool No. 1	
Haro Banff E	46
Rainbow Banff E	12
Rainbw South Banff E	55
Total	113

Table B.8. Remaining raw ethane reserves as of December 31, 2005

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	10 928	0.082	983	3 495
Bonnie Glen	2 056	0.104	292	1 038
Brazeau River	10 518	0.063	851	3 026
Caroline	13 525	0.084	1 894	6 733
Cecilia	6 921	0.058	460	1 634
Countess	36 420	0.015	570	2 027
Dunvegan	12 756	0.044	628	2 232
Edson	5 574	0.068	437	1 555
Elmworth	11 124	0.055	726	2 582
Ferrier	13 089	0.084	1 229	4 368
Fir	5 297	0.059	346	1 229
Garrington	3 680	0.070	340	1 210
Gilby	5 367	0.079	490	1 743
Gold Creek	3 834	0.077	337	1 198
Harmattan East	7 372	0.084	697	2 478
Harmattan-Elkton	4 307	0.075	398	1 416
Hussar	8 902	0.030	287	1 020
Judy Creek	3 183	0.144	568	2 018
Kaybob South	10 306	0.077	989	3 517
Karr	4 705	0.083	436	1 549
Kakwa	4 489	0.087	446	1 585
Leduc-Woodbend	3 189	0.109	413	1 469
Medicine River	3 881	0.084	390	1 387
Pembina	17 459	0.087	1 980	7 039
Pine Creek	5 755	0.073	519	1 846
Pouce Coupe South	5 600	0.049	304	1 081
Provost	22 809	0.025	631	2 244
Rainbow	6 902	0.081	727	2 586
Rainbow South	3 801	0.113	631	2 244
Ricinus	5 326	0.078	475	1 687
Sundance	8 036	0.072	651	2 314
Swan Hills South	2 548	0.174	634	2 254
Sylvan Lake	4 999	0.066	389	1 382
Valhalla	8 450	0.077	791	2 810
Virginia Hills	1 588	0.162	315	1 119
Waterton	6 372	0.028	299	1 063
Westpem	3 477	0.108	482	1 715
Westerose South	6 122	0.079	538	1 912

(continued)

Table B.8. Remaining raw ethane reserves as of December 31, 2005 (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	5 604	0.095	645	2 292
Wapiti	16 023	0.054	996	3 540
Wild River	22 751	0.070	1 705	6 060
Willesden Green	10 790	0.086	1 210	4 302
Wilson Creek	3 307	0.076	293	1 042
Subtotal	359 142	0.066	28 421	101 042
All other fields	760 619	0.028	20 677	75 197
Solvent floods			1 718	6 145
TOTAL	1 119 761	0.052[a]	50 816	182 384

[a] Volume weighted average.

Table B.9. Remaining established reserves of natural gas liquids as of December 31, 2005

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ante Creek North	1 714	322	177	609	1 107
Ansell	10 928	1 595	842	1 767	4 205
Bonnie Glen	2 056	467	260	411	1 138
Brazeau River	10 518	1 348	859	2 318	4 525
Caroline	13 525	3 007	2 269	5 221	10 497
Cecilia	6 921	631	237	1 016	1 884
Countess	36 420	793	453	402	1 649
Crossfield East	6 021	282	154	1 732	2 168
Dunvegan	12 756	1 086	628	1 059	2 773
Edson	5 574	592	286	312	1 189
Elmworth	11 124	840	375	434	1 648
Ferrier	13 089	2 270	1 196	963	4 428
Fir	5 297	526	241	246	1 013
Garrington	3 680	533	291	420	1 244
Gilby	5 367	806	405	427	1 637
Gold Creek	3 834	434	230	436	1 099
Harmattan East	7 372	906	579	1 036	2 522
Harmattan -Elkton	4 307	534	272	268	1 074
Hussar	8 902	445	247	260	951
Judy Creek	3 183	1 360	563	326	2 249
Kaybob	2 877	387	180	272	839
Kaybob South	10 306	1 601	877	1 528	4 006
Karr	4 705	688	287	289	1 264
Kakwa	1 189	815	411	557	1 784
Knopcik	3 752	369	221	455	1 045
Leduc-Woodbend	3 189	1 135	649	390	2 174
McLeod	2 872	505	234	249	988
Medicine River	3 881	629	307	291	1 228
Moose	3 015	244	174	410	828
Peco	1 975	359	196	417	973
Pembina	17 429	3 960	1 903	1 508	7 371
Pine Creek	5 755	880	450	910	2 240
Pouce Coupe South	5 600	412	243	303	958
Provost	22 809	1 351	857	639	2 848
Rainbow	6 902	1 179	719	789	2 687
Rainbow South	3 801	1 288	606	885	2 779
Redwater	2 032	523	327	132	982
Ricinus	5 326	773	373	513	1 659
Smoky	3 251	454	210	157	820
Sundance	8 036	851	371	427	1 649
Swan Hills	1 013	554	303	252	1 109
Swan Hills South	2 548	1 551	710	296	2 556
Sylvan Lake	4 999	591	281	260	1 131

(continued)

Table B.9. 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
Valhalla	8 450	1 373	733	1 066	3 172
Virginia Hills	1 588	731	243	103	1 077
Waterton	6 372	286	249	1 238	1 773
Wayne-Rosedale	6 525	439	238	228	905
Westpem	3 477	853	485	952	2 289
Westerose South	6 122	976	481	517	1 974
Wembley	5 604	1 256	746	1 717	3 719
Wapiti	16 023	1 001	432	413	1 845
Wild River	22 751	1 678	742	1 412	3 832
Willesden Green	10 790	2 151	1 007	1 017	4 174
Wilson Creek	3 307	497	268	322	1 086
Windfall	2 568	254	182	386	821
Zama	3 251	454	210	157	820
Subtotal	400 147	51 787	27 486	41 200	120 474
All other fields	719 614	28 055	15 964	17 691	61 706
Solvent floods		1 590	1 041	489	3 120
TOTAL	1 119 761	81 433	44 487	59 380	185 300

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 and the crude bitumen resources data table present the official reserve estimates of both the EUB and NEB for the province of Alberta.

Basic Data Tables

The conventional oil, crude bitumen, and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2005 on the CD that accompanies this report (available for $500 from EUB Information Services). The individual oil and gas pools and crude bitumen deposit/pool values are presented on the first worksheet of each spreadsheet. Oilfield, crude bitumen deposit, and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. Crude bitumen provincial totals are included with the deposit information. 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 Bitumen Resources and Basic Data

The crude bitumen resources and basic data spreadsheet is similar to the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns.

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, 1972-2005, 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

[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 - 2005 - Alberta Drilling Activity Monthly Statistics (ST-59).

Table D.2. Development and exploratory wells, 1972-2005, 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	1 840	603	253	3 219	48 057	3 075	1 091	10 067	49 897
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

[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 - 2005 - Alberta Drilling Activity Monthly Statistics (ST-59).