Statistical Series (ST) **2004-98**

Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013

Alberta Energy and Utilities Board

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Overview

Providing information to support good decision-making is a key service of the Alberta Energy and Utilities Board (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 report entitled *Alberta Reserves 2003 and Supply/Demand Outlook 2004-2013* includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (reserves that are ultimately expected to be recovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources.

Reserve supply, costs of development, energy demands, conservation, and social, economic, and environmental considerations influence the development of Alberta's energy resources. Changes in energy prices, drilling activity, and planned investments of billions of dollars for oil sands projects all contributed to the energy development picture in 2003 and will shape the forecast for the years to come.

Raw bitumen production, which surpassed conventional crude oil production in 2001 for the first time, continued its growth. Nonupgraded bitumen and synthetic crude oil production accounted for 53 per cent of Alberta's crude oil and equivalent production in 2003. Increased bitumen production and upgrading from oil sands mining was the main contributor to this growth. In situ bitumen production increased modestly compared to 2002. Several steam-assisted gravity drainage (SAGD) schemes have either been recently approved by the EUB or are under review. The EUB expects higher volumes of commercial production from these schemes to occur from in situ projects over the next few years.

Natural gas production in Alberta declined for the second year in 2003. The EUB has concluded that natural gas production in the province may have peaked in 2001. Natural gas production is expected to stay similar to the 2003 level in 2004 due to the high level of drilling.

Coalbed methane (CBM) development activity continued to grow in 2003, with CBM production contributing only minor volumes to the provincial total natural gas production. The EUB anticipates that this activity will likely continue to increase over the next number of years; 2003 marks the first year that the EUB is publishing a separate estimate of CBM reserves.

The following table summarizes Alberta's energy reserves at the end of 2003.

Reserves Summary 2003

	Crude bitumen		Crude oil		Natural gas		Coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in place	258 900	1 629	9 852	62.0	7 504	261	94	103
Initial established	28 392	179	2 634	16.6	4 401	156	35	38
Cumulative production	667	4.2	2 380	15.0	3 279	116	1.21	1.3
Remaining established	27 726	174	254	1.6	1 122	40	34	37
Annual production	56	0.352	37	0.230	135	4.8	0.029	0.032
Ultimate potential (recoverable)	50 000	315	3 130	19.7	5 600	200	620	683

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves are 27.7 billion m^3 (174 billion barrels), similar to 2002. To date, only 2 per cent of the initial established crude bitumen reserve has been produced.

Crude Bitumen Production

In 2003, Alberta produced 35.6 million m^3 (224 million barrels) from the mineable area and 20.3 million m^3 (128 million barrels) from the in situ area, totalling 55.9 million m^3 (352 million barrels). Bitumen produced from mining was upgraded, yielding 31.2 million m^3 (196 million barrels) of synthetic crude oil (SCO). In situ production was marketed as nonupgraded crude bitumen.

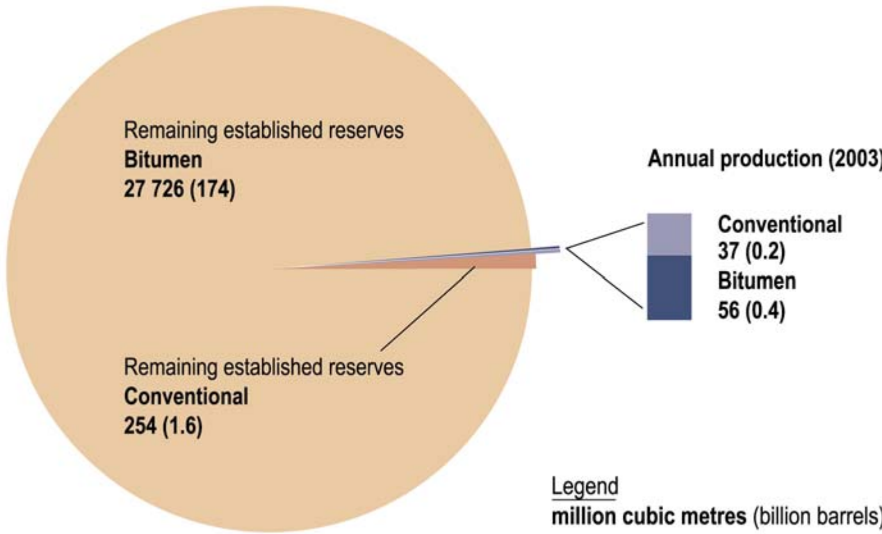
Total raw bitumen production, which exceeded total conventional crude oil production for the first time in 2001, continued to grow in 2003.

Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 254 million m^3 (1.6 billion barrels)—a 2.5 per cent reduction from 2002. Of the 30.8 million m^3 (194 million barrels) added to initial established reserves, exploratory and development drilling, along with new enhanced recovery schemes, added reserves of 13.8 million m^3 (87 million barrels). This replaced 38 per cent of 2003 production. Positive revisions accounted for the remaining 17.1 million m^3 (108 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.

The following figure shows annual production and remaining established reserves for crude bitumen and crude oil.



Alberta's oil reserves and production

Crude Oil Production and Drilling

Alberta's production of conventional crude oil totalled 36.5 million m^3 (230 million barrels) in 2003. Despite declining production over the past two decades, Alberta still produces 100 000 m^3/day (630 000 barrels/day) of conventional crude oil.

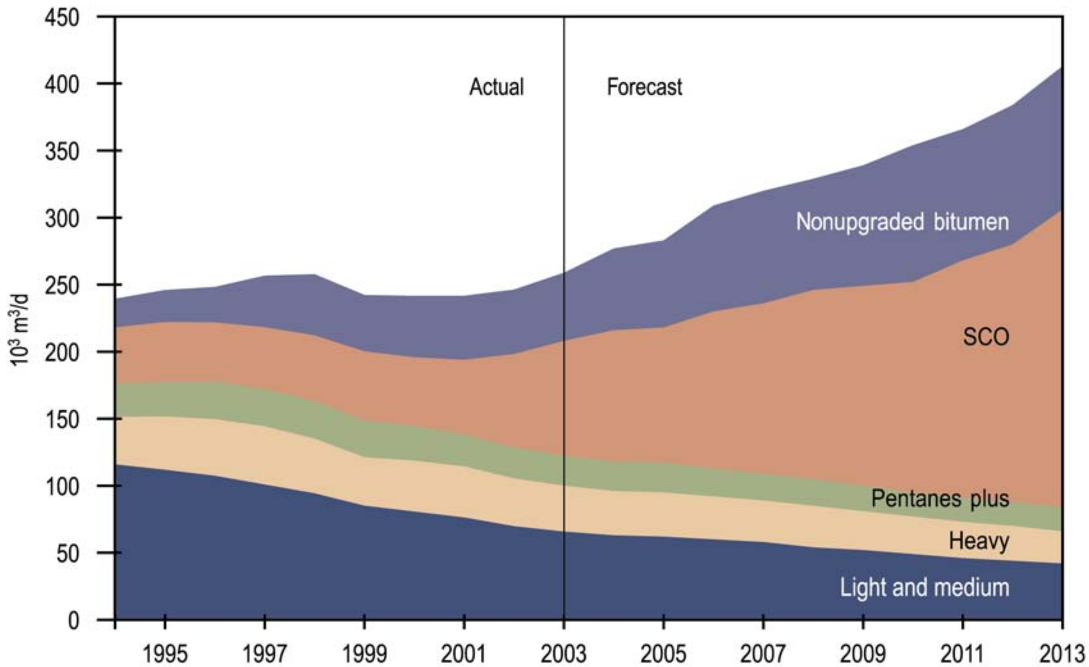
The number of successful oil wells drilled increased by 42 per cent to 2360 in 2003 from 1661 in 2002. With the expectation that crude oil prices will remain strong, the EUB estimates that 2300 successful oil wells will be drilled in 2004, and further projects that on average about 2200 successful oil wells per year will be drilled over the remainder of the forecast period.

Total Oil Supply and Demand

Alberta's 2003 production from conventional oil, oil sands sources, and pentanes plus was 259 000 m^3/day (1.63 million barrels/day)—a 5 per cent increase compared to 2002. Production is forecast to reach 413 000 m^3/day (2.6 million barrels/day) by 2013.

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

Although conventional oil production will continue to decline, the EUB estimates that production of bitumen will triple by 2013. The share of nonupgraded bitumen and synthetic crude oil production in the overall Alberta crude oil and equivalent supply is expected to increase from 53 per cent in 2003 to some 80 per cent by 2013.



Alberta's total oil supply

Natural Gas

Natural Gas Reserves

At the end of 2003, Alberta's remaining established reserves of natural gas stood at 1122 billion m^3 (40 trillion cubic feet) at the field gate. This reserve includes liquids that are subsequently removed at straddle plants. Production from new drilling replaced 77 per cent of production in 2003. This compares to 105 per cent replacement in 2002.

For the first time the 2003 natural gas reserve estimates do include CBM. Over the past several years CBM activity has continued to increase, and the EUB believes that despite several continuing uncertainties regarding production and recovery factors, it is reasonable to publish its CBM reserves estimates. CBM is methane gas found in coal, and this relationship allows for in-place volumes to be calculated with some degree of confidence. While there is still relatively limited information regarding CBM test data, the accuracy of CBM production, and the profitability of CBM projects to determine consistently reliable recovery factors, the EUB believes that there is now enough information available to calculate and publish a conservative estimate of CBM reserves.

At the end of 2003, the remaining established reserves of CBM in Alberta is estimated to be 0.97 billion m^3 (34 billion cubic feet).

In 1992, the EUB estimated Alberta's ultimate marketable gas potential at about 5600 billion m^3 (200 trillion cubic feet). To bring this estimate up to date, the EUB has undertaken an ultimate potential study targeted for completion in late 2004.

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 135 billion m^3 (4.8 trillion cubic feet) of marketable natural gas in 2003.[1]

There were 12 000 successful gas wells drilled in Alberta in 2003, a 46 per cent increase from the 8210 gas wells drilled in 2002. The EUB expects strong drilling over the forecast period, estimating 11 000 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 16 per cent of 2003 natural gas production. Over time, the EUB anticipates that the focus of exploration activity will shift to the western portion of the province and correspondingly higher-productivity wells.

Natural Gas Supply and Demand

The EUB expects gas production to remain flat in 2004 and decline by 2.5 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. Future supply of conventional gas is shown in the figure below.

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.

Other potential sources, such as frontier gas and CBM, offer options for supplementing the supply of conventional gas in the future.

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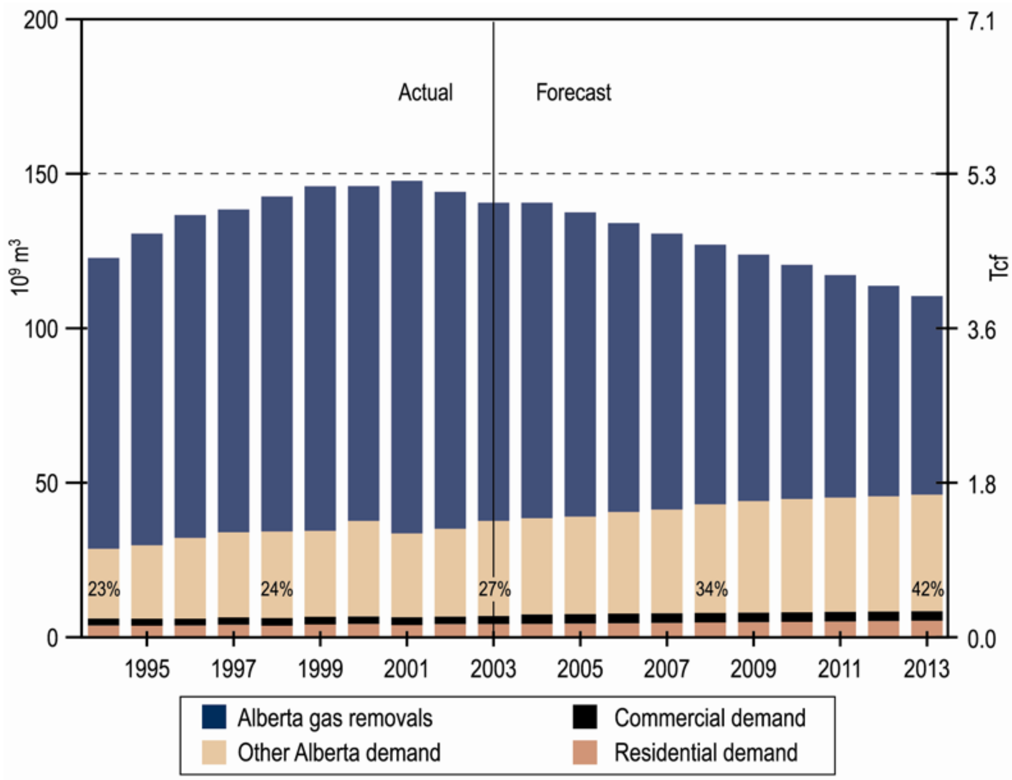
[1] Based on the actual average heating value of gas production 39 MJ/m^3. Based on the gross heating value of 37.4 MJ/m^3, gas production was 141 billion m^3.



Marketable conventional gas production and demand

Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 124 million m^3 (785 million barrels) as of year-end 2003. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

The production of specification ethane reached 13.7 million m^3 (86.7 million barrels) in 2003, the same as in 2002. 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 175 million m^3 (1.1 billion barrels) in 2003. 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 is 85 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 resources for all types of coal is about 34 billion tonnes. This massive resource continues to help meet the energy needs of Albertans, supplying fuel for about 66 per cent of the province's electricity generation. Alberta's coal reserves represent over a thousand years of supply at current production levels.

Alberta's total coal production in 2003 was 28 million tonnes of marketable coal, down about 10 per cent from 2002. The opening of the Cheviot and Grande Cache coal mines will offset the closure of the Cardinal River mine and stabilize metallurgical coal production over the next decade. The suspension of the Obed Mountain coal mine will result in reduction in thermal bituminous coal production over the forecast period.

Subbituminous coal production is expected to increase over the forecast period to meet demand for additional electrical generating capacity.

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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, the types of industry operating in the province, standard of living, seasonal temperatures, and population growth. This section presents some of the main variables and sets the stage for supply and demand discussions in the report.

1.1 Global Oil Market

The oil market in 2003 was characterized as a market with extremely high average prices not seen in over twenty years. The Organization of Petroleum Exporting Countries (OPEC) basket price of crude was highest in the first few months of the year, in anticipation of a possible invasion of Iraq and due to fallout from the strikes in Venezuela. As the war broke out in late March, Iraq crude production was all but eliminated. To offset this loss of Iraqi production, OPEC increased its production quota. This increase, along with the realization that the war in Iraq would be short-lived and the expectation that the Iraq's production would be resumed, caused crude oil prices to fall to their lowest point of the year in April. Even though there was a quick end to the war and Iraqi production was able to come back on line sooner than expected, the level of production has yet to achieve the pre-war volume.

Over the past ten years, global demand for crude oil has increased by an average of 1.5 per cent per year. The trend over the previous two years, which saw virtually no growth, was reversed this past year as global oil demand increased by over 2 per cent. Strong growth in the U.S. demand for oil and continued strong increases in demand for crude in China were mostly responsible for this increase. China, after five years of annual growth in consumption exceeding 6 per cent a year, moved into the number-two spot, surpassing Japan as the world's second largest importer of crude. China's seemingly insatiable demand for oil has made it a major driver of global oil demand.

Several factors played a role in shaping the strong average crude oil prices in 2003:

- strong global demand relative to the previous two years, particularly in China, the Middle East, countries of the former Soviet Union, and Latin America;
- the decrease in the value of the U.S. dollar with respect to European currencies, which caused erosion of the purchasing power of oil exporting countries, forcing OPEC members to keep prices up in the US$30 plus range;
- the sluggish growth in Iraq's crude oil production;
- OPEC's immediate response to market forces; and
- overall tension in the Middle Eastern oil-producing countries.

The reduction in OPEC's production quota last September, along with its recently announced plans to cut output by a further 4 per cent in April 2004, has caused the spot price of crude oil to jump to a 13-year high in March 2004. It is expected that the OPEC average price for 2004 will hover around US$30 per barrel, which translates into a US$32 per barrel price for the West Texas Intermediate (WTI), the North American crude oil yardstick.

Despite the uncertainty and concerns in the world oil market, the global demand for oil is expected to increase by 1.75 to 2.25 per cent in 2004, followed by an increase of 1.5 to 1.75 per cent in 2005. After 2005, if a 1.0 to 1.5 per cent growth rate in global demand is realized, global crude oil production will increase by 8 million (10^6) barrels per day (bbl/d) to 12 10^6 bbl/d by the end of the forecast period to meet the demand. This growth in global demand should result in international crude oil prices stabilizing within OPEC's target range of US$22 to US$28.

While the current global oil production capability exceeds the potential demand of 78 10^6 to 80 10^6 bbl/d by roughly 10 per cent, increases in production from Iraq may not be enough for OPEC to maintain its market share as new non-OPEC supply, particularly from Russia, comes on line. Nonetheless, long-term stability in the market for oil will rely on the overall state of world politics, as the continued threat of terrorism, fighting in the Persian Gulf, and political instability in Venezuela will create a very volatile global market in 2004 and beyond.

1.2 Energy Prices

The price of Alberta crude oil is determined by international market forces and is most closely associated with the reference price of WTI crude oil. The North American crude oil price is set in Chicago and is usually US$1.50-2.00 higher than the OPEC reference price, reflecting quality differences and costs of shipping to the Chicago market. The Alberta Energy and Utilities Board (EUB) uses WTI crude price as its benchmark for world oil prices, as Alberta crude oil prices are based on WTI netbacks in Edmonton. Netbacks are calculated based on WTI at Chicago less transportation and other charges from Edmonton to Chicago and are adjusted for exchange rate, as well as crude oil quality. In 2003, the price of WTI crude oil began at US$33.26 per barrel, quickly rose to hit a peak of US$36.30 per barrel in February, then fluctuated the remainder of the year between US$29 and US$33 before finishing at US$32.96 in December.

The EUB forecasts that the price of WTI will average between US$30 and US$32 per barrel for 2004, declining to US$27 by 2006 and thereafter rising by 1.5 per cent per year to the end of the forecast period. These price levels are sufficient to stimulate exploration outside of OPEC countries and can foster continued improvements in exploration and recovery technology. **Figure 1.1** illustrates the EUB forecast of WTI at Chicago. **Figure 1.2** shows the forecast for the wellhead price of crude oil in Alberta on a yearly basis in both current and constant Canadian dollars.

Differentials between prices of light-medium crude and heavy conventional crude or bitumen moved in separate directions in 2003. The heavy crude to light-medium crude price differential fell from 73 per cent to 68 per cent, while bitumen price differentials improved from 66 per cent to 70 per cent. The forecast calls for conventional heavy to average 75 per cent of the light-medium price and the bitumen price to revert to 60 per cent of the light-medium price.

While crude oil prices are determined globally, the North American market determines natural gas prices. Nevertheless, natural gas prices are influenced by crude prices, as potential substitution could occur due to the price differential between crude oil and natural gas in the market. **Figure 1.3** shows both the historical and the EUB forecast of natural gas prices at the plant gate from 1994 to 2013.

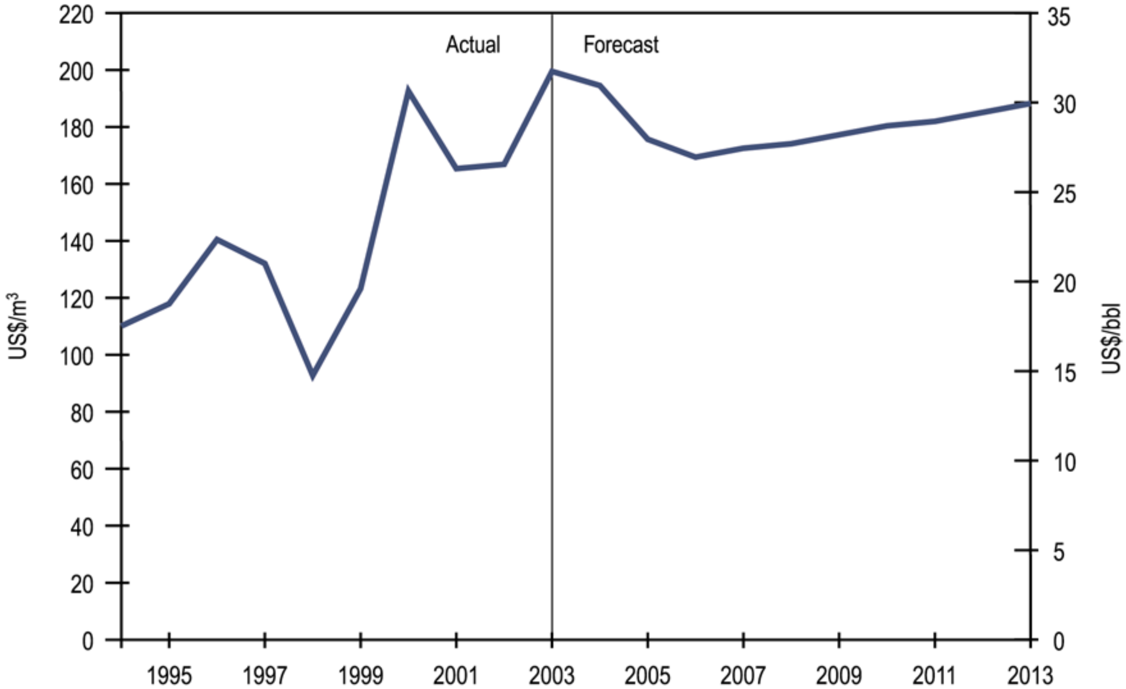

Figure 1.1. Price of WTI at Chicago

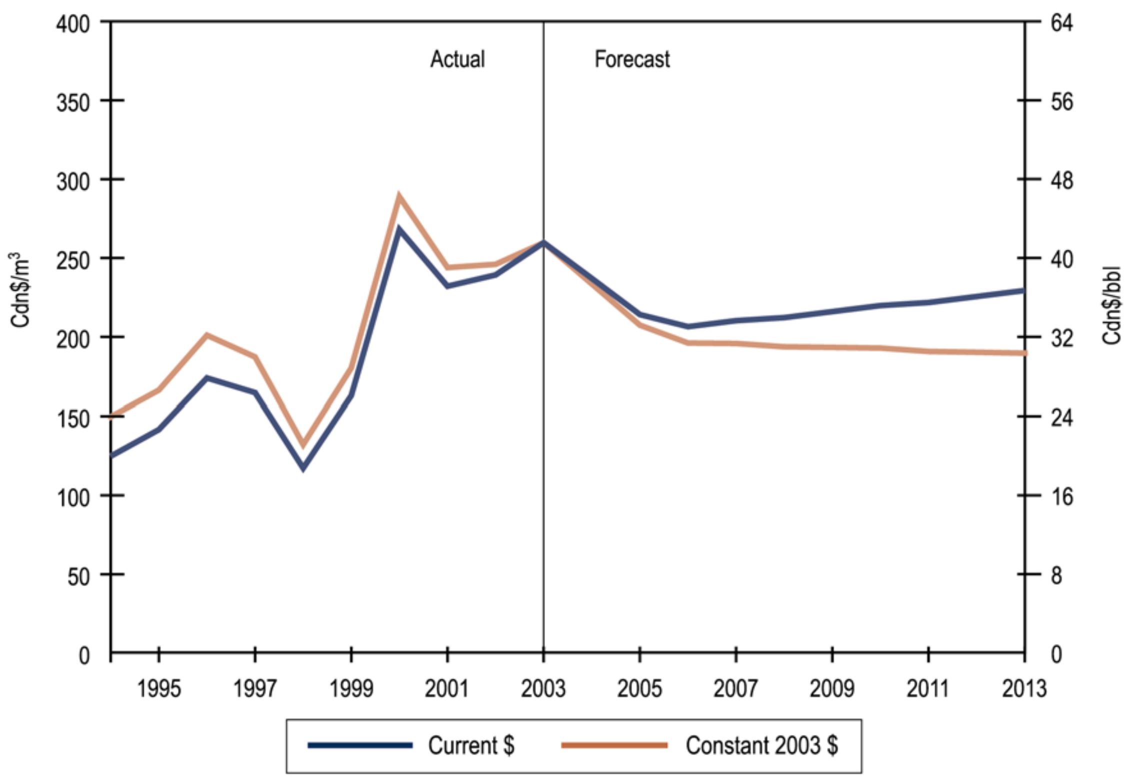

Figure 1.2. Average price of oil at Alberta wellhead

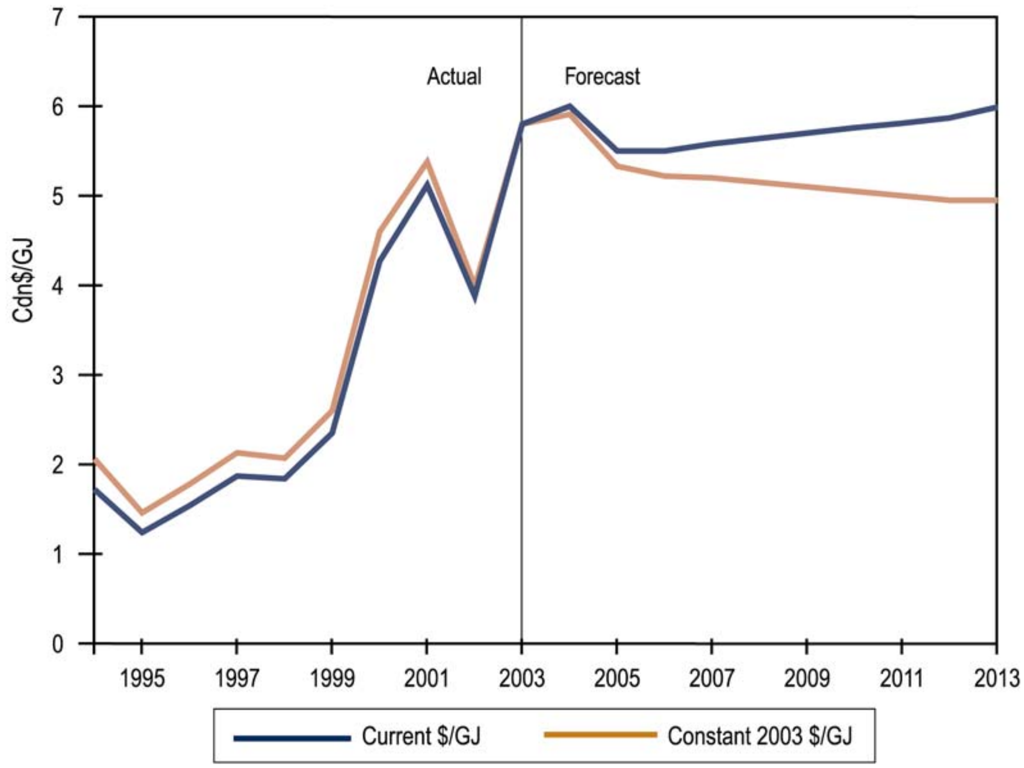

Figure 1.3. Average price of natural gas at plant gate

The average plant gate natural gas price was Cdn$1.62 per gigajoule (GJ) over the decade 1990-1999; then prices climbed to $4.27/GJ in 2000 and $5.12/GJ in 2001. The volatility in gas prices that Alberta experienced over the 12-month period starting in mid-2000 showed unprecedented price spikes during the winter months as North American gas demand escalated. The Alberta reference price peaked in January 2001 at over $11.00/GJ. Prices moderated by the spring and by September had returned to levels around $3.00/GJ. The gas industry by this time faced lower demand, as many companies that had been major consumers of natural gas switched to fuel oil or chose to suspend operations rather than pay the going price.

In 2002, the Alberta plant gate price averaged $3.88/GJ. While gas prices regained some strength in the first half of 2002, by early summer prices weakened. The Alberta natural gas market temporarily disconnected from the rest of North America due primarily to excess supply resulting from weak demand in the California market, as well as high storage levels. Increased demand later in the year reduced the basis price differential between AECO and NYMEX as the market came more into balance.[1]

In 2003, the Alberta plant gate price averaged $5.80/GJ. The influence of a cold winter in the early months resulted in storage levels shrinking to very low levels and natural gas prices rising in response. By April, prices began to retreat from the earlier year highs. Lower prices and moderate weather in the summer months allowed for significant natural gas injections to rebuild storage.

[1] AECO is a natural gas trading hub in Alberta established by Alberta Energy Company, now EnCana Corporation. NYMEX is New York Mercantile Exchange, where North American natural gas is traded.

Natural gas prices are estimated to average $6.00/GJ for 2004 and to remain within the $5.50/GJ to $6.00/GJ price range within the forecast period, as shown in **Figure 1.3**. Factors supporting high future gas prices include high oil prices, increased demand from electricity generation, and uncertainty about gas supply. Until significant new supply is available to the market, prices will continue to experience volatility.

The EUB believes that intercontinental trade in liquefied natural gas (LNG) would not capture a high market share in North America over the forecast period due primarily to the risk and regulatory requirement for construction of gasification terminals. While the LNG cost at the gasification plant gate on the U.S. east coast is in the US$3.00/GJ to $4.00/GJ range, due to its small market share it will not drastically affect the rising natural gas prices in North America, which are currently above this range. It is also possible that the LNG suppliers will not price their gas at their marginal cost, but at a level that the market can bear in order to maximize their revenue.

1.3 Canadian Economic Performance

Canadian economic growth, interest rates, inflation, unemployment rates, and currency exchange rates (particularly vis-à-vis the U.S. dollar) are key variables that affect the Alberta economy but are beyond the province's control. The most important economic indicator that can identify whether the economy is contracting or expanding is the real gross domestic product (GDP). In this section, the performance of the above economic indicators in 2003 and the first quarter of 2004 are reviewed. These economic indicators for 2003 are depicted in **Figure 1.4.**

In 2003, the performance of global economies was somewhat improved over 2002. Even though the Canadian economy faced numerous hurdles, such as the rapid expansion in the value of the dollar versus the U.S. dollar, the SARS outbreak, mad cow disease, massive forest fires, and a blackout that nearly blanketed the largest province, Ontario, the Canadian economy was still able to achieve a growth rate of 1.6 per cent. This placed Canada right in the middle of the G7 countries in terms of economic growth.

The first quarter of 2003 saw a recovery over the fourth quarter of 2002. However, the second quarter experienced, for the first time in nearly two years, a decline in growth, as the currency, SARS, the mad cow crisis, and increased interest rates weighed heavily on the economy. GDP growth in the third quarter turned positive, with an annualized growth rate of 1.2 per cent, but was well behind the annualized growth rate in the United States, which was over 8 per cent in the quarter. The fourth quarter saw a marked improvement in the growth rate, as the economy expanded at the fastest pace in over five quarters. A massive increase in both exports, as a result of increased demand south of the border, and inventories was responsible for this growth.

During 2003, the growth in the Canadian economy had little impact on the unemployment rate, which averaged 7.64 per cent, compared to 7.65 per cent in 2002. With increased GDP growth over the forecast period, it is expected that the unemployment rate in Canada will gradually decline to an average of 7.0 per cent.

The Bank of Canada attempts to control the inflation rate, which is expressed in terms of the core consumer price index (CPI), a measure of consumer prices that excludes transitory influences of volatile components, such as prices for food and energy. The Bank of Canada focuses on the core CPI, and not the total CPI, because it has very little control over the prices of food and energy. Since the Bank of Canada's main goal is low,

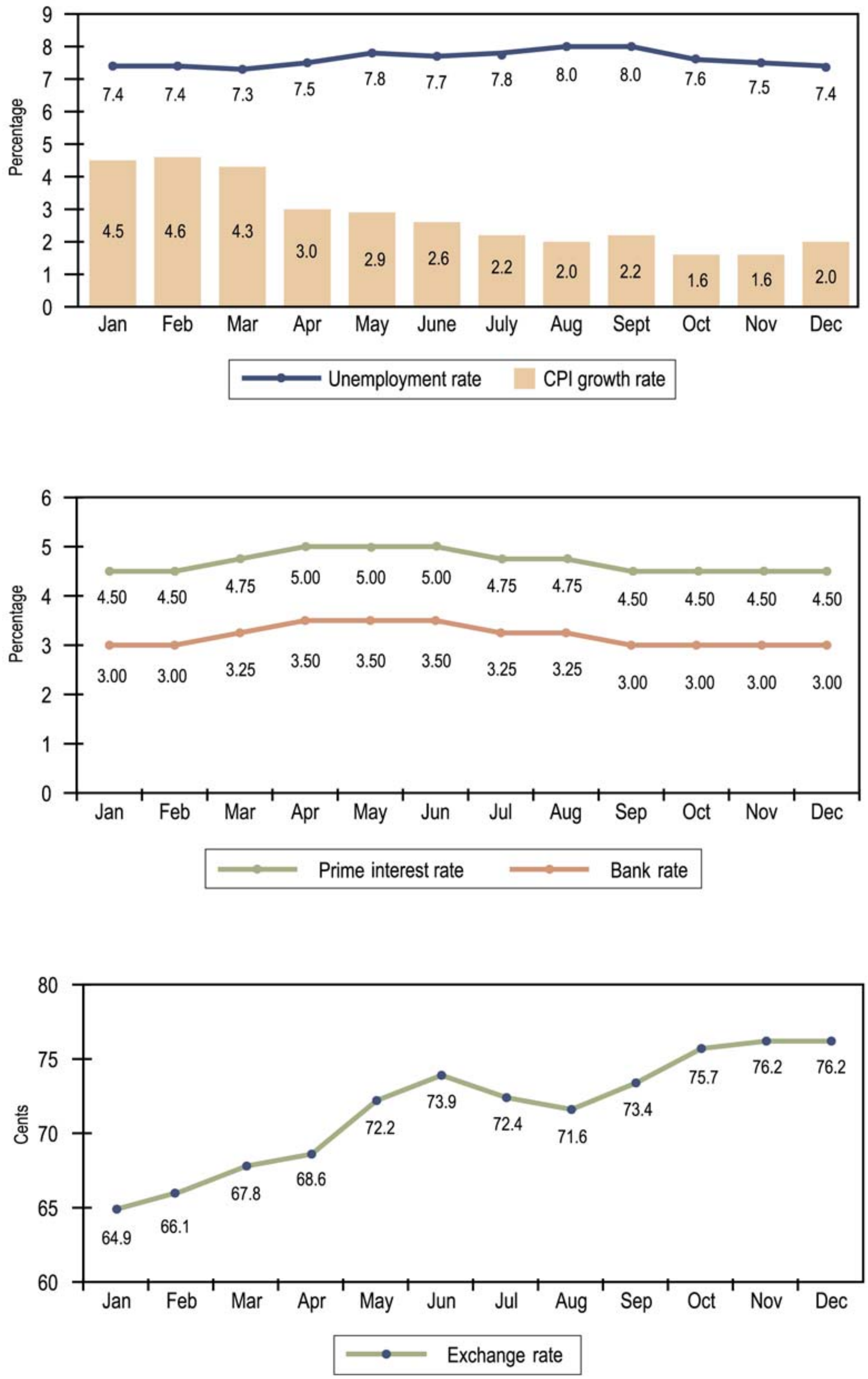

Figure 1.4. Canadian economic indicators, 2003

stable inflation, it has set the inflation control target within a range of 1 to 3 per cent until 2006 and has chosen to keep inflation within this range by adjusting interest rates.

With inflation slightly above the target range of 3 per cent in the first quarter of 2003, the Bank of Canada increased interest rates 25 basis points in March and again in April to an interest rate of 3.5 per cent. As these interest rate increases and the previously mentioned hurdles took hold on the economy, the core inflation rate fell and real growth in the economy turned negative. To stimulate the economy and eliminate fears of deflation, the Bank began reducing interest rates in both July and August back down to 3 per cent. In January and March 2004, with inflation below the midpoint of the target range, the Bank once again lowered interest rates in order to stimulate the economy by increasing domestic demand and to slow the rapid increase in the value of the currency.

The most important factors affecting exchange rates are interest rate differentials between countries, inflation, net exports, and economic growth. The Canadian dollar had a very strong year in 2003, as the currency continued to appreciate since hitting a record low of 61.8 cents in February 2002. The strength in the currency continued in January 2004, as the value of the dollar hit a high of 78.7 cents U.S., which it had not seen since early 1993. However, since January 2004, interest rate reductions, which reduced the interest rate differential between Canada and the United States, have caused the value of the dollar to fall from its highs, and it was valued at 74.6 cents U.S. at the end of February. It is expected that the Canadian dollar will remain near this current level and will average 75 cents over the forecast period.

The Canadian economic indicators assumed from 2004 to 2013 are presented in Table 1.1.

Table 1.1. Major Canadian economic indicators, 2004-2013

	2004	2005	2006	2007-2013[a]
GDP growth rate	3.0%	3.2%	3.0%	3.0%
Prime rate on loans	4.1%	5.0%	5.9%	6.9%
Inflation rate	1.5%	1.7%	2.0%	2.0%
Exchange rate	0.75	0.75	0.75	0.75
Unemployment rate	7.6%	7.4%	7.2%	7.0%

[a] Averages over 2007-2013.

1.4 Alberta Economic Outlook

The Alberta economy has experienced prosperous growth in each year for over 15 years. Alberta last experienced a contraction on a year-over-year basis in 1986, and since then Alberta real GDP has increased annually at an average rate of 3.5 per cent, reaching almost $128.5 billion in 2003. Since 1992, Alberta GDP per capita has been the highest among the provinces and has been on average 14 per cent higher than the GDP per capita of the second highest province, Ontario.

Over the forecast period, expansion of the oil sands industry will offset the economic impact of declining conventional production activities. However, recent cost overruns and announced delays in expansions in mining and upgrading operations will cause the expected production from these projects to be lower than last year’s forecast, particularly in the later part of the forecast period. Nonetheless, Alberta will continue to be Canada’s leading producer of crude oil, bitumen, natural gas, natural gas liquids, sulphur, and, in volumetric terms, coal.

The direct and indirect impacts of oil sands expansions, along with the expansion of other economic sectors, particularly the service sector, will cause Alberta's GDP to grow at an average annual rate of 3.7 per cent through 2008. As a result of the slowdown in oil sands expansion after 2008, the economic growth of Alberta may decline to an average of 3.0 to 3.5 per cent from 2009 and on, as shown in **Figure 1.5**. However, further economic diversification may enhance the economic growth beyond this range.

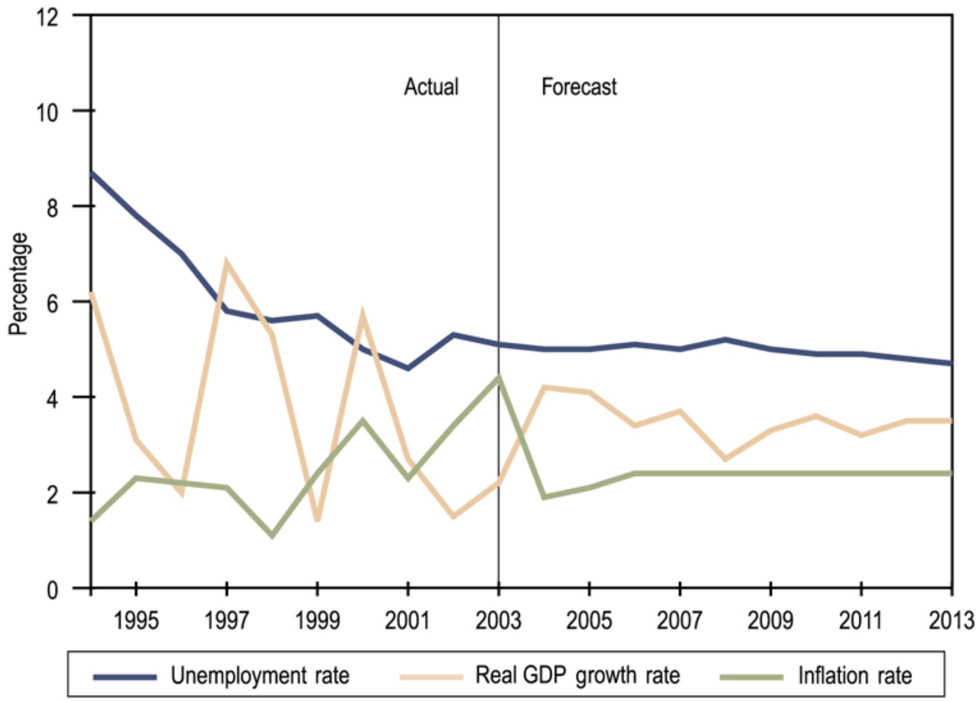

Figure 1.5. Alberta GDP growth, unemployment, and inflation rates

In the last decade, the Alberta unemployment rate has gradually declined from 8.7 per cent in 1994 to 5.1 per cent in 2003; currently, Alberta has the second lowest unemployment rate in Canada. The positive effects of continued strength in the Alberta economy on employment demand are expected to be partly offset by increases in the participation rate as people, especially those over the age of 55, enter or re-enter the workforce. As a result, both the labour force and total employment are forecast to grow at roughly the same pace, and therefore the unemployment rate will fluctuate in a tight range of between 4.8 to 5.2 per cent over the forecast period.

Alberta's inflation rate has been higher than that of the rest of Canada for all but one of the past ten years. This trend is expected to continue. Alberta's inflation rate is projected to stabilize at an average value of around 2.4 per cent a year over the forecast period.

Alberta's population has increased from 2.7 million in 1994 to slightly more than 3.15 million in 2003, representing an average annual growth rate of 1.7 per cent. It is expected that over the forecast period, as Alberta GDP grows faster than that of the rest of Canada, population growth will continue at the pace of 1.7 per cent a year.

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PowerPoint file for Section 1-Economics

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then '**Save As**' to download the file. **PowerPoint file for Section 2 – Bitumen**

2 Crude Bitumen

Crude bitumen is a type of heavy oil that is defined as a viscous mixture of hydrocarbons that in its natural state will not flow to a well. Crude bitumen in Alberta is found in sand and carbonate formations in the northeastern 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, is defined as oil sands. **Figure 2.1** shows the three areas in Alberta where oil sands deposits are found. Other heavy oil can be declared to be oil sands if it is located within oil sands area boundaries. Because these declared oil sands will flow to a well, they are amenable to primary development and are referred to as primary in situ crude bitumen in this report.

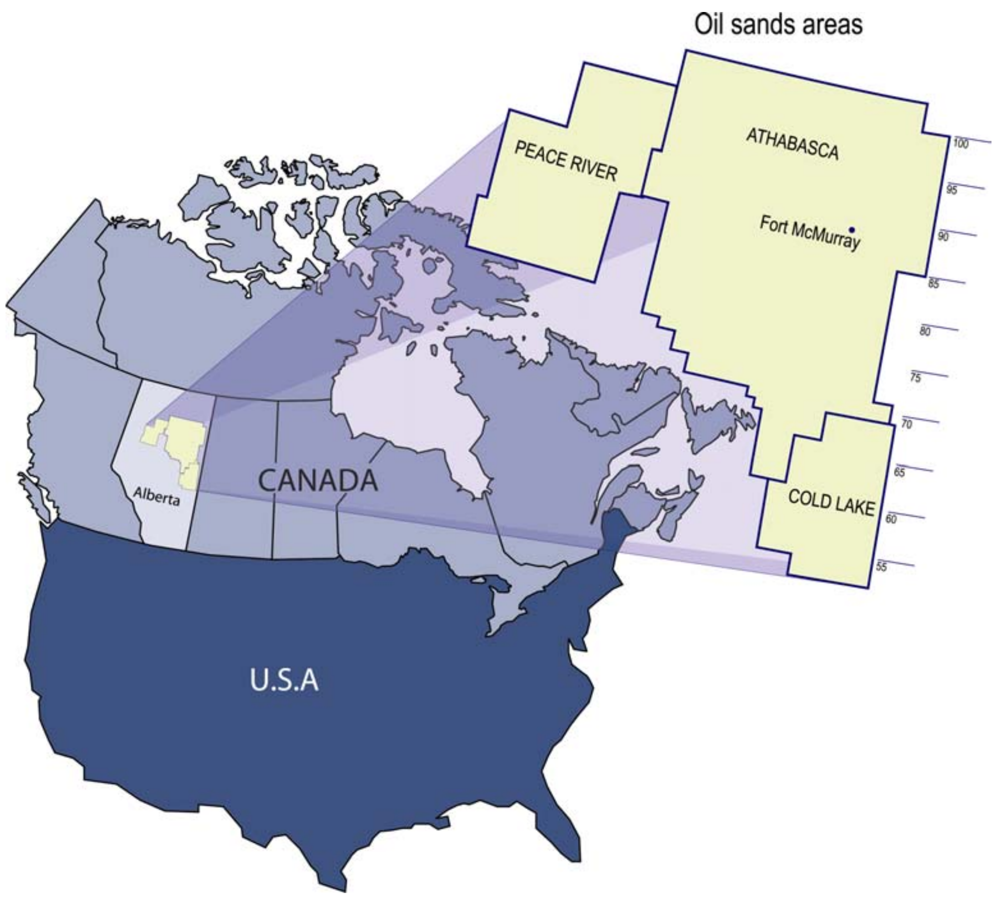


Figure 2.1. Alberta's three oil sands areas

2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

The EUB estimates the remaining established reserves of crude bitumen in Alberta at December 31, 2003, to be 27.73 billion cubic metres (10^9 m^3). Of this amount, 22.60 10^9 m^3, or about 81 per cent, is considered recoverable by in situ methods, 5.13 10^9 m^3 recoverable by surface mining methods, and 1.72 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[a]	Remaining established reserves under active development
Mineable	18.0	5.59	0.46	5.13	1.28
In situ	240.9	22.80	0.21	22.60	0.44
Total[a]	258.9 (1 629)[b]	28.39 (178.7)[b]	0.67 (4.2)[b]	27.73 (174.5)[b]	1.72 (10.8)[b]

[a] Differences are due to rounding.
[b] 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 2003 are shown in Table 2.2.

Table 2.2. Change in established crude bitumen reserves (10^6 m^3)

	2003	2002	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 802	22 740	+62
Total	28 392 (178 668)[b]	28 330 (178 280)[b]	+62
Cumulative production			
Mineable	461	425	+36
In situ[a]	206	185	+20
Total[a]	667	610	+56
Remaining established reserves			
Mineable	5 129	5 165	-36
In situ	22 597	22 555	+42
Total	27 726 (174 477)[b]	27 720 (174 439)[b]	+6

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

The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown later in the text in Tables 2.4 and 2.5 respectively.

Crude bitumen production from in situ operations totalled 20.4 10^6 m^3 in 2003. Production from the three current surface mining projects amounted to 35.6 10^6 m^3 in 2003, with 14.8 10^6 m^3 from the Syncrude Canada Ltd. project, 15.9 10^6 m^3 from the Suncor Energy Inc. project, and 5.0 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. It shows that while most of Alberta's known conventional crude oil reserves have been produced, most of the crude bitumen has yet to be tapped.

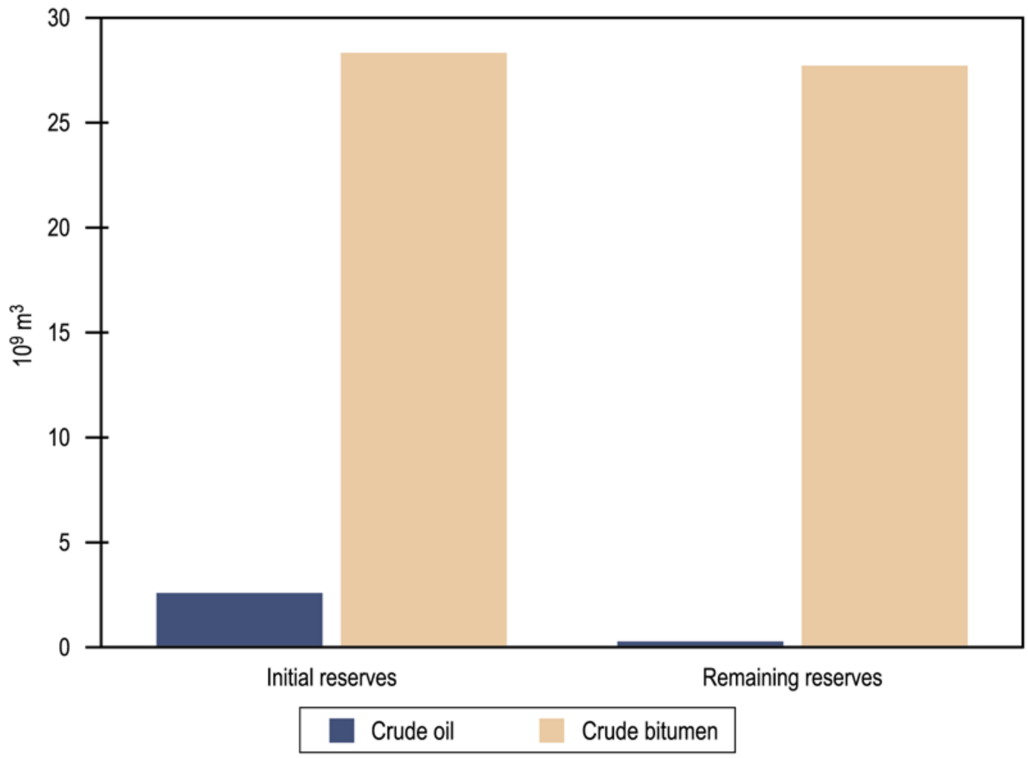


Figure 2.2. Comparison of Alberta's crude oil and crude bitumen reserves

The EUB continues to be engaged in a significant project to update the provincial reserves and plans to report the reserves for the Wabiskaw-McMurray deposit in the next edition of this report. A partial result is given in the following section.

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 Athabasca, Cold Lake, and Peace River oil sands areas. EUB-designated oil sands areas (OSAs), shown in **Figure 2.1**, define the areal extent of crude bitumen occurrence, and oil sands deposits (OSDs) designate the specific geological zones containing the oil sands.

Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data and geophysical logs. The 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, and 6 mass per cent and 3.0 m for surface-mineable areas. 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 is currently reviewing the saturation cutoff numbers for in situ areas to determine if they are still the most appropriate value and will report any change in a future edition of this report.

The volumetric resources are presented on a deposit basis in the table Crude Bitumen Resources and Basic Data, located on the accompanying CD-ROM and summarized by formation in Table 2.3. Individual maps to year-end 1995 are shown in EUB *Statistical*

Series 96-38.[1] Updated and new maps created since 1995 will likely be released with the next edition of that report but may be released separately.

Table 2.3. Initial in-place volumes of crude bitumen

Oil sands area Oil sands deposit	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Average bitumen saturation: Mass (%)	Average bitumen saturation: Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (SMA[a])	17 998	286	30.5	9.7	69	30
Wabiskaw-McMurray (non-SMA)	118 928	4 329	19.0	7.9	62	28
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	50 500	4 167	10.4	4.7	68	16
Subtotal	206 434					
Cold Lake						
Grand Rapids	17 304	1 709	5.8	9.5	61	31
Clearwater	11 051	589	15.0	8.9	64	30
Wabiskaw-McMurray	3 592	658	5.8	6.3	54	26
Subtotal	31 947					
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	328	22.5	5.3	65	19
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	20 518					
Total	258 900					

[a] Surface mineable area.

The surface mineable area (SMA) is an EUB-defined area[2] of 37 townships north of Fort McMurray covering that part of the Athabasca Wabiskaw-McMurray deposit where the total overburden generally does not exceed 75 m. As such, it is presumed that the main method of recovery will be through the use of surface-mining techniques, unlike the rest of Alberta's crude bitumen area, where recovery will be through in situ methods.

The estimate of the initial volume in place of crude bitumen within the SMA remains unchanged at 18.0 10^9 m^3. Because the SMA has been defined to fully encompass all of the potentially surface-mineable bitumen resource, it also includes some nonmineable areas. Nearly half of the above volume has been estimated to be beyond the economic range of current commercial mining. Some portion of this half, yet to be studied in detail, is or may be capable of production from in situ recovery methods.

The initial volume of crude bitumen in place for in situ areas for the designated deposits outside of the SMA as of December 31, 2003, is 240.9 10^9 m^3, a slight decrease of 0.3 10^9 m^3 due to a reassessment of the Brintnell/Pelican area in the Athabasca OSA.

[1] EUB, 1996, *Crude Bitumen Reserves Atlas, Statistical Series 96-38*.
[2] The boundary of the SMA is under review and is expected to change.

The EUB's recently released *Athabasca Wabiskaw-McMurray Regional Geological Study*[3] (RGS) contains a great deal of new and/or revised data from which the update to the complete Athabasca Wabiskaw-McMurray oil sands deposit will in due course be made. The bitumen data used in the RGS was at a 6 mass per cent saturation cutoff, a value higher than the current 3 mass per cent. For comparative purposes, a volume was determined using the existing building block method results for that portion of the Wabiskaw-McMurray that coincided with the boundaries of the RGS areas. Of the provincial total in situ bitumen initial in-place volume of 240.9 10^9 m^3, about half, 118.9 10^9 m^3, is contained within the Athabasca Wabiskaw-McMurray deposit. Of that total, some 52.5 10^9 m^3, or just under half, has previously been estimated to be contained within the north and south areas of the RGS area of study. The volume of bitumen calculated from the RGS data for the entire Wabiskaw-McMurray interval is 53.0 10^9 m^3, an amount nearly equal to the older in-place estimate. If higher cutoffs were to be used in the future to estimate bitumen volumes, it is believed that similar results will likely be seen in other areas. In general, the decrease in volume due to the higher cutoff would likely be compensated for by the increase in volume due to new areas having been drilled.

2.1.3 Surface-Mineable Crude Bitumen Reserves

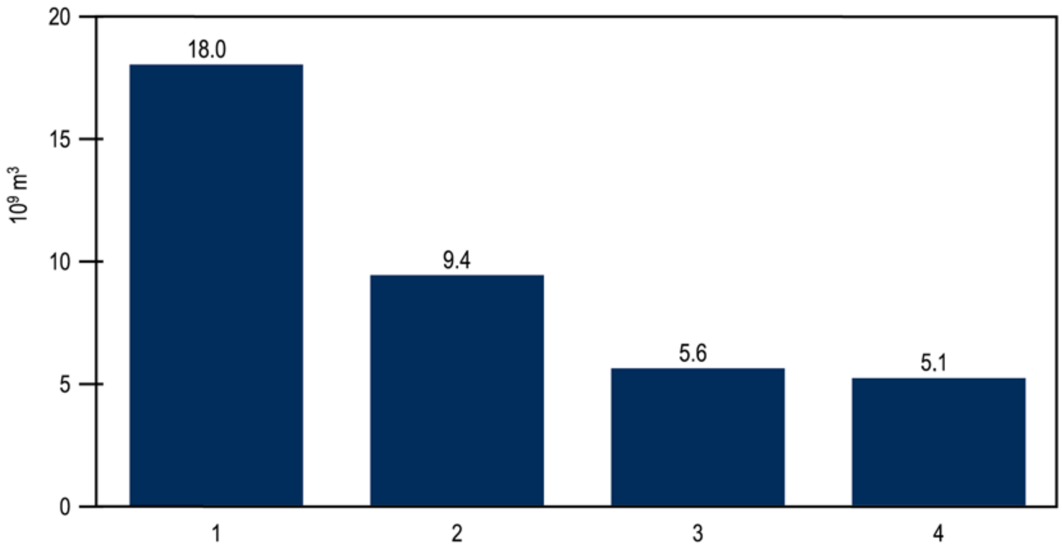
Potential mineable areas within the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[4]

The initial mineable volume in place of crude bitumen is estimated as of December 31, 2003, to be 9.4 10^9 m^3. Reduction factors were applied to this initial mineable resource volume to determine the established mineable reserve volume. These factors account for ore sterilization due to environmental protection corridors along major rivers (10 per cent), small isolated ore bodies (10 per cent), location of surface facilities (plant sites, tailings ponds, waste dumps) (10 per cent), and mining/extraction losses (18 per cent). The resulting initial established mineable reserve of crude bitumen is estimated to be 5.59 10^9 m^3, unchanged from December 31, 2002.

The remaining established mineable crude bitumen reserve as of December 31, 2003, is 5.13 10^9 m^3, slightly lower than last year due to the production of nearly 35.6 10^6 m^3 in 2003. The crude bitumen reserves categories are presented in **Figure 2.3**.

About a quarter of the initial established mineable reserve is 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 461 10^6 m^3. TrueNorth Energy received EUB approval for its Fort Hills Mine in late 2002 but it is not yet under active development (either producing or under 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 their reserves will be included in a future edition of this report when appropriate.

[3] EUB, 2003, *Athabasca Wabiskaw-McMurray Regional Geological Study, Report 2003-A*.
[4] Energy Resources Conservation Board, 1979, *Alsands Fort McMurray Project, ERCB Report 79-H.*



1. **Initial volume in place** - gross resource volume of crude bitumen established to exist within the surface-mineable area.
2. **Initial mineable volume in place** – resource volume of crude bitumen calculated using minimum saturation and thickness criteria and based upon the application of economic-strip-ratio criteria within the surface mineable area.
3. **Initial established mineable reserve** – recoverable volume of crude bitumen established within category 2 but excluding mining, extraction, and isolation ore losses and areas unavailable because of placement of mine surface facilities and environmental buffer zones.
4. **Remaining established mineable reserve** –category 3 minus cumulative production.

Figure 2.3. Crude bitumen resource and reserve categories

Table 2.4 shows the remaining established mineable crude bitumen reserves from deposits under active development as of December 31, 2003.

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2003

Development	Project area[a] (ha)	Initial mineable volume in place[b] (10^6 m^3)	Initial established mineable reserve[b] (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established mineable reserve[b] (10^6 m^3)
Albian Sands	10 096	574	178	5	173
Suncor	15 370	878	604	175	429
Syncrude	21 672	1 433	959	281	678
Total	47 138	2 885	1 741	461	1 280

[a] The project areas correspond to the areas defined in the project approval.
[b] Definitions are given in Figure 2.3.

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 attributable to thermal development were determined using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum zone thickness of 10.0 m. For primary development, the same saturation cutoff of 3 mass per cent was used, with a minimum zone thickness of 3.0 m. Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to the areas within the cutoffs. The 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.

The EUB's 2003 estimate of initial established reserves for in situ areas increased slightly to 22.80 10^9 m^3 from 22.74 10^9 m^3 in 2002. In 2003 the in situ bitumen production was 20.4 10^6 m^3, an increase from 17.4 10^6 m^3 in 2002. Cumulative production within the in situ areas now totals 206 10^6 m^3, of which 172 10^6 m^3 is from the Cold Lake OSA. Remaining established reserves of crude bitumen from in situ areas also increased slightly, to 22.60 10^9 m^3.

The EUB's 2003 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 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 440.9 10^6 m^3, a decrease of 81.7 10^6 m^3 from 2002. The increase in reserves due to the expansion of existing commercial thermal projects in the Athabasca OSA in 2003, the addition of primary reserves in the Seal area in the Peace River OSA, and the addition of enhanced recovery schemes (waterflooding) in the Brintnell/Pelican area were offset by the decrease in reserves due to production and a reassessment of the primary reserves in the Brintnell/Pelican area. The increased drilling activity in the Cold Lake OSA in recent years, and its likely increase in reserves, has not yet been reassessed.

2.1.5 Ultimate Potential of Crude Bitumen

The EUB estimates the ultimate in-place volume of crude bitumen to be about 400 10^9 m^3, consisting of 22 10^9 m^3 within the SMA in deposits that may eventually be amenable to surface mining (as well as some limited in situ recovery), and the remainder being deeper deposits that will require the use of in situ recovery or underground mining techniques.

Although drilling and log analyses indicate the large ultimate in-place volume, knowledge of variations in quality and the effect of this on recovery potential is still limited. In addition, there has been little experimentation to date to establish the expected recovery factor for some types of resources, particularly carbonates. Therefore, the portions of in-place volumes for the Cretaceous sand and Paleozoic carbonate deposits that will require the use of in situ recovery methods were broken down into established and probable categories, and different recovery factors were applied to each category in establishing the ultimate potential of crude bitumen for the in situ areas. The recovery factors selected reflect the EUB's current knowledge respecting the quality of the in-place resources, the amount of experimentation done to date to establish recovery techniques, and a projection of future improvements in those techniques.

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2003

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	21.6	40	8.6	7.5	1.1
Primary recovery schemes[c]	27.9	5	1.4	0.2	1.2
Subtotal	49.5		10.0	7.7	2.3
Athabasca Oil Sands Area					
Thermal commercial projects	155.6	50	77.8	3.9	73.9
Primary recovery schemes[d]	628.6	5	31.4	14.7	16.7
Enhanced recovery schemes[e]	(64.3)[f]	5	3.2	0.8	2.4
Subtotal	784.2		112.4	19.4	93.0
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25	200.7	125.5	75.2
Primary production within projects	601.1	5	30.1	12.4	17.7
Primary recovery schemes	4 347.1	5	217.4	29.5	187.9
Lindbergh primary production	1 309.3	5	65.5	5.0	60.5
Subtotal	7 060.3		513.6	172.4	341.2
Experimental Schemes (all areas)					
Active	8.1	15[g]	1.2	0.9[h]	0.3
Terminated	87.4	10[g]	9.1	5.1	4.0
Subtotal	95.5		10.3	6.0	4.3
Total	7 989.5		646.4	205.5	440.9

[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, 2003, includes amendments to production reports.
[c] New schemes within the Seal area.
[d] In-place and established reserves reduced from previous years due to a reassessment restricting reserves to currently producing zones.
[e] Schemes currently on waterflood in the Brintnell-Pelican area. Previous primary production is included under primary schemes.
[f] The in-place number is that part of the primary number above that will see incremental production due to waterflooding.
[g] Averaged values.
[h] Production from Athabasca area is 0.76 10^6 m^3 and from the Cold Lake area is 0.17 10^6 m^3.

The ultimate potential (which is the portion of ultimate in-place volume that is potentially recoverable) of crude bitumen from Cretaceous sediments by in situ recovery methods is estimated to be 33 10^9 m^3 and from carbonate sediments some 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. For current projects, it is also assumed that tailings ponds and discard sites will either be located on nonmineable areas or be removed from the mineable areas in order to recover underlying economic mineable ore. The total ultimate potential crude bitumen is therefore about 50 10^9 m^3.

2.2 Supply of and Demand for Crude Bitumen

In this section nonupgraded bitumen refers to the portion of crude bitumen production blended with diluent that is sent to markets by pipeline; upgraded bitumen refers to the portion of crude bitumen production upgraded to synthetic crude oil (SCO), which is used by refineries as feedstock. 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 SCO, and disposition of both SCO and blended bitumen.

Upgrading is the term given to a process that converts bitumen and heavy crude oil into SCO, which has a density and viscosity similar to conventional light-medium crude oil. Upgraders chemically add hydrogen to bitumen, subtract carbon from it, or both. In upgrading processes, essentially all 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 for use mainly in the manufacturing of 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 not returned to the province. In addition, SCO is also being 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 may decrease the amount of diluent required over time.

2.2.1 Crude Bitumen Production

In 2003, Alberta produced 153.2 thousand (10^3) m^3/d of crude bitumen, with surface mining accounting for 64 per cent and in situ for 36 per cent, a ratio similar to last year. Nonupgraded bitumen and SCO accounted for 53 per cent of Alberta's total crude oil and equivalent production, compared with 48 per cent in 2002.

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 the U.S. and Canadian markets.

2.2.1.1 Mined Crude Bitumen

Crude bitumen production increased by 16 per cent over the past year, reaching a level of 97.7 10^3 m^3/d in 2003, with Syncrude, Suncor, and Albian Sands accounting for 42, 44, and 14 per cent respectively. The primary reason for this increase was the start-up of the Albian Sands project. Bitumen production from the mine started in late 2002 but was interrupted by a fire in January 2003. Production of bitumen resumed that April and became fully operational in June 2003. This Albian Sands project produced on average some 13.7 10^3 m^3/d in 2003. Suncor continued to increase production and in 2003 raised mining production by 6 per cent to 43.5 10^3 m^3/d. Syncrude produced 40.6 10^3 m^3/d in 2003, a 5 per cent decline compared to 2002. The reduction was due primarily to an unscheduled coker turnaround, as well as extended scheduled and unscheduled maintenance work.

In projecting the future supply of bitumen from mining, the EUB considered potential production from the 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 stages three and four of the four-stage project that began in 1996;
- the Albian Sands project that began production in December 2002 and its expansion, planned for 2010 (originally scheduled for 2008);
- the CNRL Horizon Project (approved by the EUB in January 2004), with proposed production beginning in 2008;
- the Shell Jackpine Mine Project (approved by the EUB in February 2004), with production expected in late 2012 (originally expected in late 2010).

The EUB is aware of other announced projects, but they have not been considered in this forecast because of uncertainties about timing and project scope. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

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. The EUB assumed that total mined bitumen production will increase from 97.7 10^3 m^3/d in 2003 to some 226 10^3 m^3/d by 2013. **Figure 2.4** illustrates total mined bitumen production over the forecast period.

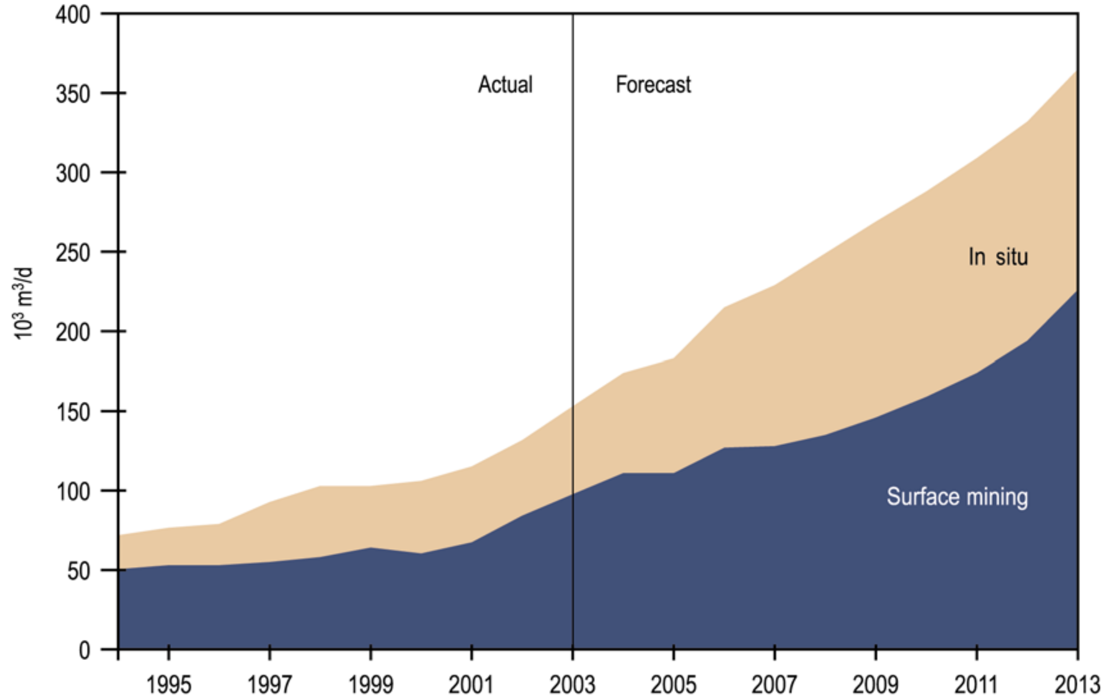


Figure 2.4. Alberta crude bitumen production

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 21.4 10^3 m^3/d in 1994 to 55.5 10^3 m^3/d in 2003. The majority of in situ bitumen, 85 per cent, was marketed in nonupgraded form outside of Alberta, and the remaining 15 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 projects. **Figure 2.4** illustrates the EUB's in situ crude bitumen forecast. It shows that in situ crude bitumen production is expected to rise to 139 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period about 25 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 34.3 10^3 m^3/d, 34.3 10^3 m^3/d, and 16.9 10^3 m^3/d of SCO respectively in 2003.

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 proposed overall liquid yield factor for the Albian Sands project, via the Shell upgrader using a hydrocracking process, is anticipated to be at or above 0.90. The OPTI/Nexen – Long Lake Project will use a new field upgrading technology and hydrocracking 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 OPTI/Nexen and CNRL. 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 addition of an in situ bitumen recovery operation (Firebag In Situ Oil Sands Operation), with start-up in late 2003
- modification of the upgrader (the addition of a vacuum tower) to increase SCO production capacity starting in 2005
- Voyageur Phase One – expansion of the existing upgrader (the construction of a pair of coke drums, a sulphur recovery plant and other crude oil processing equipment) by late 2007
- Voyageur Phase Two – increased bitumen supply through further development of the Firebag In Situ Oil Sands Project and possible further development of the oil sands mining facilities
- Voyageur Phase Three – establishment of a third oil sands upgrader by 2012

Syncrude expansions

- stage three, including the upgrader expansion and a second train of production at Aurora by mid-2006 (originally scheduled for 2005)
- stage four, including Aurora Train 3 and further upgrader expansion in 2010 (originally scheduled for 2009)

Shell

- the start-up of a new upgrader at Scotford, near Edmonton, in 2003, using crude bitumen from the Albian Sands project
- an expansion to the upgrader in 2010 to correspond with the expansion of the Muskeg Mine
- upgrading of crude bitumen from the Jackpine Mine

The proposed OPTI/Nexen – Long Lake Project is an in situ bitumen recovery and field upgrading facility located about 40 kilometres (km) southeast of Fort McMurray. Phase I of this project is expected to commence in 2007. In the second phase the capacity of all components is planned to double by 2011.

CNRL is proposing to develop its oil sands leases located within the Regional Municipality of Wood Buffalo in northeastern Alberta. The three-phase project is expected to begin operation in 2008.

The EUB is aware of other announced projects but has not included them in this forecast because of uncertainties about timing and project scope.

Figure 2.5 shows the EUB projection of SCO production. It is expected that the SCO production will increase from 85.5 10^3 m^3/d in 2003 to 222 10^3 m^3/d in 2013.

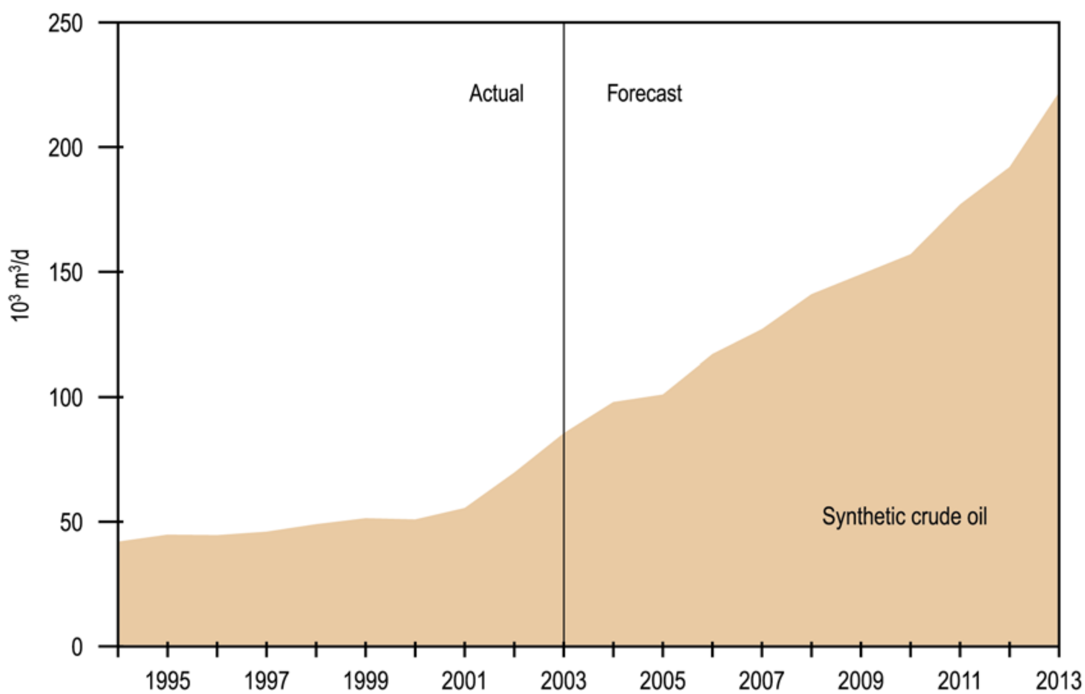


Figure 2.5. Alberta synthetic crude oil production

2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, pipeline capacity availability is essential to move new production to markets. The current pipeline systems in the Cold Lake and Athabasca areas are tabulated in Table 2.6.

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	31.8
Cold Lake Heavy Oil Pipeline	Edmonton	37.3
Husky Oil Pipeline	Hardisty	21.2
Husky Oil Pipeline	Lloydminster	24.3
Echo Pipeline	Hardisty	12.0
Fort McMurray Area Pipelines		
Athabasca Pipeline	Hardisty	21.0
Terasen Pipelines (Corridor)	Edmonton	35.1
Alberta Oil Sands Pipeline	Edmonton	43.7
Oil Sands Pipeline	Edmonton	20.7

The Cold Lake pipeline system is capable of delivering heavy crude from the Cold Lake area to Hardisty or Edmonton. The Husky pipeline moves Cold Lake crude to Husky's heavy oil operations in Lloydminster. Heavy and synthetic crude are then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge or the Express pipeline systems. The Echo pipeline system is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending.

The Athabasca pipeline delivers semiprocessed product and bitumen blends to Hardisty and has the potential to carry 90.6 10^3 m^3/d. The Terasen Corridor pipeline transports diluted bitumen from the Albian Sands mining project to the Shell Scotford upgrader. Capacity of the pipeline can be increased by 11.9 10^3 m^3/d through the addition of four pump stations. The Alberta Oil Sands pipeline is the exclusive transporter for Syncrude. An expansion to increase capacity to 61.8 10^3 m^3/d is planned for 2004. The Oil Sands Pipeline transports Suncor synthetic oil to the Edmonton area.

Table 2.7 lists the export pipelines and their destinations and capacities. Enbridge completed the third and final phase of the Terrace Expansion project in mid-2003, bringing an additional 22.3 10^3 m^3/d of capacity to the system. The Terasen Express pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends into Wood River, Illinois. Plans are under way to increase capacity to 44.8 10^3 m^3/d by 2005. The Terasen Trans Mountain pipeline system that transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State has a current capacity of 44.6 10^3 m^3/d. Terasen is also proceeding with an expansion of the Trans Mountain pipeline, which will add 4.3 10^3 m^3/d of additional capacity and is expected to be in service by September 2004. Rangeland is a gathering system and serves as another export route for Cold Lake Blend. Milk River Pipeline delivers Bow River heavy and Manyberries light oil. Both pipelines deliver primarily into Montana refineries.

2.2.4 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

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), which may have undesirable environmental properties.

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	312.2
Terasen Pipelines (Express)	U.S. Rocky Mountains U.S. midwest	27.3
Milk River Pipeline	U.S. Rocky Mountains	16.8
Rangeland Pipeline	U.S. Rocky Mountains	10.3
Terasen Pipelines (Trans Mountain)	British Columbia U.S. west coast Offshore	44.6
Total		411.2

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 2003, five Alberta refineries, with a total capacity of 69.9 10^3 m^3/d, used 28.0 10^3 m^3/d of SCO and 3.7 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand represents 33 per cent of Alberta SCO production and 7 per cent of nonupgraded bitumen production.

The proposed Petro-Canada Refinery Feed Conversion Program, described in last year's report, was put on hold in April 2003 due to concerns about rising capital costs. In December 2003, Petro-Canada announced a new plan to upgrade and refine oil sands feedstock at its Edmonton refinery. By reconfiguring the refinery and supplying it with feedstock through an agreement with Suncor Energy Inc., Petro-Canada will effectively process 8.4 10^3 m^3/d of bitumen, providing for existing and future steam-assisted gravity drainage (SAGD) production from Petro-Canada's leases.

The agreement calls for Petro-Canada to ship a minimum of 4.3 10^3 m^3/d of bitumen from its MacKay River oil sands facility to Suncor's plant north of Fort McMurray, where it will be processed into sour crude oil on a fee-for-service basis. That product will be combined with an additional 4.1 10^3 m^3/d of sour crude purchased from Suncor for upgrading and refining into finished product at Edmonton. The agreement takes effect in 2008, subject to regulatory approval.

Central to the refinery reconfiguration is an expansion of the existing coker at Edmonton allowing for direct bitumen upgrading. Initially, Petro-Canada intends to purchase 4.1 10^3 m^3/d of bitumen from other producers to fill out that bitumen processing capability. In due course, this external feedstock will be replaced by supply from Petro-Canada's next SAGD development.

Figure 2.6 shows that in 2013 demand for SCO and nonupgraded bitumen will increase to some 46 10^3 m^3/d. It is projected that SCO will account for 84 per cent and nonupgraded bitumen will constitute 16 per cent.

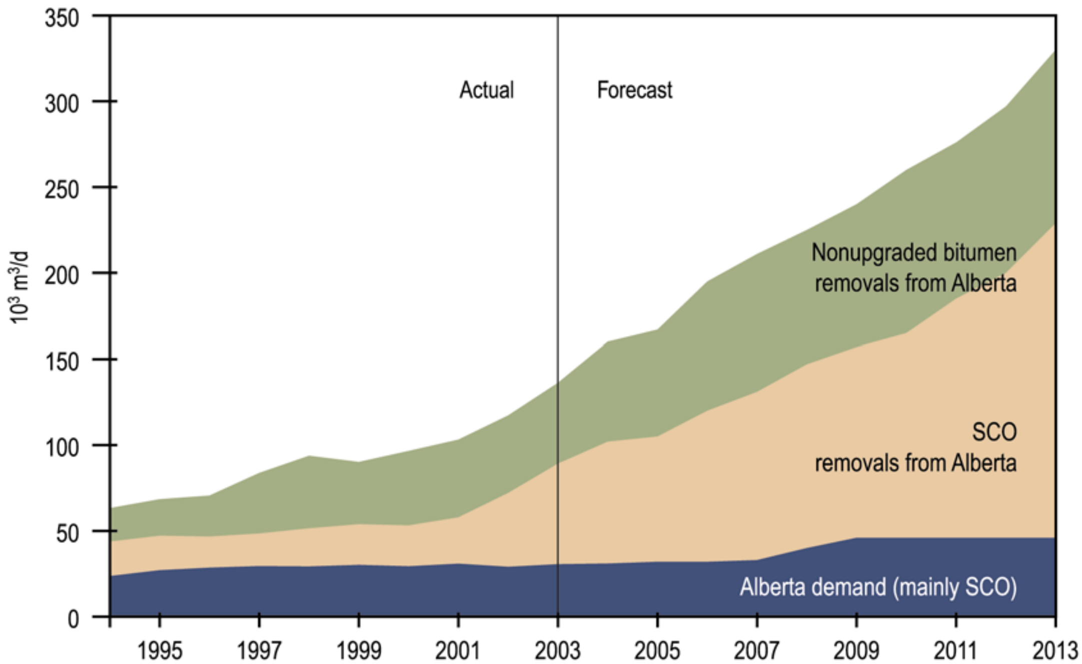


Figure 2.6. Alberta demand and disposition of crude bitumen and SCO

Given the current quality of SCO, western Canada's nine refineries, with a total capacity of 90 10^3 m^3/d, are able to blend up to 30 per cent SCO and a further 4 per cent blended bitumen with crude oil. These refineries receive SCO from both Alberta and Saskatchewan. In eastern Canada, the four Sarnia-area refineries are the sole extra-provincial 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 refined products future growth. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with refining capacity of 562 10^3 m^3/d, and the U.S. Rocky Mountain region, with refining capacity of 92 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, U.S. west coast, and the Far East.

Figure 2.6 shows that over the forecast period removals from Alberta of SCO will increase from 58.6 10^3 m^3/d to 183 10^3 m^3/d and the removals of nonupgraded bitumen will increase from 47.1 10^3 m^3/d to 101 10^3 m^3/d.

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then '**Save As**' to download the file.
PowerPoint file for Section 2 – Bitumen

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file
Power Point file for Section 3 – Oil

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 million cubic metres (10^6 m^3) at December 31, 2003. This is a decrease from December 31, 2002, of 6.4 10^6 m^3, resulting from all additions, reserve adjustments, and production that occurred during 2003. The changes in reserves and cumulative production for light-medium and heavy crude oil to December 31, 2003, 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)

	2003	2002	Change
Initial established reserves[a]			
Light-medium	2 267.5	2 251.3	+16.2
Heavy	366.6	352.0	+14.6
Total	2 634.0	2 603.3	+30.8
Cumulative production[a]			
Light-medium	2 082.0	2 058.2	+23.8[b]
Heavy	298.1	284.8	+13.3[b]
Total	2 380.1	2 343.0	+37.1[b] (233 10^6 bbls)
Remaining established reserves[a]			
Light-medium	185.4	193.1	-7.7
Heavy	68.5	67.2	+1.3
Total	253.9 (1 598 10^6 bbls)	260.3	-6.4

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

3.1.2 Reserves Growth

A detailed breakdown of this year's reserves changes, including additions, revisions, and enhanced recovery, is presented in Table 3.2, while **Figures 3.2** gives a history of these changes back to 1988. The initial established reserves attributed to the 411 new oil pools booked in 2003 totalled 6.9 10^6 m^3 (17 thousand [10^3] m^3 per pool), down slightly from 7.0 10^6 m^3 in 2002. Reserve additions from new waterfloods continue to decline due to smaller pools and lack of suitable quality candidates for such schemes **(Figure 3.3)**. Net reserve revisions totalled 17.1 10^6 m^3, mostly from heavy crude pools, which have seen average recoveries improve from 8 per cent to 13 per cent in the past 13 years. The resulting total increase in initial established reserves for 2003 amounted to 30.8 10^6 m^3, up from last year's 20.2 10^6 m^3. Table B.1 in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.

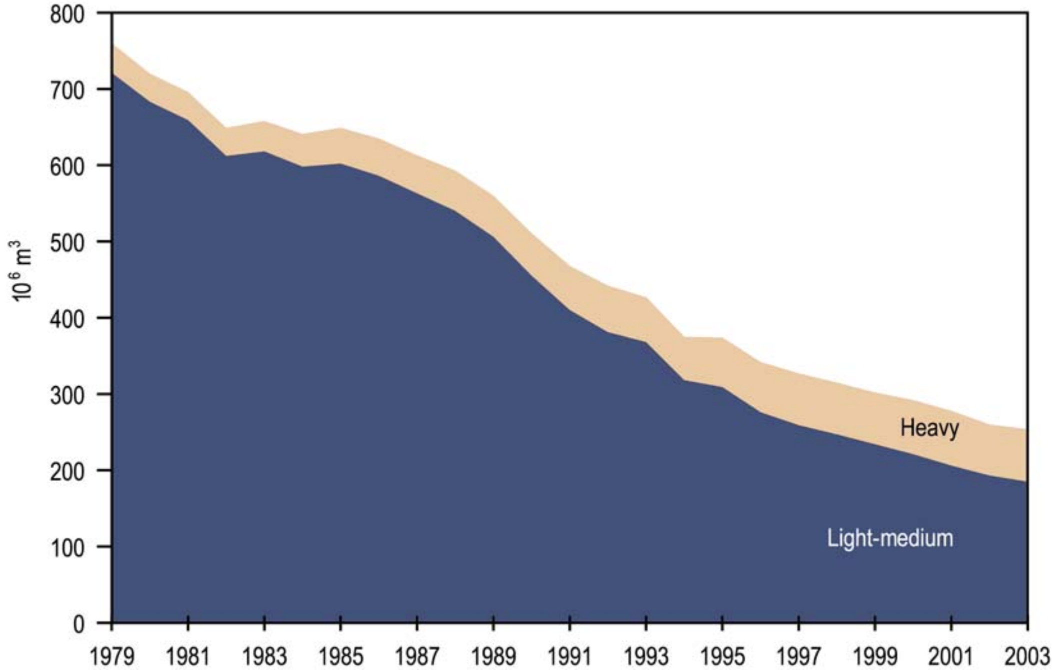


Figure 3.1. Remaining established reserves of crude oil

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

	Light-medium	Heavy	Total
New discoveries[a]	6.0	0.9	6.9
Development of existing pools[a]	2.7	3.2	5.9
Enhanced recovery (new/expansion)	1.0	0.0	1.0
Reassessment[a]	+6.5	+10.5	+17.1
Total[a]	16.1	14.6	30.8

[a] Discrepancies are due to rounding.

Reserve additions resulting from drilling and new enhanced recovery schemes totalled 13.8 10^6 m^3, down 12 per cent from 15.6 10^6 m^3 in 2002. These additions replaced 38 per cent of Alberta's 2003 conventional crude oil production of 36.5 10^6 m^3.

3.1.3 Oil Pool Size

At December 31, 2003, oil reserves were assigned to some 8044 light-medium and 2602 heavy crude oil pools in the province. About 60 per cent of these pools consist of a single well. The distribution of reserves by pool size shown in Table 3.3 indicates that some 88 per cent of the province's remaining oil reserves is contained in the largest 13 per cent of pools. By contrast, the smallest 74 per cent of pools contain only 2 per cent of the province's initial reserves and 6 per cent of its remaining reserves. **Figure 3.4** illustrates the historical trends in the size of oil pools.

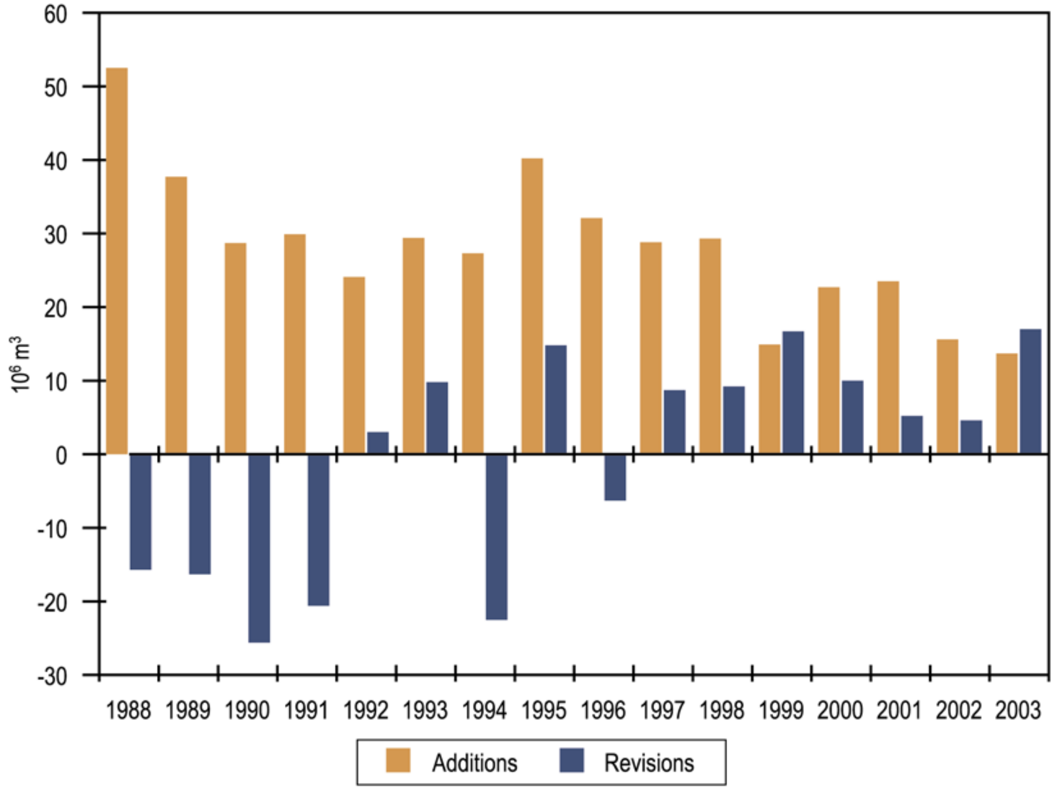


Figure 3.2. Annual changes in conventional crude oil reserves

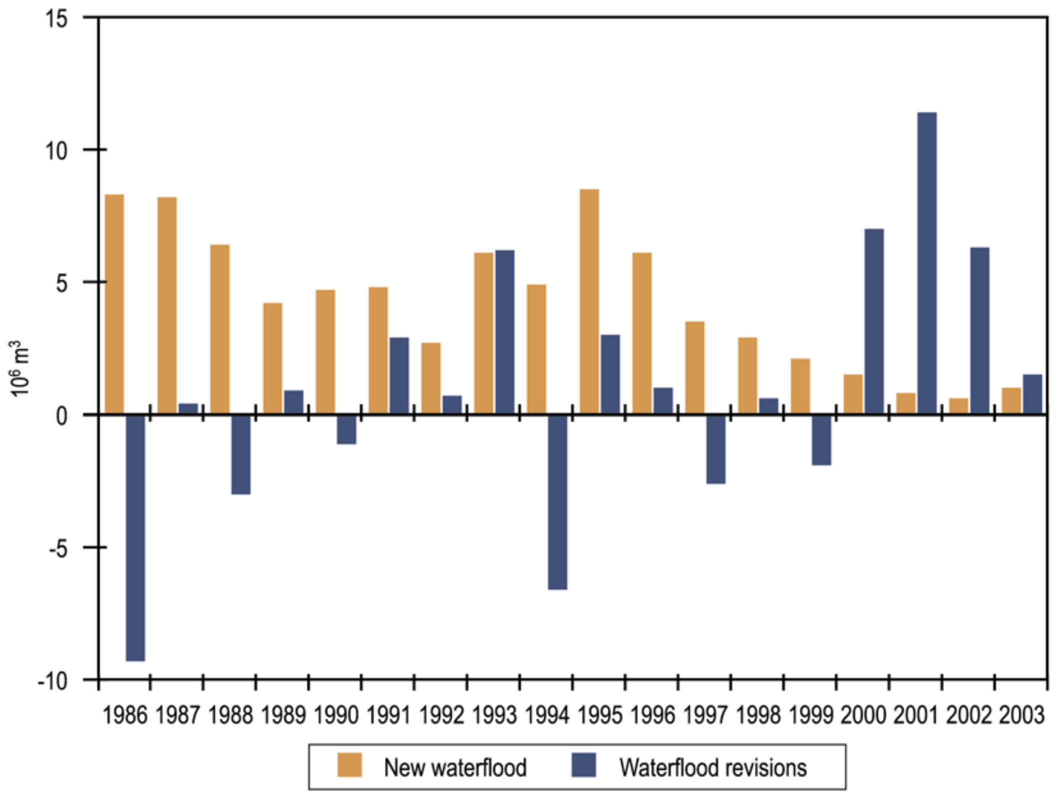


Figure 3.3. Annual changes to waterflood reserves

Table 3.3. Distribution of oil reserves by pool size

Pool size range[a] (10^3 m^3)	Pools No.	Pools %	Initial established reserves 10^6 m^3	Initial established reserves %	Remaining established reserves 10^6 m^3	Remaining established reserves %
1000 or more	290	3	2 165	82	163	64
100-999	1 102	10	340	13	60	24
30-99	1 415	13	77	3	16	6
1-29	7 839	74	52	2	14	6
Total	10 646	100	2 634	100	254	100

[a] Based on initial established reserves.

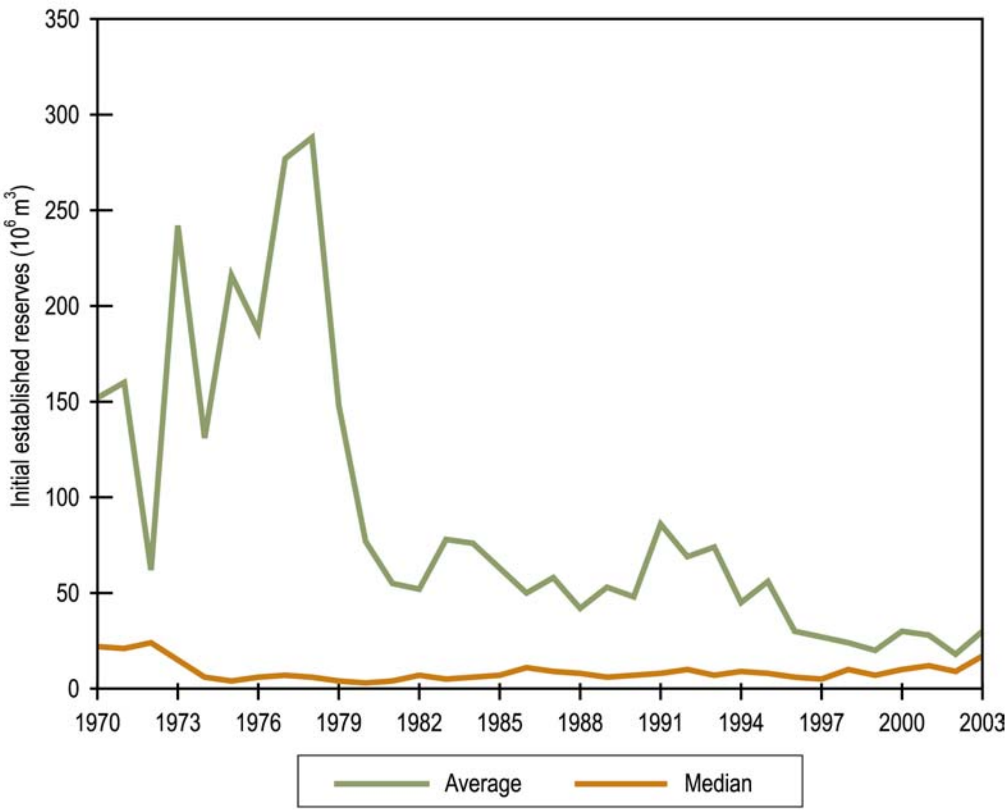


Figure 3.4. Oil pool size by discovery year

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 (over 10 10^6 m^3) oil discovery in Alberta. Its initial established reserve now stands at 13 820 10^3 m^3.

3.1.4 Pools with Largest Reserve Changes

Some 1700 oil pools were re-evaluated over the past year, resulting in positive revisions totalling 34 10^6 m^3 and negative revisions totalling 17 10^6 m^3, for a net total of plus 17 10^6 m^3. Reserves in the heavy oil Suffield Upper Mannville A Pool were revised upwards by 4310 10^3 m^3 as the result of infill horizontal drilling and recognition of a higher recovery factor. Valhalla Doe Creek I Pool saw an increase of 2786 10^3 m^3 as development drilling added new reserves. On the other hand, downward revision in the recovery efficiency of the Rainbow Keg River B solvent flood reduced reserves by 3710 10^3 m^3. Table 3.4 lists those pools having the largest reserve changes in 2003.

3.1.5 Distribution by Recovery Type and Geological Formation

The distribution of conventional crude oil reserves by drive mechanism is illustrated in **Figure 3.5**. Improved recoveries from all waterflood projects have added 653 10^6 m^3, representing 25 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, as shown in Table 3.5.

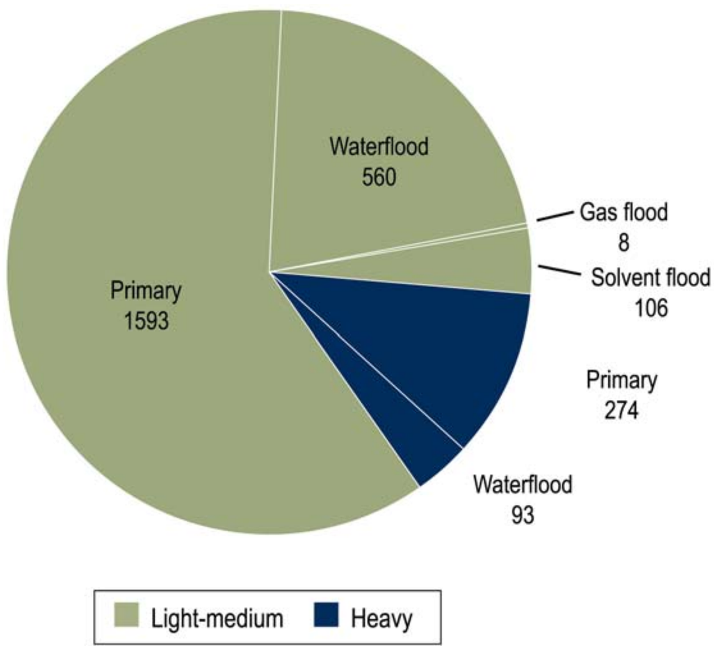


Figure 3.5. Initial established crude oil reserves based on various recovery mechanisms (10^6 m^3)

The distribution of reserves by geological period, depicted graphically in **Figure 3.6**, indicates that 35 per cent of remaining established reserves will 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 fully 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 becoming increasingly 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.

Table 3.4. Major oil reserve changes, 2003

Pool	Initial established reserves (10^3 m^3) 2003	Change	Main reason for change
Cessford Mannville C	4 947	+582	Reassessment of reserves
Chauvin South Mannville MU#1	13 920	+630	Reassessment of waterflood reserves
Enchant Arcs J and VV	3 172	+288	Reassessment of waterflood reserves
Gift Slave Point A	3 040	+790	Reassessment of reserves
Goose River Beaverhill Lake A	11 070	+897	Reassessment of solvent flood reserves
Little Bow Upper Mannville S	1 110	+273	Reassessment of reserves
Marwayne Sparky C	817	+325	Pool development and reassessment of reserves
Pembina Nisku II	481	+481	New pool
Princess Basal Mannville M	419	+313	Reassessment of reserves
Provost Lower Mannville Z	1 215	+309	Reassessment of reserves
Provost Mannville L	2 780	+334	Reassessment of reserves
Provost Sparky D	609	+305	Reassessment of reserves
Provost Upper Mannville BB	2 821	+594	Pool development
Rainbow Keg River B	27 090	-3 710	Reassessment of solvent flood reserves
Red Earth Slave Point A, Granite Wash A & VV	6 980	+912	Reassessment of reserves
Suffield Upper Mannville A	6 476	+4 310	Pool development and reassessment of reserves
Suffield Upper Mannville OOO	492	+403	Reassessment of reserves
Suffield Upper Mannville YYY	333	+333	New pool
Taber North Glauconitic A	6 047	-465	Reassessment of reserves
Valhalla Doe Creek I	13 816	+2 786	Reassessment of waterflood reserves
Valhalla Montney C & LL	1 590	+301	Reassessment of reserves
Viking-Kinsella Sparky F	2 883	+517	Pool development and reassessment of reserves
Westerose D-3	23 780	-400	Reassessment of reserves
Wimborne D-3 A	5 850	+910	Reassessment of reserves

Table 3.5. Conventional crude oil reserves by recovery mechanism as of December 31, 2003

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	3 849	876	0	0	876	23	-	-	23
Waterflood	2 917	428	394	0	822	15	14	-	28
Solvent flood	930	256	166	106	528	28	18	11	57
Gas flood	113	33	8	0	41	29	7	-	36
Heavy									
Primary depletion	1 672	224	0	0	224	13	-	-	13
Waterflood	397	50	93	0	143	13	23	-	36
Total	9 878	1 867	661	106	2 634	19			27
Percentage of total initial established reserves		71%	25%	4%	100%				

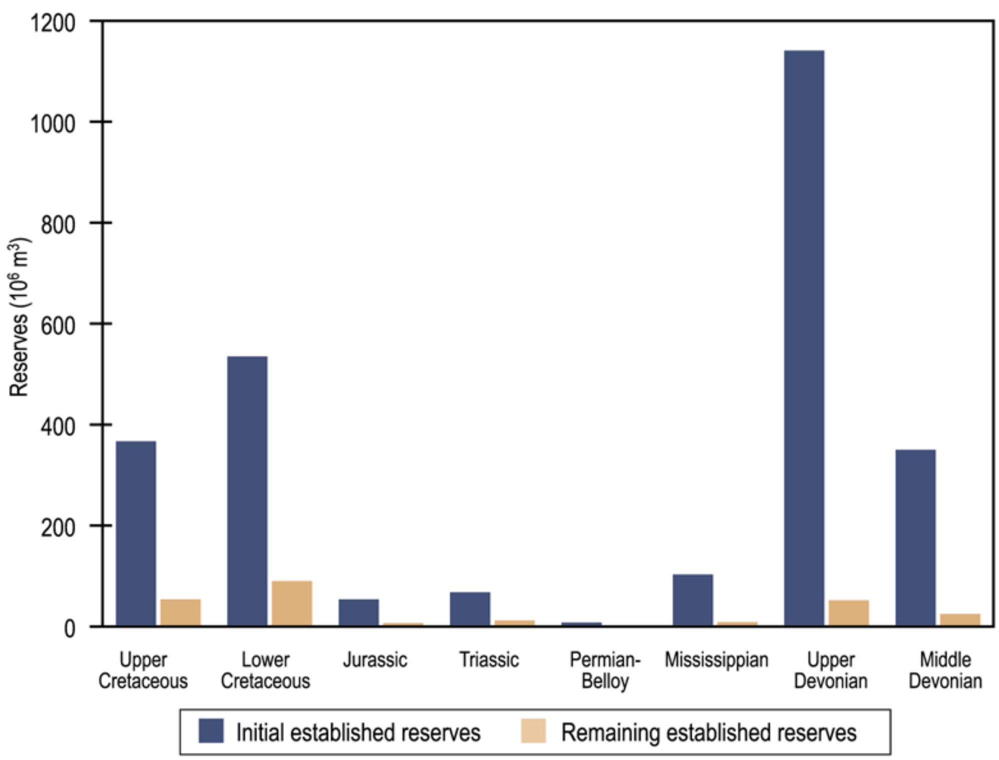


Figure 3.6. Geological distribution of reserves of conventional crude oil

3.1.6 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 3.7** illustrates the historical relationship between remaining reserves and cumulative oil production. Extrapolation of the decline suggests that the EUB's estimate of ultimate potential is still reasonable. **Figure 3.8** shows Alberta's historical and forecast growth of initial established reserves. Approximately 76 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2003. Remaining established reserves of 254 10^6 m^3 represent 8 per cent of the ultimate potential. Known discoveries represent 84 per cent of the ultimate potential, leaving 16 per cent (496 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves yields 750 10^6 m^3 of conventional crude oil that is available for future production.

In 2003, both the remaining established reserves and the annual production of crude oil declined. However, there are 496 10^6 m^3 yet to be discovered, which will mitigate the impact of these declines. At the current rate of annual reserve growth, it will take over 36 years to find the reserves projected yet to be discovered. Additions to existing pools and the discovery of new pools will continue to bring on new reserves and associated production each year.

Any future decline in conventional crude oil production within Alberta will be more than offset by increases in crude bitumen and synthetic production, as discussed in Section 2.2. In fact, starting in 2001, crude bitumen production has exceeded conventional crude oil production.

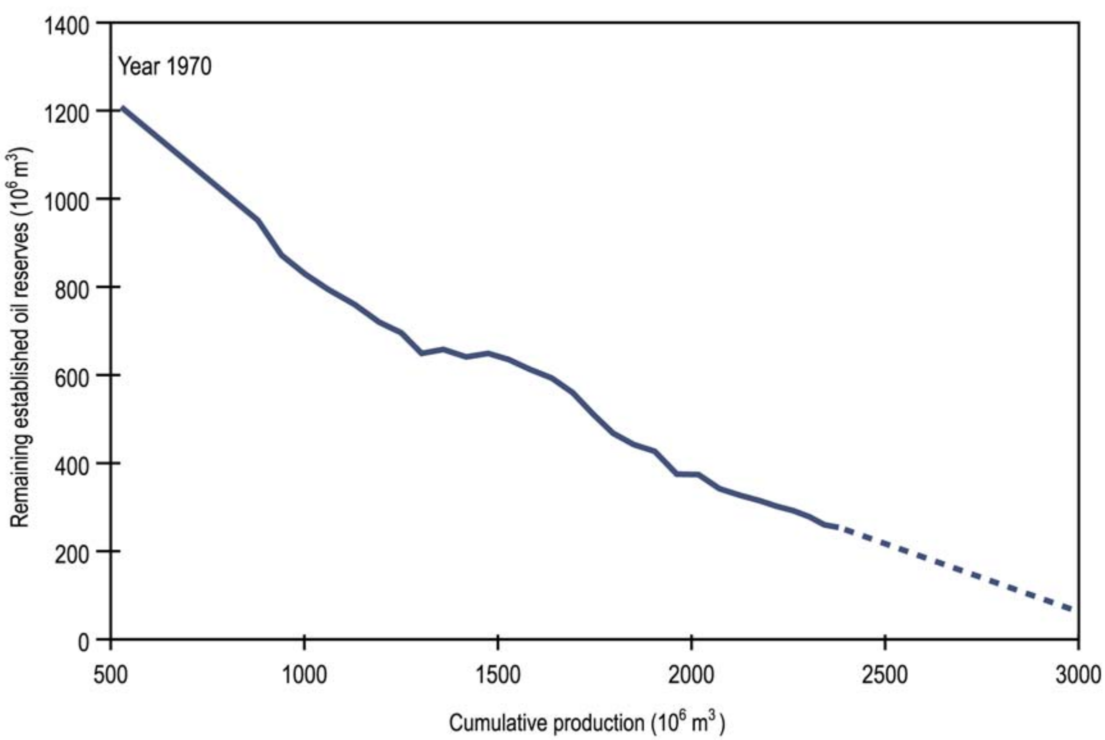


Figure 3.7. Alberta's remaining established oil reserves versus cumulative production

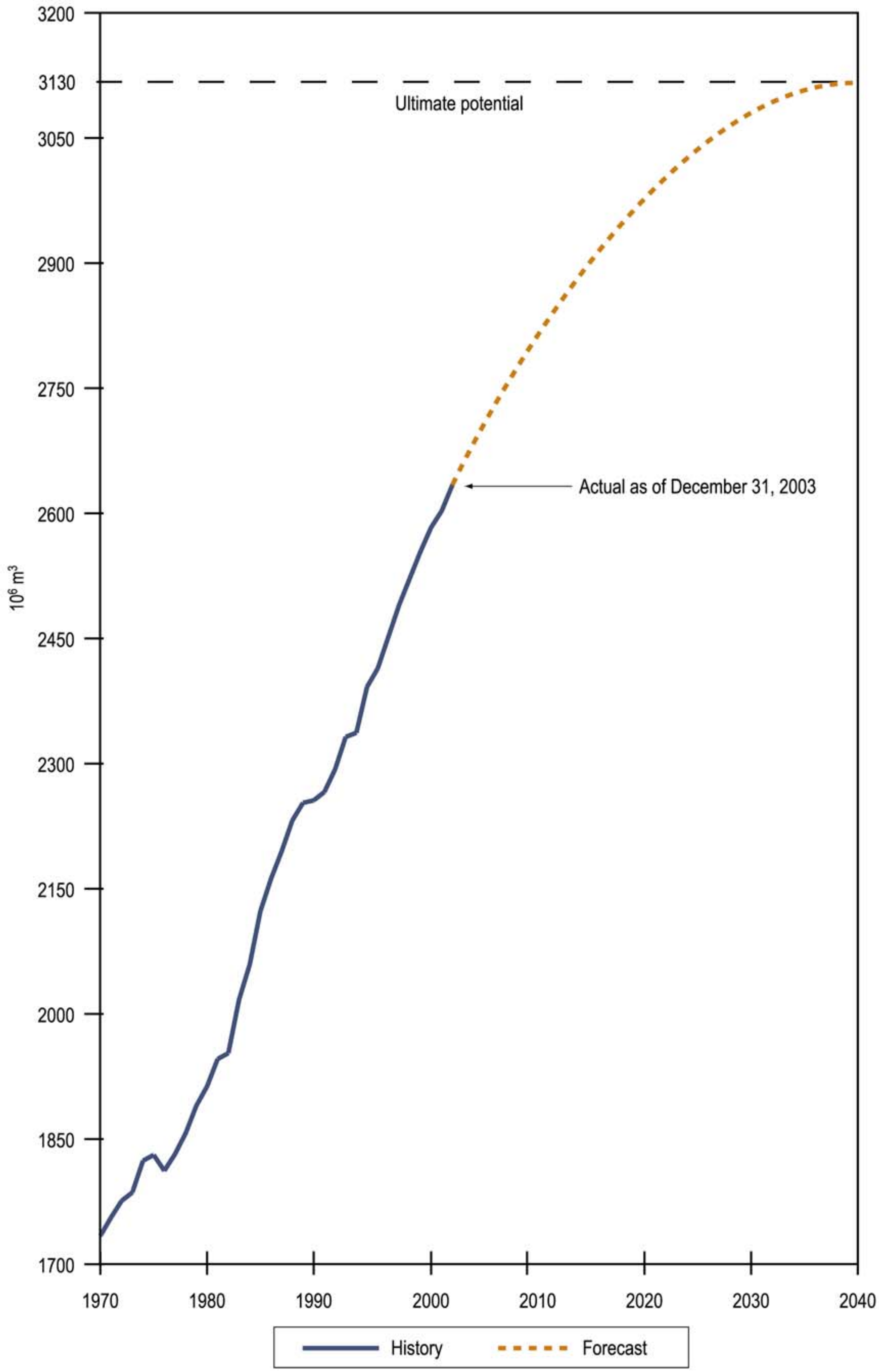


Figure 3.8. Growth in initial established reserves of crude oil

3.2 Supply of and Demand for Crude Oil

3.2.1 Crude Oil Supply

Over the past several decades, production of light-medium and heavy crude oil has been on decline in Alberta. In 2003, total crude oil production declined to 100.0 10^3 m^3/d. Light-medium crude oil production declined by about 6 per cent to 65.8 10^3 m^3/d from its 2002 level. Heavy crude oil production experienced a decline of some 4 per cent below 2002 levels to 34.2 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 5 per cent from 2002 to 2003, compared to the 8 per cent decline from 2001 to 2002.

While the number of crude oil producing wells has increased, crude oil production has been on decline since its peak in 1973. **Figure 3.9** shows total crude oil production and the number of crude oil producing wells since 1994. As illustrated in this figure, while the number of total producing wells has increased from 29 100 in 1994 to 35 500 in 2003, crude oil production has been on decline. It should be noted that of the 35 500 wells producing oil in 2003, some 2000 were gas wells. Although this represents about 6 per cent of the total number of wells, they produce at an average rate of about 0.3 m^3/d and account for less than 1 per cent of the total production.

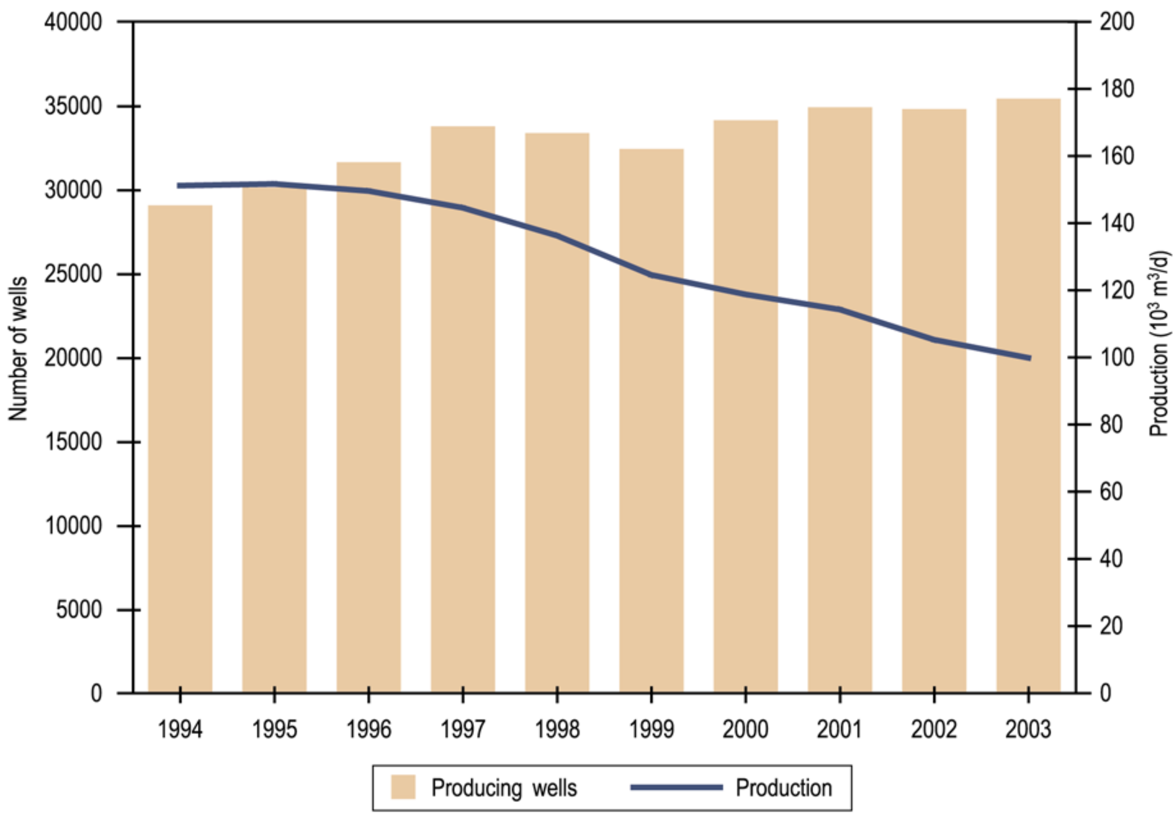


Figure 3.9. Total crude oil production and producing oil wells

The average well productivity of crude oil producing wells in 2003 averaged some 3.0 m^3/d. The majority of crude oil wells in Alberta, about 56 per cent, produced less than 2 m^3/d per well. In 2003, the 18 700 oil wells in this category operated at an average rate of 1 m^3/d and produced only 17 per cent of the total crude oil produced. **Figure 3.10** depicts the distribution of crude oil producing wells based on their average production rates in 2003.

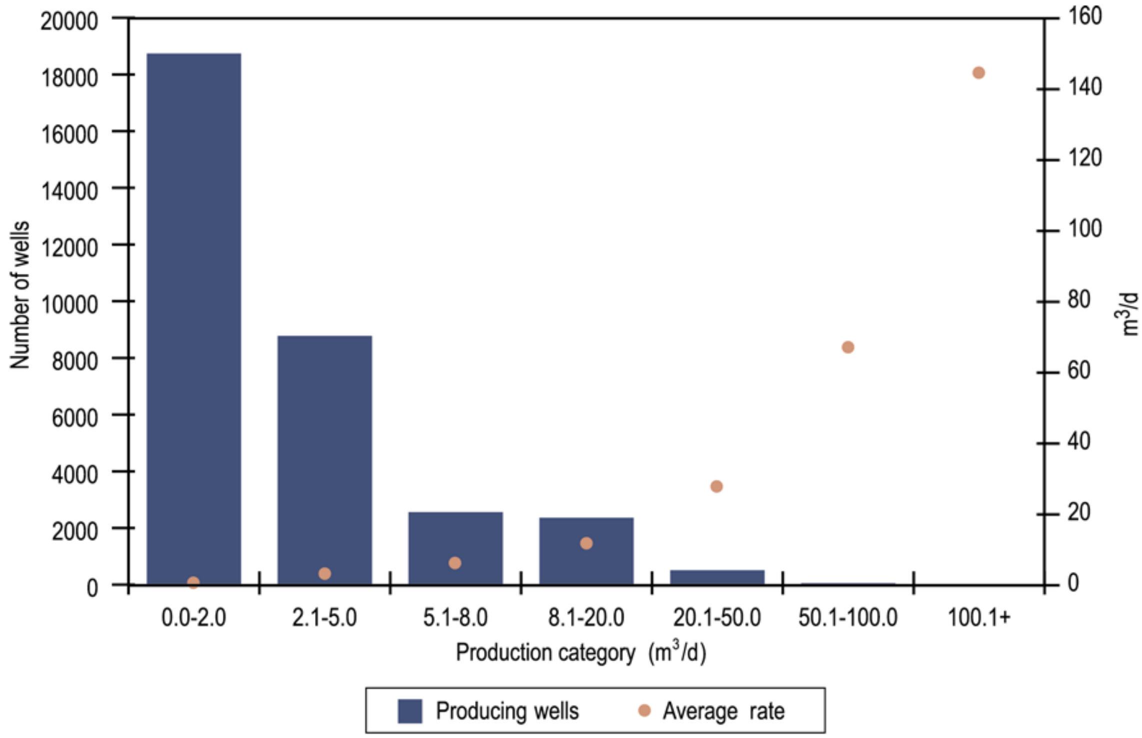


Figure 3.10. Crude oil well productivity in 2003

The number of successful oil wells drilled in 2003 was 2360, an increase of some 42 per cent over 2002 levels. This increase was due primarily to industry's reaction to sustained high oil prices throughout the year and strong demand for crude oil.

In 2003, some 373 horizontal wells were brought on production, a 13 per cent increase over 2002, raising the total to 3100 producing horizontal wells in Alberta. Horizontal wells account for 9 per cent of producing oil wells and about 17 per cent of the total crude oil production. Production from horizontal wells drilled in the past five years peaked in 1999 at an average rate of some 13.0 m^3/d. The rate of horizontal wells brought on production in 2002 averaged about 9.0 m^3/d.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2003 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 2004, the EUB considered the following assumptions:

- Production from existing wells in 2004 will be 88.7 10^3 m^3/d.
- Production from the existing wells will decline at a rate of about 15 per cent per year.

Crude oil production from existing wells by drilled year over the period 1994-2003 is depicted in **Figure 3.11**. This figure illustrates that about 33 per cent of crude oil production in 2003 resulted from wells drilled in the last four years. Over the forecast period, production of crude oil from existing wells is expected to decline to 23 10^3 m^3/d by 2013.

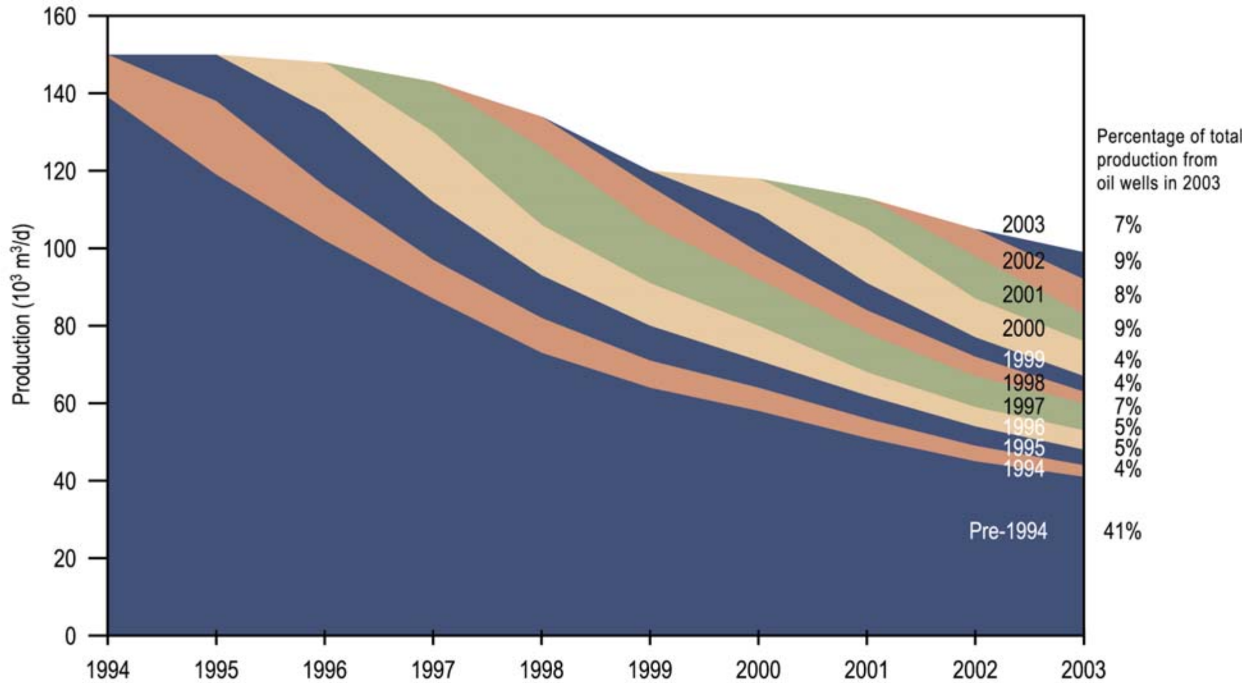


Figure 3.11. Total conventional crude oil production by drilled year

Figure 3.12 compares the production from 1950 through 2003 for Alberta crude oil and the production from Texas onshore and Louisiana onshore. Louisiana onshore reached peak production in 1970, while Texas onshore reached peak production in 1972 and Alberta in 1973. The chart shows that Alberta did not experience the same steep decline rates after reaching peak production as did Texas and Louisiana onshore production. This was likely due in part to the prorationing that existed in Alberta from the early 1950s to the mid-1980s.

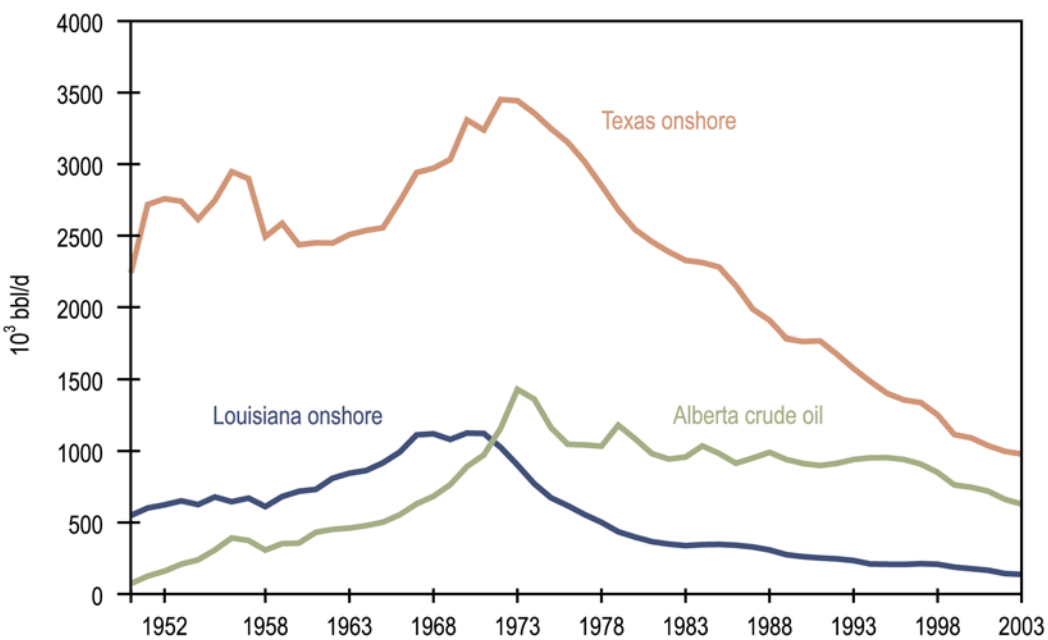


Figure 3.12. Comparison of crude oil production

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 believes that global crude oil prices will play a major role in drilling activity over the forecast period. As discussed in Section 1, the EUB expects that crude oil prices will be stable, resulting in high levels of drilling for crude oil over the forecast period. However, the EUB does not expect the high drilling rates experienced in the mid-1990s, when industry was more focused on oil than natural gas.

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

- Drilling is projected to decrease slightly to 2300 successful wells in 2004, and then decrease to 2200 wells in 2005 and remain at this level over the forecast period. **Figure 3.13** illustrates the EUB's crude oil drilling forecast for successful wells for the period 2004 to 2013, along with the historical data.
- Based on recent historical data, it is assumed that the average initial production rate for new wells will be 5.0 m^3/d/well and will decrease to 4.0 m^3/d/well by the end of the forecast period. This is a decline from an average of 8.0 m^3/d/well in the mid-1990s.
- Production from new wells will decline at a rate of 26 per cent per year.

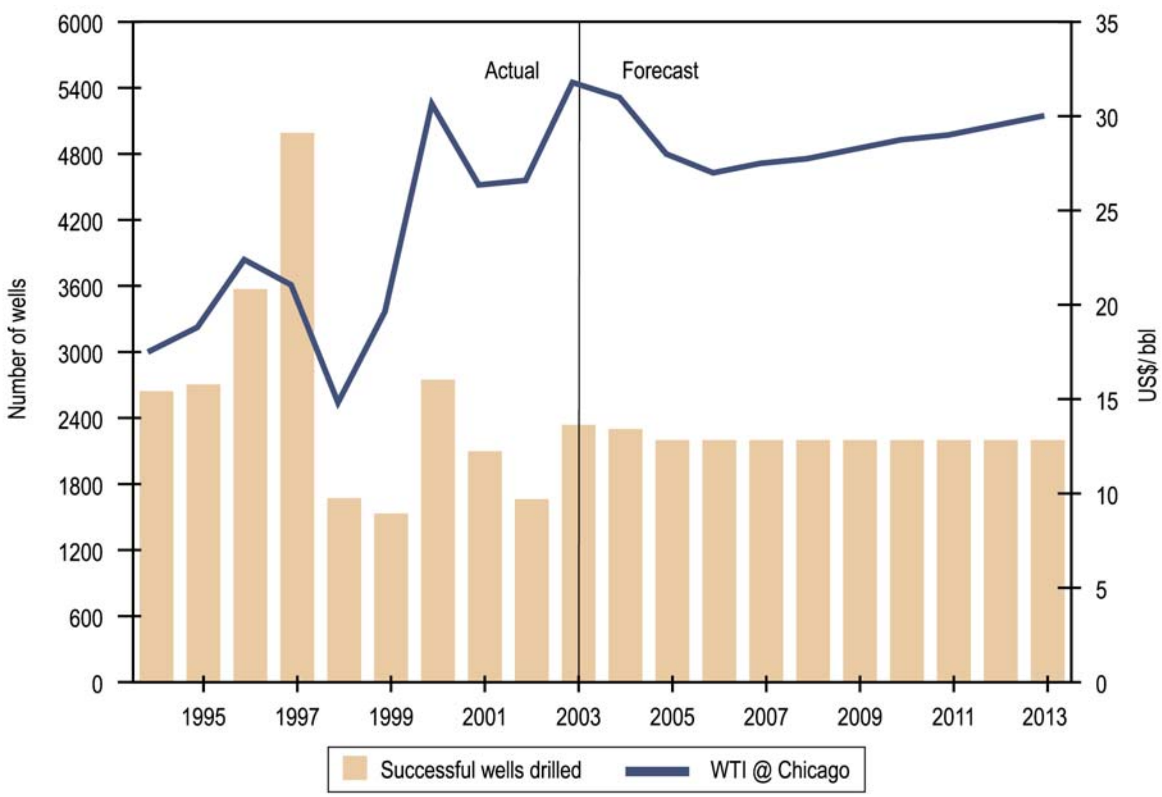


Figure 3.13. Alberta crude oil price and drilling activity

The projection of the above two components, production from existing wellbores and production from future successful oil wells, is illustrated in **Figure 3.14.** Light-medium crude oil production is expected to decline from 65.8 10^3 m^3/d in 2003 to 42 10^3 m^3/d in 2013. Although crude oil drilling is expected to remain at the level of 2005, light-medium crude oil production will continue to decline by almost 5 per cent a year, due to the failure of new wells 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 34.2 10^3 m^3/d in 2003 to 24 10^3 m^3/d by the end of the forecast period. **Figure 3.14** illustrates that by 2013, heavy crude oil production will constitute a greater portion of total production compared to 2003, although total production will be smaller.

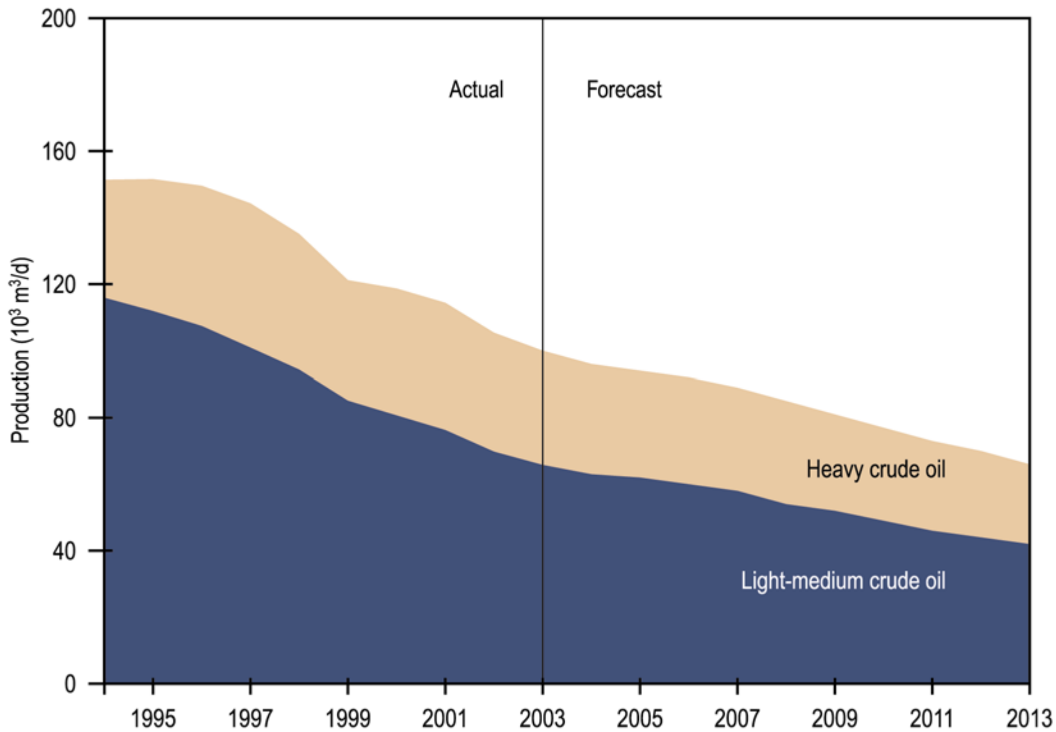


Figure 3.14. Alberta daily production of crude oil

The combined forecasts from existing and future wells indicate that total crude oil production will decline from 100.0 10^3 m^3/d in 2003 to 66 10^3 m^3/d in 2013. By 2013, if crude oil production follows the projection, Alberta will have produced some 86 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 2003, Alberta refineries, with total inlet capacity 69.9 10^3 m^3/d of crude oil and equivalent, only processed 33.2 10^3 m^3/d of crude oil. Synthetic crude oil, bitumen, and pentanes plus constituted the remaining feedstock. This accounts for roughly 50 per cent of their total crude oil and equivalent feedstock. **Figure 3.15** 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. However, it is assumed that capacity utilization will increase from the 2003 level of 94 per cent to almost full capacity by 2007, as demand for refined petroleum products increases in western Canada. Total crude oil use will reach 35 10^3 m^3/d in 2007, decline to 28 10^3 m^3/d in 2008, and further decline to 22 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.

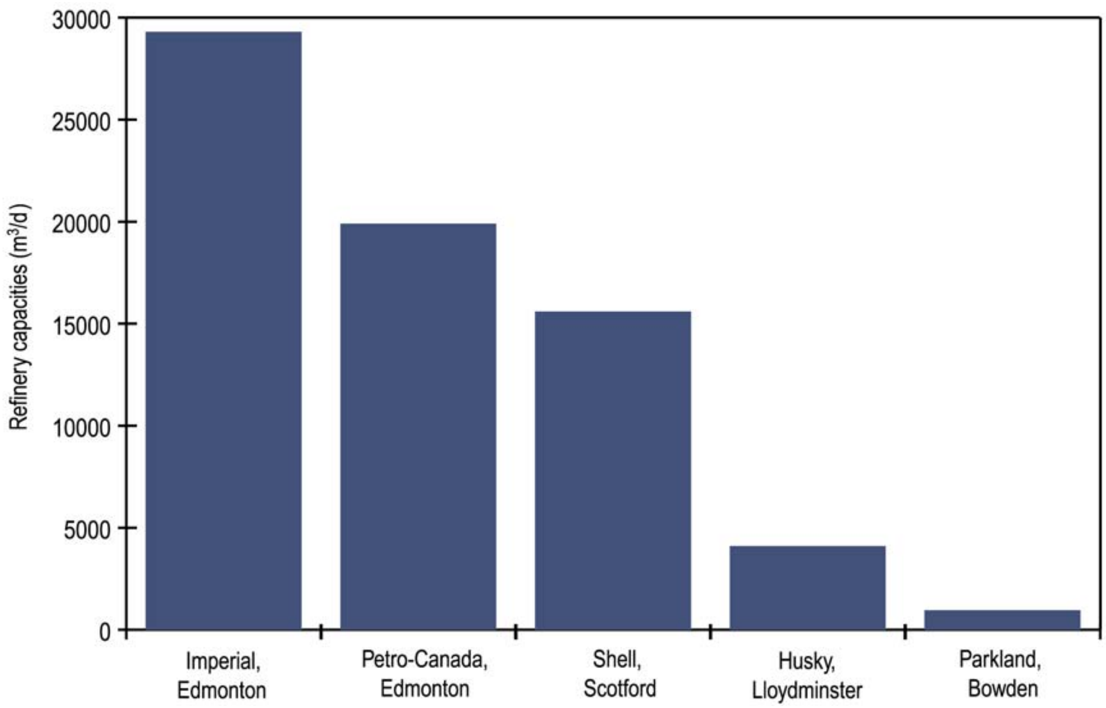


Figure 3.15. Capacity and location of Alberta refineries

Shipments of crude oil outside of Alberta, depicted in **Figure 3.16**, amounted to 67 per cent of total production in 2003. With the decline in demand for light-medium crude in Alberta, this is expected to remain at 67 per cent of production by 2013.

3.2.3 Crude Oil and Equivalent Supply

Figure 3.17 shows crude oil and equivalent production. It illustrates that total Alberta crude oil and equivalent is expected to increase from 258.9 10^3 m^3/day in 2003 to 413 10^3 m^3/d in 2013. Over the forecast period, 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 over 79 per cent of total production.

Changes to production in crude bitumen resulted in this year's forecast being lower than last year's predicted level. Announced delays in expansions caused the expected SCO production from oil sands projects to be lower than last year's forecast particularly in the later part of the forecast period.

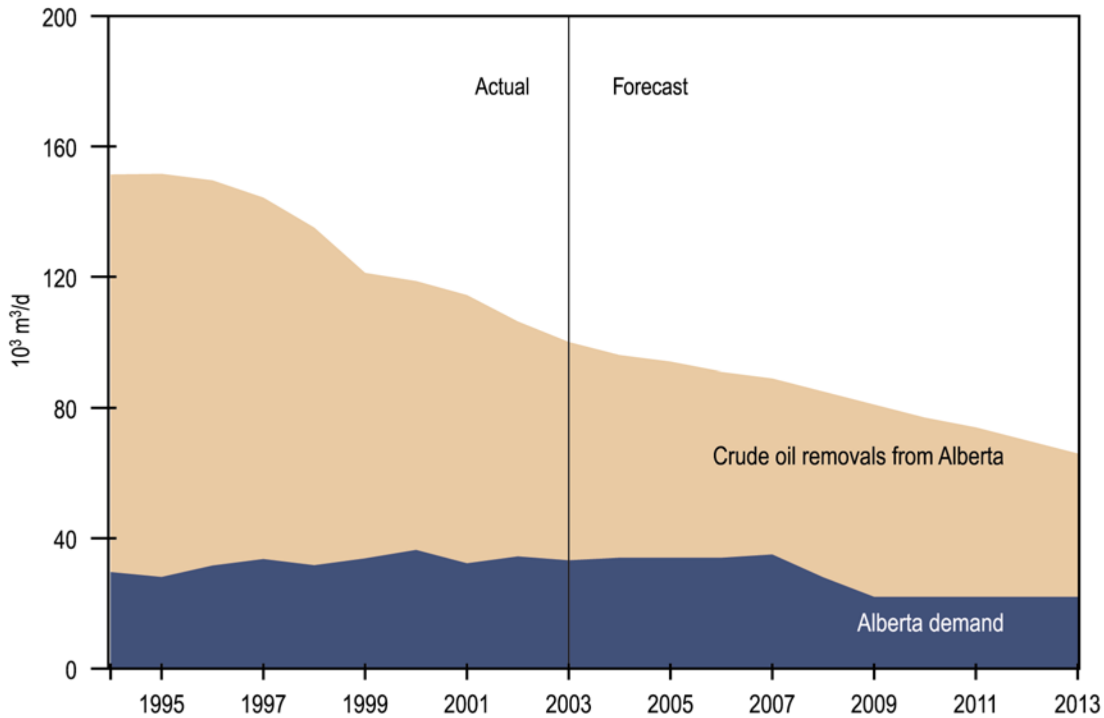


Figure 3.16. Alberta demand and disposition of crude oil

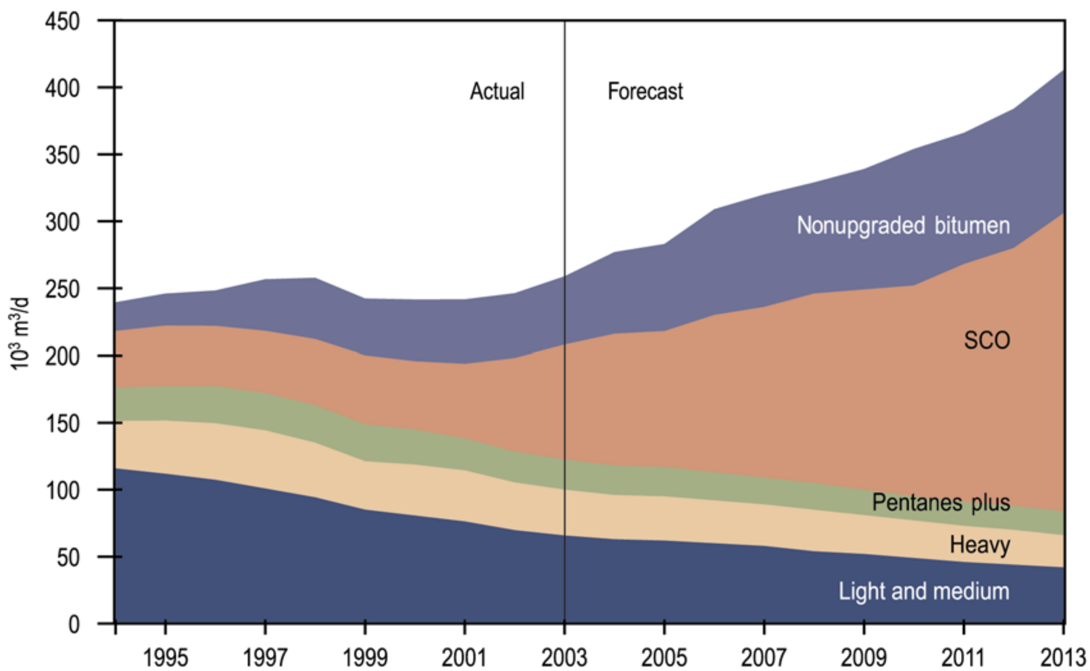


Figure 3.17. Alberta supply of crude oil and equivalent

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file
Power Point file for Section 3 – Oil

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file PowerPoint file for Section 4 – Gas

4 Natural Gas and Natural Gas Liquids

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.

4.1 Reserves of Natural Gas

4.1.1 Provincial Summary

At December 31, 2003, the EUB estimates the remaining established reserves of marketable gas in Alberta to be 1087.6 billion cubic metres (10^9 m^3), having a total energy content of 40.5 exajoules. This decrease of 43.7 10^9 m^3 since December 31, 2002, is the result of all reserves additions less production that occurred during 2003. These reserves exclude 34.6 million (10^6) 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 4.1.8. Removal of natural gas liquids results in a 4.4 per cent reduction in heating value from 38.9 MJ/m^3 to 37.2 MJ/m^3 for gas downstream of straddle plants. Details of the changes in remaining reserves during 2003 are shown in Table 4.1.

Table 4.1. Reserves of marketable gas (10^9 m^3)

	Gross heating value (MJ/m^3)	2003 Volume	2002 Volume	Change
Initial established reserves		4 400.8	4 313.5	+87.3
Cumulative production		3 278.6	3 142.1	+136.5[a]
Remaining established reserves downstream of field plants				
"as is"	38.9	1 122.2	1 171.4	-49.2
at standard GHV	37.4	1 166.7	1 258.0	
Minus liquids removed at straddle plants		34.6	40.1	-5.5
Remaining established reserves				
"as is"	37.2	1 087.6 (38.6 tcf)	1 131.3 (40.2 tcf)	-43.7
at standard GHV	37.4	1 082.7	1 149.5	

[a] May differ from actual annual production.

Annual reserves additions and production of natural gas since 1974 are depicted in **Figure 4.1**. It shows that total reserves additions have failed to keep pace with production, which has increased significantly in the last ten years. As illustrated in **Figure 4.2**, Alberta's remaining established reserves of marketable gas has been in general decline since 1982.

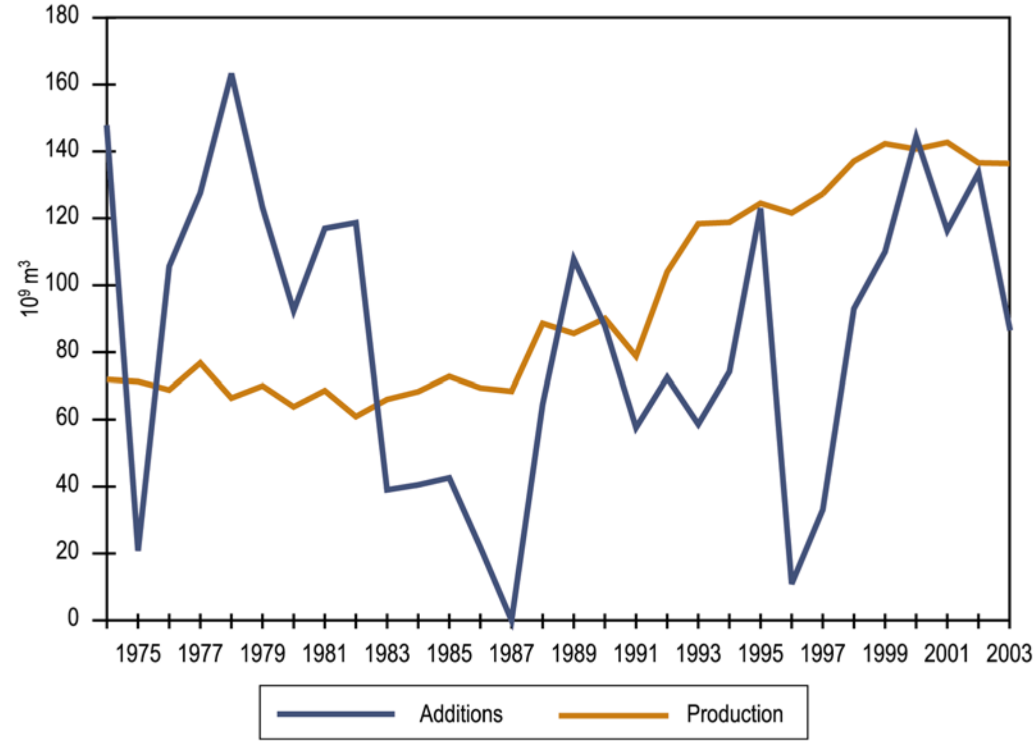


Figure 4.1. Annual reserves additions and production of marketable gas

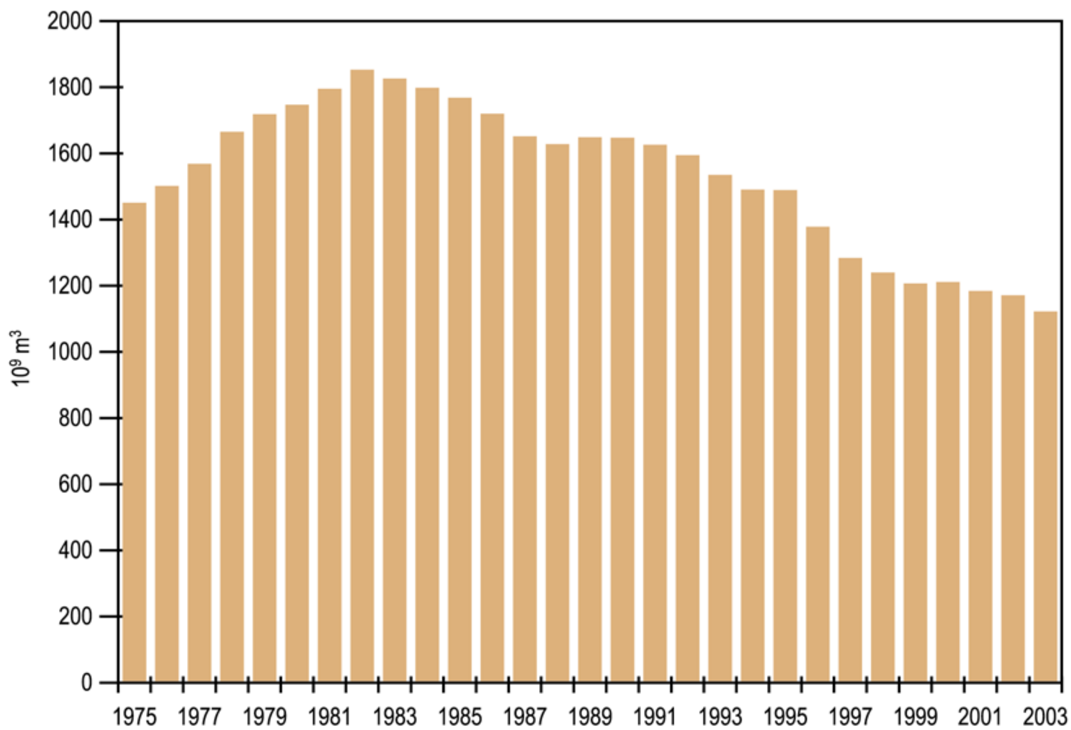


Figure 4.2. Remaining marketable gas reserves

4.1.2 Reserves in Nonproducing Pools

Nonproducing pools are those that have never been placed on production because they are uneconomic to tie in, are gas cap to an oil pool, or are "behind pipe," awaiting depletion of other producing zones in the wellbore.

At year-end 2003, 8149 pools out of a total of 39 621 pools in the province were classified as nonproducing. These pools had aggregate established marketable reserves of 71 10^9 m^3, or about 6 per cent of the province's remaining established reserves. Reserves from nonproducing pools are now only 16 per cent of the 435 10^9 m^3 estimated in 1995. This decrease is the result of the deletion of inactive pools, pools being placed on production, and reassessment of pool reserves. A breakdown of these reserves is shown by modified Petroleum Services Association of Canada (PSAC) area in **Figure 4.3.**

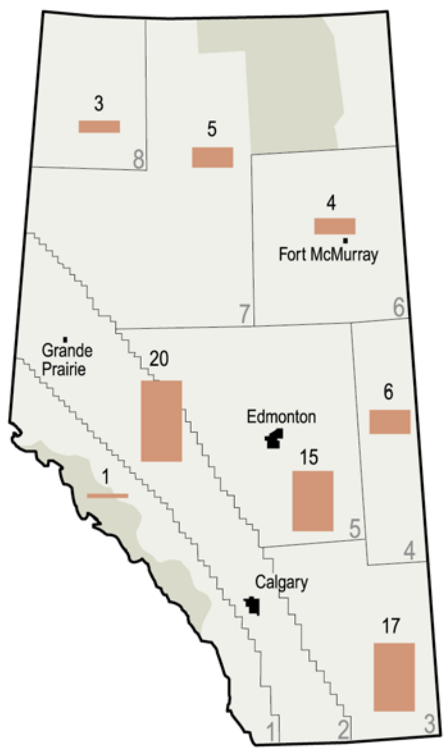


Figure 4.3. Unconnected gas reserves, 2003, by modified PSAC area (10^9 m^3)

4.1.3 Annual Change in Marketable Gas Reserves

Figure 4.4 shows the breakdown of annual reserves additions into new, development, and reassessment from 1999 to 2003. Initial established reserves increased by 87.3 10^9 m^3 from year-end 2002. This increase includes the addition of 58.6 10^9 m^3 attributed to new pools booked in 2003, 45.3 10^9 m^3 from development of existing pools, and negative net reassessment of 16.7 10^9 m^3. Therefore, reserves added through drilling alone totaled 103.9 10^9 m^3, replacing 77 per cent of Alberta's 2003 production of 135.0 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.

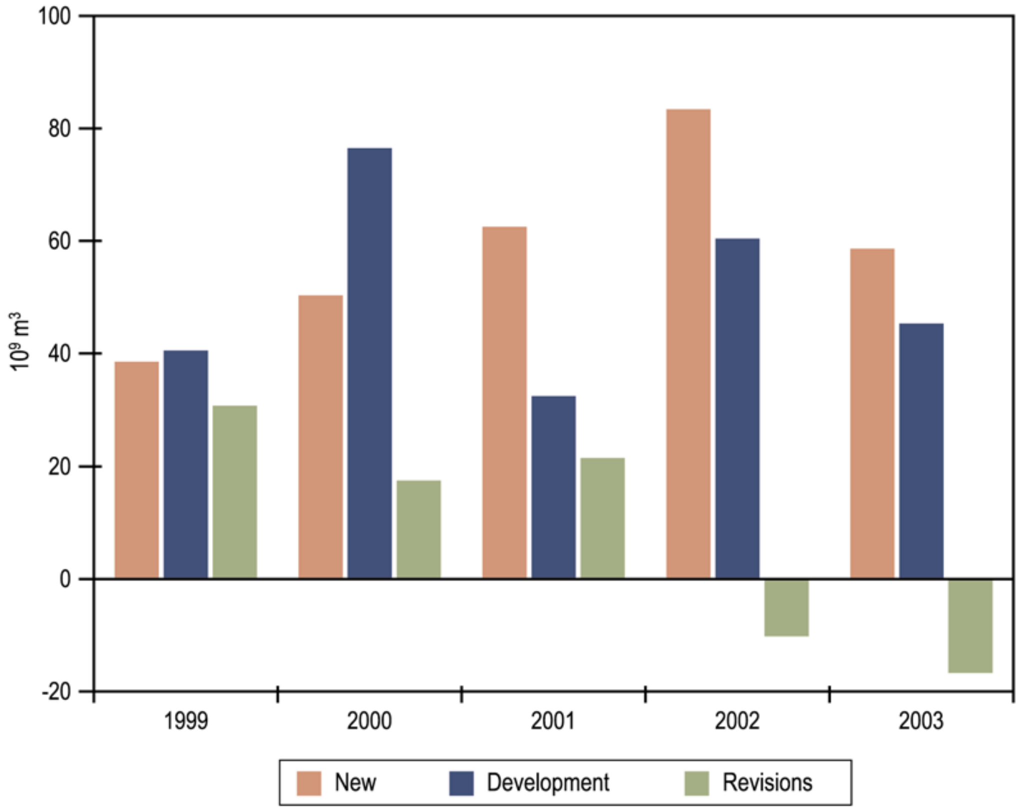


Figure 4.4. New, development, and revisions to marketable gas reserves

During 2003, the EUB re-evaluated the reserves of some 5500 pools. Net negative revisions of 16.7 10^9 m^3 resulted from negative reassessments totalling 306.4 10^9 m^3 and positive reassessments totalling 289.7 10^9 m^3. During the year, EUB staff undertook a number of projects in order to review pools that had not been re-evaluated for some time or appeared under- or overbooked based on their life index. The projects that resulted in large reserve changes are summarized below:

- Historically, area assignments used for single-well pools ranged from 100 to 250 hectares based on a 1990 study. In 2003, a new study reviewed about 7000 single-well pools that had substantial production history, many of which were subsequently abandoned. Reserves for these pools were evaluated using performance methods and the drainage areas determined from the estimated gas in place. The distribution of drainage areas depicted in **Figure 4.5** shows a overall median single-well drainage area of 63 hectares. The pools were further broken down by formation and a median area of 32, 64, 128, or 200 hectares assigned to each formation. The new areas were used to adjust the volumetric reserves of an additional 7000 single-well pools and joint assignments that had little or no production history. This resulted in a one-time reduction in established marketable reserves of 211 10^9 m^3.

- Review of shallow gas pools in Southeastern Alberta resulted in reserves additions of 40.8 10^9 m^3, equivalent to 4 per cent of Alberta's remaining reserves. This addition was due mainly to development and revisions to existing pools in the Southeastern Alberta Gas System.

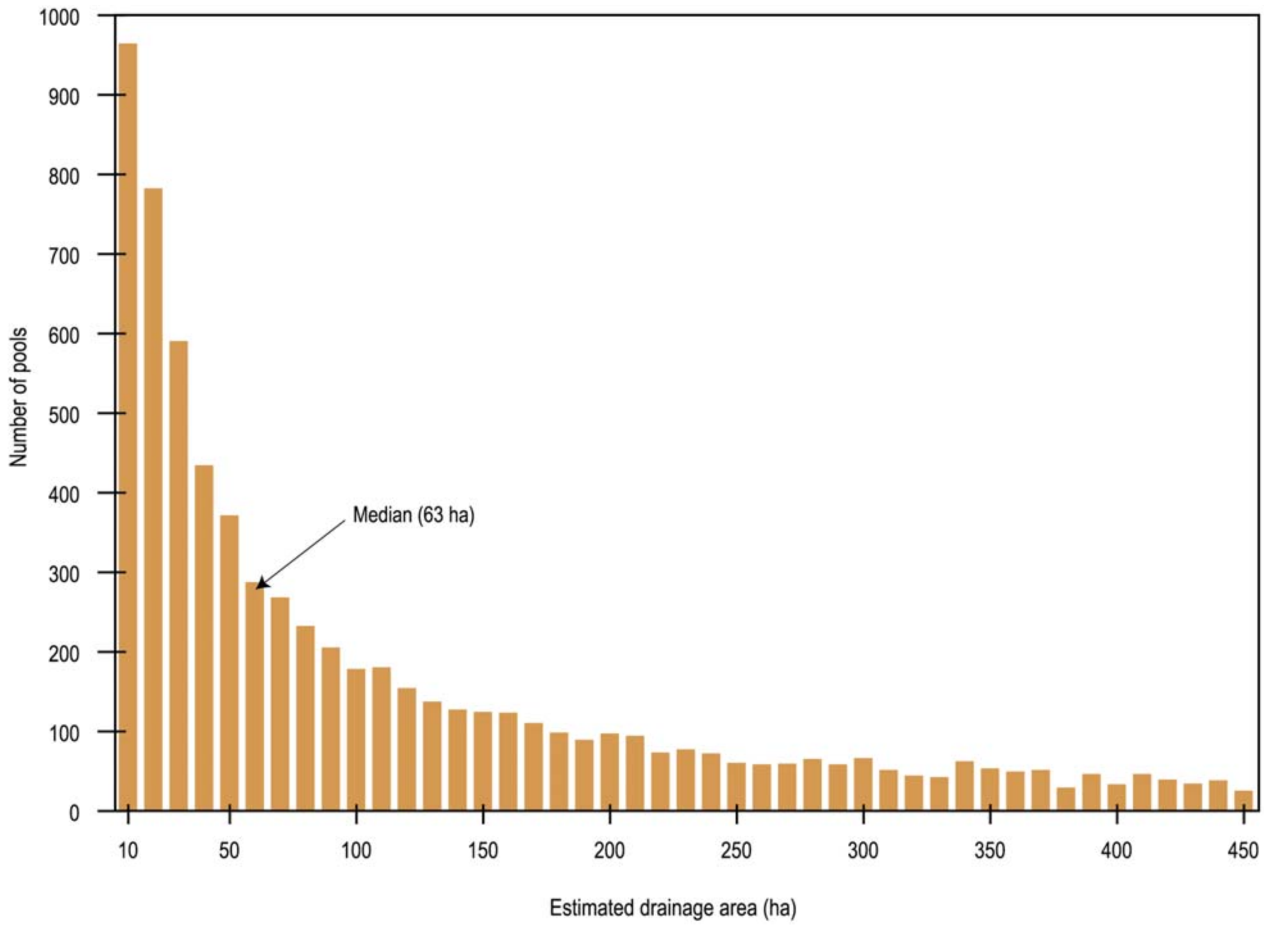


Figure 4.5. Distribution of drainage areas for single-well pools from small gas pool study

- 571 producing pools with a remaining constant rate life of over 25 years were reviewed, resulting in a reserves reduction of 55.9 10^9 m^3.
- 649 producing pools with a remaining constant rate life of less than 2 years were reviewed, resulting in a reserves addition of 95.5 10^9 m^3. Production decline analysis was used in estimating reserves for these pools.
- 1134 pools with production equal to or exceeding booked reserves were reviewed during 2003. This resulted in a reserves addition of 21.8 10^9 m^3.
- About 400 pools were abandoned during 2003, and their reserves were set to equal their cumulative production, resulting in a decrease of 4.7 10^9 m^3.
- Recognition of some 1200 previously unbooked gas wells drilled prior to 2002 resulted in a positive reassessment of 20 10^9 m^3.

Figure 4.6 depicts the changes in marketable gas reserves for 2003 by modified PSAC areas. Significant changes were made in the following areas:

- Area 2, the Western Plains area, added 19 10^9 m^3 despite a negative revision of 110 10^9 m^3 due to the small gas pool study, as outlined above.

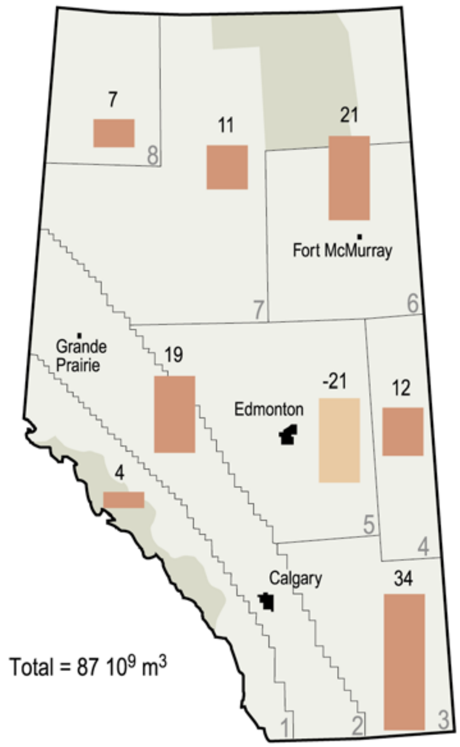


Figure 4.6. Marketable gas reserves changes, 2003, by modified PSAC area (10^9 m^3)

- Area 3 added a net 34 10^9 m^3 despite negative revisions of 33 10^9 m^3 as a result of the small pool study .
- Area 5 reserves declined by 21 10^9 m^3, primarily the result of a negative 45 10^9 m^3 revision due to the small gas pool study.
- Area 6 added reserves of 21 10^9 m^3, due mainly to positive revisions based on analysis of pool production decline.

Pools with major changes in reserves are listed in Table 4.2.

Of particular interest are a number of fields in the Southeastern Alberta Gas System (MU), where significant reserves were added in 2003, such as in the Medicine Hat field, where reserves of 11.3 10^9 m^3 were added. Other pools with significant reserve changes include Ansell Cardium Viking & Mannville MU#1 Pool, with an increase of 10.8 10^9 m^3; Provost Viking Belly River & Mannville MU#1 Pool, with an increase of 12.6 10^9 m^3; and Wild River Cardium Dunvegan Fort St. John & Bullhead MU#1 Pool, with an increase of 12.7 10^9 m^3.

Together, reserves additions for these three commingled sets of pools total 36.1 10^9 m^3.

Table 4.2. Major natural gas reserve changes, 2003

Pool	Initial established reserves (10^6 m^3) 2003	Change	Main reasons for change
Alderson Southeastern Alberta Gas System (MU)	56 971	+7 257	Pool development and re-evaluation of initial volume in place
Ansell Cardium, Viking, & Mann MU#1	17 043	+10 824	Re-evaluation of initial volume in place and recovery factor
Atlee-Buffalo Southeastern Alberta Gas System (MU)	9 221	+1 703	Pool development and re-evaluation of initial volume in place
Basing Turner Valley A	2 901	+1 421	Re-evaluation of initial volume in place and recovery factor
Benjamin Rundle A,B,C,Q,& R	9 448	+5 710	Re-evaluation of initial volume in place
Bighorn Turner Valley C	1 440	+824	Re-evaluation of initial volume in place
Bow Island Southeastern Alberta Gas System (MU)	2 250	+1 573	Pool development and re-evaluation of initial volume in place
Boyer Bluesky A, Gething A & M	16 887	+4 727	Re-evaluation of initial volume in place
Brazeau River Elkton-Shunda B	31 680	+3 678	Re-evaluation of initial volume in place
Brazeau River Elkton-Shunda A	10 354	+1 187	Re-evaluation of initial volume in place
Bruce Viking & Mannville MU#1	4 438	+944	Re-evaluation of initial volume in place
Cabin Creek Charlie Lake	694	+694	New pool
Caroline Viking, Glauconitic, & Basal Mannville MU#1	1 872	+561	Re-evaluation of initial volume in place
Cecilia Dunvegan, Fort St. John, & Bullhead MU#1	3 204	+812	Re-evaluation of initial volume in place
Cessford Southeastern Alberta Gas System (MU)	21 076	+2 150	Pool development and re-evaluation of initial volume in place
Chinchaga North Debolt-Detrial A	6 080	+1 862	Re-evaluation of initial volume in place
Cordel Turner Valley C & G	1 455	+510	Re-evaluation of initial volume in place
Countess Bow Island, Mannville, & Pekisko MU#1	4 887	+584	Re-evaluation of initial volume in place
Countess Southeastern Alberta Gas System (MU)	27 786	+2 436	Pool development and re-evaluation of initial volume in place
Crossfield East Wabamun A	16 707	+2 572	Re-evaluation of initial volume in place

(continued)

Table 4.2. Major natural gas reserve changes, 2003 (concluded)

Pool	Initial established reserves (10^6 m^3) 2003	Change	Main reasons for change
Dunvegan Debolt & Elkton MU#1	36 000	+6 762	Re-evaluation of initial volume in place
Edson Elkton A, Shunda A & B	45 035	+1 584	Re-evaluation of initial volume in place
Entice Edmonton & Belly River MU#1	6 073	+1 307	Re-evaluation of initial volume in place
Ferrier Banff B	2 799	+1 849	Re-evaluation of initial volume in place
Ferrier Ellerslie & Rock Creek MU#1	2 481	-1 393	Pool development and re-evaluation of initial volume in place
Knopcik Halfway N & Montney A	6 834	+1 387	Re-evaluation of initial volume in place
La Glace Halfway G & Montney B	5 768	+1 008	Re-evaluation of initial volume in place
Limestone Nisku A & Leduc A	2 926	+1 316	Re-evaluation of initial volume in place
Limestone Wabamun A	6 512	+1 415	Re-evaluation of initial volume in place
Medicine Hat Southeastern Alberta Gas System (MU)	150 490	+11 346	Pool development and re-evaluation of initial volume in place
Medicine Lodge Viking A	3 488	+1 226	Re-evaluation of initial volume in-place and recovery factor
Pembina Cardium, Viking, Mannville, Jurassic MU#1	10 324	+4 930	Pool development and re-evaluation of initial volume in place
Pouce Coupe South Montney A	3 694	+1 050	Re-evaluation of initial volume in place
Provost Viking, Belly River, & Mannville MU#1	51 701	+12 614	Pool development and re-evaluation of initial volume in place
Saddle Hills Wabamun A	2 649	+1 347	Pool development
Red Rock Chinook G	3 147	+1 115	Pool development
Sinclair Doig A	8 615	+1 615	Re-evaluation of initial volume in place
Suffield Southeastern Alberta Gas System (MU)	67 635	+4 308	Pool development and re-evaluation of initial volume in place
Sundance Belly River, Viking, Mannville MU#1	2 988	+1 501	Re-evaluation of initial volume in place
Westerose South Upper Mannville A, Glauconitic A, Basal Quartz F&AA	20 363	+4 793	Re-evaluation of initial volume in place
Wild River Cardium, Dunvegan, Fort St. John, & Bullhead MU#1	15 868	+12 712	Re-evaluation of initial volume in place
Small gas pool study		-211 000	Reduction in drainage area

4.1.4 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in Table 4.3. For the purposes of this table, commingled pools are considered as one and the Southeastern Alberta Gas System (MU) is considered on a field basis. The data show that pools with reserves of 30 million (10^6) m^3 or less, while representing 69 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 49 per cent of the remaining reserves. **Figure 4.7** depicts natural gas pool size by discovery year since 1965 and illustrates that the median pool size has remained fairly constant at about 18 10^6 m^3 for many years, while the average has declined from about 300 10^6 m^3 in 1965 to 45 10^6 m^3 in 1987 and has remained fairly constant since then.

Table 4.3. Distribution of natural gas reserves by pool size, 2003

Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
1500+	375	1	2 610	60	552	49
300-1499	1 388	4	765	17	181	16
100-299	2 887	7	435	10	131	12
31-100	7 654	19	365	8	144	13
Less than 30	27 309	69	226	5	114	10
Total	39 613	100	4 401	100	1 122	100

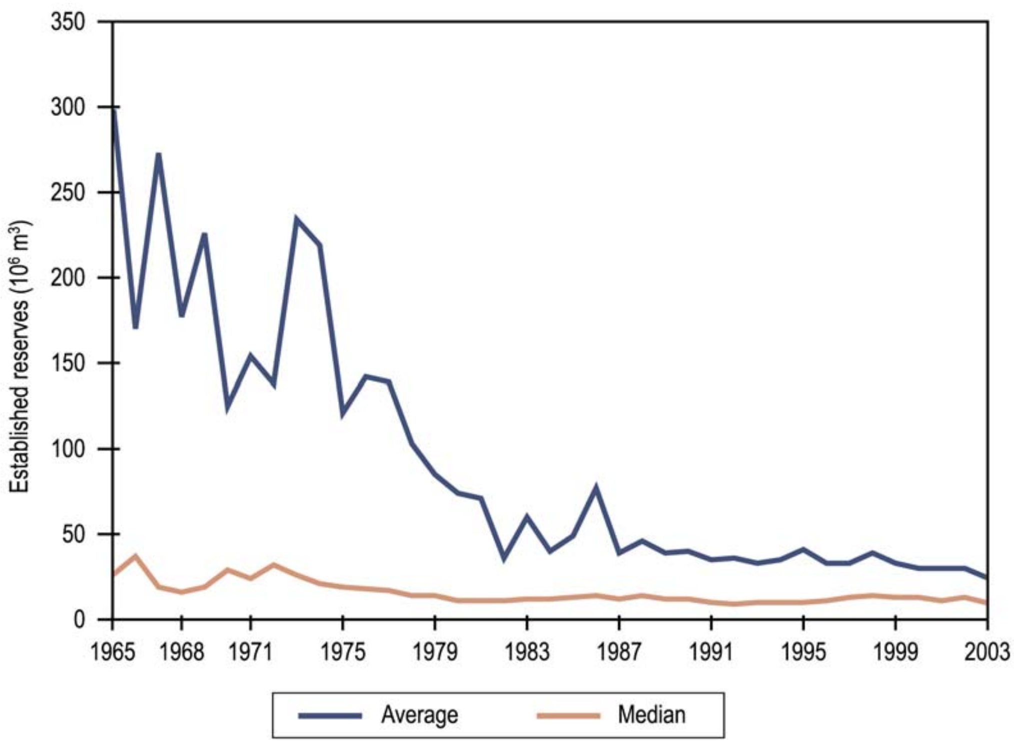


Figure 4.7. Gas pools by size and discovery year

4.1.5 Geological Distribution of Reserves

The distribution of reserves by geological period and formation is shown graphically in **Figure 4.8**. The Upper and Lower Cretaceous period contains some 68 per cent of the province's remaining established reserves of marketable gas. The formations containing the largest remaining reserves are the Lower Cretaceous Mannville, with 28.3 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 19.1 per cent, and the Mississippian Rundle, with 8.5 per cent. Table B.5 in Appendix B gives a detailed breakdown of reserves by formation.

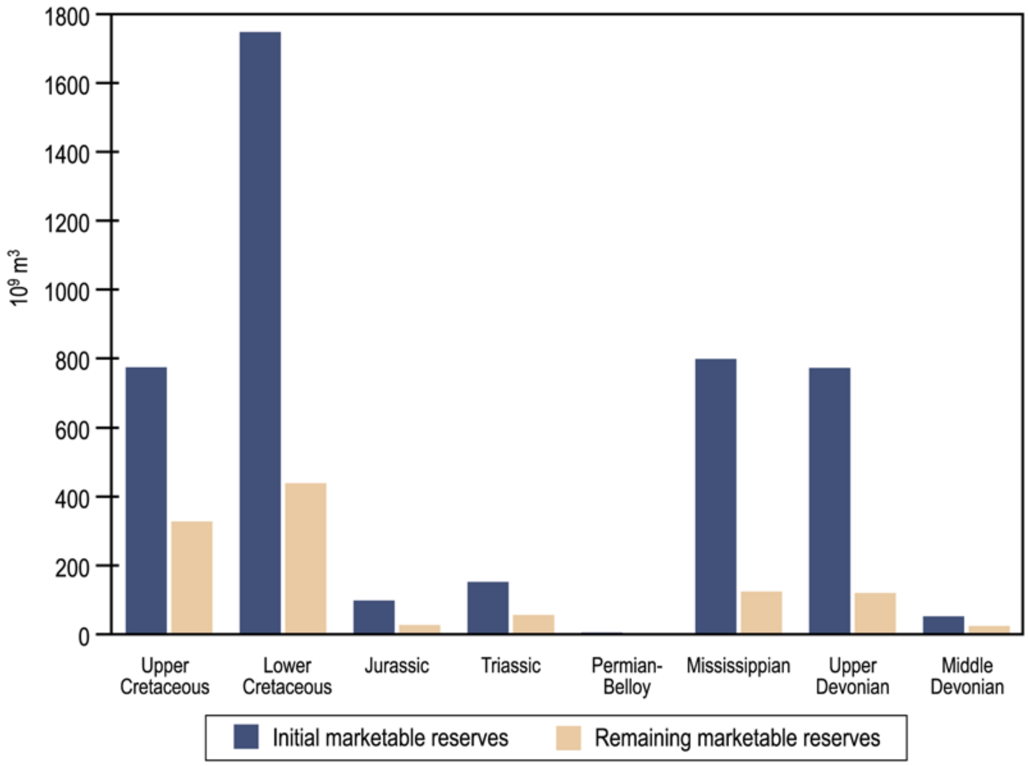


Figure 4.8. Geological distribution of marketable gas reserves

4.1.6 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, 2003, sour gas accounts for some 20 per cent (229 10^9 m^3) of the province's total remaining established reserves and about 26 per cent of natural gas marketed in 2003. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2003 is 9.2 per cent.

The distribution of reserves for sweet and sour gas (Table 4.4) shows that 165 10^9 m^3, or about 72 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 4.9** 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 4.5 and indicates that 48 10^9 m^3, or 21 per cent, of sour gas contains H_2S concentrations greater than 10 per cent.

Table 4.4. Distribution of sweet and sour gas reserves, 2003 (10^9 m^3)

	Marketable gas			Percentage	
Type of gas	Initial established reserves	Cumulative production	Remaining established reserves	Initial established reserves	Remaining established reserves
Sweet					
Associated & solution	590	430	161	13	15
Nonassociated	2 407	1 675	732	55	65
Subtotal	2 997	2 105	893	68	80
Sour					
Associated & solution	391	326	64	9	5
Nonassociated	1 013	848	165	23	15
Subtotal	1 404	1 174	229	32	20
Total	4 401 (156)[b]	3 279 (116)[a]	1 122[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.

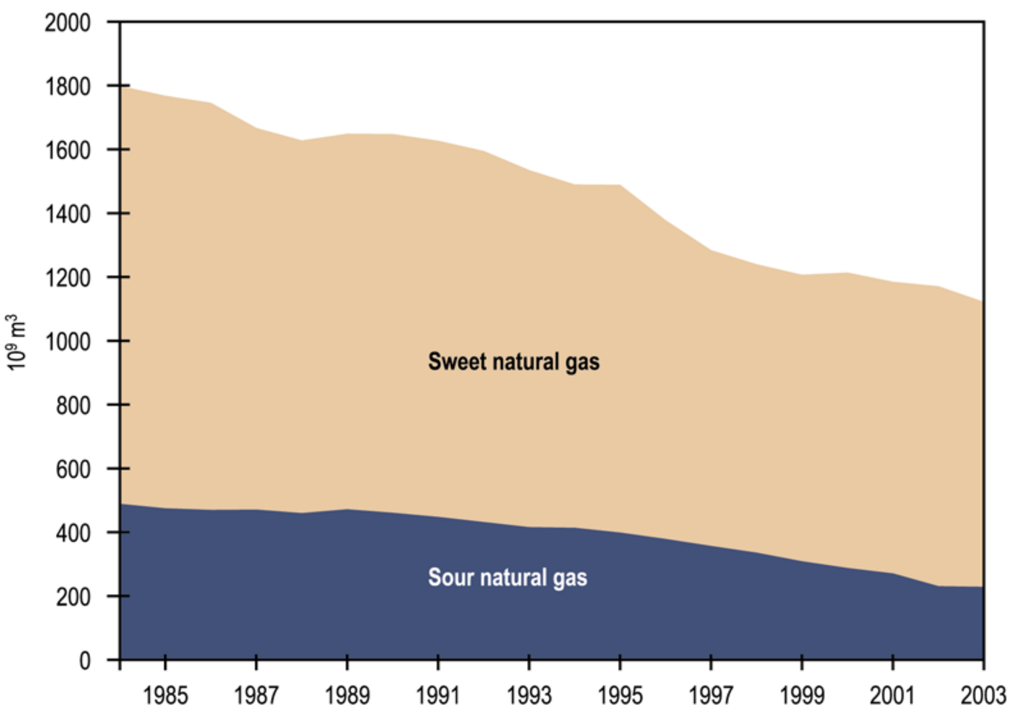


Figure 4.9. Remaining marketable reserves of sweet and sour gas

Table 4.5. Distribution of sour gas reserves by H_2S content, 2003

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	261	326	44	63	107	47
2.00-9.99	92	357	13	61	74	32
10.00-19.99	27	191	5	22	27	12
20.00-29.99	11	45	2	8	10	4
Over 30	0	94	0	11	11	5
Total	391	1 013	64	165	229	100
Percentage	28	72	28	72		

4.1.7 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).

4.1.8 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, 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 4.10.** A minimum 5 per cent is added to account for loss due to lease fuel (4 per cent) and flaring. Therefore, marketable gas reserves of individual pools on the EUB's gas reserves database reflect expected recovery after processing at field plants.

For about 80 per cent of Alberta's marketable gas (notable exceptions being Alliance Pipeline and some of the mostly dry Southeastern Alberta gas), additional liquids contained in the gas stream leaving the field plants are extracted downstream at reprocessing and 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 34.6 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 1122.2 10^9 m^3 to 1087.6 10^9 m^3 and the thermal energy content from 43.7 to 40.5 exajoules.

Figure 4.10 also shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example,

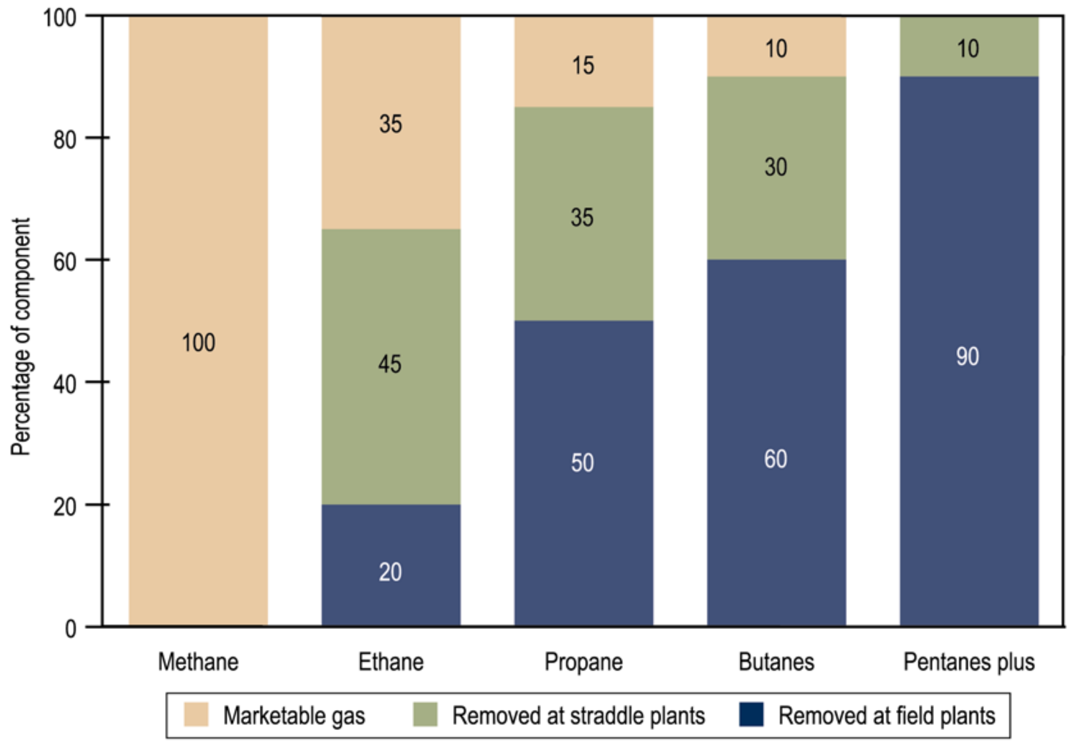


Figure 4.10. Expected recovery of natural gas components

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 4.2.

4.1.9 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 initial established reserves assigned to each field and the total initial established reserves for the multifield pool.

4.1.10 Reserves of Coalbed Methane

Coalbed methane (CBM) is the methane gas that is found in coal, both as adsorbed gas and as free gas; it is also known as natural gas from coal (NGC). All coal layers contain CBM to some extent. For this reason, coal and CBM have a fundamental relationship. Coal is known, from thousands of data points, to underlie most of central and southern Alberta, and while some individual coals may not correlate particularly well, coal zones correlate very well.[1]

[1] For the purpose of CBM administration, the EUB currently defines a single coal zone as a zone containing all coal within a formation unless separated by more than 30 m of non-coal-bearing strata.

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined until 1995, at Fenn-Big Valley. Interest in CBM development in Alberta continued to grow in 2003, with the year seeing the highest number of CBM completions to date. The actual CBM production to date continues to remain uncertain because of the current inability to completely differentiate CBM from conventional gas production. In addition to the uncertainty in production, the data from CBM testing in areas of current CBM production remains limited.

In the areas studied in detail to date, information on the gas content of coals, while still quite limited, does indicate a good relationship between gas content, depth from surface, and ash content of the coal. As the thickness and correlatability of the individual coals and coal zones can be determined from the large number of available oil and gas wells, the EUB believes that the estimation of CBM resources can be established with some degree of confidence for large areas and not just immediately surrounding wellbores. The known areal extent of CBM zones was used to assist in defining CBM pools. These CBM pools (currently confined within existing oil and gas fields) are similar to those of the conventional gas pools within lower Belly River sands, wherein multiple individual producing zones are placed together within a single pool for administrative purposes. In the case of CBM, individual coal seams, each potentially capable of producing some quantity of CBM, are grouped into zones. These coal zones are normally very extensive; however, for the purpose of determining reserves, pools are usually restricted laterally to those areas containing wells that have proven capability of producing CBM. The pool boundary is therefore often an administrative boundary, not one limited by the extent of the coal zone, but rather by where CBM production has occurred.

CBM resource estimates were done on a pool basis with a top depth limit of approximately 200 m. While resource calculations have taken place previously, and in the case Fenn-Big Valley published before, this is the first year the EUB is prepared to publish separate CBM estimates. In support of this work, the EUB will be releasing individual coal seam picks from oil and gas wells entered into its coalhole database.

However well known the coals are, as well as the gas they contain, the recovery of CBM is still not well known. Current industry practice suggests that CBM production will likely be from project-style developments combining recompletions of existing wells, as well as drilling of new development wells. The assignment of an accurate recovery factor to each pool to adequately describe the economic recovery of CBM is one of the biggest challenges in defining CBM reserves. The EUB has purposefully selected what it believes to be a conservative recovery factor of 10 per cent until such time as production characteristics are better known. While most CBM pools are geologically distinct and would be subjected to differing production methods, the EUB has decided, for the sake of simplicity, to apply the recovery factor uniformly to all CBM pools, except Fenn-Big Valley. The Mannville pools of the Fenn-Big Valley field had a recovery factor of 50 per cent initially set to account for anticipated gas production from a long-term pilot project. This project is ongoing, and if not successful, the recovery factor and the remaining reserves will be reduced accordingly.

In 2003, the Alberta Geological Survey estimated that there are some 14 trillion m^3 (500 trillion cubic feet) of gas in place within all of the coal in Alberta. Only a very small portion of that number has been studied in detail for this report. In those areas studied, only a portion of the coal resource that is well known to exist has been considered in the determination of established reserves. Table 4.6 lists the CBM in-place resources and established reserves in those fields currently under active development in the province of

Table 4.6. Coalbed methane in place and established reserves by field, 2003 (10^6 m^3)

Field	Initial volume in place	Initial established reserves	Net cumulative production	Remaining established reserves
Fenn–Big Valley	274	130.0	6.6	123.4
Rockyford	873	87.3	16.4	70.9
Gayford	1 122	112.2	34.5	77.7
Entice	5 712	571.2	34.9	536.3
Strathmore & Ardenode combined	413	41.3	12.2	29.1
Redland	1 250	125.0	5.3	119.7
Centron	141	14.1	0.0	14.1
Total	9 786	1 081.2	119.9	971.3

Alberta as of December 31, 2003. The 9.79 10^9 m^3 initial in-place volume encompasses areas of current CBM production and will likely be expanded to larger areas of known resources to include drilled but not yet producing areas. The EUB believes that the 1.08 10^9 m^3 initial established reserves value will increase in the future.

Recent additional requirements placed on industry to gather testing data and greater identification of CBM-specific activity may enable a more complete preliminary assessment of CBM reserves for additional regions of the province for the next year-end.

4.1.11 Ultimate Potential

In 1992, the EUB (then the ERCB) issued *ERCB 92-A: Ultimate Potential and Supply of Natural Gas in Alberta,* which presented the results of its detailed review of Alberta's ultimate potential of marketable gas reserves. This review took into consideration geological prospects, technology, and economics. The EUB adopted an estimate of 5600 10^9 m^3 (200 trillion cubic feet) as Alberta's ultimate potential for marketable gas. To bring this estimate up to date, the EUB has undertaken an ultimate potential study targeted for completion in late 2004. **Figure 4.11** shows the historical and forecast growth in initial established reserves of marketable gas.

Figure 4.12 plots production and remaining established reserves of marketable gas compared to the 1992 estimate of ultimate potential.

Table 4.7 provides details on the ultimate potential of marketable gas, with all values converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 4577 10^9 m^3, or 82 per cent of the ultimate potential of 5600 10^9 m^3, has been discovered as of year-end 2003. This leaves 1023 10^9 m^3, or 18 per cent, yet to be discovered. Cumulative production of 3410 10^9 m^3 at year-end 2003 represents 60.9 per cent of the ultimate potential, leaving 2190 10^9 m^3, or 39.1 per cent, available for future use.

Table 4.7. Remaining ultimate potential of marketable gas, 2003 (10^9 m^3 at 37.4 MJ/m^3)

Yet to be established	
Ultimate potential	5 600
Minus initial established	4 577
	1 023
Remaining established	
Initial established	4 577
Minus cumulative production	3 410
	1 167
Remaining ultimate potential	
Yet to be established	1 023
Plus remaining established	1 167
	2 190

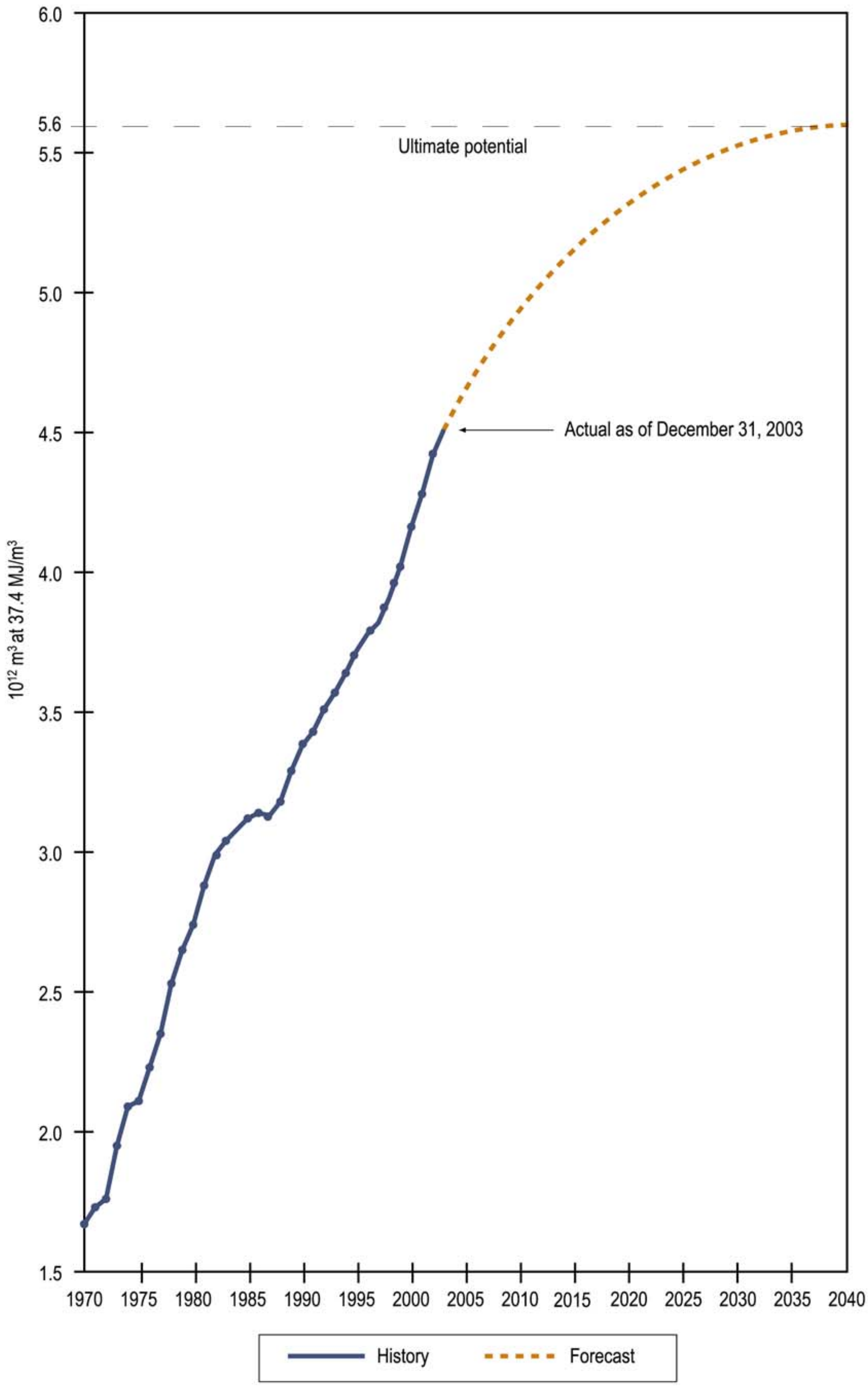


Figure 4.11. Growth of initial established reserves of marketable gas

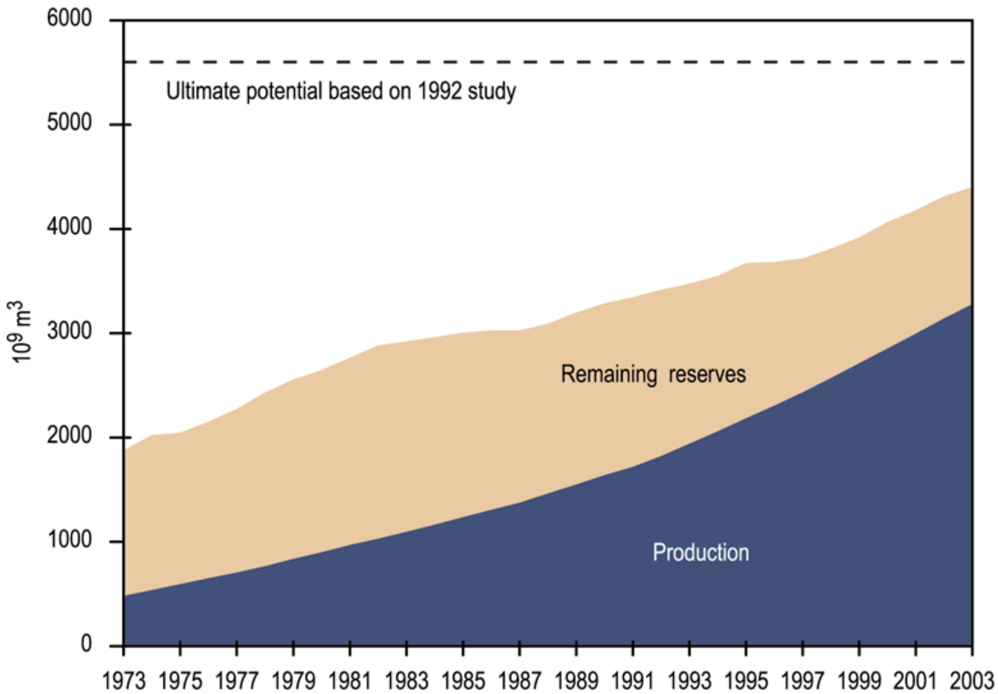


Figure 4.12. Gas ultimate potential

The regional distribution of remaining reserves and yet-to-be-established reserves is shown by PSAC area in **Figure 4.13**. It shows that the Western Plains (Area 2) contains about 35 per cent of the remaining established reserves and 50 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) and the Northern Plains (Areas 6, 7, and 8), Figure 4.13 shows that, based on 1992 ultimate potential study, Alberta natural gas supplies will depend on significant reserves being discovered in the Western Plains.

4.2 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 that it expects will not be removed from natural gas are included as part of the province's gas reserves discussed in Section 4.1. The EUB's projections on the overall recovery of each NGL component are explained in Section 4.1.8 and shown graphically in **Figure 4.10**. Estimates of the remaining established reserves of extractable NGLs are summarized in Tables 4.8 and 4.9. **Figure 4.14** shows remaining established reserves of extractable NGLs compared to 2003 production.

4.2.1 Ethane

As of December 31, 2003, the EUB estimates remaining established reserves of extractable ethane to be 123.9 $10^6\ m^3$ in liquefied form. This estimate includes 8.3 $10^6\ m^3$ of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. This is a significant drop from 29 $10^6\ m^3$ in 2002, due mainly to calculation error in the conversion from gaseous to liquid reserves that occurred in 1997 and carried forward to 2002. This year the ethane volume remaining in

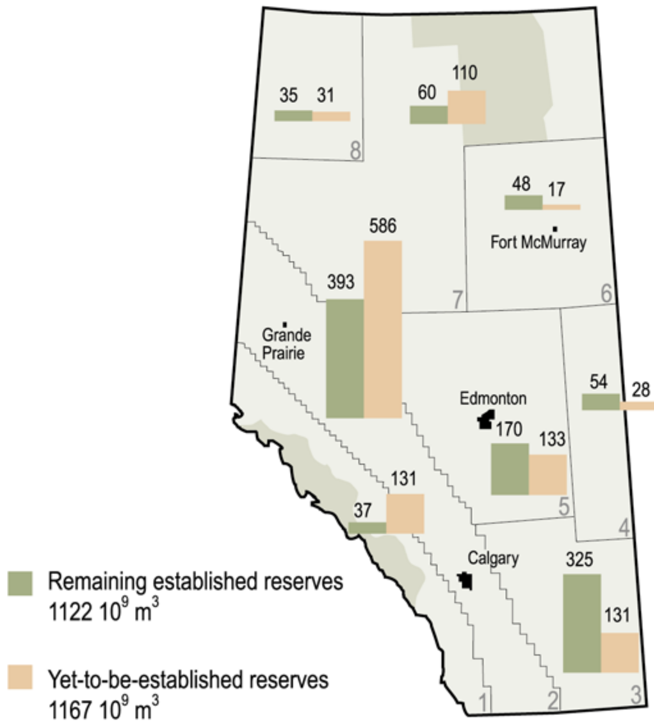


Figure 4.13. Regional distribution of Alberta gas reserves

Table 4.8. Established reserves and production of extractable NGLs as of December 31, 2003 (10^6 m^3 liquid)

	2003	2002	Change
Cumulative net production[a]			
Ethane	196.4	182.7	+13.7
Propane	222.9	214.7	+8.2[b]
Butanes	127.8	123.3	+4.5[b]
Pentanes plus	295.3	287.1	+8.2[b]
Total	842.4	807.8	+35.1
Remaining (expected to be extracted)			
Ethane	124.0	165.1	-41.1
Propane	69.4	79.3	-9.9
Butanes	41.9	46.9	-5.0
Pentanes plus	63.2	67.8	-4.6
Total	298.5	359.1	-60.6

[a] Production minus those volumes returned to the formation or injected to enhance the recovery of oil.
[b] May differ slightly with actual production as reported in *Statistical Series (ST) 3: Oil and Gas Monthly Statistics*.

solvent floods represents about 6 per cent of the total ethane reserves, compared to about 12 per cent last year. Presently there are only 10 pools under solvent flood, the largest being in the Westpem Nisku A, Rainbow Keg River F, and Judy Creek Beaverhill Lake A pools.

As shown in Table 4.9, there is an additional 62.3 10^6 m^3 (liquid) of ethane estimated to remain in the marketable gas stream and available for potential recovery. Ethane reserves reported in **Figure 4.15** have been corrected to account for the calculation error between 1997 and 2002.

Table 4.9. Reserves of NGLs as of December 31, 2003 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	186.2	81.7	46.4	63.3	377.6
Liquids expected to remain in dry marketable gas	62.3	12.2	4.5	0	79.0
Remaining established recoverable from					
Field plants	35.6	40.8	26.9	56.4	159.7
Straddle plants	80.1	28.6	13.4	6.3	128.4
Solvent floods	8.3	0.1	1.6	0.6	10.6
Total	124.0	69.5	41.9	63.3	298.7

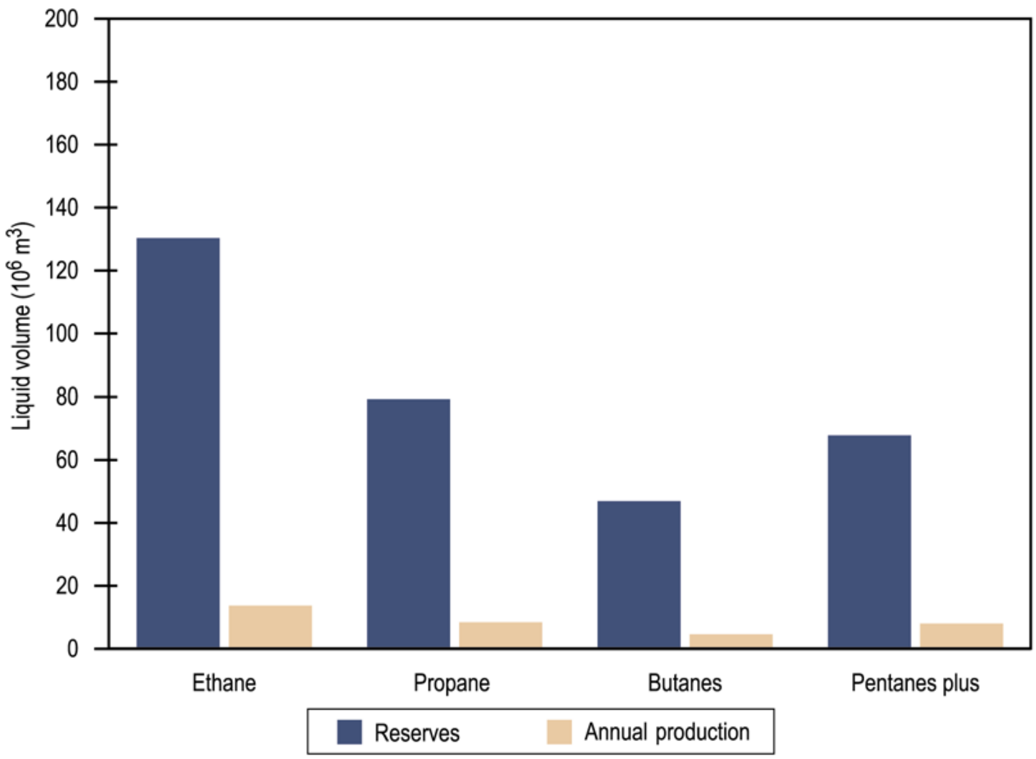


Figure 4.14. Remaining established NGL reserves expected to be extracted and annual production

During 2003, the extraction of specification ethane was 13.7 10^6 m^3. 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 four largest fields, the Caroline, Ferrier, and Pembina, and Wizard Lake, account for 11.5 per cent of total ethane reserves.

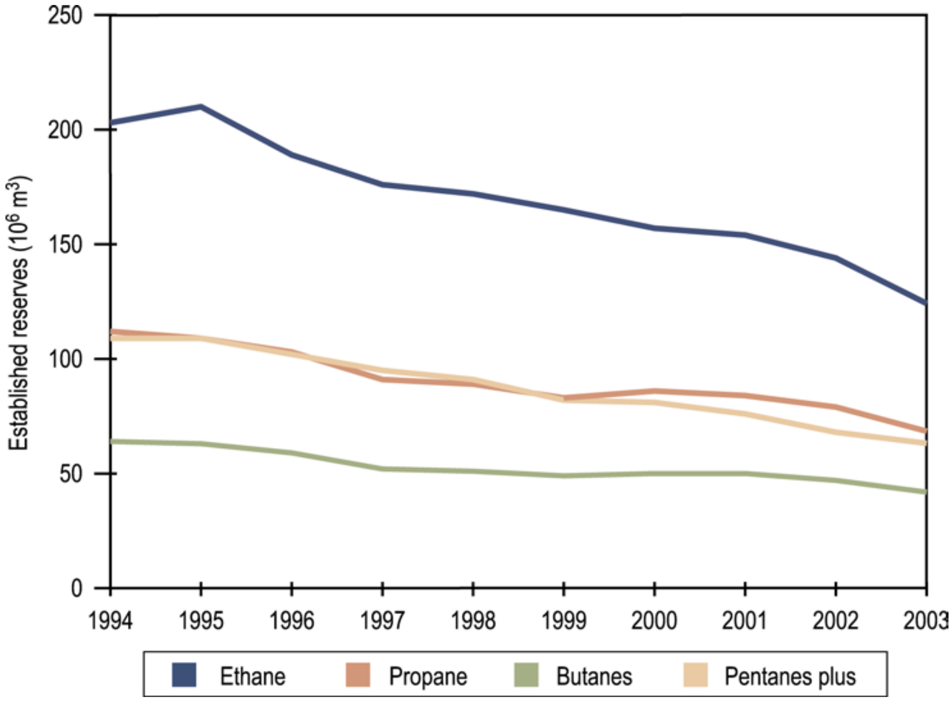


Figure 4.15. Remaining established reserves of natural gas liquids

4.2.2 Other Natural Gas Liquids

As of December 31, 2003, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 69.5 10^6 m^3, 41.9 10^6 m^3, and 63.3 10^6 m^3 respectively. The overall changes in the reserves during the past year are shown in Table 4.9. Appendix B, Table B.9, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The three largest fields, the Brazeau River, Caroline, and Pembina, account for about 14 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 2003, propane and butanes recovery at crude oil refineries was 0.4 10^6 m^3 and 1.3 10^6 m^3 respectively.

4.2.3 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 140 10^9 m^3, the EUB estimates remaining ultimate potential of liquid ethane to be 349 10^6 m^3. The other 30 per cent, or 42.0 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 419 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 40 per cent.

4.3 Supply of and Demand for Natural Gas

4.3.1 Natural Gas Supply

Alberta produced 140.6 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its gas and conventional oil wells in 2003, a decrease of 2.4 per cent from last year.[2] 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 since 1995 due to the lower risk, low cost of drilling, and quick tie-in times.

The marketable natural gas production volumes for 2002 and 2003 stated in Table 4.10 have been calculated as shown, based on *ST-3* section "Supply and Disposition of Marketable Gas."

Table 4.10. Marketable natural gas volumes (10^6 m^3)

Marketable gas production[a]	2002	2003
Total gas production	170 811.6	166 671.8
Minus storage withdrawals	5 052.6	5 592.4
Raw gas production	165 759.0	161 079.4
Minus injection total	-7 907.8	-9 090.4
Minus processing shrinkage – raw	-11 419.8	-11 139.3
Minus flared – raw	-762.9	-701.2
Minus vented – raw	-535.0	-481.2
Minus fuel – raw	-10 535.3	-10 528.1
Plus storage injection	+3 699.9	+5 830.2
Calculated marketable gas production at as-is conditions	138 298.1	134 969.4
Calculated marketable gas production @37.4 MJ/m^3	144 106.7	140 638.1

[a] The production number for 2002 was recalculated. Transition to a new production reporting system in the province last year were responsible for incomplete data in last year's calculation.

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 4.16**. In 2003, some 12 000 natural gas wells were drilled in the province, an increase of 46 per cent from 2002 levels and an all-time high. A large portion of gas drilling has taken place in Southeastern Alberta, representing 54 per cent of all natural gas wells drilled in 2003. Drilling levels were up in all areas of the province, with the exception of Area 6 (Northeastern Alberta). Note that the gas well drilling numbers represent wellbores that contain one or more geological occurrence capable of producing natural gas.

[2] Natural gas produced in Alberta has an average heating value of approximately 39.0 MJ/m^3.

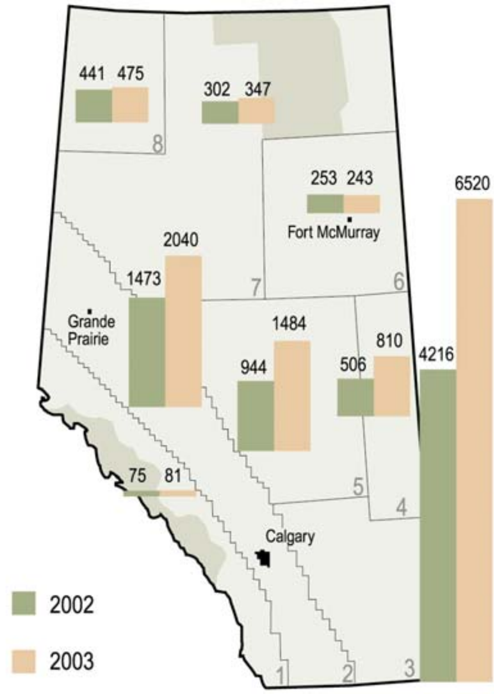


Figure 4.16. Alberta successful gas well drilling by modified PSAC area

The number of successful natural gas wells drilled in Alberta from 1994 to 2003 is shown in **Figure 4.17**, 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.

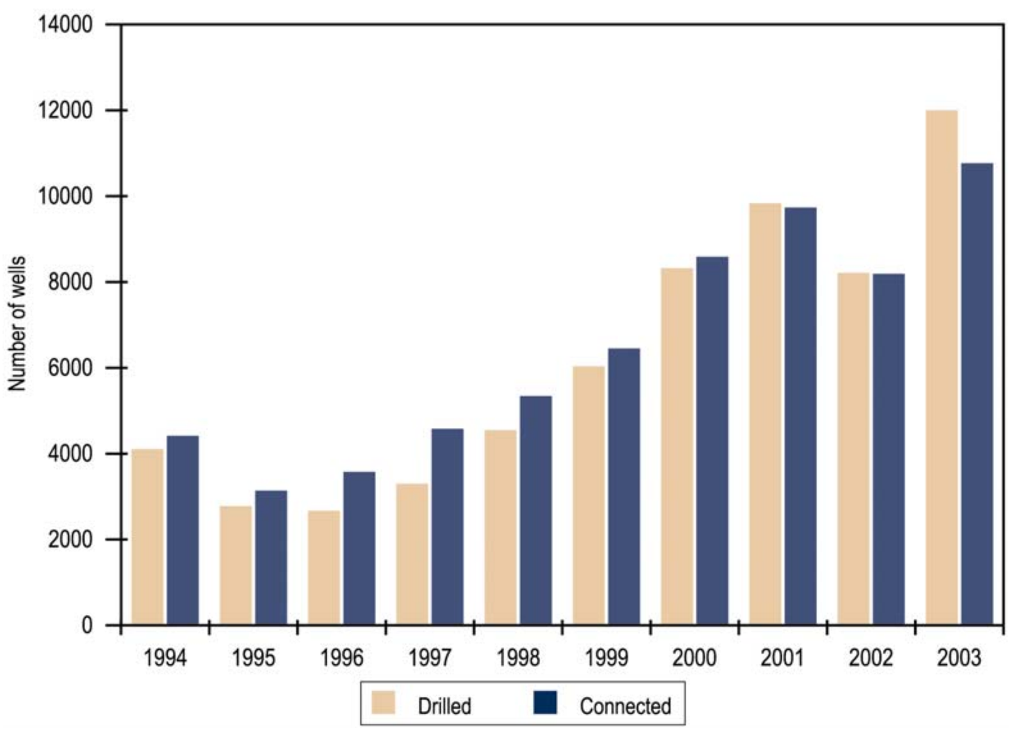


Figure 4.17. Successful gas wells drilled and connected

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 years 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 2003 the number of gas well connections increased by 31 per cent from 2002 levels. Also, 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. The distribution of natural gas well connections and the initial operating day rates of the connected wells in the year 2003 are illustrated in **Figures 4.18** and **4.19** respectively.

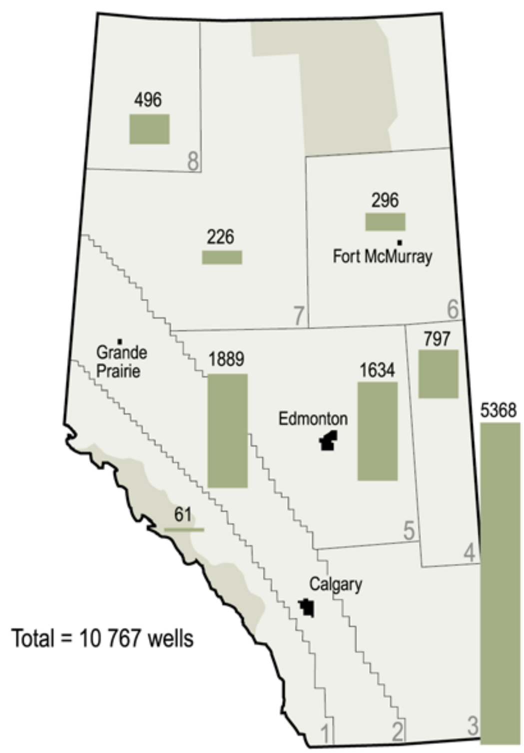


Figure 4.18. Gas well connections, 2003, by modified PSAC area

Figure 4.20 illustrates historical gas production from gas wells by geographical area. While most areas experienced a decline in production in 2003, Area 1 (Foothills) and Area 3 (Southeastern Alberta) increased production. Gas production from oil wells declined by some 3 per cent in 2003 over 2002.

Marketable gas production in Alberta from 1994 to 2003 is shown in **Figure 4.21**, 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 begun to decline after reaching its peak in 2001. By 2003, the total number of producing gas wells increased to 80 000, from 35 200 wells in 1994. 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.

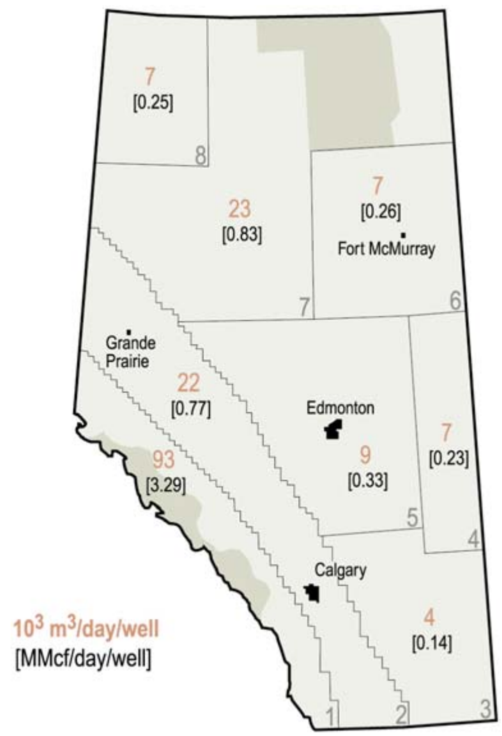


Figure 4.19. Initial operating day rates of connections, 2003, by modified PSAC area

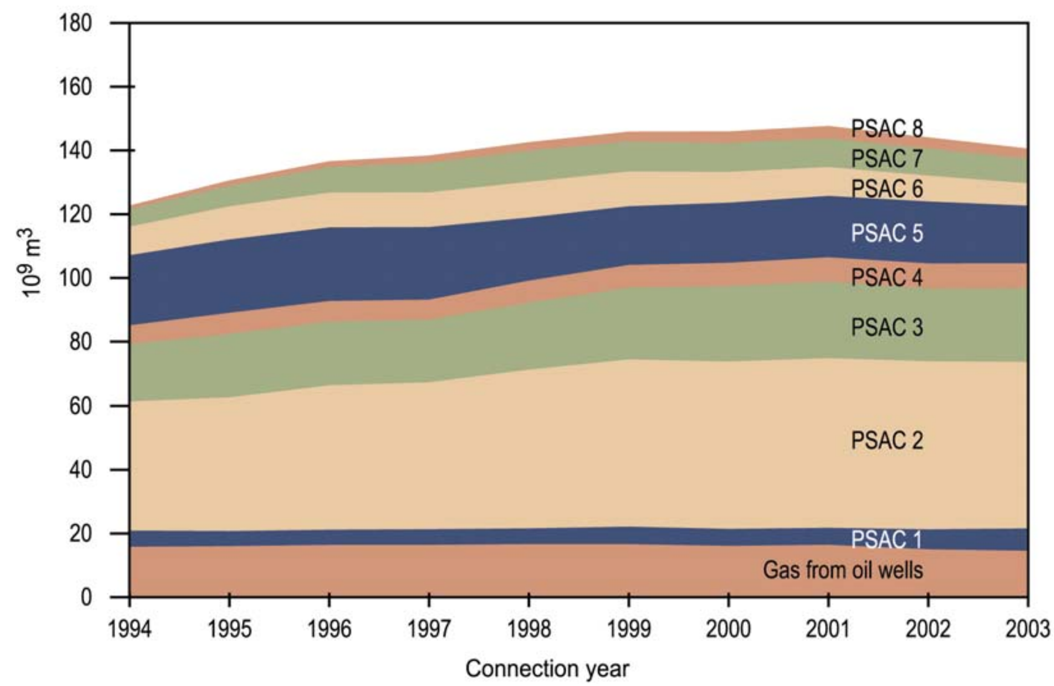


Figure 4.20. Marketable gas production by modified PSAC area

Average gas well productivity has been declining over time. As shown in **Figure 4.22**, about 58 per cent of the operating gas wells produce less than 1 thousand (10^3) m^3/d. In 2003, these 45 600 gas wells operated at an average rate of 0.9 10^3 m^3/d per well and produced less than 8 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 21 per cent of the total production.

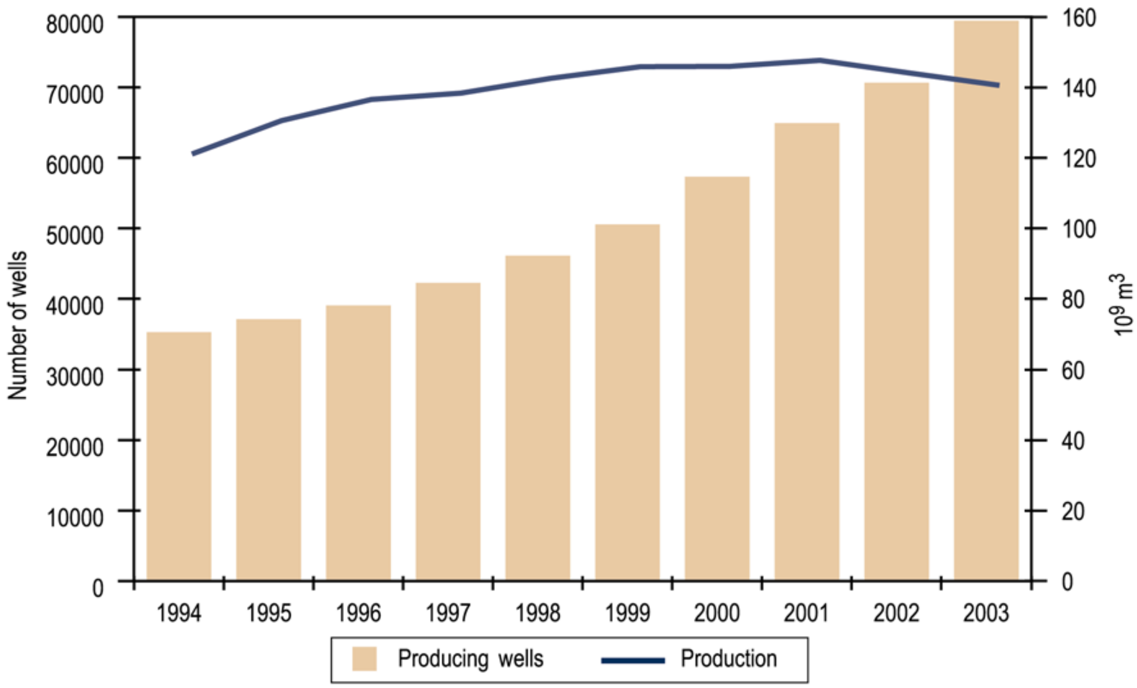


Figure 4.21. Marketable gas production and the number of producing gas wells

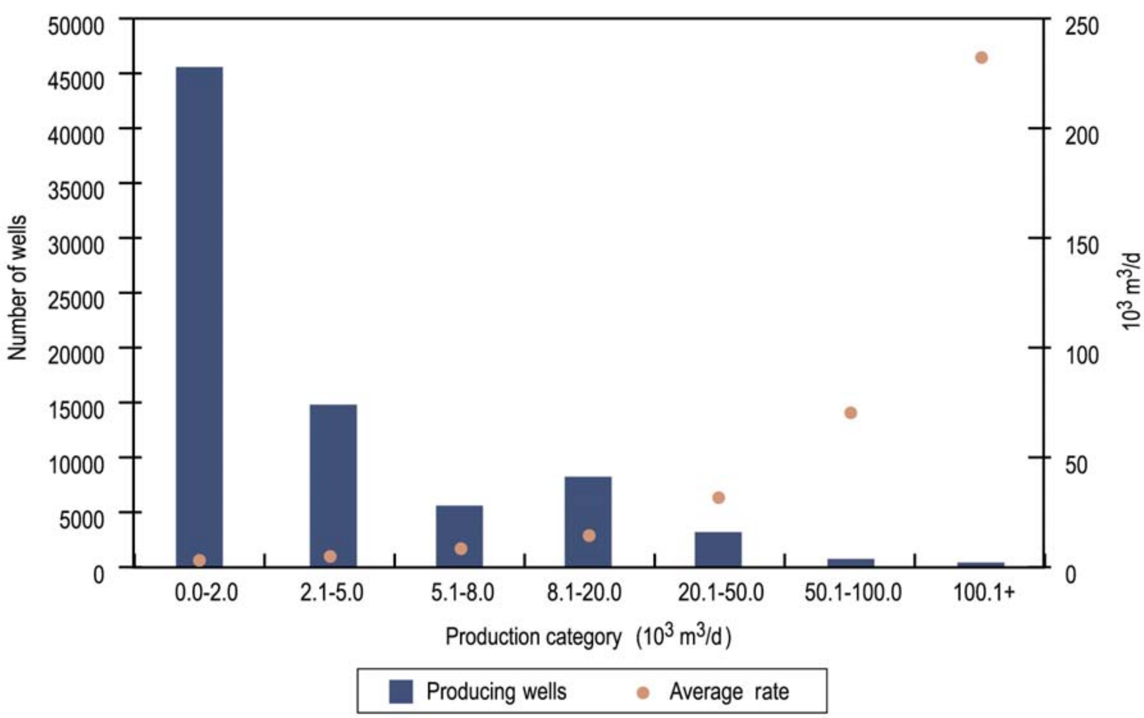


Figure 4.22. Natural gas well productivity in 2003

The historical raw gas production by connection year in Alberta is presented in **Figure 4.23**. Generally, a surface loss factor of around 15 per cent can be applied to raw gas production to yield marketable gas production. The bottom band in Figure 4.23 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 2003. For example, 12 per cent of gas production in 2003 came from wells connected in that year. The figure shows that in 2003, almost 50 per cent of gas production came from gas wells connected in the last four years.

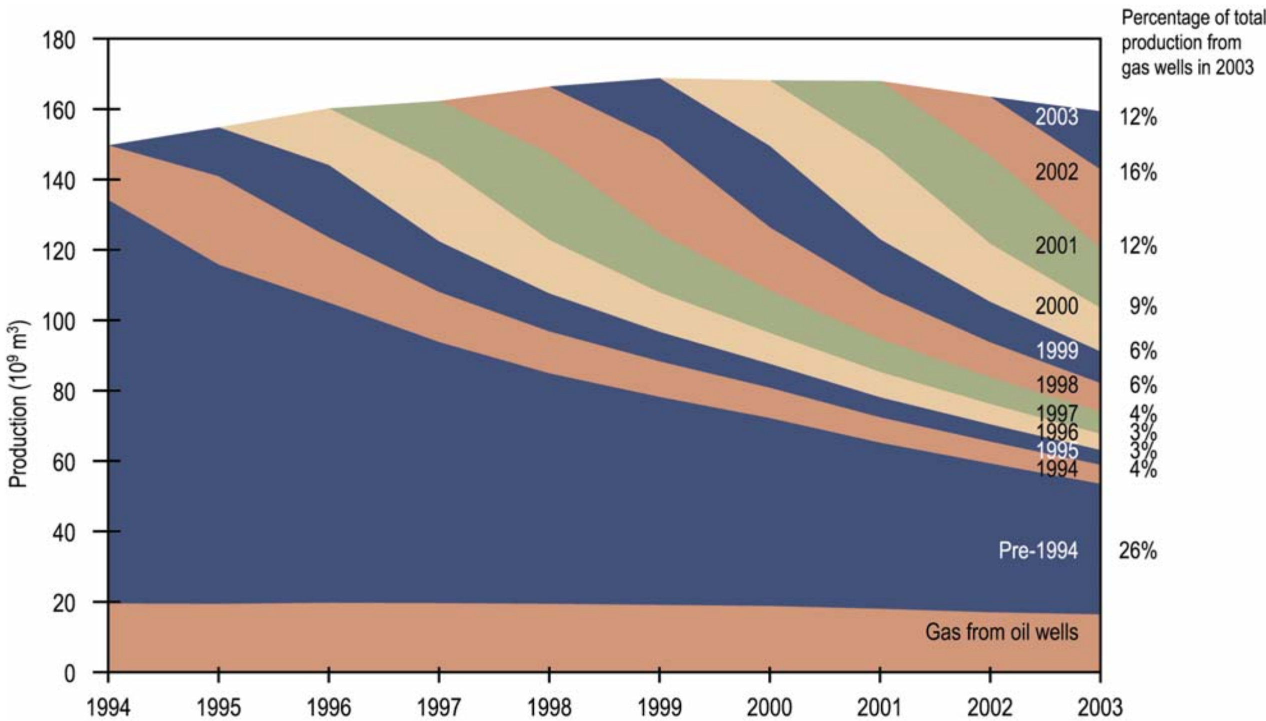


Figure 4.23. Raw gas production by connection year

Declines in natural gas production from new gas well connections from 1994 to 2001 have been evaluated after the wells drilled in a given year complete a full year of production.

Table 4.11 shows decline rates for gas wells connected from 1994 to 2001 with respect to the first, second, third, and fourth year of decline. More recently connected wells are exhibiting steeper declines in production in the first three years compared to wells connected in the early 1990s. However, by the fourth year of production the decline rates have not changed significantly over time. The decline rates tend to stabilize at some 18 per cent from the fourth year forward.

Table 4.11. Production decline rates for new well connections (%)

Year wells connected	First-year Decline	Second-year decline	Third-year decline	Fourth-year Decline
1994	26	23	16	15
1995	30	25	23	19
1996	31	27	21	18
1997	32	28	23	19
1998	32	28	24	18
1999	34	25	21	
2000	34	25		
2001	32			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 4.24** shows the average initial productivity (peak rate) of new wells by connection year. Average initial productivities for new wells excluding Southeastern Alberta (Area 3) are also shown in the figure. This chart shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average. Production data give some indication that initial productivities may be levelling off for new wells outside of Southeastern Alberta.

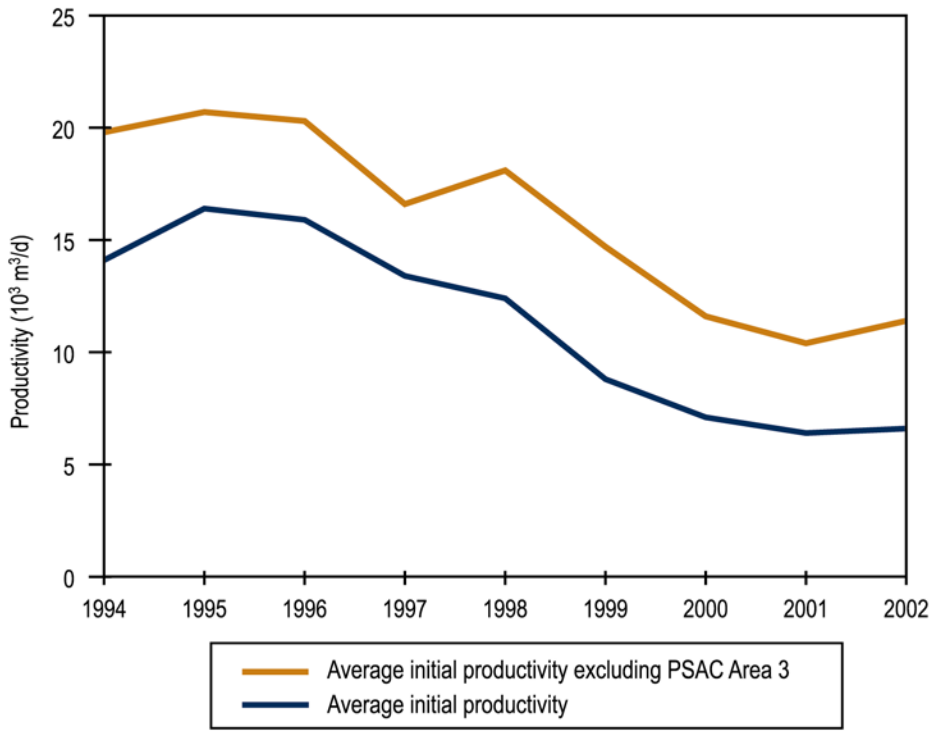


Figure 4.24. Average initial natural gas well productivity in Alberta

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 11 000 wells per year. This high level of drilling activity is expected to be a challenge for industry, but it has shown that it is capable of drilling at a higher rate. **Figure 4.25** illustrates historical and forecast new well connections and 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 2003 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 2.5 10^3 m^3/d in 2004 and will decrease to 1.5 10^3 m^3/d by 2013.

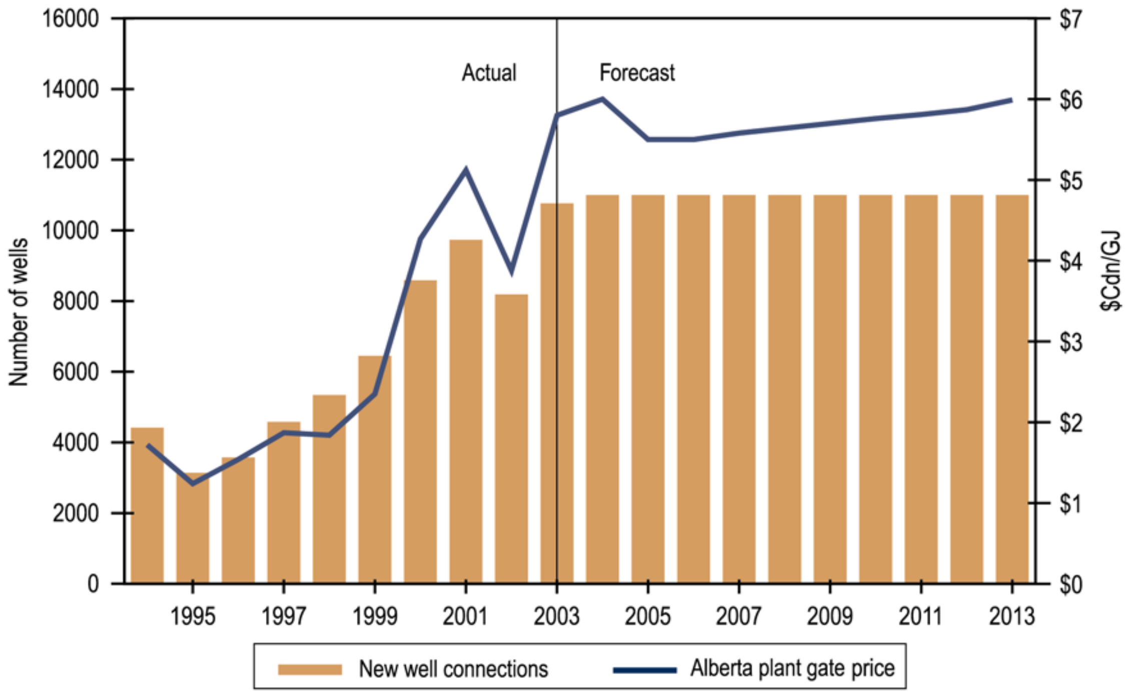


Figure 4.25. Alberta natural gas well activity and price

- The average initial productivity of new natural gas wells in the rest of the province will be 10 10^3 m^3/d in 2004 and will decrease to 6.5 10^3 m^3/d by 2013.
- Production from new wells will decline at a rate of 33 per cent the first year, 27 per cent the second year, 22 per cent the third year, and 18 per cent in 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 2013 as shown in **Figure 4.26**. The production of natural gas from conventional reserves is expected to decrease from 140.6 10^9 m^3 to 110.4 10^9 m^3 by the end of the forecast period. These projected production levels are lower than last year's as a result of expectations about future production trends.

If conventional natural gas production rates follow the projection, Alberta will have recovered some 83 per cent of the 5600 10^9 m^3 of ultimate potential by 2013. This ultimate potential volume is under review and is targeted for completion later this year.

Figure 4.27 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 the U.S. states represented here, gas production declined somewhat steeply after reaching peak production. However, over time production levels have been maintained at significant levels.

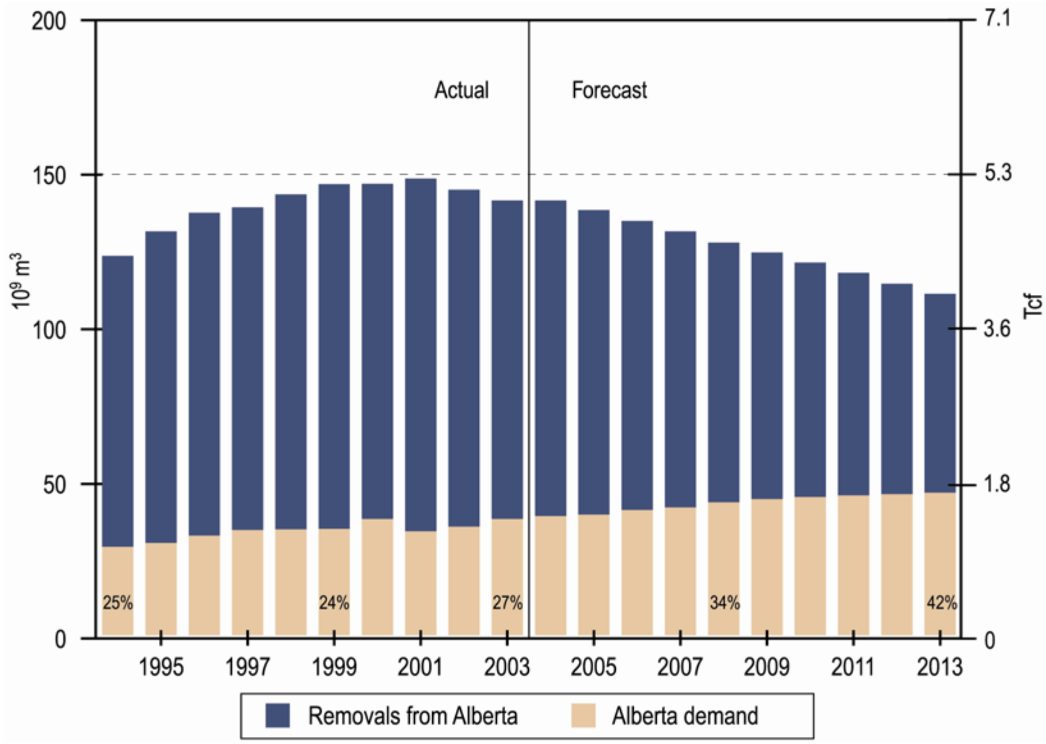


Figure 4.26. Disposition of conventional marketable gas production

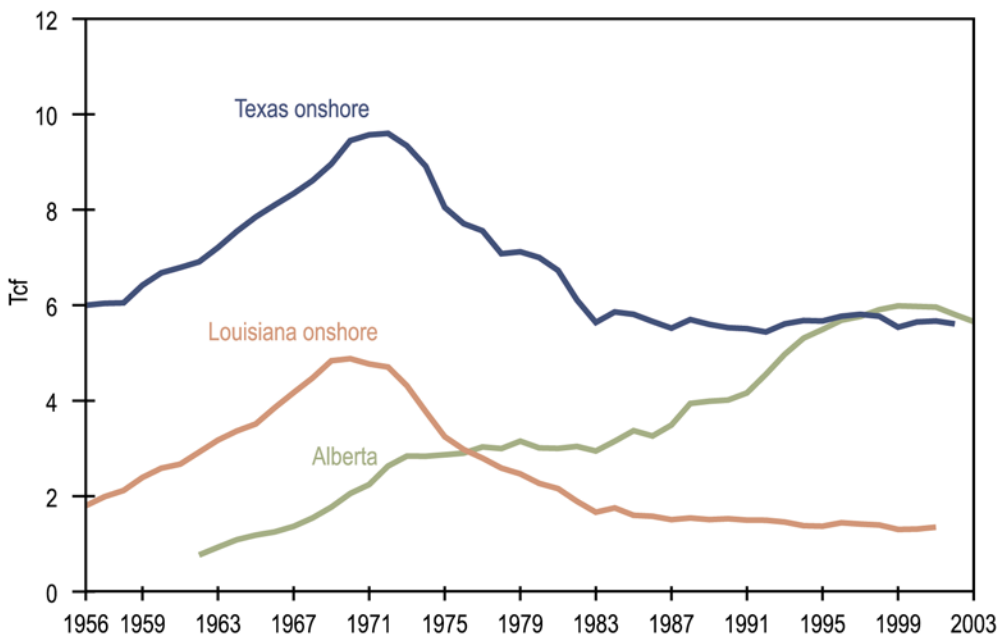


Figure 4.27. Comparison of natural gas production

Gas production from sources other than conventional gas and oil wells includes process gas from bitumen upgrading operations, natural gas from bitumen wells, and coalbed methane from coal seams. **Figure 4.28** shows the historical and forecast volumes of production from the first two categories. In 2003, some 3.7 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to

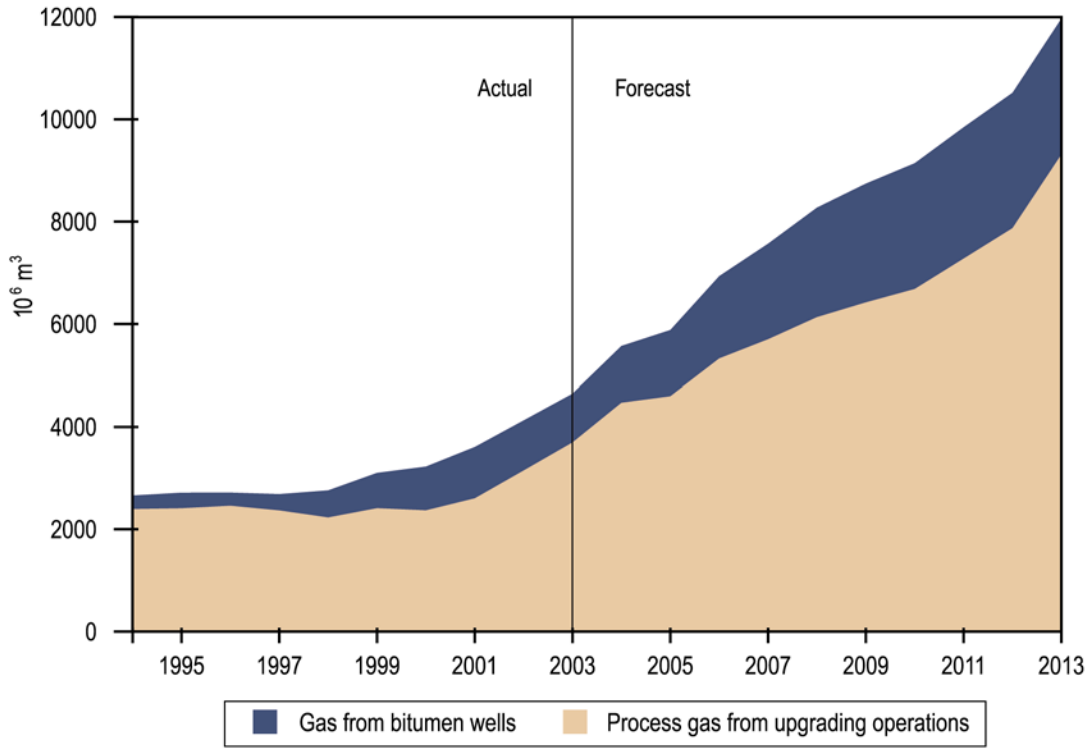


Figure 4.28. Gas production from bitumen upgrading and bitumen wells

reach 9.3 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells in thermal schemes was 1 10^9 m^3 in 2003 and is forecast to increase to 2.7 10^9 m^3 by 2013. This gas was used as fuel to create steam for its in situ operations.

Due to lack of significant information and uncertainty surrounding its potential, the EUB has not projected coalbed methane production in the province. However, it expects that coalbed methane will play a role in supplementing future gas production from conventional sources in Alberta.

Figure 4.29 shows the forecast of conventional natural gas production, along with gas production from other sources.

4.3.2 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 nonnative 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 the winter approaches, the demand for natural gas supply rises, injection slows or ends, and production generally begins at high withdrawal rates. **Figure 4.30** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province.

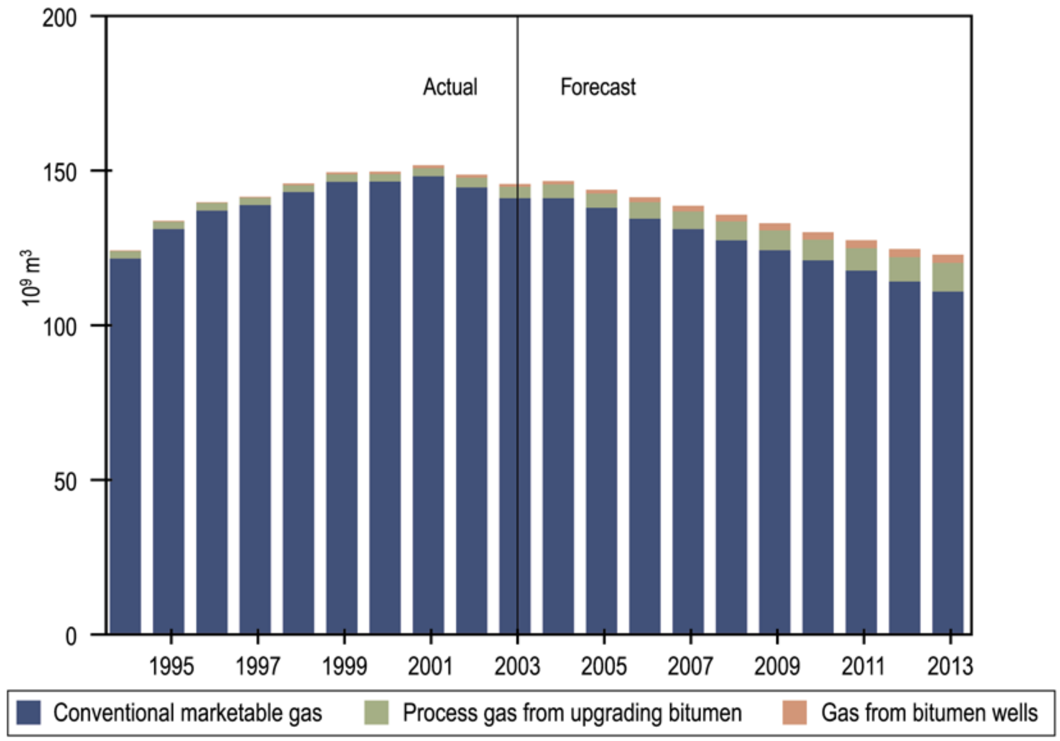


Figure 4.29. Total gas production in Alberta

Commercial natural gas storage pools, along with the operators and storage information, are listed in Table 4.12. EnCana began operating two new storage pools in 2003, known as the Countess Bow Island N and Upper Mannville M5M pools.

As **Figure 4.30** illustrates, 2003 natural gas injections came into close balance with withdrawals, with injections higher by 238 10^6 m^3.

Marketable gas production volumes determined for 2003 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.

4.3.3 Alberta Natural Gas Demand

The EUB reviews the projected demand for Alberta natural gas on a periodic basis. 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 published estimates of other organizations are used in developing the forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets and the recent historical trends in meeting that demand.

Figure 4.26 shows Alberta natural gas demand and production. Gas removals from the province represent the difference between natural gas production and Alberta demand. In the year 2003, some 27 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the United States.

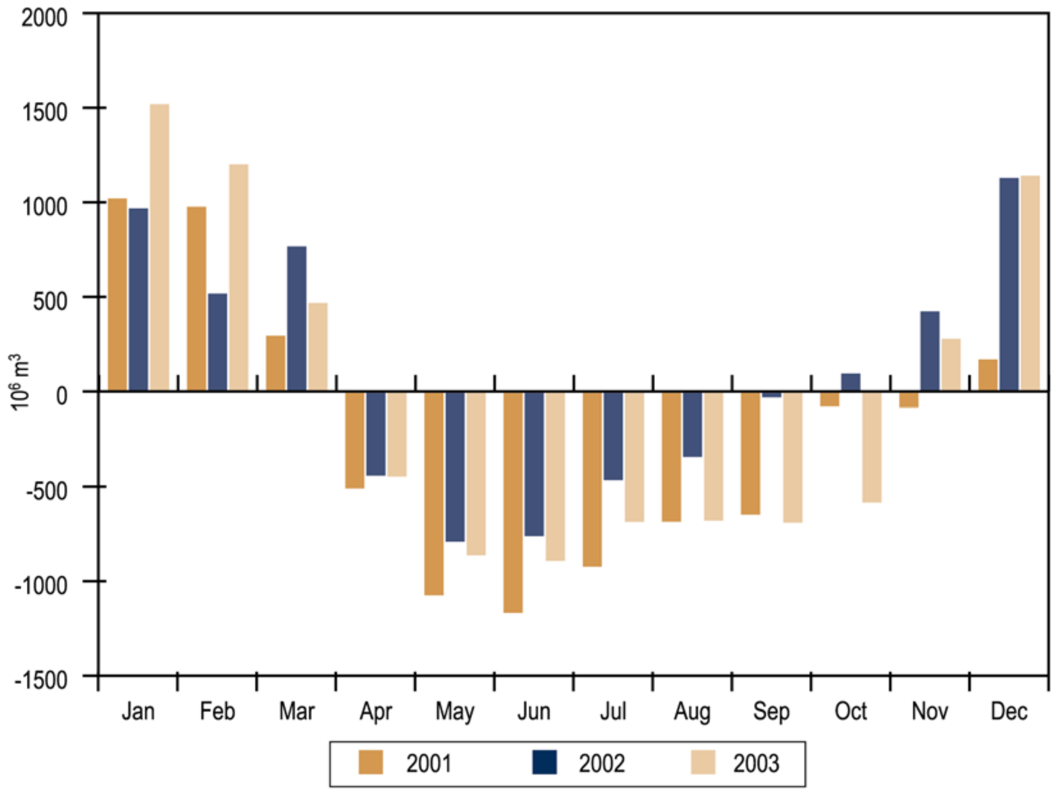


Figure 4.30. Alberta natural gas storage injection/withdrawal volumes

Table 4.12. Commercial natural gas storage pools as of December 31, 2003

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2003 (10^6 m^3)	Withdrawal volumes, 2003 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	1 148	1 153
Countess Bow Island N & Upper Mannville M5M	EnCana Gas Storage	817	23 950	427	161
Crossfield East Elkton A & D	CrossAlta Gas Storage & Services Ltd.	1 197	14 790	594	1 248
Hussar Glauconitic R	Husky Energy	423	5 635	398	322
McLeod Cardium A	Pacific Corp Energy Canada Ltd.	986	16 900	662	646
McLeod Cardium D	Pacific Corp Energy Canada Ltd.	282	4 230	236	151
Sinclair Gething D & Paddy C	EnCana Gas Storage	282	5 634	281	268
Suffield Upper Mannville I & K, and Bow Island N & BB	EnCana Gas Storage	2 395	50 715	2 084	1 643

The *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 exports 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.

By the end of forecast period, domestic demand will reach 46 10^9 m^3, compared to 38 10^9 m^3 in 2003, representing 42 per cent of total production. **Figure 4.31** illustrates the breakdown of natural gas demand in Alberta by sector.

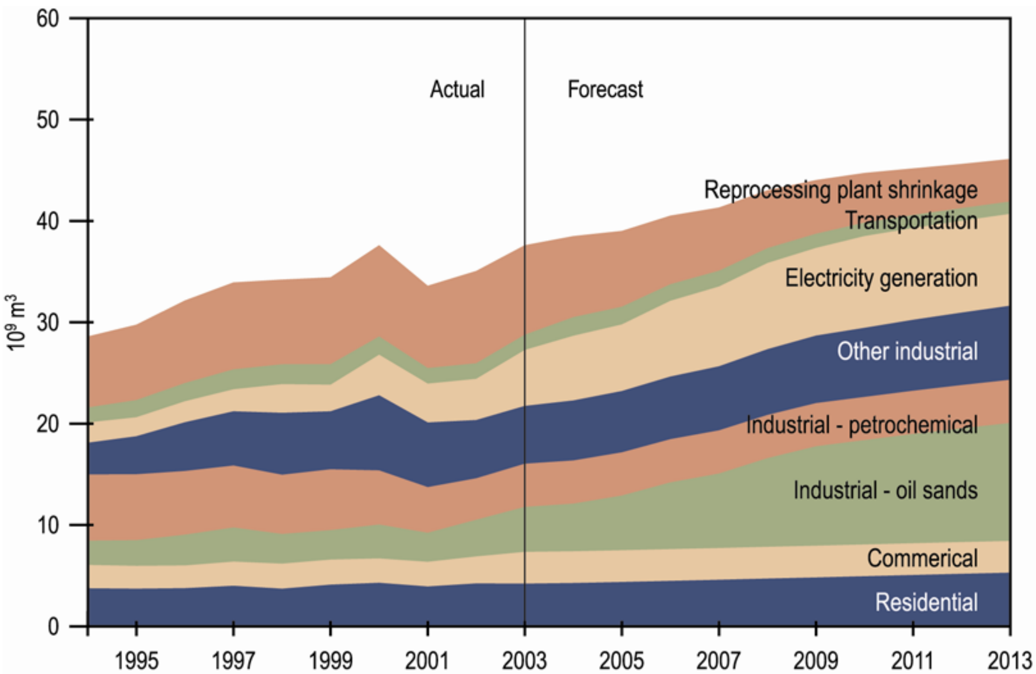


Figure 4.31. Alberta gas demand by sector

Residential gas requirements are expected to grow moderately over the forecast period at an average annual rate of 2.3 per cent. The key variables that impact 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 natural gas requirements for bitumen recovery and upgrading to synthetic crude oil are expected to increase annually from 4.4 10^9 m^3 in 2003 to 12 10^9 m^3 by 2013. It should be noted that process gas from oil sands upgrading operations and natural gas production from bitumen wells supplement purchased gas volumes.

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. These 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 5.5 10^9 m^3 in 2003 to 9.1 10^9 m^3 by 2013.

4.4 Supply of and Demand for Natural Gas Liquids

4.4.1 Supply of Ethane and Other Natural Gas Liquids

Ethane and other NGLs are recovered from several sources, including gas processing plants in the field that 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 to recover 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 plant. Although some pentanes plus is recovered in the field as gas condensate, 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 4.32** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Ethane and other NGL production is a function of raw gas production, as well as its liquid content, gas plant recovery efficiencies, and prices. For further details, see Section 4.1.7. High gas prices relative to NGL prices may cause gas processors to reduce liquid recovery.

Table 4.13 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2003. 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 (1.1 10^3 m^3/d) and 1.3 10^6 m^3 (3.7 10^3 m^3/d) respectively.

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 production. The NGL content from the new reserves is assumed to be somewhat higher than existing reserves, as a large portion of yet to be discovered gas is in the deeper part of the basin.

In 2003, ethane extraction in Alberta was 37.5 10^3 m^3/d, or 53 per cent recovery of the total ethane in the gas stream. It is expected that ethane recovery will increase to 41.2 10^3 m^3/d in 2004 and hold there for the remainder of the forecast period, as shown in **Figure 4.33**. Current processing plant capacity for ethane in Alberta is some 60 10^3 m^3/d and therefore 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. In fact, additional volumes of ethane are available for extraction, should the demand increase further in the future.

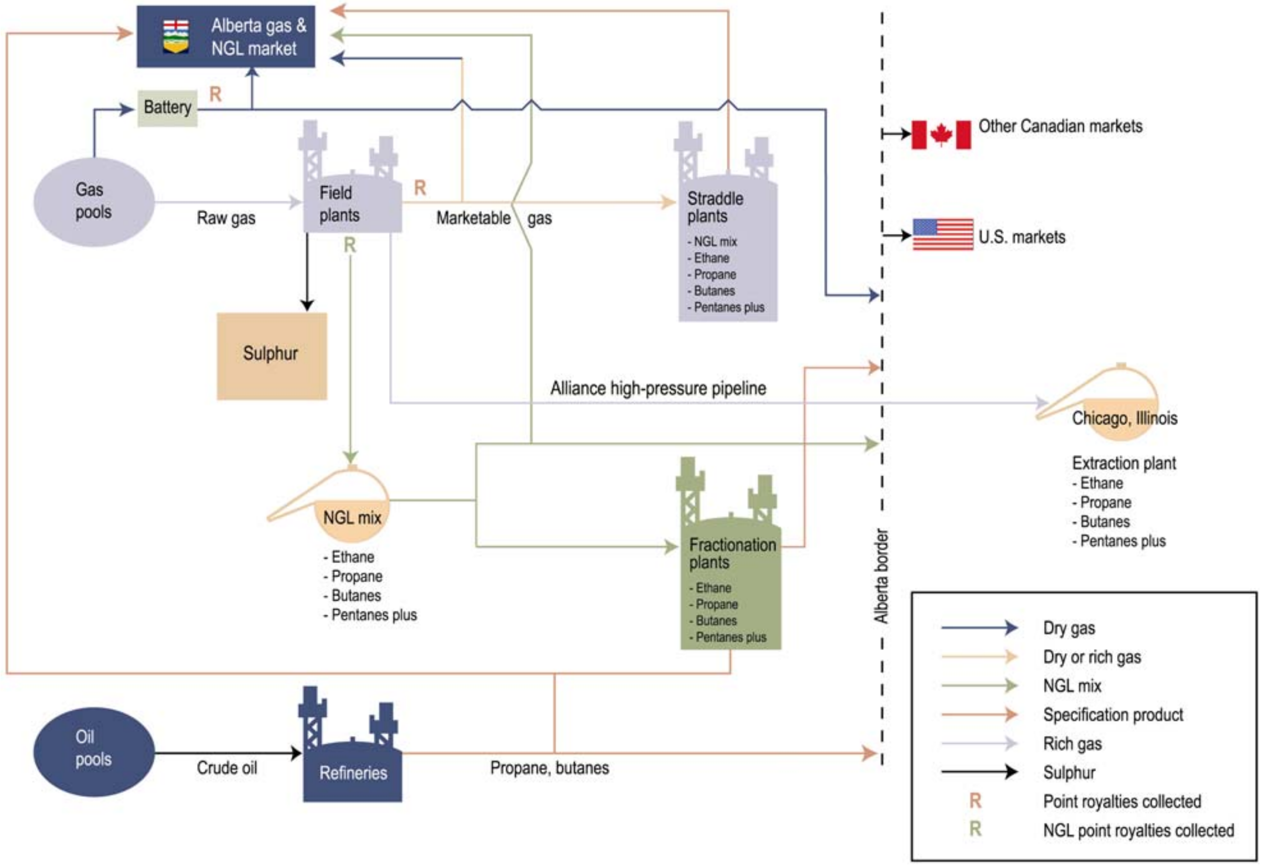


Figure 4.32. Schematic of Alberta NGL flows

Table 4.13. Liquid production at gas plants in Alberta, 2003 and 2013

	2003			2013		
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	13.7	37.5	97	15.0	41.2	147
Propane	8.2	22.5	58	6.8	18.6	62
Butanes	4.5	12.3	32	3.7	10.1	33
Pentanes plus	8.2	22.5	58	6.8	18.6	62

Over the forecast period, ratios of ethane, propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas increase, as shown in Table 4.13. **Figures 4.34** to **4.36** show forecast production volumes to 2013 for 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.

4.4.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in 2003, some 97 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 removal permits.

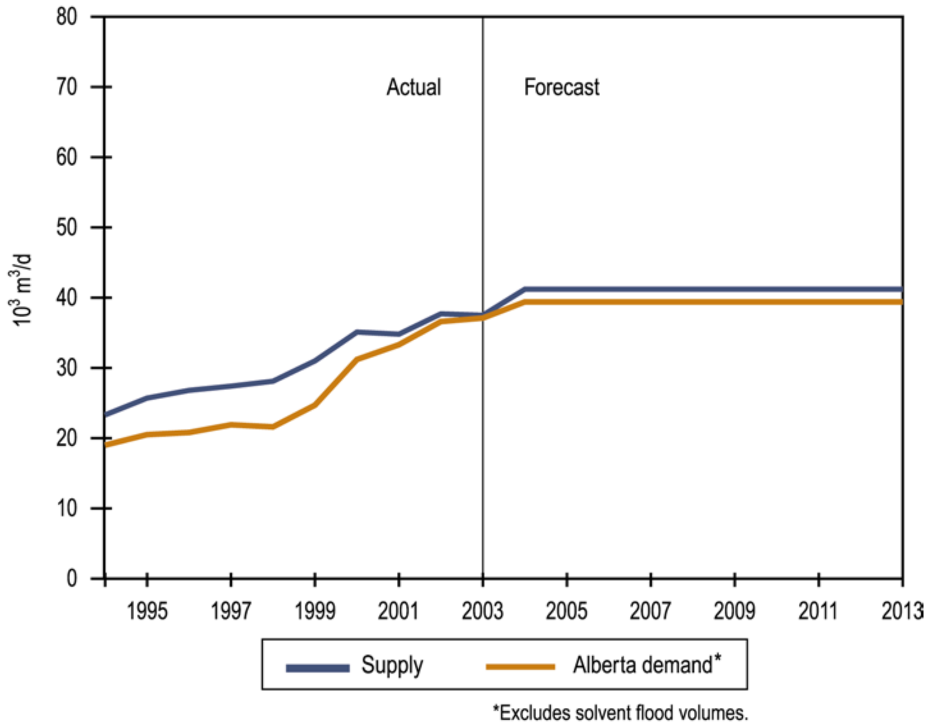


Figure 4.33. Ethane supply and demand

As shown in **Figure 4.33**, 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. Ethane supplies are tighter than they have been historically, due in part to the large increase in demand by the fourth ethylene plant placed on production in October 2000 and the Alliance pipeline that came on stream in December 2000. For purposes of this forecast, it was assumed that no new ethylene plants will be built during the forecast period requiring Alberta ethane as feedstock. For longer term growth opportunities, the petrochemical industry may consider an additional source of ethane from process gas from Fort McMurray oil sands upgraders. The majority of the process gas from oil sands upgraders is presently being used as fuel for oil sands operations.

Figure 4.34 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 through the forecast period.

Figure 4.35 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.

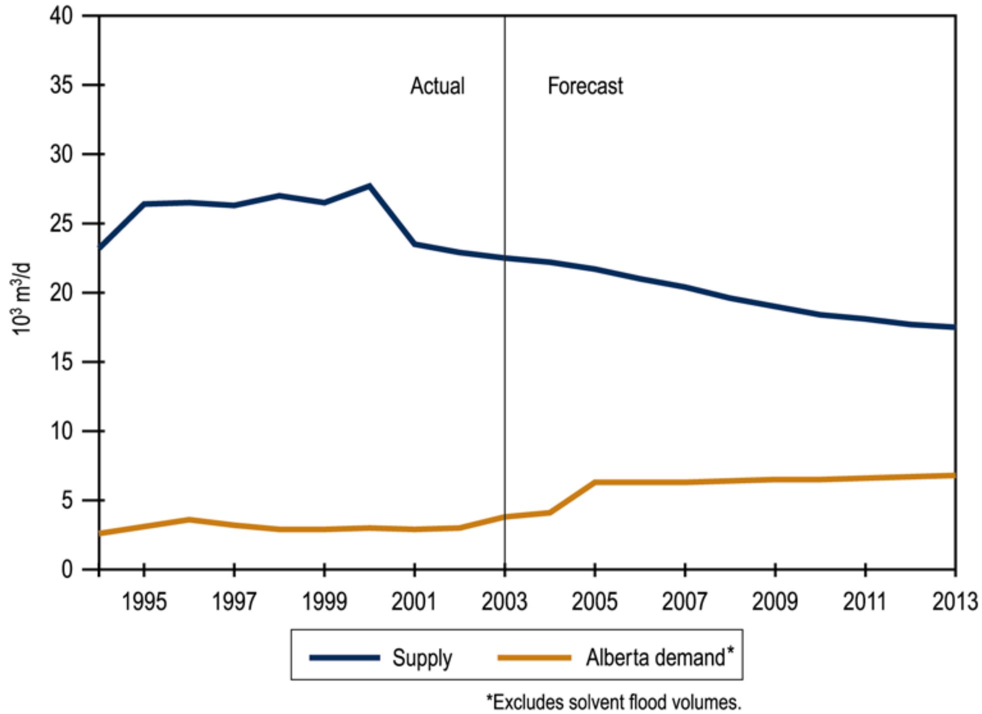


Figure 4.34. Propane supply and demand from natural gas production

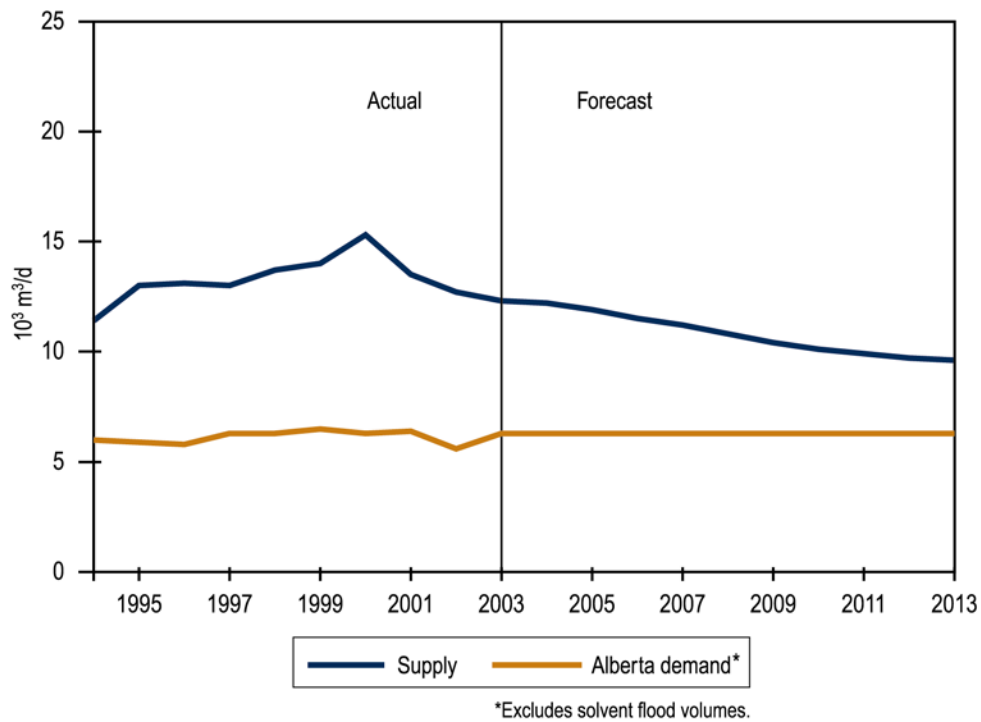


Figure 4.35. Butanes supply and demand from natural gas production

Figure 4.36 shows Alberta demand for pentanes plus compared to the total available supply. Alberta pentanes plus is used as diluent for transporting heavy crude oil and bitumen. Diluent is required to increase the API gravity and reduce the viscosity of heavy crude oil and bitumen to facilitate transportation through pipelines. It is assumed that heavy crude oil requires some 5.5 per cent diluent for Bow River and 17 per cent for Lloydminster. 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.

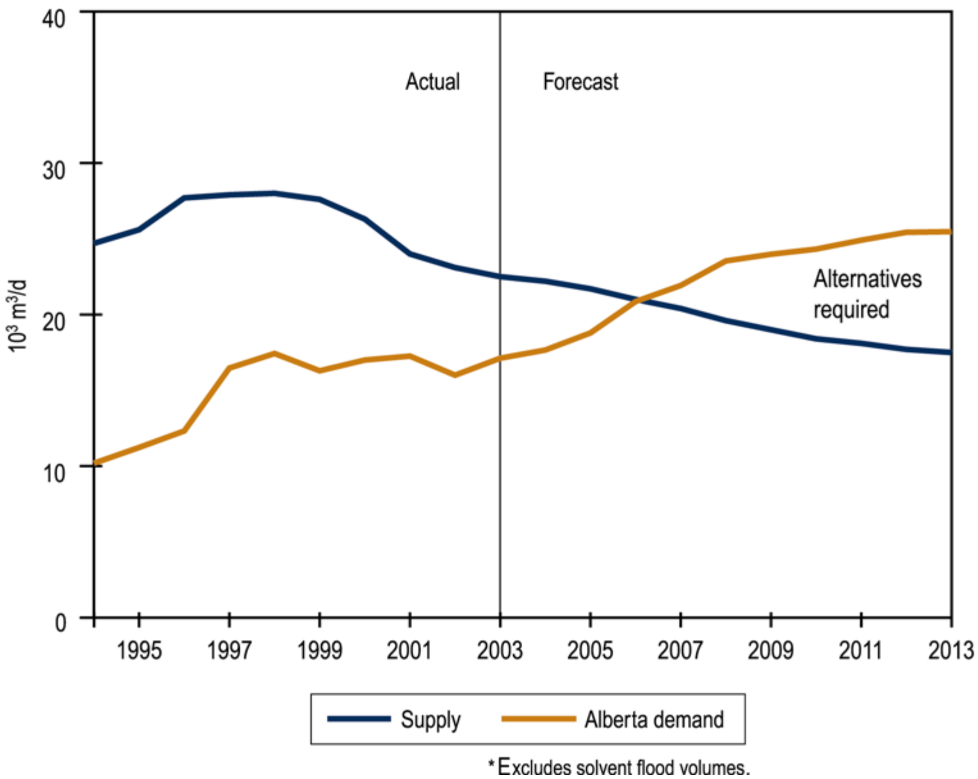


Figure 4.36. Pentanes plus supply and demand

Over the forecast period, pentanes plus demand as diluent is expected to increase from 17.7 10^3 m^3/d to 25.5 10^3 m^3/d. The diluent requirement for heavy crude oil is expected to decline from 3.0 10^3 m^3/d in 2003 to 2.1 10^3 m^3/d by the end of the forecast, due to declining crude oil production. However, diluent requirements for bitumen are expected to increase dramatically, from 12.8 10^3 m^3/d in 2003 to 22.6 10^3 m^3/d by 2013. Shortages of pentanes plus as diluent are forecast to occur by 2007 if alternatives are not considered. Several steps were taken to reduce the pentanes plus diluent requirements in past years, including the Enbridge pipeline system implementing a new viscosity standard in 1999, which reduced the diluent requirement by about 10 per cent. In the forecast period, diluent requirements for pentanes plus are expected to be offset by future upgrading of in situ bitumen production to synthetic crude oil (SCO) from projects such as Suncor's Firebag project, OPTI/Nexen's Long Lake project, and Petro-Canada's MacKay River project. In addition, SCO is being used as a diluent for some crude bitumen production.

Industry may consider alternatives to pentanes plus in the future, such as

- upgrading increasing volumes of bitumen to SCO within Alberta;
- blending increasing volumes of bitumen with SCO or light sweet oil;
- blending refinery naptha and distillates, due to their low viscosity and density; and
- heating bitumen and insulating pipelines, with little or no diluent required to move bitumen through pipelines.

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file PowerPoint file for Section 4 – Gas

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file
PowerPoint file for Section 5 – Coal

5 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 Report (ST) 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.

5.1 Reserves of Coal

5.1.1 Provincial Summary

The EUB estimates the remaining established reserves of all types of coal in Alberta at December 31, 2003, to be 33.6 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 0.95 Gt is within permit boundaries of mines active in 2003. Table 5.1 gives a summary by rank of resources and reserves from 244 coal deposits.

Table 5.1. Established initial in-place resources and remaining reserves of coal in Alberta as of December 31, 2003[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves	Remaining reserves in active mines
Low- and medium-volatile bituminous[b]					
Surface	1.74	0.811	0.219	0.592	
Underground	5.06	0.738	0.105	0.634	
Subtotal	6.83[c]	1.56[c]	0.323[d]	1.24[c]	0.032
High-volatile bituminous					
Surface	2.56	1.89	0.138	1.75	
Underground	3.30	0.962	0.047	0.914	
Subtotal	5.90[c]	2.88[c]	0.186[d]	2.69[c]	0.162
Subbituminous[e]					
Surface	13.6	8.99	0.630	8.36	
Underground	67.0	21.2	0.068	21.1	
Subtotal	80.7[c]	30.3[c]	0.698	29.6[c]	0.758
Total[c]	93.7[c]	34.8[c]	1.21	33.6[c]	0.952

[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, 2002, to December 31, 2003, resulted from increases in cumulative production. During 2003, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.001 Gt, 0.003 Gt, and 0.025 Gt respectively, a decrease for all three coal ranks from 2002.

5.1.2 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.

5.1.3 Established Reserves

Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reason, 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,[2] 70 per cent in the foothills, and 90 per cent in the plains.

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.

[2] The EUB has designated three regions within Alberta where coals of similar quality and mineability are recovered.

Table 5.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2003.

Table 5.2. Established resources and reserves of coal under active development as of December 31, 2003

Rank Mine	Permit area (ha)	Initial in-place resources (Mt)[a]	Initial reserve (Mt)	Cumulative production (Mt)	Remaining reserves[b] (Mt)
Low- and medium-volatile bituminous[c]					
Luscar	5 050	332	130	98	32
Subtotal	5 050	332	130	98	32
High-volatile bituminous					
Coal Valley[d]	6 400	349	167	101	66
Obed[e]	7 590	162	137	41	96
Subtotal	13 990	511	304	142	162
Subbituminous					
Vesta	2 410	69	54	38	16
Paintearth	2 710	94	67	38	29
Sheerness	7 000	196	150	59	91
Dodds	140	2	2	1	1
Whitewood[d]	2 800	163	98	74	24
Highvale	12 140	1 021	764	300	464
Genesee	7 320	250	176	43	133
Subtotal[b]	34 520	1 795	1 311	553	758
Total	53 560	2 638	1 745	793	952

[a] Mt = megatonnes; mega = 10^6.
[b] Differences are due to rounding.
[c] Does not include the Grande Cache Mine, approved in 2003, or the Cheviot Mine, approved in 1997. Neither was active (either producing or under construction) in 2003. The Gregg River mine is being abandoned and has been removed from the table.
[d] Does not yet include area of expansion approved in 2001.
[e] Limited operations in 2003.

5.1.4 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 the previous *ST 31: Reserves of Coal* report and adjusting them slightly to reflect the most recent trends. Table 5.3 gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potentials.

Table 5.3. 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 results of separate determinations.

[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

5.2 Supply of and Demand for Marketable Coal

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.

5.2.1 Coal Supply

In 2003, ten mine sites supplied coal in Alberta, as shown in Table 5.4. Together they produced 27.7 Mt of marketable coal. Subbituminous coal accounted for 89.7 per cent of the total, bituminous metallurgical was 4.4 per cent, and bituminous thermal coal constituted the remaining 5.9 per cent.

Six large mines and one small mine produce subbituminous coal. The large mines serve nearby electric power plants, while the small mine supplies 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. Over the past few years, subbituminous coal production has stabilized, as no new coal-fired power plants have been built and no substantial generating capacity has been taken out of operation.

Table 5.4. Alberta coal mines and marketable coal production in 2003

Company (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Epcor Generation Inc.	Genesee	Genesee	3.6
Luscar Ltd.	Sheerness	Sheerness	3.8
	Paintearth	Halkirk	1.6
	Vesta	Cordel	1.4
TransAlta Utilities Corp.	Highvale	Wabamun	12.4
	Whitewood	Wabamun	2.0
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.07
Bituminous metallurgical coal			
Cardinal River Coals Ltd.	Luscar	Luscar	1.2
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.2
	Obed Mtn.	Hinton	0.4
Total			27.7

Two operators received regulatory approval in 2001/2002 for three new coal-fired generating units, each having a capacity of 450 to 500 megawatts (MW). These units are scheduled for commissioning between 2005 and 2011. A third operator is in the process of applying for a permit to construct two 500 MW generation units, which are anticipated to be commissioned in the later part of the forecast period. All five units will be fuelled by subbituminous coal.

Alberta's only operating preparation plant producing clean metallurgical coal for export is at the Luscar Mine. While the mine itself is slated for closure due to the exhaustion of coal reserves in 2004, a new mine, Cheviot, will send its raw coal for preparation at this plant. Although the owners of the Cheviot Mine have announced that production is expected to begin in late 2004, for the sake of simplicity, it is incorporated in the forecast with an assumed start in 2005. It is also assumed that the Grande Cache Coal Mine will start in 2005, even though production may start earlier.

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. Without higher, stable prices, it is unlikely that any additional mines, other than the Cheviot Mine and the Grande Cache Coal Mine, will come on stream over the next decade.

In early 2003, Alberta's two producing thermal bituminous coal mines were negatively impacted by declining export thermal coal prices. Luscar indefinitely suspensed operations at the Obed Mountain Mine in June and reduced operations at the Coal Valley Mine. It is uncertain at this time what the long-term impacts of this decision will be, but it is assumed that production will rebound to 2002 levels by the latter half of the forecast period.

Historical and forecast Alberta production for each of the three types of marketable coal are shown in **Figure 5.1**.

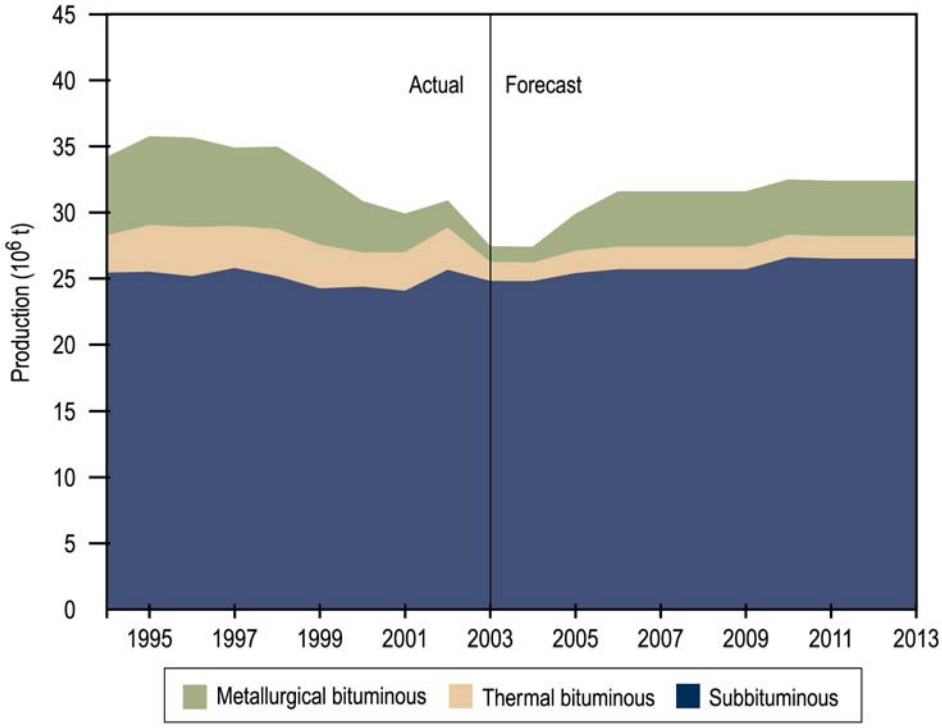


Figure 5.1. Alberta marketable coal production

5.2.2 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electric generation plants, and their production ties in with electricity generation. Subbituminous coal production is expected to increase, with potentially five units to be commissioned in the second half of the forecast period to meet demand for additional electrical generating capacity. Beyond that, it is expected that the demand for additional 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. Recently the international market for coal has strengthened, and this stronger market means that, on an annual basis, the Cheviot Mine and Grand Cache Coal Mine will be endeavouring to produce coal up to 2.8 Mt and 1.4 Mt respectively by 2006.

Prices of thermal coal entering international markets fell in early 2003, causing the reduction in coal production and also resulting in any excess stockpiled coal being consumed. Currently international thermal coal prices are on the rise, and price stabilization will occur in the latter half of the forecast period.

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file PowerPoint file for Section 5 – Coal

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file PowerPoint file for Section 6 – Sulphur

6 Sulphur

6.1 Reserves of Sulphur

6.1.1 Provincial Summary

The EUB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2003, to be some 85.1 million tonnes (10^6 t). The changes in sulphur reserves during the past year are shown in Table 6.1.

Table 6.1. Reserves of sulphur as of December 31, 2003 (10^6 t)

	2003	2002	Change
Initial established reserves			
Natural gas	244.7	238.7	+6.0
Crude bitumen[a]	67.7	67.7	0.0
Total	312.4	306.4	+6.0
Cumulative net production			
Natural gas	212.8	207.1	+5.7
Crude bitumen[b]	14.5	13.4	+1.1
Total	227.3	220.5	+6.8
Remaining established reserves			
Natural gas	31.9	31.6	+0.3
Crude bitumen[a]	53.2	54.3	-1.1
Total	85.1	85.9	-0.8

[a] Reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2003. Reserves from the entire surface mineable area are larger.
[b] Production from surface mineable area only.

6.1.2 Sulphur from Natural Gas

The EUB recognizes 31.9 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2003. 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 309 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 244.7 10^6 t, this leaves 104.3 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 6.2. 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

- Crossfield East and Limestone fields, which had a combined increase of about 2.6 10^6 t as a result of positive revisions to gas reserves in these fields, and
- Caroline field, which had a decrease of 1.9 10^6 t as a result of production.

Table 6.2. Remaining established reserves of sulphur from natural gas as of December 31, 2003

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[a] (mol/mol)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Benjamin	4 478	0.045	238	322
Bighorn	2 077	0.080	202	273
Blackstone	2 666	0.100	350	474
Brazeau River	12 597	0.050	772	1 047
Burnt Timber	1 286	0.173	327	444
Caroline	11 138	0.223	4 768	6 465
Coleman	598	0.255	224	304
Crossfield	4 565	0.160	1 072	1 454
Crossfield East	3 955	0.257	1 680	2 278
Elmworth	11 117	0.018	231	313
Fir	4 400	0.078	413	559
Garrington	5 141	0.071	339	460
Hanlan	5 993	0.089	712	965
Jumping Pound West	5 960	0.063	476	646
Kaybob South	12 215	0.044	571	774
La Glace	3 577	0.070	292	395
Lambert	702	0.167	169	229
Limestone	6 486	0.085	719	975
Moose	2 758	0.111	396	537
Okotoks	538	0.318	335	455
Pine Creek	4 262	0.058	297	403
Rainbow	9 630	0.020	216	293
Rainbow South	4 508	0.054	299	405
Ricinus West	827	0.283	391	530
Waterton	5 708	0.227	2 160	2 928
Wildcat Hills	6 648	0.031	236	320
Windfall	3 783	0.116	589	798
Zama	3 628	0.036	154	208
Subtotal	134 755	0.104	18 442	25 006
All other fields	987 419	0.005	5 089	6 921
Total	1 122 174	0.019	23 531	31 927

[a] Volume weighted average.

6.1.3 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, 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 technologies 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.

6.1.4 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 14.5 10^6 t of elemental sulphur has been produced from these projects, leaving a remaining established reserve of 53.2 10^6 t. During 2003, 1.1 10^6 t of elemental sulphur were produced from the three active projects.

6.2 Supply of and Demand for Sulphur

6.2.1 Sulphur Supply

There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to synthetic crude oil (SCO), and refining of crude oil into refined petroleum products. In 2003, Alberta produced 6.8 10^6 t of sulphur, of which 5.7 10^6 t was derived from sour gas, 1.1 10^6 t from upgrading of bitumen to SCO, and just 20 thousand (10^3) t from oil refining. Sulphur production from these sources is depicted in **Figure 6.1**. While sulphur production from sour gas is expected to decrease from 5.7 10^6 t in 2003 to 5.1 10^6 t, or some 11 per cent, sulphur recovery in bitumen upgrading industry is expected to increase to 3.2 10^6 t from 1.1 10^6 by the end of the forecast period. 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 20 10^3 t in 2003 to 49 10^3 t by 2013. Total sulphur production is expected to reach 8.4 10^6 t by the end of forecast period.

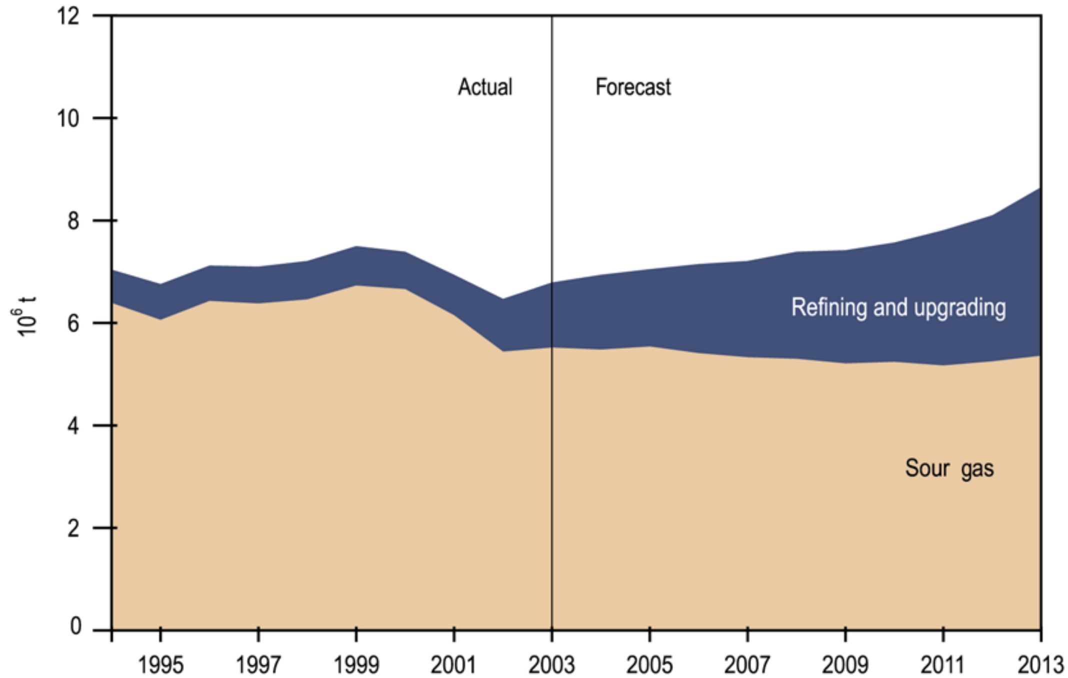


Figure 6.1. Sources of Alberta sulphur production

6.2.2 Sulphur Demand

Demand for sulphur within the province in 2003 was only 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, Asia Pacific, and North Africa.

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 2002 and 2003, China increased its sulphur imports from Canada substantially. Increased global demand for sulphur resulted in a major price change, from Cdn$16/t in 2001 to $40/t in 2003. The export demand for sulphur is expected to increase over the next few years. Demand for Alberta sulphur, both domestic and export, is expected to rise slowly, reaching 7.5 10^6 t per year by the end of the forecast period. **Figure 6.2** depicts the Alberta demand and sulphur removal.

6.2.3 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 6.2** as the difference between total supply and total demand.

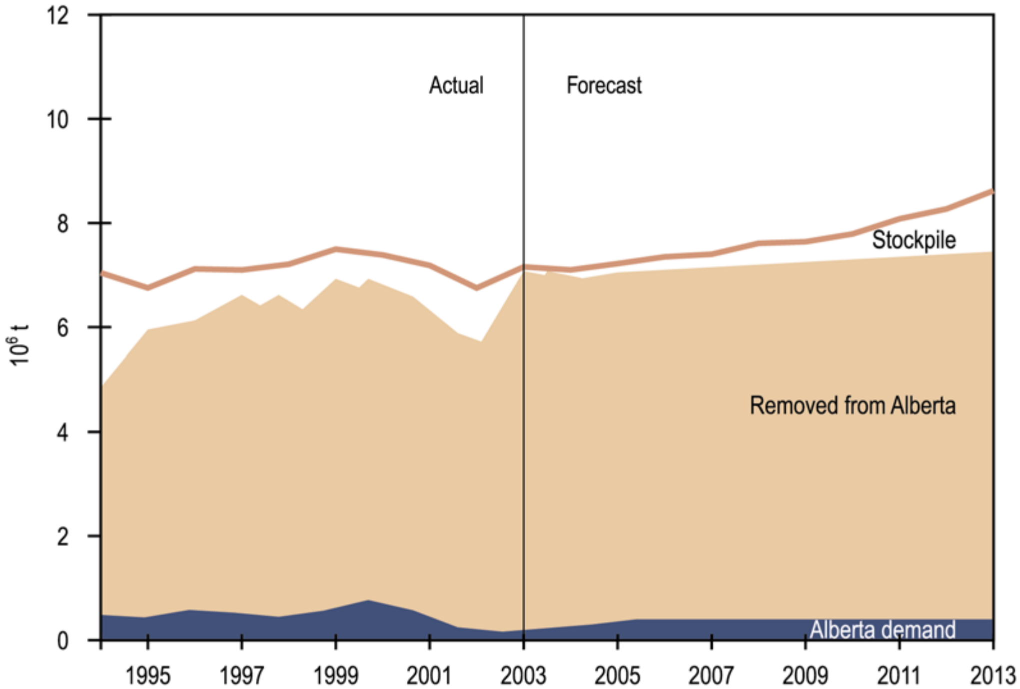


Figure 6.2. Sulphur demand and supply in Alberta

Data for the graphs in this section of the report are available for download in a PowerPoint file. **Click your right mouse button**, then **'Save As'** to download the file [PowerPoint file for Section 6 – Sulphur]

Appendix A Terminology, Abbreviations, and Conversion Factors

1.1 Terminology

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 purchasers' 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 purchasers' 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 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 Regulation* 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.
Off-gas	Natural gas that is produced from the 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.

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	New EOR schemes	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

Table B.2. Conventional crude oil reserves by geological period as of December 31, 2003

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	2 174	0	367	0	54	-	17	-
Lower	1 074	1 830	215	320	28	62	20	17
Jurassic	107	104	21	33	3	4	20	32
Triassic	335	25	66	2	12	0	20	8
Permian	14	0	8	0	1	-	56	
Mississippian	596	67	95	8	7	2	16	12
Devonian								
Upper	2 473	28	1 138	3	51	1	46	11
Middle	967	0	350	0	25	-	36	-
Other	69	15	7	1	4	-	10	7
Total	7 809	2 069	2 267	367	185	69	29	18

Table B.3. Distribution of conventional crude oil reserves by formation as of December 31, 2003

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	349	54	12	4	2	5
Chinook	5	1	0	0	0	0
Cardium	1 684	288	35	17	11	14
Second White Specks	34	3	1	0	0	0
Doe Creek	83	19	6	1	1	2
Dunvegan	21	2	0	0	0	0
Lower Cretaceous						
Viking	335	65	4	3	2	2
Upper Mannville	1 728	278	53	17	11	21
Lower Mannville	840	191	32	8	7	13
Jurassic	211	55	7	2	2	3
Triassic	360	69	12	4	3	5
Permian-Belloy	14	8	0	0	0	0
Mississippian						
Rundle	467	76	5	5	3	2
Pekisko	90	15	2	1	1	1
Banff	105	12	2	1	0	1
Upper Devonian						
Wabamun	59	7	1	1	0	0
Nisku	462	205	12	5	8	5
Leduc	834	503	13	8	19	5
Beaverhill Lake	991	393	19	10	15	8
Slave Point	154	33	7	2	1	3
Middle Devonian						
Gilwood	305	131	6	3	5	2
Sulphur Point	9	1	0	0	0	0
Muskeg	58	9	1	1	0	0
Keg River	498	178	15	5	7	6
Keg River SS	44	17	1	0	1	0
Granite Wash	54	13	2	1	0	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/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2[a]	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	58.6	45.3	-16.7	87.2	4 400.7	3 278.6	1 122.2	1 199.4

[a] At field plant.

Table B.5. Geological distribution of established natural gas reserves, 2003

	Raw gas	Marketable gas		Raw gas	Marketable gas	
Geological period	Initial volume in place (10^9 m^3)	Initial established reserves (10^9 m^3)	Remaining established reserves (10^9 m^3)	Initial volume in place (%)	Initial established reserves (%)	Remaining established reserves (%)
Upper Cretaceous						
Belly River	187	111	39	2.5	2.5	3.5
Milk River & Med Hat	763	465	214	10.2	10.6	19.1
Cardium	444	87	35	5.9	2.0	3.1
Second White Specks	22	13	9	0.3	0.3	0.8
Other	172	98	31	2.3	2.2	2.8
Subtotal	1 588	774	328	21.2	17.6	29.3
Lower Cretaceous						
Viking	406	279	61	5.4	6.4	5.4
Basal Colorado	40	33	2	0.5	0.7	0.2
Mannville	1 876	1 246	318	25.0	28.3	28.3
Other	298	190	58	4.0	4.3	5.2
Subtotal	2 620	1 748	439	34.9	39.7	39.1
Jurassic						
Jurassic	80	52	14	1.1	1.2	1.2
Other	74	46	13	1.0	1.0	1.1
Subtotal	154	98	27	2.0	2.2	2.3
Triassic						
Triassic	201	122	50	2.7	2.8	4.5
Other	44	30	6	0.6	0.7	0.5
Subtotal	245	152	56	3.3	3.5	5.0
Permian						
Belloy	8	5	2	0.1	0.1	0.2
Subtotal	8	5	2	0.1	0.1	0.2
Mississippian						
Rundle	939	587	95	12.5	13.3	8.5
Other	309	211	29	4.1	4.8	2.6
Subtotal	1 248	798	124	16.6	18.1	11.1
Upper Devonian						
Wabamun	234	116	23	3.1	2.6	2.0
Nisku	122	59	18	1.6	1.3	1.6
Leduc	464	243	21	6.2	5.5	1.9
Beaverhill Lake	482	220	40	6.4	5.0	3.6
Other	219	134	18	2.9	3.1	1.6
Subtotal	1 521	772	120	20.3	17.6	10.7
Middle Devonian						
Sulphur Point	14	9	4	0.2	0.2	0.3
Muskeg	5	2	1	0.1	0.1	0.1
Keg River	65	27	16	0.9	0.6	1.4
Other	33	14	3	0.4	0.3	0.3
Subtotal	117	52	24	1.6	1.2	2.1
Confidential						
Subtotal	3	2	2	0.0	0.0	0.2
Total	7504 (265)[a]	4 401 (155)[a]	1 122 (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, 2003

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)
Brazeau River Nisku J	557	74.44	41	0.75	0.50	15	41.01	380
Brazeau River Nisku K	1 360	74.17	101	0.75	0.60	30	42.15	718
Brazeau River Nisku M	1 832	76.22	140	0.75	0.60	42	41.36	1 013
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435
Brazeau River Nisku S	1 665	54.64	90	0.80	0.57	31	41.38	756
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200
Caroline Beaverhill Lake A	64 707	49.95	3 232	0.77	0.76	597	36.51	16 360
Carson Creek Beaverhill Lake B	11 350	55.68	631	0.90	0.39	346	41.65	8 330
Harmattan East Rundle	36 252	50.26	1 822	0.85	0.26	1 146	40.93	28 000
Harmattan-Elkton Rundle C	31 326	46.96	1 471	0.90	0.27	966	41.48	23 300
Kakwa A Cardium A	1 120	55.40	62	0.85	0.32	35	42.71	840
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 638	39.68	41 300
Ricinus Cardium A	8 316	58.59	487	0.85	0.32	281	40.52	6 950
Valhalla Halfway B	6 331	53.89	341	0.80	0.33	182	40.00	4 572
Waterton Rundle-Wabamun A	86 670	48.74[a]	4 224	0.78	0.35	2 142	39.25	53 519
Wembley Halfway B	5 740	53.89	309	0.80	0.33	165	40.12	4 133
Westerose D-3	5 230	51.55	270	0.90	0.25	182	41.72	4 369
Westpem Nisku E	1 160	66.05	76	0.90	0.54	31	44.76	709
Windfall D-3 A	21 288	53.42	1 137	0.60	0.53	320	42.42	7 560

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

Table B.7. Natural gas reserves of multifield pools, 2003

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Edmonton Pool No. 1	
Bashaw Edmonton D	228
Nevis Edmonton D	1 064
Total	1 292
Belly River Pool No. 1	
Bashaw Edmonton F, Belly River C, G, H, L, M & Q	2 698
Nevis Belly River C	1 487
Total	4 185
Belly River Pool No. 2	
Bruce Belly River J	765
Holmberg Belly River J	124
Total	889
Belly River Pool No. 3	
Fenn West Belly River J	23
Fenn-Big Valley Edmonton A, Belly River J, L, M, N, Z & JJ	1 502
Gadsby Belly River J	2 027
Total	3 552
Belly River Pool No. 4	
Michichi Belly River B & G	144
Watts Belly River B & I	81
Total	225
Belly River Pool No. 5	
Ardenode Edmonton & Belly River MU#1	2 801
Centron Edmonton O and Belly River N, Q & AAA	366
Entice Edmonton & Belly River MU#1	6 073
Gayford Belly River II, LL, MM, & AAA	790
Strathmore Edmonton & Belly River MU#1	6 009
Total	16 039
Cardium Pool No. 1	
Ansell Cardium, Viking, & Mannville MU#1	17 043
Sundance Belly River, Cardium, Viking, & Mannville MU#1	2 988
Total	20 031
Southeastern Alberta Gas System (MU)	
Alderson Milk River, Medicine Hat, Second White Specks, Belly River and Colorado	56 971
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River	9 221
Bantry Milk River, Medicine Hat, Second White Specks Belly River and Colorado	29 035
Bassano Milk River, Medicine Hat, Second White Specks and Belly River	2 967
Berry Medicine Hat	59
Bindloss Milk River and Medicine Hat	2 493
Blackfoot Medicine Hat and Belly River	948
Bow Island Milk River, Medicine Hat, and Second White Specks	2 250
Brooks Milk River, Medicine Hat and Second White Specks	1 051
Cavalier Belly River	518
Cessford Milk River, Medicine Hat, Second White Specks and Belly River	21 076
Connorsville Milk River, Medicine Hat and Belly River	2 306
Countess Milk River, Medicine Hat, Second White Specks and Belly River	27 786
Drumheller Medicine Hat and Belly River	522
Enchant Second White Specks	95
Estuary Medicine Hat and Belly River	834
Eyremore Milk River, Medicine Hat, Second White Specks and Belly River	2 706
Farrow Medicine Hat and Belly River	2 060
Gleichen Medicine Hat and Belly River	2 142
Hussar Milk River, Medicine Hat and Belly River	5 541
Jenner Milk River, Medicine Hat, Belly River, Second White Specks and Colorado	8 335
Johnson Milk River, Medicine Hat and Second White Specks	739
Kitsim Milk River, Medicine Hat and Second White Specks	974
Lathom Milk River and Medicine Hat	1 151
Leckie Milk River, Medicine Hat, Belly River, and Second White Specks	1 439
Matziwin Milk River, Medicine Hat, Second White Specks and Belly River	3 663
Medicine Hat Milk River, Medicine Hat, Second White Specks and Colorado	150 490
Newell Milk River, Medicine Hat and Second White Specks	2 381
Princess Milk River, Medicine Hat, Second White Specks and Belly River	28 668
Rainier Milk River, Medicine Hat and Second White Specks	611
Scandia Milk River and Second White Specks	24
Seiu Lake Medicine Hat	848
Shouldice Medicine Hat and Belly River	1 197
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	67 635
Verger Milk River, Medicine Hat, Belly River, Second White Specks and Colorado	18 164
Wayne-Rosedale Medicine Hat, Milk River, and Belly River	2 041
Wintering Hills Milk River, Medicine Hat, Second White Specks, Belly River, and Colorado	5 294
Total	464 211

(continued)

Table B.7. Natural gas reserves of multifield pools, 2003 (continued)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Second White Specks Pool No. 2	
Craigmyle Second White Specks E	19
Dowling Lake Second White Specks E	182
Garden Plains Second White Specks E	2 359
Hanna Second Second White Specks E	1 789
Provost Second Second White Specks E	118
Richdale Second Second White Specks E	79
Sullivan Lake Second White Specks E	228
Watts Second White Specks E	82
Total	4 856
Second White Specks Pool No. 3	
Conrad Second White Specks J, & Barons A	341
Forest Second White Specks J	130
Pendant D'Oreille Second White Specks J	494
Smith Coulee Second White Specks J	1 197
Total	2 162
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	3 610
Redwater Upper Viking A, Middle Viking A, and Lower Viking A	1 252
Westlock Middle Viking B	381
Total	5 243
Viking Pool No. 2	
Albers Upper & Middle Viking A	15
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	5 083
Bellshill Lake Upper and Middle Viking A	185
Birch Upper and Middle Viking A	23
Bruce Upper, Middle A, Lower Viking B, Upper Mannville Z, PP, G4G, H4H & B6B, and Ellerslie W, JJJ, KKK, LLL & MMM	4 438
Dinant Upper and Middle Viking A	31
Fort Saskatchewan Upper and Middle Viking A	8 119
Holmberg Upper and Middle Viking A	19
Killam Upper and Middle Viking A, Rex B, and Glauconitic Q	2 289
Killam North Upper and Middle Viking A, Upper Mannville T, Basal Mannville C, L & U, and Nisku A	1 416
Mannville Upper and Middle Viking A, and Upper Mannville K	380
Sedgewick Upper and Middle Viking A	86
Viking-Kinsella Colony	27
Viking-Kinsella Viking, Mannville, & Wabamun MU#1	30 112
Wainwright Upper and Middle Viking A, and Colony G, R, V, W, & ZZ	1 796
Total	54 019
Viking Pool No. 3	
Carbon Belly River B and Viking D, & Pekisko B	2 163
Ghost Pine Viking D	295
Total	2 458
Viking Pool No. 4	
Fenn-Big Valley Viking B	749
Fenn West Viking B	185
Total	934
Viking Pool No. 5	
Hudson Viking A	854
Sedalia Viking A & F, Upper Mannville D, and Lower Mannville B	580
Total	1 434
Viking Pool No. 6	
Hairy Hill Viking A	190
Willingdon Viking A & J and Mannville MMM & X2X	232
Total	422
Viking Pool No. 7	
Inland Upper Viking C & E, Middle Viking F, G, & I, and Upper Mannville A & V	415
Royal Upper Viking C and Lower Viking A	43
Total	458
Viking Pool No. 13	
Chigwell Viking G	230
Nelson Viking G	157
Total	387
St. Edouard Pool No. 3	
Ukalta St. Edouard B	54
Whitford St. Edouard B	80
Total	134
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	1 440
Ferrybank Viking C, Glauconitic A, & Lower Mannville W	1 189
Total	2 629

(continued)

Table B.7. Natural gas reserves of multifield pools, 2003 (concluded)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	1 155
Pembina Glauconitic I & D and Ostracod C	3 572
Total	4 727
Glauconitic Pool No. 6	
Bassano Glauconitic III	456
Countess Bow Island, Viking, Upper Mannville, & Glauconitic MU#1	2 602
Hussar Viking L, Glauconitic III, and Ostracod OO	1 152
Wintering Hills Glauconitic III and Lower Mannville W	117
Total	4 327
Bluesky Pool No.1	
Rainbow Bluesky C	1 158
Sousa Bluesky C	1 186
Total	2 344
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	2 024
Hotchkiss Bluesky-Detrital-Debolt A	5 108
Total	7 132
Wabiskaw Pool No. 1	
Marten Hills Wabiskaw A and Wabamun A	26 790
McMullen Wabiskaw A and Wabamun A	1 143
Total	27 933
Gething Pool No. 1	
Fox Creek Viking C, Notikewin C and Gething D & H	2 749
Kaybob South Notikewin J, Bluesky CC, and Gething E, H, Q	718
Total	3 467
Ellerslie Pool No. 1	
Connorsville Basal Colorado E Glauconitic A, B, C, E, I & U and Ellerslie A	2 595
Wintering Hills Upper Mannville A and Ellerslie A	990
Total	3 585
Cadomin Pool No. 1	
Elmworth Dunvegan A	457
Elmworth Dunvegan I	57
Elmworth Dunvegan T	27
Elmworth Cadotte A	3 118
Elmworth Cadotte C	1 463
Elmworth Cadotte D	563
Elmworth Cadotte F	7
Elmworth Cadotte G	7
Elmworth Cadotte I	10
Elmworth Cadotte J	172
Elmworth Cadotte K	4
Elmworth Cadotte M	2
Elmworth Cadotte P	166
Elmworth Falher A-1	6 174
Elmworth Falher A-2	1 833
Elmworth Falher A-4	192
Elmworth Falher A-5	238
Elmworth Falher A-7	132
Elmworth Falher A-10	5 670
Elmworth Falher A-16	86
Elmworth Falher A-21	16
Elmworth Falher A-34	21
Elmworth Falher A-40	8
Elmworth Falher A-43	14
Elmworth Falher B-1	2 166
Elmworth Falher B-2	533
Elmworth Falher B-3	2 488
Elmworth Falher B-4	2 610
Elmworth Falher B-9	944
Elmworth Falher B-13	12
Elmworth Falher B-14	105
Elmworth Falher B-15	210
Elmworth Falher B-16	33
Elmworth Falher C-2	9
Elmworth Falher C-3	6
Elmworth Falher D-2	575
Elmworth Falher D-3	5
Elmworth Falher D-5	8
Elmworth Falher D-6	12
Elmworth Falher D-7	395
Elmworth Bluesky A	104
Elmworth Gething A	7
Elmworth Gething I	8
Elmworth Gething J	25
Elmworth Cadomin A	5 406
Sinclair Doe Creek N, O, & Y, Dunvagen A, Paddy A, Notikewin A, B, & C, Falher A, Bluesky G, Gething O and Cadomin A	7 565
Total	43 663
Halfway Pool No. 1	
Valhalla Halfway B	4 572
Wembley Halfway B	5 798
Total	10 370
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	6 834
Valhalla Halfway N	115
Total	6 949
Banff Pool No. 1	
Haro Banff E	104
Rainbow Banff E	10
Rainbow South Banff E	84
Total	198

Table B.8. Remaining raw ethane reserves as of December 31, 2003

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	11 698	0.082	1 069	3 800
Bigstone	4 037	0.083	359	1 276
Brazeau River	12 597	0.066	1 015	3 610
Caroline	11 138	0.086	1 841	6 545
Countess	28 757	0.013	386	1 372
Dunvegan	14 105	0.044	688	2 446
Edson	5 033	0.071	398	1 413
Elmworth	11 117	0.056	730	2 595
Ferrier	13 097	0.079	1 149	4 084
Garrington	5 141	0.075	358	1 273
Gilby	5 097	0.080	455	1 618
Gold Creek	3 788	0.079	388	1 202
Harmattan East	5 526	0.090	549	1 953
Harmattan-Elkton	4 126	0.076	375	1 333
Judy Creek	3 717	0.140	579	2 060
Kaybob	3 478	0.080	308	1 095
Kaybob South	10 215	0.078	1 017	3 617
Karr	4 625	0.082	422	1 501
Kakwa	4 256	0.094	445	1 581
Leduc-Woodbend	3 049	0.092	312	1 110
McLeod	4 669	0.072	373	1 327
Medicine River	5 033	0.096	545	1 936
Narraway	4 658	0.055	289	1 029
Pembina	21 319	0.089	2 151	7 648
Pine Creek	4 262	0.068	346	1 229
Hamburg	5 957	0.076	491	1 745
Provost	22 856	0.023	560	1 990
Rainbow	9 630	0.085	919	3 266
Rainbow South	4 508	0.101	560	1 990
Ricinus	8 830	0.080	754	2 681
Swan Hills	1 725	0.147	355	1 262
Swan Hills South	2 721	0.174	629	2 236
Sylvan Lake	5 045	0.081	459	1 632
Valhalla	10 656	0.078	917	3 261
Virginia Hills	1 758	0.157	334	1 189
Waterton	5 708	0.034	322	1 144
Westpem	2 950	0.105	351	1 247
Westerose South	5 998	0.083	556	1 975

(continued)

Table B.8. Remaining raw ethane reserves as of December 31, 2003 (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	5 551	0.093	582	2 071
Wapiti	12 786	0.055	800	2 845
Wildcat Hills	6 648	0.039	294	1 046
Wild River	14 862	0.070	1 116	3 966
Willesden Green	10 513	0.087	1 017	3 615
Wizard Lake	5 355	0.203	1 211	4 306
Subtotal	348 595	0.071	28 725	102 124
All other fields	773 579	0.028	21 282	75 800
Solvent floods			2 335	8 300
TOTAL	1 122 174	0.052[a]	52 342	186 224

[a] Volume weighted average.

Table B.9. Remaining established reserves of natural gas liquids as of December 31, 2003

Field	Remaining reserves of marketable gas ($10^6 m^3$)	($10^3 m^3$ liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	11 698	1 834	984	2 144	4 962
Ante Creek North	1 726	324	182	638	1 144
Bigstone	4 037	603	258	199	1 060
Bonnie Glen	1 984	421	236	365	1 022
Brazeau River	12 597	1 647	1 083	2 810	5 540
Caroline	11 138	2 792	2 449	6 351	11 592
Carrot Creek	2 575	449	201	152	802
Countess	28 757	531	305	246	1 082
Cranberry	2 535	366	203	326	895
Crossfield	4 565	299	185	317	801
Crossfield East	3 955	365	164	862	1 391
Dunvegan	14 105	1 190	691	1 192	3 073
Edson	5 033	531	258	292	1 081
Elmworth	11 117	849	378	432	1 658
Ferrier	13 097	2 222	1 193	988	4 404
Garrington	5 141	579	329	445	1 352
Gilby	5 097	755	383	426	1 564
Gold Creek	3 788	419	224	463	1 106
Hamburg	5 957	623	365	543	1 531
Harmattan East	5 526	950	569	1 315	2 834
Harmattan -Elkton	4 126	502	256	252	1 010
Hussar	6 800	405	223	209	837
Judy Creek	3 717	1 382	574	335	2 291
Jumping Pound West	5 960	245	207	397	849
Kakwa	4 256	926	505	848	2 278
Karr	4 625	654	276	287	1 218
Kaybob	3 478	552	270	363	1 186
Kaybob South	10 215	1 667	955	1 910	4 532
Knopcik	4 835	439	260	523	1 222
Leduc-Woodbend	3 049	577	246	162	985
McLeod	4 669	790	373	387	1 549
Medicine River	5 033	943	462	434	1 838
Peco	2 133	413	248	492	1 153
Pembina	21 319	4 101	1 975	1 916	7 992
Pine Creek	4 262	600	292	483	1 375
Provost	22 856	1 190	746	580	2 516

(continued)

Table B.9. Remaining established reserves of natural gas liquids as of December 31, 2003 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Rainbow	9 630	1 542	943	1 049	3 534
Rainbow South	4 508	1 129	546	774	2 448
Redwater	1 949	523	297	146	966
Ricinus	8 830	1 302	679	1 421	3 401
Swan Hills	1 725	976	534	443	1 953
Swan Hills South	2 721	1 537	703	294	2 535
Sylvan Lake	5 045	716	354	361	1 431
Turner Valley	1 398	286	176	416	877
Valhalla	10 656	1 468	787	1 721	3 975
Virginia Hills	1 758	774	259	115	1 147
Wapiti	12 786	831	360	324	1 515
Waterton	5 708	325	292	1 594	2 212
Wayne-Rosedale	6 113	456	247	276	979
Wembley	5 551	1 133	674	1 542	3 348
Westerose South	5 998	1 007	496	532	2 034
Westpem	2 950	639	361	636	1 636
Wild River	14 862	1 045	442	802	2 289
Willesden Green	10 513	1 783	842	854	3 478
Wilson Creek	2 659	381	207	272	860
Windfall	2 932	289	215	464	967
Wizard Lake	5 355	2 496	1 256	666	4 418
Zama	3 905	429	242	248	919
Subtotal	393 313	54 200	29 416	45 029	128 645
All other fields	728 861	27 375	15 356	17 586	60 317
Solvent floods		125	1 628	685	2 438
TOTAL	1 122 174	81 700	46 400	63 300	191 400

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 natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2003 on the CD that accompanies this report. 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 Reserves and Basic Data

The crude bitumen reserves 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 reserve 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.