Statistical Series **2002-98**

Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011

- Crude Bitumen
- Crude Oil
- Natural Gas and Liquids
- Coal
- Sulphur

ACKNOWLEDGEMENTS

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Overview

Providing information to support good decision-making is a key EUB service. 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 Alberta Energy and Utilities Board (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, sulphur, and coal. This year's report entitled *Alberta Reserves 2001 and Supply/Demand Outlook 2002-2011* 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.

Resource supply, costs of development, energy demands, conservation, and social and environmental considerations influence the economic factors that shape 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 2001 and shape the forecast for the years to come.

In 2001, raw bitumen production surpassed conventional crude oil production for the first time. It is important to note that in 2001 the first commercial steam-assisted gravity drainage (SAGD) production occurred in Alberta. Several SAGD schemes have either been approved by the EUB or are under review. The EUB expects higher volumes of commercial production to occur over the next few years.

As was the case last year, the EUB expects that natural gas production will decline over the second half of the forecast period. However, over the past year significant interest in the development of coalbed methane in Alberta has occurred. If these developments are proven to be successful, conventional natural gas supply could be augmented by coalbed methane.

The following table summarizes Alberta's energy reserves at the end of 2001.

Reserves Summary 2001

	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	259 200	1 631	9 762	61.4	7122	253	94	104
Initial established	28 330	178	2 583	16.2	4 180	148	35	39
Cumulative production	562	3.5	2 304	14.5	2 996	106	1.14	1.3
Remaining established	27 768	175	278	1.7	1 184	42	34	38
Annual production	43	0.271	42	0.264	143	5.1	0.033	0.036
Ultimate potential (recoverable)	50 000	315	3 130	19.7	5 600	200	620	683

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

Alberta has the largest oil sands (crude bitumen) resource in the world; approximately 50 billion cubic metres (m^3) (315 billion barrels) are considered potentially recoverable under anticipated technology and economic conditions.

The total in situ and mineable remaining established reserves are 27.7 billion m^3 (175 billion barrels), down slightly from 2000 due to production. To date, only 2 per cent of the initial established crude bitumen reserve has been produced.

Crude Bitumen Production

In 2001, Alberta produced 25 million m^3 (157 million barrels) from the mineable area and 18 million m^3 (113 million barrels) from the in situ area, totalling 43 million m^3 (271 million barrels). Bitumen produced from mining was upgraded, yielding 20 million m^3 (126 million barrels) of synthetic crude oil (SCO). In situ production was marketed as crude bitumen.

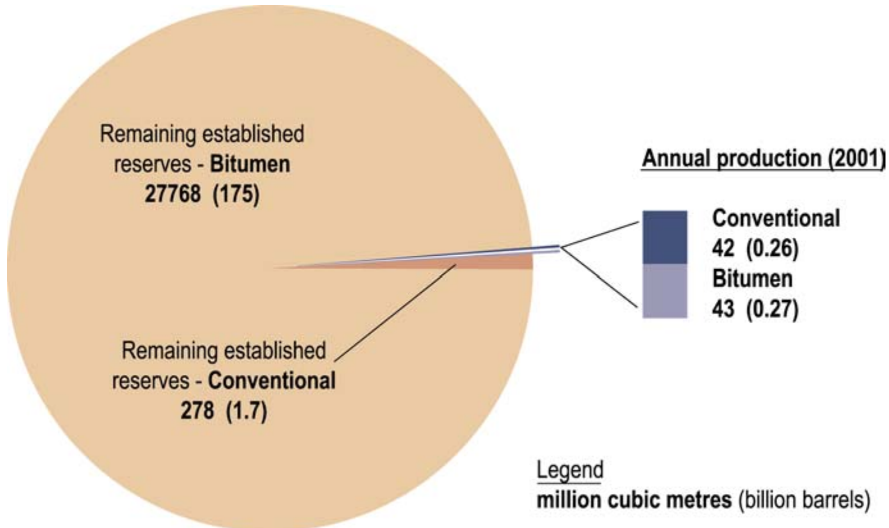
In 2001, total raw bitumen production exceeded total conventional crude oil production for the first time. The first commercial SAGD production occurred in 2001.

Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 278 million m^3 (1.7 billion barrels)—a 4.6 per cent reduction from 2000. Of the 28.6 million m^3 (180 million barrels) added to initial established reserves, exploratory and development drilling, along with new enhanced recovery schemes, added reserves of 23.5 million m^3 (148 million barrels). This replaced 56 per cent of 2001 production. Re-evaluation accounted for the remaining 5.1 million m^3 (32 million barrels) addition.

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 27 per cent.

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



Alberta's oil reserves

Crude Oil Production and Drilling

Alberta's production of conventional crude oil totalled 42 million m^3 (264 million barrels). Despite declining production over the past two decades, Alberta still produces 114 000 m^3/day (717 000 barrels/day) of conventional crude oil.

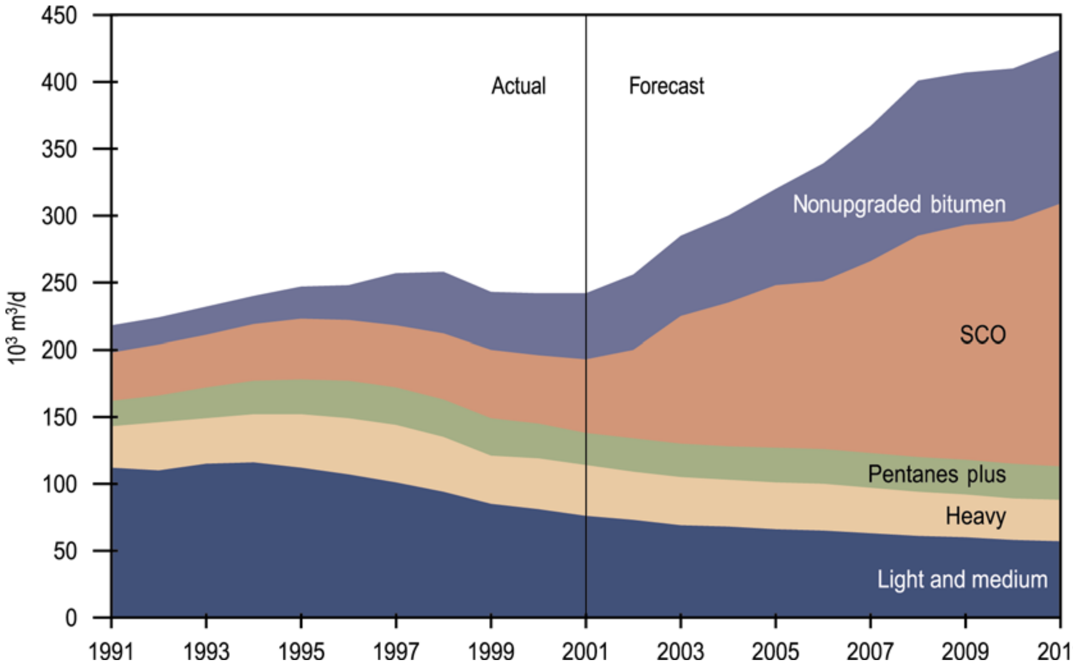
The number of successful oil wells decreased by 18 per cent, from 2700 in 2000 to 2220 in 2001. With the expectation that crude oil prices will remain strong, the EUB estimates that 1800 and 2100 successful oil wells will be drilled in 2002 and 2003 respectively, levelling at about 2400 wells per year over the remainder of the forecast.

Total Oil Supply and Demand

Alberta's 2001 production from conventional oil, oil sands sources, and pentanes plus was 243 000 m^3/day (1.53 million barrels/day)—about the same as in 2000. Production is forecast to reach 424 000 m^3/day (2.7 million barrels/day) by 2011.

A comparison of conventional oil production and bitumen production over the last 10 years clearly shows a trend towards a larger percentage being allocated to bitumen. 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, as expected, the EUB estimates that production of bitumen will triple by 2011, accounting for as much as 75 per cent of Alberta's total oil supply.



Alberta's total oil supply

Natural Gas

Natural Gas Reserves

At the end of 2001, Alberta's remaining established reserves of natural gas at the field plant gate stood at 1184 billion m^3 (42 trillion cubic feet). While new drilling has not fully replaced gas production since 1982, last year's record drilling added new reserves, replacing 67 per cent of the production for 2001, compared to 90 per cent in 2000.

Natural gas reserve estimates do not include coalbed methane, which has potential to add to Alberta's reserves in the future. Over the past year, significant interest in the development of coalbed methane in Alberta has occurred. If development is proven commercially successful, gas supply could be augmented by coalbed methane.

In 1992 the EUB estimated Alberta's ultimate marketable gas potential at approximately 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 2003.

Natural Gas Production and Drilling

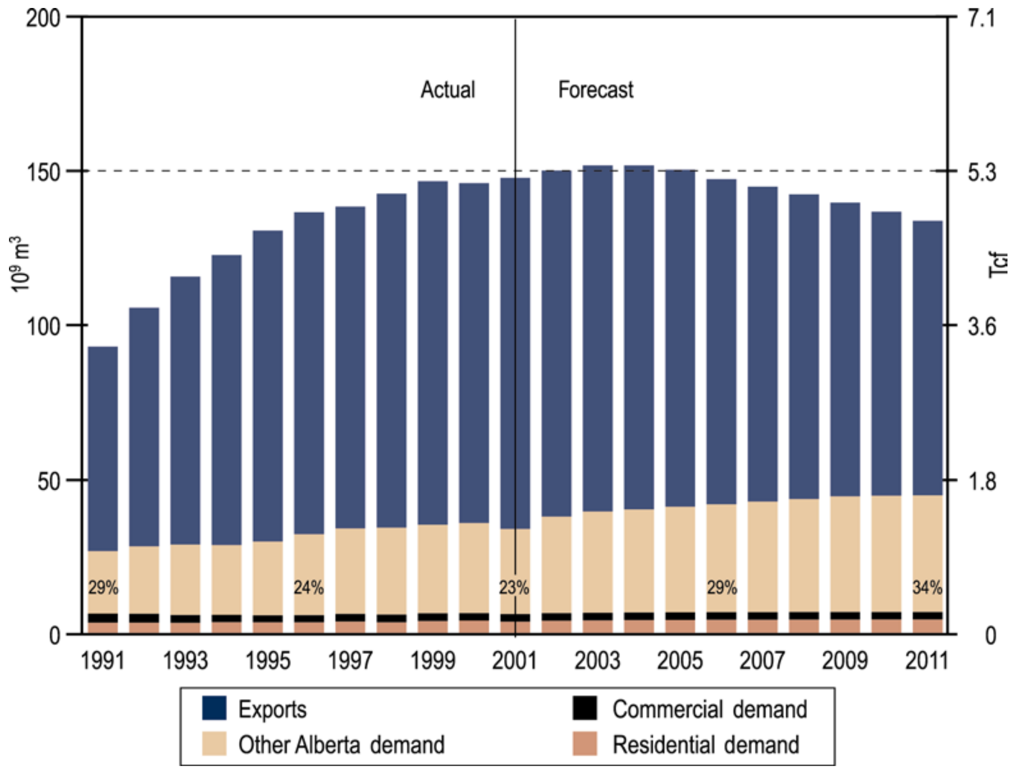
Several major factors have an impact on natural gas production, including natural gas prices, drilling activity, the location of Alberta's reserves, and the performance characteristics of wells. Alberta produced 143 billion m^3 (5.1 trillion cubic feet) of marketable natural gas in 2001. The trend of upward annual production levels evident over the past several years began to show significant flattening in 1999. Production in 2001 shows a continuation of this flattening trend despite record gas well drilling activity.

There were 9682 successful gas wells drilled in Alberta in 2001, a 17 per cent increase over the 8264 gas wells drilled in 2000. The EUB expects continued strong drilling, estimating 9500 to 11 000 wells for the period 2002 to 2005 and some 10 000 successful wells per year over the remainder of the forecast period.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta, with over half of the province's producing wells but only 16 per cent of 2001 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 decline by about 2 per cent per year over the final 5 years 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 latter half of the forecast period. Future supply is shown in the figure below.



Marketable gas production and demand

Although natural gas supply from conventional sources is expected to start declining moderately in the latter half of the forecast period, sufficient supply exists to meet Alberta's demand. If the EUB's demand forecast is realized, Alberta's natural gas requirement will be one-third 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 coalbed methane, offer options for supplementing the supply of conventional gas in the future.

Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of ethane are about the same as the 252 million m^3 (1.6 billion barrels) in 2000. Remaining established reserves of ethane, which is expected to be recovered from raw natural gas based on existing technology and market conditions, was estimated at 174 million m^3 (1.1 billion barrels) in 2001.

The production of specification ethane was 12.7 million m^3 (79.9 million barrels), about the same as the 12.8 million m^3 (80.5 million barrels) in 2000. 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— slightly decreased to 212 million m^3 (1.3 billion barrels) in 2001. 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 2006. Alternative sources of diluent would be required.

The remaining established reserves of sulphur is 94 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 75 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 2001 was 33 million tonnes of raw coal, down slightly from 2000 due to the closure of Smoky River coal mine. Recent increases in coal prices, due to high energy prices and high global steel production, improved prospects for Alberta's low-sulphur coal and created opportunities for extending coal production.

Subbituminous coal production is expected to increase in the middle part of the forecast period to meet demand for additional electrical generating capacity.

1 Energy Prices and Economic Performance

Alberta's prosperity as an energy-exporting province, and consequently its own energy supply and demand, is strongly affected by external energy markets. Alberta is Canada's leading producer of crude oil, bitumen, natural gas, natural gas liquids, sulphur and, in volumetric terms, coal. This section describes the outlook for world oil prices, Canadian economic performance, and the economic and demographic outlooks for Alberta. These factors form the basis for projecting energy supply and demand in Alberta and their impact on resource development.

1.1 Energy Prices

The price of Alberta crude oil is determined by international market forces and is most closely associated with the reference price of West Texas Intermediate (WTI) crude oil, depicted in **Figure 1.1**. The world oil prices represent crude oil entering international markets, a substantial proportion of which is produced by members of the Organization of Petroleum Exporting Countries (OPEC). The North American crude oil price is set in Chicago and is usually US$1.50-2.00 higher than the OPEC price, a reflection of quality differences and cost of shipping to Chicago. The EUB uses WTI crude prices as its proxy for world oil prices, as WTI is a more direct determinant of the prices of Alberta crude.

In 2001, the price of WTI crude oil started at US$29.71 per barrel, peaked at US$30.09 per barrel in February, and then declined to US$19.78 per barrel by December. OPEC set the target price range between US$22 and US$28.

In 2001, the world demand for crude oil amounted to 76 million barrels per day (10^6 b/d), a slight increase from last year's demand of 75.9 10^6 b/d. This global demand growth of approximately 100 thousand (10^3) b/d was the weakest since 1985. In 1999 and 2000 the global demand growth for crude oil was 1.6 10^6 b/d and 640 10^3 b/d respectively. The sluggish growth in 2001 emerged from several factors, including slowdown in the global economy, relatively high crude oil prices and mild winter weather. After September 11, 2001, unexpected high crude oil prices, in a weak economic environment, along with a mild winter in the U.S. (which uses more than 25 per cent of global energy), significantly lowered the global demand.

To prevent prices from falling, OPEC announced three quota cuts during 2001 totaling 3.5 10^6 b/d. A fourth OPEC cut of 1.5 10^6 b/d occurred in January 2002, accompanied by a 0.5 10^6 b/d production cut by five major non-OPEC oil-exporting nations.

In the first quarter of 2002, the signs of world economic recovery and the Middle East crises pushed the price of crude oil to more than US$25. It is expected that with the worldwide economic recovery, the demand for crude oil will increase between 0.5 to 0.6 per cent in 2002, followed by 1 to 1.5 per cent in the following year. Over the past two decades global demand for crude oil has increased by an average rate of 1.2 per cent per year. If 1 to 1.5 per cent growth rate in global demand is realized, then global crude production will increase by 10 to 14 10^6 b/d by the end of the forecast period. OPEC's spare capacity is currently 6.4 10^6 b/d. This growth in global demand should result in international crude oil prices stabilizing within OPEC's target range of US $22 to US$28.

The EUB recognizes that key issues, such as OPEC compliance with major production cuts and Middle East political stability, will play a major role in shaping the global market over the next few years. The EUB forecasts that the price of WTI will gradually stabilize at roughly US$24 per barrel. This price level is sufficient to stimulate exploration outside of OPEC countries and foster continuing improvements in exploration and recovery technology. The increase in non-OPEC production, stimulated by high prices, will reduce OPEC's power to increase prices without lowering its market share. **Figure 1.1** illustrates the EUB forecast of WTI at Chicago.

Wellhead oil prices in Alberta are expected to move in tandem with WTI after adjusting for transportation tariffs, exchange rates, and quality differentials. Since Alberta prices are quoted in Canadian dollars, they will vary inversely with the value of the Canadian dollar expressed in U.S. funds. The forecast wellhead price of crude oil in Alberta is shown on a yearly basis in both current and constant Canadian dollars in **Figure 1.2.**

Although they have narrowed considerably over the past year, the differentials between prices of light-medium crude and bitumen or conventional heavy crude are still wide by historical standards. The forecast calls for the bitumen price to revert to 60 per cent of the light-medium price and for conventional heavy to revert to 75 per cent of the light-medium price.

While crude oil prices are determined globally, natural gas prices are set in North America. Nevertheless, natural gas prices will be 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 the historical and EUB forecast of natural gas prices at the plant gate from 1991 to 2011. The average plant gate natural gas price was $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 spot price at the AECO-C Hub reached a monthly peak of $13.63/GJ in January 2001. The spot price then declined month by month, reaching a low of $1.95/GJ in October. Many companies in North America that had been major consumers of natural gas either switched to fuel oil or ceased operation rather than pay the going price. Declining industrial gas consumption and mild weather in 2001 combined to produce an estimated 6.2 per cent drop in Canadian natural gas demand and an estimated 5.3 per cent drop in U.S. demand.

A recent review of the economics of intercontinental trade in liquefied natural gas (LNG) concluded that although LNG would not capture a high market share in North America, it would tend to put an upper limit of US$2.75/GJ to $3.50/GJ on the city gate price of natural gas in major coastal consuming areas of the United States. This is broadly consistent with the plant gate natural gas price forecast, shown in **Figure 1.3**, of $3.50/GJ in 2002 and $4.00/GJ thereafter.

1.2 Canadian Economic Performance

Canadian economic growth, interest rates, inflation, unemployment, and currency exchange rates are key variables that impact the Alberta economy but are beyond the province's control. In addition, 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 2001 and the first quarter of 2002 is reviewed. These economic indicators for 2001 are depicted in **Figure 1.4.**

In 2001, the performance of global economies was slow, and the Canadian economy shrank in the third quarter by approximately 1.6 per cent. In the fourth quarter, consumer spending rebounded, mainly due to a sharp drop in interest rates. This led to a boost in housing construction and sales and other consumer spending. The revised Canadian GDP showed positive growth in the fourth quarter and, technically, the country avoided a recession. Two consecutive quarters of negative decline in GDP is defined as a recession. During 2001, unemployment increased from 6.9 to 8 per cent.

In 2001, the Bank of Canada, in order to combat the slowing economy, reduced the bank rate from 6 per cent in January to 4.25 per cent in August. Following the events of September 11 and the signs of a recession, the pace of interest rate cuts picked up, and from August to November the bank rate was lowered 175 basis points. This took the bank rate down to a 40-year low, at 2.50 per cent. In January 2002, there was a further drop in the bank rate to 2.25 per cent. However, in April 2002, the Bank of Canada, due to a robust recovery, raised interest rates a quarter point to 2.5 per cent. The prime rate (the benchmark for higher-cost loans to both consumers and businesses) is 150 basis points above the bank rate.

The inflation rate is expressed in terms of total consumer price index (CPI). This economic indicator is higher than core CPI, which represents the underlying trend in inflation by excluding transitory influences of volatile components such as energy, food, mortgage interest, tobacco, and indirect taxes.

Total CPI fluctuated between 2.5 to 3.9 per cent in the first nine months of 2001, before moving down to below 1 per cent in December. This fluctuation could have been the result of volatile energy prices. In 2001, the core inflation showed less fluctuation. In January, inflation began at 2 per cent, then rose to 2.3 per cent before declining to 1.6 per cent in December. The Bank of Canada has set the inflation control target within a range of 1 to 3 per cent until 2006.

The value of the Canadian dollar expressed in U.S. funds declined from 65.53 cents in January 2001 to 62.90 cents in December and to a record low of 61.80 cents in February 2002. The factors that can impact the currency exchange rates are the economic growth rate, unemployment rate, net exports, inflation rate, public debt, interest rate differential, and commodity prices.

In 2001, the dominant factor that caused the Canadian dollar to significantly depreciate against the U.S. dollar was the decline in Canadian exports, which emerged from sluggish global and domestic economies. More than 70 per cent of Canadian exports are shipped to the U.S. In 2001, Canadian exports fell for the fourth consecutive quarter, making it the longest string of quarterly declines in more than a decade. Cyclical declines in commodity prices could be considered another important factor.

Over the forecast period, a gradual upward pressure on the Canadian dollar over the medium term has been justified by the fact that Canada is keeping inflation below and interest rates above the U.S. rates and is reducing the level of public debt. In mid-April 2002, the Canadian exchange rate rose to 63.45 cents against the U.S. dollar.

The EUB assumed the average values for the Canadian economic indicators from 2002 to 2011, as shown in Table 1.1.

Table 1-1. Major Canadian economic indicators, 2002-2011

	2002	2003	2004	2005-2011[a]
GDP growth rate	3.0%	3.5%	4%	3.3%
Interest rate	3.75%	5%	6%	6%
Inflation rate	1.5%	2%	2.5%	2.5%
Exchange rate	64.50	66	67	68
Unemployment rate	7.8%	7.2%	6.5%	6.3%

[a] Averages over 2005-2011.

1.3 Alberta Economic Outlook

The Alberta economy, based on Statistics Canada data, last experienced a contraction on a year-over-year basis in 1991, with provincial GDP declining 0.2 per cent relative to 1990. Since then, Alberta GDP has increased annually and reached almost $143 billion in 2000. Throughout this period, Alberta GDP per capita was the highest among the provinces.

Over the forecast period, rapid expansion of the oil sands industry will offset the levelling off or decline in conventional fossil fuel output, and Alberta will still be Canada's leading producer of crude oil, bitumen, natural gas, natural gas liquids, sulphur, and coal. The direct and indirect impacts of energy industry expansions, along with expansion of other economic sectors, particularly the service sector, will boost the Alberta GDP to grow on average between 3.1 to 4.3 per cent annually, as shown in **Figure 1.5.**

In the last decade, the Alberta unemployment rate has gradually declined from 9.5 per cent in 1992 to 5 per cent in 2000; currently it is the lowest in Canada. Over the forecast period, the unemployment rate will fluctuate in the range of 4.6 to 7 per cent. Over the same period, the inflation rate is projected to be in the range of 2 to 2.5 per cent.

Alberta's population increased from 2.6 million in 1992 to slightly more than 3 million in 2000, representing an average annual growth rate of 1.4 per cent. Over the forecast period, the population is expected to increase by 400 000, due to natural births and migration. The Alberta population will reach 3.4 million by the end of the forecast period. **Figure 1.6** illustrates the Alberta male and female population.

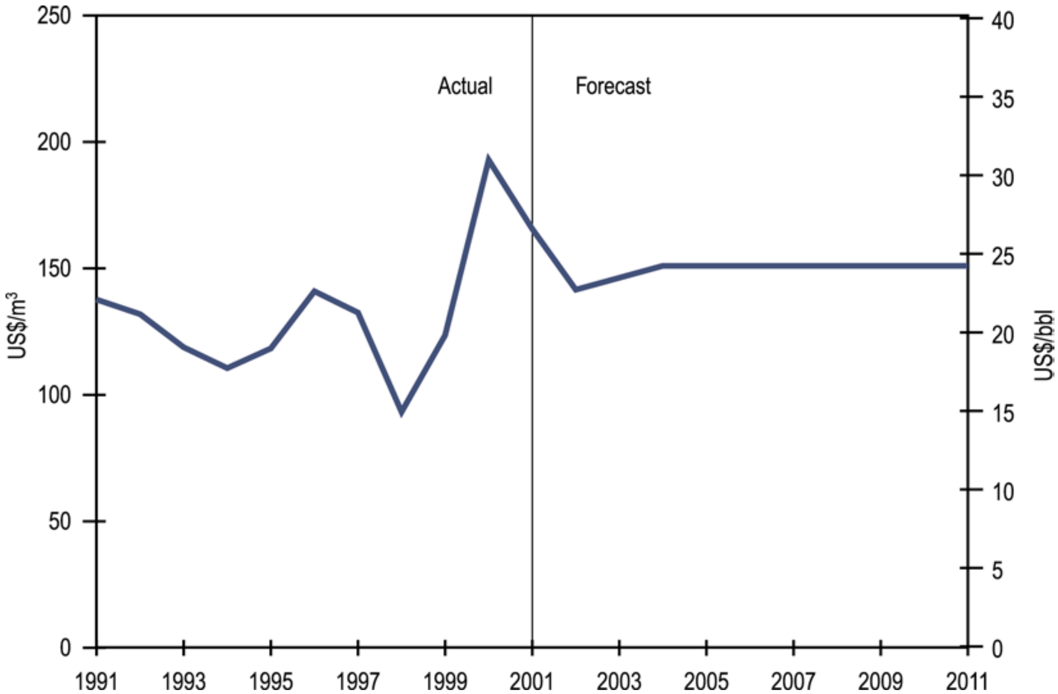


Figure 1.1. Price of WTI at Chicago

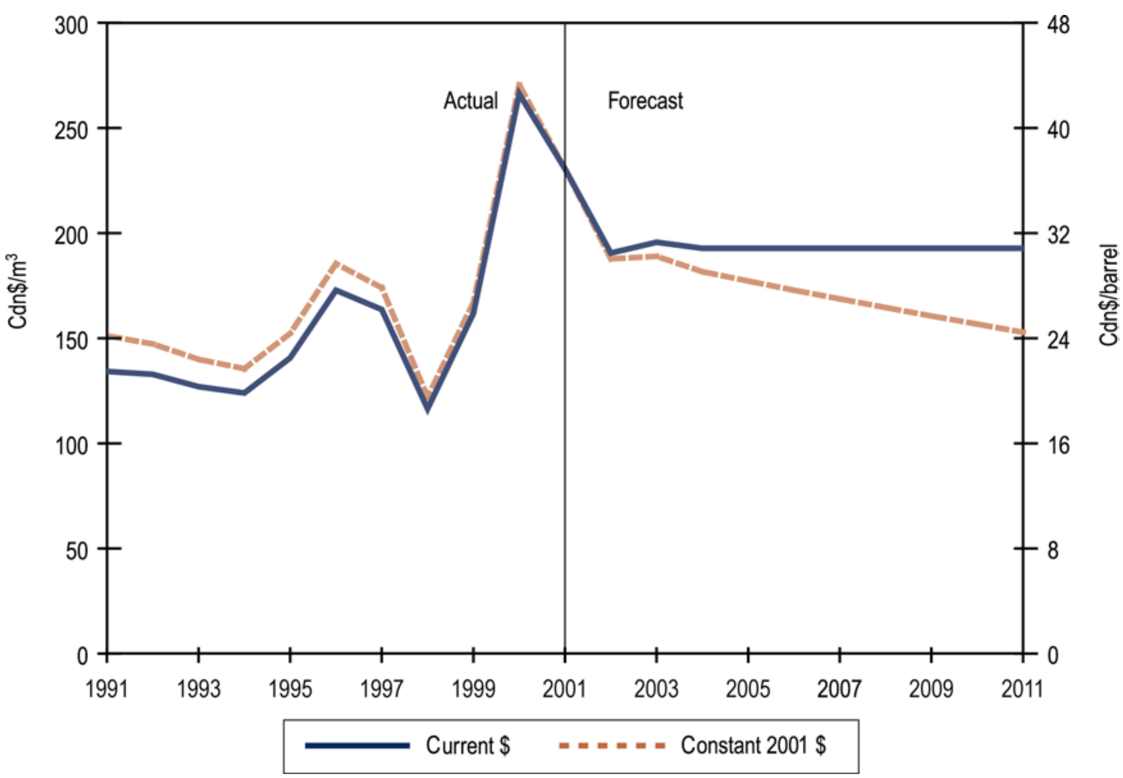


Figure 1.2. Average price of oil at Alberta wellhead

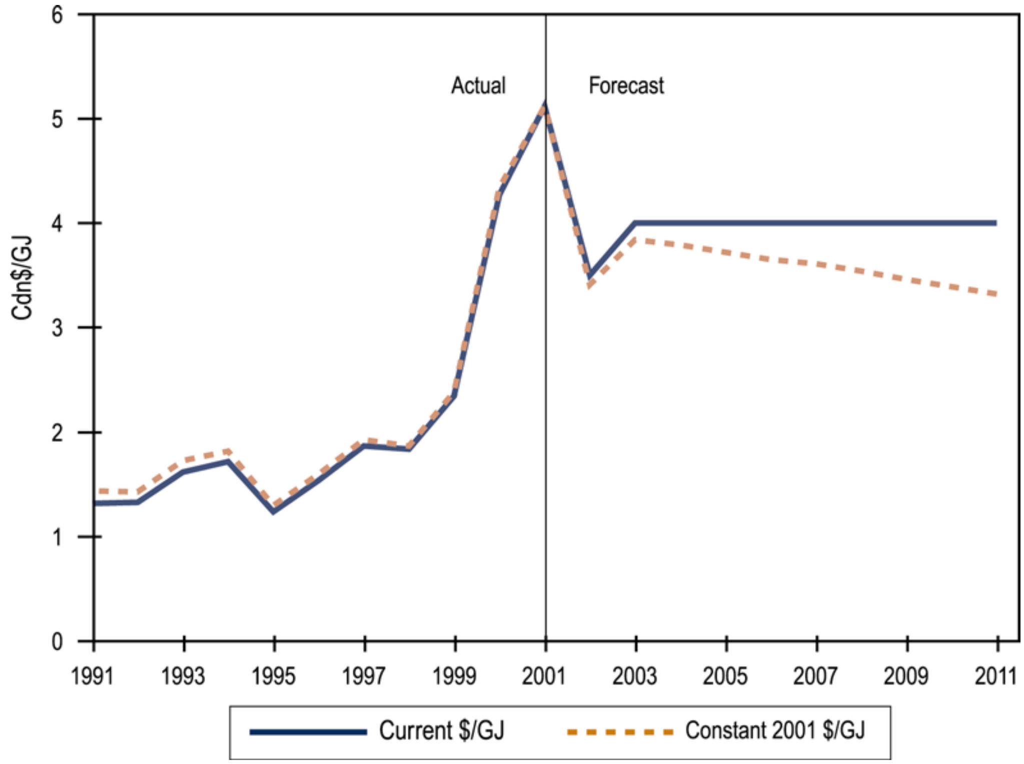


Figure 1.3. Average price of natural gas at plant gate

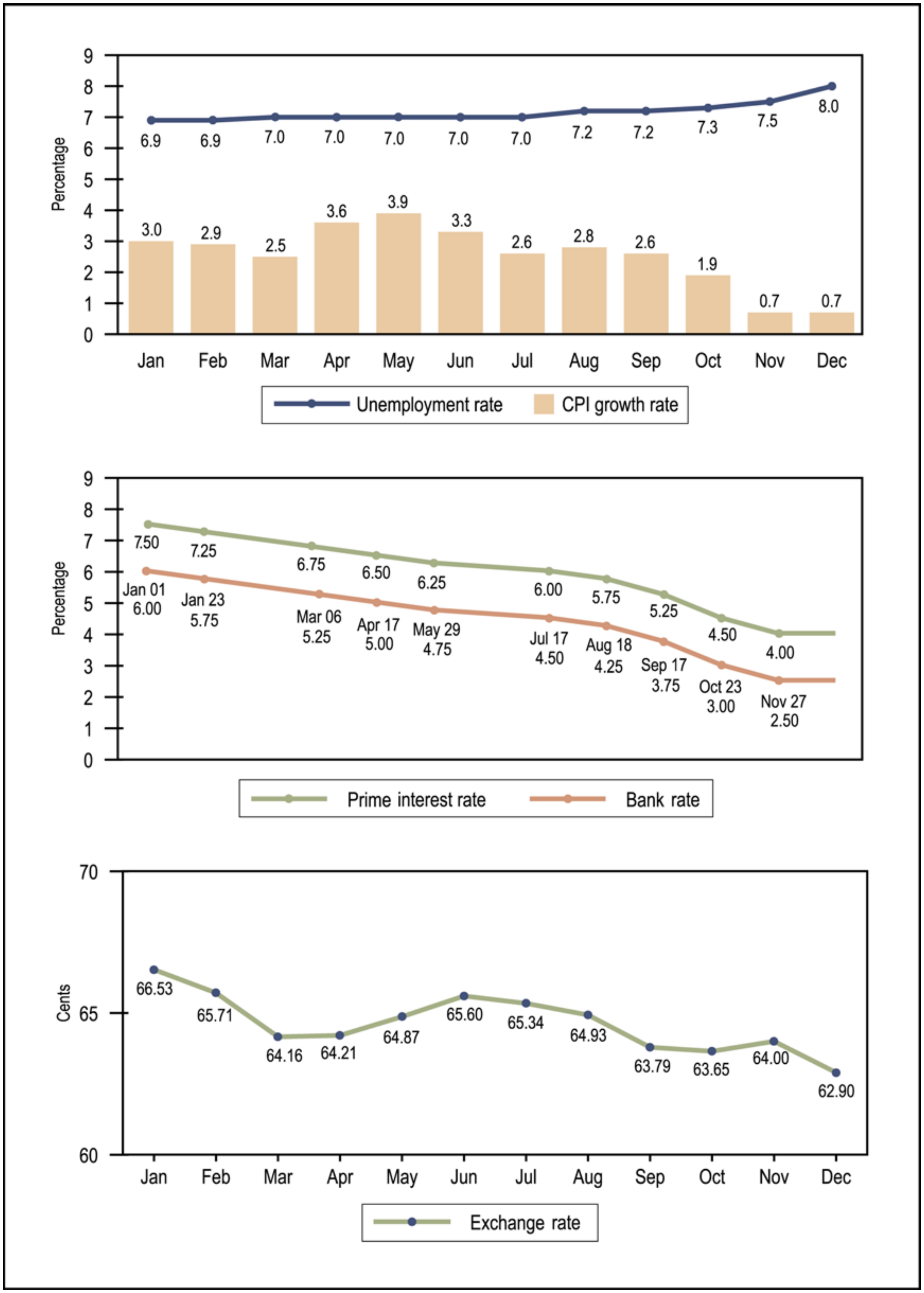


Figure 1.4. Canadian unemployment, inflation, interest, and Canada-U.S. exchange rates, 2001

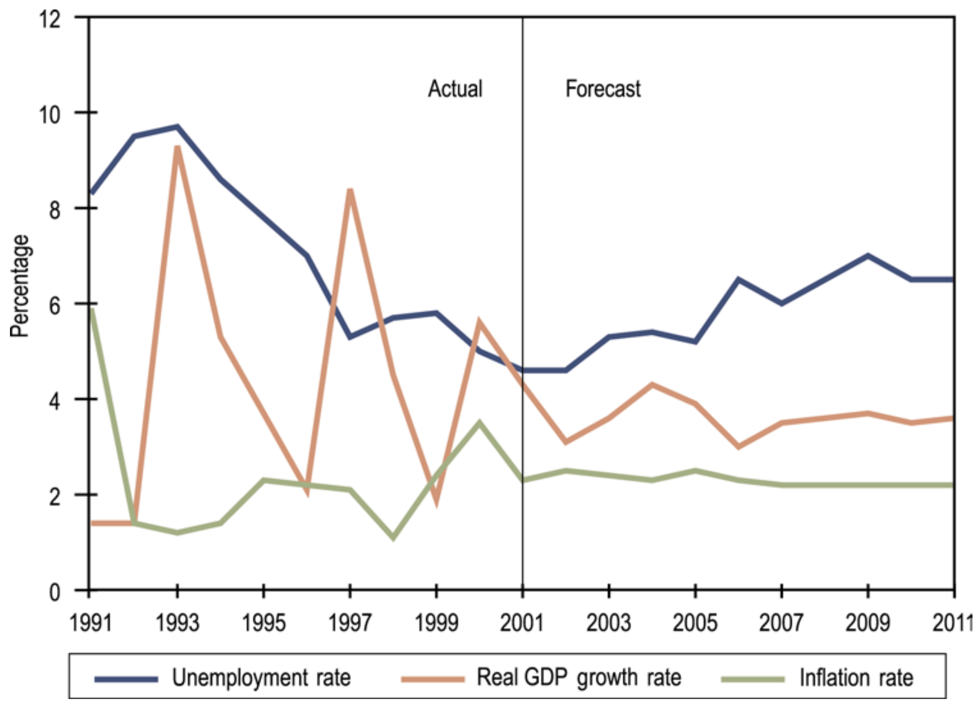


Figure 1.5. Alberta GDP growth, unemployment, and inflation rates

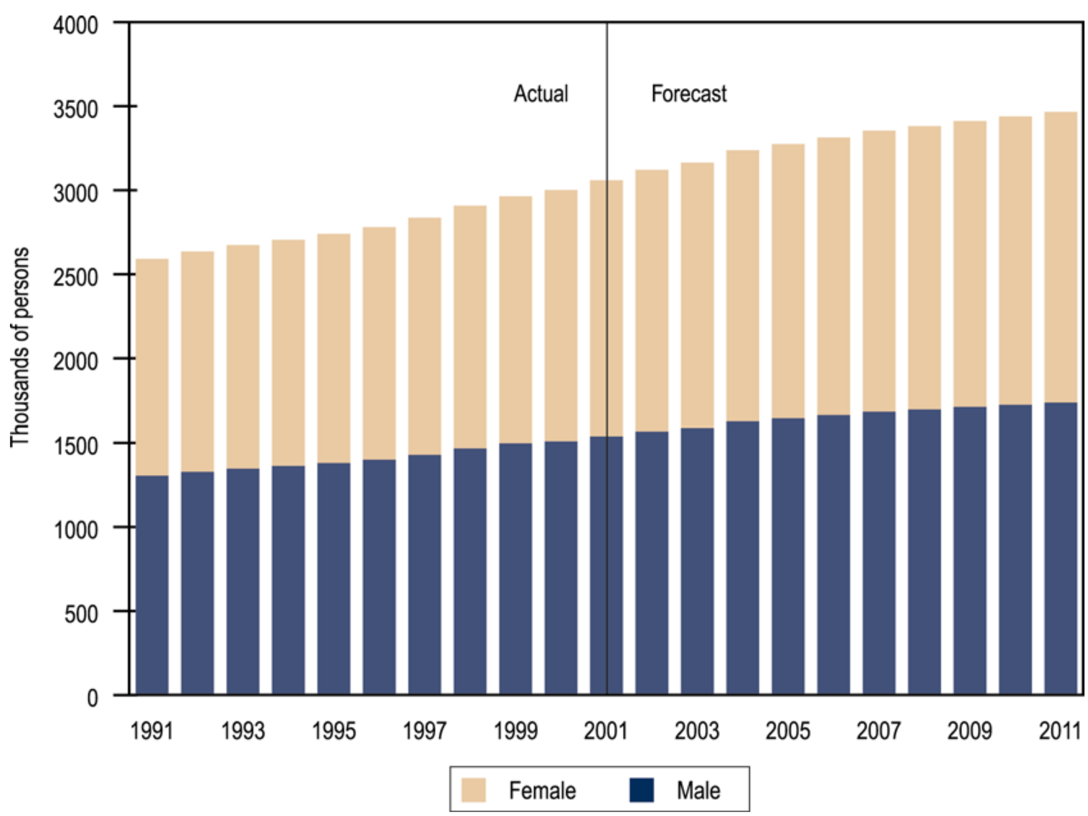


Figure 1.6. Alberta population trends

2 Crude Bitumen

2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

The EUB makes separate calculations of Alberta's crude bitumen reserves by estimating those reserves likely to be recovered by mining methods and those by in situ methods. As with the last two reports, this report shows the EUB's estimate of the established reserves determined from all areas in which crude bitumen may reasonably be presumed to be recoverable by in situ methods and not just from within active development areas. The EUB believes that this reporting method more realistically reflects the potential in Alberta for the recovery of crude bitumen.

The EUB estimates the initial volume in-place of crude bitumen in Alberta as of December 31, 2001, to be 259.2 billion cubic metres (10^9 m^3). Remaining established reserves of crude bitumen by surface-mineable and in situ methods as of this date are estimated to be 27.77 10^9 m^3, of which 1.83 10^9 m^3 are within active development areas. Other than a slight decrease due to production, these numbers are unchanged from last year. The EUB is currently engaged in a significant project to update these reserves. The new values should be available for the report scheduled for release in 2003 or 2004. Table 2.1 summarizes the in-place and established mineable and in situ crude bitumen reserves.

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

Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development[a]
Mineable	18.0	5.59	0.40	5.20	1.35
In situ	241.2	22.74	0.17	22.57	0.49
Total[a]	259.2 (1 631)[b]	28.33 (178.3)[b]	0.56 (3.5)[b]	27.77 (174.8)[b]	1.83 (11.5)[b]

[a] Differences are due to rounding.
[b] Imperial equivalent in billions of stock-tank barrels.

Figure 2.1 compares the relative size of Alberta's remaining established crude oil and crude bitumen reserves with Saudi Arabia's proven remaining crude oil reserves.

The changes in established crude bitumen reserves for 2001 are shown in Table 2.2. The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown in Tables 2.3 and 2.4 respectively.

Crude bitumen production from in situ operations totalled 17.7 million cubic metres (10^6 m^3) in 2001. Production from the only two current surface mining projects amounted to 24.6 10^6 m^3 in 2001, with 15.7 10^6 m^3 from the Syncrude Canada Ltd. project and 8.9 10^6 m^3 from the Suncor Energy Inc. project. The Albian Sands Energy Inc. project is nearing completion of construction.

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

	2001	2000	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 740	22 740	0
Total	28 330	28 330	0
	(178 280)[b]	(178 280)[b]	
Cumulative production			
Mineable	395	371	+25
In situ	167	150	+18
Total[a]	562	521	+42
Remaining established reserves			
Mineable	5 195	5 219	-25
In situ	22 573	22 590	-18
Total	27 768	27 809	-42
	(174 741)[b]	(175 000)[b]	

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

Table 2.3. Remaining established mineable crude bitumen reserves in areas under active development as of December 31, 2001

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 (10^6 m^3)
Albian Sands	10 096	574	178	0	178
Suncor	15 370	878	604	144	460
Syncrude	21 672	1 433	959	250	709
Total[c]	47 138	2 885	1 741	395	1 346

[a]The project areas correspond to the areas defined in the project approval.
[b]Definitions are given in Figure 2.2.
[c]Differences are due to rounding.

Table 2.4. Established in situ crude bitumen reserves in areas under active development as of December 31, 2001

Development	Initial volume in-place[a] (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	40.0	8.6	6.4	2.2
Subtotal	21.6		8.6	6.4	2.2
Athabasca Oil Sands Area					
Primary recovery schemes	2 435.5	5.0	121.7	10.8	110.9
Subtotal	2 435.5		121.7	10.8	110.9
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25.0	200.7	107.3	93.4
Primary production within projects	601.1	5.0	30.1	11.7	18.4
Primary recovery schemes	4 347.1	5.0	217.3	21.7	195.6
Lindbergh primary production	1 309.3	5.0	65.4	3.8	61.6
Subtotal	7 060.3		513.5	144.5	369.0
Experimental Schemes (all areas)					
Active	24.4	15.0	3.6	2.1	1.5
Terminated	71.1	9.5	6.7	3.6	3.1
Subtotal	95.5		10.3	5.7	4.6
Total	9 612.9		654.1	167.4	486.7

[a]Thermal reserves are assigned only for lands approved for thermal recovery and having completed drilling development.
[b]Cumulative production to December 31, 2001, includes amendments to production reports.

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) define the areal extent of crude bitumen occurrence, and Oil Sands Deposits (OSDs) contain the specific geological zones declared as oil sands deposits.

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 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 2.5. Individual maps to year-end 1995 are shown in EUB *Statistical Series 96-38*.[1]

Table 2.5. Initial in-place volumes of crude bitumen

Oil sands area / Oil sands deposit	Initial volume in-place (10^6 m^3)	Area (10^6 ha)	Average pay thickness (m)	Average bitumen saturation: Mass (%)	Average bitumen saturation: Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	17 998	286	30.5	9.7	69	30
Wabiskaw-McMurray (in situ)	119 234	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	206 740					
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	259 205					

The Surface Mineable Area (SMA) is an EUB-defined area 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 primary 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.

Calculation of in situ resources includes a continuing conversion from the former manual process to an automated mapping and resource evaluation system. As a result, the resources for a number of the pools have been determined from geological maps instead of by the original building-block method.

The initial volume of crude bitumen in-place for in situ areas for the designated deposits as of December 31, 2001, is 241.2 10^9 m^3, unchanged from last year.

[1] Alberta Energy and Utilities Board, 1996, *Crude Bitumen Reserves Atlas, Statistical Series 96-38* (Calgary).

2.1.3 Surface-Mineable Crude Bitumen Reserves

Potential mineable areas within the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[2]

The initial mineable volume in-place of crude bitumen is estimated as of December 31, 2001, 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 5.6 10^9 m^3, unchanged from December 31, 2000.

Only a small fraction of the initial established mineable reserve is under active development. Currently, Suncor and Syncrude are the only two producers in the SMA, and the cumulative bitumen production from these projects is 395 10^6 m^3. Albian Sands is presently constructing its Muskeg River Mine, and the reserves for this project are included in Table 2.3.

The remaining established mineable crude bitumen reserve as of December 31, 2001, is 5.20 10^9 m^3, slightly lower than last year due to the production of nearly 25 10^6 m^3 in 2001.

The crude bitumen reserves categories are presented in **Figure 2.2**.

Table 2.3 shows the remaining established mineable crude bitumen reserves from deposits under active development as of December 31, 2001.

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 2001 estimate of initial established reserves for in situ areas remains unchanged at 22.74 10^9 m^3. This estimate will be significantly refined and the results released in the report scheduled for 2003 or possibly 2004. Cumulative production within the in situ areas now totals 167 10^6 m^3, of which 145 10^6 m^3 is from the Cold Lake OSA.

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

As a result of the 18 10^6 m^3 production in 2001, remaining established reserves of crude bitumen from in situ areas are now slightly lower, at 22.57 10^9 m^3.

The EUB's 2001 estimate of the established in situ crude bitumen reserves under active development is shown in Table 2.4. 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 and 25 per cent for thermal commercial projects in the Peace River 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 areas is estimated to be 486.7 10^6 m^3, a decrease of 4.5 10^6 m^3 from 2000.

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.

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 are 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 initial ultimate potential crude bitumen is therefore about 50 10^9 m^3.

2.2 Supply of and Demand for Crude Bitumen

In this report, crude bitumen refers to total bitumen production; nonupgraded bitumen refers to the portion of crude bitumen production blended with diluent and 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, either in elemental form or as a constituent of oil sands coke, is removed. 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 in the earth. For these deposits, in situ methods have been proven technically and economically feasible. These methods typically use heat from 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 deposits could be put on production with primary recovery.

Bitumen crude must be diluted with some lighter viscosity product in order to be transported in pipelines. Pentanes plus are currently used in Alberta as diluent. 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. Other products such as naptha, light crude oil, and synthetic 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 2001, Alberta produced 116.6 10^3 m^3/d of crude bitumen, with surface mining accounting for 58 per cent and in situ for 42 per cent. In the same year, nonupgraded bitumen and SCO accounted for 43 per cent of Alberta's total crude oil and equivalent production.

The forecast of crude bitumen and SCO production relies heavily on information provided by project sponsors. Project viability depends largely on the cost of producing and transporting the products and on the price buyers are willing to pay. Other factors that bear on project economics are refining capacity and competition with other supply sources in the U.S. and Canadian markets.

2.2.1.1 Mined Crude Bitumen

Syncrude and Suncor bitumen production has increased steadily, reaching a level of 67.4 10^3 m^3/d in 2001, with Syncrude accounting for 64 per cent and Suncor for 36 per cent.

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

- the existing production and expected expansions of Suncor, including completion of Millennium and Voyageur Phases I and II;
- 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, which is currently under construction and is expected to produce bitumen in 2003, and its expansion planned for 2008;
- the TrueNorth Energy Fort Hill Oil Sands Project, with two phases of production. The first phase is to begin in 2005 and the second phase in 2009. TrueNorth Energy will be the first nonintegrated bitumen producer in the oil sands mining business. The bitumen produced, including diluent, will be transported via third-party pipelines to refineries in Canada and the midwest United States; and
- the Canadian Natural Resources Limited (CNRL) Horizon project, with proposed production beginning in 2007.

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 impact the timing of production schedules for these projects. The EUB assumed that total mined bitumen production will increase from 67.4 10^3 m^3/d in 2001 to some 223 10^3 m^3/d by 2011. **Figure 2.3** illustrates total mined bitumen production.

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has more than doubled since 1991, reaching a level of 49.2 10^3 m^3/d in 2001. To date, the majority of in situ bitumen has been marketed in nonupgraded form outside of Alberta and only a small amount (5 per cent) is used in Alberta refineries.

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 and price differentials, may delay some projects. **Figure 2.3** illustrates that in situ crude bitumen production is expected to rise to 126 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period some 20 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 two major upgraders, Suncor and Syncrude, produced 19.4 10^3 m^3/d and 36.0 10^3 m^3/d of SCO respectively in 2001. The EUB expects a significant increase in the SCO production over the forecast period. A summary of the SCO projects included in this report are

Suncor

- the completion of Project Millennium in 2002;
- the addition of an in situ bitumen recovery operation (Firebag In Situ Oil Sands Operation), with start-up expected in 2005;
- modification of the upgrader (the addition of a vacuum tower) to increase capacity of SCO starting in 2005;
- Voyageur Phase I, which involves expanding the existing facility and constructing a new upgrader by 2008; and
- Voyageur Phase II that will add additional processing units.

Syncrude

- stage one, which included the development of the North mine and debottlenecking of the upgrader in 1999;
- stage two, which consists of the Aurora Train 1 and additional debottlenecking of the upgrader at Mildred Lake in 2002;
- stage three, which includes the upgrader expansion and a second train of production at Aurora by 2005; and
- stage four, which includes Aurora Train 3 and further upgrader expansion in 2008.

Shell Canada expects to commence production of a new upgrader at Scotford, near Edmonton, in early 2003. This upgrader is adjacent to the existing Shell refinery and will upgrade crude bitumen from the Albian Sands project. Shell's production is expected to increase in 2008 to correspond with the expansion of the Albian Sands project.

The proposed OPTI/Nexen - Long Lake Project is an in situ bitumen recovery and upgrading facility located approximately 40 km southeast of Fort McMurray. Phase I of this project will commence in 2005. The second phase is expected to double the capacity of all components by 2008.

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 2007.

The conversion of crude bitumen to SCO uses different technologies at the two existing plants. 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 approximately 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 approximately 0.80. CNRL will use delayed coking with an approximate 0.86 liquid yield factor.

To project SCO production over the forecast period, the EUB included existing production from Suncor and Syncrude and their planned expansions, plus the new production expected from Shell Canada, 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 or 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 impact project timing. **Figure 2.4** shows the EUB projection of SCO production. It is expected that the SCO production will increase from 55.4 10^3 m^3/d in 2001 to 196 10^3 m^3/d in 2011.

2.2.3 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

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

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 2001, five Alberta refineries, with total capacity of 68 10^3 m^3/d, used 27.3 10^3 m^3/d of SCO and 2.5 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand for SCO represents 49 per cent of Alberta SCO production and 5 per cent of nonupgraded bitumen production. **Figure 2.5** shows that in 2011 Alberta demand for SCO will rise slightly to 28.0 10^3 m^3/d and nonupgraded bitumen will remain at a level of some 2.5 10^3 m^3/d.

Given the current quality of SCO, western Canada's nine refineries, with total capacity of 92 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.

The largest export markets for Alberta SCO and nonupgraded bitumen is the U.S. midwest, with refining capacity of 575 10^3 m^3/d, and the U.S. Rocky Mountain region, with refining capacity of 85.8 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.

Figure 2.5 shows that over the forecast period Alberta exports of SCO will increase from 28.1 10^3 m^3/d to 168 10^3 m^3/d and exports of nonupgraded bitumen will increase from 46.7 10^3 m^3/d to 113 10^3 m^3/d.

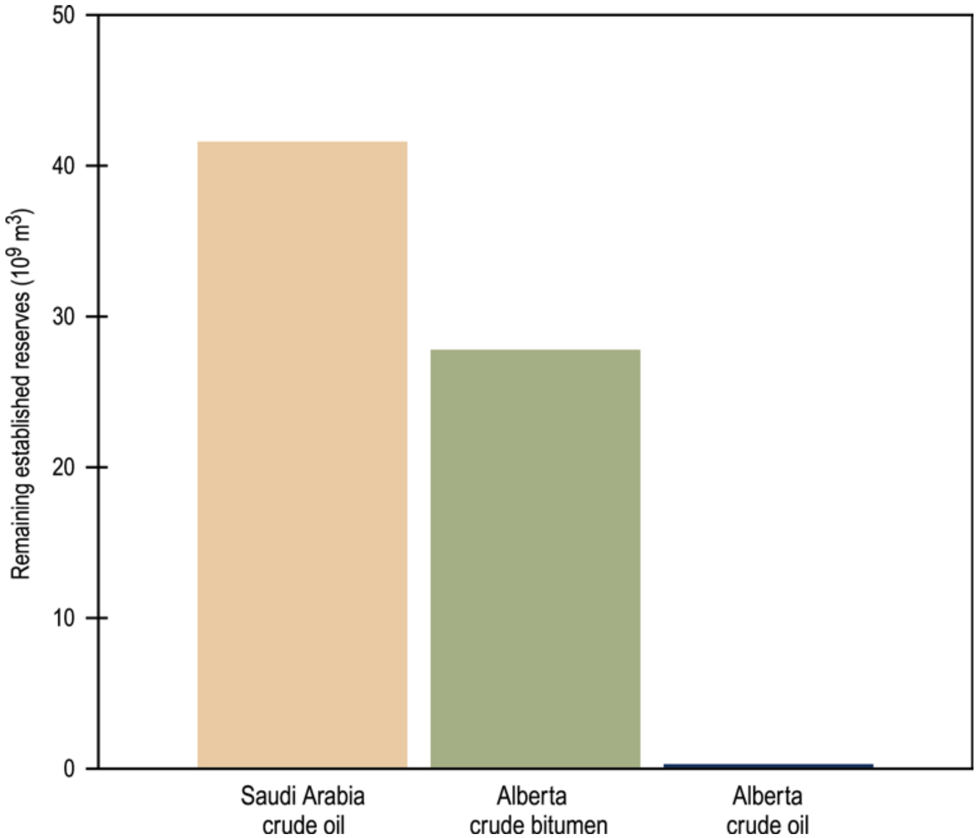
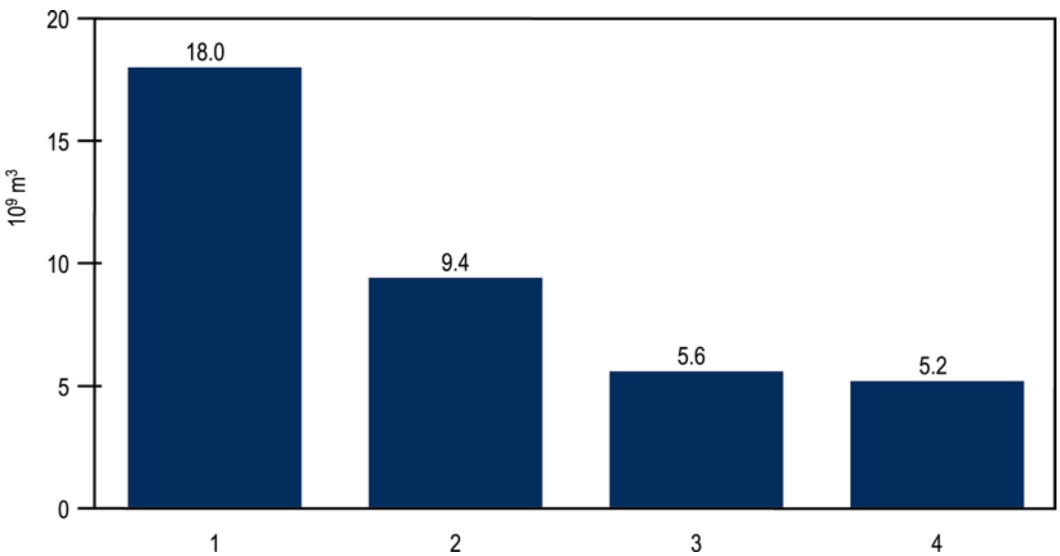


Figure 2.1. Comparison of Alberta and Saudi Arabia oil reserves



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** – recoverable volume of crude bitumen established within category 3 minus cumulative production.

Figure 2.2. Crude bitumen resource and reserve categories

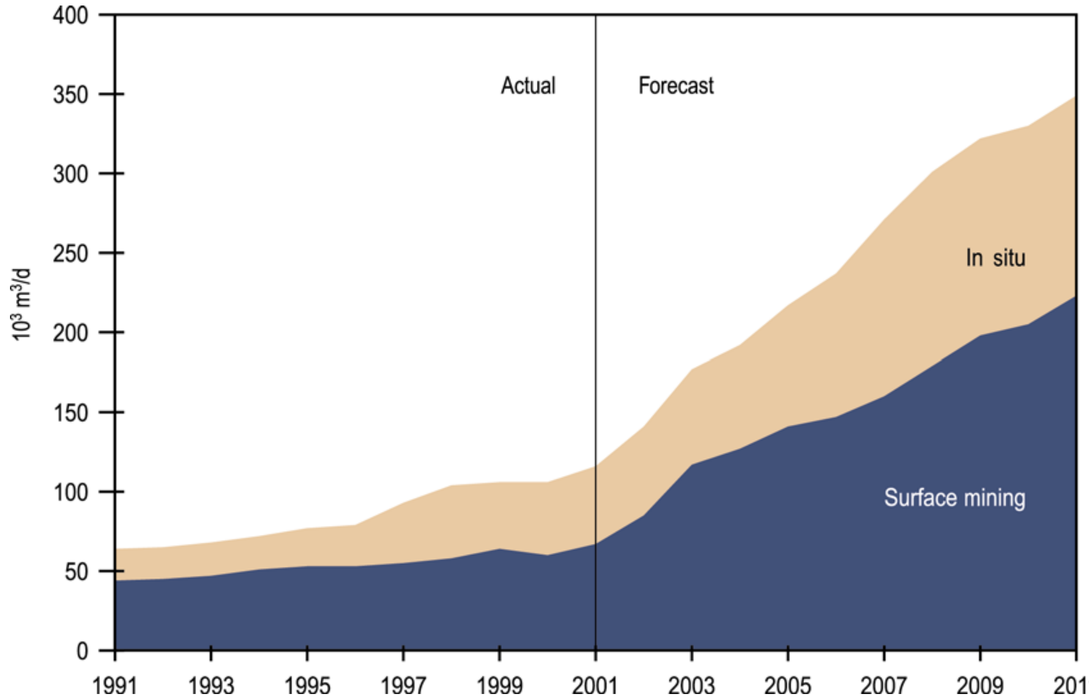


Figure 2.3. Alberta crude bitumen production

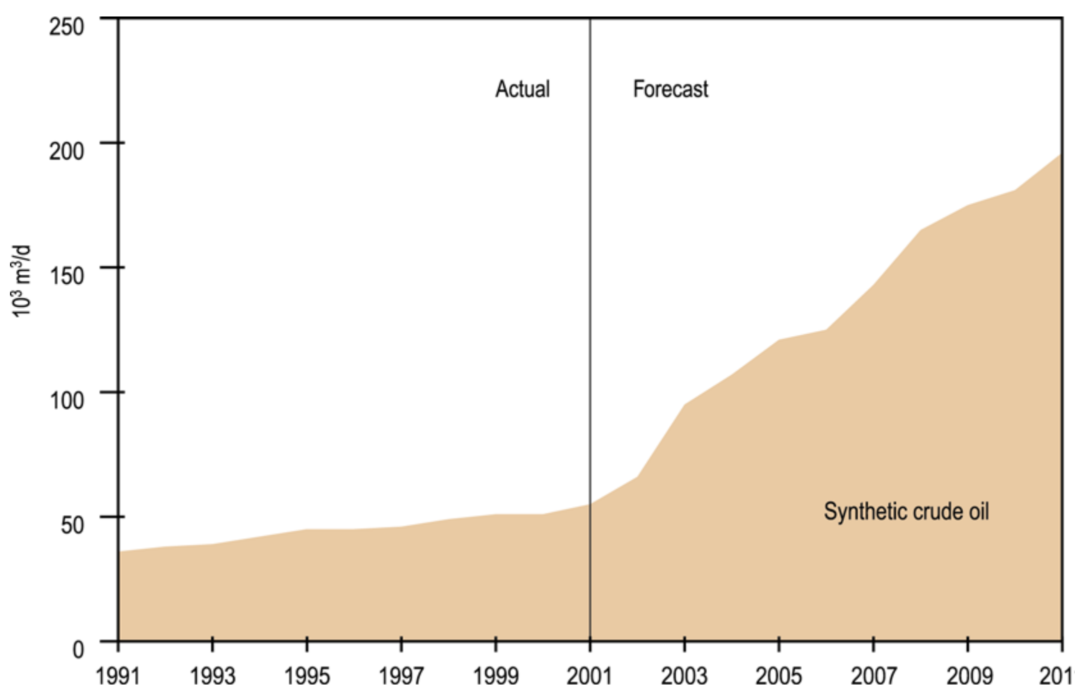


Figure 2.4. Alberta synthetic crude oil production

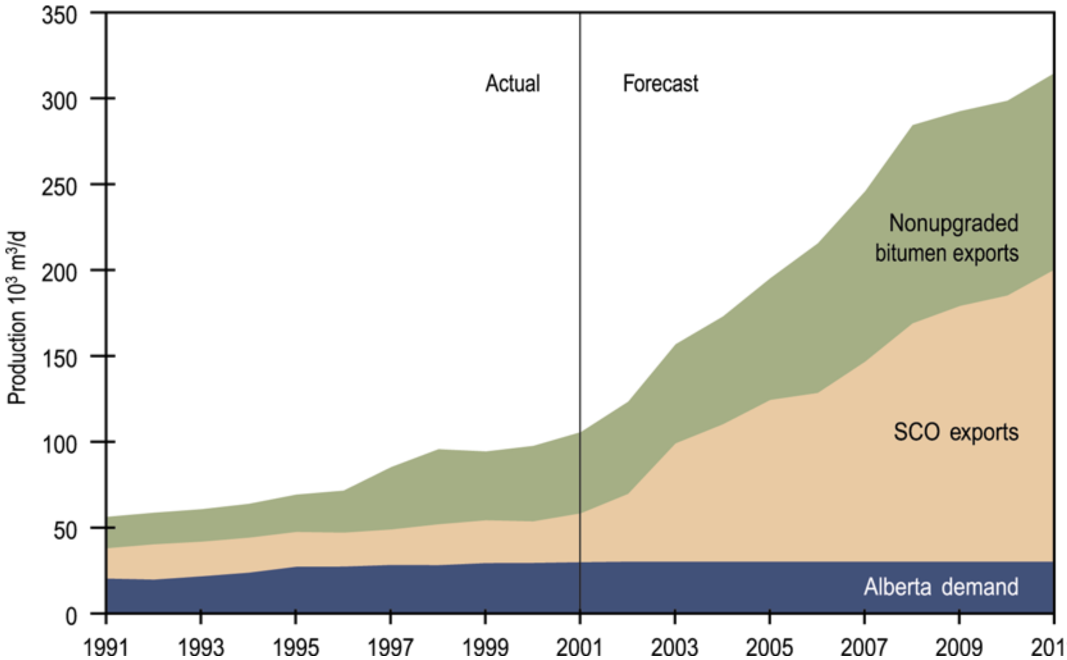


Figure 2.5. Alberta demand and exports of crude bitumen and SCO

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 278 million cubic metres (10^6 m^3), or 1.75 billion barrels, at year-end 2001. This is a decrease from year-end 2000 of 13.1 10^6 m^3, resulting from all reserve adjustments and production that occurred during 2001. The changes in reserves and cumulative production for light-medium and heavy crude oil to year-end 2001 are shown in Table 3.1. The decline in remaining conventional oil reserves from 1976 to the present is shown in **Figure 3.1**.

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

	2001	2000	Change
Initial established reserves[a]			
Light-medium	2 238.9	2 225.8	+13.0
Heavy	344.2	328.5	+15.6
Total	2 583.0 (16 254)[b]	2 554.4	+28.6
Cumulative production[a]			
Light-medium	2 032.8	2 005.3	27.5[c]
Heavy	271.9	257.6	14.3[c]
Total	2 304.7	2 262.9	41.7 (263)[b]
Remaining established reserves[a]			
Light-medium	206.1	220.5	-14.4
Heavy	72.3	70.9	+1.4
Total	278.3 (1 751)[b]	291.4	-13.1

[a]Discrepancies are due to rounding.
[b]Imperial equivalent in millions of stock-tank barrels.
[c]May differ slightly from actual production as reported in *Statistical Series 2001-17*.

3.1.2 Reserves Growth

A breakdown of the year's reserves changes, including additions, reassessments, and enhanced recovery, is presented in Table 3.2, while a detailed history of these changes is shown in **Figures 3.2** to **3.4**. The initial established reserves attributed to the 330 new oil pools booked in 2001 totalled 9.1 10^6 m^3 (28 10^3 m^3 per pool), up from 7.9 10^6 m^3 last year, while development of existing pools during 2001 added another 13.6 10^6 m^3. New and expanded enhanced recovery schemes (water and solvent floods) added initial established reserves of 0.8 10^6 m^3. This continues the trend to decreasing contributions to growth by new enhanced recovery schemes due to a lack of suitable quality candidates for such schemes **(Figure 3.5)**. Reassessment of reserves resulted in a net reserve addition of 6.5 10^6 m^3 to heavy crude and a net reduction of 1.3 10^6 m^3 for light-medium crude. The resulting total increase in initial established reserves for 2001 amounted to 28.6 10^6 m^3, down from last year's total of 32.8 10^6 m^3.

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

	Light-medium	Heavy	Total
New discoveries	6.3	2.8	9.1
Development of existing pools	7.4	6.2	13.6
Enhanced recovery (new/expansion)	0.7	0.1	0.8
Reassessment	-1.3	6.5	5.2
Total	13.0	15.6	28.6

Reserve additions resulting from drilling and new enhanced recovery schemes totalled 23.5 10^6 m^3, up from 22.8 10^6 m^3 in 2000. These additions replaced 56 per cent of Alberta's 2001 conventional crude oil production of 41.7 10^6 m^3.

3.1.3 Pools with Largest Reserve Changes

Some 1500 oil pools were re-evaluated over the past year, resulting in positive reassessments totalling 68.3 10^6 m^3 and negative reassessments totalling 63.1 10^6 m^3. Recovery efficiencies continue to improve through infill and horizontal drilling in medium and heavy density pools. For example, ultimate recovery in the Bellshill Lake Blairmore Pool is now estimated at 47 per cent under natural water drive. The Hayter Dina B Pool saw an increase in reserves of 3239 10^3 m^3 due to pool expansion and recognition of a higher recovery factor of 20 per cent. Active exploration within the Suffield Field has resulted in several discoveries, most notably the Suffield Upper Mannville CCC Pool, in which initial established reserves of 1136 10^3 m^3 have been booked. Table 3.3 lists those pools having the largest reserve changes in 2001.

3.1.4 Distribution of Oil Reserves by Size and Geology

At year-end 2001, oil reserves were assigned to some 7200 light-medium and 400 heavy crude oil pools in the province. Sixty-one per cent of these pools consist of a single well. The distribution of reserves by pool size shown in Table 3.4 indicates that some 89 per cent of the remaining reserves is contained in the largest 14 per cent of pools. The smallest 72 per cent of pools contain only 5 per cent of the province's remaining reserves. **Figure 3.6** further illustrates the historical trends in the size of oil pools.

The distribution of conventional crude oil reserves by drive mechanism is presented in Table 3.5 and illustrated in **Figure 3.7**. Table 3.5 shows that waterflood projects have added 651 10^6 m^3, or 25 per cent of the province's initial established reserves. Pools under solvent flood have realized an average increase in recovery efficiency of 30 per cent over primary depletion for those pools.

The distribution of reserves by geological period and by formation, found in Tables 3.6 and 3.7 and represented graphically in **Figure 3.8**, indicates that the majority of remaining established reserves will come from formations within the Lower Cretaceous (34 per cent) and Upper Devonian (22 per cent).

Table 3.3. Major oil reserve changes, 2001

Pool	Initial established reserves (10^3 m^3) 2001	Change	Main reason for change
Ante Creek Dunvegan D	51	-152	Reassessment of reserves
Bellshill Lake Blairmore	17 920	+1 100	Reassessment of recovery factor
Bigoray Ostracod	1 262	+237	Reassessment of waterflood reserves
Bigoray Nisku D	857	-177	Reassessment of waterflood reserves
Caroline Viking S	300	-186	Reassessment of primary reserves
Cecil Kiskatinaw G	145	+145	New pool
Chauvin South Mannville MU #1	11 150	+410	Reassessment of waterflood reserves
Chin Coulee Sawtooth B	676	+270	Pool development
Chinchaga Slave Point Q	178	+178	New pool
Countess Lower Mannville Z	1 707	+327	Expansion of waterflood scheme
Evi Slave Point A	340	+167	Pool development
Evi Keg River A & Gr Wash N	3 296	+201	Reassessment of primary reserves
Fenn West D-3 H	153	-1 220	Reassessment of primary reserves
Garrington Card , Vik and Mann #1	6 329	-82	Commingled Cardium I &, Viking A ,and Viking CC & Mannville B, and Crossfield East Cardium C
Goose River Beaverhill Lake A	10 180	+179	Reassessment of waterflood reserves
Halkirk Upper Mannville R	1 813	+363	Reassessment of primary reserves
Haynes D-2 A and D-3 A	879	+176	Reassessment of primary reserves
Hayter Dina B	9 976	+3 239	Pool development & reassessment of reserves
Jenner Upper Mannville F	1 205	+301	Reassessment of recovery factor
Johnson Glauconitic C	564	+238	Reassessment of waterflood recovery factor
Judy Creek Beaverhill Lake A	58 700	+320	Reassessment of solvent flood recovery factor
Leduc-Woodbend Upper Mann G	65	-420	Reassessment of primary and waterflood reserves
Leduc-Woodbend Glauconitic D	630	+243	Recognition of waterflood scheme
Lloydminster Sparky & General Petroleum C & D	5 583	+1 355	Reassessment of primary recovery factor
Long Coulee Glauconitic Q	1 199	-377	Reassessment of waterflood recovery factor
Loon Granite Wash P	523	+174	Reassessment of recovery factor

(continued)

Table 3.3. Major oil reserve changes, 2001 (concluded)

Pool	Initial established reserves (10^3 m^3) 2001	Change	Main reason for change
Medicine River Glauconitic D and Ostracod A	1 026	+178	Pool development, reassessment of recovery factor
Marwayne Sparky D	1 534	+719	Coalesced Sparky B and recovery reassessment
Normandville Beaverhill Lake C	148	+148	New pool
Norris Upper Mannville H	470	+295	Pool development and reassessment of recovery factor
Pembina Belly River C & O	17 870	-690	Reassessment of primary recovery factor
Pembina Nisku L	4 400	+300	Reassessment of solvent recovery factor
Provost Sparky D	304	+161	Pool development
Provost Lloyd S, X and Cumm N	870	+174	Reassessment of recovery factor
Provost Cummings F5F	157	+157	New pool
Provost Dina S	1 868	-234	Reassessment of recovery factor
Rainbow Keg River F	21 280	+1 990	Gas flood converted to solvent flood
Redwater Up-Mid-Lower Viking A	1 166	+460	Pool development and reassessment of primary recovery factor
Simonette Beaverhill A	5 040	+211	Reassessment of waterflood reserves
Surgeon Lake South Triassic F	1 664	+567	Pool development
Suffield Upper Mannville T	200	+164	Pool development
Suffield Upper Mannville CCC	1 136	+1 136	New pool
Suffield Upper Mannville OOO	236	+236	New pool
Suffield Upper Mannville PPP	155	+155	New pool
Swan Hills Beaverhill Lake A & B	141 000	-3 570	Reassessment resulting from coalescence of Swan Hills BHL A&B and C Pools
Taber Taber N	2 174	+274	Reassessment of primary recovery factor
Valhalla Doe Creek I	11 030	+910	Recognition of new waterflood scheme
Viking-Kinsella Sparky JJ	440	+180	Reassessment of recovery factor
West Drumheller D-2 A	5 020	+201	Reassessment of recovery factor
Wildmere Lloydminster MM	243	+243	New pool
Willesden Green Belly River, Cardium A and Viking MU#1	24 030	+380	Reassessment of primary recovery factor

Table 3.4. 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	287	3	2 135	83	180	65
100-999	1 061	11	325	12	69	24
30-99	1 385	14	76	3	18	6
1-29	6 931	72	47	2	14	5
Total	9 664	100	2 583	100	278	100

[a]Based on initial established reserves.

3.1.5 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the EUB in 1994 at 3130 10^6 m^3, reflecting its estimate of geological prospects. **Figure 3.9** shows Alberta's historical and forecast growth of initial established reserves. **Figure 3.10** 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 valid. Approximately 74 per cent of the estimated ultimate potential for conventional crude oil has been produced to year-end 2001. Remaining established reserves of 278 10^6 m^3 represent about 9 per cent of the ultimate potential. Known discoveries represent 83 per cent of the ultimate potential, leaving 17 per cent (547 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves yields 825 10^6 m^3 of conventional crude oil that is available for future production.

In 2001, both the remaining established reserves and the annual production of crude oil declined. However, there are 547 10^6 m^3 yet to be discovered, which will mitigate the impact of these declines. 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, in 2001, crude bitumen production exceeded conventional crude oil production for the first time.

Table 3.5. Conventional crude oil reserves by recovery mechanism as of December 31, 2001

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	3 812	860	0	0	860	23	-	-	23
Waterflood	2 908	424	387	0	811	15	13	-	28
Solvent flood	919	254	166	107	527	28	18	12	57
Gas flood	113	33	8	0	41	39	7	-	36
Heavy									
Primary depletion	1 623	208	0	0	208	13	-	-	13
Waterflood	387	46	90	0	136	12	23	-	35
Total	9 762	1 825	651	107	2 584	19			27
Percentage of total initial established reserves		71%	25%	4%	100%				

Table 3.6. Conventional crude oil reserves by geological period as of December 31, 2001

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	2 160	0	354	0	50	-	16	-
Lower	1 074	1 774	209	300	31	65	19	17
Jurassic	108	104	21	32	4	4	19	31
Triassic	323	24	64	2	12	0	20	8
Permian	14	0	7	0	1	-	50	
Mississippian	605	63	95	7	9	2	16	11
Devonian								
Upper	2 461	25	1 133	2	61	1	46	8
Middle	958	0	351	0	35	-	37	-
Other	49	20	5	0	3	-	10	5
Total	7 752	2 010	2 239	344	206	72	29	17

Table 3.7. Distribution of conventional oil reserves by formation as of December 31, 2001

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	348	46	7	4	2	3
Chinook	5	1	0	0	0	0
Cardium	1 780	289	38	17	11	14
Second White Specks	32	3	1	0	0	0
Doe Creek	73	16	4	1	1	1
Dunvegan	22	2	0	0	0	0
Lower Cretaceous						
Viking	335	65	5	3	3	2
Upper Mannville	1 623	262	57	17	10	20
Lower Mannville	890	182	34	9	7	12
Jurassic	212	53	8	2	2	3
Triassic	347	66	12	4	3	4
Permian-Belloy	14	7	1	0	0	0
Mississippian						
Rundle	471	76	6	5	3	2
Pekisko	89	14	3	1	1	1
Banff	108	12	2	1	0	1
Upper Devonian						
Wabamun	59	6	1	1	0	0
Nisku	442	202	14	5	8	5
Leduc	841	505	14	9	20	5
Beaverhill Lake	989	393	26	10	15	9
Slave Point	155	29	7	2	1	3
Middle Devonian						
Gilwood	303	130	8	3	5	3
Sulphur Point	9	1	0	0	0	0
Muskeg	52	8	1	1	0	0
Keg River	498	182	23	5	7	8
Keg River SS	44	17	1	0	1	0
Granite Wash	53	13	2	1	1	1

3.2 Supply of and Demand for Crude Oil

3.2.1 Crude Oil Supply

Over the past several years, production of light-medium and heavy crude oil has been on decline in Alberta. In 2001, total crude oil production declined to 114.4 10^3 m^3/d. Light-medium crude oil production declined by approximately 4.4 10^3 m^3/d (5 per cent) compared to 2000. Heavy crude oil production in 2001 increased slightly over 2001 levels. This resulted in an overall decline in total crude oil production of 4 per cent from 2000 to 2001, compared to the 2 per cent decline from 1999 to 2000.

While the higher decline rate in 2001 reflects industry's reaction to the decrease in crude oil prices in the latter part of 2001, over time average oil well productivities in Alberta have declined. **Figure 3.11** shows total crude oil production and the number of producing wells by year. As illustrated in this figure, while the number of total producing wells has increased, crude oil production has been on decline.

With regard to average well productivities, **Figure 3.12** shows that roughly half the crude oil wells produce less than 2 m^3/d per well. In 2001, these 16 100 oil wells operated at an average rate of 1 m^3/d and produced only 13 per cent of the total crude oil production.

The number of successful oil wells brought on production in 2001, declined to 2220, compared to 2670 in 2000. Both vertical and horizontal well drilling declined in 2001. It should be noted that the number of total producing horizontal wells has not changed appreciably over the past five years. In 2001, some 310 horizontal wells were drilled, representing 14 per cent of the total successful oil wells drilled. In 2001 there were 2750 active horizontal wells, producing approximately 15 per cent of the total crude oil production. Production from horizontal wells drilled in the past five years peaked at an average rate of some 12.0 m^3/d.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2001 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 2002, the EUB considered the following assumptions:

- Production from existing wells in 2002 would be 103.5 10^3 m^3/d.
- Production from the existing wells will decline at a rate of approximately 15 per cent per annum.

Crude oil production from existing wells over the period 1995-2001 is depicted in **Figure 3.13**. This figure illustrates that approximately 50 per cent of crude oil production in 2001 resulted from wells drilled before 1995. Over the forecast period, production of crude oil from existing wells is expected to decline to 27 10^3 m^3/d by 2011.

Production from new wells is assumed to be a function of the number of new wells that will be drilled successfully, peak production, 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 healthy activity in drilling for crude oil over the forecast period.

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

- Drilling is projected to decline to 1800 successful wells in 2002, then increase to 2100 wells in 2003. In 2004 and thereafter, drilling is projected to reach to 2400 successful wells and remain at this level over the forecast period. **Figure 3.14** illustrates the EUB's crude oil drilling forecast for successful wells for the period 2002 to 2011, along with the historical data.

- Based on recent historical data, it is assumed that the production rate for new wells will peak at 5.0 m^3/d/well, with a subsequent decline rate of 25 per cent per year. This is a decline from an average of 8.0 m^3/d/well in the mid 1990s.

The projection of the above two components, production from existing wellbores and production from future successful oil wells, is illustrated in **Figure 3.15.** Light-medium crude oil production is expected to decline from 76.3 10^3 m^3/d in 2001 to 57 10^3 m^3/d in 2011. Although crude oil prices and drilling forecasts are expected to remain at the level of 2004, light crude oil production will continue to decline almost 3 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.

Over the forecast period, heavy crude production is also expected to decrease from 38.1 10^3 m^3/d in 2001 to 31 10^3 m^3/d by the end of the forecast period. **Figure 3.15** also illustrates that by 2011 heavy crude oil production will constitute a greater portion of total production compared to 2001, although total production will be smaller.

The combined forecasts from existing and future wells indicate that total crude oil production will decline from 114.4 10^3 m^3/d in 2001 to 88 10^3 m^3/d in 2011. In the first two years of the forecast period, initial established reserves growth is expected to be about 18 10^6 m^3/year and 21 10^6 m^3/year, followed by 24 10^6 m^3/year for the remainder of the forecast period. By 2011, if crude oil production follows the projection, Alberta will have produced some 85 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 2001, Alberta refineries with 68 10^3 m^3/d of crude oil and equivalent inlet capacity used 31.4 10^3 m^3/d of crude oil. This constituted over 50 per cent of their total crude oil and equivalent feedstock. **Figure 3.16** 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 improve from the

2001 level of 92 per cent to almost full capacity by 2004, as demand for refined petroleum products increases in western Canada. Total crude oil use will reach 38 10^3 m^3/d in 2004, and remain at this level for the duration of the forecast period.

Shipments of crude oil outside of Alberta, depicted in **Figure 3.17**, amounted to 73 per cent of total production in 2001 and are expected to decline to 57 per cent of production by 2011.

3.2.3 Crude Oil and Equivalent Supply

Figure 3.18 shows crude oil and equivalent production. This figure illustrates that total Alberta crude oil and equivalent is expected to increase from 243 10^3 m^3/day in 2001 to 424 10^3 m^3/d in 2011. 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 70 per cent of total production.

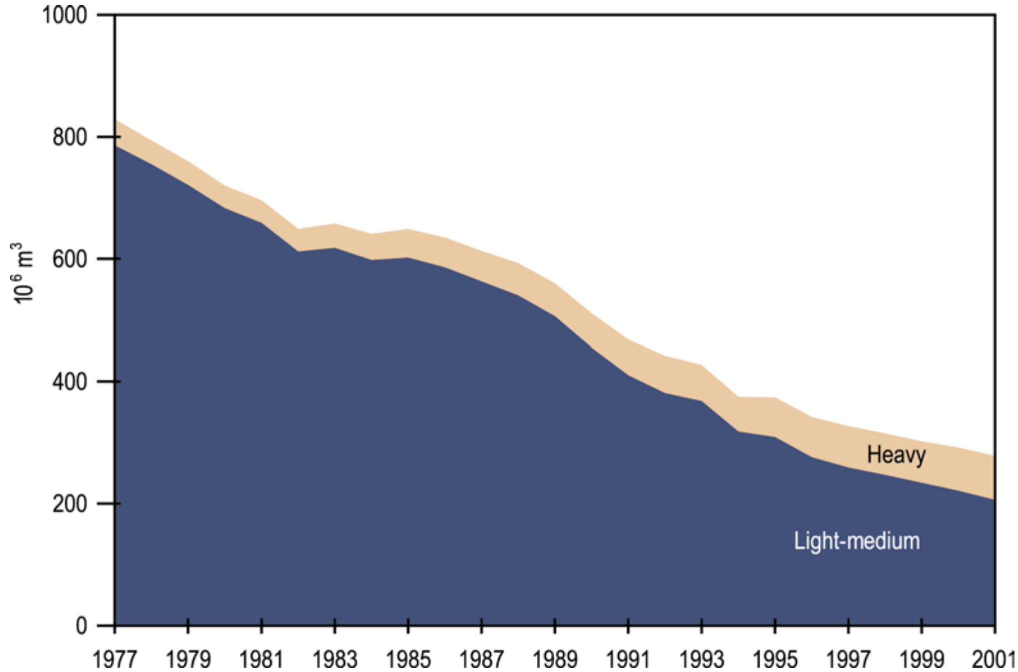


Figure 3.1. Remaining established reserves of crude oil

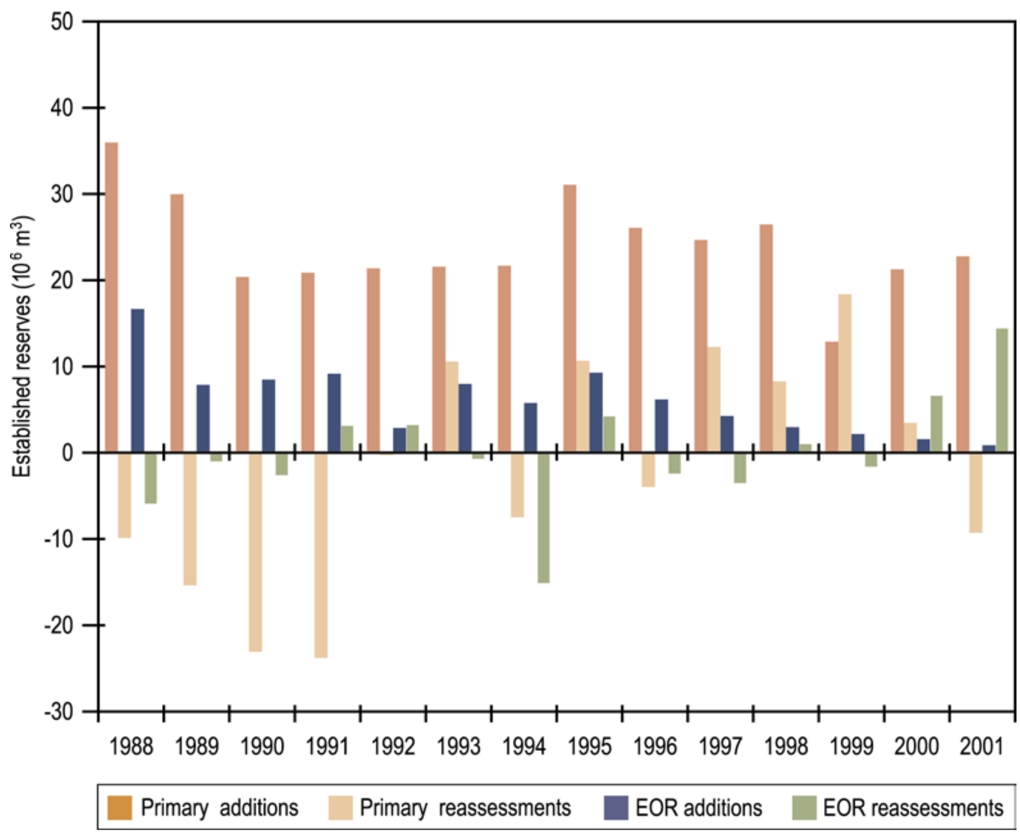


Figure 3.2. Total conventional crude oil reserves additions and reassessments

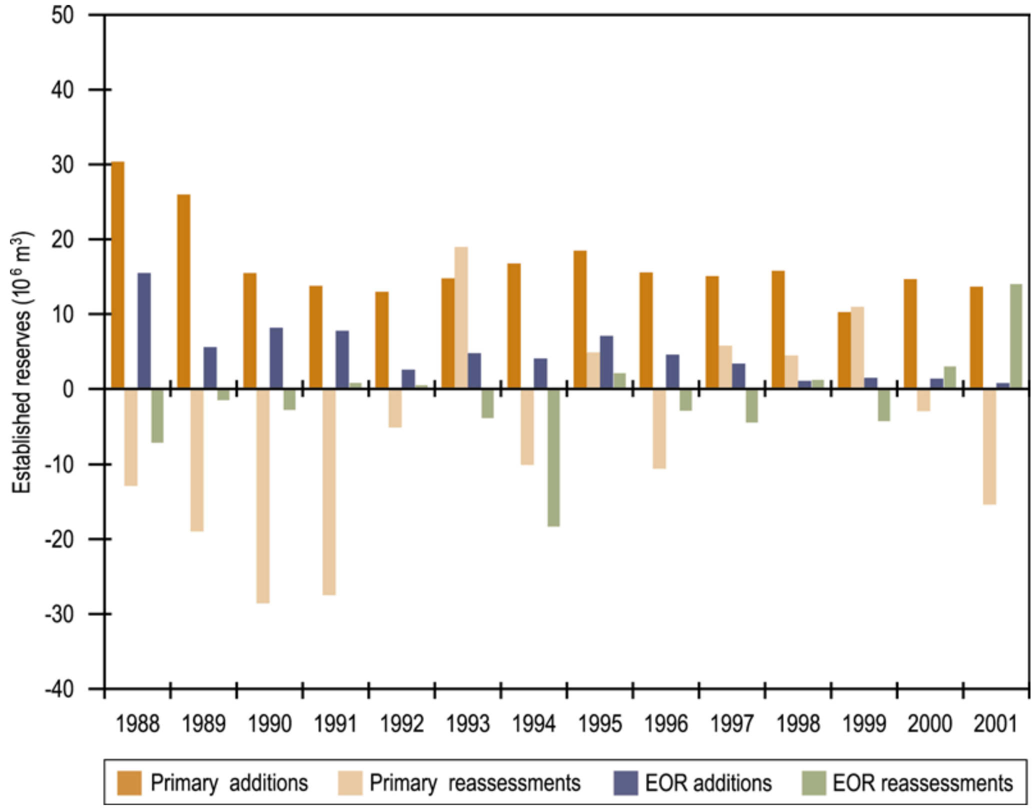


Figure 3.3. Light-medium crude oil reserves additions and reassessments

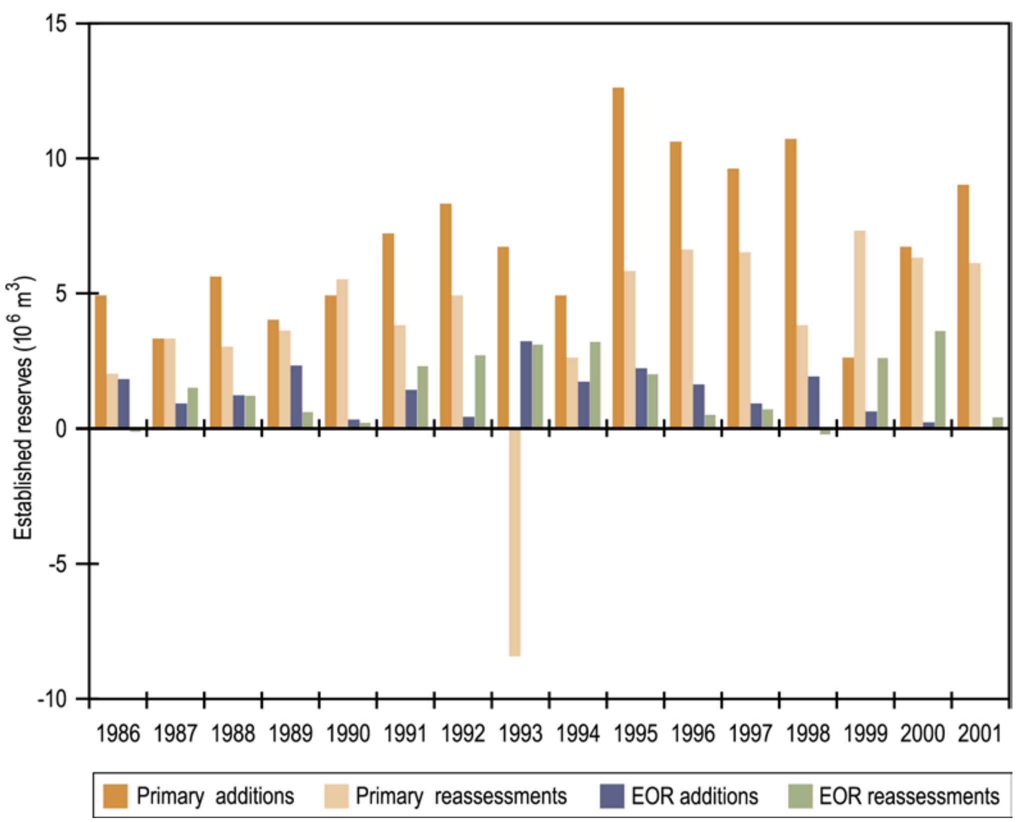


Figure 3.4. Heavy crude oil reserves additions and reassessments

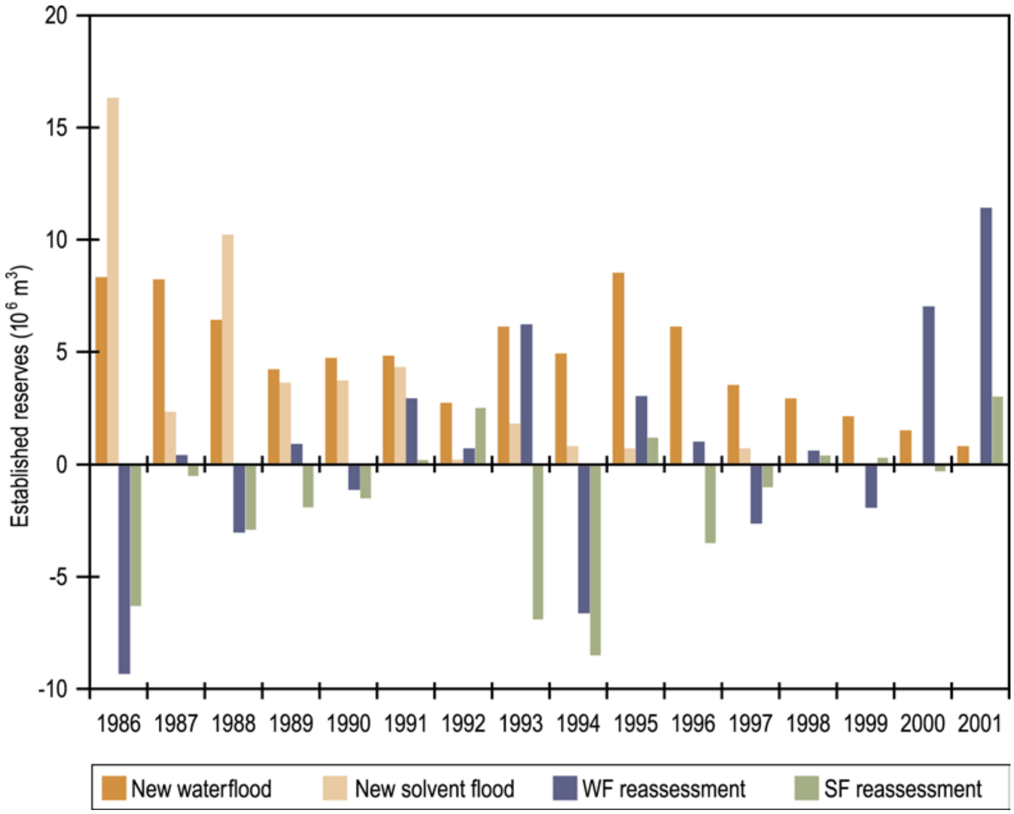


Figure 3.5. Total conventional crude oil enhanced reserves changes

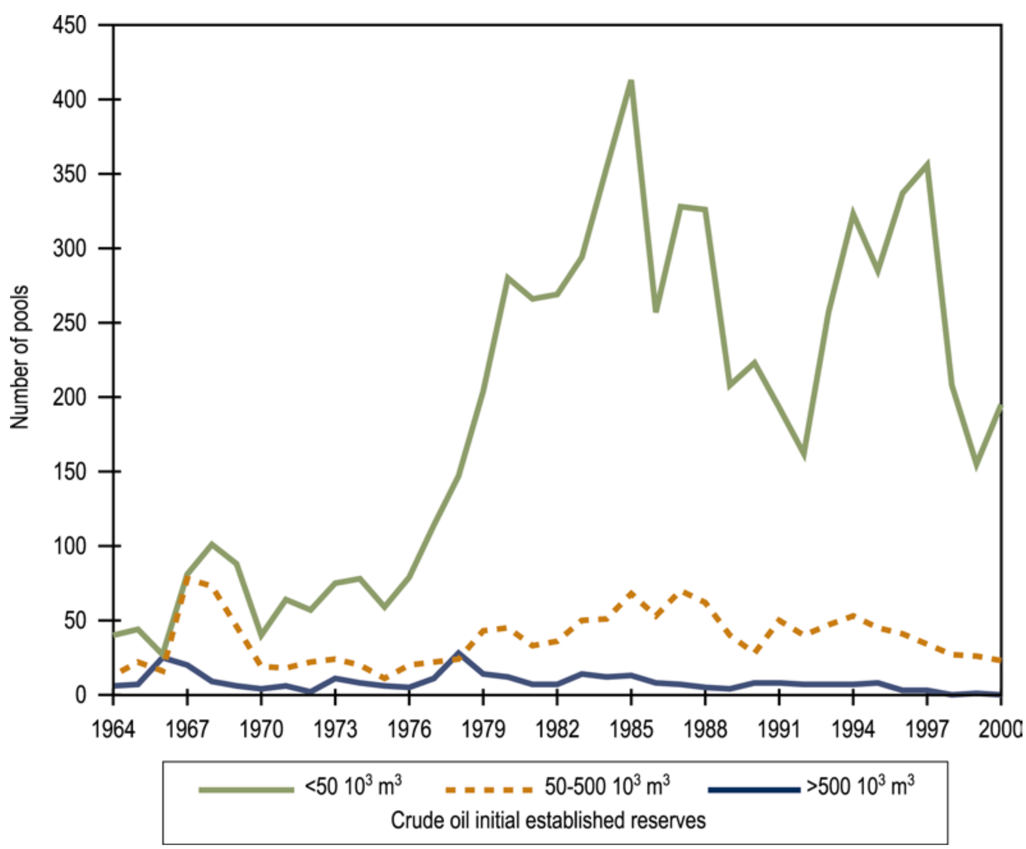


Figure 3.6. Oil pools discovered by size and discovery year

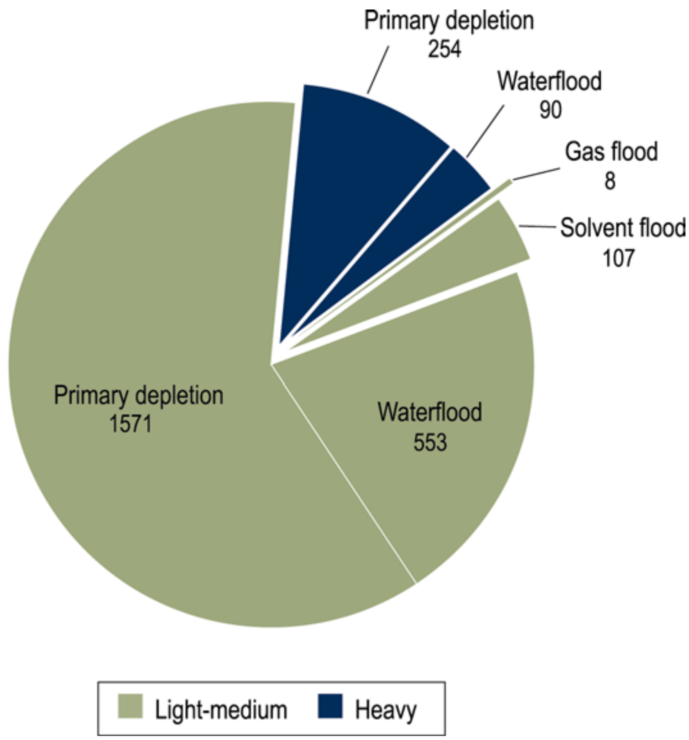


Figure 3.7. Initial established crude oil reserves (primary and incremental over primary) based on various recovery mechanisms (10^6 m^3)

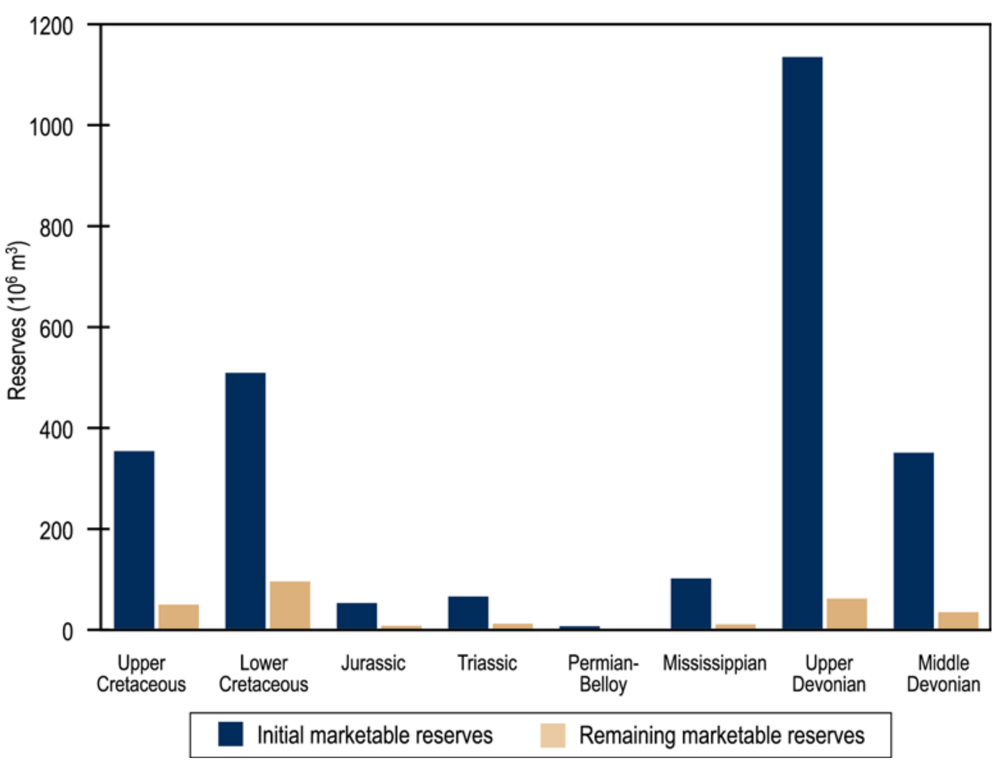


Figure 3.8. Geological distribution of reserves of conventional crude oil

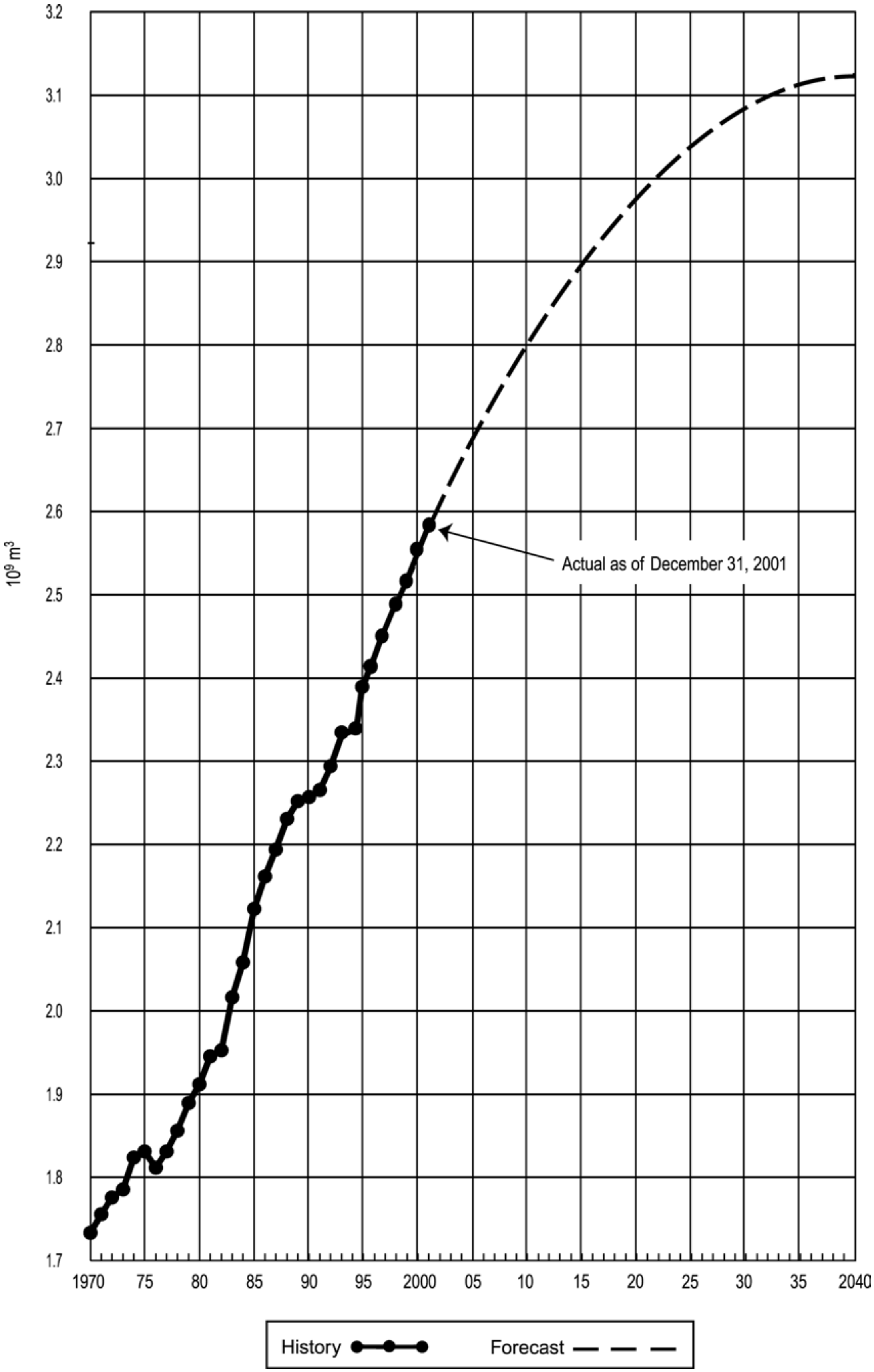


Figure 3.9. Growth of initial established reserves of conventional crude oil

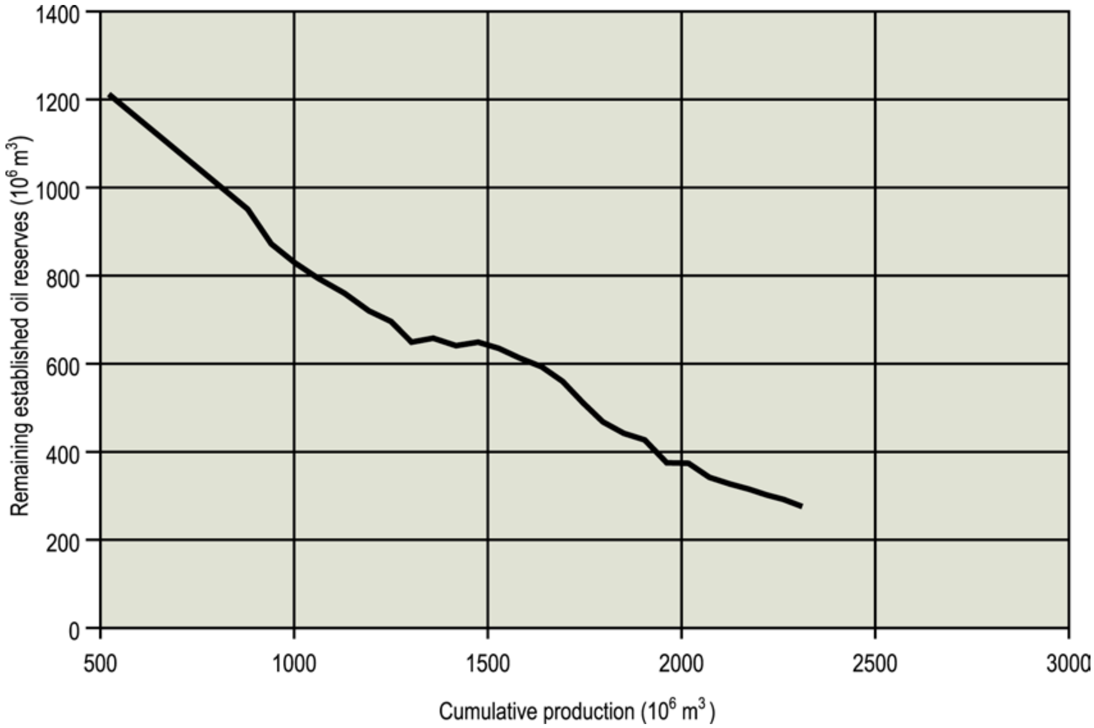


Figure 3.10. Alberta's remaining established oil reserves versus cumulative production

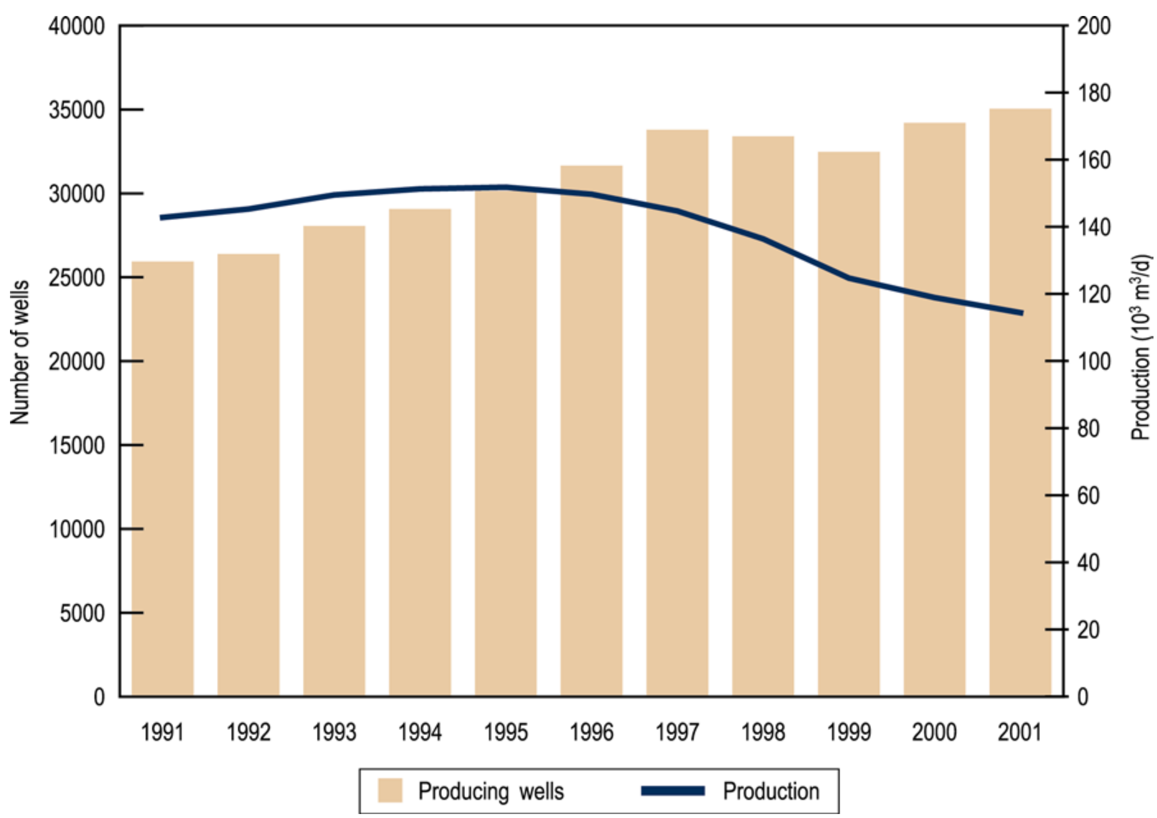


Figure 3.11. Total crude oil production and producing oil wells

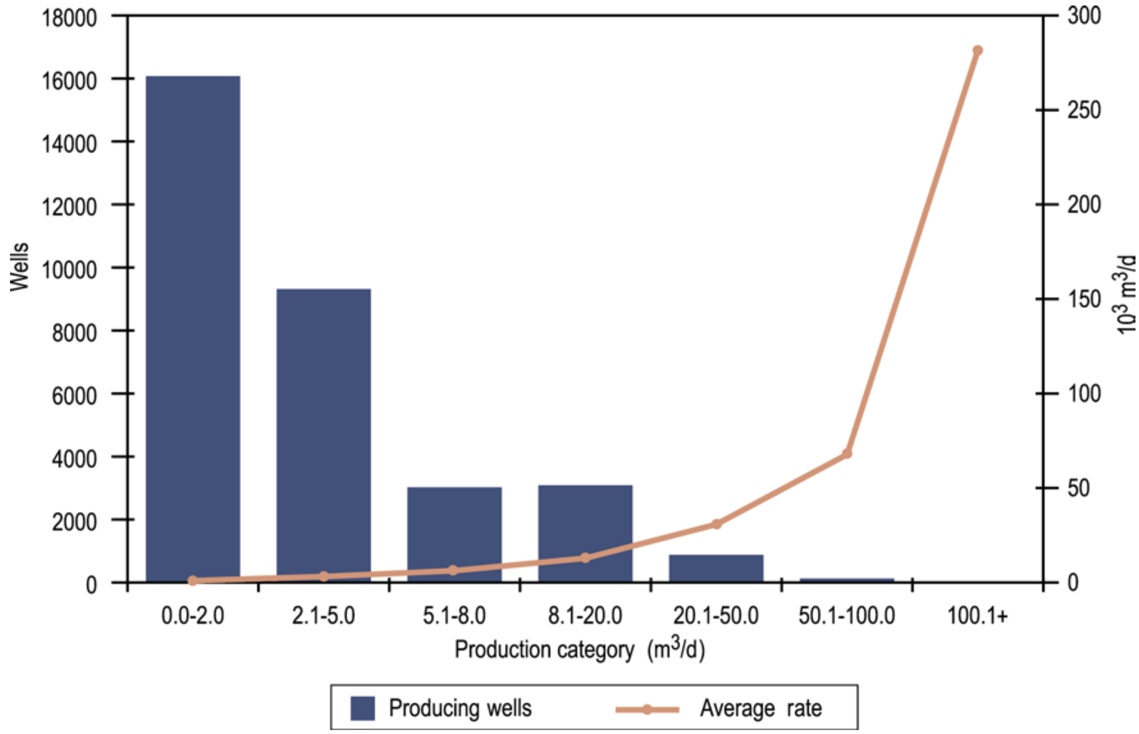


Figure 3.12. Crude oil well productivity in 2001

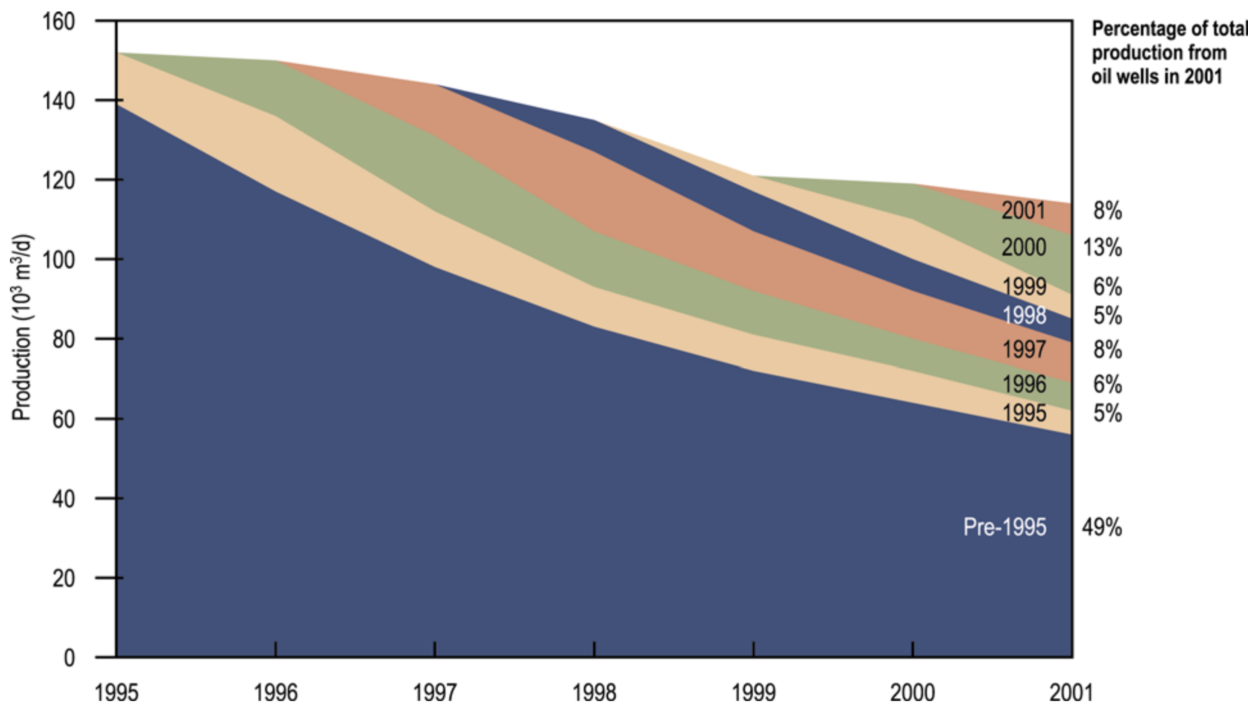


Figure 3.13. Total conventional crude oil production by drilled year

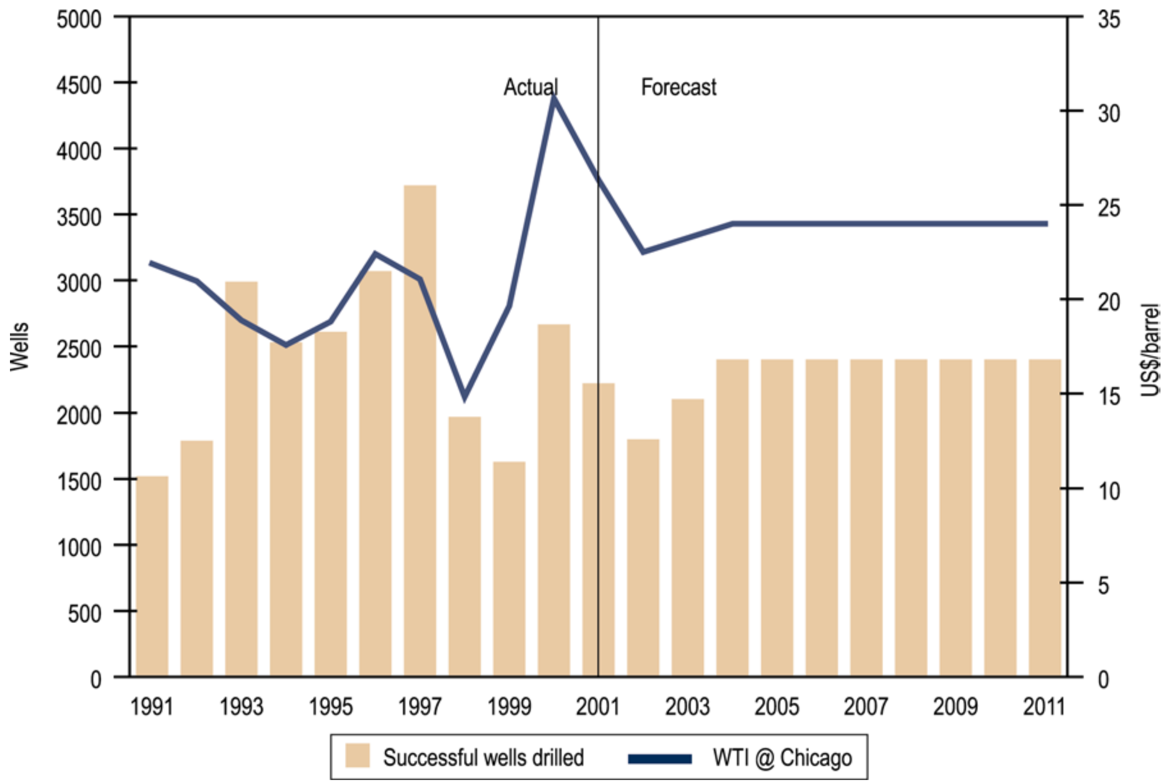


Figure 3.14. Alberta crude oil drilling activity

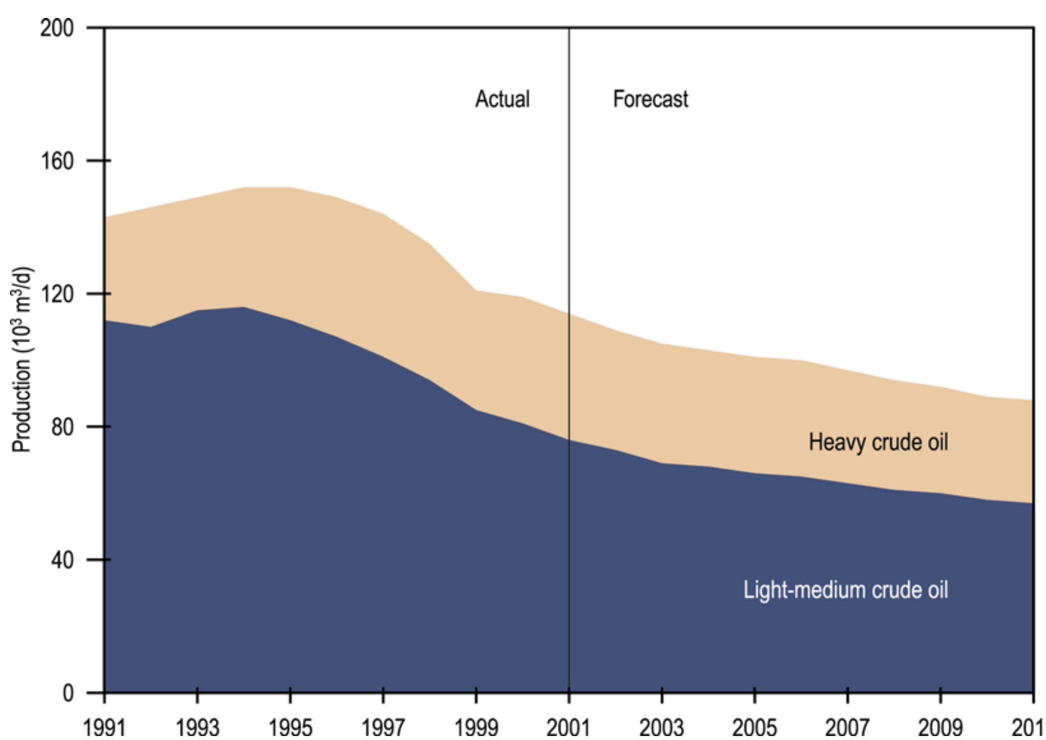


Figure 3.15. Alberta daily production of crude oil

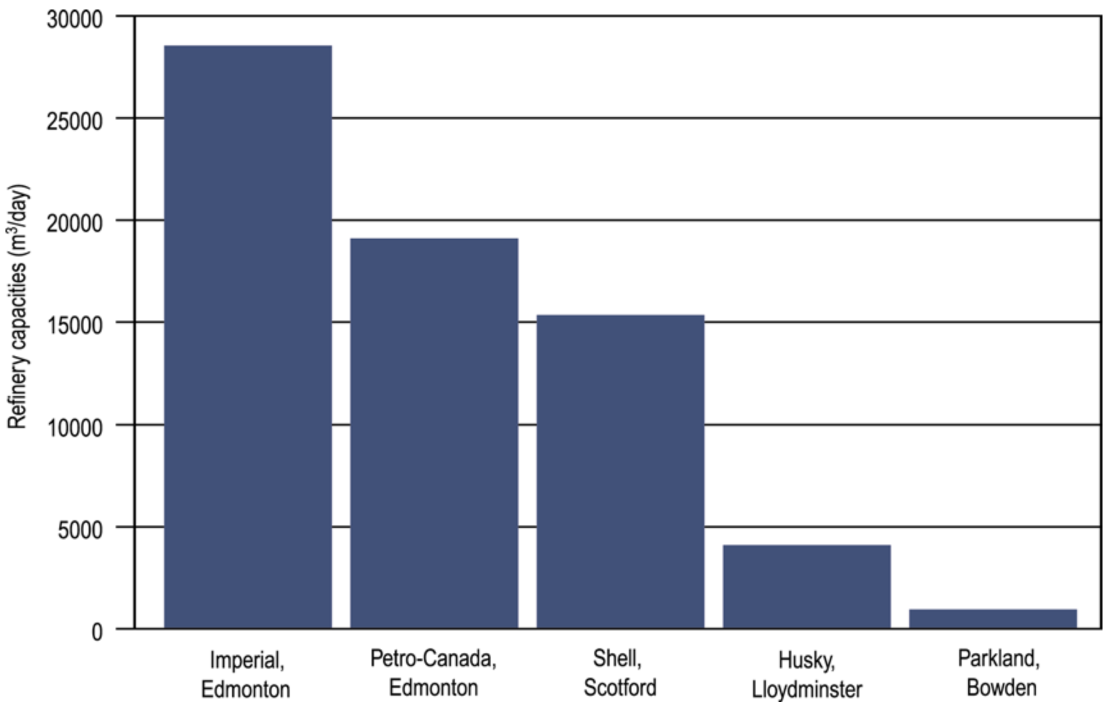


Figure 3.16. Capacity and location of Alberta refineries

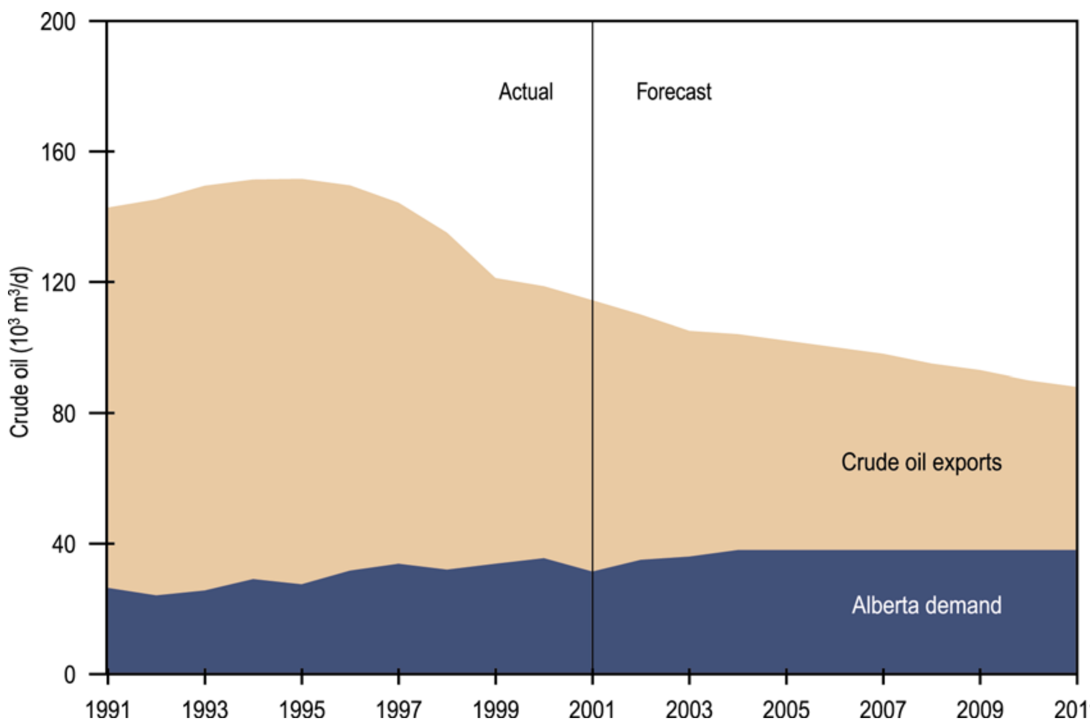


Figure 3.17. Alberta demand and exports of crude oil

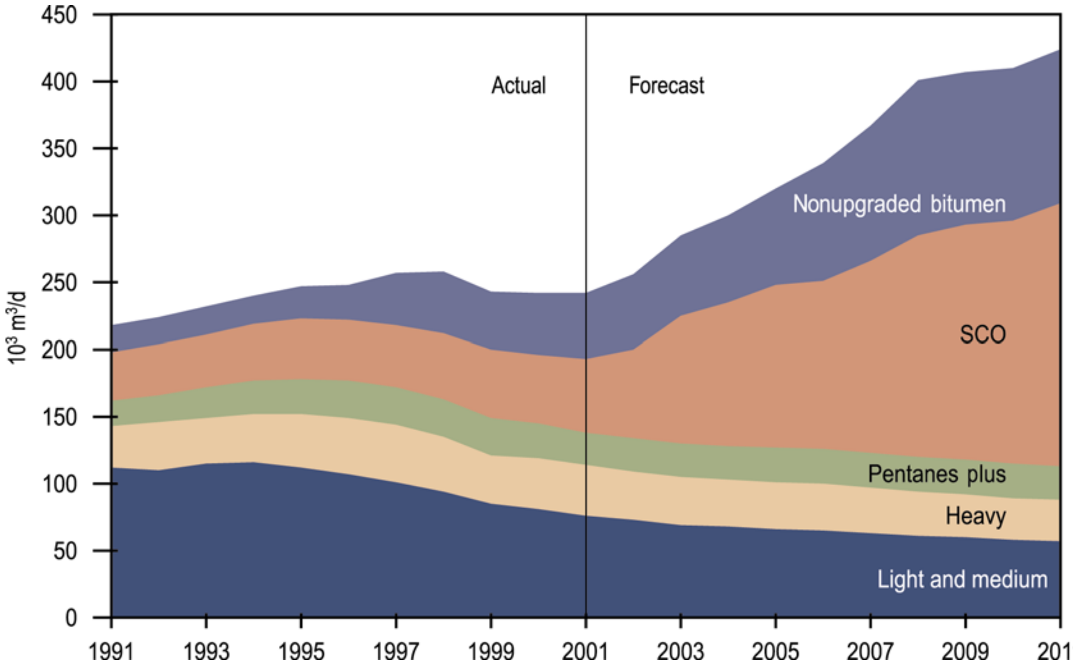


Figure 3.18. Alberta supply of crude oil and equivalent

4 Natural Gas and Liquids

Raw natural gas consists mostly of methane and other hydrocarbon gases, but also contains impurities, such as hydrogen, 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 approximately 91 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Ethane and higher paraffin hydrocarbon components are classified as natural gas liquids in this report.

4.1 Reserves of Marketable Gas

4.1.1 Provincial Summary

The EUB estimates the remaining established reserves of marketable gas in Alberta at December 31, 2001, to be 1141.4 billion cubic metres (10^9 m^3), having a thermal (heating value) energy content of 43.4 exajoules. This represents a net decrease of 25.3 10^9 m^3 since December 31, 2000, which is the result of all reserves additions less marketed production that occurred during 2001. This 1141.4 10^9 m^3 of marketable reserves excludes 43 10^9 m^3 ethane and other natural gas liquids, which are present in gas leaving the field plant and subsequently recovered at reprocessing plants, as discussed in Section 4.1.7. Details of the changes in remaining reserves during 2001 are shown in Table 4.1. Annual reserves additions and production of natural gas since 1975 are shown in **Figure 4.1**. Over the years additions have fluctuated as a result of economic factors and reassessment of existing pools, while annual production has risen. **Figure 4.2** shows that Alberta's remaining established reserves of marketable gas has been in general decline since 1983.

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

	2001	2000	Change
Initial established reserves	4 179.9	4 063.5	+116.4
Cumulative production	2 995.5	2 852.8	+142.7[a] (147.7)[c]
Remaining established reserves downstream of field plants	1 184.4	1 210.7	
Minus adjustment for liquids removed at straddle plants	43.0	44.0	
Remaining established reserves	1 141.4 (40.5)[b] (1 161)[c]	1 166.7 (41.4)[b] (1 189)[c]	-25.3

[a] May differ slightly from actual 2001 production.
[b] Imperial equivalent in trillions of cubic feet at 14.65 pounds per square inch absolute and 60°F.
[c] On basis of 37.4 MJ/m^3 in 10^9 m^3.

At year-end 2001, natural gas reserves were assigned to 29 061 pools in the province. Of these, 7152 pools have never been placed on production and had aggregate initial established reserves of marketable gas of 123 10^9 m^3, or about 10 per cent of the province's remaining established reserves. This is significantly less than in 1994, when approximately 30 per cent of the province's reserves were attributed to nonproducing pools. This decrease resulted primarily from the deletion of reserves from those pools that were abandoned or deemed uneconomic and to a lesser extent the placement of some of these pools on production.

4.1.2 Growth of Marketable Gas Reserves

Initial established reserves increased by 116.4 10^9 m^3 from year-end 2000, which is 26.3 10^9 m^3, or 18 per cent, less than Alberta's annual production of 142.7 10^9 m^3. This increase includes the addition of 62.5 10^9 m^3 attributed to new pools booked in 2001, development of existing pools, which added another 32.4 10^9 m^3, and net reassessment of 21.5 10^9 m^3. Therefore, drilling alone added a total of 94.9 10^9 m^3, replacing 67 per cent of Alberta's 2001 annual production of marketed gas. **Figure 4.3** depicts the growth of marketable gas reserves for 2001 by Petroleum Services Association of Canada (PSAC) areas and shows that 52.6 per cent of the annual growth occurred in Area 2 (Western Plains).

The addition of 21.5 10^9 m^3 from reassessments resulted from the review of some 4000 gas pools by EUB staff, which yielded positive reassessments totalling 112 10^9 m^3 and negative reassessments totalling 90.5 10^9 m^3. A positive reassessment of 20 10^9 m^3 resulted from recognition of some 665 previously unbooked producing gas wells drilled prior to 2000. During the year, EUB staff reviewed some 1500 single well pools with a remaining life of over 50 years. This resulted in a downward revision of 27.0 10^9 m^3 due to reassessment of in-place gas reserves and reduction of drainage area assigned to these wells. Pools that had significant reserve changes are listed in Table 4.2. Of particular interest are a number of new pools in the Western Plains region, which have added significant reserves to this area during 2001. Four of these pools, the Cordel Turner Valley L and Lovett River Rundle F, G, and J Pools, which are deep, high-pressured pools with excellent deliverability, together added new reserves of 6.9 10^9 m^3.

4.1.3 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 shows that pools with reserves of 30 10^6 m^3 or less, while representing 60 per cent of all pools, contain only 9 percent of the remaining marketable reserves. Similarly, the largest one per cent of pools contain 34 per cent of the remaining reserves. **Figure 4.4** shows natural gas pool sizes by discovery year since 1950 and illustrates that the majority of pools drilled since the mid-1970s were pools with 30 10^6 m^3 or less of initial established reserves.

4.1.4 Geological Distribution of Reserves

The distribution of reserves by geological period and formation is shown in Table 4.4 and graphically in **Figure 4.5**. The Upper and Lower Cretaceous period contains some 65.2 per cent of the province's remaining established reserves. The formations containing the largest reserves of natural gas are the Lower Cretaceous Mannville, with 34.8 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 11.4 per cent, and the Mississippian Rundle, with 9 per cent of the province's remaining reserves.

Table 4.2. Major natural gas reserve changes, 2001

Pool	Initial established reserves (10^6 m^3) 2001	Change	Main reasons for change
Ansell Cardiun G	6 953	+1 853	Pool development
Ardenode Belly River O	406	+406	New pool
Bashaw Edmonton & Belly River MU #1	2 698	+431	Pool development
Benjamin Rundle O	498	+498	New pool
Benjamin Rundle A & B	3 452	+1 412	Re-evaluation of initial volume in-place
Boyer Bluesky A and Gething A & M	12 160	+591	Re-evaluation of initial volume in-place
Brazeau River Nisku CC	474	+474	New pool
Cordel Turner Valley L	3 157	+3 157	New pool
Drumheller Mannville F	20	-336	Re-evaluation of initial volume in-place
Elmworth Falher F	94	-336	Reserves set at production, pool abandoned
Eyremore Southeastern Alberta Gas System (MU)	1 041	+921	Pool development
Ferrier Ellerslie V, Y & AA and Rock Creek F & H	1 534	+785	Re-evaluation of initial volume in-place
Godwin Wabamun B	20	-384	Reserves set at production, pool abandoned
Gordondale Doig A	194	-481	Re-evaluation of initial volume in-place
Hamburg Slave Point I	273	-491	Reserves set at production, pool abandoned
Hamburg Slave Point Y	431	+431	New pool
Hamburg Slave Point Z	92	+516	Re-evaluation of initial volume in-place
Kaybob South Gething P	1 812	+402	Pool development
Knopcik Doig B	238	-1 047	Re-evaluation of initial volume in-place
Lambert Viking A	521	+521	New pool
Lambert D-3 A	815	-543	Re-evaluation of initial volume in-place
Lanaway D-3 C	24	-520	Re-evaluation of initial volume in-place
Lathom Southeastern Alberta Gas System (MU)	799	+423	Pool development

(continued)

Table 4.2. Major natural gas reserve changes, 2001 (concluded)

Pool	Initial established reserves (10^6 m^3) 2001	Change	Main reasons for change
Leismer Mannville MU #1	20 056	+1 106	Re-evaluation of initial volume in-place and recovery factor
Lovett River Rundle F	1 741	+1 741	New pool
Lovett River Rundle G	494	+494	New pool
Lovett River Rundle J	1 544	+1 544	New pool
Majorville Upper Mannville F	116	-482	Reserves set at production, pool abandoned
Minnehik-Buck Lake Pekisko A	22 770	+1 170	Re-evaluation of initial volume in-place
Peppers Leduc A	859	+859	New pool
Pembina Cardium Z and Ellerslie II	634	-1 041	Re-evaluation of initial volume in-place and recovery factor
Pembina Nisku BB	83	-703	Re-evaluation of initial volume in-place
Pine Creek Bluesky A, Gething A, D, E, & F and Cardium A	4 910	+1 092	Re-evaluation of initial volume in-place
Shouldice Southeastern Alberta Gas System (MU)	1 429	+753	Re-evaluation of initial volume in-place
Smith Coulee Second White Specks J	904	+571	Re-evaluation of initial volume in-place
Smokey Cardium B	533	+533	New pool
Smokey Cardium C	386	+386	New pool
Stolberg Rundle H	711	-1 290	Re-evaluation of initial volume in-place and recovery factor
Sturgeon Lake South Triassic F	85	-386	Re-evaluation of initial volume in-place
Wapiti Falher A-10	409	+409	New pool
Wildcat Hills Viking-Blairmore E	590	-525	Re-evaluation of initial volume in-place
Wildhay Cardium A	426	+426	New pool
Wild River Leduc G	419	+419	New pool
Wintering Hills Southeastern Alberta Gas System (MU)	4 262	-679	Re-evaluation of initial volume in-place and recovery factor
Wolverine Bluesky A & Gething-Wabamun A	1 406	-1 121	Re-evaluation of initial volume in-place

Table 4.3. Distribution of natural gas reserves by pool size, 2001

Reserve range (10^6 m^3)	Pools #	Pools %	Initial established marketable reserves 10^9 m^3	Initial established marketable reserves %	Remaining established marketable reserves 10^9 m^3	Remaining established marketable reserves %
1500+	323	1	2 313	55	397	34
300-1499	1 346	4	784	19	249	21
100-299	2 955	10	494	12	222	19
31-100	7 338	25	403	10	215	18
Less than 30	18 123	60	186	4	102	9
Total	29 061	100	4 180	100	1 184[a]	100

[a] Reserves estimated at field plants.

4.1.5 Reserves of Natural Gas Containing Hydrogen Sulphide

Natural gas that contains greater than 0.01 per cent hydrogen sulphide (H_2S) is referred to as sour in this report. As of December 31, 2001, sour gas accounts for some 22.9 per cent (271 10^9 m^3) of the province's total remaining established reserves and about 28 per cent of natural gas marketed in 2001. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2001 is 9.3 per cent.

The distribution of reserves for sweet and sour gas listed in Table 4.5 shows that 204 10^9 m^3, or approximately 75 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 4.6** shows the remaining marketable reserves of sweet and sour gas since 1984 and indicates that the proportion of sour gas reserves has remained fairly constant at about 25 per cent of the total. The distribution of sour gas reserves by H_2S content is shown in Table 4.6**.** This table also shows that 59 10^9 m^3, or 21 per cent, of sour gas contains H_2S concentrations greater than 10 per cent.

4.1.6 Reserves of Retrograde Condensate Pools

Reserves of major retrograde condensate pools are tabulated both on energy content and on a volumetric basis. The initial energy in-place, recovery factor, and surface loss factor (both on an energy basis), as well as the initial marketable energy for each pool, are listed in Appendix 2-1. 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 available on CD.

4.1.7 Reserves Accounting Methods

The EUB books remaining marketable gas reserves on a pool-by-pool basis initially on volumetric determination of in-place reserves and application of recovery efficiency and surface loss. Subsequent reassessment of reserves is made using additional geological, material balance, and production decline information. 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 4.7**. A minimum 5 per cent is added to account for loss due to lease fuel (4 per cent) and flaring. Reserves of individual pools on the EUB's gas reserves database therefore reflect expected recovery after processing at field plants. Additional liquids contained in the gas stream leaving the field plants are extracted downstream at reprocessing or 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.

Table 4.4. Geological distribution of established natural gas reserves, 2001

Geological period	Raw gas Initial volume in-place (10^9 m^3)	Marketable gas Initial established reserves (10^9 m^3)	Marketable gas Remaining established reserves (10^9 m^3)	Raw gas Initial volume in-place (%)	Marketable gas Initial established reserves (%)	Marketable gas Remaining established reserves (%)
Upper Cretaceous						
Belly River	184	111	47	2.6	2.7	4.0
Milk River & Med Hat	566	367	134	7.9	8.8	11.4
Cardium	412	84	40	5.8	2.0	3.3
Second White Specks	12	8	5	0.2	0.1	0.4
Other	144	78	19	2.0	1.9	1.6
Subtotal	1 318	648	245	18.5	15.5	20.7
Lower Cretaceous						
Viking	382	268	61	5.4	6.4	5.2
Basal Colorado	42	34	3	0.6	0.8	0.2
Mannville	1 964	1 279	413	28.0	30.6	34.8
Other	241	162	51	3.4	3.9	4.3
Subtotal	2 629	1 743	528	37.0	41.7	44.5
Jurassic						
Jurassic	95	61	27	1.4	1.5	2.3
Other	52	34	10	0.7	0.8	0.8
Subtotal	147	95	37	2.1	2.3	3.1
Triassic						
Triassic	193	119	62	2.7	2.8	5.3
Other	27	19	4	0.4	0.5	0.3
Subtotal	220	138	66	3.1	3.3	5.6
Permian						
Belloy	9	6	3	0.0	0.1	0.3
Subtotal	9	6	3	0.1	0.1	0.3
Mississippian						
Rundle	908	572	106	12.7	13.7	9.0
Other	306	204	36	4.3	4.9	3.0
Subtotal	1 214	776	142	17.0	18.6	12.0
Upper Devonian						
Wabamun	237	113	28	3.3	2.7	2.4
Nisku	121	57	20	1.7	1.4	1.7
Leduc	473	244	29	6.7	5.9	2.4
Beaverhill Lake	480	214	47	6.7	5.1	4.0
Other	158	94	12	2.2	2.2	1.0
Subtotal	1 469	722	136	20.6	17.3	11.5
Middle Devonian						
Sulphur Point	13	8	4	0.2	0.2	0.3
Muskeg	5	2	1	0.0	0.1	0.0
Keg River	62	26	16	0.8	0.6	1.4
Other	33	14	4	0.5	0.3	0.3
Subtotal	113	50	25	1.6	1.2	2.1
Confidential[a]						
Subtotal	3	2	2	0.0	0.0	0.2
Total	7 122 (253)[a]	4 180 (148)[a]	1 184 (42)[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 4.5. Distribution of sweet and sour gas reserves, 2001 (10^6 m^3)

Type of gas	Raw gas Initial volume in-place	Initial producible	Marketable gas Initial established reserves	Net cumulative production	Remaining established reserves
Sweet					
Associated	475	379	537	386	151
Solution	770	287			
Nonassociated	3 410	2 454	2 277	1 514	763
Subtotal	4 655	3 120	2 813	1 900	914
Sour					
Associated	433	351	376	308	68
Solution	302	173			
Nonassociated	1 732	1 356	991	787	204
Subtotal	2 467	1 880	1 367	1 095	271
Total	7 122 (253)[a]	5 000 (178)[a]	4 180 (148)[a]	2 995 (106)[a]	1 184[b] (42)[a]
Sour gas % of total	34.6	37.6	32.7	36.5	22.9

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

[b] Reserves estimated at field plants.

Table 4.6. Distribution of sour gas reserves by H_2S content, 2001

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	247	318	46	75	121	45
2.00-9.99	91	354	13	78	91	34
10.00-19.99	27	180	6	24	30	11
20.00-29.99	11	49	2	15	17	6
Over 30	0	90	0	12	12	4
Total	376	991	67	204	271	100
Per cent	28	72	25	75		

The remaining established reserves of natural gas discussed in Section 4.1.1 excludes liquids expected to be removed from the gas stream. It is expected that some 43 10^9 m^3 will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas estimated at field plant from 1184.4 10^9 m^3 to 1141.4$10^9$ m^3 and the thermal energy content from 47.7 to 43.4 exajoules. This 1141.4 10^9 m^3 of marketable gas is composed of approximately 98 per cent methane and represents the volume and average heating content of marketable gas available after all processing.

Figure 4.7 also shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 20 per cent is expected to be removed at field plants and an additional 45 per cent at straddle plants. Therefore, the EUB estimates extractable 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 reserve is booked as part of the marketable gas and represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in Section 4.2 of this report.

4.1.8 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in Appendix 2-2. Each multifield pool shows the individual initial established reserves assigned to each field and the total initial established reserves for the multifield pool.

4.1.9 Coalbed Methane Reserves

There has been a significant resurgence in the interest in coalbed methane (CBM) development in Alberta over the past year. This interest has led to a number of pilot projects commencing in various parts of the province, resulting in initial attempts to produce this resource. However, while the EUB views CBM to be a significant resource for the province, reserves cannot be established until actual production data become available to prove its economic viability. Therefore, it is not possible to conduct a reasonable assessment of CBM reserves at this time, since such data are only now becoming available. It is anticipated that sufficient data may become available to conduct a preliminary assessment of CBM reserves for certain parts of the province for next year-end.

4.1.10 Ultimate Potential

In 1992 the EUB (then the ERCB) issued *ERCB 92-A*,[1] 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 2003. **Figure 4.8** shows the historical and forecast growth in initial established reserves of marketable gas.

Figure 4.9 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 standard heating value of 37.4 MJ/m^3. It shows initial established reserves of 4287 10^9 m^3 (at the field gate), or that 76.6 per cent of the ultimate potential of 5600 10^9 m^3 has been discovered as of year-end 2001. This leaves 1313 10^9 m^3, or 23.4 per cent, of marketable gas yet to be discovered. Cumulative production of 3074 10^9 m^3 at year-end 2001 represents 54.9 per cent of the ultimate potential, leaving 2526 10^9 m^3 or 45.1 per cent available for future use.

[1] Alberta Energy and Utilities Board, 1992, *Ultimate Potential and Supply of Natural Gas in Alberta, Report 92-A* (Calgary).

Table 4.7. Remaining ultimate potential of marketable gas, 2001 (10^9 m^3 at 37.4 MJ/m^3)

Yet-to-be-established	
Ultimate potential	5 600
Minus initial established	4 287
	1 313
Remaining established	
Initial established	4 287
Minus cumulative production	3 074
	1 213
Remaining ultimate potential	
Yet-to-be-established	1 313
Plus remaining established	1 213
	2 526

The regional distribution of remaining reserves and yet-to-be-established reserves is shown by PSAC area in **Figure 4.10**. It shows that the Western Plains contains about 40 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), it shows that 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) that are expected to be recovered from raw natural gas based on existing technology and market conditions. It also estimates the liquids reserves that are not removed from natural gas. The latter is included as part of the province's marketable gas reserves discussed in Section 4.1. The EUB's projections on the overall recovery of each NGL component are explained in Section 4.1.7 and shown graphically in **Figure 4.7**. Estimates of the remaining established reserves of extractable NGLs are summarized in Tables 4.8 and 4.9. **Figure 4.11** shows remaining established reserves of extractable NGLs compared to 2001 production.

Table 4.8. Established reserves and production of extractable NGLs as of December 31, 2001 (10^6 m^3 liquid)

	2001	2000	Change
Cumulative net production[a]			
Ethane	169.0	156.3	+12.7
Propane	206.3	197.7	+8.6[b]
Butanes	118.7	113.8	+4.9[b]
Pentanes plus	278.7	269.9	+8.8[b]
Total	772.7	737.7	+35.0
Remaining (expected to be extracted)			
Ethane	173.7	176.8	-3.1
Propane	84.1	85.5	-1.4
Butanes	49.9	50.4	-0.5
Pentanes plus	77.5	80.7	-3.2
Total	385.2	393.4	-8.2

[a] Net production means 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*.

Table 4.9. Reserves of NGLs as of December 31, 2001 (10^6 m^3)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining reserves	252.1	98.9	55.3	77.5	483.8
Liquids expected to remain in marketable gas	78.4	14.8	5.4	0	98.6
Remaining established recoverable from					
Field plants	44.8	49.2	32.5	69.2	195.7
Straddle plants	100.9	34.5	16.3	7.7	159.4
Solvent floods	28.0	0.4	1.1	0.6	30.1
Total	173.7	84.1	49.9	77.5	385.2

4.2.1 Ethane

As of December 31 2001, the EUB estimates remaining established reserves of extractable ethane to be 173.7 10^6 m^3 in liquefied form. This estimate includes 28 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into several pools throughout the province to enhance oil recovery. As shown in Table 4.9, there is an additional 78.4 10^6 m^3 (liquid) of ethane estimated to remain in the marketable gas stream and available for potential recovery. This yields a total remaining ethane reserve of 252.1 10^6 m^3.

During 2001, the extraction of specification ethane was 12.7 10^6 m^3, about the same as the 12.8 10^6 m^3 produced in 2000. 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 Table 4.10, the volume-weighted average ethane content of all remaining gas was 0.052 mol/mol. This table lists ethane volumes recoverable from major fields and from solvent floods. These major fields contain 32.6 per cent (56.6 10^6 m^3) of the remaining established reserves with the Caroline and Pembina fields, accounting for 9 per cent of the total.

Table 4.10. Remaining ethane reserves in major fields as of December 31, 2001

Fields	Ethane content (mol/mol)	Remaining established reserves of ethane	
		Gas (10^9 m^3)	Liquid (10^6 m^3)
Brazeau River	0.102	1.2	4.4
Caroline	0.169	2.4	8.4
Elmworth	0.062	1.0	3.5
Ferrier	0.093	1.1	3.8
Kaybob South	0.095	1.3	4.7
Pembina	0.094	2.2	8.0
Rainbow	0.116	1.3	4.4
Ricinus	0.084	1.2	4.4
Valhalla	0.076	1.0	3.5
Wapiti	0.072	1.3	4.6
Willesden Green	0.079	1.0	3.6
Wizard Lake	0.152	1.0	3.3
All other fields	0.044	24.9	89.1
Solvent floods	-	8.0	28.0
Total	0.052[a]	48.9	173.7

[a] Volume weighted average

4.2.2 Other Natural Gas Liquids

As of December 31, 2001, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 84.1 10^6 m^3, 49.9 10^6 m^3, and 77.5 10^6 m^3 respectively. The overall changes in the reserves during the past year are shown in Table 4.8. The fields with the largest changes for 2001 are shown in Table 4.11.

Table 4.11. Major NGL reserves (excluding ethane) changes, 2001 (10^6 m^3)

Field	Remaining established-2001	Reserves change	Main reason for change
Garrington	2.0	-1.4	Re-evaluation of reserves
Farrier	2.5	+0.5	Re-evaluation of reserves
Jumping Pound West	2.8	+1.0	Re-evaluation of reserves
Rainbow	4.2	-0.5	Re-evaluation of reserves
Wapiti	0.9	-2.1	Re-evaluation of reserves

Listed in Appendix 2-3 are propane, butanes, and pentanes plus reserves in fields containing major reserves of extractable liquids. These fields account for 53 per cent of the provincial total, with the Caroline and Pembina fields accounting for about 15 per cent of the total. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table. During 2001, propane and butanes recovery at crude oil refineries was 355 and 1157 thousand (10^3) 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 has been recovered. However, the recovery has increased over time to about 50 per cent 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 160 10^9 m^3, the EUB estimates remaining ultimate potential of liquid ethane to be 398 10^6 m^3. The other 30 per cent, or 48 10^9 m^3, of ethane gas is expected to be sold for its heating value as part of marketable gas.

For liquid propane, butanes, and pentanes plus together, the remaining ultimate potential reserves are 534 10^6 m^3. This assumes that remaining ultimate potential as a percentage of ultimate potential is similar to that of marketable gas, which currently stands at 46 per cent.

4.3 Supply of and Demand for Natural Gas

4.3.1 Natural Gas Supply

Alberta produced 147.7 10^9 m^3 of marketable gas in 2001, an increase of 1 per cent over last year.[2] Growth in gas production has slowed in recent years, while demand has grown. Major factors affecting Alberta natural gas production include natural gas prices, drilling activity, the location of Alberta's reserves, and the production characteristics of today's wells.

High demand for Alberta natural gas has led to a considerable increase in the level of drilling in the province in the past few years. Producers are using strategies such as infill drilling to increase production levels. The number of successful natural gas wells drilled in Alberta from 1991 to 2001 is shown in **Figure 4.12**, along with the number of wells connected (placed on production) in each year. In 2001, some 9682 successful natural gas wells were drilled in the province, an increase of 17 per cent over 2000 levels. A large portion of recent natural gas drilling activity has taken place in southeastern Alberta, representing 52 per cent of all natural gas wells drilled in 2001.

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 1991-2000, 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. The distribution of natural gas well connections and the initial maximum day production of the connected wells in the year 2001 are illustrated in **Figures 4.13** and **4.14** respectively**.**[3]

Figure 4.15 illustrates historical gas production from gas wells by modified PSAC area. Production has increased slightly in most areas, most notably in Area 2 (Western Plains) and Area 3 (Southeastern Alberta). Gas production from oil wells has held fairly constant over the historical period.

The number of gas wells on production in Alberta from 1991 to 2001 is shown in **Figure 4.16**, along with the marketable gas production in each year. From 1991 to 1996 the annual growth in gas production was consistent with the annual increase in the number of gas producing wells. From 1996 forward, the number of producing gas wells increased dramatically year over year, while gas production slowed to average 1.6 per cent growth per year. By 2001, the total number of producing gas wells increased to 65 000, from 29 500 wells in 1991. The large number of gas wells placed on production in Southeastern Alberta, where production rates are low, was a key contributing factor behind this increase.

Average gas well productivities have been declining over time. As shown in **Figure 4.17**, about half the operating gas wells produce less than 2 10^3 m^3/d. In 2001, these 32 000 gas wells operated at an average rate of 1.2 10^3 m^3/d per well and produced less than 10 per cent of the total gas production. Only 9 per cent of the total gas wells produced over 100 10^3 m^3/d.

[2] Marketable gas volumes are normalized to 37.4 megajoules (MJ) per m^3.

[3] The EUB has divided the province into 8 areas. This breakdown is a modified version of the PSAC areas, with PSAC Area 7 divided into Areas 7 and 8.

The historical raw gas production by drilling vintage in Alberta is presented in **Figure 4.18**. 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 represents gas production from oil wells. Each band thereafter represents production from new gas well connections by year. The percentages shown on the right-hand side of the chart by each band represent the share of that band's production to the total production from gas wells in 2001. For example, 13 per cent of gas production in 2001 came from wells connected in that year. This figure shows that in 2001, only about 37 per cent of gas production came from gas wells drilled prior to 1995.

Declines in natural gas production from new gas well connections from 1991 to 1999 have been evaluated after the wells drilled in a given year complete a full year of production. Table 4.12 shows decline rates for gas wells connected from 1991 to 1999 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 17 per cent from the fourth year forward.

Table 4.12. Production decline rates for new well connections (%)

Year wells Connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1991	11	19	19	17
1992	29	23	17	19
1993	25	17	18	16
1994	26	23	16	15
1995	30	25	23	19
1996	31	27	21	18
1997	32	28	23	
1998	32	28	-	
1999	34	-	-	

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 4.19** shows the average initial productivities (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 figure shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average.

Based on the projection of natural gas prices provided in Section 1.2 and current estimates of reserves, the EUB expects that the number of successful natural gas wells drilled in the province will hold steady for 2002 at 9500 and increase to 10 500 in 2003, with roughly half of the wells being drilled in Southeastern Alberta. By 2004, some 11 000 natural gas wells are forecast to be drilled annually, falling to 10 000 per year from 2006 onward. **Figure 4.20** illustrates the drilling forecast.

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 producing wells at year-end 2001 is assumed to decline by 17 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 3 10^3 m^3/d in 2002 and will decrease to 1.5 10^3 m^3/d by 2011.
- The average initial productivity of new natural gas wells in the rest of the province will be 11 10^3 m^3/d in 2002 and will decrease to 9 10^3 m^3/d by 2011.
- Production from new wells will decline at a rate of 32 per cent the first year, 28 per cent the second year, 22 per cent the third year, and 17 per cent in the fourth year and thereafter.

Gas production from oil wells was held constant at 2001 levels.

Based on current established and yet-to-be-established reserves and the assumptions described above, the EUB generated the forecast of natural gas production to 2011, as shown in **Figure 4.21**. The production of natural gas from conventional reserves is expected to increase slightly, from 147.7 10^9 m^3 in 2001 to 151.8 10^9 m^3 by 2003. Production levels are expected to decline to 133.8 10^9 m^3 by the end of the forecast period.

At current prices, companies are assessing the potential for coalbed methane production in Alberta, which may supplement conventional supply during the forecast period. However, due to uncertainty surrounding its potential, no allowance was made for coalbed methane production over the forecast period. Producers in Alberta are largely drilling for conventional gas strikes in areas where outcome is more certain. By 2011, if natural gas production rates follow the projection, Alberta will have recovered some 81 per cent of the 5600 10^9 m^3 of ultimate potential. This ultimate potential is under review and is targeted for completion in 2003.

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 and 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 4.22** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province. Commercial natural gas storage pools, along with the operators and storage information, are listed in Table 4.13.

Table 4.13. Commercial natural gas storage pools as of December 31, 2001

Pool	Operator	Storage capacity ($10^6 m^3$)	Maximum deliverability ($10^3 m^3/d$)	Injection volumes, 2001 ($10^6 m^3$)	Withdrawal volumes, 2001 ($10^6 m^3$)
Carbon Glauconitic	ATCO	1 127	15 500	1 071	736
Crossfield East Elkton A & D	Amoco Canada Petroleum Limited	1 197	14 790	1 480	452
Hussar Glauconitic R	Husky Oil Operations Ltd.	423	5 635	390	139
McLeod Cardium A	Texaco Canada Petroleum Inc.	986	18 310	774	350
Sinclair Gething D	Alberta Energy Company Ltd.	282	5 634	250	196
Suffield Upper Mannville I & K, and Bow Island N & BB	Alberta Energy Company Ltd.	2 395	50 715	1 995	1 380

As **Figure 4.22** illustrates, 2001 natural gas injections exceeded withdrawals by 2707 $10^6 m^3$ (2839 $10^6 m^3$ at 37.4 MJ/m^3). This volume represents 1.9 per cent of marketable gas production in the province that year. The large decrease in withdrawal volumes resulted from unusually warm weather conditions, soft natural gas demand, and record natural gas prices in the winter months.

Marketable gas production volumes determined for 2001 were adjusted to account for the imbalance in injection volumes to 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.

With the official start-up of the Alliance pipeline in December 2000, Alberta will continue to have excess take-away capacity available for some time, depending on when new natural gas supplies are developed and how they are transported to market. The Alliance
pipeline has firm service capacity to move 37.5 $10^6 m^3/d$ of rich natural gas from British Columbia and Alberta to the Chicago area, with physical capacity at some 45 $10^6 m^3/d$. Alliance is running close to physical capacity today, with 80 per cent of the natural gas sourced from Alberta.

Figure 4.21 shows Alberta natural gas demand and production. Exports represent the difference between natural gas production and Alberta demand. In the year 2001, some 23 per cent of Alberta production was used domestically. The remainder was exported to other Canadian provinces and the United States.

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 45 10^9 m^3, compared to 34 10^9 m^3 in 2001, representing 33 per cent of total production. **Figure 4.23** illustrates the breakdown of natural gas demand in Alberta by sector.

Residential gas requirements are expected to grow moderately over the forecast period at an average annual rate of 1.7 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, but has shown an overall decline rate of 0.5 per cent. This has been 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 10^9 m^3 in 2001 to 11 10^9 m^3 by 2011. 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 gasification technology is one attractive alternative now 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 double over the forecast period, from some 3 10^9 m^3 in 2001 to 6 10^9 m^3 by 2011.

4.4 Supply of and Demand for Natural Gas Liquids (NGL)

4.4.1 Supply of Ethane and Other Natural Gas Liquids

Ethane and other NGL 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 that has been 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 4.24** 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. High gas prices may cause gas processors to reduce liquid recovery. In this situation gas would be sold for its heating value.

Ethane extracted at Alberta processing facilities decreased slightly, from 12.8 10^6 m^3 (35.1 10^3 m^3/d) in 2000 to 12.7 10^6 m^3 (34.8 10^3 m^3/d) in 2001. Table 4.14 shows the volumes of specification ethane extracted at the three types of processing facilities during 2001.

Table 4.14. Ethane extraction volumes at gas plants in Alberta, 2001

Gas plants	Volume (10^6 m^3)	% of total
Field plants	1.2	9
Fractionation plants	3.0	24
Straddle plants	8.5	67
Total	**12.7**	**100**

Table 4.15 outlines the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2001. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butanes volumes recovered at crude oil refineries were 0.4 10^6 m^3 (1.0 10^3 m^3/d) and 1.2 10^6 m^3 (3.2 10^3 m^3/d) respectively.

In 2001, natural gas liquids production declined year over year due to several factors. In the first few months of the year, high natural gas prices caused the gas industry to leave more gas liquids in the gas stream for its energy value. Further, ethane recovery within Alberta was hampered due to high CO_2 concentration levels in the gas stream entering a straddle plant. It is noted that the Alliance pipeline placed on production in December 2000 moved gas directly to Chicago, Illinois, where liquid recovery occurs.

For the purpose of forecasting ethane and other NGL's, 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 2001, ethane extraction in Alberta was 34.8 10^3 m^3/d, or 47 per cent recovery of the total ethane in the gas stream. It is expected that ethane recovery will increase to 45.9 10^3 m^3/d in 2002 and hold there for the remainder of the forecast period, as shown in **Figure 4.25**. 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.

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 4.15. **Figures 4.26** to **4.28** show forecast production volumes to 2011 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. High gas prices may cause gas processors to reduce liquid recovery from the volumes forecast.

Table 4.15. Liquid production at gas plants in Alberta, 2001 and 2011

	Year 2001			Year 2011		
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	12.7	34.8	86	16.8	45.9	125
Propane	8.6	23.5	58	8.6	23.5	64
Butanes	4.9	13.5	33	5.2	14.3	39
Pentanes+	8.8	24.0	59	9.2	25.2	69

4.4.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in the year 2001, some 96 per cent was used by the Alberta petrochemical industry as feedstock to produce ethylene, while the remainder was exported out of 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.

As shown in **Figure 4.25**, Alberta demand for ethane is projected to be 42.5 10^3 m^3/d for the forecast period, with all four ethylene plants running at 90 per cent of capacity. 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. It is noted that alternative feedstock to ethane such as propane and butanes are being considered by the petrochemical industry in an effort to enhance operating flexibility and longer-term growth opportunities. Globally, naptha is by far the most common feedstock used for ethylene production.

Figure 4.26 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 as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying.

Figure 4.27 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. Another major use of butanes in the province is as a petroleum feedstock in the production of methyl-tertiary-butyl-ether (MTBE), which when added to gasoline improves combustion efficiency and reduces pollutants, especially ground-level ozone and carbon monoxide. The state of California, which is the main market for the MTBE produced in Alberta, has set a ban deadline by 2004 for its use. The one plant in Alberta currently producing this product has options available to it and may redesign the plant to produce iso-octane if MTBE is banned from the U.S. market. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

Figure 4.28 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. As a result of a review of diluent requirements, our numbers have been refined over last year, and 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.

Over the forecast period, pentanes plus demand as diluent is expected to increase from 16.8 10^3 m^3/d to 37.2 10^3 m^3/d. The diluent requirement for heavy crude oil is expected to decline from 3.2 10^3 m^3/d in 2001 to 2.6 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 quite dramatically, from 13.6 10^3 m^3/d in 2001 to 34.6 10^3 m^3/d by 2011. Shortages of pentanes plus as diluent are forecast to occur by 2006 if alternatives are not considered. Several steps have been 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 addition, industry may consider alternatives to pentanes plus, such as

- upgrading of bitumen to SCO within Alberta;
- blending 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.

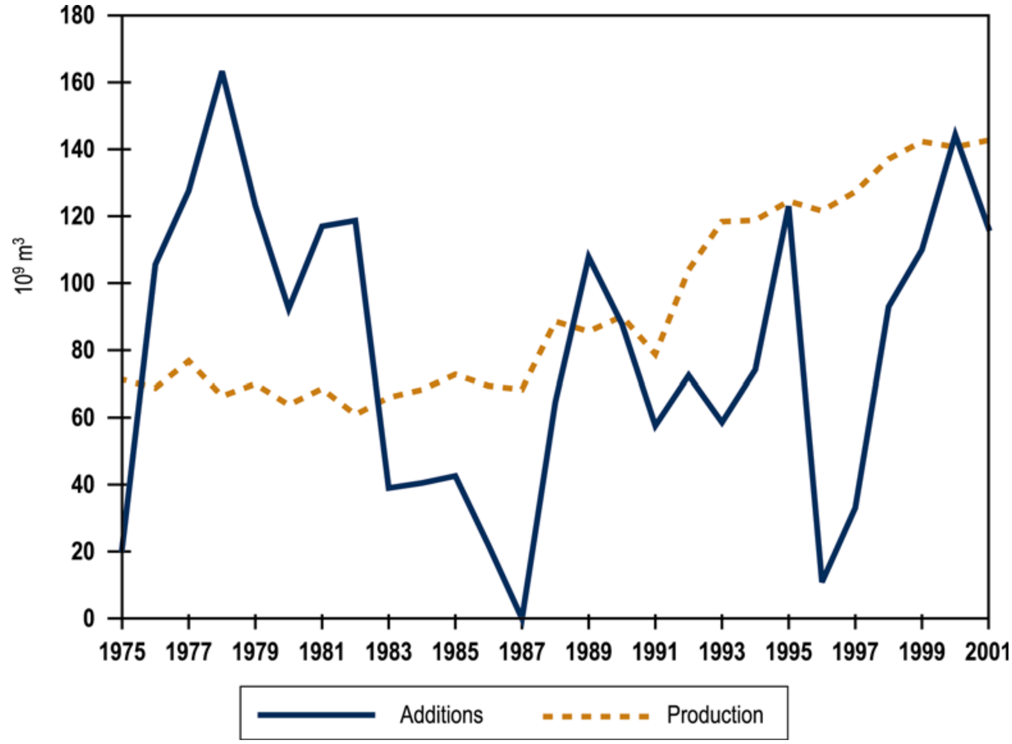


Figure 4.1. Annual reserves additions and production of marketable gas

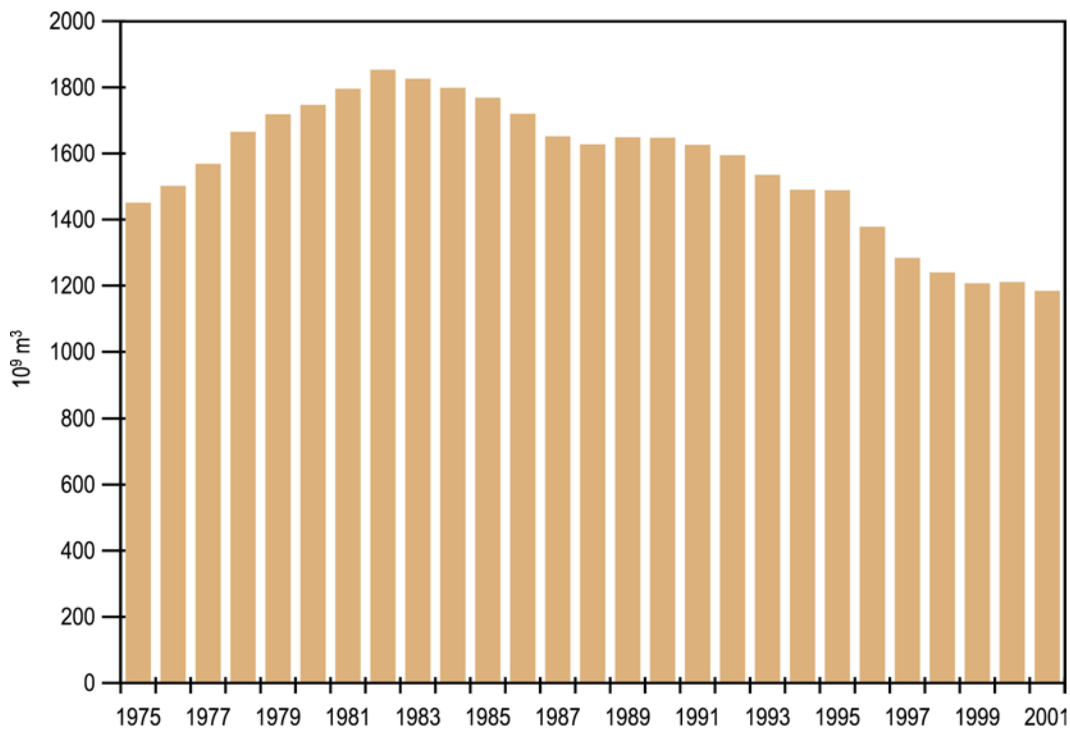


Figure 4.2. Remaining established marketable gas reserves

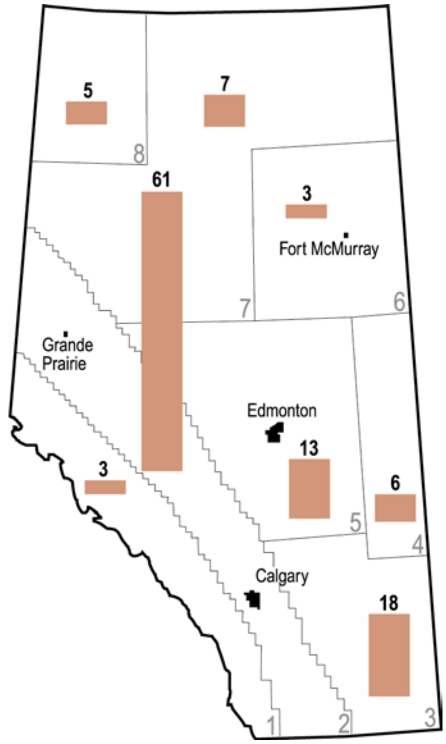


Figure 4.3. Marketable gas reserves additions, 2001 (10^9 m^3)

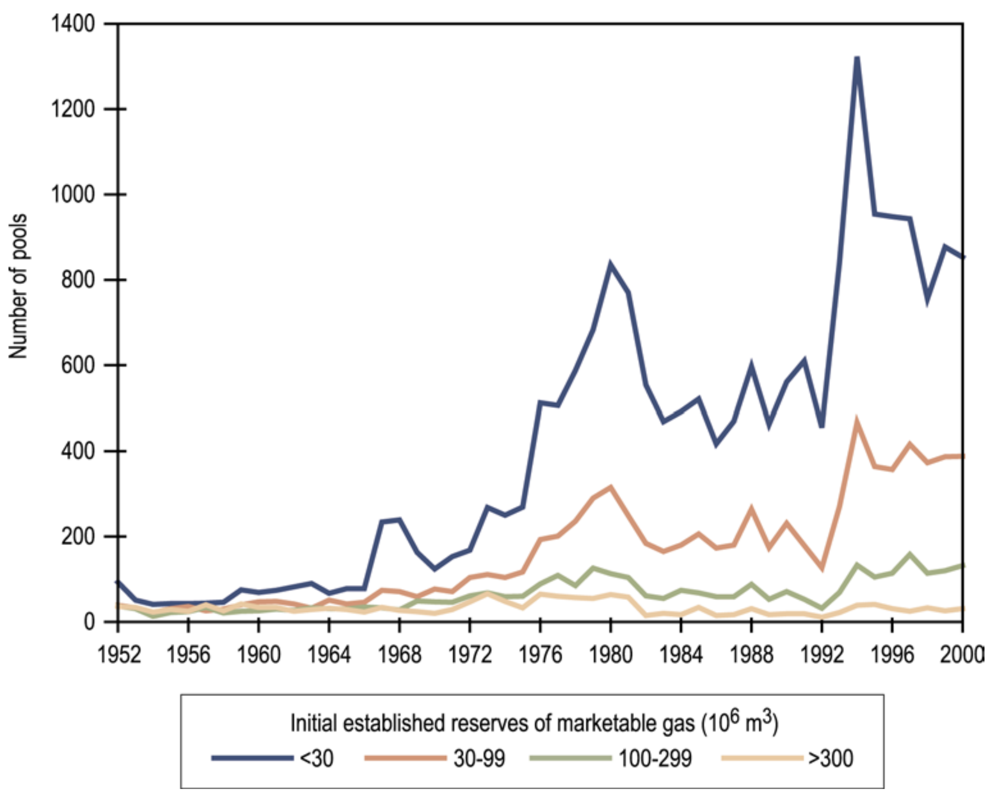


Figure 4.4. Gas pools by size and discovery year

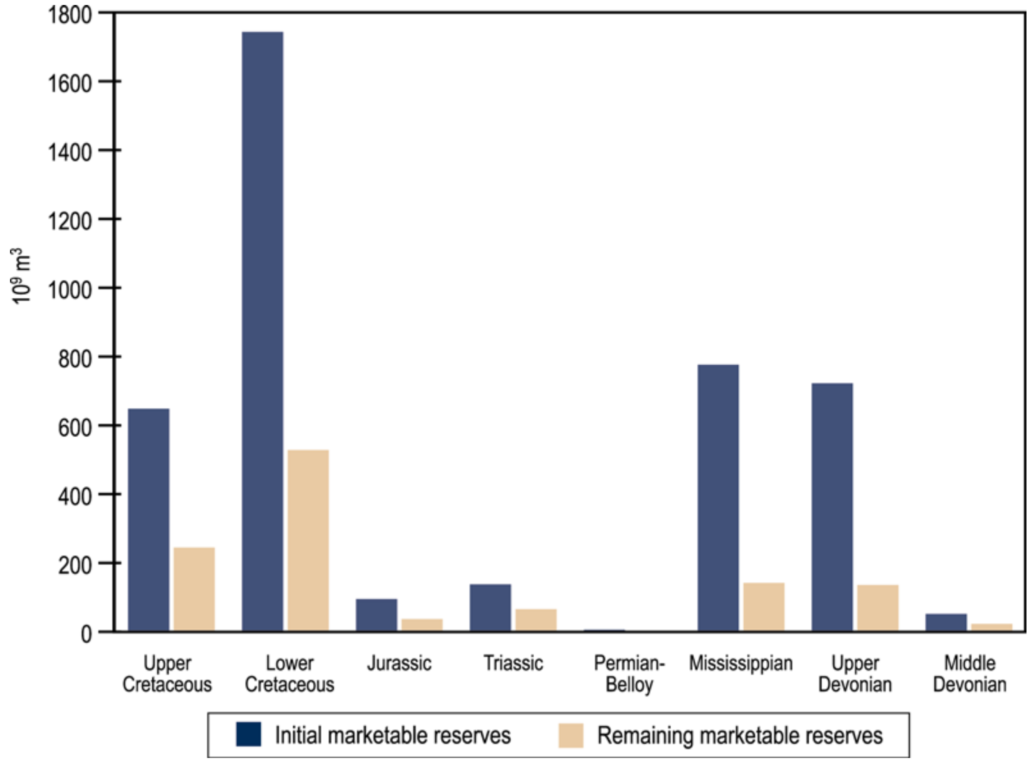


Figure 4.5. Geological distribution of gas reserves

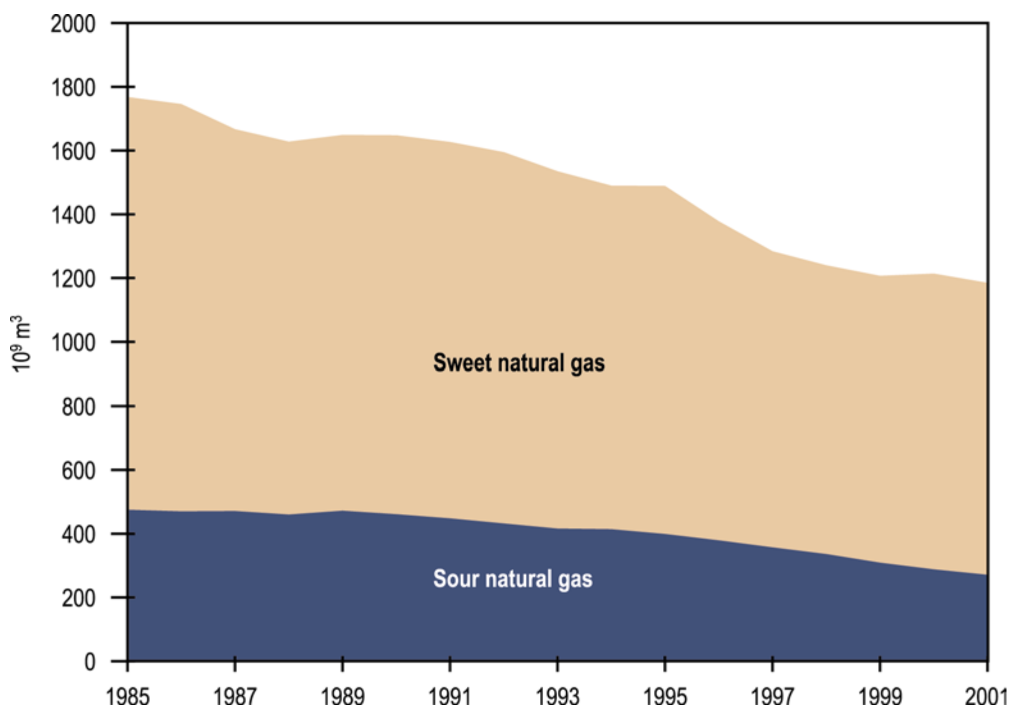


Figure 4.6. Remaining established marketable reserves of sweet and sour gas

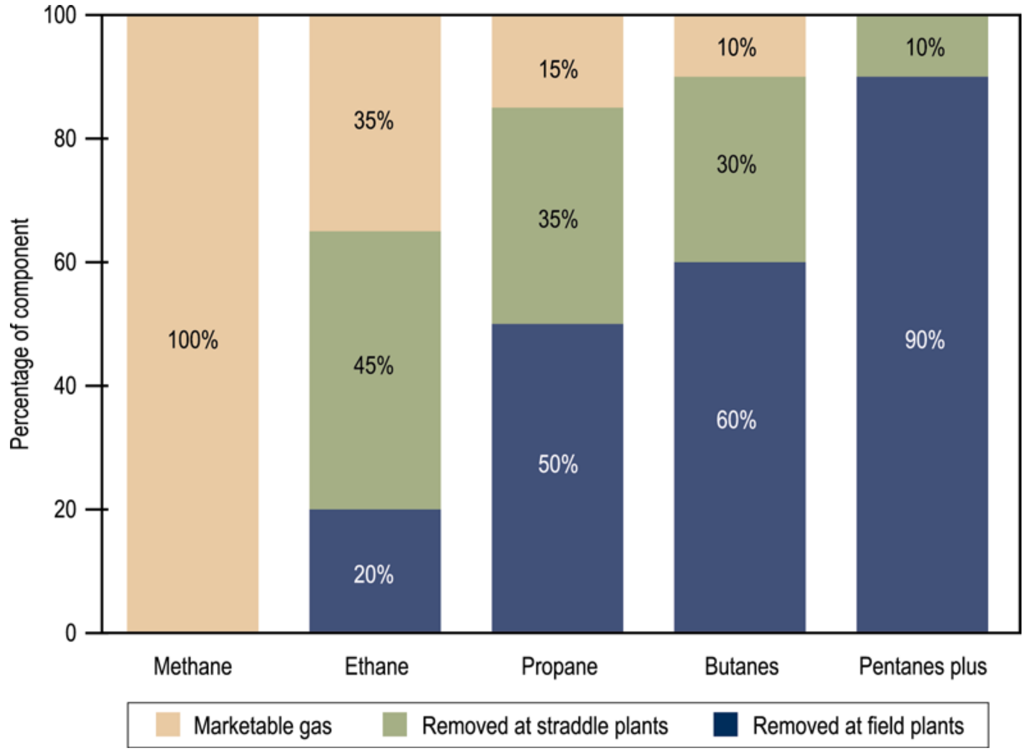


Figure 4.7. Natural gas components

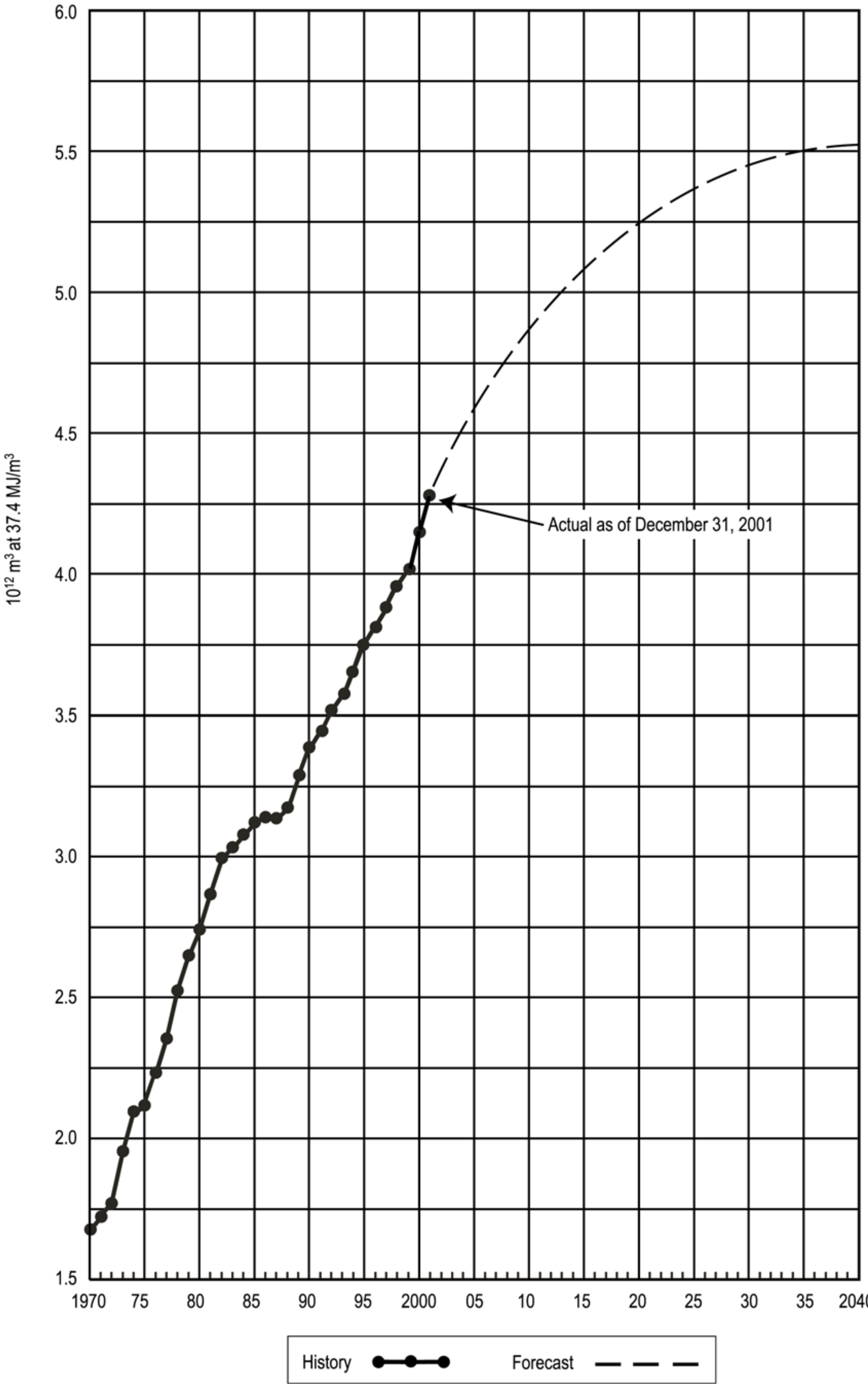


Figure 4.8. Growth of initial established reserves of marketable gas

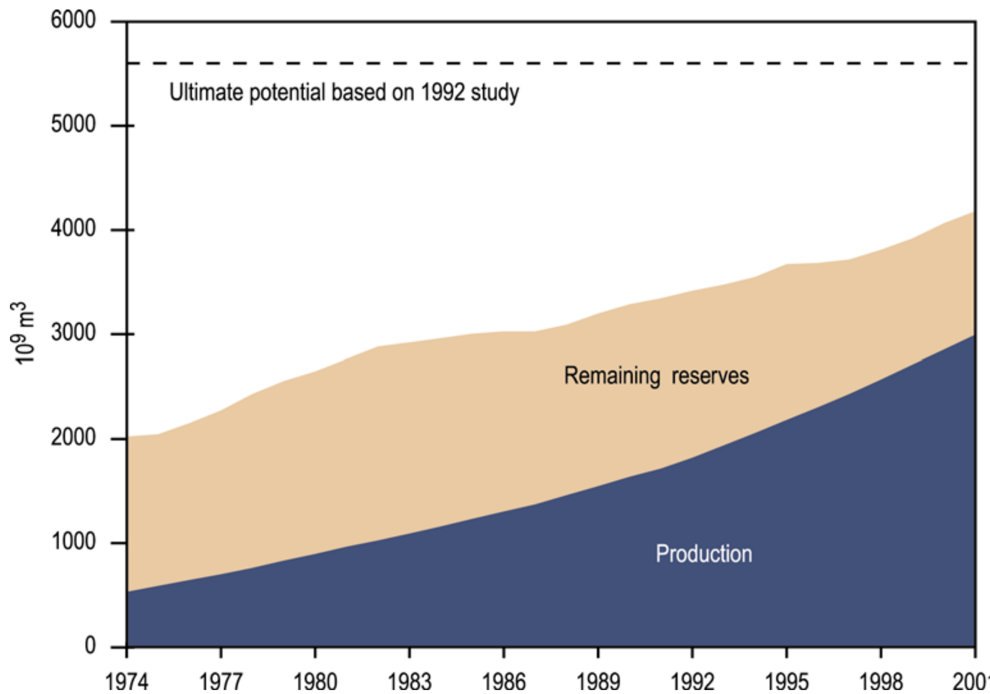


Figure 4.9. Gas ultimate potential

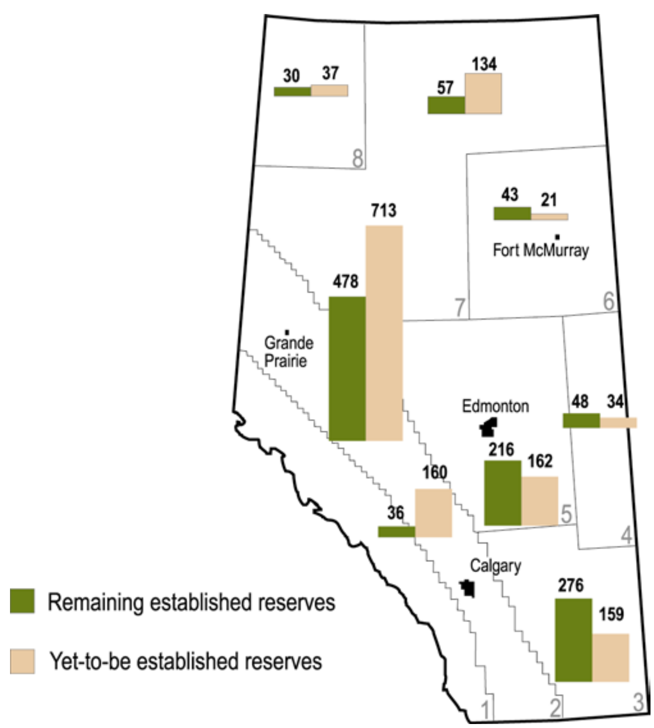


Figure 4.10. Regional distribution of marketable gas reserves (10^9 m^3)

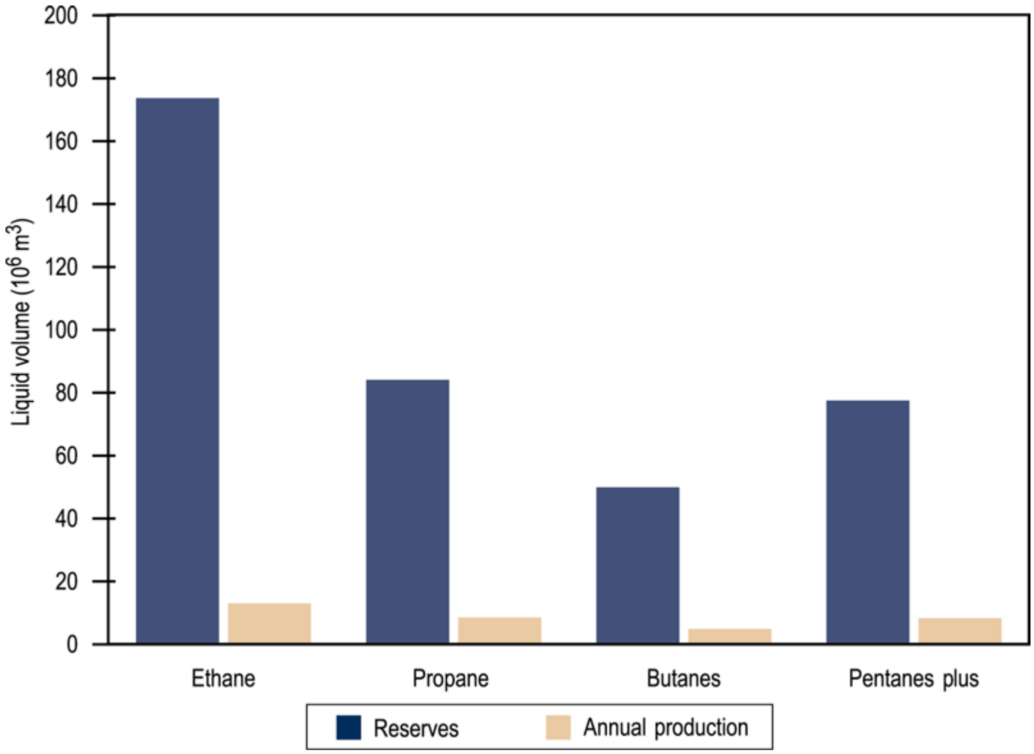


Figure 4.11. Remaining established NGL reserves expected to be extracted and annual production

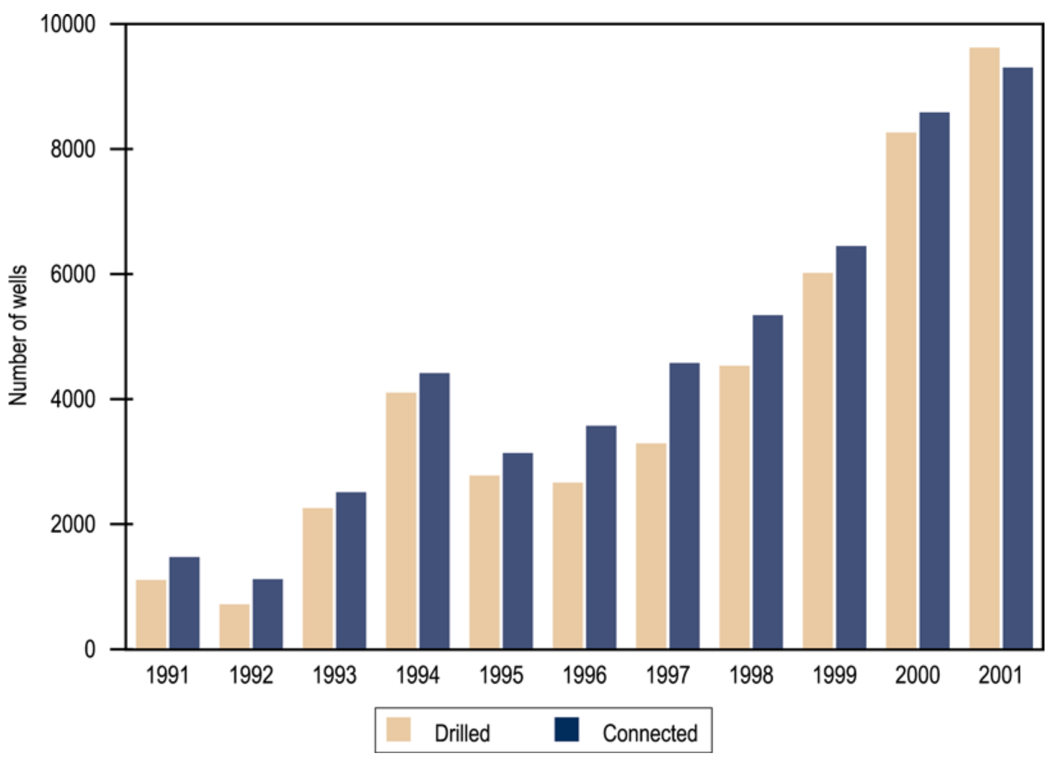


Figure 4.12. Gas wells drilled and connected

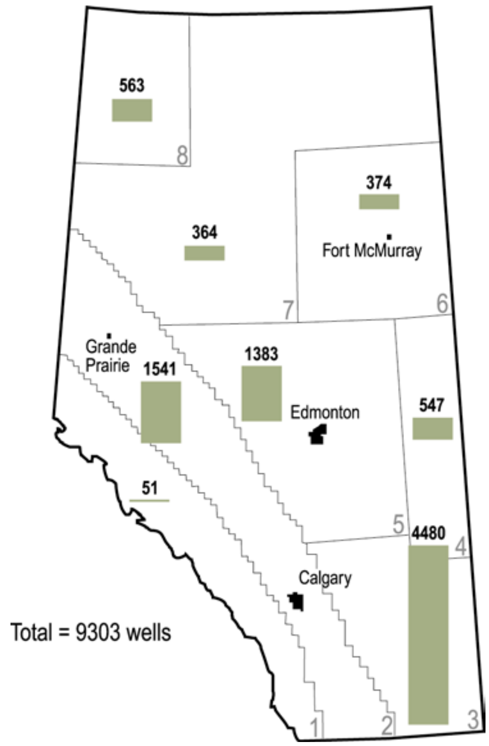


Figure 4.13. Alberta gas well connections, 2001

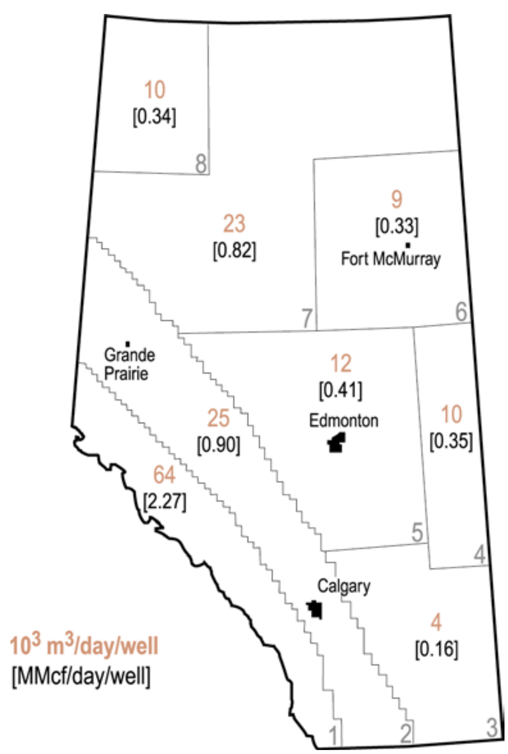


Figure 4.14. Initial operating day rates of connections, 2001

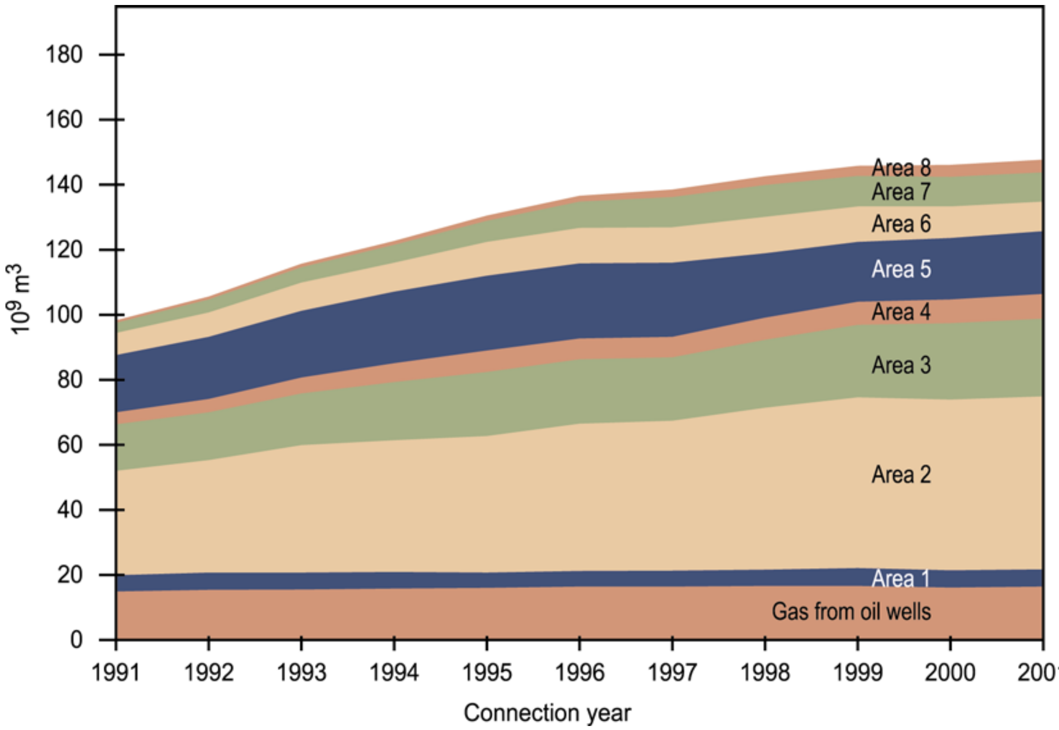


Figure 4.15. Marketable gas production by modified PSAC area

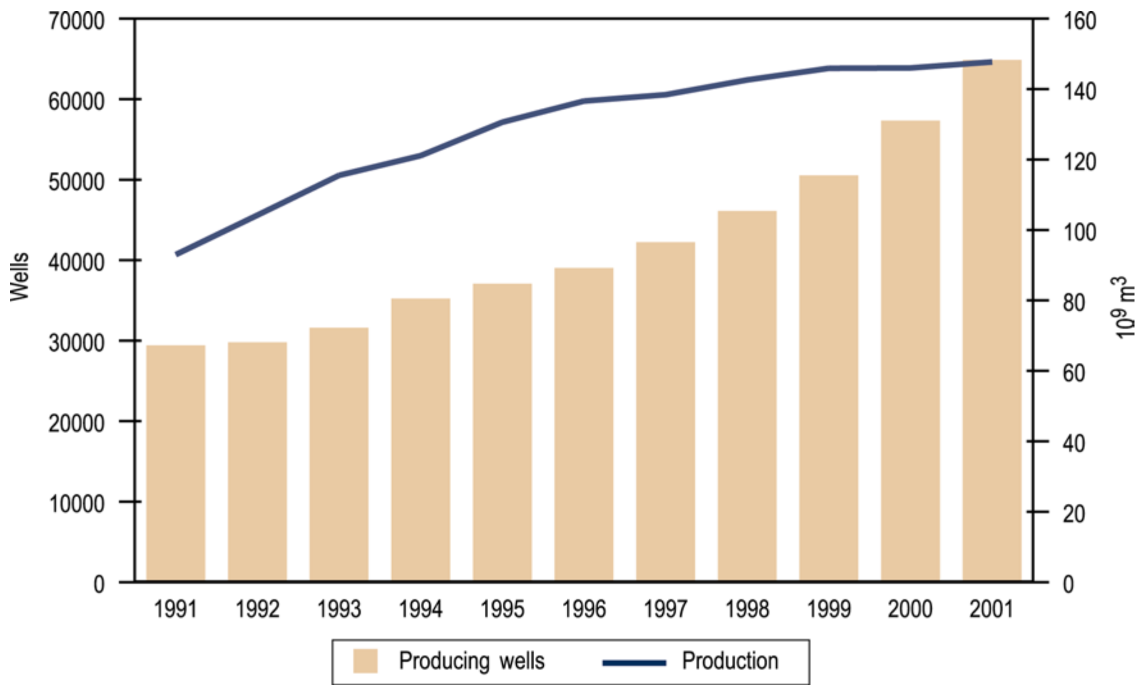


Figure 4.16. Marketable gas production and the number of producing wells

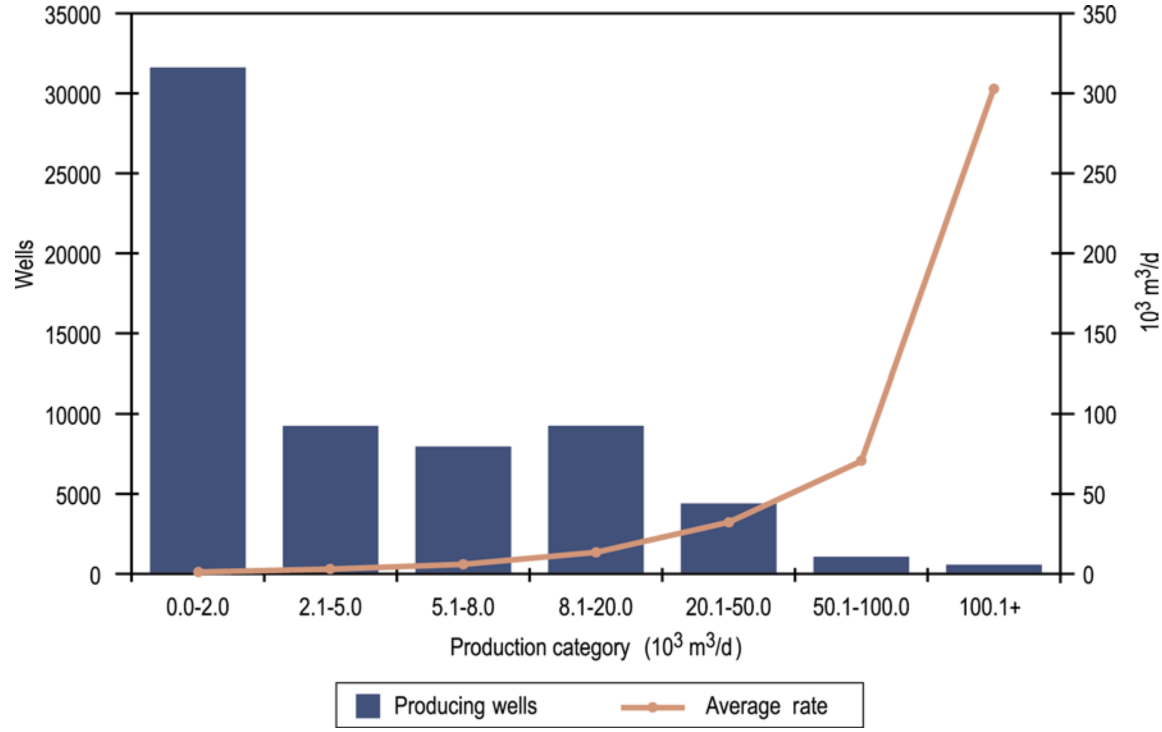


Figure 4.17. Natural gas well productivity in 2001

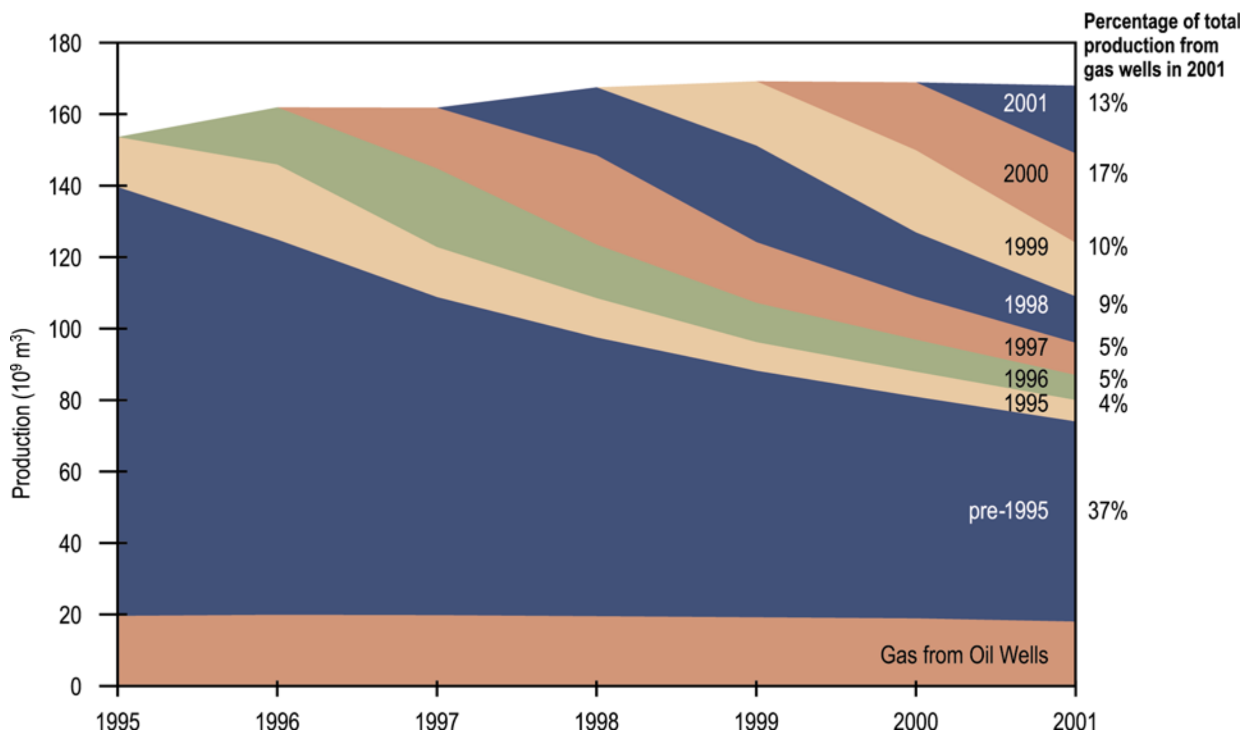


Figure 4.18. Raw gas production by connection year

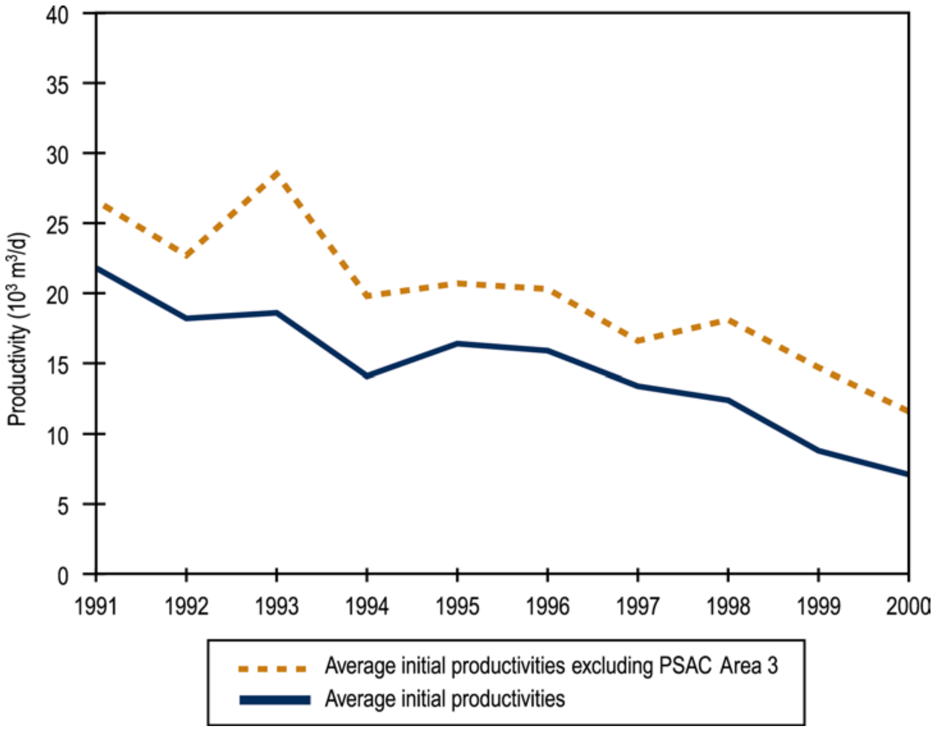


Figure 4.19. Average initial gas well productivity in Alberta

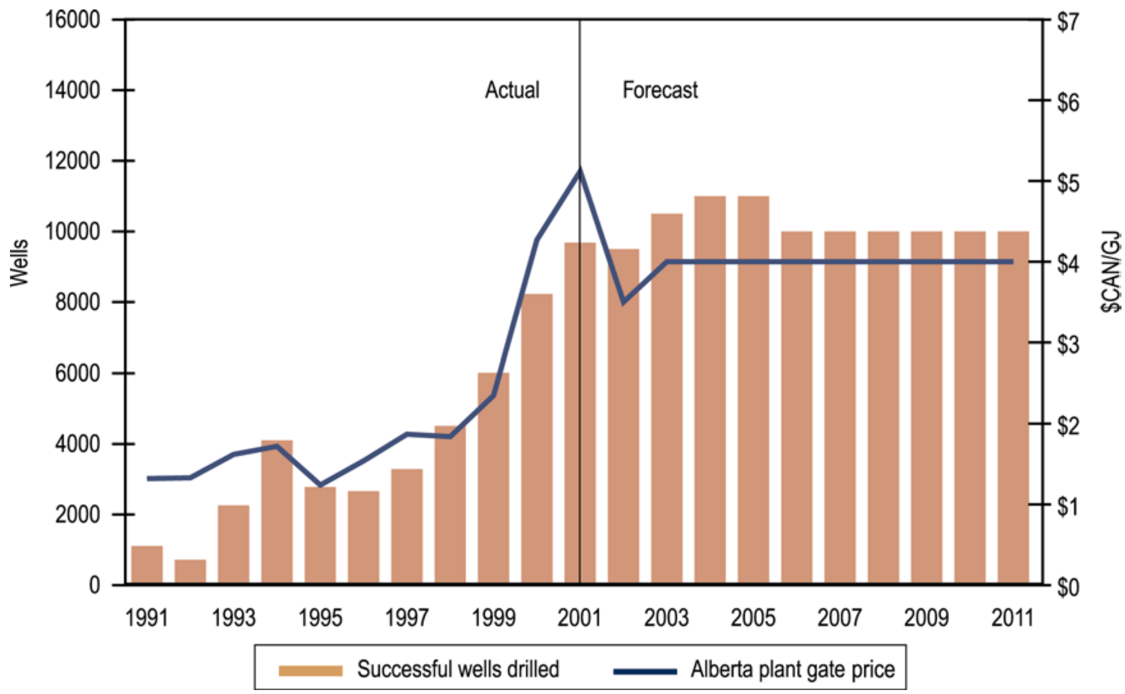


Figure 4.20. Alberta natural gas drilling activity and price

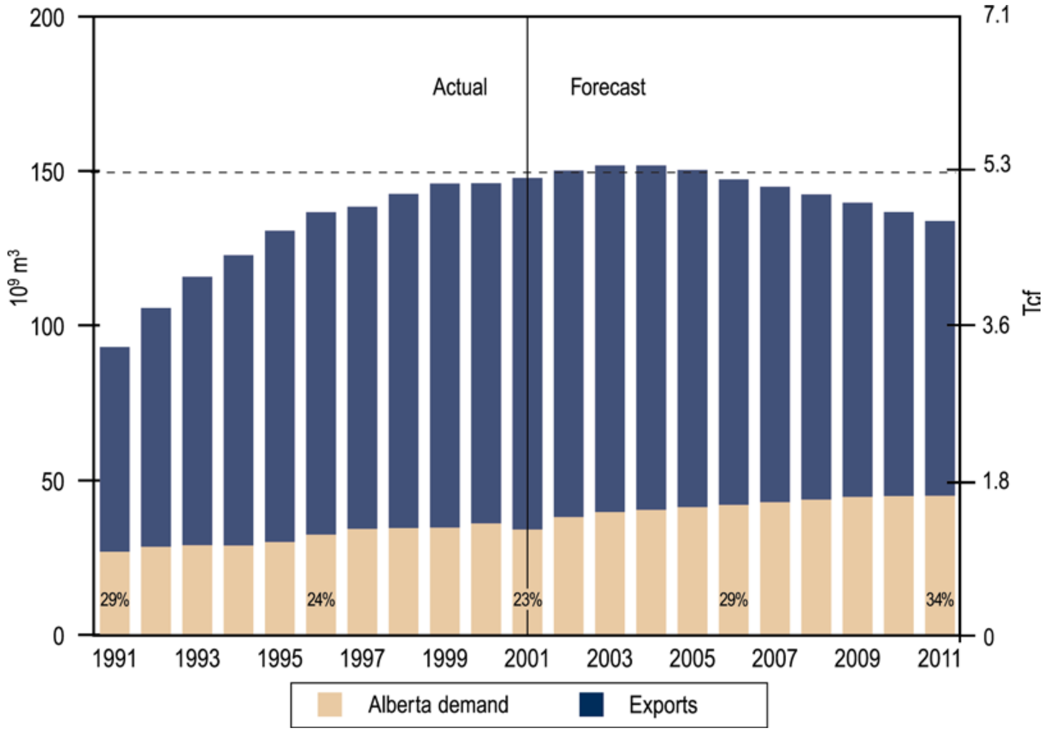


Figure 4.21. Disposition of marketable gas production

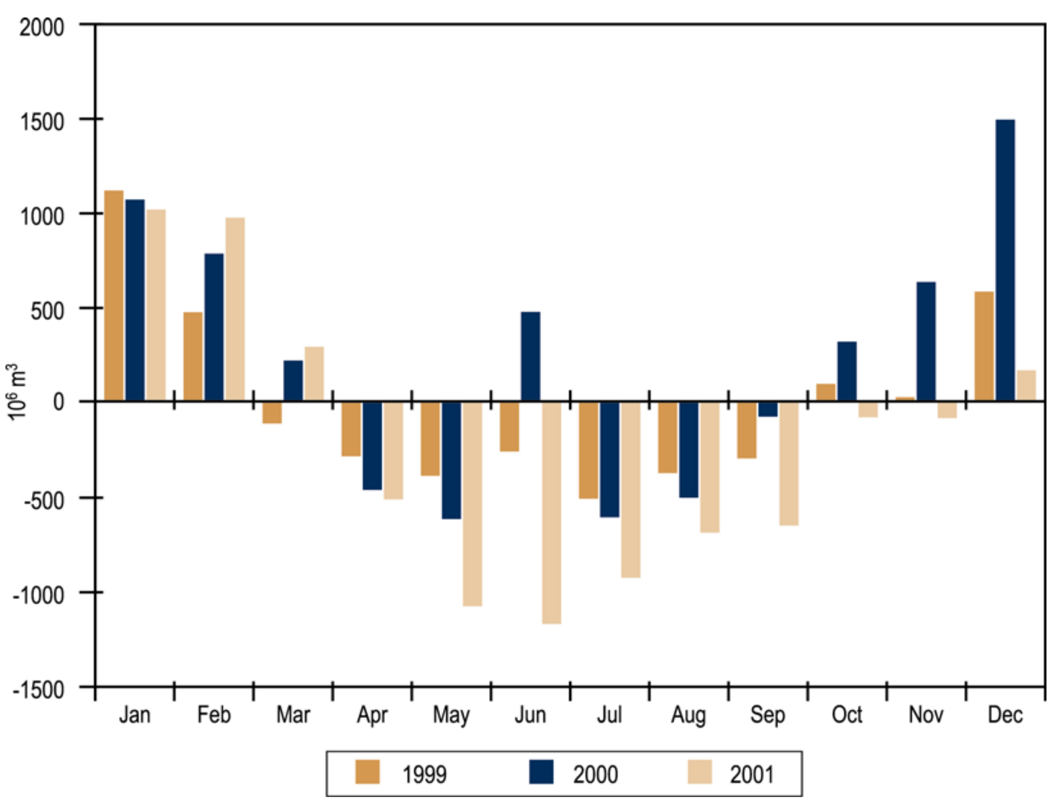


Figure 4.22. Alberta natural gas storage injection/withdrawal volumes

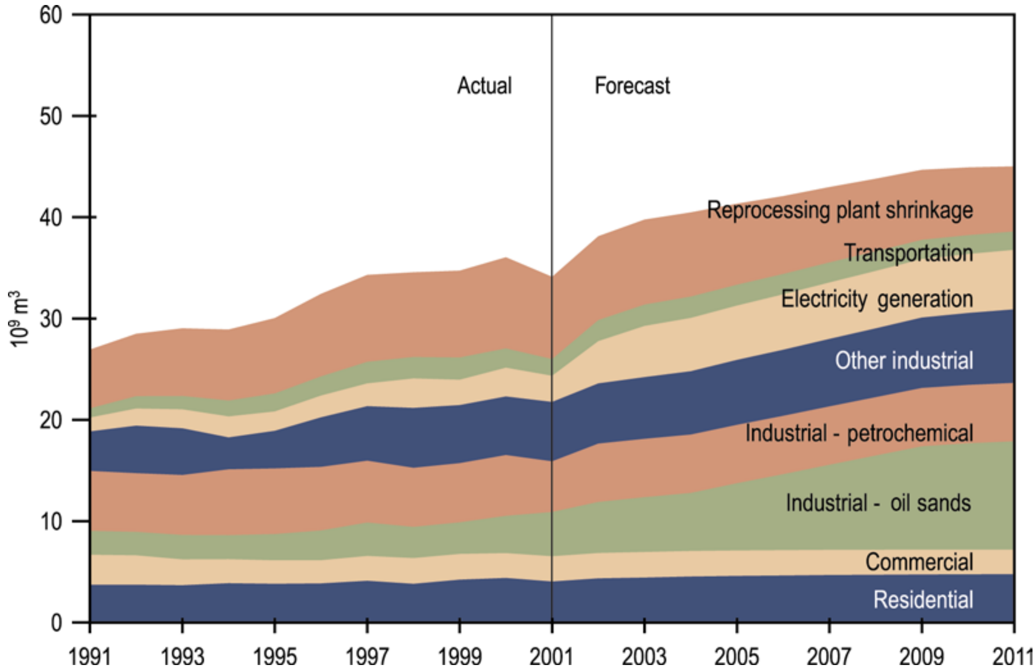


Figure 4.23. Alberta gas demand by sector

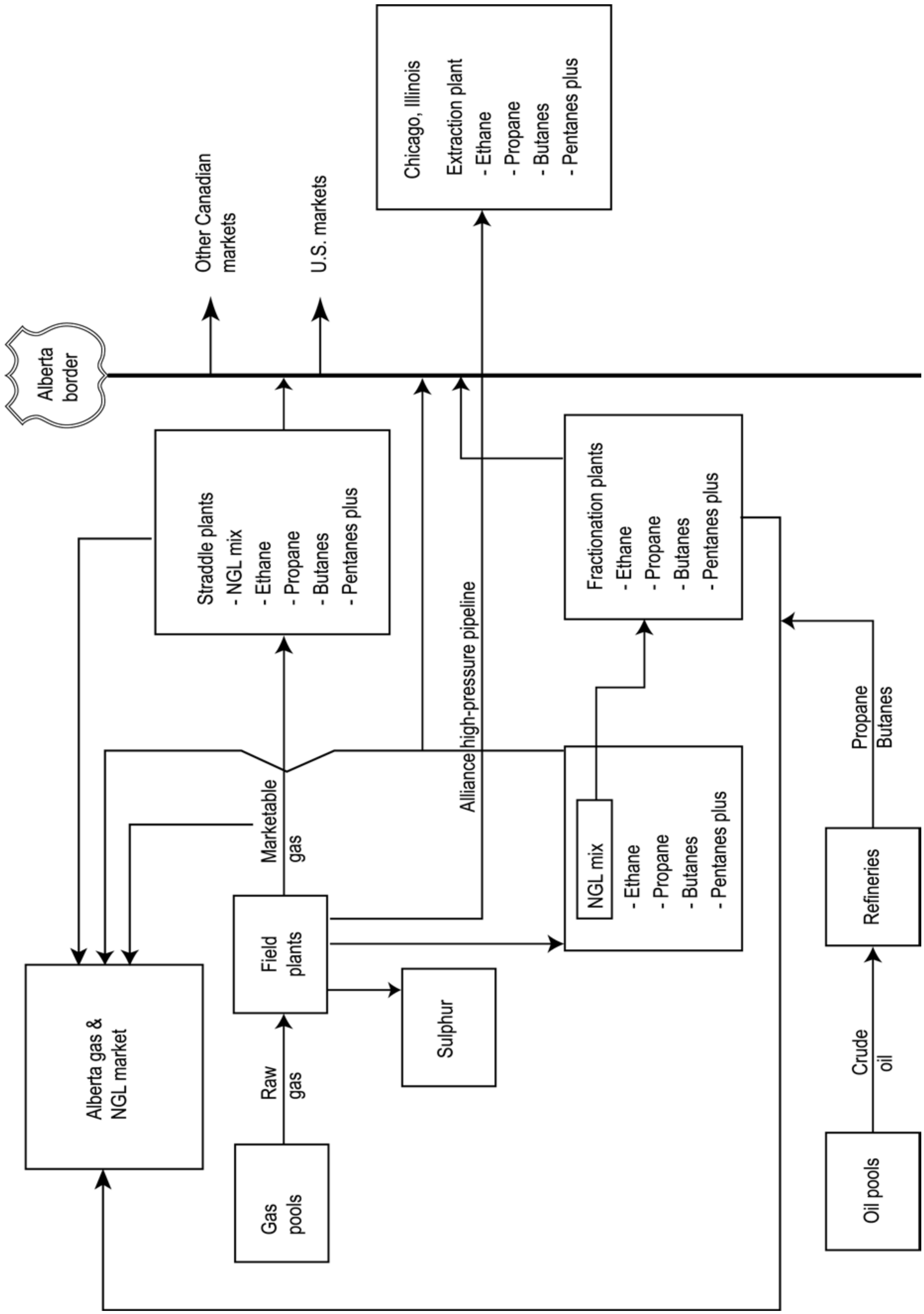


Figure 4.24. Schematic of Alberta NGL flows

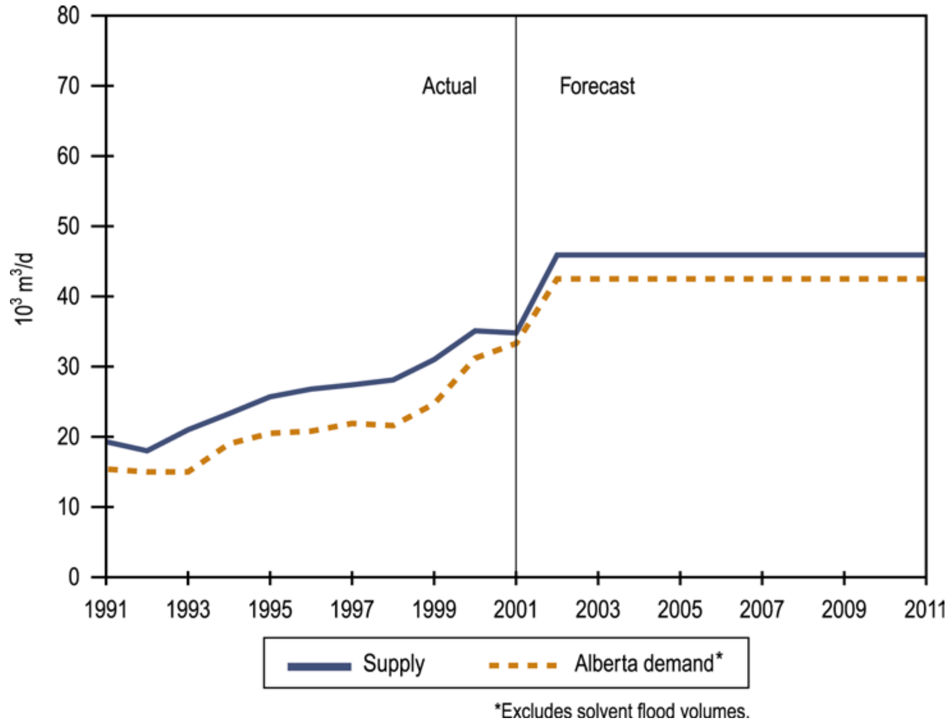


Figure 4.25. Liquid ethane supply and demand from natural gas

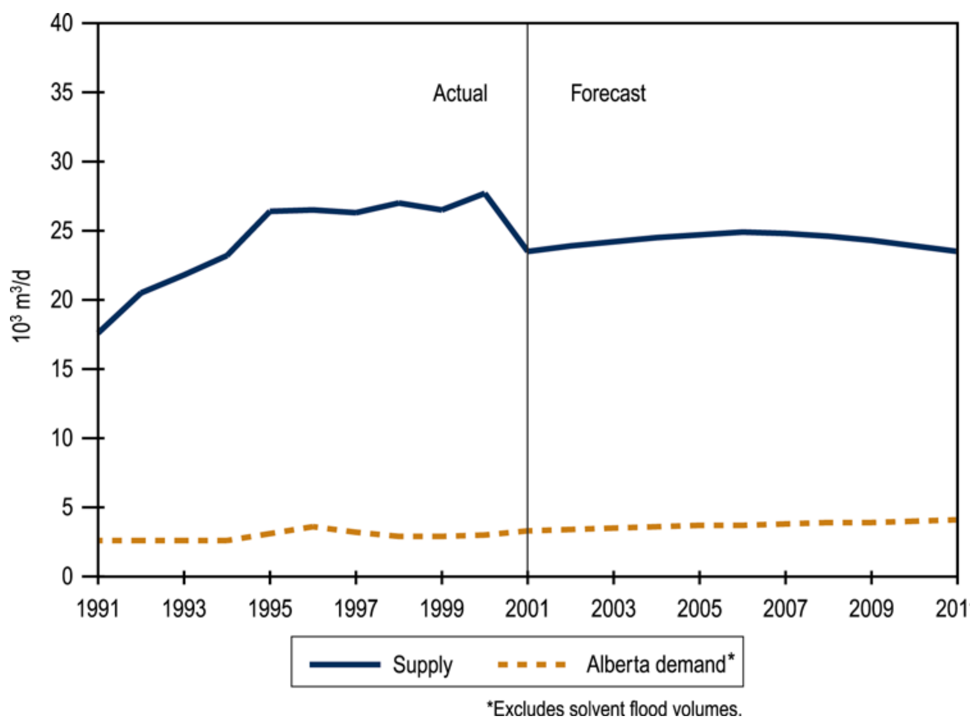


Figure 4.26. Propane supply and demand from natural gas

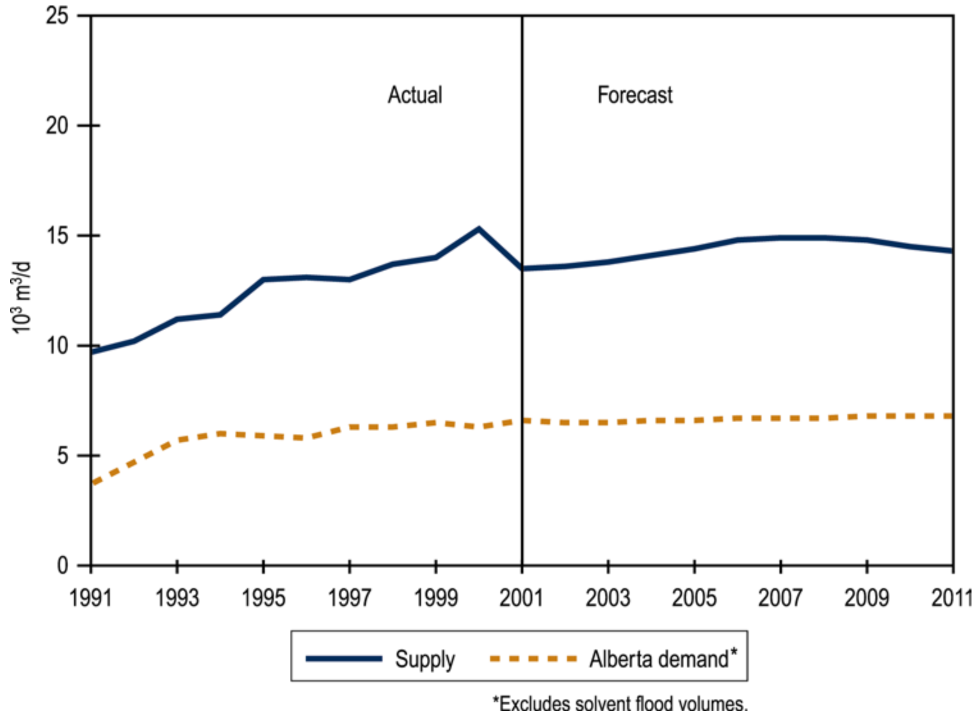


Figure 4.27. Butanes supply and demand from natural gas

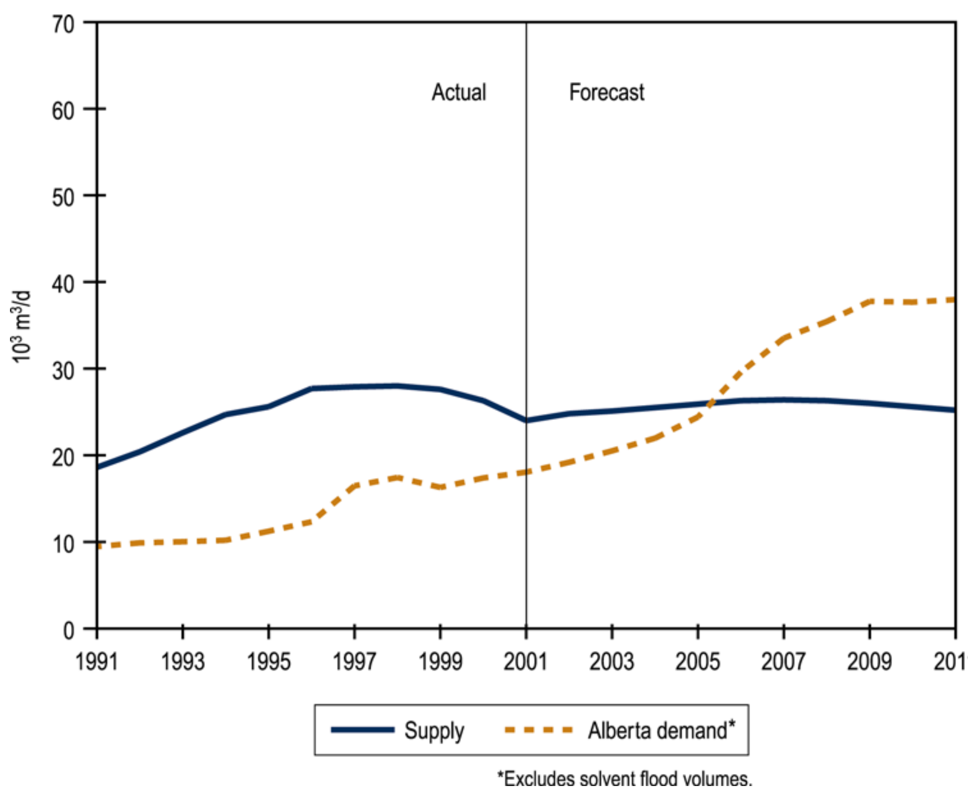


Figure 4.28. Pentanes plus supply and demand from natural gas

5 Coal

5.1 Reserves of Coal

5.1.1 Provincial Summary

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.

The significant amount of data generated in the exploration for coal has been used by the EUB to estimate coal reserves throughout the province. The EUB currently estimates that Alberta's established initial in-place resources of all types of coal total about 94 gigatonnes (Gt).[1] Of this amount, about 34 Gt, or approximately 36 per cent, are considered remaining to be recovered (by surface and underground methods), and of these reserves, 1.0 Gt are within permit boundaries of mines that were active in 2001. Table 5.1 gives a breakdown 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, 2001 (Gt)

Rank Classification	Initial in-place resources	Cumulative production	Remaining reserves	Remaining reserves in active mines
Low- and medium-volatile bituminous[a]				
Surface	1.7	0.21	0.60	
Underground	5.1	0.10	0.62	
Subtotal[b]	6.8	0.32	1.22	0.05
High-volatile bituminous				
Surface	2.6	0.13	1.80	
Underground	3.3	0.05	0.91	
Subtotal[b]	5.9	0.18	2.71	0.17
Subbituminous[c]				
Surface	14	0.57	8.4	
Underground	67	0.07	21	
Subtotal[b]	81	0.64	30	0.81
Total[b]	94	1.14	34	1.0

[a] Includes minor amounts of semi-anthracite.
[b] Totals are not arithmetic sums but are the result of separate determinations.
[c] Includes minor lignite.

Minor changes in remaining established reserves from December 31, 2000, to December 31, 2001, resulted from increases in cumulative production. During 2001 the low- and medium-volatile, high-volatile, and subbituminous production were 0.004 Gt, 0.005 Gt, and 0.024 Gt respectively.

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

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 reasons and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal, as well as the thicker underground classes.

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

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been allowed for where, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region,[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 - 3.6 m) and thick (> 3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 - <1.5 m) are not considered recoverable by underground methods.

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

Table 5.2 shows the established resources and reserves within the current permit boundaries of those mines active in 2001. The large reduction in low- and medium-volatile bituminous reserves is due to the closure of the Smoky River Mine in 2000.

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

Table 5.2. Established resources and reserves of coal under active development as of December 31, 2001

Rank Mine	Permit area (ha)	Initial in-place resources (10^6 t)	Initial reserve (10^6 t)	Cumulative production (10^6 t)	Remaining reserves[a] (10^6 t)
Low- and medium-volatile bituminous					
Gregg River[b]	3 540	103	62	46	16
Luscar	5 050	32	130	94	36
Subtotal[a]	8 590	435	192	141	52
High-volatile bituminous					
Coal Valley[c]	6 400	349	167	95	72
Obed	7 590	162	137	38	99
Subtotal	13 990	511	304	133	171
Subbituminous					
Vesta	2 410	69	54	35	19
Paintearth	2 710	94	67	35	32
Sheerness	7 000	196	150	51	99
Dodds	140	2	2	1	1
Whitewood[c]	2 800	163	98	69	29
Highvale	12 140	1 021	764	275	489
Genesee	7 320	250	176	36	140
Subtotal[a]	34 520	1 795	1 311	502	808
Total	57 100	2 741	1 807	776	1 031

[a] Differences are due to rounding.
[b] Limited operations in 2001.
[c] Does not include area of expansion approved in 2001.

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 *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 Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is the type 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. Historical and forecast Alberta coal production for each of the three types of marketable coal are shown in **Figure 5.1**.

5.2.1 Coal Supply

In 2001, Alberta sold 30.6 10^6 t of marketable coal. Subbituminous coal accounted for 80.4 per cent of the total, bituminous metallurgical was 9.6 per cent, and bituminous thermal coal constituted the remaining 10 per cent.

In the same year, ten mine sites supplied coal in Alberta, as shown in Table 5.4. Five large mines and a very small one 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. Two operators, however, received regulatory approval in 2001/2002 for three new coal-fired generating units, which are slated for commissioning in 2005 and 2006. In all cases the fuel would be subbituminous coal.

Alberta's only operating preparation plant producing clean metallurgical coal for export is at the Luscar Mine, which is slated for closure due to the exhaustion of coal reserves expected in late 2004 or early 2005. Meanwhile, other operators have proposed to begin mining in the vicinity of the defunct Smoky River Mine, to supply coal to the H.R. Milner Power Plant or to produce export grade metallurgical coal. The proposed Cheviot Mine, which has obtained regulatory approvals, is incorporated in the forecast; it is assumed that operation will start in 2005.

Although metallurgical grade coal underlies much of the mountain region, very few areas have been sufficiently explored to identify recoverable reserves. Without higher, stable prices, it is unlikely that any additional mines, other than the proposed Cheviot Mine, will come on stream over the next decade.

The two producing thermal bituminous coal mines have been shipping coal to export markets and have recently resumed shipments to Ontario. In addition, some coal from the Obed Mountain mine has been sent to the H.R. Milner power plant to make up for coal supply lost due to the closure of the Smoky River mine. Substantial reserves exist in areas that have been permitted for mining but have not been brought into production.

Table 5.4. Alberta coal mines and marketable coal production in 2001

Company (grouped by coal type)	Mine	Location	Production in 2001 (10^6 t)
Subbituminous coal			
Epcor Generation Inc.	Genesee	Genesee	3.5
Luscar Ltd.	Sheerness	Sheerness	3.6
	Paintearth	Halkirk	3.2
TransAlta Utilities Corp.	Highvale	Wabamun	11.6
	Whitewood	Wabamun	2.1
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.04
Bituminous metallurgical coal			
Cardinal River Coals Ltd.	Luscar	Luscar	2.9
Luscar Ltd.	Gregg River[a]	Gregg River	-
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.6
	Obed Mtn.	Hinton	1.4

[a] Limited operations in 2001.

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 in the middle part 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 in Japan. While prices of both thermal and metallurgical coal entering international markets have been rising in recent months, no production from export mines, except for the proposed Cheviot Mine, has been assumed in this forecast. The Cheviot Mine is expected to begin production in 2005 but is likely contingent on securing long-term contracts for its output. Alberta's export coal producers, as always, have the competitive disadvantage of long distances from mine to port.

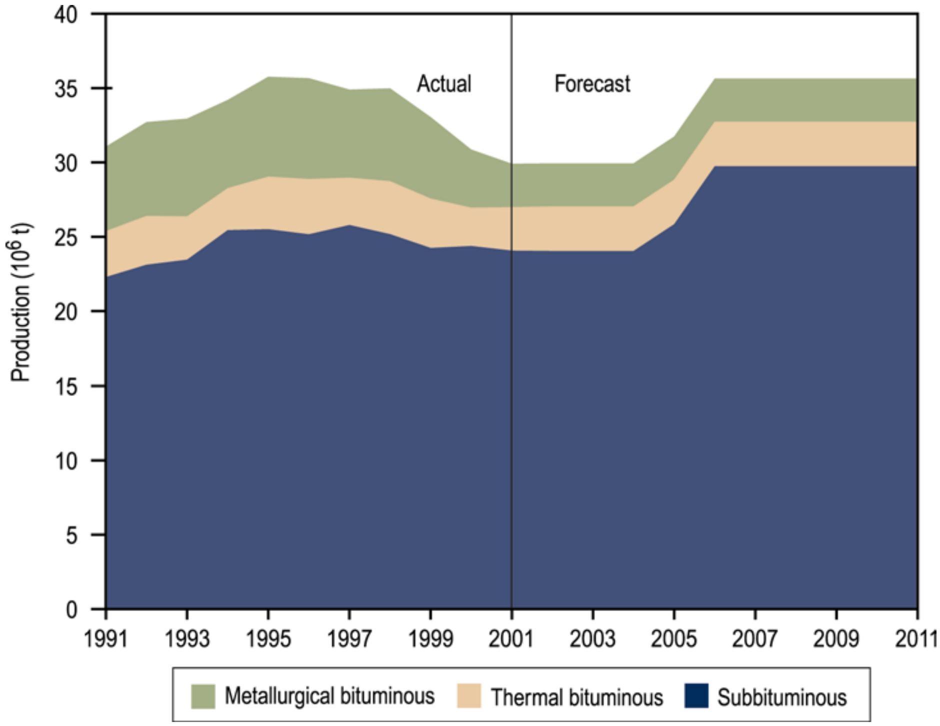


Figure 5.1. Alberta marketable coal production

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, 2001, to be some 93.8 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, 2001 (10^6 t)

	2001	2000	Change
Initial established reserves			
Natural gas	240.0	237.5	+2.5
Crude bitumen[a]	67.7	67.7	0.0
Total	307.7	305.2	+2.5
Cumulative net production			
Natural gas	201.5	195.4	+6.1
Crude bitumen[b]	12.4	11.8	+0.6
Total	213.9	207.2	+6.7
Remaining established reserves			
Natural gas	38.5	42.1	-3.6
Crude bitumen[a]	55.3	55.9	-0.6
Total	93.8	98.0	-4.2

[a] Recoverable reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2001.
[b] Production from surface mineable area only.

6.1.2 Sulphur from Natural Gas

The EUB recognizes 38.5 10^6 t of remaining established sulphur from natural gas reserves at year-end 2001. This estimate from gas has been prepared by applying the appropriate hydrogen sulphide (H_2S) content and sulphur recovery efficiency to the remaining established reserves of raw gas in each pool. Where sulphur is currently being recovered, actual recovery efficiencies have been used. Where sulphur recovery is anticipated from gas reserves not yet being produced, the recovery efficiency has been estimated on the basis of the minimum sulphur recovery efficiency guidelines published in EUB *Interim Directive (ID) 2001-03:Sulphur Recovery Guidelines for the Province of Alberta*. The remaining established reserves of sulphur for cycling schemes were determined from an assessment of each pool, but because the H_2S content in the gas changes with time, only the remaining sulphur reserves are reported. The EUB estimates the ultimate potential for sulphur from natural gas to be 330 10^6 t and from ultra-high H_2S pools to be 40 10^6 t. This leaves sulphur reserves of 130 10^6 t yet to be established from future discoveries of conventional gas.

The EUB's sulphur reserve estimates from natural gas are shown in Table 6.2. Fields containing 800 thousand tonnes (10^3 t) or more of recoverable sulphur are listed individually and those containing less are grouped under other small reserves. For historical reasons, some fields now containing less than 800 10^3 t of recoverable sulphur have also been included in this table. Sulphur reserves declined most notably in the Caroline and Waterton fields as a result of production.

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 211 10^6 t of elemental sulphur will be recoverable from the 5.2 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. In 1989, 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.

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 approved 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 12.4 10^6 t of elemental sulphur has been produced from these projects, leaving a remaining established reserve of 55.3 10^6 t. During 2001, 0.6 10^6 t of elemental sulphur were produced at the Suncor and Syncrude projects; the Albian Sands project is still to come on stream.

Table 6.2. Remaining established reserves of sulphur from natural gas as of December 31, 2001

Field	Zone	Remaining established reserves of raw gas (10^6 m^3)	H_2S content[a] (mol/mol)	Recovery efficiency[b] (%)	Remaining established reserves of sulphur (10^3 t)
Benjamin	Mississippian	5 676	0.047	99	355
	Subtotal				355
Blackstone	Beaverhill Lake	5 440	0.107	98	775
	Subtotal				775
Brazeau River	Mississippian	1 362	0.010	99	18
	Nisku[c]	-	-	-	1 465
	Subtotal				1 483
Burmis	Mississippian	7 020	0.09	98	844
	Wabamun	421	0.118	95	64
	Subtotal				908
Caroline	Mississippian	1 100	0.012	99	18
	Leduc	140	0.068	100[c]	13
	Beaverhill Lake	22 826	0.365	100[c]	11 303
	Subtotal				11 334
Coleman	Mississippian	1 146	0.279	99	429
	Wabamun	427	0.279	99	160
	Subtotal				589
Crossfield	Belly River	42	0.108	98	6
	Mannville	1 315	0.010	98	17
	Jurassic	90	0.009	92	1
	Mississippian	1 776	0.005	99	11
	Wabamun	3 402	0.315	98	1 422
	Subtotal				1 457
Crossfield East	Mannville	233	0.003	98	1
	Wabamun	396	0.350	99	186
	Subtotal				187
Gold Creek	Mississippian	149	0.015	98	3
	Wabamun	4 975	0.088	98	579
	Subtotal				582
Hanlan	Winterburn	207	0.053	95	14
	Beaverhill Lake	9 550	0.092	99	1 147
	Subtotal				1 188
Jumping Pound West	Mississippian	9 593	0.062	97	779
	Subtotal				779

(continued)

Table 6.2. Remaining established reserves of sulphur from natural gas as of December 31, 2001 (concluded)

Field	Zone	Remaining established reserves of raw gas (10^6 m^3)	H_2S content[a] (mol/mol)	Recovery efficiency[b] (%)	Remaining established reserves of sulphur (10^3 t)
Kaybob South	Triassic	1 211	0.007	99	12
	Winterburn	876	0.192	99	226
	Leduc	159	0.136	99	29
	Beaverhill Lake[c]	-	-	-	647
	Subtotal				914
Limestone	Mississippian	4 397	0.051	99	301
	Wabamun	1 347	0.183	99	330
	Winterburn	136	0.121	99	22
	Leduc	512	0.192	99	132
	Subtotal				785
Moose	Mississippian	3 037	0.137	99	558
	Wabamun	351	0.329	99	155
	Subtotal				713
Okotoks	Mannville	62	0.012	99	1
	Mississippian	54	0.014	99	1
	Wabamun	1 268	0.322	99	548
	Subtotal				550
Pine Creek	Jurassic	249	0.003	99	1
	Mississippian	300	0.023	98	9
	Wabamun	1 050	0.277	99	390
	Leduc	1 032	0.210	99	291
	Beaverhill Lake	500	0.187	98	124
	Subtotal				815
Ricinus	Leduc	684	0.305	99	280
	Subtotal				280
Ricinus West	Winterburn	109	0.007	99	1
	Leduc	1 720	0.332	99	767
	Subtotal				768
Waterton	Mississippian	6 101	0.205	99	1 678
	Wabamun	506	0.186	99	11
	Rundle-Wabamun[c]	-	-	-	544
	Subtotal				2 233
Subtotal					26 695
Other small reserves					11 777
Total reserves					38 472

[a] Volume-weighted average.
[b] All recovery efficiencies are rounded to the nearest whole percentage point.
[c] Includes gas-cycling pool. Gas reserves are calculated on an energy basis. H_2S content is not included because of gas composition changing with time.

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 2001, Alberta produced 6.9 10^6 t of sulphur, of which 6.1 10^6 t was derived from sour gas, 0.8 10^6 t from upgrading of bitumen to SCO, and just 10 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 increase to 8.0 $10^6$from 6.2 10^3 in 2001, sulphur recovery in bitumen upgrading will increase fourfold to 3.2 10^3 by the end of the forecast period. No significant change is expected in sulphur recovery at refineries.

6.2.2 Sulphur Demand

Demand for sulphur within the province in 2001 was only about 0.3 10^6 t. It was used in production of phosphate fertilizer and kraft pulp and in other chemical operations. Some 96 per cent of the sulphur marketed by Alberta producers was shipped outside the province, primarily to Florida, Asia, 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. Demand for Alberta sulphur, both domestic and export, is expected to rise slowly, levelling off at 7.5 10^6 t per year. **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 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.

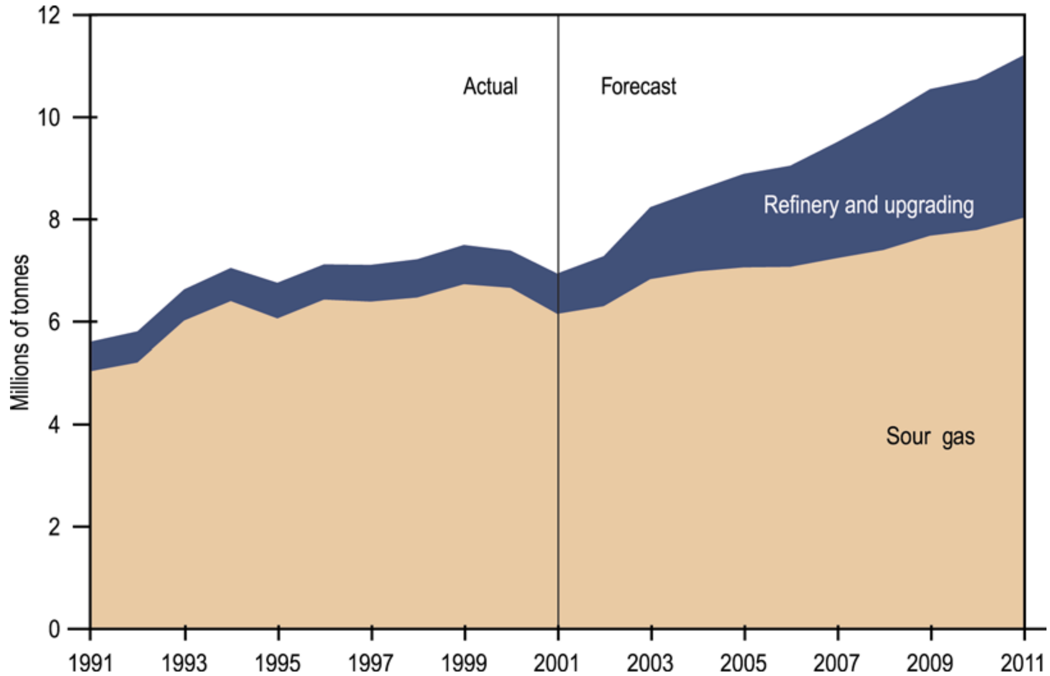


Figure 6.1. Sources of Alberta sulphur production

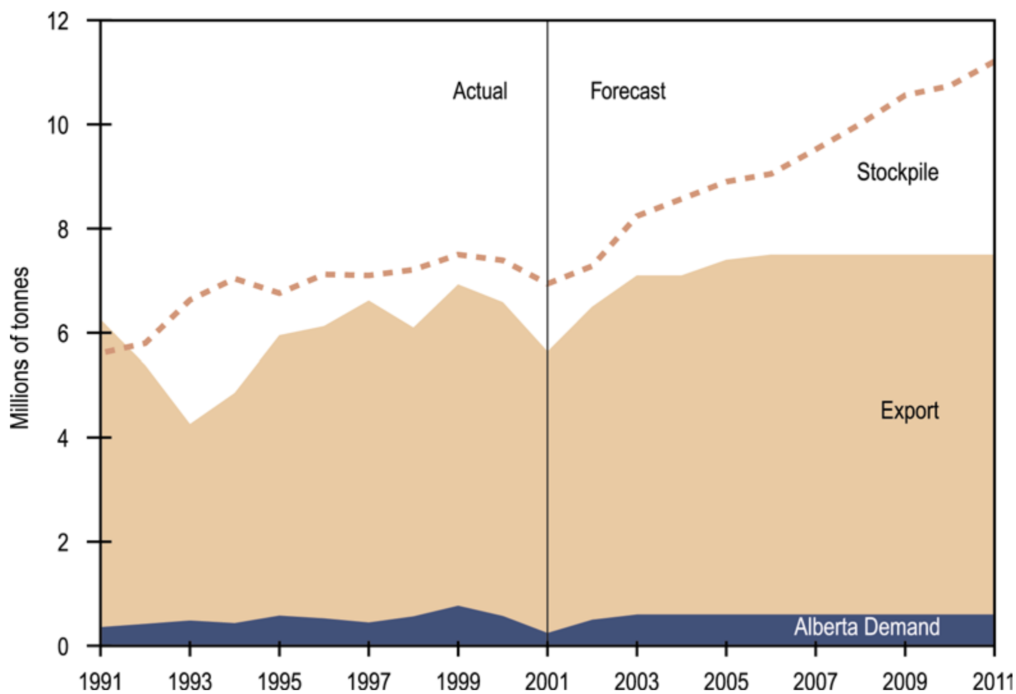


Figure 6.2. Alberta sulphur production and demand

Appendix 1 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)).
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 sulfide, 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	Gas in a free state in communication in a reservoir with crude oil

under

(Associated)	initial reservoir conditions.
Gas	A mixture mainly of methane originating from raw gas, or if necessary
(Marketable)	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	A gas processing plant 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 one 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.
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	stb	stock-tank barrel

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 pressure and 15°C)	=	6.3000 Canadian barrels of propane (equilibrium (equilibrium pressure and 60°F)
1 m^3 of butanes pressure and 15°C)	=	6.2968 Canadian barrels of butanes (equilibrium (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus pressure and 15°C)	=	6.2929 Canadian barrels of oil or pentanes (equilibrium plus (equilibrium pressure and 60°F)
1 m^3 of water and 15°C)	=	6.2901 Canadian barrels of water (equilibrium pressure (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 2 Pools and Natural Gas Liquids

2-1. Reserves of retrograde pools, 2001

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	1 129	74.17	83	0.75	0.60	25	42.15	596
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	10 941	55.68	609	0.90	0.39	334	41.65	8 030
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	85 254	48.74[a]	4 155	0.78	0.35	2 107	41.09	51 271
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.

2-2. Reserves of multifield pools, 2001

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Edmonton Pool No. 1	
Bashaw Edmonton D	228
Nevis Edmonton D	796
Total	1 024
Belly River Pool No. 1	
Bashaw Belly River C, H, L, M & Q	2 698
Nevis Belly River C	1 124
Total	3 822
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	1 479
Gadsby Belly River J	1 782
Total	3 284
Belly River Pool No. 4	
Michichi Belly River B & G	144
Watts Belly River B & I	77
Total	221
Southeastern Alberta Gas System (MU)	
Alderson Milk River, Medicine Hat, Second White Specks and Colorado	43 767
Atlee-Buffalo Milk River, Medicine Hat and Second White Specks	5 000
Bantry Milk River, Medicine Hat and Second White Specks	24 912
Bassano Milk River, Medicine Hat and Second White Specks	614
Berry Medicine Hat	81
Bindloss Milk River and Medicine Hat	497
Blackfoot Medicine Hat and Belly River	1 003
Bow Island Milk River and Second White Specks	20
Brooks Milk River, Medicine Hat and Second White Specks	852
Cavalier Belly River	198
Cessford Milk River, Medicine Hat, Second White Specks and Belly River	11 264
Connorsville Milk River, Medicine Hat and Belly River	1 865
Countess Milk River, Medicine Hat, Second White Specks and Belly River	15 709
Drumheller Medicine Hat	162
Estuary Medicine Hat and Belly River	1 539
Eyremore Milk River, Medicine Hat and Second White Specks	1 034
Farrow Medicine Hat and Belly River	2 046
Gleichen Medicine Hat and Belly River	2 694
Hussar Milk River, Medicine Hat and Belly River	4 592
Jenner Milk River, Medicine Hat and Second White Specks	731
Johnson Milk River, Medicine Hat and Second White Specks	447
Kitsim Milk River, Medicine Hat and Second White Specks	282
Lathom Milk River and Medicine Hat	427
Leckie Milk River, Medicine Hat and Second White Specks	386
Matziwin Milk River, Medicine Hat and Second White Specks	3 130
Medicine Hat Milk River, Medicine Hat, Second White Specks and Colorado	125 238
Newell Milk River, Medicine Hat and Second White Specks	1 397
Princess Milk River, Medicine Hat, Second White Specks and Belly River	24 900
Rainier Milk River, Medicine Hat and Second White Specks	558
Seiu Lake Medicine Hat	540
Shouldice Medicine Hat and Belly River	1 429
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	61 927
Verger Milk River, Medicine Hat, Belly River and Second White Specks	15 354
Wayne-Rosedale Medicine Hat	807
Wintering Hills Milk River, Medicine Hat and Second White Specks	4 262
Total	359 664
Second White Specks Pool No. 2	
Garden Plains Second White Specks E	1 167
Hanna Second White Specks E	331
Provost Second White Specks E	289
Richdale Second White Specks E & Viking E	150
Sullivan Lake Second White Specks E	101
Total	2 038

(continued)

2-2. Reserves of multifield pools, 2001 (continued)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Second White Specks Pool No. 3	
Conrad Second White Specks J	186
Forest Second White Specks J	130
Pendant D'Oreille Second White Specks J	494
Smith Coulee Second White Specks J	904
Total	1 714
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	830
Westlock Middle Viking B	381
Total	4 821
Viking Pool No. 2	
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	5083
Bellshill Lake Upper and Middle Viking A	184
Birch Upper and Middle Viking A	83
Bruce Upper, Middle & Lower Viking A, Upper Mannville Z & G4G, and Ellerslie W, JJJ, KKK, LLL & MMM	3 463
Dinant Upper and Middle Viking A	21
Fort Saskatchewan Upper and Middle Viking A	8119
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	68
Viking-Kinsella Upper and Middle Viking A, Upper Mannville YY, CCC, LLL, MMM, ZZZ, H2H & M2M, Colony G, G2G & N2N, Glauconitic J, and Wabamun I	29 113
Wainwright Upper and Middle Viking A, and Colony G, R, V, & W	1 786
Total	52 024
Viking Pool No. 3	
Carbon Belly River B and Viking D	1 872
Ghost Pine Viking D	295
Total	2 167
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	228
Total	418
Viking Pool No. 7	
Inland Upper Viking C & E, Middle Viking F, G, & I, and Upper Mannville A	409
Royal Upper Viking C and Lower Viking A	43
Total	452
Viking Pool No. 13	
Chigwell Viking G	218
Nelson Viking G	157
Total	375
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 Glauconitic A & Lower Mannville W	1 188
Total	2 628
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	1 238
Pembina Glauconitic I & D and Ostracod C	3 348
Total	4 586

(continued)

2-2. Reserves of multi-field pools, 2001 (concluded)

Multifield pool / Field and pool	Initial established reserves (10^6 m^3)
Glauconitic Pool No. 6	
Bassano Glauconitic III	432
Countess Bow Island MM and Glauconitic III	2 023
Hussar Viking L, Glauconitic III, and Ostracod OO	1 152
Wintering Hills Glauconitic III and Lower Mannville W	17
Total	3 624
Bluesky Pool No.1	
Rainbow Bluesky C	1 068
Sousa Bluesky C	886
Total	1 954
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	2 024
Hotchkiss Bluesky-Detrital-Debolt A	4 959
Total	6 983
Gething Pool No. 1	
Fox Creek Viking C, Notikewin C and Gething D & H	2 470
Kaybob South Gething H	632
Total	3 102
Ellerslie Pool No. 1	
Connorsville Glauconitic A, B, C, E & I and Ellerslie A	3 240
Wintering Hills Upper Mannville A and Ellerslie A	2 016
Total	5 256
Cadomin Pool No. 1	
Elmworth Dunvegan A	366
Elmworth Dunvegan I	62
Elmworth Dunvegan T	20
Elmworth Cadotte A	2 817
Elmworth Cadotte D	525
Elmworth Cadotte F	60
Elmworth Cadotte G	37
Elmworth Cadotte I	57
Elmworth Cadotte J	229
Elmworth Cadotte K	22
Elmworth Cadotte M	17
Elmworth Cadotte N	44
Elmworth Cadotte T	176
Elmworth Falher A-1	6 996
Elmworth Falher A-2	1 729
Elmworth Falher A-4	218
Elmworth Falher A-5	222
Elmworth Falher A-7	132
Elmworth Falher A-10	6 360
Elmworth Falher A-16	86
Elmworth Falher A-21	58
Elmworth Falher A-40	30
Elmworth Falher A-43	56
Elmworth Falher B-1	2 194
Elmworth Falher B-2	604
Elmworth Falher B-3	2 819
Elmworth Falher B-4	3 037
Elmworth Falher B-9	1 041
Elmworth Falher B-13	46
Elmworth Falher B-14	119
Elmworth Falher B-15	210
Elmworth Falher B-16	126
Elmworth Falher C-2	36
Elmworth Falher C-3	27
Elmworth Falher D-2	652
Elmworth Falher D-3	20
Elmworth Falher D-5	25
Elmworth Falher D-6	43
Elmworth Bluesky A	104
Elmworth Gething A	22
Elmworth Cadomin A	4 926
Sinclair Notikewin A, B, & C, Falher A and Cadomin A	7 055
Total	43 425
Halfway Pool No. 1	
Valhalla Halfway B	4 572
Wembley Halfway B	4 133
Total	8 705
Halfway Pool No. 2	
Knopcik Halfway N	638
Valhalla Halfway N	115
Total	753
Banff Pool No. 1	
Haro Banff E	87
Rainbow South Banff E	78
Total	165

2-3. Remaining established reserves of natural gas liquids as of December 31, 2001

Field	Zone	2 Remaining reserves of marketable gas (10^6 m^3)	3 Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas) Propane	4 Butanes	5 Pentanes plus	6 Remaining established reserves of natural gas liquids (10^3 m^3) Propane	7 Butanes	8 Pentanes plus	9 Total
Ansell	Belly River	170	59	24	59	10	4	10	24
	Cardium	3 217	35	64	236	113	206	758	1 077
	Viking	712	15	24	96	11	17	68	96
	Mannville	1 545	14	16	76	21	24	117	162
	Other	148	-	6	74	-	1	11	12
	Subtotal					155	252	964	1 371
Bonnie Glen	Mannville	324	83	52	46	27	17	15	59
	Leduc[a]	3 397	-	-	-	547	300	653	1 500
	Other	100	20	50	30	2	5	3	10
	Subtotal					576	322	671	1 569
Brazeau River	Belly River	1 834	111	53	70	204	98	129	431
	Cardium	541	15	7	142	8	4	77	89
	Mannville	1 487	69	34	328	102	51	487	640
	Jurassic	2 433	150	80	305	366	194	743	1 303
	Rundle	1 375	1	1	111	2	1	152	155
	Winterburn[a]	4 422	-	-	-	1 471	837	2 291	4 599
	Subtotal					2 153	1 185	3 879	7 217
Caroline	Cardium	1 147	158	78	132	181	89	151	421
	Mannville	3 309	147	75	136	488	248	451	1 187
	Viking	352	99	48	37	35	17	13	65
	Rundle	1 221	140	71	90	171	87	110	368
	Beaverhill Lake	7 637	583	658	1 717	4 456	5 027	13 111	22 594
	Other	209	33	19	28	7	4	6	17
	Subtotal					5 338	5 472	13 842	24 652
Carrot Creek	Cardium	176	148	108	722	26	19	127	172
	Viking	718	19	19	54	14	14	39	67
	Mannville	1 575	75	64	69	118	101	108	327
	Jurassic	1 904	64	49	77	121	94	146	361
	Subtotal					279	228	420	927
Cranberry	Beaverhill Lake	2 278	65	67	207	149	153	471	773
	Middle Devonian	153	13	20	39	2	3	6	11
	Subtotal					151	156	477	784
Crossfield	Viking	118	93	76	59	11	9	7	27
	Mannville	1 273	74	71	140	94	90	178	362
	Jurassic	115	52	113	96	6	13	11	30
	Mississippian[a]	1 619	-	-	-	50	88	106	244
	Wabamun	1 645	7	6	28	11	10	46	67
	Subtotal					172	210	348	730

(continued)

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing with time.

Dunvegan	Mannville	692	7	4	4	5	3	3	11

2.3. Remaining established reserves of natural gas liquids as of December 31, 2001

1		2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone		Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
	Triassic	455	57	31	31	26	14	14	54
	Rundle	8 154	66	39	85	537	320	697	1 554
	Wabamun	157	108	70	191	17	11	30	58
	Subtotal					585	348	744	1 677
Edson	Cardium	678	72	43	114	49	29	77	155
	Viking	654	18	12	101	12	8	66	86
	Mannville	2 476	40	24	136	100	60	337	497
	Jurassic	605	36	21	112	22	13	68	103
	Rundle	135	-	-	119	-	-	16	16
	Upper Devonian	354	-	-	189	-	-	67	67
	Subtotal					183	110	631	924
Elmworth	Second White Specks	1 126	107	50	52	120	56	58	234
	Lower Cretaceous	1 673	26	12	23	43	20	39	102
	Mannville	10 866	38	17	48	411	185	526	1 122
	Triassic	1 204	6	4	56	7	5	68	80
	Other	1 057	5	2	8	5	2	8	15
	Subtotal					586	268	699	1 553
Ferrier	Belly River	307	124	65	107	38	20	33	91
	Cardium	1 994	146	16	25	291	32	49	372
	Second White Specks	113	124	62	97	14	7	11	32
	Viking	355	121	51	56	43	18	20	81
	Mannville	5 221	114	54	74	593	281	387	1 261
	Jurassic	1 097	138	46	44	151	50	48	249
	Rundle	2 378	52	32	86	123	75	204	402
	Mississippian	210	24	24	33	5	5	7	17
	Subtotal					1 258	488	759	2 505
Garrington	Viking	280	82	50	111	23	14	31	68
	Mannville	2 852	145	77	80	413	219	229	861
	Jurassic	442	118	72	179	52	32	79	163
	Rundle	320	119	72	50	38	23	16	77
	Wabamun	1 448	52	80	135	76	116	196	388
	Leduc	1 335	97	69	172	130	92	230	452
	Subtotal					732	496	781	2 009
Gilby	Second White Specks	93	118	140	75	11	13	7	31
	Mannville	2 778	76	61	64	212	169	179	560
	Jurassic	1 253	69	97	68	86	122	85	293
	Rundle	1 876	47	67	76	89	125	142	356
	Wabamun	61	131	66	49	8	4	3	15
	Leduc	72	111	69	83	8	5	6	19
	Other	178	51	56	22	9	10	4	23
	Subtotal					423	448	426	1 297

(continued)

Gold Creek	Second White Specks	131	53	23	23	7	3	3	13
	Mannville	2 343	18	10	50	43	24	117	184

2-3. Remaining established reserves of natural gas liquids as of December 31, 2001

1		2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone		Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
	Triassic	1 522	53	28	59	81	42	90	213
	Wabamun	3 818	48	30	86	185	116	328	629
	Subtotal					316	185	538	1 039
Hamburg	Beaverhill Lake	4 760	15	17	183	70	82	873	1 025
	Other	384	3	3	26	1	1	10	12
	Subtotal					71	83	883	1 037
Harmattan East	Viking	81	86	99	74	7	8	6	21
	Mannville	213	211	131	188	45	28	40	113
	Jurassic	110	127	191	91	14	21	10	45
	Mississippian[a]	5 689	-	-	-	24	18	19	61
	Subtotal					90	75	75	240
Harmattan-Elkton	Mannville	113	230	62	53	26	7	6	39
	Mississippian[a]	5 126	-	-	-	290	24	99	413
	Subtotal					316	31	105	452
Hussar	Viking	471	19	13	28	9	6	13	28
	Mannville	4 088	73	45	79	297	185	321	803
	Rundle	94	96	53	53	9	5	5	19
	Subtotal					315	196	339	850
Judy Creek	Viking	499	36	24	54	18	12	27	57
	Mannville	157	57	25	19	9	4	3	16
	Rundle	243	41	21	21	10	5	5	20
	Beaverhill Lake	1 926	254	137	91	490	264	175	929
	Subtotal					527	285	210	1 022
Jumping Pound West	Rundle	7 674	76	69	222	585	529	1 702	2 816
	Subtotal					585	529	1 702	2 816
Kakwa	Cardium[a]	3 323	-	-	-	201	108	84	393
	Second White Specks	101	69	69	158	7	7	16	30
	Lower Cretaceous	116	95	60	17	11	7	2	20
	Mannville	223	49	31	36	11	7	8	26
	Jurassic	94	96	43	53	9	4	5	18
	Subtotal					239	133	115	487

(continued)

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing with time.

Karr	Cardium	63	127	63	48	8	4	3	15
	Second White Specks	787	123	56	43	97	44	34	175
	Mannville	4 544	141	79	121	641	360	552	1 553

2.3. Remaining established reserves of natural gas liquids as of December 31, 2001

	1	2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone		Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
	Jurassic	302	99	46	50	30	14	15	59
	Triassic	420	121	33	43	51	14	18	83
	Wabamun	995	51	36	38	51	36	38	125
	Beaverhill Lake	36	167	83	83	6	3	3	12
	Subtotal					884	475	663	2 022
Kaybob	Viking	431	9	12	65	4	5	28	37
	Mannville	2 879	14	13	44	41	38	126	205
	Beaverhill Lake[a]	795	-	-	-	210	209	350	769
	Other	175		6	69	-	1	12	13
	Subtotal					255	253	516	1 024
Kaybob South	Second White Specks	68	74	44	176	5	3	12	20
	Viking	441	36	32	50	16	14	22	52
	Mannville	8 765	68	42	72	595	365	632	1 592
	Jurassic	274	11	7	47	3	2	13	18
	Triassic	1 127	24	30	59	27	34	66	127
	Wabamun	110	109	64	55	12	7	6	25
	Upper Devonian	357	70	70	569	25	25	203	253
	Nisku	181	44	66	343	8	12	62	82
	Leduc	151	13	13	99	2	2	15	19
	Beaverhill Lake[a]	2 537	-	-	-	385	348	1 401	2 134
	Subtotal					1 078	812	2 432	4 322
Knopcik	Second White Specks	147	54	34	48	8	5	7	20
	Viking	199	40	35	90	8	7	18	33
	Mannville	636	13	9	30	8	6	19	33
	Jurassic	1 083	63	44	99	68	48	107	223
	Triassic	3 974	13	9	159	53	36	632	721
	Subtotal					145	102	783	1 030
McLeod	Cardium	1 604	102	60	92	164	96	148	408
	Mannville	3 403	72	47	121	245	159	412	816
	Jurassic	1 116	52	31	141	58	35	157	250
	Subtotal					467	290	717	1 474
Medicine River	Viking	63	190	79	79	12	5	5	22
	Mannville	2 635	104	71	57	275	187	149	611
	Jurassic	1 140	99	64	44	113	73	50	236
	Rundle	2 057	100	67	65	206	137	134	477
	Leduc	326	71	43	25	23	14	8	45
	Subtotal					629	416	346	1 391

(continued)

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing with time.

Minehead	Cardium	3 441	48	31	198	165	106	680	951
	Subtotal					165	106	680	951

2-3. Remaining established reserves of natural gas liquids as of December 31, 2001

	1	2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone		Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
Moose	Rundle	2 299	70	55	187	161	126	431	718
	Wabamun	253	36	28	51	9	7	13	29
	Subtotal					170	133	444	747
Peco	Cardium	455	64	37	516	29	17	235	281
	Mannville	1 218	96	62	324	117	75	395	587
	Jurassic	41	122	73	49	5	3	2	10
	Nisku	644	39	30	30	25	19	19	63
	Subtotal					176	114	651	941
Pembina	Belly River	2 115	83	50	97	175	105	205	485
	Cardium	2 752	248	170	160	682	469	440	1 591
	Viking	308	84	62	75	26	19	23	68
	Mannville	6 864	57	34	152	393	230	1 046	1 669
	Jurassic	5 960	55	31	186	326	186	1 111	1 623
	Rundle	391	41	26	69	16	10	27	53
	Mississippian	609	97	64	103	59	39	63	161
	Upper Devonian	44	295	205	205	13	9	9	31
	Nisku	4 378	240	112	72	1 050	489	317	1 856
	Subtotal					2 740	1 556	3 241	7 537
Pine Creek	Cardium	440	93	36	20	41	16	9	66
	Second White Specks	130	-	-	154	-	-	20	20
	Mannville	3 743	44	24	214	165	90	802	1 057
	Jurassic	385	10	8	39	4	3	15	22
	Rundle	182	-	-	104	-	-	19	19
	Wabamun	658	5	5	21	3	3	14	20
	Leduc	711	10	13	21	7	9	15	31
	Other	701	6	4	29	4	3	20	27
	Subtotal					224	124	914	1 262
Rainbow	Mannville	2 838	3	3	15	8	8	42	58
	Beaverhill Lake	116	86	52	69	10	6	8	24
	Sulphur Point	390	82	51	105	32	20	41	93
	Muskeg	400	193	83	50	77	33	20	130
	Keg River	6 946	291	153	121	2 021	1 063	841	3 925
	Subtotal					2 148	1 130	952	4 230
Rainbow South	Sulphur Point	322	16	9	71	5	3	23	31
	Muskeg	268	142	78	78	38	21	21	80
	Keg River	2 670	272	138	125	727	368	335	1 430
	Subtotal					770	392	379	1 541

(continued)

Ricinus	Cardium[a]	8 883	-	-	-	414	254	293	961
	Viking	5 308	31	18	35	162	96	185	443
	Mannville	193	62	31	52	12	6	10	28
	Subtotal					588	356	488	1 432

2.3. Remaining established reserves of natural gas liquids as of December 31, 2001

1		2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone		Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
Shekelie	Keg River	1 787	120	77	110	215	137	196	548
	Other	136	29	7	37	4	1	5	10
	Subtotal					219	138	201	558
Simonette	Second White Specks	721	122	55	53	88	40	38	166
	Lower Cretaceous	190	21	16	26	4	3	5	12
	Mannville	1 181	80	51	68	94	60	80	234
	Wabamun	509	130	90	544	66	46	277	389
	Leduc	369	328	255	187	121	94	69	284
	Beaverhill Lake	656	183	96	90	120	63	59	242
	Subtotal					493	306	528	1 327
Swan Hills	Beaverhill Lake	528	1 771	1 083	591	935	572	312	1 819
	Subtotal					935	572	312	1 819
Swan Hills South	Beaverhill Lake	1 895	279	173	197	528	328	373	1 229
	Subtotal					528	328	373	1 229
Sylvan Lake	Second White Specks	51	98	78	39	5	4	2	11
	Viking	110	127	136	91	14	15	10	39
	Mannville	2 129	107	68	78	227	145	167	539
	Jurassic	1 722	107	64	98	184	111	168	463
	Rundle	3 005	104	63	67	312	188	200	700
	Leduc	525	46	34	55	24	18	29	71
	Subtotal					766	481	576	1 823
Turner Valley	Mannville	289	128	55	28	37	16	8	61
	Jurassic	112	134	63	36	15	7	4	26
	Rundle	967	300	191	392	290	185	379	854
	Subtotal					342	208	391	941
Twining	Viking	412	12	7	68	5	3	28	36
	Mannville	493	34	32	99	17	16	49	82
	Rundle	4 373	78	72	95	340	317	417	1 074
	Subtotal					362	336	494	1 192

(continued)

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing time.

Valhalla	Second White Specks	555	7	4	47	4	2	26	32
	Mannville	1 508	4	3	25	6	4	37	47
	Triassic[a]	10 148	-	-	-	956	462	2 135	3 553
	Granite Wash	516	-	-	39	-	-	20	20
	Subtotal					966	468	2 218	3 652

2-3. Remaining established reserves of natural gas liquids as of December 31, 2001

	1	2	3	4	5	6	7	8	9
		Remaining reserves of marketable	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	Zone	gas (10^6 m^3)	Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
Virginia Hills	Mannville	288	87	42	35	25	12	10	47
	Belloy	272	110	63	74	30	17	20	67
	Beaverhill Lake	941	617	247	159	581	232	150	963
	Subtotal					636	261	180	1 077
Wapiti	Belly River	869	67	30	25	58	26	22	106
	Cardium	881	35	15	17	31	13	15	59
	Second White Specks	124	145	56	40	18	7	5	30
	Lower Cretaceous	3 775	8	5	21	32	18	81	131
	Mannville	10 885	10	5	32	105	57	344	506
`	Jurassic	1 125	10	5	50	11	6	56	73
	Other	433			23	-	-	10	10
	Subtotal					255	127	533	915
Waterton	Mississippian[a]	3 593	-	-	-	85	71	328	484
	Wabamun	313	6	6	38	2	2	12	16
	Subtotal					87	73	340	500
Wayne-Rosedale	Belly River	696	3	3	14	2	2	10	14
	Viking	890	37	22	43	33	20	38	91
	Mannville	2 617	69	44	75	181	115	197	493
	Nisku	197	-	-	949	-	-	187	187
	Other	1 118	4	4	4	4	4	4	11
	Subtotal					220	141	436	796
Wembley	Second White Specks	178	6	6	51	1	1	9	11
	Triassic[a]	5 679	-	-	-	884	416	1 859	3 159
	Other	229	4	4	44	1	1	10	12
	Subtotal					886	418	1 878	3 182
Westerose	Mannville	1 001	122	63	68	122	63	68	253
	Wabamun	203	-	-	69	-	-	14	14
	Nisku	86	-	-	128	-	-	11	11
	Other	533	8	6	6	4	3	3	10
	Subtotal					126	66	96	288

(continued)

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing with time.

Westerose South	Mannville	1 227	133	68	95	163	84	116	363
	Rundle	51	137	59	98	7	3	5	15
	Mississippian	455	185	86	48	84	39	22	145
	Wabamun	291	55	65	65	16	19	19	54
	Subtotal					27	145	162	577

2.3. Remaining established reserves of natural gas liquids as of December 31, 2001

1		2	3	4	5	6	7	8	9
		Remaining reserves of marketable gas (10^6 m^3)	Liquid recovery ratio ($m^3/10^6$ m^3 of marketable gas)			Remaining established reserves of natural gas liquids (10^3 m^3)			
Field	**Zone**		**Propane**	**Butanes**	**Pentanes plus**	**Propane**	**Butanes**	**Pentanes plus**	**Total**
Willesden Green	Belly River	947	97	71	58	91	67	55	213
	Cardium	3 088	25	20	97	76	63	298	437
	Second White Specks	251	96	84	80	24	21	20	65
	Viking	605	137	93	84	83	56	51	190
	Mannville	5 440	119	67	131	645	362	711	1 718
	Jurassic	1 385	94	61	83	130	85	115	330
	Rundle	127	94	55	94	12	7	12	31
	Mississippian	815	40	33	79	33	27	64	124
	Subtotal					1 094	688	1 326	3 108
Wilson Creek	Belly River	874	157	98	277	137	86	242	465
	Mannville	1 011	81	63	89	82	64	90	236
	Jurassic	450	87	60	58	39	27	26	92
	Rundle	422	78	45	121	33	19	51	103
	Mississippian	395	132	73	144	52	29	57	138
	Other	54	130	74	92	7	4	5	16
	Subtotal					350	229	471	1 050
Windfall	Mannville	1 156	45	27	58	52	31	67	150
	Rundle	87	46	46	138	4	4	12	20
	Mississippian	54	111	56	56	6	3	3	12
	Upper Devonian	1 066	17	29	90	18	31	96	145
	Nisku	144	35	49	410	5	7	59	71
	Leduc[a]	1 865	-	-	-	20	22	60	102
	Other	357	11	8	31	4	3	11	18
	Subtotal					109	101	308	518
Wizard Lake	Mannville	476	42	21	103	20	10	49	79
	Leduc	5 650	362	208	63	2 043	1 175	355	3 573
	Subtotal					2 063	1 185	404	3 652
Subtotal						36 196	24 030	53 041	113 267
Confidential reserves						20	10	31	61
Other small reserves						12 957	8 429	16 164	37 550
Subtotal						49 173	32 469	69 236	150 878
Recoverable at straddle plants						34 500	16 300	7 700	58 500
Recoverable at solvent floods						400	1 115	601	2 116
Total reserves						84 073 (529.8)[b]	49 884 (314.1)[b]	77 537 (487.6)[b]	211 494 (1331.5)[b]

[a] Includes gas cycling pool. Gas reserves calculated on an energy basis. Liquid recovery ratios are not included because of parameters changing with time.

[b] Imperial equivalent in millions of barrels.

Appendix 3 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 2001 spreadsheets 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.