Statistical Series **2001-98**

Alberta's Reserves 2000 and Supply/Demand Outlook 2001-2010

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

Alberta Energy and Utilities Board

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Overview

Every year the Alberta Energy and Utilities Board (EUB) issues a reserves report, providing stakeholders with one of the most reliable sources of information on the state of reserves for Alberta's diverse energy resources—crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal.

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.

The EUB's reserves report is the principal report on Alberta's reserves. It includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (reserves that are ultimately expected to be recovered). This year's report, *Alberta's Reserves 2000 and Supply/Demand Outlook 2001-2010*, also includes information on the demand for Alberta's energy resources, as well as a 10-year supply forecast for each of the sectors.

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. Higher prices, record drilling activity, and planned investments of billions of dollars for oil sands projects all contributed to the energy development picture in 2000 and shape the forecast for the years to come.

This overview provides a brief summary of the EUB's report on reserves and production for each resource at the end of 2000 and a forecast of resource supply and demand to 2010.

The following table summarizes Alberta's energy reserves at the end of 2000.

Reserves Summary 2000

	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	9 586	60.3	7 070	251	94	104
Ultimate potential (recoverable)	50 000	315	3 130	19.7	5 600	200	620	683
Initial established	28 330	178	2 554	16.1	4 064	144	35	39
Cumulative production	520	3.3	2 263	14.2	2 853	101	1.11	1.2
Remaining established	27 810	175	291	1.8	1 211	43	34	37
Annual production	39	0.245	43.5	0.274	140.7	5.0	0.034	0.037

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. Recovery is expected to improve with new technologies, such as a special thermal technique called steam-assisted gravity drainage (SAGD).

The total in situ and mineable remaining established reserves are 27.8 billion m^3 (175 billion barrels). This value is unchanged from 1999. To date, only 1 per cent of the ultimately recoverable crude bitumen resource has been produced.

Crude Bitumen Production

Production in 2000 was 22 million m^3 (138 million barrels) from the mineable area and 17 million m^3 (107 million barrels) from the in situ area, totalling 39 million m^3 (245 million barrels). Bitumen produced from mining was upgraded, yielding 18.5 million m^3 (116 million barrels) of synthetic crude oil (SCO), and in situ production was marketed as crude bitumen.

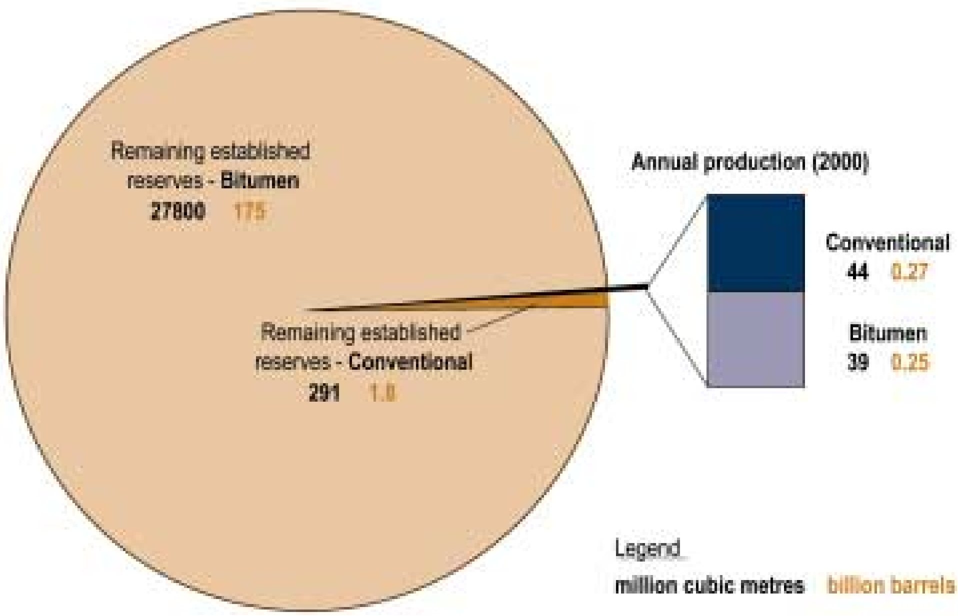
Approximately 40 per cent of Alberta's crude oil and equivalent (total oil) production for 2000 was from oil sands in the form of SCO and nonupgraded bitumen.

Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 291.4 million m^3 (1.8 billion barrels)—a 3.4 per cent reduction from 1999, but a smaller decline than in previous years. Of the 32.7 million m^3 (206 million barrels) added to initial established reserves, exploratory and development drilling, along with enhanced recovery methods, added reserves of 22.8 million m^3 (143 million barrels). This replaced 53 per cent of 2000 production. Re-evaluation accounted for the other 9.9 million m^3 (62 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

Higher prices allowed for strong production performance in 2000. Alberta's production of conventional crude oil totalled 43.5 million m^3 (274 million barrels). Despite declining production over the past two decades, Alberta still produces 119 000 m^3/day (750 000 barrels/day) of conventional crude oil.

Stability of crude oil prices in the last two years created some momentum in crude oil drilling activity for 2000. The number of successful oil wells increased 65 per cent, from 1630 in 1999 to 2700 in 2000. This had the effect of slowing the annual production decline rate from an 11 per cent decline in 1999 to 2 per cent last year.

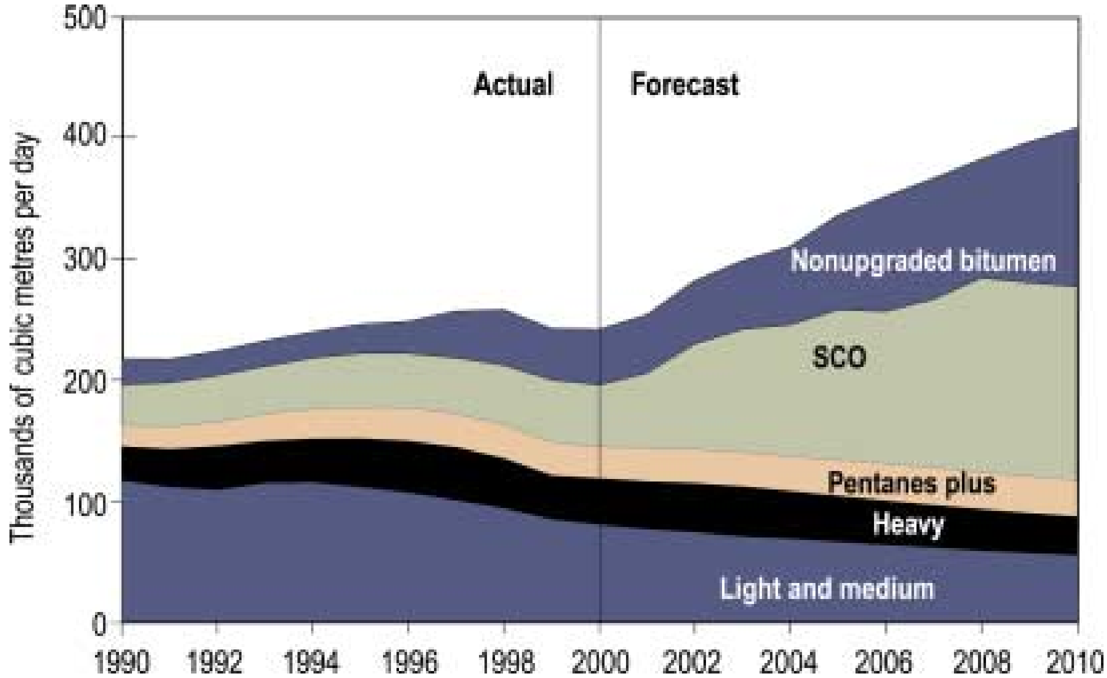
With the expectation that crude oil prices will remain generally in the same range over the next 10 years, the EUB estimates that 2700 successful oil wells will be drilled in both 2001 and 2002, levelling at about 2500 wells per year over the remainder of the forecast period.

Total Oil Supply and Demand

Alberta's 2000 production from conventional oil, oil sands sources, and pentanes plus was 242 000 m^3/day (1.52 million barrels/day)—about the same as in 1999. Production is forecast to reach 410 000 m^3/day (2.58 million barrels/day) by 2010.

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 declining, as expected, the EUB estimates that production of bitumen will triple by 2010, accounting for as much as 70 per cent of Alberta's total oil supply.



Alberta's total oil supply

Natural Gas

Natural Gas Reserves

A slight increase to the remaining established reserves of natural gas stemmed an otherwise continuing trend of reduction in reserves. At the end of 2000, Alberta's remaining established reserves of natural gas stood at 1211 billion m^3 (43 trillion cubic feet). While new drilling has not fully replaced gas production since 1982, last year's record drilling added new reserves, replacing 90 per cent of the production for 2000, compared to only 56 per cent in 1999. These estimates do not include coal-bed methane, which has considerable potential to add to Alberta's reserves in the future.

In 1992 the EUB estimated Alberta's ultimate marketable gas potential at approximately 5600 billion m^3 (200 trillion cubic feet). This estimate that now appears conservative and will be reviewed as a part of the new natural gas ultimate potential study targeted for completion in 2003.

Natural Gas Production and Drilling

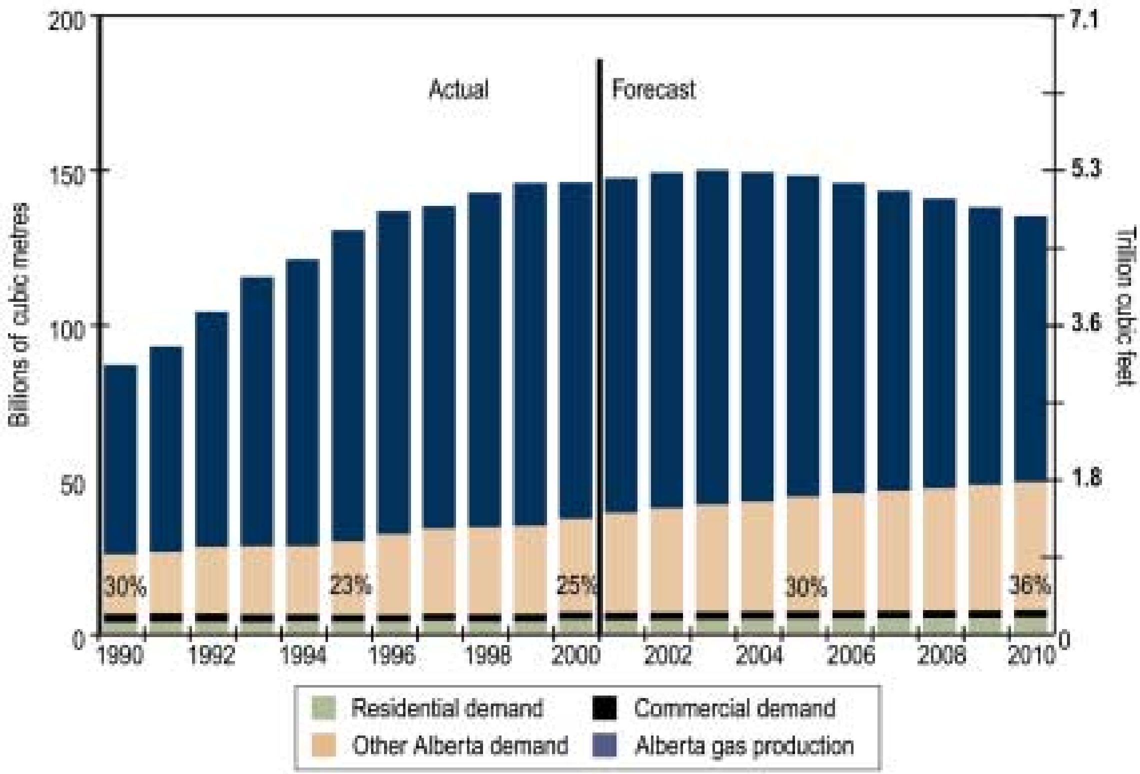
Several major factors have an impact on natural gas production, including natural gas prices, drilling activity, the location of Alberta's reserves, and the performance characteristics of wells. Alberta produced 140.7 billion m^3 (5.0 trillion cubic feet) of marketable natural gas in 2000. This represents a flattening of the upward trend over the past years.

There were 8228 successful gas wells drilled in Alberta in 2000, a 37 per cent increase over the 6015 gas wells drilled in 1999. The EUB expects continued strong drilling, estimating some 10 000 successful wells per year over the forecast period.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta. However, the EUB expects expanded exploration activity in the western portion of the province. As a result of improved cash flow fuelling investment in exploration, the EUB forecasts increased drilling levels for the coming year.

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 growing 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 ensures 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 coal-bed 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 declined slightly to 252 million m^3 (1.6 billion barrels) in 2000. The production of specification ethane increased from 11.3 million m^3 (71.1 million barrels) in 1999 to 12.8 million m^3 (80.5 million barrels) in 2000. The majority of this 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, butane, and pentanes plus—increased slightly to 221.9 million m^3 (1.4 billion barrels) in 2000. This increase was due mainly to a re-evaluation of NGL reserves in several pools in the province. The supply of propane and butane 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 2005. Other alternatives will have to be found to replace pentanes plus as a diluent.

The remaining established reserves of sulphur is 98 million tonnes from natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is not expected to increase, 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 80 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 2000 was 34 million tonnes of raw coal. Recent sharp increases in coal prices, due to high oil and gas prices and record 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

1.1 Introduction

Alberta's prosperity as an energy-exporting province, and consequently its own energy supply and demand, are 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.[1] This section describes the outlook for world oil prices, the 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.

1.2 Energy and Sulphur 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 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 per barrel higher than the OPEC price, a reflection of shipping costs of OPEC crude to the North American continent. For simplicity, the EUB uses WTI crude prices as a proxy for world oil prices, as it is more relevant to Alberta crude oil markets.

The price of WTI crude oil fell to US$10.24 per barrel (US$64/m^3) in November 1998 and then recovered to US$25.45 per barrel in September 1999, after major petroleum-exporting countries implemented production cutbacks. Since late 1999, WTI crude oil prices have fluctuated in the range of US$25-$30 per barrel, although occasionally exceeding US$35.

However, with the worldwide economic slowdown, it is expected that growth in demand for crude oil will be reduced. The supply of crude oil from non-OPEC countries has also been on the rise due to strong oil prices. The EUB believes that these fundamentals will drive the price of crude oil down if OPEC's market share is to be maintained. It expects that over the forecast period the price of WTI will gradually stabilize at roughly US$24 per barrel. This price level is sufficient to stimulate exploration outside of the OPEC countries and foster continuing improvements in exploration and recovery technology. The increase in non-OPEC production stimulated by high prices will reduce the OPEC's power to increase prices without lowering its market share.

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 exchange rate. That is, if the Canadian dollar declined in value relative to the U.S. dollar, then crude oil prices would increase in Canadian dollars. The yearly forecast wellhead price of crude oil in Alberta is shown in both current and constant Canadian dollars in Figure 1.2.

Currently, the differentials between light-medium crude, on the one hand, and bitumen or conventional heavy crude, on the other, are exceptionally wide by historical standards. The forecast calls for the bitumen price to revert to 60 per cent of the light-medium price

[1] British Columbia produced some 24 million tonnes of high-volatile coal that was shipped to export markets at a higher price than the Alberta average.

and for conventional heavy to revert to 75 per cent of the light-medium price. These are close to the average differentials over the period 1995-2000.

The natural gas price at plant gate in Alberta averaged $1.54 per gigajoule (GJ) ($1.62 per million cubic feet [mcf]) from 1989 to 1998. The average price increased to $2.35/GJ in 1999 and $4.27/GJ in 2000. The spot price, however, climbed above $8/GJ by December 2000. Additional pipeline capacity has removed bottlenecks that limited access to markets south of the border and strengthened the link between prices in Alberta and the United States. With improved transportation access, Alberta producers are now able to obtain a North American price for their gas. Higher prices will also stimulate provincial exploration and production.

It is expected that U.S. natural gas prices will be strong in the next few years due to reduced domestic supply availability, high oil prices, and growth in gas demand for electricity generation. The EUB forecast anticipates that average natural gas prices will remain high, reaching a peak of $5.75/GJ in 2001. However, the EUB projects that the price will level out at $4.50/GJ by 2002, as the higher rates of drilling activity in North America, brought on by high prices, cause new gas supplies to come on stream more rapidly. Further, high gas prices will result in some fuel switching in industries with dual fuel capability.

In the long term the price of heavy fuel oil usually sets a ceiling on the burner-tip price of gas, because many industrial customers with fuel-switching capability will stop burning natural gas and switch to fuel oil if the latter is significantly less expensive. There is, however, no obvious lower limit to the price of natural gas. Because intercontinental trade in natural gas is very expensive, its price varies widely from continent to continent, with the highest prices found in Europe and North America. The forecast of Alberta natural gas price at plant gate is shown in both current and constant Canadian dollars in Figure 1.3.

The plant-gate price of sulphur has declined drastically over the past few years, primarily because of increased sulphur recovery around the world, motivated by the environmental benefits of reduced sulphur emissions. As there is no obvious prospect for significant improvement in plant-gate sulphur prices, they are projected to be a constant $10/tonne.

Prior to 2000, prices fetched by bituminous coal in world markets had declined to the point that most Alberta export mines were facing closure. More recently, world coal prices have increased sharply, thus allowing the reopening of at least one of the mines that ceased production earlier. The rise in thermal coal prices is a delayed response to higher petroleum prices; the rise in metallurgical coal prices reflects the fact that world steel output is now at an all-time high. China, with a booming economy, has become a net importer of steel. Steel mills in Japan and Korea, which have traditionally purchased most of Alberta’s metallurgical coal output, are well placed to capture a share of rising Chinese steel imports.

1.3 Canadian Economic Performance

The Canadian economic growth, interest, inflation, and unemployment rates are key variables that impact the Alberta economy and are beyond the province’s control. Canada’s last recession year was 1991, when real gross domestic product (GDP) declined 1 per cent relative to 1990. Since then, real output has increased every year, along with real GDP. It is expected that the Canadian economy will grow every year during the forecast period, albeit at a slower pace in 2001.

The national unemployment rate fell from 9.7 per cent in 1996 to 7.6 per cent in 1999 and is expected to decline further, levelling off at 5.3 per cent before 2010. Both the prime interest rate on bank loans and the inflation rate as measured by the national consumer price index had been increasing slowly until early in 2001. However, moderation in U.S. economic activity and potential slowdown in the Canadian economy have resulted in lower interest rates on both sides of the border. While the inflation rate is expected to be modestly lower throughout the forecast period, the interest rate is expected to rise slightly by the year 2005 and decline later in the decade. Although the Canadian dollar has depreciated against the U.S. dollar in recent months, a strengthening is expected, because the economic slowdown in Canada is expected to be milder than in the U.S. A lower inflation rate and expected recovery in non-energy commodity prices also tend to improve Canada's terms of trade. Table 1.1 summarizes trends in national economic variables.

Table 1.1. Major assumptions concerning the Canadian economy (averages over 2000-2010)[1]

Canadian economic growth rate	2.8%
Canadian inflation rate	1.9%
Value of Canadian $ in terms of US$	0.69

[1] Source (except for exchange rate): WEFA Group, Canadian Macroeconomic Long-term Forecast and Analysis.

1.4 Alberta Economic Outlook

The Alberta economy has not experienced a contraction on a year-over-year basis since 1983, although there was a slowdown at the beginning of the 1990s. In the last decade, Alberta's real GDP growth has averaged 3.3 per cent, ranging from a low of 0.6 per cent in 1990 to a high of 9.0 per cent in 1993. During this period, Alberta GDP per capita remained above the Canadian average.

Over the forecast period, annual GDP growth, as shown in Figure 1.4, is expected to average 2.9 per cent, while employment growth averages 2.2 per cent. Rapid expansion of the oil sands industry in the early years of the forecast period will partly offset the levelling off or decline in conventional fossil fuel output.

Despite a slower projected pace of economic growth, the provincial unemployment rate is expected to be low. Although job creation will slow down, so will net migration into Alberta, because declining unemployment rates in other provinces will eventually lessen the incentive to migrate. International migration, on the other hand, is relatively insensitive to economic conditions.

1.5 Alberta's Demographic Outlook

In general, economic activity influences net migration, which in turn affects labour force growth. Population growth consists of two components: net migration and natural increase. Net migration (both international and interprovincial) is defined as immigration less emigration, while natural increase is births less deaths.

From 1990 to 2000, Alberta's population grew at an annual average rate of 2.0 per cent, up from 1.4 per cent during the previous decade. During the 1990s, net migration into Alberta varied from 8000 in 1994 to 50 000 in 1999. Natural increase was affected by a drop in the birth rate from 2.0 to 1.7 births per woman.

Over the forecast period, the Alberta population is projected to increase from 3.0 million in 2000 to 3.6 million in 2010, a yearly increase of 1.9 per cent. Net migration into Alberta is forecast to vary between 19 000 and 49 000. A forecast of population by gender is presented in Figure 1.5.

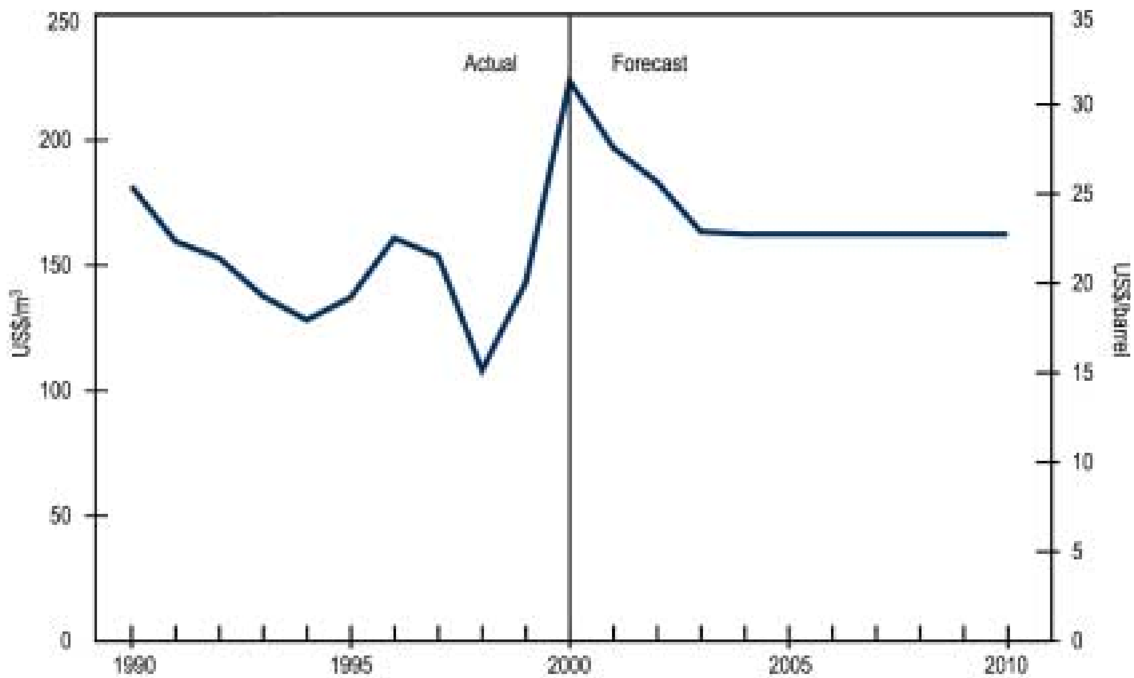


Figure 1.1. Price of WTI at Chicago

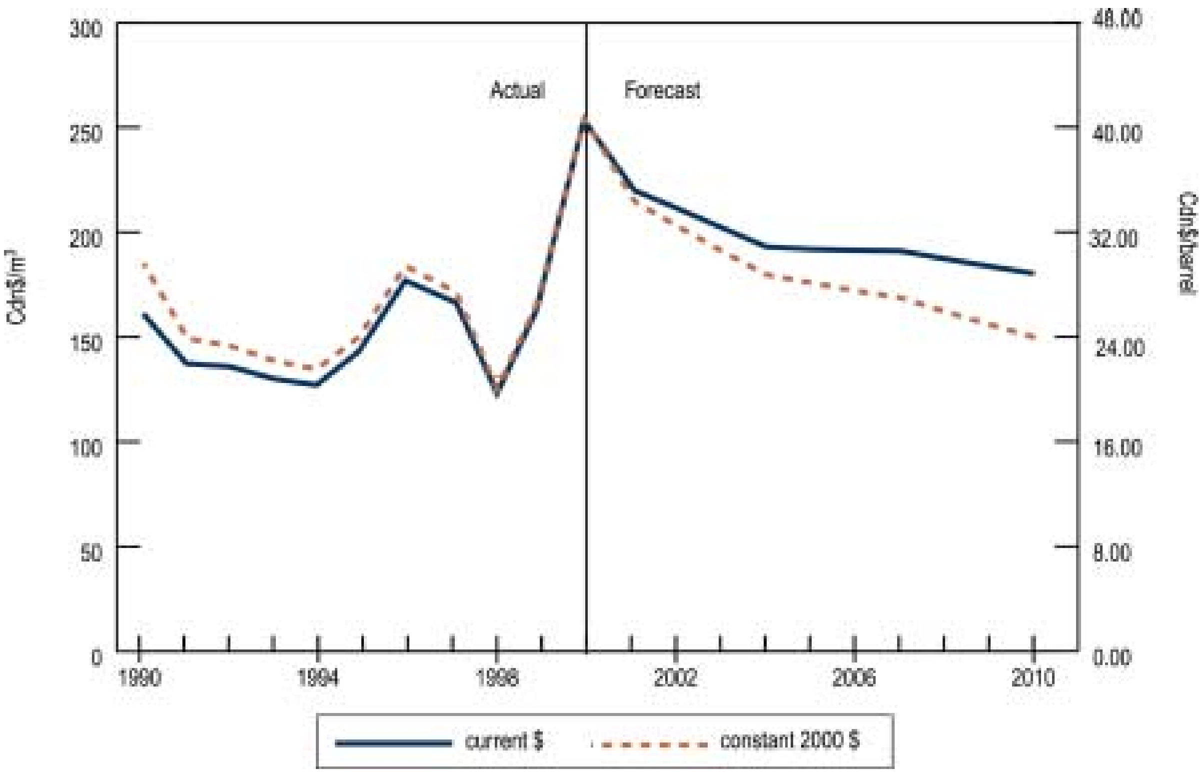


Figure 1.2. Average price of oil at Alberta wellhead

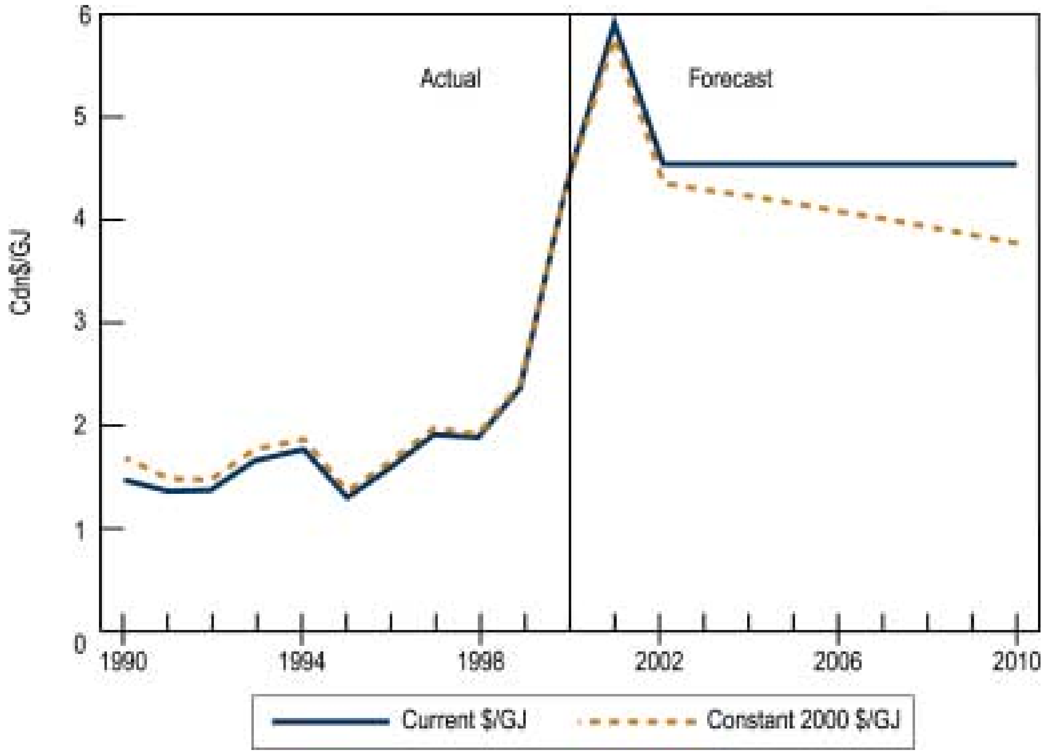


Figure 1.3. Average price of natural gas at plant gate

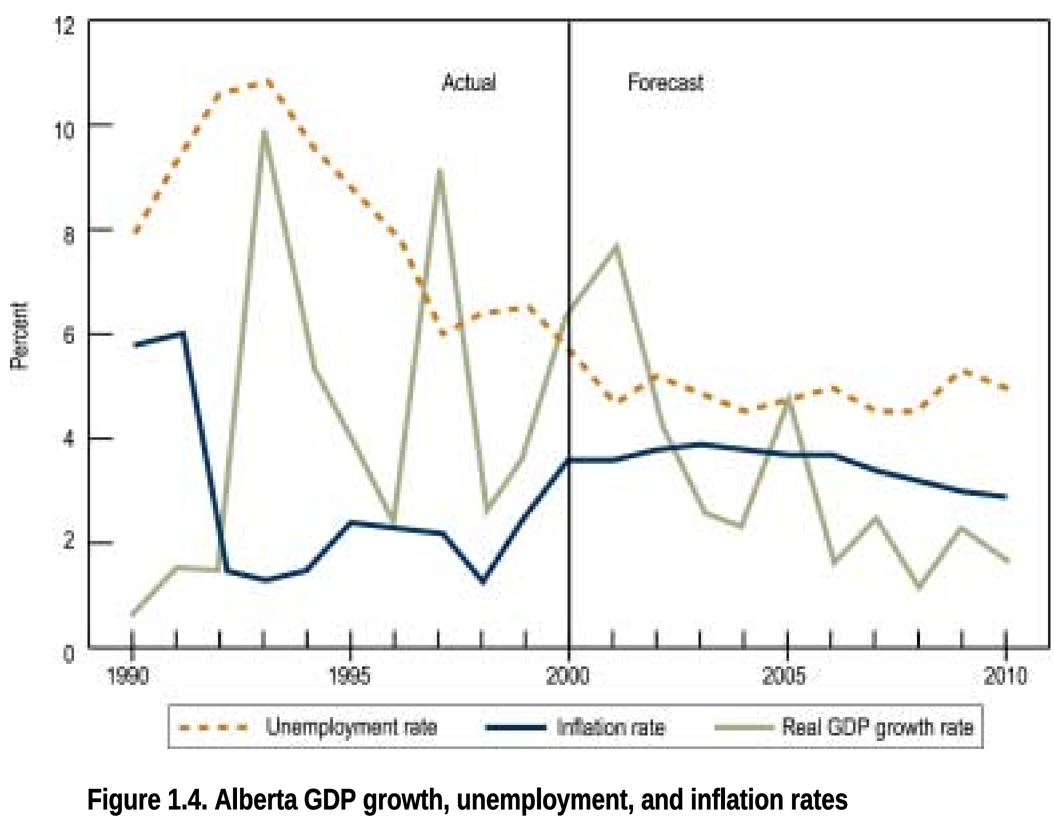


Figure 1.4. Alberta GDP growth, unemployment, and inflation rates

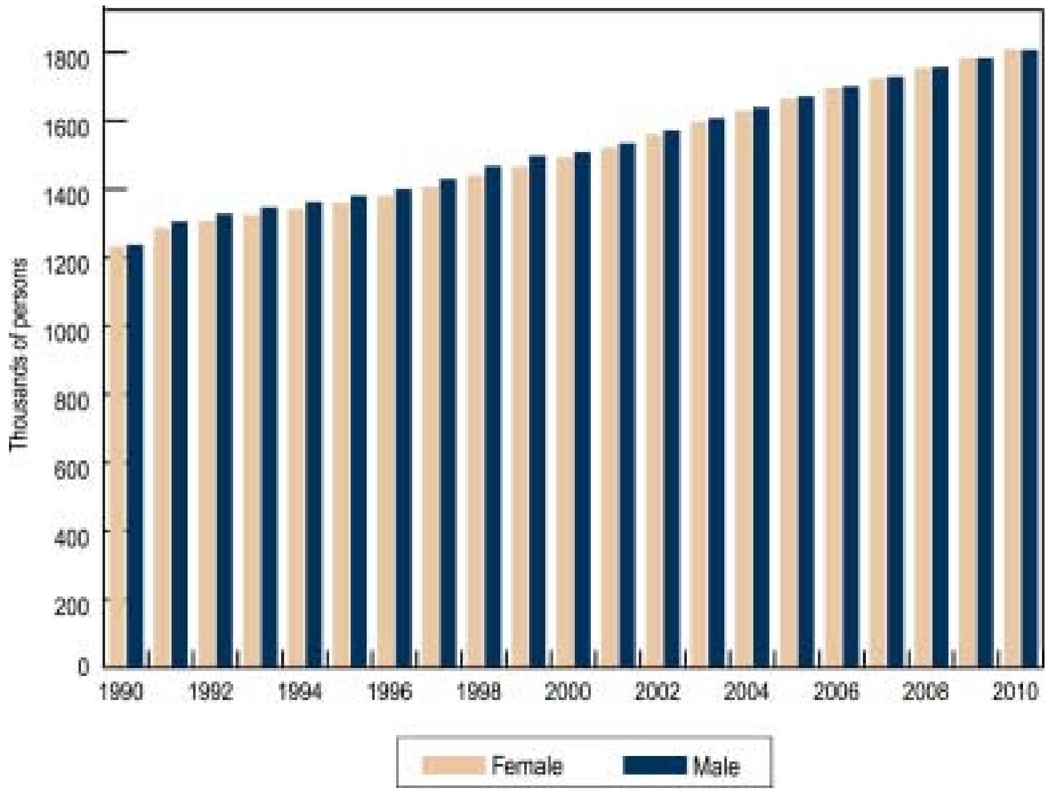


Figure 1.5. Alberta population trends

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 last year's report, 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, 2000, 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 27.81 10^9 m^3, of which 1.86 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 project to significantly update these reserves; the new values should be available for the report scheduled for release in 2003. Table 2.1 summarizes the in-place and established mineable and in situ crude bitumen reserves.

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

Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable[a]	18.0	5.59	0.37	5.22	1.37
In situ	241.2	22.74	0.15	22.59	0.49
Total	259.2 (1 631)[a]	28.33 (178.3)[a]	0.52 (3.3)[a]	27.81 (175.0)[a]	1.86 (11.7)[a]

[a] Imperial equivalent in billions of stock-tank barrels.

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

The changes in established crude bitumen reserves for 2000 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 17.0 million cubic metres (10^6 m^3) in 2000. Production from the only two current surface mining projects amounted to 21.6 10^6 m^3 in 2000, with 13.3 10^6 m^3 from the Syncrude Canada Ltd. project and 8.3 10^6 m^3 from the Suncor Energy Inc. project. The Albian Sands Energy Inc. project is currently under construction.

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

	2000	1999	Change
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 740	22 740	0
Total	28 330 (178 280)[a]	28 330 (178 280)[a]	0
Cumulative production			
Mineable	371	349	+22
In situ	150	133	+17
Total	521	482	+39
Remaining established reserves			
Mineable	5 219	5 241	-22
In situ	22 590	22 607	-17
Total	27 809 (175 000)[a]	27 848 (175 240)[a]	-39

[a]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, 2000

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[c]	15 370	878	604	136	468
Syncrude[d]	21 672	1 433	959	235	724
Total	47 138	2 885	1 741	371	1 370

[a]The project areas correspond to the areas defined in the project approval.
[b]Definitions are given in Figure 2.2.
[c]Includes the Steepbank/Millennium project area.
[d]Includes the Aurora North project area.

Table 2.4. Established in situ crude bitumen reserves in areas under active development as of December 31, 2000

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	6.1	2.5
Subtotal	21.6		8.6	6.1	2.5
Athabasca Oil Sands Area					
Primary recovery schemes	2 381.2	5.0	119.0	8.3	110.7
Subtotal	2 381.2		119.0	8.3	110.7
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25.0	200.7	97.6	103.1
Primary production within projects	601.1	5.0	30.1	11.3	18.8
Primary recovery schemes	4 178.2	5.0	208.9	17.9	191.0
Lindbergh primary production	1 309.3	5.0	65.4	3.3	62.1
Subtotal	6 891.4		505.1	130.1	375.0
Experimental Schemes (all areas)					
Active	11.5	15.0	1.7	1.6	0.1
Terminated	68.7	9.5	6.5	3.6	2.9
Subtotal	80.2		8.2	5.2	3.0
Total	9 374.4		640.9	149.7	491.2

[a]Thermal reserves are assigned only for lands approved for thermal recovery and having completed drilling development.
[b]Cumulative production to December 31, 2000, 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]

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

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
Total	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
Total	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
Total	20 518					
Grand 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 total initial volume of crude bitumen in-place for the designated deposits as of December 31, 2000, is 241.2 10^9 m^3, unchanged from last year.

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]

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

The initial mineable volume in-place of crude bitumen is estimated as of December 31, 2000, 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, 1999.

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 371 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, 2000, is 5.22 10^9 m^3, slightly lower than last year due to the production of nearly 22 10^6 m^3 in 2000.

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, 2000.

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 2000 estimate of initial established reserves for in situ areas remains unchanged at 22.74 10^9 m^3. This reserve will be significantly refined and the results released in the report scheduled for 2003. Cumulative production within the in situ areas now totals 150 10^6 m^3, of which 130 10^6 m^3 is from the Cold Lake OSA. As a result of the 17 10^6 m^3 production in 2000, remaining established reserves of crude bitumen from in situ areas are now slightly lower, at 22.59 10^9 m^3. Of this total, 69 per cent occurs within the Athabasca OSA, 23 per cent within Cold Lake, and 8 percent within the Peace River OSA.

The EUB's 2000 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 491.2 10^6 m^3, a decrease of 6.9 10^6 m^3 from 1999.

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 production refers to the portion of crude bitumen upgraded to 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 synthetic crude oil (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 manufacture of fertilizer.

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 feasible. In this method the heat from steam reduces 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 is currently used in Alberta as diluent. Diluent used to transport bitumen to Alberta destinations is usually recycled; however, the volumes used to dilute bitumen to markets outside Alberta are removed from 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 2000, Alberta produced 104.8 10^3 m^3/d of crude bitumen, with surface mining accounting for 56 per cent and in situ for 44 per cent. In the same year, nonupgraded bitumen and SCO accounted for 40 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 U.S. and Canadian markets.

2.2.1.1 Mined Crude Bitumen

Since 1990, Syncrude and Suncor bitumen production has increased steadily, reaching a level of 59.1 10^3 m^3/d in 2000, with Syncrude accounting for 62 per cent and Suncor for 38 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 EUB projects that production from Syncrude will reach 80.0 10^3 m^3/d and Suncor will produce 47.0 10^3 m^3/d by the year 2010. The EUB also considered two new projects in the mineable area. The first is the Albian Sands project, which is currently under construction and is expected to produce bitumen in 2002 and reach full production capacity of 26.0 10^3 m^3/d by 2004. The second is the project proposed by TrueNorth Energy.

TrueNorth Energy has a plan to develop the Fort Hills Oil Sands Project, with two phases of production. The first is to begin in 2005, reaching full capacity of approximately 15 10^3 m^3/d in 2006. The second phase will begin in 2008, increasing production to over 30 10^3 m^3/d in 2010. TrueNorth Energy would 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.

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.

Figure 2.3 shows that total mined bitumen production will increase from 59.1 10^3 m^3/d in 2000 to some 183.1 10^3 m^3/d by 2010, representing an average increase of some 11 per cent per year.

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has more than doubled since 1990, reaching a level of 45.8 10^3 m^3/d in 2000. To date, the majority of in situ bitumen has been marketed in nonupgraded form outside of Alberta. However, by the end of the forecast period some 23 per cent of in situ production will be used as bitumen feedstock for SCO production. A small amount of bitumen (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. Production from future crude bitumen projects takes into account past experience, 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 131.0 10^3 m^3/d over the forecast period, representing an average annual increase of some 11 per cent.

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 18.2 10^3 m^3/d and 32.6 10^3 m^3/d of SCO respectively in the year 2000. SCO production in Alberta has increased substantially since the commissioning of these two projects.

The conversion of crude bitumen to SCO uses different technology 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 EUB expects a significant increase in the SCO production over the forecast period, as shown in Figure 2.4. The forecast is based on the projection of production from the existing Suncor and Syncrude plants (including their potential expansions) plus production of SCO from one new project.

Suncor's production of SCO is forecast to reach 63.6 10^3 m^3/d in 2008 and remain at this level to 2010. Suncor has announced its vision to increase its upgraded crude production by

- the completion of Project Millennium in 2002, increasing capacity to 35.0 10^3 m^3/d;
- 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 by 8.0 10^3 m^3/d starting in 2005; and
- the addition of cokers to the upgrading complex, together with associated hydrotreating, increasing capacity to 63.6 10^3 m^3/d by 2008.

Syncrude is expected to reach 72.2 10^3 m^3/d of SCO in 2008 and remain relatively flat through the remainder of the forecast period. Its expansion plan consists of a four-staged project that began in 1996 and is expected to be complete by 2008:

- Stage one included the development of the North mine and debottlenecking of the upgrader, increasing capacity to almost 36.0 10^3 m^3/d in 1999.
- Stage two consists of the Aurora Train 1 and additional debottlenecking of the upgrader at Mildred Lake, resulting in capacity of some 41.0 10^3 m^3/d in 2002.
- Stage three will see the upgrader expand and a second train of production at Aurora, increasing capacity to over 58.0 10^3 m^3/d by 2005.
- Stage four includes Aurora Train 3 and further upgrader expansion, with capacity reaching over 72 10^3 m^3/d by 2008.

Over the forecast period, the EUB assumes that Shell Canada will commence production of a new upgrader at Scotford, near Edmonton, with capacity of 23.8 10^3 m^3/d. This upgrader is adjacent to the existing Shell refinery and will upgrade crude bitumen from the Albian Sands project.

In 2010, provincial SCO production will reach 159.6 10^3 m^3/d, with Syncrude accounting for 45 per cent, Suncor accounting for 40 per cent, and Shell accounting for 15 per cent of production.

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 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 2000, five Alberta refineries with total capacity of 68 10^3 m^3/d used 27.2 10^3 m^3/d of SCO and 2.3 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand for SCO represents 53.5 per cent of Alberta SCO production and 5 per cent of nonupgraded bitumen production. It is assumed that over the forecast period no additional refinery capacity will be installed. Figure 2.5 shows that in 2010 Alberta demand for SCO and nonupgraded bitumen is expected to increase to 38.2 10^3 m^3/d and 2.7 10^3 m^3/d respectively.

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 extraprovincial 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 23.8 10^3 m^3/d to 121.1 10^3 m^3/d and exports of nonupgraded bitumen will increase from 43.5 10^3 m^3/d to 127.9 10^3 m^3/d.

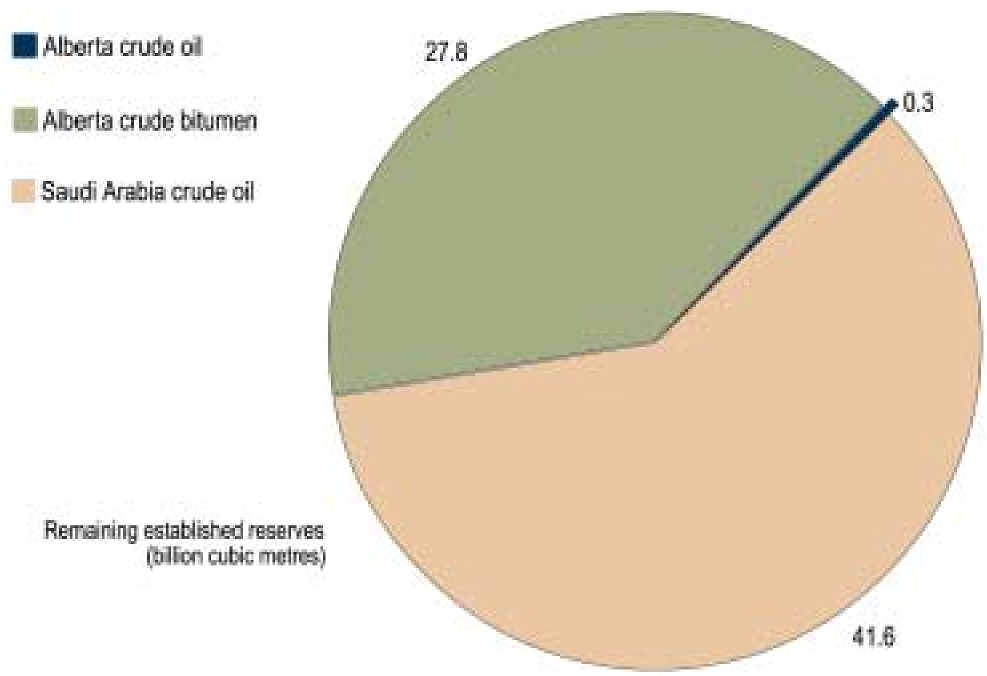


Figure 2.1. Crude oil and crude bitumen reserves in Alberta and Saudi Arabia

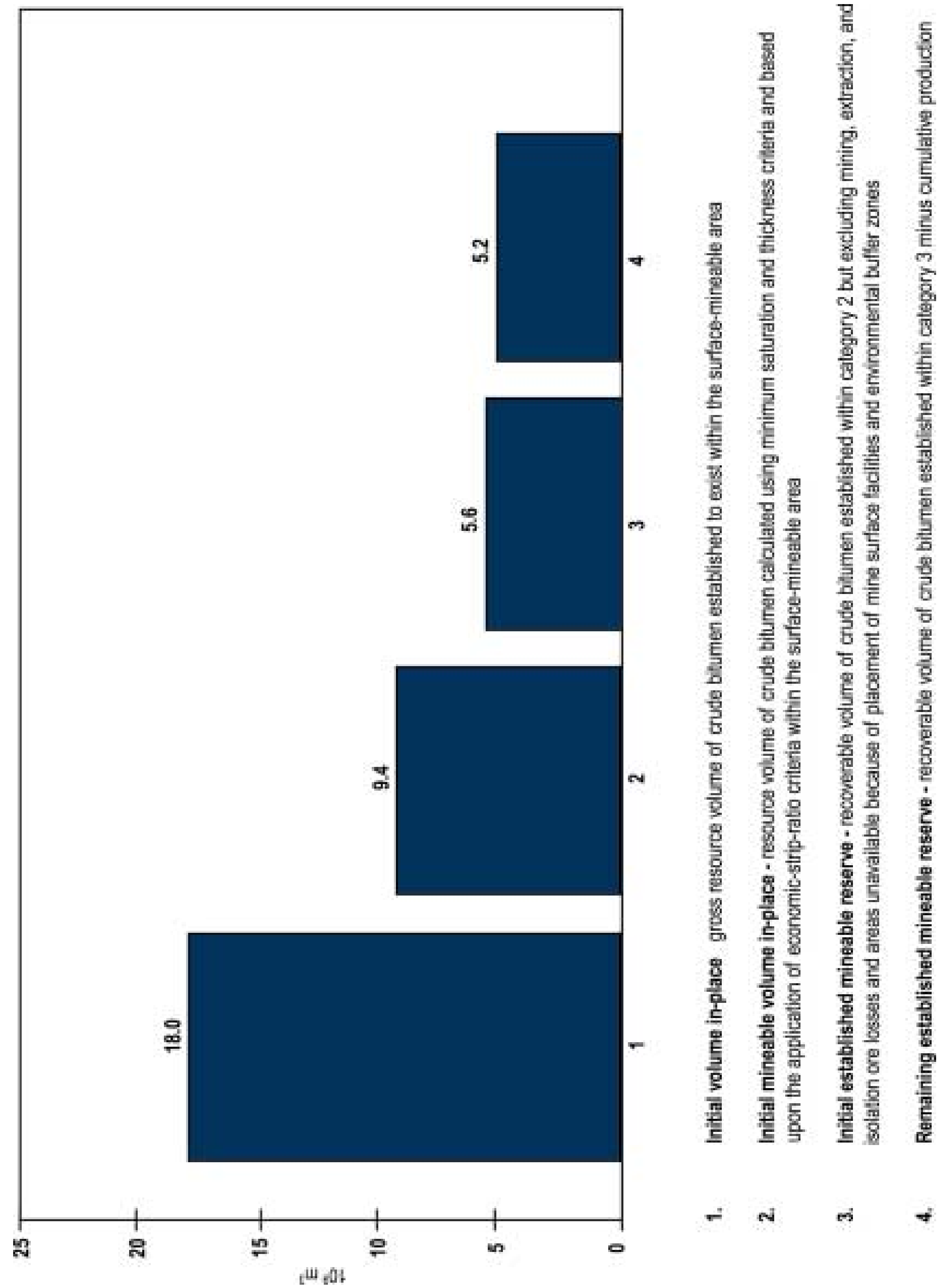


Figure 2.2. Crude bitumen resource and reserve categories

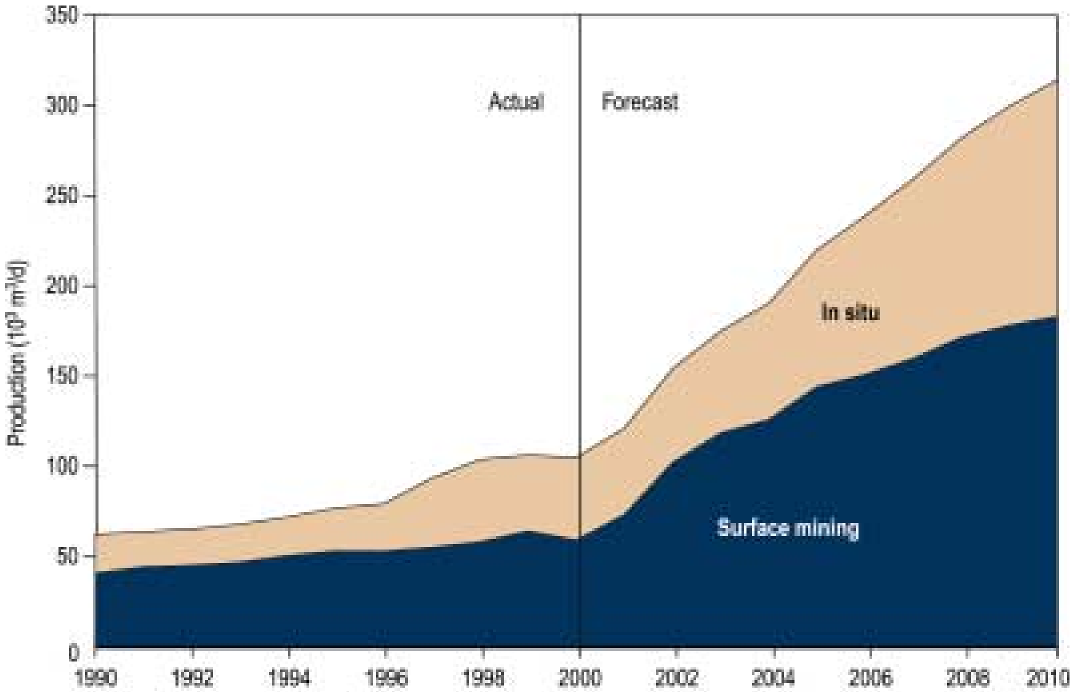


Figure 2.3. Alberta crude bitumen production

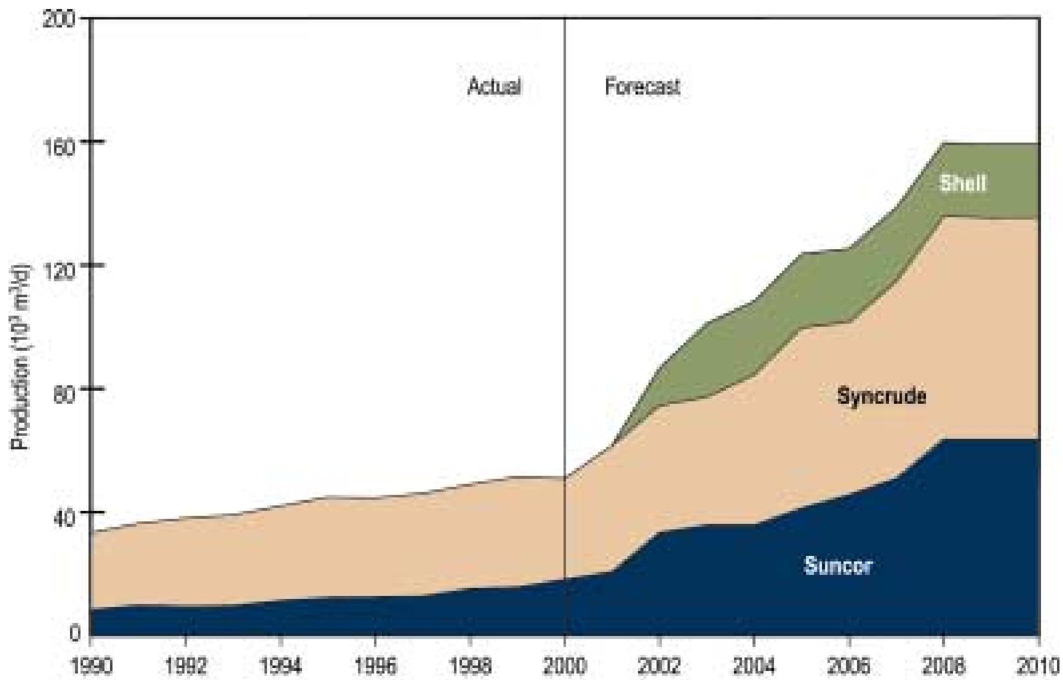


Figure 2.4. Alberta synthetic crude oil production

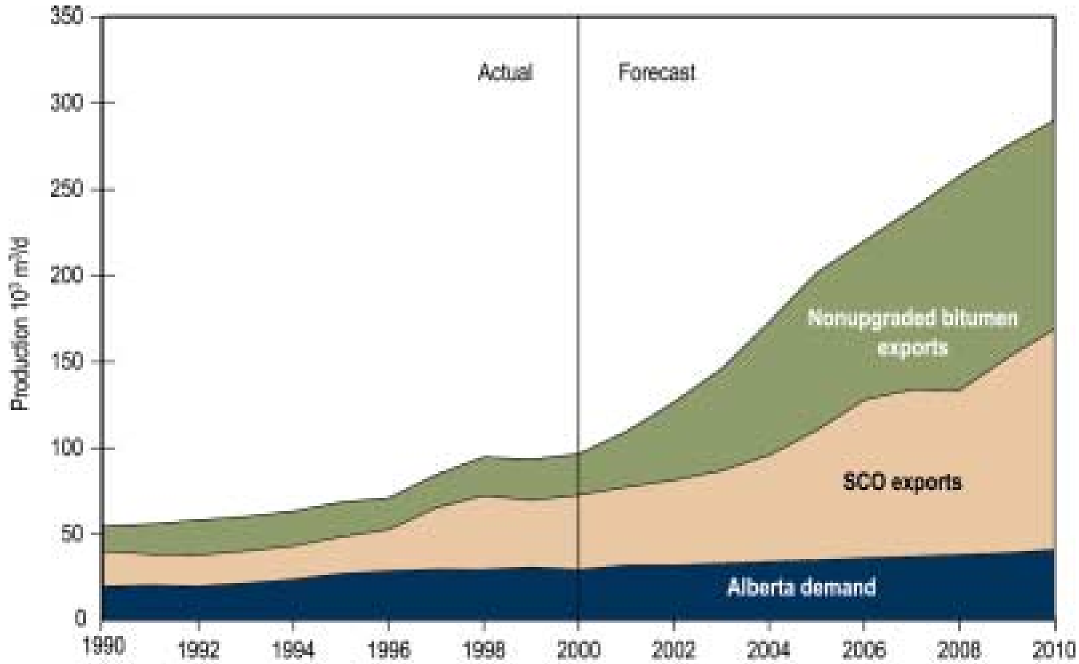


Figure 2.5. Alberta demand and exports of crude bitumen and SCO

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 291 million cubic metres (10^6 m^3), or 1.8 billion barrels, at year-end 2000. This decrease from year-end 1999 of 10.3 10^6 m^3 is a result of all reserve adjustments less production that occurred during 2000. The changes in reserves and cumulative production for light-medium and heavy crude oil to year-end 2000 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)

	2000	1999	Change
Initial established reserves[a]			
Light-medium	2 225.8	2 209.9	+16.0
Heavy	328.5	311.7	+16.8
Total	2 554.4 (16 070)[b]	2 521.6	+32.8
Cumulative production[a]			
Light-medium	2 005.3	1 976.0	29.3 [c]
Heavy	257.6	244.0	13.6 [c]
Total	2 262.9	2 219.9	43.0 (270) [b]
Remaining established reserves[a]			
Light-medium	220.5	233.9	-13.4
Heavy	70.9	67.8	+3.1
Total	291.4 (1 830)[b]	301.6	-10.3

[a]Discrepancies are due to rounding.
[b]Imperial equivalent in millions of stock-tank barrels.
[c]Discrepancies may exist with actual production as reported in *Statistical Series 2000-17*.

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 353 new oil pools booked in 2000 totalled 7.9 10^6 m^3, while development of new and existing pools during 2000 added another 13.4 10^6 m^3. New and expanded enhanced recovery schemes (water and solvent floods) added initial established reserves of 1.5 10^6 m^3. This continues the trend of decreasing contributions to growth by new enhanced recovery schemes due to a lack of suitable quality candidates for such schemes (Figure 3.5). Total net reassessment of existing reserves added 10.0 10^6 m^3, 9.9 of which were to heavy crude reserves. The resulting total increase in initial established reserves for 2000 amounted to 32.8 10^6 m^3, up from last year's total of 31.5 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	6.8	1.1	7.9
Development of existing pools	7.8	5.6	13.4
Enhanced recovery (new/expansions)	1.3	0.2	1.5
Reassessment	0.1	9.9	10.0
Total	16.0	16.8	32.8

Reserve additions resulting from drilling and new enhanced recovery schemes totalled 22.8 million cubic metres, up from 14.9 10^6 m^3 in 1999. These additions replaced 53 per cent of Alberta's 2000 conventional crude oil production of 43.5 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 33.7 10^6 m^3 and negative reassessments totalling 23.7 10^6 m^3. Established reserves in the Chauvin South MU No. 1 Pool increased by 3337 thousand cubic metres (10^3 m^3) as the result of a reassessment of its waterflood operations. In the commingled Morgan Sparky A, Lloydminster A, Rex A, and Dina B Pool, pool development and higher recovery efficiency increased reserves by 2911 10^3 m^3. Table 3.3 lists those pools having the largest reserve changes in 2000.

3.1.4 Distribution of Oil Reserves by Size and Geology

At year-end 2000, oil reserves were assigned to some 7000 light-medium and 2400 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 reveals that 90 per cent of the remaining reserves is contained in the largest 14 per cent of pools. Figure 3.6 further illustrates the historical trends in the size of oil pools.

The distribution of conventional crude oil reserves by drive mechanism, including their historical average recovery factors, is presented in Table 3.5 and Figure 3.7. Table 3.5 shows that waterflood projects have added 635 10^6 m^3, or 25 per cent of the province's initial established reserves. Also, pools under solvent flood have realized an average increase in recovery efficiency of 30 per cent over primary depletion.

The distribution of reserves by geological period and by formation, found in Tables 3.6 and 3.7 and graphically represented in Figure 3.8, indicates that the majority of remaining established reserves will be produced from the Lower Cretaceous (33 per cent) and Upper Devonian (23 per cent) Formations.

Table 3.3. Major oil reserve changes, 2000

Pool	Initial established reserves (10^3 m^3) 2000	Change	Main reason for change
Alderson Arcs D	423	+ 300	New waterflood
Alderson Lower Mannville C5C	246	+246	New pool
Bantry Mannville A	10 870	+1328	Reassessment of primary reserves
Bashaw D-2A & D-3A	873	+848	Pools commingled; reassessment of oil in-place
Bonnie Glen D-3A	83 000	-300	Reassessment of recovery factor
Bow Island Sawtooth U	625	+ 268	Reassessment of recovery factor
Chauvin Mannville A	1 869	+371	Pool development
Chauvin South MU No.1	10 740	+3337	Reassessment of waterflood reserves
Cherhill Banff A	3 060	- 505	Reassessment of primary and waterflood reserves
Countess Upper Mannville PP	740	- 349	Reassessment of primary and waterflood reserves
Enchant Arcs F & G	640	- 270	Reassessment of oil in-place
Enchant Arcs J & VV	2 884	+120	Coalesced with Arcs AAA and TT & UU Pools
Fenn West D-2 I	514	+ 514	New pool
Fenn West D-3 H	1 373	+ 1373	New pool
Garrington Cardium A & B	1 042	+ 472	Pool development and reassessment of recovery factor
Golden Slave Point A	3 308	+ 316	Pool development
Grande Prairie Halfway V	621	+355	Recognition of waterflood scheme
Hayter Dina Q	1 064	+ 564	Reassessment of recovery factor
Jenner Upper Mannville A2A	43	- 151	Pool development and reassessment of recovery factor
Kakwa Main Cardium A	228	- 171	Reassessment of recovery factor
Little Bow Upper Mannville I	1 561	+ 422	Reassessment of primary and waterflood reserves
Lloydminster Sparky K	3 412	+ 966	Pool development and reassessment of recovery factor
Marwayne General Petroleum A	356	+ 321	Pool development and reassessment of recovery factor
Marwayne Sparky C	371	+ 343	Pool development
Marwayne Sparky D	712	+ 258	Pool development
Medicine River Jurassic D & GG	4 240	+ 834	Pools commingled
Morgan Sparky A, Lloyd A, Rex A, Dina B	7 574	+2911	Pool development and reassessment of recovery factor

(continued)

Table 3.3. Major oil reserve changes, 2000 (concluded)

Pool	Initial established reserves (10^3 m^3) 2000	Change	Main reason for change
Nipisi Gilwood A	58 310	+ 770	Reassessment of primary reserves
Pembina Belly River FFF, GGG, K2K and S2S	2 471	+ 307	New waterflood
Provost Dina L	735	- 246	Reassessment of oil in-place
Provost Dina N	2 693	+ 385	Reassessment of recovery factor
Provost Dina Q	738	+ 526	Pool development and reassessment of recovery factor
Provost Dina E5E	449	- 158	Reassessment of recovery factor
Provost Upper Mannville B	1 485	- 213	Reassessment of recovery factor
Provost Upper Mannville BB	2 227	- 1114	Reassessment of recovery factor
Provost Upper Mannville T8T	1 183	+ 333	Reassessment of recovery factor
Provost Upper Mannville U8U	222	- 443	Reassessment of recovery factor
Provost Cummings A4A	1 088	+ 563	Pool development
Rainbow Keg River A	10 740	+ 290	Reassessment of solvent flood reserves
Rainbow Keg River O	4 179	- 161	Reassessment of solvent flood reserves
Rainbow Keg River AA	7 403	- 297	Reassessment of solvent flood reserves
Rainbow Keg River I4I	48	- 238	Reassessment of recovery factor
Rosevear Bluesky A	446	+ 232	Pool development
Simonette D-3 D	134	- 133	Reassessment of recovery factor
Simonette Beaverhill Lake A	4 829	+ 1529	Reassessment of primary and waterflood reserves
Strome Ellerslie D	300	- 162	Reassessment of recovery factor
Sturgeon Lake South Triassic F	1 097	+ 243	Reassessment of recovery factor
Wainwright Nisku A & Camrose A	665	- 133	Reassessment of recovery factor
Wimborne D-3 A	4 940	+ 260	Reassessment of 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	286	3	2 121	83	193	66
100-999	1 023	11	316	12	69	24
30-99	1 314	14	72	3	17	6
1-29	6 722	72	45	2	13	4
Total	9 345	100	2 554	100	291	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. It also suggests that the EUB estimate of ultimate potential is still valid. Approximately 72 per cent of the estimated ultimate potential for conventional crude oil has been produced to year-end 2000. Remaining established reserves of 291 10^6 m^3 represent about 10 per cent of the ultimate potential. Known discoveries represent 82 per cent of the ultimate potential, leaving 18 per cent (576 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves yields 867 10^6 m^3 of conventional crude oil that will be available for future production.

In 2000, both the remaining established reserves and the annual production of crude oil declined. However, there are 576 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.

3.2 Supply of and Demand for Crude Oil

3.2.1 Crude Oil Supply

Over the past several years, production of crude oil, which consists of light-medium and heavy crude oil, has been on decline in Alberta. In 2000, total crude oil production declined to 118.8 10^3 m^3/d. Light-medium crude oil production declined by approximately 4.3 10^3 m^3/d (5 per cent) compared to 1999. However, heavy crude oil production in 2000 increased by 1.9 10^3 m^3/d (5 per cent) over 1999. This resulted in an overall decline in total crude oil production of only 2 per cent from 1999 to 2000, compared to the 11 per cent decline from 1998 to 1999. This reduction in the decline rate reflects industry's reaction to continued high crude oil prices by increasing oil well drilling and bringing some marginal wells back on production.

In projecting crude oil production over the forecast period, the EUB considered two components: expected crude oil production from existing wells (established reserves) at 2000 year-end and expected production from future wells (new discoveries and

Table 3.5. Conventional crude oil reserves by recovery mechanism as of December 31, 2000

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	3 762	850	0	0	850	23	-	-	23
Waterflood	2 881	436	377	0	813	15	13	-	28
Solvent flood	882	240	159	107	506	27	18	12	57
Gas flood	146	47	10	0	57	32	7	-	39
Heavy									
Primary depletion	1 533	194	0	0	194	13	-	-	13
Waterflood	382	45	89	0	134	12	23	-	35
Total	9 586	1 812	635	107	2 554				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, 2000

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	2 164	0	353	0	53	-	16	-
Lower	1 061	1 687	205	285	32	63	19	17
Jurassic	107	102	21	31	4	4	20	30
Triassic	297	24	62	2	12	0	21	9
Permian	14	0	7	0	1	-	53	
Mississippian	599	63	94	7	10	2	16	11
Devonian								
Upper	2 434	25	1 134	2	71	1	47	10
Middle	948	0	346	0	35	-	36	-
Other	47	14	3	0	3	-	6	2
Total	7 671	1 915	2 226	328	221	70	29	17

Table 3.7. Distribution of conventional oil reserves by formation as of December 31, 2000

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	252	34	7	3	1	2
Chinook	5	1	0	0	0	0
Cardium	1 781	299	41	19	12	14
Second White Specks	31	3	1	0	0	0
Doe Creek	73	14	4	1	1	1
Dunvegan	22	2	0	0	0	0
Lower Cretaceous						
Viking	339	64	6	4	3	2
Upper Mannville	1 521	238	55	16	9	19
Lower Mannville	888	188	35	9	7	12
Jurassic	208	52	8	2	2	3
Triassic	320	64	13	3	3	4
Permian-Belloy	14	7	1	0	0	0
Mississippian						
Rundle	471	75	7	5	3	2
Pekisko	84	14	2	1	1	1
Banff	107	12	2	1	0	1
Upper Devonian						
Wabamun	59	6	1	1	0	0
Nisku	441	202	15	5	8	5
Leduc	841	504	16	9	20	5
Beaverhill Lake	968	396	32	10	16	11
Slave Point	150	28	7	2	1	2
Middle Devonian						
Gilwood	301	130	9	3	5	3
Sulphur Point	9	1	0	0	0	0
Muskeg	52	8	1	1	0	0
Keg River	490	178	21	5	7	7
Keg River SS	44	18	1	0	1	0
Granite Wash	53	12	3	1	0	1

additions). Total production of crude oil is the sum of these two components. In forecasting future production, the EUB considered the crude oil price expectations and its impact on the economics of producing wells.

Crude oil production from existing wells over the period 1994-2000 is depicted in Figure 3.11. As this figure illustrates, wells drilled before 1994 contributed some 49 per cent to production in 2000. To project the expected production from the wells drilled prior to 2001, the EUB considered the following assumptions:

- Production from existing wells in 2001 would be 107.2 10^3 m^3/d.

- The rate of decline in currently established reserves is projected to average 15 per cent.

The annual growth in production is a function of the number of new wells successfully drilled, and the peak production and decline rate of these new wells. With relative stability in crude oil prices over the past two years, crude oil drilling activity has received momentum in 2000. The number of successful oil wells increased from about 1630 in 1999 to 2700 in 2000. With the expectation that the crude oil prices will remain generally in the same range over the forecast period (as described in Section 1.2), the total number of successful oil wells is projected to be 2700 for 2001 and 2002 and then decrease to 2500 wells for the remainder of the forecast period. Figure 3.12 shows the EUB's crude oil drilling forecast for successful wells. 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. Over time it is expected that the cumulative production from each years population of new wells will approximate the annual reserve growth from new pools, new EOR schemes and development of existing pools.

Although there was an increase in horizontal drilling in 2000, the number of horizontal wells has not increased appreciably over the past five years. In 2000, some 460 horizontal wells were drilled, representing 17 per cent of the total oil wells drilled. In 2000 there were 2540 active horizontal wells, producing approximately 15 per cent of the total crude oil production. Production from horizontal wells drilled in the past five years peaks at an average rate of 12.0 m^3/d.

Light-medium crude oil production, as shown in Figure 3.13, averaged 81.0 10^3 m^3/d in 2000 and is expected to decline to 55.7 10^3 m^3/d by 2010. Although crude oil prices and drilling forecasts are favourable, light crude oil production will continue to decline almost 4 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.

Light/heavy crude oil differentials, which are currently very wide, are expected to narrow over the forecast period, with heavy crude production expected to increase to 41.0 10^3 m^3/d by 2003. However, as shown on Figure 3.13, production will decline to 31.4 10^3 m^3/d by the end of the forecast period. Production of heavy crude oil from new drilling is not expected to offset declining production from existing pools.

The combined forecasts from existing and future wells indicate that crude oil production will decline from 118.8 10^3 m^3/d in 2000 to 87.1 10^3 m^3/d in 2010. In the first two years of the forecast period, reserves growth is expected to be about 25 10^6 m^3/year, followed by 23 10^6 m^3/year for the remainder of the forecast period. By 2010, if crude oil production follows the projection, Alberta will have produced some 84 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, butane, and natural gas as feedstock, along with synthetic crude oil, 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.

Figure 3.14 shows the capacity and location of Alberta refineries. In 2000, Alberta refineries with 68 10^3 m^3/d capacity used 35.2 $10^3 m^3$/d of crude oil. Adding the other feedstock requirements indicates that Alberta refineries will operate close to their capacity in 2004, when use of crude oil will peak at 44 10^3 m^3/d. No new refineries are assumed over the forecast period.

Figure 3.15 shows Alberta demand and exports of crude oil.

3.2.3 Crude Oil and Equivalent Supply

The growth in supply of non-upgraded bitumen and synthetic crude oil is expected to significantly offset the decline in conventional crude oil. As shown on Figure 3.16, supply from crude oil and equivalent is expected to increase from 242 10^3 m^3/day to 410 10^3 m^3/d over the forecast period.

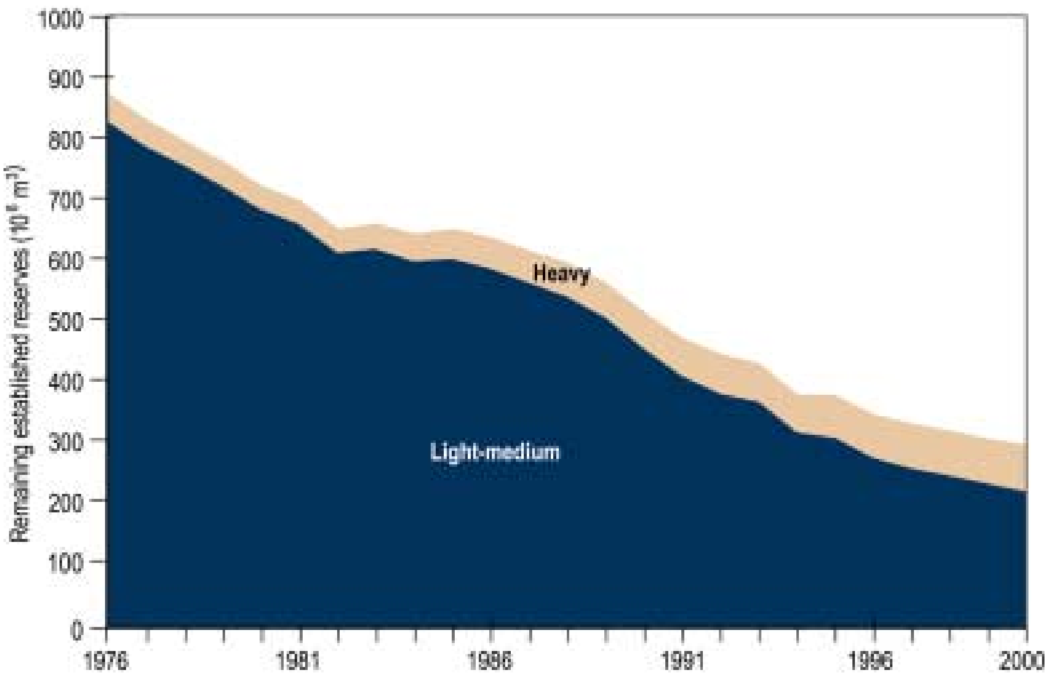


Figure 3.1. Remaining established reserves of crude oil

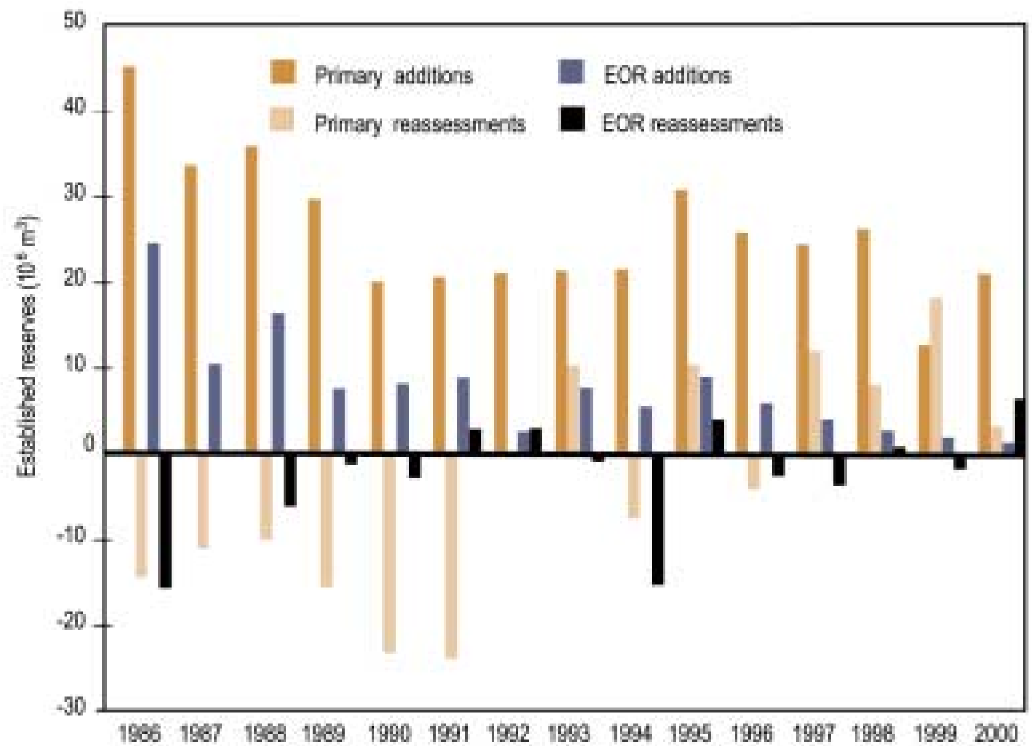


Figure 3.2. Total conventional crude oil reserves additions and reassessments

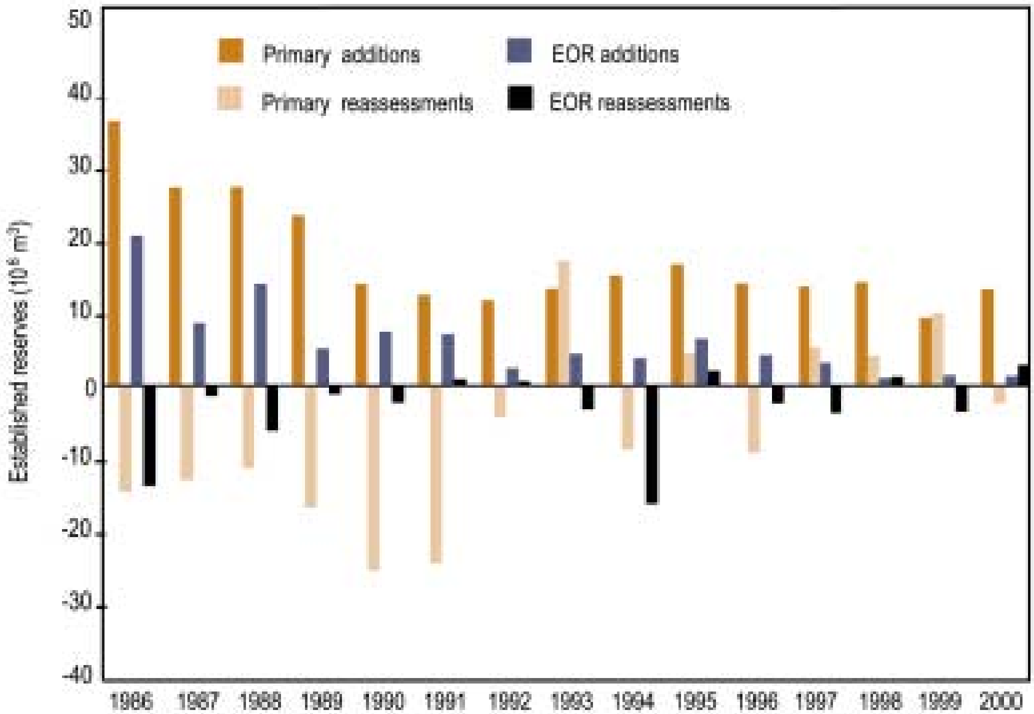


Figure 3.3. Light-medium crude oil reserves additions and reassessments

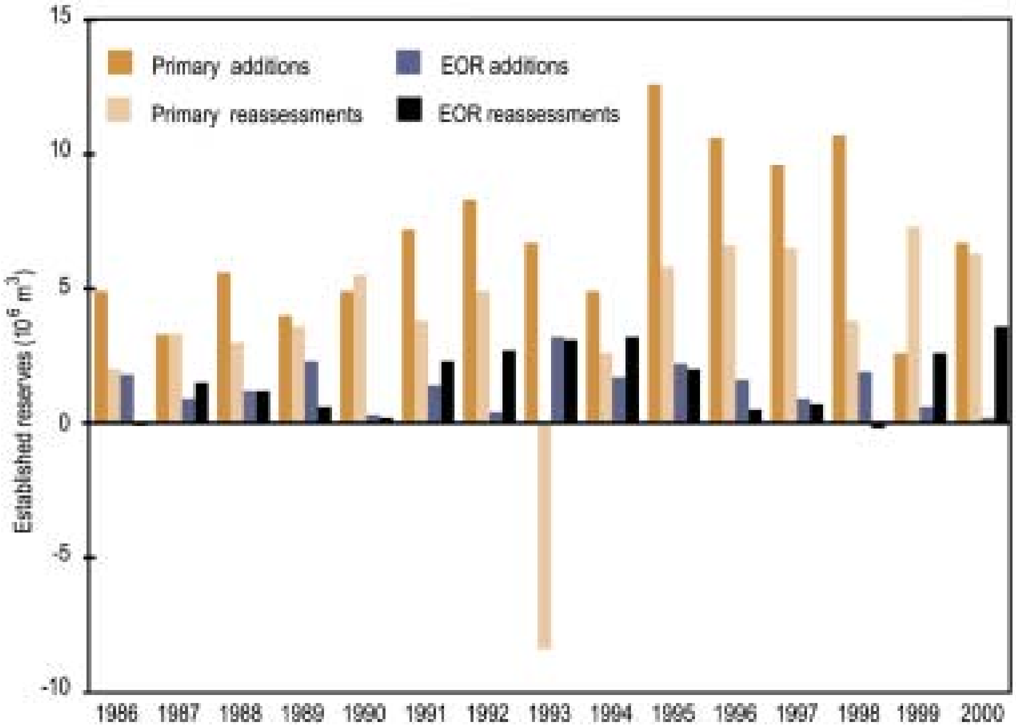


Figure 3.4. Heavy crude oil reserves additions and reassessments

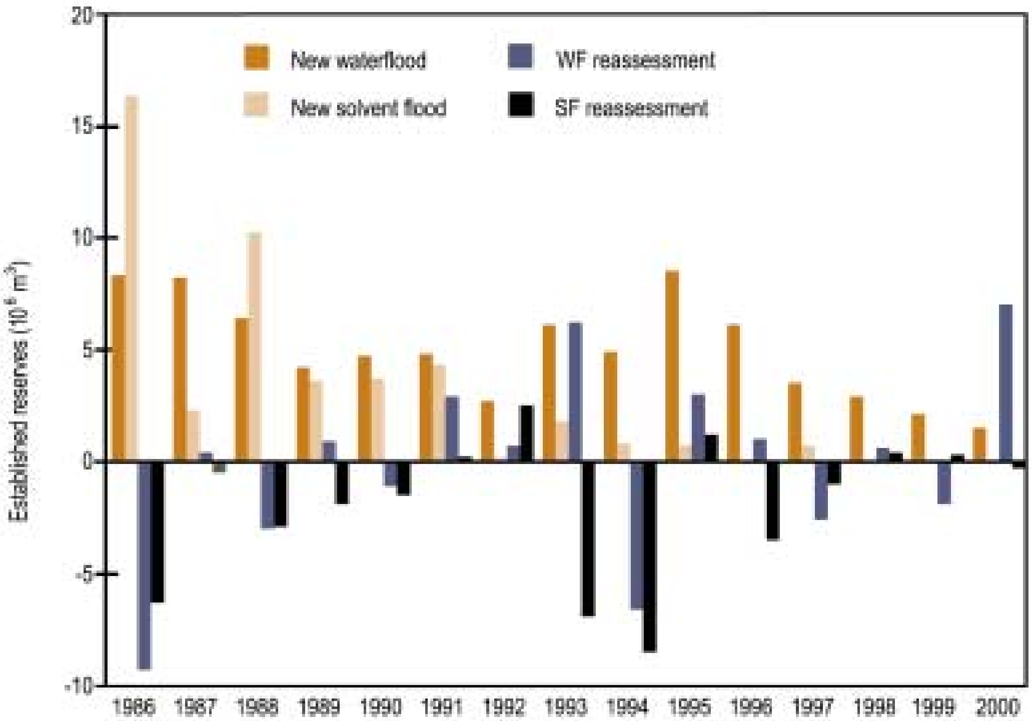


Figure 3.5. Change in reserves by recovery mechanisms

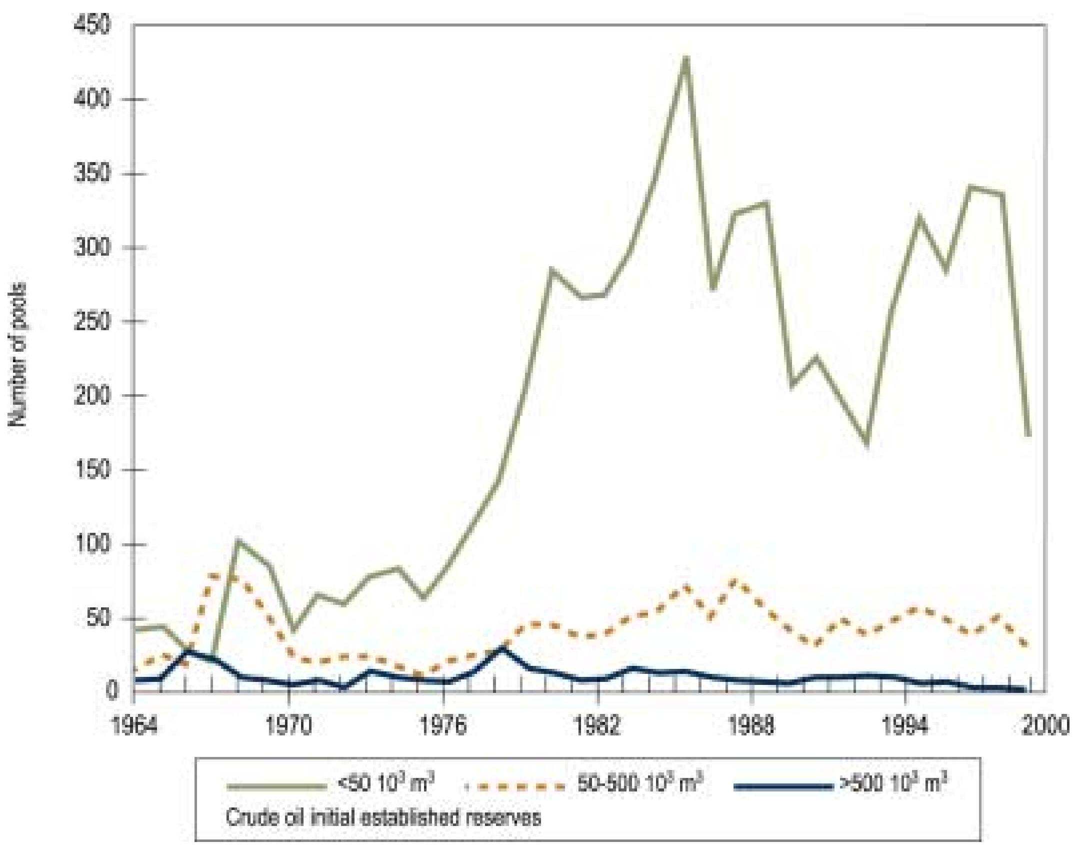


Figure 3.6. Oil pools by size and discovery year

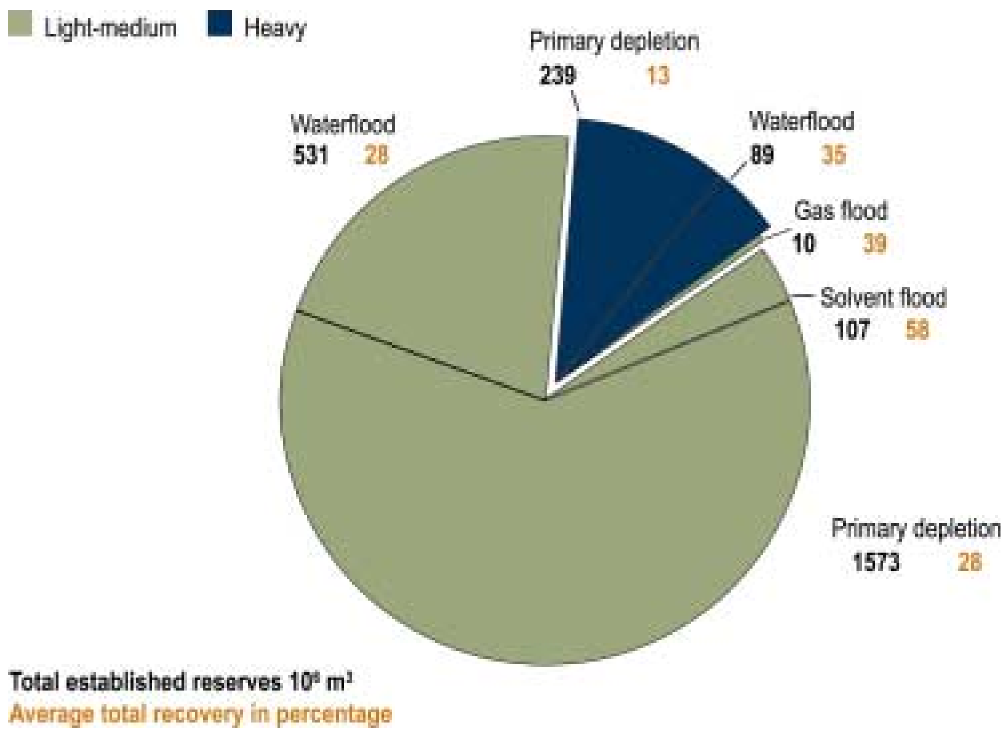


Figure 3.7. Crude oil reserves by recovery mechanisms

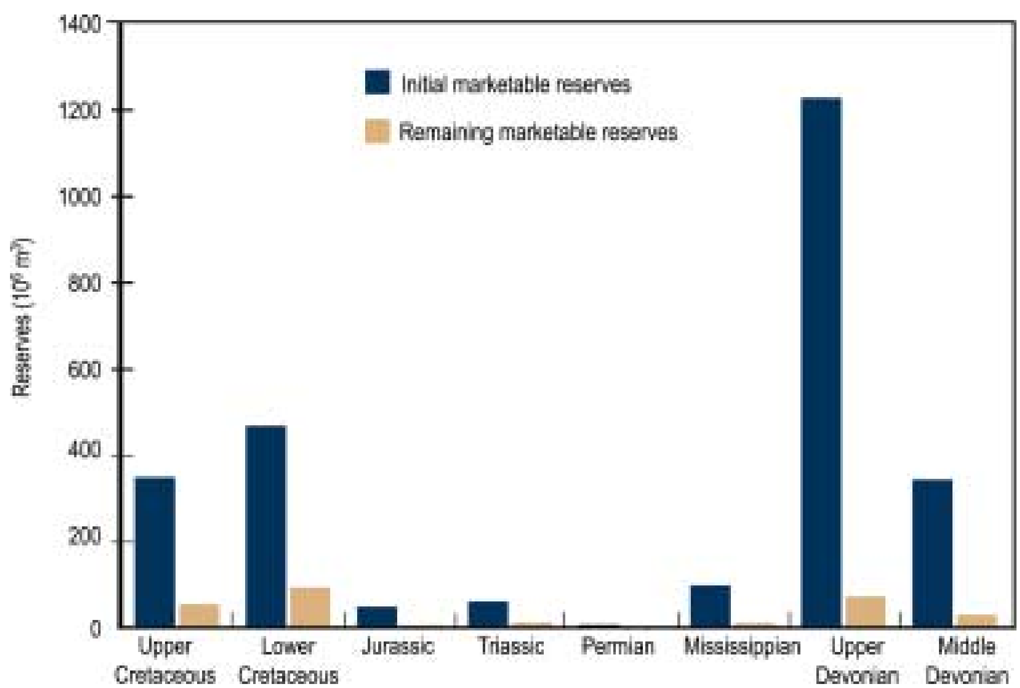


Figure 3.8. Geological distribution of conventional crude oil reserves

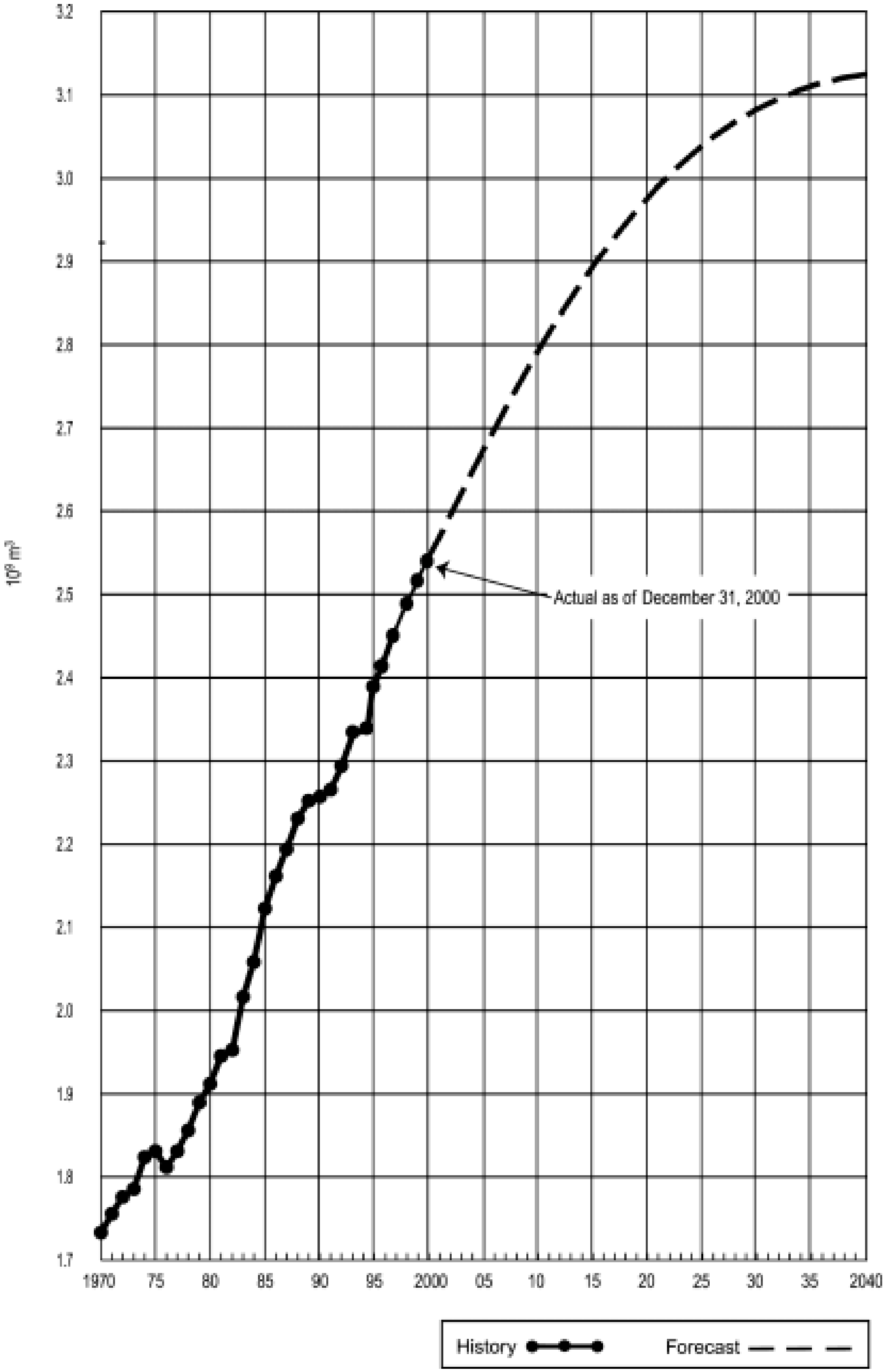


Figure 3.9. Growth of initial established reserves of conventional crude oil

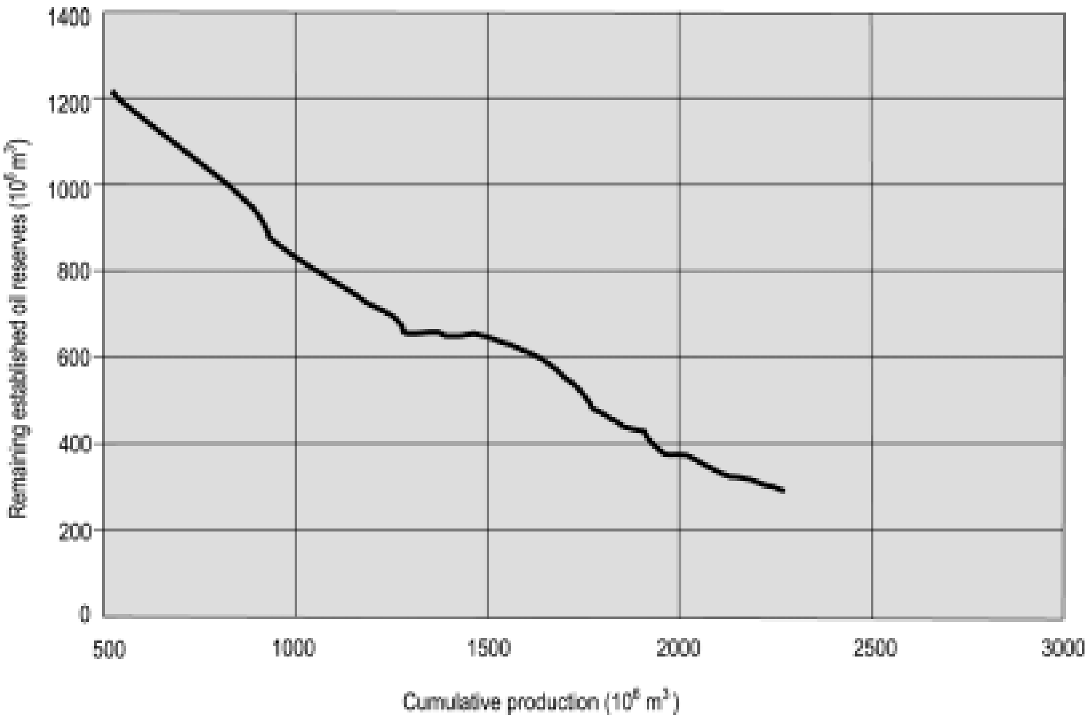


Figure 3.10. Alberta's remaining established oil reserves versus cumulative production

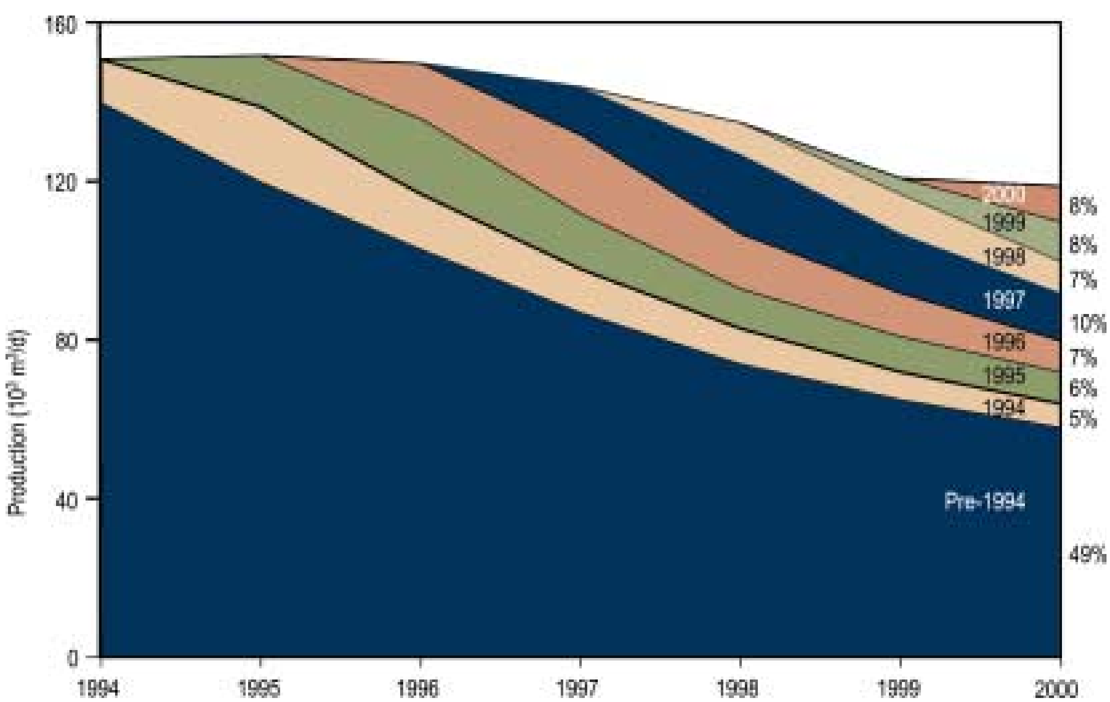


Figure 3.11. Total conventional crude oil production by drilled year

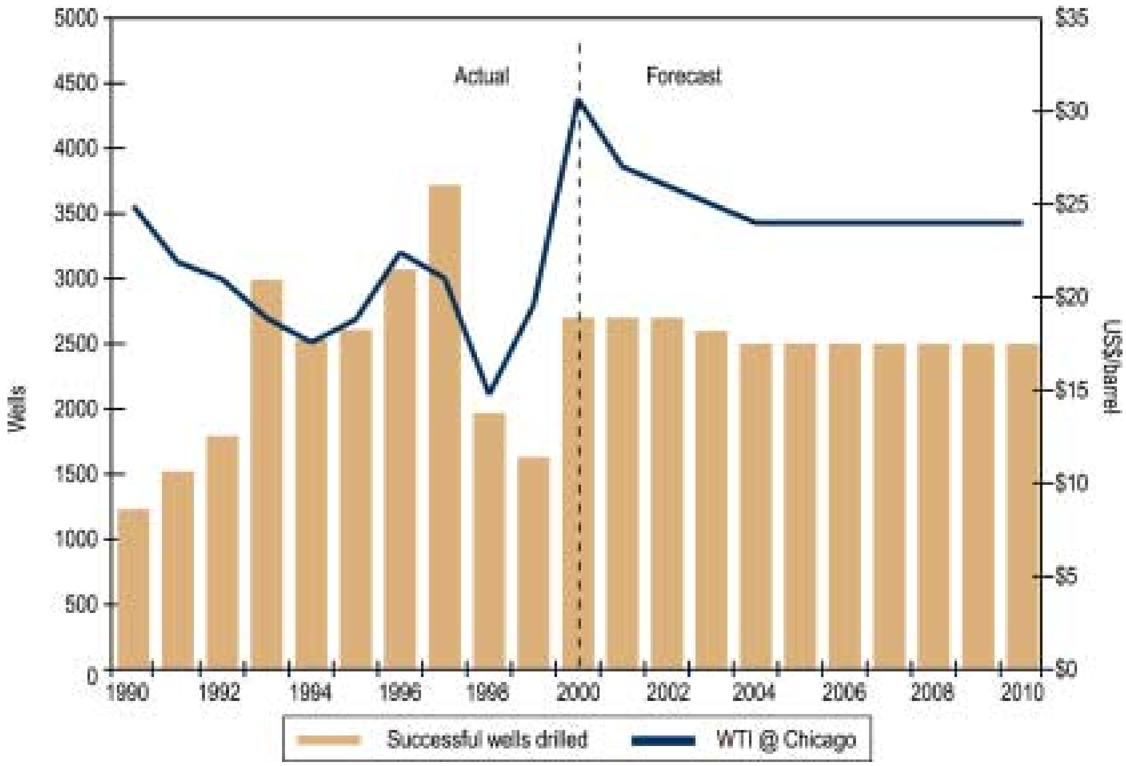


Figure 3.12. Alberta crude oil drilling activity

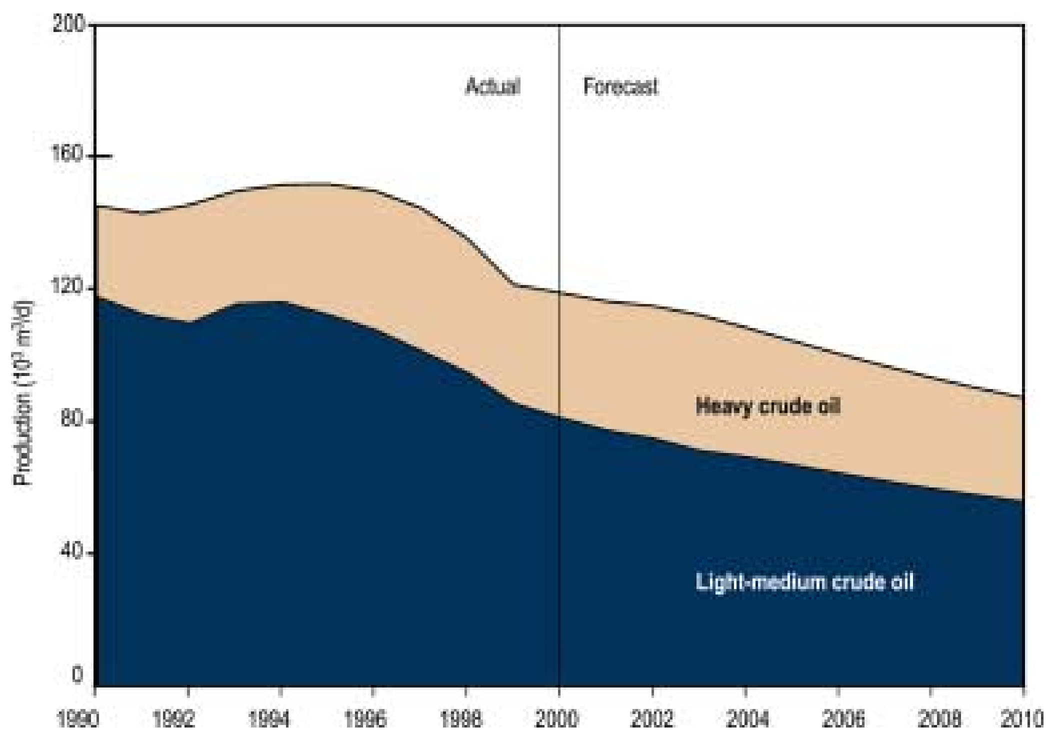


Figure 3.13. Alberta daily production of crude oil (actual and forecast)

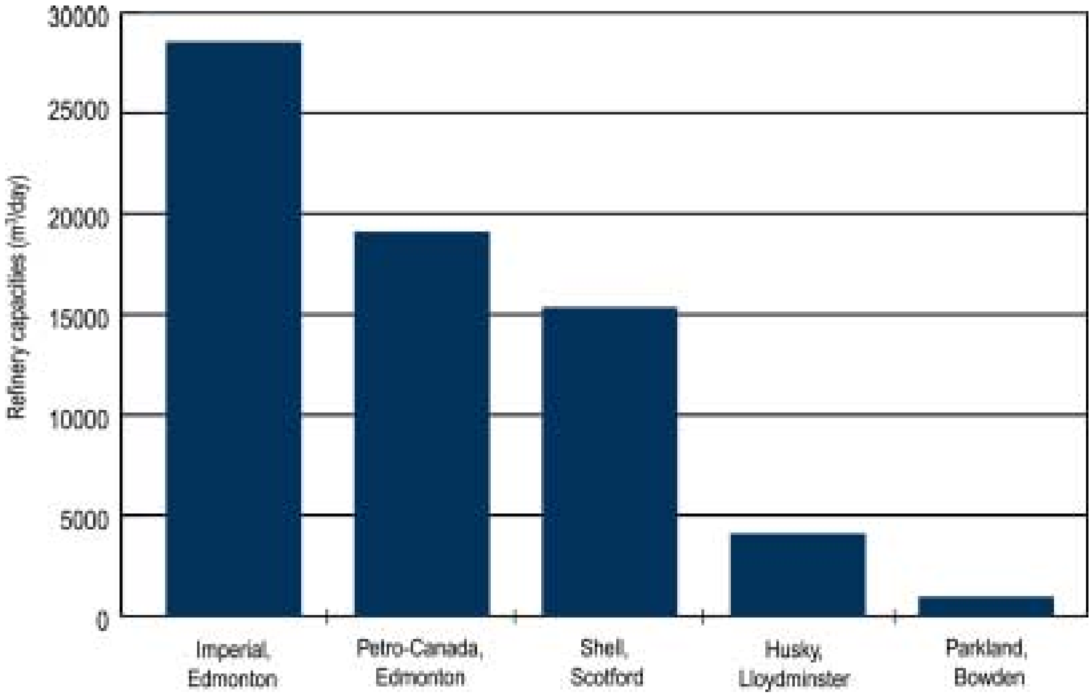


Figure 3.14. Capacity and location of Alberta refineries

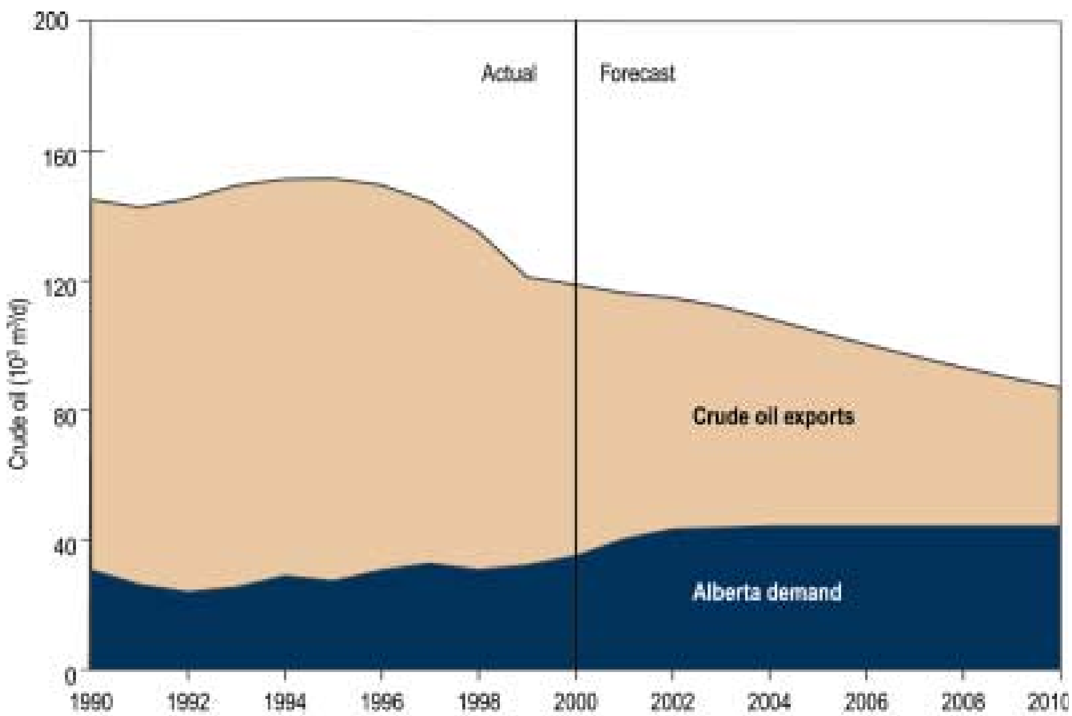


Figure 3.15. Alberta demand and exports of crude oil

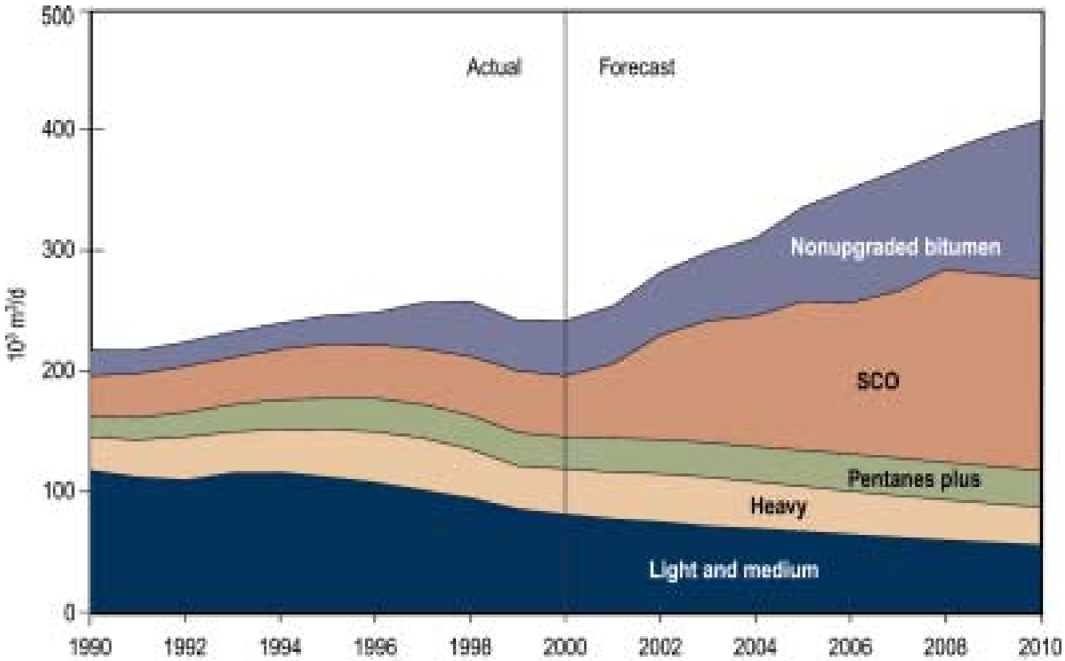


Figure 3.16. Alberta supply of crude oil and equivalent

4 Natural Gas

4.1 Reserves of Natural Gas

4.1.1 Provincial Summary

The EUB estimates the remaining established reserves of marketable gas in Alberta at December 31, 2000, to be 1210.7 billion cubic metres (10^9 m^3), having a thermal (heating value) energy content of 45.7 exajoules. This represents a net increase of 3.5 10^9 m^3 since December 31, 1999, which is the result of all reserves additions less marketed production that occurred during 2000. The reserves include ethane and other natural gas liquids subsequently recovered at reprocessing plants, as discussed in Section 4.1.8. Annual reserves additions and production of natural gas since 1974 are shown in Figure 4.1. Over the years additions have fluctuated as a result of economic factors and reassessments of existing pools, while annual production has risen steadily.

Details of the changes in remaining reserves during 2000 are shown in Table 4.1.

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

	2000	1999	Change
Initial established reserves			
Associated and solution	900.3	884.9	+ 15.4
Nonassociated	3 163.2	3 034.4	+ 128.8
	4 063.5	3 919.3	+144.2
Cumulative marketed production			
Associated and solution	671.6	650.9	20.7
Nonassociated	2 181.2	2 061.2	120.0
	2 852.8[a]	2 712.1[a]	140.7[a]
			(146.0)[c]
Remaining established reserves			
Associated and solution	228.7	234.0	-5.3
Nonassociated	982.0	973.2	+8.8
	1 210.7	1 207.2	+ 3.5
	(42 972)[b]		
	(1 270)[c]		

[a] May differ slightly from actual production.
[b] Imperial equivalent in billions 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 2000 natural gas reserves were assigned to 28 658 pools in the province. Of these, 7722 pools have never been placed on production and had aggregate initial established reserves of marketable gas of 144.1 10^9 m^3, or about 12 per cent of the province's remaining established reserves.

4.1.2 Growth of Marketable Gas Reserves

Initial established reserves increased by 144.2 10^9 m^3 from 1999, which is 3.5 10^9 m^3 more than Alberta's annual production of 140.7 10^9 m^3. This increase includes total reassessment of 17.5 10^9 m^3, the addition of 50.3 10^9 m^3 attributed to new pools booked in 2000, and development of existing pools, which added another 76.4 10^9 m^3. Thus, drilling added a total of 126.7 10^9 m^3, replacing 90 per cent of Alberta's 2000 annual natural gas production.

The addition of 17.5 10^9 m^3 from reassessments resulted from the study of some 2500 pools by EUB staff, which yielded positive reassessments totalling 127.5 10^9 m^3 and negative reassessments totalling 110 10^9 m^3. The largest positive reassessment, 42.6 10^9 m^3 (3.5 per cent of total remaining marketable reserves) was in the Southeastern Alberta Gas System. Current remaining marketable gas from the Southeastern Alberta Gas System now stands at approximately 140 10^9 m^3, or 11.6 per cent of the province's remaining established reserves. A review of 40 pools in the Foothills and Foothills Front areas resulted in downward revisions of 14.5 10^9 m^3. This was due to a reduction in in-place gas reserves and a downward adjustment of recovery factors because of water encroachment. Fields and pools with significant changes are listed in Table 4.2.

Alberta's remaining established reserves of marketable gas since 1975 are shown in Figure 4.2. A general decline has occurred since 1983.

4.1.3 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size as of December 31, 2000, is shown in Table 4.3. For the purposes of this table, commingled pools are considered as one and the Southeastern Alberta Gas System (MU) is considered on a field basis. The data show that pools with reserves of 300 million cubic metres (10^6 m^3) or more represent 6 per cent of all pools and contain about 45 per cent of the remaining marketable reserves. Figure 4.3 shows natural gas pool size by discovery year since 1951 and illustrates that the vast majority of pools drilled since the mid-1970s contained less than 300 10^6 m^3 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 Figure 4.4. The Upper and Lower Cretaceous period contains some 64.3 per cent of the province's remaining established reserves. The formations that contain the most significant volume of natural gas are the Upper Cretaceous Milk River and Medicine Hat Formation, with 11.2 per cent of the province's remaining reserves; the Lower Cretaceous Mannville Formation, with 34.7 per cent; and the Mississippian Rundle Formation, with 9.3 per cent.

4.1.5 Regional Distribution of Gas Reserves

As shown in Table 4.1, the remaining established reserves of marketable gas at December 31, 2000, is 1210.7 10^9 m^3. Section 4.1.11 discusses the ultimate potential of natural gas in Alberta and shows that 1536 10^9 m^3 are yet to be established.

The distribution of remaining established and yet-to-be-established reserves are shown in Figure 4.5. Area I includes the Foothills and Foothills Front regions, where natural gas is deep and production rates are relatively high. Areas II and III are classified as the southern and northern plains respectively and include shallow to medium-depth reserves. Although the majority of new gas wells are being drilled in Areas II and III, Alberta natural gas supplies will also depend on significant future reserves being discovered in Area I. The Foothills Front portion accounts for some 82 per cent of the yet-to-be-established reserves in Area 1.

Table 4.2. Major natural gas reserve changes, 2000

Pool	Initial established reserves (10^6 m^3) 2000	Change	Main reasons for change
Alderson Southeastern Alberta Gas System (MU)	43 767	+10 917	Re-evaluation of initial volume in-place
Bantry Southeastern Alberta Gas System (MU)	24 912	+7 653	Re-evaluation of initial volume in-place
Benjamin Rundle F	1 224	+1 043	Pool development
Blackstone Beaverhill Lake A	15 964	-4 036	Re-evaluation of initial volume in-place
Burnt Timber Rundle A & B	12 000	-2 090	Re-evaluation of initial volume in-place and recovery factor
Carrot Creek Viking C	1 037	+ 996	Re-evaluation of initial volume in-place
Chedderville Leduc D	383	-1 006	Re-evaluation of initial volume in-place
Clearwater Rundle A	2 376	-629	Re-evaluation of initial volume in-place
Coleman Rundle A & Palliser B	5 628	-1 529	Re-evaluation of initial volume in-place
Dunvagen Debolt A,B,C,D & Elkton C	29 544	+1 511	Re-evaluation of initial volume in-place
Elmworth Falher B-1	1 804	-846	Re-evaluation of initial volume in-place
George	3 003	+ 514	Re-evaluation of initial volume in-place
Golden Spike D – 3 A	3 543	+ 829	Re-evaluation of initial volume in-place
Hardy McMurray BB	1 135	+ 679	Re-evaluation of initial volume in-place
Hussar Belly River HH	474	-571	Re-evaluation of initial volume in-place
Jumping Pound Rundle C	11 840	-760	Re-evaluation of initial volume in-place and recovery factor
Knopcik Montney A	4 809	-2 076	Re-evaluation of initial volume in-place and recovery factor
Knopcik Nikanassin D	48	-664	Re-evaluation of initial volume in-place and recovery factor
La Glace Halfway G & Montney B	4 760	+2 004	Pools commingled and re-evaluation of initial volume in-place
Limestone Rundle A & B	10 193	+2 673	Re-evaluation of initial volume in-place
Lone Pine Creek Wabamun A	10 665	+ 934	Re-evaluation of initial volume in-place
Medicine Hat Southeastern Alberta Gas System (MU)	125 238	+ 9 724	Re-evaluation of initial volume in-place

(continued)

Table 4.2. Major natural gas reserve changes, 2000 (concluded)

Pool	Initial established reserves (10^6 m^3) 2000	Change	Main reasons for change
Minehead Beaverhill Lake A	603	-547	Re-evaluation of initial volume in-place and recovery factor
Moose Rundle C	293	-1 286	Re-evaluation of initial volume in-place
Pine Creek Rundle C	261	-781	Re-evaluation of initial volume in-place and recovery factor
Princess Southeastern Alberta Gas System (MU)	24 900	+6 437	Re-evaluation of initial volume in-place
Rainbow Bluesky A	8 360	+760	Re-evaluation of initial volume in-place
Rainbow South Keg River E	1 200	+714	Re-evaluation of initial volume in-place
Ram Rundle A	1 666	-578	Re-evaluation of initial volume in-place and recovery factor
Ram Rundle B	161	-511	Re-evaluation of initial volume in-place and recovery factor
Ricinus Cardium B	1 500	+854	Re-evaluation of initial volume in-place
Simonette Beaverhill Lake A	1 440	+673	Re-evaluation of initial volume in-place and recovery factor
Slater Rundle A	1 085	-793	Re-evaluation of initial volume in-place
Strachan D-3 A	27 746	+603	Re-evaluation of initial volume in-place and recovery factor
Suffield Southeastern Alberta Gas System (MU)	61 750	+ 14 250	Re-evaluation of initial volume in-place
Valhalla Halfway N	115	-589	Re-evaluation of initial volume in-place
Verger Southeastern Alberta Gas System (MU)	15 349	+3 851	Re-evaluation of initial volume in-place
Voyager Rundle F	1 507	+1 507	New pool
Waterton Rundle-Wabamun A	51 271	+771	Re-evaluation of initial volume in-place
Westerose D-3	6 647	+744	Re-evaluation of initial volume in-place
Wildcat Hills Rundle D	128	-917	Re-evaluation of initial volume in-place

Table 4.3. Distribution of natural gas reserves by pool size, 2000

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+	316	1.1	2 264	55.7	316	26.1
300-1499	1 284	4.5	750	18.5	232	19.2
1-299	27 058	94.4	1 050	25.8	663	54.7
Total	28 658	100.0	4 064	100.0	1 211	100.0

Table 4.4. Geological distribution of established natural gas reserves, 2000

Geological period	1 Raw gas: Initial volume in-place (10^9 m^3)	2 Marketable gas: Initial established reserves (10^9 m^3)	3 Marketable gas: Remaining established reserves (10^9 m^3)	4 Raw gas: Initial volume in-place (%)	5 Marketable gas: Initial established reserves (%)	6 Marketable gas: Remaining established reserves (%)
Upper Cretaceous						
Belly River	180	109	49	2.7	2.7	4.0
Milk River & Med Hat	544	355	133	7.7	8.7	11.2
Cardium	445	95	38	6.2	2.3	3.1
Second White Specks	10	6	4	0.1	0.2	0.3
Other	108	61	19	1.5	1.5	1.6
Subtotal	1 287	626	243	18.2	15.4	20.1
Lower Cretaceous						
Viking	381	265	64	5.4	6.5	5.3
Basal Colorado	42	34	4	0.6	0.8	0.2
Mannville	1 891	1 239	420	26.8	30.5	34.7
Other	341	142	47	4.8	3.5	4.0
Subtotal	2 655	1 680	535	37.6	41.3	44.2
Jurassic						
Jurassic	92	60	28	1.3	1.5	2.3
Other	49	32	10	0.8	0.8	1.0
Subtotal	141	92	38	2.1	2.3	3.3
Triassic						
Triassic	185	115	62	2.8	2.8	5.1
Other	25	17	5	0.4	0.4	0.4
Subtotal	210	132	67	3.2	3.2	5.5
Permian						
Belloy	9	6	3	0.1	0.1	0.2
Subtotal	9	6	3	0.1	0.1	0.2
Mississippian						
Rundle	899	566	113	12.7	14.0	9.3
Other	299	198	35	4.2	4.9	3.0
Subtotal	1 198	764	148	16.9	18.9	12.3

(continued)

Table 4.4. Geological distribution of established natural gas reserves, 2000 (concluded)

Geological period	1 Raw gas Initial volume in-place (10^9 m^3)	2 Marketable gas Initial established reserves (10^9 m^3)	3 Marketable gas Remaining established reserves (10^9 m^3)	4 Raw gas Initial volume in-place (%)	5 Marketable gas Initial established reserves (%)	6 Marketable gas Remaining established reserves (%)
Upper Devonian						
Wabamun	233	111	30	3.3	2.7	2.5
Nisku	120	56	23	1.7	1.4	2.0
Leduc	472	244	33	6.7	6.0	2.7
Beaverhill Lake	469	209	51	6.6	5.2	4.2
Other	162	92	12	2.3	2.2	1.0
Subtotal	1 456	712	149	20.6	17.5	12.4
Middle Devonian						
Sulphur Point	12	8	4	0.2	0.2	0.3
Muskeg	5	2	1	0.1	0.1	0.0
Keg River	61	25	16	0.8	0.6	1.3
Other	32	14	4	0.5	0.3	0.3
Subtotal	110	49	25	1.6	1.2	1.9
Confidential[a]						
Subtotal	4	3	3	0.1	0.1	0.1
Total	7 070 (251 000)[a]	4 063 (145 000)[a]	1 211 (43 000)[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.

4.1.6 Reserves of Natural Gas Containing Hydrogen Sulphide

Natural gas that contains any measurable volume of hydrogen sulphide (H_2S) is classified as sour. As of December 31, 2000, sour gas accounted for some 23.5 per cent (285 10^9 m^3) of the province's total remaining established reserves and about 30 per cent of natural gas marketed in 2000. The provincial average H_2S concentration in sour gas is 9.4 per cent.

The distribution of established reserves for sweet and sour gas for year-end 2000 is shown in Table 4.5. The remaining marketable reserves from sweet and sour gas since 1984 is shown in Figure 4.6. The distribution of sour gas reserves by H_2S content is shown in Table 4.6.

4.1.7 Reserves of Pools Calculated on an Energy Basis

Reserves of major retrograde condensate pools are tabulated both on energy content and on a volumetric basis. Table 4.7 lists the initial energy in-place, the recovery factor, and surface loss factor (both on an energy basis), as well as the initial marketable energy for each pool. 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 section (spreadsheet on accompanying CD), but with recovery factors and surface loss factors deleted.

Table 4.5. Distribution of sweet and sour gas reserves, 2000 (10^6 m^3)

Type of gas	Raw gas: Initial volume in-place	Raw gas: Initial producible	Marketable gas: Initial established reserves	Marketable gas: Net cumulative production	Marketable gas: Remaining established reserves
Sweet					
Associated	472	374	528	371	157
Solution	751	280			
Nonassociated	3 426	2 366	2 196	1 427	769
Subtotal	4 649	3 020	2 724	1 798	926
Sour					
Associated	430	348	373	301	72
Solution	290	172			
Nonassociated	1 701	1 328	967	754	213
Subtotal	2 421	1 848	1 340	1 055	285
Total	7 070 (251)[a]	4 868 (173)[a]	4 064 (144)[a]	2 853 (101)[a]	1 211 (43)
Sour gas % of total	34.2	38.0	33.0	37.0	23.5

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

Table 4.6. Distribution of sour gas reserves by H_2S content, 2000

H_2S content in raw gas	Initial established reserves (10^9 m^3): Associated & solution	Initial established reserves (10^9 m^3): Nonassociated	Remaining established reserves (10^9 m^3): Associated & solution	Remaining established reserves (10^9 m^3): Nonassociated	Total	%
Less than 2	245	299	50	71	121	42
2.00-9.99	97	352	15	85	100	35
10.00-19.99	19	178	4	27	31	11
20.00-29.99	12	49	3	16	19	7
Over 30	0	89	0	14	14	5
Total	373	967	72	213	285	100
%	28	72	25	75		

4.1.8 Reserves of Ethane and Other Natural Gas Liquids Included in Gas Reserves

The remaining established reserves of natural gas discussed in Section 4.1.1 are determined at the field plant gate. A portion of the ethane and other natural gas liquids contained in the marketable gas stream leaving the field plants are extracted downstream at reprocessing plants. It is expected that some 39 10^9 m^3 will be extracted, thereby reducing the remaining established reserves of marketable gas and the thermal energy content from 1211 10^9 m^3 to 1172 10^9 m^3 and from 45.2 to 42.6 exajoules respectively.

Reserves of ethane and other natural gas liquids (NGL) are discussed in more detail in Section 5 of this report.

Table 4.7 Reserves of pools calculated on an energy basis, 2000

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	1 489	76.22	113	0.75	0.60	34	41.36	823
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	4 036	51.55	208	0.90	0.25	140	41.59	3 366
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.

4.1.9 Multifield Pools

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

4.1.10 Coal-Bed Methane Reserves

There has been considerable interest in coal-bed methane in Alberta over the past year. However, the resource remains largely untapped. While the EUB agrees that coal-bed methane holds the potential for significant reserves, there is a lack of information, particularly reservoir and production data, to enable a reasonable reserves assessment. For this reason, the EUB has not conducted an assessment of coal-bed methane reserves for the province.

4.1.11 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. This estimate now appears conservative, and the EUB has undertaken an ultimate potential study targeted for completion in 2003. Figure 4.7 shows the historical and forecast growth in initial established reserves of marketable gas.

As illustrated in Figure 4.8, some 72.6 per cent of the ultimate potential of 5600 10^9 m^3 has been established as of year-end 2000. Of this established reserves, cumulative production of 2852.8 10^9 m^3 represents 51 per cent and the remaining established of 1211 10^9 m^3 represents 21.6 per cent of the ultimate potential. This leaves 27.4 per cent, or some 1536 10^9 m^3, of natural gas yet to be discovered. This number added to the remaining established gas reserves yields 2747 10^9 m^3 of natural gas, or 49 per cent of the total ultimate potential, that will be available for future use.

4.2 Supply of and Demand for Natural Gas

4.2.1 Natural Gas Supply

Alberta produced 146 10^9 m^3 of marketable gas (on the basis of 37.4 megajoules [MJ] per m^3) in 2000. New additions to pipeline capacity leaving the province have allowed Alberta to market natural gas throughout North America, leading to the development of a continental marketplace. This has led to a tightening of natural gas supply in the province and an increase in natural gas prices. A considerable amount of drilling has taken place in the past few years, and producers are using strategies such as infill drilling to increase production levels.

Major factors affecting natural gas production include natural gas prices, drilling activity, the location of Alberta's reserves, and the production characteristics of today's wells.

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

The number of successful natural gas wells drilled in Alberta from 1990 to 2000 is shown in Figure 4.9, along with the number of wells connected (placed on production) in each year. In 2000 some 8228 successful natural gas wells were drilled in the province, an increase of 37 per cent over 1999 levels. A large portion of recent natural gas drilling activity has taken place in southeastern Alberta, representing 50 per cent of all natural gas wells drilled in 2000.

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 continue to increase to 9100 in 2001 and 10 500 in 2002, with roughly half of the wells being drilled in southeastern Alberta. By 2003, some 11 000 natural gas wells are forecast to be drilled annually, falling to 10 000 per year from 2006 onward. Figure 4.10 illustrates the drilling forecast.

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 1991-1999 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 2000 are illustrated in Figures 4.11 and 4.12.[2]

The historical raw gas production in Alberta is presented in Figure 4.13. Each band represents production from new well connections by year, except for the bottom band, which represents production from wells connected prior to1994 as a total. The percentages shown on the right-hand side of the chart by band represent the share of each band's production to the total production from natural gas wells in 2000. Over 50 per cent of total production in 2000 came from natural gas wells connected since 1996. Declines in natural gas production from new well connections have been evaluated after the wells drilled in a given year complete a full year of production. Table 4.8 shows decline rates for wells connected from 1990 to 1998 with respect to the first, second, and third year of decline.

Table 4.8. Production decline rates for new well connections (%)

Year wells connected	First-year decline	Second-year decline	Third-year decline
1990	17	10	18
1991	12	19	19
1992	29	23	15
1993	25	17	19
1994	26	23	15
1995	30	25	16
1996	31	27	16
1997	32	28	-
1998	32	-	-

[2] The EUB has divided the province into 8 areas. This breakdown is a modified version of the Petroleum Services Association of Canada (PSAC) areas, with PSAC area 7 divided into areas 7 and 8.

More recently connected wells are exhibiting much steeper declines in production in the first two years compared to wells connected in the early 1990s. However, by the third year of production the decline rates have not changed significantly over time. The decline rates tend to stabilize at some 16 per cent from the third year forward.

Future production is estimated by assuming current decline rates for production from existing wells and adding production from new wells connected during the forecast period. Based on observed performance, existing production is assumed to decline at 16 per cent per year. The projection for new natural gas is based on production from new wells declining at a rate of 30 per cent the first year, 24 per cent the second year, and 16 per cent the third year and thereafter.

New well connections today start producing at much lower rates than new wells placed on production in previous years. Figure 4.14 shows the average initial productivities (peak rate) of new wells by connection year. A second average initial productivity for new wells is shown in the figure that excludes southeastern Alberta (Area 3). In 1999, initial rates of wells outside of Area 3 produced at rates 65 per cent higher than the provincial average.

To project production, 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 2001 and will decrease to 1.5 10^3 m^3/d by 2010.
- The average initial productivity of new natural gas wells in the rest of the province will be 12 10^3 m^3/d in 2001 and will decrease to 10 10^3 m^3/d by 2010.
- Consideration was given to the share of production expected to come from areas with significant remaining and yet-to-be-established reserves (e.g., in the Foothills Front area).

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 2010, as shown in Figure 4.15. The production of natural gas from conventional reserves is expected to increase from 146 10^9 m^3 in 2000 to 150 10^9 m^3 by 2003. Production levels are expected to decline to 135 10^9 m^3 by the end of the forecast period, a decline of 2 per cent per year over the last 5 years of the forecast.

At current prices, it is expected that companies will be assessing the potential for coal-bed 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 coal-bed methane production over the forecast period. Producers in Alberta are largely drilling for conventional gas strikes in areas where outcome is more certain. By 2010, if natural gas production rates follow the projection, Alberta will have recovered some 76 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.

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability and is not used in the EUB's long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas 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 4.15 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 4.9.

Table 4.9. Commercial natural gas storage pools as of December 31, 2000

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3)	Injection volumes, 2000 (10^6 m^3)	Withdrawal volumes, 2000 (10^6 m^3)
Carbon Glauconitic	ATCO	1 127	16 900	804	1104
Crossfield East Elkton A & D	Amoco Canada Petroleum Limited	1 127	14 090	721	1435
Golden Spike D-3A	Imperial Oil Resources Limited	349	3 380	393	839
Hussar Glauconitic R	Husky Oil Operations Ltd.	423	5 635	497	215
McLeod Cardium A	Texaco Canada Petroleum Inc.	704	19 720	326	553
Sinclair Gething D	Alberta Energy Company Ltd.	225	2 820	165	112
Suffield Upper Mannville I & K, and Bow Island N & BB	Alberta Energy Company Ltd.	2 395	50 715	1371	1899

As Figure 4.16 illustrates, 2000 natural gas withdrawals exceeded injection by 1882 10^6 m^3, which represents 1.3 per cent of marketable gas production in the province that year. This large increase in withdrawal volumes resulted from unusually high natural gas demand and record natural gas prices in the winter months.

Marketable gas production volumes determined for 2000 were reduced to account for production from these storage pools, as the natural gas had already been processed as marketable gas. 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.

4.2.2 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 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 the capacity to move 37.5 10^6 m^3/d of rich natural gas from British Columbia and Alberta to the Chicago area. Alliance is running at capacity today, with 80 per cent of the natural gas sourced from Alberta.

Figure 4.15 shows Alberta natural gas demand and production. Exports represent the difference between natural gas production and Alberta demand. In the year 2000, some 25 per cent of Alberta production was used domestically. Some 47 per cent of production was exported to U.S. markets, and 28 per cent was shipped to other Canadian provinces.

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 residents and commercial and institutional gas consumers who do not have alternative sustainable fuel sources. Alberta's established reserves and trends in growth and discoveries of reserves of gas are considered in this calculation.

By the end of forecast period, domestic demand will reach 49 10^9 m^3 from the year 2000 level of 36 10^9 m^3, representing 36 per cent of total production. Figure 4.17 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 1.6 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. Over the forecast period no real growth in commercial gas demand is expected.

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 2000 to 12 10^9 m^3 by 2010.

As well, the electricity industry will 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 2000 to 6 10^9 m^3 by 2010.

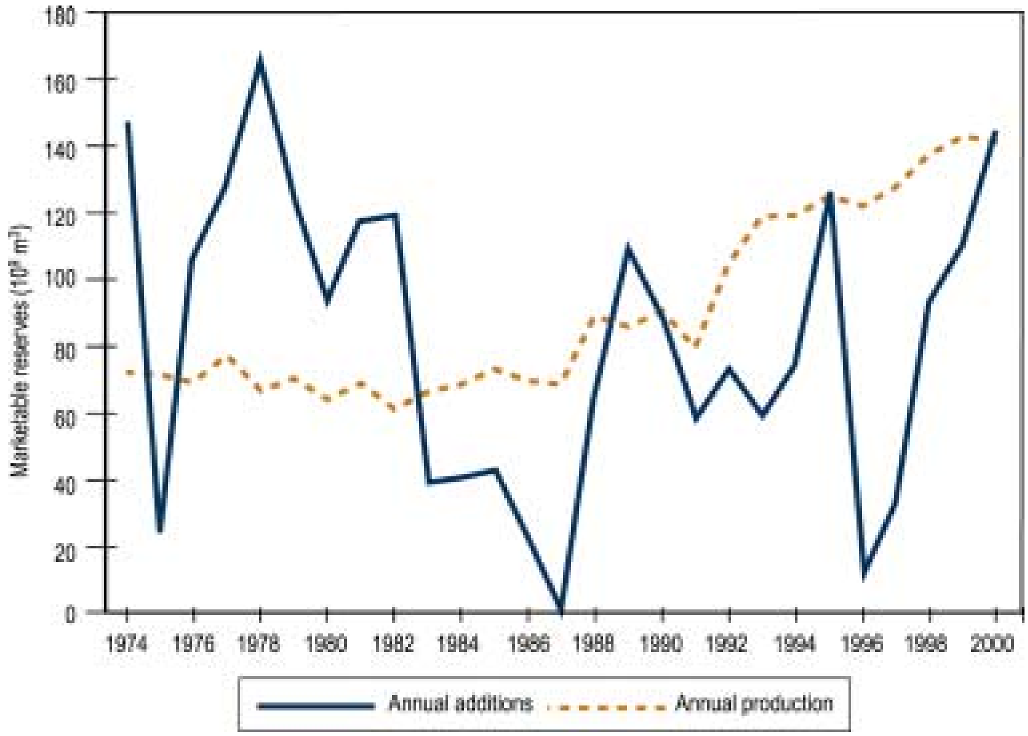


Figure 4.1. Annual additions and production of marketable gas

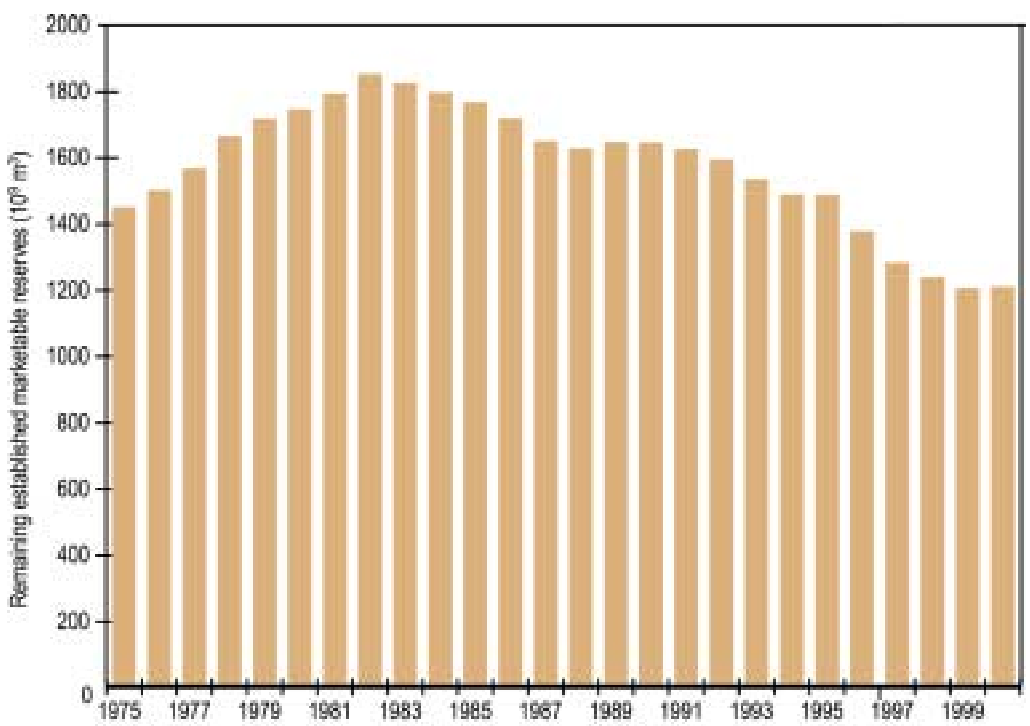


Figure 4.2. Remaining established natural gas reserves

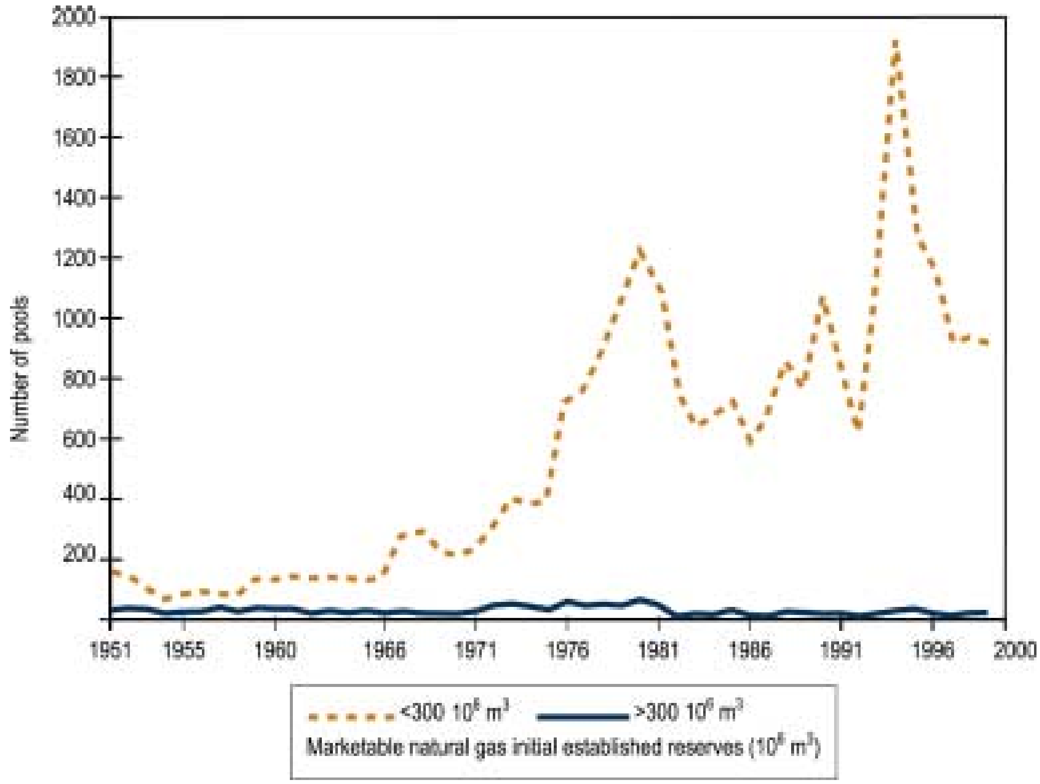


Figure 4.3. Gas pools by size and discovery year

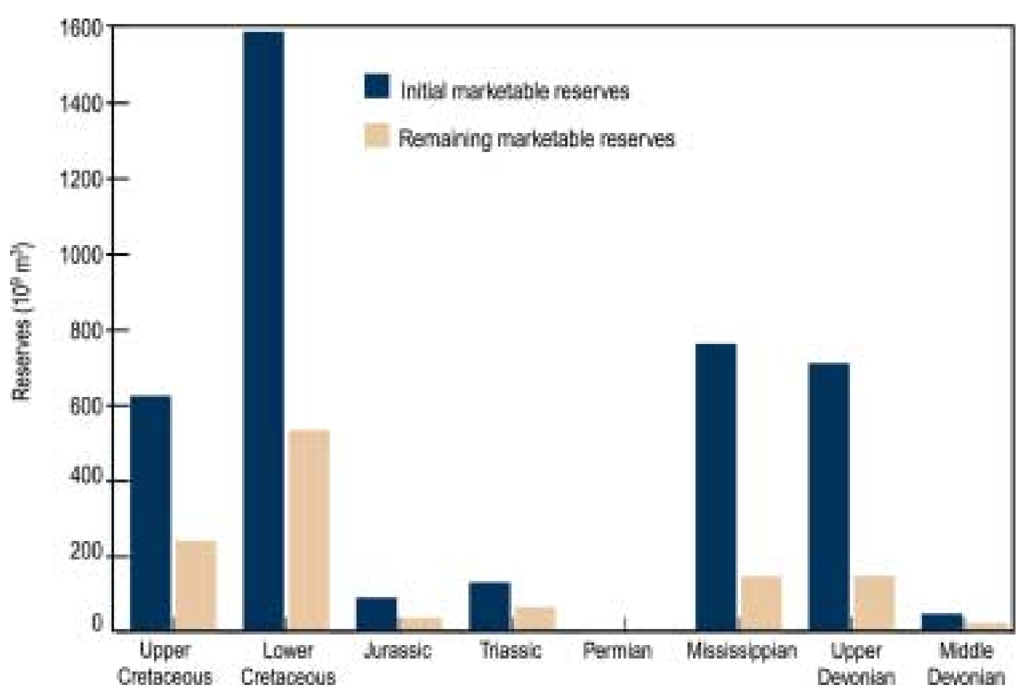


Figure 4.4. Geological distribution of marketable gas reserves

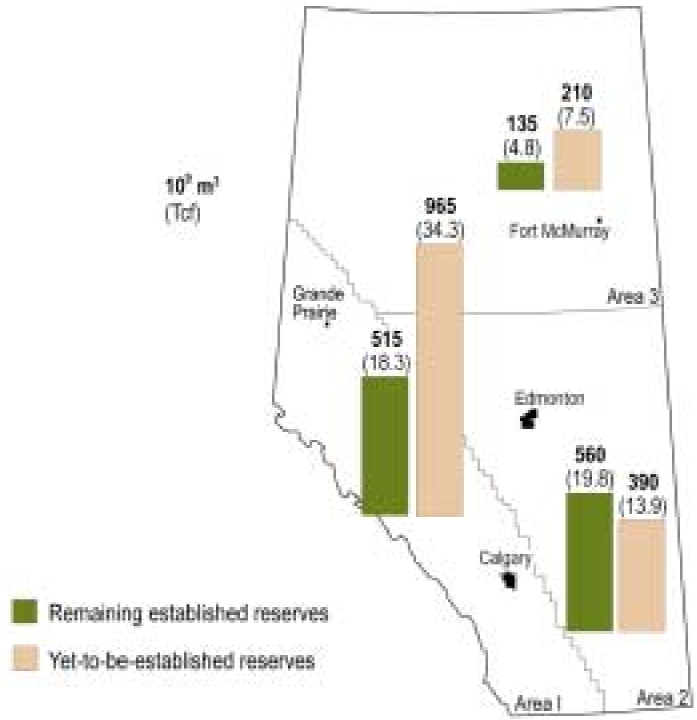


Figure 4.5. Regional distribution of reserves

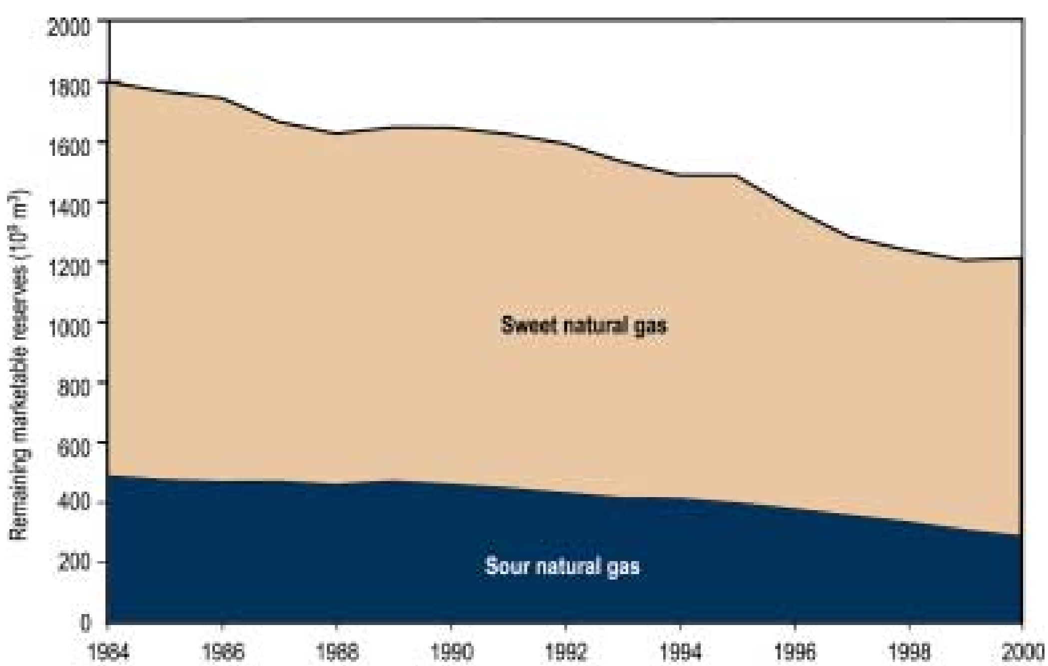


Figure 4.6. Remaining marketable reserves of sweet and sour gas

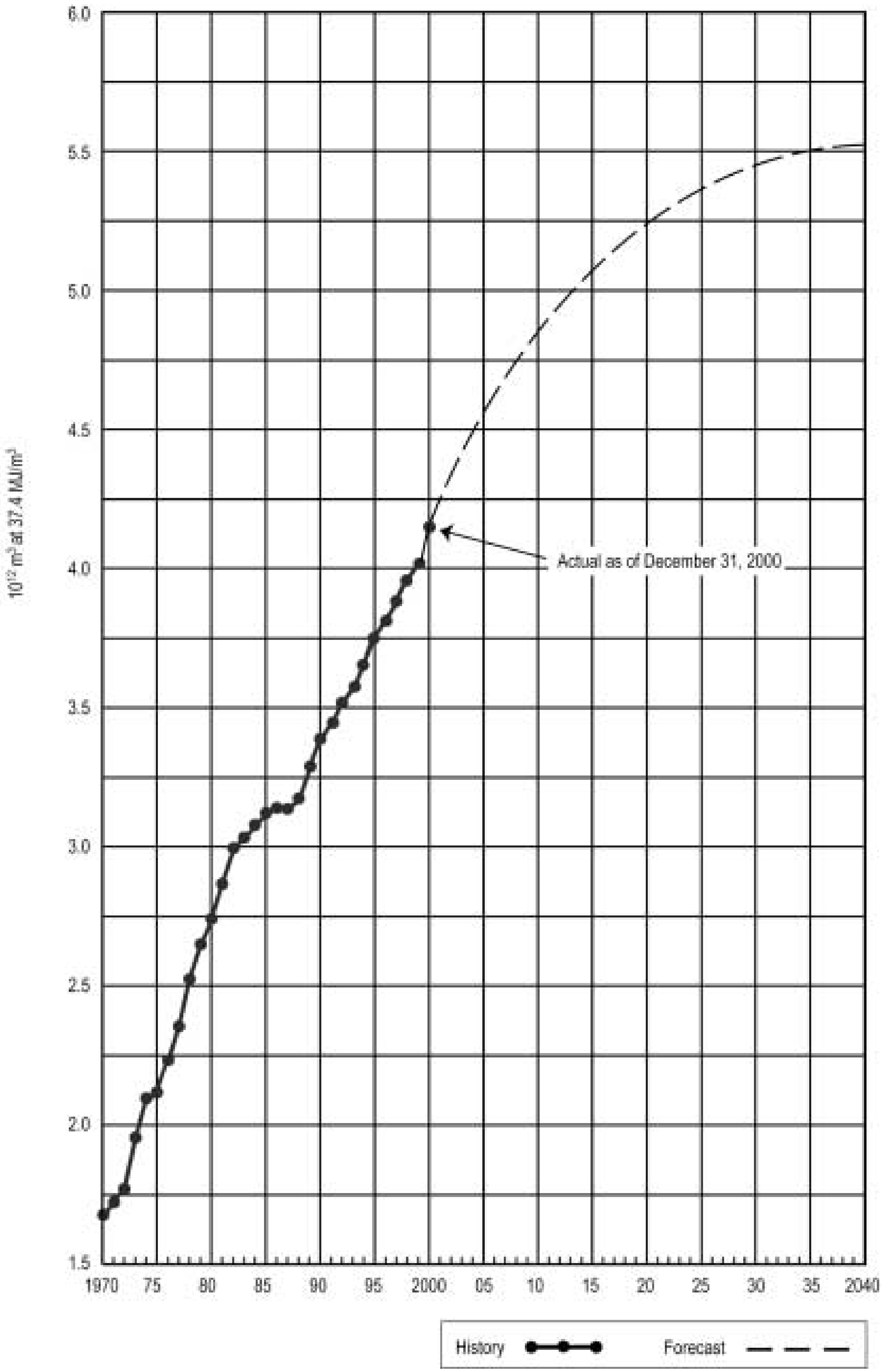


Figure 4.7. Growth of initial established reserves of marketable gas

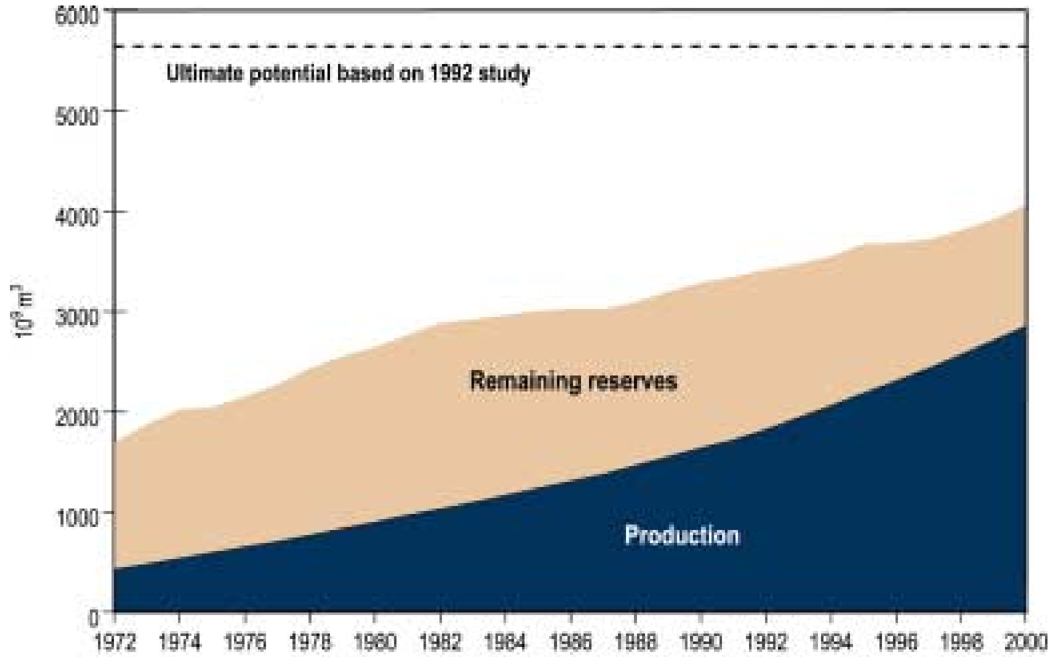


Figure 4.8. Gas ultimate potential

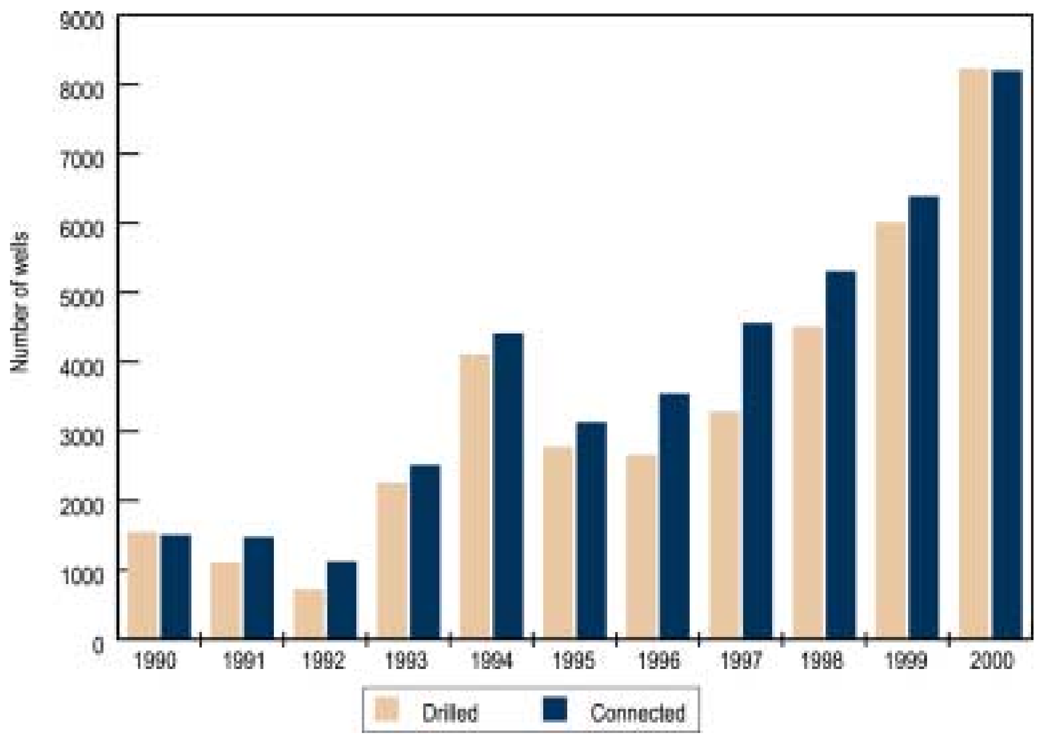


Figure 4.9. Successful natural gas wells drilled and connected

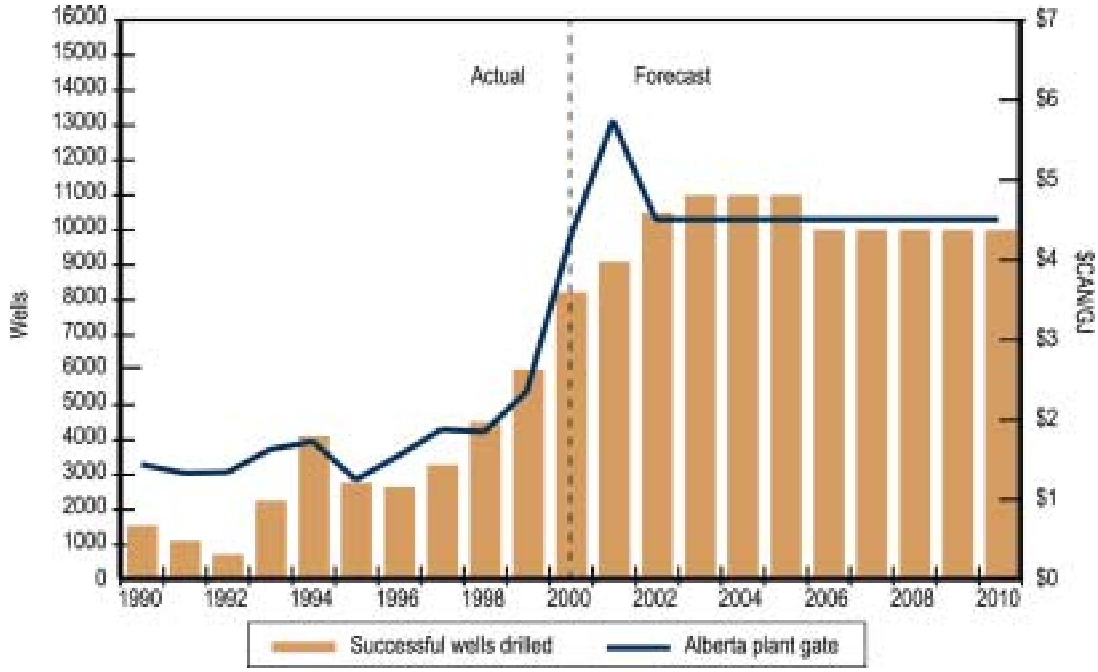


Figure 4.10. Alberta natural gas drilling activity

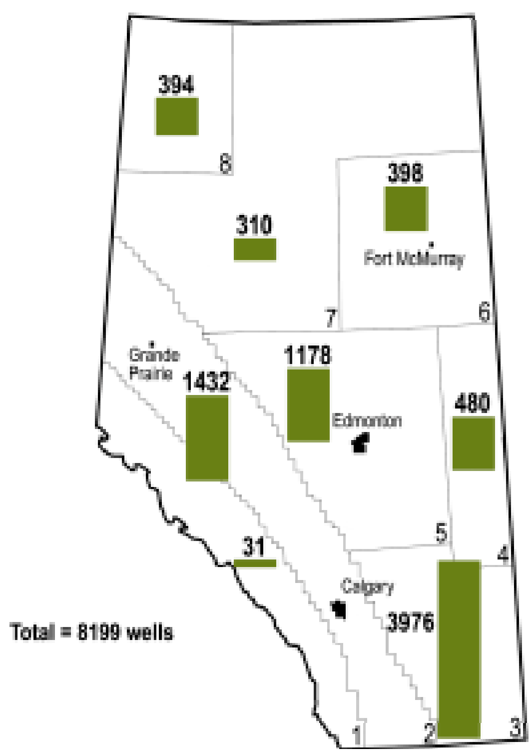


Figure 4.11. New natural gas well connections

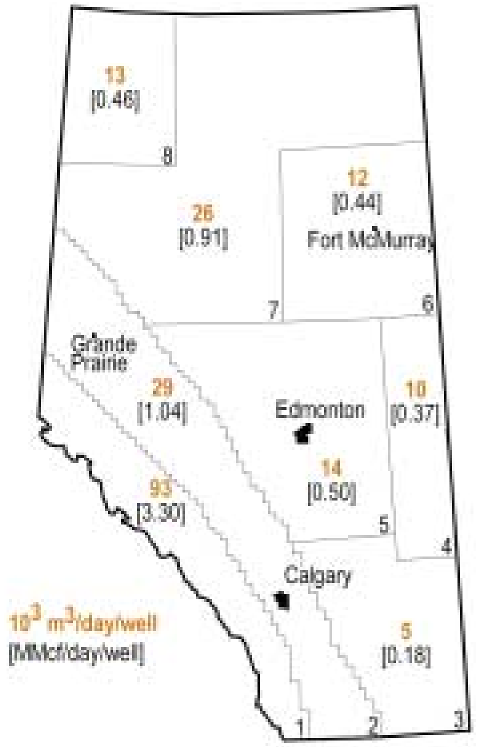


Figure 4.12. Maximum day rate of gas well connections

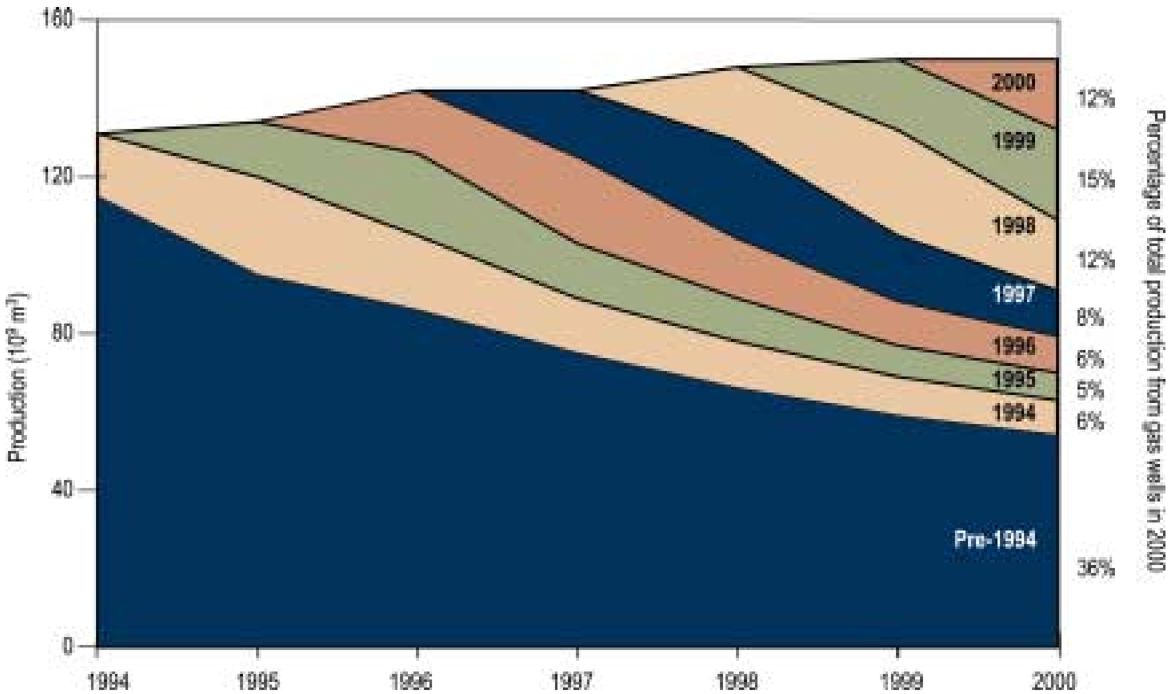


Figure 4.13. Gas well production by connection year

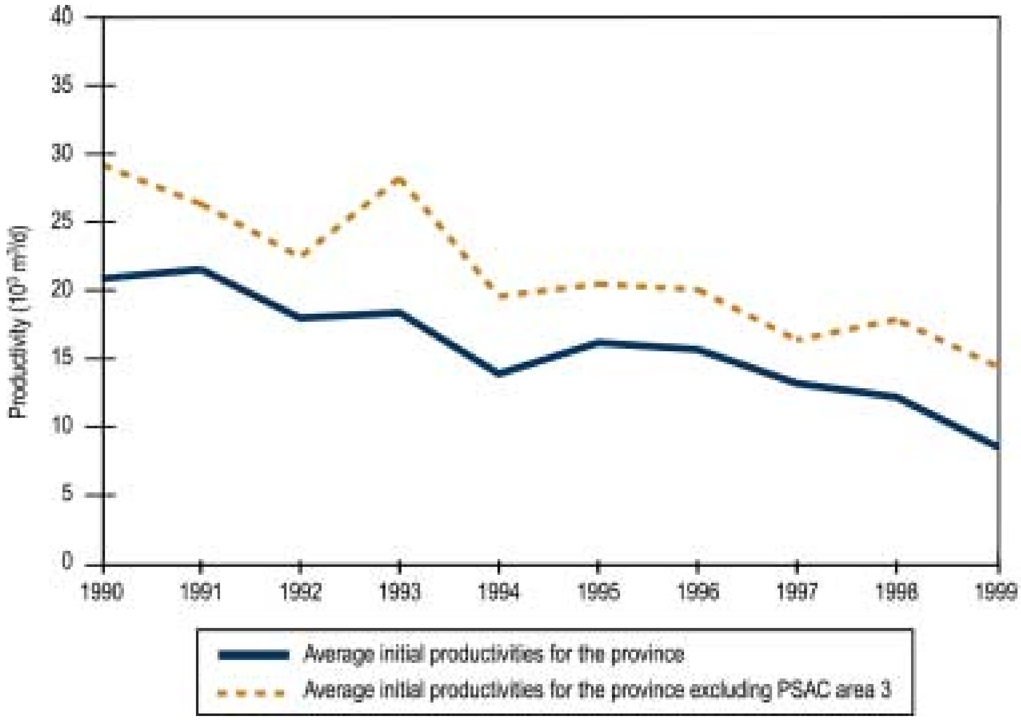


Figure 4.14. Average initial natural gas well productivity in Alberta

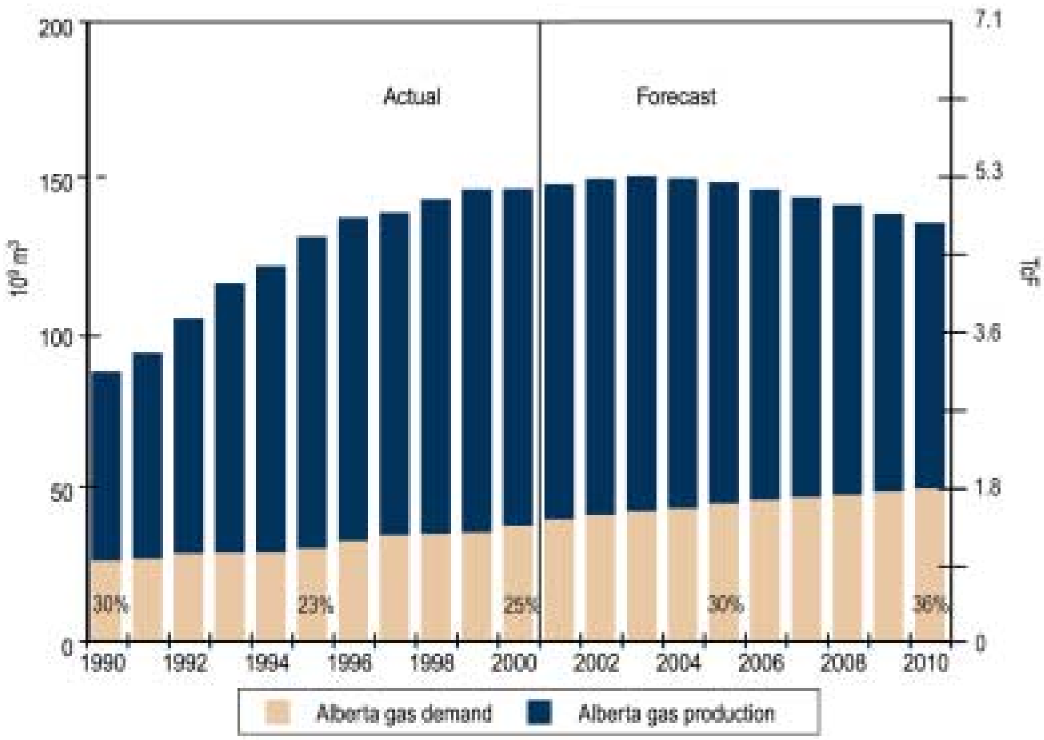


Figure 4.15. Marketable gas production and demand

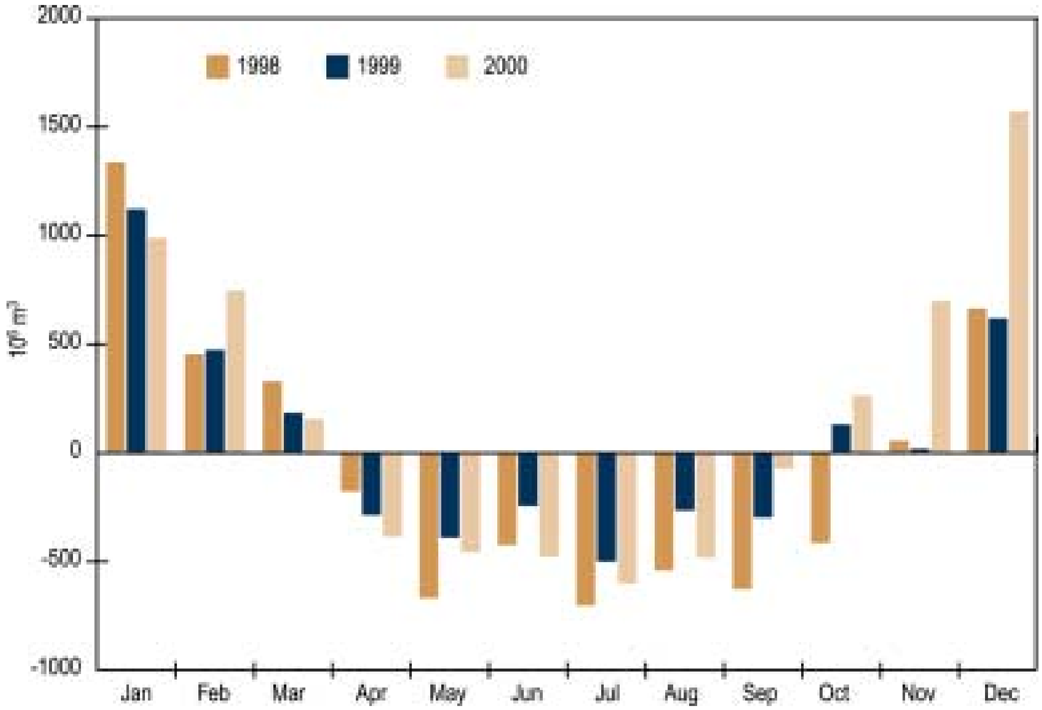


Figure 4.16. Alberta natural gas storage injection/withdrawal volumes

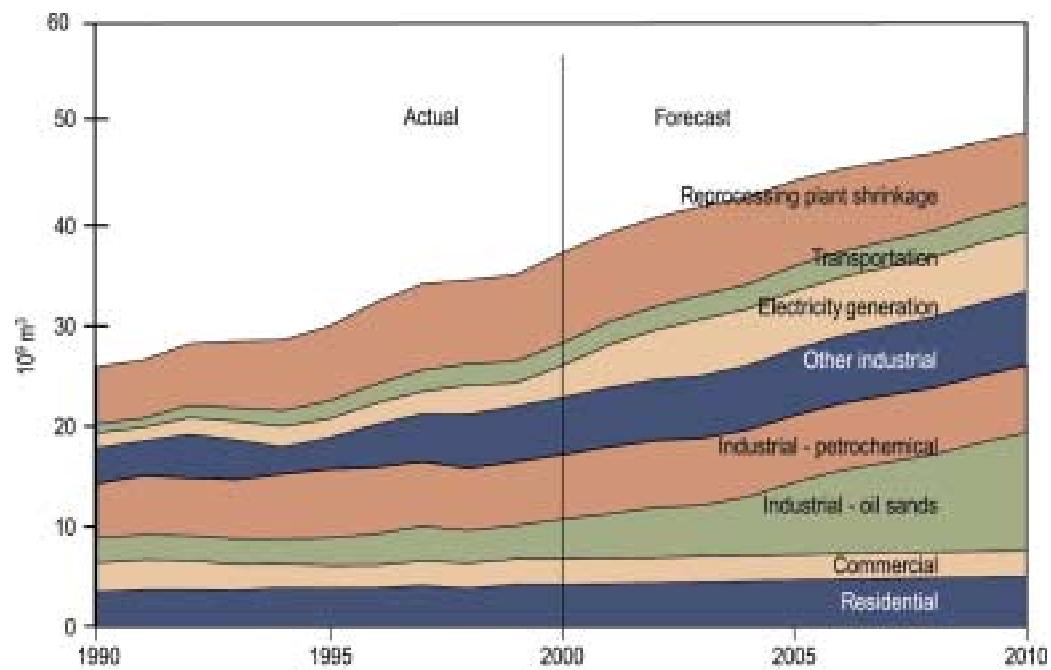


Figure 4.17. Alberta gas demand by sector

5 Ethane and Other Natural Gas Liquids

This section deals with liquids from natural gas classified as ethane and other natural gas liquids (NGL), which are discussed in Sections 5.1.1 and 5.1.2 respectively. The EUB defines ethane as, in addition to its normal scientific meaning, a mixture of ethane that ordinarily may contain some methane or propane. However, the ethane reserves estimated in this report are calculated on the basis of ethane product assumed to be 100 per cent ethane. NGL is defined as propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

5.1 Reserves

5.1.1 Reserves of Ethane

This section discusses the total ethane volumes contained in the remaining established reserves of marketable gas discussed in Section 4.1.1. The remaining established reserves of marketable gas are determined at the field plant gate and contain all of the ethane present in the gas with the exception of a portion extracted at field plants with deep-cut facilities. Although the EUB believes that ethane extraction at crude oil refineries and at plants processing synthetic crude oil might become viable in the future, it has not attempted to estimate the prospective reserves from those sources.

A file containing each pool's compositional gas analysis and remaining established reserves of marketable gas was used in preparing the ethane reserve estimates. Where a gas analysis was not available for a particular pool, a field or area average for the zone was used. The EUB estimates the remaining ethane volume from the total remaining established reserves of marketable gas to be 252 million cubic metres (10^6 m^3) in liquefied form or 70.9 billion cubic metres (10^9 m^3) in gaseous form. This estimate includes 28 10^6 m^3 recoverable from the ethane component of the solvent bank injected into several pools throughout the province to enhance oil recovery. Based on the EUB's estimated ultimate potential of 1030 10^6 m^3, there remains 279 10^6 m^3 yet to be discovered. The overall changes in reserves during the past year are shown in Table 5.1.

Table 5.1. Ethane reserves (10^6 m^3) in liquefied form as of December 31, 2000

	2000	1999	Change
Initial established	758.0	739.0	+19.0
Actual cumulative production	156.3	143.5	+12.8
Volume in marketed gas	349.7	339.5	
Remaining established	252.0	256.0	-4.0

For individual gas pools, the ethane content of marketable gas in Alberta falls within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in Table 5.2, the volume-weighted average ethane content of all remaining established marketable gas was 0.052 mol/mol. This table also gives a breakdown of ethane volumes recoverable from major fields, all other remaining fields, and solvent floods. Fields with liquid ethane reserves greater than 3 10^6 m^3 are classified as major fields and are listed in Table 5.3.

Table 5.2. Remaining ethane reserves as of December 31, 2000

Fields	Remaining established reserves of marketable gas (10^9 m^3)	Ethane content (mol/mol)	Remaining established reserves of ethane	
			Gas (10^9 m^3)	Liquid (10^6 m^3)
Major fields with liquid ethane reserves > 3.0 10^6 m^3	206.7	0.087	18.0	64
All other fields with ethane reserves	1 004.0	0.044	44.9	160
Subtotal	1 210.7	0.052	62.9	223
Recoverable from solvent floods			8.0	28
Provincial total			70.9	252

Table 5.3. Major fields with liquid ethane reserves > 3 10^6 m^3 as of December 31, 2000

Fields	Remaining established reserves of marketable gas (10^9 m^3)	Ethane content (mol/mol)	Remaining established reserves of ethane	
			Gas (10^9 m^3)	Liquid (10^6 m^3)
Brazeau River	14	0.098	1.4	5.0
Caroline	15	0.178	2.8	9.8
Elmworth	17	0.063	1.0	3.7
Garrington	10	0.109	1.1	4.0
Kaybob South	16	0.097	1.6	5.5
Medicine Hat	32	0.030	1.0	3.4
Pembina	25	0.093	2.3	8.3
Rainbow	12	0.115	1.3	4.8
Ricinus	16	0.084	1.3	4.7
Valhalla	14	0.076	1.0	3.7
Wapiti	17	0.070	1.2	4.2
Willesden Green	13	0.079	1.0	3.5
Wizard Lake	6	0.150	1.0	3.4
Total	207	0.087	18.0	64.0

5.1.2 Reserves of Other Natural Gas Liquids (NGL)

The EUB estimates the remaining established reserves of NGL in Alberta as of December 31, 2000, to be 221.9 10^6 m^3. This represents a net increase of 9.2 10^6 m^3 since December 31, 1999. Based on the EUB's estimated ultimate potential of 1160 10^6 m^3 of NGL, there remain 356.7 10^6 m^3 yet to be established. The overall changes in the reserves during the past year are shown in Table 5.4. The fields with the largest changes for 2000 are shown in Table 5.5. Also during 2000, propane and butanes recovery at crude oil refineries was 360 and 1064 thousand cubic metres (10^3 m^3) respectively.

Table 5.4. Reserves of NGL (excluding ethane) (10^6 m^3) as of December 31, 2000

	2000	1999	Change
Initial established			
Propane	283.2	270.5	+12.7
Butanes	164.2	156.8	+7.4
Pentanes plus	355.9	341.8	+14.1
Total	803.3	769.1	+34.2
Cumulative net production[a]			
Propane	197.7	187.9	+9.8[b]
Butanes	113.8	108.2	+5.6[b]
Pentanes plus	269.9	260.3	+9.6[b]
Total	581.4	556.4	+25.0
Remaining established			
Propane	85.5	82.6	+2.9
Butanes	50.4	48.6	+1.8
Pentanes plus	86.0	81.5	+4.5
Total	221.9	212.7	+9.2

[a] Net production means production less those volumes returned to the formation or injected to enhance the recovery of oil.
[b] Discrepancies may exist with actual production as reported in *Statistical Series (ST) 3: Oil and Gas Monthly Statistics*.

Table 5.5. Major NGL reserves (excluding ethane) changes (10^3 m^3), 2000

Field	Remaining established 2000	Reserves change	Main reason for change
Brazeau River	7 217	+1 932	Re-evaluation of reserves
Caroline	24 342	+1173	Re-evaluation of reserves
Elmworth	1 347	-1 519	Re-evaluation of reserves
Rainbow	4 757	+1 488	Re-evaluation of reserves
Rainbow South	1 613	+838	Re-evaluation of reserves

The remaining established reserves of NGL consist of liquids expected to be extracted from the province’s remaining established reserves of raw gas. The liquids recoverable from pools currently producing and connected to field gas processing plants were generally determined using remaining recoverable raw gas reserves, a raw gas analysis, and the current plant recovery efficiency for each component. For retrograde condensate pools where gas is cycled, product recoveries have been determined from individual reservoir studies, having regard for anticipated future cycling and blowdown operations. Also included in the remaining established reserves are volumes estimated for pools with no production and defined as nonproducing pools.

Table 5.6 shows the NGL reserves broken down into producing pools, nonproducing pools, and solvent flood categories.

Table 5.6. Remaining established NGL reserves (excluding ethane) (10^6 m^3) as of December 31, 2000

	Propane	Butanes	Pentanes plus	Total
Producing pools	71.1	41.6	76.3	189.0
Nonproducing pools	14.3	7.6	9.1	31.0
Solvent floods	0.1	1.2	0.6	1.9
Total	85.5	50.4	86.0	221.9

Natural gas liquids are also recoverable at straddle plants. This volume is estimated by multiplying the remaining marketable gas reserves by the historic ratio of liquid production to marketable gas production. This assumes that the liquid content of marketable gas volume to be processed at straddle plants will remain constant. The EUB believes this approach gives a reasonable indication of the NGL recoverable at these plants. Listed in Appendix 3 are fields containing 800 10^3 m^3 or more of recoverable reserves, while those with less are grouped under confidential and other small reserves categories. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of this table. Note that some fields containing less than 800 10^3 m^3 have been listed individually in this table for historical reasons.

5.2 Supply of and Demand for Ethane and Other Natural Gas Liquids (NGL)

5.2.1 Supply of Ethane and Other NGL

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, usually at border points, 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 Alliance pipeline, placed on-stream in December 2000, moves rich gas with ethane and other NGL in the gas stream until it reaches its destination point near Chicago, Illinois, where ethane and other liquid recovery occurs. The natural gas to be moved on the Alliance pipeline is, however, sent to field processing plants for the removal of H_2S and CO_2 before entering the pipeline.

The other source of NGL supply is from crude oil refineries, where small volumes of propane and butanes are recovered. Figure 5.1 is a schematic that 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 marketable 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.

To meet demand, ethane extracted at Alberta processing facilities increased from 11.3 10^6 m^3 (31.0 10^3 m^3/d) in 1999 to 12.8 10^6 m^3 (35.1 10^3 m^3/d) in 2000. Table 5.7

Table 5.7. Ethane extraction volumes at gas plants in Alberta, 2000

Gas plants	Volume (10^6 m^3)	% of total
Field plants	1.3	10
Fractionation plants	3.1	24
Straddle plants	8.4	66
Total	**12.8**	**100**

shows the volumes of specification ethane extracted at the three types of processing facilities during 2000.

In 2000 some 59 per cent of potentially recoverable ethane was extracted from natural gas production, while the remainder was left in the gas stream and sold for its heating value. By applying present technology to ethane recovery processes, some 80 per cent of ethane contained in Alberta's gas production could be recovered at ethane processing facilities.

In 2000, Alberta recovered 9.8 10^6 m^3 (26.8 10^3 m^3/d) of propane from natural gas processing and 0.4 10^6 m^3 (1.1 10^3 m^3/d) from crude oil refineries. In the same year, butanes recovery was 5.6 10^6 m^3 (15.3 10^3 m^3/d) from natural gas processing and 1.1 10^6 m^3 (3.0 10^3 m^3/d) from crude oil refineries. In 2000, 9.6 10^6 m^3 (26.3 10^3 m^3/d) of pentanes plus was recovered from Alberta gas.

For the purpose of forecasting ethane and other NGL, the richness and gas production volumes from established and new reserves determine future production. The ratio of potentially recoverable ethane, propane, butanes, and pentanes plus production to marketable gas production is 148, 67, 36, and 69 m^3 (liquid) per 10^6 m^3 of marketable gas respectively.

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. Ratios of potentially recoverable ethane, propane, butane, and pentanes plus production to marketable gas increase over the forecast period to 170, 74, 43, and 82 m^3 (liquid) per 10^6 m^3 of marketable gas by 2010. No attempt has been made to include ethane and other NGL production from the solvent flood bank injected into several pools throughout the province to enhance oil recovery.

By 2010 potential ethane supply is forecast to be 63.1 10^3 m^3/d, and annual propane, butane, and pentanes plus recovery will be 27.2 10^3 m^3/d, 16.4 10^3 m^3/d and 30.5 10^3 m^3/d respectively, as shown in Figures 5.2, 5.3, 5.4, and 5.5. It should be noted that high gas prices may cause gas processors to reduce liquid recovery from the volumes forecast.

Figure 5.2 shows ethane supply referred to as potential supply as it indicates the volumes of ethane that may be recovered from Alberta natural gas. The historical supply volumes assume the ethane content of marketable gas production in Alberta has been 5.2 per cent and that 80 per cent of ethane could economically be recovered at ethane processing facilities.

Approved annual processing plant capacity for ethane recovery in Alberta is currently some 62.3 10^3 m^3/d, and the extraction plant near Chicago that started operations in December 2000 has a design capacity to extract 6.3 10^3 m^3/d. This indicates that the current processing capacity is not a constraint to recovering the volumes forecast.

5.2.2 Demand for Ethane and NGL

Of the ethane extracted in the year 2000, some 89 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. The Alliance pipeline is moving ethane from the province in the natural gas stream to be recovered in the United States. All of the above requirements for Alberta ethane constitute the demand forecast.

As shown in Figure 5.2, total ethane demand is projected to increase from 35.1 10^3 m^3/d in 2000 to 51.8 10^3 m^3/d in 2001 and stay constant thereafter. Alberta demand is projected to increase from 31.2 10^3 m^3/d in 2000 to 42.5 10^3 m^3/d in 2001 and remain at these levels to 2010, representing 80 per cent of total ethane demand. The potential supply exceeds demand for ethane for the entire forecast period. However, supplies will be tighter than they have been historically, due to the large increase in demand brought on by the fourth ethylene plant placed on production in October 2000, and the Alliance pipeline that came on stream in December 2000. The forecast assumes that all four Alberta ethylene plants will run at 90 per cent capacity. Export removals from the province are expected to continue, and the extraction plant near Chicago is expected to run at a 90 per cent load. 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.

Figure 5.3 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 5.4 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, is poised to ban its use by 2002. The one plant in the province 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 5.5 shows Alberta demand for pentanes plus compared to the total available supply. Alberta pentanes plus demand will increase as diluent requirements for transporting heavy crude oil and bitumen increase, this being the primary use. Diluent is required to increase the API gravity and reduce the viscosity of heavy crude oils and bitumen to facilitate transportation through pipelines. The required diluent for bitumen accounts for 40 per cent of the total volume transported, while heavy crude oil requires about 7 per cent.

Over the forecast period, pentanes plus demand as diluent is expected to increase from 2000 levels of 19.8 10^3 m^3/d to 61.2 10^3 m^3/d. Shortages of pentanes plus as diluent is forecast to occur by 2005. The diluent requirement for heavy crude oil is expected to rise from 2.4 10^3 m^3/d in 2000 to peak in 2003 at 2.7 10^3 m^3/d and then decline to 2.0 10^3 m^3/d by the end of the forecast. Conversely, diluent requirements for bitumen are expected to increase quite dramatically from 17.4 10^3 m^3/d in 2000 to 59.1 10^3 m^3/d by 2010.

There has been concern within industry that pentanes plus supply may decrease to a level where refinery light ends may have to be used as diluent. 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. Industry may consider alternatives to pentanes plus as diluent, such as light crude oil, synthetic crude oil, and naptha, when pentanes plus demand is greater than supply. Upgrading bitumen near the production source may also be required.

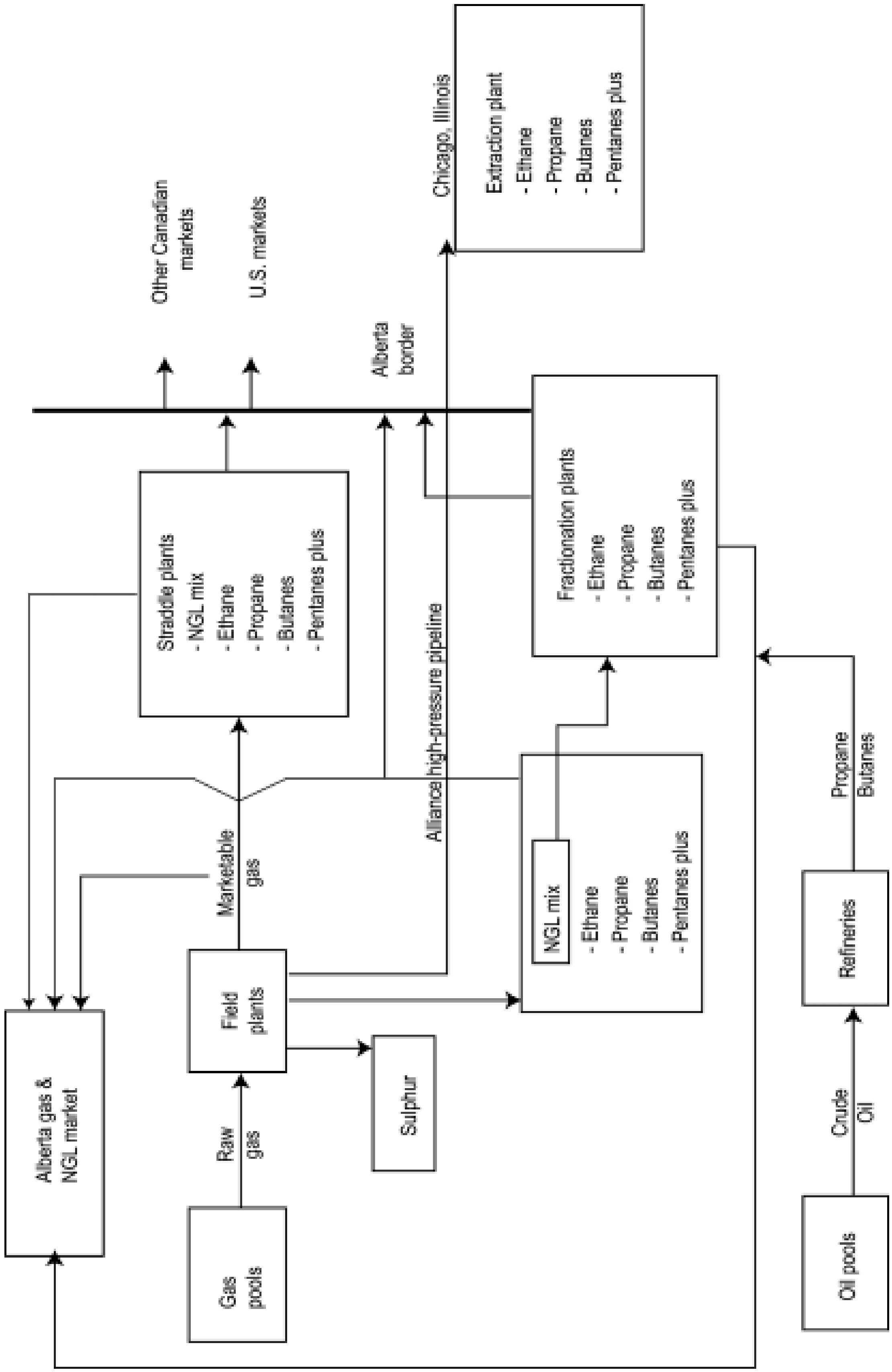


Figure 5.1. Schematic of Alberta NGL flows

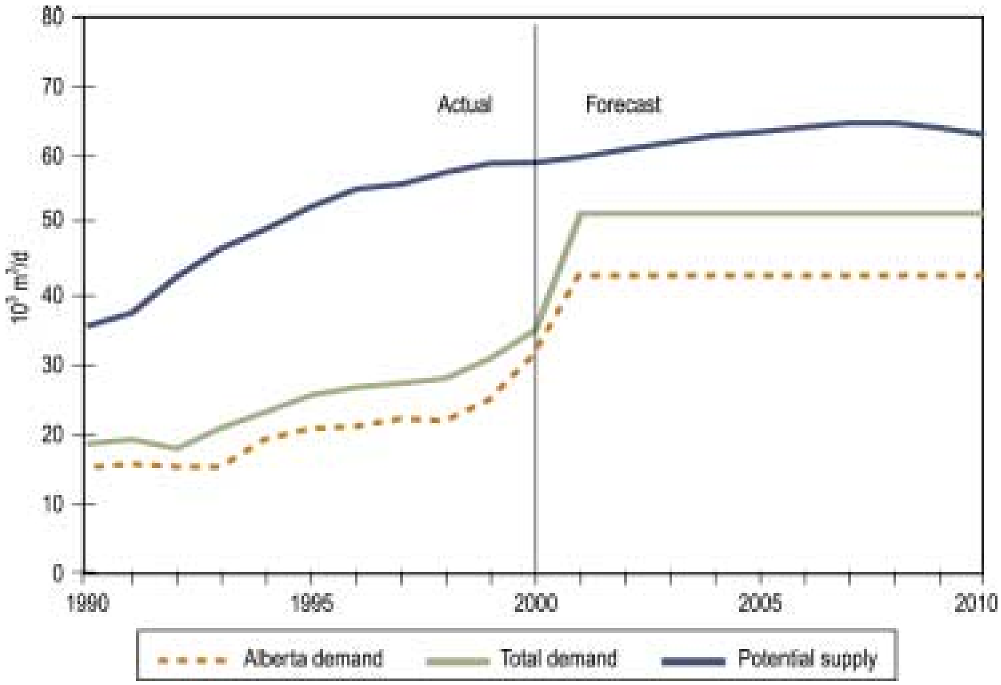


Figure 5.2. Ethane supply and demand (excluding solvent flood volumes)

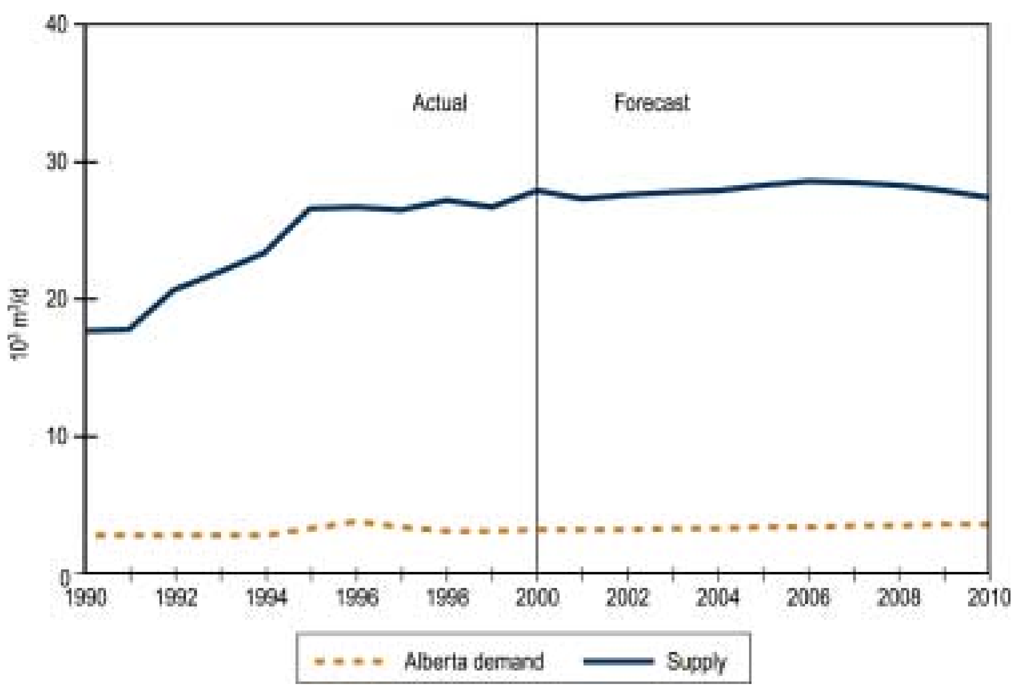


Figure 5.3. Propane supply and demand (excluding solvent flood volumes)

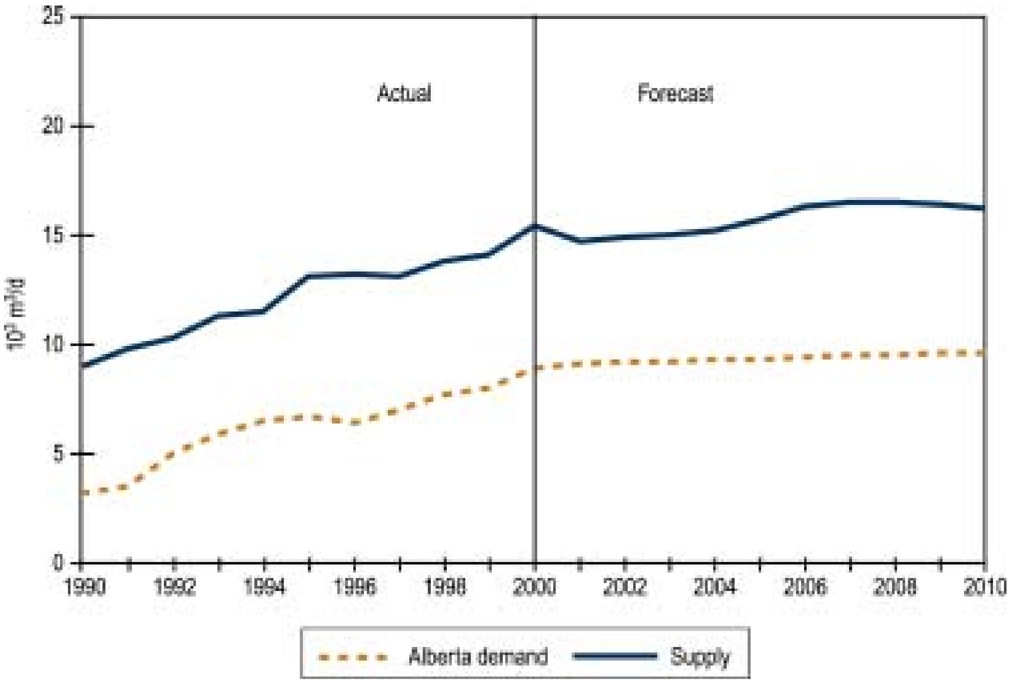


Figure 5.4. Butanes supply and demand (excluding solvent flood volumes)

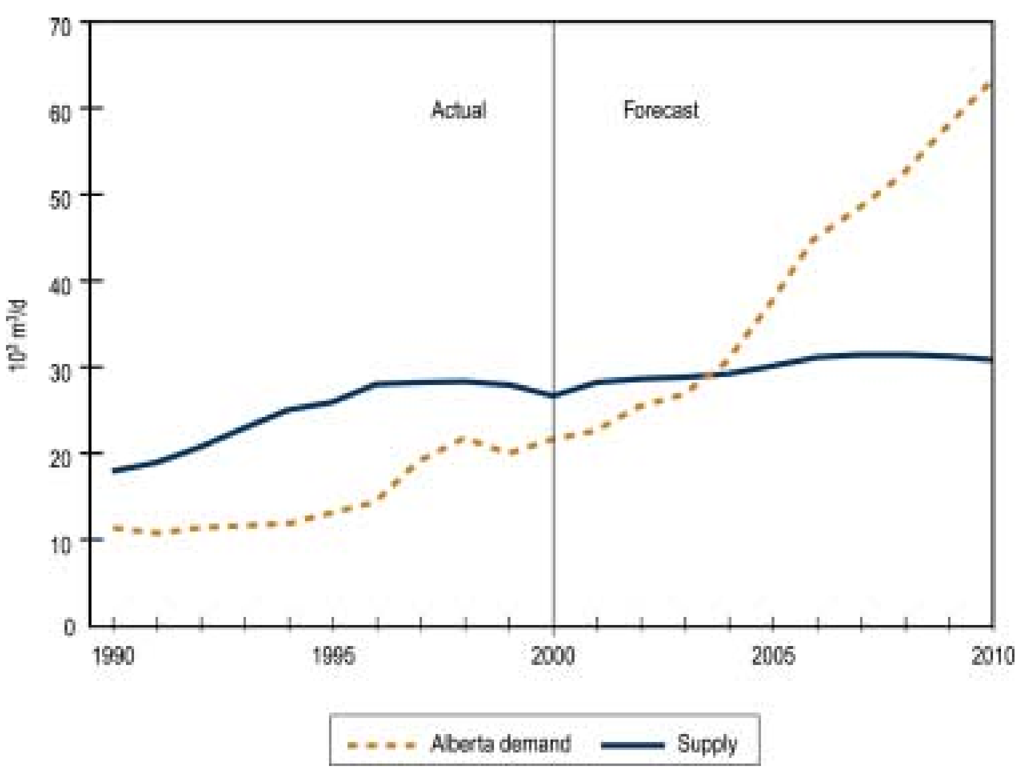


Figure 5.5. Pentanes plus supply and demand (excluding solvent flood volumes)

6 Coal

6.1 Reserves of Coal

6.1.1 Provincial Summary

The following information summarizes 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 to be recoverable (by surface and underground methods), and of these reserves, 1.2 Gt are within permit boundaries of mines that were active in 2000. Table 6.1 gives a breakdown by rank of resources and reserves from 244 coal deposits.

Table 6.1. Established initial in-place resources and remaining reserves of coal in Alberta as of December 31, 2000 (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	0.63	
Total[b]	6.8	0.32	1.2	0.15
High-volatile bituminous				
Surface	2.6	0.13	1.8	
Underground	3.3	0.05	0.91	
Total[b]	5.9	0.17	2.7	0.18
Subbituminous[c]				
Surface	14	0.55	8.4	
Underground	67	0.07	21	
Total[b]	81	0.62	30	0.83
Grand total[b]	94	1.11	34	1.2

[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, 1999, to December 31, 2000, resulted from increases in cumulative production. During 2000 the low- and medium-volatile, high-volatile, and subbituminous production were 0.005 Gt, 0.005 Gt, and 0.024 Gt respectively.

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

6.1.2 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.

6.1.3 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 6.2 shows the established resources and reserves within the current permit boundaries of those mines active in 2000.

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

Table 6.2. Established resources and reserves of coal under active development as of December 31, 2000

Rank Mine	Permit area[a] (ha)	Initial in-place resources (10^6 t)	Initial reserve (10^6 t)	Cumulative production (10^6 t)	Remaining reserves (10^6 t)
Low- and medium-volatile bituminous					
Gregg River[b]	3 540	103	62	46	16
Luscar	5 050	332	130	90	40
Smoky River[c]	8 500	604	171	77	94
Total	17 090	1 039	363	213	150
High-volatile bituminous					
Coal Valley	6 400	349	167	93	74
Obed	7 590	162	137	35	102
Total	13 990	611	304	128	176
Subbituminous					
Vesta	2 410	69	54	34	20
Paintearth	2 710	94	67	33	34
Sheerness	7 000	196	150	47	103
Dodds	140	2	2	1	1
Whitewood	2 800	163	98	67	31
Highvale	12 140	1 021	764	263	501
Genesee	7 320	250	176	33	143
Total	34 520	1 795	1 311	478	833
Grand total	65 600	3 445	1 978	819	1 159

[a] The permit areas correspond to the areas defined in the most recent EUB permit.
[b] Suspended operations in August 2000.
[c] Permanently closed in March 2000.

6.1.4 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 6.3 gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potentials.

Table 6.3. 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
Total	21	3.2
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Total	500	160
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Total	1 500	470
Grand total	2 000[b]	620

[a] Tonnages have been rounded to two significant figures.
[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

6.2 Supply of and Demand for Coal

Alberta produces three types of marketable coal. Metallurgical coal includes low- or medium-volatile bituminous coal used in steel making and is normally exported. Export thermal coal is a high-volatile bituminous coal normally used to fuel electricity generating facilities in nondomestic markets, because its higher calorific content makes it possible to economically transport the coal over long distances. Domestic thermal coal is a subbituminous coal used locally within Alberta mainly to generate electricity.

Several years of decreasing prices for metallurgical coal have led to the closure of the Smoky River and Gregg River mines in 2000, the announcement of the planned closure of the one remaining mine, Luscar, in 2002, and the announced delay in the start-up of the new proposed Cheviot mine. However, the end of 2000 saw an upturn in prices and with that the prospects for extended coal production from the Luscar-Gregg area and the intent by new operators to conduct limited mining in the Smoky River area.

The end of 2000 also saw an improvement in the export thermal coal markets, which has positively affected the short-term outlook for thermal bituminous producers, who had also experienced several years of decreasing prices.

Over the past few years subbituminous coal production has stabilized, as no new power plants have been built and no substantial generating capacity has been taken out of operation.

The historical and forecast Alberta coal production for each of the three types of marketable coal is summarized in Figure 6.1.

6.2.1 Coal Supply

Twelve mine sites supplied coal in Alberta in 2000, as shown in Table 6.4.

Table 6.4. Alberta coal mines and marketable coal production in 2000

Company (grouped by coal type)	Mine	Location	Production in 2000 (10^6 t)
Bituminous metallurgical coal			
Cardinal River Coals Ltd.	Luscar	Luscar	2.6
Luscar Ltd.	Gregg River[a]	Luscar	1.0
Smoky River Coal Ltd.	Smoky River[b]	Grande Cache	0.3
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.1
	Obed Mountain	Hinton	1.5
Subbituminous coal			
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	<0.1
Epcor Generation Inc.	Genesee	Genesee	3.5
Luscar Ltd.	Sheerness	Sheerness	3.6
	Paintearth	Halkirk	1.7
	Vesta	Cordel	1.0
TransAlta Utilities Corp	Highvale	Lake Wabamun	12.5
	Whitewood	Lake Wabamun	2.0

[a] Suspended operations in August 2000.
[b] Permanently closed in March 2000.

Alberta's ability to supply metallurgical coal in the short term is limited. While some additional mining is planned to take place at the two mine sites that shut down in 2000, it will be at lower production levels than in previous years, and neither mine has large mineable reserves available. The Luscar mine may continue production beyond 2002, but it has only limited economically mineable reserves left.

While metallurgical-grade coal underlies much of the mountain region, very few areas have been sufficiently explored to identify recoverable reserves. Without significantly increased, stable prices, it is unlikely that any additional mines, other than the proposed Cheviot mine, will come on stream in the next decade. Additionally, it is increasingly more difficult to bring a mountain mine into production due to enhanced social and environmental concerns.

The two producing thermal bituminous coal mines have shipped all of their coal out of Alberta to markets overseas and, until recently, to Ontario. However, recently some coal has been transported within Alberta from the Obed mine to the electrical power station at Grande Cache to make up for coal supply lost due to the closure of the Smoky River mine. In recent years falling prices have cut production at these mines, but the improvement in late 2000 in prices will likely lead to modest increases in production.

Substantial reserves exist in areas that have been permitted for mining but have not been brought on production. Several other areas contain significant quantities of recoverable coal.

Six large mines and one very small mine produce subbituminous coal (see Table 6.4). The large ones serve nearby electric power plants, while the small one supplies residential and commercial customers. Because of the need for long-term supply to power plants, the mines have most of their reserves dedicated to the existing plants. By either mining more within their approved limits or expanding the approved limits, several mines could increase their production. Furthermore, several deposits in Alberta could support large new mines if markets could be secured. In the very long term, vast quantities of underground mineable coal exist, which, under favourable economic conditions, could be recovered.

6.2.2 Coal Demand

With recent sharp increases in coal prices due to high petroleum prices and record-high global steel production, prospects for overseas coal sales of metallurgical coal have brightened considerably. One bituminous metallurgical coal mine that ceased production is now expected to reopen, and mining may resume at the other closed mine. Although no production from new export mines is included in this forecast, the proposed Cheviot mine could come into production within the forecast period. However, demand is not expected to be strong enough to create other opportunities for large new mines.

Although international markets for thermal bituminous coal had been expanding throughout most of the 1990s (in the face of declining prices), the expansions of supply occurred largely in Indonesia and Colombia. Alberta producers were able to sell on the spot market but were unable to secure long-term contracts, so no new mines were opened in this province. Recent price increases are likely to allow the current producers to increase production levels, but they are not strong enough to bring new mines into production within the forecast period. Additionally, together with increased international competition, Alberta’s thermal bituminous producers must overcome the competitive disadvantage of the cost of moving the coal to port.

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, unless strong increases in electrical demand cause an increase in production or lower natural gas prices (to be used to as an alternative fuel to generate electricity) cause a reduction.

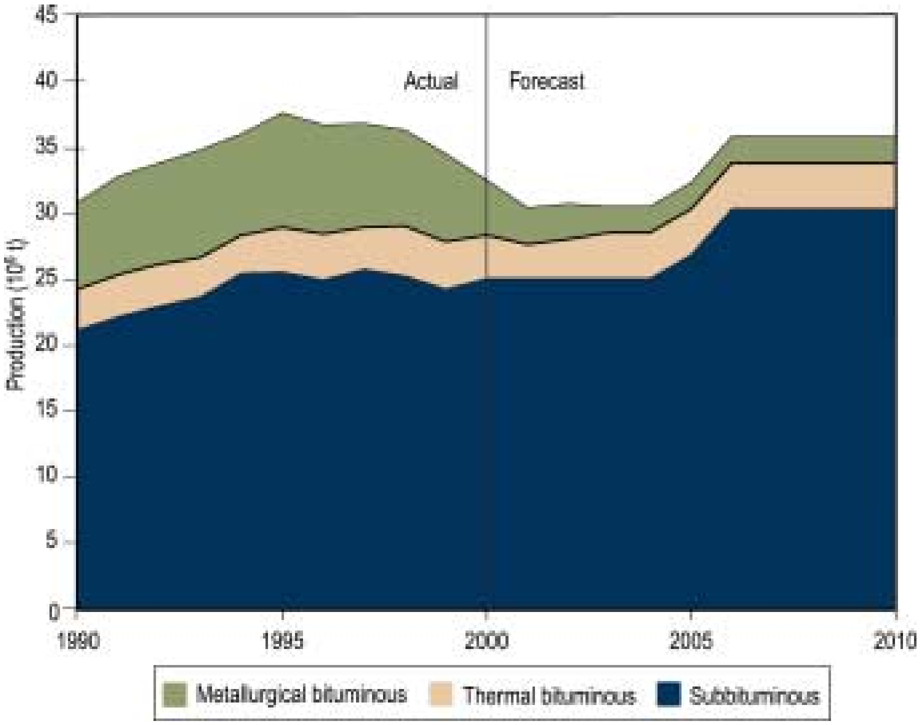


Figure 6.1. Alberta marketable coal production

7 Sulphur

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The EUB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2000, to be some 98 million tonnes (10^6 t). The changes in sulphur reserves during the past year are shown in Table 7.1.

Table 7.1. Reserves of sulphur (10^6 t) as of December 31, 2000

	2000	1999	Change
Initial established reserves			
Natural gas	237.5	241.3	-3.8
Crude bitumen[a]	67.7	67.7	0.0
Total	305.2	309.0	-3.8
Cumulative net production			
Natural gas	195.4	188.7	+6.7
Crude bitumen[b]	11.8	11.1	+0.7
Total	207.2	199.8	+7.4
Remaining established reserves			
Natural gas	42.1	52.6	-10.5
Crude bitumen[a]	55.9	56.6	-0.7
Total	98.0	109.2	-11.2

[a] Recoverable reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2000.
[b] Production from surface mineable area only.

7.1.2 Sulphur from Natural Gas

The EUB recognizes 42.1 10^6 t of remaining established sulphur from natural gas reserves at year-end 2000. 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 *Informational Letter (IL) 88-13*. 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 132.5 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 7.2. Fields containing 800 thousand tonnes (10^3 t) or more of recoverable sulphur are listed

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31,2000

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	5183	0.063	98	431
	Subtotal				431
Blackstone	Beaverhill Lake	6 557	0.107	98	934
	Subtotal				934
Brazeau River	Mississippian	1 907	0.011	99	27
	Nisku[c]	-	-	-	1 166
	Subtotal				1 193
Burmis	Mississippian	7 191	0.09	99	871
	Wabamun	433	0.115	99	67
	Subtotal				938
Caroline	Mississippian	1 241	0.012	99	20
	Leduc	140	0.068	100[c]	13
	Beaverhill Lake	26 050	0.365	100[c]	12 889
	Subtotal				12 922
Coleman	Mississippian	1 437	0.257	99	495
	Wabamun	490	0.280	99	184
	Subtotal				679
Crossfield	Mannville	1 293	0.009	98	16
	Mississippian	1 926	0.005	99	12
	Wabamun	3 664	0.312	98	1 517
	Subtotal				1 545
Crossfield East	Mannville	238	0.003	98	1
	Wabamun	771	0.347	99	359
	Subtotal				360
Gold Creek	Mississippian	94	0.016	98	2
	Wabamun	4 923	0.087	98	567
	Subtotal				569
Hanlan	Winterburn	207	0.051	98	14
	Beaverhill Lake	11 082	0.091	99	1 353
	Subtotal				1 367
Jumping Pound West	Mississippian	10 762	0.062	97	873
	Subtotal				873

(continued)

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31,2000 (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	1 315	0.008	99	14
	Winterburn	883	0.192	99	227
	Beaverhill Lake[c]	-	-	-	666
	Subtotal				907
Limestone	Mississippian	5 439	0.049	99	358
	Wabamun	789	0.151	99	160
	Winterburn	122	0.134	99	22
	Leduc	405	0.189	99	103
	Subtotal				643
Moose	Mississippian	2 625	0.140	99	494
	Wabamun	300	0.330	99	133
	Subtotal				627
Okotoks	Mississippian	113	0.013	99	2
	Wabamun	1 382	0.325	99	602
	Subtotal				604
Pine Creek	Mississippian	288	0.026	98	10
	Wabamun	1 255	0.289	99	487
	Leduc	682	0.184	99	168
	Beaverhill Lake	502	0.192	95	124
	Subtotal				789
Ricinus	Leduc	1 042	0.316	99	442
	Subtotal				442
Ricinus West	Winterburn	126	0.006	99	1
	Leduc	2 031	0.332	99	905
	Subtotal				906
Waterton	Mississippian	6 772	0.207	99	1 880
	Wabmun	751	0.167	99	168
	Rundle-Wabamun[c]	-	-	-	567
	Subtotal				2 615
Subtotal					29 344
Other small reserves					12 780
Total reserves					42 124

[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.

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 Burmis, Caroline, and Coleman fields as a result of production.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current upgrading operations in which bitumen is converted to synthetic crude oil, 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.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only a portion of the surface-mineable established crude bitumen reserves is under active development at the 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 11.8 10^6 t of elemental sulphur has been produced from these projects, leaving a remaining established reserve of 55.9 10^6 t. During 2000, 0.7 10^6 t of elemental sulphur were produced at the Suncor and Syncrude projects; the Albian Sands project is still to come on stream.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Supply

There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to synthetic crude oil (SCO), and refining of crude oil into refined petroleum products. In 2000, Alberta produced 7.4 10^6 t of sulphur, of which 6.7 10^6 t was derived from sour gas, 0.7 10^6 t from upgrading of bitumen to SCO, and just 16 10^3 t from oil refining. Output of sulphur from both sour gas and oil sands upgrading, depicted in Figure 7.1, is expected to expand considerably over the forecast period, reaching 9.3 10^6 t and 2.4 10^6 t respectively by 2010. No significant change is expected in sulphur recovery at refineries. The EUB recognizes sulphur reserves associated with reserves of both sour gas and mineable bitumen, but none associated with sour oil, as most of the sour oil produced in Alberta leaves the province without removal of sulphur.

7.2.2 Sulphur Demand

Demand for sulphur within the province in 2000 was only about 0.6 10^6 t. It was used in production of phosphate fertilizer and kraft pulp and in other chemical operations. The remaining 90 per cent of the sulphur shipped by Alberta producers goes to markets 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 its 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 megatonnes yearly.

7.2.3 Imbalances between Sulphur Supply and Demand

Because elemental sulphur (in contrast to sulphuric acid and the energy resources described in this document) is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, as was the case over the period 1985-1991, sulphur is withdrawn from stockpiles; if supply exceeds demand, as has been the case since 1992, sulphur is added to stockpiles.

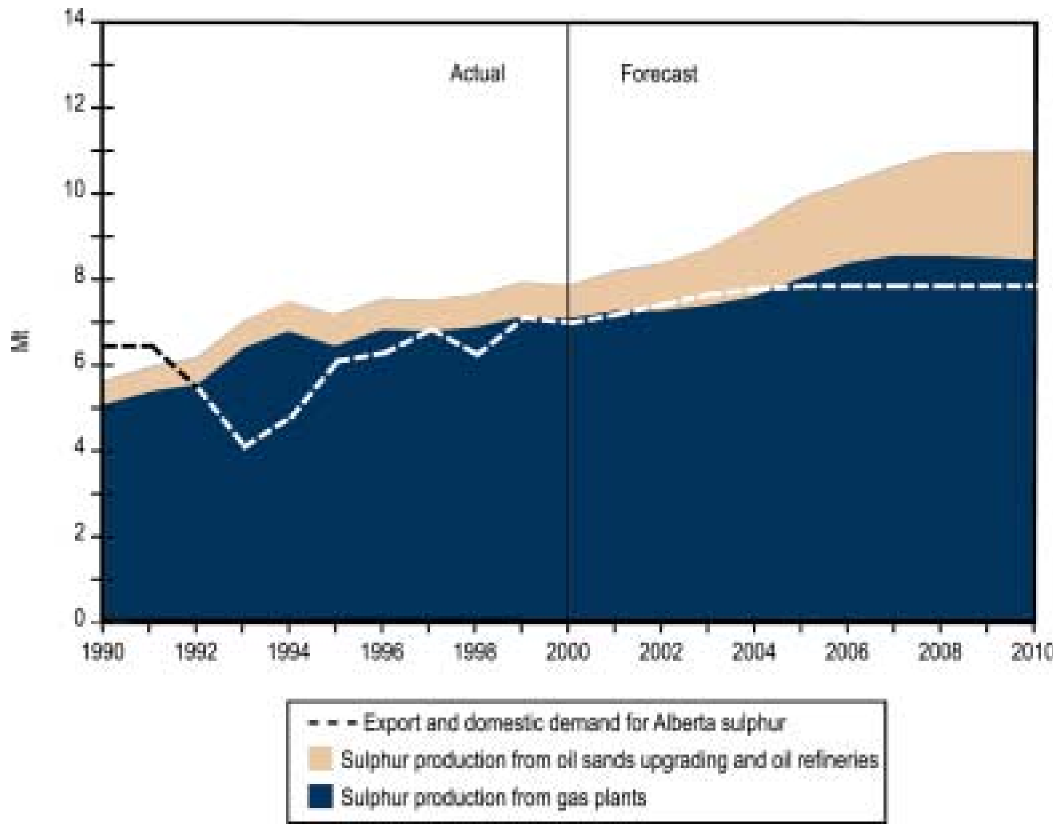


Figure 7.1. Production and shipments of Alberta sulphur

Appendix 1 Terminology

1.1 Symbols

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

1.2 SI Units

Data in *Alberta's Reserves* 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.

Conversion factors used in calculating the imperial equivalents are listed below:

1 m^3 of gas (101.325 kPa and 15°C)	=	35.493 73 cubic feet of gas (14.65 psia and 60°F)
1 m^3 of ethane (equilibrium pressure and 15°C)	=	6.33 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	=	6.300 0 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	=	6.296 8 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	=	6.292 9 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	=	6.290 1 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	=	0.984 206 4 (U.K.) long tons (2240 pounds)
1 tonne	=	1.102 311 short tons (2000 pounds)

1 kilojoule	=	0.948 213 3 British thermal units (Btu as defined in the federal Gas Inspection Act (60°-61°F))

This report uses SI prefixes throughout. A reference table is provided below.

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}

1.3 Reserves Terminology

The reserves terminology used in this report applies to all fossil energy resources (including coal) and is as follows:

Initial Volume in-Place: The volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.

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.

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

Remaining Established Reserves: Initial established reserves less cumulative production.

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.

The above terminology and definitions were recommended by the Inter-Provincial Advisory Committee on Energy and adopted by the EUB.

1.4 Other 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)).
Coal-bed 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.
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 (Associated) Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.

Gas (Marketable) A mixture mainly of methane originating from raw gas, or if necessary from the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (Oil and Gas Conservation Act, Section 1(1)(m)).

Gas (Marketable at 101.325 kPa and 15°C) The equivalent volume of marketable gas at standard conditions.

Gas (Nonassociated) Gas that is not in communication in a reservoir with an accumulation liquid hydrocarbons at initial reservoir conditions.

Gas (Raw) A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (Oil and Gas Conservation Act, Section 1(1)(s.1)).

Gas (Solution) Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.

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

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

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

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

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	Propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate (Oil and Gas Conservation Act, Section 1(1)(n)).
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.
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.
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)).

1.5 Standard Conditions of Gas Measurement

Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

1.6 Abbreviations

General Report

EOR	enhanced oil recovery
GIP	gas in place
GPP	good production practice

MU	commingling order
RPP	refined petroleum products
RF	recovery factor
RGE	range
SCO	synthetic crude oil
SF	solvent flood
STP	standard temperature and pressure
TWP	township
WF	waterflood
WM	west of a certain meridian

Computer Printout

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	non-associated 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

Company Names

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

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

Appendix 2. Reserves of multifield pools, 2000

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	1 320
Bashaw Belly River G	44
Bashaw Belly River H	603
Bashaw Belly River L	19
Bashaw Belly River M	228
Bashaw Belly River Q	15
Nevis Belly River C	1 124
Total	3 353
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	17
Fenn-Big Valley Edmonton A, Belly River J, M, N & JJ	1 370
Gadsby Belly River J	1 782
Total	3 169
Belly River Pool No. 4	
Michichi Belly River B & H	139
Watts Belly River B & I	77
Total	216
Southeastern Alberta Gas System (MU)	
Alderson Milk River A, Medicine Hat A, C & D, Second White Specks A, and Colorado A	43 767
Atlee-Buffalo Milk River A, Medicine Hat A, C & D, and Second White Specks A	5 000
Bantry Milk River A, Medicine Hat A, C & D, and Second White Specks A	24 912
Bassano Milk River A and Medicine Hat A	593
Berry Medicine Hat A	39
Bindloss Milk River A and Medicine Hat A & D	497
Blackfoot Medicine Hat A	695
Bow Island Milk River A, Medicine Hat C, and Second White Specks A, B, & C	20
Brooks Milk River A and Medicine Hat A, C & D	845
Cessford Milk River A, Medicine Hat A, C, & D, and Second White Specks A	11 206
Connorsville Milk River A, Medicine Hat A, and Belly River A	1 865
Countess Milk River A, Medicine Hat A, C & D, and Second White Specks A	14 326
Estuary Medicine Hat A	514
Eyremore Medicine Hat A & C	113
Farrow Medicine Hat A	733
Gleichen Medicine Hat A and Belly River C, E, F, H & I	1 459
Hussar Milk River A, Medicine Hat A, and Belly River C	2 631
Jenner Milk River A, Medicine Hat A, C & D, and Second White Specks A	5 132
Johnson Milk River A and Second White Specks A	321
Kitsim Milk River A and Medicine Hat A	282
Lathom Milk River A and Medicine Hat A	376
Leckie Milk River A and Medicine Hat A & C	386
Matziwin Milk River A, Medicine Hat A, C & D, and Second White Specks A	3 130
Medicine Hat Milk River A, Medicine Hat A, C & D, Second White Specks A, D, K, L, M, & R, Colorado A and Lower Colorado A	125 238
Mossleigh Medicine Hat A	43
Newell Milk River A, Medicine Hat A, C & D, and Second White Specks A	1 397
Princess Milk River A, Medicine Hat A, C & D, Second White Specks A, and Belly River F & G	24 900
Rainier Milk River A	101
Seiu Lake Medicine Hat A	415
Shouldice Medicine Hat A and Belly River A	461
Suffield Milk River A, Medicine Hat A, C & D, Second White Specks A and Colorado A	61 750
Verger Milk River A, Medicine Hat A, C & D, Belly River D Second White Specks A, and Belly River D	15 349

(continued)

Appendix 2. Reserves of multifield pools, 2000 (continued)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Wayne-Rosedale Medicine Hat A	807
Wintering Hills Milk River A, Medicine Hat A, and Second White Specks A, B, & C	4 937
Total	354 240
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
Second White Specks Pool No. 3	
Forest Second White Specks J	122
Pendant D'Oreille Second White Specks J	242
Smith Coulee Second White Specks J	333
Total	697
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	4 800
Bellshill Lake Upper and Middle Viking A	150
Birch Upper and Middle Viking A	83
Bruce Upper and Middle Viking A, Upper Mannville Z & G4G, and Ellerslie W, JJJ, KKK, LLL & MMM	3 282
Dinant Upper and Middle Viking A	55
Fort Saskatchewan Upper and Middle Viking A	7 954
Holmberg Upper and Middle Viking A	66
Killam Upper and Middle Viking A, Rex B, and Glauconitic Q	2 037
Killam North Upper and Middle Viking A, Upper Mannville T, Basal Mannville C, L & U, and Nisku A	1 513
Mannville Upper and Middle Viking A, and Upper Mannville K	380
Sedgewick Upper and Middle Viking A	88
Viking-Kinsella Upper and Middle Viking A, Upper Mannville YY, CCC, LLL, MMM, ZZZ, H2H & M2M, Colony G2G & N2N, Glauconitic J, and Wabamun I	29 045
Wainwright Upper and Middle Viking A, and Colony G, R, V, & W	1 470
Total	50 923
Viking Pool No. 3	
Carbon Belly River K and Viking D	1 692
Ghost Pine Viking D	295
Total	1 987
Viking Pool No. 4	
Fenn-Big Valley Viking B	749
Fenn West Viking B	185
Total	934
Viking Pool No. 5	
Hudson Viking A	817
Sedalia Viking A & F, Upper Mannville D, and Lower Mannville B	526
Total	1 343
Viking Pool No. 6	
Hairy Hill Viking A	230
Willingdon Viking A & J	229
Total	459
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	149
Total	367
St. Edouard Pool No. 3	
Ukalta St. Edouard B	54
Whitford St. Edouard B	29
Total	83

(continued)

Appendix 2. Reserves of multi-field pools, 2000 (concluded)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	1 440
Ferrybank Glauconitic A	900
Ferrybank Lower Mannville W	97
Total	2 437
Glauconitic Pool No. 5	
Bigoray Glauconitic I	1 207
Bigoray Ostracod D	131
Pembina Glauconitic I & D and Ostracod C	3 348
Total	4 686
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-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	1 744
Hotchkiss Bluesky-Detrital-Debolt A	4 688
Total	6 432
Gething Pool No. 1	
Fox Creek Viking C, Notikewin C and Gething D & H	2 470
Kaybob South Gething H	518
Total	2 988
Ellerslie Pool No. 1	
Connorsville Glauconitic A	239
Connorsville Glauconitic B	23
Connorsville Glauconitic C	126
Connorsville Glauconitic E	103
Connorsville Glauconitic I	45
Connorsville Ellerslie A	2 867
Wintering Hills Upper Mannville A	25
Wintering Hills Ellerslie A	1993
Total	5 421
Cadomin Pool No. 1	
Elmworth Dunvegan A	366
Elmworth Dunvegan I	62
Elmworth Cadotte A	2 817
Elmworth Cadotte D	474
Elmworth Cadotte E	21
Elmworth Cadotte F	60
Elmworth Cadotte G	37
Elmworth Cadotte I	57
Elmworth Cadotte J	52
Elmworth Cadotte K	22
Elmworth Cadotte M	17
Elmworth Cadotte N	44
Elmworth Cadotte T	176
Elmworth Falher A-1	7 260
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-43	56
Elmworth Falher B-1	1 804
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	2 816
Total	38 803
Halfway Pool No. 1	
Valhalla Halfway B	4 572
Wembley Halfway B	4 133
Total	8 705
Halfway Pool No. 2	
Knopcik Halfway N	675
Valhalla Halfway N	115
Total	790
Banff Pool No. 1	
Haro Banff E	87
Rainbow South Banff E	59
Total	146

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

	1	2	3	4	5	6	7	8	9
		Remaining reserves of marketable	Liquid recovery ratio (m³/10⁶ m³ of marketable gas)			Remaining established reserves of natural gas liquids (10³ m³)			
Field	Zone	gas (10⁶ m³)	Propane	Butanes	Pentanes plus	Propane	Butanes	Pentanes plus	Total
Ansell	Cardium	2 729	33	58	196	89	159	535	783
	Viking	730	21	25	86	15	18	63	96
	Mannville	1 413	25	19	69	35	27	97	159
	Other	160	-	15	60	-	1	10	11
	Subtotal					139	205	705	1 049
Bonnie Glen	Mannville	342	88	53	44	30	18	15	63
	Leduc[a]	4 783	-	-	-	598	321	690	1 609
	Subtotal					628	339	705	1 672
Brazeau River	Belly River	1 958	104	50	66	204	98	129	431
	Cardium	559	14	7	138	8	4	77	89
	Mannville	1 610	63	32	302	102	51	487	640
	Jurassic	2 393	153	81	310	366	194	743	1 303
	Rundle	1 908	1	1	80	2	1	152	155
	Winterburn[a]	5 501	-	-	-	1471	837	2 291	4 599
	Subtotal					2 153	1 185	3 879	7 217
Caroline	Cardium	1 182	166	84	147	196	99	174	469
	Mannville	3 428	148	77	147	508	263	505	1 276
	Viking	390	118	59	77	46	23	30	99
	Jurassic	56	125	71	107	7	4	6	17
	Rundle	1 468	138	71	89	202	104	130	436
	Beaverhill Lake	8 726	456	572	1 499	3 976	4 993	13 076	22 045
	Subtotal					4 935	5 486	13 921	24 342
Cranberry	Beaverhill Lake	2 674	65	67	206	174	179	551	904
	Middle Devonian	213	19	19	38	4	4	8	16
	Subtotal					178	183	559	920
Crossfield	Belly River	169	41	24	24	7	4	4	15
	Viking	122	90	74	57	11	9	7	27
	Mannville	1 270	85	57	133	108	72	169	349
	Jurassic	35	57	143	200	2	5	7	14
	Mississippian[a]	1 868	-	-	-	70	100	151	321
	Wabamun	1 784	7	6	28	12	11	50	73
	Subtotal					210	201	388	799
Dunvegan	Triassic	545	64	37	39	35	20	21	76
	Belloy	160	50	31	44	8	5	7	20
	Mississippian	214	9	5	70	2	1	15	18
	Rundle	9 376	60	36	83	564	336	776	1 676
	Wabamun	157	108	70	191	17	11	30	58
	Subtotal					626	373	849	1 848

(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.

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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**
Edson	Cardium	724	79	50	130	57	36	94	187
	Viking	593	19	12	86	11	7	51	69
	Mannville	1 764	67	40	109	118	71	193	382
	Jurassic	853	27	15	204	23	13	174	210
	Rundle	469	-	-	107	-	-	50	50
	Upper Devonian	429	-	-	175	-	-	75	75
	Subtotal					209	127	637	973
Elmworth	Second White Specks	1 260	106	51	47	134	64	59	257
	Lower Cretaceous	1 666	19	8	20	31	14	34	79
	Mannville	11 535	29	13	41	337	151	469	957
	Triassic	1 064	1	1	49	1	1	52	54
	Other	1 037	1	2	7	5	2	7	14
	Subtotal					508	232	621	1361
Ferrier	Belly River	451	144	60	95	65	27	43	135
	Cardium	2 262	152	21	32	343	48	73	464
	Viking	375	96	48	61	36	18	23	77
	Mannville	3 170	92	52	97	293	166	307	766
	Jurassic	551	154	29	29	85	16	16	117
	Rundle	2 875	33	25	87	94	72	251	417
	Mississippian	324	25	22	34	8	7	11	26
	Subtotal					924	354	724	2 002
Garrington	Cardium	376	146	80	221	55	30	83	168
	Viking	453	113	62	130	51	28	59	138
	Mannville	5 548	204	95	69	1 130	527	385	2 042
	Jurassic	446	119	74	182	53	33	81	167
	Rundle	392	97	59	46	38	23	18	79
	Wabamun	1 420	66	92	127	94	131	180	405
	Leduc	1 799	63	47	113	114	84	203	401
	Subtotal					1 535	856	1 009	3 400
Gilby	Belly River	37	108	108	81	4	4	3	11
	Second White Specks	98	122	133	71	12	13	7	32
	Mannville	2 488	89	63	75	222	157	186	565
	Jurassic	1 310	58	69	56	76	90	73	239
	Rundle	2 380	64	80	83	152	190	197	539
	Wabamun	61	131	66	49	8	4	3	15
	Leduc	72	111	69	83	8	5	6	19
	Other	186	111	69	14	6	5	1	12
	Subtotal					488	468	476	1 432
Gold Creek	Second White Specks	55	127	55	36	7	3	2	12
	Mannville	1 787	18	10	43	33	18	76	127
	Triassic	1 556	39	21	55	60	32	85	177
	Wabamun	3 768	-	-	95	-	-	358	358
	Subtotal					100	53	521	674

(continued)

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

	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
Hamburg	Triassic	294	31	17	20	9	5	6	20
	Beaverhill Lake	3 463	16	19	178	56	65	616	737
	Subtotal					65	70	622	757
Harmattan East	Viking	95	95	126	84	9	12	8	29
	Mannville	283	198	134	159	56	38	45	139
	Jurassic	99	101	131	91	10	13	9	32
	Mississippian[a]	5 728	-	-	-	37	22	26	85
	Subtotal					112	85	88	285
Harmattan-Elkton	Mannville	123	244	65	57	30	8	7	45
	Mississippian[a]	5 675	-	-	-	299	29	95	423
	Subtotal					329	37	102	468
Hussar	Viking	570	16	9	21	9	5	12	26
	Mannville	3 972	70	43	79	280	170	314	764
	Rundle	94	96	53	53	9	5	5	19
	Subtotal					298	180	331	809
Judy Creek	Viking	562	16	11	69	9	6	39	54
	Rundle	187	75	43	75	14	8	14	36
	Beaverhill Lake	2 321	255	135	87	591	314	203	1 108
	Subtotal					614	328	256	1198
Jumping Pound West	Rundle	8 609	42	38	126	360	331	1 086	1 777
	Subtotal					360	331	1 086	1 777
Kakwa	Cardium[a]	3 639	-	-	-	294	155	117	566
	Second White Specks	107	56	47	84	6	5	9	20
	Lower Cretaceous	117	94	51	17	11	6	2	19
	Mannville	229	44	26	26	10	6	6	22
	Triassic	94	96	43	43	9	4	4	17
	Subtotal					330	176	138	644
Karr	Cardium	63	127	63	48	8	4	3	15
	Second White Specks	224	125	58	45	28	13	10	51
	Mannville	4 384	127	71	120	555	311	524	1390
	Jurassic	241	54	25	46	13	6	11	30
	Triassic	407	93	47	54	38	19	22	79
	Wabamun	956	27	21	38	26	20	36	82
	Beaverhill Lake	47	170	85	64	8	4	3	15
	Subtotal					676	377	609	1 662

(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.

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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
Kaybob	Viking	484	19	19	76	9	9	37	55
	Mannville	2 993	21	18	48	62	53	144	259
	Upper Devonian	51	-	-	196	-	-	10	10
	Beaverhill Lake[a]	743	-	-	-	221	217	360	798
	Subtotal					292	279	551	1 122
Kaybob South	Second White Specks	73	68	41	219	5	3	16	24
	Viking	200	35	30	70	7	6	14	27
	Mannville	10 508	65	41	81	678	431	855	1 964
	Jurassic	317	13	13	47	4	4	15	23
	Triassic	1 163	41	53	73	48	62	85	195
	Wabamun	110	109	64	55	12	7	6	25
	Upper Devonian	360	75	75	644	27	27	232	286
	Nisku	182	66	115	462	12	21	84	117
	Beaverhill Lake[a]	3 106	-	-	-	386	348	1 401	2 135
	Subtotal					1 179	909	2 708	4 796
Knopcik	Second White Specks	149	27	27	47	4	4	7	15
	Viking	235	34	26	89	8	6	21	35
	Mannville	648	11	8	31	7	5	20	32
	Jurassic	1 208	45	32	102	54	39	123	216
	Triassic	5 241	12	8	122	63	43	637	743
	Subtotal					136	97	808	1 041
McLeod	Cardium	1 347	91	58	89	122	78	120	320
	Mannville	3 525	71	49	111	251	174	390	815
	Jurassic	1 178	53	33	154	62	39	181	282
	Subtotal					435	291	691	1 417
Medicine River	Viking	63	143	79	127	9	5	8	22
	Mannville	2 471	110	66	59	272	164	145	581
	Jurassic	1 533	91	59	44	140	90	67	297
	Rundle	1 924	109	61	70	210	117	135	462
	Leduc	329	219	152	340	72	50	112	234
	Subtotal					703	426	467	1 596
Minehead	Cardium	3 649	6	6	181	22	23	661	706
	Subtotal					22	23	661	706
Moose	Rundle	2 035	71	57	191	144	115	388	647
	Wabamun	180	44	33	61	8	6	11	25
	Subtotal					152	121	399	672

(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.

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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
Peco	Cardium	425	26	14	595	11	6	253	270
	Mannville	1 329	107	69	357	142	92	475	709
	Jurassic	41	122	73	49	5	3	2	10
	Nisku	748	39	29	29	29	22	22	73
	Subtotal					187	123	752	1 062
Pembina	Belly River	2 170	88	55	97	191	119	211	521
	Cardium	3 492	186	129	119	650	452	415	1 517
	Viking	388	72	52	77	28	20	30	78
	Mannville	7 461	64	37	166	481	276	1 239	1 996
	Jurassic	5 266	62	38	198	329	200	1 041	1 570
	Rundle	448	40	25	60	18	11	27	56
	Mississippian	395	114	61	81	45	24	32	101
	Upper Devonian	44	295	205	205	13	9	9	31
	Nisku	4 812	225	107	86	1 083	513	414	2 010
	Subtotal					2 838	1 624	3 418	7 880
Pine Creek	Second White Specks	135	-	-	156	-	-	21	21
	Mannville	2 683	37	19	201	98	52	538	688
	Jurassic	303	13	10	46	4	3	14	21
	Rundle	170	-	-	112	-	-	19	19
	Wabamun	787	6	5	25	5	4	20	29
	Leduc	488	18	25	39	9	12	19	40
	Other	1 047	-	3	53	2	1	22	25
	Subtotal					118	72	653	843
Rainbow	Mannville	3 052	3	3	15	10	10	46	66
	Beaverhill Lake	216	93	56	83	20	12	18	50
	Sulphur Point	396	61	38	129	24	15	51	90
	Muskeg	401	209	102	95	84	41	38	163
	Keg River	7 471	311	163	113	2 323	1 219	846	4 388
	Subtotal					2 461	1 297	999	4 757
Rainbow South	Sulphur Point	349	9	6	72	3	2	25	30
	Muskeg	312	128	74	83	40	23	26	89
	Keg River	2 734	273	139	134	747	380	367	1494
	Subtotal					790	405	418	1 613
Ricinus	Cardium[a]	9 869	-	-	-	412	275	376	1 063
	Viking	5 027	30	18	36	150	90	182	422
	Mannville	198	61	30	45	12	6	9	27
	Subtotal					574	371	567	1 512
Shekelie	Keg River	1 363	142	84	84	193	115	114	422
	Subtotal					193	115	114	422

(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.

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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
Simonette	Second White Specks	886	123	54	51	109	48	45	202
	Lower Cretaceous	214	42	23	47	9	5	10	24
	Mannville	597	121	60	74	72	36	44	152
	Wabamun	551	131	91	566	72	50	312	434
	Leduc	401	324	254	185	130	102	74	306
	Beaverhill Lake	784	182	96	89	143	75	70	288
	Other	43	182	1	8	3	1	6	10
	Subtotal					538	317	561	1 416
Swan Hills	Beaverhill Lake	695	1 345	823	449	935	572	312	1 819
	Subtotal					935	572	312	1 819
Swan Hills South	Beaverhill Lake	2 062	300	182	199	618	376	411	1 405
	Subtotal					618	376	411	1 405
Sylvan Lake	Second White Specks	51	118	59	39	6	3	2	11
	Viking	113	115	159	80	13	18	9	40
	Mannville	2 837	93	63	83	265	179	235	679
	Jurassic	1 663	106	64	97	176	107	162	445
	Rundle	2 868	96	58	67	275	166	192	633
	Leduc	510	157	94	94	80	48	48	176
	Subtotal					815	521	648	1 984
Turner Valley	Mannville	271	129	55	26	35	15	7	57
	Jurassic	101	139	69	30	14	7	3	24
	Rundle	1 086	274	171	356	298	186	387	871
	Subtotal					347	208	397	952
Twining	Viking	450	27	13	69	12	6	31	49
	Mannville	560	41	36	96	23	20	54	97
	Rundle	4 400	63	60	101	276	265	443	984
	Subtotal					311	291	528	1 130
Valhalla	Second White Specks	692	14	12	61	10	8	42	60
	Mannville	2 016	4	2	24	9	5	48	62
	Triassic[a]	9 940	-	-	-	916	421	2 141	3 478
	Mississippian	28	107	71	286	3	2	8	13
	Other	513	-	-	138	-	-	71	71
	Subtotal					938	436	2 310	3 684
Virginia Hills	Mannville	133	90	45	30	12	6	4	22
	Belloy	291	110	65	72	32	19	21	72
	Beaverhill Lake	1 018	571	228	147	581	232	150	963
	Subtotal					625	257	175	1 057

(continued)

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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**
Wapiti	Belly River	860	119	59	37	102	51	32	185
	Cardium	919	224	95	34	206	87	31	324
	Second White Specks	113	159	62	27	18	7	3	28
	Lower Cretaceous	3 030	74	44	57	223	133	156	512
	Mannville	10 688	64	36	67	680	385	721	1786
	Viking	235	30	15	44	4	2	6	12
	Jurassic	880	48	28	63	42	25	55	122
	Other	121	-	19	9	4	2	5	11
	Subtotal					1 279	692	1 009	2 980
Waterton	Mississippian[a]	3 978	-	-	-	93	77	372	542
	Subtotal					93	77	372	542
Wayne-Rosedale	Viking	749	36	21	31	27	16	23	66
	Mannville	2 752	71	45	68	196	123	186	505
	Nisku	215	-	-	698	-	-	150	150
	Other	2 236	-	14	19	5	3	4	12
	Subtotal					228	142	363	733
Wembley	Second White Specks	167	12	6	42	2	1	7	10
	Triassic[a]	6 220	-	-	-	933	446	1 938	3 317
	Other	241	150	-	2	2	1	10	13
	Subtotal					937	448	1 955	3 340
Westerose	Mannville	1 063	126	63	70	134	67	74	275
	Mississippian	221	140	77	158	31	17	35	83
	Wabamun	213	-	-	70	-	-	15	15
	Nisku	86	-	-	128	-	-	11	11
	Subtotal					165	84	135	384
Westerose South	Mannville	1 995	132	68	93	263	136	185	584
	Rundle	53	132	57	94	7	3	5	15
	Mississippian	457	214	96	55	98	44	25	167
	Wabamun	296	57	68	68	17	20	20	57
	Other	63	57	7	10	4	3	4	11
	Subtotal					389	206	239	834
Willesden Green	Belly River	1 000	97	74	65	97	74	65	236
	Cardium	3 329	22	20	99	72	67	330	469
	Second White Specks	222	81	72	72	18	16	16	50
	Viking	365	211	129	118	77	47	43	167
	Mannville	5 528	132	74	143	732	411	790	1 933
	Jurassic	1 257	104	66	96	131	83	121	335
	Rundle	127	94	55	94	12	7	12	31
	Mississippian	456	50	44	110	23	20	50	93
	Subtotal					1 162	725	1 427	3 314

(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.

Appendix 3. Remaining established reserves of natural gas liquids as of December 31, 2000

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
Wilson Creek	Belly River	771	167	109	332	129	84	256	469
	Mannville	1 003	82	66	103	82	66	103	251
	Jurassic	348	92	60	60	32	21	21	74
	Rundle	565	87	50	112	49	28	63	140
	Mississippian	255	133	75	145	34	19	37	90
	Other	56	133	12	16	5	3	4	12
	Subtotal					331	221	484	1 036
Windfall	Mannville	1 073	52	30	67	56	32	72	160
	Rundle	87	57	46	184	5	4	16	25
	Mississippian	54	111	56	56	6	3	3	12
	Upper Devonian	1 173	15	32	142	18	37	166	221
	Nisku	185	43	54	492	8	10	91	109
	Leduc[a]	1 931	-	-	-	31	30	280	341
	Other	235	16	1	5	2	2	9	13
	Subtotal					126	118	637	881
Wizard Lake	Mannville	588	37	20	100	22	12	59	93
	Leduc	5 819	351	202	61	2 045	1 178	354	3 577
	Subtotal					2 067	1 190	413	3 670
Subtotal						37 710	24 846	54 102	116 658
Confidential reserves						81	42	101	224
Other small reserves						13 174	8 423	23 959	45 556
Subtotal						50 965	33 311	78 162	162 438
Recoverable at straddle plants						34 470	15 860	7 170	57 500
Recoverable at solvent floods						48	1 237	621	1 906
Total reserves						85 483 (538.5)[b]	50 408 (317.4)[b]	85 953 (540 9)[b]	221 844 (1 396.8)[b]

[b] Imperial equivalent in millions of barrels.

Appendix 4 Basic Data Tables and Map

Introduction

The databases used to prepare this report were developed by EUB staff. Input was also obtained from the National Energy Board (NEB) through an ongoing process of crude oil, natural gas, and crude bitumen reserve 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 reserves and basic data, crude bitumen resources and basic data, and the natural gas reserves and basic data tables are included this year as Microsoft Excel 2000 spreadsheets on a 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. Oil field, crude bitumen deposit, and gas field/strike 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 along the left side and the column headings on the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first.

Crude Bitumen Resources and Basic Data

The crude bitumen resources and basic data spreadsheet is similar to the data tables in previous versions of the reserves report (EUB *Statistical Series 18*). The Oils 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 tables in previous versions of the reserves report. The spreadsheet contains all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are presented in separate columns. The total pool 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 pool names.

All fields are listed in alphabetical order, and within each field the pools are ordered stratigraphically, with the pool occurring in the most recent reservoir rock appearing first. This order is preserved regardless of whether the pool consists of light-medium or heavy oil. A data field of crude classification has been included that will allow the reader to sort the file by that category, if desired. Provincial totals for the 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 file is greatly expanded over the table that was included in past reserve reports. Previously the data table was limited to individual natural gas pools with initial established reserves of marketable gas equal to or greater than 300 million cubic metres. Pools with less than 300 million cubic metres were grouped within each field and presented as a total. The natural gas reserves data file in this report has been expanded to include all nonconfidential pools, regardless of initial established reserves values.

The number of data fields in the natural gas reserves table has also been expanded. The EUB field, pool, and sequence codes are included, as are fields to indicate associated, nonassociated, and solution gas. The solution gas data are listed under separate column headings from the associated/nonassociated gas data. Gas/water and oil/water interfaces are also given.

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

In previous reserve reports, the natural gas reserves data files used footnotes to indicate certain conditions. With the change of format for this report, the footnotes are no longer present, but the information can be deduced from the natural gas reserves spreadsheet as follows:

- Footnote a – measured heating value. This refers to the gross heating values (GHV), where the heating value was based on an analysis of the natural gas, rather than being calculated from the components. These pools are indicated on the spreadsheet by a GHV code of A (analyzed).

- Footnote b – includes solution gas production. Solution gas production was included with the associated gas production in the marketable gas net cumulative production where associated gas was present. That practice is continued in this report and occurs where the Associated Gas and Solution Gas indicator fields are both present.

- Footnote c – pool recovery and surface loss calculated on an energy basis. This footnote applied to pools that were undergoing gas cycling. These pools have a GHV code of A (analyzed) and an analysis code of GC (gas cycling).

The codes for gross heating value and reserve analysis are as follows:

Gross Heating Value Codes

A Analyzed
C Calculated

Reserves Analysis Codes

CM	Coal Bed Methane
CP	Cumulative Production
GC	Gas Cycling
MB	Material Balance
PD	Production Decline
SG	Secondary Gas Cap
TR	Total Record
VO	Volumetrics
PE	Performance Estimate

If production from two or more pools is commingled before measurement, the initial reserve estimate for each pool is given, if available, together with the total reserve estimate for the pools. Also, because production of associated and solution gas reserves for a pool has not been determined separately, the spreadsheet lists remaining associated and solution gas reserves for those pools on a combined basis.

Map of Oil and Gas Fields and Oil Sands Deposits in Alberta

The EUB map of the oil and gas fields and oil sands deposits in Alberta is included in an envelope at the end of this report. This map illustrates the feature boundaries as they existed on December 31, 2000. Also included on this map are the main pipelines, refineries, and gas processing plants.