Technical Royalty Report OG#1:
Alberta's Conventional Oil and Gas Fiscal System
- Overview of the Industry-

This report is a technical report by the Alberta Department of Energy (ADOE). The technical series is intended to contribute to the public understanding of oil and gas royalty issues.

Section I - Introduction

This report is the first of a series of technical reports describing the performance of Alberta's fiscal system for conventional oil and natural gas. The purpose of the report series is to provide information and to invite comment as part of the Government of Alberta's public review of the royalties and taxes applied to the province's oil and gas resources. Another report series provides information on the Alberta oil sands industry.

This report – Technical Report OG#1 - provides an overview of Alberta's conventional oil and natural gas industry. Technical Report OG#2 will assess Alberta's conventional oil and natural gas royalty systems with comparisons of the current system's competitiveness. Technical Report OG#3 will assess the potential impacts of fiscal system change on industry investment and activity.

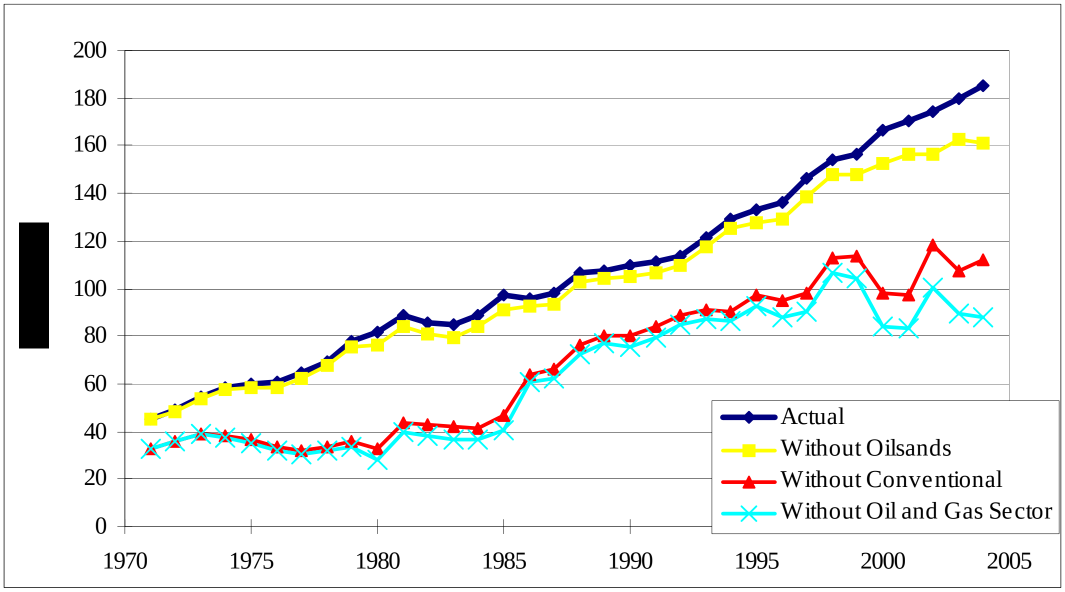
In addition to the introduction, the present report is divided into six sections. Section II – provides a brief overview of the oil and gas industry in the context of Alberta's overall economy. Section III provides a synopsis of historical price trends for both conventional oil and natural gas. Section IV outlines the characteristics of Alberta conventional oil and gas resources including pool size and trends. Section V provides and overview of industry costs and trends. Section VI provides a summary.

Section II – The Oil and Gas Industry in Alberta

The oil and gas industry is the economic engine of Alberta employing directly or indirectly nearly one in every six workers in the Province. Largely due to the value of oil and gas industry investment and production, the Alberta economy has outperformed that of the Canadian national average. Mansell and Schlenker (2006) estimate that the oil and gas industry accounts for at least half of the Province's gross domestic product (GDP) once all linkages are taken into consideration. Figure 2.1 shows the impact that the oil and gas industry has had on the Alberta economy over the past 35 years[1].

[1] Source: Energy and the Alberta Economy: Past and Future Impacts and Implications by Robert Mansell and Ron Schlenker. December, 2006.

**FIGURE 2.1 - REAL GDP IN ALBERTA:
ACTUAL AND WITHOUT OIL AND GAS SECTOR COMPONENTS: 1971-2004**



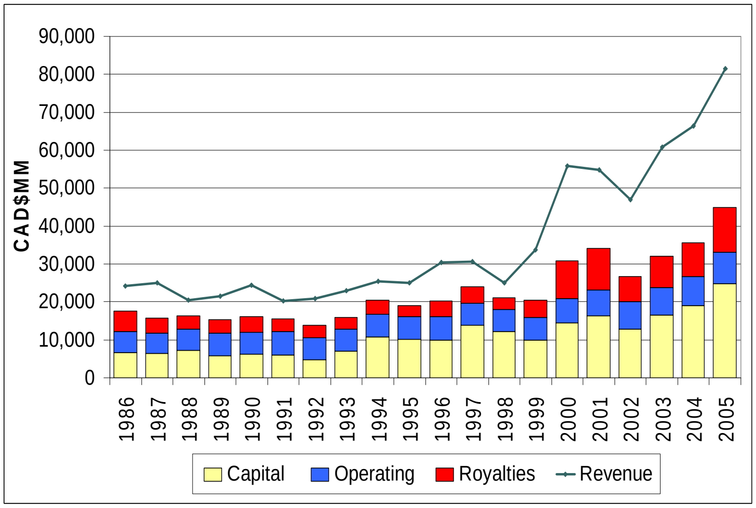
Source: Energy and the Alberta Economy: Past and Future Impacts and Implications by Robert Mansell and Ron Schlenker. December, 2006. Actual (baseline) from Alberta Treasury, Alberta Economic Accounts

Some important facts about this industry and its impact on the Alberta economy are listed bellow[2]:

- Approximately 465,600 new jobs were created between 1996 and 2006, resulting in an unemployment rate of 3.4% the lowest in Canada.
- A total of $60.3 billion was invested in Alberta in 2005 of which $30.3 billion occurred in the oil and gas industry.
- The oil and gas industry had a total of $24.9 billion in capital expenditure in 2005 and $8.2 billion in operating expenditures. Figure 2.2 below shows oil and gas revenues and expenditures. The margin between industry revenues and expenditures has widened since prices started to escalate in 1999.

[2] Source: Alberta Economic Development Department, Alberta Energy. This information includes oil sand.

FIGURE 2.2 – ALBERTA OIL AND GAS INDUSTRY REVENUES AND EXPENDITURES



Source: CAPP

- The value of Alberta's exports more than tripled since 1995 to reach $87 billion in 2005. From this amount, exports of natural gas and liquids, crude oil, and petrochemical products accounted for $63.3 billion[3] or 73% of the total.
- In 2005, the Government of Alberta collected $14.78 billion in natural resource royalties about 42% of the total provincial revenues. Table 2.1 shows a break down of the 2005/06 Alberta royalty revenues.

TABLE 2.1 – ALBERTA ROYALTY REVENUES 2005/06

	Revenues $MM	Percentage of total
Natural Gas	8,388	56.7%
Land Sales[4]	3,490	23.6%
Conventional Oil	1,463	9.9%
Oil Sand	950	6.4%
Freehold mineral tax[5]	334	2.3%
Rental and fees[6]	150	1%
Coal	11	0.07%
Total	**14,786**	

Section III – Prices

[3] Industry export breakdown: $32.1 billion natural gas; $ 24.6 billion crude petroleum; $6.6 billion petrochemical products.

[4] The Department of Energy administers Crown mineral rights on behalf of Albertans in the form of licences or leases acquired through a competitive sealed bid auction held about every two weeks.

[5] The Crown owns 81 per cent of the province's mineral rights. The remaining 19 per cent are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in national parks, and by individuals and companies.   The Crown levies an annual tax on freehold oil and gas production.

[6] The Crown charge an annual rent of $3.50 per hectare for each hectare covered by license and lease agreements.

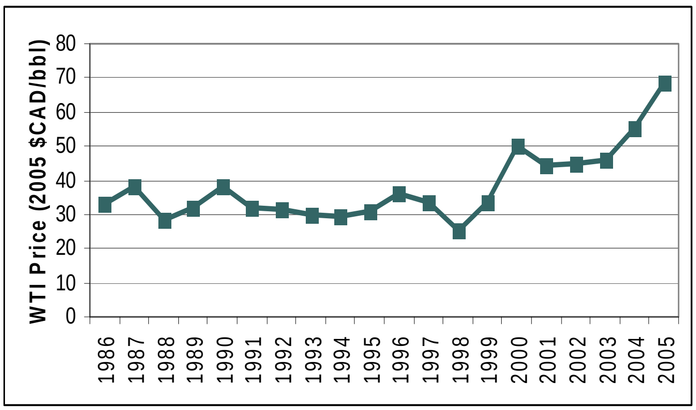
3.1 Oil Price

Crude oil is the world's most actively traded commodity, and its value is enhanced by its ability to be transported around the world at a reasonable cost as well as the diversity of products that can be derived from it. Crude oil produced in Alberta is sold within Alberta, to other parts of Canada, and is exported to the United States.

Oil prices are normally decided by market forces. However, this is not always the case given that OPEC[7] is large enough to influence world prices. Members of OPEC provide about 35% of the world oil supply and its state-owned petroleum companies control the largest share of reserves. Furthermore, the cartel usually makes decisions that affect supply levels to influence prices.

Figure 3.1.1 shows the price for West Texas Intermediate (WTI)[8], one of the world's crude oil price benchmarks. Since 2000 crude oil prices have been higher in real dollar terms than they were typically trading over the last 20 years.

FIGURE 3.1.1 – WTI REAL PRICES[9] 1986-2005



Source: CAPP, Alberta Energy

3.2 Natural Gas Price

Natural gas is primarily traded in the various continental markets (e.g., North America, South America, and Europe), rather than on a global scale due to global transportation constraints[10]. Natural gas produced in Alberta is sold within Alberta, to other parts of Canada, and is exported to the United States. The supply and demand conditions for natural gas across all of North America influence the price of natural gas in Alberta. Beginning in the year 2000, natural gas prices jumped

[7] OPEC stands for the Organization of Petroleum Exporting Countries. It was founded in 1960 and its mission is "to coordinate & unify the petroleum policies of Member Countries & ensure the stabilization of oil prices in order to secure an efficient, economic & regular supply of petroleum to consumers, a steady income to producers & a fair return on capital to those investing in the petroleum industry".

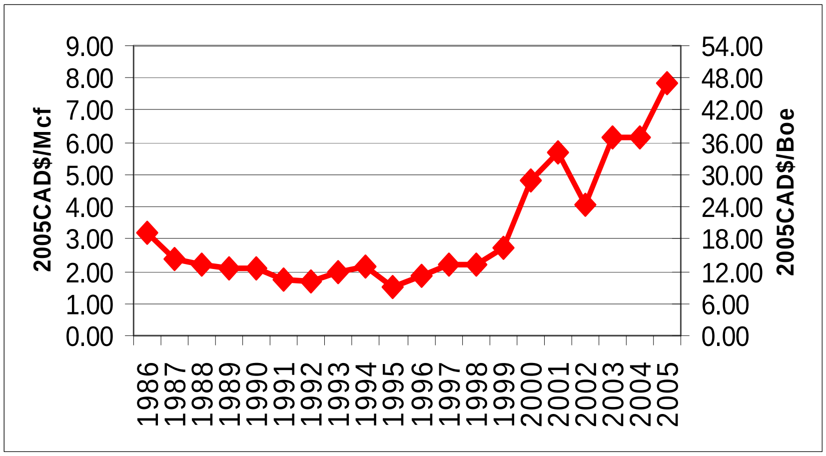
[8] WTI is light crude oil. It contains about 0.24% sulfur and 39.6 API gravity. Its properties and production location make it ideal for being refined in the United States, mostly in the Midwest and Gulf Coast regions.

[9] Prices are inflated to 2005 dollars using Canada's GDP index.

[10] Although liquefied natural gas (LNG) can be transported globally at a reasonable cost, there are still considerable supplies of natural gas that remain stranded due primarily political risks and policies and to a lack of transportation access.

significantly from previous years. Figure 3.2.1 shows how real natural gas[11] prices have evolved over time.

FIGURE 3.2.1 – ALBERTA NATURAL GAS PRICES 1986-2005



Source: Alberta Energy

Section IV - Characteristic of the Resources

The Western Canadian Sedimentary Basin (WCSB) is the largest basin in North America. About 80% of the WCSB is located in Alberta. The WCSB is considered to be a mature basin as oil and gas have been produced for almost 100 years in Alberta. The production of conventional oil and natural gas in Alberta peaked in 1973 and 2001 respectively. Characteristics of Alberta's conventional oil and natural gas resources are described below.

4.1 Conventional Oil Resources

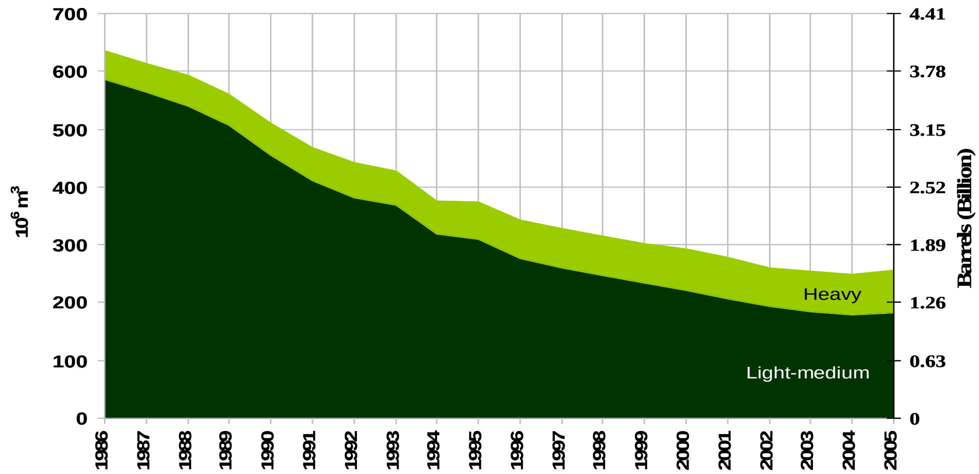
As of December 2005, Alberta's expected ultimate recovery from oil is 3.1 billion cubic metres (19.5 billion barrels). The remaining recoverable oil is 255 million cubic metres (1.6 billion barrels). Additionally, another 795 million cubic metres (5 billion barrels) are potentially recoverable with technological advancements in enhanced oil recovery techniques.[12, 13]

Additions to crude oil reserves have not kept pace with production, especially light-medium[14] crude oil where production has decreased by 69% since 1986. By comparison, heavy[15] conventional crude oil production has increased 47% over the same period. This has resulted in a decrease in the light-medium total share of production from 92% of total conventional oil production in 1986 to 72% in

[11] Prices are inflated to 2005 dollars using Canada's GDP index.
[12] "Spudding Innovation Accelerating Technology Deployment in Natural Gas and Conventional Oil" Petroleum Technology Alliance Canada and Deep Blue Associates Incorporated, October 2003.
[13] Enhanced oil recovery (EOR) techniques include hydrocarbon miscible flood, carbon dioxide (CO_2) flood and chemical flood.
[14] Density less than 900kg per cubic metre or greater than 25.72 API. Light/medium oil uses a different par price and select price than heavy oil, resulting in a different royalty rate for the same production level. Royalty formulas and rates will be addressed in Technical Report #2.
[15] Density more than 900kg per cubic metre or less than 25.72 API. Heavy oil uses a different par price and select price than light/medium oil, resulting in a different royalty rate for the ame production level. Royalty formulas and rates will be address in Technical Report #2.

2005. Figure 4.1.1 shows the remaining reserves of conventional crude oil (not including bitumen) over time.

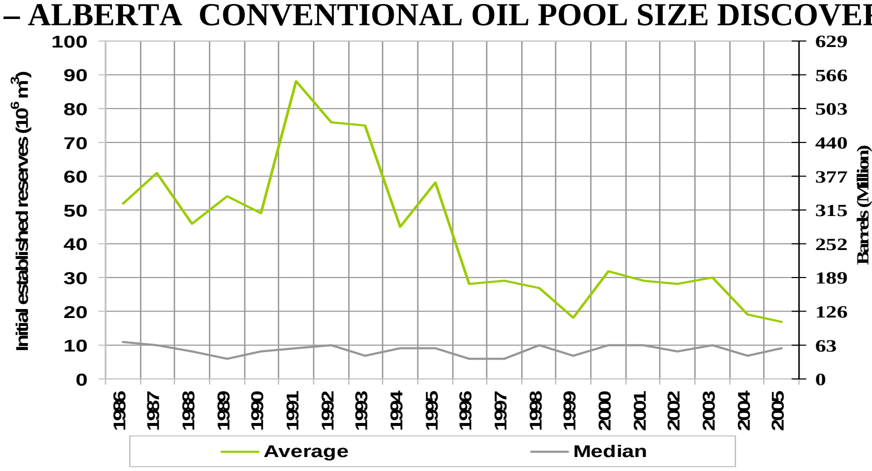
FIGURE 4.1.1 – ALBERTA CONVENTIONAL OIL REMAINING ESTABLISHED RESERVES 1986-2005



Source: EUB. ST98-2006

One consequence of a maturing basin is that the pool discoveries are getting smaller. Figure 4.1.2 shows the average oil pool sizes discovered in Alberta over time. Since 1986, the mean pool size has decreased from 52 million cubic metres (327 million barrels) to 17 million cubic metres (107 million barrels), a decline of more than 67%. Over this same time period, the median oil pool size has remained relatively stable at around 10 million cubic metres (63 million barrels). This contrast between the mean pool size getting smaller while the median pool size is remaining stable relates to the fact that there are many more small pools (both discovered and undiscovered) than there are large pools. As fewer very large pools are found, the mean pool size decreases, while the median pool size is largely unaffected. Stated a different way, the pool size typically found over the last twenty years has not changed.

FIGURE 4.1.2 – ALBERTA CONVENTIONAL OIL POOL SIZE DISCOVERED 1986-2005



Source: EUB. ST98-2006

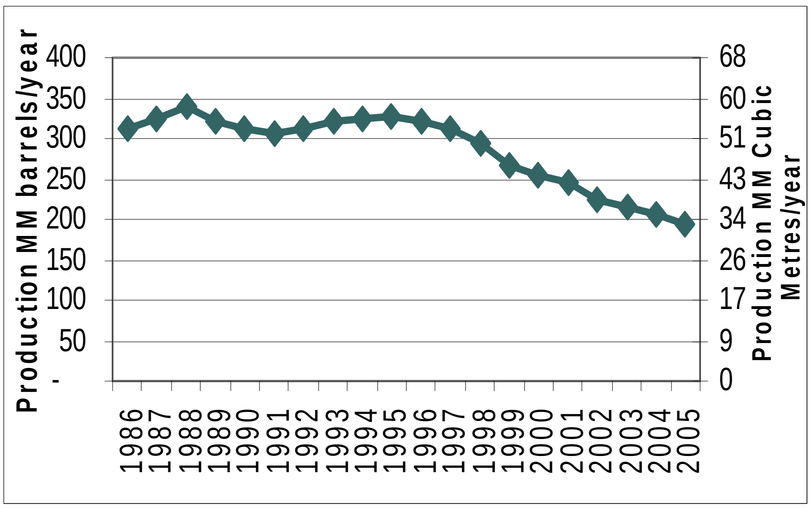
A break down of the conventional oil reserves, level of production, and number of wells drilled by PSAC area[16] in 2005 is shown is the table below. Notice that the distribution of production and drilling for oil is reasonably evenly split between the 5 areas of Alberta.

TABLE 4.1.2 – ALBERTA CRUDE OIL RESERVES, PRODUCTION AND DRILLING STATISTICS 2005

	PSAC 1	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 6	PSAC 7	TOTAL
Reserves (10^6m^3)	12.3	58.8	35.1	4.3	10.4	1.1	3.7	125.7
Share of Total	10%	47%	28%	3%	8%	1%	3%	100%
Production (10^6m^3)	0.12	5.51	7.44	6.76	6.90	0.01	6.39	33.13
Share of Total	0%	17%	23%	20%	21%	0%	19%	100%
Wells drilled	6	319	361	470	335	1	348	1840
Share of Total	0%	17%	20%	26%	18%	0%	19%	100%

Historical production of conventional oil in Alberta is shown in Figure 4.1.3.

FIGURE 4.1.3 – ALBERTA CONVENTIONAL OIL PRODUCTION 1986-2005



Source: CAPP

4.2 Conventional Natural Gas Resources

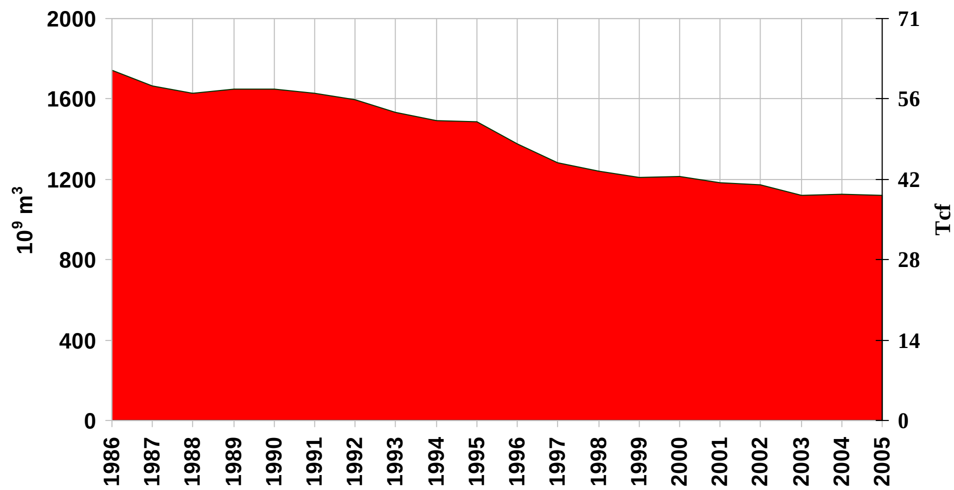
Alberta's remaining established natural gas reserves are set at 1,086 billion cubic metres or 38.4 trillion cubic feet (Tcf). Additionally, reserves that are yet to be established were estimated at 1,604 billion cubic metres (56.7 Tcf) by the EUB/NEB in 2006.

The remaining established reserves of conventional natural gas have declined over time as production continues. Despite this trend reserves have remained stable for the past couple of years. This is attributed to a very intensive drilling effort partly in response to higher commodity prices.

[16] Alberta is often divided into seven areas of production. This division is due to different characteristics of the resources such as geological formation, depth and cost of production. A map showing these seven areas referred to as PSAC areas are shown in the Appendix.

Figure 4.2.1 shows the remaining marketable reserves[17] of conventional natural gas over time. Since 1986, remaining reserves have declined by 37%.

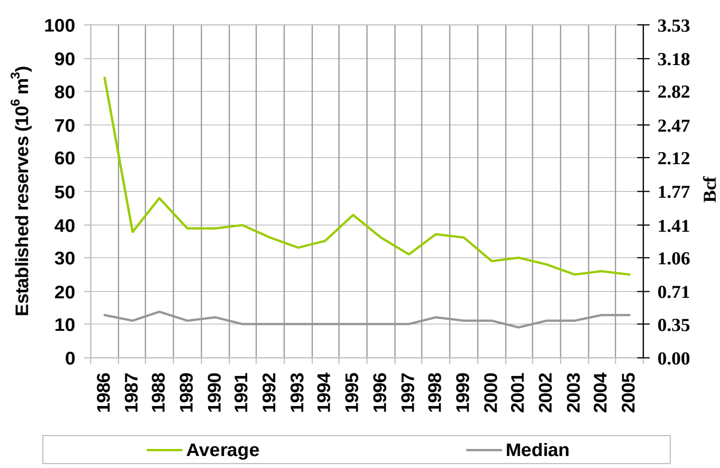
FIGURE 4.2.1 – ALBERTA NATURAL GAS REMAINING ESTABLISHED RESERVES 1986-2005



Source: EUB. ST98-2006

As with crude oil, the average pool size being discovered for natural gas is declining over time. Since 1986, the mean gas pool size has declined from 84 million cubic meters [3 billion cubic feet (Bcf)] to 25 million cubic metres (0.9 Bcf) in 2005. Over this same time frame, the median pool size has remained comparatively stable at 13 million cubic metres (0.5 Bcf). Figure 4.2.2 shows the change in average and median natural gas pool size over time.

FIGURE 4.2.2 – ALBERTA CONVENTIONAL NATURAL GAS POOL SIZE DISCOVERED 1986-2005



Source: EUB. ST98-2006

[17] Marketable reserves are determined after raw gas has been processed to remove some constituents to meet specifications for use as a domestic, commercial or industrial fuel or as an industrial raw material.

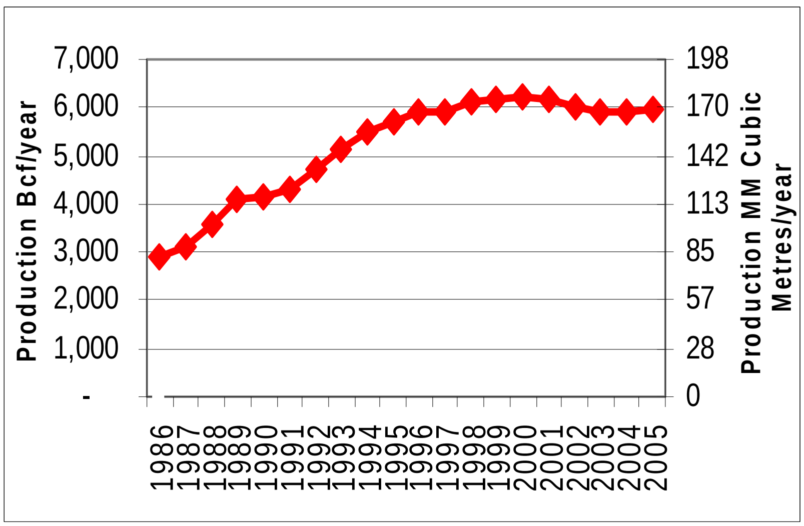
Table 4.2.1 shows the break down of conventional marketable gas reserves, level of production and number of wells drilled by PSAC area in 2005. In contrast to oil, natural gas production and drilling are less evenly distributed through Alberta, with the area along the foothills contributing the most production and the southeast area having the most wells.

TABLE 4.2.1 – ALBERTA NATURAL GAS RESERVES, PRODUCTION AND DRILLING STATISTIC 2005[18]

	PSAC 1	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 6	PSAC 7	TOTAL
Reserves (10^9m^3)	47	406	347	52	142	44	80	1118
Share of Total	4%	36%	31%	5%	13%	4%	7%	100%
Production[19] (10^9m^3)	7.3	53	27.9	6.7	16.1	4.6	9.4	125
Share of Total	6%	42%	22%	5%	13%	4%	8%	100%
Wells drilled	54	1809	6268	563	2435	159	859	12,147
Share of Total	0.4%	14.9%	51.6%	4.6%	20.0%	1.3%	7.1%	100%

Historical production of marketable gas in Alberta is shown in Figure 4.2.3. The aggressive increase in production throughout the 1990's and then a subsequent levelling of production after 2000 is noticeable.

FIGURE 4.2.3 – ALBERTA MARKEATEBLE NATURAL GAS PRODUCTION 1986-2005 [20]



Source: CAPP

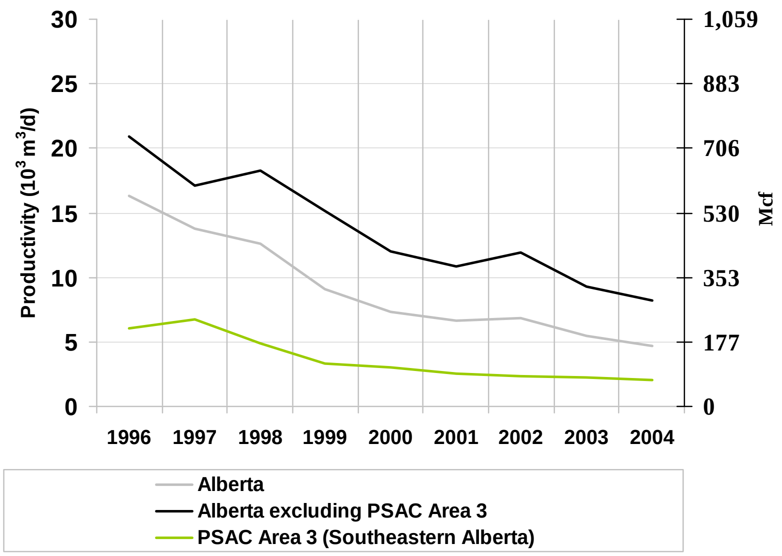
In addition to conventional natural gas, Alberta has large potential for coal-bed methane (CBM[21]), tight sands gas[22], and shale gas[23]. Estimates of the gas in place for CBM exceed 500 trillion cubic

[18] Production in this table refers to production of natural gas and natural gas liquids from natural gas wells and as such specifically excludes natural gas produced from oil wells.
[19] Production in this table refers to production of natural gas and natural gas liquids from natural gas wells and as such specifically excludes natural gas produced from oil wells.
[20] Natural gas production in this chart includes gas from oil wells.
[21] Coalbed methane (or CBM) is unconventional natural gas trapped in coal deposits. Its extraction tends to involve more extensive development and more serious water risks than conventional natural gas.

feet (TCF), while tight sands gas and shale gas could represent even larger resources. These resources could potentially increase levels of production and remaining reserves.

As average pool sizes have been declining, so to have the production rates from natural gas wells. Average initial productivity per well has declined from about 16.3 thousand cubic metres per day [about 575 thousand cubic feet (Mcf) per day] in 1996 to about 4.7 thousand cubic metres per day (166 Mcf per day) in 2004. Figure 4.2.4 shows average initial productivities per well over time and the difference in initial productivity between PSAC 3 which represents over 40 per cent of new wells and the rest of Alberta. PSAC 3 is characterized by shallow, low productivity, high per unit cost resources.

FIGURE 4.2.4 – ALBERTA NATURAL GAS PRODUCTIVITY PER WELL 1996-2004



Source: EUB. ST98-2006

Section V - Oil and Gas Costs

Cost increases in the oil and gas industry are happening world-wide. The reasons for the cost increases are many; however, much of the increase can be attributed to improved economics, and in particular to increasing oil and gas prices. As prices increase, new higher cost resources become economic and this increases average costs. Moreover, it is these new higher cost resources that are on the margin, therefore marginal costs are increasing as well. Additionally, improved economics translates into increased industry activity. The increasing activity results in increasing demand for, and ultimately, the cost of inputs. The net result is increasing per unit costs. The global nature of this trend is recognized in the upstream capital cost index developed by the IHS Incorporated (IHS)

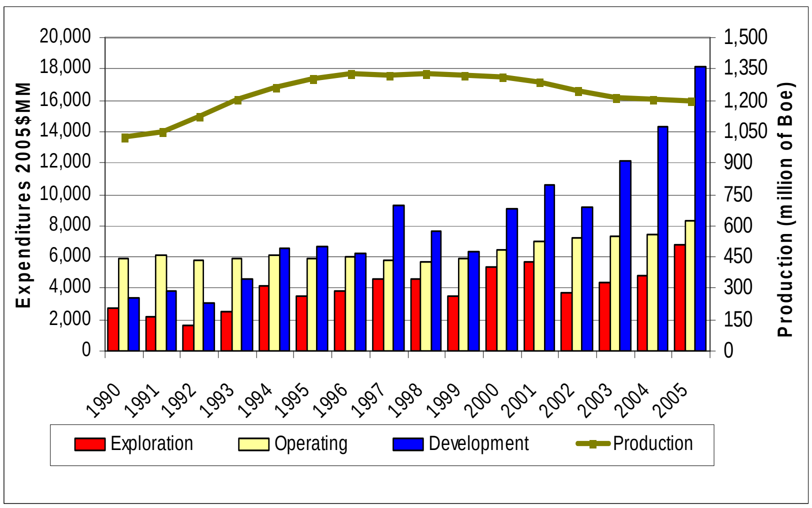
[22] Tight sands gas is located in reservoirs with low permeability; it cannot be produced economically without assistance from special recovery processes and technologies.

[23] Shale gas is produced from reservoirs predominantly composed of shale and fine grained rocks rather than from more conventional sandstone or limestone reservoirs. It cannot be produced economically as it needs special recovery processes and technologies.

and Cambridge Energy Research Associates (CERA). Their index shows that global oil and gas industry costs have increased by 67% from the year 2000 to the third quarter of 2006.[24]

Although a similar index for Alberta is not available, Alberta has also experienced cost increases. Evidence of these cost increases can be seen in relation to rising expenditures while production has fallen slightly. Expenditure increases are not a direct proxy for increased costs as the level and type of activity are also important. Exploration expenditures, including geophysical/geological, exploratory drilling, and land purchase costs (bonus payments), have increased 90% since 1999. Similarly, development expenditures composed by field equipment, gas plant, enhanced oil recovery, and development drilling went up 185%. In addition, operating expenditures including well and flow lines rose 40% in the same period. Meanwhile combined conventional oil and gas production has declined by 9% in the same period. Figure 5.1.1 shows how expenditures in the conventional oil and natural gas sector have escalated while production output has remained fairly constant.

FIGURE 5.1.1 – ALBERTA CONVENTIONAL OIL AND GAS EXPENDITURES AND PRODUCTION 1990-2005



Source: CAPP

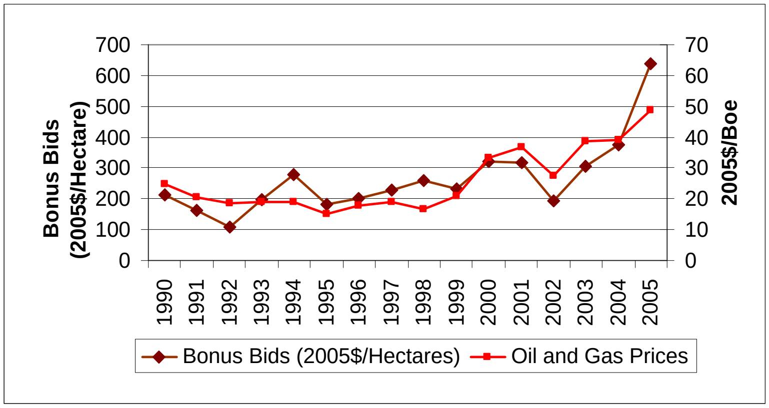
Other measures of cost trends such as finding and development costs (see Appendix 2) and operating costs show a similar trend. Many industry commentators tie this back to the declining pool size (see figures 4.1.1 and 4.2.1 in Section IV) and suggest that the underlying cause of these increases is a maturing basin. A more comprehensive assessment of the reasons for the increase in per unit costs warranted. This is provided below. Specifically, several components of cost are looked at individually to explain the trend of increasing costs.

[24] IHS/CERA created a global cost index for upstream capital project. The new Upstream Capital Costs Index (UCCI), which tracks nine key cost areas for offshore and land-based projects, has risen 67% since the year 2000.

Land Costs

Land expenditures are the bonus bid amounts that are paid to government for the opportunity to explore for, develop, and produce the oil and gas in Alberta. These bonus bids are made in a competitive sealed bid auction[25]. Bonus bids are entirely left to the market to determine the value of acquiring mineral leases. The recent increase in bonus bids is consistent with improved overall project profitability. Figure 5.1.2 shows the relationship between bonuses paid per hectare for petroleum and natural gas agreements and conventional oil and natural gas prices. The strong positive correlation between oil and gas prices and bonus payments is clearly evident.

FIGURE 5.1.2 – ALBERTA PRICES FOR OIL & GAS AND BONUS BIDS 1990-2005

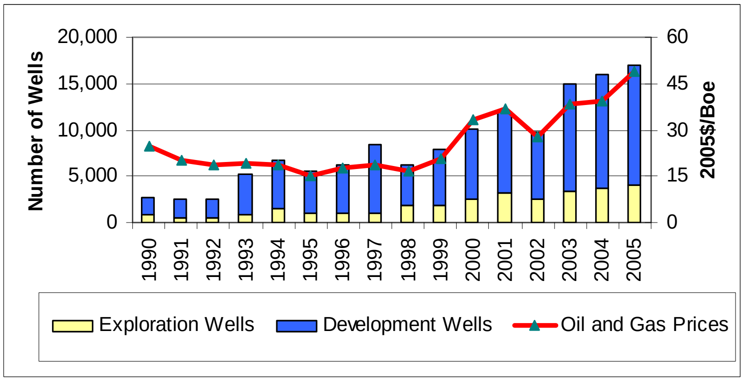


Source: Alberta Energy

Drilling Expenditures

Higher prices yield more activity; more activity puts demand on drilling rigs and other inputs; this subsequently causes input costs and drilling rig day rates to increase. The opposite is also true, lower prices create less activity and therefore reduce demand for inputs causing costs to decline. Below is a chart showing historical oil and gas prices and wells drilled and completed in Alberta.

FIGURE 5.1.3 – ALBERTA EXPLORATION & DEVELOPMENT WELLS AND REAL PRICES 1990-2005

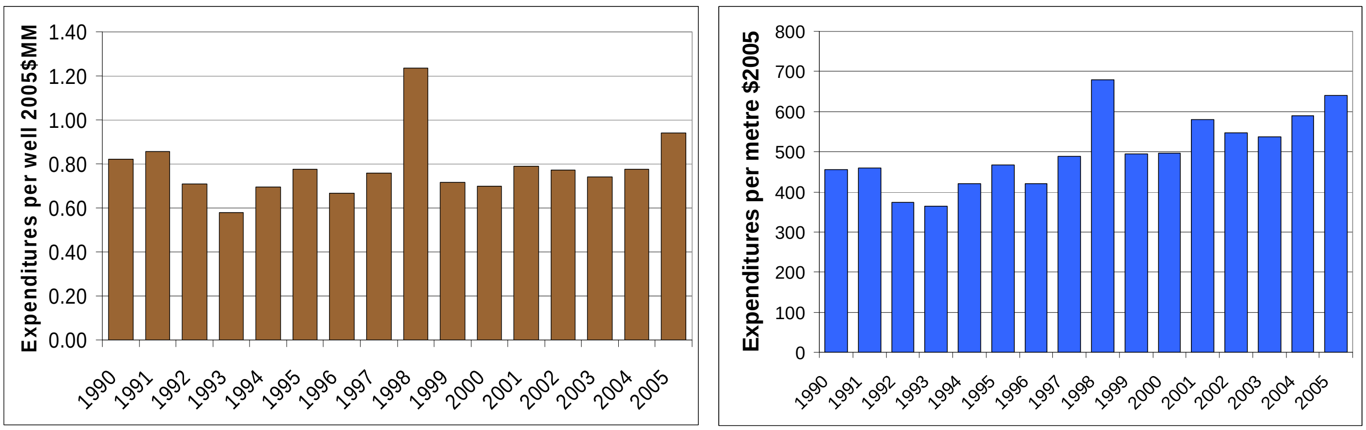


25 Individual industry investors have complete discretion over the amounts they wish to competitively bid for land acquisition. Detailed information on Alberta's Land Tenure system can be accessed at: http://www.energy.gov.ab.ca/docs/tenure/pdfs/tenure_brochure.pdf.

Source: EUB. ST-59, Alberta Energy

Drilling expenditures have increased on a per well basis. The average expenditure per successful oil and gas well increased 36% since 1999. Also, the average expenditure per metre drilled increased 29% in the same period. This can be seen in figures 5.1.4 and 5.1.5. Notice that results in 1998 are unusually high compared to the other years. This is because 1997 was a record year for drilling activity which caused drilling costs to increase significantly. 1998 saw a drop in oil prices (see figure 3.1.1) with a corresponding 72% drop in oil well completions. Natural gas drilling only experienced a 6% decline as natural gas prices remained relatively stable (see figure 3.2.1). The sharp slow-down in wells drilled was not offset by an immediate reduction in per well cost given the lag in cost responsiveness. Costs returned to more normal levels in 1999.

FIGURE 5.1.4 & 5.1.5– ALBERTA REAL EXPENDITURES PER WELL AND PER METRE DRILLED 1990-2005



Source: CAPP, Alberta Energy

The increased numbers of wells has put pressure on the rig utilization rate in Alberta. Table 5.1.1 shows how rig utilization jumped from 47% in 1999 to 67% in 2006[26]. As rig utilization increases, there is upward pressure on rig costs.

TABLE 5.1.1 – ALBERTA RIG UTILIZATION RATES 1990- 2006

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Average Number of Rigs Drilling	135	115	99	179	242	213	244	310	218	210	296	298	231	314	331	381
Average Number of Rigs Availables	376	354	329	323	326	351	349	377	446	448	464	487	514	502	540	569
Rig Utilization Rate	36%	32%	30%	55%	74%	61%	70%	82%	49%	47%	64%	61%	45%	63%	61%	67%

Source: CAODC

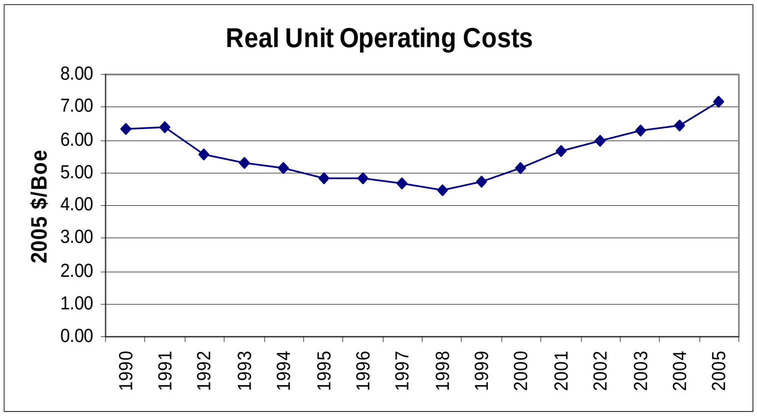
Operating Expenditures

The link between operating costs and prices is not as obvious as the link between capital costs and prices. Although a few components that comprise the cost to operate a well can be traced directly to oil and gas prices, many of the individual components that are required to maintain and operate a

[26] Canadian Association of Oil well Drilling Contractors (CAODC).

well have very little relationship with prevailing commodity prices. Figure 5.1.6 shows how the combined oil and gas per unit operating costs have increased by 52% since 1999[27].

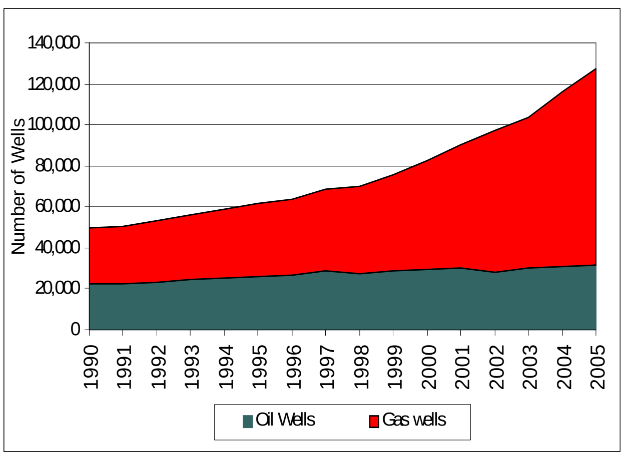
FIGURE 5.1.6– ALBERTA REAL UNIT OPERATING COST OIL AND GAS 1990-2005



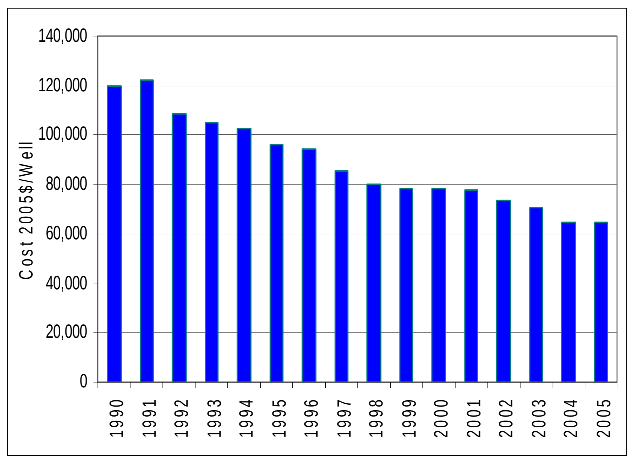
Source: CAPP, Alberta Energy

It is interesting to note that while the operating cost per unit of oil and gas is increasing (as shown by figure 5.1.6); the cost per well has been declining over time (as shown by figure 5.1.8). The average cost per well has declined from about $120,000/well in the 1980s to about $65,000/well in 2005.

FIGURE 5.1.7 & 5.1.8– ALBERTA OPERATING WELLS AND REAL COST PER WELL PER YEAR 1990-2005



Source: EUB, Alberta Energy



Source: CAPP, Alberta Energy

Adding up the Pieces

Falling productivity per well (discussed in section 4) and the increasing number of wells required to maintain production are posited by some as the reasons for the increase in per unit costs in Alberta as the basin is maturing. This increase would appear to be greater than offsetting efficiencies due to improved technology. This however, is not the full picture. Examining the impact that price has on

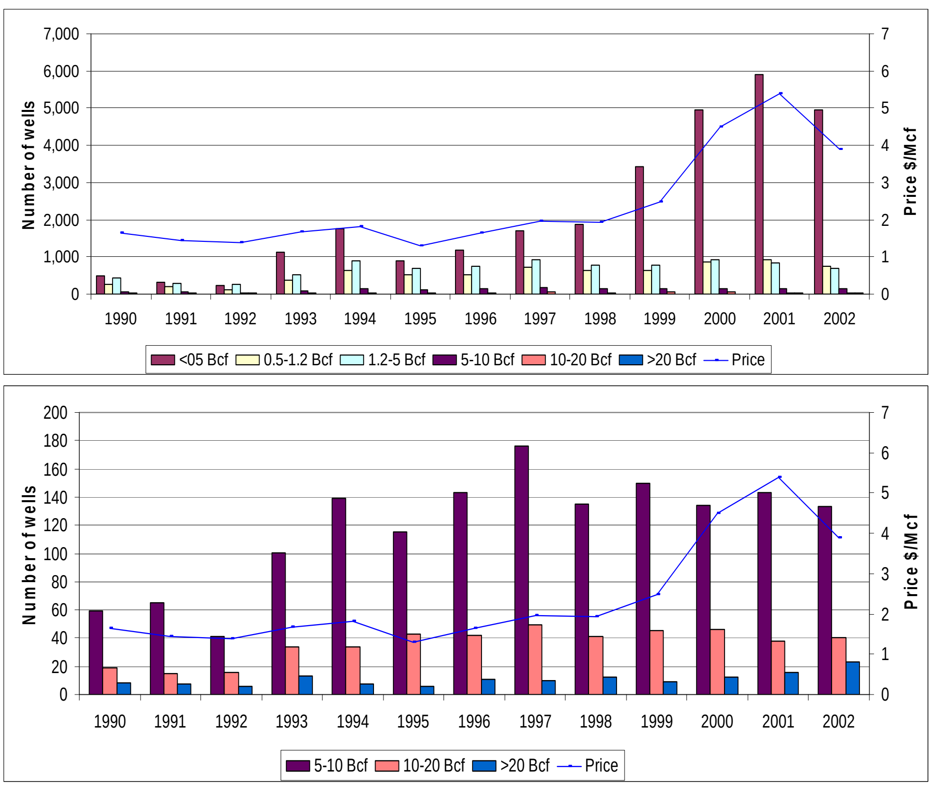
[27] Per unit operating costs were calculated by taking total operating expenditures for oil and gas reported by CAPP divided by annual production.

drilling behaviour is quite insightful. While the number of wells have increased dramatically between 1990 and present, almost all of this increase has been in low productivity wells. That is, higher prices, not basin maturity, have resulted in the drilling of more low productivity wells.

Figure 5.1.9 and 5.1.10 breakdown the successful natural gas wells drilled between 1994 and 2002 by year, into histograms reflecting the number of wells with reserves of a certain size. What is particularly striking is that (for the price range experienced) there is almost no price relationship for wells that could be considered as having large reserves (in this sample that would include all wells with 5 Bcf of reserves or more). Even for more moderate wells (those with reserves between 0.5 Bcf and 5 Bcf), there is little correlation with prices.

The rapid increase in small wells (having reserves of less than 0.5 Bcf per well) is directly correlated with price. This would indicate that more of these wells are economic as prices increase. The result of the higher prices is many more small wells are drilled, leading to increased expenditures and a lowering of the average productivity per well. The net result is higher per unit costs. In other words investment economics in Alberta's oil and gas sector are so strong that even higher cost resources are now economically viable.

FIGURE 5.1.9 & 5.1.10 – ALBERTA GAS PRICES AND WELLS DRILLED 1990-2005 [28]



Source: Alberta Energy

[28] Note: the scale in the two charts. The lower chart is a subset of the upper chart to allow the trend in larger wells to be observed.

Section IV - Summary Observations

Oil and gas continue to be the economic engine of Alberta's economy. Recent trends in oil and gas resource characteristics and costs are related to oil and gas commodity prices. In a sense, these trends are part of a good news story that the Alberta economy is strong as a result of high oil and gas prices.

Costs have been increasing on a global basis and this trend it is not particular to Alberta. The main reason for cost increase is improved economics (because of high commodity prices) in the oil and gas industry that allows the development of low productivity and high cost resources.

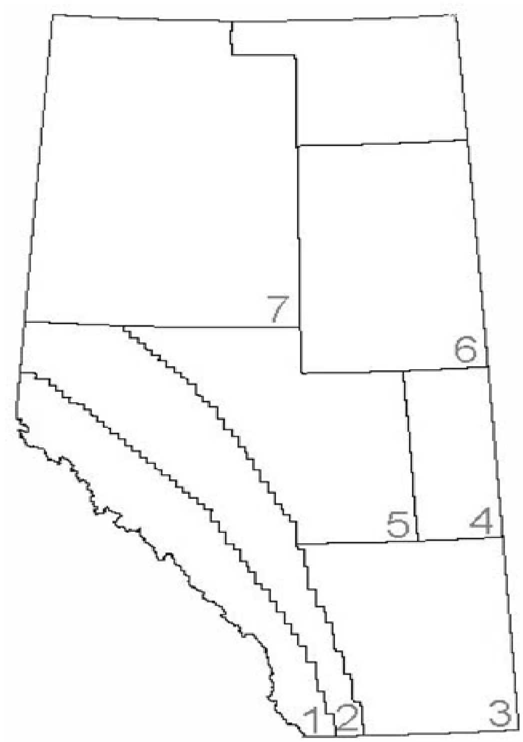
Despite the increase in costs in recent years there is evidence that costs in Alberta are still competitive. Alberta is still ranked below average in terms of costs and above average in terms of profitability in North America. A recent study by IHS/CERA[29] ranks a number of different areas in North America based on costs and profitability. Of the 76 areas studied for Canada and the United States, CERA identifies 6 areas in Alberta (3 conventional natural gas areas and 3 unconventional natural gas areas). The study shows much of Alberta's resources are ranked near the lowest cost. All 6 of the Alberta areas are shown to be below average for cost and above average for profitability.

[29] Diminishing Returns: The Cost of North American Gas in an Unconventional Era, IHS/CERA, 2007

Section VIII – Appendix

1

PSAC Area



2

Conventional Natural Gas
Finding and Development Costs for WCSB

Finding and Development Cost (F&D cost) is often used as proxy for per unit capital cost. It is the cost spent on exploration and development activities in a given time period divided by the reserves added in the same period. F&D cost is relatively easy to calculate due to the availability of data. However, it has a number of methodological issues that create a mismatch between expenditures and reserves that suggest that the use of F&D costs has limited use for economic evaluations. The proper way to evaluate per unit capital costs is project by project based on the amount of expenditure and the resulting production.

The methodological problems associated with F&D calculations depend on the technique used to calculate. One method uses total capital expenditures over a fixed time period (e.g., 1 year, 5 years, or 10 years) divided by the total reserves added in that same time period. As years are included or excluded, the results can change dramatically. This is caused by timing differences between when the capital expenditures occur and when the reserves are ultimately booked. Often significant expenditures are made in one year and the reserves added in later years. The longer the time period included in an F&D cost calculation the less likely that this will be material; however, with longer time periods included the trend becomes less useful. An example of this methodology is shown in Figures 8.1 and 8.2. Notice that there are big swings in F&D costs for the 1 year F&D cost and smaller changes in the 5 year F&D cost.

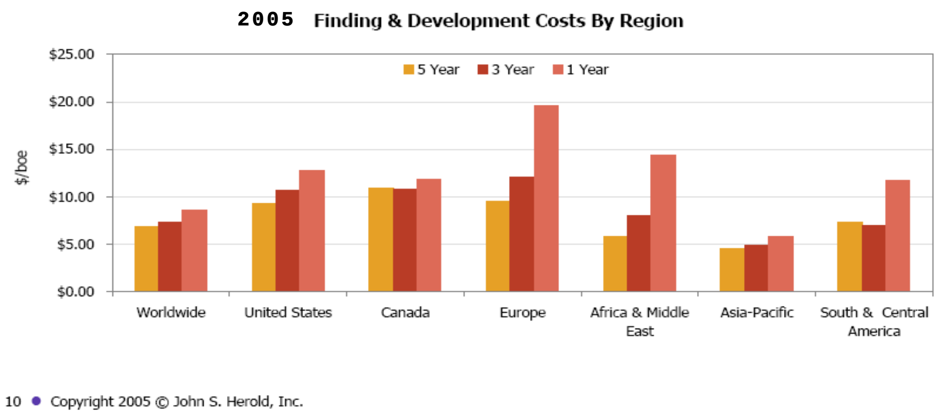
A second methodology is a subtle variation that uses a moving average of expenditures over a given time period divided by the reserves added over this same time period. The intent of this approach is to measure the trend more readily while not being exposed to the volatility of a single year's mismatch in expenditures and reserves. The underlying assumption is that the mismatch in the new-year addition is offset by the mismatch in the year that is no longer part of the moving average. The difficulty that arises is that reserve changes are typically credited back to the year of discovery. The treatment of exploration and development reserve additions is important in these calculations. A simple example helps to identify this:

> Assume that only one well is drilled in 1999 at a cost of 40. This well discovers a pool with reserves of 100. This results in an F&D cost of 40/100 = $0.40. Assume that in 2005 two wells are drilled at a cost of 40 each. One of these wells discovers a new pool with reserves of 100 and the other is into the pool discovered in 1995 adding 100 to that pool. The F&D cost for 1999 is now reported as 40/200 = $0.20 and the F&D cost for 2005 is 80/100 = $0.80.

Notice that the increase in development expenditures and the reserves associated with this development are not allocated to the same time period. The result is that earlier year's costs are fundamentally understated and later year's costs are fundamentally overstated. In using aggregate data, this is further compounded by reserve revisions that arise as a result of new information learned about a reservoir without additional capital spending. Unlike reserve additions that result from development expenditures, reserve revisions that result from new information (either additions or reductions) should be allocated back to the year that the reservoir was initially discovered. This complication is rarely addressed properly for the calculation of per unit capital costs in aggregated data. Figure 8.3 is an example of this type methodology.

One final comment on F&D costs is that they trend with price. Figure 8.4 shows the relationship between commodity prices and F&D costs for the United States. These results are consistent with those demonstrated in Figures 5.8 and 5.9 in which higher prices resulted in an increase in the number of low productivity wells being drilled.

FIGURE 8.1 & 8.2 – 2005/06 FINDING AND DEVELOPMENT COST COMPARISON



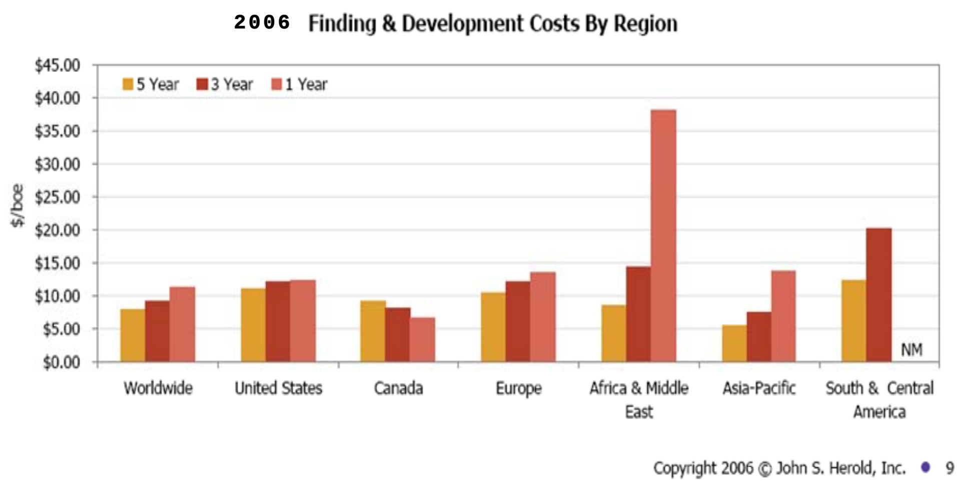


FIGURE 8.3 CONVENTIONAL NATURAL GAS F&D COSTS FOR WCSB

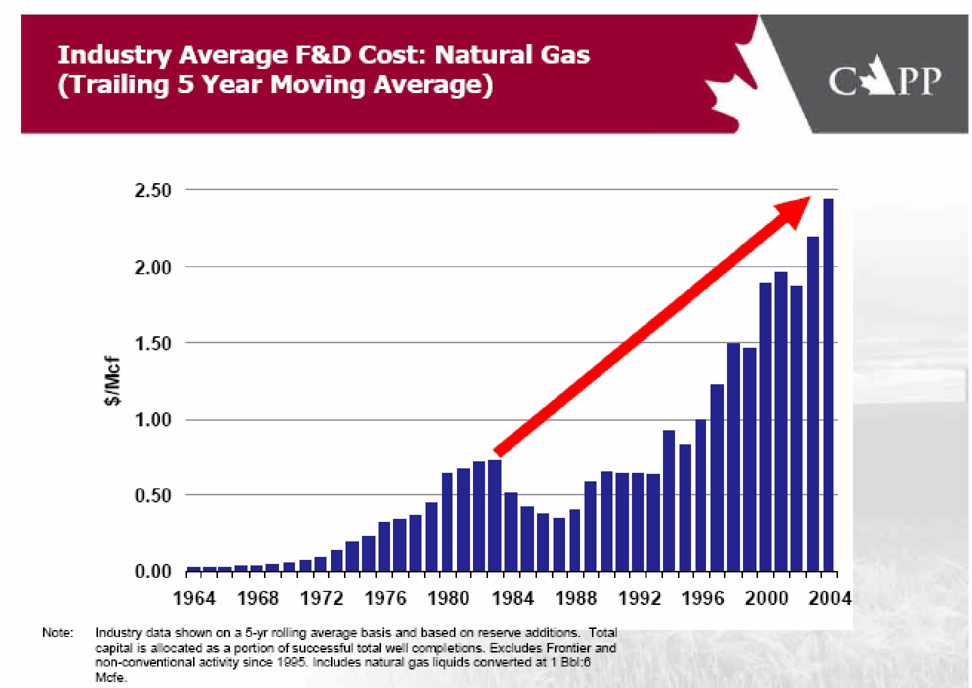
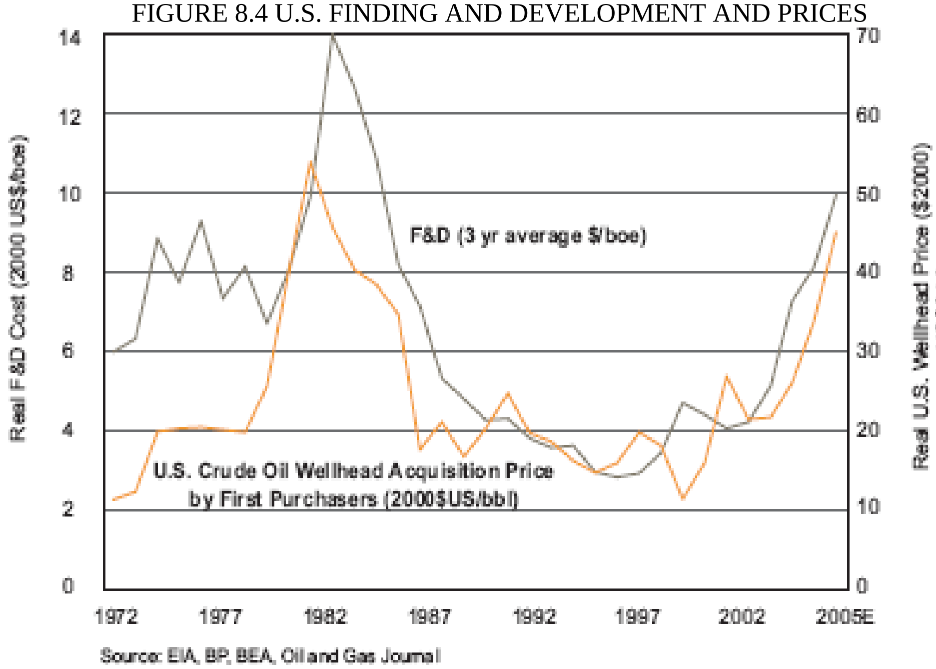


FIGURE 8.4 U.S. FINDING AND DEVELOPMENT AND PRICES



Source: Ross Smith Energy Group