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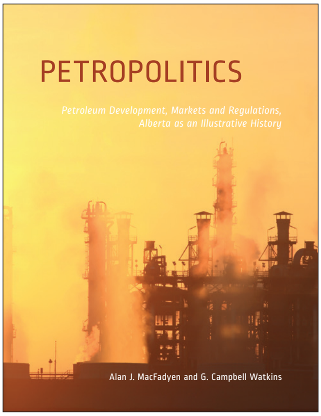

PETROPOLITICS: PETROLEUM DEVELOPMENT, MARKETS AND REGULATIONS, ALBERTA AS AN ILLUSTRATIVE HISTORY

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Part Two: Overview

Ultimately the story of an exhaustible natural resource industry in a region is one of rise and fall. But within this skeletal history, many particular lifetimes are possible. Moreover, as Part Five of this book will argue, a regional economy need not mirror exactly the emergence and decline of a key natural resource: other natural resources may rise to take its place, and the benefits of natural resource production may be parlayed into a viable, ongoing, dynamic economy based on the wealth and skills of the local population.

Part Two of this book examines the Alberta crude oil industry from the beginning of its rapid growth in the late 1940s through to the early twenty-first century. Nature and humanity jointly determine this history. Nature conveys opportunities and imposes limits; humanity must determine which opportunities to exploit and how hard to push the limits. It is important to note that the activities of the oil industry reflect two quite different types of human influences: the directly productive decisions of individuals and companies in the petroleum industry and the government regulatory framework, which constantly changes the set of legal options open to these decision-makers. It is the inescapable presence of government that has lead to our use of the term 'petropolitics' in the title to this book. Our focus, articulated in the Overview to Part One, is on the interplay of nature, individuals, companies, and governments to generate the economic history of the crude petroleum industry.

This section of the book details the history of Alberta crude oil largely from the industry's point of view, while Part Three is primarily concerned with the rationale for, and course of, government regulation. The distinction is one of convenience rather than reality, since industry decisions reflect the actual and anticipated regulatory environment, and the regulations introduced by government derive from actual and anticipated industry activities.

Part Two includes four chapters: Chapter Five examines the evolution of Alberta's oil reserves; Chapter Six considers production and pricing; Chapter Seven looks at the province's non-conventional oil resources; and Chapter Eight discusses various attempts to measure the 'economic supply' of Alberta oil.

CHAPTER FIVE

Alberta's Conventional Oil Resources

Readers' Guide: The crude oil industry in a region derives from nature's bounty. But no one can know for certain how much oil lies beneath the surface in an area such as Alberta and how much of that might eventually be produced. Chapter Five is concerned with attempts to understand how much conventional oil Alberta has and how these estimates have changed over time.

1. The Concept of Reserves

No one knows exactly how much conventional crude oil lies beneath Alberta or how much will eventually prove to be commercial. Exploratory activities of the petroleum industry are designed, in part, to reduce such uncertainties. Ongoing geophysical activities and exploratory drilling allow the interpretation and re-interpretation of accumulating records to generate theories and hypotheses about the pre-historic sources and migration of petroleum into trapped pools. However, our ability to see hundreds of metres beneath the surface will always be limited, so knowledge of the province's underlying resource base will remain imperfect. Moreover, knowledge and expectations in this regard are products of the human mind and are necessarily subjective. Skills, training, and experience differ among experts providing information to decision-makers in the oil industry. The resultant diversity of opinion is one of the engines driving industry activity, as different companies seek out niches that reflect their particular expectations. Differences in behaviour among companies are observable to some degree, but the subjective evaluations that influenced that behaviour are rarely made public. Thus, while it is the expectations and decisions of individuals that determine what happens, most economic analysis of the oil industry is based on aggregate results, as reported in published statistics from government agencies, like Statistics Canada, the Energy and Resources Conservation Board (ERCB), the National Energy Board (NEB), the Geological Survey of Canada (GSC), and private industry groups, like the Canadian Petroleum Association (CPA), the Independent Petroleum Association of Canada (IPAC), or their 1992 amalgam, the Canadian Association of Petroleum Producers (CAPP). This chapter examines information about the amount of crude oil in the ground in Alberta, both the underlying physical resource base and the rate at which this oil has been discovered and rendered producible.

Some terminological and conceptual issues must be dealt with. (Tanner, 1986, and Thompson et al., 2009, provide useful reviews.) The term 'resources,' or 'resource base,' is commonly used to refer to the total physical volume of a resource as it exists in nature. However, as one early resource economist put it, resources "are not, they become" (Zimmermann, 1951, p. 15), and the becoming involves more than physical existence; usefulness and accessibility to humans are also required. In a similar vein, Firey (1960) noted that natural resources have characteristics of possibility (physical existence), adoptability (cultural acceptance), and gainfulness (economic feasibility). More is at issue than the fact that a natural phenomenon must be recognized as of value before it is seen as a resource. Of what is available only some portion will ultimately prove to be utilizable by us. Some deposits may never be located, some that have been located may never be exploited, and some of the resource in a produced deposit will be left behind forever. In this light, it is wise to be skeptical of the simplistic view that we face a fixed stock of petroleum that must somehow be spread out over time until the resource is completely gone. Adelman (1990, pp. 1–2), in his discussion of the concept of a fixed stock, argues that:

> … there is no such thing. The total mineral in the earth is an irrelevant non-binding constraint. If expected finding-development costs exceed net revenues, investment dries up and the industry disappears. Whatever is left in the ground is unknown, probably unknowable, but surely unimportant; a geological fact of no economic interest.… What actually exist are flows from unknown resources into a reserve inventory.… The fixed-stock assumption is both wrong and superfluous.

Profitable volumes of crude, as defined by physical, technological, economic, and political factors, are known as 'reserves.' Reserves consist of the entire resource in the ground multiplied by a recovery factor that equals the percentage of the resource that is actually produced. Only when an oil reservoir is abandoned, never to be reopened, is it known with certainty what the 'ultimate reserves' of the pool have been (abstracting from any errors in measuring production over the life of the deposit). Prior to that, any estimates of reserves are very much conditional, depending on assumptions made about a variety of key factors, and they always reflect the judgment of the individual or group making the estimate, including that party's subjective evaluation of underlying uncertainties. Aguilera et al. (2009) provide a recent example of the argument that the world's recoverable conventional petroleum resources will prove to be larger than has generally been expected, due both to exploration in new geological arenas and development extensions.

The basic meaning of the word 'reserves' is well accepted. The ERCB defines established reserves as "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" (ERCB, *Reserves Report 2010*, ST-98, p. A-2). As Tanner (1986, p. 23) notes, however, this basic definition leaves abundant room for disagreement. For example, the World Petroleum Congress has suggested a concept of 'proven reserves' that is based on current economic and technical conditions, while the 'established reserves' concept commonly used in Canada assumes current technology but anticipated, not just current, economic conditions. Beyond this, the necessity of 'reasonable' assurance for recovery, leaves room for differences of opinion. The conclusion is that reserves data must be treated with a certain amount of caution: estimates for a region, or a pool, may not be completely compatible if they come from different sources. Aggregate reserve estimates (e.g., all of Alberta) inevitably involve estimates from a number of different sources, though bodies like the ERCB and the CAPP (formerly CPA) have tried to ensure that all those making estimates use the same criteria; as a result, the aggregate reserves each of these bodies reports is widely regarded as reliable and consistent over time. Tanner notes (1986, p. 28) that the actual estimation practices did not change much for either the CPA or ERCB when they switched to 'established' reserves in the 1960s from 'proved' (ERCB) or 'proven and probable' (CPA) reserves.

Given the basic definition of reserves, there are three commonly used bases for measurement: 'remaining,' 'initial,' and 'ultimate' reserves. 'Remaining reserves' are those currently in the ground and recoverable, whereas 'initial reserves' are those that were initially in pools (at the time of discovery) and therefore consist of remaining reserves plus any past production. 'Ultimate reserves' are the total oil that will ever be produced in the region, and they are often not true 'reserves'; in effect, they drop the requirement for 'reasonable certainty' in estimation in order to allow for the effects of more speculative future activities such as the discovery of new oil pools, extension drilling, and EOR schemes. Everyone knows with absolute certainty that many of these ventures will occur in Alberta, but no one can say with sufficient ('reasonable') certainty exactly where or when they will occur, so future activities of this sort are excluded from initial and remaining established reserves estimates.

Estimates of remaining established reserves will change over time. Production clearly reduces remaining reserves (while leaving initial reserves unchanged). There are three additional reasons for changes:

(1) The industry undertakes activity to add reserves: exploration for new discoveries, and development to extend pool boundaries or add EOR schemes.
(2) Apart from adding reserves, industry activity adds new information that may lead to a re-evaluation of the previous period's estimates: production, for example, provides additional information on reservoir characteristics including production decline, lifting costs, water to oil ratios, etc., which may or may not correspond exactly with what was anticipated last year.
(3) Economic, political, and technological changes occur: e.g., oil prices fall unexpectedly, taxes are increased, a new and cheaper miscible flood agent is developed.

Whereas the first of these always leads to an addition to estimated reserves, the second and third may involve either increases or reductions. In practice, published estimates of reserves are not fine-tuned with the regularity that the discussion so far implies. Reserves additions for reason (1) are typically estimated each year, and any relatively significant re-evaluations for reason (2) are allowed for; but more minor adjustments of type (2) in any one pool often go unmarked, and only significant changes in economic or political conditions (reason (3)) will usually generate an adjustment in published reserves data.

The ERCB (and, for some years, the CAPP) have reported reserve additions due to new discoveries; this is the estimate, as of December 31, of the reserves in pools discovered that year. Recall that this typically underestimates the eventual reserves that will be booked in these pools since it makes no allowance for revisions and extensions or EOR investment (i.e., appreciations). The economic analyst faces severe data problems here. Suppose, for example, we are trying to model the exploration process. What volume of oil does this year's exploration actually discover? A company drilling on a large structure certainly expects that a success will hold much more oil than will be reported in that year as the size of the new discovery; this argues for some attempt to increase, or 'appreciate,' the new discovery reserves estimates. This can be done relatively easily for pools discovered many years ago. As we noted in Chapter Two, the ERCB estimated that a representative Alberta oil pool, unless very small, appreciated about nine times over the first year's estimate of initial reserves. But for recent finds future reserves additions due to extension drilling or EOR are unknown. Moreover, reserves additions that do occur for these reasons may not have been anticipated but reflect new technologies or changes in economic conditions years after the initial discovery. As a further complication, this year's exploration may generate knowledge that makes future discoveries easier. The conclusion, in more formal economic terminology, must be that it is almost impossible to set out an 'oil reserves production function' that is completely satisfactory from an analytical point of view. An oil reserves production function is a quantitative (mathematical) relationship that relates the inputs in the oil exploration process (G&G, exploratory wells) to the resultant outputs – reserves additions of various types. In describing exploration, one must be satisfied with workable empirical models that seem 'reasonable enough.'

This chapter continues with two main sections: a review of the history of Alberta crude oil reserves additions and a survey of some studies of Alberta's ultimate reserves potential. Chapter Eight will review attempts to build supply models that 'explain' the process of oil discovery and reserves additions in Alberta.

By way of introduction, we present information from the ERCB's 2013 assessments of the size of Alberta's oil reserves (from chap. 4 in the 2013 *Reserves Report and Supply/Demand Outlook*, ST-98). By the end of 2012, the ERCB reported that 13,374 separate oil pools had been discovered in the province, 10,570 with light and medium oil and 2,804 with heavy crude. A majority of these pools (about 60%) were being drained by a single well. However, the smallest 75 per cent of pools held only 6 per cent of the estimated recoverable oil, while the largest 3 per cent contained 82 per cent of estimated initial recoverable reserves (and 70% of remaining reserves). The ERCB reported initial discovered oil-in-place at the end of 2012 as 12,026 million m^3 (about 76 billion barrels), of which 17 per cent was expected to be lifted by primary means and a further 7 per cent by EOR, for a total recovery factor of 24 per cent. The average recovery factor was higher for light and medium crude (18.6% primary and 26.5% in total) than for heavy crude (11.7% primary and 15.8% in total). These recovery factors have changed little over the years.

2. Historical Reserves Additions

The CAPP (formerly CPA) and ERCB (the EUB from 1993 to 2008, and Oil and Gas Conservation Board in the 1950s and early 1960s) are the two main sources

Table 5.1A: CAPP Canadian Conventional Established Oil Reserves, 1951–2009 (10^3 m^3)

Year	*Remaining at Beginning of Year*	*Gross Additions*	*Net Production*	*Remaining at End of Year*	*Net Changes*
1951	191,106	35,169	7,519	218,756	27,650
1952	218,756	57,749	9,614	266,891	48,135
1953	266,891	39,222	12,857	293,256	26,365
1954	293,256	72,750	15,194	350,812	57,556
1955	350,812	68,240	20,262	398,790	47,978
1956	398,790	80,910	26,907	452,793	54,003
1957	452,793	32,868	28,882	456,779	3,986
1958	456,779	72,701	26,386	503,094	46,315
1959	503,094	81,832	29,198	555,728	52,634
1960	555,728	59,197	30,368	584,557	28,829
1961	584,557	113,788	35,123	663,222	78,665
1962	663,222	87,720	38,914	712,028	48,806
1963	1,062,733	13,944	40,758	1,035,919	–26,814
1964	1,035,919	255,384	43,033	1,248,270	212,351
1965	1,248,270	196,556	46,337	1,398,489	150,219
1966	1,398,489	208,887	50,224	1,557,152	158,663
1967	1,557,152	124,587	54,690	1,627,049	69,897
1968	1,627,049	93,668	59,030	1,661,687	34,638
1969	1,661,687	66,636	62,516	1,665,807	4,120
1970	1,665,807	26,894	69,606	1,623,095	–42,712
1971	1,623,095	37,636	76,297	1,584,434	–38,661
1972	1,584,434	22,229	82,319	1,524,344	–60,090
1973	1,524,344	6,537	99,423	1,431,458	–92,886
1974	1,431,458	–5,065	95,530	1,330,863	–100,595
1975	1,330,863	–6,280	79,897	1,244,686	–86,177
1976	1,244,686	5,921	69,683	1,180,924	–63,762
1977	1,180,924	10,227	70,872	1,120,279	–60,645
1978	1,120,279	37,426	67,647	1,090,058	–30,221
1979	1,090,058	71,415	79,469	1,082,004	–8,054
1980	1,082,004	–56,247	74,529	951,228	–130,776
1981	951,228	178,220	65,873	1,063,575	112,347
1982	1,063,575	19,314	61,756	1,021,133	–42,442
1983	1,021,133	66,074	64,488	1,022,719	1,586

/continued

of aggregate reserves data for Alberta. Tanner (1986) provides a review of the methodologies of these two bodies as well as detailed summaries of their estimates.

The CAPP Reserves Committee consisted of experts from member companies who were responsible for assembling reserves estimates for individual oil pools, concentrating on the largest ones in a region, and drawing on the practical expertise of the large companies in operating most of these pools. It has been more problematic to estimate reserves for the many small oil pools of the province, so after 1984 the CPA relied upon ERCB estimates for them (Tanner, 1986, p. 43). Commencing in the year 2010, CAPP began to derive its conventional crude oil reserves from provincial sources and the NEB. Table 5.1 shows the type of reserves information available from the CAPP *Statistical Handbook*, as of 2011. Table 5.1A shows estimated (remaining) reserves at year end for all Canada for years from 1951 to 2009 and the major sources of changes in reserves each year. The change from a proven to an established reserves basis in 1963 increased estimated reserves by 64 per cent, largely as a result of the inclusion of 50 per cent of 'possible' reserves as established reserves after 1963. In some years, the CAPP reported only total gross

Table 5.1A/continued

Year	*Remaining at Beginning of Year*	*Gross Additions*	*Net Production*	*Remaining at End of Year*	*Net Changes*
1984	1,022,719	–588	73,108	949,023	–73,696
1985	949,023	39,837	73,030	915,830	–33,193
1986	915,830	98,719	70,138	944,411	28,581
1987	944,411	67,943	72,192	940,162	–4,249
1988	940,162	108,468	73,482	975,148	34,986
1989	975,148	31,677	68,832	937,993	–37,155
1990	937,993	18,350	68,386	887,957	–50,036
1991	887,957	22,359	69,014	841,302	–46,655
1992	841,302	39,697	71,265	809,734	–31,568
1993	809,734	65,439	74,587	800,586	–9,148
1994	800,586	56,607	78,400	778,793	–21,793
1995	778,793	78,078	78,844	778,027	–766
1996	778,027	71,518	80,176	769,369	–8,658
1997	769,369	97,177	82,607	783,939	14,570
1998	783,939	72,883	81,473	775,349	–8,590
1999	775,349	48,966	76,468	747,847	–27,502
2000	747,847	103,550	79,368	772,029	24,182
2001	772,029	48,559	80,492	740,096	–31,933
2002	740,096	58,867	84,986	713,977	–26,119
2003	713,977	47,049	84,739	676,287	–37,690
2004	676,287	97,629	81,975	691,941	15,654
2005	691,941	215,224	79,227	827,938	135,997
2006	827,938	36,292	78,540	785,690	–42,248
2007	785,690	92,816	81,169	797,337	11,647
2008	797,337	46,565	78,767	765,135	–32,202
2009	765,135	–7,786	69,693	687,656	–77,479

Note: Proved reserves, 1951–62.
Source: CAPP, *Statistical Handbook*, Tables 2.6a and 2.6b.

Table 5.1B: Canadian Liquid Established Conventional Oil Reserves, December 31, 2009 (10^3 m^3)

	Initial Volume in Place	*Initial Established Reserves*	*Remaining Established Reserves*
British Columbia	461,062	130,153	18,005
Alberta	10,644,160	2,803,966	237,716
Saskatchewan	6,752,312	951,610	152,398
Manitoba	222,442	51,610	8,400
Ontario	92,973	15,656	1,634
Other Eastern Canada	2,860	128	0
Mainland Territories (S.68°N)	92,911	43,003	1,906
East Coast Offshore	1,272,240	394,013	213,647
Total Conventional Areas	19,540,910	4,389,700	633,706
Mackenzie Delta/Beaufort Sea	173,000	54,000	53,950
Arctic Islands	1,440	463	0
Total Frontier Areas	174,440	54,463	53,950
TOTAL CRUDE OIL	19, 715,350	4,444,163	687,656

Source: CAPP, *Statistical Handbook*, 2011, Table 2.15a.

reserve additions (1963–77, 1984–present) as shown in this table, while other years provided more detail including estimated new discoveries and (with varying degrees of breakdown) revisions and extensions. Gross reserves additions may be negative, reflecting large downward revisions of earlier discoveries, as occurred in 1980. Remaining reserves will decline (net reserves additions will be negative) when production exceeds gross additions, as has been the case in most years since 1969. Table 5.1B shows the December 2009 reserves reported for various regions in Canada, including Alberta. The CAPP *Statistical Handbook* includes a number of other tables of oil reserves, by region, detailing them, for example, by year of discovery and major geological formations.

The ERCB oversees most provincial regulation of the petroleum industry. It has a large technical staff that analyzes company data, including reserves and well reports, which it uses to estimate pool by pool oil reserves. The reserves estimates were important in determining allowable output rates under Alberta's prorationing regulations, as will be discussed in Chapter Ten. If an oil producer disagrees with the ERCB estimates for its pool, the producer may request reassessment. The ERCB provides reserves data for most individual pools in the province, including estimates of major pool characteristics, oil-in-place and initial and remaining reserves. Table 5.2 is a summary table of Alberta conventional crude oil reserves and reserves additions from 1951 to 2012. Additions have, over varying time periods, been divided into new discoveries, 'development and re-evaluation,' and (since 1958) EOR additions; gross additions are generally, but not always, positive. As with CAPP data, remaining crude oil reserves peaked in 1969. It is noteworthy that the ERCB's estimate of remaining conventional oil reserves rose significantly after 2009, attributable at least in part to newer horizontal drilling techniques and hydraulic fracturinging which expanded oil recovery (ERCB 2013 *Reserves Report*, ST-98, p. 4-9).

The CAPP and ERCB each provide relatively consistent historical time series of reserves and reserves additions, but the two series are not directly comparable. The CAPP, for instance, estimated remaining Alberta conventional oil reserves at December 31, 2009, as 237.7 million m^3, while the EUB reported 236.9 million m^3. Tanner (1986, pp. 47–53) contrasts the two series, noting that the CPA's estimates of established reserves (from 1962 to the early 1980s) consistently exceeded the ERCB's, particularly prior to the 1980s, in part because of CPA's earlier willingness to credit reserves to EOR proposals. In earlier years, the CPA may also have tended to overestimate reserves in the small pools for which detailed reservoir analyses were not undertaken. The general trends in remaining reserves estimates over time have been similar for both data series. Year-to-year correlations between reserves additions estimates are somewhat lower; for example, in the decade from 1964 through 1973, the ERCB estimate of new discoveries (gross reserve additions) varied from 34 per cent less (70% less) to 500 per cent more (300% more) than CPA estimates (Foat and MacFadyen, 1983).

Such differences highlight the dangers inherent in mixing data sources but raise more fundamental questions for economic analysis; if two such reputable data sources offer different time-patterns for what is, presumably, the same process – discoveries of conventional oil – then the same economic model is likely to generate different empirical results depending upon which series is used. Differences may relate in part to different criteria by the ERCB and CAPP on what determines the size of reserves, but it seems more likely that a significant part of the problem relates to differences in the timing of receipt of information and some differences in opinion on what constitutes 'reasonable certainty' about the existence of reserves. If three-year moving averages of reserve additions (or new discoveries) are used, the CPA and ERCB series are more similar, suggesting that time factors in estimation are critical.

Tables 5.1A and 5.2 showed CAPP and ERCB estimates of gross crude oil reserves additions from the early 1950s to the early 2000s. Immediately apparent are the great year-to-year variability of reserves additions and a tendency to long-term decline. The latter reflects a complex mix of factors, including: (1) depletion of the stock of undiscovered resources as exploration continues, (2) changing levels of exploration activity (where more drilling will add more reserves), and (3) growing knowledge and technological changes. Figure 5.1 shows reserves additions per well drilled, thereby reducing the influence of the second of the three factors; the values plotted are three-year moving averages, reducing the impact of wide year-to-year variability in drilling results. These simple adjustments make no allowance for the joint product nature of the exploratory process. The measure considers neither the full range of inputs like G&G, land and development investment, nor the complex mix of hydrocarbon and by-product outputs. Also, the economic principle known as the law of diminishing marginal returns suggests that incremental discoveries in any year due to drilling more wells will tend to be

Table 5.2: ERCB Conventional Crude Oil Reserves and Changes, 1947–2012 (10^6 m^3)

Year	*New Discoveries*	*EOR Additions*	*Development*	*Net Revisions*	*Net Total Additions*	*Cumulative Production*	*Remaining Established*	*Annual Production*
1948	0.5	0.0	7.9		8.4	14.8	14.0	
1949	4.8	0.0	41.2		45.9	18.0	56.7	3.2
1950	3.2	0.0	96.9		100.1	22.2	152.6	4.3
1951	15.3	0.0	29.2		44.5	29.4	189.9	7.2
1952	14.0	0.0	48.5		62.5	38.8	243.0	9.4
1953	24.2	0.0	42.4		66.6	51.0	297.3	12.2
1954	1.9	0.0	53.7		55.6	65.0	338.9	14.0
1955	9.4	0.0	58.8		68.2	82.8	389.3	17.8
1956	3.5	0.0	78.5		82.0	105.7	448.4	22.9
1957	10.8	0.0	29.1		39.9	127.4	466.6	21.8
1958	1.3	4.9	–4.8		1.4	145.2	450.2	17.8
1959	14.3	16.0	37.2		67.5	165.7	497.2	20.5
1960	0.5	18.1	29.9		48.5	186.6	525.0	20.8
1961	1.7	24.5	31.5		57.7	211.5	557.6	24.9
1962	2.9	19.9	21.8		44.5	237.9	575.6	26.4
1963	14.6	29.2	12.6		56.4	264.6	605.4	26.7
1964	9.5	250.8	88.2		348.5	292.4	926.1	27.8
1965	28.6	–2.4	42.6		68.8	321.6	965.7	29.2
1966	89.1	38.3	13.5		141.0	353.9	1074.2	32.3
1967	57.2	22.2	15.7		95.2	390.4	1132.8	36.5
1968	62	42.9	14.8		119.8	430.3	1212.8	39.9
1969	40.5	58.5	–44.5		54.5	474.7	1222.8	44.4
1970	8.4	36.1	–7.6		36.7	526.5	1207.9	51.8
1971	14	–0.8	8.7		22.1	582.9	1173.6	56.4
1972	10.8	14.8	–5.6		20	650.5	1126	67.6
1973	5.1	10.2	–6.0		9.2	733.7	1052	83.2
1974	4.3	30.8	3.3		38.5	812.7	1011.5	79.0
1975	1.6	3.3	2.1		7	880.2	950.9	67.5
1976	2.5	–27.0	5.9		–18.6	941.2	871.3	61.0
1977	4.8	9.2	5.1		19.1	1001.6	830	60.4
1978	24.9	1.4	–1.9		24.4	1061.6	794.5	60.0
1979	19.2	4.8	10.3		34.3	1130.1	760.2	68.5
1980	9	8.6	5.1		22.8	1193.3	719.9	63.2
1981	15	7.2	10.4		32.6	1249.8	696	56.5
1982	16.8	6.6	–16.5		6.9	1303.4	649.4	53.6
1983	21.4	17.9	24.8		64.1	1359	657.8	55.6
1984	29.1	24.1	–11.2		42	1418.2	640.7	59.2
1985	32.7	21.6	9.7		64	1474.5	648.5	56.3
1986	28.6	24.6	16.6	–30.7	39.1	1527.7	634.7	53.2
1987	20.9	10.5	12.8	–11.2	33	1581.6	613.8	53.9
1988	18	16.5	18	–15.8	36.7	1638.8	592.9	57.2
1989	17	7.8	12.9	–16.2	21.4	1692.6	560.5	53.8
1990	13	8.4	7.2	–25.6	3	1745.7	510.4	53.1
1991	10.2	9.1	10.6	–20.5	9.4	1797.1	468.5	51.4
1992	9	2.8	12.3	3	27.1	1850.7	442	53.6
1993	7.3	7.9	14.2	9.8	39.2	1905.1	426.8	54.4
1994	10.5	5.7	11.1	–22.6	4.7	1961.7	374.8	56.6
1995	10.2	9.2	20.8	14.8	55	2017.5	374.1	55.8

/continued

Table 5.2/continued

Year	*New Discoveries*	*EOR Additions*	*Development*	*Net Revisions*	*Net Total Additions*	*Cumulative Production*	*Remaining Established*	*Annual Production*
1996	9.7	6.1	16.3	–9.5	22.6	2072.3	341.8	54.8
1997	8.5	4.2	16.1	8.7	37.5	2124.8	326.8	52.5
1998	8.9	2.9	17.5	9.2	38.5	2174.9	315.2	50.1
1999	5.6	2.1	7.2	16.6	31.5	2219.9	301.6	45.0
2000	7.8	1.5	13.4	10	32.8	2262.9	291.4	43.0
2001	9.1	0.8	13.6	5.2	28.6	2304.7	278.3	41.8
2002	7	0.6	8.1	4.6	20.2	2343	260.3	38.3
2003	6.9	1	5.9	17.1	30.8	2380.1	253.9	37.1
2004	6.1	3.2	8	13.6	30.9	2415.7	249.2	35.6
2005	5.5	1.2	13.2	18.9	38.8	2448.9	254.8	33.2
2006	8.2	1.9	14.8	2.2	27.1	2480.7	250.1	31.8
2007	6.8	2.2	11.8	–0.2	20.6	2510.9	240.7	30.2
2008	6.9	6.2	9.3	–0.7	21.7	2540.1	233.0	29.2
2009	4.0	4.8	7.4	5.8	21.8	2566.5	228.4	26.4
2010	3.8	5.8	23.5	1.7	34.8	2592.8	236.9	26.6
2011	4.0	6.4	14.0	9.0	33.5	2617.3	245.9	24.5
2012	5.8	2.2	52.9	-2.4	58.5	2652.5	269.2	35.2

Sources:
ERCB ST98-2013 (*Alberta's Energy Reserves 2012 and Supply Demand Outlook*), p. B8, Table B.3 for New Discoveries, Net Total Additions, Cumulative Production and Remaining Established 1968–2012, for EOR 1981–2012 and for Development and Net Revisions 1986–2011.
ERCB 77-18 and 86-18 (*Alberta's Reserves of Crude Natural Gas, Natural Gas Liquids and Sulphur*) Tables 9a and A-4 for years 1948–67, plus 1968 to 1986 for EOR and Development. Values in the 'Development' column are for 'Development and Re-evaluation' plus 'Enhanced Recovery' 1948–57; enhanced recovery additions were first reported for 1958; for 1948–1985, 'Development' includes 'Development and Revisions.

smaller the greater the number of exploratory wells drilled, regardless of whether or not there is a tendency to declining discoveries over time.

Three series are shown in Figure 5.1: (1) ERCB 'new discoveries' per exploratory well drilled, for Alberta; (2) ERCB 'gross reserves additions' per well drilled (development and exploratory), for Alberta; and (3) CAPP 'initial established reserves by year of discovery' (that is, 'appreciated' reserves as assessed at the end of 2008) per exploratory well, for western Canada. Each series has problematic features, as discussed in Section 1 of this chapter. 'New discoveries' measure only the first year's estimate of the volume of recoverable reserves, not the ultimate size of the find as proved up through subsequent development activities. 'Gross reserves additions' do include all estimated reserves established in that year, but most of these are from fields actually discovered much earlier. 'Appreciated reserves' include additions from development activities, including EOR, which may have become viable only years after the initial discovery.

The yearly fluctuations in Figure 5.1 reflect, in part, the vagaries of the reserves reporting procedures. More fundamentally, however, the inherently stochastic nature of reserves additions is responsible. Reserves additions inevitably include significant random variability as companies are unable to predict results, especially of exploration, with certainty. From the perspective of risk analysis, reserves additions instability is significant. It would hardly be surprising that different companies experience markedly different 'efficiencies' in reserves additions in any single year (even apart from variations in technical and management skills). For small firms in particular, there is a real risk of bankruptcy in the crude oil industry, even for well-run companies. The risk is smaller for larger firms, which are more able to spread exploratory risk around and to withstand runs of bad luck. Of course, even large firms may overextend themselves through a combination of unfortunate happenstance, such as large mega-projects that fail and poor management, for example insufficient spreading of risk. In any

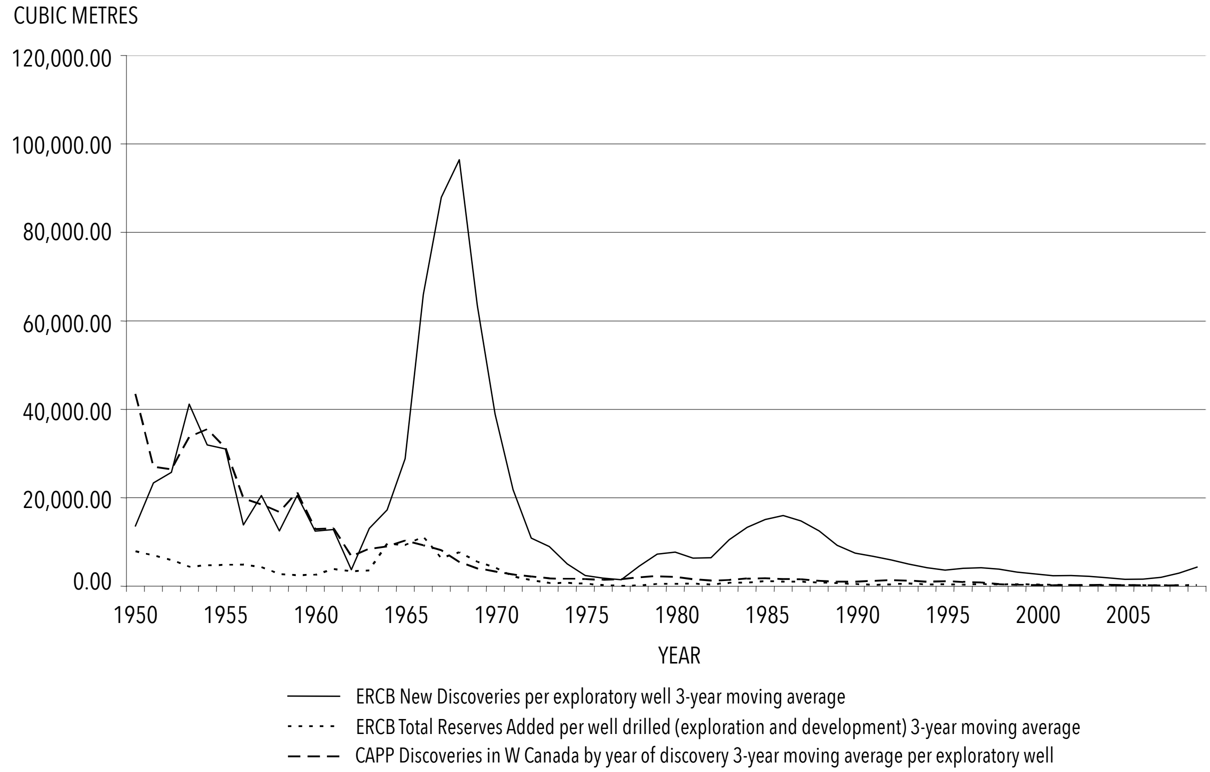


Figure 5.1 Alberta Conventional Oil Reserve Additions per Well Drilled, 1950–2009

particular year, even averaging across the many firms in the industry, the good and bad, lucky and unlucky, volatility in reserves additions per well still remains.

The three-year moving averages of Figure 5.1 smooth out some of this underlying variability and make clearer the long-term tendency to declining crude oil reserves additions in Alberta. This suggests that the first of the three factors noted above (a depleting resource base) outweighs the third (growing knowledge). An anticipated corollary might be that real crude oil costs will rise over time. This need not be true, however, as declining costs of exploration could offset the reduced physical productivity, as might productivity gains or falling real costs of development and/or lifting. As can be seen, the data is affected by the nature of the Keg River play in the mid-1960s in northwest Alberta; many small oil pools were discovered with a large proportion of the pool reserves credited in the year of discovery rather than waiting for subsequent development as is the case with larger pools. This factor has a particular effect on the annual 'new discovery' reserve additions; its impact is muted when all reserves additions are considered, or when our current knowledge of reserves is used to credit reserves back to the year in which the pool was discovered.

Aggregate reserves addition data fail to provide much evidence on one of the more remarkable characteristics of the Alberta crude oil industry: major oil discoveries have occurred through a sequence of geologically distinct oil plays. As discussed in Chapter One, before nature can bequeath us a commercial crude oil reservoir, a complex set of underlying physical conditions regarding the generation, migration, and entrapment of hydrocarbons must occur in just the right way. This does not happen very often, but when it does significant numbers of deposits are typically created, all exhibiting much the same history; such a group of pools is known as an oil 'play,' defined by the specific geological formation in which these pools are found. Some geological judgment is required to define plays, so different authorities may use somewhat different groupings of pools. Table 5.3 shows a recent ERCB tabulation of discovered Alberta oil reserves, illustrating that a large portion of reserves lie in a small number of formations. (See also the CAPP *Statistical Handbook*. Hardy, 1967, chap. 2, provides a summary of Alberta geology.) Geologists have

Table 5.3: Alberta Conventional Oil Reserves by Geological Formation, End of 2007 (106 m^3)

Formation	*Initial Volume in Place*	*Initial Established Reserves*	*Remaining Established Reserves*
UPPER CRETACEOUS			
Belly River	302	47	9
Chinook*	6	1	0
Cardium	1,704	294	31
Second White Specks	42	5	1
Doe Creek	79	7	2
Dunvegan	24	2	0
LOWER CRETACEOUS			
Viking	355	68	5
Upper Manville	2,054	318	56
Lower Manville	997	226	30
JURASSIC	217	57	7
TRIASSIC	450	86	15
PERMIAN-BELLOY*	14	8	0
MISSISSIPPIAN			
Rundle	350	62	7
Pekisko	97	16	2
Banff	106	14	2
UPPER DEVONIAN			
Wabamun	70	8	2
Nisku	474	213	12
Leduc	824	511	9
Beaverhill Lake	1,142	408	23
Slave Point	181	36	8
MIDDLE DEVONIAN			
Gilwood	309	134	5
Sulphur Point	9	2	0
Muskeg	61	10	1
Keg River	494	179	10
Keg River SS	43	18	1
Granite Wash	56	14	2

* from 2007 ERCB *Reserves Report* ST-98-2007.

Source: ERCB, *Alberta's Energy Reserves 2007 and Supply/Demand Outlook, 2008* (ST98-2008), Table B.5. Later *Reserves Reports* did not include this information.

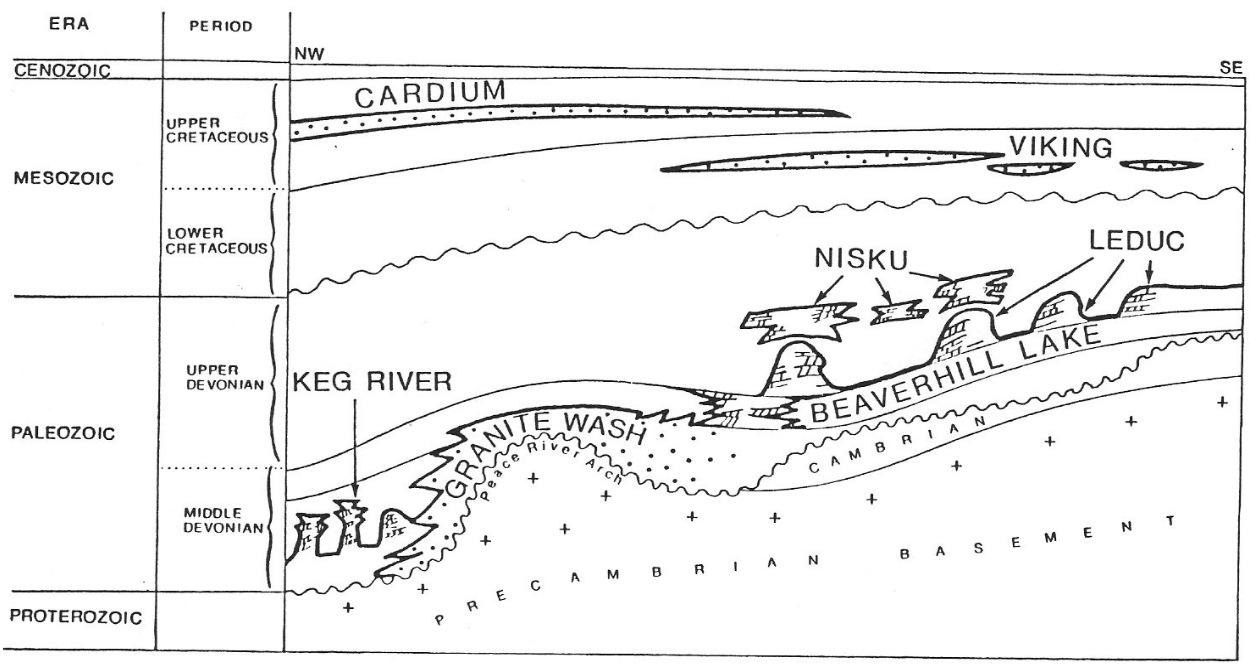
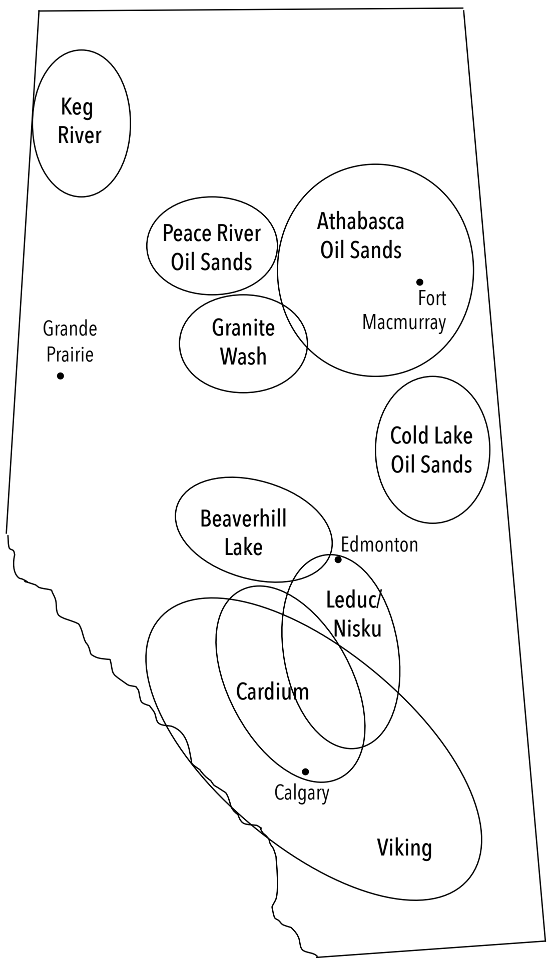


Figure 5.2 Main Alberta Oil Plays

Source: Foat and MacFadyen, 1981, p.25.



Map 5.1 Six Major Alberta Conventional Crude Oil Plays and Three Oil Sands Areas

Sources: The areas for geological plays are from Foat and MacFadyen (1981), Figures C.3 to C. 9. Areas for oil sands deposits from ERCB, *Reserves Report 2010*, ST-98, p. 2-1.

long been aware of the importance of oil plays, but the emphasis on separate plays in models utilized by economists is more recent; in the Alberta context, see, for example, Ryan (1973a,b), Uhler (1976, 1977), and Foat and MacFadyen (1983).

Figure 5.2 is a stylized geological cross-section showing seven of the most important Alberta crude oil plays; Map 5.1 shows the approximate geographic location of each (Foat and MacFadyen, 1983). There are many other small plays, and more are likely to be found.

The Geological Survey of Canada (1987) undertook play-specific modelling of the Canadian crude oil industry. It reported 78 'established plays' (with reported discoveries) and 49 'conceptual plays' (with no discoveries yet, but oil potential) in Western Canada, for light and medium crude oil. Table 5.4 looks at 50 (mainly established) plays that lie largely in Alberta. Column (1) tells the first year a pool was discovered in that play; column (2) shows the number of pools discovered up to 1987; and column (4) gives initial established reserves as estimated in 1987. (The 'potential' columns will be discussed later in this chapter.) It can be seen that these 50 oil plays are a heterogeneous mix. In total over 3,000 pools have been discovered, ranging from 439 in the Keg River play to 2 in the Turner Valley (the only 'conceptual play,' included in Table 5.4). Column 4 shows that reserves thus far established also vary considerably. The ranking of plays in terms of reserves is also shown. The five largest plays hold 43 per cent of the reserves from all fifty plays; the largest ten hold 52 per cent of reserves. The preponderance of Devonian formations for Alberta oil is evident. These are the oldest of the geological horizons indicated, and their importance reflects both the timing of major prehistoric oceans over Alberta, and the relative tectonic stability of the region (without frequent disturbances that would allow oil to migrate to newer formations).

Each oil play tends to mimic the pattern of aggregate oil reserves additions shown in Figure 5.1. There is considerable year-to-year variation in the size of the pools discovered, but the average discovery size tends to fall over time. Figure 5.3, for example, from data in Foat and MacFadyen (1983), plots annual discoveries by year from 1947 to 1976 in the Leduc 'D-3' play (using early 1980s estimates of reserves).

One artefact of discovery data arranged by year of discovery, as noted earlier, is the tendency to understate the size of more recent discoveries, since these pools may not be fully developed. Since average pool size has been falling for new discoveries, and smaller pools will tend to exhibit less appreciation, this underestimation may not be too severe. A large, or otherwise promising, initial discovery generates a rush of exploratory drilling directed at that play. However, a small initial find may be viewed as an isolated incident; in effect, the play is not widely recognized and concerted exploratory activity may not occur until after one or more additional discoveries many years later. The same result may occur if the initial discovery was largely accidental (e.g., by a well targeted at some other formation) and locating prospects in this play requires an undeveloped technology (e.g., there is no obvious structural feature locatable by seismic). A similar result may occur if the play seems to hold only

Table 5.4: Alberta Light and Medium Oil Reserves and Potential by Play: GSC 1987

Formation/Play	*Year of Discovery*	*Number of Pools*		*Initial Recoverable Reserves, 1986, 10^6 m^3*		*Median Recoverable Potential, 110^6 m^3*		*Ultimate Potential 10^6 m^3*		
		Discovered	*Expected*		*(Rank)*		*(Rank)*	*Oil in Place*	*Recoverable*	*(Rank)*
DEVONIAN										
Beaverhill Lake	1956	21	60	406.1	(1)	25.1	(6)	1027	431.2	(1)
Leduc-Rimbey	1947	23	40	351.4	(2)	29.7	(4)	625	381.1	(2)
Keg River	1965	439	846	137.4	(4)	61.9	(1)	491	199.3	(4)
Nisku-Shelf	1947	65	150	119.4	(5)	37.3	(2)	278	156.7	(5)
Gilwood-Mitsue	1956	3	3	97.6	(6)	–	(50)	238	97.6	(6)
Leduc-Bashaw	1950	51	80	54.3	(7)	14.5	(8)	121	68.8	(8)
Leduc-Deep	1953	10	40	54.2	(8)	25.8	(5)	132	80.0	(7)
Nisku-W. Pembina	1977	45	50	32.8	(10)	3.6	(26)	91	36.4	(12)
M.Devon. Clastics	1954	106	280	32.8	(10)	33.3	(3)	161	66.0	(9)
Slave Point-Sawn	1958	37	80	6.7	(25)	4.6	(23)	72	11.3	(27)
Leduc-Nisku-S.	1951	11	60	6.2	(26)	7.7	(13)	45	13.9	(25)
Slave Point-Golden	1970	12	40	5.8	(28)	2.7	(30)	22	8.5	(32)
Nisku-Meekwap	1965	7	30	5.1	(29)	9.9	(12)	37	15.0	(22)
Zama	1965	71	160	3.6	(31)	5.7	(21)	56	9.3	(29)
Wabamun-Peace R.	1956	29	80	3.1	(33)	2.5	(32)	31	5.6	(34)
Keg River-Senex	1969	14	50	2.9	(34)	6.6	(17)	43	9.5	(28)
Bistcho	1965	15	70	0.8	(40)	1.6	(35)	17	2.4	(40)
Wabamun-Eroded	1952	9	40	0.8	(40)	0.9	(42)	11	1.7	(43)
Muskeg	1965	4	42	0.6	(44)	6.4	(18)	37	7.0	(33)
Leduc-Peace R.	1949	4	10	0.3	(48)	0.4	(47)	4	0.7	(48
CARBONIFEROUS										
Elkton Edge	1955	36	60	30.8	(12)	4.1	(25)	125	34.9	(14)
Pekisko Edge	1946	78	110	27.3	(15)	1.3	(37)	220	28.6	(17)
Turner Valley	1936	2	n/a	22.3	(16)	4.2	(24)	189	26.6	(18)
Banff Edge-Central	1954	32	80	6.1	(27)	2.6	(31)	50	8.7	(31)
Desan	1983	17	80	0.8	(40)	2.8	(29)	44	3.6	(37)
Carbon. Sweetgrass	1936	11	40	0.5	(45)	1.2	(38)	17	1.7	(43)
Banff Edge-S.	1970	6	25	0.1	(50)	0.1	(48)	2	0.2	(50)
PERMIAN										
Belloy-Peace R.	1951	14	40	11.1	(22)	3.1	(28)	51	14.2	(24)
TRIASSIC										
Boundary Lake	1955	25	70	28.3	(14)	6.8	(16)	133	35.1	(13)
Peejay-Milligan	1957	35	50	14.1	(19)	1.6	(35)	49	15.7	(21)
Montney	1952	5	20	7.5	(23)	5.8	(20)	78	14.3	(23)
Halfway Strat.	1978	23	90	6.8	(24)	6.2	(19)	46	13.0	(26)
Inga Structure	1962	12	35	3.2	(32)	1.2	(38)	29	4.4	(35)
Halfway Drape	1960	12	35	1.3	(37)	0.8	(44)	11	2.1	(42)
Charlie L. Sond.	1952	32	100	1.2	(38)	1.0	(41)	13	2.2	(41)
Charlie L. Algal	1976	9	45	0.4	(46)	0.5	(46)	7	0.9	(47)
Doug Structure	1976	11	30	0.2	(49)	0.1	(48)	4	0.3	(49)
JURASSIC										
Gilby-Medicine R.	1956	23	45	12.3	(20)	7.5	(14)	79	19.8	(19)
Sawtooth	1944	12	40	1.1	(39)	1.7	(34)	13	2.8	(39)
Rock Creek	1956	14	35	0.4	(46)	0.7	(45)	7	1.1	(46)

/continued

Table 5.4/continued

Formation/Play	*Year of Discovery*	*Number of Pools*		*Initial Recoverable Reserves, 1986, 10^6 m^3*		*Median Recoverable Potential, 110^6 m^3*		*Ultimate Potential 10^6 m^3*		
		Discovered	*Expected*		*(Rank)*		*(Rank)*	*Oil in Place*	*Recoverable*	*(Rank)*
CRETACEOUS										
Cardium Sheet	1953	128	200	288.5	(3)	3.6	(26)	1506	292.1	(3)
Viking-Alta	1949	137	270	43.5	(9)	16.5	(7)	312	60.0	(10)
Lower Mannville	1920	329	600	29.1	(13)	11.3	(9)	268	40.4	(11)
Belly R. Shoreline	1954	37	90	19.9	(17)	11.3	(9)	151	31.2	(15)
Upper Mannville	1957	177	450	18.4	(18)	11.3	(9)	197	29.7	(16)
Cardium Scour	1962	48	90	12.0	(21)	7.0	(15)	99	19.0	(20)
Belly R. Fluvial	1956	34	100	4.5	(30)	5.5	(22)	48	9.0	(30)
Dunvegan-Doe Cr.	1957	13	50	2.3	(35)	1.9	(33)	47	4.2	(36)
Ostracod	1959	32	80	1.8	(36)	1.2	(38)	20	3.0	(38)
1 and 2 White Specks	1961	16	50	0.7	(43)	0.9	(42)	16	1.6	(45)
TOTAL		3036	5141	1918.4		404.0		7370	2322.4	

Source: Canada, Geological Survey of Canada, 1987.

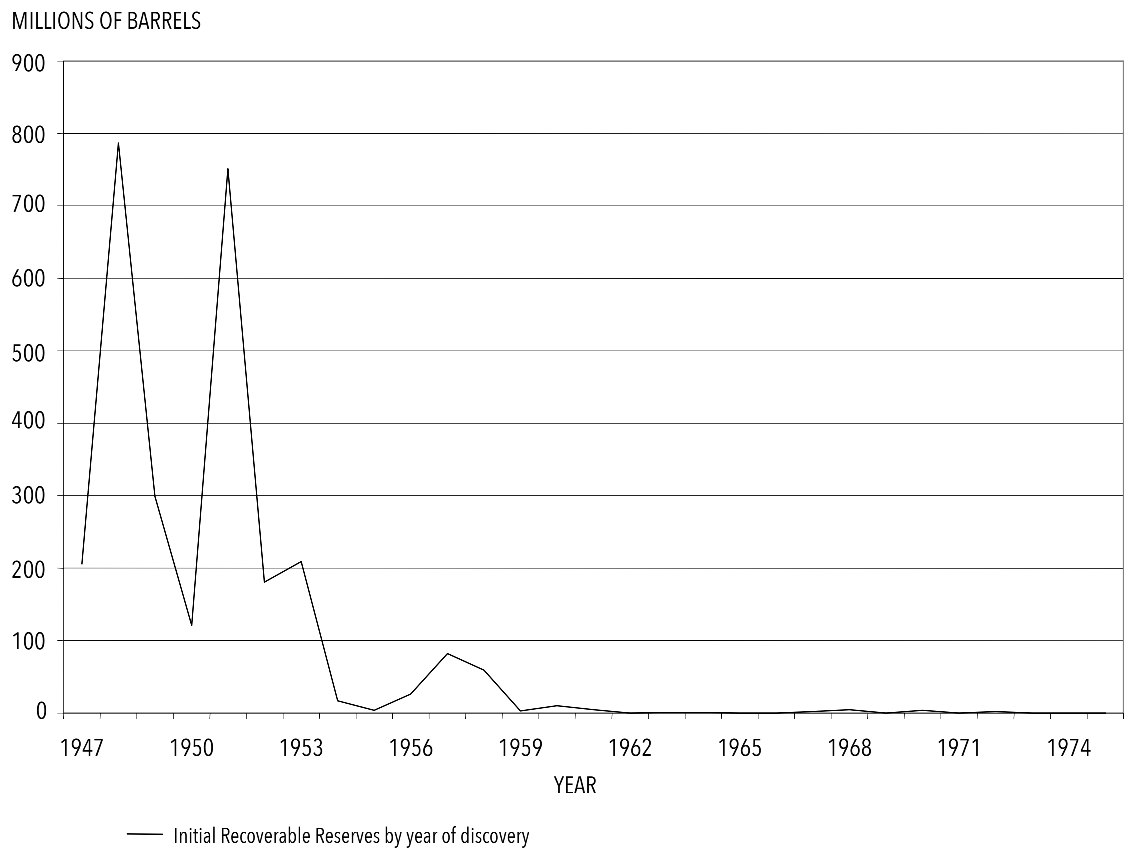


Figure 5.3 Leduc Play: Reserves by Year of Discovery

relatively small pools of questionable commercial feasibility, whence continued exploration may be delayed until the economics improves (e.g., oil prices rise).

The importance of the oil play as a significant factor in the underlying natural resource base provides a convenient opportunity to return to consideration of the inevitable and ubiquitous uncertainty of crude oil industry activities. There are at least four different 'levels' of uncertainty:

U1: Existence of Oil Plays. Of the large number of different geologic formations in Alberta, which ones will prove to be significant oil plays? In each case the resolution of the uncertainty tends to come abruptly, coincident with the first significant discovery in the play. As the industry matures, with a larger cumulative number of wells drilled throughout the region and a greater number of the plays discovered, the likelihood of finding a major new play becomes smaller; in this sense, uncertainty of type U1 will tend to become less significant over time.

U2: Extent of the Oil Play. The geographical and geological extent of the potential oil-bearing rock in the play will be subject to uncertainty. After the initial discovery, reinterpretation of records from already drilled wells will allow preliminary estimation of the extent of the play. Further refinement, and, presumably reduced uncertainty, will occur as more new wells are drilled looking explicitly for new discoveries in the play.

U3: Existence of an Oil Pool. Knowledge of the extent of the oil play begins to allow the selection of 'prospects' or specific drilling sites, but, prior to drilling, it is not possible to know for certain whether or not the prospect will contain oil. As with U1, uncertainty of this type is usually resolved in a sudden discontinuous manner as the exploratory well is either dry or successful. There may be more ambiguous cases in which very low porosity or permeability in the reservoir, or this part of the reservoir, make it difficult to tell whether a commercial deposit has been found.

U4: Size of an Oil Pool. Finally, it is the commercial volumes of oil (the reserves) which are of ultimate interest to the oil company. Reserves estimates are subject to geologic uncertainties (how large is the pool?), reservoir engineering uncertainties (what is the permeability in the pool, and is it homogeneous across the entire pool?), technological uncertainties (will horizontal well-drilling techniques be effective here?), economic uncertainties (what will the price of oil be?), and political uncertainties (will the government change tax and royalty rates?). The geological and engineering uncertainties tend to be reduced by development activities and some production history, but the economic and political uncertainties are always present.

All oil companies are aware of these uncertainties and will take them into account in their decision-making. Part of the dynamism of the crude oil industry comes from companies' varying assessments. Moreover, risk preferences of decision-makers differ, reflecting different underlying psychological propensities and varying financial situations. Most of the aggregated economic analysis of the petroleum industry assumes that these individual differences between companies average out, in some sense, and so do not have to be considered explicitly. We would note that this assumption may be very useful in assessing total Alberta oil supply but is not at all helpful in deciding which company's stock you should buy. Nor would picking a Hawaiian holiday resort with very low average annual rainfall keep you from scanning the sky each day as you leave your room.

3. Ultimate Reserves Potential

Planners and decision-makers, both public and private, have an obvious interest in the potential for future oil discoveries in a region. The ERCB defines ultimate potential as "an estimate of the initial established reserves that will have been developed in an area by the time all exploration and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions" (ERCB, 2010, *Reserves Report*, ST 98, p. A-8). Reflection will demonstrate that ultimate reserves consist of the current remaining established reserves plus past production plus any future reserves additions. Estimates of ultimate potential, particularly its future reserves addition component, involve the exercise of subjective judgment to resolve the manifold uncertainties – geological, reservoir engineering, technological, economic, and political – attendant on forecasting possible future petroleum production.

Many methods have been used to estimate ultimate natural resource potential in a region. (Harris, 1984; Kaufman, 1987; Power and Fuller, 1992; Walls, 1992; and Sorrell and Speirs, 2009, provide useful reviews.) Virtually all approaches are extrapolative, trying to extrapolate some historical evidence through the future. Many differences exist amongst studies, and some utilize a combination of approaches, but four main types of analysis emerge:

(1) **Volumetric.** The (cubic) volume of potential oil-holding sediment in the region or play is estimated, and an anticipated quantity of oil (m^3 or barrels) per unit volume is multiplied by the total volume. The quantity number may come from 'similar' geological formations somewhere else, especially if this region is relatively unexplored; or it may simply reflect considered expert judgment on potential for the region.

(2) **Subjective Probability.** This method simulates ultimate oil volumes as the outcome of a multiplicative relationship among key underlying variables that define oil reserves, as in equation 5.1:

$$UR = (NP)(SR)(A)(D)(P)(WOR)(GOR)(RF)(7{,}758) \qquad (5.1)$$

where:

UR	is ultimate recovery in barrels of oil;
NP	is the number of prospective drilling sites (prospects);
SR	is the success ratio, or chance that a prospect holds crude oil;
A	is the surface acreage of a prospect;
D	is the depth in feet of the oil-bearing sediment in the prospect;
P	is the porosity of the project (percentage pore space in the rock);
WOR	is one minus the water saturation (percentage of pore space with fluid other that water);
GOR	is one minus the gas to oil ratio (percentage of non-water fluid that is crude oil rather than gas);
RF	is the recovery factor (percentage of oil that will be recovered); and
7,758	is the number of barrels of fluid in an acre foot of pore space.

Equation 5.1 is an identity, showing ultimate reserves as the product of a number of variables. Each of the underlying variables is defined by a subjective probability distribution across possible values, as assessed by experts in the field. Sampling techniques like Monte Carlo analysis can be used to generate a probability distribution of possible values for UR, ultimate reserves. Generally the median value of the distribution is reported; this is the value for which higher values are just as likely as lower. Briefly, a Monte Carlo simulation work as follows: Assume that the variables in equation 5.1 are all independent of one another. Values are then selected 'at random' from the underlying probability distributions assumed for the variables in equation 5.1, so that the likelihood of selecting any value is equal to the specified probability of its occurrence. It may be useful to describe the process in detail. First select a value for NP, the number of prospects (e.g., 122), from the probability distribution for the number of drilling prospects in this region. Then this number (122) of drawings are made from the other probability distributions; each of the 122 drawings involves one value for each of the variables in equation 5.1, which, when multiplied together, give an estimate of likely reserves for that prospect. Then these 122 values are added together to give an estimate of the ultimate potential of oil reserves from the region. If this entire process is repeated a great many times (e.g., 10,000) then a frequency distribution of ultimate reserves can be constructed. Enough information on a region is necessary to allow construction of the subjective probability distributions.

(3) **Econometric Estimation.** Statistical (econometric) techniques may be used to estimate the 'most likely' quantitative relationship in the past between variables that are assumed to be associated with one another. If one of the variables were, for example, reserve additions, then it would be possible, by assuming that the same relationship holds through the future, to estimate future reserves additions, and therefore ultimate reserves. The simplest case, for instance, would look at the impact of the passage of time on reserves added. If the relationship was a declining one, and therefore relatively bounded, 'forecast' future reserve additions

could be generated by extrapolating the declining reserves through the future until the new additions became small enough to ignore. Ultimate reserves would be total reserves added over the life of the industry including past history and the extrapolated future. Sufficient historical data is needed to allow econometric estimation of the hypothetical relationships between variables.

(4) **Discovery Process.** Oil discoveries are viewed as occurring in separate oil plays, each of which exhibits its own discovery history. Discoveries in each of these plays are seen as involving a process of sampling without replacement from the finite number of pools that lie in that play in nature. Moreover, the larger pools are assumed to be easier to find than the smaller, so are generally discovered earlier in the life of the play. If very specific assumptions are made about the distribution of pools in nature (e.g., 'the size distribution is log normal'), and the likelihood of discovery for each pool (e.g., 'the likelihood of discovery is proportionate to the size of the pool') then sophisticated statistical analysis may be applied to the discovery history of pools in the play to develop estimates of the total number of pools in the play and the size of each. Finally, a sum of all pools in the play (often subject to a minimum economic size constraint) provides an estimate of ultimate recovery. This method is obviously complex and requires a significant discovery history before it can be used.

Numerous attempts have been made over the years to estimate Alberta's ultimate crude oil reserves. Many of the estimates were made by individuals for planning purposes for their companies; such estimates are not usually publicly reported. We will summarize the results of the main analyses undertaken by governmental bodies, federal and provincial, with two early estimates by private groups, the CPA (in 1969) and the Canadian Society of Petroleum Geologists (CSPG) in 1973. (See Canada. Energy Mines and Resources, 1973.) Unfortunately, not all studies separate Alberta from other parts of the Western Canadian Sedimentary basin (N.W.T., Northeast B.C., Alberta, Saskatchewan, and Southern Manitoba). As of December 31, 2008, according to the CPA, 70 per cent of initial established reserves of crude oil in this area was in Alberta (CAPP, *Statistical Handbook*).

CPA. In 1969, the CPA released results of a volumetric analysis of Canadian conventional crude oil potential that set ultimate reserves for the Western Canadian Sedimentary Basin at 7.5 billion m^3 (47.4 billion barrels) (Energy, Mines and Resources, 1973, vol. II).

CSPG. In 1973 members of the CSPG gave a petroleum potential of about 3.5 billion m^3 (22.3 billion barrels) for the Western Canadian Sedimentary Basin (McCrossan and Porter, 1973, p. 74). The estimates were derived from "a very thorough analysis by volumetric techniques using geological analogy and by setting upper and lower limits of the yields through comparisons with a number of known areas to achieve what is probably a very reasonable figure for Alberta." It was explicitly noted that no formal economic criteria were applied, so the numbers should not be interpreted as ultimate established reserves (McCrossan and Porter, 1973, pp. 595–97). The CSPG was substantially less optimistic than the CPA.

Federal Government. The Department of Energy, Mines and Resources (EMR – which in 1993 became part of the Department of Natural Resources) and the National Energy Board (NEB) have been actively involved in modelling Canadian oil supply. As far as ultimate potential is concerned, federal government bodies have generally relied in part on the work of the Geological Survey of Canada (GSC), a research body housed within EMR.

Geological Survey of Canada (GSC) models have progressed from volumetric through subjective probability to discovery process techniques. Table 5.5 summarizes the estimates of the GSC for the Western Canadian Sedimentary Basin. As can be seen, the GSC estimates were initially (1972) over 25 per cent more optimistic than the CSPG but have fallen considerably since 1973, with the 1987 estimate of ultimate potential for the Western Canadian Sedimentary Basin at 2.8 billion cubic metres (17.6 billion barrels), though this is only for light and medium, not heavy, oil pools. Of the 2.8 billion, about 500 million m^3 (3.2 billion barrels) were yet to be established as reserves.

Table 5.4 provides more detail for 49 established oil plays, and one conceptual oil play (Turner Valley), largely in Alberta. The GSC uses a subjective probability approach for the conceptual plays. The established oil plays are subject to a discovery process model that provides an estimate of the total number of pools expected to be discovered in the play (column (3)) and the potential recoverable oil volumes still to be discovered (column (6), for the median, 50% probability estimates). Columns (7) and (8) show ultimate potential oil in place and recoverable volumes (i.e., initial established reserves, column (4) plus the potential, column

Table 5.5: GSC Estimates of Ultimate Crude Oil Potential

	Estimated Ultimate Potential 10^9 m^3 (10^9 bbl) (Western Canadian Sedimentary Basin)		Method	Source
1972	4.5	(28.6)	Volumetric	EMR, 1973, Vol. II, p. 32–3
Feb. 1973	3.6	(22.4)	Volumetric	EMR, 1973, Vol. II, p.32–3
March 1973	3.4	(21.6)	Subjective Probability	EMR, 1973, Vol. II, p. 32–3
1977	3.3	(20.7)	Subjective Probability	EMR, 1977
1983	2.9*	(18.2)	Subjective Probability	Procter, Taylor and Wade, 1984
1987	2.8+	(17.6)	Discovery process and Subjective Probability	Canada, GSC, 1987

* The Alberta Basin and disturbed belt which cover Alberta and northeast British Columbia have ultimate potential of 2.4 billion m^3 (15.2 billion barrels). These are the 50% probability estimates.

\+ The 1987 study is for light and medium oil pools only.

(6)). Potential of 404 million cubic metres amounts to 21 per cent of already discovered reserves, though the percentage varies greatly across plays, from 0 per cent for the Gilwood-Mitsue play (in a very restricted geological formation) to over 1,000 per cent for the Muskeg play. The rankings of potential in column (6) are quite different from those for established reserves in column (4), though the largest volumes of anticipated additions do tend to occur in relatively large plays. Anticipated additions, like past discoveries, are concentrated mainly in a limited number of formations – 46.5 per cent in the most promising five and 66 per cent in the top ten. Of course, such potential numbers are subject to a wide range of uncertainty, and some of the 'conceptual' plays not included in Table 5.4 may turn out to be large. The 3,000 plus pools discovered in these 50 plays so far generated almost two billion cubic metres of oil reserves; the pools vary greatly in size but averaged about 630 thousand cubic metres (almost 4 million barrels). The remaining 2,105 pools anticipated (in the median case) would hold 404 million m^3 of potential reserves, averaging about 190 thousand m^3 in size. This declining average discovery size, at levels of both the play and the aggregate province, are a strong force pushing towards higher oil production costs.

In 1998 the GSC updated the 1987 study of light and medium oil in Western Canada, using similar methods and data up to the end of 1994. (This report, *Oil Resources of Western Canada*, by P. J. Lee, is summarized in NEB, 2001.) The number of established oil plays was reduced from 78 to 69, and the conceptual ("immature") from 49 to 25; the GSC applied a modified discovery process modelling to the conceptual plays. This report considered only oil in place, with no consideration of economic factors or estimated ultimate recovery of oil. Perhaps the most striking feature of the 1998 estimate was an increase in the estimated number of undiscovered pools, from 4,000 to 18,000, with newly discovered pools expected to be much smaller than the historical average. Discovered oil in place had been estimated at 7,377 10^6 m^3 in the 1988 Report, and undiscovered at 1,874 10^6 m^3; in the 1998 Report the equivalent numbers were much higher at 12,547 and 6,958. These estimates suggest that considerable amounts of conventional light and medium oil still lie undiscovered in the WCSB. However, for major additions to reserves to materialize, oil prices must be sufficiently high to offset the smaller pool sizes, and/or significant technological advances in discovery and recovery of oil must occur.

In 2001, the NEB published a study of conventional heavy oil in the WCSB (NEB, 2001), using the GSC methodology. This report drew on the oil plays from the 1998 GSC report; discovery process modelling was used, and prospective oil pools were subject to an economic analysis as well. The heavy oil plays lie in all four western Canadian provinces, not just Alberta. The NEB estimated that total heavy oil in place amounts to 7,926.6 10^6 m^3, of which 2,894.8 10^6 m^3 is as yet undiscovered. The recovery factor for previously discovered heavy oil is estimated at almost 25 per cent, with 372.8 10^6 m^3 of additional reserves additions expected from already discovered pools. Undiscovered pools are expected to be much smaller on average than already discovered pools; the NEB reports an estimated recovery factor of less than 12 per cent, yielding 337.8 10^6 m^3. It is interesting to note that the possible

Table 5.6: NEB Estimates of Ultimate Conventional Crude Oil Potential in Western Canada (10^6 m^3)

	1982	*1984*	*1986*	*1989**	
LIGHT AND MEDIUM CRUDE					
Initial Established Reserves	2,055	2,165	2,264	2,370	(1,982)
EOR in Discovered Pools	404	367	295	295	(260)
New Discoveries	280	308	563	521	(454)
Ultimate Potential	2,739	2,840	3,122	3,086	(2,696)
HEAVY OIL					
Initial Established Reserves	366	404	434	488	(172)
EOR in Discovered Pools	381	378	370	320	(115)
New Discoveries	140	125	250	270	(107)
Ultimate Potential	887	907	1,054	1,078	(395)
ALL CONVENTIONAL CRUDE					
Initial Established Reserves	2,421	2,569	2,699	2,757	(2,154)
EOR in Discovered Pools	785	745	665	615	(375)
New Discoveries	420	432	813	791	(561)
Ultimate Potential	3,626	3,746	4,177	4,163	(3,091)

* Values for Alberta in 1989 are in parenthesis.

Sources:
1982: NEB, Canadian Energy Supply and Demand, 1983–2005 (September 1984).
1984: NEB, *Canadian Energy Supply and Demand, 1985–2005* (October 1986).
1986: NEB, *Canadian Energy Supply and Demand, 1987–2005* (September 1989).
1989: NEB, *Canadian Energy Supply and Demand, 1990–2010* (June 1991).

future reserves additions for heavy oil amount to 710.6 10^6 m^3, which is about 3.75 times larger than remaining conventional heavy oil established reserves at the end of 2000. Supply costs (including royalties and taxes, and based on a 10% discount rate) varied significantly, from \$35/m^3 to \$270/m^3. As with conventional light and medium oil, this suggests that considerable potential for reserves additions of heavy oil exists, but at much higher costs than were seen in the earlier days of the industry.

NEB. In 1974 the NEB began to issue a series of reports dealing initially with Canadian oil supply and demand, then, starting in 1981, with all energy forms. The September 1984, October 1986, September 1988, and June 1991 studies all reported NEB estimates of ultimate conventional crude oil potential in Western Canada. The NEB relied heavily on GSC research, especially for light and medium crude. Potential, in addition to initial established reserves, included both enhanced oil recovery and new discoveries for light and medium oil and for heavy oil. Table 5.6 summarizes the estimates in the four NEB reports. It can be seen that the NEB estimates rose from 1984 to 1986, particularly insofar as possible new discoveries were concerned. The 1984 Report alludes to rising prices, though no formal model illustrating the effect of rising prices is included. The 1989 estimate for light and medium crude from established reserves plus new discoveries is close to the GSC 1987 estimate (2.8 billion m^3), but the NEB adds a further 295 million m^3 of possible reserve additions through increased recovery in established pools. (The 1987 GSC model focused on oil in place, then applied recovery factors based upon averages in various oil plays.)

The 1991 NEB study provided a breakdown by geographical area, indicating that 87 per cent of the potential for light and medium oil lies in Alberta, as opposed to 36 per cent for heavy oil (where Saskatchewan is more important). It is also noteworthy that, for Alberta, possible additions to reserves were estimated at 36 per cent of already established reserves for light and medium oil, but 71 per cent for heavy oil. This suggests that the future mix of Alberta conventional oil output may tend to shift towards heavy oil.

ERCB. The ERCB has provided reserve estimates for Alberta, generally in conjunction with its Reserves Report (as noted above, since the late 1960s, this has

Table 5.7: ERCB Estimates of Alberta Ultimate Conventional Crude Oil Potential

Date	*Ultimate Potential 10^6 m^3*	*(10^9 bbl)*	*Source (ERCB Report)*
1963	1.9	(1.2)	Report 64-8
1968	2.9	(18)	Report 69-18
1973	3.2	(20)	Report 74-18
1975	2.9	(18)	Report 76-18
1976	2.5	(15.9)	Report 77-18
1978	2.4–2.7	(15.1–17.0)	Report 79-18
1980	2.6	(16.4)	Report 81-B
1982	2.67	(16.8)	Report 83-E
1984	2.65	(16.7)	Report 85-A
1987	2.91	(18.3)	Report 88-E
1990	2.84	(17.9)	Report 91-18
1993	3.13	(19.7)	Report 93-18

Notes: The ERCB did not increased its estimate of ultimate potential through to the 2013 *Reserves and Supply/Demand* report (Report 2013-98), although it suggested in 2012 that "this estimate does not include potential oil from very low permeability reservoirs, referred to by industry as "tight oil," which is now starting to be exploited using horizontal multistage fracturing technology" (p. 4-9).

Sources:
Report 64-8 and Reports xx-18 are *Reserves* Reports.
Report 81-B is *Estimates of Ultimate Potential and Forecasts of Allowable Production Capacity of Alberta Crude Oil and Equivalent*.
Report 83-E is *Alberta Oil Supply, 1983–2007.*
Report 85-A is *Alberta Oil Supply, 1985–2010.*
Report 88-E is *Alberta Oil Supply, 1988–2003.*

been issued annually as Report number ST-18 or ST-98). The ERCB has not provided much detail on its estimation procedures. Prior to 1977, "volume of sediments and exploration well statistics methods" were used. Since then, however, estimates have been based on "geological judgment with respect to trends reflected in exploration success, extent of exploration and development and likelihood of hydrocarbon accumulations in unexplored geologic horizons" (ERCB *Reserves Report* ST-18, 1977, p. 9-2). Table 5.7 reviews the ERCB estimates since the mid-1960s, with values reported for years in which the estimate of ultimate potential was changed. As can be seen, the estimate of 1.9 billion m^3 in the early 1960s was increased to 3.2 billion m^3 by 1973, perhaps due to the Keg River and assorted plays that developed in Northwestern Alberta in the late 1960s. In 1975 estimates were reduced and have been in the 2.4 to 3.1 billion m^3 range since then. The ERCB has indicated that the 1993 estimate is still felt to be reasonable, although the board states that "[g]iven recent reserve growth in low permeability oil plays, the ERCB believes that this estimate may be low" (2012 *Reserves Report*, ST-98, p. 6). Comparison with the NEB estimates for 1989 of Table 5.6 suggest that the ERCB is slightly less optimistic than the NEB. Comparison with the GSC is difficult, since the GSC estimates include only light and medium crude.

4. Summary and Conclusions

As of December 31, 2012, the ERCB estimated that Alberta held the ultimate potential to produce 3.13 billion cubic metres of conventional crude oil; of this, 2.65 billion (85%) has already been produced, 269.2 million (8.6%) lay in remaining established reserves, and 209 million (6.6%) had yet to be established as reserves through new discoveries or other means (e.g., EOR schemes). The degree of certainty attached to these numbers varies greatly, the past production data being very accurate, and the remaining reserves estimates reasonably good, though subject to revision in light of future production levels and other information. Considerable caution must, however, attend the 209 million m^3 of possible future reserves additions, since they will hinge upon the major uncertainties associated with exploration at untested sites, the course of future technological changes, and the vagaries of oil prices and government regulations.

If the ERCB is right, we have, as of 2013, less than ten percent of Alberta's recoverable conventional oil reserve base left to find and develop. Moreover, these reserves are likely to lie in deposits that are relatively small in comparison to those that generated the large reserve additions of the first two decades after 1947. The GSC estimated in 1987 that discovered Western Canadian Sedimentary Basin conventional oil pools numbered about 3,300, while more than 4,000 pools remained undiscovered; the latter would hold only 25 per cent of the oil that might be recovered from the Basin (GSC, 1987, p. 124). On the basis of such expectations, prevailing wisdom has the Alberta conventional crude oil industry turning to increasingly more costly reserves additions, while undergoing a tendency to declining output as established reserves are run down. On a more optimistic note, the GSC 1987 estimate of about 7,300 light and medium crude oil pools in the entire Western Canadian Sedimentary Basin, had, by the year 2002, been surpassed in Alberta alone. And exploratory drilling in Alberta is not yet as intensive as in the lower-48 United States.

Physical resource estimates are not infallible guides to economic outcomes and so must be treated with care. Adelman (1990, p. 1) said "The total mineral in the earth is an irrelevant non-binding constraint" and also that whatever is left after abandonment is "a geological fact of no economic interest." Most useful analysis looks to only some portion of the total petroleum available in the ground. Consider, for example, the least controversial, and most widely accepted, of the various resource measures – the established reserves of crude oil. One might think that those reserves are a prime determinant of output rates, now and in the future. Often established reserves are compared to annual production in the form of the R/P (reserves-to-production) ratio, sometimes called the 'life index.' For example, in 1991, Alberta produced 51.4 million m^3 of crude oil (per year), out of reserves as of December 31, 1990, of 510.4 million m^3, yielding a R/P ratio of (510.4 million m^3 / 51.4 million m^3/year) or 9.9 years. The R/P ratio is not, however, an estimate of the future lifetime of the industry in Alberta; consider, for example, that in 2010 Alberta was still producing significant volumes of conventional crude oil, and the conventional oil R/P ratio was still close to ten years! As industry observers quite properly emphasize, remaining reserves are a dynamic concept, diminished by production but augmented by new reserves additions. Adelman (1990) is helpful in suggesting that established reserves are best seen as the industry's on-the-shelf working inventory. As in any ongoing business, one of the industry's tasks is to develop optimal withdrawals from and additions to this inventory. The R/P ratio itself is a measure of the intensity with which the current inventory is worked. While oil pools vary significantly in their physical characteristics, the dynamics of oil reservoirs probably mean that sustained operation of oil pools at R/P ratios much less than 10 is difficult, without significantly damaging pool recovery mechanisms. In this case, established reserves serve as a severe constraint on the ability to increase production. On the other hand, high reserves to production ratios, like values in excess of 100 for some Middle Eastern countries, imply that output could be increased relatively easily from existing reserves. The Alberta conventional oil R/P ratio has, since 1947, been at both higher and lower levels. The point is that any given volume of reserves allows many different possible output rates.

As the Adelman quotes of the previous paragraph makes clear, the concept of ultimate potential must also be used cautiously. (See also Adelman and Watkins, 1992 and 2008, and Watkins, 1992.) In the first place, its precise value is subject to a wide range of uncertainty, since ultimate oil recovery depends on so many future technological, economic, and political factors, which simply cannot be forecast with accuracy. This is on top of inevitable uncertainties in basic geological knowledge. Moreover, what is critical from the economic point of view is the course of annual reserves additions and how they are brought into production, rather than the ultimate stock of such additions. Of course, the ability to add reserves in any period is limited by the amount potentially available, but this is only one of the factors affecting actual reserves additions.

From this discussion of Alberta's conventional oil reserves, we turn to the question of the levels of Alberta oil production, and the prices received for that output.

CHAPTER SIX

Crude Oil Output and Pricing

Readers' Guide: Chapter Six looks at the history of the prices for Alberta crude oil and the levels of conventional crude oil production. In economic terms, price and output are determined in the market for crude oil, in which Alberta oil meets other crude oils in competition. However, the prices and output have a petropolitical dimension, since the operation of crude oil markets is affected by a variety of government regulations. As this chapter illustrates, Canadian government regulation of the crude oil market since the end of World War II has covered the spectrum from a relatively hands-off policy to an approach that directly fixes oil prices by government fiat. This chapter looks at the prices and output of Alberta conventional crude oil, while Chapter Nine presents detailed analysis of the government policies.

1. Introduction

As was discussed in Chapter Four, Alberta crude oil output and prices have been determined in crude oil markets whose operations reflect four factors: (1) supply-side decisions; (2) demand-side decisions (including refining and transportation components); (3) governmental regulations; and (4) adjustment processes as the market reacts to changing circumstances. The common assertion that demand and supply determine market outcomes is widely accepted, but, unfortunately, ambiguous. We must distinguish at least three senses in which supply equals demand in the market for lifted crude oil:

Sense (1): As an accounting identity and reflecting material balance requirements in the physical world, every unit produced ('supplied') in a period must end up somewhere (i.e., 'demanded').

Sense (2): As a condition for economic equilibrium, the total quantity willingly produced ('supplied') will equal the total amount willingly consumed ('demanded'); in other words, there are no undesired build-ups or downturns in inventories of crude oil held by producers or users. It should be remembered that the inventories of crude oil held by producers are generally in the form of reserves in the ground.

Sense (3): As a condition for a perfectly ('effectively') competitive equilibrium, price and quantity will be where the willingly undertaken supplies of 'price-taking' producers just equal the willingly undertaken demands of 'price-taking' purchasers. (Price-takers are producers or consumers who form such a small part of the market that their variations in output or purchases have no effect on the market price.)

Supply and demand are always equal in sense (1). In the real world, participants in a market are often in the process of adjusting their behaviour in response to changing conditions with some undesired change in inventories, so that the market is not in equilibrium in senses (2) and (3). However, it is common for economists to assume that markets adjust to equilibrium quite quickly, as would be anticipated if buyers and sellers are well-informed and communication flows accurate and rapid. Thus, observed values in the market are taken to be equilibrium values subject only to some small random error reflecting adjustment difficulties (disequilibrium). At any point in time, the crude oil market can be in short-run equilibrium, when, for example, at current prices, producers are lifting and selling just as much as they wish from installed productive capacity, but in medium-run disequilibrium, if producers wish to install more capacity in existing reservoirs to add more reserves. In long-run equilibrium, producers would have the desired levels of lifted crude oil, productive capability and reserves, including anticipated reserves from newly discovered reservoirs.

It is the effectiveness of competition in the market that determines whether prices and output are determined by demand and supply in sense (2) or sense (3). Sense (2) encompasses sense (3), effective competition, but also includes those instances in which market participants exercise their ability to manipulate quantities in order to influence price. As was discussed in Chapter Four, this may include producers restricting output to generate higher prices (oligopoly), buyers restricting sales to generate lower prices (oligopsony), or some combination of the two (bilateral oligopoly). Such exercise of market power will generate prices that differ from the effectively competitive level. It may also involve price discrimination, typified by the case in which different consumers pay different prices for identical products, and more accurately "defined as implying that two varieties of a commodity are sold (by the same seller) to two buyers at different net prices, the net price being the price (paid by the buyer) corrected for the cost associated with the product differentiation" (Phlips, 1983, p. 6). Economists are generally concerned with persistent price discrimination, rather than isolated cases that may occur as markets feel their way towards equilibrium.

Vertical integration in the petroleum industry complicates the issue. Many 'crude oil' companies are both producers of crude oil and purchasers (as oil refiners) and most of the large oil refineries have crude oil production facilities of their own. In such circumstances, the major buyers of crude oil (even if an oligopsony) might prefer higher prices for crude oil, particularly if high crude oil prices help to serve as a barrier to entry to 'independent' refiners (those without their own crude oil). Lower effective income tax rates on profits from crude oil than on profits from refining, as has generally been true in North America, might reinforce this preference by major vertically integrated refiners for higher crude oil prices. The main point is that a highly concentrated market on either the seller or the buyer side tends to translate into pressure for higher or lower prices for crude oil than under effective competition.

This chapter is concerned with how the four factors underlying the oil market have operated to determine the price of Alberta crude oil. Section 2 sets out the underlying data with minimal discussion – the annual course of crude oil prices, conventional crude oil output, and domestic and export sales from 1947 through 2012. Section 3 then discusses the major influences on Alberta oil prices and output, with five time periods considered:

(i) **Prior to 1947**, when Alberta was an oil-importing region;
(ii) **1947 to 1960**, when new market areas were being established;
(iii) **1961 to 1972**, when the Canadian National Oil Policy and U.S. Import Oil Quota Programs were dominating influences;
(iv) **1973 to 1984**, when stringent federal (Ottawa) controls operated, including the National Energy Program; and
(v) **1985 to the present**, when deregulation exposed Alberta to direct contact with an increasingly volatile international market.

Section 4 looks briefly at the corporate structure of the industry, including the degree of concentration of production and the extent of foreign ownership.

2. Alberta Oil Production and Prices: The Data

Table 6.1 details Alberta annual oil production, including conventional crude oil and, since 1967, synthetic crude oil. The synthetic crude oil industry is discussed in more detail in Chapter Seven of this book. Synthetic crude oil rose from 3 per cent of Alberta's liquid hydrocarbons production in 1970 to over 35 per cent by 2012. Petroleum from the oil sands (synthetic crude oil plus bitumen) accounted for over 72 per cent of Alberta production by 2012. Since crude oil is not a perfectly homogeneous product, output in any year includes a mix of hydrocarbons, ranging from lighter crude oils and condensate from natural gas pools through to heavy crudes and bitumen. Table 6.1 divides the oil into that sold in domestic markets and

Table 6.1: Alberta Oil Production and Sales, 1914–2012 (10^3 m^3/d)

		Sales				
	Crude Oil Production	*Domestic*	*Export U.S.A. (East)*	*Export U.S.A. (West)*	*Export (Offshore)*	*Synthetic Crude Production*
1914–21	0.003	.003				
1925	0.07	.07				
1930	0.6	0.6				
1937	1.2	1.2				
1942	4.4	4.4				
1946	4.0	4.0				
1947	3.8	3.8				
1948	4.8	4.8				
1949	8.8	8.8				
1950	12.0	12.0				
1951	20.2	20.2				
1952	26.0	25.5	0.5			
1953	33.7	32.7	1.0			
1954	38.5	37.4	0.7	0.4		
1955	49.6	43.2	1.5	4.9		
1956	63.1	47.1	4.9	11.1		
1957	60.3	42.7	2.7	14.9		
1958	49.8	43.9	2.0	3.9		
1959	57.3	49.4	2.1	5.8		
1960	58.7	47.5	3.3	7.9		
1961	72.0	49.1	8.5	14.4		
1962	79.1	48.1	11.2	19.8		
1963	82.3	50.2	12.6	19.5		
1964	87.0	51.6	13.3	22.1		
1965	91.7	56.2	13.6	21.6		
1966	100.4	58.4	17.9	24.1		
1967	113.4	61.1	23.9	28.4		0.2
1968	125.6	66.9	34.1	24.6		2.5
1969	142.1	68.9	42.4	30.8		4.4
1970	165.6	76.4	56.2	33.0		5.3
1971	181.2	80.3	68.4	32.5		6.8
1972	213.5	81.3	90.7	41.5		8.2
1973	261.8	102.6	120.1	39.1		8.0
1974	249.2	123.2	95.4	30.6		7.3
1975	215.7	115.6	73.3	26.8		6.8
1976	196.3	132.5	49.2	14.6		7.6
1977	194.7	156.7	34.5	3.5		7.2
1978	192.9	161.8	28.9	2.2		8.9
1979	222.0	184.9	33.1	4.0		14.6
1980	211.4	187.6	20.6	3.2		20.3
1981	191.8	172.0	16.7	3.1		17.7
1982	186.4	162.0	21.4	3.0		19.1
1983	195.3	164.1	28.1	1.5	1.6	25.4
1984	205.6	162.1	40.5	2.8	0.2	21.2
1985	207.2	150.1	53.6	2.9	0.6	26.7
1986	205.5	135.9	64.7	3.4	1.5	29.4
1987	214.9	140.3	71.1	1.4	2.1	28.7
1988	227.8	140.3	83.5	1.1	2.9	31.9

/continued

Table 6.1/continued)

		Sales				
	Crude Oil Production	Domestic	Export U.S.A. (East)	Export U.S.A. (West)	Export (Offshore)	Synthetic Crude Production
1989	221.6	139.9	78.3	1.6	1.8	32.6
1990	217.1	133.4	81.2	0.6	1.9	33.1
1991	216.7	121.6	90.9	0.8	3.4	35.9
1992	224.0	122.1	98.9	–	3.0	37.7
1993	228.8	124.4	102.6	–	1.8	38.7
1994	235.8	127.8	102.3	7.1	0.6	41.6
1995	242.4	122.1	117.4	6.3	0.8	44.7
1996	245.2	117.8	120.8	10.3	2.0	44.7
1997	253.0	103.8	136.7	10.8	1.9	43.7
1998	254.6	101.3	139.3	11.3	3.2	49.0
1999	239.4	101.2	136.4	7.1	0.5	51.4
2000	257.3	96.6	139.1	7.5	–	51.0
2001	259.0	88.2	156.8	7.5	–	55.4
2002	243.7	94.2	155.6	6.2	–	70.1
2003	257.9	128.2	161.7	8.5	3.3	80.9
2004	274.7	132.4	176.2	14.3	1.4	96.3
2005	268.9	123.6	175.2	11.3	4.4	86.9
2006	287.2	127.4	199.6	14.3	4.0	104.4
2007	295.0	131.4	197.0	16.2	6.1	109.2
2008	293.7	127.3	200.5	17.7	6.7	104.1
2009	305.8	134.3	203.8	15.9	22.0	121.7
2010	326.4	128.6	198.7	18.9	21.7	125.8
2011	355.1	135.5	192.1	22.0	7.0	137.1
2012	389.8	143.2	201.8	21.1	9.7	140.0

Notes: All production prior to 1952 is assumed to be for domestic use. Production includes condensate and pentanes plus and synthetic (tar sands) oil. Domestic sales include inventory changes and miscellaneous losses and adjustments plus resale of minor volumes of crude imported into Alberta in some years. Western U.S.A. is PAD (Petroleum Administration District) V (Washington, Oregon, California, Nevada and Arizona). There are data problems for the year 2001 which the ERCB has indicated it is addressing.

Sources:
1914–51: *Annual Report of the Department of Mines and Minerals* for the Fiscal Year Ended March 31, 1952;
1952–2012: Energy Resources Conservation Board (or Energy Utilities Board or Oil and Gas Conservation Board) as follows:
1952–61: *Oil and Gas Industry Annual Report*, 1961;
1962–63: *Oil and Gas Industry Annual Report*, 1963;
1964–71: *Cumulative Annual Statistics of Western Oil and Gas Industry*, 1973 (ST74-17);
1972–80: *Cumulative Annual Statistics of Western Oil and Gas Industry*, 1981 (ST82-17);
1981–97: *Alberta Oil and Gas Industry Annual Statistics*, assorted years (ST-17);
1998–2012: *Alberta Energy Resource Industries Monthly Statistics*, various issues (ST-3).

that exported to the United States, where the 'west' of the United States is PAD V (Petroleum Administration District V, which includes states on the west coast plus Nevada and Arizona). Occasional barrels of Alberta crude oil made their way to other markets; markets other than those in Canada and the adjacent northern part of the United States have had ready access to easily transported international crude oil supplies at prices with which Alberta has been unable to compete.

Table 6.2 shows the course of Alberta light crude oil prices from 1948 through to 2012, for 35° crude oil at the field gate of the Redwater pool just northeast of Edmonton to 1985 and for Alberta 'Par' at Edmonton

Table 6.2: Alberta Crude Oil Prices, 1948–2013

i) Market Penetration		$/m³	$/b
1948	(January 1)	20.14	3.20
1949	(January 1)	16.87	2.68
	(September 1)	18.12	2.88
1950	(October 16)	17.18	2.73
1951	(April 24)	15.35	2.44
	(June 1)	15.48	2.46
1952	(April 23)	14.57	2.315
	(June 1)	15.48	2.46
1953	(March 19)	15.01	2.385
	(July 21)	16.64	2.645
1954	(October 15)	16.08	2.555
1955	(January 7)	15.64	2.485
	(February 1)	15.67	2.49
1957	(January 16)	16.80	2.67
	(August 30)	16.55	2.63
1958	(April 12)	16.11	2.56
1959	(March 24)	15.23	2.42

ii) National Oil Policy (Covert Controls)		$/m³	$/b
1961	(September 11)	15.86	2.52
	(May 10)	16.49	2.62
1970	(December 15)	18.38	2.92
1973	(May 1)	21.9	3.48
	(August 1)	24.42	3.88

iii) Covert Controls		$/m³	$/b
1974	(April)	41.41	6.58
1975	(July)	50.82	8.075
1976	(April)	51.00	8.105
	(June)	51.13	8.125
	(July)	57.74	9.175
	(November)	57.99	9.215
1977	(January	62.40	9.915
	(June)	62.58	9.945
	(July)	68.88	10.945
1978	(January)	75.17	11.945
	(February)	74.98	11.915
	(July)	81.24	12.91
1979	(July)	87.54	13.91
	(October)	87.67	13.93
1980	(January)	93.95	14.93
	(August)	106.35	16.9
1981*	(January)	112.71	17.91
	(June)	113.21	17.99
	(July)	119.57	19.00
	(October)	132.97	21.13

iii) Covert Controls/continued		$/m³	$/b
1982*	(January)	146.31	23.25
	(July)	185.64	29.5

iv) Deregulation		$/m³	$/b
1985	(June 1)	231.27	36.75
	(4th quarter)	232.83	37.00
1986	(March)	111.2	17.67
	(October)	124.2	19.11
1987	(March)	142.4	19.74
	(October)	155.52	22.62
1988	(March)	119.65	19.01
	(October)	100.13	15.91
1989	(March)	135.61	21.55
	(October)	143.41	22.79
1990	(March)	149.9	23.82
	(October)	255.83	40.65
1991	(March)	137.07	21.78
	(October)	156.67	24.90
1992	(March)	132.33	21.03
	(October)	163.31	25.95
1993	(March)	146.31	23.25
	(October)	139.69	22.20
1994	(March)	114.54	18.20
	(October)	141.29	22.45
1995	(March)	155.95	24.78
	(October)	140.73	22.36
1996	(March)	176.17	27.99
	(October)	207.57	32.98
1997	(March)	176.53	28.05
	(October)	179.48	28.52
1998	(March)	127.45	20.25
	(October)	131.97	20.97
1999	(March)	131.43	20.88
	(October)	204.77	32.54
2000	(March)	273.30	43.42
	(October)	311.77	49.54
2001	(March)	258.21	41.03
	(October)	213.15	33.87
2002	(March)	239.30	38.01
	(October)	276.52	43.94
2003	(March)	309.86	49.24
	(October)	242.29	38.50
2004	(March)	305.84	48.60
	(October)	405.87	64.50
2005	(March)	425.38	67.60
	(October)	472.13	75.02
2006	(March)	429.13	68.19
	(October)	397.52	63.17

/continued

Table 6.2/continued

iv) Deregulation/continued		*$/m³*	*$/b*
2007	(March)	435.86	69.26
	(October)	511.31	81.25
2008	(March)	664.51	105.60
	(October)	538.68	85.59
2009	(March)	379.83	60.39
	(October)	483.18	76.78
2010	(March)	511.89	81.34
	(October)	470.38	74.75
2011	(March)	614.41	97.63
	(October)	589.14	93.62
2012	(March)	541.36	86.03
	(October)	581.37	92.39
2013	(March)	560.54	89.07

Note: Quarterly figures are end-quarter prices. * Price refers to "old" oil. 1948–85, price is for Redwater 35° oil. After 1985, price is 'Canadian Par Price.'

Sources: 1948 to 1974, Alberta, Energy Resources Conservation Board, unpublished data, and Esso Canada, *Esso Price Bulletins* (various years); 1975 to 1985, Alberta Petroleum Marketing Commission, Selling Price Bulletin for Crown Petroleum (various years); 1985, Esso and Shell, *Crude Oil Pricing Bulletin* (various months); 1986 to 2013, Natural Resources Canada, Petroleum Resources Branch, *Crude Oil Data, Selected Oil Prices* – Monthly Data.

after that. Oil of different quality or at a different location would exhibit a price differential from this oil but would otherwise tend to follow the same historical price path. Only when a crude oil differs quite significantly from the Redwater "reference" crude oil, for example very heavy oils from some eastern Alberta pools, might changes in the size of the price differential itself be a significant factor in the general trend.

Little concerted economic analysis of crude oil price differentials is available. Conceptually, in a well-functioning relatively competitive market, one would expect that there is, in any time period, an equilibrium set of price differentials that reflects:

(i) **transportation cost differences**, with crude oil further from market than the reference oil having a lower price (a higher negative differential relative to the reference crude oil), as would heavier crude oils which are more costly to ship;
(ii) **refining cost differences**, with heavier crude oil having higher refining costs (especially if subject to special processes such as cracking designed to increase the yield of lighter products), and therefore less value to the refiner, generating a larger negative differential; and
(iii) **refined petroleum product refinery gate values**, with heavier crude oil having a lower yield of the more highly valued light products, therefore commanding a larger negative differential.

Changes in transmission costs, in the configuration of purchasing refineries, in refinery technology and in the values of refined petroleum products would all change price differentials across different grades of crude oil. In practice, the industry and governments have generally handled the hydrocarbon quality part of the price differential by means of relatively fixed conventions, accepted by all and holding for lengthy periods of time. The locational differences have reflected the costs of transmission.

Historically, Alberta oil price differentials from 1947 on (as set out by Imperial Oil) were 3 cents per barrel for every degree API difference, and 2 cents per barrel for every 0.1 per cent sulphur difference (above .49% sulphur). (See Bertrand, 1981, vol. iv, pp. 4–8.) Bradley and Watkins (1982, pp. 66–68) argue that the inability of individual refineries to select output from particular oil pools as a result of the Alberta government market-demand prorationing scheme meant that market flexible differentials were not viable and some more arbitrary way of determining relative crude oil values was required. Acceptable fixed differentials provide a low-cost solution to this problem. Much of the analysis of the crude oil industry in the Bertrand Report on the *State of Competition in the Canadian Petroleum Industry* (Bertrand, 1981, vol. iv) was concerned with whether these set differentials up to 1980 were, in fact, appropriate.

Figure 6.1 shows two price differentials for the years from 1986 to March 2013. One largely represents a locational differential: it shows amount by which the Alberta light oil price at Edmonton is less than the price of North Sea Brent oil delivered to Montreal. If Alberta oil were to be competitive in Montreal, the Alberta price had to be lower than the Brent price by at least the shipment cost from Edmonton to Montreal. Up until 2005, the price differential was relatively small, usually less than $10/m³. However, after 2005 it increased, rising sharply in 2011 until reaching over $160/m³ by the time of final editing in March 2013.

The second differential shown is for Alberta heavy oil as compared to Alberta light oil. Except for a brief

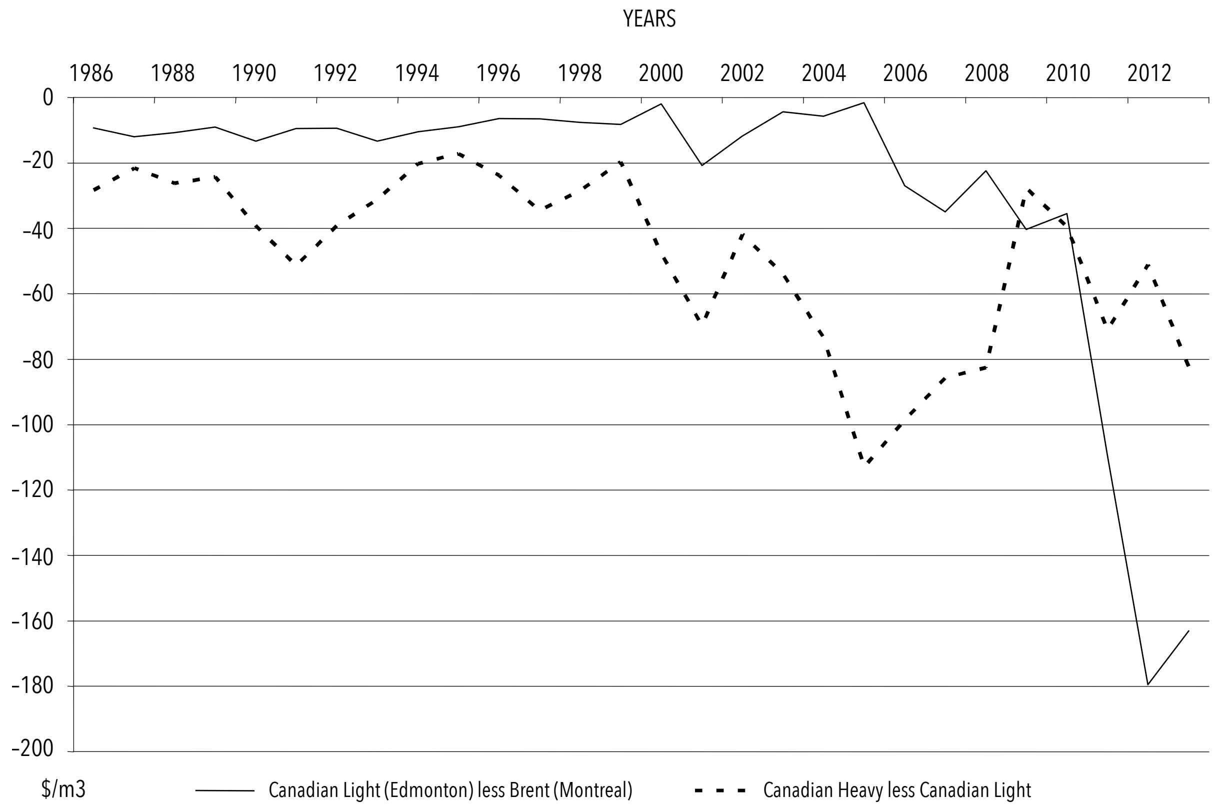


Figure 6.1 Oil Price Differentials

Note: Annual averages, except for 2013, which is the month of March.
Source: Natural Resources Canada, *Selected Crude Oil Prices Monthly*, 1986–2013.

period in 1990, the price difference was less than \$40/m³ until the year 2000. After that it tended to rise, to as much as \$60/m³ (in December 2007), until falling back below \$10/b through much of the next two years. The differential has fluctuated since then but was up to \$94/m³ at the time of writing in April 2013. A larger price differential indicates a relative surplus of heavy crude oils relative to lighter grades and offers an incentive to refiners to buy and upgrade the heavier oil. Some observers of the international oil market have been on record for many years arguing that larger differentials are to be expected as world crude oil production shifts to heavier grades and transportation demands (for light refined petroleum products) become more dominant; however, this forecast has not yet been realized.

The discussion of price and output that follows draws heavily upon Watkins (1977a), Watkins (1981), Bradley and Watkins (1982), Watkins and Bradley (1982), Watkins (1989), and Helliwell et al. (1989).

3. Determination of Alberta Crude Oil Output and Prices

A. Tentative Beginnings: Pre-1947

Native Indians and early explorers and settlers found scattered evidence of Alberta's petroleum potential in oil and natural gas seepages, frequently in ravines or springs by rivers or creeks. (For more detailed discussion of the earliest industry activities in Alberta, see Beach and Irvin, 1940, Toombs and Simpson, 1957, Hanson, 1958, Simpson et al., 1963, de Mille, 1969, Gray, 1970, Gould, 1976, Dow, 2005, and Finch, 2007. Also useful are the *Annual Reports* of the Alberta Department of Lands and Mines after the transfer of resources from Ottawa to the province on October 1, 1930.) Henry Kelsey, of the Hudson's Bay Company, was brought a rock sample from the Athabasca tar sands in 1719 by a Native named Wa-pa-su, and Peter Pond (1778) and Alexander Mackenzie (1781) both saw the Athabasca deposits during their expeditions. Other early reports of oil seepages were by John G. (Kootenay) Brown at Cameron Creek near Waterton (in 1874), John Ware on the Sheep River (in 1888), and G. M. Dawson and R. G. McConnell of the Canadian Geological Service at Tar Island near Peace River (1893). (Dormaar and Watt, 2008, provide a history of the Waterton finds.) However, the earliest commercial petroleum activities in Alberta centred on natural gas for local use, though this was more a result of accidents of discovery than intent.

The first commercial petroleum well came in at Langevin near Medicine Hat when a CPR water-directed well hit gas. Despite oil traces in several wells at Cameron Creek at the turn of the century, the significant early discoveries were of natural gas, particularly in two major finds at Turner Valley in 1914 and 1922. The Turner Valley natural gas reservoirs signal the start of the Alberta crude oil industry, since both held 'wet' gas (with high liquid – i.e., condensate – content). In fact, the production of gas from Turner Valley was largely driven by the demand for liquid oil, with much flaring of gas and public concern about waste of the gas resource.

As Table 6.1 shows, Alberta oil production was negligible until the late 1930s and did not increase significantly until the late 1940s. Most date the Alberta oil industry from the Leduc finds of February and May 1947. The only significant oil discovery prior to that was the Turner Valley discovery of 1936, on a deeper southwest incline below the gas cap that had been discovered in 1922. Seventeen other smaller oil pools were discovered before Leduc, including Del Bonita (1931), Princess (1939), and heavy oil deposits at Wainwright (1925), Taber (1937), Lloydminster (1939), and Vermilion (1939) (Hanson, 1958, pp. 52–57). None of these early oil finds were part of a major oil play, so the initial discovery was not followed by a flurry of drilling activity and new discoveries in the same geological formations. Turner Valley is anomalous, apparently a large oil pool that is not part of a larger play; this may reflect some chance element in its generation, or the peculiarities of the complex highly fractured geology of the Foothills. Small discoveries, and those involving less attractive heavy oil, are not likely to stimulate an active oil play.

Turner Valley proved to be both a large oil pool and a learning experience. Production there raised several problems that would continue through the years after Leduc. Problems related to the rule of capture, to protection of correlative property rights of oil producers on adjacent properties, and to the orderly marketing of crude oil. The problems were interrelated. The rule of capture pushed companies to attempt rapid recovery of the fugacious (flowing) oil before their neighbours could capture it, but this pressure occurred in a market that was underdeveloped both in terms of infrastructure for shipment and institutional forms for market exchange.

Companies that built their own pipeline facilities and/or had well-established connections with refiners would have a competitive advantage and might be able to produce significant volumes of oil from beneath neighbouring companies' property. The large, so-called 'major,' oil companies were especially favoured, with good access to financial capital and their own refineries. Smaller producers, concerned about the situation for obvious reasons, cried out for some control over development of the Turner Valley field, and the government responded by establishing the Petroleum and Natural Gas Conservation Board (PNGCB) in 1938. A Turner Valley Gas Conservation Board had been set up in the early 1930s. The PNGCB was the precursor of the Alberta Oil and Gas Conservation Board (OGCB, 1948), its successor in 1968, the Alberta Energy Resources Conservation Board (ERCB), the 1994 Alberta Energy and Utilities Board (EUB), and, once again in 2008, the Energy Resources Conservation Board. Regulatory duties are due to be taken over by the new Alberta Energy Regulator in June 2013. For a detailed history of these bodies prior to 1990 see Breen (1993).

The low recovery rates under the rule of capture were accentuated for the Turner Valley field by production from the natural gas cap discovered in 1922; total primary recovery for the main oil pool is currently estimated at only 13 per cent. Imperial Oil in 1931 limited its purchases of oil from Turner Valley to one half of well potentials in what seems to be the first recorded example of 'proration' in Alberta, albeit at the instigation of private industry rather than government. Later in the 1930s the PNGCB initiated a prorationing scheme in the Turner Valley field to help control depletion of reservoir energy. (See Chapter Ten for a discussion of prorationing.) The McGillivray Royal Commission on Petroleum and Petroleum Products (McGillivray, 1940) agreed that prorationing was necessary for Turner Valley oil, but argued that, for other oil pools, it would be preferable to apply unit operations, where each pool would be operated as a single entity. However, Alberta continued to utilize prorationing in preference to unitization right through to the end of the 1980s.

Turner Valley pushed Alberta's liquid hydrocarbon production up from about 3,600 b/d (570 m^3/d) in 1936 to a war-time peak of 27,800 b/d in 1942, transforming Alberta from a net oil importer to a net oil exporter, with ex-Alberta sales going primarily to Regina. However, by 1947 Alberta's oil output had fallen to 24,000 b/d, as Turner Valley moved into a phase of production decline.

The price of Alberta crude oil in this period was tied to the price of oil from adjacent areas of the United States, particularly the Cutbank pool in Montana. The McGillivray Commission of 1940 summarized the explanation of Alberta oil pricing that has gained most credence (McGillivray, 1940, pp. 56–57). North America was viewed as an integrated crude oil market, with prices everywhere, including Montana, tied to prices at the U.S. Gulf (of Mexico). This reflects the Gulf Coast pricing system for oil throughout the world ('Gulf Plus') as discussed in Chapter Three. Montana oil served as the competition to Alberta oil in Regina and hence was the prime determinant of the price of Turner Valley oil. For example, in 1939, a field price of US$1.10/b for Cutbank 37° oil in Montana generated a delivered price (in Regina) that could then be netted back to Turner Valley by deducting the Turner Valley to Regina shipment cost, with further allowance for quality differences and the exchange rate. This implied a price in Turner Valley for 43° oil of CDN$1.28/b, which was just about the prevailing price. The Commission noted that if Turner Valley oil were shipped further east to Portage la Prairie, its price would have to fall to compete with oil and products supplied from Sarnia and that the revenue earned would fall since the extra volume shipped would not make up for the price decline. The report did not, however, discuss what forces prevented sales from occurring in the Portage market, though it noted that production decline would soon necessitate a falling off of sales in Saskatchewan.

Thus, Alberta crude oil prices, from the beginnings of production in 1914, followed U.S. crude oil prices. In the period from 1925 through 1946, average per barrel receipts on Alberta crude oil fluctuated with North American prices with a low of CDN$1.22/b in 1939 and a high of $4.60 in 1927. The average value of Alberta oil sales in 1947 was $2.66/b.

The McGillivray Commission noted that the vast sedimentary basin covering most of Alberta offered high crude oil potential but that new discoveries were essential even to maintain the output levels of the early 1940s. The full extent of Alberta's oil potential was uncertain.

In the early 1900s, the chief geologist of Standard Oil had been negative about Alberta's potential. However, the company's subsidiary in Canada (Imperial Oil) had persuaded Standard that an exploration program in the Western Canadian sedimentary basin was warranted (de Mille, 1969, p. 154). Imperial had a share in the Turner Valley pool, but of 134 Imperial exploratory wells drilled up to 1946, only one had found a significant oil pool (and that was too far north, at Norman Wells, in the Northwest Territories, to be of commercial value) (Gray, 1970, p. 98). Despite contrary pressures, Imperial decided not to abandon exploration in Alberta. A group of senior geological experts recommended drilling on land Imperial held near what was then understood to be the Alberta 'hinge belt' where the shallower sedimentary rock layers to the northeast suddenly deepened very sharply to the southwest. The well was targeted primarily to rocks of Mesozoic age. The ironies of the Leduc well have often been noted. Oil was discovered, unleashing the first of the major oil plays that transformed the Alberta economy. The irony lies, not in the discovery of oil itself, but in the location, which was not in the geologic target but in a deeper Devonian formation; moreover, an Alberta hinge belt, as envisioned in 1947, does not exist. Decision-making in an uncertain world guarantees surprises, some of them pleasant!

B. Market Penetration: 1947–60

After Leduc, Alberta's reserves swelled with new discoveries. New markets for western Canadian crude oil needed to be found. This would entail displacement of other oil supplies in areas increasingly far from Alberta. Expansion in an eastward direction would require acceptance of lower netbacks to compete with the delivered price of oil from the alternative source of supply – the United States. Markets progressively further east from Alberta were closer to U.S. mid-continent pipeline terminals, so had lower shipment costs for U.S. crude oil. Figure 6.2 (a modification of Figure 3.1) illustrates the general relationships. Distance is shown along the bottom of the figure, while the vertical distance shows the price of oil. P_T represents the delivered price of U.S. crude oil, up the Niagara peninsula, to Toronto. The line $P_T X$ shows the delivered price of such crude oil moved westward from Toronto to various Canadian markets. In 1947 Alberta crude oil was competitive as far east as Regina; this is indicated by an Alberta price at level P_A and a delivered price for Alberta oil in markets to the east as indicated by line $P_A Y$. As can be seen, the watershed market (where U.S. and Alberta crude oils are equally attractive) is just east of Regina. In Winnipeg, Manitoba, in 1947, U.S. oil was cheaper than Alberta

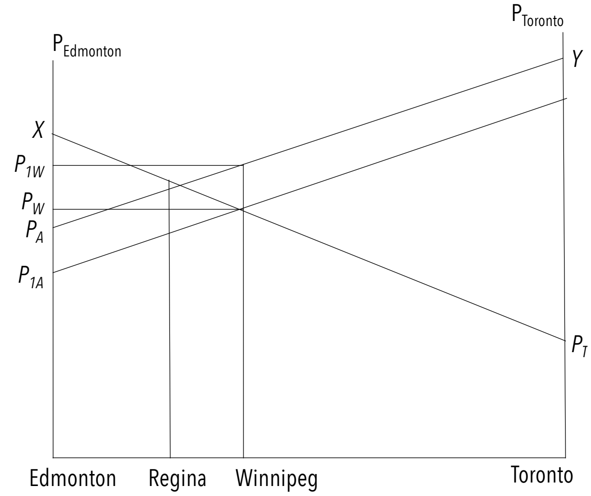


Figure 6.2 Alberta Crude Oil Market Penetration

oil ($P_W < P_{1W}$). Only if the Alberta oil price fell to level P_{1A} would customers in Winnipeg be induced to purchase Alberta crude oil.

The precise way in which the market would respond to increased Alberta oil reserves would depend upon the degree of competition in the market. We begin by considering two possible geographic pricing patterns.

1. Competitive Pricing Patterns

What sort of pricing structure would arise if output grew under competitive market conditions? As just discussed, acquisition of new eastern markets would involve absorption of shipping charges. To meet the United States delivered price in, say, eastern Saskatchewan, Alberta producers would have to lower their wellhead price.

As still more reserves were discovered, Alberta output would continue to expand, absorbing all Saskatchewan demand, then moving into Manitoba. A lower Alberta price would be necessitated with each eastward extension of the market area in order to keep the oil competitive with imported oil into the new market. Under competition, this would become the price at which all Alberta crude oil would be sold, regardless of destination. At each step, sellers would, of course, like to maintain the previous higher price level. However, if individual companies tried to hold the price up, producers without contracts would bid down the price of all oil to the new, lower level. Under competition, this process would continue until the Alberta wellhead price fell to the long-run incremental cost of supply.

2. Monopolistic Pricing Patterns

What price structure would have evolved had Alberta producers been able to exert monopolistic power? Such power would likely involve price discrimination. Producers would have continued supplying Alberta at the original Alberta wellhead price, while supplying Saskatchewan at a lower wellhead price, and Manitoba at a still lower price, reflecting higher transportation costs. The incremental benefit of each market expansion step would be greater for producers than in the competitive case: even though the netback on new, more distant sales would be lower, prices would be maintained at previous levels in nearer markets.

Price on at least some of the sales would be in excess of the long-run incremental supply cost of the crude oil. Although producers would clearly prefer to keep price higher in markets adjacent to the supply region and only cut it for the new markets, a monopolistic result might occur without price discrimination, but with price in excess of incremental costs. That is, a uniform wellhead price could emerge but be held above long-run marginal cost by restricting output.

3. What Pattern Evolved?

What happened to Alberta oil prices as output expanded in the late 1940s and 1950s? Table 6.2 shows that, by and large, crude oil prices were reduced in a series of steps corresponding to the penetration of successively more distant markets.

In 1947, Alberta oil supplied Alberta requirements and a portion of Saskatchewan's. By 1948, Alberta oil had begun to penetrate the Manitoba market, and in 1951 deliveries to the Ontario market commenced, as did exports to the United States.

In 1947, the price of Alberta oil was $3.20 per barrel. By December 1948, this price had been reduced to $2.68 to make Alberta oil competitive with the delivered price in Manitoba of United States supplies from Illinois, Oklahoma, and Texas. Alberta oil prices fluctuated in 1949 and 1950, according to changes in the exchange rate of the Canadian dollar. The reduction in price in 1951 was intended to make Alberta crude oil competitive with Illinois crude oil at Sarnia. The price rise in 1953 reflected an increase in equivalent delivered prices of U.S. and world oil at Sarnia. The price fell in 1955 with a change in the price of Illinois crude oil and exchange rate adjustments but rose in 1957 as world oil prices increased. Subsequently, the 1958 decline in world oil prices induced a fall in Alberta oil prices. In 1962, the devaluation of the Canadian dollar to a pegged rate (CDN$1 = US$0.925) resulted in an Alberta (Redwater) wellhead price of $2.62. This price held until 1970.

Up to 1960, the behaviour of Canadian oil prices is compatible with the competitive model outlined above. The build-up in supplies induced market expansion. Prices for all markets were reduced as the competitive interface for Alberta oil shifted eastwards to displace United States supplies. Also, up until 1960, changes in world crude oil prices were directly reflected in Alberta prices.

However, further consideration suggests that neither the price adjustments nor the level of prices were fully consistent with the competitive market outcome. Rather, a mix of oligopoly (with some large powerful sellers) and oligopsony (with some large powerful buyers) was operating (Bradley and Watkins, 1982).

4. The Oligopoly-Oligopsony Case

In a situation of few sellers (and that of few buyers can be treated similarly), it would be irrational in the view of an economist, and folly in the view of a business manager, for a given seller to adjust the terms of sale – in particular, the price – without taking account of how rival sellers would respond. As the most familiar example, consider the possibility of a unilateral price cut. Word of bargains usually travels fast, so, long before the path to the price-cutter's door could become well worn, rivals might be expected to match the price cut in order to preserve their sales. If this were the case, why make the initial cut, creating only the prospect of lower prices for everyone? This recognition of mutual dependence must form part of the explanation of price formation in oligopolistic industries, as was seen in the discussion of OPEC in Chapter Three.

The degree of group organization in oligopoly can vary greatly, yielding results that bear resemblance to monopoly at one extreme or to competition at the other. Resemblance to monopoly is most likely to occur where the group is small in size, its members share similar situations and interests, and entry to the industry by outsiders is impeded. Such a group can enjoy greater aggregate profits by exerting some degree of control over price without the aid of any formal organization because individual producers condition pricing decisions upon recognition of the circumstances facing the group as a whole. Discretionary behaviour by the group is curtailed if these conditions are altered – for example, if there is a larger group, members with diverse situations and conflicting interests, or if entry to the industry is unimpeded. In this case, the industry is subject to the discipline that would be imposed by an impersonal, competitive market. Because market behaviour in an oligopolistic industry can vary so widely, industry analysis must identify and take account of factors that enhance or diminish group action.

Drawing on commonly observed patterns, it is possible to formulate a model of price formation in an oligopoly. The key presumption of recognition of mutual dependence has already been noted. The success with which individual pricing decision can be aligned will depend on what may be classed as internal considerations (Osborne, 1978), the two main ones being: (1) the degree to which a given price level suits all sellers; and (2) the degree of confidence possessed by each seller that others are adhering to the given price. The first, or 'compatibility' factor, is determined by such circumstances as the similarity of cost structures and growth objectives among the sellers. The second, or 'discipline' factor, rests upon the availability of information about transactions and the means for deterring individual departures from the industry price. The effectiveness of a pricing strategy for increasing group profits (hence, those of individual sellers) will depend on external considerations, of which the key factor is the ease with which new sellers can join the industry.

Much of our discussion will focus on how external and internal circumstances condition price formation in crude petroleum markets, but any explanation is incomplete without an indication of the mechanism by which price itself is established. If there is no outside auctioneer or broker, some member of the group must name a price. The development of active international spot markets and the growth of futures trade for crude oil on various Mercantile Exchanges in the 1980s has provided an outside source of oil prices in recent years; but earlier this was not the case. There must be some means for efficiently adjusting price because a group of sellers is not well served by a rigid price when demand and cost conditions in an industry are continually changing. This means is most frequently provided through the convention of price leadership.

The price-leader is likely to be the largest or the longest-established member of the group, although this is not necessarily the case. It is more important that the prices set by the price-leader be regarded by the members of the group as appropriate, or at least tolerable, in light of market conditions. Where such a leader exists and is followed, not only can price wars be avoided, but prices can be adjusted appropriately to 'soft' or 'firm' market conditions. Where leadership is not well-established, a price announcement by a prospective leader might be followed by some jockeying – other members testing slightly higher or lower prices – before the group price is established. This interval of uncertainty can be avoided when the leader has been identified through practice and the firm's prices continue to seem reasonable to other sellers.

Whether or not oligopoly pricing can be sustained depends on elements we characterize as internal factors. For instance, a company desperate to increase its market share in order to spread overhead or meet cash needs might provoke a price war if it incorrectly believed it could successfully conceal price concessions. At the same time, external factors determine the degree of market power that can be achieved through successful oligopoly pricing. We have noted that if new firms can join the industry readily when price–cost margins rise, then this threat will limit price increases. (Such markets are sometimes said to be 'contestable,' as argued by Baumol, 1986, and Baumol et al., 1988). There can be other constraints, for example, loss of markets to imports or fear that government will remove industry privileges or actually intervene to set prices.

The oligopoly-oligopsony model of price formation proves useful in understanding the evolution of Canadian crude oil prices as the market area was expanded in the 1950s. Deliveries through two pipelines, the major Interprovincial Pipe Line (IPL) to the east (now known as Enbridge), and the smaller Trans Mountain, to the west (now known as Kinder-Morgan), disposed of the bulk of the increased output. As noted above, during this period, prices paid by a small number of refiners in the most easterly markets – refiners who had access to alternative crude oil sources – were decisive in establishing the price of all Western output. Alberta crude oil prices evolved to meet competition in the most distant market as a competitive model would imply.

What were the actual circumstances of crude oil markets in the 1950s? There was a moderate degree of concentration in the production sector. (See Table 6.6 and Section 4 of this chapter.) In 1957, the largest four producers accounted for about three-eighths of total output; the largest eight, for just over half. There were many smaller producers, some affiliated with refiners and marketing organizations, but most independent. The extent of concentration in the industry was less than is generally assumed to be necessary in order to achieve significant market power through coordinated oligopoly pricing. However, the possibility of price competition in the sale of crude oil within Canada was constrained by government regulation. Market-demand prorationing in Alberta, the principal supplying province, suppressed competitive selling strategies. (See Chapter Ten.) A seller had little reason to propose a lower price when there was no possibility of increasing the quantity of oil sold, since any increased sales at lower prices would be spread across all the producers in the province.

Not only had discoveries materialized, but throughout the 1950s development drilling, overstimulated by the land tenure system and by incentives in the Alberta prorationing system, had proceeded at a rate that maintained and even widened the gap between productive capacity and actual output. In fact, there was more to the predicament than is revealed by the low overall utilization of capacity since the method of quota allocation under prorationing was such that low-cost fields bore the brunt of unused capacity. As an example, Imperial Oil noted that its Golden Spike field in 1958 had a "maximum permissible rate" (MPR) of 45,000 barrels per day but was only assigned production of 3,400 barrels per day.

How then was the price of crude oil established? The task could have been assigned to the Alberta Oil and Gas Conservation Board, which was then supervising the prorationing system. In fact, while it was authorized under the *Oil and Gas Conservation Act* to regulate quantities produced, the board had no authority to establish prices directly. It remains to look to the buyers' side of the market, where the price of oil was given by matching posted prices of major refiners.

There are only a few refiners in any region of Canada. Even on a national basis, the number of different companies represented in refining is not large since each of the four major oil companies has refineries in most regions. This level of concentration suggests potential market power on the buyers' side. Because the refiners were in varying degrees integrated back into crude oil production, different objectives might have been served by the exercise of market power. However, it will be shown that the range within which prices could be set was severely limited. The price that could be charged in the market most distant from Alberta was limited by the price of that region's alternative crude oil supply, while the way in which prorationing suppressed pressures from excess capacity tended to preclude market-clearing price reductions. Furthermore, price discrimination by destination was never instituted.

Organizing a market so that pricing may serve group interest proceeds in our model through the mechanism of price leadership. Individual refiners are likely to see it to be in their long-term interest to match the crude oil price postings of a leader. There is evidence that Imperial Oil consistently led in posting crude oil prices from the 1950s onward (Bertrand, 1981, vol. iv, pp. 6–7). Imperial Oil was a pioneer in exploring the Western Canadian sedimentary basin, and by the 1950s it had succeeded in establishing itself as the largest producer. In 1957, Imperial's share of Western Canadian production exceeded that of the next three largest producers combined (see Table 6.6). In fact, output shares understate Imperial's position. Much of its crude oil came from the more productive and hence lower cost reservoirs, and Alberta prorationing imposed the most severe output restrictions on such reservoirs. Consequently, Imperial's share of marketable reserves would have been higher than its share of production. Thus, it had strong motivation to promote market expansion.

Before Interprovincial Pipe Line was organized, Imperial had already taken the initiative toward market expansion to the east by making arrangements for construction of a pipeline from Edmonton to Regina. In July 1948, after a survey of possible routes, negotiations were begun for 16-inch diameter pipe. When mounting discoveries provided justification for a pipeline that would reach the east via the Great Lakes, Interprovincial Pipe Line Company (IPL) was incorporated by a special act of Parliament in April 1949 to carry forward construction of a line. In August 1949, Imperial subscribed to the first 10,000 shares of IPL. For several months, until October 1949, IPL was a wholly owned subsidiary of Imperial, but at that time a further 10,000 shares of stock were sold, of which 3,000 were subscribed by oil companies – 2,000 by Canadian Gulf Oil and 1,000 by Canadian Oil Companies Limited. Imperial assumed significant parental responsibilities with respect to IPL. It undertook to provide guarantees that a minimum amount of crude oil would be shipped (the Throughput Agreement) and that if throughput fell below a stipulated figure it would make up the tariff shortfall to IPL in cash. Inability of IPL to meet its financial obligations would be remedied by Imperial under a Three Party Agreement among Imperial, IPL, and the Royal Trust Company, stipulating that if IPL failed to meet interest or principal payments to Royal Trust, the deficiencies would be made up by Imperial. (These agreements are reproduced as Appendices C and D in Interprovincial Pipe Line Company, Submission to The Royal Commission on Energy, February 1958.)

To foster the development of IPL, Imperial not only utilized the line for transport of crude oil to its Regina, Winnipeg, and Sarnia refineries, but it also signed contracts with British American Oil Company (BA) and Canadian Oil Companies Limited to supply crude oil to their refineries in Ontario. Contracts were also made to supply U.S. refiners who could be served by IPL. Shipments of crude oil under all these contracts reduced the risk that IPL would fail to meet projected shipment volumes, thereby necessitating payments by Imperial under its throughput and financial deficiency agreements.

In describing the model of oligopoly-oligopsony price formation, reference was made to internal factors related to compatibility and discipline. Willingness to match a price posted by the leader is enhanced if that price is seen to serve well-understood industry objectives. In the 1950s, there was consensus among producers on the desirability and even need to supply the Ontario market and parts of the U.S. market that could be reached by the Interprovincial pipeline. This established a clear limit for price: it had to match the price of alternative suppliers at the competitive interface, which came to be Sarnia, Ontario.

The explanation thus far for Canadian crude oil price changes in the 1950s may be summarized briefly: sellers had little influence on prices that were set by buyers acting as a group in pursuit of the industry objective of orderly market expansion. Accordingly, crude oil prices were reduced in a series of steps, corresponding to the penetration of successively more distant markets.

The policy of expanding the marketing area placed a ceiling on crude oil prices. We must now consider how the price floor was supported. The guiding spirit of the system set up under the *Oil and Gas Conservation Act* was equality of treatment for all producers. The act is strongly worded in its insistence that no discrimination be practised, although there does not appear to have been any subsequent litigation that developed the law on this point. Had the price-setters not been operating in this atmosphere, they might have been more aggressive in lowering the price of crude oil in order to increase the level of utilization of low-cost fields (where their ownership interest was strongest) at the expense of high-cost fields.

It will be recalled that the evolution of Alberta crude oil prices began from a starting point at which price matched the delivered cost of U.S. imports. Thus, it was economically feasible to develop a particular pool of oil so long as costs were no higher than this price. Pools developed under this price umbrella were entitled to produce according to the formulae of the prorationing system. Aggressive price-cutting by refiner-buyers, as might have occurred in other circumstances, would have rendered the high-cost pools unprofitable. Re-allocation of output in favour of low-cost pools would not have constituted discrimination as the economist defines it, but it seems certain that it would have been at variance with the non-discriminatory thrust of the statute, which allowed for a "reasonable opportunity to produce." The regulatory regime not only eliminated competition among sellers but precluded buyers from selectively securing lower-cost crude oil by posting lower prices.

Crude oil price formation in the 1950s does appear to have evolved in a manner consistent with our oligopoly model, but the degree of buyer power was circumscribed within narrow bounds. The structure of prices at the end of the decade was similar to what would have been observed under a competitive pricing model: one price was quoted at Edmonton for a particular grade of crude oil regardless of its destination or place of origin. Had complete monopoly power been available and exploited, buyers in each market (not just the most distant one) would have been charged a price for Alberta crude oil that approached or matched the price from alternative sources. Had monopsony (or buyer) power been exploited, different prices would have been offered for different crude oils, depending on their cost of production. Both forms of discrimination were precluded by several factors – the fairness principle inherent in the prorationing system and associated regulation, the administrative complexity that would have been entailed, and probably also a sense of what was customary elsewhere in the petroleum industry.

While the structure of prices that evolved was consistent with what would have occurred under competitive markets, the level was not necessarily so. A downward trend in prices had taken place as a prerequisite to continued extension of the market area. However, the downward pressure on prices was never severe enough to force demand to be met from lowest-cost sources. Instead, excess productive capacity was always present. Price changes supported the objective of increasing industry output through orderly market expansion and were sustained by the way proration automatically adjusted supply. But the dynamics of price formation were both conditioned and restrained by the Alberta Oil and Gas Conservation Board.

Alberta's oil production and sales, as shown in Table 6.1, reflect the expansion of the market westward to Puget Sound and eastward to Sarnia in 1953 and Port Credit (near Toronto) in 1957. The capacity of the initial Interprovincial Pipe Line facilities was increased by the installation of various extra loops, pumping stations, and compressors. By the early 1970s, there were three large-diameter lines between Edmonton and Superior, Wisconsin, and two from there to Sarnia. The temporary surge in sales in 1956 and 1957 reflected, in part, increases in North American oil output to offset the international oil supply decrease associated with the Suez Crisis of 1956. Alberta oil output was largely supply driven from the start of construction of the major trunk pipelines in 1950 through to 1957, and demand driven subsequently, as sales were tied to demand growth in the markets adjacent to the pipeline.

As was discussed above, the tie to refinery demand was supported by the Alberta market-demand prorationing regulations. The significance of demand constraints can be illustrated in several ways. For example, the ratio of remaining oil reserves to annual production rose from about 18 in 1956 to 22 in 1960, suggesting relatively low, and declining, utilization of available reserves. Furthermore, after 1953, the growth of output was exceeded by the growth of production capability. After being restored to over 70 percent from its 1950 low of under 45 percent, capacity utilization fell steadily so that by 1957 only about half of Alberta's potential was being utilized (Bradley and Watkins, 1982, p. 70).

The situation for the Canadian industry by the late 1950s was graver than the low and sagging capacity utilization indicated. The U.S. oil industry was lobbying vigorously for more effective protection from imports. With voluntary limitation proving inadequate, the United States was moving toward mandatory controls. Canadian producers were concerned that they might be prevented from expanding exports into the mid-continent of the United States. Exports to the West Coast appeared to be restricted to the Puget Sound area already connected by pipeline. If the oil had to be transhipped by tanker to the California market, it could no longer compete with overseas crude oil.

The decline in international oil prices that began in 1957 served to heighten the oil industry's concerns. The Canadian industry was in trouble, and it turned to the federal government for help.

C. The National Oil Policy and Covert Controls: 1961–73

1. The Borden Commission

In October 1957 a Royal Commission, chaired by Henry Borden, was appointed by the federal government to look into such questions as energy export controls, the regulation of pipelines, and the functions that might be assigned to an administrative agency to be known as the National Energy Board. The Commission did indeed investigate these various issues, but the specific question that dominated its deliberations was how best to nurse the ailing crude oil industry back to health. Chapter Nine elaborates on these issues, but an outline will be given here.

Submissions to the Royal Commission addressing the problems of the crude oil industry all endorsed the need to find markets for more Canadian crude oil. The most widely discussed means was to supply Canadian crude oil by pipeline to Montreal refineries. The Montreal pipeline proposal was championed by the independent oil producers, but it was strongly opposed by the Montreal refiners, who were at that time being supplied by cheaper offshore crude oil, principally from Venezuela. The refineries included major oil companies that were important producers in Alberta (Imperial, Shell, McColl-Frontenac [Texaco], and British American [Gulf], as well as Petrofina [which had a little western Canadian output] and British Petroleum [BP, which shortly afterward acquired Triad Oil with Alberta crude production]). The majors and BP were also affiliated with the international majors which held Middle Eastern and Venezuelan oil concessions.

Companies which refined in Montreal made submissions to the Borden Commission setting out the difficulties with an oil pipeline extension to Montreal. For Canadian crude oil coming east as far as Toronto, to remain competitive with United States crude oil involved meeting price in a market where the price level was relatively high. But bringing Canadian crude oil into Montreal meant meeting world competition, implying western producers faced an immediate price cut, with the risk of more to follow. Furthermore, past pipeline expansion had involved guarantees by users to maintain agreed-upon levels of throughput. As long as they had access to alternative supplies from overseas, the Montreal refiners were certainly not prepared to offer guarantees of this sort. Based on market conditions in April 1958, W.J. Levy estimated Canadian crude oil would have been delivered in Montreal at a price disadvantage of about 12 cents per barrel compared with oil from Venezuela. Canadian producers would have had to reduce the price on all the crude oil they sold by 12 cents in order to meet the overseas price (Levy, 1958, pp. II-18, 18A). This would have greatly diminished the marginal value of the extra sales to them. The continuing decline in international oil prices in the late 1950s only exacerbated this difficulty.

It was evident to Levy and to others that, before Montreal refiners would accept Canadian crude oil, either a method would have to be devised to offer special prices in that market or the government would have to erect some kind of barrier to offshore imports. Levy recognized “the possible commercial preference of refiners in the area (Montreal) for foreign crude oil, even should Canadian crude oil be available at competitive prices.” He explained:

> Access to the foreign production of international companies with which Montreal refineries are affiliated offers opportunities of profit that Canadian crude cannot match. So long as this is the case for the area as a whole, no individual company could reasonably afford to switch to Canadian crudes no matter what other considerations it may wish to defer to. (Levy, 1958, p. III-19)

To meet this problem, proposals were advanced to establish pricing procedures that cross-subsidized Canadian crude oil going to Montreal at the expense of crude oil delivered elsewhere. One approach was to have refiners post delivered prices (including costs, insurance, and freight) at all refinery centres, prices that would reflect the delivered cost of competitive crude oil. This discrimination by destination would have been at variance with the Alberta regulatory system and would have created a complex administrative problem of dividing the proceeds from different markets of varying profitability. Another suggested form of cross-subsidization was through the pipeline tariff structure, which would have been amended in order to load charges onto short-haul crude oil so as to reduce the Edmonton-Montreal tariff.

When these types of special treatment found little support, attention turned to protection – in particular the imposition of tariffs or import quotas. Imperial Oil suggested an alternative to penetration of the Montreal market, as an intermediate strategy. It contained two lines of action, the first of which was to secure the entire Ontario market for Canadian crude oil. Although the volume of foreign crude oil refined in Ontario at this time was small, a substantial volume of oil products was imported, either from abroad or from Montreal refineries. It was suggested that these imports should be supplanted with oil products refined from Canadian crude oil. The second part of Imperial's proposal was to expand crude oil exports to the United States. In the longer term, Imperial expected that the United States would rely much more heavily on imports and that Canada would be a natural supplier to northern and western regional markets. It was important, therefore, to negotiate favourable treatment of Canadian exports by the United States. To alleviate the immediate problems of the Canadian producing industry, an effort to saturate the United States Puget Sound market was suggested – an effort parallel to that proposed for Ontario.

In July 1959, the Borden Commission published its *Second Report*, which dealt entirely with the problems of the Canadian oil industry. In essence, the Commission followed the suggestions of the major oil companies, at least as a near-term strategy. It recommended the oil industry take "vigorous and imaginative action … to enlarge its markets in the United States" and "displace, with products refined from Canadian crude, … products now moving into the Ontario market from the Montreal refinery area." A Montreal pipeline was to be held in abeyance, pending the opportunity given "to the oil industry to demonstrate it can find markets elsewhere in Canada and the United States." But the Commission recommended that import licensing be imposed if markets for Canadian oil did not expand (Borden, 1959, pp. 6–32, 33). In effect, then, the Commission told the integrated majors with refineries in Montreal to expand markets for Canadian oil in Ontario and to increase exports of Canadian oil to the United States or face displacement of foreign oil in the Montreal market by Canadian crude oil.

2. The National Oil Policy (NOP)

In 1961 the government adopted the recommendations of the *Second Report* of the Borden Commission with little alteration. The measures selected to secure designated markets for Canadian oil became known collectively as the National Oil Policy (NOP). Target levels of production were set at 640,000 barrels per day in 1961 rising to 800,000 barrels per day by 1963. The latter figure was expected to approximate levels that would have been achieved with a Montreal pipeline. A production goal of 850,000 barrels per day was set for 1964, but no targets were specified thereafter. The targets were to be reached by substituting Canadian crude oil for both foreign crude oil refined in Ontario and imports of oil products from Quebec or offshore to Ontario, and by additional exports to markets served by established pipelines. The National Energy Board (NEB) was to exercise surveillance over progress of the program. Subsequently, the United States indicated the acceptability of the general levels of exports contemplated under the NOP. In this way the policy was 'continental' rather than nationalistic. It relied on a voluntary (covert) mechanism, but regulation loomed if the voluntary program was not effective.

U.S. acceptance of the export provisions of the NOP were important because that country was also adopting measures to protect output of the domestic oil industry in the face of increasing international competition (falling world oil prices). In March 1959, the United States had adopted an oil import quota program that limited the volumes of foreign oil allowed into the country. (See, for example, U.S. Cabinet Task Force on Oil Import Control, 1970; Adelman, 1964; Shaffer, 1968; Watkins, 1987a; Bradley and Watkins, 1982.) Initially, Canadian oil was treated like any other oil import, but on April 30, 1959, Canadian and Mexican oil, shipped overland to the United States, were exempt from mandatory quotas, though their utilization did involve a slight penalty on the U.S. refinery purchasing Canadian crude oil. From 1959 through 1972, increased volumes of Canadian exports to the United States were accepted by the U.S. government, but the U.S. market was never completely and unrestrictedly open to Canadian oil; a number of formal and informal controls were imposed.

The NOP essentially divided the Canadian market into two parts, along the Ottawa River Valley (ORV). Markets to the west were to utilize Canadian oil only. Markets east of the ORV (the Maritimes, Quebec, and several eastern Ontario counties) would continue to utilize imported oil, attainable at prices below those prevailing in the United States and in Canada west of the ORV.

3. Alberta Crude Oil Prices under the NOP

As Table 6.2 shows, Alberta oil prices rose by 10 cents per barrel in 1961, and again in 1962 and were then fixed (at $2.62/b for Redwater crude oil) until late 1970. Why were crude oil prices so rigid?

Given the United States Oil Import Quota Program and the way in which it dealt with Canadian oil, the price of Alberta oil would, of necessity, be located between an upper limit set by the United

States domestic price and a lower limit set by the landed price of Middle East or African crude oil in the United States. During this period, crude oil import prices were falling, while United States prices rose markedly in the latter half of the decade. It is somewhat difficult to determine U.S. oil import prices precisely, since international sales generally took place at a discount to posted prices and transport rates are variable over time and between different buyers. However, by way of illustration, Newton (1969) estimated the price of Saudi Arabia 34° API crude oil, delivered to the north east coast of the United States, at US$3.07/b in 1956, $2.48 in 1959, $2.08 in 1963, and $1.78 in 1968. (At the fixed exchange rate of the 1960s of US$0.925 per Canadian dollar, the latter two prices would be CDN$2.25 in 1963 and CDN$1.92 in 1968.)

The posted price of U.S. mid-continent 36° API crude oil was US$2.97/b from 1959 through 1963, fell slightly (US$2.92/b in 1965), then rose up to US$3.23/b by 1969 (Bradley and Watkins, 1982, p. 117). It will be noted that the gap between U.S. and import crude oil prices widened considerably over the decade, so that the effective protection to the U.S. domestic crude oil industry due to the oil import quota program was around $1.50/b (Adelman, 1964, 1972) by the end of the 1960s. (At an exchange rate of US$0.925 per Canadian dollar, the per barrel mid-continent crude oil price would be CDN$3.21 in 1963 and CDN$3.49 in 1969.)

It can be seen that a Canadian price of $2.62/barrel lies between the upper limit of U.S. domestic prices and the lower limit of U.S. offshore oil import costs. Precise comparisons would involve the inclusion of actual or hypothetical transportation costs to a watershed market such as Chicago for all three types of crude oil, as well as the requisite quality adjustments. In any event, in the 1960s there was, it would appear, scope for either upward or downward movements in Canadian crude oil prices. Neither occurred. Why?

Consider first possible upward movements. One consideration was the exchange rate. As previously noted, the Canadian dollar was pegged at 92.5 cents United States during the 1960s, so adjustments to Canadian prices were not required for this reason. With United States prices creeping up, and with Canadian pipeline tariffs falling, there would seem to have been room for a modest upward movement in Canadian crude oil prices in the United States without a marked impact on market penetration. (The Interprovincial Pipe Line tariff from Edmonton to Superior, Wisconsin, fell from $0.465 per barrel in 1954 to $0.363 in 1964 (Lawrey and Watkins, 1982, p. C-6).) A comprehensive time series on delivered costs of oil in U.S. markets is not available, but data for the Detroit area, for example, show a trend of widening differentials in delivered prices of Alberta and United States crude oils in U.S. markets in the 1960s, from 20 cents per barrel in 1961 to 62 cents per barrel in 1969 (Bradley and Watkins, 1982, p. 128). At the same time, the attraction of Canadian oil to U.S. refineries under the Oil Import Quota Program decreased somewhat, implying a rising penalty to the use of Canadian oil instead of domestic U.S. oil. (For reasons discussed in Chapter Nine, the use of oil imported from Canada reduced U.S. refiners' claims on cheap foreign oil; the lower the foreign oil price, the greater the penalty for buying Canadian instead of domestic U.S. oil.)

The rising penalty may help explain the reluctance of the price-leader (Imperial Oil) to offer higher posted prices for Canadian oil. But a more compelling explanation may lie in the increased political tensions that higher prices would probably have created. In particular, higher Alberta oil prices would have made even larger the growing disparity in prices in Canada east and west of the Ottawa River Valley, as eastern consumers used ever cheaper international oil. By holding the Alberta crude oil price fixed, instead of increasing it, Canadian consumers west of the ORV would be more accepting of the market division imposed by the NOP.

What about lower prices for Canadian crude oil? Certainly this would have reduced pricing tension between the unprotected and protected parts of the Canadian market. But it would have increased the attractiveness of Canadian oil in the U.S. market. The excess demand for Canadian oil which already existed was only held in check by intergovernmental agreements. Increasing the attraction of Canadian oil would have been provocative, leading in all likelihood to controls of a more formal nature, which in turn would have made the special treatment given to Canadian oil under the U.S. Oil Import Quota Program more obvious. In other words, a lower price for Canadian oil would have entailed the risk of further U.S. regulation of export volumes.

These conflicting factors within the framework of government policy appear sufficient to explain why inertia in Canadian oil prices made sense during the 1960s: Imperial Oil's adherence, as price-leader, to $2.62 per barrel at Edmonton may have seemed unrealistic, but it was also astute. Keeping Canadian crude oil prices where they were caused fewer problems than varying them up or down.

However, when international oil prices began to increase in 1971 under the stimulus of the Tehran-Tripoli agreements between OPEC members and the international oil companies, these restraints on Canadian oil prices were loosened. The Alberta price began to rise. But, by this time, the revolution in the world oil market was ringing the death knell for both the NOP and the U.S. Oil Import Quota Program.

4. Alberta Oil Output under the NOP

In the 1960s, Alberta's output was conditioned in large measure by government regulatory programs – the NOP, the U.S. Import Quota Program, various agreements between the U.S. and Canadian governments and Alberta market-demand prorationing. The NOP reserved markets west of the ORV exclusively for Canadian produced crude oil. So long as the price of oil remained fixed, demand would respond primarily to economic growth in this region. Canadian oil was priced attractively for U.S. refiners, but expanded sales into the United States were limited by U.S. unwillingness to increase imports from Canada too far (thereby offending domestic U.S. producers and other oil exporters such as Venezuela). A 1967 secret agreement between the two countries limited imports into the Chicago area when the Interprovincial Pipe Line facilities reached that market, and in March 1970 the United States imposed a ceiling on imports from Canada. Thus there were sharply increased exports of Canadian oil to the United States in the 1960s, stimulated by the output targets of the NOP, and the attractive pricing of Canadian oil, but the exports never became as large as they might have.

In small part, the demand for Canadian-produced oil was met from provinces other than Alberta (mainly Saskatchewan, especially for heavier crude oil). However, the large residual came from Alberta, as determined by the market-demand prorationing regulations. Prorationing kept over 50 per cent of Alberta's crude oil productive capacity inactive in every year from 1960 through 1969 and prevented the downward pressure on prices that the excess capacity might have been expected to generate. Of course, a large price fall would have been necessary to stimulate much of an increase in sales since: (i) the elasticity of demand for crude oil in established Canadian markets west of the ORV, especially in the short term, is relatively low; (ii) the Quebec market could only have been attracted with a major price decline, both to cover the incremental transportation cost beyond Toronto, and to meet the lower delivered price of Venezuelan and Middle Eastern crude oil; and (iii) the U.S. government, under pressure from U.S. producers, and competitive oil-producing areas such as Venezuela, simply would not have tolerated large incremental sales of Alberta oil.

In summary: after the 1950s, the pricing and production of Alberta oil came under increasing regulatory control, though largely of an indirect or voluntary nature (hence the use of the term "covert controls"). The 1950s had been influenced by the extension of Alberta's market into central Canadian markets, with prices adjusted so as to make the oil competitive. The period of the NOP from 1960 through the early 1970s saw regulations by Ottawa to define a protected Canadian market, and a restricted market extension into the United States under the watchful eye of the Washington regulators of the U.S. oil import quota program. The levels of prices possible were limited by these regulatory programs, and even more so by the political realities of the situation. Alberta's market-demand prorationing regulations were the mechanism that ensured that expanded output from Alberta did not upset the equilibrium that resulted.

D. Overt Controls: 1973–85

North American oil policy in the 1960s was protectionist: both Canada and the United States created a sheltered market for domestic crude oil producers, at prices higher than international levels. In the early 1970s, changing internal and external circumstances overtook these regulations.

In the United States, it became increasingly clear that reserve additions were insufficient to support the output levels that the U.S. Oil Import Quota Program was designed to allow. Initially *ad hoc* modifications were made to the program, and then, in April 1973, the United States abandoned it entirely. External changes had improved the political acceptability of this to domestic oil-producing interests, since the price of international oil had increased markedly in the wake of the Tehran-Tripoli Agreements of early 1971. In fact, as reviewed in Chapter Three, by mid-1973, international oil prices were beginning to lead U.S. prices upwards. Then, in the fourth quarter of 1973, international oil prices quadrupled, and U.S. authorities began to ponder the effects of domestic oil prices following international prices.

Canada's National Oil Policy cracked under these pressures. Initially, the changes were favourable to the domestic crude oil industry. Increasing demand for imported oil in the United States meant rising Canadian shipments. Table 6.1 shows sales of Alberta oil in Canada rising from about 47,000 m^3/d in 1960 to 81,300 in 1972 (a gain of 73%), while exports to the United States rose from 11,200 to 132,200 m^3/d (up 1,078%); by 1972 exports accounted for 62 per cent of Alberta's crude oil output. From 1967 to 1973, sales in U.S. markets east of Alberta climbed by over 400 per cent. As the United States opened to more Canadian oil, and as international prices began to rise, the U.S. market began to look like the 'watershed' that would determine Canadian prices. The link would be those marginal oil supplies to the United States with which Canadian oil was competing. The Canadian price-leader (Imperial Oil) increased the posted price for Redwater oil by 30 cents per barrel, to $2.92, in December 1970. Several other increases followed, up to $3.48/b by May 1973, when Canadian oil was priced competitively with U.S. domestic oil supplies delivered to Chicago.

The sharp rise in Alberta oil production in the late 1960s and early 1970s came just as the Alberta crude oil finding rate fell off as the last major oil play (the Keg River play in northwestern Alberta) began to die down. The ratio of conventional crude oil reserves to annual production (R/P ratio) fell from about 30 in 1966 to about 14 by 1973. Meanwhile the capacity utilization rate rose from about 50 per cent in the late 1960s to 85 per cent by 1973.

Changes this rapid are often perceived as revolutionary, and it is often felt that revolutionary change calls for revolutionary action. Ottawa may not have verbalized the situation in exactly this way, but in 1973 the NOP was completely overturned: the month of May saw export limits placed on crude oil shipments; September saw the imposition of a price freeze on crude oil, an export tax on oil, and announcement that Montreal would be connected to the Interprovincial Pipe Line; and in December Prime Minister Trudeau formally acknowledged the death of the NOP and the advent of an oil policy based on direct control of pricing and exports.

1. Price Controls

Table 6.2 outlines the changes in regulated oil prices over the period from the initial price freeze of September 1973 ($3.88/b) through to deregulation in 1985 ($29.50/b in July 1983 as the last regulated price, in this case for what is called "old oil"). These prices are for Alberta-produced crude oil. It is noteworthy that oil imports were also price regulated, in the sense that consumers of imported oil in eastern Canada paid a price equivalent to the price for Canadian-produced oil (delivered to Central Canadian markets), with the Canadian government paying the differential up to the import price on foreign-oil deliveries. Price controls on Canadian-produced crude oil led the government into an export tax so that U.S. consumers would not be subsidized by the Canadian program. The export tax would raise the price of Canadian oil to the level of the U.S. marginal supply source, i.e., imports from OPEC.

Chapter Nine provides detailed discussion of these oil control programs. At this point, it might simply be said that the policies tread a fine political line (for an energy abundant, developed nation) between the interests of energy consumers in lower prices and the interests of energy producers (and the provincial governments which owned oil and gas Crown land) in higher prices. International crude oil prices (for Saudi Arabia 34° crude oil in the Persian Gulf) rose from under $3.00/b in 1972 to $10.50 in 1974 to $36.00 by 1981; the market value of crude oil throughout the world followed right along. Federal government authorities in Ottawa argued that such rapid rises in oil prices might significantly disrupt Canadian macroeconomic performance, that they had startling implications for the federal-provincial Equalization Program, and that they were not based directly on either international or Canadian costs of supplying crude oil. Furthermore, there was no guarantee that OPEC control would be successful in maintaining price increases. Thus, for a variety of reasons, it was argued that it was reasonable for Canada to allow only moderate increases in the price of oil, so that consumers and the economy could adjust gradually. Needless to say, most oil-producing interests and many others (including a large number of economists) were not fully persuaded.

The precise regulatory mechanism controlling oil prices varied over the 1973–85 period. The initial price freeze was a unilateral act by Ottawa, tied both to the price explosion in oil markets and to the government's fall 1973 anti-inflation package. By 1975 Ottawa had passed legislation giving it the legal authority to set the price of any oil (or natural gas) moving interprovincially or leaving the country. However, in practice, beginning in 1974, oil prices were set by joint agreement among the federal and provincial governments, sometimes at ministerial conferences involving all the provinces and, on occasion, by negotiation between Ottawa and Alberta (sometimes with other oil-producing provinces represented).

The federal government's 1976 energy study, called *An Energy Strategy for Canada*, announced that Canadian oil prices would gradually be increased to international levels, but the doubling of world oil prices that began in 1978 left the regulated Canadian oil price further and further behind. In this environment, Ottawa and Alberta had great difficulty in reaching a new agreement on prices. This difficulty was complicated by the defeat of the Progressive Conservative minority government in the House of Commons in December 1979 and election of a majority Liberal government (which was bound by a campaign promise to maintain a "made-in-Canada" oil price). In August 1980, Alberta unilaterally raised the crude oil price by $2.00/b. The newly elected federal government responded with a budget in October 1980 that consisted in large part of a National Energy Program (NEP). Among its many provisions were schedules of anticipated crude oil prices, including proposed regulated prices for Canadian oil over the coming years. Alberta vigorously objected to such unilateral federal price controls and introduced output cutbacks in protest. Accommodation ensued, with a September 1, 1981 *Memorandum of Agreement* between Ottawa and Alberta (and similar agreements between Ottawa and each of B.C. and Saskatchewan). From this date, until deregulation in 1985, Canadian oil prices were once again set by joint intergovernmental agreement. The NEP itself is defined by a total of eight sets of documents over the five years from the initial October 1980 announcement.

The complexity of the institutional mechanisms for establishing controlled Canadian oil prices pales beside the intricacies of the prices themselves. For Alberta crude oil, the key regulations applied to wellhead prices, but not all oil was treated in the same way. Once oil was produced, export prices were subject to further regulation via the export tax, and various government levies entered into Canadian consumer prices. Moreover, since the price controls applied to reference crude oil ("Alberta light" – of average grade delivered to the Edmonton terminals of the main trunk pipelines), the issue of the quality differentials for different grades of crude oil was also relevant. Table 6.2 provides details of the changes in wellhead prices for Alberta crude oil. (We discuss the major price changes; the minor changes in the table represent adjustments due to changes in location/quality differentials or the exchange rate.)

a. Alberta Producer (Wellhead) Prices

Throughout the controlled-price period, there was continual tension between the wish to hold prices below world levels in order to benefit oil-consuming interests and the obvious disincentive effects on production of lower prices. At first glance, it may seem reasonable to suggest that domestic prices for an abundant (and critically important) natural resource should reflect domestic production costs. In practice, for a heterogeneous natural resource such as crude oil, where different natural deposits have quite different costs, the notion of the domestic production cost is hopelessly ambiguous. It can be noted that certain reserves were voluntarily brought into production at historic (e.g., pre-1973) prices, but production decline means that the volumes of oil forthcoming from these reserves will eventually begin to fall. Output therefore becomes increasingly dependent upon new reserve additions, and the incentive to undertake such additions is positively tied to the level of the oil price. Initial recognition of this came with respect to tar sands oil, which was obviously high cost, and was, in the late 1970s, allowed international prices.

Incentive pricing for conventional crude oil was introduced in October 1980 with the NEP and became increasingly complex. The October 1980 regulations defined a new category of conventional oil output labelled "tertiary" oil, which consisted of oil from new (and officially recognized) reserves additions and enhanced recovery techniques other than waterflooding. Tertiary oil would command a price of $30/b (as compared to the $16.75 price for other conventional oil, and the world price of about $38.00/b, netted back to Edmonton). At Alberta's insistence, the principle of higher prices for incremental supplies was broadened in the September 1981 *Memorandum*, to create a price category called NORP ("new oil reference price") which would apply to "new" oil from pools discovered after 1980, as well as oil from all new enhanced recovery projects other than waterfloods, and from the Cold Lake heavy oil deposits. (It went also to oil from the frontier "Canada Lands" and synthetic crude oil, including that from "experimental" projects.) Effective July 1, 1982, after the June 1982 NEP *Update*, the NORP was applied to all tertiary and experimental oil, and to output from wells that had been shut down for at least three years (so long as the provincial government also levied lower "new" oil royalties on these wells). In addition, a SOOP (supplemental old oil price) category was created, above the "old" oil price but below NORP for oil discovered between April 1974 and December 1980. Subsequently, a June 1983 amendment to the NEP moved SOOP up to NORP and added oil from infill wells in all pools. Watkins (1989) notes that by the last year of the NEP there were 10 classes of Alberta oil. Overall, about 60 per cent of Alberta's oil production was "old" oil and 40 per cent NORP oil of one class or another.

Table 6.3: Crude Oil Prices under Overt Controls, 1973–85 (Canadian $/b, at year end)

	World Oil (W_p)			*Old Oil*				*New Oil (NORP)*	
	Actual	*Oct. 1980 Forecast*	*Sept. 1981 Forecast*	*Conventional Oil 1973–80*	*Oct. 1980 NEP*	*Sept. 1981 Schedule*	*Oct. 1980 75%W_p*	*Sept. 1981 Tertiary*	*June 1982 Schedule*
1973	5.28	n/a	n/a	3.00*	n/a	n/a	n/a	n/a	n/a
1974	12.40	n/a	n/a	6.58*	n/a	n/a	n/a	n/a	n/a
1975	13.78	n/a	n/a	8.08*	n/a	n/a	n/a	n/a	n/a
1976	13.68	n/a	n/a	9.18*	n/a	n/a	n/a	n/a	n/a
1977	16.14	n/a	n/a	10.95*	n/a	n/a	n/a	n/a	n/a
1978	18.25	n/a	n/a	12.91*	n/a	n/a	n/a	n/a	n/a
1979	30.42	n/a	n/a	13.93*	n/a	n/a	n/a	n/a	n/a
1980	40.68	38.00	n/a	n/a	16.75*	n/a	n/a	n/a	n/a
1981	40.38	41.85	41.67	n/a	(18.75)	21.25*	30.29	30.00*	n/a
1982	40.63	45.80	47.69	n/a	(20.75)	25.75*	30.47	(33.05)	(49.22)
1983	37.39	49.85	56.25	n/a	(22.75)	(33.75)	28.04	(36.15)	(57.06)
1984	39.71	54.10	62.31	n/a	(27.25)	(41.75)	29.78	(39.35)	(63.48)
1985	n/a	58.55	69.10	n/a	(31.75)	(49.75)		(42.70)	(70.23)

Notes: n/a = not applicable.

Old oil shows 35° Redwater oil from 1973–79, and the 38° reference crude in the various agreements after 1979.

The October 1980 world oil price forecast is the projected synthetic crude price in the NEP, which was to be the lesser of the international price or the 1980 value of $38.00, increased by the Canadian Consumer Price Index. It therefore is a lower limit on the international oil price projections of the October 1980 NEP. (By 1989, the value had risen to $79.65/bbl.)

Tertiary oil entered the NORP category in the September 1981 *Memorandum of Agreement*. SOOP oil is not shown; it originated in the June 1982 Update and was to be priced at 75% of the world level, but in June 1983 was incorporated in oil subject to NORP.

Values with * are the actual prices received on Alberta oil, except that old oil exceeded the limit of 75% of the world price by July 1983 so received $29.75/bbl from that date up to June 1985. Values in parenthesis were prices specified in an agreement but which were superceded by another provision or agreement.

Only end-of-year values are shown, although scheduled prices under the various NEP agreements generally rose each six months.

The actual world oil price is based largely on the Official Government Selling Price for 34° Saudi Arabian Crude, f.o.b. Ras Tanura, shown in Chapter 3, and as reported in the *Petroleum Economist*. The SA price in U.S. dollars has been increased by $2.05/bbl to derive a Canadian oil price (for par crude) in U.S. dollars in Alberta; this takes the average excess of the WTI price over the SA price from 1987 to 1991 ($3.13/bbl as reported in the OPEC, 1991 *Annual Statistical Bulletin*), less the average excess of the WTI price over the Alberta par price in 1991 and 1992 ($1.08/bbl as reported in the Energy, Mines and Resources, *The Canadian Oil Market*). The resultant price for Alberta oil in U.S. dollars per barrel was then translated into Canadian dollars using the end-of-year exchange rate reported in IMF, *International Financial Statistics*.

The categorization process was obviously fluid and increasingly complex. The associated controlled prices were also complicated. This arose in part from the inherent contradictions of a "made-in-Canada" oil price. The phrase suggests a price reflective of Canadian demand and supply conditions, but, from the very beginning of the control period, the level of price was always established with reference to prevailing world prices. Thus, as noted above, the 1976 federal government plan, *An Energy Strategy for Canada*, envisioned a gradual adjustment of Canadian prices to world prices. The NEP exhibited an even more marked interdependence. The October 1980 budget included a projection of world oil prices through the future and set out a schedule of regulated Canadian prices that were lower than, but reflective of, the anticipated trend in international prices. Moreover, the authors of the NEP were well aware that no one could accurately forecast future world oil prices; in fact, the October 1980 projections were soon revealed as far too high. As a result, throughout the NEP period, controlled prices were often set as the lower of: (i) some specified price (presumably tied to forecast world oil prices) or (ii) some percentage of the actual world oil price.

Table 6.3 provides further detail on the various regulated prices. (It shows the price provisions at year end, so not all price changes are noted.) The prices are for the reference crude oil of the various agreements, which was 38° crude oil (instead of the 36° Redwater oil used in Table 6.2). The symbol n/a (not applicable) indicates that the particular category did not apply at that date (e.g., NEP price forecasts before 1981; NORP oil before 1981). A price in parenthesis is a controlled price under one regulation, which was superseded by another regulation. Where several prices might apply in different years, the actual regulated price is indicated by an asterisk (*). As can be seen, the failure of world oil prices to match the increases in the early NEP forecasts meant that by 1983 wellhead prices were established by world oil prices, rather than specified levels of controlled prices. For example, a decline in world prices in 1983 meant that the price level fixed under NORP now exceeded the world price, so the new oil price was the world price. Rather than reducing the old oil price in line with the fall in world prices, old oil was simply held at $29.75/b from July 1982 on.

The shift to actual world oil prices as the basis for calculating Canadian oil prices raised a practical problem of administration – what was the relevant world oil price? Under the NEP, world prices were calculated on the basis of the average price of imported oil landed in Montreal in the latest three months for which data were available. This meant that Canadian prices lagged about one quarter (three months) behind world prices (Helliwell et al., 1989, p. 46). From the start of 1984, world price estimates were based on current official government selling price (OGSP) for international crude oil, therefore eliminating the problem of the lag, but failing to allow for the increasing prevalence of spot sales at discounts from OGSP. As a result, the NORP was sometimes in excess of international values.

b. Alberta Producer Prices: Price Differentials

The issue of quality differentials became increasingly problematic as North America became more fully integrated with the international oil market. Until 1981 differentials for light and medium crude oil continued to be established on the same basis as had been introduced by Imperial Oil in 1947. The September 1981 *Memorandum* set up wider differentials for NORP oil and allowed the established differentials on old oil to increase as the old oil price rose (Helliwell et al., 1989, pp. 46–47). Schedule A of the *Memorandum of Agreement* established the NORP differentials at $0.22/b per API degree and $0.165/b per 0.1 per cent sulphur; old oil differentials were eventually to reach $0.15 per API degree and $0.101 per 0.1 per cent sulphur. The differentials were also supposed to be in line with those in the international market. This would prove to be a difficult task in tracking. OPEC members would be acutely aware of the appropriate differential so as to ensure they met output quotas (after 1982), and might, further, utilize price differentials to test out possible gains from cheating on the group agreement.

Effective at the start of 1984, each quality of crude oil in the NORP category was to be priced on the basis of the cost of equivalent quality crude oil delivered to Montreal (with the field to Montreal transportation costs then netted out). However, so long as OGSP rather than spot prices were used, and for grades of crude oil that were not actually shipped to Montreal, it was very difficult to ensure that the NORP was accurate. Thus the differential problem also contributed to NORP values in excess of international price levels as were observed in 1983 and 1984. As Watkins (1989, p. 117) notes, these pricing problems, plus difference in import compensation for crude oil and product imports, led some Montreal refiners to begin importing oil instead of purchasing Western Canadian oil.

c. Purchase Price for Alberta Oil: Domestic Sales

One might assume that refiners would buy oil from Alberta producers at the regulated prices. However, field price regulation covered only a part of the federal government's policy, and other aspects of the policy impacted on the refiners' purchase price. In essence, the government argued that refiners should pay an average or "blended" price for oil that covered the costs of all the various types of oil utilized in Canada, though the interpretation given to this requirement varied somewhat over the 1973–85 period. The initial move in this direction came in 1976, when a charge was imposed on all oil refined in Canada to provide the extra payment to Syncrude's synthetic tar sands oil, which received the world price. After 1980, there was an additional charge assessed on the refiners' cost of oil, the Canadian Ownership Special Charge designed to help cover the government's costs of establishing and expanding Petro-Canada. Prior to the NEP, the cost of subsidizing imported crude oil had been viewed as being offset to a significant extent by the export tax on oil sold to the United States. As crude oil exports fell sharply in the later 1970s, even with reduced imports due to the Montreal pipeline extension, the net cost to Ottawa grew, and pressures to include imports in a blended price became very strong.

The blended concept idea was embedded in the October 1980 NEP, which had refiners paying an amount equal to the average cost of oil to Canadian

Table 6.4: Canadian Crude Oil Exports and Export Taxes, 1973–85

	(Net) Exports (10^3 m^3/d)				Year-end Export Tax (\$/m^3)	
	Light and Medium[a]	Heavy	Total	Crude Oil Exchanges	Light and Medium Blend	Heavy[b]
1973[c]	n/a	n/a	149.4	n/a	2.52	2.52
1974	n/a	n/a	144.8	n/a	32.72	25.80
1975	n/a	n/a	112.4	n/a	28.32	23.28
1976	n/a	n/a	73.9	2.7	23.60	18.25
1977	34.6	8.6	43.2	8.7	32.41	21.71
1978	16.1	10.6	27.7	14.8	33.98	23.60
1979	6.9	18.1	25.0	19.7	119.65	107.00
1980	0	14.8	14.8	14.2	180.80	102.90
1981	0.8	15.0	15.8	10.8	165.05	108.70
1982	0.3	24.5	24.8	10.0	97.20	44.40
1983	11.0	31.8	42.8	4.9	43.75	16.25
1984	14.3	36.0	50.3	7.7	32.55	34.50
1985	33.4	41.9	75.3	4.0	36.30[d]	31.35[d]

Notes:
n/a: figures not available.
a Includes condensate and synthetic crude.
b Lloydminster blend; other grades of heavy oil faced other export taxes.
c 1973 exports are for March to December.
d May and June 1985.

Source: National Energy Board, *Annual Reports*; *National Energy Program*; NEP *Update*.

refineries, essentially the costs of old oil, imported oil at world prices, synthetic crude oil, tertiary crude oil, and after 1981 NORP oil, and after 1982 SOOP oil.

d. Purchase Price for Alberta Oil: Export Sales

After September 1973, foreign refiners purchasing Alberta oil were assessed an export tax designed to raise the cost of Canadian oil to that of other foreign suppliers to the U.S. market. Initially, the Chicago market was used as a basis for comparison, and all Canadian exports were assessed the same tax, one presumably based on the values of blended light oil in the Chicago market. The export tax in the 1970s rose or fell in line with changes in world oil prices and the regulated Canadian price, based largely on the analysis and recommendations of the National Energy Board (NEB). The tax began at $0.40/b in September 1973, and rose to $6.40/b by February 1974. By late 1980, as the NEP was introduced, the export tax hit $26.00/b, for light crude oil. The initial export tax, in 1973, had applied at the same level to all crude oil, but producers of heavy oil were soon complaining that the tax discriminated against their less-valued product and was harming sales to U.S. refiners. In November 1974, the NEB allowed a special, lower tax on heavy oil and continued as time progressed to set differential taxes for different grades of crude oil (Helliwell et al., 1989, p. 37). Here, as elsewhere in the regulated oil environment, it was apparent that more and more detailed fine-tuning of regulations was necessary if undesirable distortions of production and consumption were to be avoided. Table 6.4 includes more detail on the NEP crude oil export taxes.

Table 6.4 shows the level of the crude oil export tax at year's end over this period. (The 1985 value is for June, the last month in which an export tax was assessed.) Taxes are shown for two grades of oil: (i) light and medium blend (and condensate); and (ii) Lloydminster blend heavy crude oil. By June 1985, the NEB distinguished 13 different grades of oil, each with a different level of export tax subject to review each month. It can be seen that while the general trends in the tax for heavy and light oil are similar, there is no consistent relationship between the two. The taxes reflect the NEB's efforts to follow changing world crude oil quality differentials, as well as demand conditions for Canadian heavy oil in the specialized mid-continent U.S. refineries that bought such crude oil.

2. Production Under Overt Controls

The 1973 changes to Canadian oil policy essentially reversed the National Oil Policy of 1961. Instead of reserving the Montreal market for oil imports, the Interprovincial Pipe Line would be extended from Toronto to Montreal; rather than encouraging increased exports, the volume of exports would be limited through a licensing scheme to ensure they were not 'excessive.'

Table 6.1 shows the impact of these changes as exports fell off drastically (from about 160,000 m^3/d in 1973 to 31,000 m^3/d by 1978, down to the 1962 level). As the Montreal extension came on stream in 1976, Canadian use of Alberta oil rose, from 115,600 m^3/d in 1975 to 187,600 m^3/d by 1980. Other factors influenced oil sales as well. For example, exports to the U.S. west coast fell sharply in the mid-1970s, reflecting the contribution of North Slope Alaskan oil to the U.S. market – in the early 1980s U.S. authorities specified that Alaskan oil could not be sold outside the United States. Sales in domestic markets, and oil output, declined in response to declining oil consumption as a result of the sharply increased price of oil. (See Helliwell et al., 1989; Berndt and Greenberg, 1989.) In 1980 Ottawa imposed formal procedures for light and medium crude oil to ensure that available supplies were allocated 'fairly' to refiners in Montreal and Ontario; allocations were based largely on historic refinery runs (Ontario) and available capacity (Montreal).

Export controls, as introduced in March 1973, consisted of a licensing system administered by the NEB. Such licensing had been permissible under law ever since the act creating the NEB and had been applied to natural gas since the early 1960s (as Chapter Twelve details). Concern about oil exports was initially stimulated by complaints about crude oil availability by some Canadian refiners and deepened with the Arab oil embargo and output cutbacks of late 1973, during the Arab-Israeli war (Helliwell et al., 1989, pp. 39–40). The NEB was willing to issue export licences for 'surplus' crude oil; it argued that, especially with the Montreal pipeline extension, no obvious surplus existed so that exports should be eliminated. For light and medium oil, this is basically what happened in the later 1970s. However, heavy crude oil was not acceptable to most refineries unless it is passed through a special upgrader to be transformed into lighter oil. The mid-1970s saw significant excess production capacity for heavy crude oil, so the NEB was quite willing to allow its export.

Table 6.4 shows Canadian exports of crude oil from 1973 through 1985, with separate details for heavy and light crude oils after 1977. Net light oil exports virtually disappeared by 1980, while heavy oil exports were allowed to increase from 1977. Saskatchewan was a particularly important source for heavy oil. Light crude oil exports were allowed again in 1983. The table also includes a column for crude oil 'exchanges'; those included agreements in which crude oil (usually of light or medium gravity) was exported to the United States (generally the mid-continent region), and in turn equivalent volumes of U.S. oil were provided to eastern or central Canadian areas. Net exports exclude such exchanges.

3. Conclusion

Whatever the advantages of a "made-in-Canada" price for oil, the administrative complexities in such regulation were huge and failed to capture fully all the heterogeneities of crude oil markets. Moreover, as is discussed in Chapter Nine, the whole idea of fixing Canadian prices below world levels was coming under concentrated attack as the 1980s progressed. Certainly, even for proponents of such regulation, the process began to look increasingly trivial as world oil prices, instead of rising, become progressively weaker. A change in the federal government consolidated the forces for change.

E. Deregulated Markets: 1985–

On March 29, 1985, the recently elected federal Conservative government negotiated the Western Accord with the provincial governments of Alberta, B.C., and Saskatchewan. The Accord deregulated crude oil prices and eliminated a variety of federal taxes and grants, thereby eliminating the NEP. Starting June 1, 1985, Canadian oil prices would be free from both overt and covert controls for the first time since the 1961 NOP. Procedures to allocate light and medium oil supplies to central Canadian refiners were also dropped, as were quantity and price restrictions on exports of light and medium crude oil with shorter than a one-year contract (less than two years for heavy oil). The 1989 Free Trade Agreement (FTA) essentially codified much deregulation through formal

Canada-U.S. commitments to allow free movement of oil between the two countries, without discriminatory trade practices. (Chapter Nine discusses the FTA, and its successor, the North American Free Trade Agreement (NAFTA), in more detail.)

After the long period of government-administered pricing, oil companies found the need to market their oil a novel and, for some, chastening experience. The basic price-setting procedure that was established was familiar from the post-Leduc days, with the major refiners 'posting' the price they would pay at Edmonton for any oil offered to them. As the 1990s progressed, new market initiatives began to develop, such as specialized electronic clearing houses that enabled prospective buyers and sellers to establish quick contact.

If deregulation were effective and a 'workably' competitive market established, what kind of pricing behaviour might be observed?

First, the price of Alberta crude oil posted at Edmonton by refiners would be set within a narrow band at any one point in time. A significant spread in posted prices for oils of the same quality would suggest price discrimination, behaviour not sustainable in a competitive market.

Second, the level of posted prices would be closely related to 'netbacks' from the main market interfaces where Alberta crude oil competes with other supplies, namely (in 1985) Montreal and Chicago. Or to put it another way, the delivered price (laid-down cost) of Alberta oils in market regions where Alberta faces competition would correspond closely to the delivered prices from other sources. Since international prices are denominated in U.S. dollars, the price in Canada would also reflect changes in the exchange rate, rising as the Canadian dollar depreciates relative to the U.S. dollar and falling as the Canadian dollar appreciates.

Third, refiner postings would be sensitive to changes in world prices. If world prices were quite volatile, correspondingly frequent changes would be seen in posted prices.

To what extent do refinery postings in Alberta satisfy these tests? We look at the market in the late 1980s to assess this issue.

August 1989 postings at Edmonton by three major refineries – Esso, Shell, and Petro-Canada – were $21.61/b, $21.29/b, and $21.29/b, respectively, for 40° API gravity crude oil (0.5% sulphur). The spread in prices is minimal.

Estimated netbacks in July 1989, for international crude oil at Montreal and Chicago are shown in Table 6.5 (Watkins, 1989, p. 25). The upper panel develops the Edmonton netback for North Sea Brent oil delivered to Montreal; the lower panel develops Edmonton netbacks for West Texas Intermediate (WTI) oil delivered to Chicago (WTI is the most popular 'benchmark' crude oil in the United States). The spread in netbacks is about $1 per barrel, suggesting that Chicago (the nearer market) is a more attractive one for Alberta crude oil. More importantly, the actual light crude oil price prevailing was CDN$22.98/b, straddling the two netbacks. This confirms that Alberta oil was competitively priced with international crude oil.

Finally, over the period July 1988 to June 1989, one refiner – Shell – registered eleven changes in postings, precisely the kind of volatility expected in light of the frequent changes in world oil market conditions. Parallel changes were registered by other refiners.

Table 6.5: Alberta Netbacks from Foreign Crudes

Netback for Brent Crude from Montreal, July 20, 1989	*$/b*	
Representative Price (spot) Brent 38.0° API	18.25	(US$)
Plus Tanker Charge	0.81	(US$)
Plus Portland-Montreal Pipeline Tariff (includes terminaling charge)	0.96	(US$)
Laid Down Cost at Montreal	20.02	(US$)
Laid Down Cost at Montreal	23.80	(CDN$)
Less IPL Tariff to Edmonton	1.53	(CDN$)
Netback at Edmonton	22.27	(CDN$)
Quality Adjustment for 40° API	0.30	(CDN$)
Netback for 40° API, equivalent type crude	22.57	(CDN$)

Netback for WTI Crude from Chicago, July 20, 1989	*$/b*	
Representative Price (spot) West Texas Intermediate at Cushing, 40° API)	20.35	(US$
Plus Pipeline Tariff, Cushing to Chicago	0.39	(US$)
Laid Down Cost at Chicago	20.74	(US$)
Less IPL U.S. Tariff	0.46	(US$)
Border Price	20.28	(US$)
Border Price	24.11	(CDN$)
Less IPL Tariff to Edmonton	0.51	(CDN$)
Netback at Edmonton	23.60	(CDN$)
Quality Adjustment for 40° API	0.00	
Netback for 40° API, equivalent type crude	23.60	(CDN$)

(Based on Exchange Rate of $0.84 US/$1 Cdn.)

Source: Watkins (1989), p. 25.

Thus, all three competitive pricing criteria have been met: deregulation has been effective. A competitive market exists for the sale and purchase of Canadian crude oil, interfacing with the world oil market.

Formerly, the supply of Alberta crude oil was governed by prorationing. Prorationing reduces incentives for direct price competition. It remains on Alberta's legislative books. But, in large measure, deregulation induced changes in administration of the prorationing scheme that allowed producers to sell any shut-in oil on the spot market, although control for technical reasons is retained on maximum production rates. Before, strict quota control kept the prices of oil from a reservoir uniform. And by 1989, market-demand prorationing was consigned to history.

Of course, pipeline transportation remains federally regulated, but common carrier legislation provides for open access. However, the pricing mechanism has yet fully to intrude on the 'menu' of pipeline services offered.

Deregulation has also affected the disposition of Canadian production. With the removal of federal transportation subsidies, Atlantic refineries no longer used Canadian oil, and the share of refinery runs held by imports in Quebec began to rise, until the Sarnia–Montreal link of the Interprovincial Pipe Line was closed in 1991, and then reversed in October 1999 to allow imports into Ontario. At the same time, the share of Canadian output absorbed by more proximate (U.S. Midwest) export markets has tended to increase. This more efficient distribution of Canadian production is what would be expected if deregulation were effective.

The 1986 price collapse, when the spot price of Persian Gulf oil fell into single-digit figures, provoked proposals for re-regulation of prices (not the least from some in private industry), with calls for import tariffs, floor prices, income stabilization plans, and the like. Admittedly, most proposals stressed that assistance would be temporary. However, the federal government resisted the temptation to introduce price supports and confined itself to some tax relief and incentives.

In sum: deregulation has resulted in a more competitive market structure for the oil industry than at any time since the Leduc discovery of 1947.

Table 6.1 shows that Alberta conventional oil production rose from 1984 to 1988, but then fell, largely reflecting production decline in established reservoirs along with relatively small reserve additions. However, oil sands production continued to rise, offsetting declining conventional production and generating modest total production increases for Alberta oil production through the 1990s. Sales in Canadian markets east of Ontario fell off through to the early 2000s with deregulation and closure of the pipeline link to Montreal but have since risen again. Exports to the U.S. mid-continent region have risen sharply. The increased exports are based largely on expanding non-conventional oil production (synthetic crude oil and bitumen from the oil sands), as will be discussed in Chapter Seven. Closure of the Montreal pipeline link makes it clear that the competitive price watersheds for Alberta oil now lie in the Chicago and Toronto markets. Sales prices internationally, and for Canadian crude oil, have become increasingly volatile in the short term as a preponderance of sales have become tied directly or indirectly to spot markets for crude oil. Oil brokerage services have grown in importance, providing intermediaries between crude oil producers and refiners, and more oil companies are developing their own trading division to monitor and participate in spot markets and the futures and options markets for oil, which expanded rapidly in the 1990s.

Expectations of further increases in Alberta crude oil production have raised the issue of major market expansion for the first time since the 1960s. Expansion of existing facilities, into existing markets, had begun in the 1990s as crude oil output in Alberta rose somewhat. However, with larger output increases, driven by the oil sands, the most obvious routes would be to press further into the U.S. market, effectively driving out more offshore imports. As of March 2013, TransCanada was still awaiting approval of its Keystone XL line which would carry additional Alberta bitumen through Cushing, Oklahoma to the Texas Gulf. The northern portion of this line was denied U.S. regulatory approval in 2012; a modified route is now under consideration. TransCanada has announced plans to proceed independently with the Oklahoma to Texas portion. The possibility of increased sales of Alberta oil in central Canada has attracted attention, as Enbridge is applying to re-reverse the Sarnia–Montreal pipeline so Alberta oil can once again access the Quebec market. Attention has also turned to the possibility of significant sales in east Asian markets, especially China and Japan. At the time of writing in the Spring of 2013, Enbridge is pushing forward with plans for a new oil pipeline (called the Northern Gateway) from near Edmonton to Kitimat on the B.C. coast; a parallel line would carry condensate eastward from Kitimat, which could be blended with bitumen to allow its movement back to Kitimat. In addition, Kinder Morgan has expressed interest in expanding its pipeline from Edmonton to Vancouver, which would enable additional exports to the U.S. west coast and to Asia. Given the longer distance to Asian markets, it is not clear Canadian oil could be as competitive with Middle Eastern oil there as it is in North America. However, the project sponsors seem to feel either that buyers in Asia (most likely Chinese) will be willing to pay a premium for Alberta oil (especially if it is produced from the oil sands by the Chinese companies establishing a presence there) or that the international price differentials between light and heavy oils will be such as to establish a demand for Canadian bitumen in Asia. (The markets for Canadian oil and the transmission alternatives are discussed in NEB, 2006, chaps. 4 and 5.) Another possibility is that North American crude oil production will increase sufficiently to allow exports of oil from the Texas Gulf Coast, but that the U.S. government will prohibit such exports, restraining prices in the United States. In this case, Alberta oil producers would find the Asian export market more attractive than the United States.

Table 6.2 shows that Canadian oil prices increased dramatically after 1999, following international oil prices; the rise was somewhat less pronounced than in the United States, since the Canadian dollar appreciated significantly beginning in 2003. Canadian prices followed world oil prices, up to a peak in mid-2008 (the maximum monthly price was $138/b in July 2008 for the Canadian par price at Edmonton), then collapsing (to $32/b in December 2008). The Alberta crude oil price rose after that, and has fluctuated in line with world crude oil prices.

However, as Figure 6.1 showed, the usual small price differential between Alberta and North Sea light crudes oil rose dramatically, particularly after 2010, and persisted through final editing of this book, in spring 2013. This reflected a combination of increased oil production in central North America (including in Alberta, but also in regions such as Texas and North Dakota) and pipeline constraints in moving this oil to the most profitable markets. As a result, the crude oil market centred on Cushing, Oklahoma exhibited a supply excess with downward pressure on the price of WTI (West Texas Intermediate) and such linked oils as that from Alberta. (Chapter 1 of the ERCB 2012 *Reserves Report*, ST-98, offers a discussion of this issue.) Presumably this unusual price discount for Alberta oil reflects a temporary (short-run) disequilibrium in the crude oil market while modifications in the transmission system are made to allow the increased crude oil supplies access to the broader world market. The modifications are of two types, both under consideration in 2013. The first is new pipeline capacity, such as the Keystone XL, Northern Gateway, and Kinder Morgan projects mentioned above. The second is the reversal of pipelines which allow imports of oil into central North America, turning them into export lines; we mentioned the proposed reversal of Enbridge's Sarnia–Montreal line, and several companies are planning reversals of pipelines currently carrying oil from the U.S. Gulf Coast to Cushing, Oklahoma.

It is interesting to note that no significant price differentials between Alberta and world oil were apparent in the first period of rapid expansion of Alberta oil production following the Leduc find of 1947, when producibility of Alberta oil exceeded the pipeline capacity to carry it to market. At that time, prorationing regulations restricted production to levels the available market would absorb, so the potential excess supply could not push prices lower. Since the late 1980s this government output control mechanism has no longer been in operation, so, after 2010, WTI and Alberta prices were free to fall (relative to the world price) as local supplies increased.

Alberta oil prices will continue to be determined primarily by international crude oil prices, which reflect the output decisions of OPEC, but with significant day-to-day variability as stockpiles, weather conditions, political events, and changing expectations impact on the spot market.

4. Crude Oil Market Structure

For much of the historical period, as we have seen, the price and output of Alberta crude oil have been strongly influenced by government regulations, both provincial (e.g., market-demand prorationing) and federal (e.g., the NOP and the NEP). However, industry behaviour also reflects the structure of the petroleum industry, in particular the degree to which the industry is or is not free of large, concentrated, monopoly-like firms, an issue that has been touched on already. Government regulations have had the most pronounced impact, so much so that we have argued that understanding the economics of the industry is an exercise in 'petropolitics.' During those periods that allowed market price flexibility, oil did not exhibit such clearly oligopolistic behaviour as geographic price discrimination. This concluding section of Chapter Six will discuss, briefly, two structural issues that have attracted much critical attention. The first is whether the private market structure is so concentrated as to make monopolistic behaviour likely. The second is whether the presence of foreign capital in the industry has significantly affected behaviour.

A. Competition in the Alberta Oil Industry

It is widely recognized that real-world markets rarely meet all the conditions of the economists' model of perfect competition (i.e., many small buyers and sellers trading units of a perfectly homogeneous commodity in a market with free entry and exit and with instantaneous, perfect, and costless information flows). The question, rather, is how 'effective' or 'workable' the competition is. Does the real-world market come close to approximating the perfectly competitive outcome? This is not easily determined, if only because a number of key determinants of perfectly competitive prices are typically not observable (for example, individual buyer's utility or preference functions, and individual seller's expectations about the future). The Canadian petroleum industry has frequently been accused of harmful 'monopolistic' (more properly, oligopolistic) actions. For examples, see Laxer (1970, 1974, 1983). Our discussion earlier in this chapter relied on an oligopoly-oligopsony view of the market in the 1950s but noted that there were external upper and lower bounds on the price that the industry might set.

The most detailed examination is undoubtedly the 1981 study of the Canadian petroleum industry by the Director of Investigation and Research of the (federal) *Combines Investigation Act* (Bertrand, 1981). Vol. iv of the *Bertrand Report* considered the Canadian crude petroleum industry in detail, finding that (pp. 211–14):

> [W]hile production was not highly concentrated, the disposition of crude production was controlled by a small number of firms.
>
> … The high level of concentration in 'controlled' crude discouraged the entry of other companies who wished to purchase crude oil.…
>
> The monopoly situation which was produced by the control possessed by the leading firms was exploited in several different ways. First, it was used to establish a crude pricing formula which resulted in prices that were higher than they would otherwise have been. In addition complementary devices were used to maintain the prices of other hydrocarbons such as condensate and heavy crude and to prevent the price structure for light crude from deteriorating.…
>
> … The major firms which possessed control were able to wielded [sic] their power in such a way as to entrench their market position downstream from production.…
>
> This practice lessened competition from small and large competitors who lacked crude control.

We will not report in detail on the Bertrand analysis, in part because the follow-up federal government study by the Restrictive Trade Practices Commission (RTPC) concluded that in its view "the Director failed to establish his allegations against the producing companies" (Canada, RTPC, 1986, p. 140). The RTPC (p. 132) did note:

> [T]here is little doubt that, as the Director has argued, the Alberta Government's prorationing scheme and the Federal Government's National Oil Policy had the effect of raising the price of domestic crude oils and hence petroleum products, for many Canadian consumers. On the other hand, there is no doubt that both programs produced many benefits as well.

This ascribes the higher prices to the government policies, not monopolistic behaviour. At a more pragmatic level, the RTPC pointed out (in 1986) that Canadian crude oil prices had been set by governments since 1973, so detailed investigation of crude oil pricing was not warranted.

However, despite the lack of evidence in support of the hypothesis that the oil industry has exercised market power over crude oil prices, there has been significant interest in the structure of the Canadian petroleum industry. Attention has focused largely on two issues – the degree of concentration of production and the level of foreign ownership in the industry.

B. Structure of the Canadian Crude Oil Industry

1. Concentration

Crude Oil. The lower the concentration of output, the less likely the exercise of monopolistic behaviour by producers. Further, if entry and exit into the industry were relatively easy, it would be difficult to maintain

Table 6.6: Concentration in Canadian Crude Oil Output (8 Largest Producers)

	Percentage Shares of Output					
	1957	1970	1980	1990	2000	2009
Imperial (Esso)	19.2	13.4	12.9	17.5	13.0	6.4
British American (Gulf)	7.1	7.3	8.0	3.9	3.8	
Texaco	6.9	8.9	8.6			
Mobil	4.6	7.6	5.8	4.1		
California Standard (Chevron)	4.5	5.0	5.6	4.1	3.7	
Hudson's Bay Oil and Gas	4.5	4.8				
Shell Canada	2.3	5.4				4.5
Pan American (Amoco)	1.9	4.5	5.1	6.5		
PetroCanada			4.1	7.0	3.8	
Dome			4.1			
Pan Canadian[c]				4.8	5.5	
Suncor Energy				3.2	5.9	9.9
Canadian Natural Resources					7.7	10.9
Husky Energy					5.8	6.4
Alberta Energy Co.[c]						3.7
Encana[c]						9.7
ConocoPhillips						6.3
Devon						4.5
	Concentration Ratios					
4-Firm	37.8%	37.2%	35.3%	35.8%	32.4%	36.9%
8-Firm	51.0%	56.9%	54.2%	51.1%	49.2%	58.6%
HHI	566[a]	528[b]	507[b]	516[b]	432[b]	524[b]

a It was assumed that the next 13 largest firms all produced 1.5% of industry output and that all the other firms in the industry were too small to add anything to the HHI. Once the production share is less than one, each extra firm adds a minimal amount to the HHI.

b Based on the top 20 producers. (The 20th largest in 1970 and 1980 produced 1.3% of output; in 1990, the 20th largest produced 0.8% of output, in 2000, it produced 0.9% of output, and, in 2009, 1.1%.)

c PanCanadian and AEC merged in 2002 to form Encana. In 2009, Encana separated into Conovus (oil operations) and Encana (focusing on natural gas).

Sources: *Oilweek*, May 15, 1972, p. 24; June 15, 1981, p. 42; June 17, 1991, pp. 22–25; July 2, 2001, p. 32. The 2009 data was provided by Dale Lunan of *Oilweek* and appears in a July 2010 issue.

high monopolistic prices for any great length of time. Significant entry and exit would imply that the relative size of firms changes over time, rather than remaining stagnant. Specific corporate information on Alberta oil production is not readily available, but data for Canada is (and, recall, Alberta provides a large majority of Canadian crude oil). Table 6.6 provides data on corporate production of Canadian crude oil, for select years: it shows the eight largest crude oil producers for the year 1957 and similar values for 1970, 1980, 1990, 2000, and 2009 as drawn from *Oilweek* magazine's annual tabulation.

The level of concentration is measured in two ways. Four (eight) firm concentration ratios give the percentage of total oil output from the largest four (eight) producers. It is, of course, hard to interpret such numbers. One prominent expert in industrial organization suggested (Bain, 1968, p. 464) that "[T]entative indications are that if seller concentration exceeds that in which the largest eight sellers supply from two-thirds to three-fourths of the output of an industry … there is a strong disposition toward significant monopolistic price-raising and excess profits." By this criterion, Canadian crude oil production is relatively unconcentrated. The rising concentration ratios for 2009 reflect the growing importance of the large oil sands mining operations.

The second measure of concentration is the HHI (the Hirschman-Herfindahl Index), which is the sum of the squared output shares (percentages) of all firms in the industry. A monopoly would show a value of 10,000 (i.e., 100^2), while a very unconcentrated industry would have small value (e.g., if 100 equal-sized firms made up the industry, the value would be 100 – i.e., 100×1^2, while 1,000 equal-sized firms would have an HHI of 10). The HHI is harder to calculate than the concentration ratio, since the output of all firms in the industry must be known; in practice, firms that produce less than 1 per cent of the industry's output add very little to the HHI. Once again, no precise interpretation can be attached to particular values of the HHI. The most prominent use of the HHI has been since 1982 in the *Merger Guidelines* of the U.S. Department of Justice. The precise criteria of the Department are quite complex, but mergers would clearly be challenged if the industry HHI were above 1,800, and would not be if it were less than 1,000. Once again, by this standard, the Canadian crude oil production industry appears quite unconcentrated.

However, as many observers have noted, the degree of output concentration may not be the only, or the most, relevant measure in a vertically integrated industry. Bertrand's report, for instance, emphasized the role of the major oil producers, especially Imperial Oil, as builders and equity shareholders in the major pipelines (especially Interprovincial Pipe Line).

Pipelines. By the late 1940s, as discussed above, Imperial Oil had begun initial plans to construct an oil pipeline east of Edmonton. In April 1949, a special act of Parliament incorporated Interprovincial Pipe Line (IPL), and Imperial was the first subscriber for shares, with a 50 per cent equity holding by 1950 (Bradley and Watkins, 1982, pp. 105–6). Imperial also guaranteed minimum shipment volumes and agreed to make up debt repayments if IPL were in default. Trans Mountain Pipeline was incorporated in 1951, also with major oil companies as majority shareholders and guarantors of debt. These two main (trunk) lines were connected to Alberta oil pools by a system of local gathering pipelines linked to a number of main feeder lines running to Edmonton; these local pipelines were usually owned and built by the first oil companies to generate significant discoveries in that part of the province.

The key question of concern is whether the relatively concentrated control of essential pipeline links by the major oil companies was utilized to their competitive advantage. This might have happened in a number of ways including:

(i) excessively high pipeline tariffs;
(ii) denying access to facilities to crude oil from competing oil producers;
(iii) restricting total facility throughout to keep oil prices artificially high.

Bertrand (1981, vol. iv) discusses these and other possible practices, but most observers have not found the evidence convincing (e.g., Lawrey and Watkins, 1982; Restrictive Trade Practices Commission, 1985). Why not?

(i) The effective controls on Alberta crude oil production were the government prorationing regulations, and these were designed to ensure a 'fair' allocation to all companies. (The situation was somewhat different for heavy crude oil, which came from Saskatchewan to a large degree and was not subject to market-demand prorationing in Alberta.)
(ii) The pipelines, certainly the two trunk lines, seem to have operated essentially as 'common carriers' and there are few recorded complaints from non-owner producers. (A common carrier pipeline is one which is open to all potential users on an equal basis; it does not discriminate in favour of its owners by offering them preferred access or lower tariffs.)
(iii) The 1959 *National Energy Board Act* gave the NEB the authority to regulate tariffs of the trunk lines. While this power was not exercised until 1977, it was potentially available, and rates did have to be filed with the NEB. The sections of IPL and Trans Mountain which were in the United States were rate regulated by the U.S. government. Regulations, and the threat of regulations, will inhibit excessive tariffs.
(iv) Lawrey and Watkins (1982) find the IPL and Trans Mountain tariffs before NEB regulation in 1977 to be somewhat higher (12–16% greater) than they would have been under the NEB rules. However, they note that the tariffs seem to be consistent with the rate procedures established by the U.S. Interstate Commerce Commission and suggest that a higher risk premium may have been called for in the earlier years of operation of the pipelines.

On balance, then, there is little evidence that the major oil companies' control of pipeline facilities was used to generate significant excess profits.

Refiners. One might suppose that oil refiners are interested in the highest possible price for refined petroleum products (RPPs) and the lowest possible price for the crude oil they purchase. As discussed in Chapter One, there are economies of scale in refining – by the 1960s an efficient refinery producing the light-end slate of products typical in North America would need a capacity of 100,000 barrels per day or more. However, this is a relatively small share of the RPP market in highly populated parts of the continent. Moreover, a refiner charging high prices would have to worry not only about new competitive refineries in its market area but also about imported products from other areas. Therefore, some observers have suggested that an oligopolistic refining industry, consisting mainly of vertically integrated companies, might prefer to pay high prices for crude oil. This would generate high profits for their crude oil affiliates, necessitate high prices for refined products, but not offer an incentive to new refining companies to enter the market. The strategy makes particular sense for a company that produces a large amount of crude oil relative to its total refining operations and is especially attractive if income tax laws favour crude oil profits over refining and marketing profits. (The latter was generally true, at least up to 1980, as Chapter Eleven discusses.)

There is no doubt that the purchases of Alberta crude oil exhibit higher concentration than do sales. Table 6.7 shows the nominations for Alberta crude oil for the month of August (a seasonally high demand month) for a number of years from 1955 through 1986. Nominations are the volume that buyers (usually refiners) indicate to the ERCB that they plan to purchase and serve as the basis for market-demand prorationing allocations. All buyers who asked for one percent or more of total Alberta nominations (in any of the indicated months) are shown in Table 6.8, as well as the number of smaller buyers. In total, buyers ranged in number from 6 (in 1955) to 31 (in 1976). It will be recalled that producers of crude oil in Alberta number in the hundreds. The concentration ratios and the HHI are higher than on the seller side, and particularly high for 1956. It can be seen that the lowest concentration occurred in those years (1971 and 1986) when access was open to U.S. markets and in 1976 before the U.S. market was severely restricted and when the Montreal link of Interprovincial Pipe Line was open. Note that the year 1986, with deregulation of North American energy markets, saw the emergence of several crude oil purchasers who were not refiners (e.g., the Alberta Petroleum Marketing Commission [APMC] and Northridge Petroleum) but operated as crude oil-marketing middlemen.

However, claims that refiner-buyers were able to generate artificially high prices for Alberta crude oil must remain suspect. Output control came, not from the refiners themselves, but from the Alberta government market-demand prorationing scheme. For the years 1973 through 1985, governments also set the oil price. Up to the National Oil Policy of 1961, and since 1985, the Alberta oil price seems to have been set by competitive interface with other North American crude oil. The NOP years, 1962 through 1972, are the most difficult to assess, with Canadian prices relatively fixed, lying between falling international and higher relatively stable U.S. prices. We suggested above that this reflected oligopolistic price rigidity, where the Alberta Oil and Gas Conservation Board administered quantities, and refiners, aware of the political uncertainties associated with the NOP, simply refrained from altering oil prices. Thus, the level of Alberta crude oil prices has reflected government policies at least as much as the market power of crude oil buyers.

Other structural features of the Alberta crude oil industry, such as the changing relative importance of the major integrated companies, the other large crude oil producers and the small ('junior') companies, are not discussed in this book. Nor do we examine the reasons for and extent of merger activity in the industry, or why mergers occurred so much more frequently in some time periods rather than others.

Performance. Industry profitability is a key indicator of market 'performance.' (Differences between individual companies or types of companies will not be discussed here.) High levels of profit are often taken as evidence of market power, although careful interpretation is necessary. Profits, for instance, tend to be sensitive to cyclical fluctuations in the economy so that a single year's high profit is not necessarily meaningful. Moreover, the preponderance of fixed costs means short-run profits are highly levered by price variations, up or down. Beyond this, there are difficulties in measuring profit rates, especially in terms that the economist finds meaningful. Reported measures of profit typically are annual rates (for an entire corporation) derived using a variety of accounting conventions regarding things such as historic costs and capital depreciation rates. Economists are inclined to view profits as the present value lifetime return

Table 6.7: August Nominations for Alberta Crude Oil (10^3 m^3/d)

	1986	*1981*	*1976*	*1971*	*1966*	*1961*	*1955*
PetroCanada	45.6	0.6	–	–	–	–	–
Imperial Oil[a]	41.5	45.6	39.4	31.4	21.2	22.0	5.6
Shell	27.1	30.4	30.7	27.0	20.6	7.3	–
Texaco[b]	18.5	20.6	16.0	20.9	19.4	12.3	1.4
Koch	13.1	3.0	2.9	–	–	–	–
Sun Oil	11.2	12.2	9.9	5.3	1.7	2.0	–
APMC	8.4	–	–	–	–	–	–
Petrosar	7.7	14.5	1.2	–	–	–	–
Husky	7.5	3.2	1.9	0.9	0.7	0.2	–
Dome	6.3	–	4.3	0.7	–	–	–
Northridge	5.7	–	–	–	–	–	–
Turbo	5.4	1.0	–	–	–	–	–
Chevron	4.5	4.8	4.6	2.5	2.5	1.8	–
Consumers' Co-op	4.3	3.8	2.7	3.3	2.5	1.7	–
Amoco	3.7	–	1.0	2.7	–	–	–
Union Oil	3.5	–	0.8	0.3	–	–	–
Gulf[c]	2.9	32.6	31.2	21.2	16.9	10.9	1.9
Mobil	2.9	0.2	5.4	14.3	4.9	3.2	–
Murphy	2.5	1.9	5.9	4.9	1.4	0.3	–
BP	0.3	13.9	11.8	2.5	2.5	–	–
Ultramar	1.6	6.1	–	–	–	–	–
Petrofina	–	4.6	2.5	–	–	–	–
Hudsons Bay	–	–	9.7	13.5	2.5	–	–
Ashland	–	–	7.3	10.4	2.1	1.6	–
Consumer Power	–	–	2.2	–	–	–	–
Atlantic Richfield	–	–	2.1	1.9	–	–	–
Sohio	–	–	1.8	6.0	3.2	2.1	–
United Refinery	–	–	0.7	2.7	–	–	–
Clark	–	–	–	4.2	–	–	–
Bay	–	–	0.2	2.2	1.5	0.7	–
Cities Service	–	–	–	1.5	–	2.1	–
International	–	–	–	–	0.9	2.3	–
Northwestern	–	–	–	–	0.5	–	–
Canadian	–	–	–	–	–	3.6	–
Anglo American	–	–	–	–	–	0.4	0.5
Wainwright Prod.	–	–	–	–	–	–	0.2
# of Other Cos.[d]	(5)	(1)	(7)	(6)	(4)	(2)	(1)
Total	229.3	198.4	148.4	184.5	104.9	75.2	9.8
			Concentration Ratios (%)				
4-Firm	57.9	65.1	59.2	54.4	74.5	69.9	96.8
8-Firm	75.6	87.6	80.3	78.2	87.0	84.7	100.0
HHI	1060	1312	1111	953	1463	1525	3951

Notes:

a Includes nominations from one Royalite refinery (in 1961) and a U.S. Humble Oil Refinery from 1971 on.

b Includes McColl-Frontenac and Regent in 1956.

c Includes BA Oil before 1971.

d All nominators who took 1% or more of Alberta oil in any of the years are listed separately.

Sources: Various issues of Oil in Canada and Oilweek.

associated with particular projects, using replacement cost criteria to value assets. Moreover, there are ambiguities involved in assessing the profits expected under effective competition in natural resource industries since economic rent over and above normal profits is to be expected. Unusually high profits might, in this case, say more about the ineffectiveness of government rent collection schemes than the degree of competition in the industry! Effective competition requires only that the marginal project does not generate excessive profits (that is profits above normal profits and marginal user costs, as discussed in Chapter Four). We will not provide information on the industry's profitability over the historical period but will briefly refer to several studies of the petroleum industry's profits.

Jenkins (1977) examined rates of return to Canadian industries; accounting data was adjusted to reflect economic valuation of assets. He reports rates of return for the "mineral fuels and petroleum" industry for private companies for years 1965 through 1974. For the first eight years of this decade, annual returns on capital varied from 3.6 per cent to 5.9 per cent, averaging 5.0 per cent; for the final two years, the return rose to 7.0 per cent and 7.3 per cent, in line with rising energy prices. Over the entire decade, the rate averaged 5.4 per cent as compared to 5.9 per cent for all Canadian manufacturing and all non-manufacturing industries. DataMetrics Limited estimated annual real rates of return on capital for oil and gas production from 1972 to 1980, a period of rapidly rising prices. Two series were reported, the second incorporating an allowance for rising costs in the petroleum sector relative to the economy at large (DataMetrics, 1984, Tables 2.1 and 2.2). The latter series showed an average rate of return of 5.5 per cent for the nine years; the rate was at its lowest, at 1.9 per cent, in 1972, and then rose sharply to 4.3 per cent in 1973. It fell the next year, and then rose again to a peak of 9.4 per cent in 1979, before falling back to 6.6 per cent in 1980. The average real return was higher than in the utility or manufacturing sectors (at 3.7% and 4.6%, respectively); however, these sectors exhibited much more stable rates of return, indicating somewhat less risk. Mining (exclusive of petroleum), like oil and gas, showed more variability in returns over this period and also a somewhat lower average rate of return (at 4.7%).

The *Annual Reports* of the Petroleum Monitoring Agency (set up on August 1, 1980, by the federal government) give more conventional accounting measures of profitability. The rate of return on total capital for upstream (crude petroleum) industry activities can be compared to that of all non-financial Canadian industries, for the years 1980 through 1990. Annual differences are great; for example, in 1980, the petroleum industry earned 14.1 per cent while other industries averaged 10.3 per cent, while in 1986 the respective values were –1.0 per cent and 9.1 per cent. From 1981 to 1985, oil averaged 8.3 per cent, and other industries 7.7 per cent; from 1986 to 1990, oil was at 3.4 per cent, others at 8.8 per cent. Crude oil may have been slightly more profitable than average during the late 1970s and early 1980s when international oil prices were high but became much less profitable once oil prices tumbled. These averages cover a wide range of values for individual companies.

Overall, this brief review of profitability does not support the claim that the Canadian crude oil industry has generated large oligopoly profits.

2. Foreign Ownership

A second structural feature of the Canadian petroleum industry that should be addressed, if only briefly, is the relatively high level of foreign investment. The presence of foreign-owned capital in Canada's oil industry can be placed in context from two somewhat broader perspectives:

(i) Many sectors of the Canadian economy have high foreign investment, and some people have seen this as a major problem.
(ii) In most parts of the world, except where oil is nationalized, development of the oil industry has depended heavily on foreign (largely U.S., British, or French) capital from major oil companies, and many people have seen this as a major problem.

Most people would likely accept that there is nothing inherently wrong with the international mobility of capital. Economists, in particular, have suggested that it is an important part of the process of economic development. Inflows of capital allow regions to finance imports in excess of exports, thereby providing a net inflow of goods and services that can, potentially, spur greater economic development. Of course, the owners of the capital expect that they will recover their investment plus a return (profit) at least as high as they could obtain in the next best alternative investment of equal risk. Foreign capital flows in the form of official government assistance or charitable donations will not usually have the same expectations about repayment and return. Some economists and business leaders have also stressed that international capital flow, especially in the form of 'direct investment' that carries ownership of (equity participation in) projects, may also bring valuable technical and management skills that are not indigenous to the region. But the benefits of foreign investment are not necessarily without cost.

There is a large academic and popular literature in Canada on the benefits and costs of foreign investment; no clear resolution of the debate has occurred, or is likely. Some flavour of the main issues can be obtained from Levitt (1970) and Safarian (1973); Baldwin and Gellatly (2005) and Baldwin et al. (2006) provide an historical overview. Six separate issues might be highlighted. Our discussion is cursory.

(i) **Necessity of Foreign Investment.** Critics have argued that, at least in part, foreign investment simply displaced Canadian capital, entrepreneurial talent, and technological skills. In other words, foreign capital simply was not needed. Others respond that foreign investment responded to opportunities available in Canada which Canadians were not undertaking, often when there was little unemployment or spare capacity, and Canadians were unwilling to reduce consumption in order to invest more. Further, they argue, it is unfair to blame foreign investment for failures in Canadian macroeconomic policy.

(ii) **Profitability.** Critics of foreign investment argue that foreign investors received higher rates of return than were required or fair, thereby reducing the standard of living of Canadians. Excess payments may have occurred partly through transfer pricing practices, in which artificially low prices are paid on exports from Canada to affiliates and/or artificially high prices are paid on imports from the foreign affiliate. They also note that if excessive profits are reinvested in Canada they become almost impossible for Canadian governments to claim for Canadians, since this would involve expropriating the newly acquired assets (or their depreciation payments). Those more supportive of foreign investment often say that these arguments are less against foreign capital than they are in support of Canadian government policies to encourage workable competition and corporate income taxes which capture a significant share of profits for Canadians. Both policies are desirable in their own right.

(iii) **Decision-Making.** Critics suggest that sectors with high foreign investment may make decisions differently than they would if Canadian-owned corporations dominated. Common examples include a reluctance to invest in R&D in Canada, failure to train Canadian staff for high-level technical or management positions, and failure to process raw materials in Canada. Furthermore, in sectors with some, but not complete, foreign ownership, Canadian-owned companies may be forced to behave in the same manner or be at a competitive disadvantage. In response, others have expressed scepticism that companies would deliberately forego potentially profitable investments, and argue that importing R&D from abroad may be the lowest cost way to obtain new knowledge.

(iv) **Extraterritoriality.** This occurs when a firm in Canada acts in a particular way because it is foreign-controlled and the home government of the foreign investor requires certain action. For example, the U.S. government has, on occasion, ordered U.S. corporations, including their affiliates, to restrict trade with certain communist and Middle Eastern countries. Another possibility is that state-owned oil companies from other countries might devise policies for political rather than commercial reasons; for example, might Chinese state-owned oil companies who have recently invested in the oil sands attempt to ship bitumen or synthetic oil to China at lower than market prices to ensure it is competitive with Middle Eastern crude oil? Others argue that such an exercise of extraterritoriality has been rare, and that, if it occurred, the Canadian or Alberta government may wish to pass countervailing regulations applicable to companies operating here.

A related argument is that Canada's openness to foreign companies may not be matched by the same degree of openness to Canadian investors in the home country of the foreign interests.

(v) **Resource Depletion.** Critics of foreign investment have sometimes argued that foreign investors have been particularly prone to come into a country and produce large volumes of a depletable natural resource for export markets (often in the company's home country), thereby accelerating depletion of the country's valuable and limited natural resources. Those more favourable to foreign investment usually note that, if valuable export markets exist, domestic corporations usually behave in exactly the same way and that the government always has the right to control levels of output and exports.

(vi) **Cultural Sovereignty.** High levels of foreign investment, critics argue, tend to lead to changing social and cultural norms, often with greater homogenization and adoption of foreign values. The process may be direct, with the influx of foreign management and workers, or more indirect through the influence of a foreign corporate ethos, or very indirect through the loss of political resolve on the part of local governments who come to feel dependent on the goodwill of foreign firms and their governments. (Urquhart, 2010, in this vein, discusses whether Alberta might be considered a 'Petro-state.') Others, in response, argue that social values are not all that fragile, that governments can do many things to encourage national cultural institutions, and that the higher standards of living derived from foreign investment should increase the governments' options in this regard.

Before returning to the Alberta petroleum industry, we should discuss the distinction between foreign 'ownership' and 'control.' Ownership relates to the distribution of equity shares in a corporation; it is the prime determinant of the distribution of dividends from current income and claims on the net assets of the firm. An emphasis on equity capital, rather than debt capital, is consistent with the tenor of the six arguments above. Foreign debt capital does entail an obligation to transfer the capital borrowed plus interest to the foreigner making the loan, but it is normally at a fixed rate of interest and does not transfer decision-making power to the foreign lender.

Foreign control refers to the ability of foreign equity interests to control decision-making in the corporation. Since outsiders do not have a window on decision-making procedures in corporations, control is difficult to assess. The most common criterion was that developed for CALURA, the *Corporations and Labour Unions Return Act* (now CRA, the *Corporate Returns Act*). From 1962, CALURA required most corporations and unions to file data annually with Ottawa, including details on the degree of foreign involvement. (The *Petroleum Corporations Marketing Act* gave the Department of Energy, Mines and Resources the responsibility to gather information on petroleum companies' activities and resulted in the annual report of the Petroleum Monitoring Agency [PMA]). CALURA defined 'foreign control' as occurring when more than 50 per cent of the voting shares in a corporation were owned by non-Canadians (or by some other corporation that in turn is foreign controlled). Weaknesses in this convenient definition are easy to find. If the 50 per cent or more foreign shareholding is dispersed, effective control could lie with Canadian shareholders or management. Conversely, a large, but minority, foreign shareholder could effectively control decision-making.

There is also the question of what is controlled. A crude oil company builds up a stock of assets (land, oil and gas reserves, employees, capital) in order to produce physical output to generate sales revenue that gives the company profits. Foreign ownership and control shares of an industry will vary depending what dimension of the industry is measured.

High levels of foreign ownership and control in the Canadian petroleum industry have long been indisputable. By 1890, Standard Oil had acquired a majority interest in the first large Canadian crude oil producer and refiner (Imperial Oil). Royalite Oil was an Imperial subsidiary; Royalite acquired the assets of one of the first discoverers in the Turner Valley gas field in 1914 (the Calgary Petroleum Products Company), was responsible for the deeper 1924 gas discovery, and helped finance the 1936 Turner Valley oil find (Hanson, 1958, chap. 5; Gray, 1970). Foat and MacFadyen (1983) looked at seven of the largest Alberta crude oil plays; in all of them, the discovery well was by a foreign-controlled corporation (e.g., Imperial Oil for Leduc in 1947, Socony-Mobil for Pembina in 1953; Banff-Acquitaine for Rainbow West in 1965). The major vertically integrated companies, in particular, were foreign-owned and controlled, until the creation of Petro-Canada in the 1970s.

The federal government's comprehensive 1973 study, *An Energy Policy for Canada* (EMR, 1973) included a detailed discussion of foreign ownership in Canadian energy industries. In 1970, the Canadian petroleum industry (including crude petroleum, refining, and marketing operations) had assets that were 77 per cent foreign-owned and 91 per cent foreign-controlled (EMR, 1973, vol. v, pp. 219–29). Foreign control was also 91 per cent for industry equity, 93 per cent for reported (accounting) profits, and 96 per cent for the value of sales. These percentages had held during most of the 1960s, with slightly rising foreign control shares of profits and sales. Foreign control was somewhat lower as far as crude petroleum activities were concerned, and somewhat

Table 6.8: Foreign Ownership and Control in the Canadian Petroleum Industry, 1971–2007 (% of petroleum industry revenue)

	Ownership	*Control*
1971	79.5	94.4
1975	76.1	92.9
1979	73.8	82.5
1985	56.2	62.6
1989	55.1	63.9
2000	n/a	51.1
2007	n/a	48.3

Note: 2000 and 2007 are for oil and gas extraction and related activities.

Sources:
Canadian Petroleum Monitoring Agency *Monitoring Reports* for 1971–91.
Statistics Canada catalogue #61-220 (*Report of findings under CRA*) for 2000 and 2007; available from CANSIM as table 179-0004.

higher for refining and marketing. EMR reported foreign ownership and control at around 20 per cent for the oil and gas transportation industry. In 1974, the government established the Foreign Investment Review Agency (FIRA) to monitor foreign acquisitions to ensure that they provided 'significant benefits' to Canada. (Eden, 1994, pp. 14–16, provides a summary history.)

After the 1973 EMR Report, continued statistics on foreign ownership in the Canadian petroleum industry were available through CALURA and PMA surveys. Table 6.8 shows the evolution of Canadian ownership and control percentages as reported by PMA for select years from 1971 through 1991, and from CALURA (CRA) reports for 2000 and 2007, based on the total revenue earned by the industry; the early years are for both upstream and downstream activities, while 2000 and 2007 include petroleum extraction only. The very high levels of foreign involvement in the 1970s had fallen by the 1980s, particularly with the rapid growth of Petro-Canada and Dome. Mergers and acquisitions have been common in the Canadian petroleum industry (PMA, 1990, provides a list of the main takeovers from 1976 through 1990). With this activity, the foreign share of the industry fluctuated, but generally it has stayed around 55 per cent for ownership and 60–65 per cent for control through to 1990, after which foreign control fell to near 50 per cent. The apparent decline to 2000 reflects the exclusion of downstream activities in these numbers. Foreign control of assets has continued to be lower than of revenues.

As was discussed earlier, the share of the industry held by foreign firms varies depending upon the type of firm and industry activity considered. For example, in 1985, the year that FIRA was disbanded and monitoring of foreign investment shifted to Investment Canada, petroleum industry exploration expenditures were only 31 per cent by foreign-controlled firms, and upstream petroleum revenues by non-integrated firms were 49 per cent under foreign control, while upstream revenues earned by integrated firms were 61 per cent foreign-controlled (Canada, PMA, 1986). These contrast with the 57 per cent foreign control for all petroleum industry revenues as reported in Table 6.8. By 1990 the foreign control percentages corresponding to those of the previous two sentences were 47 per cent, 49 per cent, 80 per cent, and 52 per cent (Canada, PMA, 1991). Rising levels of Canadian ownership and the closer integration of the U.S. and Canadian economies under the Free Trade Agreement led to a relaxation of regulations regarding foreign acquisition of Canadian oil and gas assets in 1992. Petroleum would henceforth be treated like most other industrial sectors (Globerman, 1999, p. 19). Investment Canada was eliminated in 1994 and the Department of Industry took over responsibilities for overseeing foreign investment; acquisitions of Canadian-owned assets above certain values would be monitored to ensure they offered 'net benefits' to Canada.

The high level of foreign investment in the Canadian petroleum industry is likely to continue to be of concern to some Canadians, who view the petroleum industry as a particularly critical one and who suspect that a foreign-dominated industry will behave differently than a Canadian-owned industry would. Those more accepting of foreign investment in the Canadian petroleum industry emphasize the benefits of the greater access to financial capital and technology and note that foreign-owned corporations are subject to regulation by Canadian governments if their actions are perceived to be harmful. Moreover, physical assets, in the form of oil-production equipment and developed reserves, cannot be removed from the country, so remain subject to Canadian laws and regulations.

Both views are likely to persist, so that the foreign-ownership issue will likely be a recurring one on the Canadian political agenda. We would suggest that the persistent disagreement stems in part from differing views on the two sides of the debate about the role in society of economic markets and the corporate sector in particular. Most economists adopt an 'economic' focus in which corporations, for example, are generally viewed as working to maximize profits within whatever regulatory environment they operate. Governments are free to initiate policies that they believe to be in the public interest, and individuals are similarly free to pursue whatever objectives they feel are important. In this view, foreign investment is not in itself undesirable, but governments have a responsibility to introduce regulations ensuring that after-tax corporate profits are not much in excess of 'normal' levels, with the additional profits captured for the public benefit. In addition, governments always have the ability, and responsibility, to introduce laws and regulations to control any corporate behaviour that is not in the public interest. However, other analysts, and some economists, have taken a different perspective on foreign ownership, from a 'political economy' point of view, generally with a leftist slant. In this view, the corporate sector is important, not primarily for the allocative economic functions it performs, but as a social power structure that imposes its values on the broader society and subverts the government's willingness to act in the broader public good. From this perspective, foreign investment is seen as problematic for the economy because it is not only tied to the corporate sector but because it imports foreign values and culture. Barrie (2006) does not deal with the foreign-investment question but does provide interesting comments on Alberta's political culture.

Our view is the 'economic' one that, subject to appropriate government regulations, the international flow of capital – and the inevitable foreign ownership that results – is a desirable component of a dynamic and growing world economy. We do not view foreign investment in the petroleum industry as being, or having been, detrimental to Canadian interests. We will return to the issue of foreign investment in Chapter Nine when we discuss the impact of government regulations to control the price of oil. It is also one of the issues lying beneath the analysis in Chapter Eleven of the efficiency of the regulations devised by the government to capture a 'fair' share of the economic rent from producing oil for the government.

5. Conclusion

In this chapter, we have reviewed the history of prices and output for Alberta conventional crude oil. (The market outcomes reflect as well the production of bitumen and synthetic crude oil from the oil sands. The unique features of the oil sands are discussed in Chapter Seven.) We argued that our focus has been largely from a 'private' perspective, as seen through the activities of crude oil producers and refiner purchasers in the crude oil market. However, throughout the period, the activities of private market participants played out against a backdrop of government regulations: petropolitics was ever-present.

Private market behaviour was sometimes more constrained, and sometimes less, by government regulations. Of the four main periods into which we divided the history of the Alberta oil industry, the first and the last were relatively more loosely regulated. From the early days of production, and especially after the 1947 Leduc discovery, up to the end of the 1950s, the key issue was the expansion of the market for Alberta oil, in competition with imported crude oil. Market growth fell behind increases in reserves additions, but major price declines were contained by the market power of the large integrated oil companies and, most critically, the government of Alberta's market-demand prorationing regulations. With deregulation of the crude oil market in 1985, and high U.S. demand for imported crude oil, Alberta production was once again facing a relatively unregulated market in which it had to meet competition from other sources in the world. The welcome reception of non-OPEC oil in the U.S. market (so long as competitively priced) meant that the market for Alberta crude oil was large; after 1989, market-demand prorationing no longer constrained production. The main new government regulations in this later period were the two free trade agreements. Their impact was not to constrain Alberta oil production or prices but to offer some certainty to the private industry that the Canadian government was committed to the relatively unimpeded operation of a free market for crude oil.

The years bracketed by these two periods of relatively free markets saw government regulations aimed at affecting the price of Canadian-produced crude oil. Initially, from 1960 through to the early 1970s, the main concern was low world oil prices, and the federal government's National Oil Policy operated indirectly ('covertly') to keep Alberta oil prices above world levels. From the early 1970s through to 1985, Ottawa was concerned by the high level of international oil prices, and explicit ('overt') price controls kept Alberta crude oil prices below world levels; at times, the prices were set unilaterally by the federal government, but most often federal-provincial agreements applied.

As with the degree of government regulation, the range of crude oil prices since the end of World War II has been large. Nominal prices have been as low as $2.00/b and as high as over $130/b, and have, especially since 1970, varied considerably within a relatively short period of time. This price instability has posed considerable problems for decision-makers in energy industries, especially since many of the factors causing the instability – Middle East crises, the degree of stability within OPEC – cannot be forecast with any precision. Thus decision-makers have been forced to find ways to live with oil price instability and uncertainty. One can interpret the price regulation periods of 1960 through 1985, in part, as governmental responses to this problem. And, in Chapter Thirteen, we will see that the price instability for crude oil also raised macroeconomic policy issues for the province.

Before turning to governmental regulation of the oil industry, we will review the history of the Alberta oil sands (Chapter Seven), and briefly summarize some of the literature that has attempted to build economic models of Alberta conventional crude oil supply (Chapter Eight).

CHAPTER SEVEN

Non-Conventional Oil: Oil Sands and Heavy Oil

Readers' Guide: Alberta's gigantic non-conventional oil sands resources have been known to exist for over a century. In this chapter, we review the long history of the evaluation of this resource and the development of production techniques thought to be commercially viable. The initial projects of the 1960s and 1970s are discussed in detail, including the important public policy issues raised by the prospect of large oil sands output. We then discuss the absence of large new projects in the 1980s and 1990s, with smaller bitumen projects appearing, and the two existing mining ventures engaging in moderate expansion. Finally, the resurgence of interest in the oil sands at the turn of the millennium is discussed.

1. Introduction

The difference between the conventional and the non-conventional is hazy and changeable. Some lifestyles progress from unacceptable to tolerated to conventional within the space of a generation. A similar transition is occurring for the so-called 'non-conventional' oil from the Alberta oil sands and very heavy oil deposits. The non-conventionality of these resources lies in the fact that they cannot be produced by the techniques that have conventionally been used in the oil industry. The hydrocarbons (bitumen) in the ground are so heavy and viscous, and so firmly attached to the rock pores, that the oil will not easily flow to and up the well bore, even with the 'primary' inducements that the industry commonly uses (fracturing the reservoir rock around the well and pumping). Loosely put, commercial primary recovery rates are very low, and the EOR techniques required are not those that the industry has developed for conventional oil pools. The ERCB has defined crude bitumen as "a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes, that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well" (ERCB, 2010 *Reserves Report* ST-98, p. A1). The resources discussed in this chapter include more than those shallow oil sands deposits around Fort McMurray that are amenable to strip-mining. There are also extensive oil sands deposits that are too deep to be effectively strip-mined, and from which oil must be recovered by *in situ* processes that typically inject heat into the reservoir to make the viscous heavy oil more fluid and allow it to flow beneath the surface to a well bore. Early prospectors attempted this in the shallow Athabasca sands, but much of the experimentation has been more recent, relying on new technologies such as horizontal drilling.

There are four very large areas in Northern Alberta on which bitumen deposits are recognized to exist: Athabasca, Wabasca, Peace River, and Cold Lake. (See Figure 5.1, in Chapter Five.) Recently the Athabasca and Wabasca sands, which border one another, have often been combined. There are also other smaller deposits of a similar bitumen nature in Northern Alberta, for example in the Buffalo Hills area. Typically, there are a number of heavy oil or bitumen formations in each of these deposits. Overall, as of 2012, the ERCB recognizes fifteen separate bitumen sand deposits in these four areas. On balance, the distinction between conventional and non-conventional heavy oil resources is somewhat arbitrary, perhaps best viewed as involving a division along a continuum of heavy oil pools. The non-conventional resources are usually considered to be those very large accumulations of heavy oil in Northern Alberta that were not historically producible by conventional techniques. However, the ERCB shows a number of heavy oil projects that are ascribed primary production. Moreover, there are undoubtedly smaller 'conventional' heavy oil deposits that hold oil in formation in a manner very similar to a deposit such as Cold Lake. Such conventional heavy oil pools often exhibit increased recovery rates with EOR schemes that are similar to the *in situ* production techniques used in the non-conventional heavy oil pools. We suspect that the crucial difference, which will soon be commonly accepted, is between mining and *in situ* production techniques, though it will still be of interest whether an *in situ* scheme is located in one of the huge bitumen sand 'fields.'

By 2012 crude bitumen made up 78 per cent of Alberta's oil production (ERCB, *Reserves Report* ST-98, 2013, p. 2), as conventional output continued to exhibit production decline and non-conventional output expanded. Most analysts see the share rising. The non-conventional is becoming commonplace! The reasons for this lie in a mix of natural, technological, economic, and political factors. Alberta's bitumen resource base is huge. Higher oil prices beginning in the 1970s served to attract more attention to higher-cost energy sources such as the oil sands. Companies and government research agencies have long investigated new production techniques explicitly for Alberta's oil sands and heavy oil resources, and there was significant 'learning by doing' along with production. Governments offered encouragement to oil sands projects and came to believe that the special features of this petroleum resource warranted different royalty and tax treatment than conventional oil.

2. Early History

Alberta's oil sands were probably the first of its hydrocarbon resources to be discovered. (Carrigy, 1974; Chastko, 2004; Ferguson, 1985; Fitzgerald, 1978; Gray, 1970, chap. 14; Pratt, 1976, chap. 3; NEB, 2000, Section 3 and Nikiforuk, 2008, provide historical detail on the oil sands.) In 1778, Peter Pond, an early white trader, remarked on the shows of oil in the banks of the Athabasca River north of the present town of Fort McMurray. Pond noted that the local aboriginal population used the bitumen in a number of ways. However, the difficult nature of the bitumen – heavy, viscous and high in sulphur – discouraged its development, even after the start of the modern petroleum industry about 1860. The federal government's geological service turned its attentions to the oil sands in 1882. Robert Bell ascertained the Lower Cretaceous age of the Athabasca sands, suggested that the bitumen might be separable from the rock by a hot water process, and argued that the bitumen in the sands had originated in Devonian era rocks. Three years later, Robert McConnell provided further geological analysis and estimated that the oil sands area was at least 1,000 square miles with at least 30 million barrels in place. In the Ottawa labs of the Geologic Service, G. Hoffman had discovered the asphaltic nature of the bitumen. He demonstrated that, by heating the bitumen-laden rock, the concentration of bitumen could be increased from under 15 per cent to about 70 per cent.

Attention focused initially on the presumed presence of deeper large conventional oil deposits from which seepages to the surface must have occurred. In the late 1890s, a series of wells was drilled by the Geologic Service in the oil sands region; several gas strikes occurred, but no underlying oil reservoirs were located, a result confirmed by private sector drilling early in the century. However, the non-conventional bitumen sands themselves were so obvious, and large, that numerous prospectors and scientists were drawn to speculate on, and experiment with, ways of producing the bitumen. After World War I, both private and public enterprises were involved, most notably Sidney Ells with the Mines Branch of the federal government, Karl A. Clark with the provincial government-funded Alberta Research Council, Robert C. Fitzsimmons, who founded the International Bitumen Company, and Max Ball, who founded the Abasand Oil Company.

Ells first became convinced of the potential of the oil sands when commissioned to undertake a survey in 1913. For the next three decades, he became a firm proponent of the oil sands, suggesting production methods and actively pursuing uses for the bitumen. Ells was especially active in demonstrating the utilization of concentrated bitumen for paving projects (in Edmonton in 1915 and Jasper in the 1920s). Ferguson (1985) suggests that Ells's difficult personality slowed federal involvement in the oil sands and encouraged the government of Alberta to take a more active role.

Clark began work in the early 1920s, based on hot water extraction methods, which had been applied since before the turn of the century to petroleum from heavy oil deposits in California and elsewhere. Laboratory work and pilot plants at the University of Alberta (1923), Dunvegan (in Edmonton, 1924), and on the Clearwater River near Fort McMurray (1930) confirmed the technological feasibility of Clark's hot water process. Clark also demonstrated the possibility of using bitumen for paving purposes, but, unlike Ells, emphasized that it was more costly than the usual materials. While researchers like Ells and Clark established a firmer understanding of the resource and technological potential of the mineable Athabasca oil sands, commercial viability had not been proved. With falling oil prices and the Great Depression in the early 1930s, government interest in the oil sands waned.

Private entrepreneurs continued to pursue commercial development. Fitzsimmons headed the International Bitumen Company (1927, successor to the Alcan Oil Company, a drilling company funded by a group of New York policemen in 1922). Fitzsimmons initially drilled for conventional oil in the Athabasca area, where his self-promoting claims of success seem to have been derived from bitumen that flowed into the well bore as a result of the heat of the revolving drill bit. He turned his attention to a mining and separation facility and in 1930 constructed a hot water separation plant at Bitumount, near Fort McMurray. International Bitumen struggled along with a mix of high promises, technical problems, and management and financial crises until bankruptcy occurred in 1938. In 1942 a Quebec investor, Lloyd Champion, bought International Bitumen, re-organized it as Oil Sands Limited, and approached the Alberta government about the possibility of government funding to complete and re-open the Bitumount plant. Alberta refused to provide loans or loan guarantees to the company, but in late 1944 it entered into a joint venture. This decision reflected advice from experts such as Karl Clark, who argued that the private sector could not be expected to invest heavily in the oil sands in light of their uncertain commercial viability, especially when technical issues about separation and upgrading had still to be resolved. The provincial government took over sole operation of Bitumount in 1948 when Oil Sands Limited proved unable to continue its financial share. There were numerous technical problems and accidents, but Bitumount did operate for part of 1948 and 1949. In September 1949, the plant was closed, issues of technical feasibility having been substantially addressed. The government hosted the First Athabasca Oil Sands Conference in 1951 and used this as a forum to make available to the public the technical information that had been gained at Bitumount.

Max Ball was an American engineer who became interested in bitumen sands in the 1920s while working at a lab in Denver. In 1930 he founded Abasand Oils Limited (originally the Canadian Northern Oil Company) to operate a separation plant in the Athabasca oil sands. (See Comfort, 1980, for a history of Abasands.) Ball consulted with Karl Clark, and by 1936 Abasand was in production using a hot water separation process. There were numerous technical problems, many of them involving mining difficulties, since the sands quality was poorer at the Abasand site than at International Bitumen's. Abasand was, however, much more effective than International Bitumen in its financing, management, and operation. In 1941, Abasand finally began to operate consistently, only to burn down in November. In April 1943, the federal government, concerned about war-time oil supplies, decided to finance the rebuilding of the Abasand plant. A restructured Abasand Oil would run the facility and have the right to purchase it from the government at a later date, at market value. Numerous construction delays and unexpected cost increases plagued the re-building, with the separation plant beginning sporadic production in the fall of 1944. Experiments were undertaken in 1945 with a second separation plant using a cold water process. But in June 1945, a fire destroyed part of the project including both separation plants. The federal government delayed in committing more funds to the project, in part because the war pressures had ended and also because much of the desired technical information had been gained. In June 1946, Ottawa formally announced what most people had come to expect; it was out of the Abasand project. Abasand Oil took over the remaining assets but was essentially inactive until the mid-1950s when it sold its oil sands leases to Sun Oil.

What conclusions can be drawn from this brief early history of the Athabasca oil sands? The period from 1880 to 1950 was primarily one of knowledge generation. It was soon clear that the natural resource base was huge, but time had been needed to demonstrate that the resource was the Lower Cretaceous bituminous sands themselves, not an underlying conventional oil play. The bitumen content of the sands varies, averaging around 12 per cent (by weight) in the Fort McMurray area, but rising to almost 20 per cent at some locations. While some investors attempted *in situ* recovery methods, it was commonly accepted by the 1930s that strip-mining of shallow sand deposits was the most promising production approach. By 1950, it was also pretty clear that the initial commercial production of oil sands oil would involve the three stages that Clark, Fitzsimmons, and others had been advocating for at least twenty years. A mining process would strip-mine the bitumen-laden rock that lay near the surface; a hot water flotation process would free the bitumen from the rock; and a refining process would upgrade the bitumen from very heavy and high sulphur crude to sweet, light crude or into specific light refined petroleum products.

In their 1927 *Report* for the Scientific and Research Council of Alberta, Karl Clark and Sidney Blair summarized the view prevalent amongst many early oil sands researchers (vol. II, p. 35).

> It will require but a small diminution in the supply of crude oil or increase in the demand for gasoline to render possible the development of the Alberta bituminous sands for the production of motor fuel. If, as appears to be the case, separated bitumen can be produced for a dollar a barrel, and can be turned into a forty-five per cent yield of cracked gasoline, conditions in the near future should cause a profitable basis for an industry. On the other hand, prospecting may reveal extensive petroleum pools in Western Canada which would cause a delay in bituminous sand development. The results of the search for oil fields to date does not give strong hopes that this will happen. It is not improbable that the great bituminous sand deposit represents Nature's major gift of crude oil to Western Canada, and that it must be turned to as the source of supply of mineral oil products for the Prairie Provinces.

Clark and Blair were quite correct to remark on the connection between the conventional oil industry and the likely appeal of the oil sands and were not alone in suggesting that the oil sands were not quite commercially attractive.

From an economic point of view, there are a number of issues of interest, though data is somewhat sketchy. Commercial viability is one issue, and some information is available from the pilot projects and from reports by such careful analysts as Karl Clark. (Most of the data we use are drawn from Ferguson, 1985.) The desirability of an upgrading stage, for example, is evident in the finding that separated bitumen was not competitive as a paving material. (Clark noted that one seller charged Camrose $1/square yard for paving with bitumen, and probably lost money; the City of Edmonton costed paving by more conventional means at $0.66/square yard.) However, the likely cost of synthetic (upgraded) crude is harder to estimate. For one thing, the cost is a function of project-specific factors such as the grade, depth, and location of the bituminous sands being mined and the separation and upgrading techniques. Further, both learning-by-doing and economies of scale are likely to be significant. The former implies that costs fall as more is produced and that new plants may be cheaper than older ones. The latter implies that per unit costs may be significantly less for larger plants than for small pilot projects. The 'hardest' data on synthetic crude costs comes from the two large pilot projects, Bitumount and Abasand. The experience of both projects suggested that unanticipated technical difficulties, including equipment failures and long shut-down times, would be likely to affect commercial ventures, at least in the early years, and these, of course, increase the cost of the synthetic crude. (Costs that are incurred even when there is no output must be spread over the output when it does occur; also, delayed output has a lower present value than earlier output, and so increases the effective capital cost of a unit of output.) On both these projects, the capital costs turned out to be higher than initially projected. This was especially true for the war-time Abasand project, which was projected to cost $500,000 to rebuild and which by 1945 had absorbed more than $1,900,000. (Bitumount was initially budgeted at $250,000 in 1942 and had spent $750,000 by 1949.) However, since both projects were pilot projects, and neither produced for long, no reliable unit costs can be derived from them.

Another source of synthetic crude oil costs came from estimates made by those involved in the bituminous oil business. Such estimates have the advantage of allowing for factors such as economies of scale and utilization of the (presumed) best production technique. But they have the disadvantage of being hypothetical, a major problem when virtually all the actual projects undertaken exhibited unexpected technical problems and cost overruns. Further, the cost estimates of promoters are particularly suspect, since they were often attempting to raise capital from investors. They may also have been drawn to reduce the cognitive dissonance they felt as their cash dissolved in unprofitable investments; if they could convince themselves, however inaccurately, that profitability was just around the corner, they would feel less unhappy about the money they had already lost. For example, Fitzsimmons estimated a synthetic crude cost in the mid-thirties of $0.72/b, even as his company was slowly going bankrupt. Contrast this with Karl Clark who, in his detailed *Report* on the oil sands for the Research Council of Alberta, had estimated mining and separation costs at $1.00/b for bitumen alone (Clark and Blair, vol. II, 1927, chap. III). However, Clark and Blair had noted (p. 31) that this 'is evidence that the separation process besides being efficient is also economically possible.' Finally, it is often difficult to compare cost estimates since they do not always include the same elements. For example, it is not always clear how the cost of capital is treated, some estimates are for only one of the three processes (e.g., separation) and some estimates included the cost of shipping the synthetic crude out of the Athabasca region while others did not.

Ferguson (1985) notes a number of independent studies, especially in the 1940s as governments considered investing in oil sands operations, which suggested that if a few of the technological uncertainties could be resolved, synthetic crude production costs would be in the vicinity of light crude oil prices. However, these cost estimates varied considerably. For example, two federal government studies in the early 1940s estimated bitumen costs (mining and separation but not upgrading) at $1.31 (G. Hume of the Geologic Survey) and $2.00 (Federal Oil Controller G. Cottrelle) per barrel, when bitumen was selling for about $1.60/b. G. Webster of Abasand estimated that a 1,000 b/d separation plant could produce bitumen at a cost of about $2.50/b, when crude at that time (September 1945) was selling for about $1.00/b.

In 1949, the government of Alberta commissioned Sidney Blair, a former Research Council colleague of Clark's, to write a report on the oil sands. Blair undertook a detailed examination of all the technical tasks involved in producing synthetic crude and came up with a cost estimate (Blair, 1950, p. 75). He estimated the cost of light oil from a 20,000 b/d oil sands project at $3.10/b; Blair also estimated that the oil would sell for at least $3.50/b (delivered to Lake Superior) to yield a return on capital of 5.5%/year. The $3.50 value was considerably higher than the price of conventional Alberta light (Redwater) crude, reflecting the very light, high quality of the upgraded bitumen. In 1950 Blair noted that Alberta Redwater crude delivered to the Lakehead sold for $3.00/b, which is just under his estimated $3.10/b cost. Since his cost estimates do not appear to include a cost of capital nor any taxes or royalties, and given the constant technical problems the pilot plants had consistently experienced, it is hardly surprising that no commercial ventures followed immediately on the Abasand and Bitumount closures. Falling Alberta oil prices after 1949 offered further discouragement, as did the rapid acceleration in both production and excess production capacity of conventional Alberta oil. Some observers (e.g., Pratt, 1976) suggest that the major oil companies acted to tie up leases in the oil sands and deliberately refrained from production in order to maintain output from their conventional oil reserves in Alberta and elsewhere. Commercial production of oil sands oil did not commence until 1967.

The question of whether synthetic crude should obtain a value appreciably higher than Alberta light conventional oil has been controversial. The upgrading process is, in very simplified terms, a coking and distillation procedure. Bitumen, as a very heavy hydrocarbon, has a relatively high proportion of carbon relative to hydrogen. In upgrading, some of the carbon is removed as coke (a by-product, along with sulphur) and the remaining hydrocarbons are separated by distillation. For example, Fitzgerald (1978, p. 3) notes that four main products result from the Suncor plant: gases (used internally by the plant), naphtha (which is readily processed into motor gasoline), kerosene and light fuel oil (gas-oil). These light products (other than the gases) typically have prices higher than crude oil. However, to obtain such prices it would be necessary to ensure that the products meet consumer specifications and that they are transported to market in a pure form, which is not inexpensive given the distance from Fort McMurray to major petroleum product markets. In fact, the practice for existing oil sands mining plants (e.g., Suncor and Syncrude) has usually been to blend the three liquid products together and ship the mix, which is then valued as a light sweet crude.

Early government policy with respect to the oil sands was much more active than that with respect to conventional oil, where exploration, development, and production decisions were left to the private sector, subject of course to a regulatory framework (e.g., mineral rights and taxation/royalty policies). However, both the federal and provincial governments saw the oil sands deposits as unique in at least two important respects. The first was geological, their non-conventionality, their apparent size, and unusual nature. In part this piqued the curiosity of government scientists such as Bell, McConnell, and Ells. The second was an engineering problem, how to treat the bitumen in such a way as to produce valuable products, and this too attracted the attention of university and government scientists such as Clark. There is an economic argument for a government role in generating basic engineering and geologic knowledge. Since the information, once gathered, has very low marginal costs of transmission, it should be provided to prospective buyers at a very low price. However, if this were the case, private companies would have very little incentive to invest in the production of such knowledge. If private companies do undertake such research but charge high prices for their information, then society at large may not benefit as much as would be desired; high prices can be a particular problem since the firm producing the new, valuable information may be in a monopoly position. Of course, this problem of the 'public good' nature of information is a ubiquitous one in society and is handled in a variety of ways. (Information is a public good in terms of its non-exclusivity – my consumption of a bit of knowledge does not prevent you from also consuming it, quite unlike my consumption of Skor bars.) If the knowledge is of a narrow and specific nature, it is most frequently left in the hands of the private sector with the innovator offered patent protection to encourage investment in generating new knowledge. However, for more 'basic' research, which may have no immediate apparent commercial use, or for which the possible uses are so broad as to be hard to define, it is common for governments to play an active role in generating or funding the production of knowledge. Of course, there is no clear demarcation between these two classes.

The federal government was particularly active in oil sands research prior to 1920 and with the Abasand plant during World War II. The provincial government was heavily involved in the 1920s with Clark's hot water process and then in the Bitumount plant from 1945 to 1949. By 1950 the Alberta government had decided that further oil sands development would be left to the private sector, using the 1951 Athabasca Oil Sands Conference as a venue for conveying to private entrepreneurs the information it had gathered. (The government continued to offer some support for basic oil sands research through its universities and bodies such as the Alberta Research Council. In 1974 it created AOSTRA, the Alberta Oil Sands Technology and Research Authority, which undertook joint research with industry on oil sands, heavy oil, and EOR technologies. AOSTRA was later incorporated into the Alberta Energy Research Institute, which in 2010 became part of Alberta Innovates.)

Another significant policy responsibility of governments was in managing the leasing of mineral rights on oil sands lands, which are largely Crown owned. As with conventional oil and gas, such lands were under the jurisdiction of the federal government until 1930, in which year most were transferred to the province. (Ottawa continued to hold control of some mineral rights in Alberta, for example on Indian reservations and in National Parks; in the oil sands area, small acreages were still federally held, including the plot on which the Abasand plant was built.) However, there were relatively few bituminous sand leases issued. By March 31, 1946, the province had only four outstanding leases covering 3,952 acres, and by March 1949 there was only one outstanding. (Data in this chapter on mineral rights and oil sands royalties and taxation come largely from the *Annual Reports* of the provincial government departments responsible, i.e., Mines and Minerals, Energy and Natural Resources or Energy, depending on the year.)

3. Resources, Reserves, Production and Costs

In this section, we discuss oil sands projects from a 'private' point of view, largely that of the oil producer. In the next section, we review government policies.

A. Resources and Reserves

The word 'reserves' is often used rather loosely, as has been the case in oil sands analysis. (Chapter Five included discussion of this terminology). The ERCB *Reserves Reports* (ST-18 and ST-98) set out criteria used in determining estimates of producible volumes. Dunbar et al. (2004, chaps. 2 and 3) provide a good review of the resource characteristics of Alberta heavy oil deposits and the production technologies currently under consideration. See also NEB (2000); Engelhardt and Todirescu (2005); and the ERCB *Reserves Report* ST-98. Some have used the word 'reserves' to mean 'resources;' that is, the amount of bitumen or synthetic crude in place. (The produced natural resource is bitumen, which may then be upgraded to light synthetic crude, or 'syncrude.' The first two commercial oil sands mining plants, for instance, produce a little over 0.8 of a barrel of syncrude per barrel of bitumen.) More careful analysts restrict the use of the word 'reserves' to an estimate of recoverable volumes, but this is often an amount assumed to be eventually recoverable under hypothetical (and often undefined) technical and economic conditions. We prefer to label such estimates 'ultimate potential.' Reserves (initial or remaining) are volumes known with a reasonable degree of certainty to be producible under current technologies and anticipated economic conditions. Until recently, this meant that bitumen volumes recognized as oil reserves were restricted to projects currently in production. Almost all such reserves come from large commercial projects, though small amounts may be credited to experimental pilot projects. However, since the early 2000s, Alberta and Canadian statistics have accepted large volumes of oil sands resources not currently in production as qualifying as reserves, and in 2003 the U.S. Energy Administration Information (EIA) accepted these estimates. Thus, for example, BP estimated end of 2004 Canadian crude oil reserves as about 16 billion barrels, in contrast to the EIA's 174 billion; by 2010, BP had raised its estimate of Canadian oil reserves to 33.2 billion barrels by including 27.1 billion barrels of oil sands 'under active development' and, in 2011, it reported 175.2 billion barrels. However, even those sources that now place Canada a not-so-distant second to Saudi Arabia in oil reserves acknowledge that the quality of the two countries' reserves differ by many orders of magnitude, with the Saudi production costs a fraction of those for Alberta heavy oil.

It is also important to realize that Alberta's oil sands and heavy oil deposits are not homogeneous. The natural product is a mix of hydrocarbons (bitumen), water, sand, and other earth materials like clay. Amongst the important ways in which deposits differ are: specific gravity (some crudes are heavier than others), bitumen concentration (the proportion by weight or volume that is bitumen), and depth (where shallow deposits, usually up to 75 m deep are regarded as amenable to mining operations). The concentration of bitumen, by weight, may range from 1 to 18 per cent. The physical chemistry of the Alberta oil sands is such that bitumen encases sand particles with a film of water between the sand and the oil; this separation between sand and bitumen seems to make commercial production somewhat easier than for other non-conventional oil resources such as U.S. oil shale. Deposits of intermediate depth may be the most difficult to produce since they are too deep to be mined, but so shallow that injection fluids leak quickly to the surface.

As discussed above, it was soon recognized that Alberta's heavy oil and bitumen resource base was huge, though it was not until after the turn of the nineteenth century that the idea of large underlying lighter oil pools was abandoned. The mapping and drilling programs of the federal Geologic Service prior to 1900 had made clear that the deposits occurred over a very large area, and examinations of specific sites in the Fort McMurray region had allowed assessment of the characteristics of shallow deposits at those locations. Allen, in his 1920 report to the Alberta Legislature, said that there were 10,000 to 15,000 square miles in the Athabasca region underlain by bitumen, and repeated an estimate by T. Davidson of Imperial Oil that they might hold 30 billion barrels (Allen, 1920). In their extensive Report on the bituminous sands for the Alberta Research Council, Clark and Blair simply noted that outcrops of oil sands in the Athabasca area covered at least 750 square miles, but that actual bitumen deposits covered a much larger area; they provided no estimate of total oil accumulations (Clark and Blair, vol. I, 1927). Sidney Blair's 1950 Report to the Alberta government noted that "outcrops and drillings proves a vast deposit" but that "the evidence is inadequate to appraise the total bitumen" (Blair, 1950, p. 13). The federal government undertook a drilling program of 291 wells on federal leases during World War II, and a consortium of 11 companies completed 91 wells on provincially issued leases from 1952 to 1954, clearly demonstrating the richness of the sands on those leases.

Estimating petroleum reserves was one of the tasks undertaken by the OGCB (later ERCB and EUB), and one can follow the evolution of its estimates through various board publications, including its annual *Reserves Report* (Reports ST-18 and later ST-98). By 1962 the board was basing its estimates on 600 wells and a further 1,200 observational drillings in the bituminous sands areas and, excluding Cold Lake, estimated in-place volumes at 710.8 billion barrels (625.9 billion in the Athabasca deposit) and potentially recoverable volumes at 300.9 billion barrels (266.9 Athabasca). In 1967 the board estimated Cold Lake in place bitumen 'reserves' at 75 billion barrels. By 1981 the ERCB estimated in place bitumen in Alberta at 1,163 billion barrels (including 862 in the Athabasca and 187 in the Cold Lake deposits). However, the estimated ultimate potential had been cut to about 150 billion barrels. Initial established syncrude reserves of 24.5 billion barrels were associated with deposits similar to those underlying the two producing oil sands mining projects.

In 2003, the board began to update resource and reserve estimates for 15 separate oil sands deposits. By the time of the 2013 *Reserves Report* (ST-98), 11 deposits, including the largest, had been reviewed. As of the end of 2012, the ERCB puts in-place bitumen at 1,844 billion barrels (293.1 billion cubic metres), with over 1,500 billion barrels in the Athabasca-Wabasca deposits, over 180 billion barrels in the Cold Lake deposits, and 135 billion barrels in the Peace River deposits. Initial established reserves of bitumen are estimated at 176.8 billion barrels (28.1 billion cubic metres), of which 39 billion barrels is mineable and 138 billion barrels recoverable by *in situ* means. However, only 33.7 billion barrels of this was under active development in 2011, 82 per cent of it in mining projects, including several projects that had not begun yet, but were, in the board's judgment, likely to proceed. The mining projects exhibit an expected recovery factor (recovered syncrude as a proportion of bitumen in-place) of 29.6 per cent, while the *in situ* projects average 10.4 per cent, usually including 5 per cent credited to primary recovery techniques.

These numbers might be compared to the ERCB's estimate for year-end 2012 of Alberta's initial reserves of conventional crude of 18.0 billion barrels (2,863.2 million cubic metres) and remaining conventional crude oil reserves of 1.5 billion barrels (245.9 million cubic metres). The current and potential significance of the oil sands and heavy oil deposits is evident.

B. Production

In the 1930s and 1940s, various small pilot projects produced small amounts of bitumen and syncrude, but in a very sporadic manner as projects began and folded, going through numerous financial and technical problems. With the closing of the Bitumount plant in 1949, production of non-conventional oil ceased. Interest in the oil sands picked up again in the mid-1950s, and once again small pilot projects began to operate, including a mining venture run by Cities Service Athabasca and *in situ* experiments by Shell and Pan Canadian. In 1960, Great Canadian Oil Sands Ltd. (GCOS) applied to the OGCB to build a 31,500 b/d mining plant; permission was given in 1962 and the plant (now known as Suncor) began production in 1967. (George, 2012, provides a recent history of Suncor and the oil sands by one of Suncor's CEOs.) There were a number of other proposed mining projects in the 1970s, but by 2000 only one other plant had been built. In 1967, Syncrude (owned, at the time, 30% each by Imperial Oil, Atlantic Richfield Canada, and Canada-Cities Service and 10% by Gulf Canada) applied to the OGCB for an 80,000 b/d mining plant; in 1972, permission was given, and, in 1977, production began. Both Suncor and Syncrude amended their applications to a larger size. By 2013, both Syncrude and Suncor had expanded considerably, Syncrude to a capacity of 350,000 b/d and Suncor to over 300,000 b/d. Both companies experienced start-up difficulties in the early years of operation and have had occasional shut-down periods for maintenance or due to accidents. Reliability since about 1990 has been better than earlier, although unexpected closures still occur. A third mining venture, Shell's Albian Sands began production in late 2002. The Albian-mined bitumen is shipped to a Shell Canada upgrading plant near Edmonton, rather than being upgraded on site. In September 2008, the Horizon project, owned by Consolidated Natural Resources Limited, commenced production. As of the end of 2012, these were the only mining operations in production, although the ERCB regards three other projects as under active development, including Fort Hills (owned by Suncor, Teck, and UTS Energy), Jackpine (Shell) and Kearl (Imperial and ExxonMobil). The Kearl project was slated to begin production in spring 2013, at the time of the final editing of this volume, with initial output of 110,000 b/d and an eventual capacity of 345,00 b/d. A number of other mining projects have been proposed, including planned expansions by existing operators.

Experimental *in situ* projects have continued to produce small volumes of oil, but there have been an increasing number of commercial *in situ* ventures, the largest of which is Esso Resources' Cold Lake cyclic steam project, which began in the mid-1980s (with a rated capacity of 140,000 b/d of bitumen). The EUB (in its *Alberta Crude Bitumen Production Report*) listed 9 'commercial schemes' operating in 1997, with an average daily bitumen output of 149,350 b/d (23,706 cubic m/d); 72 per cent of this came from Esso Resources' Cold Lake project. In addition, in December 1997, there was 101,400 b/d (16,099 cubic m/d) from 55 'primary recovery schemes,' 5,610 b/d (891 cubic m/d) from 'conventional bitumen recovery not associated with an approved oil sands project,' and 1,600 b/d (255 cubic m/d) from experimental schemes. The relative importance of the smaller primary recovery schemes increased during the 1990s. For instance, in December of 1993, the ERCB had reported only 13 such ventures with a total output of 5,580 b/d (887 cubic m/d). The impetus in oil sands development had shifted from the mining and *in situ* megaprojects to smaller ones, many relying on primary recovery. Many of these small projects draw on new horizontal drilling techniques and may have been encouraged by Alberta royalty regulations, which offered some relief to horizontal drilling projects (and to new EOR schemes, in some cases).

The Alberta Department of Energy reported that, by August 2009, the number of *in situ* projects in operation had risen to 87. The ERCB's 2013 *Reserves Report* (ST-98) noted that the number of producing

Table 7.1: Alberta Oil Sands Production, 1967–2012 (10^3 m^3 per year)

Year	*Suncor*	*Syncrude*	*Total Synthetic Crude*	*Bitumen*
1967	72	0	72	42
1968	835	0	835	64
1969	1,601	0	1,610	69
1970	1,904	0	1,904	38
1971	2,451	0	2,451	15
1972	2,963	0	2,963	71
1973	2,906	0	2,906	71
1974	2,654	0	2,654	73
1975	2,506	0	2,474	199
1976	2,810	0	2,779	440
1977	2,641	0	2,611	486
1978	2,629	624	3,239	453
1979	2,425	2,827	5,329	581
1980	2,760	4,691	7,410	556
1981	1,548	4,732	6,446	753
1982	1,011	4,989	6,958	1,281
1983	2,320	6,319	9,258	1,455
1984	2,822	4,961	7,738	1,943
1985	2,175	7,394	9,746	3,030
1986	3,271	7,487	10,728	5,410
1987	2,503	7,918	10,472	6,750
1988	2,972	8,719	11,643	7,540
1989	3,343	8,631	11,901	7,482
1990	3,044	9,086	12,091	7,856
1991	3,552	9,675	13,121	7,113
1992	3,369	10,445	13,778	7,362
1993	3,326	10,736	14,123	7,685
1994	3,579	11,173	15,191	7,810
1995	3,967	11,885	16,328	8,630
1996	3,895	11,752	16,318	9,505
1997	3,808	12,152	15,960	13,806
1998	4,062	12,322	16,384	16,364
1999	3,712	13,059	16,771	14,171
2000	4,416	11,946	16,362	16,781
2001	4,537	13,142	17,679	17,954
2002	8,050	13,537	21,587	17,560
2003	12,563	12,296	29,522	20,248
2004	12,807	14,085	34,841	22,455
2005	9,936	12,412	31,709	25,553
2006	15,080	14,964	38,093	27,161
2007	13,665	17,689	39,860	29,230
2008	13,230	16,820	38,008	33,047
2009	16,863*	16,248	44,406	33,047
2010	14,999*	17,316	45,918	39,453
2011	17,690*	16,722	50,042	44,209
2012	18,792*	16,617	51,105	52,086

Note: * Excludes the Suncor share of Syncrude output following the August 1, 2009 merger of Suncor and Petro-Canada.

Sources: Mining project output from ERCB *Alberta Oil Sands Annual Statistics* (series 43, various years) for 1975–96; mining output from *Alberta Oil Plant Statistics* (ST-39) for 1997–2004, 2010. Other data from ERCB *Alberta Oil and Gas Annual Statistics* (ST-17, various years), and ERCB, *Alberta Energy Resource Industry Monthly Statistics* (ST-3, various years). For years 1967–69 data in barrels was converted to cubic metres by assuming 6.3 b per cubic metre. For 1967–74 it was assumed that all synthetic crude came from the Suncor plant. The 2003 and 2005–12 data for Suncor and Syncrude come from the companies' web sites.

wells had increased from 2,300 in 1991 to 11,500 in 2012 (p. 3-13). In 2012, 25 per cent of bitumen production was credited to 'primary' recovery techniques (which include 'water and polymer injection'); cyclical steam stimulation (used by Esso in its 1980s Cold Lake development) contributed 26 per cent, while the steam-assisted gravity drainage (SAGD) techniques, which became popular in the early 2000s, generated 49 per cent (p. 3-14). According to the ERCB (2009 Reserves Report, p. 2-23), the average SAGD well produces about ten times as much bitumen as wells using either of the other techniques.

Table 6.1 in the previous chapter included synthetic crude production in Alberta, showing it rising from less than 1 per cent of the total in 1967, when the Suncor plant opened, to 3.7 per cent in 1977, to 13.4 per cent in 1987, 17 per cent in 1997, and 36 per cent in 2012. In 2012, almost all the mined bitumen output, and 7 per cent of *in situ* produced bitumen, was upgraded to synthetic crude oil at the five Alberta upgrading facilities. (The mining projects, Suncor, Syncrude, Shell, and Consolidated Natural Resources, have all built their own upgrading facilities; in 2009, Nexen opened an upgrader at Long Lake, just outside Fort McMurray.) Table 7.1 shows yearly synthetic crude and bitumen output since the Suncor plant began operation in 1967. The lengthy start-up periods, and unpredictability of shut-down times, are evident for the two mining projects (especially Suncor). Bitumen output was about one quarter the size of synthetic crude output in 1984 but had risen to almost 60 per cent by 1996, and 108 per cent by 2012, indicating the growing importance of *in situ* heavy oil projects without associated upgraders.

Prospects for future oil sands production are good. Of course, such forecasts are subject to a wide range of uncertainty, but they illustrate the prevailing optimistic expectations regarding oil sands production. Chapter Six, commented briefly on the necessity for market expansion as oil sands output rises. In 2013, the ERCB (*Reserves Report*, ST-98) projected mined crude bitumen output of 1,602,000 b/d by the year 2022 (up from 930,000 b/d in 2012). Since 2006, the board had reduced its medium-term mined bitumen output forecasts somewhat. On the other hand, in recent years, the board has increased its estimates of future *in situ* bitumen production; the 2013 Reserves Report saw output rising from 992,000 b/d in 2012 to 2,207,000 b/d in 2022. As noted, mined bitumen is currently upgraded. The precise nature of the upgrading varies somewhat (pp. 2–24 in the 2010 Reserves Report):

> Suncor produces light sweet and medium sour crudes plus diesel, while Syncrude, CNRL Horizon, and Nexen Long Lake produce light sweet synthetic crude, and the Shell upgrader produces intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy SCO.

In early 2013 it was announced by Suncor and Total that their projected Voyager upgrader had been cancelled. Even before this announcement, the ERCB had expected the proportion of bitumen sold, relative to syncrude, to rise.

The sharp rise in world oil prices after 2004 was undoubtedly a factor encouraging expansion of oil sands output. At the same time, a number of newspaper reports indicated that companies were also revising their expected costs in an upward direction. Such cost inflation had been seen in the earlier construction boom, with Suncor and Syncrude, and seems to reflect a combination of design modifications, errors in cost estimation and rising input costs (spurred in part by the increased industry activity due to higher oil prices). In the following section, we examine the costs of oil sands production.

C. Costs

In our discussion of costs, we will focus mainly on costs for the mining projects, for which individual project costs are more readily available and may exhibit somewhat greater consistency across projects than do costs for the greater number, and generally smaller scale, of *in situ* ventures.

As discussed above, the 1960s saw the beginning of large-scale private production of bitumen deposits in Alberta. Profit expectations have not always been realized as the investor hoped, in part because project costs have often escalated and in part because it has been harder to attain and maintain output levels than was expected. This is especially apparent with oil sands mining projects. The unexpected rapid increases in world oil prices after 1972 were a great help to high cost oil projects and played a role in the increased interest in *in situ* recovery starting in the late 1970s.

Per barrel cost estimates for oil sands oil are difficult to derive, in part because much of the actual cost information is confidential to the companies concerned. However, some information has been provided in company annual reports and applications to governments and in public statements from company officials. It is useful to divide syncrude costs into at least three components – capital costs, operating costs, and 'government take' (taxes and royalties). The last of these will be discussed below and has frequently been subject to negotiation between companies and governments. The operating cost can be calculated on an annual basis as operating expenditures divided by annual output. It is often considered to include a 'fixed' and a variable component. The fixed component consists of expenditures that must be undertaken as soon as the decision is made to run the plant this year instead of shutting it down, whereas the variable operating expenses are those extra costs incurred each time an extra barrel is produced. The unit operating cost will be particularly high in those years in which there are technical operating difficulties; this is because the fixed operating costs must be spread over a smaller annual output and because operating expenditures on maintenance and repair will likely be higher. Economists usually calculate the unit capital cost as a 'supply cost' that spreads the total capital cost over the lifetime output of the plant and which includes a normal profit allowance as a cost. (Formally the supply cost is the present value of capital expenditures divided by the present value of output, where the present values are calculated on the basis of the 'marginal opportunity cost of investment' (the normal profit rate of return). The supply cost is, therefore, a unit charge on output that will generate a present value total just equal to the present value of the capital costs.) An unexpected breakdown that shifts output into the future has the effect of raising the capital cost of production since the present value of output will be reduced. Expressed in other terms, per unit capital cost estimates are dependent, not only on the accuracy of the capital cost numbers, but also on the accuracy of the output estimates for the project.

As discussed above, in 1950 Sidney Blair had estimated that a 20,000 b/d mining, separation, and upgrading project would be able to produce synthetic crude delivered to Edmonton for $2.08/b excluding a normal profit allowance. Allowing for general inflation (the GDP price deflator) and assuming a 1950 cost with normal profit of $2.20, this would imply a cost in 1965 of $3.18/b. The actual price of Redwater crude at Edmonton in 1965 was $2.62/b. This simple calculation would suggest that oil sands oil was not economic in the 1950s or early 1960s. However, two commercial ventures were initiated in the 1960s, Suncor and Syncrude. Can we say anything about their costs?

When Suncor was announced, it was expected to have a capital cost of $110 millions and a capacity of 31,500 b/d. A conservative estimate of the implied per unit capital cost can be calculated by asking what the supply cost would be for an infinite life project, costing $110 million this year and commencing production this year at 11,500,000 b/year. The cost depends on the normal profit rate chosen. At a 10 per cent rate, the implied capital cost is $0.96/b. (This combines a variety of errors. Since the $110 million is spread over time, its present value will be reduced slightly lowering the capital cost. However, the supply cost would be higher if it took account of the fact that present value output is overstated by this calculation. It would be lower than this cost since output too is delayed, since the project will likely have a 25- or 30-year life rather than an infinite one and since the project will not run at capacity all days in the year. On balance, the $0.96 understates costs.) The OGCB Feb.1964 *Report* on the Suncor (GCOS) application noted that cost escalation had increased the estimated capital cost to $137 millions (an implied per barrel cost of $1.20 on our rough estimate). Estimated operating costs had also increased. Both GCOS and the board now viewed the 31,500 b/d project as uneconomic. Hence GCOS was applying for a capacity increase to 45,000 b/d of bitumen, at a capital cost of $171 million ($1.04/b on our basis). Camp (1976, p. 63) reports that Suncor ended up spending $230 millions for a capacity of 45,000 b/d. Calculating as before, this implies a capital supply cost of $1.40/b. (In 1974, Suncor applied to increase capacity to 65,000 b/d, without any further capital expenditures. This would give a lower implied per barrel capital cost.) Suncor began producing in 1967 with a rated capacity of 45,000 b/d but did not attain that output level until 1972, as a result of significant start-up difficulties.

Reports by company spokesmen in the mid-1990s suggest that operating costs for both Suncor and Syncrude had been over $20/b in the late 1980s. However, they were falling, presumably as a result both of increased plant reliability and also due to efficiency improvements (due in part to what many call 'learning-by-doing'). Syncrude reported that operating costs in 1997 were $13.78/b and could fall as low as $10/b by the early years of the twenty-first century (Syncrude Canada, *Annual Report*, 1997; note that, with inflation in the economy, real operating costs per barrel are falling even more than these numbers indicate). If we assume a $13/b operating cost for Suncor and increase the $1.40/b capital cost for GDP price inflation from 1967 to 1997 (the investor would need payments to compensate him for rising costs over time due to inflation), we would find a total cost of production of $19.65/b ($13 + $6.65), as compared to an average price for synthetic oil in 1997 of $27.84/b. (However, from the viewpoint of 1967, if that year's price of $2.80/b had increased by the GDP deflator, the 1967 real price would have been only $13.30/b. That is, it was the rising real price of oil that would have allowed profitable operations by the late 1990s.) Hence, it would seem that crude oil prices since the early 1980s would have been high enough to cover the costs of a 'Suncor,' given the operating-cost savings that have been realized, but it is not at all clear that the prices anticipated in 1967 would have done so.

Syncrude's capital costs were much higher, for reasons that are not entirely clear. Among factors leading to higher costs are: (1) high inflation in the mid-1970s, (2) higher cost increases for the petroleum industry than other sectors of the economy as oil and gas activities increased with the OPEC-induced price rises beginning in the early 1970s, and (3) unexpected design adjustments as the Syncrude project came closer to completion. In its first guise, a consortium including Cities Service, Atlantic, Imperial Oil, and Royalite filed an application with the OGCB for a 100,000 b/d mining project to produce syncrude with an expected capital cost of $356 million ($0.98/b on our rough calculations). For reasons to be discussed below, OGCB permission was not granted. In 1964, the group re-constituted itself as Syncrude and filed in 1968 for an 80,000 b/d plant, which the OGCB authorized in 1969. In 1971, Syncrude filed an amended application to increase capacity to 125,000 b/d, with an estimated capital cost of $500 million, implying a cost per barrel (using our approximation) of $1.10. By the time production began in 1977, actual capital expenditures had escalated to $2.2 billion ($4.82/b).

Syncrude was the last oil sands mining venture in Alberta in the twentieth century. A number of other proposals were advanced, most notably the Alsands project in the 1980s (25% owned by Esso Resources, 20% by Canadian Occidental, 20% by Gulf Canada, 15% by Petro-Canada, 10% by Pan Canadian, and 10% by the Government of Alberta). The 1991/92 *Annual Report* of the Alberta Department of Energy estimated that it would produce 80,000 b/d of syncrude at a capital cost of $5.4 billion or $18.50/b! In 1982, Brandie et al. (1982, p. 158) reported likely costs for a 140,000 b/d syncrude plant. Operating costs were estimated at $16/b (excluding taxes and royalties). Capital expenditures included a low estimate of $5.1 billion ($9.98/b) and a high estimate of $8.5 billion ($16.63/b). Eglington and Uffelman (1984) estimated the cost of upgraded crude from the proposed Alsands project at $33/b to $48/b and suggested it would not be economic at anticipated world oil prices.

However, the expansion of Suncor and Syncrude apparently allows the realization of economies that lower unit capital costs for the incremental output. Presumably, it is possible to fit in new facilities that utilize spare capacity in existing facilities and to integrate new capital with old in ways that realize efficiencies. For example, the 'Syncrude 21' expansion was estimated to involve capital expenditures of $6 billion from 1999 to 2010, while increasing output from 220,000 b/d to 425,000 b/d. Our rough method of cost estimation shows a capital cost of $8.01/b for the incremental output. Combined with operating costs of about $12/b, this expansion would be profitable at oil prices over $20/b, apart from royalties and taxes.

Given the cost estimates of the 1980s, and the fall in world oil prices after 1985, it is hardly surprising that Syncrude was the last mining project opened before the millennium. In the early 1980s, however, many were optimistic about the possibilities for additional oil sands mining projects, partly because of the persistent, and long-standing, tendency to underestimate costs, and partly because of overestimates of oil prices. For example, Volume III of Foster Research's 1980 report for the Alberta government on *A Re-assessment of the Elements of an Economic Strategy for the Province of Alberta* offered a 'reference case scenario' in which mining plant capacity in the year 2000 was over 1,100,000 b/d, including expanded Suncor and Syncrude plants, the Alsands plant, and three large new mining projects. On the other hand, the National Energy Board in its June 1981 *Supply-Demand Report* showed a 'base case' in which only Alsands came on stream prior to 2000. The 1992 NEB *Supply-Demand Report* showed no new oil sands mining projects by the year 2010, estimating supply costs in the $22 to $30 per barrel range. (Chapter Eight, Table 8.3, includes more information on the NEB's cost estimates for syncrude and bitumen.)

In the late 1990s, a number of companies began to express renewed interest in large-scale oil sands projects, although the fall in oil prices in 1998 injected a note of hesitancy into some of these announcements. (In mid-February 1999, Alberta light crude was selling at under $17/b.) In February 1998, the EUB gave approval to a 140,000 b/d Shell project, the Albian Sands project, which would mine bitumen north of Fort McMurray, then ship it by a slurry pipeline to an upgrader just outside of Edmonton. The expected capital cost of $3.2 billion translates into approximately $6.26/b. As was noted above, beginning in the early 2000s, a number of companies revised their cost estimates in an upward direction, indicating sharp cost inflation, a process that continued over the next five years. By 2007, many were suggesting that integrated oil sands projects would be just economic at oil prices as high as $50/barrel. To illustrate the higher cost estimates, the December 18, 2010, *Globe and Mail* (p. B10) reported on an agreement between Suncor and Total in which the two would cooperate on investment in two bitumen mining projects, with capital costs of $6 billion and $9.5 billion and output levels of 100,000 b/d and 160,000 b/d, respectively. Also proposed was a 200,000 b/d upgrader at capital cost of $6 billion. Using our approximation of per unit capital costs, this translates into $16.44/b for mined bitumen and $8.22/b to upgrade it to syncrude, for a total capital cost of about $25/b; with the recent levels of operating costs discussed below, total per barrel costs for syncrude would come close to $45/b, and higher once royalties and income taxes are included. (Since the royalty/tax component is price dependent, it is difficult to include them in a cost estimate.) Costs may have been rising since then. The ERCB, in its 2013 *Reserves Report* (ST–98, p. 3-25), estimated that bitumen from *in situ* SAGD would require a WTI price of U.S.$50–80/b; mined bitumen would need WTI at U.S.$70-85/b.

As can be seen, cost estimates for mining projects have varied dramatically over the years. We suspect that costs for smaller-scale *in situ* ventures show at least as much variation, both in initial estimates and in actual outcome. The industry expenditure data

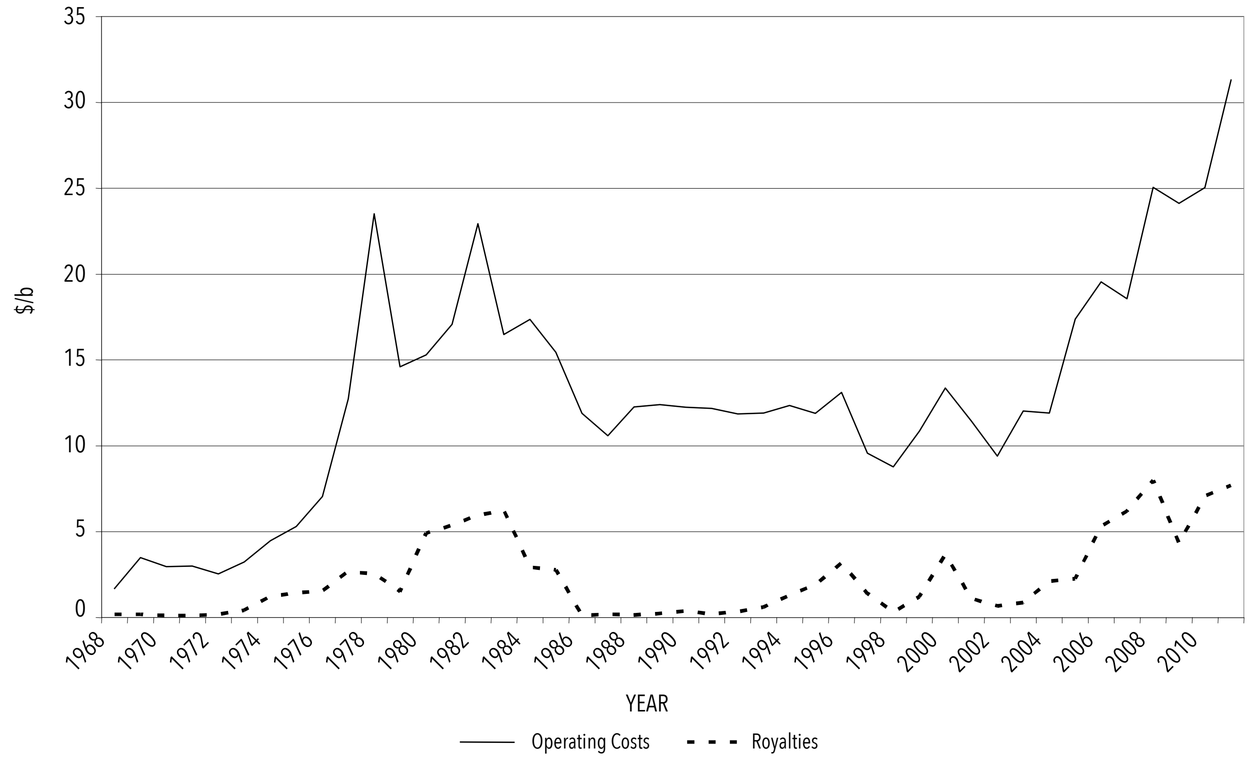


Figure 7.1 Unit Oil Sands Operating Costs and Royalties, 1968–2011

Source: CAPP, *Statistical Handbook*, 2012, Tables 3.2a and 4.16a.

reported by CAPP allow estimates over time of the unit operating costs and royalties for oil sands production (from both mining and *in situ* production). Figure 7.1 shows per barrel operating costs and royalties for the years 1968 through 2011. Operating costs started at under $5/b in 1968, and then rose dramatically to over $20/b in the years 1978 and 1982. They fell after that, hovering around $12/b after the mid-1980s until rising sharply again after 2005. Syncrude's *Annual Reports* show its operating costs falling to around $12/b in the late 1990s, but then rising above $16/b in the early 2000s, apparently reflecting a number of operating problems and shut-down periods. (Royalties will be discussed below.)

Two components of operating cost are particularly critical, since oil sands projection techniques (particularly mining projects) are energy- and water-intensive. Hence costs are sensitive to the prices of these resources, and the policy issues and uncertainties related to each.

Thus far, natural gas has been the major energy source utilized. A CERI oil sands study (Dunbar et al., 2004, pp. 60 and 67) suggests that one barrel of bitumen from a mining project requires between 250 and 300 feet of natural gas, while an integrated mining, separation, and upgrading project uses between 400 and 750 Mcf per barrel of synthetic crude. Using the average values, this implies that a two dollar per Mcf rise in the price of natural gas would increase the annual operating costs of a 100,000 b/d bitumen mining venture by some $20 million (about 0.55 cents per barrel); the operating cost for a synthetic crude operation of the same size would rise by over $40 million per year (or a little under $1.20 per barrel). The CERI study notes a rule of thumb for *in situ* bitumen ventures of 1,000 cubic feet of natural gas per barrel of bitumen, but reports a range of 510 to 1610 cubic feet, depending on the required steam to oil ratio. The rule of thumb value implies that a $2/Mcf increase in the natural gas price would raise the bitumen cost by $2/barrel.

Rapidly rising gas prices in the early 2000s increased operating costs for the oil sands and spurred interest in alternative energy sources. There were occasional presentations of the argument that costs might be reduced if the oil sands operators were able to self-generate the required energy, for example by using bitumen itself as fuel or by gasifying hydrocarbons from the heavy oil. The argument is curious because the appropriate cost of an input is its 'opportunity cost.' Hence gas produced from the heavy oil resource is not costless but has an economic cost equal to the price one might sell it at; if natural gas prices rise, the value of the self-produced gas also increases. The decline in North American natural gas prices after 2009 would, of course, reduce oil sands operating costs.

A further complication relates to the controversial question of whether energy and water inputs are bearing their full social costs (Nikiforuk, 2008). If not (for example, because energy prices fail to include environmental costs such as those associated with global warming, or water is underpriced), then oil sands operating costs could increase appreciably in the future as government programs are introduced to address such inefficiencies. Of course, such input price rises encourage input substitution, which can be particularly effective for new ventures. Thus, use of alternative energy sources such as nuclear power or coal (which could produce hydrogen as an injection fluid), increased use of carbon dioxide as an injection substance, and greater water recycling could well result.

There can be no doubt that output from the oil sands is costly, frequently more costly than has been anticipated, often due to unexpected technical problems. Operating costs fell somewhat from the mid-1980s, especially in real terms, but development and operating costs are still high, and there are continuing uncertainties attendant to the cost estimates. Escalating costs may reflect ever-present design problems and may be providing some incentive to companies to phase in projects more gradually, and in smaller increments. The high costs have meant that anticipated oil prices play a major role in project planning. Moreover, costs must be considered from both a project and an industry perspective, since oil sands production is concentrated in a relatively small regional economy. Greater construction activity puts pressure on local input supplies and requires greater in-migration of workers and materials. The labour and goods markets react through price increases that attract more workers and supplies from outside the region. Price increases also raise costs to local producers, thereby discouraging some projects and freeing inputs for other projects (such as the oil sands plants). This can raise major problems for the local community; for instance, the projects squeezed out by rising input costs might be local government services and community and recreational facilities (Nikiforuk, 2008). These broad-based regional economic effects raise the possibility that a more active government role is desirable to address inefficiencies in market reactions and/or to help smooth adjustment costs. Examples of the former might be government investment in vocational training for specific skills in short supply and provision of information in other regions of job opportunities in northern Alberta. Examples of the latter might include financial aid from Edmonton to local governments for infrastructure such as roads and schools.

More controversial, as government policy, would be a requirement that the licensing of projects take into explicit account the 'optimal timing' of construction in light of socio-economic adjustment costs. Thus far, the ERCB has noted some of these problems but has not explicitly taken them into account when issuing approvals for expansions or new facilities; this has lead some to suggest that it is failing to uphold its responsibilities to assess the extent to which projects are in the public interest (Fluker, 2005; Nikiforuk, 2008). The government, as much as market forces, would then be playing an active role in selecting which project would proceed and when. Growth pressures on the local economy, including input price inflation, could be moderated. However, the government, or its regulatory representative, would have to develop criteria to distinguish amongst competing projects to see which would be approved first, and it must be recognized that some local workers, homeowners, and businesses might prefer to see their services rise in value.

4. Government Policy in the Oil Sands

A. Mineral Rights

As noted, Alberta decided in 1950 that oil sands development would be undertaken by the private sector. Bitumen leases were generally issued following application to the government, rather than through the competitive bidding process used for most conventional petroleum mineral leases. This reflected the uncertain economics of the oil sands, and the desire to encourage companies to develop and test new technologies. More recently (since 1992), bonus bids have been solicited on leases on oil sands lands, but bids per hectare have been low compared to much land more promising for conventional oil or natural gas; this is not surprising given the relatively high expected costs, and low prices, of bitumen. Bitumen and oil sands leases have also incurred annual rentals. (For example, the 1978 regulations for oil sands leases specified an annual rental of $2.50 to $3.50 per hectare.)

Oil sands leases have generally applied only to the geologic formations that hold the oil sands, thereby allowing the government to issue conventional petroleum mineral rights for other formations on the same land area. In the late 1990s, some potential oil sands operators were questioning the wisdom of this policy since they felt that the production of natural gas from formations adjacent to oil sands formations might serve to reduce recovery of *in situ* bitumen. The EUB held hearings on this issue, and in 2004 the EUB issued an interim order that a significant number of natural gas wells in the oil sands area be shut in. A final decision, EUB Decision 2005-122 of November 2005, reaffirmed the shut-in of 917 natural gas wells.

By the mid-1950s companies were beginning to take up bitumen leases (starting in 1961 the leases were issued as 'oil sands leases'). These were 21-year leases, renewable for another 21-year term, and then for a third 21-year term, so long as the lease had attained a minimum output level specified in the lease. (In the mid-1990s, the government amended these regulations so that third-term renewals were possible so long as the operator and the EUB had agreed upon a plan to commence production.) From 1 lease at March 31, 1946, covering 3,834 acres, the number of outstanding leases rose to 9 (17,788 hectares) in 1956, 86 (1,254,409 ha) in 1962, 138 (1,686,815 ha) in 1970, 197 (2,023,000 ha) in 1979, and 345 (2,032,000 ha) in 1994. By March 31, 1996, a total of 526 leases covered about half of Alberta's estimated bitumen in place; 118 of these leases were in their second term, some nearing the end. By fall 2003, a total of 1,807 leases were in operation covering 32,000 square kilometres (3,200,000 ha), and from then until March 31, 2010, another 5 million hectares were issued. (Data are from the *Annual Report*s of the provincial government department handling mineral rights; outstanding lease areas were not reported for 1996 or subsequently; new leases after 2003 are from the *Annual Summary of Oil Sands Public Offerings* on the Department of Energy's website.)

B. Approvals

Before commercial syncrude production can commence, provincial government approval is required for the project. An initial report (usually following a public hearing) by the ERCB (previously OGCB, and EUB) makes a recommendation to the Lieutenant Governor-in-Council. After the provincial government gives approval, the ERCB issues an order allowing production. Approval depends on the project being in the 'social interest,' but the critical question is what this means. The ERCB has, at various times, considered a number of factors including the technical efficiency of the project (does it use a viable technology? does it recover a sufficient proportion of the bitumen in place? is the upgrading procedure efficient?, etc.), the economic and financial viability of the project, the social and regional impact, environmental effects, the impact on government revenue, and others. (See Atkins and MacFadyen, 2008. Fluker, 2005, McCullum, 2006, and Nikiforuk, 2008, argue that the ERCB has been negligent in failing to take a broad enough view of the Alberta public interest.)

In the 1960s, however, the key issue was the impact that a large oil sands project would have on the conventional petroleum industry. Two factors made this an important matter. The first was the high cost and large scale of oil sands mining projects. It was assumed that economic viability depended on their operation at full capacity (so that the high capital costs and significant 'fixed' operating costs could be recovered as quickly as possible), and large plants were needed to realize economies of scale. The second factor was the provincial market-demand prorationing scheme, which, in the early 1960s, fixed the output of the conventional Alberta oil industry at only about 50 per cent of productive capacity. (Chapter Ten looks in detail at prorationing. Simply put, prorationing regulations restricted oil production to estimated market demand at current prices.) If a new oil sands project were to provide oil to customers who would otherwise buy conventional Alberta crude, prorationing regulations would have to cut back conventional production even further. The government faced an obvious dilemma. On the one hand, it wished to encourage development of technologies that would unlock the large bitumen resource base. On the other hand, this would mean displacing relatively low-cost conventional crude with high-cost syncrude.

The issue was recognized as early as 1955, when the *Bituminous Sands Act* was passed with a key provision ensuring that the *Oil and Gas Resources Conservation Act* of 1950 did not apply to surface mining oil sands projects or the sale of the resultant products. We shall trace the evolution of the Alberta policy with respect to oil sands development through the historical applications for approval.

GCOS 1960 Application. As discussed above, Suncor (then known as Great Canadian Oil Sands, GCOS) applied for a 31,500 b/d integrated mining project in 1960. GCOS indicated that almost all the output would be sold to two Sarnia refineries, owned by Sun and Canadian Oil Companies, largely using conventional Alberta crude. The OGCB estimated that 80 per cent of the oil displaced would come from Alberta and that 'proratable market demand' for conventional oil would fall by 20–30 per cent (OGCB, 1960, pp. 5, 73–74). (Proratable market demand was total market demand less the well based economic allowances and was the basis for the variable output allowable production levels under the province's market-demand prorationing regulations.) The size of this impact on the conventional industry, along with its doubts about project economics, led the OGCB to defer its decision and invite GCOS to submit further evidence by June 1962.

GCOS 1962 Application. The board cited three factors to aid in assessing the impact of oil sands production on Alberta's conventional oil industry: (1) trends in the life index (R/P ratio); (2) capacity utilization; and (3) the market-demand prorationing allocation factor (OGCB, 1962, p. 39). (The prorationing factor was essentially the proportion of productive capacity a well was allowed to use under market-demand prorationing.) On October 2, 1962, the OGCB approved the GCOS (Suncor) project for a 31,500 b/d capacity plant. It argued that the impact of the project on the market for conventional oil, the allocation factor, and the ratio of output to capacity was not sufficient "to have any serious detrimental effect on the conventional oil industry" (OGCB, 1962, p. 42).

Oil Sands Development Policy of 1962. The provincial government accepted the OGCB recommendation, but Premier Manning took the occasion in October 1962 to announce a provincial policy on oil sands developments. The policy statement is reprinted as Appendix B in the February 1964 *Report* of the OGCB on the GCOS application for expansion (OGCB, 1964a). The statement noted that

> the Government has an obvious responsibility to regulate the timing and the extent of oil sands production to protect the interests of the public as the owners of the resource....
>
> Obviously it would be detrimental to the public interest to permit unregulated development of an alternative source of supply to impair the economic soundness of the conventional oil industry by further reducing its already limited market.… Having regard to these circumstances, the policy of the Government will be to so regulate oil sand production that it will supplement but not displace conventional oil. At the same time, an opportunity will be provided for the orderly development of the oil sands within the limits dictated by the Government's responsibility to the public interest in preserving the stability of conventional oil development.…

The Policy Statement suggested that there were two categories of oil sands oil. "For such production from the oil sands as may be able to reach markets clearly beyond present or foreseeable reach of Alberta's conventional industry, there is no need to restrict the rate of production." However, three criteria were imposed for oil sands oil that did compete with conventional oil in "present or foreseeable markets":

(a) in the initial stages of oil sands development, by restricting production to some 5 per cent of the total demand for Alberta oil – i.e., at a level of the order of that recently approved for Great Canadian;
(b) as market growth enables the conventional industry to produce at a greater proportion of its productive capacity, by permitting increments in oil sands production as recommended by the Oil and Gas Conservation Board, and on a scale, and so timed, as to retain incentive for the continued growth of the conventional industry; and
(c) by relating the scale and timing of increments of oil sands production also to the life index of proven reserves of conventional oil allowing the index to decline gradually from present levels but ensuring that it does not drop below 12 to 13 years.

1963 Applications by Cities Service et al. and Shell. In early 1963, the OGCB held hearings on two new mining project applications, one by a group led by Cities Service Athabasca (including also Imperial Oil, Richfield Oil, and Royalite Oil) for a 100,000 b/d mining plant, and a second by Shell Canada for a 97,000 b/d project. The board interpreted the 1962 government policy as favouring the sharing of any market growth in excess of that which would maintain the conventional industry's level of capacity utilization. So long as this capacity utilization grew by at least one percentage point per year, the 'excess' market growth could be shared between conventional and oil sands production. However, the board argued (OGCB, 1963, pp. 231–32) that these projects would violate the provincial policy: synthetic crude output would exceed 5 per cent of the market; the R/P ratio wasn't likely to fall below 12–13 years within the forecast period the board was using; and even synthetic crude of 100,000 b/d commencing in 1971 (let alone what these two projects planned) would deny growth opportunities for conventional oil until 1973. Both projects were denied, but the board would allow reconsideration of the projects up to the end of 1968.

Additional GCOS *Application, 1963*. In September 1963, GCOS filed an application to increase the capacity of their project to 45,000 b/d, arguing that a larger capacity was economically essential. Clearly the 1962 government Policy Statement provided a rough guideline that the OGCB had to interpret in a specific manner. From an economic point of view, the two-fold market distinction was strange. Why should there be markets for high-cost oil sands oil that were not accessible to lower-cost conventional oil? If there were significant buyer power in the crude oil market, a refiner might refuse to buy oil from conventional producers in Alberta but be willing to switch from non-Alberta producers to its own oil sands oil. However, in a reasonably competitive market, conventional light Alberta oil and syncrude should be equally appealing to a prospective buyer. The OGCB seems to have accepted the competitive market view as it took "the position that the boundaries to such markets are geographical, and would not be defined according to individual company policies" (OGCB, 1964a, pp. 60–61). Hence, the three criteria (a), (b), and (c) were the critical ones. In essence, the OGCB undertook forecasts of consumption of Alberta oil and conventional reserves additions and then saw what conventional oil output would be at different hypothetical syncrude production levels; this allowed assessment of syncrude's share of demand (was it close to 5% as (a) required?), of spare capacity in the conventional industry (was the percentage of spare capacity falling as (b) required?), and of the R/P ratio (was it around 13% as (c) required?). In 1964, the board approved the GCOS amended application, even though at startup the project was expected to absorb 7.5 per cent of the market for Alberta oil. While this was seen as beyond "a narrow interpretation" of the five per cent limit, the project was seen as falling "within the intent of the policy for the initial development of the oil sands" (OGCB, 1964, p. 80).

Oil Sands Development Policy of 1968. A new oil sands policy was issued by the government in February 1968 (reprinted as Appendix A, Part 2 in OGCB, 1968) in response to several developments since 1962. These included the 1964 modifications to the prorationing plan that had reduced incentives to develop extra conventional crude oil production capacity. In addition, the market for Alberta oil had grown more slowly than the OGCB had expected, and several new oil plays had added to conventional reserves, so that the R/P ratio in 1968 was at 31 years, much higher than the 21 years the board had forecast. A number of modifications were made to the oil sands policy:

- The oil sands provisions were extended to heavy oil deposits like Cold Lake.
- 'Beyond reach' markets (definitely accessible to oil sands output) were not to be interpreted in a purely geographic sense. Rather, they were to be interpreted as any markets, including 'specialty markets,' not served, nor expected to be served in the foreseeable future because of price, quality specifications, or other reasons.
- For 'within reach' markets, the capacity utilization requirements were dropped, leaving the trend in the R/P ratio as the prime criterion. In addition, if an applicant could demonstrate provision of additional growth in demand by developing a 'new' within reach market, then 50 per cent of the new market could be granted to the applicant. A 'new' market was "one not being served today; one over and above growth in existing markets; and one representing a net increase in the total market." However, up to 1973, oil sands production in such 'new' markets was limited to 150,000 b/d including the 45,000 b/d from GCOS.

Syncrude (Cities Service) Application, 1968. In 1968, an amended application was made by the Cities Services group for an 80,000 b/d oil sands project. The operating company would be Syncrude Canada. Each Syncrude member proposed to market its share of the project's oil in 'new within reach' and 'beyond reach' markets. The board, in its decision, fleshed out the 1968 government policy distinction between 'within reach' and 'beyond reach' markets (OGCB, 1968, pp. 73–74):

- 'Within reach' markets were defined geographically by the current and prospective pipeline network available to Alberta producers; 'beyond reach' markets lay outside this geographic area. However, the board did allow for specialty markets in the 'within reach' geographic area which were not serviceable, now or in the foreseeable future, by the conventional industry; such specialty markets would be classified as 'beyond reach.'

- The board set out its interpretation of the three criteria for 'new within reach' markets. This would include 'within reach' requirements not served by Canadian sources of supply. 'Markets over and above normal growth' had to allow for increased penetration by conventional oil over the medium term, so would involve accelerated market acquisition and could involve serving a market which otherwise would be unlikely to use oil from Alberta. The board felt that corporate proprietary interests could be important for such 'new' markets. 'Normal growth' included growth in feedstock requirements for refineries heavily dependent on Canadian supplies, increased penetration of refineries which were showing a trend of rising reliance on Canadian oil, and requirements of any refineries with no alternative supply sources. A 'net increase in the total market' would not be satisfied if absorption of Canadian supplies in a 'new within reach' market displaced Canadian supplies to other portions of 'within reach' markets, or precluded normal growth of sales in such markets.

With respect to the Syncrude application, the board found that the marketing plans aimed largely at 'new within reach' export markets were valid and that proposed specialty market sales of syncrude and naphtha would satisfy the 'beyond reach' criterion. However, the board felt that for the export sales to qualify as representing a 'net increase in the total market,' the U.S. restrictions on imports of Canadian oil would have to be removed. (The U.S. Oil Import Quota Program is discussed in more detail in Chapter Nine.) Since it was uncertain whether this would happen, especially given the developing oil supplies from the North Slope of Alaska, the board refused approval of the Syncrude application. It did invite a reconsideration of the application in late 1969 if the applicants could provide information to allay the board's concerns about the impact of Alaskan supplies in reducing the markets for Canadian oil.

Syncrude's March 1969 Appeal. In February 1969, Syncrude applied to the Alberta government, appealing the OGCB decision and requesting a new hearing. Syncrude argued that uncertainties about Alaskan oil supplies could not be resolved at this time. Syncrude alluded to new evidence that U.S. oil consumption was growing faster than earlier studies had estimated and proposed deferring the start-up date of the project three years to 1976. Syncrude argued that these factors should assuage the board's concerns about the impact on oil imports of a rapid build-up of Alaskan oil production. The government referred these matters to the OGCB, which invited an amended application from Syncrude.

Syncrude's Amended Application, 1969. After a May 1969 hearing, the board issued a September Decision Report approving the amended Syncrude application. The decision was not unanimous, but the majority agreed that Syncrude's plans now met the 'net increase' criterion. The dissenting board member disagreed with this conclusion but saw the proposal as "appropriate" in light of the declining trend in the R/P ratio and the expected need for oil sands oil to supplement conventional oil around the year 1980.

This dissenting opinion was prescient: following approval of the Syncrude application, neither the government nor the board expressed much concern with the question of whether oil sands production would reduce the market for conventional Canadian oil. The U.S. import quota program was eliminated in the early 1970s, and the unsettled world oil market led the Canadian and U.S. governments to favour North American oil supplies, including oil sands production.

Alberta's Conservation and Utilization Committee. In 1970, the Social Credit government, which had been in power since 1935, was defeated by the Progressive Conservatives under Peter Lougheed. The new government established an internal Conservation and Utilization Committee to prepare an oil sands development strategy. In a statement of its 'primary objective,' the Committee noted (p. 5):

> Alberta is not under any pressure to develop synthetic crude oil from the bituminous tar sands for the purpose of meeting either Albertan or Canadian petroleum requirements. The pressure to develop synthetic crude from the tar sands emanates from markets external to Canada.…
>
> … [I]t becomes axiomatic that Alberta's primary objective should be to regulate, guide and control the bituminous tar sands development in order to meet the growing socio-economic needs of Albertans as well as Canadians.

The authors noted that this left a variety of relevant concerns (provincial economic development, conservation, stimulus to Canadian businesses, government revenue, regional economic development, manpower training, environmental protection) which were not all mutually consistent but did provide the guiding principle that "foreign energy demands should not be the only force influencing development" (p. 6). The "pro-Canadian and pro-Albertan flavour" (p. 27) of this approach made itself manifest in suggestions that the Canadian engineering and design input should be maximized, that the local Fort McMurray region should be heavily involved in the planning and implementation process, and that "[t]he oil sands offer a unique opportunity to change the historical trend of ever-increasing foreign control of non-renewable resource development in Canada" (p. 16). Research was suggested to study the feasibility of channelling private and public Canadian investment into the oil sands. Under the heading "Suggested Dimensions of Development Model" (p. 24), it was noted that, while "the actual rate would depend on Alberta's and Canada's capability to generate sufficient capital as well as our requirements for socio-economic development," their "projection is based on approximately 1,000,000 barrels capacity per day by the year 2000."

Underlying this policy document is a common, but debatable, view of the oil sands as an almost limitless constant cost resource. Once the price rises high enough that they are economic, they would become a perfect substitute for other crude oil supplies. Consumers anxious to reduce dependence on OPEC, and unstable Middle Eastern suppliers in particular, will turn en mass to the oil sands. From such a perspective, it is natural that the government should be concerned with the orderly development of the resource. A more realistic view casts some doubt on this vision. In the first place, the oil sands are not a constant quality resource; the depth of the overburden, the bitumen content, the serviceability of the deposit, the closeness of process water, and other factors vary for mineable deposits. There is probably even more variability for *in situ* sources (Ruitenbeek, 1985). However, it does seem likely that the long-run supply curve is relatively elastic once the oil price is high enough. Moreover, the resource base is so large, and the quality of deposits is consistent enough over the area necessary to support a single project, that the user cost of bitumen production is undoubtedly very low. A second problem with this view of the oil sands is that it ignores the strategic and dynamic nature of world crude oil markets. OPEC is acutely aware of the necessity of pricing oil in such a way as to maintain markets and would not tolerate a large loss of market share to a competitor such as the oil sands. In a reasonably well-functioning crude oil market, one would expect that potential investors in oil sands projects would be aware of this and regulate investment accordingly. (Such commercial caution could be overridden by some government policies, such as, for example, a minimum price guarantee high enough to cover capital and operating costs.)

The Conservation and Utilization Committee's report was quite properly concerned with the development of Alberta's oil sands resources in a manner consistent with the public interest. It is likely that the oil sands and heavy oil deposits raise potential problems beyond those associated with the conventional crude oil industry. The huge resource base is regionally concentrated, mining mega-projects have relatively high manpower requirements during both construction and operation, and the separation and upgrading processes pose special environmental problems. These were, in fact, not entirely new concerns in the early 1970s, many of them having been considered by the OGCB in the 1960s under the guidelines established by Manning's Social Credit government. The 1971 Progressive Conservative government under Peter Lougheed may be seen as offering an oil sands policy that differed in two main respects. One was the high emphasis placed on the regional economic impact of syncrude production. The other was the suggestion that direct government investment in oil sands ventures might be desirable. The latter did become an important factor, although not for the reasons that the Conservation and Utilization Committee suggested.

Syncrude's Construction. The story of the building of the Syncrude project is complicated and overlaps in part with negotiations about government take. (Pratt, 1976, provides a detailed review of the history of Syncrude, although one that is coloured by distrust of the major oil companies.) As discussed above, in September 1969, the OGCB approved an 80,000 b/d Syncrude plant. In December 1971, it approved an expansion to 125,000 b/d capacity. The market for Alberta oil was growing rapidly, and additions to conventional reserves were slowing with the result that the board foresaw continuing declines in the Alberta conventional oil R/P ratio (or 'Life Index,' as the board preferred to call it). Hence the output from Syncrude could be absorbed in the market without a significant negative effect on the conventional Alberta industry.

By 1973, conflicting pressures were evident. On the one hand, escalating costs were inhibiting the private Syncrude investors. On the other hand, the 1973 international oil crisis, and the OPEC price rises in 1973 and 1974, increased the value of Alberta oil and its attractiveness as a North American supply source. The Conservation and Utilization Committee had implied that there might be such high demand to invest in the oil sands that the government would have to limit investment and that both the provincial and federal governments might desire to invest themselves in order to maintain Canadian control over the resource. Rising cost estimates for the Syncrude project changed this picture dramatically. It became unclear whether *any* mining projects would be economic, and government involvement became a possible means of ensuring that Syncrude went ahead. By 1973, the capital cost estimate for Syncrude had escalated from $500 million to $2.4 billion. Planned capacity had also been raised to 125,000 b/d, but the 56 per cent increase paled beside the almost 400 per cent cost rise. Intense negotiations between the Syncrude consortium and Canadian governments ensued, covering tax/royalty, pricing and investment issues, the resultant agreements proving to be very controversial. (Pratt, 1976, chaps, 8, 9, 10, and 11, provides a very interesting review of the process, while arguing that the governments caved in to demands of the multinational oil companies. Fitzgerald, 1978, chap. 11, reports much more favourably on the governments' roles, suggesting that the project would not have proceeded without their involvement.) Alberta and Syncrude had reached an initial agreement in September 1973, which established a new royalty regime unique to Syncrude, a provincial-government-established oil company (Alberta Energy Company) providing utility and transportation infrastructure and taking a minority equity share in Syncrude and government guarantees of some stability in environmental and trade union regulations.

However, the taxation and pricing provisions required the agreement of the federal government as well. (As will be discussed in Chapter Nine, Ottawa had imposed a freeze on the price of crude oil in Canada in September 1973, holding it below the international price, whereas Syncrude and Alberta had agreed that Syncrude should obtain the international price. Also, the unusual royalty arrangement had to be recognized in the corporate income tax regulations.) Negotiations were proceeding with Ottawa when, in December 1974, Atlantic Richfield announced its withdrawal from the Syncrude consortium, necessitating a reassessment of the project.

A new agreement was reached in Winnipeg on February 3, 1975. This affirmed the international pricing and royalty provisions of the earlier agreement with Alberta, the provincial infrastructure provision and investment in utilities by the Alberta Energy Company, and the exemption of Syncrude output from prorationing restrictions. The governments would step in to replace Atlantic Richfield. The Winnipeg agreement left equity ownership in Syncrude as follows: Imperial Oil, 31.25 per cent; Cities Service, 22 per cent; Gulf, 16.75 per cent; Ottawa (Petro-Canada), 15 per cent; Alberta, 10 per cent; and Ontario, 5 per cent. In addition, Alberta agreed to loan $100 million each to Gulf and Cities Service (with an option to convert to equity, which was exercised 1982), and the Alberta Energy Company was given an option to buy from 5 per cent to 20 per cent of the project, an option that could be exercised before cumulative Syncrude output hit 5 million barrels and was taken up in 1979. Hence Syncrude, the last oil sands mining venture before the turn of the century, proceeded with significant direct government investment. After 1975, the ownership of Syncrude changed somewhat. As of 2013, it is as follows: Imperial Oil Resources, 25 per cent; Suncor (which acquired the Petro-Canada share when the two companies merged in August of 2009), 12 per cent; Sinopec Oil Sands Partnership (a Chinese state oil company, effective April 2010, acquired the ConocoPhillips share, which it had gained when it took over Gulf Canada in 2002), 9.03 per cent; Nexen Oil Sands Partnership (formerly Canadian Occidental), 7.23 per cent; Murphy Oil, 5 per cent; Mocal Energy (a subsidiary of Nippon Oil from Japan), 5 per cent; and Canada Oil Sands Limited, 36.74 per cent. (The latter is a royalty trust that makes payments to its investors on the basis of Syncrude operations.)

It is difficult to undertake detailed economic analysis of the Syncrude project from either the private or social points of view. Private analysis is hard, given the changing corporate ownership and the lack of detailed cost data. In part, this difficulty extends to the government sector as well since the governments were equity participants. But analysis for the governments is further complicated by uncertainty about exactly what governments were trying to achieve with their oil sands investments. Was it security of supply (higher Canadian oil production and reduced imports)? Was it improved knowledge about oil sands production techniques? Broader spreading of commercial risks? Economic diversification? Regional economic development in north eastern Alberta? Canadian participation in the development of oil sands technologies? All of these may have been obtained to some extent by the governments' investments in Syncrude, but there is no clear indication of the value that ought to be placed on such benefits.

The sale by the Alberta Government of its equity interests in Syncrude in the early 1990s provides some basis for assessing economic returns associated with the plant. In December 1993, Alberta sold a 5 per cent share in Syncrude to Murphy Oil for $150 million (or $30 million for a 1% equity share). In November 1995, Alberta sold 11.74 per cent to Torch Energy for $352.2 million (again $30 million for 1%, a slightly lower value, allowing for inflation over the two years since 1993). If we take $30 million as the value of expected discounted profits to an investor in Syncrude for each 1 per cent ownership share, we can derive a rough estimate of the expected profitability of a barrel of Syncrude production as seen by market participants in the mid-1990s. If we assume that output would continue for twenty more years, that Syncrude had a capacity of 220,000 b/d, and that the requisite rate of return on capital is 10 per cent, then the anticipated per barrel profit (after taxes and royalties) would be $4.32/b. (The life of the plant is hard to determine. Syncrude is now over thirty years old but may be able to maintain its separation and upgrading equipment for many years and simply mine new parts of the sands; moreover, more efficient use of existing equipment has apparently allowed both Syncrude and Suncor to expand output somewhat beyond rated capacity with minimal new investment. Further, both Syncrude and Suncor have undertaken large expansions.) This estimated return is an implicit function of the tax/royalty regulations, expected oil prices, expected operating costs, and the past depreciation and capital cost provisions that dictate how much of past capital has been 'recovered.'

It might be tempting to compare Alberta's share of Syncrude investment to the return from its sale of ownership, but it is hard to know how to interpret the resultant figure. If Syncrude had a capital cost of $2.4 billion, a 16.4 per cent cost share would be $394 million spent in the mid-1970s, making a return of $502 million after almost twenty years seem relatively small. ($394 million invested at 5%/yr would give over $1 billion after twenty years.) However this calculation fails to account for the payments made to the government over the years as a partner in Syncrude. These would have been relatively small in early years when operating costs were very high but became more significant as operating costs fell. (The 1997 Syncrude *Annual Report* shows operating cash flow, i.e., revenue less operating costs and royalties, rising from $6.39/b in 1993 to $11.34/b in 1997.) *Annual Reports* of the provincial government's Energy Department show total equity payments to the province from 1980 to 1992 of $496.2 million, making the total return to the province over the twenty years on its equity investment almost $1 billion. (This calculation allows for neither the province's share of Syncrude's incremental investment costs after the first stage nor the time value of money in the time flow of these receipts.)

In retrospect, it appears that high risks probably necessitated active government involvement in Syncrude, while recognizing that some of the risks were government generated (e.g., risks of changes in regulations). An integrated oil sands mining project involves a very large capital commitment, and the high per unit capital and operating costs mean that the project is very vulnerable to falling oil prices.

The other large proposed mining venture in the 1980s was the Alsands project (or OSLO, Other Six Lease Owners project), which was reportedly expected to produce 70,000 b/d of syncrude at a capital cost of $4.1 billion ($16/b by our rough estimates, based on numbers in the 1988/89 *Annual Report* of the Alberta Department of Energy). Another estimate put production at 80,000 b/d of syncrude at a capital cost of $5.4 billion ($18.50/b). In September 1988, the private participants reached an agreement similar to that with Syncrude, including federal (10%) and provincial (10%) government equity participation. But in February 1990, Ottawa withdrew, and work officially stopped two years later. Costs were simply too high, given world oil prices in the 1990s.

On the other hand the commercial *in situ* projects of the 1980s (e.g., Esso's Cold Lake and BP's Wolf Lake, since sold to Amoco, but re-acquired when BP and Amoco merged internationally) were undertaken without government financial contributions, even though one of them (Cold Lake) was also very large and costly. The large oil sands projects proposed in the late 1990s, some proceeding after the turn of the century, came from private participants with no indication that they required government equity participation or loan guarantees, nor any hints that governments were considering this possibility. While the involvement in Syncrude might be justified on grounds of learning or higher private than social risk, the judgment now appears to be that oil sands projects must stand on their own in commercial terms. Alberta still requires that such projects be approved by the ERCB after demonstrating that they are in the public interest by making efficient use of available technologies, meeting environmental standards, and not placing undue burdens on regional economies and infrastructure. Subject to these conditions, the Province expects that commercial exploitation of the oil sands and heavy oil deposits will proceed under private development.

C. Pricing

As has been noted, Alberta syncrude is a light, low sulphur crude and hence is priced a little higher per barrel, delivered to Edmonton, than a typical reference crude such as Redwater. In general, syncrude prices have tracked the light crude oil prices shown in Chapter Six. It should be noted that there are unique characteristics of synthetic crude oil from the oil sands that prevent a typical refinery from running entirely on this oil; currently synthetic crude can provide up to about 30 per cent of the oil input for such a refinery.

As will be discussed in Chapter Nine, from 1973 until 1985, there were government price controls on Canadian crude oil. These arose after the international price rises engineered by OPEC beginning in the early 1970s and served to keep oil prices in Canada lower than international prices. A key issue for potential investors in the oil sands was how their oil was to be priced under the government price control regulations. As it happened, it was agreed that Syncrude's output would be allowed the international price, even while much conventional Alberta crude received lower domestic prices. This reflected the presumption that syncrude was high cost so would be produced only if it were allowed a high price and the realization that it would be preferable for Canada to produce syncrude rather than importing oil so long as the production cost of the syncrude was less than the cost of the imported oil. This decision did raise an issue of fairness with respect to Suncor. Starting in 1978, it too was allowed the world price. Thus from 1978 to 1985, synthetic crude was at the world price, rather than the domestic controlled price.

If the oil from the oil sands is not upgraded, the value of the oil is much less. While bitumen prices have tracked the broad trends in lighter crude oil prices, the correlation is not perfect; in other words, the light oil-bitumen price differential changes over time. Part of this reflects the changing relative values of light and heavy oil prices. From 1987 through 2001, the posted price for Lloydminster Heavy oil at Hardisty averaged $6/barrel below the Alberta light par price; but the differential varied considerably as well, from as little as $2/barrel to over $20/barrel. In addition, the differential between heavy oil and bitumen also changes. Precht and Rokosh (1998) present a figure (their Figure 8) plotting Lloydminster Heavy and Cold Lake bitumen prices from 1994 to 1998 in which bitumen prices are consistently lower than the Lloydminster price by amounts varying from $2 to $7 per barrel. Bitumen prices are not regularly posted, but the Alberta Energy and Utilities Board does obtain some bitumen price data from producers. Figure 7.2 shows crude oil price differentials in Alberta from 2002 to 2011, where the differential between bitumen and light oil can be seen as comprising two components: (1) the differential between light and heavy oil (as represented by the Alberta 'par' price less the price of heavy oil at Hardisty), and (2) the differential between the Hardisty price and that for bitumen. As can be seen, the light/bitumen differential over this period has varied from as little as $9/b (in summer 2009) to $60/b (in spring 2008). In general, the differential rose from 2002 to 2005/6, then declined, before hitting the spring 2008 peak; after this, it fell back to the levels of 2002–4. In 2011, the heavy/bitumen differential widened again; in addition, as was discussed in Chapter Six, a significant differential opened up between Alberta and International oil prices. As can be seen in Figure 7.2, until 2008 changes were more due to the fluctuating light/heavy differential than the heavy/bitumen differential.

The light oil-bitumen price differential is a prime determining factor in the level of bitumen upgrading in Alberta. So long as the expected differential is higher than the unit cost of upgrading the bitumen into a light crude oil, there is an economic incentive to build upgraders. Reflection shows that the future development of Alberta's heavy oil industry could involve one of a number of rather different paths, or some mix thereof. The result will reflect all of the following:

- the level of future world light crude oil prices and the price differentials between lighter crudes and both bitumen and the very light hydrocarbons that are used as diluents when shipping heavy crude;
- current and future techniques and costs for shipping light oil and bitumen, and the decline in price needed to sell Alberta bitumen or synthetic crude in more distant markets;
- current and future techniques and costs for refining heavy oil and the prices of heavy refined petroleum products;
- current and future techniques and costs of upgrading bitumen into light synthetic crude;
- current and future techniques and costs of refining synthetic crude oil; and
- current and future techniques and costs of shipping refined products.

Given the cost disadvantages of shipping refined petroleum products (RPPs), as compared to crude oil, it

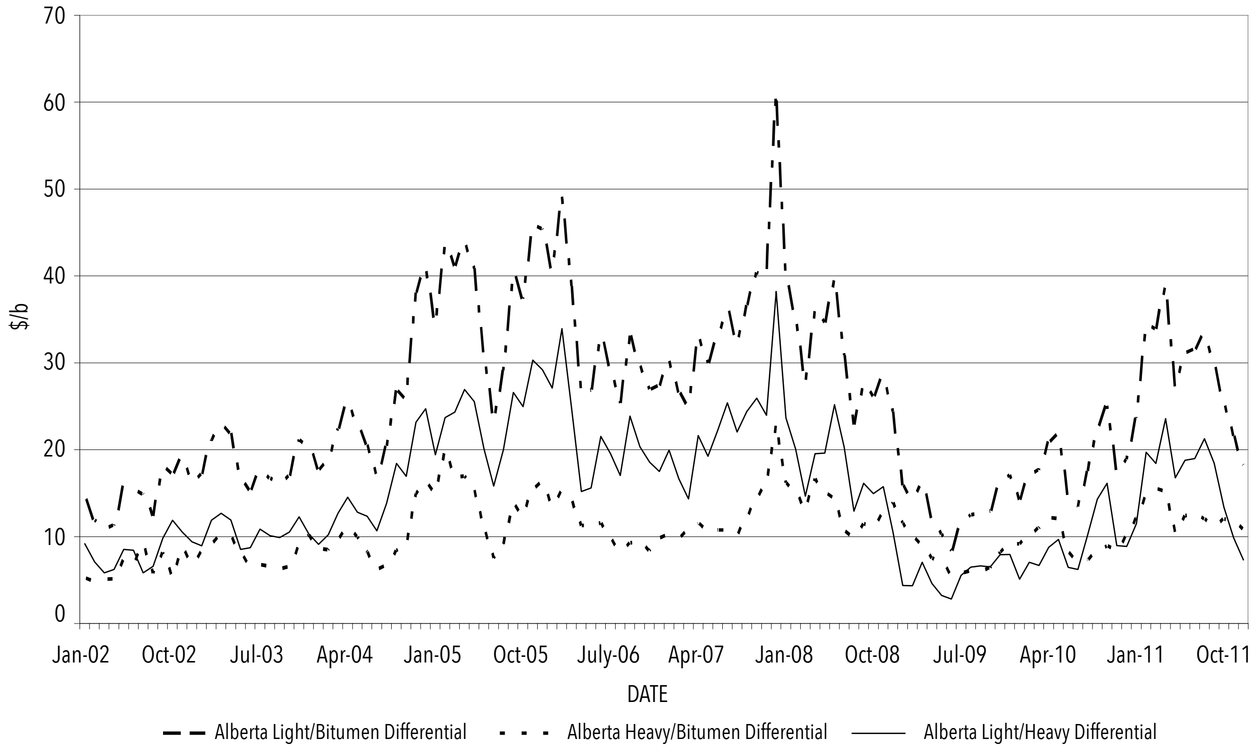


Figure 7.2 Bitumen Price Differentials Jan 2002–Dec 2011

Source: From data in CAPP *Statistical Handbook*, Table 5.5 and ERCB, *Alberta Energy Resource Industries Monthly Statistics*, ST-3

is unlikely that large volumes of bitumen would be upgraded and refined in Alberta for export as refined products. However, increased growth in the Alberta economy may translate into higher local demand for RPPs. Combined with the expected falling conventional oil production, this would mean a retooling of existing refineries and some expansion in capacity to handle a growing volume of upgraded synthetic crude.

A more critical question is whether it will be more attractive to upgrade the bitumen in Alberta and ship the lighter synthetic crude to export markets, or to export bitumen for refining (or upgrading and refining) elsewhere. One might suppose that the former is favoured by the relative difficulty in shipping the exceptionally heavy bitumen. However, if the bitumen is mixed (diluted) with a lighter hydrocarbons, which are slated to be exported anyway, this shipping cost disadvantage may disappear; currently pentanes plus, in a proportion of about 30 per cent, are normally used as the diluent. The diluent might even be upgraded synthetic crude (in a proportion of about 50%, according to the ERCB 2010 *Reserves Report*, ST-98, p. 2-18), which would imply a need for some upgrading within the province. It would also require long-run planning to ensure that the purchasing refineries in the export market are constructed so as to handle the heavier oil. Extension of the Alberta oil market as far as the Texas Gulf Coast, as has been planned since 2011, would open potential markets for bitumen from refineries that have been importing heavy oils from Venezuela and Mexico. While export of bitumen might be economically feasible, Alberta interests have generally favoured the 'value-added' approach of upgrading bitumen in the province, with the associated expansion in economic activity and, from some points of view, economic 'diversification.' (We return in Chapter Thirteen to this issue of diversification.) It is obvious, however, from a shorter-term perspective, that exporting bitumen, without upgrading, would be one way to reduce the regional economic inflationary pressures of rapidly expanded oil sands production. Whether Alberta should reply on relatively unfettered markets to handle these investment options or look to a more activist government policy in scheduling the timing and type of facilities built is likely to generate lively debate.

D. Government Take

We use the term 'government take' to refer to the payments made by the oil company to the government; governments derive these payments in part through their role as the owner of mineral rights and in part through their powers of taxation. On both grounds, the government of Alberta has been concerned that a 'fair' share of the value of petroleum goes to it, as representative of the public. Chapter Eleven contains an extensive discussion of objectives of government with respect to payments it assesses on the petroleum industry and the instruments that might be used to collect revenue. In brief, the government simultaneously pursues objectives of revenue generation, risk sharing, equitable treatment of all parties, and administrative simplicity. The industry might make payments to the government in the form of bonus bids to obtain mineral production rights, land rental payments, taxes based on the value of production (usually called 'royalties' or severance taxes), corporate income taxes, and/or the government share of profits if it is a part-owner of the company. In the oil sands, companies have obtained mineral rights through competitive bonus bidding and face annual rental payments on the area under which they own the rights. However, the most controversial parts of government take have been the provisions applied to projects once they have begun to produce bitumen or upgraded synthetic crude oil. (Plourde, 2009, provides a useful review of government take in the oil sands up to 2008).

Experimental oil sands projects have typically been assessed a gross royalty of 5 per cent. When Suncor began production in 1967, it was governed by the prevailing royalty and income tax regulations on conventional oil, as discussed in Chapter Eleven. In 1978, the royalty was set at 8 per cent on production below 143,019 cubic metres/month (30,000 b/d), at 20 per cent on output above that up to 217,389 cubic m/month (45,000 b/d), at 8 per cent again on output to 258,704 cubic m/month, and at 20 per cent again above that. (The second tier at 8% applied to the Suncor expansion of the late 1970s.)

With Syncrude, the Esso Cold Lake project and the BP Wolf Lake projects, the royalty and tax regimes became subject to negotiation on a project-by-project basis with the provincial and federal governments. This recognized that oil sands projects were not 'like' conventional crude oil projects. They were very high cost and involved unusual technological risks since they used untested processes. At the same time, governments want to ensure that they derive a fair share of the profits from the oil sands. The picture was complicated with the new taxes on petroleum introduced by Ottawa with its National Energy Program of October 1980. (These taxes were removed with the federal-provincial 'De-regulation' Agreement of 1985, so were of concern only to Suncor and Syncrude.)

The approach agreed to by Syncrude and the Alberta government was a new royalty arrangement based largely on the profitability of the project. This was attained through a 50 per cent net royalty arrangement, where Syncrude would pay 50 per cent of net operating profits (that is, after operating costs were deducted from revenues) once the project had recovered its investment costs and an agreed-upon (8%) annual return on unrecovered capital costs. To ensure that the province would receive some revenue in all periods, there was a minimum 5 per cent gross *ad valorem* royalty. In the mid-1980s the net royalty was modified to require amortization of remaining unclaimed capital expenditures (although expansion investment undertaken in the mid-1980s could be written off immediately). Alberta had a non-reversible one-time option to replace the 50 per cent net royalty with a 7.5 per cent gross royalty, but this option was never exercised. In the Winnipeg Agreement, Syncrude and the governments agreed that this net royalty would be deductible as an expense in calculating the federal/provincial income tax owing. They also agreed that companies would be allowed to 'flow through' capital expenses to the parent companies, so that they could be deducted from the parent's revenues for income tax purposes without having to wait until Syncrude itself generated sufficient revenue to allow deduction of these costs. (The sooner a company can deduct expenses in calculating taxable income, the earlier the tax savings are earned, and the more valuable they are to the company.) In addition, under the corporate income tax regulations, mining expenses could be deducted immediately, rather than expensed over time. As a result, Syncrude's royalty payments per barrel of oil were relatively small as compared to payments by most conventional oil production, and the owners gained a significant corporate tax advantage.

In situ oil sands projects were assessed royalties based on the Esso Cold Lake project, which paid a 1 per cent gross royalty initially, rising to 5 per cent over six years. After recovery of capital expenses, payment was to be the maximum of a 5 per cent gross royalty or a 30 per cent net royalty. (However, unlike bitumen mining, *in situ* investments had to be expensed over time for corporate income tax purposes.) A fairness issue arose with respect to Suncor after these special

Table 7.2: Oil Sands Royalties, 1968–2012

Fiscal Year Ending	*Royalties ($millions)*
1968	1.0
1969	2.3
1970	3.1
1971	2.4
1972	3.0
1973	3.8
1974	8.2
1975	13.9
1976	15.4
1977	19.1
1978	23.8
1979	30.6
1980	46.2
1981	224.9
1982	299.7
1983	362.3
1984	303.8
1985	185.5
1986	24.8
1987	11.2
1988	22.6
1989	19.0
1990	27.7
1991	39.0
1992	30.6
1993	64.9
1994	66.4
1995	209.1
1996	311.6
1997	512.2
1998	192.4
1999	59
2000	426
2001	712
2002	185
2003	183
2004	197
2005	718
2006	950
2007	2,411
2008	2,913
2009	2,973
2010	3,160
2011	3,723
2012	4,513

/continued

Note: Values from 1968 to 1972 include oil sands rentals and fees.

Source: *Annual Reports* of the Alberta Department of Energy and of Energy and Natural Resources.

deals were negotiated for large mining and *in situ* projects. Effective in 1987 the Suncor royalty was changed to the greater of a 2 per cent gross royalty or a 15 per cent net royalty, with these percentages increasing to 5 per cent and 30 per cent respectively in 1992.

Table 7.2 shows Provincial receipts from syncrude and bitumen royalties for fiscal years ending March 31 from 1968 to 2012. The jump in the early 1980s reflects a combination of the start of Syncrude production and the very high international oil prices that determined the value of Syncrude's output. The sharp decline in royalties after 1985, as international crude oil prices plummeted, illustrates the sensitivity of a net royalty to oil prices. The move to 'profitability' of the mining ventures is the main factor leading to the rapid increase in payments after 1990, with the large decline in 1998 and 1999 once again demonstrating the sensitivity to oil price declines. Payments rose markedly after 2004, as output and oil prices both increased. In the 2006/7 fiscal year, oil sands royalties for the first time surpassed conventional oil royalties; in 2009/10, they also exceeded natural gas royalties, due largely to falling natural gas prices.

In the 1990s, potential investors and the government both found the absence of an agreed-upon royalty for oil sands projects to be less than satisfactory, since it meant that project-by-project negotiations were needed, and companies could not assess the commercial viability of their project until the negotiations were concluded. In 1995, a 'Task Force,' including both government and corporate representatives, recommended that Alberta implement a 'generic' oil sands royalty regime that would apply to all new projects (National Task Force on the Oil Sands, 1995). The task force had been set up in 1993 under the chairmanship of Dr. Erdal Yildirim to examine the lack of interest at the time in expanded oil sands production. Alberta accepted the recommendations with respect to royalties, announcing on November 30, 1995, that oil sands projects would be subject to a minimum 1 per cent gross royalty and would be assessed a 25 per cent net royalty after capital costs, including an interest allowance, had been recovered; the interest charges would be determined by the long-term Government of Canada bond rate. Oil sands investments, whether for mining or *in situ* projects, could be written off immediately against income from the project. (Alberta Energy, 2006, Plourde, 2009, and Mitchell et al., 1998 summarize the new regulations, which became effective in September 1997.) For the net revenue royalty, most 'project' costs would be deducted, including any gross royalties paid, but not bonus bids or pre-investment start-up costs. This royalty is quite different from that assessed on conventional oil (a sliding-scale gross royalty). It recognizes that oil from the oil sands is now, and is likely to continue to be, high cost, and hence very dependent on the level of oil prices and the size of the tax burden. By assessing payments to the government (both royalties and corporate income taxes) largely on the basis of the project's profits, the commercial risk is shared by the company and the government, and any disincentive to invest due to the necessity to make payments to the government is minimized.

Recognition of the significance of this new royalty regime, and the efforts of the National Task Force, was made manifest in a ceremony at Fort McMurray in June 1996; the governments of Canada and Alberta and executives of almost twenty oil companies signed a document expressing their commitment to expanded oil sands development. It is important to note that the generic royalty could be applied to either the bitumen or the synthetic oil produced; since bitumen prices were lower than synthetic crude prices, companies had a clear incentive to reduce the size of the royalty by electing to pay on the basis of bitumen prices, as has been the case. (The issue is more complicated than this suggests. If bitumen were chosen as the product to which the royalty applies, upgrading costs could not be deducted as a cost for royalty purposes. Therefore, until payout, companies would likely prefer to base the royalty on the upgraded product. After that, as long as upgrading is expected to be profitable, companies would prefer not to pay a royalty on upgrading as well as bitumen operations. Suncor and Syncrude, covered by royalty arrangements agreed to before the generic regime, had the option to switch from a royalty on syncrude to a royalty on bitumen anytime prior to 2009. Both companies exercized this option, Syncrude in late 2008.) (Alberta Energy, 2003, 2007a, 2007b reviews Alberta petroleum royalty provisions. The department now maintains a webpage with ready links to relevant royalty documents: www.energy.alberta.ca/About_Us/Royalty.asp.)

The generic royalty regime removed some of the political uncertainty faced by prospective oil sands producers, as well as the additional project costs involved in negotiating specific tax/royalty regulations for each project. As was noted above, reliance on a net royalty provided an explicit sharing of economic risk. For instance, if prices were insufficient to cover costs (including an allowance for return on capital invested), payments to the government would be relatively small (mainly the 1% gross royalty, much less than the average rate of nearly 20% assessed on conventional oil and gas production); however, once prices were high enough to generate profits, the government and company would split them on a 25/75 basis. That is, in order to encourage investment in the oil sands, the province was willing to allow the companies a significant proportion of price-related upside profit potential. (Plourde's simulations [Plourde, 2009] suggest that the companies' share of anticipated economic rent did increase on mining projects as the oil price rose up to about $70/b. It is not clear whether *in situ* projects showed similar price sensitivity.) From a public policy perspective, this might be justified in several ways, for example, to offset high corporate risks (e.g., risks with still developing technologies, risks of high cost inflation or risks of world oil prices collapsing). If the government foresaw little chance of very high oil prices, the chance of foregoing large amounts of royalty revenue would be seen as low.

In comparison to the conventional royalty formula, the generic oil sands royalty involved two main elements of increased administrative complexity. First, it involves accounting for the specific costs of the project. Since companies would pay lower royalties if they absorb higher costs, there would be an incentive to inflate reported costs or pass on benefits to the company and its managers in the form of higher costs; hence, the government would be expected to incur incremental monitoring costs. A second complexity relates to the relative lack of 'transparency' in bitumen markets, which are less well-developed than North American markets for conventional light and heavy crude oil. The tax base for the net royalty depends on the price paid for bitumen, so companies would have some incentive to report relatively low prices, especially if the sales are made to an affiliate company (which would then receive relatively high profits on the subsequent processing and sale of the oil products). Hence, in assuring it is receiving its fair share of profits, the government would incur additional costs of monitoring the North American bitumen market.

The generic regime was explicitly designed to encourage oil sands development. In part, this was attained by the introduction of a net royalty based on project profits, rather than a gross royalty. But it also stemmed from the relatively low rate of the net royalty. This became an issue of concern to many as international oil prices rose in the early years of the new millennium; the net royalty would capture only 25 per cent of the increased profits due to price increases, although it should be remembered that the 75 per cent accruing to the companies would be subject to the corporate income tax. It is difficult to separate the effect of higher price expectations from the impact of a royalty regime designed to encourage investment, but, as was discussed above, by the year 2013, three major new oil sands projects were already in production, both Suncor and Syncrude had undertaken expansions, and numerous other projects had been announced, a number of which had received approval from the EUB/ERCB.

Smaller heavy oil projects in the oil sands area (known as Township 53), which are capable of producing heavy crude by primary techniques, were initially subject to conventional oil royalties. These projects were particularly encouraged by some of the oil royalty relief measures introduced in Alberta beginning in the mid-1980s. Of special importance were the EOR-tertiary project and the horizontal production well royalty relief programs of the early 1990s. As part of the 1995 generic royalty regulations for the oil sands, projects that produce heavy oil in the oil sands part of the province were given the option of selecting the generic oil sands royalty instead of the conventional crude oil royalty, an option most companies have taken.

Suncor and Syncrude, who were still producing the majority of the mined oil in the first decade of the twenty-first century, were not covered by the generic royalty regulations but by the deals they had negotiated earlier, which lasted up to the year 2015.

Figure 7.2, above, included per barrel royalties for syncrude and bitumen from 1968 to 2011. These varied considerably, from a high of $8/b to almost nil. The high per barrel values came with high crude oil prices such as during the early 1980s and after 2006, the low royalties with low prices. Since the introduction of the generic royalty scheme, based mainly on a measure of profitability, the royalty per barrel has fluctuated considerably as world oil prices rise and fall.

Petroleum corporations are also subject to federal and provincial corporate income taxes. From 1972, the mining portion of oil sands plants were allowed rapid write-off of capital costs. As part of the 1995 revisions to the oil sands royalty regulations, the mining portion of oil sands projects and *in situ* ventures were granted an accelerated capital cost allowance that allowed immediate deduction of the costs up to the full amount of income from the sale of the oil from the project. In effect, corporate taxes could be delayed until all investment costs were recovered. This also generated some support for projects to include an upgrader since the upgraded synthetic crude has a higher value than bitumen and therefore allows earlier write-off of the capital costs of the mine. Taylor et al. (2005) argued that such measures provided an unfair advantage to oil sands investors compared to those in other Canadian industries. The March 2007 federal budget announced that the accelerated allowance would be phased out entirely by 2015, at least as far as the federal share of the corporate income tax was concerned.

In September 2007, the Alberta Royalty Review Panel released its *Report* (Alberta Royalty Review Panel, 2007). (Plourde, 2009, who was a member of the Royalty Review Panel, presents a detailed summary and some simulation results.) The panel reported that, as of the end of December 2006, a total of sixty-six projects were covered by the generic oil sands royalty regulations, of which thirty-four were past the payout stage (p. 76). The panel reported on simulations of project profitability undertaken for and by the Department of Energy, which suggested that the share of economic rent (profits) captured for the government on oil sands projects was significantly less than what other jurisdictions in the world were gathering on oil investments. Across a number of different cost and price levels, they estimated that Alberta would receive about 47 per cent of the economic rent under the present regulations, a significantly lower share than the 60 per cent or so that had been anticipated when the generic royalty was introduced in late 1995 (pp. 7 and 11). Plourde's simulations suggest that the share of expected profits accruing to government (provincial and federal) over the entire life of an oil sands project would be relatively stable under the generic royalty regime, for oil prices of $70/b or more ($50/b or more for an *in situ* project) (Plourde, 2009). He argues that the lower than expected share under the generic regime reflects changes to corporate tax provisions, including reductions in the rates after 1995. (In 1995, the combined federal–Alberta corporate income tax rate was 43.62%; by 2007, it had been reduced to 30%.)

Accordingly, the panel recommended a number of changes to the oil sands royalty regulations, including an increase of the net royalty rate from 25 per cent to 33 per cent, the introduction of a new price-dependent 'severance tax,' and making the 1 per cent gross royalty payable in all years and an expense in calculating the net revenue tax. The new severance tax would be based on bitumen revenues less base and net royalties and rentals and would be set at 0 per cent for oil prices (WTI) at $40/b or less and rise linearly to a rate of 9 per cent on oil prices of $120/b or more; the severance tax would not be an allowable deduction for either net royalties or the corporate income tax. The panel also urged the government to take steps to ensure that bitumen prices are fair market values and recommended a tradable credit against oil sands royalties for companies undertaking oil sands upgrading investments (pp. 85–89). From an economic perspective, the severance tax seems likely to be more distortionary than a larger increase in the net revenue royalty but may have been appealing since a new tax could be more easily applied to Suncor and Syncrude as well as those producers covered by the generic royalty system. The panel's report also expresses obvious concern about the efficiency of synthetic crude and markets, as evidenced by both the desire for an assessment of bitumen prices and the apparent unwillingness to allow investment in bitumen upgrading to be handled solely by market forces.

Late in 2007, the government announced its response to the recommendations of the Royalty Review Panel (Alberta Department of Energy, 2007c). The government said that new royalties on bitumen values would become effective at the start of 2009. It did not introduce the new severance tax recommended by the panel. Instead, the 1 per cent gross royalty would be revised to a price-sensitive sliding-scale fee, at 1 per cent for oil prices less than $55/b, rising to 9 per cent when the oil price reached $120/b; the net revenue royalty rate would continue to be 25 per cent at oil prices of $55/b or less but would increase with higher prices to a maximum rate of 40 per cent at prices of $120/b or more. The gross royalty would be paid up to the time costs (including a normal return) were recovered and then the higher of the base or net royalty would be paid. Negotiations would be undertaken with Suncor and Syncrude to revise their agreements with the government prior to the expiry date of 2016. (In 2008, Suncor and Syncrude both agreed to increase royalty payments starting in 2010 until they became subject to the new regulations in the year 2016.) The government also announced that it would follow Ottawa's plans in making oil sands capital expenditures deductible over time for the corporate income tax rather than being immediately expensible. Plourde's simulations (Plourde, 2009) suggest that the new regulations would generate a share of profits for the provincial and federal governments (combined) in the range of 60 per cent, about what had been projected under the generic royalty regime in 1995 and about 12 to 17 percentage points higher than actually occurred. However, the share is significantly lower than that which would have resulted from the Royalty Review Panel recommendations (though there is a shift in share under the government's announced regulations from the federal government to the Alberta government).

The government did not adopt the Royalty Review Panel's recommendation for a royalty credit against new upgrading investments. In late June 2008, it announced a proposal for the determination of bitumen values in the absence of a clear fair market (arms-length) value (e.g., for bitumen retained by the producer for upgrading or for intercorporate transfers). Subject to a floor value based on heavy Mayan crude from Mexico, the value would be determined by the price for heavy crude at Hardisty, Alberta, with quality adjustments (Alberta Department of Energy, 2008). It also announced plans to take delivery of bitumen in place of royalty payments (a 'bitumen in kind' royalty).

5. Conclusion

Alberta's non-conventional oil resources are huge, even by global standards, and dwarf the province's conventional oil reserves. They are often seen as a part of the world's 'backstop' to conventional crude oil: that is, a large-volume but high-cost perfect substitute for conventional crude. Producers have been holding out high hopes for significant oil sands production since the start of the twentieth century. Many of the main technical innovations needed to allow production of shallow deposits through strip-mining and upgrading were made in the first half of that century, and the evolution of EOR technologies for conventional oil offered knowledge for use in *in situ* production from the deeper oil sands. However, commercial production proved elusive.

The first mining/upgrading venture, now known as Suncor, started in the 1960s. It was seen by many as a precursor to rapid development of the oil sands, but only the 1970s Syncrude mining/upgrading and Cold Lake *in situ* projects materialized. Costs of these projects exceeding initial estimates and falling world oil prices after 1985 inhibited further investment. Syncrude and Suncor began some cautious expansions in the 1980s, suggesting that there might be economies that they could capture as existing operations. In addition, the continuing development of horizontal drilling technologies encouraged a number of small-scale *in situ* projects. But it was rising oil prices around the turn of the millennium that appears to have been the main factor leading to a surge in oil sands investments at that time. by 2005, most forecasters were projecting rapid output growth from the oil sands of both bitumen and light upgraded synthetic crude; output has been expanding and, as of March 2013, several new projects are underway, have received approval, or have been announced.

The significance of the oil sands to the province can hardly be overestimated. By the year 2012, syncrude and bitumen provided over 75 per cent of Alberta's crude oil and had more than offset the decline in conventional oil production. Forecasts of rising oil output depended entirely on expanded oil sands production. However, this involves major changes since oil sands output differs in a number of important respects from conventional crude oil. Some of the changes are largely 'physical' and technical. Thus, for example, the oil resource in the oil sands is bitumen, a very heavy viscous hydrocarbon which is difficult to move and handle and which has had a limited market. Thus, the expansion of oil sands production saw the growth of a large upgrading industry to transform bitumen into light syncrude; it has also seen a rising demand for very light oil products in pipeline transmission to mix with and dilute the bitumen, and development of plans to extend the pipeline network from Alberta to the U.S. Gulf Coast where refineries are equipped to handle very heavy oil. Mining, upgrading, and *in situ* production technologies are very energy intensive, leading some to expect that large amounts of natural gas will have to be diverted from export markets to oil sands production. Further, growing environmental concerns are raised by the large water requirements of the mining operations, the strip-mining itself, and the sulphur content of the bitumen.

There are also economic differences between the oils sands and conventional crude oil production. Conventional production has been spread broadly across Alberta, but expenditures on the oil sands have been concentrated in a small geographical area in east central Alberta, with further potential to the west in the Peace River region. The costs in the oil sands are high, and the prospective economic rents seem to be smaller, though this will obviously hinge on the price of oil. Thus, the impacts on the province seem likely to come through the economic activity directly associated with oil production and somewhat less from the 'surplus' revenues collected by the government. Finally, the operating phase of oil sands production is much more labour-intensive than the operations phase of the conventional industry, especially for mining and upgrading activities. This also implies a more direct and regionally concentrated impact from oil sands than was seen with the conventional petroleum industry in Alberta. That the government has come to recognize the problems this might raise is suggested by its appointment of a committee to investigate the impacts of increased oil sands production; the committee's final report focused on regional planning and infrastructure investment needs in the oil sands area (Oil Sands Ministerial Strategy Committee, 2006). The *Alberta Land Stewardship Act*, proclaimed on October 1, 2009, may provide a framework within which many regional planning issues can be addressed, but the hard work of financing and building new facilities remained to be addressed.

CHAPTER EIGHT

The Supply of Alberta Crude Oil

Readers' Guide: Supplying crude petroleum is a complex process. In this chapter, we review a number of attempts to build models of this process, or, as is more frequently the case, some part of the process, for the province of Alberta. Rather than a history of the Alberta petroleum industry, this chapter might be seen as a history of Alberta oil-supply modelling. Readers with a limited interest in the details of oil-supply modelling will likely find Section 3 of most interest; it summarizes the conditional forecasts of oil production made by the National Energy Board from about 1970.

1. Introduction

This chapter summarizes various studies of the supply of conventional crude oil in Alberta. Rather than building our own model of crude oil supply, we provide an overview of the broad range of published models. Also relevant are the studies of Alberta crude oil potential set out in Chapter Five, especially the 'discovery process' models.

We will first briefly review what economists typically mean by the 'supply' of a product.

As was discussed in Chapter Four, the 'supply of crude oil' is ambiguous. For example, it could be used to refer to the size of the total resource base in a region, or to the quantity of reserves additions added in a particular period, or to the volume of oil lifted to the surface in a particular period. However, for the economist, 'supply' typically has a much broader meaning, referring to the constellation of factors that might influence production. Formally, this broader use of the term 'supply' is called a 'supply function'; it is best seen as a formulation that documents all factors potentially affecting oil production, as well as the strength of impact of each. In a more restricted manner, economists often speak of the 'supply curve' for crude oil (or more simply 'the supply of oil'), which shows how the production of crude oil will change as the price of crude oil changes. This aspect of supply is of particular interest to economists, who focus on the way in which the oil market determines prices. It is important to realize that only one level of price and production will actually occur at any point in time; in other words, only one specific point on the supply curve is actually observed in any time period, and the other possible price/output combinations are hypothetical. It is also important to recall that the concept of a supply curve does not say that *only* the price of oil is important in determining production. Rather, it says that out of all the factors that have influence, price is the one upon which analysis will focus. One can define a meaningful price/output relationship only for fixed values of the other variables that influence output. If other things change, then a new price/output relationship will occur. A change in supply can be associated with a change in price (which leads to a 'change in quantity supplied,' or a movement along a supply curve) or a change in other factors affecting supply (which leads to a 'change in supply' or a new supply curve).

Chapter Four provided a list of the main factors that might be expected to enter into the supply function for conventional crude oil in Alberta. Included are: the price of crude oil; the underlying natural resource base; knowledge about the resource base; the technologies currently governing production; the costs of various inputs into production (wage rates, interest rates, the prices of types of capital equipment, the cost of hiring a drilling rig, the price of electricity, etc.); the extent to which the quantity of capital equipment can be varied; government regulations (such as tax and royalty rates, rules for the issuance of mineral rights, drilling requirements on mineral rights, price controls, export limits, production controls, well-spacing regulations, gas-flaring regulations, etc.); the determinants of oil companies' behaviour (i.e., company objectives including risk preferences); and expectations about the future. A complete supply function would specify exactly how all these variables impact upon the level of production of crude oil.

Estimation of such a comprehensive supply function must remain an unattainable ideal. The number of variables influencing supply is large, especially when it is realized that each individual oil company will have its own objectives, current knowledge, and expectations about the future. Beyond this, some variables are difficult to know. We cannot know for certain what the underlying resource base looks like (the number, size, and location of all the oil pools that nature has given us). We may not even be able to define all the possibilities. If we can't do this, we can't include all of the possible expectations companies might have, nor how these expectations will vary in response to changing circumstances. Thus, the estimation crude-oil-supply functions is another example of the 'art of the possible,' and, as with all the arts, what is beautiful lies very much in the eye of the observer.

The essential first step in crude-oil-supply modelling is simplification. Simplifications may or may not be explicitly acknowledged by the analyst. A common assumption is that certain variables, which might theoretically be expected to affect oil production, simply are not relevant and therefore will not be included in the analysis. This clearly reduces complexity. The assumption may reflect the analyst's judgment that the variable is not significant enough that it is worthwhile expending time and effort to gather the data. Or it may reflect the belief that the variable did not change very much over the period and therefore changes in output cannot be due to this variable. Analysts often report only the variables that they include in their analysis and not the ones that they exclude. Simplification frequently involves explicit assumptions that the analyst realizes are not necessarily true, but which it is believed (or hoped) will allow the major factors affecting supply to be assessed. The analyst is aware that the model will not capture all aspects of reality but hopes that it will come close and that errors will be random (so, for example, a forecast will be equally likely to over- or underestimate oil production). An example of such a simplifying assumption relates to the determinants of companies' behaviour. Economists often assume that all oil companies are profit-maximizers; therefore, companies will always pursue the lowest cost methods of production and will exploit all profitable investment opportunities. In this case, as argued in Chapter Four, the supply curve is a marginal cost curve, which ranks possible units of crude oil production from the lowest cost unit to the highest cost unit. Thinking of a supply curve as a marginal cost curve is a useful way to see how various crude oil 'products' differ from one another; thus, undeveloped oil reserves require development investment to become developed reserves, and these require operating expenses to become oil in the field, which require pipeline expenses to become oil at a main gathering point. It also follows that the price that elicits oil supply differs in each case as well; that is, the price of oil in the ground (reserves) differs from the price of oil as lifted. If we further assume that all companies have the same knowledge and expectations, it is not necessary to treat the industry as consisting of many different firms, each influenced by different factors. Instead, we can treat the industry as if it were a single large profit-maximizing firm. Other simplifying assumptions commonly adopted are to assume: that current conditions (for example, prices) reflect expected future conditions; that all pools, once discovered, tend to be depleted in the same manner; that future reactions to prices and other variables will mimic past reactions; and that the supply function takes a particular mathematical form.

This chapter includes five main sections. Section 2 offers a more detailed discussion of the framework for oil-supply modelling. Section 3 summarizes the results from the most well-known and accessible estimates of Western Canadian crude oil supply, those undertaken on a regular basis by the National Energy Board (NEB) since the 1970s. We refer briefly to similar analyses from the Canadian Energy Research Institute. Section 4 discusses studies that assess Alberta oil supply by attempting to directly measure the cost of oil production. Section 5 turns to research that provides 'indirect' estimates of oil supply by attempting to estimate various forms of an oil-supply function. We conclude with some general comments in Section 6.

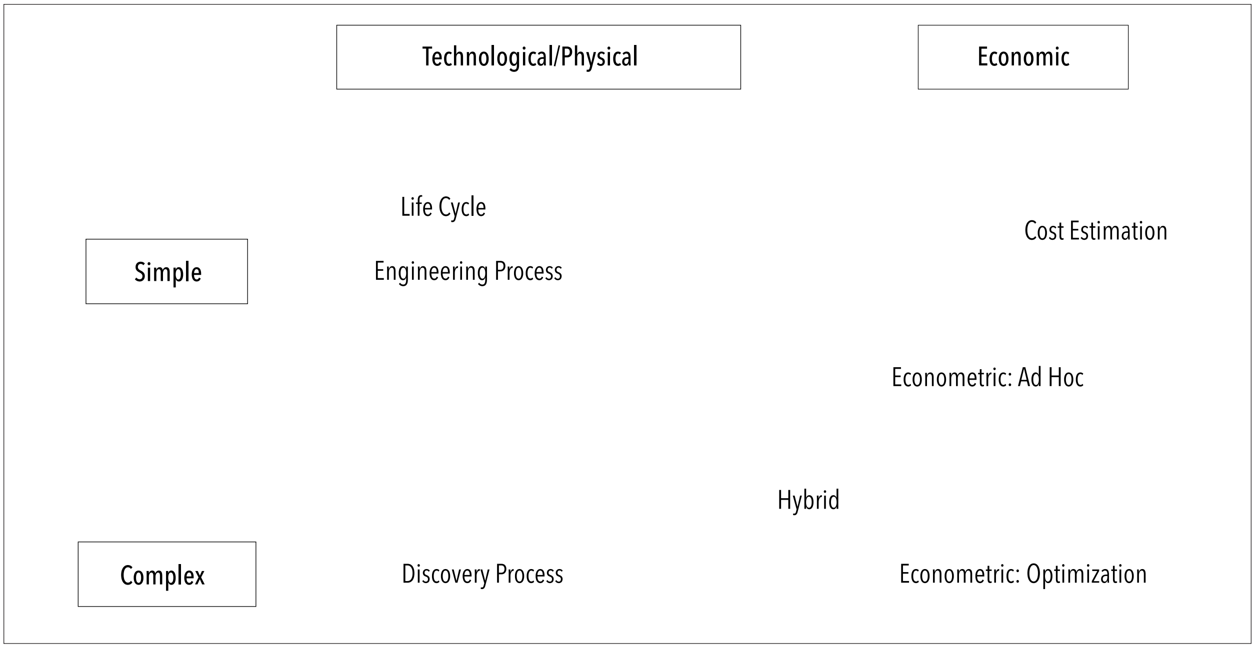


Figure 8.1 Models of Oil Supply

2. Concepts of Crude Oil Supply

As mentioned in the Introduction to this chapter, the term 'crude oil supply' has a number of different meanings. (Bohi and Toman,1984, provide a useful review.)

The 'product' **crude oil resources** is of a qualitatively different order than the others. Here economists often speak of a 'Resource Stock Supply Curve' (RSSC), which, on the basis of an assumed set of underlying conditions (regulations, input prices, technology) ranks, by marginal cost, the total quantity of crude that it is thought lies in the ground. This is quite unlike the economists' usual supply notion, which is a flow concept; that is, it refers to the quantity of oil supplied in a particular period – **discoveries** in 1967, total **gross reserves additions** in 1987, or **oil lifted** in 1992. However, the idea of an RSSC is often the starting point for detailed oil-supply analysis in a region such as Alberta. Exploration and development activities translate the resource stock into reserves in the ground, and production facilities translate reserves in the ground to production at the surface.

We would also remind readers that oil is found in separate 'pools' ('deposits' or 'reservoirs') and that these pools tend to accumulate within a relatively small number of geological plays. A grouping of nearby pools in the same geological formation is called a 'field.'

A number of authors review different approaches that have been used in crude petroleum supply modelling (for example, Adelman et al., 1983; MacFadyen and Foat, 1985; Kaufman, 1987; Power and Fuller, 1992; Walls, 1992; Adelman, 1993b; Brandt, 2009). We will provide a brief summary of some of the main approaches. As we shall see, many of them have been applied to the Alberta crude oil industry.

Following Kaufman (1987), Figure 8.1 provides a simple classification of these modelling approaches along two key dimensions: the extent to which the models are primarily 'economic' or 'technological' and the extent to which the model utilizes relatively 'simple' as opposed to 'complex' quantitative or statistical procedures. It is important to realize that the approaches are not mutually exclusive. They can overlap and researchers may utilize more than one approach.

Cost Estimation. Estimates or reports of expenditures are tied to the resultant output to derive a measure of the unit cost of oil.

Engineering Process. A relatively simple relationship affecting oil supply is assumed, based on the physical activities involved in oil production. Sometimes this is a purely 'engineering' relationship. It might be assumed that all oil reserves are developed and depleted in identical fashion; for example, development occurs in equal stages over three years, output commences at a reserves to production ratio of 10, and the pool exhibits constant exponential decline at a 7 per cent annual rate. Another engineering approach posits a consistent relationship between the discovery rate of oil (or average discovery size, or reserves added per foot drilled) and the passage of time (or cumulative footage drilled); this relationship is often based on historical experience, and, in mature regions, normally shows 'depletion effects' where oil becomes increasingly hard to find.

Life Cycle. This approach assumes a regular relationship between the passage of time and the rate of oil discoveries and production; it is a specific example of an engineering process model.

Econometric: Ad Hoc. Econometric approaches argue that economic variables are a prime determinant of crude oil supply and that one can utilize regression techniques applied to historical data to estimate the precise relationship between oil supply and the underlying variables that affect it. The model may also include non-economic variables, for instance representing different geological plays. The 'Ad Hoc' approach begins with a 'conceptual' model that suggests the variables most likely to affect crude oil supply and then utilizes statistical estimation procedures to see how strongly these variables are connected. The investigator may assume a specific functional form for the relationship amongst the variables (e.g., a linear relation) or try a number of possible functional forms and select the one that appears to 'fit' best.

Econometric: Optimization. Optimization models begin with a formal analytical model of industry behaviour, which is utilized to generate the list of variables that are expected to affect oil supply, as well as constraints on the precise mathematical relationship amongst the variables. Normally a number of simplifying assumptions are necessary in order to make the theoretical model and its operationalized version tractable. Thus, for example, all firms may be assumed to be effective profit-maximizers, with identical expectations based on the current values for key variables, and the underlying production functions may be assumed to have specific 'regularity' properties.

Discovery Process. These models assume that the discovery of oil pools involves a non-random sampling process without replacement from an underlying distribution of crude oil pools. Given assumptions about the nature of the underlying pool distribution in nature (e.g., that the size distribution of pools is log-normal) and the sampling process (e.g., the probability of discovery for a pool of size 's' is proportional to the volume of oil still in the ground in pools of that size), it is possible to calculate the probability that the next discovery will be of size 's,' and the expected size of the next discovery. In Chapter Five, results of the Geologic Survey of Canada's discovery process model were summarized.

Hybrid. Hybrid models typically combine aspects of the engineering, economic, and discovery process approaches. Thus, for example, the level of exploratory drilling and anticipated success rates might be estimated econometrically while the volumes of discoveries are drawn from a discovery-process model.
Many of these modelling approaches have been applied to the Alberta crude oil industry, often in combination. In Chapter Five, we reviewed some of the estimates of the total availability of crude oil in Alberta. In this chapter, we will emphasize studies that assess the flows of oil supply, specifically reserves additions and production (or productive capacity). Recall that the two are connected, since production comes out of reserves.

The next section will review the crude-oil-supply scenarios of the National Energy Board (NEB). Beginning in 1969, and periodically since then, the NEB has issued conditional forecasts of Canadian oil supply. These studies have drawn on many modelling approaches, including cost estimates, engineering process analysis, discovery process analysis, and econometrics. They provide a very useful review of how expectations about Canadian crude oil supply have changed over the past three decades.

3. NEB Supply Studies

In providing information about its regulatory responsibilities, the NEB has produced a number of reports that forecast the future production of Canadian crude oil. These reports are of interest for a number of reasons. They are the most visible forecasts of Canadian energy production and consumption (or 'Supply' and 'Demand,' as they are usually labelled). They also depict how prevailing expectations about Canadian energy industries have changed over time. It is tempting, in this regard, to emphasize the ways in which the forecasts have been 'wrong,' but this is not the most profitable way to view them. The NEB forecasting procedures have evolved over time, learning from new information and modelling techniques. And the NEB studies have usually been at pains to point out how and why the forecasts have changed from one report to the next. Failure to revise forecasts in light of changing circumstances would be a much more serious concern than the continual revision of the forecasts. The more interesting question is why the forecasts have changed.

The Appendix to this chapter (Appendix 8.1) provides a number of tables showing oil-production (or productive capacity) forecasts from NEB reports, which we will refer to simply by the year in which they were issued. We consider reports issued from 1974 through to 1999, and look at oil output projected up to the year 2010. (The NEB 'Supply/Demand' Reports after 1999 include numerical values for total oil output, rather than the disaggregated categories we utilize; some graphs for disaggregated output are included in the reports, but the precise output values are difficult to determine from the graphs.) In what follows, we briefly review the various types of crude-oil-supply models utilized by the NEB, the forecasts of conventional crude oil reserves additions in the Western Canadian Sedimentary Basin (WCSB), and the forecasts of light and heavy crude oil output (or potential production) in the WCSB. (The NEB does provide detail by province, but the main reports are for the entire WCSB. Alberta is the source of most of this oil, although less so for heavy crude oil.) The NEB has not usually labelled its projections as 'forecasts,' instead using terms such as 'cases' or 'scenarios.' Our preference is to label them as conditional forecasts, that is, forecasts of future output conditional on a number of underlying assumptions.

A. The NEB Modelling Procedure

The first NEB report in 1969 utilized a simple aggregate engineering approach based on the estimated availability of oil reserves; these in turn were drawn largely from relatively simple geological-volumetric estimates provided by the Canadian Petroleum Association. As discussed in Chapter Five, the geological-volumetric approach estimates the total volume of potential oil-bearing rock in a sedimentary basin and applies an assumed average amount of oil found per unit volume of rock. Often, this average oil volume is based on experience from other petroleum basins elsewhere in the world.

Since the 1969 report, the NEB has built up a considerable bank of data that allows much more detailed forecasting. Some of these data consist of detailed reserves and output information on all significant oil pools in production in Canada. Cost and planned output data is obtained from many of the main oil producers. The NEB also draws extensively on the play-based models of the Geological Survey of Canada (GSC). Beginning as early as the 1974 report, this allowed the NEB to make disaggregated forecasts of crude oil producibility.

The 1994 report provides extensive detail on the modelling procedures. A number of the approaches discussed in Section 2 are utilized. Some of the forecasts are largely engineering or technical in approach. For instance, already discovered pools normally are assumed to produce following specified depletion paths; oil sands output is based to a significant extent on announced projects; reserves additions follow assumed time paths of development and depletion. Production of pentanes plus and condensate falls out of the NEB's natural gas forecast through assumed liquids to gas ratios. Cost estimation is often used. Thus 'supply costs' are estimated or assumed for large oil sands mines, for bitumen and frontier projects, and for the potential reserves additions. Reserves additions are normally separated into those added through new discoveries, those added through extensions and revisions of extant discoveries, and those added through enhanced oil recovery (EOR) projects. The resource potential for conventional oil is derived from the GSC discovery process and subjective probability models (discussed in Chapter Five). The NEB recognizes that future production is conditional on many factors that cannot themselves be forecast with certainty. Hence, a number of different forecasts are usually provided to indicate how oil production might change as underlying conditions change; such 'sensitivities' may relate to variations in the price of oil, in technologies, in the size of the resource base, or in government regulatory policies.

The NEB has undertaken a very difficult task. The crude oil industry is complex, and to provide detailed and frequent forecasts of the total Canadian output of crude is a major undertaking. The openness of the NEB to a variety of modelling approaches – the eclecticism of its approach – is probably one of its main strengths. Yet it is quite different to the modelling procedure most common in academic studies, which is to select a more restrictive problem and apply a relatively sophisticated technique to this smaller issue.

B. Potential Reserves Additions

A key determinant of the future producibility of Canadian crude oil is the volume of conventional crude oil that remains to be added to reserves. The production from reserves additions depends not only on their volume but also on the rate the reserves are added and developed, which in turn reflects the willingness of producers to undertake the necessary investments. Readers may recall our argument that resource limits are not absolutely binding since the real issue is what volumes from the indeterminate underlying physical resources will ultimately prove to be economic. The NEB, like many oil-supply modellers, has felt it necessary to recognize the exhaustible nature of conventional oil by incorporating in their model some estimate of the volume of oil that may ultimately prove to be economic. If all else were equal, one would expect to find that the volume of potential reserve additions would fall over time since reserves additions over time would reduce the total amount remaining in the ground still to be added to reserves, making additions more difficult. However, while such 'depletion effects' will reduce reserves addition potential, changing knowledge and technology could increase it by making larger volumes commercially accessible.

Table A8.1 in Appendix 8.1 shows that declines in reserves additions potential have not been the norm in the NEB reports. In fact, for both light and heavy crude, and for both new discovery and EOR reserves, the NEB has become much more optimistic since the mid-1970s. For light oil discoveries, the latest report considered here (1999) shows the highest potential (666 million m^3). For heavy oil, estimated potential was increased sharply to 1991 but has since been lowered for both new discoveries and EOR reserves additions. The potential for light crude EOR reserves was also cut in 1999, although this may partially reflect the application of economic criteria to the 1999 figures. In general, the data in Table A8.1 suggest that there is a tendency for the passage of time to generate improved expectations about possibilities for reserves additions. This may well be a common occurrence in disaggregated models since the ability to foresee entirely new techniques or geologic plays is necessarily limited and the willingness to extrapolate trends in these supply components may be constrained by the presumption of depletion effects in discovery.

Rising estimates of potential reserves additions cannot be tied to rising oil prices. Table A8.1 shows the approximate level of the crude oil price at the time the report was issued. (These prices are in nominal dollars, so the earlier prices are actually understated in real terms compared to more recent prices.) As can be seen, the highest reserves potential does not occur in the year with highest prices; for example, the January 1981 report had the highest price ($38/b), but the light crude potential is significantly higher for all years since then, even at prices 50 per cent lower. Changing knowledge must be the most significant factor in the revisions of the NEB forecasts, and the knowledge changes must tend to be 'positive' (that is, leading to more optimistic forecasts over time).

C. WCSB Crude Oil Producibility

Appendix 8.1 includes four tables showing the NEB forecasts of crude oil producibility in the WCSB: conventional light oil (Table A8.2), conventional heavy oil (Table A8.3), syncrude (Table A8.4), and bitumen (Table A8.5). In each table, actual output is also shown for years from the mid-1970s to 2010. Where a number of scenarios were reported, we normally show the 'Base' or 'Reference' case, selecting the case that seems most accurately to reflect actual world prices in the years immediately following the forecast. We shall discuss, briefly, each of the four crude oil categories. The first NEB supply/demand report of 1969 did not report estimates for these separate grades of crude oil. It did forecast rapid increases in Canadian crude oil output. (The report did not distinguish between production and producibility.) Thus, for example, Table 17A(1) of the 1969 report showed Canadian petroleum production rising from 161,000 m^3/d in 1966 to 361,000 in 1975, to 522,000 in 1980 and to 654,000 by 1990. Actual production of conventional and non-conventional crude oil in 1991 was 243,500 m^3! These extremely high production forecasts presumably reflected the high resource potential stemming from the volumetric estimation procedures.

1. Conventional Light Crude in the WCSB

Each of the eleven forecasts exhibits pronounced decline over time. This reflects decline rates in individual oil pools, which apply to the sizable number of pools already in production at the time the forecast was made. Since the forecasts are usually for productive capacity, they may tend to overstate the amount of production anticipated in those years from 1974 to 1985 when there were government limits on the volume of exports from Canada. (See Chapter Nine.) Note, also, that the 1974 and 1975 reports include all WCSB crudes, not just light oils. It is therefore not surprising that these two reports forecast higher oil output than actually occurred for light and medium crude in the 1970s. But, by 1984, actual production exceeded the forecasts of both the 1974 and 1975 reports.

The year 1993 is instructive, since this year included forecasts for all the preceding reports. Forecast production tended to be higher the later the report was issued. (The 1991 report is an exception; the 1977 report also appears to be, but remember that the 1974 and 1975 reports included all crude, not just light and heavy.) Actual production in 1993 exceeded the forecast from all reports for 1974 through 1991. In line with these revisions, the 1994 report was more optimistic about future production than the 1991 report. A comparison of 1999 to 1994 is more ambiguous, with the more recent forecast lower for the first decade but higher from 2005 on.

These results are quite consistent with the changes we mentioned for estimates of reserves additions, where the additional information garnered over time led to more optimistic projections. It also highlights the dangers in emphasizing the exhaustible nature of conventional oil since there seem to be persistent tendencies to underestimate future availability. These probably stem from the difficulties imposed by (or the conservative reluctance to go beyond) the constraints of current technology and knowledge. This raises a classic induction problem, however: the fact that virtually all the historical forecasts have been overly pessimistic does not mean this pattern exists of necessity.

2. Conventional Heavy Crude in the WCSB

Table A8.3 shows NEB forecasts of conventional heavy crude production in its reports from 1977 through 1999. We see the same pattern as for light and medium crude oil. Forecasts have underestimated the actual growth in heavy oil production, and later forecasts have tended to be more optimistic. Thus, for example, the 1977 report foresaw heavy crude oil production in 1995 of 19,000 m^3/d, whereas output was actually 73,000. The 1991 report put the level in 1998 at 48,700 m^3/d; that year output hit 85,000.

3. Synthetic Crude

NEB reports from 1974 through 1999 provided future output paths for syncrude, as did the NEB's three later reports on the oil sands. (See Table A8-4.) The 1974 report provided the most optimistic forecast, and all three reports from the 1970s substantially overestimated the future syncrude output. These reports all reflected the siren call of the huge synthetic crude resource base and optimistic estimates of the associated production costs. However, as was discussed in Chapter Seven, it soon became apparent that the oil sands were much more difficult and costly to bring into production than had initially been thought. The NEB reports after 1978 reflected this information and also a change in estimation methodology in which the projected paths of syncrude output mainly reflected announced projects or expansions. Given the long lead times in constructing integrated mining projects, this meant that the forecasts were relatively accurate for a period of five or maybe ten years, but the reliability had to be suspect beyond that. As it happens, up to 2000, no new mining projects had been commenced, but addition to capacity in the Suncor and Syncrude plants has been greater that was anticipated in the NEB reports from 1981 through 1991. The 1999 report anticipated that one large new project would begin production by 2005, which was accurate as the Albion Sands project began production in late 2002.

4. Bitumen

Table A8.5 shows that the NEB estimates of future bitumen production exhibited the same pattern as for conventional crude. The forecasts underestimated future production. Later forecasts were more optimistic, but still tended to be too conservative.

D. Implied NEB Supply Elasticities

As we mentioned, the NEB often provides a number of 'conditional' forecasts in its reports; that is, the specific forecast is conditional on particular assumptions. The previous section looked at the NEB forecasts that assumed prices closest to those that actually occurred and found that, except for synthetic crude, the NEB tended to underestimate future production. In this section, we consider a different dimension of the NEB forecasts. In those cases, where the NEB provided forecasts at different prices, and price was the only variable that changes, it is possible to look at the responsiveness of the forecast to the price difference; that is, there is an implied elasticity of supply given by the two estimates. (Remember from Chapter Four that the elasticity of supply is the percentage change in output divided by the percentage change in price that brings it about, all other factors affecting supply held constant.) These are 'arc' estimates of the elasticity of supply, since the two output values are typically estimated at prices that are quite distant. (As such, they contrast with 'point' elasticity estimates, which indicate the responsiveness of output to very small price changes. A number of varying 'paths' of point

Table 8.1: Implied Oil Supply Elasticities in NEB Reports, 1984–99

	1984	*1986*	*1988*	*1991*	*1994*	*1999*
Established Reserves, Light and Heavy	0.8/**0.15**					
New Discoveries, Light and Heavy	1.48/**0.67**					
EOR, Light and Heavy	2.68/**1.12**					
Established Reserves, Light		0.04	0.04			
EOR, Light		0.28	0.50		0.9/**1.94**	
New Discoveries, Light		0.96	0.02		0.33/**0.17**	
Light and Medium				0.83/**1.5**		1.03/0.32*
Established Reserves, Heavy		0.08	–0.84			
EOR, Heavy		0.98	0.90		1.03/**2.46**	
New Discoveries, Heavy		0.96	–0.5		0.4/**0.26**	
Heavy Crudes and Bitumen				1.07/**1.73**		
Conventional Heavy						0.52/0.59*
Bitumen		5.62	2.68		5.27/**2.43**	2.21/2.77*
Syncrude		1.00	1.60		1.17/**0.34**	1.31/2.23*

Notes: Most elasticities reflect the supply response to higher prices; numbers in bold are elasticities with respect to price declines. In 1999, the values marked with an asterisk (*) are from the "Low-Cost Supply Case," which assumes that greater volumes of low-cost resources are available.

supply elasticities are all compatible with any particular arc elasticity.) The values that we calculate below are not always true supply elasticities because in some cases the difference between the two NEB forecasts involves more than simply two prices of crude oil; we have noted the most important differences. It is also important to note that there is usually no single supply elasticity involved in comparing two cases since the relative difference between outputs typically varies depending how long into the future one is looking. Since the NEB production forecasts tend to exhibit short-run price inelasticity (as is entirely appropriate), we have normally picked a year for comparison at least ten years into the forecast. And, finally, not all price assumptions involve constant prices over time, so that the percentage change in price is not necessarily constant between two forecasts; once again, we try to take note of exceptions in this regard.

The 1969, 1974, and 1975 reports included no explicit price assumptions. Appendix A8.6 has tables showing the ranges of forecasts for the subsequent NEB reports. We shall briefly review the price assumptions of each report and make comments on the implied elasticities where appropriate. Table 8.1 summarizes the estimated price elasticities from the 1984 to 1999 reports.

1977 Report. A constant real price (at the 1980 international level) was assumed in the 'expected' case; in the 'maximum price' case, the real price rises by 5%/yr, while in the 'minimum price' case, the real price falls by about 5%/year (the nominal price is constant). The NEB estimates show significant price response for both conventional and synthetic crude, especially if prices fall.

1978 Report. The base, high, and low price assumptions are the same as for the three cases in the 1977 report, but with greater supply desegregation. Production from current established reserves was completely unresponsive to price differences. Presumably this oil has only to recover operating costs, so the effect of different prices is on the abandonment date, when output rates are small. Bitumen production is low and is shown as responding asymmetrically to price changes; a higher price does not call forth any more production, but output falls dramatically if the price declines. Synthetic crude is also shown as particularly affected by lower prices. Conventional light reserves additions are particularly responsive to higher prices.

1981 Report. The 1981 report showed sharply rising nominal (and real) prices, as international prices were assumed to continue to rise, and Canadian prices increased under the various schedules of the National Energy Program. The sensitivity cases shown in this report do not reflect price differences but, rather, differences in geologic and technological potentials and in fiscal regimes. Of course, reduced government take is like a price increase as far as producers are concerned. The modified base case allowed for reduced taxes or royalties. The low case assumed somewhat higher government take and poorer geological potential. The high case assumed higher geological potential and more rapid approach to international oil prices. Specific price effects cannot be estimated since price is not the main variable changing between cases and the netback changes assumed are not explicitly described. This report shows bitumen as completely unresponsive to changes between cases, while synthetic crude production is highly responsive to improved conditions. Conventional crudes are clearly regarded as also sensitive to changing conditions; of course, this is true pretty well by definition as far as changes in geological potential are concerned.

1984 Report. The report showed high and low prices relative to the reference case. In 1983, U.S. dollars/b, the reference price in 2005 was $37.60, the high price was $50.10 (or 33% higher) and the low price was $28.10 (or 25% lower). These price differences were not constant across time, so the implied elasticities of supply are only approximate. We have estimated elasticities of supply by taking the percentage change in quantity between cases and dividing it by the percentage change in price. For example, as Appendix A8.6 shows, at higher prices, output from currently established reserves is 5 per cent higher (20/19); since the price was 33 per cent higher the elasticity of supply implied is 0.15 (5/33). As Table 8.1 shows, higher elasticities are implied for output from new discoveries than for established reserves, with EOR output even more responsive to price changes.

It will be noted that these estimates show supply as being more responsive to lower prices than higher. This is true even for already established reserves; by 2010, the output from these reserves has fallen dramatically due to production decline, so small changes in production appear more significant. It is not clear why supply should be less responsive to price rises, although this could reflect a higher government take as prices increase. Another possibility is related to the tendencies we noted above to underestimate reserves additions. Forecasts tend to be conditioned by the existing knowledge gained at prevailing prices, so tendencies to underestimate resource potential may be particularly pronounced for cases that assume prices higher than we have seen. Alternatively, it may reflect a judgment that additions to volumes of recoverable oil become smaller as prices rise.

1986 Report. By 2005, the high price of US$27/b (real 1986 dollars) is 50 per cent higher than the low price. The implied elasticities in Table 8.1 show that output from current established reserves is minimally sensitive to price changes, which is not surprising. Light oil output from EOR projects is estimated to be relatively inelastic. Unlike the 1978 and 1981 reports, bitumen is highly responsive to price increases. The other output categories all exhibit about unitary elasticity.

1988 Report. As in the 1986 report, the high price (at US$30/b in 1987 dollars) is 50 per cent higher than the low price. Using the same procedure as before, the elasticities shown in Table 8.1 are derived. The negative supply price elasticities for two of the heavy oil categories stand out. Why would higher prices reduce output? The reason seems to lie in the exhaustibility implications of the NEB's models, where higher prices induce increases in reserves but may also speed up production so that, by the year 2005, heavy established reserves and reserves additions actually show less production at higher prices. (This highlights the difficulty of deriving precise supply elasticities when what is really being compared is production paths over time.) As in the 1986 report, non-conventional supply sources are shown as particularly price responsive; large volumes are waiting, if only the price gets high enough. From the mid-1970s to the mid-1990s, however, it seemed that the 'magic' price was always above prevailing market prices! The production possibilities for light oil in 2005, due to higher prices, have flipped in the 1988 report as compared to the 1986 report, with EOR now offering most of the incremental output.

1991 Report. The control case had a price of US$27.00 in 2010 (1990 real dollars). The other cases are described in slightly vague terms but seem to involve a price 26 per cent lower and 30 per cent higher. Supply elasticities (Table 8.1) are generally elastic and are higher for heavy crudes than light.

1994 Report. The reference price in 2010 is US$23.00/b (in real 1991 dollars). The low price is 35 per cent lower, and the high price is 30 per cent higher. Table 8.1 includes implied supply elasticities based on the production amounts for 2010. EOR is quite price sensitive, especially to price declines. On the other hand, this report shows conventional crude as being particularly sensitive to price rises, though the supply response is still inelastic. The high supply elasticity of bitumen is evident.

1999 Report. This report gave two price sensitivities, a 29 per cent higher price in a case involving 'current supply trends,' and a 22 per cent higher price in a case with a greater volume of low-cost oil available. Once again, the NEB analysis implies particularly high supply elasticities for non-conventional crude, as Table

8.1 shows. Conventional heavy oil is seen as supply inelastic. The sharp fall in the supply elasticity for light oil between the two cases suggests that a significant portion of the expected reserves additions for light oil are booked at the lower price, leaving relatively small incremental volumes to draw under the stimulus of higher prices: the supply curve gets steeper.

E. Conclusion

We have reviewed the NEB supply forecasts from the early 1970s through to 1999 in some detail because they are the most widely reported and accepted supply estimates in Canada. They incorporate all types of crude, have been revised and published on a regular basis, and have seen the gradual development of a large data base and increasingly sophisticated modelling. The modelling approach is eclectic, involving a variety of techniques ranging from 'rules of thumb' through to elaborate statistical estimation. Because the techniques are so varied, and the underlying data so extensive, it is not always obvious what factors are of most significance in giving changes in forecast oil production from report to report. The NEB reports have tended to become increasingly optimistic about the oil production capabilities of the Western Canadian sedimentary basin. The disaggregated supply estimation methods imply that crude oil supply is price responsive to some degree. Supply from already established reserves normally appears as very price inelastic, and the various categories of reserves additions, EOR potential, and non-conventional crude show widely varying implicit supply elasticities in different NEB studies, but the clear, emerging message is that 'price matters.' The NEB has generally found that price is particularly important for non-conventional crude oils. Underestimates of supply for the conventional oil may reflect a tendency to underestimate the impact of changes in technology and knowledge (for example, with respect to new geological plays or new recovery techniques). But this could also stem from underestimation of the price elasticities of conventional crude oil supply since much technological change is, in fact, induced by expectations of profit that is, clearly, enhanced by higher prices. That is, higher prices will induce increased crude oil production because higher cost oil (under current technologies) becomes profitable; they also induce more production as a result of the new technologies and knowledge that the price rises stimulate. Our sense is that the NEB forecasts of the 1970s and 1980s tended to be insufficiently optimistic about these new technological possibilities. This in turn may reflect a natural conservatism in making forecasts that manifests itself in the difficulty in allowing for truly novel possibilities. However, that this has been the case in past forecasts is not a guarantee that it will prove to be so for the most recent forecasts, which may be more accurate as forecasting procedures have improved. In addition, it may well happen that the tendency to resource 'pessimism' turns out, at some point in time, to be correct!

The NEB is not the only research organization to build a disaggregated model of Alberta oil supply, although it is the only body to provide continually updated forecasts over an extended period of years. Both the ERCB and the Canadian Energy Research Institute (CERI) have also provided forecasts of Alberta conventional crude oil production, using relatively detailed supply models. The ERCB forecasts have appeared in the series of publications to which we have made frequent allusion entitled *Reserves and Supply/Demand Outlook* (ERCB, ST-18 and, since 2001, ST-98) and will not be reviewed here. We will summarize some of the CERI work.

Heath (1992) and Heath, Chan, and Stariha (1995) set out the **CERI conventional-oil-supply model**. It is difficult to disentangle all the details, which involve numerous assumptions to go from separate oil pools to total Alberta supply. We will provide a brief outline of the model as we understand it. To some extent, they rely on data and assumptions from the NEB models. For geological information, they draw on analysis from the Institute of Sedimentary and Petroleum Geology (ISPG), which set out a total of 45 crude oil plays in Alberta (39 of them light and medium crude, and 9 heavy crude). CERI researchers added a 46th play to represent small and unclassified pools and oil from natural gas pools with high condensate content. The ISPG data was largely drawn from discovery process modelling, which provided estimates of the size distribution of pools in the 45 plays and, by deducting historic discoveries, gave a distribution of the number and expected sizes of as-yet-undiscovered pools. The ISPG model also estimates a parameter that indicates the extent to which pools have been discovered in a strict largest-to-smallest sequence; this variable can be used to indicate the likelihood that the next discovery in the play will be of any specific size. Drawing on a number of sources, CERI assumes exploration success ratios for each play. In addition, play-specific depletion paths are assumed, as are two abandonment quantities, one for larger pools and one for smaller. Heath, Chan, and Stariha also discuss economic criteria for determining the abandonment date for oil pools and the willingness to invest in pools, but it is not clear how these criteria interact with the more deterministic rules they also discuss. The economic criteria appear to be used largely for a separate cash flow and profitability analysis of the oil pools available in each play; in effect, these involve the estimation of 'resource stock supply curves,' which indicate the volumes of oil available at various possible costs. The estimates of Alberta production to 2014 are apparently assumed to be drawn from the economic pools. The CERI study also assumes that results from Saskatchewan for increased recovery factors due to new EOR and horizontal drilling (Chan et al., 1994) can be generalized to Alberta.

The CERI production model incorporates short-, medium-, and long-run perspectives. In the short-run, existing established reserves are run down using established production decline relationships and 1995 economic and fiscal conditions. The analysis assumed a WTI price of US$19.50/b at Cushing, netted back to Alberta, with quality and local transmission cost adjustments appropriate to each oil play.

In the medium-run, oil pools are developed up to some level for primary production and are also assessed for EOR potential. The EOR is assessed as waterflood potential but draws on EUB data for all types of EOR. Considerable judgment was used in defining the number of development wells required in an oil pool, based on four factors: an assumed 80 per cent success rate; the provincial average, for each pool size, of reserves divided by the estimated lifetime production of an average well; an assumed average well spacing (e.g., 64 hectares for a well in a light oil pool); and the historic average number of wells in each pool size. Planned development is usually the smaller of that suggested by the latter two of these criteria and is assumed to take five years, following an 'S'-shaped curve, with assumed maximum numbers of wells possible each year in a pool. Within any play, development is assumed each year to start with the largest pools and progress through to smaller pools, in so far as development expenditures allow. (See below for the determination of these expenditures.)

In the long-run, new pools can be discovered from the 46 plays, based on the estimate of the size distribution of undiscovered pools and the likelihood of finding each pool. At any time, the relative appeal of different oil plays is based on each play's share of as-yet-undiscovered reserves in the province.

The level of investment activity, and hence the actual amount of development and exploration that takes place, is said to be based on econometric estimates that CERI derived from the Alberta Department of Energy. Heath, Chan, and Stariha (1995) provide insufficient data to understand this model clearly. Their Appendix A.6 suggests that the model estimates constant dollar expenditures on exploratory drilling, G&G expenses, land rental costs, and development drilling as a function of variables such as interest rates and oil netback values (price net of operating costs including taxes and royalties). However, Appendix A.4 describes the independent variable as "the producers' probability of reinvesting" (p. 259) and says that the reference cases assume a constant reinvestment rate of 88 per cent (p. 260) with 62.5 per cent of this going to development and the rest to exploration. Thus, the key factor is the reinvestment of the net operating income of the industry (which we assume is revenue less operating costs, royalties, land rentals, and taxes). Exploration and development expenditures are then allocated across the plays on the basis of each play's share of undiscovered oil volumes. In this model, reserves additions fall off rapidly. For example, in 1995, in millions of barrels, there are new discovery reserves additions of 220.5, but in 2014 there are only 2.8. Less drastically, EOR reserves additions fall from 32.0 to 7.1.

Table 8.2: CERI Alberta Oil Model: Forecast Oil Production (m^3/d)

	Existing, fully developed pools	*Existing pools, not completely developed by 1992*	*New pool discoveries*	*Total*
1995	87,758	4,088	58,187	150,032
2000	33,051	1,087	51,359	85,497
2005	17,221	391	27,310	44,923
2010	11,002	174	14,960	26,093
2014	8,306	130	9,045	17,439

Table 8.2 (with data from Heath, Chan, and Stariha, 1995, p. 29) shows forecast Alberta conventional crude production for several years from 1995 to 2014 in cubic metres per day. The extremely rapid forecast decline in Alberta conventional oil production is apparent, much more rapid than the declines forecast by the NEB in 1994 and 1999 for WCSB conventional light and heavy crude (Appendix Tables A8.2 and A8.3). CAPP shows conventional Alberta oil production in 2000 as 119,188 m^3/d, almost 40 per cent higher than the CERI forecast for that year; in 2005, CAPP reported 90,804 m^3/d as compared to 44,923 for

CERI; for 2010 the numbers were 72,957 m^3/d (CAPP) and 26,093 m^3/d (CERI) (CAPP *Statistical Handbook*).

Thus, the CERI forecast seems to share the under-estimation characteristics of the NEB forecasts.

4. Direct Cost Estimation

A. Introduction

Recall that, if we are willing to assume that the industry is dominated by profit-maximizing companies, then the supply curve for crude oil can be interpreted as the marginal cost curve of crude oil. From this perspective, one way to assess the supply of Alberta crude oil would be to directly estimate the actual and potential costs of production. This procedure is often used, both in cost assessments for specific projects and in industry-wide studies of 'Finding' and 'Replacement' costs. And the profitability analysis internal to most companies either explicitly or implicitly incorporates the unit costs of the oil associated with specific investment proposals; of course, these analyses are usually kept confidential as propriety information to the company.

In this part of the chapter, we will review some studies that directly estimate the cost of Alberta crude oil. In estimating the costs of oil production, only variable costs are relevant. This leads to the distinction between 'full-cycle' costs (when new exploration, development, and lifting costs must be incurred) and 'half-cycle' costs (in already discovered pools, when only new development and lifting costs are needed).

Direct cost estimation normally relates quantities of crude oil production (Q) to the expenditures (E) undertaken to produce those quantities. In the simplest format, we could define an average cost of oil production as E/Q. But this is not the marginal or incremental cost that economists think of as defining a supply curve of oil. Complications abound, including the following seven:

(i) Care must be made to distinguish between oil-in-the-ground (for example, additions to oil reserves) and oil as it is lifted (crude oil production).

(ii) The time value of money must be considered. In practice, a base year must be defined (usually the current year or a recent one), and expenditures after this year assigned a smaller value than the actual expense since their present value is reduced by the advantage of being able to wait before incurring them and investing the capital funds in the intervening period. Mathematically, if r is the annual rate of 'discount' or time value of money, expressed as an annual interest rate, then the present value of $\$I$ spent a t years from the base year is:

$$Z = \frac{I}{(1+r)^t} \;;$$

that is, $\$Z$ invested today at r% per year would give $\$I$ in t years time. Let us suppose that $\$I^*$ is the present value of the investment expenditures needed to add R barrels of oil to reserves. Then I^*/R would be a measure of the average cost of the additional oil-in-the-ground.

Timing is also important for the process of oil production since reserves are depleted over many years and much of the revenue will not be received until far into the future. If the analyst is estimating the cost of oil as lifted, it is therefore necessary to adjust production for timing as well. This involves the concept of the 'supply cost' or 'supply price' or 'levelized cost' of oil, which is the present value of costs divided by the present value of production, or, in symbols, where $q(t)$ is output in year t, and year T is the last year of production:

$$\frac{I^*}{\sum_{t=0}^{T} q(t)(1+r)^{-t}} \, .$$

If output follows an exponential decline relationship, falling at annual rate of a% per year, and $q(0)$ is the initial annual output rate, and continuous rather than discrete time is used, then the supply cost is:

$$\frac{I^*}{\int_{t=0}^{T} q(0)e^{-at}e^{-rt}dt} = \left(\frac{I^*}{q(0)}\right)\left(\frac{a+r}{1-\frac{1}{e^{(a+r)T}}}\right).$$

These timing factors must be kept in mind when estimating the costs of oil.

(iii) Determination of the appropriate rate of discount (r) is not easy. From the start, care must be taken to ensure that both expenditures and r are in the same 'units,' that is either nominal (current or 'as spent') dollars or real (constant or 'inflation free') dollars. A number of different inflation rates are potentially available to translate nominal into real discount rates.

(iv) The supply curve is a ranking of potential units of oil production from low cost to high cost, where the cost is the incremental, or *marginal*, cost of that unit of oil. However, reported cost data is normally an *average* cost for an aggregated volume of oil. This may be all the costs in a region for a particular time period, or it may be the total costs for an entire project. Relating these costs to the associated reserves or output will, therefore, yield an average cost. For a specific project, the data may reflect indivisibilities ('lumpiness'), in the sense that one cannot typically vary capital expenditures in such a way as to change production on a unit-by-unit basis. Hence, the calculated cost might be interpreted as a marginal cost since it does represent the incremental cost per unit of the next 'lump' of output. However, even for individual projects, the data are often not in an appropriate form to calculate a marginal cost, since it represents the *total* investment plan of the producer and does not include the sequence of smaller investment options that preceded the one selected. It is the sequence of these incremental projects that really defines the marginal costs. In certain circumstances, this may not pose much of a problem. Thus, for example, in a reservoir that has homogeneous physical characteristics – porosity, permeability, thickness, water-to-oil ratio, etc. – extra units of production from extension drilling will exhibit relatively constant returns, where average and marginal costs are equal as production expands. However, activities like infill drilling and EOR projects are more likely to involve diminishing returns as the scale of the project is increased. Thus, the average cost of the entire development investment will understate the marginal cost of the last units produced.

It may be possible to approximate marginal costs from average cost data. Suppose that we know the equation for the average cost curve. We also know that total cost (TC) is the average cost (AC) multiplied by quantity (Q); marginal cost (MC) is the first derivative of the total cost curve with respect to quantity. For example, suppose that we assemble average cost data that suggest that the average cost curve is a straight line that starts at zero. That is, costs begin at a minimal level for the very first unit of production, then increase so that $AC = bQ$, where b is the slope of the average cost curve. Then total cost is $(bQ)(Q)$, and $MC = 2bQ$; the marginal cost curve is twice as steep as the average cost curve.

(v) Direct estimation of the cost of oil production is plagued by joint-product problems since much expenditure is not clearly tied to specific units of output. Remember that in a joint-product process a single activity necessarily generates more than one output. Petroleum exploration is an outstanding example since exploration expenditures almost invariably yield knowledge that is useful in the location of both oil and natural gas deposits and also for both current and future discoveries. How, then, can a particular exploratory investment be tied to specific units of output? One point of view is that it cannot and that attempts to directly estimate 'finding' (or exploration or discovery) costs are futile and meaningless (Adelman, 1992). Other analysts disagree, suggesting that simplifying assumptions allow us to derive meaningful cost measures in joint-product cases. Often the argument is not so much that the specific value is a 'true' measure of cost, but that, so long as we always make the same assumptions, these costs may serve a useful comparative purpose. For example, trends across time in costs for a region may be calculated, or cost comparisons may be made between different companies in order to assess their relative performance. The assumptions required are of two main types, one related to *timing* and one to the *types of products* produced.

For the first, it is normally necessary to make some assumption about the timing of the output tied to a particular expenditure. Thus, for example, it might be assumed that geological and geophysical (G&G) expenses are tied to oil discoveries one year later (and therefore include one year's interest cost), while exploratory drilling costs relate to discoveries in the same year. It is also necessary to decide whether discoveries are the reported 'new discoveries' in the year of the exploratory expenses, or whether an attempt should be made to estimate 'appreciated discoveries,' including the reserves that will be added through subsequent development activities. Presumably, exploration discovers the whole oil pool, but some of the reserves subsequently added may reflect later economic or technological conditions, especially where EOR schemes are concerned. However, if only year-of-discovery 'new discovery' reserve estimates are used, then these reserves will be allocated a relatively high cost of exploration, and the subsequent reserves added in the pool will not show any exploration cost at all.

Exploration normally generates both oil and natural gas discoveries. In any region where both products are valuable, it is necessary to: (a) model oil and gas discoveries together, (b) divide the expenditures between the two products, a cost allocation process, or (c) combine the two products into a single one (e.g., barrels of oil equivalent), an output aggregation process. In the cost allocation or output aggregation cases, a 'reasonable' criterion will be selected, but there are a number of such criteria and no firm basis for thinking that any one is *the* valid method. For example, total exploratory drilling costs may be allocated on the basis of the relative number of successful oil and gas wells, or some measure of the 'intent' of companies when drilling the exploratory wells, or the relative footages of successful oil and gas wells. Oil and natural gas could be combined into a single product on the basis of their respective energy contents or their relative market values. The absence of any obviously valid solution to the joint-product problem leads some to deny the validity of any direct cost measures where joint-product problems are significant. Adelman and Watkins (2002) note the range of different results depending on the method used and argue that no one approach is more meaningful than any other. The contrary view is that, once a specific assumption is made about how to treat joint-product cases, trends in the value calculated are meaningful.

Readers may recall that, if the proportions of the joint products can be varied by varying the types of expenses undertaken, then it is possible to calculate marginal costs for the separate products, even though the average costs are still arbitrary. The marginal cost is the 'full' opportunity cost per unit of the incremental output, where the opportunity cost includes the incremental investment expenditures to produce the extra product plus the net operating profits given up on any units of the other product which are sacrificed. For example, a company might redirect its exploration away from wells that have a higher probability of locating natural gas and toward wells with a higher probability of finding oil. One would expect to see a net increase in oil discoveries from the new wells drilled, but there would be an additional opportunity cost in terms of reduced discoveries of gas. In practical terms, however, cost data are rarely available in sufficient detail to allow the estimation of such marginal costs.

(vi) It is also important to realize that expenditures (even including allowance for the time value of money) do not account for all costs that go into the supply curve. Both user costs and any costs associated with the foregone value of future options will also enter marginal costs. That is, direct estimation of a marginal cost curve on the basis of industry expenditures will normally underestimate the marginal costs of production and therefore overestimate supply.

(vii) Finally, when time series data are used to directly estimate unit oil costs, there are 'identification problems' in interpreting the resultant values (one per year) as a supply curve. This is because, as time passes, the factors underlying the supply curve change so that it is not clear whether the cost has changed across time because there has been a movement along a supply curve or because the supply curve has shifted.

Despite these problems, direct cost estimates of oil are frequently made. They can be very useful when data are available for specific projects, as they can provide a check on whether that project is potentially profitable at the current level of oil prices. The project will not necessarily be undertaken even if this condition is met, since the willingness to invest depends not only on the current price of oil but also on expected

Table 8.3: NEB Supply Costs for Non-Conventional Oil ($\$/m^3$)

NEB Report	*Integrated Mining (mining and upgrading)*	*Bitumen*	*Bitumen and Upgrading*
June 1981	$260	N/A	N/A
October 1986	$185–$275	$70 and up	$140–$230
September 1988	$170	$65–$100	$150–$185
June 1991	$200	$65–$90	N/A
December 1994	$157–$189	$57–$100	N/A
1999	$94–$151	$50–$107	N/A
2000	$94–$114	$44–$88	N/A
2003	$138–$176	$63–$120	N/A
2006	$226–$251	$88–$138	N/A

prices. And even were it profitable based on expected oil prices, the company might find it profitable to delay production for 'user cost' or 'option value' reasons. Also, a company might be willing to undertake a project even if it did not generate expected profits itself, if, for example, it was expected to generate geological information that would help the company make better exploration decisions in subsequent periods.

We will not attempt to summarize all the published direct cost estimates for Alberta oil, but we will provide several examples falling into two broad classes. The first involves cost estimation for specific projects, while the second involves time trends in costs for the entire industry.

B. Costs of Specific Projects

Companies undertake project evaluations all the time, which could be readily translated into unit cost estimates. These could be either for oil in the ground (i.e., the present value of exploration expenditures divided by the volume of oil reserves expected to be discovered) or for crude oil as produced (i.e., the present value of expenditures divided by the present value of the output that is expected to result). However, companies rarely make this information public.

There are several examples of studies that have used this approach to analyze the supply of crude oil in Alberta. We will see a detailed example in Chapter Ten, where Watkins estimated the costs in the 1950s of developing a number of particular oil pools in Alberta under three possible sets of regulatory conditions. Cost estimation has also formed a part of the NEB's analysis in their 'Supply/Demand' reports. Starting with the June 1981 report, the forecasts of bitumen and oil sands production summarized above, for instance, derived in large part from direct estimation of supply costs and their size in relation to anticipated oil prices. There seems to be a common presumption that the resource base of the oil sands is so large that per unit development and operating costs are constant and the user cost component of marginal cost is minimal. This may well be reasonable for mining type operations, where it seems to be relatively easy to move on to a new piece of land to strip mine more ore without appreciably impacting production opportunities in the near future. For *in situ* ventures, the assumption of zero user costs may not be as appropriate since current production may deplete reservoir energy and therefore increase future production costs, much as happens in a conventional oil pool. Table 8.3 summarizes the varying supply costs reported by the NEB for syncrude from combined oil sands mining and upgrading projects and for bitumen from heavy oil projects. The costs are in dollars per cubic metre and have not been adjusted for inflation. As can be seen, current dollar cost estimates for upgraded synthetic crude oil tended to fall from 1981 to 2000 (and real costs would have fallen even more dramatically), but then rose again after that. In 2011, the NEB was estimating that new mining and upgrading projects would require a price for WTI of US$535-600/m³ (NEB, 2011). Estimated bitumen costs showed less variability, but also rose after the year 2000.

The NEB has also used the supply cost approach to assess the likely future production from enhanced oil recovery (EOR) projects. An extensive data base was built up and used to screen major oil reservoirs to see which had technical characteristics that might be amenable to particular types of EOR; from this, the NEB estimated the supply costs of the various possibilities to see if they would be economic at various oil prices. The NEB reports do not give detailed estimates of these supply costs. Supply cost analysis of EOR projects in Alberta was also undertaken by the Canadian Department of Energy, Mines and Resources (1977), Watkins (1977b), Prince (1980), and Eglington and Nugent (1984).

Watkins (1977b), for example, examined thirteen EOR projects in Alberta. At the time there were 370 such schemes in place in the province, but these thirteen accounted for about 40 per cent of the reserves credited to EOR. Most of the projects were waterfloods, with one solvent flood, and one combined water and solvent flood. The data were supplied by the firms involved in the EOR projects and included actual development and operating expenditures (excluding taxes and royalties) and output to 1974; costs incurred after 1974 were projections. All values were in real 1973 dollars; the deflator used was a U.S. oilfield equipment price index. The supply costs of crude ranged from $0.25 to $2.35/b, with an average reserves-weighted cost of $0.83/b, supply costs evaluated at a 12 per cent rate of discount. Ten of the projects had unit development and operating costs below $1/b, and the highest cost project was the solvent flood in the Swan Hills South pool. Field prices in these pools in 1973 were in the $3–$4/b range. Supply prices less than market prices would be anticipated since the investors in the EOR projects presumably anticipated that they would earn profits over and above a normal rate of return – that is, they would enjoy some economic rent. Of course, this expectation is not necessarily met since an EOR project may function less well than anticipated and/or the actual market price could turn out to be lower than was anticipated.

Prince (1980) undertook an extensive study of Canadian EOR potential based upon economic analysis of Alberta oil pools. He considered 'tertiary' EOR, after waterflood recovery. Prince looked at the potential for eight different EOR processes in 1,372 individual Alberta oil reservoirs. An initial screening of reservoir characteristics eliminated a number of these reservoirs as suitable for any of the EOR techniques but left a total of 1,536 possible EOR projects. (Some reservoirs could potentially support more than one type of EOR project.) Economic analysis (based on the implementation of projects over a ten-year period, an 8% required real rate of return and an oil price of $20/b) reduced the number of reservoirs with positive expected profit to 460. (This also involved selecting the most attractive project in reservoirs where more than one EOR scheme was feasible.) His analysis allowed construction of a reserves additions supply curve, showing the supply cost associated with the various projects. The lowest cost project began at about $14/b ($88/m³) and showed approximately 2.4 billion barrels accessible through the 460 projects, at a cost of $20/b ($126/m³) or less. Prince's results show much higher EOR costs than in the previously established projects analyzed by Watkins but also show a flat supply curve for a large supply addition.

Supply costs studies also formed a part of the research funded by the Economic Council of Canada in its extensive review of Canadian energy policies in the early 1980s. **Eglington and Nugent (1984)** undertook extensive analysis of hydrocarbon miscible flood projects in three Alberta oil reservoirs. They estimated both 'social' supply costs (which excluded the effects of taxes and royalties) and 'private' supply costs (which included the payments to governments, on the basis of 1983 tax and royalty regulations). These costs were estimated using a 10 per cent real discount rate and are in 1983 dollars; they include no formal allowance for risk. Table 8.4 summarizes some of their results.

The three EOR projects are of quite different size and are in three different reservoirs. Costs do not vary strictly with the size of the project, though the smallest project is the most costly. At the prices in effect in 1983 (for oil from new EOR projects), the Violet grove project was marginal, but the other two appeared profitable. However, all three would have been unprofitable, if the costs including royalty/tax payments had stayed the same, at average prices from 1986 through 2000. It should be noted, however, that the costs of the hydrocarbon flooding agent would likely fall along with oil prices. The size of the tax/royalty burden is apparent, even though there were a number of special incentives for EOR investments. The Eglington and Nugent study suggests that oil from hydrocarbon miscible flood projects is quite expensive and appreciably more costly than Prince found. (Prince shows an average cost of about $96/m³ for hydrocarbon miscible flood projects.) Eglington and Nugent's study considered only three projects and was designed largely to allow an assessment of Canadian oil policies in the mid-1980s.

Taken together, these studies demonstrate the reservoir-specific nature of EOR, both with respect to the technical viability of different schemes and the costs of the oil produced.

Table 8.4: Eglington and Nugent Supply Costs for EOR Projects

EOR scheme, Reservoir, acres	*Recoverable Reserves before Scheme (10^6 m^3)*	*Recoverable Reserves in Scheme (10^6 m^3)*	*Private Supply Cost ($/$m^3$)*	*Social Supply Cost ($/$m^3$)*
Violet Grove AB Lease, Pembina Cardium, 640 acres	0.81	0.27	261.24	161.30
Nipisi Gilwood Unit 1, Nipisi Gilwood Middle Devonian A, 3,840 acres	6.07	2.73	206.71	99.26
West Waterflood Area, S. Swan Hills Beaverhill Lake A&B, 11,000 acres	18.15	7.25	160.29	124.85

Note: Costs are in 1983 dollars.

C. Province-Wide Supply Costs

Some studies have estimated the average cost of oil produced in Alberta by relating reported industry expenditures to the resultant oil volumes. *Oilweek* magazine, for instance, has frequently reported annual average oil costs but using a suspect methodology that combines values for oil in the ground (investments divided by reserves additions) with values for oil as produced (operating costs divided by production).

One of the earliest estimates of the cost of Alberta's conventional crude oil was **Watkins and Sharp (1970)**, which used expenditure and production data for all pools discovered in the province from 1947 through 1968. A variety of allocation factors divided total expenditures between oil and gas. They also forecast future operating costs, development costs for pool extensions and production to the year 1990. (Remember that a supply price estimate shows the present value of expenditures divided by the present value of output.) A number of different sensitivities were undertaken, but their 'normal case,' assuming a 10 per cent rate of discount, generated a 'social' cost for Alberta crude oil of $1.20/b; adding payments to landowners (including the provincial government) increased the cost to $1.91/b, and adding projected income taxes generated a 'private' cost of $2.24/b. (The three costs just given, if transformed to a cost per cubic metre, would be $7.55, $12.02, and $14.10.) This compared to a 1969 market price of $2.55/b. Watkins and Sharp suggested that on average oil companies were earning approximately a 15 per cent rate of return over this period. The two governments' policies seemed quite effective in capturing a large share of the profits on this oil. Using a 10 per cent rate of discount as representative of the marginal opportunity cost of investment, the governments were estimated to capture 77 per cent (that is, $1.04/$1.35) of the economic rent on an average barrel. Of course, such an average cost covers an unknown range of marginal and average costs for different pools.

While the Watkins and Sharp study examined the cost of all conventional Alberta crude found from 1947 through 1968, others have looked at the year-to-year variation in the average cost of oil. One early study was Blackman and MacFadyen (1974), but we will focus on work done for the Economic Council of Canada in the mid-1980s (Eglington and Uffelman, 1983) and after that by the Canadian Energy Research Institute (Slagorsky and Pasay, 1985; McLachlan, 1990, 1991; Kolody, 1992; Chan, 1993; Heath, Chan, and Stariha, 1995; and Quinn and Luthin, 1997).

The **Eglington and Uffelman (1983)** analysis considered the capital cost of oil reserve additions in Alberta for the years 1957 through 1979; the cost was a cost of oil-in-the-ground in 1981 dollars, for the most part using the Canadian Industrial Selling Price Index as the price deflator. Expenditure data came from the Canadian Petroleum Association (CPA, now CAPP), and a number of factors were used for different expenditure categories to allocate costs between oil and natural gas. Reserves data were the Energy Resources Conservation Board's reported annual 'booked' reserves. It was assumed that bonus payments were those that occurred three years before the reserves were booked; geological expenses were those incurred two years previously, and exploratory drilling expenses those incurred the previous year. In each case, an interest factor was added to costs to allow for the required return on capital during the delay between the expenditure and the reserves additions. Development expenses were assumed to be tied

Table 8.5: Eglington and Uffelman Supply Costs of Reserves Additions

	Social Cost ($/m³)	Private Cost ($/m³)	Social Supply Cost ($/m³ of lifted oil)	Booked Reserves (10^6 m³)
1957	11.82	13.94	23.64	51.8
1958	12.25	15.56	24.50	47.9
1959	13.96	17.27	27.92	43.0
1960	13.24	16.66	26.48	43.8
1961	10.76	13.33	21.52	100.0
1962	5.14	6.32	10.18	104.0
1963	4.97	6.00	9.94	106.3
1964	4.40	5.33	8.80	131.7
1965	4.17	5.09	8.34	142.0
1966	4.09	5.20	8.18	154.5
1967	7.03	9.07	14.06	95.8
1968	7.57	9.98	15.14	89.4
1969	10.11	13.62	20.22	65.7
1970	12.50	17.14	25.00	50.6
1971	20.49	27.00	40.98	28.5
1972	20.30	26.35	40.60	25.3
1973	22.98	29.01	45.96	19.4
1974	33.34	41.13	66.68	11.2
1975	31.66	37.78	63.32	11.0
1976	29.45	34.71	58.90	10.3
1977	42.20	48.58	84.40	13.2
1978	53.92	63.79	107.84	16.4
1979	44.43	53.68	88.86	21.7

Note: Costs are in 1981 dollars.

to the booked reserves in that year. The per barrel 'social' cost excluded bonus bids, which were considered to be part of the economic rent transferred to the government. The 'private' cost included the bonus bids. Eglington and Uffelman noted that the cost of oil-in-the-ground could be transformed into a supply price per barrel of oil produced by multiplying it by an appropriate factor that reflected the time value of money and the expected timing of lifting the oil; for example, with an annual percentage decline rate of 8 per cent per year in production over a production life of thirty years, and an annual discount rate of 10 per cent, this factor would be about 2. (The equation to make this adjustment is shown in Section 4.A.) Due to the tremendous year-to-year variability in booked reserves, Eglington and Uffelman preferred to use five-year moving averages of expenditures and booked reserves. Several sensitivity cases were run, but the main results are seen in Table 8.5.

The table shows private and social costs for oil-in-the-ground and a social supply cost for lifted oil (assuming a factor of two to go from oil-in-the-ground to produced oil) with all costs in dollars per cubic metre. The table also shows the five-year moving average of booked reserves in millions of cubic metres. It should be noted that the social supply costs are much higher than Watkins and Sharp's $7.55/m³, which includes an operating cost of $2.25. This is true even if only the earlier years (1957 to 1968) covered by the Watkins and Sharp study are considered. The oil found prior to 1955 may have been particularly cheap. But there may also be major differences in the ways in which the data were treated. Thus Eglington and Uffelman include implied interest costs on top of the exploratory spending to account for lags between expenses and reserve additions, and they have put all values in terms of 1981 dollars. The latter adjustment is significant, due to the high inflation felt in the 1970s. (If the Watkins and Sharp capital cost of $5.30/m³ [= $7.55–$2.25] is inflated by the Industrial Selling Price Index from 1969 to 1981, the average exploration and development cost of Alberta oil becomes $15.14/m³, which is more in line with the costs reported by Eglington and Uffelman for the period before 1970.)

An obvious question of interest is what meaning one might give to the annual costs derived by Eglington and Uffelman. It is important to note that neither the social nor the private costs trace out an average cost curve for reserve additions. This is because an average cost curve is a ranking of reserve additions from low cost to high cost; thus, in any year, if there are more reserves additions, more higher-cost projects will have been undertaken, and the average cost of reserves additions in that year will be higher. But the average costs reported in Table 8.5 tend to be lowest in the period of highest reserves additions and highest in times of the smallest reserves additions. One might argue that this simply reflects the great uncertainty in the process of reserves additions, so that when oil companies are unusually lucky their costs tend to be low, and vice versa. While this is true, one might expect that over a number of years things would tend to average out, and, if the yearly values were tracing out an average cost or marginal cost (supply) curve, the expected positive relation between costs and the volume of reserves additions would be apparent. However, this is not seen. Rather, as economic logic would suggest, the reported average costs reflect a mix of movements along the curve and shifts in the curve. Presumably movements along the curve are driven largely by increases in the expected level of oil prices, while shifts in the curve reflect a variety of factors, including the following three: (1) technological changes and knowledge generation, including the discovery of new oil plays, which increase supply and allow more reserves to be added at any given cost; (2) depletion effects, which reduce supply as oil becomes harder and harder to find; and (3) shifts in the curves due to uncertainty, that is, good or bad luck. Since real oil prices were relatively low and falling in the 1960s, when reserves additions were at their highest, and real prices increased markedly in the 1970s when reserves additions were low and tending to decline, movements along an average cost curve offer little explanatory value. Rather, shifts in the curves seem to be particularly significant, with new knowledge (and good luck?) operating strongly in the 1960s, and the 1970s showing strong depletion effects (and bad luck?). Table 8.5 does indicate that the cost of reserves additions is higher in periods with higher prices, as economics would lead us to expect: that is, higher prices induce companies to search for higher-cost oil.

The **Canadian Energy Research Institute** (CERI) has also undertaken average cost studies, both of annual costs for the Province, and a comparison of costs for a sample of companies in the early 1990s. McLachlan (1990) estimates both 'short-term replacement costs' (STRC) and 'long-term replacement costs' (LTRC) for Alberta oil and natural gas, from 1970 to 1988. Several cases are presented. The results we will summarize calculate STRC's as the sum of appropriately lagged expenditures divided by total reported reserves additions and so are a cost of oil-in-the-ground. It can be interpreted as "the *weighted average* of the finding cost and development cost components for the **reserves additions from a particular year**" (McLachlan, 1990, p. 45). Reserves added in year *t* are associated with land expenditures two years previously, geological expenses one year prior, and exploratory and development drilling costs in the same year as the reserves additions. The inclusion of land expenditures, which are largely bonuses paid to the provincial government, implies that the costs are from a 'private' rather than 'social' perspective. Early work by CERI included implied interest costs for the expenses from an earlier year, but McLachlan's study did not. LTRC's use appreciated estimates of reserves added, where reserves are credited to the discovery year. McLachlan (1990, p. 45) argues that the LTRC is "the *sum* of the finding and development cost components for the **fully appreciated reserves from a particular discovery year**." It is assumed that

Table 8.6: McLachlan's CERI Reserves Addition Costs

	STRC (\$/m^3)	*LTRC* (\$/m^3)	*Appreciated Reserves* (10^6 m^3)	*Price* (\$/m^3)
1970	na	142.54	4.3	39.27
1971	na	67.66	10.9	42.33
1972	na	117.63	4.8	40.42
1973	na	18.53	30.5	45.39
1974	na	71.99	8.2	65.84
1975	na	148.55	4.2	75.37
1976	na	112.32	6.5	81.22
1977	na	38.88	26.4	91.75
1978	na	25.89	51.1	103.56
1979	37.11	53.46	32.7	101.67
1980	72.04	102.92	17.5	108.20
1981	52.48	173.14	10.1	118.25
1982	248.86	124.71	14.9	148.62
1983	29.11	103.33	21.8	175.48
1984	54.07	119.49	19.9	178.41
1985	43.17	76.09	30.3	177.49
1986	65.06	84.75	20.0	95.37
1987	75.30	64.59	22.9	110.01
1988	32.95	70.50	11.0	78.42

Note: Prices and costs are in 1981 dollars.

reserves in a pool are completely proved up in five years, with the allocation of development expenditures to the five years mimicking the reserves appreciation pattern. The same lags as in the STRC calculations are applied to exploration expenditures, while development expenditures in any year are allocated to pools discovered in the previous five years. This required estimated development expenses for the years 1989 to 1993, so total development costs could be included for reserves found up to 1988. All expenditures are in 1988 dollars, with deflators drawn mainly from the inflation cost indices of the Canadian Petroleum Association. Expenditures are allocated between oil and natural gas on the basis of the relative total drilling footage.

Table 8.6 summarizes the results. The costs are in dollars per cubic metre of oil-in-the-ground. Average oil prices are shown as well, in dollars per cubic metre. Also shown are the appreciated reserves credited to each year (in millions of cubic metres); these are the reserves used for the LTRC estimates. In order to allow some comparability with the Eglington and Uffelman estimates, costs and prices are shown in 1981 dollars; McLachlan's 1988 costs and average Alberta oil prices were adjusted using the Canadian GDP price deflator.

Interpretation of McLachlan's results is difficult, and costs show an erratic pattern over time. The only comment McLachlan offers is that costs seem to have fallen after the early 1980s. Clearly, the combination of reserve volumes discovered and the LTRC does not trace out a single average cost curve. Larger volumes tend to exhibit smaller costs, as might be expected if larger pools imply an unusually lucky year in exploration. (The LTRC and the quantity of reserves move in opposite directions in all years.) But this seems to suggest that shifts in the curve (for example, the new knowledge that a particular pool is large) tend to overwhelm the basic shape of the curve. The chanciness of discoveries may also help explain the rather strange result that in seven years the LTRC (which is a cost of oil-in-the-ground) is actually higher than the average market price of oil as lifted. Alternatively, this might reflect bad decision-making, expectations of price rises, or flaws in the whole concept of replacement costs. (Eglington and Uffelman suggested that in the late 1970s the cost of oil reserves additions were higher than the expected value of oil-in-the-ground, although their costs were lower than the market prices for lifted oil.)

Perusal of the assorted oil-in-the-ground costs generated so far make clear why it is difficult to place much reliance on any single estimate. The STRC and LTRC costs from McLachlan not only differ greatly in value but do not even change in the same direction in four of the ten years. The McLachlan LTRC and the Eglington and Uffelman private cost estimates also differ greatly and move in opposite directions in seven of the nine yearly changes that they share. In six of ten years, the LTRC is greater than the private cost estimate, usually by large amounts. (The average private cost from 1970 to 1979 is \$36.32/cubic metre, while the average LTRC is \$79.75/cubic metre.) One implication of this is that the particular assumptions made in estimating oil costs are critical. (It should be noted that the two studies utilize mainly the same data sources.) And it is also clear that the changes from one year to the next have relatively little meaning. Broader trends may be more meaningful, but even here it is hard to see similarities in the 1970s between the Eglington and Uffelman and the McLachlan studies. This could mean that direct cost estimate studies are of little value at all. Or it may mean that the form of the reserves data (i.e., whether appreciated discoveries or reported gross reserves additions) is critical to the results. McLachlan, in fact, places relatively little weight on her numerical results, suggesting that she is primarily concerned with issues of methodology.

Heath, Chan, and Stariha (1995) and Quinn and Luthin (1997) continued the CERI cost analysis in a somewhat more disaggregated manner. Quinn and Luthin, for example, calculated unit costs for oil reserves additions for a sample of forty-three Western Canadian oil companies, divided into three size groups. The sample accounted for around 40 per cent of industry activity. Their estimates allocate expenditures between oil and gas on the basis of the relative proportions of successful wells, and they relate exploration and development expenditures in a particular year to proven reserves additions in that year, without any assumed lags. (They argue that the lags between land acquisition and geological expenditures and resultant reserves additions are so variable that one might as well assume no lag.) They generally excluded 'Revisions' from their reserves additions figures since these primarily reflect reassessment of oil flow rates and are not associated with current investments. Table 8.7 summarizes some of their findings; values have been transformed from 1996 dollars per barrel into 1981 dollars per cubic metre to facilitate comparison with the previous tables. The deflator for inflation is the Canadian GDP Price Deflator. The 'social' cost is the 'private' cost less land expenditures.

Oil reserves additions increased over this period, suggesting that there were some improvements in technology and knowledge. (That is, more reserves additions resulted each year, while the average cost showed a tendency to decline.) Quinn and Luthin's private costs are higher than those estimated by Eglington and Nugent for years prior to 1974, but lower than the 1974–79 costs, and lower than McLachlan's SRTC's. (Averages are: Quinn and Luthin, 1992–96, \$27.67/m^3; Eglington and Nugent, 1957–73, \$13.93/m^3; Eglington and Nugent, 1974–79, \$39.76/m^3; McLachlan, 1979–88, \$71.01/m^3.) Clearly the average cost of reserves additions tends to follow oil prices, with higher prices (as in 1980–85) drawing forth higher-cost oil. There are, it must be noted, two main reasons for oil costs to rise as prices rise: (1) with constant input prices, producers are encouraged to look for deeper, harder to find and smaller pools and to undertake more expensive development projects; and (2) the extra exploratory and development effort attracted by higher prices will tend to push up the prices of drilling rigs and other inputs, making oil industry activities more expensive relative to other activities in the economy. Thus, for example, McLachlan (1990, p. 56) shows drilling costs rising by 289 per cent from 1972 to 1981, when the GDP price deflator rose by 126 per cent. (McLachlan's study

Table 8.7: Quinn and Luthin CERI Reserves Addition Costs by Company Size (1981$/$m^3$)

	Private Cost	Social Cost	Private Cost Seniors	Private Cost Intermediate	Private Cost Juniors	Market Price
1992	28.90	26.49	26.39	57.66	27.96	96.68
1993	28.05	24.59	25.35	45.59	31.40	91.53
1994	32.20	27.26	31.31	47.46	25.96	88.96
1995	24.62	22.09	22.87	46.82	22.90	84.85
1996	24.56	21.49	23.42	33.70	32.17	88.06

attempted to isolate the first of these effects by deflating exploratory costs by the drilling cost index.) Such cost rises could reflect 'rent seeking' behaviour by input suppliers, as they attempt to gain some of the increased value of oil and gas.

Quinn and Luthin offer no real explanation of why oil companies of intermediate size apparently exhibit such high costs of oil reserves additions. If the forty-three companies are considered separately, there is wide variation in the five-year average costs, the highest cost company having a per unit cost almost 300 per cent higher than the lowest cost company. They suggest that companies may find this sort of information useful for 'benchmarking' purposes, in which a company can see how well it is doing compared to others in the industry. The wide company differentials, like the large range of historical variation in reserves additions costs, point out the great heterogeneity in industry experience with respect to the cost of incremental oil supplies.

Even apart from the conceptual difficulties involved in directly measuring the unit cost of adding oil reserves, it is difficult to weave any but the simplest stories ('Higher prices draw out higher cost oil') out of the costs calculated. Therefore, while 'replacement cost' studies are common in the industry, most economists have tended not to rely on this approach as the main avenue of petroleum supply modelling. Instead, they have generally tried to deduce the position of, and shift in, the marginal cost (supply) curve for crude oil by more elaborate and indirect means.

Lasserre (1985) provides an example of a researcher drawing directly on discovery cost estimates to try to understand the oil-supply process. He looked at the discovery cost of Alberta oil in order to examine the suitability of using discovery cost as a proxy for the user cost of crude oil production. Recall, from Chapter Four, that the user cost is the present value of the future profits given up by lifting a unit of crude oil today, rather than leaving it in the ground. Consider a simple resource extraction model, which treats exploration as an activity to increase reserves, and which assumes that crude oil lifting costs are a function of the volume of reserves and that there are no 'depletion' effects in the process of adding reserves through exploration. In this model, the marginal benefit of adding reserves is the anticipated profit from a unit of added reserves; this profit is measured by the marginal user cost. (That is, the present value profit of adding one unit to reserves would be the same as the present value profit foregone by producing a unit out of reserves.) The profit-maximizing competitive producer would, then, add reserves through exploration until the marginal cost of new discoveries just equalled this marginal benefit. Hence, marginal discovery cost provides a measure of the marginal user cost. This is a potentially useful result since the marginal user costs depends on such unobservable factors as producer's expectations about future oil prices so is not easily estimated by an outside observer. However, if, contrary to Lasserre's assumption, current discoveries deplete the stock of available reserves and thereby raise future discovery costs (a depletion effect), there is a user cost of discoveries, and the estimated capital cost of discoveries will understate the total cost. In this case, the estimated discovery cost would understate the user cost of production.

Lasserre, drawing on cost information from Uhler and Eglington (1983), calculates the cost of reserves additions per barrel of oil in-the-ground from 1957 to 1981 for various components of cost, and for 'full marginal development cost' (FMDC). There is considerable year-to-year variation in FMDC and its components, as seen in the tables above. Roughly, FMDC rises slightly to the year 1960 from a little over $2.00/b in 1957, falls to not much over $1.00/b in the early and mid-1960s, then rises sharply, peaking at almost $10.00/b in 1978, and ending the study period at about $8.30/b in 1980. From the late 1960s, exploratory drilling and development costs increased particularly markedly. Lasserre draws a number of conclusions, including the following (Lasserre, 1985, pp. 480–82): (1) there is considerable stochastic variability in unit reserves addition costs; (2) rising costs in part reflect depletion effects, as the stock of undeveloped reserves declines and reserves additions become harder to make; (3) rising costs may also reflect diminishing returns to effort in any one year as the level of exploration and development increases (independent of depletion effects), reflecting, for example, the problems in spreading fixed knowledge and inputs over more effort, and (4) user costs in the reserves addition process are significant, as indicated by significant bonus bids, implying that discovery costs are not a valid proxy for the user costs of lifting oil.

Lasserre provides an interesting application of direct-cost data. Most economists, however, have been skeptical about the possibility of drawing meaningful conclusions from trends in unit costs alone and have turned to more complicated econometric estimation of oil-supply relationships and functions. We now turn to some of this literature as applied to Alberta crude oil supply.

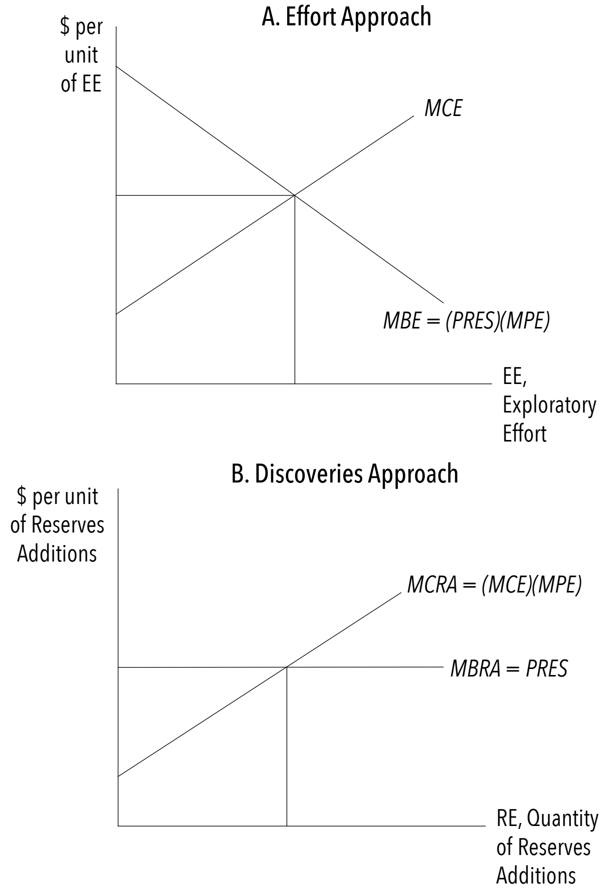


Figure 8.2 Reserves Additions: Discoveries and Effort Approaches

5. Indirect Supply Estimation

A. Introduction

Since the oil-supply process is so complicated, different studies make quite different simplifying assumptions and focus on different parts of the process. We will begin by reviewing some of the major dimensions of difference.

One is the specific variable that the model is designed to explain. Most models look at oil as the product, but some studies focus primarily on oil in the ground (e.g., reserves additions), while others look at the volume of crude oil lifted. As has been discussed previously, these are related products. Crude oil cannot be lifted unless there are reserves available, and the value of a unit of reserves added is based in part on the expected prices of lifted crude. Other studies, however, set the level of industry activity ('effort') as the variable to be explained. They might, for instance look at total real exploratory spending or at the number of exploratory wells or the exploratory well footage drilled. It is also necessary to decide whether a single variable measures the 'effort,' or whether there are a number of separate activities involved (e.g., land acquired, G&G activities, drilling).

The two types of variables ('oil' and 'effort') are related. The volume of oil added to reserves obviously depends on the amount of exploration undertaken, and the quantity of effort must be a function of expected discoveries. Figure 8.2 provides a simple reconciliation of the 'discovery' and 'effort' approaches for an effectively competitive, profit-maximizing crude oil industry. Figure 8.2(A) is drawn on the assumption that companies will undertake exploratory effort (*EE*) up to the level at which the marginal benefits of exploration (*MBE*) equal the marginal costs of exploration (*MCE*). The *MCE* curve is drawn as upward-sloping on the assumption that more exploration causes price rises in the costs of the inputs used for exploration. (If we were looking at a region that is a small part of the total North American oil industry, these input costs might not change, and the *MCE* curve would be a horizontal line.) The marginal benefit of exploration is the product of two key variables, the value of a unit of discovered reserves (*PRES*) and the marginal product of exploration (*MPE*, that is, the number of reserves that would be found by one unit of exploratory effort.) The optimal amount of exploratory effort is shown where these two curves intersect. That is,

$$MCE = MBE = (PRES)(MPE) = (PRES)\left(\frac{\partial RA}{\partial EE}\right),$$

where *RA* stands for reserves additions, and the last expression is the change in (the derivative of) reserves with respect to the change in (the derivative of) exploratory effort. In order to understand how exploratory effort changes, it is necessary to look at how the two curves might shift. More exploration could result from anything that causes a fall in the cost of exploration, anything that might increase the price of reserves and/or anything that would increase the marginal productivity of exploration. Remember that the price of reserves is the value of a unit of oil in the ground; it would increase the higher is the expected market price of (lifted) crude, the faster reserves will be depleted, the lower are variable development and operating costs and the lower the rate of discount. The marginal productivity of investment tends to fall as a result of depletion effects, which specify the extent to which new discoveries become more difficult as more and more of the available resource base is discovered. However, the marginal productivity of investment will also increase as a result of technological innovations (like 3-D seismic) that make exploration more efficient, or knowledge changes, like the discovery of a new oil play in a geologic formation that was not previously known to hold oil.

Figure 8.2(B) takes the quantity of reserves additions as the 'dependent' variable instead of the amount of exploration. Rational companies will add reserves up to the level where the marginal benefits of reserves additions (*MBRA*) equals the marginal costs of reserves additions (*MCRA*). The former (for a price-taking industry, which is a small part of the total oil market) is equal to the price (value) of reserves (*PRES*). The marginal cost of reserves additions will be equal to the marginal cost of an extra unit of exploration (*MCE*) multiplied by the marginal exploratory effort required to add one more unit of reserves. Equilibrium will occur where the marginal benefits of reserves additions equals the marginal costs of reserves additions.

That is,

$$MBRA=PRES=MCRA=MCE\left(\frac{\partial EE}{\partial RA}\right) = \left(\frac{MCE}{MPE}\right).$$

Since this is describing exactly the same process as the exploratory effort model, it is not surprising that this equation shows exactly the same relationships amongst *PRES*, *MCE*, and the two derivative terms. Variations in the volume of reserves added will reflect any factors that shift either the marginal costs or marginal benefits of reserves additions. These, of course, are the same factors that might cause a change in the level of exploratory effort!

A second major difference amongst the 'indirect' supply studies relates to what might simply be called the degree of sophistication of the analysis, as illustrated in Figure 8.1. The simplest approach is relatively atheoretical trend extrapolation, where a simple historical correlation is assumed to continue in the future as it has held in the past. This could involve time extrapolation (e.g., production per year or the reserves added per year) or might involve the continuation of the trend in the change of one variable (e.g., the quantity of oil found per successful well) relative to another (e.g., the number of exploratory wells drilled). More complicated statistical modelling can take place through 'reasoned' but informal or *ad hoc* methods. Thus, on the basis of one's understanding of the industry, a list of variables could be set out that might be expected to affect the variable of interest, and then an equation estimated to show the relationships amongst the variables. For example, the volumes of reserves added in a year are specified as a function of the price of oil, the cost of hiring a drilling rig, the cost of money (that is, an interest rate), time (to allow for technological improvements) and the cumulative discoveries up to this time (to allow for depletion effects). At a higher level of complexity, one might build a formal model of industry behaviour and derive a set of equations from it that reflect the anticipated behaviour of the industry, and then estimate this set of equations. We call this 'econometric (statistical) optimization modelling.'

The degree of complexity that may arise in the formal economic modelling approach warrants discussion. Most such models begin at the level of the individual oil company. It is normally assumed that companies make decisions in an optimal way. Thus, for example, a company might be imagined to be looking at the possibility of adding to its crude oil reserves through a joint-product production function, which describes the current state of knowledge and technology. The production function would describe the volumes of oil and natural gas reserves additions (output) that would result from the efficient utilization of various inputs such as land, geological surveys, exploratory wells, undeveloped reserves, and labour. Given the prices of oil and natural gas reserves and the costs of the various inputs, the company would purchase the optimal quantities of the productive inputs to produce the optimal quantity of oil and natural gas reserves additions. 'Optimal' is most frequently taken to mean 'profit-maximizing.' This model typically leads to a set of interrelated equations describing both the input demands and the supplies of reserves additions. Moreover, since the equations are interrelated, they must normally be estimated jointly and assume a particular form because some of the equations impose constraints on the forms that other equations can take.

A further degree of complication is added by the fact that data are not usually available on a firm-by-firm basis, and, even if they were, it would be too complicated to estimate equations for all of the firms separately. Accordingly, optimization models typically are simplified by assuming that the optimization model (which is normally set out for a single firm) also holds at the aggregate level for the entire industry. This 'aggregation' assumption can come from two quite different premises. The first is a 'true' aggregation process, in which the sum of the optimization procedures of all the separate firms happens to lead to a total that is exactly the same optimization problem at the aggregate provincial level. However, most of the literature on aggregation suggests that the conditions necessary for this to happen are so extreme as to be very unlikely. (For instance, it might require the assumption that all companies have exactly the same knowledge and initial holdings of land.) More frequently, a more *ad hoc* assumption is made that the industry behaves as if it were like a single optimizing decision-maker with characteristics reflecting the aggregate characteristics of the industry; or that the industry operates as if it consists of a number of 'representative firms' who are all identical and behave in an optimizing manner. This representative firm approach might be seen as an example of a simplifying assumption; that is, an industry consisting of a number of different firms, each in a different position, is assumed to behave as if it consisted of a number of identical representative firms.

This issue of simplifying assumptions lies at the heart of many of the disagreements about what is the 'best' oil-supply model. Is it valid, for instance, to build a model that looks at crude oil reserves additions alone, ignoring the joint-product connection with natural gas? Given that different oil pools are so different in characteristics, must the pools be treated separately as sources of reserves additions or lifted crude, or can a simpler, province-wide, aggregate model of oil supply be built? From a practical point of view, the aggregate models have great appeal since they are simpler and because they have far smaller data requirements. But can one move to the aggregate level and still derive a useful representation of industry behaviour? These are open questions about which different analysts have different opinions, and the response may be different at different points in time or for different types of industry activity.

B. Input Measures: Studies of Industry Expenditures

In 1984, as part of the Economic Council of Canada's study of Canadian energy policy, **Scarfe and Rilkoff** undertook an econometric analysis of petroleum industry exploration and development expenditures in Alberta. The modelling framework was an inventory adjustment process in which companies are assumed to estimate an optimal level of petroleum reserves and undertake investment in such a way as to move towards this optimum. The optimal size of reserves is a function of expected profitability. Estimation of expected profitability is complicated by the dynamic aspects of industry activity: reserves additions may become more difficulty over time due to depletion of the stock of undiscovered reserves, but technological advances may make reserves additions less costly. All monetary values were in 1981 dollars, deflated with the Canadian Industrial Selling Price Index. The major variables that Scarfe and Rilkoff included in their equations were as follows:

- The dependent variables that they were trying to explain were **the industry's expenditures** in Alberta for three categories of exploratory investment and four of development, as reported by the Canadian Petroleum Association (now, CAPP, the Canadian Association of Petroleum Producers).
- A **value ('price') of oil and gas reserves in the ground**, derived from Uhler and Eglington (1983), with the expectation that higher prices generate higher profits and therefore higher industry expenditures. Essentially, this is an estimate of the present-value after-tax profit expected from a unit of reserves. It takes the expected future wellhead price of petroleum and reduces it to allow for future operating and development costs and for the delay involved in the depletion of oil

Table 8.8: Uhler and Eglington Oil Wellhead and Reserves Prices and Development and Operating Costs (nominal $/m^3$)

	Wellhead Price	*Netback Price*		*Developed Reserves Price*		*Undeveloped Reserves Price*		*Operating Cost*	*Development Cost*
1947–51	18.19	14.36	(.79)	6.42	(.35)	5.59	(.31)	1.98	0.64
1952–56	15.81	10.94	(.69)	4.39	(.27)	3 51	(.22)	2.08	0.59
1957–61	15.71	10.12	(.64)	4.03	(.26)	2.53	(.16)	2.75	1.01
1962–66	15.98	10.65	(.66)	4.59	(.28)	3.15	(.20)	2.46	0.96
1967–71	16.45	11.25	(.68)	4.15	(.25)	2.63	(.16)	2.09	1.02
1972–76	35.07	24.31	(.69)	14.93	(.43)	12.99	(.37)	2.87	0.93
1977–81	88.47	52.20	(.59)	38.25	(.43)	30.20	(.34)	6.37	3.01

Note: Numbers in parentheses show the value as a proportion of the wellhead price.

reserves (since a reservoir is typically drained over several decades). The reserves prices are in nominal dollars. The annual adjustments for operating costs (for the developed reserves price) and operating and development costs (for the undeveloped reserves price) are based on the industry's average costs during that year. Total industry operating expenses are divided between oil and gas on the basis of the proportion of operating wells of each type. Development costs include a development well component based on the average cost of drilling a well and an oilfield equipment component based on average industry expenses in that year. For years prior to 1974, the actual crude oil price is assumed to represent future expected nominal oil prices. For 1974 and 1975, it is assumed that producers expected the nominal price to rise by 5%/year, rising to an expectation of 10%/year from 1976 through 1981. Table 8.8 summarizes Uhler and Eglington's prices; it shows average prices over five-year periods, including a wellhead price, a 'netback' price at the wellhead after operating costs and royalties, and both developed reserves and undeveloped reserves prices. Prices are in nominal dollars per cubic metre; the number in parenthesis shows the price as a proportion of the wellhead price. The last two columns show the estimated operating and development costs per cubic metre. As was discussed in Chapter Six, the average field price of crude fell in the 1950s, as Alberta oil penetrated more distant markets, and only began to rise markedly after international oil prices began to rise in the 1970s. The fall in the netback price as a proportion of the wellhead price after 1951 and in the 1977–81 period reflects the increase in provincial royalties in 1952 and 1974. From 1947 through 1976, average operating costs varied around $2.00/cubic metre, while development costs rose on average after the first decade but were relatively stable from 1956 through 1976. After 1974, both operating and development costs rose appreciably as wellhead prices increased, but by relatively less; that is, the value of oil in the ground rose somewhat faster than wellhead prices. For industry expenditures that applied to both oil and natural gas, weighted average petroleum prices were calculated with the weights given to oil as opposed to gas based either on a measure of the drilling 'intent' of producers or the relative numbers of completed oil or gas wells.

- **Production of petroleum the previous period**, with the expectation that higher production requires higher expenditures in order to increase reserves back up to the desired level. The variable used was a weighted average of the logarithms of the oil and gas output, the weights being the relative completion rates of oil and gas wells.
- **The previous year's expenditure**, which is expected to correlate positively with this year's expenditures. That is, one of the 'independent' explanatory variables was the one-year lagged value of the dependent variable being explained. This procedure is designed to allow for rigidities in the inventory readjustment process. For example, if a rise in the price of oil induces more investment this year, then this increase in investment will in turn be associated with more investment the year after, and so on. In fact, the size of the influence of the lagged dependent variable can be taken

Table 8.9: Estimated Coefficients in the Scarfe/Rilkoff Oil Expenditure Model

Expenditure	*Price*	*Output*	*Lagged Dependent*	R^2	*Long-run price elasticity*
Geological	.1953*	.1359*	.6583*	.85	.57
Exploratory Drilling	.1657*	.1294*	.8914*	.95	1.53
Land acquisition and rents	.3432*	.1227*	.5376*	.81	.74
All exploration	.2495*	.1282*	.7328*	.94	.93
Development drilling	.1393	.1461*	.8760*	.92	1.12
Field equipment	.2135*	.4198*	.4998*	.95	.43
Enhanced oil recovery	.1853	.2873*	.5460*	.79	.41
All development	.1786*	.2058*	.6077*	.91	.46

* Significant at the 5% level.

as a measure of the speed with which industry behaviour adjusts to a rise in the petroleum price. (A value of zero means that all of the adjustment occurs in the initial year, and there is no effect on current expenditures through past expenditures. The closer the value comes to one, the longer the time it takes to fully adjust behaviour to the higher price. That is, a value appreciably greater than zero implies that the long-run elasticity of expenditure with respect to price changes is significantly greater than the short-run elasticity.)

Equations were estimated by simple Ordinary Least Squares (OLS) regression, using annual data from 1957–81 (1960–81 for exploration expenditures). The equation estimated was of the following form, which is linear in the natural logarithms of the variables:

$$(investment_t) = a_1(price_t)^{a_2}(output_t)^{a_3}(investment_{t-1})^{a_4}.$$

The four '*a*' terms are the numerical coefficients that are estimated by the OLS procedure to provide the best fit to the data. In this form, the price and output coefficients are estimates of the short-run elasticities of expenditures with respect to that variable. (Remember that elasticity shows the percentage change in one variable – e.g., exploration expenditures – in response to the percentage change in another variable – e.g., the price of petroleum.) The long-run elasticities can be derived by dividing the short-run elasticity by one minus the lagged dependent variable's estimated coefficient. Table 8.9 shows some of Scarfe and Rilkoff's results, where coefficients that were significant at a 5 per cent level of confidence are indicated with an asterisk (*). (This means that one can be 95% confident that the coefficient is not actually equal to zero.) The *R*-square value is the adjusted correlation coefficient, and it provides a measure of the per cent of variation in the dependent variable that is 'explained' by the equation.

It is not unusual to find that a large amount of the variation in a dependent variable is captured by a time series equation that includes the lagged value of that variable. Scarfe and Rilkoff note that both price and output are positively related to expenditures, as was expected. They found that they had to try a number of different forms of the price variable to derive what appeared to be reasonable results for the development equations, and two of the price elasticities (drilling and EOR) failed to pass the 5 per cent significance test; the estimated equation tracked the historical data most poorly in these cases. All the exploration equations and the field equipment development equation were based on prices weighted by the intent ratios. However, development drilling and total development expenditures used prices weighted by numbers of completions, and the EOR equation used the netback wellhead price. They noted that their results suggested, in comparing exploration and development, that "reserves prices … are more important with respect to exploration expenditures, … expenditure levels are more sensitive to production on the development side, … [and] the adjustment process is somewhat slower for exploration" (Scarfe and Rilkoff, 1984, p. 21). They also note that, in the long run, drilling expenditures are the only categories that are elastic in response to price.

Two further aspects of the Scarfe and Rilkoff study merit brief attention. One relates to an alternative set of regressions, which included a variable measuring the current 'cash flow' to the industry, after allowance for operating expenses (i.e., royalties, well-operating costs, and land rentals). The production variable was dropped, in part because it correlated very highly with cash flow. The results were generally very similar to the ones reported earlier, although several equations had to be estimated with variants of the cash flow variable before good results were obtained. This version was run because of frequent reports in the industry press that investment in the industry is constrained by available cash flow. In other words, there are capital market constraints that may make it difficult for firms to raise outside capital, so they must rely on their own funds. In general, the cash flow results seem quite unconvincing for a variety of reasons. They are not as strong as those with production as a key variable; Scarfe and Rilkoff had to experiment to find a cash flow variable that seemed to work in a satisfactory manner; a number of Canadian petroleum companies clearly were able to tap financial markets for funds; and the cash flow argument does not imply that all cash flow is spent, but that in some circumstances cash flow may constrain spending, so cash flow would not be a general influence on expenditures.

Scarfe and Rilkoff also found that their model seemed to fit the final year of their sample quite poorly, and, even after a revision in the price series to allow for less buoyant expectations in 1981 than the Uhler-Uffelman numbers, their model mis-forecast the observed expenditures in 1982. Exploration expenditures, in particular, were significantly overestimated (by over 45%), as was development drilling (by over 25%). They noted that total development spending was forecast quite well, and that the trauma of the National Energy Program provided a very unsettled period in which to attempt a forecast.

It is satisfying to find that a simple econometric estimation of industry expenditures in Alberta can generate results that seem plausible theoretically and have a relatively high degree of statistical validity. However, it is important to remind readers that this is only one part of the oil-supply process. It is still necessary to determine how much petroleum production (in this case largely reserves additions) results from the expenditures.

It is also discouraging to see that, while many of Scarfe and Rilkoff estimated equations appeared to fit the historical data well, their results did not serve to provide a good forecast for even the first year after their sample period. This relatively poor forecasting ability has also been found in a number of U.S. econometric petroleum supply models. It is, of course, a rather surprising result, given that the estimated equations typically fit the historical data well. One interpretation is that the modelling interest of economists tends to be attracted to the industry when unusual events occur, and it is precisely at these times that the historical regularities are most likely to be broken. For instance, in stable times, current prices may form the basis of price expectations for most producers, but this may not be true in more revolutionary times. The economic model suggests that investment should reflect long-term price expectations, but these are largely unobservable.

A key question, then, is whether estimates like those of Scarfe and Rilkoff would regain their legitimacy as a forecasting tool once a more stable industry regime is established again. It is possible to undertake a rough test of this possibility by comparing the actual investment expenditures from the mid-1980s through the 1990s (after the industry had operated a number of years in a deregulated environment) with those implied by the Scarfe/Rilkoff econometric results. It is important to note that the inclusion of the lagged dependent variable will tend to keep the forecast 'on track' to some degree; that is, variables that are of major significance in affecting industry expenditure, but are missing from the model, will influence the actual level of expenditures in any particular year, and then this will influence the following year's estimated expenditures. (That is, inclusion of a lagged dependent variable in the estimating equation, not only accounts for lags in the ability to adjust expenditures, but also serves as a way to 'capture' the effect of missing variables.)

Our out-of-period forecast of total exploration and development spending in 1981 dollars to the year 1992 uses a number of simplifying assumptions that impose obvious limitations on the interpretation of the results. However, it does provide a rough idea of whether the relationship estimated by Scarfe and Rilkoff over the period from the 1950s to the 1970s is reasonably predictive of industry activities once the trauma of the National Energy Program ended in 1985. Our forecast assumes: that the intent ratio data reported by Scarfe and Rilkoff for 1982 (p. 47), and used to obtain weighted petroleum price and production figures, continue through the forecast period; that the average of the 1979–81 ratio of reserves values to average wellhead prices (as reported in the CAPP *Statistical Handbook* for western Canadian crude) holds over this period; and that inflation in the Consumer Price Index (CPI) as reported by CAPP tracks inflation in the Industrial Selling Price Index used by Scarfe and Rilkoff. The differences between forecast exploration and development expenditures (from the Scarfe and

Table 8.10: Out of Period Forecast Based on the Scarfe/Rilkoff Model

	Exploration: Forecast – Actual (10^6)	*Exploration Forecast Error as % of Actual*	*Development: Forecast – Actual (10^6)*	*Development Forecast Error as % of Actual*
1984	2,473.4	79.9	916.5	45.3
1985	2,506.3	87.5	966.3	49.0
1986	1,490.9	56.4	623.9	55.4
1987	1,718.3	70.8	740.3	59.5
1988	1,353.4	60.4	657.9	69.9
1989	1,550.8	76.3	756.0	73.6
1990	1,705.7	92.2	827.9	76.8
1991	1,454.4	87.7	767.4	88.2
1992	1,381.1	85.8	759.6	93.3
1993	1,329.6	85.6	765.2	99.4
1994	1,373.7	88.8	797.3	100.4
1995	1,523.7	102.7	873.4	101.3
1996	1,705.7	118.7	953.6	100.4
1997	1,577.9	113.3	912.0	105.4
1998	1,208.3	88.3	773.4	117.8
1999	1,610.9	121.8	940.3	109.3
2000	2,080.0	165.9	1,131.1	104.5

Rilkoff equations) and the actual values (in millions of 1981 dollars, and as a per cent of the actual value) are shown in Table 8.10. The forecast errors are very large.

It can be seen that the tendency to overestimate in the years of the National Energy Program (1984 and 1985), remarked by Scarfe and Rilkoff, is present in this forecast, but that this tendency persists throughout the entire period, even after deregulation in 1985. For exploration, the percentage forecast error drops noticeably in 1986, but soon rises again, and shows a general tendency to increase. For development, the percentage forecast error is smaller at the start of the period but rises throughout. Part of the forecasting error may be due to the simplifying assumptions that we have made; our percentage errors of 80 per cent and 45 per cent for 1984 are higher than the errors of 45 per cent and 25 per cent noted by Scarfe and Rilkoff for 1982. Despite this, our simple simulation suggests that there was a persistent shift in the expenditure relationship from that estimated by Scarfe and Rilkoff. Of course, one would expect that the Scarfe/Rilkoff model would forecast much better for this period if it were re-estimated using data up to the end of the 1990s, but we have not undertaken this task. Moreover, the need to re-estimate the model to obtain valid coefficients suggests that there are some structural elements missing.

Desbarats (1989) provides an extensive critical review of the Scarfe/Rilkoff model. She thinks that the focus on expenditures as the key variable of interest is appropriate. However, her re-estimation of Scarfe/Rilkoff using a different (and longer) series for reserves values finds that the reserve price variable does not appear to be significant and that the estimated coefficients seem to be very unstable. She suggests that the exploration expenditure model needs to be drawn from a more precise theoretical foundation and that more sophisticated econometric techniques for analysis should be used. There are three main foundations of the model that Desbarats constructs. The first relates to the profit-maximizing equilibrium condition for the desired level of reserves, assuming that the production function for petroleum exhibits a constant elasticity of substitution. (The elasticity of substitution measures the ability to substitute between different inputs while holding production constant.) Desired reserves (and also total exploration spending) are a function of the level of petroleum output, the elasticity of demand for petroleum, the input cost of adding reserves, and the elasticity of substitution between resources and other inputs in generating petroleum production. Secondly, Desbarats argues that uncertainty in the exploration process is inevitable, so that the way in which producers form their discovery expectations is critical; this expectation is represented by the producers' expectations regarding the size distribution of oil pools in the region, which may change over time as exploration proceeds. Finally, Desbarats accepts that there will be lags in the adjustment of reserves to the desired level.

The resultant general model is far too unconstrained to be estimated with the limited time series data available: for example, there are no strong guidelines on the functional form that should be used; any number of lag structures are possible; determination of a precise cost of non-resource inputs is not possible given the variable number of inputs that might be used and uncertainty about the extent to which certain expenditures (e.g., geophysical) relate to current or future reserves additions. Finally, the joint-cost problem is present, since exploration expenditures will add both oil and natural gas reserves. Thus, while Desbarats uses sophisticated econometric procedures, the final exploration expenditure equation she generates reflects a certain amount of pragmatic judgment. We will reproduce the estimated equation for which she reports an R-square value of 0.99 and which was based on annual data for the years 1949 to 1982. The dependent variable was real exploration expenditures (*E*), in 1981 dollars. Explanatory variables included: a two-year average of the real reserves price of oil plus the reserves price of gas (*P*; the reserves values are from Uhler and Eglington, and the units are $\$/m^3$ for oil and $\$/10^3\ m^3$ for natural gas); the sum of oil and gas output (*Q*); the inflation rate (*IR*, as measured by the CPI); the ratio of reserves additions for natural gas to gas output (*RAG*/*QG*); this variable summed for natural gas and oil (*RA*/*Q*); and the difference between domestic and import oil prices (*PD*). Finally, some of the variables are lagged values; we use (–*t*) to represent a lag of *t* years. We do not report any of Desbarats evaluating statistics in the following equation (Desbarats, 1989, p. 55):

$$\ln(I) = -2.27 + .60\ln(I(-1)) + 1.24\ln(P) - .09IR(-1) + .003RA/Q(-1) + .002RAG/QG(-2) + .13\ln Q(-1) - .21PD(-1) - .87[Q(-1)-Q(-2)] - .20[IR(-1)-IR(-2)].$$

Given the number of variables included in the equation, the estimation possesses relatively few degrees of freedom, and the underlying properties of the time series have not been subject to the tests that are now common in cointegration analysis.

Desbarats suggests that this model explains exploration expenditures better than the Scarfe/Rilkoff model. The estimated coefficients generally have the expected sign; thus, a higher value for reserves additions stimulates more exploration expenditures, as does higher production in the previous year. Several variables are somewhat harder to interpret. Thus, the negative effect of an increase in production for the previous year leads Desbarats to speculate that scarce investment capital may be allocated away from exploration to more intensive development when companies are trying to increase production rapidly. Desbarats also notes that her model underestimates actual 1980 investment spending, if she uses estimates based on the 1949–79 period and uses the results to forecast 1980 expenditures. We suspect that, if the estimated coefficients for this period were applied to events after 1985, including the lower real prices after that date, the model would tend to significantly overestimate actual expenditures, much as did the Scarfe/Rilkoff model.

Helliwell et al. (1989) undertook a detailed econometric analysis of the Canadian petroleum industry, largely with the intent of analyzing the very extensive policy interventions from 1973 to 1985. Amongst other work, they estimated econometric equations for land payments (bonuses) for the crude petroleum industry in the Western Canadian Sedimentary Basin, an area dominated by Alberta. We include discussion of this equation here because land payments are one type of industry expenditure. However, it is important to recognize that the size of bonus bids made for mineral rights is determined largely by the anticipated profits from the rights acquired; that is, rather than a cost item, land bonuses are best viewed as a part of economic rent.

Helliwell et al. drew on annual data from 1951 to 1985. Costs seem to have been divided between oil and gas on the basis of the relative footages of development drilling. Amongst the variables used to explain the level of expenditures is what is called a 'profitability' ratio. It is a little difficult to interpret their descriptions of how the profitability ratio is calculated. Their Figure 8.3 (Helliwell et al., p. 152) describes it as "Net Wellhead Revenue Divided by Marginal Cost," while the text of the previous page says it is "real after-tax wellhead or field prices divided by the sum of real operating costs and the amortized exploration and development costs." Neither of these descriptions seems adequate since each involves a ratio between a total and a per-unit measure. The profitability ratio (*PR*) for oil takes values ranging between about 0.6 to 1.9 over the period from 1951 to 1985, and we interpret it as the ratio of a discounted value per unit of oil sales (after royalty and income tax), over a typical lifetime of a pool, divided by a per-unit 'supply cost' for capital and operating costs. The authors assume that wellhead prices remain constant at the level of the initial year. The notion of a supply cost or price was described above. The profitability ratio used was a three-year moving average, the current year and the two previous years, which helps level out extreme values and allows for lag effects in the responses of expenditure to changes in profitability.

With respect to oil land payments (*L*), the more significant equation (R-square = 0.3091) is:

$$\ln L = 2.2714 + 1.1422\ln PR + 0.4168\ln CF,$$

where *CF* stands for industry cash flow, defined as revenues net of operating costs, royalties and income taxes. (*t*-values for the three estimated coefficients are 2.22, 3.75, and 2.73.) In this double logarithmic form, the estimated coefficients are elasticities, so a 10 per cent rise in the profitability ratio implies an 11.4 per cent rise in land payments. Note that factors that increase profits are also likely to raise cash flow, so land bonus payments would actually rise by more than this.

One possible interpretation of the limited forecasting ability of aggregate industry expenditure models like that of Scarfe and Rilkoff is that relatively simple econometric estimation fails to provide a useful depiction of activity for a complex industry in a complex environment. With sufficient effort, and 'manipulation' of explanatory variables like price, it will usually be possible to find some equation that seems to provide a reasonably good fit to the historical data. However, the failure to explicitly address the complexities of the industry almost inevitably means that the estimated equation will be of limited value in understanding how the industry actually functions or in forecasting future industry activities.

It may be useful, by way of conclusion, to discuss three somewhat different perspectives amongst economists who utilize econometrics to study petroleum industry behaviour.

(1) Some believe that it is possible to estimate relatively simple single equations ('reduced form models') that are useful for forecasting and understanding industry behaviour. (For example, Moroney and Berg, 1999, have estimated what they argue is a meaningful simple log-linear equation for lower-48 U.S. crude oil production, based on time series data from 1950 to the 1990s. Yu (2003) finds that this model does not perform well for conventional oil in Alberta or western Canada.)
(2) Other economists believe that much more elaborate models are required if econometric analysis is to be useful. Some of the elaborations are in terms of econometric technique. (Kaufman and Cleveland, 2001, for instance, use cointegration techniques to estimate a crude oil production relationship for the United States that is very similar to that of Berg and Moroney.) Others argue that more elaborate underlying conceptual models are needed, thereby adding more variables to the explanatory equation, and/or moving into more complicated estimation procedures in which a number of related aspects of industry activity (e.g., expenditures, reserves additions, and output) are explicitly treated as co-dependent, and are jointly estimated.
(3) Others feel that the uncertainties affecting the petroleum industry are so great that it may be futile to try to estimate long-term forecasting equations, which are based on an attempt to capture fundamental causal relationships explaining industry behaviour. Instead, useful forecasting models must be largely 'technical' studies of the path of the dependent variable over time. Pindyck (1999), for instance uses the techniques of cointegration analysis and Kalman filters to try to derive a depiction of how crude oil prices have evolved over time; his model includes no explicit recognition of variables such as GDP, which economists might expect to affect the demand for oil and hence the price of oil.

Examples of all three types of econometric approaches will undoubtedly continue to appear in the literature.

C. Output Measures: Studies of Reserves Additions or Production

Rather than looking at industry activity as the main variable to be explained, some researchers have looked at the results of industry activity in terms of volumes of oil produced. This could involve either oil-in-the-ground (i.e., reserves added) or volumes of crude oil lifted to the surface. The expenditures required to attain this output could be estimated by assuming some particular cost function for oil supply. For example, in a reserves addition model, it might be assumed, following historical trends, that the reserves added per unit drilling effort becomes smaller and smaller as a region matures; this relationship could be used to estimate the amount of drilling required to add the forecast reserves additions, and then the expenditures for this drilling could be calculated.

From an economic point of view, the problem of explaining the volume of oil output is intimately connected to the form of the oil-supply production function, which tells, at any particular point in time, the minimum quantities of various inputs required to produce any given amount of output. There have been different representations of the required inputs. In general, one might suppose that inputs include 'land' (i.e., areas over which petroleum rights are held), geological and geophysical (G&G) surveys, labour, materials (e.g., drilling mud), and various forms of capital equipment. The practical question of how to measure these inputs generates a variety of responses. Sometimes authors rely on largely physical measures (e.g., the number of wells drilled, or the number of feet drilled). Other authors use economic aggregates, for example, the real value of expenditures on drilling. Since such measures are not perfectly correlated, it is possible for different studies to reach different conclusions, even working with essentially the same model.

A production function reflects the existing state of knowledge and, as has been discussed earlier, will change over time as knowledge and technology advance and as the stock of undiscovered resources declines. In the crude oil industry, in any large region, a particularly important source of knowledge change is the continuing discovery of new geological plays. For ease in modelling, it is frequently assumed that knowledge and technological changes are primarily 'exogenous,' perhaps occurring at a relatively regular rate over time. However, technological changes may have a strongly 'endogenous' character, in which economic conditions in the industry affect the amount of new knowledge produced. Thus, for example, increased exploration makes discovery of a knowledge-shifting new oil play more likely. There are also possibilities related to what Leibenstein (1976) has called *X*-inefficiency. Companies may not always exploit all the profitable opportunities available, but some conditions may drive them to be more efficient in this regard; for example, rising production costs, which put downward pressure on profits, may spur application of unutilized cost-reducing technologies.

While the production function sets out current technological constraints, the actual level of production hinges also on the specific point on the production function that is selected. In the conventional economic model, this is a function of the prices of the output produced and the inputs that must be hired.

Without entering into a discussion of the range of possible econometric estimation procedures available or returning to the joint-product problem, it is easy to see that a large number of oil-supply models might be constructed. In what follows, we will summarize some aspects of a number of models of Alberta crude oil supply, treating them in order of publication. The focus here is on equations estimating the quantity of Alberta (or Western Canadian) crude oil output, whether lifted crude or reserves additions. As will be noted, many of the studies also include estimates of other variables, such as the unit cost of oil. (Explanations of expenditures were reviewed in the previous section, and econometric estimates of cost functions will be covered in the next section.)

Russell Uhler's influential work, emphasizing the depletability of oil plays, provides an excellent starting point (Uhler, 1976, 1979, 1981; and Uhler and Eglington, 1983). Uhler's work might be seen as part of economics' negative reaction to the famous earlier research of M. King Hubbert (Hubbert, 1956, 1962). Hubbert argued that conventional petroleum, as an exhaustible natural resource, would necessarily go from some starting point for production through a life history to zero production at some future date. Drawing on the history of oil reserves additions (and production) in the lower-48 states, he proposed that they would exhibit a period of increase, followed by a mirror image path of decline, with the reserves addition curve preceding the production one by about ten years. He proposed that the curves would look much like normal curves; formally, he proposed that cumulative output or reserves additions would follow a logistic curve. Initially, he fitted these curves by eye, but subsequent analyses used statistical curve-fitting procedures. Apart from the simplicity of Hubbert's approach, and its appeal to notions of resource exhaustibility, his model derived great popularity from the fact that Hubbert was dead on in his forecast of 1970 as the peak year for U.S. lower-48 oil production. Critics have pointed out, however, that production since 1970 has fallen off less rapidly than would be implied by Hubbert's symmetric model and that it underestimated recoverable oil volumes.

Hubbert's model struck many as far too simple. Some, for instance, pointed to the importance of geological plays in the crude oil industry and argued that the general pattern of reserves additions that Hubbert suggested might be appropriate for a single play, where accumulating knowledge and drilling effort initially allowed rising reserves additions, but where depletion of the play would eventually mean falling additions to reserves. Even within a single play, many thought that the more likely pattern was a short period of rising reserves additions as the best prospects were explored, followed by a lengthy decline period, rather than Hubbert's symmetric rise and fall. But why would the same pattern be observed across all of industry activity, which would depend on the pattern of sequencing of oil plays? More fundamentally, it was argued that discoveries and production reflect a variety of factors, including changing economic conditions, government regulations, technological and knowledge changes, etc., which would make any number of production histories possible, not just Hubbert's logistic one. Ryan (1973a,b) provided a cogent early criticism; his paper includes estimates of changing discovery patterns for a number of Alberta crude oil plays, with a tendency to falling reserves additions as plays mature. Falling reserves additions can be connected to the asymmetry in pool sizes within an oil play, with a small number of large pools and a large number of small pools. (There is some discussion of this issue in Chapter Five; Allais, 1957, was among the first to note the skewed size distribution, hypothesizing that the distribution was log normal, and McCrossan, 1969, provided evidence for Canadian oil and gas fields. Smith, 2010, provides a recent assessment of Hubert-type 'peak oil' models from an economic perspective.)

Uhler follows in this line of work by emphasizing the importance of geological plays in oil discoveries and accepting that the total amount of oil in a play is not unlimited. As is common in discovery-process models, the discovery process is viewed as an uncertain process that involves sampling (i.e., discovering new pools) from an underlying distribution of pools that is log normal in size distribution.

Uhler's 1976 paper develops such a stochastic model and sets out to estimate it empirically for two sets of regions in Alberta; results are reported for only one region, an area of about 13,300 square miles in Central Alberta. Strictly speaking, Uhler argues, the model should be applied separately to separate plays, but he notes that the major plays in Alberta are geographically distinct to a considerable degree. Uhler is concerned both with the nature of the production function for oil and gas discoveries and the associated cost functions. We will focus here on the reservoir discovery model, setting out a brief, non-technical, overview, commenting on some of the measurement problems and giving a flavour of the results. The initial part of the model is concerned with the number of petroleum deposits that exploratory effort might locate in any specific time interval. Uhler reports results for both ninety-day and annual time intervals. Discoveries reflect three stochastic variables: the number of potential drilling sites available at any time; the likelihood that any particular site will be drilled; and the likelihood that a drilled site will hold a deposit. Uhler argues that the latter component reflects opposing tendencies. As drilling proceeds, more knowledge is gained, which enables an improved selection of drilling sites; however, as drilling proceeds and more pools are discovered, there are fewer pools left to be located, making new discoveries more difficult. It is likely, he argues, that the first of these effects will be strongest in the initial phases of exploration and the second later on.

The specific form that he assumes for this process is as follows, where $P(N = n)$ is the probability that the number of reservoirs discovered is equal to n:

$$P(N = n) = \exp(-l)(l)^n/n!$$

where

$$l = aD^a \exp[-b(C_{t-1}-K)^2].$$

In this equation, D measures the amount of exploratory effort undertaken in the period, so that more exploration increases the number of discoveries. The variable C is the ratio of the cumulative exploratory footage drilled to the size of the area; it obviously increases as exploration proceeds. (The variables a, α, b, and K are parameters that are estimated by econometric maximum likelihood procedures, so that the model best fits historical data.) Initially, C is very small, and as it rises the gap between it and K becomes smaller and smaller, so that the negative effect of the (C–K) term on l becomes smaller; that is, any given amount of exploratory effort (D) has more effect as C rises. But, after C exceeds K, the opposite is true, and as drilling proceeds, any given amount of exploratory effort generates fewer and fewer discoveries.

The final phase of Uhler's model is estimating how much oil lies in the n discoveries made in any time interval. This could be defined as the number of discoveries (i.e., n) multiplied by the expected size of an average discovery (y). But what will determine the average discovery size? Uhler argues that the uneven pool size distribution and the tendency to find larger pools first drives the average discovery size lower, as captured in the following functional form:

$$\log y_t = \log b - gC_{t-1}.$$

There are a number of practical difficulties that arise in applying this model empirically, specifically that of defining what is meant by exploratory effort (D), and how to handle the joint-product problem since exploration generates both oil and gas discoveries. Uhler elects to measure exploratory effort by the exploratory drilling footage undertaken in a period. He suggests that one would ideally like to separate drilling into oil-drilling and gas-drilling, based on the intent of the company undertaking the drilling, although he notes that drilling directed towards one product may still find a reservoir of the other. He does not credit oil pools with their associated or solution gas, or gas pools with the condensate present. In the absence of reliable intent data, and the rather arbitrary methods that might be used to separate exploratory footage into the oil/gas categories, he uses total exploratory footage in both the oil discovery and gas discovery equations. Finally, he notes that his discovery volumes "have not been adjusted for any expected appreciation, and these sizes are *initial*, not recoverable, magnitudes." This means that the size of more recent discoveries may be understated relative to earlier finds since there may be significant appreciation in these pools as development occurs, although the tendency to falling average discovery size may reduce the significance of the failure to allow for appreciation. The reference to the size of discovery volumes is somewhat ambiguous about whether it means that oil-in-place is used or simply makes clear that initial reserves are used, rather than a later estimate of remaining reserves.

In his 1976 paper, Uhler does not report oil-supply results for the entire province of Alberta, so his paper is best understood as presenting a new petroleum supply modelling technique, which happens to have been applied to parts of Alberta for years up to 1972. The equations he has specified seem to fit the data reasonably well. The results show a pronounced tendency in Alberta towards falling reserves discoveries over time for both oil and gas. For example, in the area studied, estimated oil discoveries based on his equations totalled 62,117 thousand barrels from May 12 to August 10, 1951, but only 2,786 thousand barrels from April 21 to July 20, 1972.

Uhler's 1979 study builds on concepts from his 1976 research in an application to the entire Alberta industry for years from the Leduc discoveries of 1947 to 1975. He notes that, while it would be ideal to consider separate oil plays, the absence of play-specific data for exploratory effort makes this difficult in practice; however, if each separate play tends to exhibit falling discoveries, and the sequence of plays itself exhibits a tendency to declining size, then the industry aggregate discovery data will also exhibit declining size. Since it is possible to accumulate reserves and successful well data by play, he proposes two discovery models, one using entirely aggregate provincial data, and a second that looks at total Alberta discoveries but retains some play-specific drilling information. Uhler suggests that discoveries in any period (y) might be seen as the separable product of a function ($\boldsymbol{h}(x)$) of exploratory effort (x) and a function for discoveries ($\boldsymbol{g}(R)$) based on cumulative discoveries (R) up to that date; the discovery part of this relationship could be set up for the entire province or for separate geological plays. This approach differs from the 1976 paper in a simplifying manner by not separating the effects of number of finds and average discovery size. A complicating difference from the 1976 paper is the explicit inclusion of a translog production function ($\boldsymbol{h}(x)$) to capture the effects of three different components of exploratory effort: exploratory drilling footage; land holdings; and geophysical crew-weeks. The $\boldsymbol{g}(R)$ function in this model is designed to capture the impacts of growing knowledge and depletion, and uses a function of the form:

$$g(R) = A\exp(-\beta R)$$

where A and β are parameters to be estimated. Note that this equation implies a steady tendency to declining discoveries as cumulative discoveries grow. (It is interesting that in his natural gas model, Uhler does not select this form, but one like the D function of the 1976 study, allowing for a positive initial effect of cumulative discoveries on this year's discoveries due to greater knowledge.) He also discusses the possibility of a separate price effect on discoveries, although the reasons for including this are not as obvious as might be thought since one would expect that the main effect of petroleum prices is felt through the level of exploratory effort (x), which is already included in the model. Uhler notes that higher prices will tend to shift the classification of deposits from the non-commercial to the commercial category, including previous discoveries; hence, higher prices will tend to have an effect on reserves additions in addition to the impact through current exploration.

Uhler, of course, faces data problems. Discoveries can be separated relatively easily into oil and gas categories (with some complications raised by the presence of condensate in gas pools and associated and solution gas in oil pools), based on the official categorization of reservoirs as oil or gas. However, there is ambiguity on how many reserves to credit to any one year; as in his 1976 research, Uhler uses the most recent ERCB estimates of initial reserves by year of discovery, with no attempt to increase recently discovered reserves for possible appreciation in subsequent years. Exploratory effort of necessity raises joint-product problems, as discussed earlier in this book. These joint-product problems are both product-related (dividing activities between oil and gas) and temporal (relating an activity at one date to specific reserves additions). Uhler draws on data that separated exploratory drilling from 1947 through 1970 by intent ('oil,' 'gas,' or 'both oil and gas'). The 'both' wells were treated as oil-intent. The ratio of oil-intent to total exploratory wells was then multiplied by the measures of total industry activity to derive oil-directed exploratory footage, geophysical activity, and land holdings. For years after 1970, it was assumed that the oil-intent well-drilling proportion in the years just before 1971 continued to hold. With respect to the timing issue, Uhler generally assumes that the current-year activities are associated with the current-year discoveries; for land, he assumes that the amount 'used' in reserves additions is the average of the start-of-year and end-of-year acreages.

The separable multiplicative form of the reserves addition process (discoveries = $\boldsymbol{h}(x)\boldsymbol{g}(R)$) is linear in its logarithmic form. Rather than jointly estimating the equation, Uhler uses a two-stage estimation procedure, initially estimating the production function ($\boldsymbol{h}(x)$), and then inserting the estimated annual values for $\boldsymbol{h}$ into the discoveries equation, and estimating the coefficients of the $\boldsymbol{g}$ relationship. It is this latter relationship that is of most interest here, the relationship that shows the negative impact on current reserves additions of rising cumulative reserves additions. Uhler estimates three versions of this equation. The first incorporates the separate impact of four major Alberta oil plays – Leduc, Pembina, Swan Hills, and Rainbow-Zama. Uhler suggests that the estimated equation fits the observed pattern of reserves additions quite well. As with actual reserves additions, the volumes estimated by the model exhibit significant year-by-year variability; in addition, the estimated equation tends to show pronounced peaks in the same years as the actual data. Such peaks typically reflect the emergence of a new oil play, which, of course, this equation captures quite well. He notes that the estimated equation seems to miss spurts in reserves additions in 1952 (when significant Leduc discoveries took place), 1959 (Swan Hills successes), and 1964 (with the Gilwood play, which was not included as a separate play). In addition, actual discoveries from 1968 on were less than predicted by the model. In part, this might reflect the failure to apply appreciation factors to the more recent discoveries. However, it would also seem to stem from the apparent dearth of significant new oil plays in this period and the inclusion of only four oil plays in the estimation. That is, the effects of other oil plays in the period prior to 1968 will tend to be captured by the estimated coefficients for the four plays included, and hence these coefficients will tend to understate the rate of decline in discoveries within the typical play.

The other two equations that Uhler estimates are based on cumulative reserves additions for the entire province rather than for specific plays, one of the equations adding the wellhead oil price as a variable. It turns out that the oil price is not significantly related to reserves additions. This does not mean that the price of oil has no effect on discoveries; remember that the oil price has already entered Uhler's model indirectly through its impacts on the level of exploratory effort. As noted earlier, Uhler's equation is set up so that current reserves additions are a declining function of cumulative reserves additions (R), and the estimated negative coefficient for R is significant. However, the equation will obviously fail to show the assorted upward shifts in actual reserves additions that were captured by the equation that included the four separate oil plays. On the other hand, Uhler finds that the aggregate model generates estimated reserves additions that are closer to actual values for the last years under study (1968 to 1975) than the play-inclusive equation.

It is tempting to interpret Uhler's findings as a good news/bad news story. On the one hand, it suggests that our understanding of oil discoveries in the Alberta oil industry can be greatly aided by explicitly recognizing two relatively simple factors: the majority of the many separate oil discoveries occur in a small number of discrete plays, and each of these plays tends to exhibit strong depletion effects, with falling reserves additions over time. However, while such a model can be of great value in understanding past developments, it is problematic as a forecasting model since "it is my belief that a model cannot be constructed which can forecast exactly the point in time and the magnitude of a new play" (Uhler, 1979, p. 63).

Uhler and Eglington (1983). Uhler continued his research on Alberta oil reserves additions in work undertaken with Eglington for the Economic Council of Canada's major evaluation of Canadian energy policies in the early 1980s. The 1983 study continued to contrast play-specific and aggregate Alberta approaches, this time incorporating eight 'geological formations and areas' that accounted for 98 per cent of the conventional oil that had been discovered in Alberta up to 1981. The eight categories do not exactly correspond to separate oil plays but are typically dominated by such a play. As in the earlier research, this study continues to emphasize the significance of depletion effects, but it also moves towards a more explicit incorporation of the impact of economic circumstances.

In general, it is argued that producers can be seen as profit-maximizers operating under the constraints of resource limits and current production technologies, and therefore reserves additions will be positively affected by factors such as a higher price for oil and technological improvements, and negatively affected by things like higher oil royalties or increases in the costs of inputs. The main focus of the 1983 study is on discoveries (reserves additions, D) in relation to drilling effort (E) and cumulative drilling (CE), which is hypothesized to fit the following functional form:

$$D = A_0 E^{A_1} e^{-A_2 CE}.$$

The *A*'s are coefficients to be statistically estimated.

As in Uhler's 1979 study, this equation shows depletion effects with no allowance for initial rising finding rates as knowledge grows. Reserves additions are measured differently in this study; reported reserves additions for each year are used, which includes new discoveries plus appreciations in that year from discoveries in previous years. From this perspective, reserves additions are due to both exploratory and development drilling, so drilling effort includes both types of wells. Drilling effort (annual and cumulative) is measured by the number of wells penetrating the formation under study, whereas Uhler's earlier work used footage drilled. Unlike the 1979 study's three-input production function, only the single measure of reserves addition effort is used. Uhler and Eglington argue that one would ideally like to use the number of well penetrations that were *targeted* at that particular formation and therefore measure wells by the number of wells that hit the particular formation and did not go any deeper. This will obviously fail to count wells that were targeted at a shallower formation but went deeper, either because the well accidentally was drilled deeper, or because the company was simultaneously interested in finding out about a deeper formation. There is a joint-product complication since there will typically be some non-associated gas pools found within any one of the eight specified formations/regions. Thus some wells may be drilled with a primary intent of finding gas rather than oil, and the total number of wells drilled with the intent of testing this formation will be affected by both oil and gas prices.

The net result is that Uhler and Eglington run a number of different cases for each of the eight formations/regions. These include two cases based on total well penetrations, one 'unrestricted,' based on the equation given above, and a second 'restricted' case in which the coefficient on the current drilling variable is set equal to one; this implies a unitary elasticity of reserves additions (*D*) to drilling effort (*E*), forcing changes in the efficiency of the reserves addition process entirely onto the resource-depletion variable of cumulative drilling (*CE*). In most cases, the coefficient of the current drilling variable in the unrestricted model is relatively close to one, and it could be argued that constraining this variable to the same elasticity across all areas allows more direct comparisons of the depletion effects in different areas. For each region, they also estimate equations that show the discoveries of non-associated gas as a result of the drilling. Another set of estimates is based on separate oil-well and gas-well penetrations, where the total number of wells drilled are allocated between oil- and gas-intent wells on the basis of the proportion of oil-well completions to total well completions. Finally, factors unique to a particular area sometimes lead to another set of estimates. For example, the Upper Devonian category consists in large measure of the D-2 and D-3 plays, which began with Leduc in 1947 and were therefore quite advanced by the 1970s; however, in the later 1970s, a new play began in the Nisku formation, leading to a sharp increase in reserves additions. If the analysis were truly play-specific, one could treat this new play separately, but the use of broader groupings means that its impact is lumped in with the earlier plays in the Upper Devonian group. Uhler and Eglington report equations both including and excluding the new Nisku discoveries.

There are obviously a large number of estimated equations in Uhler and Eglington, so their study is best seen as presenting ranges of likely results for the oil-producing areas. Table 8.11 gives a flavour of their findings. It shows the estimated coefficients in the restricted oil-reserves-additions equation using the total data available without allocating wells between oil and gas. That is, in terms of the equation above, it reports the estimated value for the constant ($logA_o$) and the coefficient of the cumulative wells variable (A_2); also shown are the coefficient of determination (R^2) and standard errors of the estimated coefficients (in parenthesis; the coefficient has greater significance the lower the standard error relative to the size of the coefficient). Table 8.11 also includes estimates the authors made, on the basis of the reserves additions equations, of possible future reserves additions for each of the seven areas. (The eighth is Upper Cretaceous formations in southeast Alberta, which hold no significant oil volumes.) In brief, they asked what volume of incremental reserves would be economic based on the estimated reserves addition equation, the current (1981) real cost of drilling in that region/formation, and the anticipated real market values of the discovered oil and associated and non-associated gas. The values of oil and gas are reserves values since their model looks at discovered volumes in the ground; as has been discussed above, a reserves price is less than the wellhead price for lifted petroleum since there are still additional costs to be incurred to lift the petroleum, and one must wait to receive much of the revenue since petroleum reserves are lifted over many years. Many estimates of future reserves additions

Table 8.11: Uhler and Eglington: Coefficients of Reserves Additions Equations and Possible Reserves Additions

Formations/Region	*log A(0) Coefficient*	*A(2)/1000 Coefficient*	*R-squared*	*1979 Reserves (10^6 m³)*	*Reserves additions @\$35.78 (10^6 m³)*	*Reserves additions @\$70.00 (10^6 m³)*
Upper Devonian/all Alberta	3.980 (0.052)	−0.146 (0.075)	0.11	554.4	47.7	57.9
Beaverhill Lake and Lower Devonian/all Alberta except area 5 (far NW Alberta)	5.41 (0.68)	−0.84 (0.21)	0.42	236.8	0	0
Mannville/all Alberta	1.67 (0.30)	−0.117 (0.032)	0.31	87.5	Minimal (due to gas-intent wells)	Minimal (due to gas-intent wells)
Beaverhill Lake and Lower Devonian/ Area 5 (NW Alberta)	5.990 (0.533)	−0.378 (0.067)	0.72	118.53	0	almost 0
Upper Cretaceous/Area 8 (around Pembina)	4.503 (0.880)	−0.494 (0.179)	0.23	163.05	0	0
Viking/all Alberta	1.845 (0.555)	−0.41 (0.240)	0.09	29.65	3.95	8.58
Mississippian/all Alberta	3.029 (0.668)	−1.167 (0.291)	0.36	54.47	0.01 (due to gas-intent wells)	0.01 (due to gas-intent wells)

are possible, depending on the specific reserves additions equation chosen and the drilling cost and prices assumed. The results that we show assume a gas reserves price of \$11.65/10³ m³; oil reserves prices of \$35.78/m³ and \$70.00/m³ are shown. This \$70.00/m³ for developed reserves is about \$11.10/b. It is doubtful that the real value, in 1981 dollars, of developed oil reserves attained this level for any extended time in the 1980s and 1990s. The gas price and the lower oil price are the estimated reserves prices for 1981, based on Alberta wellhead prices of \$117.12/m³ (about \$18.60/b) for oil and \$98.74/10³ m³ (about \$2.80/mcf) for gas.

It is striking that this analysis generates valid results for the model in all seven formations/regions but also suggests that the prospects for additional conventional crude oil reserves additions in Alberta in established oil plays are very restricted, except for the Upper Devonian plays. The Uhler/Eglington results cannot easily be related to more up-to-date Alberta statistics, but it is apparent that reserves additions have been significantly larger than was indicated in their analysis. In Table 8.12, we show ERCB initial oil reserves by geological formation for the years 1976, 1999, and 2007; where possible, geological categories as close as possible to the Uhler/Eglington ones have been noted.

It can be seen that the geological formations as listed here generally hold somewhat more oil than similar formations in the Uhler/Eglington study. It can also be seen that the actual reserves additions from 1976 through 1999 were quite significant, even though oil reserves prices in real terms were below the \$70/m³ assumed in the earlier table. (The decline in Beaverhill Lake reserves additions over the period reflects downward 'Revisions and Extensions,' mainly associated with modifications in the estimated effectiveness of EOR projects.) While some of the reserves additions over this period will reflect new oil plays, and small plays as of 1980 that were excluded from the Uhler/Eglington study, it would also appear that actual reserves additions within established plays exceeded those estimated by their model. In most of the plays, reserves additions, albeit generally rather small, occurred after 1999.

Uhler and Eglington go on to estimate two aggregate models of oil reserves additions in Alberta. The first estimates the simple oil reserves additions equation for the entire province, with wells allocated between oil and gas on the basis of the proportion of completed wells that were classified as oil wells. The estimated coefficients are 4.278 for log $A(0)$, and −0.069 for $A(2)/1000$; the respective standard errors are 0.419 and 0.021, and the equation has an R-square of 0.25. (Inclusion of dummy variables for the starting date of four successive oil plays, as might be expected, increases the R-square considerably to 0.47 and allows more rapid depletion effects as the $A(2)$ variable

Table 8.12: ERCB Oil Reserves by Formation, 1976 and 1999 (10^6 m^3)

	1976 Reserves	*1999 Reserves*	*Change in Reserves, 1976–99*	*2007 Reserves*
Upper Cretaceous: Cardium	284	297	13	294
Viking	49	62	13	68
Mannville	100	407	307	544
Mississippian	71	100	29	92
Upper Devonian: Wabamun, Nisku and Leduc	547	708	161	732
Upper Devonian: Beaverhill Lake	421	393	–28	408
Middle Devonian: Keg River	158	195	37	197
Other	183	350	167	400

Source: ERCB (and EUB) *Reserves Reports* (ST-18 and ST-98).

becomes –0.323.) However, in this model (without the oil-play dummy variables), no further reserves additions at all in Alberta are estimated to be economic at reserves prices of $70 or less per cubic metre. In other words, this model, while not restricted to existing oil plays, is even less optimistic than the findings from the separate established plays!

Their second aggregate model utilizes a different data set, closer to that used by Uhler in his earlier work. Reserves additions are measured by estimated appreciated reserves discovered, and the variables used to explain oil discoveries (*OD*) are the prices of oil and gas (*P*(*o*) and *P*(*g*), undeveloped reserves prices), a cost of drilling (*c*) and the cumulative number of oil discoveries (*d*, the variable used to capture depletion effects). The estimated equation (*R*-square = 0.27) is:

$$\log OD = 4.416 - 0.440\log P(o) + 2.82\log P(g) + 0.373\log c - 0.0046d.$$

There is a strong depletion effect, but the oil price variable shows *fewer* reserves discovered the *higher* the oil price. The coefficient on the gas price variable (2.82) suggests a very high elasticity of oil discoveries to gas prices. However, neither the price nor the drilling-cost variables are particularly significant. Overall, this model is not very satisfactory, and the lack of a reliable relationship between price and discoveries makes it impossible to estimate possible reserves additions as a function of the price of oil.

In summary, Uhler provides one of the most detailed approaches to modelling Alberta oil supply. His research generated a mix of useful and discouraging results. The presence of strong depletion effects in the oil reserves additions process was clearly demonstrated, as was the value of seeing reserves additions as embedded within a succession of geological plays. However, as Uhler noted, the emphasis on oil plays poses major problems for forecasting models since it is impossible to predict when new plays will occur. In addition, much as in the NEB reserves estimation models of the 1980s, it would appear that actual reserves additions in plays under study turned out to be larger than was estimated. There could be a number of reasons for this, including: (1) technological developments that reduced the costs of adding reserves; (2) a tendency of the model to underestimate the volumes of oil in smaller oil pools, perhaps because the data available provided less information about this part of the reserves base; and (3) the likelihood that, while the model projects new discoveries of progressively smaller size, a few of the new finds in any play will actually turn out to be relatively large.

Other Models. Foat and MacFadyen (1983) also looked at oil discoveries from a geological-play perspective, for nine Alberta oil plays. A geographical area was defined for each play, and reserves (*R*) were the reported appreciated reserves as of 1976. The cumulative number of wells that penetrated the formation prior to the current year (*CumPen*) was used to capture depletion effects. Reserves additions were also argued to be determined by the number of formation penetrations in that period (*Pen*). The specific form of the equation estimated was a simple one:

$$lnR = A + B(lnPEN) + C(CumPen),$$

where *A*, *B*, and *C* are estimated coefficients; *B* is expected to have a positive sign and *C* a negative sign. This assumes a negative exponential depletion effect. A number of different equations were estimated for

Table 8.13: Foat and MacFadyen Model of Oil Discoveries in Nine Alberta Oil Plays

Play and year of first discovery	*1976 initial reserves (10^6 b)*	*Number of pools discovered*	*A (estimated constant)*	*B (estimated coefficient for ln Pen)*	*C (estimated coefficient for CumPen)*	*R-square*
Leduc, D-3, 1947	2,262	71	16.511* (5.37)	.99111* (1.72)	–.00891* (–8.49)	0.71*
Keg River, 1964	1,099	407	6.525 (1.20)	2.7592* (2.72)	–.00320 (–1.40)	0.60*
Beaverhill Lake, 1957	1,000	20	19.610* (2.43)	0.65982 (0.32)	–.01479* (–4.95)	0.55*
Cardium, 1953	966	59	1.0122 (0.10)	3.4651 (1.33)	–.00396* (–1.94)	0.20
Nisku, D-2, 1947	559	58	4.9649 (0.80)	2.6347* (1.94)	–.00248* (–3.86)	0.36*
Viking, 1949	173	39	4.1920 (0.29)	1.6794 (0.60)	–.00063 (–1.42)	0.01
Granite Wash, 1956	43	15	15.125* (4.78)	–1.1705 (–0.98)	–.01952* (–1.84)	0.14
Slave Point, 1958	24	9	2.3409 (0.60)	1.4520 (1.60)	.00081 (0.77)	0.08
Sulphur Point, 1967	3	13	14.05 (1.63)	–0.2292 (–0.19)	–.00632 (–1.00)	0.03

* Significant at the 5% level.

different oil plays, including estimates for oil-in-place as well as reserves, and with the use of moving averages to smooth the data somewhat. A flavour of the results can be garnered from Table 8.13, which is for initial reserves for the annual (unsmoothed) data; 1976 initial reserves are shown for each play in millions of barrels. The Cardium equation also included a 'Dummy variable,' which took the value of 1 in 1953, the year of the initial Pembina discovery; the coefficient for this variable was 9.5, and it was highly significant.

A play-specific approach seems to capture some aspects of the reserves addition process. The coefficients on the penetrations and cumulative penetrations variables have the correct sign in fifteen out of the eighteen estimates, and for four of the five largest plays the equation exhibits significance at the 5 per cent level, as does the tendency to negative reserves additions as cumulative reserves additions increase. The fit is not good for the smaller plays. Similar regressions were also run for the average size of a discovery in an oil play, and, similarly, depletion effects were found for all plays, and at a 5 per cent significance level for four of the five largest plays.

These results are entirely consistent with the somewhat ambiguous conclusions we have drawn from Uhler's work: our understanding of past discoveries of oil in Alberta is greatly enhanced by utilizing a play-specific analysis, but the inability to foresee the appearance of new plays limits this as a forecasting method.

The emphasis on depletion effects in oil plays in the Uhler and Foat and MacFadyen studies is consistent with sophisticated discovery-process modelling in the 1988 study of Western Canadian oil potential by authors from the **Geological Survey of Canada (1987)**. The GSC analysis was discussed in Chapter Five. One advantage of this modelling approach is that it generates results that show the tendency towards reduced reserves discovered as the play is depleted and also generates an estimate of the underlying distribution of oil pools in the play. Hence, one can match past discoveries with pools in the estimated distribution to derive a size distribution of *undiscovered* pools, some of which may be relatively large. This differs from the Uhler and Foat and MacFadyen approaches in which new finds are all progressively smaller. As will be recalled, the authors of the GSC study suggested that a different modelling technique had to be used for new and potential oil plays; they applied subjective probability techniques in these cases.

Another example, applied to Alberta, is found in **MacDonald et al. (1994)**. They approximate a general discovery-process model for three Western Canadian oil plays (two in Alberta) by an equation in which cumulative discovery volumes are related to the number of discoveries in the play and the square of the number of discoveries. They too find noticeable depletion effects. Their approximation, however, unlike the GSC discovery-process model, forces smaller discovery sizes onto forecast reserves additions.

Siegel (1985) includes an Uhler-type oil discovery equation in his study of the 'information externality' in oil exploration, as seen in the Rainbow-Zama play in northwestern Alberta. In brief, this externality applies when there is a depletion effect in exploration; that is, there are a limited number of oil pools, which tend to be discovered in order of size, so that a new discovery depletes and degrades the stock of remaining undiscovered pools, creating a user cost of exploration in the process. (That is, exploration today, by depleting the stock of undiscovered prospects, increases the cost of future exploration.) The individual company will have no reason to consider the negative effect that its (successful) exploration has on the exploratory prospects of other firms; therefore, from a social perspective, there will tend to be more exploration in any period than is socially desirable. (This and other possible externalities in exploration are discussed in Chapter Eleven.) Siegel uses quarterly data for the years 1965 through 1970, excluding three quarters where no discoveries were reported. As independent variables, he includes the number of exploratory wells drilled this year (W), and both the cumulative number of wells (CW) and this value squared (CW^2); including the two terms for cumulative drilling allows a nonlinear relation with both 'depletion' and 'learning' effects. The dependent variable is the volume of new discovery reserves (D), in thousands of barrels. Siegel's equation has an adjusted R-square value of 0.68 (t-statistics in parenthesis):

$$\underset{(10.258)}{\ln D = 7.4347} + \underset{(3.488)}{.6557\ln W} + \underset{(1.268)}{.00102CW} - \underset{(-2.435)}{.0000009CW^2}$$

Siegel notes that the depletion effect, generating diminishing returns from cumulative exploration, begins to offset the increasing returns from 'learning' when about 550 exploratory wells have been drilled. The nonlinear cumulative drilling relationship, which was not included in the Foat and MacFadyen analysis of this play, appears to have been important. Siegel also estimates similar equations for real exploratory costs in the Rainbow-Zama play, presumably exploratory drilling costs. He finds a unitary elasticity for the number of wells, and that the CW term is significant, with costs falling as cumulative drilling rises, indicative of a learning effect in drilling costs, although technical changes or some time-related fall in real input costs would generate a similar result. There is no reason why depletion effects should influence total exploration costs, though such an effect would lead to increased per unit costs, as exploration activities find progressively less oil.

A somewhat different approach to estimating oil reserves additions (discoveries) is found in the extensive econometric research of **Helliwell et al. (1989)**. Their analysis covers the Western Canadian sedimentary basin but is dominated by Alberta. The discovery variable (D) that they use is not reported reserves added but a variable they have created by dividing the total expenditures devoted to adding reserves by an estimated 'adjusted' marginal cost of adding reserves. (Their marginal cost estimate will be discussed below. This cost was 'adjusted' by reducing the estimated marginal cost somewhat to allow for the impact of regulations that encouraged investment in existing reserves rather than in new reserves additions.) To illustrate the discovery variable: if the (adjusted) marginal cost of adding reserves were \$10.00/m³, and a total of \$50 million were spent, then there would be 5 million cubic metres of reserves added: \$50 million/\$10.00/m³ = 5 million cubic metres. It is not altogether clear what went into the oil expenditures: it includes real exploration and development expenditures, presumably excluding expenditures on gas plants; it is not clear whether exploration includes land acquisition costs, and there is a statement that costs are allocated between oil and gas on the basis of proportionate drilling footages for oil and gas development wells.

Results are shown for three equations, estimated in a double log form. All three include a constant and the same two explanatory variables, a 'profitability ratio' (P), and a 'ratio of estimated to adjusted capital costs' (CR), but differ with respect to the third variable, which is either output (Q), cash flow (CF), or lagged land payments (L). As it happens, only the last of these three variables (L) had a significant effect, which is interpreted as reflecting the necessity of holding land before drilling, plus the exploration requirements on newly acquired land. The profitability ratio was discussed above, and, as noted, is a three-year moving average. The ratio variable (CR) is the ratio of the estimated marginal cost to the 'adjusted' marginal cost. The preferred form of the oil discoveries equation (R-square = .9053) is:

$$\ln D = 3.0821 + 1.1957\ln P + 0.4839\ln CR + 0.5585\ln L.$$

(t-ratios are 8.66, 9.88, 5.59, and 7.88, for the four estimated coefficients. Appendix 8.1 in Helliwell et al. provides a number of alternative econometric estimations of the oil-discovery equation.) It can be seen that oil discoveries are estimated as being very elastic (1.2) with respect to the profitability ratio. The estimated elasticity of the cost ratio variable of 0.4893 shows an inelastic impact on discoveries; that is a smaller 'adjustment' (implying a higher CR value) has a less than proportionate impact on reserves additions. Of course, the equation does not provide a perfect fit to actual discoveries; Helliwell et al. note that their equation overestimated reserves additions from 1974 to 1978 but underestimated them from 1979 to 1981. Overall, however, they view the fit as good, though their Figure 8.2a shows that the model significantly underestimated discoveries in 1985. So far as we know, there has been no report comparing their discovery model's forecast to actual discoveries after 1985, and the complexity of the cost ratio and profitability variables do not allow us to do so with any degree of reliability.

Finally, **Livernois and Ryan (1987)** addressed the reserves-discovery process for Alberta in a model that explicitly recognized the joint-product nature of exploration. They studied reserves of oil and natural gas by the year of discovery for the years 1948 to 1979. Their model is complex, both theoretically and in terms of the econometric estimation. Alberta oil producers are assumed to be price-takers in both input and output markets. The production function involves the production of oil and gas discovery reserves through the utilization of four 'inputs': land acquisition and exploratory drilling, which can be varied by a producer, and two fixed factors, 'the state of depletion,' measured by the cumulative number of wells drilled so far, and geological knowledge, measured by cumulative geophysical crew-months. Under the assumption of profit-maximization, expected industry activity can be set out in terms of a profit function, and estimated 'share' equations showing revenues for the two outputs, and costs of the variable factors as a share of profits. As the extent of 'separability' and 'jointness' varied amongst the two outputs and the various inputs, there would be differences in the anticipated relationships between the variables in these equations. Separability, in this context, means that the output part of the production function can be separated from the input part, as is normally assumed by economists when they write a production function in the form $X = f(L,K)$ where X is output, L is labour, and K is capital. Livernois and Ryan note that if, but only if, separability is true, one can legitimately model industry output as if it consisted of a single aggregate product, although problems do exist in constructing such an aggregate and its price. Several types of non-jointness exist, the most frequently cited form implying that the output of a product (e.g., crude oil) is affected by its own price but not that of the other product (i.e., natural gas).

Livernois and Ryan's results are tantalizing, partly because of their ambiguity. At the broadest level, they are able to reject the hypothesis of separability, but they cannot reject that of non-jointness; however, despite this, they find significant and positive cross-price elasticities, implying that higher prices for one of the products will stimulate more discoveries of the other. Their results warrant further research and suggest that the results of much of the research on conventional crude oil supply, which assumes non-jointness and/or separability, must be accepted with caution.

Thus far, we have reviewed econometric studies that focus on either the total expenditures undertaken by the oil industry or on the additions of oil reserves in Alberta. We will now summarize several econometric analyses that focus on the costs of adding reserves.

D. 'Indirect' Estimation of Costs

In Section 3, above, we looked at direct estimates of the cost of oil in Alberta in which the analyst divided actual expenditures by the actual amount of output that resulted. We noted that it is difficult to know how to interpret the results. The costs are an after-the-fact measure and therefore reflect the ongoing interplay of shifting supply and demand factors, as well as the inevitable stochastic dimension of oil discoveries. Thus, simple time trends in costs rarely convey unambiguous information: are costs rising because low-cost conventional oil resources are depleting? Or is it because higher prices make the higher-cost resources look more attractive? Or a combination of these factors? One way to begin to address this issue is by undertaking more elaborate econometric analysis to see what factors affect the estimated costs; we call this an 'indirect' cost-estimation process.

Helliwell et al. (1989), discussed above, relate annual 'marginal costs' (C) of oil reserves additions to the cumulative volume of oil discoveries (CD). In their analysis, marginal costs appear to be annual real expenditures on exploration (drilling and G&G) and development divided by the reserves added through new discoveries and revisions and extensions. Years from 1952 to 1985 are included (except for 1976, which saw negative reserves additions, due to a significant downward revision of reserves in several pools). Their preferred equation also includes a variable (EP) from 1982 to 1985 that shows the excess of the 'new' oil price in Alberta above the 'old' oil price; 1982 saw the extension of the higher price to certain development activities such as EOR. The estimated equation (Helliwell et al., 1989, p. 147) with the t-statistics in parentheses is:

$$C = \underset{(0.80)}{0.4517} + \underset{(1.51)}{0.07807CD} + \underset{(4.42)}{16.067EP}.$$

The adjusted R-square value is 0.4846. This equation suggests that 'depletion' effects have been significant in pushing up the unit cost of reserves additions, and that a move to higher-cost reserves additions through development followed the extension of higher oil prices to such reserves in 1982. However, it is notable that the estimated coefficients are relatively unstable as the equation specification changes, such as by using a different time period. Also, the cumulative discovery variable is not highly significant.

We will briefly review two other studies of the costs of Alberta oil supply.

Livernois and Uhler (1987) are primarily concerned with models of natural resource extraction that view exploration as a process to reduce extraction costs by increasing the size of available reserves. They argue that the resource base should *not* be viewed as an aggregated whole, the size of which is inversely related to lifting costs. By way of analogy, think of a region's reserves as being held in a giant cistern. Suppose that the greater the volume of oil present, the greater the pressure pushing down on the oil and the higher the output flow rate is through the spigot at the bottom of the cistern (and the lower the unit cost of production). Then adding more reserves will reduce per-unit lifting costs. But Livernois and Uhler argue that this picture does not fit the oil industry since reserves are not in fact an aggregate but the sum of many separate reservoirs. There is strong reason to assume that the industry faces depletion effects in the addition of reserves, in the sense that at any point in time the lowest-cost potential reserves tend to be the ones that are added, while those left undiscovered and undeveloped are those expected to be of higher cost. Such depletion effects in the reserves-addition process mean that the incremental reserves added tend to be of higher cost; adding reserves in this model would not tend to reduce average lifting costs. What is required is a disaggregated model. Here the reduction of reserves in any single deposit (the 'intensive margin,' as they label it) will tend to increase extraction costs, as in the usual aggregated model. However, the addition of reserves (the 'extensive margin') may also lead to higher costs as more costly reserves additions take place.

Livernois and Uhler illustrate their model with data for Alberta oil costs over the years 1951 to 1982. Initially they estimate an 'aggregate' cost equation, which shows that the sum of real operating and capital costs (C) was positively related to the size of reserves (R), rather than exhibiting the negative connection suggested by the aggregate resource-depletion model. The equation also included the annual output level (Q), and, with an adjusted R-square of 0.83, was (with t-statistics in parenthesis):

$$C = \underset{(-1.3)}{-33.48} + \underset{(3.4)}{.00000206Q} + \underset{(2.9)}{.0000000316R} - \underset{(-1.1)}{.029338(R)(Q)}.$$

They then draw on data for 166 oil pools discovered between 1950 and 1973 to do a cross-sectional estimate of oil extraction costs per pool ($C(i)$) in 1976. (These data were presumably generated as part of Livernois' interesting study of pressure maintenance water injection procedures in Alberta oil pools; Livernois, 1987.) The estimated equation assumes that costs are related to the pool's output rate ($q(i)$), the proportion of initial reserves yet unproduced ($r(i)$) and the cumulative number of oil discoveries made in Alberta prior to this pool's discovery ($N(i)$). The estimated equation, with an R-square of 0.93, and t-statistics shown as before, was:

$$C(\mathrm{i}) = \underset{(-1.5)}{-1{,}800{,}000} + \underset{(47.1)}{61.86q(i)} - \underset{(-2.0)}{4{,}300{,}000r(i)} + \underset{(3.3)}{47.47N(i)}.$$

As can be seen, costs rise as reserves in the pool are depleted, and costs are higher the later the pool was discovered, indicating significant depletion effects at both the intensive (pool) level and the extensive (discovery) level.

Livernois (1988) undertakes a joint econometric estimation of the marginal discovery costs of crude oil and natural gas in Alberta, using annual data from 1955 to 1983. His interest, in part, is to address the joint-cost problem in exploration: producers searching for petroleum in Alberta find both oil and gas and are unable to separate their activities into a search for one of the products only. Hence, it may be inappropriate to estimate a discovery-cost relationship for oil alone; one would expect, for instance, that natural gas prices influence oil discoveries, and the strength of depletion effects for one of the products would affect discovery of the other.

Livernois begins with an optimization model in which producers operate to produce the joint products of oil and gas discoveries using three competitively produced inputs (land acquired for exploration, geophysical activities, and exploratory drilling). Cumulative past exploratory drilling effort is included as an 'input' variable, to capture the cost-reducing effect of technological change and the cost-increasing effect of the depletion of the resource base as discoveries proceed. Discoveries are measured by the 1985 estimate of appreciated reserves by year of discovery. (That is, as discussed above, discoveries in any year are based on the 1985 estimate of the size of the pool, not the estimate that was made in the year of discovery.) The basic problem is one of minimizing the cost of the discoveries, given the prices of the inputs and a production function relationship tying the quantities of oil and gas discoveries to the quantities of the four inputs used. Livernois draws on economic theory that shows that this problem can be rephrased as the estimation of a cost function and of cost-share equations derived from that function. He assumes a 'translog' cost function, a flexible functional form capable of capturing a wide variety of interrelationships amongst the variables. The model is complex, as are the econometric estimation procedures. Autocorrelation (serial correlation) was found to be a problem; that is, there was a positive (rather than random) tie between year-to-year differences between the observed values of variables and the values estimated in the equation. Including a dummy variable to capture the new Keg River play starting in 1965 reduced this serial correlation somewhat, suggesting that the Keg River play had characteristics somewhat different from earlier plays. The results showed that, in twenty-one of the twenty-seven years, the cumulative drilling effort variable acted to increase costs, suggesting that depletion effects were more significant than technological improvements. The exception was six consecutive years from 1973. Livernois notes that the negative effect had been small for several years prior to this, and that the widespread adoption of new computer techniques in geophysical analysis began in the late 1960s.

From his estimated cost equations, Livernois is able to calculate the marginal costs of finding additional units of oil and gas each year from 1956 through 1983 (Livernois, 1988, p. 389). Both costs show considerable variation from year to year but also a general tendency to increase. A simple time (t) trend for oil marginal finding costs (MC, measured in 1985\$/m^3) yields an R-square value of 0.71 for the following equation (standard errors, rather then t-statistics in parenthesis):

$$\begin{array}{lcll} \ln(MC) & = & -415.4 + & 0.211t. \\ & & (50.3) & (0.025) \end{array}$$

That is, oil finding costs were rising at 21%/year. (For natural gas, the annual average cost increase was about 17%.) Finding-cost estimates generally smaller than estimates of the in-ground value of new reserves indicate that the marginal finding cost is not a good proxy for the user cost of oil and gas; this is consistent with the resource models reviewed above, which include a depletion effect in the discovery process. Livernois notes that his finding-cost estimates do approach the in-ground value around 1970, then fall lower again. As a possible interpretation, he suggests that the most profitable exploration opportunities available at the low price level of the late 1960s had been pretty well exploited by 1970 and that it was only the sharp price rises after 1970 that made significant discoveries economic again and therefore 'resurrected' the importance of exploration depletion effects.

6. Conclusions

This chapter (along with the sections of Chapter Five reviewing discovery-process models like that of the Geological Survey of Canada) has surveyed much of the empirical economic literature on Alberta conventional crude oil supply. The details are overwhelming and must leave the reader wondering whether any firm conclusions can be drawn from the forest of individual results! However, the complexity of the findings reflects the complexity and inevitable uncertainties of the crude-oil-supply process. With the exception of the NEB, which has a government mandate to provide regular progress reports on the supply of and demand for energy in Canada, most analysts respond to the complexity of the oil-supply process by restricting their research to a small part of the activities of the total crude oil industry. As a result, there is no single model that stands out as providing the best description of Alberta oil supply.

On the basis of the literature we have reviewed, the following conclusions seem warranted:

- Crude oil supply (industry activity and resultant reserves additions and production) are responsive to economic signals. All else being equal, higher real prices net of royalties do generate more output.
- Resource-depletion effects have been apparent over time; there has been a general tendency for the real costs of producing oil in Alberta to increase, and most models that explicitly include some type of degradation effect find that it is significant. This is not to say that technological

progress has been unimportant, but the industry does seem to work its way through the underlying resource base by exploiting the lower-cost deposits first and then moving on to the higher-cost deposits.

- Notwithstanding this ranking procedure, there is a great deal of stochastic instability in the reserves addition process. In any year, reserves additions may turn out to have been considerably less expensive or more expensive than was anticipated.
- Alberta oil supply is difficult to model as a process of tapping a single aggregate resource base. A number of the supply models point out the importance of recognizing the development of the industry in Alberta as progressing through a sequence of geologically distinct oil plays. However, while the oil play may be a critical unit for understanding oil supply, the problem arises that there seems to be no reliable way of anticipating as yet unrecognized new plays. This is a case in which the most useful way to understand the history of discoveries in Alberta is of limited value for forecasting purposes.
- There seems to be a persistent tendency for historical models of oil supply (which includes pretty well all models) to underestimate longer-term oil supply. This tendency has been marked in the NEB's work and also seems to have held for the burst of econometric modelling in the late 1970s and 1980s. As mentioned, most of these models found relatively strong depletion effects in reserves additions and/or strongly rising unit costs. Particularly in light of the large fall in real oil prices after 1985, one might have expected that reserves additions since then would be minimal. While production of conventional crude oil since the mid-1980s has exceeded reserves additions most of the time, there have been continuing additions to reserves. This suggests that there has been some tendency for econometric models to underestimate the impacts of changing technologies and, perhaps, to fail to pick up new oil plays. The newer technologies could be major new techniques like horizontal drilling and 3-D and 4-D seismic but might also include the cumulative impact of many small new innovations in all aspects of industry activity, including the electronic revolution, which some observers cite in the productivity increases in the United States in the 1990s. We are unaware of any recent studies that have addressed in a formal way the importance of such technological changes in the Alberta crude oil industry. Technological and knowledge change is a difficult variable to include in supply models since some of the changes lie in the minds of the companies supplying oil, and others may be embodied in a wide number of specific capital assets: how can this complex mix of tangibles and intangibles be measured? (Cuddington and Moss, 2001, look at U.S. petroleum supply and include a technological change variable measured by patent applications.) Of course, there is no way of being sure that the tendency to produce more than various oil-supply models have forecast will continue through the future!

This chapter concludes the part of the book that deals primarily with the 'private' sector's role in the Alberta petroleum industry. We will now turn to a detailed examination of the role of governments, in other words to public policy analysis of the industry.

Appendix 8.1
National Energy Board: Western Canadian Sedimentary Basin Oil Supply Forecasts

1. WCSB Potential Reserves Additions

Table A8.1: National Energy Board Reports: WCSB Potential Reserves Additions (10^6 m^3)

Report	*Light: New Discoveries*	*Light: EOR*	*Heavy: New Discoveries*	*Heavy: EOR*	*Approximate Oil Price (US$/$m^3$)*
October 1974	270**				11.00*
September 1975	270**				12.00*
February 1977	77	156	99	173	14.00
September 1978	207	156	64	345	18.00
January 1981	225	302	80	169	38.00
September 1984	404	280	140	381	28.00
October 1986	308	367	125	378	18.00
September 1988	563	295	250	370	16.00
June 1991	521	295	270	320	17.50
December 1994	519	395	260	300	19.00
1999	666	253	229	187	18.00

Notes:

* Approximate price in the year the report was issued of WTI at Cushing Oklahoma. Prices are in nominal dollars (unadjusted for inflation). It should be noted that reserves additions depend on forecast prices, which vary from report to report. This price is taken as representative of the anticipated price of oil in each report.

** Reserves additions over two decades of light and heavy crude.

2. Productive Capacity of WCSB Conventional Light Crude

Table A8.2: National Energy Board Reports: Productive Capacity of WCSB Conventional Light Crude (10^3 m^3/d)

	Actual	*1974**	*1975**	*1977*	*1978*	*1981*	*1984*	*1986*	*1988*	*1991*	*1994*	*1999*
1974	230.1	321.8										
1975	194.7	324.2	294.8									
1976	174.1	318.6	280.5	239.6								
1977	169.3	308.9	270.1	227.9								
1978	165.6	289.2	252.7	212.0	222.9							
1979	188.2	266.2	230.7	191.6	209.8							
1980	173.7	247.1	209.8	169.7	193.7							
1981	154.5	225.6	191.5	150.3	175.9	167.6						
1982	150.7	205.0	174.3	133.3	159.5	156.4						
1983	153.3	185.1	172.4	118.9	144.8	135.7	165.1					
1984	164.5	166.1	139.0	106.6	131.6	123.6	167.7					
1985	159.8	147.8	129.5	96.3	120.3	114.3	157.0	168.1				
1986	149.3	131.9	116.1	87.9	111.1`	109.8	144.5	168.0				
1987	152.3	118.4	104.1	80.4	102.2	104.0	134.5	158.2	159.9			
1988	158.1	106.5	98.5	74.3	94.7	99.1	125.4	143.0	159.7			
1989	148.2	96.1	90.4	68.8	87.7	94.8	116.8	130.0	152.2			
1990	141.2	87.4	85.8	64.2	82.0	90.3	109.1	118.4	143.8	144.7		
1991	137.7	79.5	82.2	60.2	77.4	86.2	102.3	108.4	135.3	137.4		
1992	139.2	72.3	77.1	55.6	73.1	81.9	96.1	100.0	127.6	126.2		
1993	143.9	65.9	72.8	52.9	69.4	78.2	90.6	93.0	120.6	117.2	142.1	
1994	148.5		69.1	49.9	65.8	74.0	85.8	86.9	113.9	110.1	144.9	
1995	145.1		68.0	46.9	62.1	68.1	81.7	81.6	107.4	104.4	150.9	
1996	140.0					66.6	77.9	76.5	98.2	99.4	148.9	
1997	135.1					64.9	74.0	72.4	94.7	94.7	143.5	132.0
1998	140.4					59.4	71.0	68.8	91.0	90.4	137.9	
1999	140.2					56.0	68.1	65.1	85.7	86.4	131.9	
2000	134.6					52.7	65.7	61.1	82.3	82.6	125.8	111.5
2001	127.3						63.5	57.7	78.8	80.4	118.9	
2002	119.4						61.1	54.7	75.4	76.0	112.5	
2003	91.8						58.9	51.7	72.2	73.0	105.5	
2004	87.6						57.0	49.0	69.3	70.3	99.9	
2005	83.9						55.1	46.6	66.5	67.9	94.6	101.1
2006	83.1									65.8	89.3	
2007	82.4									63.9	83.9	
2008	86.2									62.0	78.6	
2009	82.2									60.7	73.2	
2010	83.5									59.5	69.1	82.2

Note:
*Includes light and heavy crude and pentanes plus. The 1975 values were read off two graphs, so are approximate.
1988 and 1989 actual output from CAPP *Statistical Handbook*.

3. *Productive Capacity of WCSB Conventional Heavy Oil*

Table A8.3: National Energy Board Reports: Productive Capacity of WCSB Conventional Heavy Oil (10^3 m^3/d)

	Actual	*1977*	*1978*	*1981*	*1984*	*1986*	*1988*	*1991*	*1994*	*1999*
1974	30.3									
1975	25.2									
1976	24.6	33.1								
1977	30.8	32.9								
1978	32.2	32.4	34.5							
1979	31.7	31.3	34.5							
1980	31.7	30.0	33.5							
1981	28.0	28.8	31.9	27.4						
1982	28.7	27.8	31.1	23.6						
1983	33.0	26.9	29.9	22.0	34.4					
1984	37.6	26.1	29.1	20.6	37.6					
1985	39.1	25.3	28.6	26.9	36.5	40.7				
1986	39.9	24.6	29.1	28.4	34.2	41.2				
1987	43.1	23.7	29.6	30.1	32.5	38.1	44.1			
1988	45.4	22.9	30.5	31.6	31.4	34.5	44.9			
1989	46.2	22.4	31.1	32.5	30.1	31.9	42.2			
1990	49.8	21.8	31.5	33.7	28.7	29.5	40.6	49.6		
1991	50.5	21.1	31.8	34.5	28.7	27.6	38.4	48.8		
1992	55.4	20.5	32.3	34.6	28.3	25.9	36.3	48.1		
1993	61.5	19.9	32.3	34.2	27.9	24.6	34.4	47.8	65.4	
1994	65.7	19.2	32.4	33.5	27.5	23.7	33.1	48.3	73.9	
1995	73.4	18.8	32.3	32.7	27.1	22.2	31.7	49.0	86.1	
1996	82.3			31.5	26.8	22.1	30.5	49.5	89.6	
1997	89.3			30.2	26.6	21.4	29.2	49.5	90.0	88.4
1998	85.2			28.8	26.2	20.5	28.0	48.7	88.2	
1999	82.9			27.5	25.8	19.3	26.9	47.5	85.3	
2000	89.0			26.0	25.6	18.7	26.0	46.2	80.7	82.5
2001	90.7				25.5	18.3	25.1	44.7	76.0	
2002	88.0				25.4	17.7	24.1	42.3	71.8	
2003	86.7				25.4	17.2	23.0	42.0	67.7	
2004	86.5				25.4	16.9	22.1	40.5	64.0	
2005	83.3				25.4	16.6	21.3	39.4	60.8	81.4
2006	82.0							39.0	58.0	
2007	79.4							38.5	55.5	
2008	73.6							38.0	53.5	
2009	68.6							38.0	51.7	
2010	67.2							38.0	50.4	60.0

Note: 1988, 1989 and 1990 actual from CAPP *Statistical Handbook*.

4. Production of Synthetic Crude

Table A8.4: National Energy Board Reports: Production of Synthetic Crude (10^3 m^3/d)

	Actual	*1974*	*1977*	*1978*	*1981*	*1984*	*1986*	*1988*	*1991*	*1994*	*1999*
1974	7.3	8.7									
1975	6.8	9.5									
1976	7.6	10.3	7.9								
1977	7.2	10.3	7.9								
1978	8.9	10.3	7.9	11.1							
1979	14.6	18.3	16.7	21.5							
1980	20.3	24.6	23.8	23.0							
1981	17.7	31.0	27.0	24.6	20.0						
1982	19.1	35.0	27.0	26.2	25.0						
1983	25.4	45.3	28.6	28.6	28.0	23.5					
1984	21.1	54.8	29.4	30.2	29.0	24.2					
1985	26.7	63.6	30.2	35.8	29.0	25.0	26.1				
1986	29.4	80.2	30.2	38.1	29.0	25.0	28.5				
1987	28.7	93.0	34.2	47.7	29.0	25.0	28.5	28.5			
1988	31.9	105.7	42.1	65.9	29.0	28.5	29.0	28.8			
1989	32.6	115.2	50.1	75.5	29.0	28.5	29.5	30.5			
1990	32.9	132.7	54.0	82.6	29.0	28.5	29.5	31.2	32.2		
1991	35.9	146.2	67.5	89.0	29.0	28.5	29.5	32.5	33.4		
1992	37.2	164.5	76.3	95.3	29.0	33.5	29.5	33.9	33.9		
1993	38.6	183.5	81.0	103.3	29.0	38.5	29.5	34.9	34.8	38.9	
1994	41.6		85.0	108.9	29.0	38.5	30.0	34.9	36.6	41.7	
1995	43.2		89.0	115.2	29.0	38.5	30.5	34.9	36.4	43.8	
1996	42.7				29.0	38.5	30.5	35.0	36.4	44.3	43.2
1997	45.5				29.0	38.5	30.5	35.0	37.6	45.2	
1998	48.2				29.0	38.5	30.5	35.0	37.6	45.2	
1999	45.9				29.0	43.5	30.5	35.0	37.6	45.2	
2000	44.8				29.0	48.5	30.5	35.0	37.6	48.2	59.2
2001	48.4					48.5	30.5	35.1	37.6	54.2	
2002	59.1					48.5	30.5	35.1	37.6	54.7	
2003	80.9					48.5	30.5	35.1	37.6	55.2	
2004	95.5					48.5	30.5	35.1	37.6	56.5	
2005	86.9					48.5	30.5	35.1	40.0	57.0	87.3
2006	104.4								47.1	57.0	
2007	108.3								49.7	57.0	
2008	103.8								49.7	57.5	
2009	121.7								52.1	58.0	
2010	125.7								59.2	58.0	103.1

5. Production of Bitumen

Table A8.5: National Energy Board Reports: Production of Bitumen (10^3 m^3/d)

	Actual	*1977*	*1978*	*1981*	*1984*	*1986*	*1988*	*1991*	*1994*	*1999*
1976	1.2	0.8								
1977	1.2	0.8								
1978	1.2	0.8	1.1							
1979	1.5	0.8	1.6							
1980	1.5	1.0	1.6							
1981	2.0	1.3	2.4	2.0						
1982	3.2	1.6	2.4	3.0						
1983	4.0	1.6	3.2	4.0	4.0					
1984	5.3	1.6	4.0	4.0	5.5					
1985	8.1	2.4	4.8	5.0	7.0	8.3				
1986	14.8	2.4	4.8	5.0	9.0	14.5				
1987	18.4	2.4	4.8	5.0	11.0	16.0	18.4			
1988	20.7	2.4	4.8	5.0	13.0	15.7	20.1			
1989	20.5	2.4	4.8	5.0	15.0	16.0	25.2			
1990	21.5	2.4	4.8	5.0	17.0	19.3	30.2	20.6		
1991	19.4	2.4	4.8	5.0	19.0	20.0	30.8	20.9		
1992	19.9	2.4	4.8	5.0	21.0	20.8	30.8	23.0		
1993	20.9	2.4	4.8	5.0	23.0	21.5	30.9	24.6	21.4	
1994	21.2	2.4	4.8	5.0	24.0	22.0	30.5	25.4	22.8	
1995	23.7	2.4	4.8	5.0	25.0	22.5	30.2	26.5	24.7	
1996	26.2			5.0	26.0	22.5	30.2	27.2	28.1	
1997	37.8			5.0	27.0	22.5	30.9	27.5	33.4	37.8
1998	45.7			5.0	28.0	22.5	30.9	28.4	37.0	
1999	38.8			5.0	29.0	22.5	31.3	31.9	41.3	
2000	46.0			5.0	30.0	22.5	31.8	36.5	44.5	48.8
2001	49.2				31.0	22.5	35.0	39.1	44.2	
2002	48.1				32.0	22.5	36.4	44.0	44.1	
2003	55.5				33.0	22.5	37.8	47.9	43.8	
2004	61.5				34.0	22.5	38.2	53.3	42.8	
2005	70.0				35.0	22.5	39.4	55.9	42.2	68.8
2006	74.4							56.6	41.2	
2007	80.3							57.3	40.9	
2008	87.5							62.3	40.9	
2009	90.5							67.5	40.8	
2010	108.0							76.8	40.8	78.9

6. Price Sensitivity Cases

Table A8.6: National Energy Board: Price Sensitivity Cases

I. FEBRUARY 1977 REPORT
1995 production in 10^3 b/d

	Expected case	Maximum case	Minimum case
All oil	1032	1425	500
Syncrude	575	855	180
Oil excl oil sands	457	570	320

II. SEPTEMBER 1978 REPORT
1995 production 10^3 b/d

	Base case	High case	Low case
Light from est. res.	196	196	196
Light from res. add.	195	388	111
Syncrude	725	1175	170
Heavy from est. res.	37	37	37
Heavy from res. add.	166	236	91
Bitumen	30	30	5

III. JUNE 1981 REPORT
2000 production in 10^3 m^3/d

	Base case	Modified base	High	Low
Conventional light	52.7	61.6	89.0	32.4
Conventional heavy	26.0	34.5	46.4	17.2
Syncrude	29.0	158.0	158.0	29.0
Bitumen	5.0	5.0	5.0	5.0

IV. SEPTEMBER 1984 REPORT
2005 production in 10^3 m^3/d

	Reference	High	Low
Established reserves	19	20	16
New discoveries	27	33	21
EOR	35	48	16

V. OCTOBER 1986 REPORT
2005 production 10^3 m^3/d

	Low	High
Light established reserves	17.0	17.4
Conventional light EOR	14.0	15.9
Conventional light, discov.	15.5	22.9
Conventional heavy EOR	9.0	13.4
Heavy established reserves	2.4	2.5
Conventional heavy discov.	5.2	7.7
Syncrude	37.3	56.0
Bitumen	22.3	84.9

VI. SEPTEMBER 1988 REPORT
2005 production 10^3 m^3/d

	Low	High
Light established reserves	22.2	22.7
Light EOR	13.0	16.2
Light discoveries	31.2	31.5
Heavy EOR	6.5	9.4
Heavy established reserves	2.9	1.7
Heavy discoveries	12.0	11.7
Syncrude	50.1	90.2
Bitumen	39.4	92.3

VII. JUNE 1991 REPORT
2010 production 10^3 m^3/d (Approximate values, read from a graph)

	Control	High	Low
Light and medium	188	235	115
Heavy	121	160	55

/continued

Table A8.6/continued

VIII. DECEMBER 1994 REPORT
2010 production 10^3 m^3/d

	Reference	*High*	*Low*
Light established res.	13.1	13.1	13.1
Light EOR	45.1	57.1	14.3
Light new discoveries	10.9	12.0	10.2
Heavy est. reserves	2.9	2.9	2.9
Heavy EOR	37.7	49.3	5.4
Heavy new discoveries	9.8	11.0	8.9
Syncrude	58.0	78.1	47.5
Bitumen	40.8	105.1	5.8

IX. 1999 REPORT
2010 production in 10^3 m^3/d

	$14, current supply trends	*$18, current supply trends*	*$18, low cost supply*	*$22, low cost supply*
Conventional light	62.8	82.2	86.2	92.6
Conventional heavy	52.3	60.0	63.9	72.0
Synthetic	74.7	103.1	111.1	165.7
Bitumen	48.0	78.9	74.5	119.6