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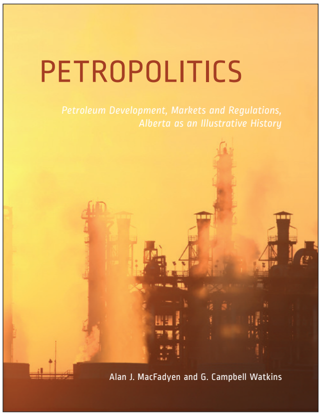

PETROPOLITICS: PETROLEUM DEVELOPMENT, MARKETS AND REGULATIONS, ALBERTA AS AN ILLUSTRATIVE HISTORY

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Part Four: Overview

Thus far, this book has concentrated mainly on the crude oil industry. Part Four goes beyond crude oil to consider three other issues.

The petroleum industry is complex in any number of ways. At the beginning of activities, a major source of complexity lies in the joint-product nature of the industry. A joint-production process is when one product cannot be produced without another. The petroleum industry produces liquid ('crude') oil and natural gas. Both consist of hydrocarbon compounds and have often been generated by the same prehistoric forces. Moreover, pools of liquid oil invariably hold natural gas ('associated gas'), and many natural gas pools ('non-associated gas') include some liquid products ('natural gas liquids' and 'condensate'). Exploration companies may have expectations (and hopes) about which product their efforts will yield – certain areas, for example, may be thought 'gas-prone.' But the inevitable uncertainties of exploration mean that attempts to direct effort to one product rather than another are imperfect. Hence it is inevitable that oil-producing companies (or regions) are also natural gas producers. Oil and natural gas are strongly linked beyond the joint-production phase. They are both valued largely for their energy content. However, while the crude production linkages are largely complementary, the consumption linkages are primarily competitive (substitutive). Chapter Twelve provides an overview of the Alberta natural gas industry. Of course the joint-product relationship means that much of what we have said about the 'crude oil industry' is relevant to the 'natural gas industry.' In this chapter, we shall discuss natural gas in a manner broadly analogous to our discussion of oil in Parts Two and Three. We will look initially at the historical development of natural gas reserves, production, and prices. Then we will move to the regulatory environment with particular emphasis upon trade and price controls and royalty provisions.

Chapter Thirteen is concerned with the 'macroeconomic' role of the petroleum industry. Since it is a major industry, its activities will affect the Alberta provincial economy. This chapter examines the contribution of the petroleum industry to the Alberta economy and explores several important policy issues related to this contribution, illustrating once again the importance of 'petropolitical' concerns.

Finally, in Chapter Fourteen we briefly speculate on the lessons that other jurisdictions might take from Alberta's experience with the petroleum industry.

CHAPTER TWELVE

The Alberta Natural Gas Industry: Pricing, Markets, and Government Regulations

Readers' Guide: Crude oil and natural gas are different products, but highly interconnected. At the consumption level, they are both used primarily as energy products and hence are highly competitive in many uses. Thus the prices of the two products exhibit interdependency, though not a fixed ratio. On the production side, both are naturally occurring hydrocarbons, so a region with resources of oil typically also has natural gas resources, as has been the case in Alberta. This chapter examines the evolution of natural gas markets and regulations in Alberta over the lengthy history in which natural gas moved from being a relatively unimportant by-product of crude oil to a product of greater value to Alberta than conventional crude oil. Many of the regulatory issues with respect to natural gas mirror those discussed with respect to crude oil in previous chapters, so the analytical arguments about oil often apply also to natural gas. However, unlike crude oil policies, both Alberta and Canada have had direct regulations on natural gas sales outside the region that have been based on anticipated natural gas consumption needs within the region. This chapter provides a detailed review of these regulations.

1. Introduction

This chapter parallels the discussion of oil in previous chapters, but with respect to natural gas production. As above, we focus on natural resource production, with only the briefest attention to the downstream activities of natural gas processing, transmission, and distribution. Nor do we investigate such joint products of lifting natural gas as natural gas liquids (NGLs) or sulphur; and, as noted before, the environmental impacts of the petroleum industry are outside our purview. (Guichon et al 2010, provide a review of a number of important issues in Alberta regarding the ownership of NGLs and their removal from the gas stream.)

As with oil, government involvement in the Canadian natural gas industry is pervasive, not only concerning what might be viewed as normal practice, such as the setting of taxes, royalties, and the like (fiscal systems) and utility regulation (pipeline tariffs), but extending to specific policies directed towards natural gas exports, both in terms of quantities (export licensing) and pricing – even within the prevailing climate of deregulation. These are the issues covered here. As was the case with crude oil, the threads of development, markets, and regulation tangle in a complex petropolitical web.

Following several preliminary comments in this Introduction, the chapter is organized in five sections. Section 2 looks at the evolution of natural gas output and prices. Section 3 examines policies governing the quantity of Alberta natural gas exports at both the provincial and federal levels. Section 4 concerns government controls on the price of natural gas, as well as fiscal systems, including royalty regulations. Section 5 is a brief conclusion.

By way of introduction, however, several comments should be made about natural gas transmission.

Shipment is, arguably, a more important stage of the natural gas industry than of the crude oil industry. This is because gas is a more volatile product than crude oil, and also less concentrated in energy content, so that a larger volume of gas than oil must be transported to deliver the same quantity of energy. High volume, long-distance shipment of natural gas lagged many decades behind such shipments of oil, awaiting technical developments in high-pressure pipelines, and transmission charges normally make up a higher proportion of delivered gas costs than oil costs. Since the volume of gas shippable by a pipeline rises more than proportionately to the diameter of the pipe, pipeline transmission exhibits economies of scale. (That is, the unit cost of shipment falls as the quantity of gas moved increases.) This 'natural monopoly' aspect of gas pipelines has given rise to public interest concerns. One response was the regulation of gas transmission tariffs on a cost of service basis. Despite this, as will be discussed below, the Government of Alberta and many natural gas producers worried that the main interprovincial gas transmission companies (especially TransCanada PipeLines [TCPL], now called TransCanada Corporation, which moved gas eastward from Alberta) had market power that allowed them to keep Alberta gas prices artificially low.

Also, in the 1950s, the Alberta government granted a single company almost exclusive rights to gather and move natural gas to the provincial border for export. (The company was Alberta Gas Transmission Limited, AGTL; in the 1970s, this company diversified considerably, including into ex-Alberta gas transmission and petrochemical production, and was renamed NOVA Corporation of Alberta; NOVA merged with TCPL in 1998. Throughout this period relatively small volumes of gas have been moved to Alberta gas consumers by Alberta natural gas distribution companies instead of by AGTL/NOVA.)

AGTL, and its successors, have transported gas on a regulated cost of service basis, but there has been much controversy about the nature of the transmission charge, which, for much of the period, was set on a 'postage stamp' basis; that is, all Alberta gas paid the same tariff regardless of the transportation distance involved. The field price received by a natural gas producer is usually a 'netback' price, the price in a major 'market' area, for example, the main gathering terminal for export sales at the Alberta border, less the transmission tariff to that market. Hence a postage stamp tariff, in contrast to one where each producer pays the transmission cost associated with moving its gas, tends to favour producers more distant from markets and using more expensive newer facilities relative to producers close to the border gathering terminals or using older largely depreciated facilities. (Since the freehold leases tended to be concentrated in the more southern part of the province, it also involved their cross-subsidizing the more distant Crown leases.) Discussions amongst NOVA and assorted interested parties after 1996 yielded no agreement on this controversy, and in 1999 NOVA applied to change the pipeline tariff process. Decision 2000–2006 by the Alberta Energy and Utilities Board (EUB) allowed replacement of the postage stamp tariff with "Receipt Point Specific Rates," which could vary with distance and volume of gas moved, and also removed NOVA's monopoly on the construction of 'lateral' pipelines to connect gas pools to the main NOVA pipelines. (NEB, 1996, provides a useful review of changes in natural gas pipeline regulation, and the declining role of transmission companies in contracting natural gas, in the decade following deregulation in 1986.) In 2009, after application by TCPL/NOVA, regulation of the Alberta system was transferred from the ERCB to the NEB on the grounds that it formed an integral part of TransCanada's intercontinental gas transmission network.

From this brief review of gas transmission, we now turn to more detailed discussion of other issues. (In addition to other references in this chapter, Helliwell et al., 1989, chaps. 4 and 5, provides a good survey of Canadian natural gas market evolution and regulations up to 1990. See also Winberg, 1987, chaps. 3 and 4. Angevine, 2010b, provides an overview from the perspective of the year 2010.)

2. Natural Gas Production and Pricing

Table 12.1 includes summary statistics on key dimensions of the Alberta natural gas industry for years since 1947. Much of the data parallels that for crude oil in earlier chapters of this book. Our discussion of the natural gas industry will be much less detailed than that of oil and will emphasize the features of natural gas markets and regulations that differ from crude oil.

A. Resources and Reserves

In ground natural gas resources in Alberta can be divided into 'associated' and 'non-associated' categories. The former are the gas volumes within crude oil pools,

Table 12.1: Alberta Natural Gas Reserves, Production, Deliveries and Prices, 1947–2012

	Established Marketable Reserves (10^9 m^3)	Remaining Marketable Reserves Additions (10^9 m^3)	Marketable Production (10^6 m^3)	R/P Ratio (Years)	Deliveries (10^6m^3)			Average Wellhead Price		Gas Price/ Oil Price
					Alta	Other Canada	U.S.A	($/ 10^3 m^3)	($/mcf)	
1947	n.a.	n.a.	924	n.a.				2.40	0.07	0.14
1948	112	n.a.	1,062	105.1				2.32	0.07	0.11
1949	129	18	1,150	112.1				2.24	0.06	0.12
1950	145	17	1,425	101.8				2.08	0.06	0.11
1951	207	61	1,607	128.8				2.17	0.06	0.14
1952	295	88	1,785	165.2				3.32	0.09	0.22
1953	372	76	2,043	182.1				3.29	0.09	0.21
1954	431	59	2,453	175.7	2,291	15	0	3.28	0.09	0.20
1955	490	59	3,002	163.2	2,730	19	0	3.32	0.09	0.22
1956	520	65	3,208	162.1	2,948	26	0	3.42	0.10	0.22
1957	582	65	3,781	153.9	3,229	639	4	3.22	0.09	0.22
1958	686	110	5,242	130.0	3,362	2,036	4	3.23	0.09	0.24
1959	768	89	7,074	108.6	3,738	3,498	3	3.22	0.09	0.23
1960	879	120	9,058	97.0	4,000	5,264	3	3.22	0.09	0.23
1961	880	13	11,868	72.5	4,012	4,744	2,803	4.29	0.12	0.29
1962	912	50	17,504	50.3	4,319	5,426	7,191	4.51	0.13	0.32
1963	928	36	19,532	47.6	4,555	6,415	8,115	4.94	0.14	0.32
1964	992	86	21,903	45.3	4,649	7,589	8,747	5.17	0.15	0.32
1965	1,058	90	24,039	44.1	5,032	8,746	8,693	5.10	0.15	0.32
1966	1,073	41	25,409	42.4	5,346	8,999	9,673	5.33	0.15	0.33
1967	1,119	74	27,400	40.8	5,646	9,251	11,152	5.49	0.16	0.35
1968	1,224	135	31,038	39.5	5,827	10,198	13,407	5.51	0.16	0.35
1969	1,273	88	36,735	34.7	6,474	12,974	14,948	5.46	0.16	0.35
1970	1,279	46	42,874	29.8	6,835	15,655	17,531	5.69	0.16	0.36
1971	1,276	45	47,529	26.9	7,164	16,366	20,879	5.60	0.16	0.32
1972	1,269	45	52,189	24.3	7,926	19,941	21,457	5.89	0.17	0.33
1973	1,397	183	55,521	25.2	8,266	22,734	21,672	6.62	0.19	0.30
1974	1,487	147	56,817	26.2	8,646	24,272	20,562	10.46	0.30	0.29
1975	1,451	21	58,142	25.0	9,213	24,319	21,125	21.79	0.62	0.48
1976	1,502	106	59,456	25.2	9,656	24,749	21,783	35.34	1.00	0.67
1977	1,568	128	62,666	25.0	11,388	25,740	22,571	45.69	1.29	0.72
1978	1,665	163	61,600	27.0	12,588	25,642	20,402	52.57	1.49	0.69
1979	1,718	123	66,200	26.0	13,185	25,554	22,946	59.84	1.69	0.73
1980	1,747	92	62,070	28.1	13,465	24,703	19,356	82.51	2.34	0.85
1981	1,795	117	61,950	29.0	13,362	25,716	18,434	87.19	2.47	0.74
1982	1,853	119	64,113	28.9	14,069	25,318	19,937	94.31	2.67	0.59
1983	1,826	39	60,590	30.1	13,721	24,241	17,771	100.39	2.84	0.51
1984	1,798	41	65,819	27.3	15,086	27,112	19,057	103.28	2.92	0.50
1985	1,768	43	72,849	24.3	15,881	27,368	23,155	99.00	2.80	0.47
1986	1,720	22	64,945	26.5	15,109	27,416	18,236	77.74	2.20	0.66
1987	1,652	0	69,940	23.6	14,541	25,763	24,979	59.98	1.70	0.43
1988	1,628	65	80,963	20.1	16,679	26,616	32,694	54.02	1.53	0.52
1989	1,649	108	83,479	19.8	17,527	26,952	33,367	54.73	1.54	0.44
1990	1,647	88	84,578	19.5	17,340	25,966	35,706	55.18	1.56	0.36
1991	1,626	58	89,286	18.1	16,941	24,897	40,193	48.65	1.38	0.39
1992	1,595	73	98,860	16.2	17,809	27,973	48,801	48.68	1.38	0.38

/continued

Table 12.1/continued

	Established Marketable Reserves (10^9 m^3)	Remaining Marketable Reserves Additions (10^9 m^3)	Marketable Production (10^6 m^3)	R/P Ratio (Years)	Deliveries ($10^6 m^3$)			Average Wellhead Price		Gas Price/ Oil Price
					Alta	Other Canada	U.S.A	($/ 10^3 m^3)	($/mcf)	
1993	1,535	59	110,658	13.9	17,963	30,437	55,573	60.08	1.71	0.52
1994	1,496	74	119,688	12.5	18,067	31,805	64,530	68.07	1.93	0.55
1995	1,489	123	124,024	12.0	18,905	32,095	67,195	49.99	1.41	0.37
1996	1,378	10	131,743	10.5	22,197	36,184	68,834	58.90	1.67	0.36
1997	1,284	30	133,243	9.6	20,643	37,352	69,167	70.96	2.01	0.48
1998	1,240	93	136,782	9.1	16,730	43,028	67,040	69.70	1.97	0.67
1999	1,207	110	141,034	8.6	20,805	43,813	67,184	88.68	2.51	0.58
2000	1,211	144	142,239	8.5	23,054	45,028	66,064	162.34	4.59	0.67
2001	1,184	116	139,942	8.5	20,513	42,136	64,359	198.39	5.61	1.01
2002	1,171	134	137,483	8.5	21,403	39,190	78,015	139.48	3.95	0.65
2003	1,122	87	134,732	8.3	25,431	29,574	74,460	224.62	6.36	0.97
2004	1,127	146	135,824	8.2	24,225	30,572	75,713	228.84	6.48	0.83
2005	1,120	126	136,838	8.2	22,744	36,037	72,943	301.75	8.54	0.86
2006	1,115	126	136,261	8.2	27,697	34,720	73,979	240.86	6.82	0.64
2007	1,069	95	135,735	7.9	28,180	35,322	72,294	235.66	6.67	0.58
2008	1,098	155	127,953	8.6	31,223	37,529	62,119	283.86	8.03	0.49
2009	1,056	82	118,374	8.9	32,361	36,651	52,366	142.86	4.04	0.38
2010	1,025	83	112,804	9.1	32,107	29,352	49,552	137.98	3.90	0.29
2011	945	70	104,975	9.0	34,137	29,682	45,397	125.36	3.22	0.22
2012	916	58	n/a	n/a	35,402	29,775	39,817	n/a	n/a	n/a

Notes and Sources:
Column (1): From EUB, ERCB, and OGCB *Reserves Reports* (ST-18 and ST-98). Marketable gas excludes gas for reinjection purposes and NGLs that will be removed at gas plants.
Column (2): From EUB, ERCB, and OGCB *Reserves Reports*. 1949 and 1950 were estimated as the change in remaining reserves plus production.
Column (3): From CAPP *Statistical Handbook*.
Column (4): Column (1) divided by Column (3).
Columns (5), (6) and (7): From ERCB and OGCB *Alberta Oil and Gas Annual Statistics*, and *Cumulative Annual Statistics of the Alberta Oil and Gas Industry*; from 1993 on, ERCB/EUB, *Alberta Energy Resource Industries Monthly Statistics* (ST-3). Deliveries generally add up to less than marketable production (Column (3)) because of line losses, pipeline fuel, and other shrinkage, and because the figures come from different sources. Data are not available on deliveries prior to 1954, but marketable production went almost entirely to Alberta.
Column (8): CAPP *Statistical Handbook*. The Alberta average wellhead/plant gate price.
Column (9): From Column (8). 1 cf = .0283 m^3.
Column (10): Derived from data in CAPP *Statistical Handbook*. The Alberta average wellhead/plant gate natural gas price and average wellhead crude oil price were translated into dollar costs per joule of energy and the ratio taken.

lying as a gas cap and/or dissolved within the crude oil. Output of such gas, associated with crude oil, is governed by oil output rates. Moreover, this natural gas is often re-injected back into the oil reservoir ('recycled') to aid in the recovery of the oil.

Non-associated gas is derived from deposits that are predominantly gaseous hydrocarbons (methane, for the most part). However, natural gas pools will hold varying amounts of hydrocarbons heavier than methane (e.g., natural gas liquids [NGLs] comprised of ethane, butane, propane, and pentanes plus). The 'wetter' the gas pool, the higher the proportion of these NGLs, and the more likely it is that the development and output levels for the pool will be affected by market conditions for these products as well as those for natural gas. Natural gas normally passes through a processing plant to remove some or all of the NGLs before the gas is moved to market. Natural gas plants have included field plants and 'straddle plants' located at several points on the main NOVA transmission lines. In a series of decisions starting in 1981, the ERCB approved construction of 'deep-cut' natural gas plants that remove almost all the non-methane hydrocarbons. (These plants were controversial because the gas moving from the deep-cut facilities to the straddle plants had little NGL content, so the straddle plant was not needed for this gas. The board affirmed that the gas producer retained ownership rights for the gas and NGLs until the gas was sold, so could remove NGLs prior to sale of the gas. As mentioned above, we shall not discuss gas processing or NGL markets and regulations.)

The volume of hydrocarbons in place in a pool (the natural gas 'resource') forms the basis for 'marketable' natural gas reserves. In place volumes must be adjusted for the recovery factor (the proportion of in place gas that will be lifted) and for losses and shrinkage in operations (e.g., volumes that will be injected back into the ground for conservation reasons, adjustments to volumes due to differences in temperature and pressure in the reservoir and at the surface, and the NGLs that will be removed before the gas goes to market). (See the ERCB, 2010, *Reserves Report*, ST-98, pp. 5.13–15.) Non-associated natural gas reservoirs show higher recovery factors than crude oil reservoirs (about 80% in Alberta as compared to 25%).

The most recent estimate of the conventional Alberta natural gas resource base is that it holds 9,203 10^9 m^3 of conventional natural gas. Of this, there are 6,528 10^9 m^3 (232 Tcf) of potentially marketable reserves (ERCB, 2013, *Reserves Report*, ST-98, p. 5-23; and EUB/NEB, 2005); this is a 'medium-case' estimate. Cumulative production up to the end of 2012 has been 4,425 10^9 m^3 and 916 10^9 m^3 was estimated to lie in established reserves, leaving 935 10^9 m^3 (14%) still to be added. (The EUB/NEB estimated 'low' case marketable reserve potential at 5,765 10^9 m^3 and 'high' case potential at 7134 10^9 m^3.)

Columns (1) and (2) of Table 12.2 show the changes since 1948 in Alberta's remaining conventional marketable natural gas reserves and reserves additions. As can be seen, gas reserves grew rapidly through to 1970, and again in the mid- to late 1970s, hitting a peak of 1,853 10^9 m^3 (65.4 Tcf) in 1982. In twenty-six of the thirty years from 1982 to 2012, marketable gas reserves declined; that is, production exceeded reserves additions. However, the decline is not as pronounced or as long-standing as that for conventional crude oil. Recall from Chapter Five that Alberta's conventional crude oil reserves have been in decline since 1969; by the start of 2013, remaining oil reserves were at about 22 per cent of the peak 1969 level. Remaining gas reserves in 2012 were at 49 per cent of their 1982 peak. In other words, since the early 1970s, Alberta's conventional petroleum reserve base has been shifting more towards natural gas.

Reserves additions for gas, as for oil, show great year-to-year variation, as would be expected in an industry with pervasive geological uncertainty. In contrast to the conventional crude oil industry, natural gas reserves additions do not show as dramatic a decline over time as do liquid hydrocarbon reserves additions. Obviously, natural gas has been of increasing relative importance at the exploration level over the past two decades.

The rising importance of natural gas relative to oil could reflect a variety of factors including: (i) a larger and more homogeneous group of undiscovered natural gas reservoirs, so that depletion effects in the discovery process are less significant for gas than oil; (ii) a larger inventory by 1970 of observed, but not developed or proved up, natural gas pools as compared to oil pools; (iii) gas-pool-specific technological changes in exploration and development; and (iv) a shift in industry effort away from exploration and development of crude oil toward natural gas. These are not independent factors. For example, a more attractive remaining gas reserve base would induce a shift in relative industry effort toward gas. We are unaware of any empirical model that provides valid measures of these four factors but believe that the first is of particular significance, followed by the fourth and then the second.

Non-conventional sources of natural gas have been growing in significance within North America, including Alberta. (We consider gas from the Alberta 'deep basin,' in the northwestern part of the province, much of which lies in small pools in low permeability rock and is therefore difficult to produce, to be conventional gas.) Non-conventional natural gas is a heterogeneous category including coal bed methane, gas trapped tightly in shale (where it is typically spread thinly through the shale rather than occurring as a concentrated pool), gas hydrates, and various synthetic gases (e.g., biogas or gasified coal). Since the turn of the century, two of these, coal bed methane and shale gas, have attracted significant investment within North America and appear to be available in large volume at costs that are within the range of historical gas prices. Alberta's ERCB has studied only coal bed methane in any depth. (Alberta has uncharted shale gas potential as well. In its 2011 *Reserves Report*, the ERCB indicated that, while it "expects to publish in-place resource estimates soon, the estimate of established reserves will likely be delayed until sufficient data are available to conduct a reasonable assessment of shale gas recoverability," p. 5-20.) Methane may be held in coal seams either as free gas or within the coal itself. Vast coal resources lie beneath much of central and southern Alberta, as has been demonstrated in core samples from many wells drilled by the petroleum industry. Many producing (conventional) gas wells pass through coal seams; some of these have been modified to allow commingled production of conventional gas and coal bed methane.

In 2010, the ERCB provided an 'initial determination' of Alberta's coal bed methane resource in place, based on a study from the Alberta Geological Survey, of 14 10^{12} m^3 (500 Tcf), which is a third larger than its estimated resource base for conventional natural gas (ERCB, 2010, *Reserves Report*, ST-98, p. 5-9). What portion might ultimately be recoverable is unknown, and only a small part is included in reserve estimates; the ERCB reported (p. 5-2) 2012 remaining recoverable reserves of coal bed methane as 56.7 10^9 m^3, 6.2 per cent of conventional gas reserves. Thus, as of early 2013, there is large potential for coal bed methane (and for shale gas) in Alberta, but insufficient development to permit large volumes to qualify as reserves.

B. Production and Delivery

Column (3) of Table 12.1 shows Alberta marketable natural gas production from 1947. Output grew tremendously to a peak in 2000, at an average rate of over 9 per cent per year. Except for the decade from 1977 to 1987, rapid growth was the norm up to the mid-1990s. (1957 output was 310% more than 1947; 1967 was 620% higher than 1957; 1977 was 130% over 1967; and 1992 was 40% over 1987; but 1987 was only 10% above 1977.) However, in the later 1990s, growth slowed, hitting a peak output rate in the year 2000 and then trending downward, albeit relatively slowly. One might expect production to follow the decline in remaining reserves, and at some point it must. However, continued development investment can delay or reduce the output decline as reserves are used more intensively. (In this case, the reserves to production [R/P] ratio will fall, as happened in Alberta from 1983 to 2007, as shown in Column (4) of Table 12.1.) After 2007, however, this ended and output of natural gas fell markedly.

Coal bed methane (and a minimal amount of shale gas, for the last few years) is included in Column (3). The ERCB estimated coal bed methane production at 5.6 10^9 m^3 in 2012, just under 6 per cent of Alberta's natural gas production (ERCB, 2013, *Reserves Report*, ST-98, pp. 5-2 and 4). In 2012, the board noted (p. 5-19) that commercial coal bed methane production began in 2002, very much aided by horizontal well-drilling advances that allow multiple completions within a single horizon. In contrast to conventional gas output, that from coal bed methane has been increasing since 2002 and is expected to make up a rising share of Alberta's natural gas production.The ERCB has examined the appropriate regulatory framework for non-conventional gas and issued a report looking at other regulatory approaches within North America (ERCB, 2011).

The production rises in the first two decades, as with crude oil's first decade after Leduc, are closely tied to the extension of pipeline linkages from Alberta, particularly the TransCanada PipeLine (TCPL), east to Ontario, which was begun in 1957 and completed in 1958, and the Alberta and Southern connection to California, completed in 1961. (Alberta and Southern operated as a gas purchaser. It was a wholly owned subsidiary of Pacific Gas and Electric, a Northern California distributing company, which also owned Alberta Natural Gas and Pacific Gas Transmission, the two pipeline companies that moved gas from the Alberta border to California.) Gas exports to Montana began in 1951 in small volumes through the Canada–Montana Pipeline. In the late 1960s, Consolidated Natural Gas began to contract Alberta natural gas reserves for a new export pipeline to the mid-western United States. However, for reasons discussed in Section 3, this project was not approved by the National Energy Board.

We would emphasize three ways in which Alberta natural gas and its associated market development differed from convention crude oil. Natural gas was initially viewed as a by-product; regulation of the natural gas industry was greater and earlier; natural gas had a more limited market.

The natural gas reserves to production (R/P) ratio provides an initial introduction to these points (Column (4) in Table 12.1). Until the 1990s, Alberta's gas R/P ratio was far higher than that for conventional crude. The ratio exceeded 100 from 1948 through 1959 before the completion of the TransCanada PipeLine; it fell sharply after that but remained at twenty-four years or greater through 1986. After 1986, it fell again, and by the mid-1990s was approaching the level of the conventional crude oil reserves-to-production ratio.

Looking at the R/P values in excess of 100 prior to 1960, one might ask: Why would companies add more to natural gas reserves if inventories (reserves) were so high relative to output? And why wasn't output increased much more rapidly in these circumstances? The answers, in essence, are that "they didn't" and "they couldn't." At the time, natural gas reserves were largely the unintentional by-product of crude oil. Exploration (and development of associated gas in crude oil reservoirs) is a joint product process that generates both crude oil and natural gas reserves in a petroleum basin. Natural gas reserves rose rapidly as a result of the active corporate search for crude oil reserves. In other words, the build-up of natural gas reserves in the 1940s and 1950s was unintentional.

Opportunities for exploitation of natural gas pools were more limited than for oil pools. Both had to await the development of large-diameter continental pipelines from Alberta, and so entry into new markets was delayed. And the natural gas market was continental, not overseas. The high cost of moving gas, especially by ocean, makes transportation a more critical component of delivered price. As a result, it was harder for natural gas, than for crude oil, to break into more distant markets. Since transmission costs are relatively high, the difference between developed prices in central Canada and field prices in Alberta must be higher for natural gas than for crude oil. Consequently, there was increased likelihood either that delivered prices would be too high to capture sales as large as might be hoped or that the field price would be so low that rapid development did not appear an attractive proposition.

The nature of regulation in gas markets provided further restraints on increased output, particularly with respect to exports. Specifically, both the Alberta Oil and Gas Conservation Board (OGCB), in 1950, and the federal National Energy Board (NEB), in 1959, introduced requirements that further gas exports from a region would be allowed only if they were seen as surplus to regional requirements. In effect, this required the maintenance of large inventories (reserves) before ex-regional sales could occur. Such surplus tests were in existence through the mid-1980s and served to keep the gas R/P ratio high. Gas exports rose tremendously in the 1960s, but, beginning in 1970, a period ensued in which new gas export permits were denied. (These tests are discussed in detail in Section 3 of this chapter.)

The gas market, like crude oil, was subject to strict price regulation from the mid-1970s to the mid-1980s. Table 12.1 shows that gas exports fell sharply after 1979; the decline was to levels well below authorized volumes, indicating that export prices had been set higher than compatible with allowable exports. After 1986, the gas market, like oil, moved to deregulation and exports could rise without rigid surplus test requirements; sales to U.S. customers increased and the R/P ratio fell.

The nature of the relationship between buyers and sellers also differed greatly between the Alberta crude oil and natural gas markets as the Alberta petroleum industry grew after 1950. For oil, as discussed in Chapter Six, refiners bought from crude oil producers (often within a single vertically integrated company) and hired the use of transmission facilities. There were long-standing trading relationships but long-term contracts were rare, and the price paid for crude was the current posted price. From the 1940s through the 1960s, natural gas was purchased from the producer by a natural gas transmission company (or a local Alberta utility) under a long-term contract with relatively rigid prices for the contract term. The transmission company, in turn, signed long-term contracts with local gas distribution companies. Since there were few transmission companies, and since the surplus regulations hindered those aimed largely at exports, the Alberta natural gas market was oligopsonistic (tending toward monopsony when only TransCanada was actively contracting). This market structure, and the surplus regulations, made it difficult for producers to market natural gas.

It has been argued that natural gas requires long-term contracts because pipelines and distributing utilities must install so much capital to service customers and because customers are so dependent on the natural gas they receive. Many public regulatory bodies required that utilities sign long-term contracts to ensure gas supplies. Such contracts also contributed to high R/P ratios and dictated a somewhat different development pattern for natural gas pools than oil pools in North America. Natural gas reservoirs generally commenced with a lower initial output rate relative to reserves; further, rather than allowing production decline to begin relatively early in the pool's life, the producer often continued development drilling so as to maintain a constant output level for a number of years.

The thesis that natural gas requires long-term contractual arrangements and oligopsonistic purchasing was not much challenged until the 1970s. However, developments in the late 1980s saw gas markets evolving toward the more open, competitive, short-term sales arrangements common in crude oil markets and a far greater number of companies involved in active trading of natural gas. In its assessment of the first decade of deregulation in the Canadian natural gas market, after 1986, the NEB noted that the share of gas purchased for customers by local utilities had fallen from 91 per cent of the market in 1985 to 41 per cent, that short-term sales arrangements were of increasing importance, that many companies now purchased natural gas in the producing region and purchased transmission services from the pipeline company, and that even long-term natural gas sales contracts typically had prices that were wholly or partially tied to natural gas spot prices (NEB, 1996).

In summary, the pattern of change in Alberta gas production and deliveries can be divided into four periods. A by-product phase held from 1947 to the late 1950s, characterized by growing local sales and high and generally rising R/P ratios as gas discoveries followed from oil-directed exploratory activity. There was a market penetration phase from 1959 through 1971 when pipeline links to other Canadian and U.S. market areas allowed rapid production growth and declining R/P ratios. Natural gas was developing as a product itself, beyond by-product status. A tightly regulated period ensued from 1972 to 1986 when prices and exports were strictly controlled, with relatively constant R/P ratios and less sales growth. Finally, deregulation began in 1986 with rapid output growth directed mainly to exports, a falling R/P ratio, even greater independence of natural gas and oil supply decisions, and the entry of many new players into buying and selling natural gas in Alberta.

Sections 3 and 4 will discuss the changing government regulations that attended these developments in the natural gas markets.

C. Prices

1. Market Expansion, 1947–71

Alberta natural gas prices from 1947 are shown in Table 12.1, columns (8) and (9). Column (8) shows average prices at the wellhead or plant gate in dollars per thousand cubic metres (10^3 m^3); dollars per thousand cubic feet (Mcf) are shown in column (9). Column (10) compares average Alberta field natural gas and crude oil prices, by looking at the price of a given quantity of energy in the form of natural gas as a proportion of the price of the same amount of energy from crude oil.

The nominal (current dollar) price of natural gas fell somewhat immediately after 1947. It jumped sharply (by over 50%) in 1952, as buyers began to contract large volumes in anticipation of large shipments from Alberta. From 1952 to 1971, nominal prices tended upwards, but at a slow rate (less than 3% per year, just about the average inflation rate) so that in 1971 the real average wellhead price of gas in Alberta was almost exactly what it had been in 1952 (using the Consumers Price Index). Output grew by almost thirty times over this period, suggesting that the evolution of the Alberta natural gas market over the first twenty-five years after Leduc was predominantly supply driven, with large reserves seeking market outlets. This interpretation is consistent with the high R/P ratios observed. Purchases of natural gas for sale outside Alberta were normally under long-term contracts between the gas producer and the major natural gas pipeline companies (TransCanada for shipments east and Westcoast for shipments west). The contracts established relatively fixed prices for natural gas, with a base price (in cents per Mcf) and small periodic increases, as can be seen in Column (9) of Table 12.1 for years from the early 1950s through to the end of the 1960s. Contracts sometimes included a 'most-favoured-nation' clause, which would accord higher prices in newly signed contracts to the gas sold under older contracts. This is a clear disincentive to the buyer to offer higher prices on new contracts.

By the early 1970s, natural gas producers and the Alberta government were expressing concern about the 'low' level of natural gas prices and the inflexibility of pricing provisions in the long-term contracts, which were common at the time. (Hamilton, 1974, provides a good review of the Canadian situation at this date.) These concerns were stimulated in part by the rise in oil prices, which began in the early 1970s, and were the subject of investigation in a report of the Stanford Research Institute (1972). As is shown in column (10) of Table 12.1, the prices of Alberta natural gas relative to crude oil had been rising consistently from 1948 to 1970. In 1971, this was reversed. Increasingly the presumed undervaluation of natural gas was tied to what was called its high 'commodity value'; this valuation concept was given a prominent role in Alberta legislation in the early 1970s governing the arbitration procedure to be used in renegotiating gas sales contracts. However, as a basis for pricing, the concept of the commodity value of natural gas turned out to be hopelessly ambiguous. What might the term mean? A brief discussion in general terms will help set the stage for the later discussions of Alberta natural gas policies in the 1970s.

2. A Digression on 'Commodity Values'

The appeal of the term 'commodity value' in the early 1970s was clearly related to differences in the prices of crude oil and natural gas and was a shorthand way of saying that natural gas is an energy commodity like oil, so its price should be closely connected to the oil price. In other words, it was implied that in a well-functioning natural gas market, gas should not be viewed as a separate commodity, but as part of a larger energy commodity. The most simplistic view runs as follows. Consumers demand and are willing to pay for energy. It is possible to substitute other goods or services for energy, but generally this cannot be done very easily; so energy has no perfect and few close substitutes. Within the energy category, however, consumers just need a power source and different energy products are close substitutes in this regard. Therefore, energy products should be priced at much the same level per unit of energy content. The implicit view of the natural gas market is given in Figure 12.1. Here P_{CO} is the price of natural gas if it were at the same level per joule of energy as current crude oil prices. The simple commodity pricing argument views the demand curve for natural gas as D_{NG}; it is very elastic around P_{CO} because of the assumed almost perfect substitutability of crude oil and natural gas. Then, as shown, the supply curve for natural gas could vary widely, and the price of natural gas would still be near the oil-based price. Some observers further argued that, because of its convenience and clean burning properties, natural gas was actually a 'premium' fuel relative to oil, so should command a higher price than the thermal equivalence price. The appeal of the argument to Alberta gas producers and the rent-collecting Alberta government is plain; after all, gas prices in 1972 were just one third of crude oil prices (in the field) on the basis of thermal content (joules or Btus). Of course, the simple commodity price theory would require an explanation of why natural gas prices were not at their 'true' commodity value. Part of any explanation lies in the difference between short-run and long-run equilibria. In the short-run market, participants are constrained by existing capital equipment. In particular, pipeline and distribution facilities may not be in place, and consumers may not possess gas-fired equipment. Thus, the short-run demand

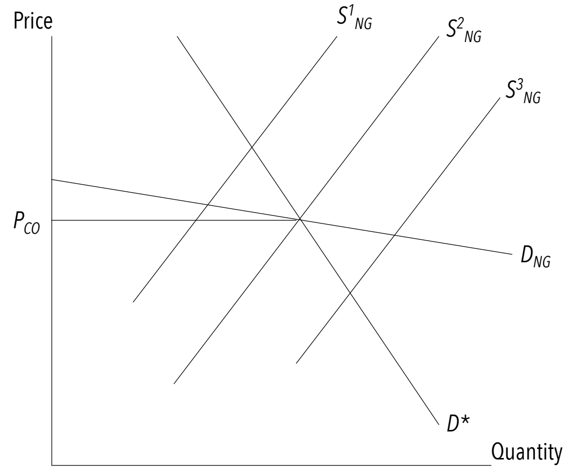

Figure 12.1 Commodity Pricing of Natural Gas

curve is much more inelastic than the long-run one (like curve D^* in Figure 12.1). If gas supply were large, the natural gas price could be well below the oil-based "commodity" price. However, in Alberta in 1970 natural gas prices had been far below that value for at least twenty years (since the Leduc find). That was plenty of time for most long-run capital investment decisions to be undertaken. Why had gas prices risen so little compared to oil? And why was the relative price falling in the early 1970s? Explanations typically emphasized four linked factors: (i) the oligopsonistic nature of the industry, with a few gas purchasers able to force low prices; (ii) the presence of long-term contracts, which tied up large gas volumes at low and rigid prices for many years; (iii) limitations on the freedom to export gas, which inhibited new buyers from entering the market; and (iv) inherent differences in transportation costs.

Now let us consider some flaws in the simple commodity-pricing argument. Two related problems stand out: complications posed by geographically separate markets and problems related to energy substitutability. Geographic differences highlight the transmission cost differences between crude oil and natural gas. If natural gas were priced at the energy equivalent commodity value for crude oil in Alberta, then its price would be relatively higher than crude oil in markets outside Alberta, and it would be overpriced. Proponents of simple commodity-value pricing quickly conceded this point but went on to suggest that natural gas should be priced at the oil level in the most distant major market (e.g., Toronto or Montreal). This would imply a field price for natural gas lower than crude oil but still higher than historical levels.

It would also imply, if the simple commodity-value approach were correct, that markets closer to Alberta than the distant ones would rely entirely on natural gas to the exclusion of oil. That this would not be the case (was not the case at even lower gas prices) highlights the other main weakness of this approach.

Natural gas and crude oil are not perfect substitutes in use. For one thing, energy consumers buy natural gas but almost never use crude oil; they purchase various refined petroleum products (RPPs). One might think that this gives an advantage to natural gas, allowing a higher energy price than crude oil, since oil must incur additional refining charges before it gets to consumers. Remember, however, that refining is a joint product process; while the entire slate of RPPs must, in the long-run, earn sufficiently more than crude costs to cover refining costs, not all individual RPPs must be priced above crude. RPPs exhibit a wide range of prices per unit of energy content. Under the simple commodity theory, with which of these should natural gas be commodity-priced?

The presumed perfect energy substitutability of natural gas and crude was too unrealistic an assumption to serve as a basis for gas pricing. We mentioned that many gas producers were quick to argue that gas had a cleanliness and convenience advantage over oil in the eyes of most households, so might be expected to enjoy a 'premium' over crude oil prices. This observation did not take the argument far enough. For example, for a rural farmhouse far from a natural gas distribution system, natural gas would be far more 'inconvenient' than light fuel oil. The fact is that there are many different energy (and non-energy) uses of RPPs and natural gas and the different fuels are substitutable to varying degrees in these uses, and only occasionally close to perfect substitutes. For virtually all the main uses of natural gas, there are RPPs that are technologically capable of serving as substitutes, though convenience factors may lead customers to prefer one fuel to another. (Some cooks swear by gas stoves in preference to electric, kerosene, or wood ones.) However, there are RPPs for which natural gas is not an attractive substitute (e.g., aviation fuel, motor gasoline, asphalt).

As a result, one would not expect the long-run demand curve for natural gas to be perfectly elastic at the crude oil energy price. Some users would be willing to purchase gas even if it cost more than this, while many oil users would need prices of natural gas far lower before they would shift. Berndt and Greenberg (1989, p. 84), for example, report long-run own price elasticity of demand estimates for natural gas in Canada ranging from −0.3 to −0.7; those are not even elastic, let alone perfectly elastic. To return to Figure 12.1, the long-run demand curve for natural gas will look more like D^* than D_{CO}, and it would only be by purest chance that supply conditions were such as to give a price at P_{CO}. We do not deny that natural gas demand is affected by oil prices, as would be expected of goods which are substitutable. (Higher crude oil prices generate an increase in the demand for natural gas, and higher competitive gas prices; but only by chance would the higher gas price be an energy equivalent to oil.)

What, then, of the commodity value approach to natural gas pricing? One might hold on to the concept in one of two ways, but neither is particularly useful. The simple approach might be saved by saying that there is some use of gas in a market (at the margin) in which one expects that the long-run equilibrium prices of natural gas and some RPP would be equal in energy terms. Presumably, this would be a relatively important (large) market for gas and one in which natural gas and the RPP are close to perfect substitutes. Some analysts, for instance, focused on the market for low temperature process heat in large industrial uses in the Toronto area, in which natural gas competes with heavy fuel oil. There are always marginal uses, but which they are, and whether or not any of them involve near-perfect substitutability with an oil product, will be a function of the entire constellation of factors determining the supply and demand for natural gas. Therefore, the simple commodity-values approach does not serve as a general method for determining natural gas prices. Rather, the appeal of the concept in Alberta in the early 1970s seemed to be much more political, as a way for critics to emphasize the presumed monopsony power of TransCanada PipeLine as a buyer, transporter, and seller of natural gas.

Alternatively, one might turn to a more complex 'commodity-value' approach, which is, in concept, a reversal of the previous one. Here, one argues that natural gas is a commodity whose value should be determined by the free interplay of demand and supply factors. In other words, rather than tying the gas price directly to some other commodity, this approach stresses the separation (or uniqueness) of gas as a commodity. In fact, the prevailing view of the natural gas market has evolved since 1970 from the simple commodity-value theory to this more complex one, but it seems somewhat disingenuous to still claim to be using a 'commodity-value' approach!

However, this view of natural gas as a commodity does tie into the research that emphasizes the "commoditization" of the world crude oil market (Verleger, 1982, 1986). In this context, the term 'commodity' refers to a relatively homogeneous and storable product that is widely traded within a market setting that exhibits significant price variability. "Commoditization" of a market refers to the transition from a rigid, highly controlled market with relatively fixed prices to a more flexible market. The price flexibility is generally associated with a heavy reliance on spot sales, in preference to long-term contracts with inflexible prices. The instability in prices that results serves as a stimulus to the development of futures and options markets. It is sometimes suggested that such commodity markets must be effectively competitive, so that prices will tend to equilibrium values where supply equals demand. In fact, this need not be the case, as is illustrated by the commoditization of the world oil market. OPEC clearly exercises oligopolistic power, but so long as it functions as a quantity-fixing cartel there may be large numbers of traders in spot markets and oil prices will be very flexible. (See Chapter Three.) In retrospect, it is the idea of 'commoditization' rather than the idea of 'commodity value' that captures the essence of concerns about low natural gas prices in the early 1970s. What was really at issue was not, in fact, the precise correspondence between crude oil and natural gas prices but the inflexible nature of the long-term purchase contracts and oligopsonistic price rigidity in the market.

3. Price Controls, 1972–86

a. Domestic Prices

On January 17, 1972, Alberta premier Lougheed announced that the ERCB would be instructed to investigate the pricing of Alberta natural gas. Order in Council 204/72 of February 16 made this official, with the ERCB directed to advise the government on four matters:

(a) factors that influence field prices for natural gas and their suitability in the Alberta public interest,
(b) the pricing provisions of prevailing contracts for the purchase of natural gas for marketing outside the province and their suitability in the Alberta public interest,
(c) present and anticipated field prices of natural gas in Alberta and their suitability in the Alberta public interest,
(d) possible modifications or alternatives to current practice affecting field price, which would enhance the benefit to all residents of the province.

The ERCB immediately commenced public hearings, which lasted until June, and issued its *Report* in August (ERCB, 1972b). This lengthy report provided a review of the Alberta natural gas marketing and contracting procedures. It discussed a variety of factors influencing natural gas prices, with particular emphasis on the demand for gas and the degree of competition in the market. With respect to the latter,

> the Board does not agree that prices would have reached their present level without purchasing competition among Trans Canada, Alberta and Southern and Consolidated. The Board agrees with the producers that competition in field purchasing has declined since the refusal by the NEB of the authorization of increased exports of gas to the United States. The Board considers that competition in field purchasing of gas is vitally important to the Alberta public interest. (p. 7-4)

In discussing factors that should influence price, the board argued that

> it is in the Alberta public interest for gas to be priced at its commodity value in the marketplace. The Board accepts that in some end uses gas may be priced lower than alternative fuels, while in other applications it may be priced higher. In the Board's view it is important, however that, for the aggregate market the price of gas be comparable to that of alternate fuels. Further, the Board believes it to be in the Alberta public interest that the field price of gas reflect its field value – the commodity value less adjustments for transmission and distribution.
>
> The Board expects that under the pressure of the gas shortage in North America, the field price of gas in Alberta will be influenced increasingly by its commodity value in all market areas. The Board recognizes that because of the long term contracts common in

> the gas industry, and the regulatory time lag, gas prices cannot under present circumstances, be expected to adjust immediately to changing market conditions. It believes changes are required in contracts and in regulatory process to permit a quicker response of field price to changing conditions in the market. (p. 7-8)

On the natural gas supply side, the costs of exploration through to field processing of gas were seen

> as the factor which determines, whether, at any level of price, a sufficient incentive exists for a producer to explore for and develop new reserves.… The Board does not believe that costs have had much direct effect on field prices in the past nor that they will or should have much direct effect in the future. (p. 7-24)

Since the board acknowledged that gas supply costs varied across deposits, the implication is that Alberta was seen as a price taker in natural gas markets and that the value of alternative fuels would determine the appropriate gas price. The board did note that

> the term commodity value was used extensively at the hearing but not defined in any precise manner. The Board believes that most people using the term meant by it the maximum price that could be obtained in a specific regional market area having regard for the mix of end use and the prices of competitive fuels in the area. Commodity value does not imply that gas be priced equivalent to competing fuels in each class of applications in the market area but rather that it be so priced on a total or overall basis. (p. ii)

The board's emphasis upon the demand side of the market as determining values was somewhat contradicted by its suggestion that gas prices would have to be much higher by the early 1980s, essentially to cover the costs of Arctic gas (ERCB, 1972b, p. 9-13).

After looking at prevailing market conditions, and the level of prices and other contract provisions for Alberta gas exports, it concluded "that the actual field price for Alberta gas is less than the field value by some 10 to 20 cents per Mcf.… [A]nd therefore concludes that current field prices are not suitable in the Alberta public interest" (p. 9-9). Established price escalation factors would leave gas prices well below these field values. Most contracts (governing some 85% of Alberta's gas exports) included renegotiation clauses, such that "the Board believes that providing there is free negotiation between seller and buyer and effective competition in buying the future field prices will approach the future field value and thus be in the Alberta public interest" (p. 9-14). However, effective competition required the removal of restrictions on exports from Canada on gas where removal from the province of Alberta had already been approved. Moreover, in many contracts with provision for renegotiation, this happened at five-year intervals, so that there could be considerable time lags in attaining appropriate field prices. The board noted that only 30 per cent of contracted gas volumes were governed by most-favoured-nation clauses (which passed on to this contract any higher prices offered by the buyer in another gas purchase contract) (ERCB, 1972b, p. 8-13).

The board recommended that "competition in the buying of Alberta gas be increased" (p. 11-4), which would require authorization for increased exports to the United States. It also recommended that governments act to remove "unnecessary restrictions and delays operating against the realization of the field value of gas" specifically better monitoring of export prices and values and quicker responses of public utility regulators in passing on gas price increases (pp. 11-4, 5). The board did "not believe Government intervention with respect to the contract provisions is necessary or desirable" so long as the government let producers and purchasers know that contracts should reflect full field values when first negotiated, have adequate price adjustment clauses (plus 3–4% per year), and include provision for price redetermination of field values as frequently as practicable (at least each five years) (pp. 11-7, 8).

On November 16, 1972, the provincial government essentially endorsed the board's findings, urging the renegotiation of contracts in light of field values higher than prices. Renegotiation each two years should be a standard feature of contracts. The ERCB was asked to provide a report in spring 1973 assessing the status of old and new contracts in light of the government's gas pricing objectives (i.e., attainment of prices at higher levels equivalent to "commodity values"). The board's July 1973 *Report* found that prices in new contracts were noticeably higher and that many old contracts had been renegotiated with higher prices and generally with two-year price renegotiation provisions (ERCB, 1973). Some 52 per cent of authorized gas removals reflected such higher prices, although many of the contracts still had prices less than the board's estimated commodity value.

A follow-up *Report* by the ERCB (ERCB, August 1974) found that the field value of natural gas had risen sharply due to "interfuel competition" (i.e., OPEC oil price rises), from $0.29/Mcf at the start of July 1972 to $1.12/Mcf at the start of July 1974 (p. 2-7). These were based on a weighted average cost of refined petroleum products to Toronto users less an allowance for natural gas distribution costs in Toronto. The board thought that commodity values would be about the same in Montreal and much higher in California, where oil prices were higher (p. 2-8). The board noted that prices had been renegotiated, and two-year price redetermination accepted, in contracts covering some 96 per cent of gas leaving Alberta. The board estimated the average field price of gas leaving Alberta would be $0.46/Mcf, as compared to $0.16/Mcf two years earlier. The increases were clearly viewed as desirable by the provincial government but had come about largely through supplier–purchaser contract negotiations.

The government had not been entirely passive, however. It had announced that the level of prices would be a key ingredient in the assessment of new permits to remove natural gas from the province, and requests by TransCanada Pipelines (TCPL) for additional gas to be placed under permit were shelved by the government on the grounds of inadequate prices. Moreover, legislation was introduced (the *Alberta Arbitration Amendment Act*, RSA 1973, chap. 88, Section 16.1) to ensure that price redetermination clauses in energy contracts would be applied in such a way as to ensure prices for gas at a level consistent with what would be expected under effective competition. The legislation saw this as the "commodity value," which would be derived from the price of substitutable fuels plus premiums reflecting "inherent special qualities of gas." Prices on new contracts rose sharply in the summer of 1972 when a new purchaser, Pan Alberta Gas Ltd., entered the market, offering an initial field price of $0.38 per Mcf, some $0.15 more than TCPL was offering. TCPL's lower offer prices are consistent with the behaviour anticipated of a monopsonistic buyer; TCPL's preference for lower prices was strengthened by the presence in some of its existing long-term purchase contracts of most-favoured-nation clauses.

Thus, despite TCPL's dominance as a purchaser, which the NEB's denial of new gas export permits in 1971 had reinforced, there was inexorable upward pressure on gas prices, and from a variety of sources. Purely economic forces included rising prices for crude oil, which increased the attractiveness of natural gas as a fuel, and the entry of a major new gas purchaser (Pan-Alberta). Regulatory pressures came from the acceptance of the Alberta government of a commodity value standard for gas prices, which was utilized by the government in assessing gas removal permits and formalized as the proper basis for gas price redetermination procedures. As shown in Table 12.1, the average field price of Alberta natural gas rose from $0.17/Mcf in 1972 to $0.19 in 1973, $0.30 in 1974, and $0.62 in 1975. In the spring of 1975, an arbitration board awarded a price of $1.15/Mcf, effective November 1975, in a price renegotiation dispute between TCPL and Gulf Oil Canada.

The reliance upon market-pricing procedures for natural gas (albeit with strong pressure for higher prices from the governments of Alberta and B.C.) contrasted sharply with the regulated pricing environment for crude oil, which had been in place since the September 1973 oil price freeze. Gas prices could have been left unregulated, as with coal, another energy product that competes with oil-based fuels. This, however, was unlikely, given that most of the factors that had led Ottawa to regulate crude oil prices also held for natural gas: it provided a large share of Canadian energy in markets west of Quebec (far larger than coal, and higher than oil in more western markets); the value of natural gas was strongly affected by oil prices, which in the absence of oil price regulation in Canada meant OPEC prices; Canada was a large natural gas producer, and net exporter, so that a "made-in-Canada" price was feasible. The fact that Canadian natural gas producers were also crude oil producers may have led policy-makers to feel that symmetric regulatory treatment was desirable. At a more political level, the rapid increase in natural gas prices after 1972 could be seen as pitting the interests of natural gas producers concentrated in Alberta and northeast B.C. against the interests of natural gas consumers spread across a much larger part of the country (i.e., in markets as far east as Montreal).

In 1975, Ottawa passed the *Petroleum Administration Act*. (Edie, 1976, summarizes the main legal issues associated with the federal and provincial gas pricing provisions in this period.) Under Section 52, this gave Ottawa (through the NEB) the power and responsibility to set the price of gas crossing provincial boundaries. Section 50 gave the minister responsible for energy the power to enter into gas-pricing agreements with any province. The June 1975 federal budget announced that Ottawa and Alberta had reached an agreement on natural gas prices under which they would set gas prices. The exact regulations and the

Table 12.2: Regulated Natural Gas Prices, 1975 to 1985

		Domestic Gas Prices		*Export Gas Price*[3]	
		Toronto Gate[1] *($/10⁶ BTU)*	*Alberta Border*[2] *($/10⁶ BTU)*	*U.S. ($/10⁶ BTU)*	*Canadian ($/10⁶ BTU)*
1975	(November 1)	1.25	0.78		1.60
1976	(July 1)	1.405	0.92		
1976	(September 10)				1.80
1977	(January 1)	1.505	0.99		1.94
1977	(August)	1.68	1.16		
1977	(September 21)			2.16	2.36
1978	(February 1)	1.85	1.26		
1978	(August 1)	2.00	1.41		
1979	(May 1)			2.30	2.68
1979	(August 1)	2.15	1.54		
1979	(August 11)			2.80	3.29
1980	(November 3)			3.45	4.05
1980	(February 1)	2.30	1.64		
1980	(February 17)			4.47	5.20
1981	(September 1)	2.60	1.94		
1981	(April 1)			4.94	5.95
1982	(September 1)	2.96	1.82		
1982	(February 1)	3.55	2.07		
1983	(August 1)	3.80	2.32		
1983	(February 1)	3.99	2.57		
1983	(April 12)			4.40	5.43
1983	(July 13)			Base 4.40	5.43
				VRIP[4] 3.40	4.20
1983	(August 1)	3.99	2.82		
1984	(February 1)	3.99	2.98		
1984	(August 1)	4.15	2.98		
1984	(November 1)			*	
1985	(February 1)	4.14	2.98		
1985	(June 1)	4.06	2.98		
1985	(November 1)	4.06**	2.98**	***	

Source: Royal Bank, "The North American Natural Gas Industry," and DataMetrics Limited.

Notes:
1. After September 1981, the Toronto city gate price was set by adding transportation charges and the excise taxes to the regulated Alberta border price.
2. Prior to September 1981, the Alberta border price was determined by netting transportation charges from the Toronto city gate price.
3. After 1977, the Canadian export price was set in U.S. dollars.
4. VRIP is 'volume related incentive price.'

* Canadian exporters were given the option of negotiating gas prices with the proviso that these prices not be less than the wholesale price of gas at the Toronto city gate.

** Domestic prices frozen until November 1, 1986, when full deregulation took effect.

*** Floor price for exports is the adjacent border domestic price.

economic implications will be described in more detail in Section 4 of this chapter. From November of 1975 through November of 1986, Canadian natural gas prices were set by governments. The Government of Alberta allowed a discount on gas sold within the province. Alberta gas sold elsewhere in Canada was at price levels set, for the most part, by joint Alberta–Ottawa agreement. Average wellhead price levels are shown in Table 12.1, rising to a peak of $2.92/Mcf in 1984, before falling back, with oil prices, to $2.20 in 1986.

Regulated prices for domestic and export gas over the price control period (November 1, 1975 through October 31, 1986) are shown in Table 12.2 in dollars per million BTU (which is approximately the same as the price per Mcf). From 1975 to the September 1, 1981, *Memorandum of Agreement* between Ottawa and the Alberta government, the price of natural gas was fixed at the Toronto city gate; the Alberta border 'price' was the Toronto price net of transmission charges from Alberta to Toronto. After September 1981, the Alberta border price was fixed by regulation and the Toronto city gate price was the Alberta price plus transmission charges, plus a new federal tax on natural gas (discussed in Section 4.6.2). As can be seen, natural gas prices increased sharply under regulation, just as crude oil prices were increased. (See Chapters Six and Nine; recall that Canadian domestic crude oil prices were held below international crude prices.) After 1983, as world crude oil markets weakened, gas prices were held constant at the Alberta border at $3.00/Mcf.

b. Export Prices

As Section 4 will set out in more detail, the National Energy Board was given the responsibility for overseeing natural gas export prices (NEB *Act*, Section 83(a)). In the 1950s and 1960s, natural gas for export was purchased on much the same basis as gas for domestic use, that is, under long-term contracts with quite rigid pricing provisions. The OPEC-induced oil price increases of the early 1970s increased the attractiveness of Canadian gas to U.S. users but did not immediately generate higher contract prices. In September 1970, the federal government ordered the NEB to monitor export prices; "where in the opinion of the Board there has been a significant increase in prices for competing gas supplies or for alternative energy sources, the Board shall report its findings and recommendations to the Governor in Council" (NEB, 1970, p. 2-1). In its July 1974 *Report on Natural Gas Export Pricing*, the board concluded "considering that in all cases the border price has fallen well below the Board's estimate of the current value of the gas, it would seem that a major increase in price to a uniform border price for all export licenses is appropriate to the circumstances" (NEB, 1974a, p. 5-28). The board recommended a minimum price of $1.00/Mcf. On September 20, 1974, Ottawa, after consultation with the producing provinces, set a one dollar per Mcf border price effective January 1, 1975. In its March 1975 *Report*, the NEB recommended that the price be increased to $1.60/Mcf, and the federal government concurred. Table 12.2 shows gas export border prices from November 1975 on, as set by regulation. It was noted above (see Column 7 of Table 12.1) that gas exports fell after 1979. Effective July 13, 1983, gas exporters were given more flexibility in negotiating export prices. Initially, this involved a VRIP (volume related incentive price), which allowed reduced prices on volumes in excess of a certain amount (e.g., 50% of authorized exports). In November 1984, export price regulations were further relaxed; buyers and sellers were free to negotiate prices with a floor equal to the Toronto city gate price, and later (November 1985) a floor equal to the domestic price at the export border point. The average export border price peaked at $6.06/Mcf in 1982, falling each year after that to $3.35/Mcf in 1986 (Watkins, 1989, p. 120).

4. The Deregulated Era, 1986–

Many economists would argue that the period of natural gas price controls beginning in 1974 sowed the seeds of its own destruction, much as had the overt oil control period discussed in Chapter Nine. Gas pricing and export provisions were subject to ongoing review and modification as new 'problems,' such as falling exports and rising excess deliverability, manifest themselves. The industry, the government of Alberta, and many independent analysts argued for a dismantling of controls and acceptance of a deregulated natural gas market. The *Western Accord* of March 1985, which accepted June 1, 1985, as the date for deregulation of the oil market, also stressed the need for a more "flexible and market oriented pricing system" (p. 3) for gas (Canada, 1985a). On October 31, 1985, Ottawa and the three natural-gas-producing provinces (Alberta, B.C., and Saskatchewan) signed an *Agreement on Natural Gas Markets and Prices* (sometimes called the *Halloween Agreement*), following recommendations of a task force established under the Western Accord (Canada, 1985b). The intent of the agreement was to "foster a competitive market for natural gas in Canada, consistent with the regulated character of the transmission and distribution sectors of the gas industry." Furthermore, "effective November 1, 1986 the prices of natural gas in interprovincial trade will be determined by negotiations between buyers and sellers," as had been the case since 1984 for gas exports (though exports were subject to a price floor).

However, natural gas could not be deregulated with the same ease as crude (see Watkins, 1991a). Amongst reasons for this were:

(i) The **different nature of natural gas regulation**, in particular the export regulations, which had encouraged very high reserves to production ratios for gas. Deregulating natural gas was, in this respect, analogous to tearing down a dam, something that might best be carried out in a series of careful steps rather than at once as with crude oil.
(ii) The very **concentrated buyers' side of the market**, in which TCPL had long operated both as the major gas transmission facility and as the prime buyer of natural gas in the field. In contrast, oil pipelines functioned as common carriers.
(iii) The **prevalence in the market of long-term contracts** between natural gas producers and the purchaser, so that neither volumes produced nor prices paid exhibited immediate flexibility in response to changing market conditions, although most contracts had moved to two-year price renegotiation just prior to the price control regime of 1975.

More detail on how deregulation of natural gas actually occurred will come in Sections 3 (on export limitations) and 4 (on prices). (See also Watkins, 1991a, and Bradley and Watkins, 2003.) At this point, we will simply remark that since 1986 North American natural gas markets have been revolutionized. (Since the late 1980s the NEB has produced a continuing series of useful reports on Natural Gas Markets; NEB, 1992, 1996, 1997, and 2002 are particularly good reviews of the evolution of Canadian gas markets after 1986.) Canadian export limits have been largely dismantled – a result which has been entrenched in the Canada–U.S. FTA and NAFTA. The large transmission companies have been joined by numerous other buyers of natural gas in the field, including large consumers and a variety of gas trading companies. At the same time, the transmission companies have shifted to common carrier status; tariffs are still regulated, but others have right of access to ship gas. Rigidities in sales arrangements have been largely eliminated, as increasing volumes of natural gas are exchanged in the spot market, and as long-term contracts have adopted increasingly flexible pricing arrangements. The transmission and gas trading activities of the major transmission companies have been separated ('debundled'); for example, in 1986, TCPL set up Western Gas Marketing Limited (WGML) as a wholly owned subsidiary to handle its purchases and sales of natural gas.

Table 12.1 shows changes in the average field price of Alberta natural gas since 1986. Prices fell dramatically after 1985, as did oil prices internationally and in Canada. In part, the lower gas prices reflected the decreased value of crude oil, but increasing deregulation also led to rapid increases in the production of natural gas, putting downward pressure on the price. Natural gas prices remained lower throughout the 1990s than they had been in the first half of the 1980s, even in nominal terms. The price of natural gas relative to oil varied as a function of different market developments for the two products; in general, from 1985 through the 1990s, gas was relatively lower-priced than it was in the price control period. This is not surprising given the very high R/P ratio for gas relative to oil at the start of the deregulation period and the relatively greater ease of natural gas reserve additions in the province.

However, the average field price of Table 12.1 covers a wide variety of sales arrangements, not all at identical prices. For instance, by the mid-1990s, significant volumes of gas were moved under four different types of sales arrangements (NEB, 1992, 1997).

(1) In part as a legacy of the long-term contractual agreements common in the 1950s, 1960s, and early 1970s, companies such as WGML and Pan Alberta acted as '**supply aggregators**,' which purchase gas from large numbers of separate gas pools for resale, largely to natural gas distribution companies ('LDCs' or local distribution companies that operated as 'demand aggregators' for large numbers of individual consumers). The field price for gas traded in this manner was usually negotiated annually between the supply aggregator and the pool of gas purchasers, and held for a November 1 to October 31 contract year; beginning in the 1990s, more and more of these contracts moved to agreed-upon flexible pricing provisions tying prices to Alberta spot market natural gas prices.
(2) **Individual term contracts** (for longer than 30 days) have been negotiated between an individual producer and a purchaser (which may be a natural gas user or a trading company that operates as a market intermediary) for sale of gas **in the producing region**. Typically the field price of this gas is tied to a thirty-day average of reported spot market price.

(3) **Individual term contracts** between a producer and a purchaser for sale in the consuming region. Typically the price **in the consuming region** is tied to spot markets, and the field price received by the producers will be this price less the transmission cost for the gas. For a producer that has contracted space over the long-term on a pipeline, the transmission charge will normally consist of a small "commodity charge" to cover the fuel and other operating costs of the pipeline place a larger "demand charge" to cover the capital cost of the pipeline. If the producer has not already contracted pipeline space, it must be purchased at current prices, which may be the very low commodity charge if the pipeline has spare capacity, but much more if there is none.
(4) A **spot sale** (for less than thirty day's exchange) may be negotiated between a producer and an interested buyer. As the number of intermediary trading institutions (e.g., electronic bulletin boards) has increased, it becomes increasingly likely that spot sales occurring at any point in time will all be at 'identical' prices (allowing for any gas quality differentials). The tendency to equal prices was also facilitated prior to 2000 by NOVA's reliance on a 'postage stamp' tariff for gas shipped within Alberta.

In a well-functioning, fully integrated North American natural gas market, one would expect that natural gas field prices under these various sales arrangements would be relatively close to one another, since the various alternative sales arrangements are close substitutes for one another from either a buyer's or a seller's point of view. Some field price differences would remain, reflecting varying transmission costs, depending upon how transportation is handled (i.e., paid by the producer or the buyer; bought on a longer-term contract or at prevailing rates). In addition, less flexible pricing arrangements will generally differ from spot prices; thirty-day averages will lag any spot price trends, and one-year prices should approximate expected average spot prices but not reflect any unexpected (random) market developments. In a well-functioning market there could also be some small differences between prices in different contracts reflecting differing risk preferences (e.g., one-year contracts have a reduced risk of price change as compared to a series of spot contracts over the year). The growing commoditization of gas markets, for example NYMEX natural gas futures, offers other ways for companies to reduce market risks. Another indication of increased commoditization is the major rise in gas storage capacity, which is serving to reduce the seasonal variation in natural gas prices.

On balance, by the early 1990s, Alberta natural gas had become part of a flourishing and flexible integrated North American natural gas market. This implied that Alberta natural gas prices would be closely tied to those in the United States, with price changes reflecting all supply, demand, and transportation changes across the continent. Traditional trading regions will tend to evolve over time along with the integrated market. Deregulation has seen a rapid rise in exports relative to domestic Canadian sales. By 1995, there had been new pipeline links established between Ontario (the largest market for Alberta natural gas from the early 1960s on) and U.S. producing centres, providing further evidence of today's interdependence in continental natural gas markets, and harkening back to Waverman's hypothetical analysis of efficient, integrated North American gas markets in the 1960s (Waverman, 1973). The rise in exports of Alberta gas was indeed dramatic, as exports more than tripled from 1986 to 1993.

In the 1990s, increased attention was focused on the market impact of transmission facilities. Spare capacity in transmission out of the province leaves field prices and production volumes very sensitive to supply and demand changes elsewhere on the continent. This is particularly true as increased competition enters the transmission industry. In this respect, the opening of the Alliance pipeline in late 2000 was important, running from Alberta to Illinois, connecting with the U.S. Midwest pipeline grid, and offering competition to TCPL on eastward natural gas shipments. Spare capacity in the pipelines means that space can be purchased for 'commodity' charges only (i.e., pipeline operating costs); if this is done by gas producers, it implies higher field values (netbacks for the gas). On the other hand, if there is no excess pipeline capacity then Alberta sales volumes and field prices will be less responsive to changes in market conditions elsewhere in North America. Furthermore, shipment costs will reflect operating and capital costs (commodity and demand charges), implying a larger gap between delivered prices and field values than if spare pipeline capacity exists.

Natural gas producers will favour spare pipeline capacity under these conditions. Of course, transmission companies will be willing to install new capacity only if they expect to recover both operating and capital costs. These complications would not exist if we lived in a world of perfect certainty and with perfectly malleable capital: in such a world, new pipeline capacity could be constructed (and deconstructed) exactly as required. However, with both demand and supply uncertainties, and economies of scale in natural gas pipelines, new facilities must be large and are planned and constructed over a number of years in anticipation of future market conditions. The regional gas market may, then, operate for some period of time in a short-run equilibrium that differs from the anticipated long-run equilibrium. For example, this could be with unused pipeline capacity and 'higher' netback prices. Such a situation typically conveys its own market message, inducing adjustment towards the long-run equilibrium; in this case, a higher field price attracts more output that will fill the spare pipeline capacity. Similarly, if pipeline capacity is fully booked, a rise in market prices may fail to translate back into higher field prices, but the increased margin between market and field prices serves as an incentive to contract new supplies and construct additional pipeline facilities.

The commoditization of the North American natural gas market has raised these new uncertainties for participants in the market, a major change from the days of long-term contracts with almost all gas brought and sold by the pipeline companies. Moreover, the adjustment problems seem to be more pronounced in the North American natural gas market than in the crude oil market, where prices are primarily determined by the world market and where domestic markets are ready to accept any domestic crude available before drawing on OPEC supplies.

As Table 12.1 illustrates, starting in 1999 Alberta natural gas prices began to rise dramatically, to the highest level they have attained (at least in nominal dollars); the average price in 2006 was $8.54/Mcf, and it had been as high as $11.38/Mcf in October of 2005. (See the Alberta Department of Energy, *Alberta Gas Reference Price History*.) These high prices reflected increasing tightness in North American natural gas markets and the loss of upward flexibility in production as reserves-to-production ratios in both Canada and the United States fell below ten. In the early years of the new century, there was much uncertainty about whether these high prices would be temporary or long-lived. Economists would expect that significant price increases will generate long-term production increases and consumption declines. However, some industry spokesmen suggested that geological prospects for large increases in low-cost production were unlikely, and that North America would have to rely increasingly on gas that is high cost (e.g., hard to produce 'tight' gas that is in reservoirs with low permeability and such non-conventional sources as coal bed methane, shale gas, or new supply sources that have high transmission costs, such as Alaska and Arctic gas or imported liquefied natural gas [LNG]). On the consumption side, the sharp rise in oil prices starting in 2003 inhibited substitution out of natural gas into refined petroleum products.

As Table 12.1 shows, natural gas prices fell from the October 2005 peak; by 2009, the average wellhead price in Alberta was $4.04/Mcf. The Alberta Department of Energy reported a monthly natural gas price below $4/Mcf for every month from April 2010 to February 2013, ranging from $1.58/Mcf to $3.69/Mcf. Price expectations by 2013 were much less optimistic than they had been several years earlier, reflecting in large part the increased availability in North America, despite falling gas prices, of non-conventional gas from coal bed methane and, especially, U.S. shale gas. Horizontal drilling techniques have been particularly critical in lowering costs of these non-conventional gas sources. Vidas and Hugman (2008) provide a useful survey of North American non-conventional gas resources and possible producibility. U.S. shale gas output rose by 25 times from 2000 to 2012, rising, from 1.67 per cent of U.S. natural gas supply to 34 per cent (EIA, 2013, Figure 91, p. 79).

We might return to the issue of 'commodity pricing,' or, more generally, the relationship between natural gas and oil prices. As Table 12.1 illustrates, in the late 1990s, the price of natural gas relative to crude oil increased sharply in Alberta, from less than 0.4 in the mid-1990s to just over 1 by 2001; it remained at relatively high levels for about five years, before plunging down, below 0.3, by the year 2011. It is clear that full commodity pricing equivalence has not held in Alberta (where the price of natural gas and oil would exhibit the same price per unit of energy content, so the relative price would always equal one). Nor is there a one-to-one correspondence in changes in crude oil and natural gas prices on an energy-content basis (where the relative price would remain unchanged). Plourde and Watkins (1998) utilized statistical co-integration analysis to examine the link between crude oil and natural gas prices from late 1975 through 1999. They found that the prices moved together during the regulated price period (1975 to mid-1985); this would be expected, since gas prices tended to be set in relation to oil prices, as mentioned above and reviewed in more detail in Section 4, below. Similar connections were found in what they labelled the deregulated period (from 1988 on), but "a rather different picture emerges when the deregulation period is split into earlier and later parts. The relationship between upstream prices of crude oil and natural gas has weakened as deregulation has progressed." This suggests that the natural gas market has become increasingly sensitive to supply and demand factors specific to natural gas as the time since deregulation has lengthened and is consistent with a gas market in which pricing and contract volumes have become increasingly flexible and short-term. Serletis and Rangel-Rui (2004) also find increasing independence of oil and natural gas prices in North America; however, Brown and Yücel (2008) and Hartley et al. (2008) argue that a long-term link still exists, so long as allowance is made for such factors as weather and storage.

Finally, we should briefly discuss the increased role of natural gas storage within North America. Markets for Canadian natural gas generally exhibit significant seasonality, with particularly high demand from residential and commercial users during the winter season, as much as six times higher than in summer (NEB, 2008, p. 17). In the absence of ready and costless production variability or storage capabilities, this seasonality generates seasonal price variability and higher transmission costs. (The former because prices are higher during the peak season; the latter because pipeline facilities must meet peak demand and are not fully utilized throughout the year.) While gas can be stored in containers, most gas storage is below ground. Gas storage facilities increased particularly rapidly in North America with the deregulated markets that developed beginning in the mid-1980s. (EIA, 1995 and 2006 provide a good overview of natural gas storage. Hartley et al. 2008, and Brown and Yücel, 2008, provide statistical analysis showing that storage affects natural gas prices.) By storing gas during off-peak times (seasons) and releasing it during peak times, the seasonal variability in gas prices can be reduced; of course, gas stocks are also available to meet unexpected events (e.g., unusually cold weather). Storage facilities have been installed in both gas-producing and consuming regions and have been built by gas transmission companies, gas producers, and other parties who hope to profit from owning such facilities either for their own gas trading or by leasing space to other parties.

In Alberta, a number of old reservoirs have been converted to gas storage, with a total capacity at the end of 2012 of 11,417 10^6 m^3, and a maximum deliverability of 178.7 10^6 m^3/d (ERCB, 2013, *Reserves Report*, ST-98, Table 5.8). At this deliverability rate, the facility would be drained in two months; storage facilities are capable of much faster drainage than a conventional gas pool but have correspondingly higher lifting costs.

3. Alberta and Canadian Natural Gas Protection Policies

We use the term 'removal' to refer to the movement of natural gas beyond Alberta's borders, irrespective of whether it is destined for markets in other parts of Canada or in the United States. We use the term 'export' to refer to the movement of natural gas to the United States. After the 1950s, no distinction was made at the provincial level in terms of gas removals, whether to other regions of Canada or to the United States. The national controls solely relate to exports destined for foreign markets. Any party wishing to export gas from Canada must surmount both relevant provincial and national hurdles.

Alberta's policies governing removal of natural gas are outlined below. These policies are crucial, not only because about 85 per cent of Canada's established gas reserves are located in Alberta, but because the policies initially followed at the national level by the National Energy Board (NEB) after its inception in 1959 were closely allied to those of Alberta – and indeed after that remained in symbiotic relationship with them. Policies pushed by the NEB are dealt with after the discussion of Alberta's initiatives in the protection arena. (This discussion is largely based on Watkins, 1982a, 1990. See also Winberg, 1987, chap. 5.)

A. Development of Alberta Policy

The growth in Alberta's reserves of natural gas was sufficiently rapid after the Second World War that by 1950 they represented a very considerable inventory in relation to existing markets. This build-up in reserves provoked plans for large-scale removal of gas from the province. The Alberta government became concerned about future shortages if use of the province's gas reserves were not adequately controlled.

1. The Dinning Commission and Early Alberta Legislation

In November, 1948, the Alberta government appointed a commission headed by Robert J. Dinning to investigate the province's natural gas situation. The 'Dinning Commission,' as it became known, submitted a report in March 1949 that strongly recommended that Albertans have first claim on the province's gas reserves. This recommendation did not fall on deaf ears, and in 1949 the Alberta Legislature passed the *Gas Resources Preservation Act*.

The intent of the act was outlined by Premier Manning in his Budget Address of 1950 (March 3, 1950, p. 6):

> The Government's first and foremost responsibility is to protect the interests and welfare of the people of this Province.… To this end, no application for the export of natural gas will be given favourable consideration until such time as the Government is satisfied beyond question that … there are sufficient gas reserves to meet the present and future domestic and industrial requirements of this Province. When fully satisfied that a surplus exists over and above these requirements, the Government will approve the export of such surplus with each application being considered on its own merits and in the light of all prevailing circumstances.

The key passages of the act were (Chapter 157, Statutes of Alberta):

> The Board shall not grant a permit for the removal of any gas or propane from the Province unless in its opinion it is in the public interest to do so having regard to:
>
> (a) the present and future needs of persons within the Province and
> (b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the Province.

The board referred to here was the Alberta Oil and Gas Conservation Board (OGCB; after 1970, and again in 2007, it was renamed the Energy Resources Conservation Board, ERCB, and, from 1994 to 2007, the Energy and Utilities Board, EUB).

The 1949 act was amended frequently. However, its overall nature and purpose did not change materially. Significantly in 1984 another clause was added to considerations (a) and (b) listed above, namely: "(c) the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta" (*Gas Resources Preservation Act*, 1984, Section 5(3)). Moreover, conditions to be attached to a permit were to refer to the price of the gas and to "other factors relevant to the expected economic benefits to Alberta" (Section 6(d)). In 1986, clause (c) was replaced by a general criterion, which will be discussed later.

2. Initial Policy of the Alberta Conservation Board

The intent of the *Gas Resources Preservation Act* – adequate protection of Alberta consumers – was clear, but the manner by which such protection would be implemented was not. In essence, it was left for the Conservation Board to adorn the legal skeleton with regulatory flesh.

Initially, the board interpreted its mandate conservatively, and as a result most early applications to export gas from the province were refused. The original regulatory framework required the board to be satisfied that Alberta's established gas reserves were sufficient to meet the province's forecast annual gas requirements, including peak day, for a period of thirty years, plus any extant export commitments (including their peak-day requirements), before authorizing gas exports (OGCB, 1961, pp. 4–5).

In essence, then, the protection formula was a straightforward comparison of stocks and future demands on them. If the bins (established reserves) were full – exceeding thirty years of estimated future consumption plus any already authorized exports – the harvest was available for export. In symbols, the export formula was:

$$G_s = R_{EST} - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \qquad (1)$$

where

G_s	=	surplus gas.
R_{EST}	=	established gas reserves, Alberta.
A_i	=	estimated Alberta gas requirements, year i.
E	=	remaining authorized exports.
$f(PD_{30})$	=	reserves necessary to protect Alberta peak-day requirements in the thirtieth year.

The figure for established reserves was adjusted by deducting reserves found but considered beyond economic reach. The reserves set aside to meet peak-day requirements were often called 'cushion' gas.

Because of constraints on distribution systems within the province, protection of the province's gas requirements was also considered on a detailed regional basis. Thus, even if Alberta enjoyed an overall gas surplus under the formula, removals from a particular area might be denied because of a perceived local shortage.

The reason for selecting thirty years as the period of protection was not identified at the time of adoption, but it seemingly was largely a matter of judgment, based on the life of a typical gas reservoir, the period of amortization of a major investment and the period over which new technology and developments would be expected to influence energy supply (G.W. Govier, interview, *Canadian Petroleum*, November 1978, pp. 61–64).

Exporters needed to ensure most of their gas supply was under contract – the guideline evolved by the board eventually became 80 per cent of the prospective export volumes (OGCB Report 69-D, 1969c, p. 63). This provision was intended to avoid distributing export permits in a way tantamount to the award of hunting licences.

In addition to protecting Alberta requirements under the surplus formula, the removal permits themselves provided for local utilities to access gas under permit in the event of local shortages. These 'fail-safe' clauses were:

> … a condition that the permittee will supply gas or propane at a reasonable price to any community or consumer in Alberta that is willing to take delivery of gas or propane at a point on the pipeline transmitting the gas or propane or at a processing plant producing the propane and that, in the opinion of the Board, can reasonably be supplied by the permittee; … (*Gas Resources Preservation Act*, 1984, Clause 6(f))

3. Policy Developments in the 1950s

The decade was marked by gradual relaxation by the board of the strict canons of policy it initially adopted. Relaxation was consistent with continued growth in Alberta's gas reserves, the development of transmission and distribution systems within the province, and the attachment of firm markets outside the province. The way the policy was relaxed is outlined below.

First, the Alberta Gas Truck Line Company Limited (later NOVA and now part of TransCanada), a common carrier under provincial jurisdiction and control, was established in 1957 to serve as an efficient means of gathering gas from various fields within the province for transportation to points of removal. The inception of the trunk line system, the further growth and geographical scatter of the province's reserves, and the extensions in utility company distribution systems increased the degree of supply flexibility within the province and enabled the board to put less weight on regional discrepancies in both supply and future requirements. Later, regional aspects were virtually eliminated from the board's deliberations.

Second, the consistent growth in the province's gas reserves resulted in the board adopting a less conservative approach in estimating the supply available to meet future requirements. By 1958, the board allowed for satisfying some part of future Alberta requirements from new discoveries. In this vein, established reserves were allocated to meet annual requirements for twenty-six to thirty years and peak day requirements for twenty-five years. Reserves to be developed in the future were assumed to meet the remaining annual and peak-day requirements at the end of the thirtieth year, as long as reserve growth remained consistent. Such reliance on new discoveries to satisfy a portion of future Alberta requirements marked a significant policy change.

Third, before 1959, the board recognized preference for ex-Alberta Canadian requirements for Alberta natural gas before recommending removal of gas to foreign markets. Thus the policy made only gas surplus to Alberta's needs plus the immediate contractual requirements of other Canadian provinces eligible for export from Canada and required that adequate future reserves based on growth trends be available to satisfy estimated Canadian requirements (other than Alberta's) over a twenty-five-year period. Such responsibilities were effectively transferred to the federal government's National Energy Board (NEB) in 1959.

Fourth, by 1959, the Conservation Board considered that the trends in reserves growth were sufficiently well founded to justify giving full weight to reserves to be developed in the next two to five years in assessing total reserves available to satisfy requirements. Specifically, in applying the gas removal formula after 1959 the board formally included a two-year reserve growth figure to meet future demand. In the vernacular, this allowance became known as 'trend gas' (OGCB, Report 66-C, 1966, pp. B2–B3). Typically, this meant protection of future Alberta requirements from established reserves was set at the equivalent of about twenty-five years.

In effect, then, the Alberta export formula which held sway when the NEB entered the fray was:

$$G_s = R_{EST} + 2T_g - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \tag{2}$$

where T_g = annual allowance for 'trend gas,' and other symbols are as before.

4. Policy Changes in the 1960s

Two main policy changes were made in the 1960s: one in 1966, the other in 1969. The first was designed to increase near-term protection for Alberta consumers, and the second was to increase reliance on future discoveries in assessing gas supply. In addition, an adjustment was made in 1964 to established reserves to add back a proportion (usually 50 per cent) of established reserves 'beyond economic reach' that might land up as 'within economic reach' over the thirty-year protection period, and to subtract reserves deferred for conservation reasons (OGCB, Report 64-1, 1964c).

a. 1966 Changes

The 1966 change introduced a two-tiered definition of surplus, distinguishing between a 'contractible' and a 'future' category (OGCB, Report 66-C, 1966). The contractible surplus compared established reserves with contractible requirements, where the latter was defined as thirty times Alberta's first-year requirement ($30A_1$) plus permit related requirements. Thus, the contractible surplus was:

$$C_s = R_{EST} - 30A_i - E \qquad (3)$$

where C_s = contractible surplus, and other symbols are as before.

Any gas surplus to the contractible requirements was presumed to be available for contracting to meet Alberta's future requirements.

The future surplus compared future reserves with future requirements. The former were primarily the 'trend gas' allowance, plus certain reserves subtracted from established reserves that may be available within the thirty-year period, mainly 'deferred' gas plus discovered gas that may become within economic reach over thirty years. Future requirements were the thirty-year projected Alberta requirements less requirements already included in the contractible category ($30A_1$), plus reserves required to meet estimated peak-day demand in the thirtieth year. (Actually, the portion of these requirements that reserves dedicated to them could deliver over the thirty-year period.) An allowance was made here for contractible reserves still available to meet peaking requirements in the thirtieth year. The future surplus formula can be approximated by:

$$F_s = T_g - \left(\sum_{i=1}^{30} A_i - 30A_1\right) - f(PD_{30}) \qquad (4)$$

where F_s = Future Surplus

Issuance of a permit required a positive contractible and overall (contractible plus future) surplus.

The intention of the contractible surplus initiative was to "focus on the established gas available for immediate contracting to meet Alberta requirements" (OGCB, Report 66-C, 1966, p. 30).

The concern the board saw was that its previous test did not evaluate the ability of local utilities to contract for future supplies. The board concluded (OGCB, 1966, p. 30) "that a method of assessment which would focus on the established gas available for immediate contracting to meet Alberta requirements is desirable and would to some extent afford a greater degree of protection to local consumers of gas."

At this junction, the board also slightly opened the door for more reliance on 'trend' gas, a chink that in 1969 – as described below – became wider. No changes were contemplated for reserves set aside in the future surplus calculation to satisfy requirements for delivery, that is, requirements other than those for 'cushion' gas. But to provide for peak-day deliverability, the board decided: "to give weight to more than the two-year growth in reserves when considering the cushion gas protection" (OGCB, 1966, p. 30).

b. 1969 Changes

The main change in 1969 was to the calculation of 'trend' gas, of which two elements were identified: the average annual reserve growth rate and the number of years to which the growth rate was to apply (OGCB, Report 69-D, 1969c, pp. 17–18). The board decided the growth rate in gas reserves should be based on the most recent ten-year period, not the long-term post-1950 period, but retained some flexibility in just how it would project the growth rate. In terms of the number of years of growth, the board saw its use of two years as conservative and adopted instead a formula that used estimated ultimate reserves to indicate the extent "to which reliance may be placed on future gas reserves" adding, however, that "prudence dictates that potential reserves should be assessed on a conservative basis" (OGCB, 1969c, p. 25). The formula adopted by the board was:

$$T_G = ((\mathrm{R}_{POT} - \mathrm{R}_{EST})/Q)/10 \qquad (5)$$

where

T_G = years of reliance on future gas reserves; rounded up or down to the nearest half year.
R_{POT} = estimated potential, initial marketable Alberta reserves.
R_{EST} = established initial marketable reserves in Alberta at the time of application of the formula.
Q = current output

It noted the formula has (OGCB, 1969c, p. 26) "the desirable characteristics of reducing the number of years of such reliance as the remaining potential reserves of the Province decrease. The Board believes the denominator of 10 used in the formula is reasonable at the present time."

Under this mechanism, then, the future gas reserves used in the future surplus was calculated by extending historical growth T_G years into the future. At the time of its implementation, the new formula increased the number of years of reliance on new discoveries from the earlier two years to about five years: a substantial adjustment.

5. Policy Changes in the 1970s

The board's procedures for determining surplus gas were reviewed in 1976 and 1979. The changes adopted in 1976 were modest; those in 1979 were substantive. In addition, the question of gas pricing intruded in the early 1970s.

a. Natural Gas Pricing and Removals

Before 1972, the Alberta Board's evaluation of removal proposals made no specific reference to price, although as part of its broad understanding of the economic feasibility of a proposal, the board reviewed pricing information. This situation changed after the gas-pricing imbroglio of 1972, when on the grounds of price the Alberta government withheld the approval of permits to TransCanada PipeLines Ltd. (TCPL). (For more discussion, see Section 4 on natural gas pricing. Basically, rising oil prices in the world and North America were felt by many to increase the value of natural gas, but prices in natural gas contracts, both old and new, were slow to rise.) At this time, the board had also reviewed the question of Alberta gas pricing, and, after issuance of its report in August 1972 (ERCB, Report 72-E-VG, 1972b), a policy statement was tabled in November in the Alberta legislature called "Alberta Government Statement on New Natural Gas Policies for Albertans."

Here the government urged accelerated price redetermination on all gas contracts and required purchasers of gas for removal to file pricing information with the board. Moreover, the government indicated its intent to "assess pending and future permits for export of gas from the Province in light of this policy statement." Given this injunction, the board as part of its export application review began to "offer its views on the suitability of the field prices, in the contracts of the applicant, in relation to the Alberta Government policy" (ERCB, Report 74-G, 1974, pp. 1-6, 1-7).

Inclusion of pricing as a removal criterion continued until the 1975 gas-pricing agreement between the Alberta and federal governments made it irrelevant. With deregulation, it emerged again, albeit in a somewhat subdued form (see below).

b. 1976 Changes

The two main issues were how reserves under contract to holders of removal permits in excess of permit authorizations should be treated and how detailed 'deliverability' schedules should be used in determining any surplus.

The first issue arose because of a perception that it would be desirable to have most of Alberta's requirement met by direct contracts with producers, while at the time evidence had suggested local utilities were experiencing difficulties in contracting for gas.

In essence, no changes were proposed to the extant procedure for determining current, future, and overall surpluses (see equations (3), (4), and (5), above). Attention focused on a refinement to the 'current surplus' test component, which did not identify the volumes of gas actually available for contracting by local utilities but was a key indicator of whether there were proved reserves surplus to current requirements. The new hurdle introduced by the board, called the 'availability for contracting test,' was intended to determine (ERCB, Report 76-C, 1976, p. 3-5) "whether there are sufficient reserves available to permit the Alberta Utilities and other Alberta consumers to contract directly for the province's general requirements ($30A_1$)." The mechanism was to deduct from the current reserves used in the 'current surplus' calculation (namely, proved reserves within economic reach less those deferred for conservation reasons), those reserves under contract to holders of removal permits, to identify reserves available to Alberta users; from this figure "reserves required for contracting by Alberta users" ($30A_1$) was subtracted to then define "the surplus of reserves available for contracting" (ERCB, 1976, p. 3-5).

The policy implications of this embellishment were as follows: if the 'contracting' surplus were zero or positive, enough gas would be available for contracting to satisfy the $30A_1$ requirement; if the figure were "modestly negative," the board would look at the gas that might be made available by permit-holders to Alberta utilities; if a significant deficit existed, no new permit volumes would be authorized even if the contractible and overall surplus calculation were positive (ERCB, 1976, p. 3-5).

The question of deliverability arose because of declines in the productivity of older gas reservoirs. The board rejected deliverability as a separate surplus test but intended to develop more detailed deliverability schedules as part of its background analysis. And if a serious deliverability problem became apparent, "the Board would likely refuse a removal application even if current, future and availability for contracting surpluses were found to exist" (ERCB, 1976, p. 3-10).

c. 1979 Changes

The 1979 changes reshaped the board's methodology for determining surplus gas and were comparable in extent to the adoption of the dual surplus calculation in 1966. The major changes were to (ERCB, Report 79-1, 1979):

- continue with the current surplus test but to reduce the associated protection allowance for $30A_1$ to $25A_1$;
- replace the future and overall tests with a deliverability test to assess whether long-term annual requirements can be met (deliverability is a general term used to denote an actual or expected rate of gas production);
- suspend the "availability for contracting" test.

The reduction in protection under the current surplus test presumed conditions had changed quite radically from when the $30A_1$ formula was introduced: there was greater confidence now in estimates of reserves and requirements; and long-term consumer protection might increasingly devolve on gas supplies from the substantial coal deposits with which the province was endowed. The supposition was that the level of protection should "have regard for the normal contracting period.… In the Board's view this suggests protection in the order of $20A_1$ to $25A_1$. In recognition of the NEB's adoption of $25A_1$ (see below), the Board also decided to select $25A_1$ as an appropriate protection period" (ERCB, 1979, p. 4-2).

The future surplus test was seen by the board as "not completely successful" (ERCB, 1979, p. 4-4), and the "method of allowing for future reserve growth is very conservative and consequently, yields misleading results" (ERCB, 1979, p. 4-6). The board suggested the purpose of the future surplus test could be achieved more successfully by a "broad assessment of demand and supply" (ERCB, 1979, p. 4-4). The availability for contracting test was dropped because the circumstances that led to its implementation were no longer present "nor … likely to occur in the foreseeable future" (ERCB, 1979, p. 4-6).

The supply side of the long-term assessment of gas supply–demand relationships was to be handled by a deliverability test, involving (ERCB, 1979, p. 4-7):

> … the best estimate of the annual productive capacity of both established and future reserves and would be compared to forecast Alberta requirements. The forecast period should be at least as long as the term of the requested permit but the Board for its own analysis probably would make its projection for a 25-year period.

The precise degree of reliance on gas discoveries was not identified in the report. Apparently the board was to make its best estimate of future reserve growth over the period of analysis without tying the estimate into any specific 'trend' gas formula.

The board expected that if the future deliverability test disclosed a significant supply deficit, conditions would be placed on permits and lesser volumes for removal would be authorized, but the board wanted to (ERCB, 1979, p. 4-8) "retain sufficient flexibility in interpreting the deliverability test so that it could judge each application on its own merits and authorize such volumes as it considers to be appropriate under the circumstances."

No changes were made to the Alberta surplus test between 1979 and 1986, but in 1987 the test was reviewed – a commitment made by Alberta in the October 1985 *Agreement* with Ottawa to make the controls more compatible with a 'market oriented pricing system' (*Agreement*, 1985, clause 23(1)).

Changes have been made to the legislation and most recently to that governing the issuance of export permits from Alberta. The latter was quite important in terms of accommodating deregulation. Moreover, the Alberta government issued a policy statement on long-term protection of Alberta natural gas consumers. All these matters are reviewed below.

6. Post-1979 Legislative and Policy Resonances

As mentioned earlier, in 1984, the *Alberta Gas Resources Preservation Act* was amended. The provision for diverting exports to meet any local shortages was written into the act, rather than simply appended to export permits. More importantly, a cost-benefit criterion was added to the requirements and reserves features to which the board was to "have regard" in granting permits, namely, "(c) the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta" (*Gas Resources Preservation Act*, 1984, Section 5(3)).

To accommodate the intent of the 1985 federal–provincial *Agreement*, the act was amended in 1986 to remove the clause (c) criterion in granting a removal permit and replaced with a general criterion, namely, "(c) any other matters considered relevant by the Board" (*Gas Resources Preservation Act*, 5A 1986 C1753). The former clause (c) (cost-benefit) criterion has since been included as one of the ministerial conditions attached to removal permits. The new general criterion left the board with quite a lot of latitude.

Under the revised act, gas could not be removed from Alberta unless under a permit issued by the ERCB. Once the ERCB granted a permit, the permit was forwarded to the Alberta Minister of Energy for final approval. It is at this stage that conditions can be imposed if the government so chooses. Until the start of the one-year transition for implementing the October 31, 1985, *Agreement*, no conditions were attached to the permits, with the exception of a now-defunct British Columbia LNG project for which Alberta natural gas was to be supplied.

However, ministerial permit conditions emerged during the transitional period. They include:

(a) **Surplus test requirement** – gas should not be removed from Alberta after July 1, 1987, unless the Minister of Energy was satisfied with the surplus test review then being undertaken by the NEB and the ERCB.
(b) **Market requirements** – permittees could not serve a market other than the one filed by the permittee with the Department of Energy.
(c) **Incrementality condition** – permittees were not allowed to displace an existing market served under a contract in force on October 31, 1985, unless the Minister allowed so.
(d) **Delivery commencement** – gas would not be removed if pipeline deliveries did not commence within the ninety-day period following permit issuance.
(e) **Contract carriage condition** – if gas were moved in a provincial distributor's system outside Alberta, then the law in that province must provide for the possibility of the transporter of the gas being able to arrange for transportation service on that distribution system.

At the same time, the federal authorities urged the Alberta government to give heed to the following principles in revising its surplus determination procedures (letter from Marcel Masse, Minister of EMR to Neil Webber, Alberta Minister of Energy, undated but October 1986).

- Market forces will ensure that natural gas supply and demand will balance.
- Certain categories of end users will continue to require explicit supply protection because of their inability to switch readily to alternate fuels and to contract directly with producers for their supply needs. It can be assumed that the period of protection required by those consumers will correlate to the contractual arrangements entered into on their behalf.
- However, where end users elect to contract directly for gas supply on a short-term or a long-term basis, it was assumed these contractual arrangements would provide the level of supply protection desired.
- Natural gas marketed for sale outside of Canada, should be presumed to be protected by the contractual arrangements underlying the sale.
- Natural gas imported to Canada can be presumed to contribute to the protection of reasonably foreseeable requirements.
- Surplus determination procedures should not be considered as a substitute for private sector contractual arrangements.

Subsequently, the Alberta government issued a "directive" that the ERCB consider certain policy parameters in its review of natural gas protection, all in the context of the intent of the *Agreement* to provide freer access to domestic and export markets and to achieve a market-oriented pricing system (letter from Neil Webber, Alberta Minister of Energy to Vernon Millard, Chairman ERCB, October 28, 1986).

Specifically, the Alberta government suggested that provision be made for "reasonable needs" of end users unable to contract directly with producers (typically residential, commercial, and small industrial users served by utilities), but not for end users (typically industrial users) capable of arranging security of supply through their own contracting activities. The latter were seen as not requiring mandated protection. Moreover, the government thought it possible to devise surplus procedures that would not distort market forces, which were seen as reliable arbiters to balance supply and demand. Surplus determinations were not to be viewed as a substitute for private-sector contractual arrangements to meet market requirements (*Policy Statement by the Government of Alberta Respecting Long-Term Protection for Consumers of Natural Gas*, October 1986).

7. The 1987 Alberta Surplus Test

Not surprisingly, the climate of natural gas deregulation initiated in 1985 and the policy directives of both the federal and provincial governments described beforehand fostered further relaxation of Alberta policies. The 1987 policy afforded a fifteen-year period of protection for Alberta's so-called "core" markets (residential, commercial, and small industrial), plus protection of non-core contracted requirements, in contrast with the previous twenty-five-year protection period for all (core and non-core) markets (ERCB, 1987).

In more detail: at any point in time, the gas reserves available for export from Alberta were defined as the difference between total available reserves and Alberta's requirements for the core market, plus amounts under contract to non-core (larger industrial) Alberta markets, plus remaining export permit commitments. Symbolically, the formula looked like:

$$G_S = R_{EST} - 15C_1 - CNC - PFS - E \qquad (6)$$

where:

G_S = surplus gas.
R_{EST} = established gas reserves.
C_1 = core market requirements, current year.
CNC = contracted non-core market requirements.
PFS = permit related fuel and shrinkage.
E = remaining authorized exports.

At that time, the following values approximately held for each component of (6); units are in trillions of cubic feet (Tcf's) at 1,000 BTU/cf.

$R_{EST} = 59.2$; $15C_1 = 3.5$; $CNC = 1.7$; $PFS = 4.0$; and $E = 40.0$

Inserting these values in (6) yielded a volume of gas reserves available for inclusion in new export permits of some 10 Tcf.

However, while the Alberta government blessed relaxation of the surplus test, at the same time it tightened controls over the conditions governing removal of gas from the province. An amendment to the *Gas Resources Preservation Act* was passed in June of 1987, which gave the Alberta government the power to impose ministerial conditions on all gas removal permits, including permits issued before enactment of this amendment. This retroactive feature was intended to prevent gas from flowing to domestic markets at "discount" prices under certain existing gas removal permits that had hitherto provided for gas sales under virtually any terms. The government also moved (in 1988) to base royalties on natural gas from Crown leases on the highest of the actual sales price or 80 per cent of the average Alberta field price, hence discouraging "excessive" price discounting.

In early 1995, the Alberta government dropped the permit removal conditions for short-term contracts, thereby giving producers greater flexibility in negotiating gas sales. Also, Alberta core market users were given freedom to enter into direct gas purchase arrangements. In the event that Alberta domestic use began to impinge on available supplies, short-term permits would be the first to be relinquished, particularly as Alberta users bid on available supply. Should market disruptions lead to local shortages, legislation provides for diversion to the local market of gas licensed for removal, although the proportionality provisions of the Free Trade Agreement among Canada, the United States, and Mexico may then kick in. (See the discussion of the Free Trade Agreements in Chapter Nine.)

This section has reviewed the details of the Alberta policy to regulate ex-provincial natural gas sales to 'protect' Alberta consumers. The complexity of the protection formulae and their frequent modification attest to the difficulty of the task and may partly explain the willingness to allow a greater reliance on market mechanisms in the natural gas market as deregulation gained favour after 1984. Section C, below, offers some evaluative comments on the gas protection policies, but before doing that we will review the federal export control polices for natural gas.

B. Development of Federal Policy

As mentioned above, initially the Alberta Board included protection for Canadian requirements in its removal formula, but inevitably this responsibility devolved on the federal government itself, and specifically on the National Energy Board (NEB), established in 1959. (McDougall, 1982, chaps. 4, 5 and 6, discusses Canadian policy with respect to exports from before 1959 and up to 1971. He also reviews the Borden Commission's recommendations on natural gas.)

The motivation for federal policy can be traced back to the *Report* of the Royal Commission on Canada's Economic Prospects, which contained the following recommendation (Royal Commission on Canada's Economic Prospects, 1957, p. 146):

> In order that a sound and comprehensive policy may be worked out with regard to development, exports, imports and consumption of forms of energy in Canada, we propose that a national energy authority be established which would be responsible for:
>
> (a) advising the Federal Government and, upon request, any provincial government in all matters connected with the long-term requirements for energy in its various forms and in different parts of Canada; methods of promoting the best uses of energy sources from a long-term point of view; export policy, including such questions as the further refining of oil and gas in Canada and the disposal of by-products; coal subsidies, etc.
> (b) approving, or recommending for approval, all contracts or proposals respecting the export of oil, gas and electric power by pipeline or transmission wire.

As Bradley remarks (1972, p. 3), "the recommendation displays primary concern with establishing policies that make certain that Canadian energy resources be developed with regard to Canadian needs for these resources, and it implies that one way in which this goal might be frustrated would be by excessive exportation."

1. The Legal Framework

Control by the federal government on exports of natural gas was implemented by the *National Energy Board Act* of 1959. Section 81 provides that no export of gas from Canada shall take place except under licence, while Section 82 provides for issuance of licences under such terms and conditions as prescribed by the regulations. Section 83 of the act said:

> Upon an application for a license the Board shall have regard to all considerations that appear to it to be relevant and, without limiting the generality of the foregoing, the Board shall satisfy itself that:
>
> (a) the quantity of gas or power to be exported does not exceed the surplus requirements for use in Canada having regard to trends in discovery of gas; and
> (b) the price to be charged by the applicant for gas or power exported by him is just and reasonable in relation to the public interest.

Note the similarity between the wording of clause (a) and Alberta's *Gas Resources Preservation Act*. However, the specific reference to price in clause (b) did not correspond to the Alberta statute; in Alberta, the price issue was subsumed at that time in the general admonition of public interest.

The duration of any export licence was not to exceed twenty-five years (see *Act*, Section 85(b)). The act also enabled the NEB to revoke or alter any export licence it may issue, but (NEB, 1970, p. 10-2):

> … it is a premise of the Board's approach … that once a license for firm export for a fixed period has been issued, it should not be diminished in effect or put in jeopardy so long as the conditions of license are observed. (Reliability of licenses was seen as desirable both) … in equity to producers, exporters, United States importers and consumers of gas licensed for export, and in the interest of orderly development of relations between Canada and the United States in respect of natural gas.

Originally the Federal Power Commission in the United States had viewed Canadian natural gas supplies as insecure. To the board, this also entailed the use of "reasonable caution" in assessing Canadian requirements to avoid any potential conflict between reliability of exports and first preference being given to Canadian customers. This is important in terms of interpreting the mechanisms that emerged.

The treatment below of federal policy is not quite as detailed as that for Alberta. The interested reader is referred to Watkins (1982a) for further details.

2. Initial Policy and Policy Changes in the 1960s

Again, it was up to a regulatory board to develop procedures to apply the statute. The procedures developed by the National Energy Board (NEB) were very similar to Alberta's – a characteristic not entirely divorced from the fact that the NEB's first chairman was formerly chairman of the Alberta Conservation Board. Thus, in its first gas export report in 1960, the NEB saw a thirty-year period as appropriate for calculating "reasonably foreseeable" Canadian gas requirements (NEB, 1960). An allowance for Canadian requirements and proposed exports was deducted from established reserves, but a more distinct division was made between the current and an overall or future surplus calculation than employed by the Alberta Conservation Board at that time.

A twenty-one-year period (1960–80) was selected as that for which requirements should be met from presently established reserves. In the case of Alberta, such protection, necessitated by provincial policy, was extended to thirty years. The requirements elsewhere in Canada were levelled at the 1963 rate for the balance of the twenty-one-year period. The NEB's rationale for selecting 1963 as a base was (NEB, 1960):

> … in general it has not been practicable for pipeline companies to obtain contracts for the purchase and sale of gas for incremental requirements commencing three or four years in the future. Incremental requirements beyond the 1963 level accordingly have been allocated to future discoveries of gas. In every case, all requirements accruing after 1980 are assumed to be met from future reserves.

Note here the intention that, excepting Alberta, the protection for ongoing requirements from established reserves over the twenty-one-year period was dictated by commercial contractual practices.

Symbolically, the current surplus calculation was:

$$C_s = R_{EST} - E - \sum_{i=1}^{3} A(EA)_i - 18A(EA_4) - \sum_{i=1}^{30} A_i \qquad (7)$$

where

C_s = "current" surplus.
$A(EA)_I$ = requirement for all provinces excluding Alberta, year i.
$A(EA)_4$ = fourth-year requirement for all provinces excluding Alberta.
A_i = Alberta requirement, year i.
E = authorized exports, and other symbols as defined previously.

The future surplus calculation effectively embraced the current surplus calculation. The increment in gas demand for all Canadian provinces other than Alberta between the fourth year (1963) and the twenty-first year (1980), plus all demand from the twenty-second year (1981) to the thirtieth year (1989), plus thirtieth-year, peak-day requirements were to be satisfied from yet-to-be discovered reserves (i.e., trend gas). The trend gas allowance was set at some 2.5 trillion cubic feet (Tcf) per annum for at least the next ten years, and thereafter on a somewhat decreasing scale. Thus the "future" surplus was:

$$F_s = C_s + 30T_g - [\sum_{i=1}^{30} A(EA)_i - 18A(EA_4)] - f(PD_{30}) \qquad (8)$$

What is significant in this formula is that while the framework remained the same as Alberta's the provisions were considerably more liberal. Established reserves only protected the equivalent of about twenty-one to twenty-two years of the first-year gas requirements for provinces other than Alberta, compared with some twenty-five years of cumulative projected requirements in Alberta, while continuous extrapolations of trend gas – not just for the two years in the Alberta future surplus calculations – were used to protect all future demand (excluding Alberta) from year four to year twenty-one.

Interestingly, the export permits issued by the NEB never provided a loophole similar to that in the Alberta permits, whereby local utilities could access export gas in the event of local supply exigencies. But the NEB *Act* gave the NEB the right to alter any licence it issued, which allowed for possible diversion of gas to the domestic market. In effect, this was a "*force majeure*" type of clause.

Some minor adjustments were made in 1965. More substantive changes were made in 1966 (NEB, 1966). In essence, the "current" surplus formula simply became the difference between established reserves and twenty-five times the fourth-year requirement (a_4) plus already authorized exports, thus:

$$C_S = R_{EST} - 25a_4 - E \qquad (9)$$

In terms of the future surplus calculation, the 1966 report of the NEB treated future supply as comprising: available reserves; established reserves to become contractible between the fifth and thirtieth year, comprising nearly all the reserves currently beyond economic reach plus all deferred gas; and twenty years of long-term trends. Future requirements were: Canadian requirements projected over thirty years; terminal-year peak-day protection; and existing export licences. Thus, the future surplus was approximated by:

$$F_s = R_{EST} + 20T_g - \sum_{i=1}^{30} A_i - E - f(PD_{30}) \qquad (10)$$

In 1967, price entered the picture. (See Section 4.2, for more detail.) The NEB adopted three specific price guidelines, which in effect fleshed out clause 83(b) of the NEB *Act*. The adopted guidelines were as follows. The export price (1) should cover all costs, (2) should be fair compared to prices charged to customers in Canada next to the export point, and (3) should not be noticeably lower than the prices of substitute fuels (NEB, 1967, p. 3-19).

Subsequently, the second price test was more formally defined as 5 per cent above the "adjacent" Canadian price (NEB, 1971). To facilitate application of these guidelines, in 1970 the NEB *Act* was amended to 'unhook' the gas export price set by the board from any price written into gas export contracts.

3. Policy Changes: The Formula in 1970

In 1970, the NEB's current surplus calculation remained similar to the Alberta Board's then "contractible" surplus calculation, namely, total existing supply – consisting of established reserves, less adjustments for deferred reserves, reserves beyond economic reach, and pipeline losses and shrinkage, plus imports of gas (mainly minor amounts into Ontario) – was compared with current Canadian requirements plus authorized exports. Canadian requirements distinguished between other areas of Canada and Alberta.

The NEB did not use a formal future surplus calculation comparable with that employed by the Alberta Board. Instead, the current surplus test was extrapolated, with established reserves augmented by a fixed long-term growth rate of 3.5 Tcf per year (NEB, 1970, pp. 4-40 and 4-41). The policy implications of the results of the extrapolation were left quite open, but, of course, satisfaction of the current surplus test remained a necessary condition for any award of export permits. In the main, the extrapolation was used to determine by how much the long-term growth rate in reserves might have to vary to provide the same degree of protection fifteen to twenty years in the future as the policy granted in the initial year (NEB, 1970, p. 10-13).

The NEB's policy at that time also covered some more peripheral aspects, including the need for (NEB, 1970, p. 10-15):

> … sound development of those pipeline transmission systems which are the means of providing gas service to Canadian consumers. The carrying of export gas should be a profitable activity, which, when undertaken by transmission systems serving Canadian customers, should make available to such customers a share in the economies of scale and such benefits as may arise from the contribution of exports to the financial health of the transmission system. In effect this means that where a choice has to be made between licensing exports by a project wholly oriented to export and a project which serves Canadian customers and export customers, if all other factors were equal the choice would have to be in favor of the project serving Canadian as well as export customers.

Also, in 1970, the NEB recognized that established transmission systems may receive licences for less than the twenty-five-year maximum provided by the statute but a new export system might have to be given a longer initial licence to enable the project to be financed. One concern was that too great a dedication of gas reserves to export commitments could force Canadian requirements beyond the short term to be met from gas discoveries in relatively high-cost, remote areas. Shortening the export permit period would assist in meeting this kind of objection, and fifteen years was the period the NEB thought appropriate, except possibly where extension would be necessary to finance new pipelines or major looping programs (NEB, 1970, p. 10-21).

In essence, the 1970 formula held until a substantial change was made in 1979. But after denial of export applications in 1971, the formula was effectively in abeyance during most of the 1970s.

4. The 1979 Changes

The NEB issued some criteria for determining surplus, on which the 1979 formula review was predicated. The criteria were that the surplus formula should: be easily understood and applied; incorporate gas deliverability rather than reserves in the supply considerations; be flexible to respond to changing circumstances; provide continuing protection for Canadian demand throughout any period of export; provide incentive and encouragement to the gas industry; satisfy licensed export commitments to the extent possible; and reserve to Canadians any benefits from conservation restraints undertaken by Canadians (NEB, 1979b, p. 94).

After an extensive review, the NEB adopted a tripartite test procedure: current deliverability, current reserves, and future deliverability. Under current deliverability tests (NEB, 1979b, p. 95):

> … it would be necessary to demonstrate a surplus of annual deliverability from established reserves in excess of the sum of total annual Canadian requirements and authorized exports for a minimum period of highly assured protection. This test would be used to determine the upper limit of the maximum annual quantities that might be surplus during a period of highly assured protection.

The NEB set the "highly assured" protection period as a minimum of five years.

Surplus deliverability – an annual quantity – would be:

$$S_{Di} = D_{Ei} - A_i - E_i \tag{11}$$

where

S_{Di} = surplus deliverability, year i.
D_{Ei} = Deliverability from established reserves, year i.
A_i = Canadian requirements, year i.
E_i = authorized exports, year i.

The NEB suggested tests solely relying on deliverability could lead to excessive industry activity to increase deliverability at the expense of developing new reserves. Thus, a reserves test was deemed necessary to maintain a "reasonable relationship" between established reserves and deliverability, defined as:

$$C_S = R_{EST} - E - 25A_1 \tag{12}$$

Licences for export of gas could be granted but should not exceed the maximum total quantity surplus under the reserves test and should fall within the limits established by the current deliverability test.

In considering new exports that met both the current deliverability and the current reserves test, the NEB was concerned to ensure such exports would not result in deficiencies over the longer term. Accordingly, under the future deliverability test (NEB, 1979b, p. 95),

> … annual quantities of gas could be deemed to be surplus if the forecast deliverability from established reserves and reserve additions, etc., exceeded expected Canadian demand plus authorized exports for a reasonably foreseeable period. At present the Conservation Board believes this period of future deliverability protection should be some ten years.

Thus the future deliverability was to ensure: first, that any proposed exports that might satisfy the first two tests would not cause a future deliverability shortfall within a ten-year period; and second, if the NEB granted a licence term in excess of that indicated by deliverability from established reserves, the extended licence would be limited by projected deliverability from future reserves. The NEB indicated "frontier" natural gas reserves would not be included until it was satisfied that the transportation facilities would be constructed.

5. The 1982 Policy Change

In the early 1980s, significant underlifting of authorized exports, along with slow growth in domestic natural gas demand and relatively abundant supply, triggered another review by the NEB of its export formula.

As discussed, the 1979 decision involved a triumvirate of tests – current reserves, current deliverability, and future deliverability – all of which required satisfaction. Moreover, for any exports dependent on reserve additions, the export licence was conditional. If gas deliverability were less or if Canadian requirements were greater than estimated when the licence was granted, these conditional export authorizations could be reduced or revoked (NEB, 1982, p. 12).

In its 1982 decision, the NEB renamed and modified the current reserves test, now calling it the "Reserves Formula" (NEB, 1982, p. 16). The modification related to the allowance for existing licensed exports: the amount set aside was adjusted to reflect the maximum quantities exportable under existing licence conditions; previously, the amount set aside reflected the remaining licensed quantities, whether exportable or not. The Reserves Formula set the maximum surplus available for export and could be written:

$$C_S = R_{EST} - E' - 25A_1 \tag{13}$$

where

E' = quantities exportable under existing licences and other symbols as previously defined.

The current deliverability test adopted in 1979 was dropped. Instead, a deliverability evaluation was adopted involving "best" estimates of future gas supply and demand, comprehending: (a) deliverability from established reserves and future reserve additions; (b) expected Canadian requirements; and (c) estimated exports under existing licences. In essence, points (a) and (b) subsumed elements in the 1979 current and future deliverability tests. The allowance for exports was a forecast by the NEB of exports that would be taken under existing licences, rather than the maximum annual exports licensed. The decision in 1979 to exclude supply from frontier regions unless transportation facilities were to be constructed was upheld in the 1982 decision.

The new deliverability appraisal did not cite minimum protection periods – the five- and ten-year periods previously adopted in the 1979 current and future deliverability tests. Rather, "the Board will use its judgment to determine the annual deliverability profile which may be deemed surplus to Canadian needs" (NEB, 1983, p. 17).

The intention of the revisions was to provide more flexibility in determining surplus gas, subject to the upper limit represented by the Reserves Formula. The NEB noted that its new procedures were similar in structure to those of the Alberta Conservation Board.

The specific export surplus tests were used for awarding export licences. In addition, the NEB made provision for limited short-term exports for up to two years – a new departure. Such flexibility was intended to expeditiously permit exports to "replace quantities foregone because of regulatory or construction delays associated with long term licenses, or to take advantage of a new market opportunity" (NEB, 1983, p. 21).

On the pricing front, the 1970s saw emergence of uniform border prices for all gas exported to the United States (Watkins and Waverman, 1985). It was not until July 1984 that a more flexible pricing policy was adopted. And in 1985 export gas prices were deregulated subject to the adjacent border price test that the price to U.S. buyers be not less than the price for Canadian buyers purchasing gas near the border-crossing point (Canada, Western Accord, 1985).

6. The 1986 Policy Change

Deregulation of the Canadian petroleum industry in 1985 provoked a further review of the export formula. The changes mark elimination of the cherished reserves test, a test that was seen as resulting in excessive inventory carrying costs and as not being needed in a market-sensitive pricing environment. The NEB pronounced its expectation of being "able to place increasing reliance in the future on the responsiveness of supply and demand to price and less reliance on the size of currently established reserves in protecting future Canadian requirements" (NEB, 1986c, p. 23).

The new surplus determination procedure was based on the ratio of reserves to production, called the R/P Ratio Procedure, entailing four steps. First, the maximum potential surplus is calculated for each year as the amount by which annual supply, defined as remaining reserves divided by a stipulated R/P ratio, exceeds estimated annual demand (domestic demand plus already authorized exports). The stipulated R/P ratio was set at fifteen. The second step consisted of an array of trial "profiles and durations for possible additional exports" to identify years in which the R/P ratio might drop below fifteen. The third step was the "Productive Capacity Check," replacing the Deliverability Appraisal. Here productive capacity would be assessed to see whether forecast demand could be met, especially for years during which the actual R/P ratio might fall below fifteen. The final step is to determine the "most appropriate" export profile predicated on the preceding steps and on security of supply if the R/P ratio dips below fifteen, on the capacity of the existing infrastructure to produce and transport new exports, and on the estimated net economic benefits to Canada.

The procedure was intended to embody "a combination of security of supply and flexibility which the Conservation Board considers to be appropriate in the context of market sensitive pricing and the maturity of the Western Canada Sedimentary Basin" (NEB, 1986c, p. 24).

In essence, then, the (upper bound) total surplus was:

$$S = \sum_{j=1}^{n} [\frac{R_{EST_j}}{15} - A_j - E_j] \quad (14)$$

where

j = year counter.
n = projection period, and other symbols, as defined earlier.

Although the NEB had adopted an R/P ratio of fifteen, this ratio was seen as one varying over time in response to changing conditions, especially to reflect the desired margin between actual and stipulated R/P ratios. The adjacent border price test was dropped in October 1986. Instead, general surveillance of export pricing was instituted (letter from Marcel Masse, Minister of EMR to Roland Priddle, Chairman of the NEB, October 29, 1986).

7. Mandated Surplus Test Abandonment, 1987

Almost as soon as the ink was dry on the 1986 policy change, a further review was set in motion. Hearings on prospective revisions were completed in May 1987.

The federal government – which in effect initiated the review – mentioned some parameters it felt should be considered. These include the implications for surplus determination of: growth in direct sales to domestic customers; imports of gas from the United States; and renegotiation of domestic prices under long-term "system" gas contracts. Moreover, the then Minister of Energy had clearly indicated that as market forces increase more emphasis should be given to contractual arrangements – distinguishing between core and non-core customers – than to the formalities of surplus calculation. The implication seems to be that it might be desirable for the government to monitor the market to ensure that buyers of natural gas enter into contracts that protect the long-term interests of their core customers.

In light of the minister's pointed strictures, it was not altogether surprising that the NEB had decided to eliminate the mandated surplus test entirely and allow gas exports to be determined in large part by market forces (NEB, 1987, pp. 24–27). No transition period was provided in this move to deregulate gas exports.

Under the new market-based procedure (MBP), the NEB would hold public hearings on any application to export natural gas under contracts lasting at least two years. The hearings would include a complaints procedure to ensure that all Canadian users can gain access to additional supplies of gas under the same terms proposed for the export sale. Prospective gas exporters had to submit an export impact assessment at the hearing demonstrating that the proposed exports are surplus to Canadian gas requirements. As well, exporters had to provide evidence to the board that the proposed sales are in the Canadian public interest.

The MBP also required the NEB to monitor Canadian energy markets on an ongoing basis. And the board was to conduct periodic studies analyzing natural gas supply, demand, and prices to determine whether Canadian gas requirements continued to be met under this new policy.

Note that, although the surplus formula was dropped, the legislation still enjoins the NEB to only approve exports surplus to 'foreseeable' requirements. In effect, the meeting of the surplus test devolved on the prospective exporter with the NEB appearing to act more as an adjudicator between domestic and exporting interests.

On March 15, 1989, the reliance upon MBP was furthered when "the Board decided it would no longer use benefit-cost analysis in considering gas export license applications and decided that, with respect to contract flexibility, it would operate on the presumption that, where contracts are freely negotiated at arm's length, they would be in the public as well as the private interest" (NEB, 1990, p. 31).

As was noted in Section 2, following deregulation, the natural gas market continued to evolve toward greater contractual flexibility, including greater reliance on spot markets. A growing volume of gas was exported under short-term contracts. The 1994 *Annual Report* of the NEB noted that 35.4 billion cubic metres of gas in 1994 would be exported under contracts of two years or less. This was about one half of total exports, as contrasted with 30 per cent of exports in 1986. No public hearing was required, and, while the NEB presumably continued to monitor the gas prices, such exports were generally presumed to be in the public interest. By 2001, about 80 per cent of Canadian gas exports were short-term.

NEB hearings were still held for gas exported under contracts with duration longer than two years. Most frequently, these were associated with the construction of new facilities either to move the gas or for consumption (e.g., a gas-fired electricity generating plant). Presumably, the buyer and/or pipeline desired an assurance of gas supply before financing and/or building the new facility. The appropriate focus of such hearings was left somewhat vague under the MBP, with its presumption that freely negotiated deals are likely to be in both the private parties' and the public's interest. Formal criteria for establishing whether a "surplus" exists have been dropped, leaving some domestic interests worried about long-term Canadian supplies but with no obvious procedure for showing that exports are excessive. A party applying for a long-term export licence was obliged to inform potential Canadian purchasers of the intent and that they were offered access to the gas on the same terms as the U.S. buyers. This amounts to a 'complaints procedure,' and if no prospective Canadian buyer offers objections, the licence will normally be granted. (This 'complaints procedure' to market-based exports differs in basis from the 'fair market access procedure' for crude oil discussed in Chapter Nine.)

Some government export hearings have seen intervener groups arguing that the environmental impacts of natural gas exports should be assessed so that the full social costs and value of the gas are taken into account before export authorization is given. The environmental concerns expressed relate in part to any damage caused to the Canadian ecosystem by gas production that would imply a social cost of gas higher than private production costs, apart from royalty (tax considerations). Concern has also been expressed about the effects of gas utilization in the United States (e.g., if conservation or benign renewable energy forms are abandoned), where the price paid may exceed the social value of gas consumption. Thus far, the NEB has not been persuaded that these concerns are significant enough to warrant formal modification of the MBP.

Now that the gas protection policies of Alberta and the federal government have been described, we will offer some evaluative comments.

C. Economic Analysis of Natural Gas Protection Policies

The obvious complexity of the regulations to generate protection for natural gas consumers – and the frequent modifications to the regulations – makes detailed analysis difficult and tedious. Instead, we focus on two related issues: (1) what were the general effects of the regulations? and (2) were they a desirable form of regulation?

1. Reserves and Supply

The natural gas protection policies involved potential restrictions on sales to customers outside the region (ex-Alberta or ex-Canada). They operated by comparing 'available' natural gas volumes to projected regional consumption in order to determine whether a surplus existed. The initial regulations used a 'stock' concept of availability, by employing reserves. As time passed, more 'flow'-related concepts were admitted to measures of availability, beginning with the admission of projected future discoveries and eventually leading to more emphasis upon deliverability than on reserves. Despite such changes in regulations, their primary effect was to require large industry inventories in support of current sales. (The discussion below draws substantially on that in Bradley, 1972. Waverman 1972, 1973, considers the trade effects of the policies.)

All the surplus formulae identify current stocks as one element and then make varying provisions for future stocks. Current stocks correspond to the notion of working inventory. In the context of surplus policies, they normally consisted of established reserves less certain volumes deferred for conservation reasons and less an allowance for reserves currently uneconomic, called 'beyond economic reach' reserves. An example of conservation reasons would be cycling schemes, where natural gas is cycled back into the reservoir to recover liquids that might otherwise be lost if the reservoir were produced on a normal basis. Established reserves comprise both proved reserves – those believed to exist with virtual certainty under prevailing economic conditions and technology – and a proportion of probable reserves. Probable reserves are those that may be recovered in the vicinity of proved reserves but where there is some degree of geological, engineering, or operational risk.

Established reserves do not constitute the resource base. The latter is at the behest of nature: the total amount present in the earth's crust within a given geographic area. Established reserves are only a fraction of reserves that might become available if prices rose or technology improved, quite apart from those reserves that may be added in the normal course of exploration under prevailing conditions.

The distinction between proved reserves and beyond economic reach reserves – expected reserves in discovered but undeveloped reservoirs – is shown in Figure 12.2. Here, the current price is designated P_c. To the left of the vertical broken line, proved reserves are shown in blocks of ascending cost, all with costs lower than P_c. To the right of the line are shown blocks of reserves with costs exceeding P_c, the beyond economic reach category. Figure 12.2 is static, simply classifying established reserves according to whether they

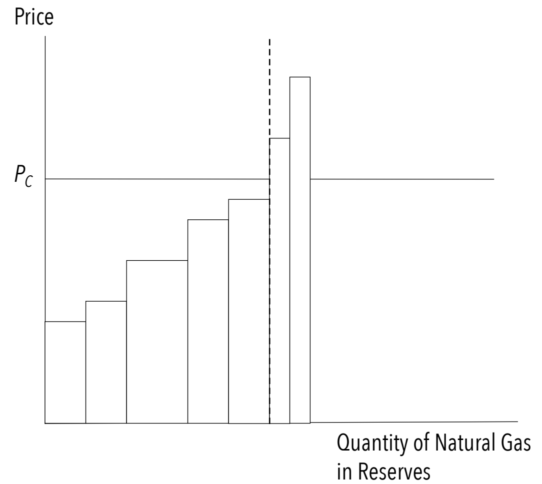

Figure 12.2 Natural Gas: Economic and Beyond Economic Reach Reserves

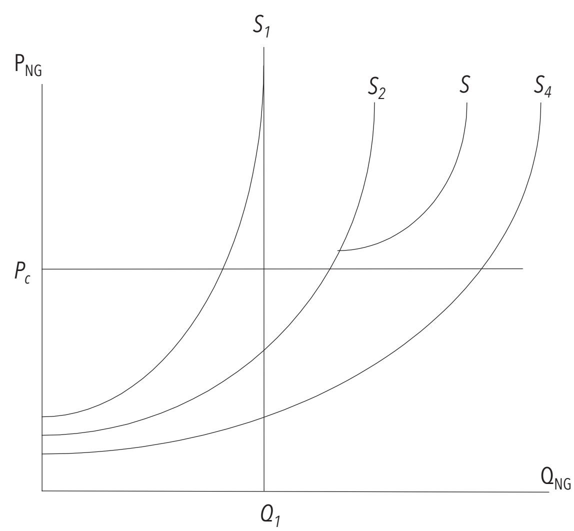

Figure 12.3 Natural Gas Supply

are economic to produce at prevailing prices or not; it is an example of what, in Chapter Four, was called a 'resource stock supply curve.'

Another way of looking at supply is to map stocks of reserves into rates of output and examine dynamic aspects over time. This is done in Figure 12.3, where various conventional supply curves are shown. The leftmost curve, labelled S_1, relates to output from established reserves given installed capacity. It is long-term in the sense that the prevailing price, P_C, is sufficient to cover both operating and investment costs, but the fixed installed well capacity precludes any increase in output beyond Q_1, irrespective of price. The curve labelled S_2 represents additional capacity added by more intensive development of reserves already economic to produce. The assumption is that additional development can take place at much the same unit cost of output as beforehand.

The curve in Figure 12.3 labelled S_3 extends the S_2 curve by including output from known discoveries not economic to develop at prices below P_C. The curve S_4 illustrates the outward shift in supply in response to exploration, at various price levels. More generally, the curve S_3, which represents supply from current established reserves, can be viewed as shifting to the left as these reserves are depleted, but this may be offset by shifts to the right as new reserves are discovered and developed.

Overall, it is fair to say that the basic uncertainties governing the exploration process make supply analysis difficult. Hence, widely accepted estimates of the price elasticity of supply are elusive. Figure 12.3 suggests such elasticity arises not only from new exploration inspired by higher prices but via increased recovery from existing reserves. An indication that the latter is not trivial is provided by estimates of the Energy Resources Conservation Board (ERCB) in 1972 that an increase in the field price of gas would lead to a lower abandonment pressure, improved economics of developing marginal gas reserves, and increased recovery of oil field solution gas (ERCB, 1972b, p. 6-12). At that time, the ERCB estimated than an increase in the field price of gas of 10 cents would increase Alberta's established reserves by about 10 Tcf (ERCB, 1972b, p. 6-14). Given a field price at the time of about $0.16/Mcf and initial recoverable reserves of some 60 Tcf (ERCB, *Reserves Report*, 84-18, Table 8-2), this translates into a crude supply elasticity of 0.27 with respect to established reserves. A higher elasticity would result from the inclusion of reserve additions associated with higher prices.

That the surplus tests were associated with unusually high inventories is strongly suggested by the much higher reserves to production (R/P) ratios of natural gas than crude oil from the late 1950s on, after connections to ex-Alberta markets had been established. The R/P ratio was also lower for the U.S. natural gas industry than the Canadian (e.g., 10 in the U.S. in 1980, and 28 in Alberta). This evidence would be stronger if there were a 'natural' R/P ratio that might be used as a standard of reference. For example, at what R/P ratio would a unitized, effectively competitive industry operate? It has been suggested that an R/P ratio in the order of ten would be likely. Much lower and intensive use of reserves probably damages ultimate recovery. Much higher and the investments to establish reserves would be waiting unnecessarily long for payout. Despite these arguments, it is impossible to be precise about a 'natural' R/P ratio. For one thing, the ratio is bound to be affected by short- and medium-term lags and uncertainties. Large discoveries, for instance, may have to wait a number of years for the development of transmission facilities and new markets. Beyond this, the optimal drawdown of reserves (especially via infill drilling) should vary with current and anticipated market conditions. For example, suppose new discoveries generate production increases and begin to drive down current prices, while leaving longer-term price expectations relatively unchanged. Then future profits will begin to appear relatively more attractive (the 'user cost' becomes a more significant proportion of cost) and the optimal R/P ratio will rise. In spite of these caveats, an Alberta natural gas R/P ratio consistently in excess of twenty-five throughout the period of regulatory gas protection policies is remarkable.

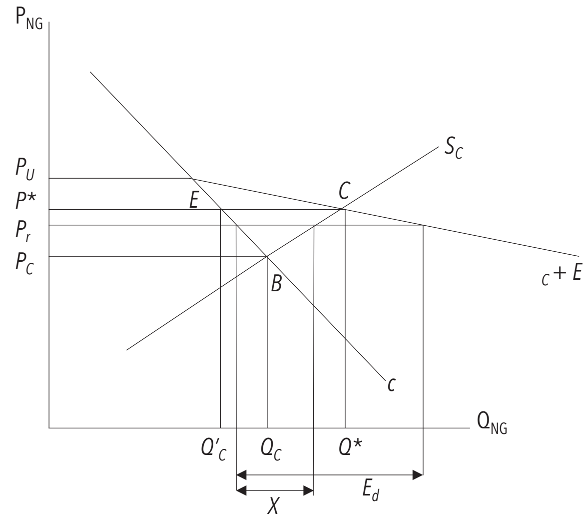

Figure 12.4 Natural Gas Export Limitations

The reader may well ask the question: why would there be any excess or surplus of established reserves at any point in time, as the various surplus formulae discussed earlier presume? The reasons are fourfold. First, some natural gas reserves occur in conjunction with oil reserves and so their availability is not calibrated to natural gas market requirements. Second, the exploration process is not well defined directionally. While some areas are more gas prone than others, it is not possible to channel exploration activity specifically towards gas. Indeed, the initial build up of Alberta's gas reserves after World War II largely resulted from what was intended as oil-directed exploration. Third, surplus policies themselves could encourage accumulation of reserves in excess of those required on a normal commercial basis. In other words, such policies can become self-fulfilling. Fourth, market imperfections may preclude market clearance. The first two of these reasons would account for surplus reserves for some period of time, but not persistently over the thirty-five years from 1950 through 1985. The last two reasons could explain continuing excess stocks.

2. Analytics of Gas Export Limitations

At the most basic level, the natural gas protection policies served to limit shipments of gas from the region (Alberta or Canada, depending upon whether the regulations were by the Alberta government or the NEB). The impact of policies to restrict exports can be examined in the context of resource rents (see Bradley, 1972). The illustration below is couched in terms of exports from Canada, for ease of exposition. But the analysis would apply equally to removal of gas from Alberta.

The following analysis compares two extreme possibilities, no exports and completely unrestricted exports. The latter has been approximated since deregulation and the FTA in the late 1980s, although, as we shall see, short-run and long-run adjustments differ. Prior to that, exports from Canada were limited by the gas protection policies but were not nil.

Figure 12.4 compares the two cases. D_C is the Canadian demand for natural gas. P_U is the price at which the U.S. natural gas market would clear if no imports were allowed. At lower prices, U.S. consumers want more gas and producers provide less. The lower the price, the higher the 'excess demand' in the United States. This excess demand (E) translates into a demand for Canadian gas. In Figure 12.4 the total demand for Canadian gas is shown by $D_C + E$.

In reality not all of such excess demand in the U.S. market would be added to the demand for Canadian gas. There could be other sources of gas available to the United States, for example offshore (LNG) and Mexico. Moreover, regional aspects and constraints on the flexibility of pipeline systems would preclude Canada filling the entire gap. But our exercise is theoretical and such adjustments would not detract from the implications of the analysis.

Given a Canadian policy that prohibits exports, the market clearing price would be P_C and Q_C.

Given an open, competitive market, the equilibrium price and output as shown in Figure 12.4 (at point *C*, where S_C intersects $D_C + E$) would be P^* and Q^* respectively. Output absorbed by the domestic market would be Q'_C, which would be lower than the quantity (Q_C) absorbed domestically when exports are inhibited and the equilibrium is where domestic supply (S_C) meets domestic demand (D_C). The reason for the reduction in domestic consumption with an open market is of course the impact of higher prices compared with the case of the closed economy. The quantity of exports is $Q^* - Q'_C$.

Who might be the gainers and losers under a permissive export policy? The immediate gainers would be the Canadian natural-gas-producing sector. The producing sector embraces the interests of privately and publicly owned companies and governments that obtain revenues from it. In comparison with a closed market, production sector rents increase by the area P_CBCP^* in Figure 12.4. Natural gas consumers in the United States would also gain since some portion of their excess demand would be satisfied.

The losers would be Canadian natural gas consumers. The reduction in consumer surplus (compared with a closed market) is represented by the area P_CBEP^* in Figure 12.4.

Since the welfare loss felt by consumers is more than offset by production-sector gains, ostensibly a sufficient portion of the extra revenues enjoyed by the production sector could be transferred to consumers to make them as well off or better off than under a closed economy (Kaldor-Hicks Compensation Principle). The net improvement in rents and thus welfare is represented by the area *ECB* in Figure 12.4.

In this sort of calculus, what happens to the economic rents is crucial. Bradley (1972) outlines two extreme cases. The first is where the additional production-sector rents escape any taxes and royalties, where the entire industry is foreign-owned, and where all the rents leave the country. The second extreme case is where all the additional production-sector rent accrues to governments that redistribute monies to consumers to ensure they are no worse off than under a closed system.

The realities, since large-scale exports of Canadian natural gas commenced in the 1950s, lie between these two extremes. Exports have been permitted but are nevertheless restricted by the surplus and other policies. The tax system does capture considerable amounts of economic rent via lease sales, royalties, permits and rentals, and income taxes. Not all the industry is foreign-owned, and foreign owners do not immediately repatriate additional rents. Note that when the surplus policy is binding, this can have repercussions for domestic prices if domestic consumers enjoy some monopolistic power. Certainly the regime prevailing at the time of writing under the North American Free Trade Agreement (NAFTA) is the nearest Canada has had to a totally permissive export policy.

One modification to the analysis of Figure 12.4 should be introduced. It is well established that U.S. natural gas pricing regulations in the 1960s and 1970s served to hold prices below market clearing levels (MacAvoy and Pindyck, 1975). In Figure 12.4, this is shown by P_r. If this price also applied to imports from Canada, as was the case, then P_r would serve as an equilibrium price (due to U.S. regulations). There would be excess demand in U.S. markets equal to E_d, of which an amount *X* would be met by imports from Canada.

3. Impacts of the Gas Protection Policies

The Alberta and Canadian policies did not in fact prohibit exports – the regulations were more complex than an absolute prohibition and operated more indirectly. Thus the analysis above illustrates the type of effects expected but fails to provide a reasonable explanation of how the surplus policies operated. That the general effects were as illustrated is suggested by Waverman's (1973) linear programming model of North American natural gas flows in the 1960s. He finds that more Canadian gas was used in domestic markets, and less exported, than would be expected in a deregulated North American gas market. Exactly how the surplus policies operated to generate these results is less clear. For example, exactly why did the natural gas protection policy generate large reserves relative to production? The explanation must lie in the behaviour of the various market participants. There is no full behavioural model of the Alberta natural gas industry, including wide latitude in development options for natural gas producers. Rowse (e.g., 1986, 1987, 1990) has built an ambitious and valuable operations research model of the Canadian gas industry that develops conditional forecasts of both production and consumption behaviour, but it assumes elasticity and resource cost parameters, rather than estimating them historically, and contains limited reserve development options. The same can be said of the Canadian components of the North American

Regional Gas (NARG) model developed by a private consulting firm, Data Resources Inc., and widely used by Canadian private firms and governments (including the NEB in its *Supply/Demand Reports*). However, economic analysis provides some guidance as to the effects of the natural gas protection policies.

Historically, the consumption side of the market for Alberta natural gas has included a limited number of buyers, thereby taking an oligopsonistic form. Within Alberta, most of the gas has been purchased by the two main utilities. (Known as Northwestern Utilities and Canadian Western Natural Gas for much of their lives, they were acquired by ATCO in 1980.) Buyers for removal of gas from the province have mainly been the large gas transmission companies, TransCanada Pipe Line (for sale in Canada and the United States east of Alberta), Westcoast Transmission (which primarily contracts gas in north eastern B.C., for sale in B.C. and the U.S. Pacific Northwest) and Alberta and Southern (for sale on the U.S. Pacific coast, mainly California). All these large buyers have been rate-regulated on a cost of service basis.

At first glance, the Alberta and NEB surplus tests for export of natural gas might be viewed as a controlling device that allowed buyers to obtain an oligopsonistic result of lower prices. (Here, lower prices means in comparison to an effectively competitive market.) The necessity of preserving sufficient supplies to meet internal needs would serve as a significant barrier to entry to buyers from outside the region who could not be guaranteed regulatory approval for gas removal from Alberta or Canada. However, the usual oligopsonistic preference for low prices on inputs is not fully operative in this case; since the utilities and transmission companies are rate-regulated, they cannot generate higher profits by buying inputs (i.e., field gas) low and then selling output (i.e., delivered gas) high. Hence, the impact of the natural gas protection policies on the buyers' side of the market must be somewhat more subtle than this.

We would emphasize two effects. First, the restrictions did imply a potential (or binding) limitation on competition between regional and ex-regional buyers, and hence may have allowed lower prices within the region than outside, as the analytical model suggested. A gas seller would prefer a lower-priced contract with a buyer from within the region to a higher-priced contract with an ex-regional buyer that ran some probability of being overturned because there was no regional gas surplus. However, one would expect these price effects on new contracts only when the region was judged to have a very small or no export surplus. (This held for Alberta only in the early 1980s, and for Canada as a whole after 1970.) In the 1980s, the gas surplus tests may have had a positive effect on the appearance of gas export pipelines since they helped to ensure that exports would not be interrupted and such reduced risk made the financing of the pipelines easier.

A second effect of the surplus tests was the stimulus it offered to long-term contractual arrangements between buyers and sellers and to the appearance on the market of uncontracted reserves. Until the 1980s, the gas-protection policies essentially required twenty-five or more years of reserves in support of current sales. Buyers may have been induced to contract volumes for this length of time, thereby removing the reserves from the hands of other potential buyers. However, given the limited number of buyers, especially when the gas surplus restrictions were binding, the regional buyers could afford to leave some reserves uncontracted. The seller would have no alternate buyer within the region, and ex-regional buyers would be disallowed if there were no gas surplus. Long-term contracts plus any uncontracted reserves would contribute to a higher R/P ratio.

Moreover, the long-term contracts tended to have inflexible pricing terms. In contracts signed in the 1950s and 1960s, prices were often fixed with small escalation factors, and there was generally no provision for frequent or drastic renegotiation of price. This likely reflected the risk preferences of the regulated utilities: stable prices meant that sales were also likely to be stable, and the risk of losses in demand reduced. Sellers may also have preferred relatively stable prices, but even if a seller did not, the oligopsonistic nature of the market would give it little choice. As was discussed in Section 2 of this chapter, the inflexibility in gas contracts, and limitations in Canadian exports under the gas surplus tests, posed a real dilemma for Alberta energy policy-makers when international crude oil prices began to shoot up in the early 1970s, pulling the value of natural gas along.

Our discussion of the natural gas protection regulations have dealt primarily with the buyers' side of the market. It has been noted that the regulations probably served to strengthen the position of buyers in their negotiations with natural gas producers. At any given level of natural gas prices, the export surplus regulations would tend to increase the effective cost of reserves and to reduce their effective price. The regulations raised the investment cost of gas reserves since reserves would have to be carried for longer before sale (Hamilton, 1973). This could come about in two ways. First, the regulations led to contracts in which relatively high reserves were held per unit of output (i.e., pools tended to be depleted slower rather than faster). Second, new reserves might go uncontracted for a longer time. With respect to price, unless the natural gas price was expected to rise very rapidly, the present value of the revenue received from the reservoir is reduced when the gas output is delayed; that is, the effective value of a unit of gas reserves is reduced.

Our argument may begin to seem contradictory. If the gas-protection regulations tended to inhibit investment in reserve additions, how can they contribute to higher than expected R/P ratios? In part, the response lies in the individual contracts, which, as noted above, tended to involve large reserves in support of production, as was, in fact necessitated by the gas-surplus regulations. But part of the answer must also lie in the aggregate market results of the gas-surplus policies. Here, we would suggest that these policies, for natural gas, served to induce significant price stability (rigidity) in the natural gas market, much as market-demand prorationing did for crude oil. Hence one does not observe the downward pressure on natural gas prices in the 1950s that the rapid growth in gas reserves might have led one to expect. The higher gas prices meant somewhat less consumption. In addition, higher prices increase the attractiveness of reserves additions, tending to offset the negative stimulus of delayed production. Both reduced consumption and higher reserves additions operate to increase the R/P ratio.

We hesitate to offer a complete normative analysis of the gas-protection policies that were in place from 1950 to the mid-1980s. Some comments are in order. A number of observers (e.g., Hamilton, 1973) have stressed the negative effects of the increased costs associated with high R/P ratios. More inputs than were necessary were drawn into the natural gas industry, when society might have used them elsewhere.

Economists are generally critical of policies that reduce the reactivity of markets, thereby inhibiting consumer and producer responses to changes in underlying market conditions. In the case of inflexibility in natural gas prices, the beneficiaries would seem to be the natural gas consumers at the expense of producers, as the analytical model suggests, although it is hard to be definite in this regard. (The view that gas-surplus tests must benefit consumers is suspect since the policies also induced high reserve levels in support of consumption, and therefore did not necessarily generate lower prices.) We judge it likely by the late 1960s that the policies were probably holding prices lower than they would otherwise have been. From the mid-1970s to 1986, as Section 4 of this chapter details, natural gas prices were fixed by the government. Thus the gas-protection policies may have redistributed some of the benefits of Canadian natural gas to Canadian consumers and away from U.S. consumers and producing interests (including the Alberta government and foreign shareholders in the petroleum companies).

As was discussed above, deregulation brought the loosening and eventual abandonment of the long-standing gas-protection policy. This occurred in conjunction with other changes in North American natural gas markets, including the Canada–U.S. Free Trade Agreement (FTA) and NAFTA. Beginning in the 1970s, new buyers had begun to appear for natural gas. This accelerated in the 1980s in both Canada and the United States as high-volume gas consumers, marketing consortia, and other trading partners began to contract for natural gas and lease-delivery space in the major transmission lines. Long-term contracts were revised to become much more flexible, shorter-term contracts became increasingly common, and an active spot market for natural gas developed.

The result was a revolution in Canadian natural gas markets even greater than that in crude oil markets. Canadian gas sales, particularly exports to the United States, rose rapidly after 1986, as shown in Table 12.1. The R/P ratio fell dramatically, from 24 in 1985 to 8.3 by 2003. And natural gas prices became much more flexible as increasing volumes are sold under shorter-term (e.g., two years or less) contracts or under longer-term contracts with prices renegotiated frequently.

And what of protection of gas supplies for Albertan and Canadian consumers? The changes in the late 1980s and early 1990s have led to a situation in which natural gas consumers are protected in much the same manner as they are in the consumption of any other commodity – by the market. Impending scarcity puts upward pressures on prices, which induces consumers to conserve natural gas and draws forth greater supplies. Consumption by Canadians is warranted only if Canadians are willing to pay as much as foreign buyers; otherwise, the gas is exported and Canada derives the export revenue. McDougall suggests that the NEB's policies in the 1960s were biased towards encouraging exports, as indicated by the loosened restrictions in estimating domestic supply, and that price tests were never taken very seriously, at least so far as determining the economic value of gas in the export market is concerned (McDougall, 1975, chap. 5). He interprets the prime purpose of the exportable surplus policy as the "protection" of Canadian gas consumers, but expressed largely as trying to ensure access to low-cost supplies. Exports, he argues, draw on low-cost supplies and therefore force domestic consumers to rely on higher cost volumes.

This raises a fundamental question: are there any reasons that natural gas should not be treated as another economic commodity? The gas-protection regulations implied that there were, though exactly what these were was not made clear. Three possibilities come to mind, all related to prohibition of gas removal (exports), although are all debatable.

First, natural gas is a depletable natural resource and therefore, it might be argued, should be reserved for Canadians, especially if the free market is unable to allocate depletable resources efficiently and equitably. We have touched on variants of this argument numerous times with reference to oil, so we will only reiterate some of the earlier responses briefly. In Canada, many other depletable resources are handled by relatively unrestricted markets. Producers of natural gas do have a strong profit incentive to take likely future market conditions into account and therefore do have 'conservation' tendencies. Whether depletable or not, many people feel that the resource should be used where it generates the greatest value for Canada, even if that is by means of generating foreign exchange on export sales. We have also emphasized that exhaustibility of petroleum resources is primarily a physical phenomenon, rather than an economic one, while production and consumption are economic activities. From a dynamic point of view, greater sales and higher prices resultant from exports will call forth additional supplies and encourage faster adoption of any new technologies that have a strong 'learning-by-doing' component. There are a number of contentious arguments related to the possible undervaluing of future consumption needs, but if these arguments are accepted they apply to current domestic sales as well as to ex-regional sales. On balance, we view the depletability argument as a weak basis for petroleum export limitations.

Second, natural gas might be argued an essential good for home heating and for many industries. But there are substitutes for natural gas in virtually all uses, at least in the long run. Moreover, there are many 'essential' goods (e.g., food stuffs) and we neither limit the export of these nor would we be very understanding if some other country severely restricted our ability to buy from them.

Third, natural gas is a continental rather than international product and involves very capital-intensive transmission and consumption capital; therefore, it could be argued that domestic consumers, once linked to supplies, need to be assured of continued accessibility. Economists may argue in response that capital intensity is not peculiar to the use of natural gas, and that natural gas can be imported or produced from other sources such as grain, peat, or coal. Moreover, one advantage of well-functioning economic markets is exactly that they make gas available to anyone who 'needs' it (and is willing to pay!) and that the market facilitates the gradual adjustment to changing conditions such as growing scarcity. We would reiterate that there are equity effects of a decision to follow open markets, with the producers of an exported product benefiting at the expense of domestic consumers. This has implications for taxation policies, especially those on economic rents, but is, in our view, an insufficient reason to impose export limitations.

Overall, we are not convinced by the arguments that natural gas is somehow special and cannot be allocated through traditional economic markets. The recent rapid evolution of active and flexible natural gas trading institutions provides evidence in this regard.

This section has focused on the export volume limitations. The next section considers pricing issues, including export pricing.

4. Price Controls and Other Market Regulations

This section deals with those government regulations that impacted significantly upon the market for natural gas other than the export surplus rules discussed in Section 3. We are primarily concerned with regulations impacting upon natural gas prices. Of necessity, some of this material was presented above, in Section 2C, in the discussion of natural gas prices. This section draws upon Helliwell et al. (1989, chap. 4), Plourde (1986), Watkins (1977a, 1981, 1987a, 1989, 1991a), and Watkins and Waverman (1985).

A. Market Regulations

1. Domestic Pricing

As will be recalled, domestic natural gas prices were quite stable in the 1960s, and NEB denial of export permits commencing in 1970 removed the stimulus of growing U.S. demand for gas in the interstate markets. TransCanada Pipelines (TCPL), the major buyer of Alberta gas, was left in a situation tantamount to

Table 12.3: Relationship between Natural Gas and Crude Oil Prices, Toronto, 1970 to 1987 ($/GJ)

	Refinery Average City Gate Gas Price (1)	*Acquisition Cost Crude Price (2)*	*Ratio of Gas to Crude Oil (3) = (1) / (2)*
1970	0.36	0.56	0.64
1971	0.44	0.56	0.78
1972	0.45	0.56	0.80
1973	0.52	0.64	0.81
1974	0.55	1.05	0.52
1975	0.82	1.32	0.62
1976	1.24	1.52	0.82
1977	1.47	1.81	0.81
1978	1.77	2.15	0.82
1979	1.92	2.40	0.80
1980	2.23	2.91	0.77
1981	2.42	4.52	0.54
1982	2.80	5.46	0.51
1983	3.38	5.93	0.57
1984	3.71	6.01	0.62
1985	3.76	6.25	0.60
1986	3.85	3.43	1.12
1987	2.84*	4.07	0.70

* direct selling price at Toronto, upper scale.

Sources:

(1) 1970–74 – based on ERCB and DataMetrics Limited; 1975–87 – Petroleum Monitoring Agency, *Monitoring Survey*, Annual 1986; Texaco *Energy & Economic Data Book*; and Corpus, *Energy Pricing News*, 1987 issues.

(2) 1970–73 – wellhead price & IPL tariff – ERCB and IPL *Annual Reports*; 1974–87, and Energy, Mines and Resources, Energy *Statistics Handbook*.

(3) 1970–78 – Industry Source; 1979–87 – EMR Ottawa. Note that 1979–87 prices are based on Ontario value/volume data.

monopsony. Rising oil prices at the start of the 1970s had minimal impact on natural gas prices, which rose, on average, from $0.16/Mcf at the wellhead in 1970 to $0.17/Mcf by 1972. In 1972, the Alberta government began a campaign to increase gas prices by asking the ERCB to study field prices, as was discussed in Section 2, above. There we noted that gas prices began to increase in 1973, and contract provisions moved to greater flexibility in prices.

In the spring of 1975, a price of $1.15/Mcf was awarded by an arbitration panel in a dispute between TCPL and Gulf Oil Canada. This was widely interpreted as representing a suitable commodity value for gas in line with the sharp increases in oil prices, which had taken place since 1972. The sevenfold increase over the 1970 natural gas price focused the attention of the federal government, much as had rising oil prices. The June 1975 budget announced that Ottawa and the producing provinces had agreed on a government-fixed price effective November 1, 1975. The price would be 85 per cent of the price of crude oil, on a Btu parity basis, at the Toronto city gate, rising to 100 per cent of the crude price over three to five years. Initially, the price would be $1.25/Mcf. The Alberta border price for natural gas would be the Toronto city gate price less transmission charges; the field price would be the border prices less the NOVA transmission charge within Alberta and gas-processing-plant charges. Note that the full brunt of any transmission cost rises fell on the natural gas producer.

As Table 12.2, shows, Toronto city gate prices were increased a number of times by federal and provincial government agreement over the November 1975 to February 1980 period; the increases followed agreed-upon oil price rises and attempted to keep the natural gas price at 85 per cent parity with crude oil in Toronto. Table 12.3 looks at the Toronto market in more detail, including average city gate natural gas prices in comparison to the average cost of crude oil to refineries for years 1970 through 1987. It can be seen that gas prices were well below 85 per cent crude oil equivalence in 1970 but had risen close to that level by 1973. However, rising oil prices in 1974 and 1975 left gas prices behind the standard until the November 1975 increase.

Government authority to set natural gas prices was derived from Ottawa's 1975 *Petroleum Administration Act* and from Alberta's *Natural Gas Pricing Agreement Act* (RSA, 1975, chap. 38), which overrode any award under arbitration or other price redetermination agreement.

As was discussed in Chapter Nine, the inability of Ottawa and Edmonton to reach agreement on oil prices in 1979 and 1980 led Ottawa to introduce the National Energy Program (NEP) in conjunction with its October 1980 budget (Energy, Mines and Resources, 1980). The NEP noted that

> … pricing policy for natural gas must meet two needs: provision of adequate incentive to production and strong encouragement for consumers to use natural gas in preference to oil. Producers' returns from natural gas have risen dramatically since the mid-1970s – in fact, faster than oil prices, despite a growing surplus of gas. (p. 31)

The desire to reduce reliance on oil imports also influenced policy under the NEP.

> Linking Canadian natural gas prices to world oil prices is also unwise, because Canadian endowments of oil and gas resources differ: we have, judging from evidence thus far, abundant supplies of natural gas that could be produced at moderate prices, but less certain prospects for oil. Linking Canadian prices to world prices would keep the price of gas to the consumer rising at the same rate as the price of oil. This would inhibit the massive-scale substitution away from oil that must take place if Canada is to achieve energy security.

Increased use of gas would be encouraged by subsidies to pipeline extensions east of Montreal to keep city gate natural gas prices at the Toronto level (p. 58), and consumer grants would encourage substitution away from oil to other fuels, including natural gas (p. 56).

Under the NEP, natural gas prices would fall somewhat relative to crude oil at the Toronto city gate. From 1975 to 1980, every $1/b oil price rise gave a $0.15/Mcf gas price increase; under the NEP, for three years from 1981 through to 1983, gas prices would rise $0.10/Mcf for every dollar per barrel increase in domestic oil prices; this meant gas price increases of $0.45/Mcf per year for the three years. Alberta border prices, however, would not rise for the first year in order to make room for a $0.45/Mcf Natural Gas and Gas Liquids Tax (NGGLT), "which will be applied in lieu of a gas export tax" (p. 31), on all Canadian-produced natural gas. As can be seen in Table 12.3, the price of natural gas in 1981 was at 54 per cent of the crude oil price at Toronto, as compared to 80 per cent in 1979.

The NEP also set up a "Canadian Ownership Account, to be financed by special charges on all oil and gas consumption in Canada, to be used solely to finance an increase of public ownership in the energy sector" (p. 51). City gate gas prices were increased in May 1981 by $0.15/Mcf for the Canadian Ownership Special Charge (COSC).

Chapter Nine outlined Alberta's outrage at the NEP, and the program of oil output cutbacks introduced in protest. The two governments reached accommodation in the September 1, 1981, *Memorandum of Agreement relating to Energy Pricing and Taxation*. The *Memorandum* switched the geographical bias for pricing from Toronto to the Alberta border and agreed upon a new pricing schedule in which the price would rise by $0.25/Mcf every six months through to the end of 1986 (starting on February 1, 1982) (p. 7). The *Memorandum* further specified the intent "to establish the level of the NGGLT on domestic sales so that, taking into account a range of factors, including gas transportation costs, the parity relationship between the wholesale price of natural gas at the Toronto city gate and the average price of crude oil at the Toronto refinery gate will be approximately 65%" (p. 9). (Presumably the COSC would also fill the gap between the Alberta and Toronto prices.) Table 12.3 shows that the Toronto gas price had fallen to 51 per cent of the crude cost by 1982 and rose again to 60 per cent in 1985, the year of crude oil price deregulation.

It will be recalled that the domestic oil price schedule in the *Memorandum* soon proved to be too high, as world oil prices began to weaken in 1983. Similar problems arose with domestic natural gas prices. The upshot was an amendment to the agreement for the eighteen-month period starting July 1, 1983. Alberta agreed to modify the schedule to the lesser of (i) 65 per cent of the Btu equivalent of the blended oil price at Toronto, less transportation charges and COSC, or (ii) the level given by the increases of $0.25/Mcf as previously agreed upon. The implication was that the NGGLT would gradually decrease as the border price rose but was not matched by the rises in Toronto city gate prices (i.e., at 65 per cent of crude costs). By February 1, 1984, the NGGLT had fallen to zero, so that the Alberta border price was governed by the 65 per cent rule. In fact, from February 1984 on, Alberta and Ottawa agreed to keep the Alberta border price at $3.00/Mcf, which held until November 1, 1986, and gas price deregulation. (The Toronto city gate price changed slightly, as Table 12.3 shows, due to changes in transmission tariffs and COSC.) The one-year lag in deregulating natural gas prices as compared to oil prices (November 1986 opposed to June 1985) meant that gas prices were above Btu parity with crude in Toronto in 1986.

The price regulations in place from 1975 to 1985 held domestic Canadian natural gas prices below natural gas export prices and below Btu equivalence with imported (and domestic crude) in central and eastern Canada. Within Alberta, prices were held even lower for consumers from 1975 through 1995 under the *Natural Gas Pricing Act*. The mechanism in this case was not reduced payments to natural gas producers but a subsidy from general tax revenues that was paid to buyers of Alberta gas (largely to natural gas distribution utilities).

Section 2 of this chapter provided information on the process of natural gas deregulation, which occurred November 1, 1986, against a backdrop of high gas reserves to production ratios, significant excess deliverability with spare capacity both in the field and in transmission facilities, and a high degree of concentration on the buyers' side of the market. The Alberta government and producers were particularly concerned that 'excess supplies' and oligopsony would force gas prices down to unreasonably low levels. There was widespread feeling that the market might require considerable guidance if it was to evolve in a smooth manner to effective competition; expressed in other terms, judicious regulation might be an essential ingredient of the transition to a deregulated natural gas market.

Naturally, much attention focused on TCPL, which had been seen as a near-monopsonist buyer of Alberta natural gas in the years immediately before price regulation. The opening up of export markets offered more competition, and several new large buyers and large sellers of natural gas offered potential competition to TransCanada; these included the Alberta Petroleum Marketing Commission, which had been set up by the Alberta government to handle the sale of the oil and gas from Crown lands during the years of regulated prices. Companies such as Pan Alberta and ProGas had also been controlling natural gas supplies. TransCanada's decision, at the start of 1986, to separate transmission and gas trading activities, with the creation of WGML as the natural gas buyer and seller, helped clear the way to more open access to TCPL pipeline facilities.

During the transition year, November 1, 1985, to October 31, 1986, direct sales were made at prices negotiated between producers and large industrial gas users; and several Competitive Marketing Programs allowing system gas sales to offer competitive discounts were put in place. (System gas refers to the gas bought and sold by a transmission company as a demand and supply aggregator.) WGML, the marketing arm of TCPL, renegotiated sales contracts with the four major natural gas distributors in eastern Canada. These two-year contracts offered residential and small commercial customers an immediate discount of $0.21/Mcf off the $3.00/Mcf frozen Alberta border price, followed by price stability over the contract term. Price flexibility was provided by allowing distributors to match direct sale prices in their respective industrial markets. These contracts could result in substantial discounts off the Alberta border price. On the regulatory side, the NEB ruled that the TCPL system should be accessible to all users and ordered changes to TCPL's tariffs to open up the pipeline (NEB, 1986b).

At the provincial level, as noted above, provisions in Alberta's *Gas Resources Preservation Act* linking the award of removal licences to economic benefits accruing to Alberta were removed, only to be replaced by new latitude given to the Alberta Energy Resources Conservation Board to consider "other matters," including price, in evaluating gas removal applications. The *Alberta Arbitration Act* was amended to allow arbitrators to consider a much broader range of criteria than "commodity value" in redetermining Alberta field prices (a commitment made under the 1985 *Agreement on Natural Gas Markets and Prices*).

Thus, during the transition period, blocks of gas for industrial customers in eastern Canada were sold at prices below the prescribed Alberta border price of $3.00/Mcf. Indeed, by September 1986, TCPL's average Alberta border netback on domestic sales was already $2.64/Mcf.

With deregulation on November 1, 1986, the prescribed Alberta border price for natural gas leaving the province was abolished. Domestic (and export) gas prices were now negotiated between producers and purchasers. Although the environment was competitive, pricing information was not transparent as selling prices of Alberta natural gas were generally confidential.

Renegotiation of pricing provisions in TCPL's contracts with Ontario and Manitoba utilities resulted in creation of funds by TCPL to finance the discounting of gas. These funds distinguished between customer-specific funds, operated by WGML, and a utility-wide market fund. However, the latter was still to be disbursed on the basis of criteria established between the distributor and TCPL. There was a strong stipulation that the funds not be spread over all customers – they were to be devoted to meeting individual competitive circumstances. In short, they were to be used on a discretionary basis. These arrangements resulted in price discounts at the Alberta border varying from $0.16 for small industrial customers to $1.07 per thousand cubic feet for large industrial users (Ontario Energy Board, 1986).

Several provincial regulatory bodies developed policies concerning the cost of gas purchased by utilities under their jurisdiction and the availability of transportation services on local distribution systems.

The Ontario Energy Board's (OEB) decision in 1986 on the two-year gas-price agreement between WGML and Ontario distributors focused on the board's jurisdictional mandate to determine rates for all customers in Ontario. In particular, the OEB wanted all natural gas purchased by utilities to be delivered to Ontario without being streamed to specific customers and customer groups.

As well, in early 1987, the OEB ruled that all natural gas consumers had freedom of choice in selecting gas supply purchasers; this ruling in effect broke the marketing monopoly held by distribution utilities (Ontario Energy Board, 1987). While the distribution companies retained their franchises on moving gas, the decision opened up the entire provincial market to increased gas sales competition by allowing purchasing entities, such as school boards, municipalities, hospitals, households, and small business co-operatives, to enter into contracts with any supplier. The effect of these arrangements would be to shrink distributor core market requirements for higher-priced system gas and to drive gas prices toward the levels large industrial users pay, as long as appropriate "removal permits" were available from the Alberta government and access to transportation capacity was enjoyed.

The Manitoba government also objected to the segmentation of markets under the 1986 renegotiated gas pricing agreements between WGML and the Manitoba distribution utilities.

Thus, downstream authorities do not like upstream price discrimination. Partly this is pique – if price discrimination were to take place, they would rather it be theirs than someone else's. But also it does represent a valid objection – that upstream discrimination is not consistent with fostering a competitive market since the essence of competitive price formation is that differentials for a homogeneous product cannot be sustained.

Producing interests, on the other hand, were very much worried that customers would abandon their traditional supply sources like WGML, which had signed contracts for gas purchase, and enter into new contracts at lower prices, effectively displacing the gas under long-term contract. This could be a general problem in a deregulated environment unless the longer-term production contracts were matched by longer-term sales contracts by the supply aggregators. However, it was a particular concern during the transition period when the high gas R/P ratio was being worked down. In 1988, Alberta's Minister of Energy and Natural Resources wrote to the Ontario Minister of Energy indicating that Alberta had no objection to "core" gas consumers entering into direct purchases in Alberta, so long as they did so in the form of ten- to fifteen-year contracts (APMC, 1988 *Annual Report*). This could be seen as a way of ensuring that small-volume customers had access to gas supplies that might be essential to them. However, in an effectively deregulated market, it is more accurately viewed as a prohibition on small consumers covering their needs through an ongoing sequence of spot or short-term purchases. In the context of the Canadian gas market in the late 1980s, it would blunt somewhat the downward price pressures.

After deregulation, a wide range of natural gas prices at the Alberta border emerged, with spreads between short-term and long-term prices in excess of $0.50/Mcf (EMR, 1987). This in part reflected the degree of market segmentation and volatility that existed. But note that price variations do not themselves indicate lack of competitive price formation or market imperfections. They may simply reflect different terms and conditions, such as manner of delivery (storage costs), reliability of services (continuous or interruptible supply), length of service (short- or long-term contracts), load factors, and the like. Price differences arising from such product variations do not constitute price discrimination.

In the late 1980s, TCPL system-gas contacts showed appreciable Alberta border price differentials between various categories of end users. Such a degree of price differentiation was not compatible with a competitive market-pricing regime unless sustained by variations in the service offered between customers. It is unlikely that differences in load factors or other service features between customers were sufficient to account for the degree of discount differentials shown. Moreover, the main basis for the award of discounts was the price of competitive fuels, a criterion that has little to do with service characteristics. It follows that such differentials do demonstrate market power – the desire to impose different prices on customers according to their ability to pay. In short, they represent monopolistic, not competitive, pricing practices. What lay behind TCPL's position?

TCPL occupied a very strong market position through WGML. But the dominant supply position of TCPL created serious problems for the company, with weak gas markets eroding the take-or-pay position of Canadian gas purchasers.

The legacy of take-or-pay arrangements was particularly serious for TCPL since it had entered into area-purchase contracts committing the company to purchase a proportion of all reserves developed in a relatively large geographical area. For example, TCPL's contractual purchase obligations during the 1977 contract year totalled 1.3 Tcf. Although the company had not signed any new contracts by 1986, contractual obligations amounted to some 2 Tcf. The take-or-pay wedge developed because gas supplies increased just as markets were levelling off. (As Table 12.1 shows, Alberta's production in 1983 was less than in 1978.) By the early 1980s, TCPL could not meet its take-or-pay obligations, which were then taken over by a consortium of banks. Under the negotiated TOPGas (the acronym stood for take-or-pay gas) agreements, the principal on monies paid to producers was recovered by TCPL through the sale of prepaid gas and transferred to the TOPGas consortium. Producers enjoyed any surplus between the ongoing gas price and the (initial) price received under the TOPGas advances. However, if the selling price was less than the initial price, producers were liable for the difference, and TCPL had the right to make up any deficiencies by retaining monies from other gas deliveries by producers. But in the event that producers default on repayments of the principal, TCPL was liable to the TOPGas consortium for up to $355 million. Recovery of the principal was on a first-incurred/first-recovered basis. For example, prepayments for gas made in 1979 were recovered before prepayments made in 1980. The 1987 recovery of prepayments would appear to have been based on advances made to producers in the 1979/80 contract year. These advances were predicated on prices of about $1.70/Mcf (at the gas plant gate exit).

The TOPGas prepayment schedule had implications for netback prices from eastern markets requiring approval by TCPL's TOPGas producers. Such prices will tend to be sticky since producers were liable for any deficiencies on the sale of prepaid gas. Thus, TOPGas producers and TCPL would be reluctant to indulge in price cutting unless compelled, and especially not in a way that would involve reducing prices to all customers – the competitive market solution under surplus conditions.

In contrast to the position of system-gas producers and TCPL, consuming interests in eastern Canada sought non-discriminatory prices, prices at the city gate that did not distinguish between end-use customers except insofar as they reflect different terms and conditions of sale. Ontario dismantled the gas-marketing monopoly previously conferred on its gas utilities. Manitoba initially sought to take action by purchase of the provincial natural gas utility and delegation of buying and selling gas solely to a Crown corporation to provide one city gate price for natural gas. After a change in government, these intentions were dropped.

As was noted at the end of Section 2, the Alberta government conducted a rearguard action to hold up prices. The mechanism was the imposition of pricing and volume conditions on gas removal permits. A 'ghost' floor price of $1.45/Mcf was said to be held; volume restrictions tended to preclude all but large individual customers making deals with producers. And beginning January 1, 1988, royalties were based on reference rather than actual prices, with the intention of discouraging discount sales and preserving reserves. (Under this provision, royalties are assessed on the higher of the actual price or 80 per cent of the average Alberta field price.) Alberta required long-term permits for core customers seeking gas-removal permits, and such permits were not given for any volumes that displaced TCPL/distributor contracts prevailing before the October 31, 1985, federal–provincial Gas Agreement.

The Alberta permit-removal conditions remained in place until 1995. In that year, the government also moved for the first time to allow domestic Alberta core gas users to enter directly into gas-purchase contracts with marketers or producers. As argued in Section 2, by 1995, Alberta was part of an integrated North American natural gas market with a large number of gas producers, interacting with many more gas purchasers than in the past, and an even larger number of potential purchasers. The gas-trading and transmission activities of the major pipelines had been largely separated ('debundled'), and access to pipeline facilities made more readily available to all shippers. Natural gas price exhibited significant flexibility, including a large volume of gas traded on a spot basis or tied to spot prices with only a month's lag. As noted above, since 1986, there has been a significant growth in natural gas storage capacity, both in producing and consuming regions. This began to dampen the seasonal swings in natural gas prices and to allow production, gathering, processing, and pipeline facilities to operate at closer to capacity throughout the year, thereby reducing the costs associated with spare capacity. (Higher annual throughput allows fixed charges to be written off over more units of output, effectively reducing the cost of shipment.)

The change from the rigid long-term contractual world of the 1960s could hardly be more complete.

2. Export Pricing

As early as 1907, in the *Exportation of Power and Fluids and Importation of Gas Act*, Ottawa had specified that natural gas should not be exported without a licence or at a price lower than it was sold for in Canada under similar sales conditions. (See McDougall, 1975, chaps. 5 and 6, for a review of gas pipeline and export issues prior to 1970.) Section 83 of the 1984 *National Energy Board Act* re-entrenched this concern, giving the NEB responsibility to ensure that natural gas export prices were "just and reasonable in relation to the public interest." In the gas export applications that the NEB approved in the 1960s, the main emphasis was put on the surplus tests discussed in Section 2 above, with the board generally accepting the negotiated prices. In 1967, the Federal Power Commission (FPC) in the United States disallowed prices that Westcoast Transmission and El Paso Natural Gas had renegotiated in a gas-export contract. (Prices charged by Westcoast in the original contract of 1957 were lower than those charged to Canadian customers; McDougall, 1973.) As was summarized in Section 2, the NEB in turn enumerated three formal criteria that would be applied to judging the reasonableness of prices in gas-export contracts (NEB, 1967, p. 3-19):

1. the export price must recover its appropriate share of the costs incurred;
2. the export price should, under normal circumstances, not be less than the price to Canadians for similar deliveries in the same area; and
3. the export price of gas should not result in prices in the United States market area materially less than the least cost alternative source of energy.

The first two tests established a floor price; the third was more in the nature of a price ceiling or a target price. In 1970, the board elaborated on the second test, suggesting that the export price should not be less than 105 per cent of the price in the domestic market area adjacent to the border where the gas was sold (NEB, 1970). McDougall (1982) points out that in both the Westcoast export case of 1967 and in the Alberta and Southern export application of 1970, the NEB acknowledged that the third of these tests did not appear to be met with alternative energy sources costing more to energy users in the export market than the Canadian gas.

The contradictions here foreshadow the gas pricing issues that became central in the early 1970s. The third test clearly points to a commodity value pricing criterion. The question of contractual rigidity also enters. For instance, there is obviously no guarantee that a contract with a relatively rigid price and small escalations will pass the third test after a number of years, even if it did when signed. Moreover, gas pipeline companies may have been reluctant to sign much higher prices on new contracts than old, especially if older contacts had most-favoured-nation clauses, or if they fed into higher prices as well on domestic contracts that domestic consumers and public utility boards would have been reluctant to accept. There were also regulatory problems in that the FPC was reluctant to approve imports to the United States at gas prices appreciably higher than interstate U.S. gas prices, which had, since 1954, been set by the FPC on a 'cost of service' basis. By the late 1960s, however, it was becoming evident that the FPC had set such prices too low. (This, of course, helps explain why the cost of alternatives to Canadian gas might exceed prevailing interstate prices in the U.S. natural gas market.)

Tensions with respect to natural gas export pricing were becoming apparent by the early 1970s. As with so many other energy questions, rising OPEC prices brought the issue to the boil. Since the NEB had ruled in 1971 that no exportable surplus existed, the question was not about the suitability of price in new gas export applications being considered by the board. Rather, it was what should be done about prices on previously approved exports. Contracts were being renegotiated, but the Canadian government felt driven to take action.

In July 1974, the NEB submitted a report on natural gas export pricing. This followed from a 1970 government order that "where in the opinion of the Board there has been a significant increase in prices for competing gas supplies or for alternative energy sources the Board shall report its findings and recommendations to the Governor in Council" (NEB, 1974a, p. 2-1); the government could in turn order increases in the gas export price. The NEB recommended a gas export price of at least $1.00/Mcf, which the government ordered on September 20, 1974, effective on gas exports January 1, 1975. The same price applied to all exports; as the board said "considering that in all cases the border price has fallen well below the Board's estimate of the current value of the gas, it would seem that a major increase in price to a uniform border price for all export licenses is appropriate to the circumstances" (NEB, 1974a, p. 5-28). In determining the value, the board looked to "commodity values" in main export markets, noting that these values would differ in different markets. "While the Board relies primarily on the weighted average estimate of the commodity value of the natural gas, it has also used more approximate but more readily available measures based on prices of crude oil and no. 6 fuel oil" (NEB, 1974a, pp. 17–18). (One small export permit to Minnesota (GL-29) was consistently given a lower export price on the grounds that the buyer – a pulp mill – would otherwise be likely to switch from Canadian gas to coal.)

Until July 1983, gas export prices continued to be set at a uniform border price by the Canadian government at prices based on recommendations by the NEB. Alberta and other producing provinces concurred in this arrangement. Unlike crude oil, the excess of gas export prices over domestic prices flowed back to the producing provinces. After 1975, Alberta (the APMC) allocated these funds across all Alberta natural gas producers, so that those companies lucky enough to have sold gas under contracts destined for export markets did not solely benefit from the higher export prices. In its March 1975 to April 1977, reports on natural gas export prices, the NEB shifted from a "commodity value" approach to a "substitution value" or "replacement value" emphasis, where the value of Canadian gas exports was based on the cost of a unit of energy delivered to Toronto in the form of imported crude oil (NEB, 1975a, pp. 4–5). The NEB also noted (NEB, 1981a) that the U.S. government requested that Canada apply uniform border pricing on gas. Table 12.2 shows changes in the uniform border price. In 1975 and 1976, the price was set in Canadian dollars; after that U.S. dollar pricing was utilized.

On September 21, 1979, U.S. Secretary of Energy Duncan sent a letter to Canada's Minister of Energy, Mines, and Resources proposing a "discounting pricing mechanism." The NEB argued that this was not in Canada's interest at the time but the NEB was prepared to review the need for discount pricing in the future, particularly if export markets became scarce at existing prices – a harbinger of later developments and perhaps an implicit admission that there is no fixed relationship between oil and gas prices.

A gas-pricing agreement called the Duncan-Lalonde formula was reached March 24, 1980, between the U.S. and Canadian governments. Under the agreement, the United States accepted the oil price substitution formula for the pricing of Canadian natural gas exports. In return, Canada agreed to certain price-increase deferral arrangements. Later in 1980, the NEB deferred two increases in the export price of gas called for under the substitution formula, amounting in total to some (US)$0.75/$10^6$ Btu. This price plateau was prompted by a sharp decrease in Canada's natural gas exports to the United States. In April 1980, U.S. gas distributors took only about 57 per cent of gas available to them; their average take in 1979 had been about 90 per cent.

On April 1, 1981, the NEB announced that the Canadian border price would rise to (US)$4.94/$10^6$ Btu (see Table 12.2). This was in response to further increases in world oil prices but did not impose full oil substitution value. Partly induced by depressed gas export sales, the federal government waived an October 1, 1981, export gas price increase. Other contributing factors were a desire to avoid aggravating already-strained energy relations with the United States and a desire to maintain momentum to remove legislation hampering the Alaska Highway Natural Gas Pipeline Project.

In response to declining markets, the Canadian government reduced the export price from (US)$4.94/$10^6$ Btu to (US)$4.40/$10^6$ Btu in April 1983. However, it soon became apparent that this decrease was not enough to stimulate export demand. Therefore, in July 1983, a volume-related incentive price of (US)$3.40/$10^6$ Btu was adopted, but the kicker was that it could only apply to volumes exceeding 50 per cent of those authorized under existing licences or to volumes exceeding actual 1982 sales, whichever was lower. To some degree, the two-tier system was little more than a sympathetic gesture, but it did demonstrate a less rigid attitude on the part of the Canadian government.

In July 1984, the Canadian government adopted a more flexible policy, allowing negotiated price contracts – subject to regulatory approval. Approval depended on satisfaction of certain side conditions, including: the border price must not be less than the Toronto city gate price (then (Cdn)$3.15/$10^6$ Btu); and the export price must at least equal the price of competing fuels in relevant U.S. markets (shades of 1967 price tests 2 and 3). Under this policy, exports of Canadian gas began to recover. By early 1985, about 95 per cent of existing export contracts had been renegotiated, and several long- and short-term new contracts had been drawn up under the July 1984 NEB provisions.

The federal–provincial natural gas pricing agreement of October 31, 1985, contained a new set of export price criteria (Canada, *The Agreement*, 1985, p. 4).

1. The price of exported gas must recover its appropriate share of costs incurred;
2. The price of exported natural gas shall not be less than the price charged to Canadians for

similar types of service in the area or zone adjacent to the export point;
3. Export contracts must contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;
4. Exporters must demonstrate that export arrangements provide reasonable assurance that volumes contracted will be taken;
5. Exporters must demonstrate that producers supplying gas for an export project endorsed the terms of the export arrangement and any subsequent revision thereof.

Of these criteria, the first was straightforward in the sense that it reverted to the original 1967 provisions. The second criterion effectively replaced the Toronto city gate floor price with regionally variable adjacent domestic prices. The third criterion repeated the earlier July 1984 provision and echoed the flexibility demanded by U.S. import regulations. The fourth criterion was delightfully vague but reflected the demise of firm take-or-pay arrangements (and repeated a July 1984 clause). The fifth criterion was to ensure that producers were aware of commitments to which they subscribed!

Even more drastic steps towards export price deregulation were taken by the Canadian government on October 26, 1986. Federal Minister of Energy Marcel Masse revoked the specific contractual gas export price regulations and terminated the volume-related incentive pricing program. In terms of export pricing policy, Mr. Masse simply requested the NEB to monitor export contracts and prices and to provide advice. These latest policy changes seemingly left export prices wide open. However, genuflections were still made towards not exporting Canadian gas at prices less than those in domestic markets.

The transition to freer natural gas markets in North America at a time when major producing regions such as Alberta held excess deliverability raised some of the same controversies in export markets as in domestic markets. Some of the concerns related to pipeline regulations, where U.S. and Canadian approaches often differed. As occurred in Manitoba and Ontario, there were also pushes by U.S. consuming interests (particularly the California Public Utility Commission) to allow core gas users and utilities tied into long-term contracts access to the lower prices of new spot and short-term contracts. Alberta's permit removal conditions made this difficult and potential negotiation between the governments, pipelines, and supply and demand aggregators were necessary to work out adjustments that largely maintained existing authorized export arrangements while allowing greater price flexibility.

By 1995, export pricing issues were effectively covered by the NEB's market-based procedure, discussed above. The board presumably monitors prices and sees information on prices as one component of the hearings into long-term (greater than two-year) export licences. However, the usual presumption, unless there is clear evidence to the contrary, is that freely negotiated export prices are "just and reasonable in the Canadian interest." In its 1996 review of changes in natural gas markets over the previous decade, the board stated (NEB 1996, 9. x) that:

> … the current functioning of the Canadian natural gas market is consistent with the basic premise of the MBP. The market is generally working so that the requirements of Canadian natural gas buyers are being satisfied at fair market prices. There are no barriers which would prevent major gas buyers from accessing competitively-priced supplies from western Canada. The eastern Canadian LDCs continue to purchase almost all of their gas requirements from western Canada even though they have established a large import capacity from the U.S. Gas prices are set through the operation of competitive markets, and gas production and marketing are very competitive businesses which provide maximum choice to gas buyers. Finally, the available evidence indicates that domestic gas buyers have been able to obtain Canadian natural gas supplies on terms and conditions at least as favourable as those available to U.S. buyers.

3. Free Trade (FTA and NAFTA)

Chapter Nine, Section 5, reviewed the energy clauses of the Canada–U.S. Free Trade Agreement, and the successor NAFTA incorporating Mexico into the free trade zone. The main provisions relating to natural gas were discussed there and will not be repeated. A main impact of the FTA and the NAFTA is to commit Canada to an integrated North American market for natural gas without any discriminatory pricing provisions, except in clearly defined circumstances. Export surplus policies for gas are allowable, but subject to the "proportionality" provisions in times of supply crises. As discussed in Chapter Nine, these ensure that in times of crisis export customers are ensured that their access to gas is not unduly restricted, so that they have proportionately as much access to supplies before and after the crisis on the same commercial terms as domestic energy users. (An indication that the proportionality provisions do not apply under normal market conditions can be seen in the fact that they did not apply between 2007 and 2009 when the U.S. share of Alberta natural gas production fell from 53% to 44%.) As noted above, provincial legislation in Alberta allows the government to shift ex-provincial sales to Alberta consumers in the event of a market disruption. It is not clear how this provincial regulation would operate under the federally negotiated NAFTA.

In addition, under the free trade agreements, national governments retain their jurisdiction over a number of matters where they have traditionally exercised power, such as in the authorization of pipelines.

B. Analysis of Natural Gas Pricing Regulations

In this section, the natural gas pricing regulations are analyzed. We do not discuss the free trade agreements or fiscal take as they apply to natural gas because the comments we would make are essentially the same as the ones made for crude oil in Chapters Nine and Eleven.

1. Domestic Pricing

Formal price regulation began in 1975 and continued through 1986 in the domestic market. Throughout this time span, domestic prices were held below export prices and values, though the differences became less pronounced with the adoption of the Volume Related Incentive Plan in July 1983 and the abandonment of fixed export prices in November 1984. As a first approximation, one might argue that the natural gas policy had much the same effect as the oil price regulations policy over the same period: by holding domestic prices below export prices, and limiting export sales by a licensing program, the policy transferred revenue from domestic producers and foreign consumers to domestic consumers. (See Figure 9.1 for graphical analysis of these effects.) Unlike the oil case, the revenue generated by an export price higher than the domestic price went to natural gas producers instead of governments. In efficiency terms, the key aspect is that the domestic price was held below the free market value of the gas, which would reflect the value in U.S. markets where marginal gas values were strongly affected by OPEC oil prices. As a result, Canadian producers failed to produce some gas that had a cost less than the hypothetical market value, and consumers used gas that possessed a marginal value to them less than this market value.

This initial discussion of the effects of natural gas price regulations requires some qualification. One difference with the crude oil analogy is that gas export controls were in place before price regulation, whereas crude oil export volume limitations were an integral part of the oil-regulation policy. A second is that crude oil price regulation was already in place in November 1975 when domestic gas prices were first fixed by the government.

We have touched on a familiar point: to assess the impact of a policy, it is necessary to specify clearly what would have held in the policy's absence. Our preference is to view the natural gas price control policy as part of a broader energy policy, which, beginning with OPEC price rises in late 1973, elected to hold Canadian petroleum prices – for both oil and natural gas – below international market levels. The general effects of the earlier paragraph would hold.

Alternatively, the natural gas pricing policy might be viewed against a backdrop of two other policies – the gas export surplus policies discussed in Section 3 of this chapter, and the oil price and export controls that commenced in 1973. It is more difficult to assess the natural gas pricing regulations against this backdrop, but some sort of gas export pricing regulations makes sense. Recall that the export surplus requirements tended to generate relatively high R/P ratios for gas, and fed into an oligopsonistic market situation, particularly after 1970 when export permits were denied. Partly as a result of the regulatory environment – the gas export policy plus pipeline and natural gas distribution utility regulations – natural gas domestically was bought and sold under long-term contracts with relatively rigid pricing terms. By the early 1970s, it was widely accepted that Canadian natural gas prices were lower than they would have been had there been unrestricted access to the U.S. market and had contractual terms been more responsive to rising prices of oil, which was the main competitor to natural gas in many markets. Largely at the instigation of the government of Alberta, domestic gas contracts were being revised to higher prices and more frequent price renegotiation.

Two questions arise. The first is hypothetical: how would Canadian gas markets have evolved in the 1970s in the absence of the domestic price regulations? The second is what effect the price regulations had relative to this hypothetical situation?

If a definite answer to the first question is required, it must be that no one knows how gas markets might have changed in the 1970s. However, if a more speculative response is allowed, the changes in the early 1970s could be seen as the first step toward a freer more competitive natural gas market; but real competition on the buyer's side of the market hinged on things that had not yet occurred – opening the market to U.S. purchasers and removing TCPL as an oligopsony buyer-shipper. In the absence of these changes, oligopsonistic power remained and price renegotiation was being driven mainly by Alberta's insistence on "commodity value." The domestic price controls adopted "commodity value" as a touchstone of sorts, with domestic gas prices tied to domestic crude oil prices in Toronto, at first with 80 per cent of Btu parity, then, after 1980, with 65 per cent. Market experience since 1985 suggests that the resultant prices overvalued natural gas relative to crude oil. After 1986, natural gas prices fell relative to crude and stayed at a lower relative level than under price controls until the year 2001. (See Table 12.1, Column 10.) That is, natural gas was somewhat overpriced during the price-fixing era, relative to what freer competitive market conditions would likely have generated. This would have been to the advantage of Alberta gas producers and the Alberta government and to the disadvantage of natural gas consumers. (It is notable that the policies to fix natural gas prices under the NEP were accompanied by measures to stimulate natural gas consumption beyond the level that prices generated. Ottawa indicated that the delivered price of gas in new markets east of Montreal would be held to the Toronto city gate price, and Alberta and Ottawa both agreed to contribute to a market development fund for natural gas.)

In conclusion, we would argue that the impact of the price-regulation period was to hold natural gas as well as oil prices lower than they would have been (assuming that steps were also taken to free up natural gas exports and increase competition in the gas market). However, the price of natural gas was held at a relatively higher level under regulation than they would have been without the energy price controls.

2. Export Pricing

Prior to 1975, and after 1984, the export price of natural gas was subject to indirect influence through the NEB's export-licensing procedures, which required the NEB to ascertain whether export prices were "just and reasonable." For the most part, the NEB has applied this by seeing whether the export price is at least as high as the price paid by customers on the Canadian side of the border point. McDougall (1973) and McDougall (1982) point out that this condition was not met in the mid-1950s contract between El Paso Natural Gas and Westcoast Transmission until the contract was renegotiated in the mid-1960s. More problematic was a different pricing criterion, the third price test as formalized by the NEB in 1967 – that the export price should reflect the cost of alternatives to consumers in the export market, a 'commodity value' criterion. One could argue that the border price comparison sets a price floor for export of gas, but the alternative fuel comparison sets a price ceiling. So long as the ceiling is as great as the floor, the gas export should be allowed (i.e., so far as price is concerned), but it is in Canada's interest to obtain the ceiling price amount.

In a well-functioning, effectively competitive market, one expects that the two prices will converge. High values in the export market will draw incremental suppliers, serving simultaneously to reduce the marginal value in the export market, increase marginal costs and prices in the supply centre (as new sources of gas are tapped), and increase marginal values in domestic markets (as gas is diverted to the export market). This is how deregulated North American gas markets evolved after the mid-1980s.

However, this was not true of the North American natural gas markets in the earlier period. By the late 1960s, it was apparent – and recognized by the NEB even as it approved specific export licences – that the export price was lower than the price of the alternative non-gas energy sources in the U.S. market (McDougall, 1975, chap. 5). The board argued that the exports were in the Canadian interest since the second price test (a price higher than the adjacent Canadian one) was passed. Why was the third price test not insisted on? Three reasons suggest themselves. First, while the "commodity" pricing approach appears eminently reasonable, it turns out to be very difficult to apply and often somewhat ambiguous, for reasons discussed above. It is not as easy as one might initially assume to determine that export values exceed export prices. Second, prices in export contracts appreciably above prices in purchase contracts for domestic sale imply different netbacks for producers and raise concerns of fairness. (Which producers are lucky enough to get the higher netbacks? Netbacks accrue to producers because the pipeline-purchasers are regulated on a cost of service basis.) Market forces did not eliminate the difference in netback values because the export surplus regulations blunt the forces of foreign demand. (In fact, the purpose of the removal permit restrictions is precisely to allow lower domestic than foreign marginal values!) Third, Canadian natural gas was demanded in the United States in part because of the regulation-induced shortages of interstate natural gas; customers in California and the U.S. Midwest had to turn either to Canadian gas or to more expensive non-gas substitutes. But, for political reasons that are easy to understand, the FPC was very reluctant to admit natural gas imports at prices higher than they would give to U.S. producers. Thus, while U.S. customers may have been willing to pay more for Canadian gas, regulatory permission for imports probably would not have been forthcoming from the FPC in the 1960s.

As with so much else in the world of energy, the OPEC price revolution starting in 1973 led the parties involved to change their mindsets. The potential export value of natural gas, in a world of high oil prices, was evident to Canadians. The advantage of Canadian gas over OPEC oil was apparent to the United States (though the price of Canadian gas relative to OPEC oil was obviously a consideration).

How effective was the Canadian export pricing policy for 1975 through 1986? The question has two parts. Was the price level selected by the Canadian government (on the advice of the NEB) the best one for Canada? Was a uniform border pricing policy appropriate? The latter question is important because the shift to a uniform border price was really an exercise in price discrimination. Readers may wonder how charging the same price to foreign customers can be price discrimination. The reason is that the cost of accessing different border points differs, with lower costs to border points nearer the producing region (i.e., Alberta). Hence non-discriminatory pricing implies lower border prices the closer the export point is to Alberta. Uniform border prices implies relatively higher prices close to Alberta and relatively lower prices further away; given any average export value, uniform border pricing discriminates in favour of U.S. customers who get their gas from the border points more distant from Alberta.

Our evaluation draws extensively on Watkins and Waverman (1985), who ask whether the Canadian natural gas pricing policy appears to have been more like monopolistic (oligopolistic) or effectively competitive behaviour. They start from the premise that there is a potential for monopoly-like profits on Canadian gas exports to the United States. In 1983, while Canadian gas met only 4 per cent of total U.S. gas use, "in the Great Lakes and Rocky Mountain states it reaches about 6 per cent, while for the West coast region the proportion is as high as 12 per cent" (Watkins and Waverman, 1985, p. 416).

Watkins and Waverman assume that Canada could act to increase the returns to Canadian gas producers (and governments as rent collectors) by a dual price system in which export prices are at a higher level than Canadian prices. (Note that a dual price system is clearly inefficient if Canada does not possess significant market power, since lower-valued domestic consumption is then being encouraged at the expense of higher-valued export revenues.) Of course, short-run market power is often higher than long-run power, for example, if competing transmission systems are operating at capacity so that more domestic U.S. gas cannot readily flow into a market as Canadian gas prices increase.

The Canadian gas export pricing policy of 1975–83 is consistent with monopolistic behaviour by Canada. Watkins and Waverman conclude, however, that the natural gas policy did not maximize Canadian welfare in part because Canadian prices were fixed at artificial levels domestically and in part because export prices did not fully fit a monopolistic model. The latter assessment involved a number of comparisons. For instance, they note (p. 422) that "a monopoly seller would have … aligned export gas prices to the highest cost source of gas in the United States market – the so-called Section 207 gas under the *Natural Gas Policy Act* (NGPA)," but this was not the criterion used by the NEB. (After 1977, it will be recalled, the NEB looked at a substitution or replacement value of Btu parity with crude in Toronto, though even here the government, especially after 1980, did not impose the full substitution value.) Moreover, Watkins and Waverman find that the pattern of price discrimination implied by uniform border pricing does not accord with that expected from an effective monopolist. Table 12.4 includes some relevant information. Watkins and Waverman calculated netback values for natural gas exports across various border points; these are Alberta netbacks equal to the average selling price of gas at the export point less transmission costs from the Alberta border to the export location. In Table 12.4, these netbacks are shown as a proportion of the netbacks at the Emerson, Manitoba, border point for two years, 1968 and 1983. The fourth column shows an estimate of the elasticity of demand for natural gas by end-users in that regional market in the year 1983.

The 1983 netbacks and elasticities are relevant to the uniform-border-pricing period. A monopolist

Table 12.4: Natural Gas Export Pricing: Netbacks and Elasticities

Export Border Point	U.S. Markets Served	Alberta Netback Relative to Emerson		Estimated Price Elasticity of Demand
		1968	*1983*	
Huntingdon, B.C.	Pacific N.W.	0.836	0.965	–1.24
Kingsgale, B.C.	California	1.005	1.002	–1.31
Aden/Cardston, Alta.	Montana	1.202	1.020	–1.02
Monchy, Sask.	N. Central	n/a	0.984	–1.02
Emerson, Man.	Great Lakes	1.000	1.000	–1.02
Fort Francis, Ont.	Great Lakes	0.852	0.951	–1.02
Cornwall, Ont.	New York	0.623	0.866	–1.02
Phillipsburg, Que.	New York	0.585	0.849	–1.07

Notes: Monchy, Saskatchewan, opened as a border point in 1982. The Emerson price was $0.183/Mcf in 1968 and $5.09/Mcf in 1983.

Source: Watkins and Waverman (1985), Tables 1 and 2.

exercising effective price discrimination would take advantage of variations in demand responsiveness by charging relatively higher prices in the markets with the lowest price elasticities of demand. (In these markets, any given price rise generates a smaller percentage decline in sales.) However, as Table 12.4 shows, there was no tendency for netbacks to vary with the elasticity of demand.

Table 12.4 shows that the range of netbacks on natural gas exports was much narrower under the uniform-border-pricing policy of 1983 than in 1968. The wide spread of netbacks in 1968 is interesting. One would expect that an effectively competitive market, with price flexibility in contracts, would tend to exhibit identical netbacks on all sales. (Strictly speaking, the field netbacks should equalize, but, since most gas went through one of the straddle plants and NOVA used a postage stamp tariff, Alberta border prices and field netbacks should exhibit the same differences.) The netback variations in 1968 are consistent with an oligopsonistic market structure with an overhang of excess supply as characterized the market under the 1960s policies on export removal.

But how would we characterize Canada's export pricing policy from 1975 to 1983 if it was neither monopolistic nor effectively competitive? Watkins and Waverman (1985) suggest that some form of oligopoly market provides the best fit. Specifically, they suggest that a model with "zero conjectural variations" provides a good fit. In this model, the decision-makers take other sellers' prices as fixed. Canadian authorities after 1977 (in setting prices for gas exported to the United States), focused on Toronto crude prices, rather than on U.S. natural gas prices, essentially treating U.S. gas prices as fixed. In this model, the oligopolistic supplier "will absorb transportation costs by accepting decreasing delivered prices as the distance to market rises (Phlips, 1983, p. 43)" (Watkins and Waverman, 1985, p. 422). Uniform border pricing of a good such as natural gas, with output concentrated in Alberta and Northwest B.C., exhibits just such a pricing pattern. Certain other features of uniform border pricing may have appealed to the NEB and the Canadian government. It was "easily computable" and readily changed and did not require detailed information on price elasticities; moreover, a uniform price "could be sold as 'non-discriminatory' (which it wasn't)" to U.S. authorities; and it did generate somewhat higher profits for Canada than sales at domestic Canadian prices would have (p. 424).

Overall, Watkins and Waverman give the Canadian natural gas export pricing policy a grade of B+ (p. 425). Canada could have charged higher prices to its benefit in the mid-1970s and probably should have charged somewhat lower prices in the early 1980s when exports fell to half of authorized levels. But the policy did generate higher gas revenues to Canada and did so without pushing U.S. authorities into retaliatory action.

A residual question remains. If a dual-price system for natural gas – low domestic prices and high export prices – was in Canada's interests in the 1970s and early 1980s, wouldn't it also be beneficial to the country after deregulation in 1986? Expressed in other terms, if Canada has some market power in U.S. gas markets, isn't it in the national interest to use that power? On the whole, deregulation, NAFTA, and the market-based export policy seem to argue against such an export pricing policy. In general, the exercise of market power in the pricing of a particular commodity by one country against a main trading partner is economically and politically dangerous since the trading partner may retaliate. There were special circumstances in the 1975–85 period in natural gas pricing that restrained U.S. impulses to retaliate. Most important was the wish of the United States to reduce reliance on OPEC oil, while seeing the OPEC price as setting the opportunity value of energy in general. (The confusion in U.S. natural gas markets after decades of FPC price regulation left no obvious U.S. natural gas reference price.) Accordingly, it was quite acceptable to U.S. authorities for Canada to base natural gas export prices on OPEC crude oil prices, even while holding domestic gas prices lower. This unusual set of circumstances no longer exists. Moreover, it is arguable that the effective deregulation of U.S. gas markets has served to increase considerably the long-run elasticity of demand for Canadian natural gas in the United States, and hence to reduce considerably the scope for a dual-price policy.

C. Fiscal Take (Royalties and Taxes)

Chapter Eleven reviewed the conceptual basis for special taxation provisions governing the crude petroleum industry, as well as the characteristics of various types of taxes, royalties, and other mechanisms used by governments to capture economic rent or influence the behaviour of the industry. These conceptual arguments will not be repeated here. What follows is a brief summary of the major fiscal measures that apply specifically to the Alberta natural gas industry. Price controls, which may be used to capture and redistribute economic rent, were discussed above. The corporate income tax applies to total company operations, rather than natural gas specifically, and was discussed in Chapter Eleven. Bonus bids for petroleum rights cannot generally be ascribed specifically to natural gas as the bids are usually for petroleum rights including both oil and gas. However, as was noted in Chapter Eleven, Alberta has, on occasion, auctioned off leases or licences for natural gas alone from a specific formation. In 2008, the government announced that shallow mineral rights, above producing reservoirs, would revert back to the government for subsequent sale; this seems likely to involve mainly shallow gas deposits. The Petroleum and Natural Gas Revenue Tax (PGRT), the Petroleum Incentive Payments (PIP grants), and the Canadian Ownership Special Charges (COSC) of the National Energy Program (NEP) were also covered in Chapter Eleven; they applied to both crude oil and natural gas and will not be discussed further here. This leaves two fiscal measures specific to natural gas to be discussed: provincial natural gas Crown royalties and the federal Natural Gas and Gas Liquids Tax (NGGLT) of the NEP.

1. Alberta Crown Royalties

The Alberta government assesses a gross *ad valorem* royalty on natural gas produced from Crown leases, much as it does for crude oil. There has also been, since 1973, a Freehold Minerals Tax, which applies to the more minor gas volumes produced from freehold leases in Alberta. As for crude oil, the government felt that the public, as well as private mineral rights owners, should benefit from the tremendous rise in the value of petroleum in the early 1970s. Tables 11.1 and 11.2 set out Alberta government petroleum revenues, including separate natural gas and NGL royalties from 1972 on. Prior to the mid-1970s, crude oil royalties were much higher than natural gas royalties, but after that gas royalties increased in relative significance, reflecting in part the rising value of gas relative to oil as seen in Table 12.1. In 1986 and 1988, natural gas royalties exceeded conventional oil royalties and did so every year except one from 1992 to 2008. In large measure, this reflects rising gas production and declining conventional crude oil output. By 2003, natural gas and NGL royalties were over five times higher than conventional oil royalties. However, in 2009, for the first time, oil sands royalties exceeded natural gas royalties and by a widening margin as natural gas production and prices fell.

The June 1, 1951, royalty regulations set a 15 per cent royalty rate for natural gas, with a minimum of $0.0075/Mcf (which would apply if the price received for the gas was less than five cents/Mcf).

Effective April 1, 1962, the natural gas royalty rate was increased to 16 2/3 per cent, with the same minimum royalty as before. In addition, producers were allowed a Gas Processing Allowance, which was a deduction from the value of the gas to allow for any costs involved in processing the gas to remove sulphur or natural gas liquids. We shall not summarize all the details of regulations covering this Gas Processing Allowance, which proved to be rather complicated over the years. In effect, the allowance was designed to allow recovery of the costs for facilities that processed the gas. Most operators effectively contracted these processing services from operators of large gas-processing plants in the province and would claim an allowance on the basis of the costs of these large facilities. However, some gas producers built their own field processing plants and could claim a deduction on the basis of the costs of their plant. The process of calculating allowable gas-processing allowances became very complex as the number of processing plants rose and gas producers increasingly used a number of different facilities. Effective in 1994, Alberta simplified the regulations to base the Gas Processing Allowance on a provincial average processing cost, thereby removing the obligation for producers to file detailed statements documenting the various costs actually incurred on all the natural gas they produced.

On January 1, 1974, the province implemented a new natural gas royalty, which was a sliding-scale royalty based on the price of natural gas (and anticipating the forthcoming oil royalty regulations of March 1974, discussed in Chapter Eleven). There was a minimum royalty rate of 22 per cent, which applied when the price of gas was $0.50/Mcf or less ($17.75/10^3 m^3 or less). When the price exceeded this level, the royalty rate increased, with the royalty designed to capture a specific fraction of the higher revenue. A higher rate was assessed on 'old' gas, that discovered prior to 1974. Initially the royalty formulae were set up to capture 65 per cent of the 'additional' revenue on old gas when the average Alberta Market Price is above $0.50/Mcf; on 'new' gas (gas discovered after December 31, 1973) 35 per cent of the higher revenue was collected as royalty.

The general nature of the natural gas royalty formula was unchanged from 1974 to 2008, but, as with crude oil, there were a number of adjustments over the years (Alberta Department of Energy, 2003, 2007a,b). For example:

(1) the proportion of revenue above the minimum price taken in royalties was changed. On old gas it was reduced to 50 per cent in 1978, then 45 per cent effective April 1, 1982, and then to 40 per cent in June 1985 and 35 per cent in 1992. On new gas, the share of incremental revenue going to Alberta was cut to 30 per cent in June 1985. There were temporary further cuts in October 1986. Rates vary between 15 per cent and 30 per cent and were at an average rate of 20 per cent in 2005.

(2) on July 1, 1978, a reduced royalty was introduced for low-output non-associated natural gas wells; if output was less than 600 Mcf/d (averaged over a month; this is 16.9 m^3/day), the royalty rate was reduced in such a way that the royalty fell to 5 per cent as output fell to zero. In 1994, the low-output royalty was extended to associated gas from low-output crude oil wells.

(3) With deregulation, natural gas pricing became much more diverse. As mentioned above, Alberta responded by specifying that gas revenue for royalty purposes must at a minimum be 80 per cent of the average Alberta field price in any year (effective December 1987). In 1994, the government decreed that a company could value all of the gas it sold at the company's average gas price, so long as this was at least 90 per cent of the average Alberta field price; if companies did not elect to do this, they were to value gas at a 'reference' price that was the average price at the exit of gas plants. These modifications both offered some protection to the Alberta government in terms of minimum royalty receipts and also helped reduce the administrative costs to companies of calculating their royalty payments.

(4) As of January 1, 1993, the gas royalty formulae were to be modified annually to allow for inflation, as seen in the GDP price deflator.

(5) Effective in October 2002, natural gas also began to be assessed NGL royalties based on the NGL content of the gas.

(6) In addition to a number of the incentive programs discussed in Chapter Eleven, there were several programs aimed explicitly at natural gas activities, in addition to the low-productivity allowance set out in (2). These included: a deep gas royalty holiday (1985); a royalty waiver on solution gas that was not flared (1999); a royalty credit for certain sulphur removal investments (1999); and a royalty credit on gas used in cogeneration projects (2001).

As was the case with conventional crude oil (Chapter Eleven), the fairness of the royalty share accruing to the province became an issue of concern as natural gas prices rose at the start of the new millennium. In 2007, the province commissioned a Royalty Review Panel, which issued a *Report* in September of that year. As was the case with crude oil, the panel found that Alberta collected a smaller share of the economic rent from natural gas than other regimes in North America and recommended a simplified royalty regime that would raise the anticipated government rent share from 58 per cent to 63 per cent (Alberta Royalty Review Panel, 2007, p. 7). The suggested royalty would remove the vintage distinctions and the special incentive programs and include a two-part royalty with sliding scales based on volume and on price, with the royalty rate varying from 2 per cent up to 50 per cent. (Alberta Royalty Review Panel, 2007, pp. 71–73).

In October 2007, the government announced its reaction to these recommendations (Alberta Department of Energy, 2007b). Effective in January 2009, there would be a new natural gas royalty that sounded close to what the panel had recommended: the vintage distinction would be eliminated and the royalty formula would have price and volume components, with rates ranging from 5 per cent to 50 per cent (the highest rate becoming effective at a price of

$16.59/Gigajoule), and rates lowered for lower output wells. Although it had not been a recommendation of the Royalty Review Panel, the government announced that it would be implementing lower royalties for deep gas wells and 'lower-productivity' reserves, in recognition of their high costs. As was the case for conventional oil, Mintz and Chen (2010) found that, under these regulations, Alberta would have a 'marginal effective tax and royalty rate' higher than other provinces.

As was noted in Chapter Eleven, the new royalty regime occasioned criticism from industry and further study by the government. As with conventional crude oil, a 'transitional' option (up to January 1, 2014) for new wells deeper than 1,000 m was announced in November 2008, as was, in May 2010, a revised set of royalty rates, to be effective January 1, 2011. The new rates involved a larger reduction for natural gas than for oil. They maintained the 5 per cent minimum rate, but the highest rate was reduced to 36 per cent; there was, as in the 2007 plan, a separate ceiling of 30 per cent on each of the price and output components of the royalty. A 'depth factor' was incorporated into the output part of the royalty, reducing the rate for wells deeper than 2,000 m. The government expressed particular concern about the economic viability of deep gas reserves, culminating in a five-year royalty credit plan announced in late 2008 for gas wells deeper than 2,500 m. (This was in addition to the other incentive programs briefly outlined in Chapter Eleven.) For shallower gas wells, the minimum 5 per cent royalty would apply on low-output wells (60 Mcf/d or less) for prices as high as $16.00/Mcf. A high-output well, of 1,000 Mcf/d, would not hit the ceiling royalty rate of 36 per cent until the price of gas was above $6.50/Mcf. As was the case for crude oil, the new plan involved reduced royalties, compared to the pre-2009 regime, on lower-volume wells (below about 300 Mcf/d) and at lower prices (below about $5.00/Mcf), but higher royalty rates for higher-output wells and at higher prices.

The prime impetus for the royalty changes was the desire for a new royalty regime as North American energy moved into a higher price environment, although, as noted in Chapter Eleven, the declining government rent share reflected in part the reductions taking place in corporate income tax rates. As discussed above, much higher than historical prices are far from certain; this is even more so for natural gas than crude oil, given the better geological prospects in North America for natural gas than oil, especially as large volumes of non-conventional gas prove economic at relatively low costs. As seen in Table 12.1, natural gas prices in North America fell dramatically after 2008.

2. Natural Gas and Gas Liquids Tax (NGGLT)

The NGGLT was introduced by the federal government in its October 1980 budget as part of the National Energy Program. Since the size of the tax was intimately tied to the natural gas pricing provisions of the NEP, it was discussed above in the gas-pricing section. However, for the sake of completeness, we will briefly outline the main features of the NGGLT here, in the 'fiscal take' part of this chapter.

Prior to the NEP, the federal government had no specific fiscal measures assessed on natural gas. It did, of course, have its corporate income tax and, after 1974, natural gas royalties paid to provincial governments had not been deductible as a cost for the federal portion of the corporate income tax. (These issues were discussed in Chapter Eleven, with specific reference to crude oil.) Also, since 1973, the discrepancy between domestic and export prices for natural gas had not been set by an export tax (as was the case for crude oil), but rather by Ottawa directly fixing the export price.

The NEP introduced the NGGLT, which was to apply to all natural gas sales, including exports. (The application of the tax to exports was delayed until February 1, 1981, to allow the government to meet its obligation to the government of the United States to give ninety days notice before changing gas export prices.) The NGGLT was to be $0.30/Mcf effective November 1, 1980, rising in three steps of $0.15/Mcf on July 1, 1981, January 1, 1982, and January 1, 1983, to an ultimate level of $0.75/Mcf.

In the NEP, Ottawa claimed that the stimulus for the NGGLT was the adamant refusal of the natural-gas-producing provinces to accept a gas export tax, even if Ottawa agreed to split the revenue with them. Ottawa argued that "there is no doubt of the federal government's constitutional right to impose export taxes on any commodity." However, it recognized "the strong opposition of Alberta and British Columbia to the gas export tax," and "is, therefore, not proceeding with a natural gas export tax." However, Ottawa did have to find additional revenues. "The Government of Canada lacks the revenues necessary to fulfill its national obligations. Some of these obligations flow from the same international oil crisis that provides growing revenues to the governments of Alberta and British Columbia." (Quotations from the NEP, p. 34.)

Hence, in Ottawa's view, the need for the new federal taxes on petroleum, the PGRT (discussed in Chapter Eleven) and the NGGLT.

Extensive negotiations between Ottawa and Alberta in 1981 led to the September 1981 *Memorandum of Agreement*. Alberta and British Columbia had been firm in their contention that a federal excise tax on natural gas (particularly exports) was a discriminatory attack on provincial natural resources, amounting to an attempt by Ottawa to override the constitutional provisions giving control of mineral resources to the provinces. In the *Memorandum of Agreement*, Ottawa preserved the right to set a natural gas export tax, but agreed to set the rate at 0 per cent; that is, the NGGLT was removed from natural gas exports. As discussed in the pricing section above, the NGGLT on domestic sales of natural gas would be set at the rate which would allow the Alberta border price to attain the levels agreed to in the *Memorandum*, given that the price of Alberta gas delivered to Toronto should reflect 65 per cent Btu parity there with crude oil. That is, the fixed rate NGGLT of the NEP was replaced with a variable rate NGGLT that depended on the petroleum pricing levels agreed to in the *Memorandum* and on the international price of oil. As it happened, by February 1984, the NGGLT had fallen to zero as international crude oil prices failed to rise to the levels anticipated. (Delivered prices of Alberta natural gas, at agreed-upon Alberta border prices, equalled or exceeded the 65 per cent Btu parity with crude in Toronto, so there was no room for a NGGLT.)

With deregulation of the oil market in 1985 (and the natural gas market with the 1986 *Halloween Agreement*), the special federal tax provisions of the NEP were dropped. Since then, Ottawa's revenue from natural gas production has, once again, derived essentially from the corporate income tax. Remember, however, that the federal corporate income tax is now a more effective rent-collection device than it was prior to 1972 since the depletion allowance has been phased out. As noted in Chapter Eleven, in 2002, the Resource Allowance was eliminated and provincial royalties on natural gas are now deductible as a cost.

5. Conclusion

Commercial production of natural gas began in the 1880s, when a water-directed well drilled by the CPR hit a gas deposit near Medicine Hat. From this accidental birth, a major Alberta industry has grown. Five periods in the life of the industry can be discerned, though real-life distinctions are never quite as clear as such categorizations suggest.

Period 1. The local market era (1882–1946). The town of Medicine Hat began using natural gas in the 1880s. By the early 1900s, utility companies were being set up to explore for and contract gas from Alberta pools to service local markets, most notably, of course, Calgary and Edmonton.

Period 2. The by-product of oil era (1947–57). The rush of crude oil exploration engendered by the 1947 Leduc find and subsequent oil boom tremendously increased the availability of natural gas. This reflected both the output of associated gas produced along with crude oil and the discovery of non-associated natural gas pools by drillers looking for oil. Local markets could not absorb such large volumes of gas, and government regulations limited the ability of companies to burn it off (flare it), so increasing amounts accumulated as potentially accessible reserves but with no immediate economic value.

Period 3. A market expansion era (1958–71). Long-distance, high-diameter, high-pressure natural gas pipelines were completed, which allowed Alberta natural gas to establish itself as a valuable export product. TransCanada PipeLines (TCPL) reached the Niagara Peninsula in 1958. The decision to build the line involved a major political commitment from the federal government; it generated the most intense political debate of the 1950s and was partly responsible for the defeat of the Liberal Party in 1957 after governing continuously for twenty-two years. Access to California markets came with the Alberta & Southern and Pacific Gas Transmission lines in 1961, and TransCanada built a new link through the U.S. Great Lakes area (south of the original all-Canadian line of 1958), which opened in the late 1960s.

Period 4. A regulated-market era (1972–86). From the beginning, the natural gas industry had been more regulated than crude oil, including rate regulation of the major transmission and distribution companies and surplus test requirements for natural gas exports. Beginning in 1970, the regulations became even more stringent. Export permits for Alberta gas to the United States were denied (beginning in 1970) and government price regulation was instituted (1975–86). The forces of industry attention shifted from active participation in natural gas markets to a more passive reaction to the government prices and various political and public relations activities designed to influence government policy. Production stagnated, and the industry saw the appearance of regulation-induced problems such as TCPL's take-or-pay difficulties and growing shortfalls of actual below authorized exports.

Period 5. A deregulation, "commoditization" period (1987–). Government price and market control regulations were removed, and Alberta natural gas was encouraged to integrate with a rapidly evolving North American gas market. The number of active buyers and sellers in the market has increased, as have such intermediaries as the NYMEX natural gas futures market and various computer bulletin boards to allow inexpensive rapid exchanges of market information. Transmission companies have been shifted to common carrier status, spot sales of natural gas have mushroomed, and both sellers and purchasers of gas under long-term contracts have accepted the inevitability of frequent price readjustment in light of prevailing market conditions. With the international crude oil market, the North American natural gas market has been evolving to very flexible market trading arrangements like those that characterize many other commodities and financial instruments.

Whether the natural gas market will evolve into an international one, like the oil market, is very much an open question. In the 2000s two quite different avenues to internationalization were suggested. One might be called a 'low availability/high price' possibility in which reduced supplies of North American natural gas drive prices high enough that imports of liquefied natural gas (LNG) from overseas become economic. As natural gas prices rose after 2000, some observers saw this as a possibility. However, plummeting prices after 2008 suggested another possibility, which might be labelled 'high availability/low price', with low North American natural gas prices stimulating significant LNG exports. As of final editing in spring 2013, a number of LNG export proposals have been made to move B.C. and Alberta gas from terminals on the west coast to Asian markets. (In part, the appeal of these exports is based on very high gas prices in Japan and China where the gas price has been tied to international crude oil prices. It seems unlikely that this pricing formula would continue in the face of large-scale shipments of LNG to these markets.) Of course, neither of these cases may materialize, with North America continuing to function as a separate natural gas market with prices too high to stimulate LNG exports and too low to induce LNG imports. (In this case there might be some small scale LNG trade as companies continue to operate previously-constructed facilities, which they regret having built, so long as they can recover operating costs.)

The various problems that were apparent in the days of tighter regulation before 1987, plus the commitments to free markets implicit in the Canada–U.S. FTA and NAFTA, suggest that Alberta natural gas will continue to operate in a deregulated free-market environment through the indefinite future. The industry is adjusting to declining reserves of conventional natural gas, and moving into non-conventional resources.

CHAPTER THIRTEEN

The Petroleum Industry and the Alberta Economy

Readers' Guide: Petropolitics has been significant in the petroleum industry in part because the industry makes up an important part of many regional economies. In this chapter, we explore the broader economic linkages of the Alberta petroleum industry. The chapter examines the relative importance of the petroleum industry to provincial output and employment and how its role has changed over time. It also looks at related issues such as policies to encourage economic diversification in Alberta and to spread the receipt and use of government petroleum revenues more evenly over time.

1. Introduction

So far, we have emphasized the microeconomic dimensions of the Alberta petroleum industry – the operation of oil and gas markets and government regulations that have affected those markets. However, as mentioned several times, the petroleum industry is large enough that it may also have noticeable effects on the overall economy – macroeconomic impacts. This chapter looks at the interrelationships between the Alberta petroleum industry and the Alberta economy, although without any detailed examination of other industries, even those such as pipelines, natural gas processing, and petrochemicals that depend directly on crude oil and natural gas. The economic linkages generated by petroleum are complicated, but a useful distinction can be made between cyclical impacts, especially those provoked by petroleum price fluctuations, and effects on overall economic growth. Our Introduction briefly sets out the main cyclical and growth effects. We then turn to the impact of petroleum on the size and development of the Alberta economy, concluding with consideration of the impact of unstable resource revenues on the provincial government and the government's actions to save some of its resource rents through the Alberta Heritage Trust Savings Fund.

A. Cyclical Effects

Some of the macroeconomic effects of the petroleum industry occur through the consumption side of the petroleum market since petroleum is such a significant energy source for most countries. When oil prices change dramatically, as they are prone to, expenditures on oil by consumers also change significantly, with attendant effects on their ability and willingness to spend on other goods and services. This effect is especially significant in the period immediately after a large oil-price change since the demand for oil products is highly inelastic in the short-run, meaning that consumption is quite unresponsive to price changes. Therefore, a major price rise, like in 1973/74 or 1979/80 or 1999 or 2006/08, will generate a dramatic increase in payments for oil. Economists refer to a changed willingness to spend on goods and services in general as a change in the quantity of 'aggregate demand.' If increased expenditures on oil products reduce the income left to spend on other things, a decrease in the aggregate demand for goods and services in the economy occurs. This typically means a fall in Gross Domestic Product (GDP) and higher unemployment.

Inflation is a monetary phenomenon characterized by a general rise in price levels. A move in relative prices, resulting from scarcity or abundance of one product, is not inflation. Normally the increase in price of a single commodity implies, simply, an increase in the cost of this good relative to others, but with a negligible effect on the general level of prices (i.e., the inflation rate). However, energy prices also play a significant role in the price indices used to measure inflation in the economy. More importantly, higher energy prices may contribute to demands for higher wages, which contribute to higher prices for goods and services that employ labour. Thus rising oil prices may be seen as adding to inflation at the same time as they contribute to declining GDP, a situation referred to as 'stagflation.' (Helliwell, 1981, discusses the pathways to stagflation from higher oil prices; for examples of a macro model of higher oil prices in Canada, see Jump and Wilson, 1975, and Empey, 1981.) These effects of large oil-price changes would be expected to operate in opposite directions for large price rises and large price falls; there is some debate about whether the macroeconomic effects are symmetric in this way. Some analysts have accepted the stagflationary impacts of large oil-price rises but have questioned whether large price declines do in fact generate expansionary and deflationary impulses. This lack of symmetry may in part reflect the reduced share of oil in total energy use when oil prices fell (1985/86) as compared to when they rose in the 1970s and early 1980s. However, it also may suggest that the macroeconomic effects of oil-price changes are more complicated than in the discussion so far. Two additional factors must be considered.

First, it is important to realize that macroeconomic effects are the result of both oil-price changes and the macroeconomic policy response of the government. Appropriate use of monetary and fiscal policies, which are largely the responsibility of the federal government in Canada, may offset the aggregate demand and inflationary effects of the petroleum-price changes.

Secondly, there are also macroeconomic effects from the supply side of the oil market. Higher expenditures on oil by consumers is increased revenue to oil producers, and the higher oil prices make additional investment in oil exploration and development attractive. That is, oil-price increases lead to increases in aggregate demand in oil-producing regions, and therefore to increases in GDP.

There are, therefore, some uncertainties in the macroeconomic effects of major oil-price changes. The precise macro effects turn out to hinge on two important factors, geography and what has usually been called 'recycling.' Since oil deposits are so unevenly distributed beneath the earth's surface, the primary macro effects tend to be opposite in sign for regions that produce a lot of oil and those that do not and must import oil. It can be appreciated that these regional differences are not country-specific; within large countries like Canada, Russia, and the United States, there are oil-exporting regions and oil-importing regions.

The 'recycling' problem refers to the uses to which oil producers put their increased earnings from higher-priced oil. Is the additional money spent on goods and services from the oil-consuming region that provided the revenue to the oil producer? If so, then the aggregate demand effects in the consuming region will be minimal. The reduced spending by oil consumers is offset by the increased spending of oil producers. Of course, the oil producers are better off, and the consumers worse off, since some of the goods and services that residents of the consuming region used to buy are now being exported to the oil producers. However, there will be reduced aggregate demand in the consuming regions in total to the extent that oil producers save some of their increased earnings instead of spending them. The increased saving, as a supply of financial capital, may drive down interest rates, which may in turn stimulate more investment spending, but it is widely accepted by economists that, in the absence of offsetting government policies, such increases in saving will tend to reduce aggregate demand in the economy, at least in the short term. Of course, some consuming regions could actually see a net stimulus to the economy if increased spending in the region by oil producers (e.g., OPEC) is higher than the region's extra payments for oil imports.

From this more complete perspective, it is difficult to offer many generalizations about the macroeconomic cyclical effects of changing oil prices. While governments of oil-importing regions have been very concerned about the possibility of such effects (and they concerned Ottawa in the 'overt control' days of 1973 to 1985), we shall not investigate such cyclical economic effects in Alberta in any great detail. In part, this is because there are obvious limitations in the macroeconomic policy responses of a Canadian province, as compared to the federal government in Ottawa. It is the federal government that has access to the levers of monetary policy and the main levers of fiscal policy. Furthermore, in an open provincial economy, it may be difficult for the provincial government to pursue an effective fiscal policy; cuts in provincial income tax rates to spur the local economy may lead primarily to an increase in imports into the province rather than much additional spending on locally produced goods and services.

Our main emphasis in this chapter will be on the longer-run impacts of the petroleum industry on the size and structure of the Alberta economy. The income and employment data we assemble will provide evidence on short-term cyclical performance. In addition, later in this chapter, we will consider how the provincial government might respond to the pronounced variability in the revenues it generates from the petroleum industry.

B. Growth Effects

In the remainder of this chapter, we shall be concerned primarily with the long-term effects of the petroleum industry on the economy of an oil-producing region, Alberta in particular.

This point seems intuitively obvious to residents of Alberta. Those with long memories can look back to the end of the Second World War, when the economies of Alberta and Saskatchewan bore a close resemblance. Populations were under one million in both provinces, and agriculture was the predominant industry. By July 1, 2012, Alberta had a population of almost 3,900,000 million, while Saskatchewan was still hovering near the one million mark. The most obvious difference between the two provinces is the development of the Alberta petroleum industry following the Leduc discovery of 1947. Saskatchewan has seen significant oil and gas investments since 1945 but not by any means of the same magnitude as Alberta's.

Thus, a sound working hypothesis is that the petroleum industry has served as a key engine of growth for the Alberta economy. Of course, the growth of the petroleum industry is not the only difference between the two provinces over this period. Alberta has its mountains in the west with good tourist potential; Saskatchewan has its potash deposits. Albertans often express pride in their province's frontier spirit and the individualistic values of its governments. Many in Saskatchewan are proud of a tradition of community spirit and communitarian government. Moreover, we must be careful not to equate increasing size with improved welfare. While Alberta's GDP grew at a far faster rate than that of Saskatchewan, there were forces in play that kept average living standards closer to one another.

The main purpose of this chapter is to examine in more detail the role that the petroleum industry has played in the economy of the province of Alberta. The next part of this chapter will provide a brief overview of some of the models and concepts that economists have used to study the process of economic growth and the contribution of particular industries to the economy and its growth.

2. Models of Economic Growth

A. Concepts

An economy consists of people and their production and consumption activities. Analysts are interested in three somewhat different characteristics of an economy: (1) the total levels of production and consumption; (2) the average (per capita) levels of production and consumption; and (3) the equality of the distribution of productive activities and consumption. Our specific concern is the contribution of the petroleum industry to the economy. We will focus mainly on the first two characteristics.

Conceptually, our interest lies in anything that is perceived as having value to Albertans: How large is the value? How was whatever provides value produced? And what were the costs involved in producing it? Did this production process decrease or increase other things that Albertans value? It is a big step to move from this general conceptual framework to meaningful empirical analysis. Neither the concept of 'value' nor that of 'Albertans' is as straightforward as one might initially assume. (Here we repeat and elaborate on some of the issues that were initially raised in Chapter Four in our discussion of 'welfare economics,' and in the Introduction to Part Two of this book.)

Consider, first, the term 'Alberta.' Does this mean the productive activities within the geographical region ('domestic' activities), or the productive activities undertaken by people with declared residence in the region ('national' activities)? The two may differ because Alberta residents engage in production outside of Alberta; for example, an oil worker from Edmonton spends six months a year working in the Middle East, or a financier in Calgary loans money to a manufacturing plant in Nova Scotia. Even the notion of Alberta residents is ambiguous. Do we mean all people living here? Or only Canadian citizens? Do we mean the people in Alberta prior to a change in the economy or those in the province after the change? (These differ if changes attract immigrants into Alberta or induce people to leave the province.) In what follows, we shall follow the main conventions and include all Alberta residents (a changing total, with interprovincial and international migration) and focus on the economic activities that take place within the borders of the province (a 'domestic' point of view).

The concept of 'value' has always attracted controversy. As was discussed in Chapter Four, we follow the pervasive utilitarian tradition in economics and accept that whatever individuals say is of value to them is therefore of value to society; the value of something is the amount that a person is willing to pay for it. This perspective is both individualistic and democratic. But it is not unassailable: individuals may be inconsistent in their preferences; they may exhibit weakness of will, behaving in ways their 'better' self cautions them against; and there are any number of reasons to question whether what people want is actually in their best interest. However, any paternalistic attempt to impose a different set of values is likely to be more controversial than simply accepting individuals' own evaluations. Hence, we accept the willingness to pay criterion of conventional welfare economics. Further, the use of money as a measuring rod is convenient in an advanced mixed-capitalistic economy such as Canada's since many of the things that people value are produced and exchanged through economic markets, and the dollar values (both positive and negative) that individuals place on things are provided by market prices.

The role of market prices in providing measures of value provides the basis for the most common measure of the size of an economy and its rate of growth: Gross Domestic (or Provincial) Product (GDP). We shall utilize GDP extensively in the remainder of this chapter but must initially provide some discussion of what it is (and is not). (More detailed discussion of the concept can be found in any introductory economics textbook; see also Statistics Canada catalogue #13-001.) GDP can be measured in two ways, one of which draws on the consumption side of the economy, and the other which draws on the production side.

From a consumption point of view, we ask: what is the total value to consumers of all the goods and services produced in the economy? Of course, we cannot simply add the value of all the goods that are marketed since this would involve much double-counting. (We would, for instance, include the cost of the drilling rig services sold to an oil exploration company, then count it again when the crude oil producer sells its crude to a refinery and then again when the refiner sells its refined petroleum products to final users.) Rather, we want to add up the values of all the 'final' goods and services that people purchase. Final users are normally defined as consumers (who buy durable goods such as cars, non-durable goods such as motor gasoline, and services such as financial consultations), businesses that purchase capital goods to allow production of other things through the future (if the annual depreciation of these capital goods is deducted from GDP, one is left with NDP or Net Domestic Product), governments, and foreign buyers. Of course, some of the goods bought by local residents may have been imported rather than produced locally, so must be removed from spending if the size of the local economy is to be measured accurately. This generates the well-known equation: GDP $= C + I + G + X - M$. (Gross Domestic Product (GDP) is consumption spending (C), plus investment spending (I), plus government spending (G), plus export spending (X), less imports (M).)

From the production perspective, one wishes to measure the value that is produced in the economy by adding up the contributions of all producers (including producers of 'final' goods and services and of 'intermediate' goods and services). This would allow assessment of the roles of all the producers in the economy. From this point of view, GDP is the sum of the 'values added' by each producer on top of the purchases they make from other producers. Thus, for example, the value of the crude oil that an oil company sells to refiners includes the cost of purchases from other companies (e.g., the cost of hiring a drilling rig from an oilfield drilling contractor), but it also includes 'values' that the oil company 'added.' 'Values' are derived from the amount that people are willing to pay for the crude oil (which, in turn, derives from the values that final consumers put on the refined petroleum products). The 'additions' made by the crude oil producer (on top of its purchases from other businesses) include the oil company's purchases of labour, interest payments it makes on borrowed funds, rental payments it makes on land, and the profits it earns. The sum of these values added across all industries also measures GDP. For simplicity's sake, we have abstracted from such details as where taxes fit into this. In general, since the payments made by final users cover taxes, they are also a part of value added. There is a particular problem in the crude petroleum industry with the significant payments made by producers to governments and private landowners from the economic rent earned on crude petroleum. These payments are largely in the form of royalties and bonus payments. The problem is in deciding which industry should be credited with these amounts as value added when they seem to lie in the qualities of the natural resource in the ground as much as in the activities of the crude oil industry. In Canadian National Accounts data, royalties and bonus payments are credited as value added by the "financial" sector.

In what follows, we will be using value-added measures of GDP as our main description of the contribution of the petroleum industry to the Alberta economy. Other measures are possible and will be referred to as needed. Thus, for example, one could also ask what proportion of the Alberta labour force is employed in the crude oil industry, or what the industry's share is in the total stock of capital in the province. Readers will be aware that the oil industry is a 'capital intensive' industry with relatively few directly employed workers, so its share of the labour force is much less than its share of value added, but its share of the capital stock is higher.

We shall focus on three main questions: How important is the petroleum industry to the Alberta economy? How has the petroleum industry contributed to the growth of the Alberta economy (considering both total and per capita GDP)? And what has been the contribution of the petroleum industry to the 'public' through its impact upon provincial government finances? Our view is that dollar values – value-added measures of GDP, and the financial payments by the industry to the provincial government – are the best available tool to address these questions. Once again, however, it is wise, even when accepting this stance, to keep in mind the limitations of GDP as a measure of the value of a society's economic consumption and production since, among other things, it excludes certain valuable 'products' such as leisure time, unpaid activities, and the quality of the environment. Critics of the concept have also argued that GDP includes undesirable elements; for instance, if drilling an exploratory well (which adds to GDP) generates an undesirable outcome such as a well blowout, the expenses to control the blowout will also add to GDP, so even bad outcomes may lead to higher GDP. Such criticisms need to be considered carefully. After all, there can be little doubt that controlling the blowout does generate a gain to society; the real question is whether the potential environmental costs of oil industry activity are adequately recognized.

Possible modification of a country's National and Provincial Accounts to better incorporate natural resources such as petroleum is an interesting issue (Hartwick, 1990, 1994; Diaz and Harchaoui, 1997; Smith 1992). At the conceptual level, one might suppose that the national balance sheet of a country's assets should include the net value of the natural resource, which could be estimated as the anticipated economic rent from production (the present value of the excess of expected revenues above expected production costs). Then the annual flow of economic activity, as measured by GDP, could include the change in the asset value of the natural resource. (This is analogous to the change in inventory values for conventional businesses included as part of the investment component of GDP.) The depletable nature of the resources would suggest that the asset value should decline as the remaining stock is reduced. At the same time, the more dynamic view of resources that we have advocated in this volume suggests a number of reasons why resource asset values might rise, even above and beyond unexpected price increases: new knowledge and technology consistently add to the volume of recoverable resources and their value. The inclusion of natural resources into national accounts is very difficult to implement in practice for many reasons, including uncertainty about the size of the resource base and about future prices and costs that are needed to estimate expected future production and economic rents. Hence, conventional data as used in this chapter do not include values associated with the changing natural resource base of the province; rather, the petroleum industry is assessed in terms of its annual production activities. Diaz and Harchaoui (1997) provide an interesting analysis of Canadian petroleum in which they find that inclusion of the asset value of the natural resource would have a relatively small impact on Net National Product measures, but a more significant effect on Net National Wealth. We would note that explicit consideration of the asset value of petroleum resources provides one possible approach to the policy issue of the utilization of petroleum revenues. If oil and gas production reduce the value of the province's wealth (including the value of petroleum assets in the ground), then it could be argued that only part of petroleum revenues received by the government should be utilized for current expenses. This perspective would suggest that some portion should be invested in capital assets, which would provide ongoing revenues to compensate for the declining value of the natural resource stock. The Alberta Heritage Trust Savings Fund, which will be discussed later in this chapter, could be seen as an example of such use of petroleum revenues.

In conclusion, GDP is widely accepted as a measure of the size of the most obvious part of the economic system, that part which operates directly through economic markets (including labour markets). At its most basic level, an increase in real GDP, all else being equal, implies that society has increased its potential for producing things that members of society might value. As a measure of the actual efficiency of the economy in meeting the needs of its citizens, GDP is more problematic. Most economists regard it as one of the most useful indicators in this regard, but only one of them. One might also want to consider factors as diverse as the distribution of income, the state of the environment, the size of the natural resource base, the length of the average working day, the changing proportion of stay-at-home parents, the average health and educational level of the population, etc. All else being equal, higher real GDP per capita is commonly regarded as signalling an improvement in the economy's performance. We accept this conclusion. However, for some critics, the concept of GDP is so flawed that even this qualified conclusion is not warranted.

Input-output (I-O) tables are an extension of the value-added approach to measuring GDP, providing a 'snapshot' of interindustry connections in a particular year. They show how aggregate demand is spread across imports and different local industries and also how the expenditures of each industry are spread across other industries and various value-added categories (labour, profits, etc.). They give an idea of what an expansion in production of one industry will mean for other industries in the region. At the same time, there are limitations in the usefulness of I-O tables. For one thing, they reflect the unique features of the year in which they were constructed, including constrained short-run responses. The tables show the total of economic activity in the year and so can be used to understand total linkages or average linkages (e.g., that $1 of crude oil exports required on average $0.10 of Alberta well-drilling services). But economists are most often interested in marginal changes; unless production occurs under constant cost conditions, marginal costs and input requirements may differ from the average levels shown in I-O tables. Despite these limitations, I-O tables provide a useful tool for examining the economic role of an industry within a region.

B. Models of Growth

In what follows, we present a brief and select review of some of the models that economists have used to explain the level and growth of GDP in an economy. The review draws on the literature on macroeconomic growth and on regional economic development.

1. Export Base Models

In these models, the growth of an economy is driven jointly by its natural resource base and by the external demand for these resources. The underpinnings of this model can be found in the "Staples" theory, a theory that is largely associated with Canadian economists (Innes, 1927; Easterbrook and Aitken, 1956; and M. H. Watkins, 1963, for example). In this model, the world can be divided into two categories, 'central' economies, which are populous, industrialized and diverse, and 'peripheral' economies, which depend upon trade linkages with the centre. The central economies draw on the peripheral economies for the natural resources needed to fuel their industries. A peripheral economy's growth is a function, therefore, of its resource base and the demands of the central economies. More specifically, growth will hinge on the size of export demand, the nature of the production technology for the natural resource, and the resource's 'backward' and 'forward' linkages in the local economy. The production function is important in large part because it indicates the local labour requirements to produce natural resources in the periphery. Are few local residents needed as in the case of fishing (where ships can come from the central economy and return without even having to land on the shores of the peripheral economy), trapping, and mechanized mineral production? Or are there significant numbers of workers needed, as in nineteenth-century agriculture and logging or mineral strip mines? Backward linkages refer to local producers who service the input needs of the staple resource-producing industry. This would include the provision of inputs for staple production itself (e.g., rafts to move logs to the export port), as well as the production of goods and services for labourers in the staple industry (clothing and grocery stores, saloons, seamstresses, opera houses, gambling establishments, schools, churches, etc.). Forward linkages refer to industries that further process the natural resource before it is shipped to the central economy; sawmills and gas processing plants are examples.

The staples model was devised as a model of political economy; it purported to deal with more than the implications of production technologies and the resultant size of GDP. Inherent in the division of the world into central and peripheral economies were a host of questions related to political dependency and exploitation. Moreover, the demands for staples by the central economies and the ways in which they controlled production in the peripheral economies were also seen as determining cultural, social, and political institutions in the periphery. The flavour of the staples model lives on in approaches that emphasize the political significance of the resource industry, as in discussions of the 'petrostate,' which see the levers of government and the local political culture as captured by the interests and mindset of the petroleum industry.

The export base model is, in essence, the staples political economy model without the politics. That is, the primary forces shaping the local economy are the export demand for a locally produced good or service and the specific production technology and economic linkages of that export product. Caves and Holton (1959), for example, provide an economic history of Canada that is based largely on a succession of natural resource staples – first fish, then furs, then forestry, then agriculture (wheat), then mining and the petroleum industry.

There are problems with the export base/staples theory approach. The dichotomous separation of the world into central and peripheral economies seems extreme. These roles cannot be fixed forever, but at what point does the economy switch from being a periphery (e.g., Upper Canada in the early 1880s) to being a centre (e.g., Ontario in the second half of the twentieth century)? And is this an either/or categorization, or are there intermediate phases that might last for an extended period of time? Moreover, the implicit view of the central economies as independent, powerful importers driving growth processes in the periphery through their export demand is suspect. The central economies are exporters as well (and not only of manufactured goods); surely their economic structure and growth must be affected by the demand for their exports and the production technologies involved.

It may, then, be a matter of degree. Some economies may be natural-resource-rich but have very small local markets (due to small populations and/or low standards of living). In such economies, growth will inevitably be heavily linked to trade, with the external demand for the region's resources determining the region's main industry and providing earnings for local residents to import the goods and services they consume. But as a region grows, even if stimulated by a resource staple, the local market will expand and more industries will develop at home to produce goods for local consumption. The economy is, then, less heavily dependent on the natural resource staple. Further, some of the goods manufactured for locals may become competitive as export products so that even the region's exports show less dependence on immobile natural resources and more on those industries that could, potentially, be located anywhere in the world. In this way, the economy, as it has grown, initially under the impetus of a natural resource staple, has become more diverse and less dependent on staple exports; it has developed a greater degree of autonomy. Consequently, the export base model would become less valuable as a way of explaining the region's continued growth.

2. Closed Economy Models

The previous paragraph suggests that the true opposite to the export base economy is not really a Central economy but a 'closed' economy, one that is completely self-sufficient so that it has no exports (and no part of the economy is 'based' on exports). Models of closed economies are, of course, unrealistic for the modern world, but much of the early development in modern macroeconomics and growth theory stemmed from simple closed economy models. It will be useful to comment briefly on the two most popular modelling frameworks. It should also be noted that there are open economy models of both types as well.

a. Keynesian Models

Keynesian models stress aggregate demand in the economy as the prime determinant of the levels of GDP, unemployment, and prices. These models provide the basis for the short-term cyclical phenomenon discussed in the first part of this chapter but also introduced concepts that have been applied in other modelling frameworks. The basic idea is that if aggregate demand is low (below capacity), there will be insufficient demand to purchase all that the society is capable of producing and there will be involuntary unemployment. Should aggregate demand be too high, the economy would produce at potential GDP with full employment, but the excess demand would translate into rising prices (inflation). One element of the low-aggregate-demand case provides an interesting link to the export-base models with their emphasis on forward and backward linkages in the economy. In Keynesian theory, these linkages translate into a 'multiplier effect' whereby the impact on GDP exceeds the initial change in aggregate demand. Consider a fall in consumption spending, for example, if consumers for some reason decide to save more of their income. When consumers spend less, the producers they buy less from will in turn cut their workforces and reduce their purchasers from input suppliers, and the input suppliers and workers who are now unemployed will cut their spending, which further reduces demand, and so on, until these effects peter out. In many Keynesian models, the cyclical aspects of the economy are heightened by what is called an 'accelerator process,' where investment demand is driven by the *change* in the level of income. Thus, a rise in income stimulates investment, which, through the multiplier effect, generates a larger income rise, which stimulates a further increase in investment, accelerating the growth; but, as soon as the income growth slows, investment demand will decline, drawing the economy into a downward cyclical phase.

b. Neoclassical Models

Neoclassical models might be contrasted with Keynesian models by saying that the neoclassical models focus on aggregate supply rather than aggregate demand. The emphasis is on the productive potential of the economy and how it changes. Neoclassical models essentially assume that the economy operates at full employment. In the neoclassical closed economy model, the level of GDP is a function of the quantities of productive inputs in the economy and the efficiency with which they are used. GDP can increase if the quantity of inputs rises; that is, if there are more workers, or if the capital stock rises. The capital stock should be interpreted as including capital equipment, natural resource capital, and human capital (the knowledge and skills of the labour force). GDP can also rise due to technological change; this is new knowledge that increases the efficiency of utilization of a fixed quantity of inputs. The neoclassical model serves as the basis for 'general equilibrium' models of an economy, which set out (1) the ways in which the economy's productive inputs (labour, capital, and natural resources) generate output; (2) the division of this output amongst the inputs as income; (3) the consumption and savings behaviour of individuals from their various sources of income; and (4) the way in which savings generate additions to the capital stock (i.e., investment), which allows more production in the next period. Obviously this is a complicated economic framework, but in recent years economists have greatly advanced the construction of empirical models (labelled 'computable general equilibrium' [CGE] models) to describe the operation of national and regional economies.

While neither of these closed economy models is appropriate to an economy like Alberta's, which is so open to exports and imports, they both have been extended in versions for open economies.

3. Open Economy Models

An open economy allows for trade of goods and services with other economies and for the import and export of financial capital. In addition, it is possible to supplement the quantity and quality of local inputs with inflows from outside the region, and local inputs could elect to leave for elsewhere. It should be noted that many open economy models have introduced the simplifying assumption that capital is very mobile between regions but labour is not. While this assumption about labour may have some validity when considering international trade, it is much less appropriate for a regional economy like Alberta's, which is part of a single country within which people are free to relocate.

At any point in time, the potential (full employment level) of GDP in the economy is determined by the quantity and quality of the inputs available in the region. The actual level of GDP will be heavily influenced by the level of aggregate demand in the economy, of which export demand is an important part. For many regions, export demand will consist in large part of demand for natural resource staples. Low aggregate demand, which might, for instance, come from a decline in export demand for the natural resource, will be associated with unemployment in the region. If this problem persists, it is likely that labour and capital will begin to leave the region.

If aggregate demand is excessive, there will be upward pressure on local prices, but this tends to be limited by the regional mobility of goods and inputs. Thus prices of goods and services that move easily and cheaply in trade cannot rise very far even in the short run because local consumers will turn to imports and external customers will stop buying from this region. For goods and services that are slow to move in response to higher prices, increases in price can be somewhat greater; labour might be an example. Price increases can be still larger for non-tradable goods and services; housing is a prime example. (Non-tradable does not mean goods that cannot be exchanged in trade, but goods that are immobile.) In the longer run, the increased prices of local goods and services stimulate the in-migration of new productive inputs such as workers who are drawn by higher local wages and capital to produce those goods that have risen in price. Such inflows tend to drive prices back down. They also increase the quantity of inputs in the economy and hence raise the full employment level of GDP. These factors explain why the Alberta economy could increase in size so much relative to Saskatchewan but without extremely large and persistent difference between per capita GDP levels in the two provinces. Expansion of the local market can encourage in-migration and development of new industries to produce goods for local consumers; often these industries exhibit economies of scale so that a certain minimum size of the market is necessary before producers attain competitive costs. If this happens, the local economy will become more diversified and less trade-dependent.

4. Natural Resource Models

As was noted, export base models typically emphasize natural resources, although not all export industries need be natural resource producers. In this section, we briefly review two models of economic growth that are basically natural resource models.

a. Boom and Bust Models

These models are based on the exhaustible nature of mineral deposits. If this characteristic of minerals is a dominating feature, and if there is only the one significant resource available to a region, then one would expect the regional economy to follow a path of expansion followed by decline, as is seen in many mining towns. If this process is not handled carefully, the growth cycle may be very rapid (as production of the resource grows rapidly to meet large export demands) followed by equally rapid economic decline as resource deposits are exhausted. This cycle is likely to be very inefficient. There are problems in the boom phase in providing adequate social infrastructure for in-migrating labour; local inflation is likely to be high and social relations strained. Social ties are severely strained with the ensuing bust, and local infrastructure is abandoned long before it is physically depreciated. These problems suggest that it would be socially desirable to force a more 'attenuated' resource development policy to smooth out resource production and so extend the (milder) boom and following (slower) contraction (Scott, 1973, 1976).

However, in many cases, the boom and bust model will not be relevant to regional economic development. (Nor need it apply solely to natural resource production; history is full of stories of once booming industries dying due to population movements, taste changes, or technological changes; think of blacksmiths and typewriter manufacturers.) The model seems to be most relevant to very small regions (for example, the isolated single-mine town). It fits larger regions less well for two reasons. First, as we have stressed in this book, the underlying concept of a depletable resource is not straightforward. In most oil-producing regions of any large areal extent (for example, Alberta or Texas), there is a very large resource base that will never be fully exhausted. As long as knowledge is generated and new technologies are developed, the oil industry may continue producing for many, many years. That is, there may be a boom, but the bust phase may be delayed almost indefinitely. Secondly, for larger regions, the presumption of a single natural resource is less likely to be met, and there are increased prospects that the region will grow prosperous and populous enough to become relatively self-sustaining, especially as agglomeration effects occur. Hence, we view the boom and bust model as being relatively unimportant for the Alberta economy, although it could be of some value in understanding economic conditions at a very local level (e.g., in a particular town).

b. Industrial Diversification and the 'Dutch Disease'

Governments in most regions that rely heavily upon a single industry are motivated to try to diversify the economy, thereby providing somewhat more cyclical stability. This is particularly true if the natural resource is a depletable one, as the government may then have concerns about declining production as reserves run out. This desire holds some contradictions because the stronger the single resource industry, the higher economic growth in the region will be, but the greater the share of GDP contributed by the extractive resource industry. Thus, Middle Eastern OPEC members such as Saudi Arabia appeared to have more diversified economies in the 1990s than the early 1980s in the sense that the relative contribution of the crude oil industry to their economies had fallen after oil prices collapsed. But GDP per capita had also declined. Economic diversification may be desirable, but new industries should be commercially viable on their own merits if they are simultaneously to diversify the economy and contribute to economic growth in a meaningful way. This is not easy to accomplish!

The issues here are similar to those associated with the well-known 'infant industry' argument, that a new industry may require protection from imports until it has had time to establish itself as commercially viable; such viability may hinge on the industry expanding enough to realize economies of scale or to operate for a sufficient period of time to allow local inputs to gain the knowledge and skills required. The argument has been controversial. In a world of uncertainty, it is very hard for governments to pick 'winners'; that is, it is easy to decide to protect or subsidize currently unprofitable businesses but hard to know which ones will become competitive in the future. Further, from a political economy point of view, virtually all producers (business owners and workers) have an incentive to claim that they need assistance to become more competitive; which of these claims the government responds to, and which it ignores, may relate more to political influence than to economic merit. Finally, it is hard to remove government support once it is established. Partly this is 'political,' in the sense that supported industries made more profitable by government assistance also have developed greater political power to fight against any removal of support. Further, the ability to operate under government support may have inhibited the necessity to become internationally competitive; that is, the government support itself allows the industry to remain an 'infant' requiring support.

The concept of economic diversification ties into what is called the 'Dutch Disease' (Ismail, 2010; Sosa and Magud, 2010). This refers to the economic adjustments that may occur in a relatively diversified economy when a new natural-resource-exporting industry comes into being. The term was applied to The Netherlands' experience with the development of the gigantic Groningen gas field in the 1970s. Macroeconomic models suggested that development of the natural resource would tend to squeeze out other traditional export industries (manufacturing, for example). This could happen partly through 'external' economic adjustments if inflows of financial capital and growing resource exports increase the exchange rate and make it harder for traditional exports to compete. Some of the economic adjustments would be 'internal,' with expanded resource production driving up input prices and raising production costs for traditional exports and for non-tradable goods and services. As a result, capital-intensive resource industries expand and traditional labour-intensive industries contract. Note that these effects would be less if there were relatively easy in-migration of inputs to the economy; that is, the 'Dutch Disease' argument, in the sense of a pathological outcome, has particular force in a closed economy. In effect, addition of the new resource industry might reduce the diversity of the economy. This was seen as a particular concern by those who foresaw a sharply peaked production profile for the natural resource; then, when depletion effects reduce production of the natural resource, the traditional export industries are no longer there to fill the economic gap, nor, for some reason, are they able to redevelop quickly. This presumes an asymmetrical response, with manufacturing contracting quickly as petroleum production increases, but failing to expand when petroleum output declines; reasons to expect such asymmetry have often not been clearly set out. The Dutch Disease might lead to an extreme result often labelled 'the resource curse' in which development of a large natural resource endowment actually leaves a nation worse off; Frankel (2010) provides a survey of this literature, while Alexeev and Conrad (2009) examine this proposition empirically for oil and argue that it is not valid.

In a neo-classical framework, these economic adjustments also impact on the distribution of income. Thus expansion of a capital-intensive resource industry would increase the demand for capital relative to labour, generating a decrease in the wage rate relative to the 'prices' of capital (interest rates, dividend rates, and retained earnings). The intersectoral production shifts (expansion of natural resource exports and contraction of other export or import-competing industries) would also be affected by these input price changes. Overall, one would expect the share of capital in national income to rise and that of labour to fall. The impact of these structural changes might be mitigated by appropriate government policies, particularly monetary policy, which can help to offset (or 'sterilize') the interest rate and exchange rate effects. However, a subregion such as Alberta has no control over monetary policy.

Literature on the Dutch Disease suggested, once again, that an attenuated (more drawn out) resource depletion path might be optimal, thereby reducing the structural shifts in the economy. On the other hand, these broad macro concerns seemed less immediate to those who were relatively optimistic about the size and expandability of the petroleum resource base. In light of this, we prefer the term 'Dutch Adjustment' to 'Dutch Disease' to refer to contraction of other sectors of the economy to make room for expansion of the petroleum industry, unless there is clear evidence that this process is pernicious.

We are not of the opinion that the Boom and Bust or Dutch Disease models, in their pure forms, are of much importance to the Alberta economy, so we shall rely on more traditional macroeconomic analysis in the material that follows. However, readers should keep in mind the general insights of the models in terms of the possible impacts of a non-renewable natural resource.

3. The Petroleum Industry in the Alberta Economy

As preamble, we summarize Eric Hanson's well-known research from 1958 arguing that the petroleum industry was proving to be a vital export-base, stimulating rapid growth in the Alberta economy. We then go on to provide a brief overview of the province's economic development since the 1940s and the role of the petroleum industry. Then we turn to several more specific topics such as economic diversification, transfers from Alberta to the federal government during the years of the National Energy Program, macroeconomic fluctuations associated with the changes in the oil market, and the Heritage Trust Fund.

A. The First Ten Years: Eric Hanson's Dynamic Decade

The modern Canadian crude oil industry is normally dated from the 1947 Leduc discovery, which stimulated a sequence of significant oil plays. While local residents and governments were optimistic about the province's economic future, some economists were less enthralled. Thus, for example, in their highly regarded economic history of Canada, Caves and Holton (1959, p. 215) compared the petroleum industry to other historically significant resource staples and argued that the impact on the Alberta economy might be relatively small. Crude oil and natural gas were normally exported as raw materials, so forward linkages would be minimal, and the capital-intensive nature of their production implied a very low demand for labour and heavy reliance on imported capital equipment so that backward linkages would also be small. The pipelines used to ship oil and natural gas were also very capital-intensive and required little labour to operate; they could only be used to move petroleum. Caves and Holton argue that the contrasts drawn with the wheat boom, and associated construction of the railways, were marked. (Growing wheat required large numbers of farmers; equipment suppliers and grain-processing facilities did not exhibit strong economies of scale so were easily established; the rail links necessary to move grain and flour to markets were also ideal for bringing people to the region. Owram, 1982, provides a useful overview of economic development in western Canada.)

In 1958, Eric Hanson, an economist at the University of Alberta, published *Dynamic Decade,* the first extensive economic survey of the Alberta petroleum industry. Hanson included estimates of the economic impact of the petroleum industry on the Alberta economy, using a Keynesian economic multiplier approach as applied to an open economy. In this approach, it was assumed that the direct expenditures of the industry in Alberta had an income multiplier effect of approximately two; that is, $1 in expenditures in Alberta by the petroleum industry would generate a $2 increase in Alberta income (Personal Income). (Hanson used a multiplier that fell from 2.3 to 2 over the decade from 1946 to 1956.) Petroleum industry expenditures stimulated capital inflows into the province, which would not have occurred without the development of the industry. In order to estimate expenditures in Alberta, Hanson drew upon estimates from the Alberta government and information he gathered from interviewing oil industry personnel to estimate the proportion of direct industry expenditures that flowed immediately out of the province. His income multiplier was applied to the residual of industry expenditures in the province.

To illustrate the significance of the petroleum industry to Alberta, Hanson sets up a counterfactual history in which the population of Alberta follows a path similar to that of Saskatchewan, starting at 803,000 in 1946, and falling gradually to 775,000 in 1956. Alberta's actual population in 1956 was 1,123,000. He then estimates the impact of the petroleum industry on the Alberta economy by deducting the contributions of the petroleum industry (the multiplier income contributions) from the actual income levels

(Hanson, 1958, p. 271). On this basis, the Alberta economy would have been 98 per cent of the actual size in 1946, if the petroleum industry had not been present. This percentage fell over time, so that in 1956 Hanson estimated that, without the petroleum industry, the level of Alberta Personal Income would have been only 55 per cent of that recorded. The values for per capita income are less dramatic since the growth of the oil industry attracted immigrants, but he estimates that by 1956 personal income was $275 higher per capita (at $1,370, a gain of 20%) than it would have been without oil (Hanson, 1958, p. 273).

Hanson's perspective is consistent with the export base model, as suggested by one of his concluding paragraphs (Hanson, 1958, p. 293):

> The Alberta economy is no longer dependent on the export of any one staple. Less than one-fifth of its income is subject to the vagaries of wheat growing. Another fifth or so is derived from livestock raising and processing, activities which are relatively stable. About one-quarter is generated from the land acquisition, exploration and development activities of the petroleum industry. A fifteenth is provided by the producing activities of the petroleum industry and by its capital and operating expenditures for transportation, refineries, natural gas plants and petrochemical plants. Finally, there is a miscellany of activities, many of which are derived from oil operations, providing the rest of the income of the province.

Hanson was sceptical about the possibility of Alberta moving beyond an export-base economy, with a high dependence on natural resource exports, arguing that its "location precludes the economical manufacture of a great many commodities" (p. 293); presumably this also reflects a judgment that the local economy was too small to realize economies of scale in the production of many manufacturing commodities. He concluded that "the major basis for the development of Alberta lies in its potential natural resources" (p. 293), although he saw Alberta developing as the centre for exports of petroleum services to an expanding northern Canadian petroleum industry.

Dynamic Decade provides a convincing portrayal of the petroleum industry as a strong export-base growth engine for the Alberta economy in the decade following the Leduc discoveries.

B. The Role of the Petroleum Industry

This section will provide some basic statistical information about the petroleum industry in relationship to the Alberta economy.

1. Background and the Alberta Economy

Obviously, it is very difficult to estimate with reliability the contribution of the petroleum industry to the economy since we have no way of knowing exactly what Alberta would have been like without the industry. While it is possible to use input-output tables to see the interindustry linkages of an industry, it is hard to determine the full extent of the induced growth effects and even harder to assess whether petroleum industry activities might have displaced other economic activities. Here we look at the most immediate measures of the economic activities of the Alberta petroleum industry: direct contributions to provincial GDP, capital accumulation, and employment. We also provide some comparisons to Saskatchewan and Canada as a whole and look at several key economic indicators over time. (Emery and Kneebone, 2008, look at the differing economic development paths of Alberta and Saskatchewan and emphasize the differences in resource endowments.)

This chapter does not provide a complete survey of the Alberta economy and its features in comparison to other parts of Canada. Readers can find useful surveys in Mansell and Percy (1990), and Polèse (1987a, especially the chapter by Mansell), Norrie (1986), Richards and Pratt (1979), and a number of the Working Papers for the Economic Council of Canada's study of regional economic disparities in the early 1980s (Norrie and Percy, 1981, 1982, 1983; Owram, 1982); Melvin (1987) provides an interesting review of regional economic differences; Emery (2006) provides a survey focusing on the changes following the price collapse of 1985. We have not attempted to build an econometric model of the Alberta economy so our observations are based upon relatively simple observations about the connections between key variables and our knowledge about what was happening at various points in time. Therefore, our observations, about what is, after all, a complex developed economy, should be regarded more as plausible hypotheses than established conclusions.

We will begin with some time series data for the period since 1947 to provide a broad overview of the Alberta economy. Then, we provide a brief review of a

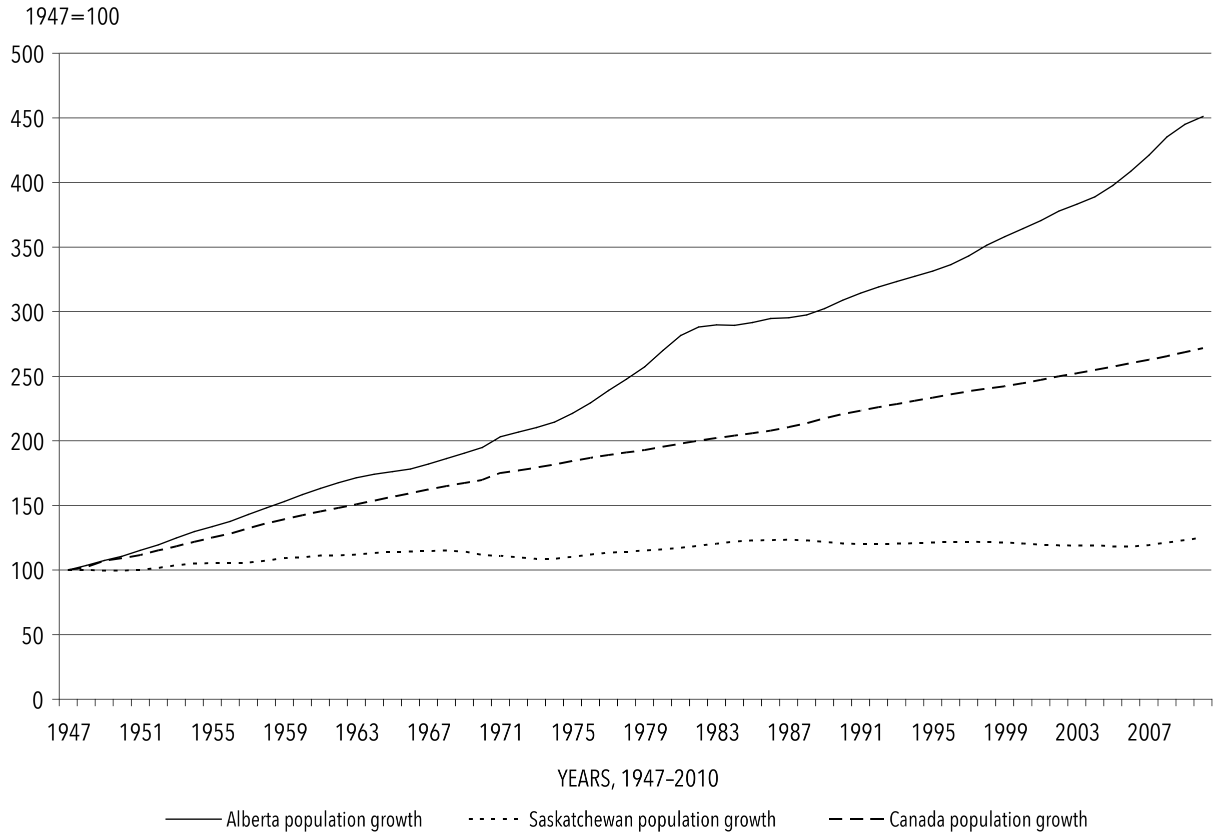

Figure 13.1 Population Growth, 1947–2010

number of observations made by other analysts about the performance of the Alberta economy relative to other parts of Canada. Next, we turn to the relative magnitude of the petroleum industry as a part of the provincial economy. Following this, we examine a number of specific issues that have been raised about the role of the petroleum industry.

a. Alberta's Economic Development, 1947–2012

In this section, we provide information about the development of the Alberta economy since 1945, using a number of common economic indicators. In some cases, comparisons will be made between Alberta and Saskatchewan, which were at similar stages of economic development at the end of World War II. We also include some comparisons to Canada as a whole. For the most part, the data are depicted in a graphical manner.

Population. Figure 13.1 shows population growth since 1947 for Canada, Alberta, and Saskatchewan, with the 1947 value set at 100. (At that date, Alberta held about 825,000 people, and Saskatchewan 836,000.) By 2012, Alberta's population had grown to more than 3.8 million, an increase of four times, much higher than the Canadian average. Saskatchewan still held barely more than one million, showing much slower population growth than Canada as a whole. Figure 13.2 makes the differences between the two prairie provinces clear. It shows that the ratio of Alberta's population to Saskatchewan's rose from about 1 in 1947 to well over 3 by 2007. Alberta's share of the Canadian population rose from under 7 per cent to more than 10 per cent, while Saskatchewan's share fell. However, it is also apparent that the growth in Alberta's population was not constant over this period. Thus, for example, the 1950s and 1970s saw particularly rapid growth, corresponding to the initial surge in petroleum discoveries after Leduc in 1947 and the rapid international price rises in the later period. On the other hand, from 1982 through 1988, population growth was slow; this followed the imposition of the National Energy Program (NEP) in 1980 and the substantial fall in international oil prices in 1985.

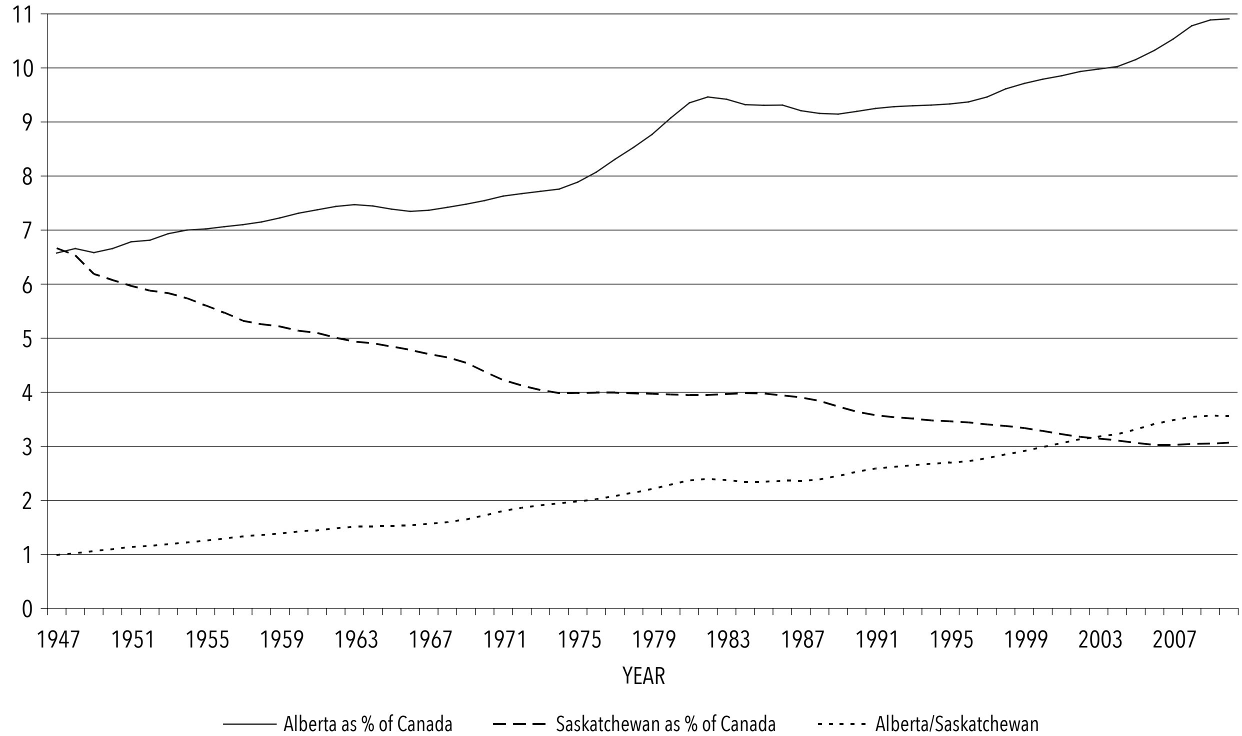

Figure 13.2 Alberta and Saskatchewan Relative Population, 1947–2010

Gross Domestic Product (GDP). Figure 13.3 shows the increase in real GDP for Alberta, Saskatchewan, and Canada, with 1951 set at a base value of 100. (Real GDP values for all three regions were obtained by applying the Canadian GDP price deflator to nominal GDP for the region, thus showing the increase in output after allowance for inflation.) As would be expected from the population trends, since more people normally generate more economic activity, Alberta's GDP increase exceeded that for the entire country, which was, in turn, higher than that for Saskatchewan. However, it was not until after 1972, when crude oil prices began to rise sharply, that Alberta's growth in GDP began to significantly exceed Canada's. Figure 13.3 makes very clear the rapid rise in Alberta's GDP from 1972 until 1980. However, this was followed by a period of no growth, then actual decline in GDP, until relatively rapid growth commenced again in 1993. As mentioned above, this period saw the implementation of the NEP, from October 1980 through to mid-1985, and the sharp decline in international oil prices in 1985. It is noteworthy that the mid-1990s did not see a sharp rise in the real price of crude oil or natural gas. Rather, it looks as though the Alberta economy took some time to adjust to the transition from a period of high and optimistic oil prices and, perhaps, the 'excessive' boom that had been generated. Once 'on track' again, the economy resumed robust growth, with the rise in oil prices after 2003 providing a further boost.

It is difficult to separate out the impacts in the 1980s of government regulatory programs (such as the NEP) and falling oil prices. Helliwell et al. (1984) suggest (partly by comparison with the United States) that the NEP had an immediate depressing effect on oil-industry activity in Alberta (in 1981 and 1982) but that this was short-lived, offset by the subsequent modifications in the NEP, and that by 1983 the most important depressing factor was declining natural gas prices. A comparison of Alberta's falling and static GDP after the oil and natural gas price declines of 1985 with the growth in total Canadian GDP, as seen in Figure 13.3, points out the quite different impact of lower petroleum prices: the effect is deflationary in a petroleum-producing region such as Alberta but has a net stimulatory impact on a developed industrial economy such as Canada's. (For a summary of economic models assessing the impact of lower oil prices in Canada, see, for example, Waverman, 1987.)

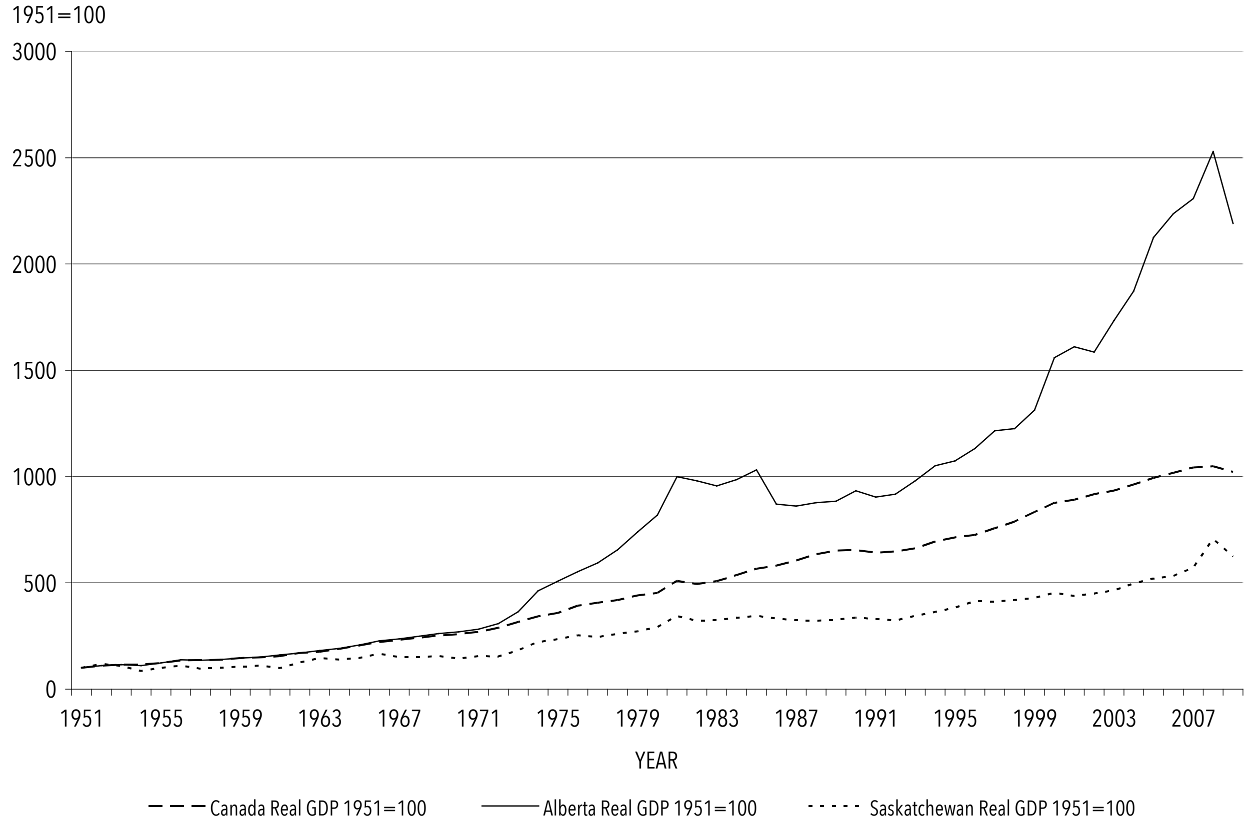

Figure 13.3 Canada, Alberta and Saskatchewan Real GDP, 1951–2009

Unemployment Rates. Figure 13.4 includes the annual unemployment rates for Alberta, Saskatchewan, and Canada. Prior to 1966, Statistics Canada provided this data only for the combined Prairie provinces (Alberta, Manitoba, and Saskatchewan), so this value is shown for years from 1947 through 1966. It can be seen that unemployment was almost always lower in Alberta and Saskatchewan than in Canada as a whole, the Canadian value, of course, being coloured by the generally high unemployment rates in Atlantic Canada. The rates for the two western provinces generally follow movements for the country at large, reflecting business cycle trends and structural changes (such as modifications in employment insurance regulations). The Alberta unemployment rate was usually a little higher than Saskatchewan's, but the reverse was true after 1996 and through to 2008, when Alberta's rate rose appreciably more than that of its neighbouring province; by 2012, Alberta's unemployment rate was slightly lower than Saskatchewan's again. The varying size of the difference between the Alberta and Canadian unemployment rates indicates that unemployment has been more variable across time in Alberta. Two periods can be seen in which the unemployment rate for the province approached the Canadian average: briefly in the early 1970s (just prior to the large international oil-price rises) and in the decade from 1983 to 1992 (which was marked by stagnant GDP, as noted above). The Alberta unemployment rate actually exceeded the Canadian average briefly in the late 1980s, but after 1993 the Alberta rate once again fell well below the Canadian average.

Per capita Income. Figure 13.5 shows per capita GDP, Personal Income (PI) and Personal Disposable Income (PDI) in Alberta and Saskatchewan relative to the Canadian average for years from 1947 to 2010. (A value greater than 1 obviously means that the province exceeds the Canadian average.) Detailed definitions of these income measures can be found in assorted Statistics Canada documents; we will provide a brief overview. GDP is a measure of total economic

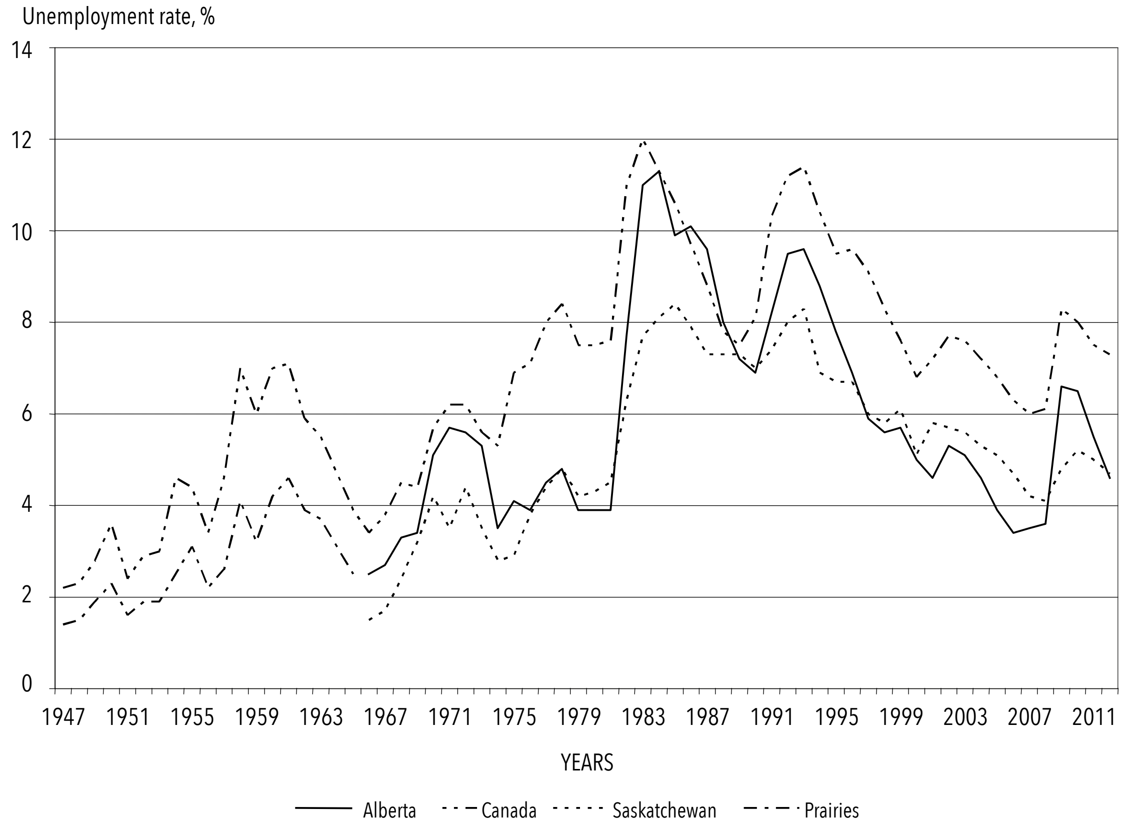

Figure 13.4 Unemployment Rates: Canada, Alberta and Saskatchewan, 1947–2012

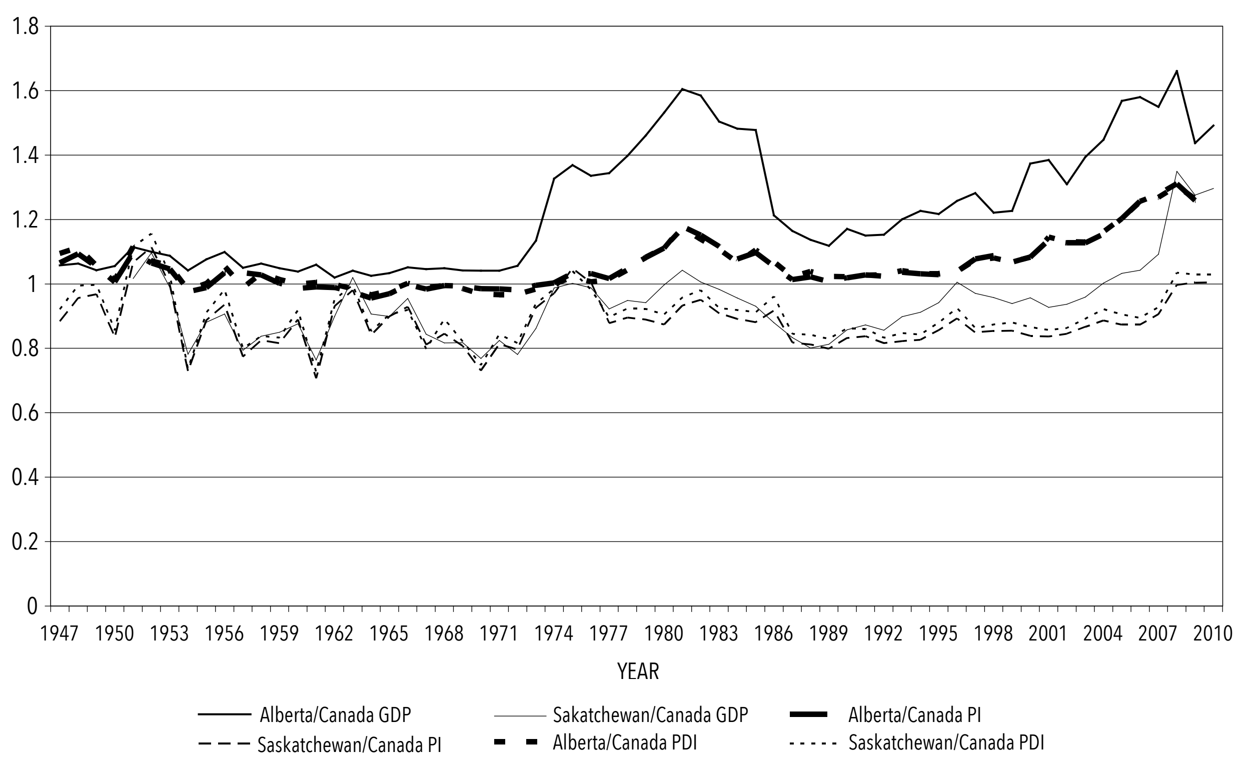

Figure 13.5 Relative per capita GDP, PI, and PDI: Alberta and Saskatchewan, 1947–2010

activity in the region; the meaning of the concept was discussed in more detail above. Personal income differs from GDP largely by the exclusion of depreciation and corporate taxes and retained earnings plus reductions for income generated in the region which leaves (e.g., payments to non-resident owners) and additions for income from outside which flows to people in the region (e.g., federal welfare benefits and interest payments received from non-resident entities). Disposable income excludes direct payments to governments, including personal income taxes, and payments to governments for social insurance and pension plans; it is, essentially, the income households have to spend on consumption or saving.

As can be seen in Figure 13.5, since 1947 Alberta's per capita GDP has always been above both the Canadian average and that for Saskatchewan. (Values are available for Saskatchewan only from 1951 on, and that province, in most years, had a per capita GDP below the Canadian average.) Until 1973, Alberta's per capita GDP was no more than 10 per cent above the Canadian average. This was the year in which international oil prices increased dramatically, and since then, Alberta's per capita GDP relative to Canada's has been much higher, as much as 60 per cent greater in the early 1980s and again in 2006/7. The sharp fall after 1983 and much lower relative values for the next decade (but still higher than before 1974) are not surprising in light of the previous comments about this period.

Patterns for Personal Income and Personal Disposable Income per capita are similar to one another but somewhat different than for GDP. The Alberta values are almost always higher than the values for Saskatchewan, but the differences between the two provinces are not as marked as for GDP, largely reflecting the exclusion of much corporate income. And the Alberta values are much closer to the Canadian average than they were for GDP, with personal income values up to the mid-1970s sometimes falling below the Canadian average. As with a number of the other economic indicators, a sharp rise is noted in the late 1970s, followed by a rapid decline (although remaining above the Canadian average), and relative stability into the 1990s. In the later 1990s, PI and PDI per capita in Alberta once again increased relative to the Canadian average.

We would note that, until the mid-2000s, Alberta's relatively lower individual income tax levels did not translate into a PDI standing that is noticeably higher than that for PI. (The absence of an Alberta sales tax would not be evident here.) While Alberta GDP, PI, and PDI, compared to the Canadian average, show similar time trends, the relatively higher values for GDP are evident in Figure 13.5. This may reflect the higher capital intensity of the Alberta economy, so that depreciation and corporate profits are more important. But it may also reflect the importance of the petroleum industry. Consider, for example, the increased spread, after 1972, between the GDP and the personal income values. This began with the sharp rise in international oil prices as OPEC became more effective and stimulated price increases for substitute energy products such as natural gas. Even with the oil and natural gas price controls imposed by Canadian governments, the sales prices of oil and natural gas in Canada moved well above the levels of the 1950s and 1960s. Thus the 'value added' in petroleum production increased, raising per capita GDP. However, the increase in personal income (and PDI) was much less pronounced since (1) a significant part of the increased value of oil and gas went to governments in higher royalties and taxes and (2) much of the increased profit of the oil companies did not find its way into the hands of Alberta residents. That oil-price changes are still important is suggested by the decline in per capita values in the year 1998/9 and 2001/2, and the subsequent rise as international oil prices recovered, and as North American natural gas prices attained new highs.

Summary. At the end of the Second World War, Alberta and Saskatchewan held approximately the same number of people and appeared similar in economic structure, with agriculture the key industry. After the Leduc find of 1947, the economic development of the two provinces diverged, with Saskatchewan growing much slower than the Canadian average and Alberta much faster. We have not constructed a formal economic model of the Alberta economy, but it seems plausible that this difference stems from the growth of the petroleum industry in Alberta. In addition, periods of more rapid growth in Alberta and times of weaker economic performance also appear to be tied to changes in conditions in the oil industry, particularly movements in crude oil prices. Finally, this dependence on the petroleum industry seems to have led to a somewhat more unstable economy in Alberta. Figure 13.6 compares annual percentage changes in real GDP for Alberta and Canada from 1952 through 2011. The Alberta economy has tended to show wider swings in GDP than Canada as a whole, particularly in the 1972 to 1992 period and again after 2000. Further, the

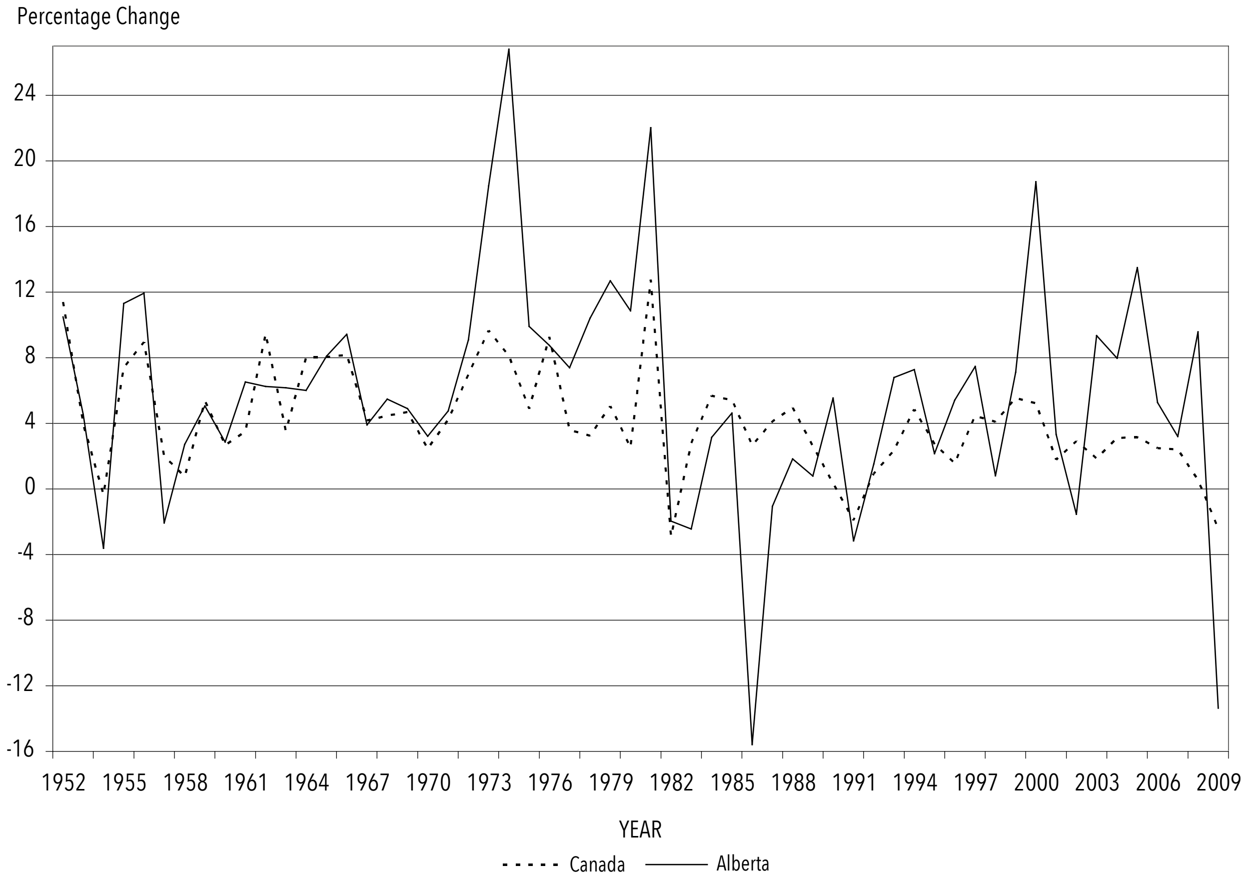

Figure 13.6 Canada and Alberta % Change in Real GDP, 1952–2009

widest swings are consistent with the interrelationship we have been suggesting in this section of a positive correlation between Alberta GDP and oil prices.

b. Other Analysts' Descriptions of the Alberta Economy

The depiction that we have provided of the Alberta economy and its relative strength compared to Saskatchewan and Canada as a whole in the years after 1947 is confirmed in other studies such as Hanson (1958), as described above, Coffey and Polèse (1987a), Lithwick (1977), and Mansell and Percy (1990).

The last of these studies argues that both Alberta and Saskatchewan exhibit much greater income instability than the Canadian average. Drawing on data from 1961 to 1985, Mansell and Percy (1990, p. 72) calculate an index of 'regional economic instability' (REI). They first established a time trend in the relevant series. They then calculated the sum of squared differences between actual values and the values shown by this time trend; squaring made sure that both positive and negative deviations from trend were positive values and also assigned greater weight to larger deviations. Then the square root of this sum was divided by the average value for the series, to provide the REI. A higher value denotes greater instability. Values of the REI for Canada, Alberta, and Saskatchewan for three measures of economic activity are shown below.

	Canada	Alberta	Saskatchewan
GDP	169	2,672	1,000
Personal income	216	1,328	720
Per capita personal income	176	685	793

Both provinces exhibit much greater economic instability than Canada as a whole or any other province. (The NWT and Yukon showed even greater GDP instability.)

Mansell and Percy (1990, p. 21) also calculate annual employment 'location quotients' for Alberta relative to Canada for the years 1973 to 1987. A location quotient is the share of employment in Alberta in an industrial sector relative to that share for Canada. We show values for three years.

	1973	1980	1987
Agriculture	2.45	1.65	1.81
Mining	2.63	3.24	3.66
Construction	1.18	1.65	1.10
Manufacturing	0.41	0.47	0.43
Transportation and Utilities	1.00	1.06	1.01
Trade	1.09	1.05	1.02
Finance	1.06	0.96	0.87
Services	1.03	0.96	1.05
Government	0.96	0.93	1.07

The regional significance of the resource industries and lesser significance of manufacturing is clear. Construction has been important, as might be expected given the capital intensity of the petroleum industry and Alberta's rapid growth.

In conclusion, assorted analysts have found that the Alberta economy grew rapidly after the Leduc find of 1947 and performed well in relationship to the rest of the country. Compared to Canada as a whole, the mining and agricultural sectors have played dominant roles. Generally speaking, per capita income was near or above the Canadian average, and Alberta's unemployment rate has normally been lower than average. However, the Alberta economy has been much more unstable than those of almost all other provinces.

We now turn to a more direct measure of the significance of the petroleum industry to the Alberta economy.

2. Petroleum's Contribution to GDP

The direct significance of different industries can be measured by looking at the 'value added' to GDP. As mentioned above, an industry's value added is the sum of wages, rent, interest, and (before-tax) profits paid. In essence, it is the value of an industry's production less its purchases of goods and services from other industries, and it can be used to measure the relative significance of different industries to the total economy. As noted above, when added up across all industries, it provides as measure of the total value of production in the economy. One complication is in determining exactly what properly constitutes an industry. For example, does the petroleum industry include only the crude-oil-producing industry, or does it also include pipelines, refineries, petrochemicals, oilfield service companies, geological consulting firms, etc.? In this regard, the researcher is often constrained by the form in which statistics are collected.

We draw on the Alberta Provincial Accounts to show value-added shares of different industries for the years 1961 to 2001, and from CANSIM for 2002–2008, the last data available at the time of revision of this volume. Data are unavailable for years prior to 1961. A significant change in statistical methodology was applied to the statistics for years from 1971 on; definitions were changed again with the 2009 data. Accordingly, we utilize values for two separate time periods, 1961–71 and 1971–2008. The two are not strictly comparable, although at the level of aggregation we use they are broadly consistent with one another. The 'Mining' industry is almost entirely petroleum activities, and, in our data, has been expanded to include natural resource royalties (which are included in the "Finance" sector in the primary data sources). Coal is the other major mineral product produced in Alberta, partially for export, but also for electricity generation in the province. Bitumen and heavy oil upgrading, which are an important part of oil sands activities, are included in the mining sector. The provincial statistics include "Support activities for mining and oil and gas" in the mining sector.

However, as implied by open economy models, and discussed by Hanson in *Dynamic Decade*, the contribution of the petroleum industry is likely to go far beyond its direct contribution to provincial GDP. Mansell and Percy (1990, pp. 17–19) quote a government discussion paper that suggested that "in 1981, about half of the construction activity and one-quarter of the manufacturing activity in the province were related to oil and gas." Moreover, the industry purchases a variety of other services and is a major source of revenue to the provincial government. And, of course, the incomes generated by these activities directly tied to the petroleum industry help fuel the demand for assorted other household and business goods and services. It also appears that exports of petroleum-related goods and services have been of increasing importance.

Figures 13.7 and 13.8 include five broad industrial groups: mining; agriculture and forests; manufacturing; construction, transportation and utilities; and trade, finance, public administration and other services. The years 1961–71 are shown in Figure 13.7. In this period, the mining industry contributed between 10 and 15 per cent of Alberta GDP, with the share rising slightly to 1968, then falling off slightly. Overall, industry shares were relatively constant in this decade;

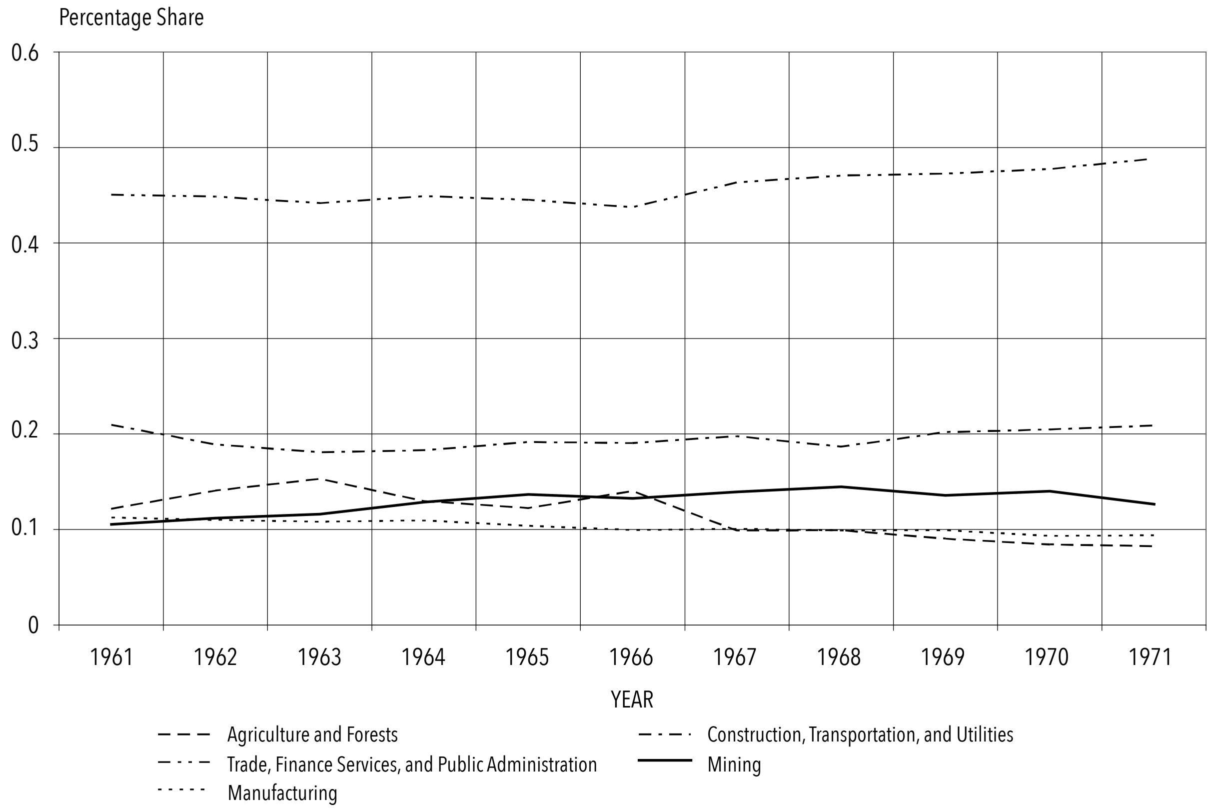

Figure 13.7 Industry Shares in Alberta GDP, 1961–1971

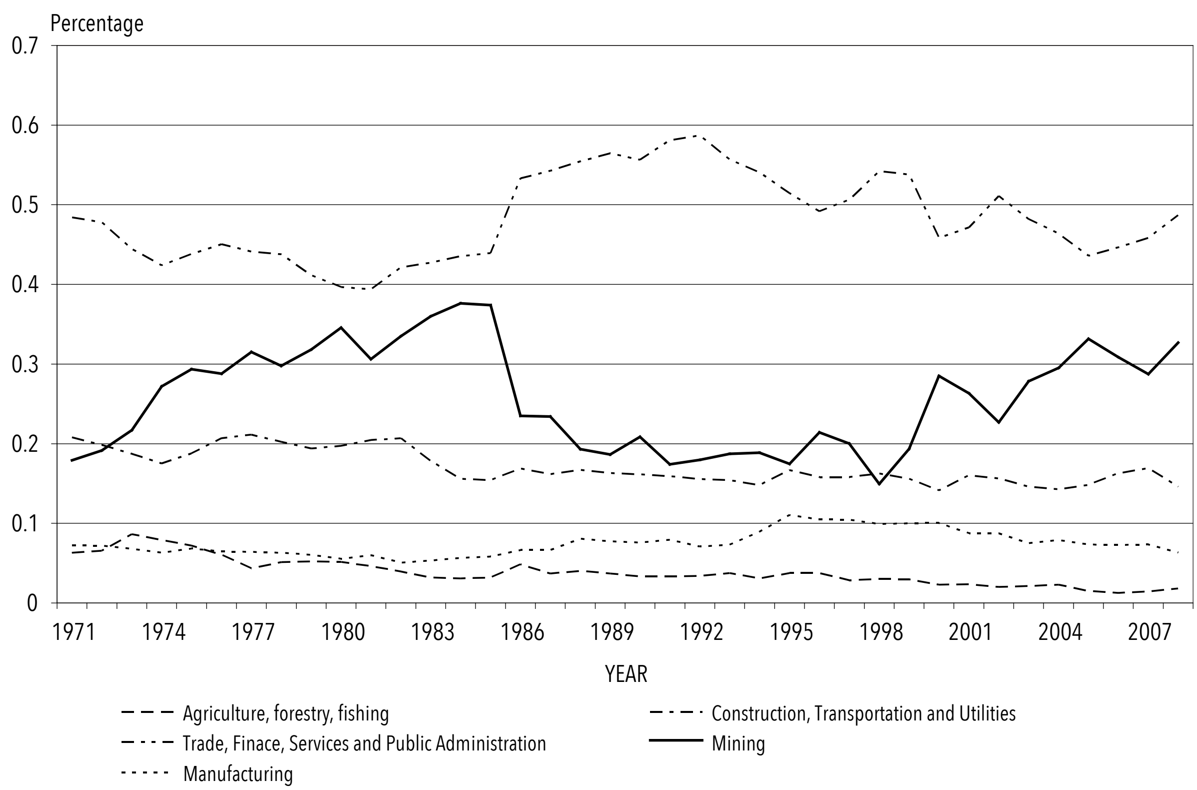

Figure 13.8 Alberta Industry Shares in GDP, 1971–2008

Source: Calculated from data in Alberta Department of Finance, ASIST Matrix 6106 and CANSIM II Table 3790026.

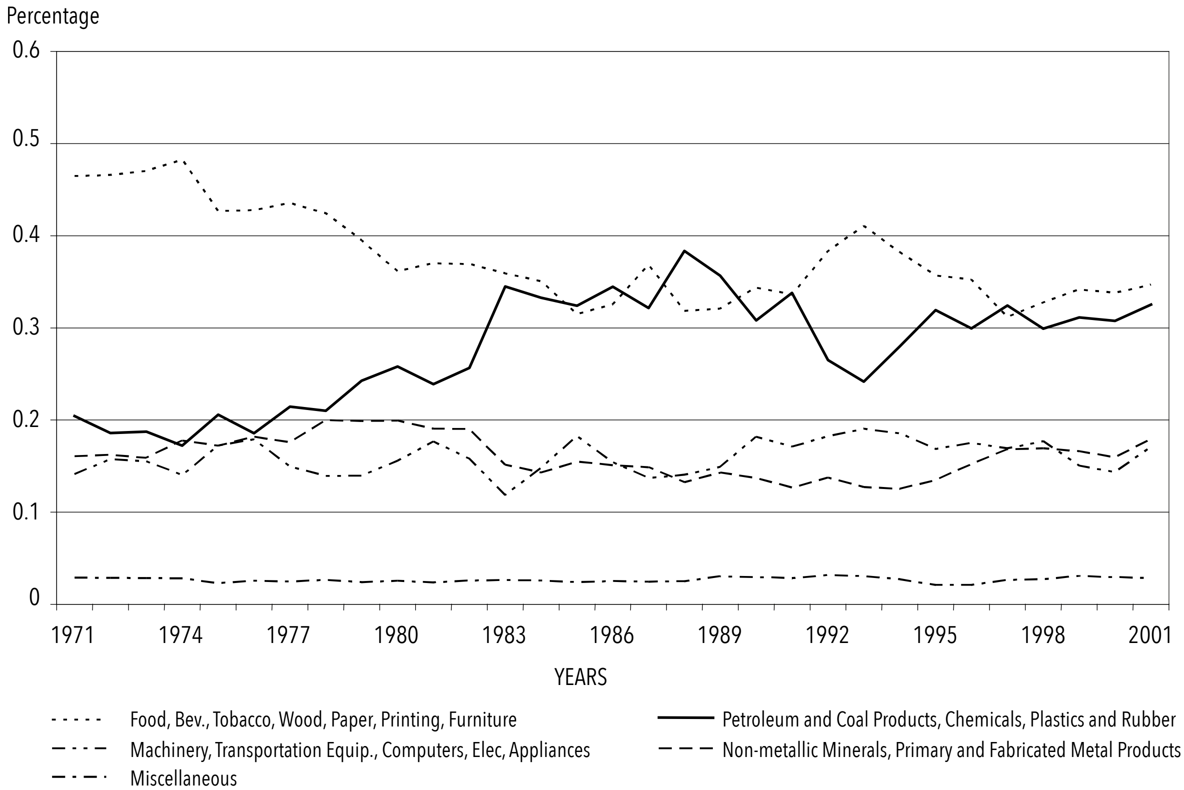

Figure 13.9 Shares in Alberta Manufacturing, 1971–2002

Source: Calculated from data in Alberta Department of Finance, ASIST Matrix 6106 and CANSIM II Table 3790026.

agriculture and forestry saw a reduced share, as, less dramatically, did manufacturing. Mining and services increased shares. A shift away from goods-producing industries towards services has been common for developed economies in the latter half of the twentieth century.

Figure 13.8 shows that more dramatic changes in the industrial structure of the Alberta economy occurred in the three decades following 1970. From 1971 to 1985, the share of mining in Alberta GDP rose from under 20 per cent to over 35 per cent. It will be recalled that this period saw large oil and natural gas price rises. (Figure 13.10, which will be discussed below, shows the relative changes in oil and natural gas production and real prices after 1969.) When international crude oil prices fell in 1985, the share of the mining industry in GDP also declined, to back below 20 per cent by 1988. From then, it varied up and down from a low of about 15 per cent in 1998 to just over 25 per cent in 2000, after which it rose again to over 30 per cent in 2005, before falling back somewhat then rising again in 2008. Oil and natural gas prices seem to be a major factor in these changes, with the natural gas price hitting a high in the year 2005. The early 1980s bubble in the mining contribution to GDP includes the period of rapid growth in total Alberta GDP and per capita GDP discussed above. Obviously, a sharp rise in the mining share must be matched by declines in the shares of one or more other industrial group. This is seen to varying degrees in the 1971–85 shares for the other sectors, though only minimally so for manufacturing, and up to 1982 the construction, transportation, and utilities sector largely held its share. If the final years are compared to 1971, increased shares can be seen for mining, manufacturing, and the services group; the other primary industries and construction, transportation, and utilities show reduced shares of GDP.

The GDP shares for a broad aggregation of manufacturing industries for the years 1971 to 2001 are shown in Figure 13.9. (CANSIM data after 2002 included too many missing values, for confidentiality reasons, to be used.) One of these categories (petroleum and coal products, chemicals, plastics and rubber, which includes oil refining) is closely associated with the crude petroleum industry in the sense that these

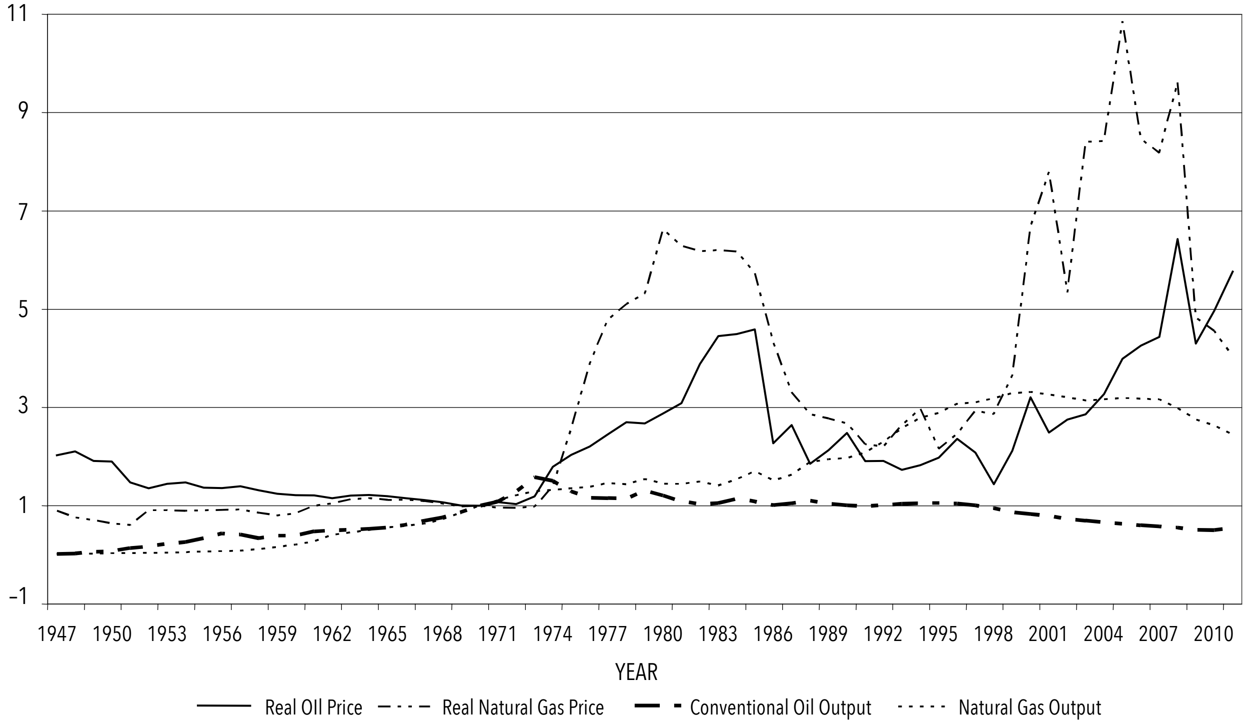

Figure 13.10 Indices of Real Oil and Gas Prices and Output, 1947–2011, 1970=1

manufacturing processes typically draw on oil or natural gas products as feedstock input (i.e., in addition to the need to buy energy to heat the manufacturing plant and provide process energy). From 1971 to 1988, the share of this group in Alberta manufacturing GDP increased dramatically, from just over 20 per cent to almost 40 per cent. The share of the agriculture and forestry-based manufacturing sector fell in a corresponding fashion, from over 45 per cent to about 32 per cent. This increase in the petroleum-based industries is similar to the increased share of the primary petroleum (mining) sector and reflects at least in part the increased value of petroleum in the marketplace. However, the peak for the petroleum products manufacturing sector (in 1988) comes after crude oil prices had fallen dramatically, and while the share of this sector did fall after 1988, and has shown significant variability, it maintained a value-added share in manufacturing that is some 50 per cent higher than its 1971 share. In 2009, the latest year for which data are available, petroleum-related manufacturing industries contributed 32 per cent to Alberta's manufacturing value added, while agricultural and forestry manufacturers contributed 28 per cent.

The significance of the petroleum industry to the services sector is difficult to determine with precision. Casual observation of the economy indicates that service providers to the Alberta petroleum industry have developed export markets, as well as meeting the needs of Alberta oil and gas producers. A 2001 government survey of the services sector (Alberta Departments of Economic Development and International and Intergovernmental Relations, July 2001) found that, in 1999, oil and gas services made up over 20 per cent of services sector revenue (for the seven key service sectors surveyed); this was second to construction services, which generated 61 per cent of the revenue. But the survey also found that for most non-oil-and-gas service providers (such as construction, computers, management consulting, and engineering), a part of the services provided were petroleum-related activities.

In summary, the petroleum industry obviously plays a major direct economic role in Alberta. In 1961, it was the least important of the five industry groups into which we separated Alberta GDP. (Mining, manufacturing, and agriculture and forestry were close in shares at that date.) By 2009, mining ranked second, its share having risen from barely 10 per cent to almost 30 per cent.

As earlier tables in this book have demonstrated, both the volumes of production of conventional oil and natural gas and their real prices increased significantly since 1947. Figure 13.10 illustrates the importance of these changes since 1947, using 1970 as a base year. It can be seen that, prior to 1970, rising output of oil and gas was the dominating factor. After that, higher prices were of significant importance as was increasing natural gas production. (So, eventually, was rising oil sands output, which is not shown in Figure 13.10.) While both output and price could have generated higher value-added shares for the mining sector, the year-to-year variability in share suggests that price has played a particularly important role. In Alberta manufacturing, there has also been a shift over time towards a greater share for the sectors that utilize petroleum products as a material input for the good produced. The pipeline and construction industries obviously depend on the petroleum sector, and some manufacturers provide inputs to oil and gas production and transmission. Petroleum-related services also appear to have been increasing in value; in addition to meeting needs of the Alberta petroleum sector, some of these services providers engage in export sales, so are developing an existence independent of the Alberta petroleum industry. Unfortunately, published data on value added or revenue by industry is insufficiently detailed to allow precise estimation of the contribution of the petroleum industry to the Alberta economy as a supplier of inputs to other sectors and as a market for the output of other sectors.

We now turn to another measure of the relative size of the Alberta petroleum industry, its share in employment. Rather than giving extensive time series data, we utilize information from a recent year. (The contribution of the highly capital intensive petroleum industry to Alberta's total stock of capital is another measure of the significance of the industry, but not one about which we possess specific information.)

3. Petroleum's Contribution to Employment

Oil and natural gas production are capital-intensive activities, which do not require many direct workers. Of course, the total contribution of the petroleum industry to employment in Alberta is difficult to assess for the same reasons that its full contribution to GDP is hard to determine. (Which workers in other industries are employed only because they provide goods or services to the petroleum industry or because they provide goods and services for the use of industries and households who reside here only because of the petroleum industry?)

In the broad historical context, Alberta, like other developed economies, has seen a decline in the importance of goods-producing industries, especially primary industries, relative to services. Thus, for example, the Alberta Bureau of Statistics (*Alberta Provincial Accounts*, 1973, p. 139) reported that the percentage of the employed labour force in agriculture, forestry, and fishing fell from 53 per cent in 1921 to 15 per cent in 1971, while service sector employment rose from 30 per cent to 60 per cent. This study lumped together mining, manufacturing, and construction, where the share rose from 16 per cent in 1921 to 25 per cent in 1971, rising markedly from a low of 13 per cent in 1941. More recently, in its *Facts on Alberta* of January 1994, the Industry Development Branch of the Department of Economic Development and Tourism (p. 8) showed 'fishing, forestry and mining' as providing 5.8 per cent of Alberta's employment (almost 90 per cent of this in mining, of which the petroleum industry provides most). The October 2010 issue of the same series (now from the Department Finance and Enterprise, p. 25), showed the employment share of "Energy" as 6.9 per cent. (Manufacturing's share fell from 7.6 per cent to 6.2 per cent over the same period.)

As these numbers make clear, the economic significance of the petroleum industry to the Alberta economy is not primarily through its direct employment.

4. Conclusion

In this section, we have set out broad features of the Alberta economy and the relative significance of the petroleum industry. The industry itself is highly capital-intensive, so that its direct contribution to provincial GDP is much larger than its contribution to employment. The value added by the petroleum industry has been a significant part of the Alberta economy, growing strongly after 1947, and especially during the period of historically high oil prices during the late 1970s and the early 1980s. The importance of the oil industry almost certainly is a major factor in explaining why, since 1947, growth of both population and real GDP in Alberta have been above the Canadian average, as has per capita GDP. The capital intensity of the industry and the high ex-Alberta ownership and government-take of petroleum profits lead to per capita personal income in Alberta closer to the Canadian norm than per capita GDP; nevertheless, ever since the early 1970s, Alberta per capita personal income and personal disposable income have exceeded the Canadian average. Finally, it appears that the reliance of the Alberta economy on this single industry and the variability of oil and gas prices has led to greater instability in the Alberta economy than other provinces or Canada at large.

We now turn to five specific topics that relate to the role of the petroleum industry in Alberta: the degree of diversification of the Alberta economy (Section C); macroeconomic 'costs' of the NEP, and transfers from Alberta to the rest of Canada (Section D); the role of migration and price changes as economic 'equalizers' (Section E); impacts on Alberta government revenues and expenditures (Section F); and the significance of petroleum resource depletability and the *Alberta Heritage Savings Trust Fund* (Section G). We provide broad overviews rather than detailed analysis.

C. Diversification

1. Introduction

It is often taken as obvious that a more diversified economy is preferable to a less diversified one. However, a proposition of this sort requires critical consideration. For example, that greater diversification is desirable is likely true only under some 'all else being equal' condition. For example, for any given size of the population, attainment of a more diversified economy at the expense of a sharp fall in the region's GDP would not be seen as a gain. Or, in an example of particular relevance to Alberta, a sharp rise in the value of the output in a major sector (e.g., rising oil prices from 1973 through the early 1980s) would lead to an increase in the contribution of that sector to the economy and, probably, a reduction in the industrial diversification of the economy; but it is hard to see this as necessarily undesirable.

One might suggest, as a tentative hypothesis, that a more diversified economy is preferable for any given level of GDP in the economy. The question now is "Why?" There seem to be two main answers, though they are often not made specific.

The first is that a more diversified economy is likely to prove to be more stable and resilient. (See, for example, Mansell and Percy, 1990, with regard to Alberta.) This will hold true if the economic conditions in different industries are not highly correlated with one another, as when oil prices and wheat prices move largely in response to different factors. This argument for diversification would seem to be particularly strong when applied to regional economies from an export-base perspective. The diversification in this case relates to the exporting industries, where, for example, a collapse in the market for one export good will have a less drastic effect on the economy if the region has a number of other export goods for which market conditions remain strong. A secondary hypothesis might be that diversification is even more important for economies that depend heavily on non-renewable natural resources, which must, at some point, exhibit strong depletion effects.

A second possible argument for diversification is that a more diversified economy is likely to be more self-sufficient and hence less dependent in general on the vagaries of external market conditions. This argument is less convincing, as it confuses to some extent cause and effect and does not seem to focus on the most important variables in attaining a degree of self-sufficiency. Increased self-sufficiency hinges to a large extent on the economy attaining sufficient size that it can realize the economies of scale and agglomeration effects that make it efficient for producers of a wide variety of goods and services to produce for the local market rather than importing them. Thus it is not that diversification brings more self-sufficiency, but that, as a region grows large enough to attain more self-sufficiency, diversification follows.

It is important, then, to distinguish between diversification as a characteristic of an economy and increased diversification as a justification for public policy.

Thus, one could argue that greater diversification provides more economic stability for people in the economy but also that any government steps to raise the level of diversification are likely to prove either ineffective or more costly than is justified. Proponents of this line of argument would suggest that responsibility lies largely with individuals to protect themselves from the costs of instability (for example, by building up nest eggs in good times), with the government, perhaps, providing some economic 'built-in stabilizers' (e.g., unemployment insurance, food banks).

Others have argued that, since more economic diversification is desirable, governments should pursue an active 'industrial policy' designed to encourage the development of new industries. It is important to recognize that, in a country such as

Canada with a relatively mobile population, such policies, if successful, would almost inevitably lead to an increase in the size of the economy as well. In the Canadian context, this has led to speculation that the real purpose of such policies is not diversification but 'province-building' (Richards and Pratt, 1979; Pratt, 1984). This could reflect an interpretation of 'diversification' like the second of the two noted above, and/or the belief by regional politicians that a larger local economy is in their more selfish interests (for power, prestige, etc.).

Development of an 'industrial policy' is necessarily controversial since it involves the interplay amongst at least three questions.

1. *Who benefits?* In the real world of individual mobility, this is not a trivial question, as was noted above. At its most basic, the question is whether the policies should be aimed largely at those who are currently resident in the region (and their children and grandchildren, a 'generational' perspective) or at those who are currently and will in the future be residents of the region (a 'successor' perspective). From a 'generational' perspective, 'diversification' matters as a possible economic stabilization policy. As noted above, one way to attain this might be to extend the production life of the depletable resource over a longer time period, which might both keep the overall size of the economy smaller, and also reduce the concentration of GDP in the resource sector. In addition, there would be some advantages to mechanisms that transfer the rents from resource production into the hands of current resident households (e.g., through lower taxes or royalty trusts). On the other hand, from a 'successor' perspective, 'diversification' attained through the expansion of new industries could appear very attractive, generating income for more residents attracted to the region. Policies could involve using resource rents to help new industries get established and to provide additional public services available to newcomers as well as existing residents (which, if an improvement on public facilities in other provinces, could serve to attract immigrants).
2. *Given that a group has been defined, what are the policy objectives?* Here, it is common for economists to assume a 'public interest' perspective, with goals of efficiency and equity. However, readers will recall that economists have also applied a 'public choice' viewpoint in which it is assumed that the policies will be those that politicians view as being in their own best interests, which may or may not correspond with the interest of the population at large.
3. If we assume that the objectives of public policy are such broad public interest goals as efficiency and equity, what specific policies should be adopted? While oversimplified, it is useful to suggest two general answers to this question. The first is that the appropriate 'industrial policy' is a largely passive, non-interventionist one. It is argued that attempts to force development of new industries almost always generate higher costs than benefits, and frequently involve permanent subsidization. Given the realities of a region's resources and location, and the increasingly globalized world economy, the best policy of the government is to ensure a flexible, well-functioning regional economy, with as neutral a tax system as possible; labour and business will then exploit the economic opportunities available to the advantage of the region and its residents. The second viewpoint argues for an interventionist 'industrial policy,' on the grounds that some corrections are needed in the existing system to attain the diversification/growth goals. A variety of 'failures' might be cited, including the following three: (1) the 'infant industry' argument, that a new industry requires government support until it attains sufficient size to realize the economies of scale and learning that allow it to compete in wider world markets; (2) the 'knowledge externality' argument, that governments have a responsibility to fund research and development and educational activities since they provide benefits that accrue to the economy at large; and (3) the 'agglomeration' argument, that the government should encourage economic growth to bring the economy to the size at which it can realize the widespread benefits of greater size and increased self-sufficiency. In addition, advocates of an interventionist approach often suggest that a non-interventionist policy frequently brings unacceptable 'equity' costs, for example by redistributing income away from workers towards owners of capital. Of course, these two policy approaches are the extremes; many analysts are willing to accept that some degree of active government policy is justified, but the question is how much.

We now turn to the specific issue of the petroleum industry and economic diversification in Alberta. Initially, we will discuss the degree of economic diversification of the economy. Then government diversification policies will be reviewed briefly.

2. The Extent of Economic Diversification in Alberta

The statistical information provided above allows some comments to be made on the question of diversification.

First, the expansion of the petroleum industry in Alberta after 1947 provided diversification of the economy away from agriculture, which did not occur to the same extent in Saskatchewan. However, as shown above, Mansell and Percy (1990) argue that the Alberta economy, from 1961 to 1985, was the most unstable provincial economy.

Second, the rise in oil and natural gas prices starting in the early 1970s might be interpreted to have reduced the diversification of the Alberta economy because the petroleum sector increased its relative significance. However, we argued above the impact of an increase in the price of an important industry's output is probably better seen as increasing the gross production of the economy (GDP) than as reducing the economic diversification of the region, unless the high prices lead to a continued expansion of that particular industry at the expense of other sectors (as in the 'Dutch Adjustment'). The value-added data for Alberta industries does not suggest that this occurred in Alberta. However, it is likely that instability in petroleum prices has been a significant factor in the instability in the Alberta economy noted by Mansell and Percy. Their measure of instability (the size of deviations from a trend line) would obviously be very sensitive to the sharp rise in value for many economic measures in the decade from 1973 and the fall and flatness for the next decade (as seen in the GDP and GDP per capita lines in Figures 13.3 and 13.5). Recall, also, that Figure 13.6 shows greater percentage variability in Alberta real GDP than Canadian, even after 1993.

Third, following the crude oil price collapse of 1985, there seems to have been a rise in the share of the manufacturing sector in the Alberta economy. That sector does appear to show greater diversification recently than at the start of the 1960s, largely as a result of a decreased share for the agriculture/forestry-based goods and a rise in petroleum-based products. (See Figure 13.9.)

However, the aggregated industrial statistics we have presented may hide the actual level of diversification. Thus, for example, the energy sector includes conventional crude oil, non-conventional oil, natural gas, and coal. While there does appear to be a positive correlation between the prices of these energy products, the correlation is not perfect, as we pointed out in Chapter Twelve, when comparing crude oil and natural gas prices. In addition, each energy product exhibits its own unique production characteristics; for example, depletion effects could differ between conventional oil and natural gas, and the production linkages for non-conventional oil differ significantly from those for conventional petroleum. Thus it is possible that the increased relative shares of natural gas and non-conventional oil (relative to crude oil) starting in the 1970s provided increased stability to the Alberta economy even while the energy sector continued to be a major production sector. In another example, Norrie and Percy (1981) note that Alberta's agricultural sector is much more diversified than those of the other two Prairie provinces.

On the other hand, if the rising share of manufacturing comes largely in the form of increased processing of petroleum products, it may not provide as much economic diversification as it appears because these manufacturing industries may be subject to the same instabilities (due to price changes or depletion effects or the like) as the crude petroleum industry.

Thus, more detailed modelling is needed to address in a meaningful way the impact of the petroleum industry on the functioning of the Alberta economy. We will note, briefly, four such approaches, although not all specifically address economic diversification.

First, as mentioned above, Richards and Pratt (1979) and Pratt (1984) see Alberta's economic development in the 1970s as following a model in which (Pratt, 1984, p. 194)

> … the powers and resources of an interventionist 'positive' government are being employed to defend the province-building interests of an ascendant class of indigenous businessmen, urban professionals, and state administrators. The objectives of this nascent class are to strengthen its control over the Alberta economy, to reduce Alberta's dependence on outside economic and political forces, and to diversify the provincial economy before oil and natural gas reserves are exhausted.

Obviously, this approach sees economic development largely in terms of class interests. It also draws heavily on a 'staples theory' perspective, wherein market economies tend to separate into strong diversified centralized economies and undiversified, resource-based hinterland economies. Only through strong government policies can the hinterland economy (hampered by its distance from the centre's large markets and corporate decision-making processes) hope to attain some economic independence. Pratt sees the Lougheed government's policies in the 1970s and early 1980s as involving a three-pronged process of (1) wresting control over the petroleum industry away from the federal government after Ottawa's strongly interventionist policies began in 1973; (2) increasing economic rents on Alberta-produced petroleum, and gathering a higher share of these rents for use by the provincial government; and (3) encouraging the development of new industries in Alberta, particularly the petrochemical industry. Presumably the intent is that Alberta's locational advantage in terms of accessibility of petrochemical feedstocks (e.g., ethane) offset its locational disadvantage in terms of long distances from major consuming markets. We will not review Alberta's policies regarding petrochemicals, but there have been suggestions that the policy is likely to require continuing subsidies, either direct or indirect (e.g., by prohibiting the free sale of potential feedstocks in export markets, thereby reserving their use in Alberta at lower prices to petrochemical plants).

Within Pratt's political economy approach, there seems to be some doubt about whether a single hinterland region can effectively offset the inherent locational problems of a capitalist market economy. However, the activist government policies are seen as reflecting "the anxieties and aspirations of a dependent business community and an ascendant urban middle class, neither of which seek the elimination of the market economy – merely promotion within it" (Pratt, 1984, p. 220). Diversification, then, will require an activist approach to support the larger domestic economy. Most economists have been unconvinced about the inevitability of the centre–periphery economy dichotomy, arguing that the development of new industries and the growth of a larger domestic market may occur, allowing a greater degree of local autonomy and self-reliance.

Assessment of the extent of economic diversification of the Alberta economy, as has been seen, is often approached in the context of comparisons with other regional economies. In the Canadian context, this raises a number of issues that have been discussed in the context of regional economic disparities; that is, a second avenue of research suggests that the degree of economic diversification may be one of the factors that contribute to regional economic differences. An economic approach to Canadian regional development can be found in two reports from the Economic Council of Canada, *Living Together* (1977) and *Western Transition* (1984), and in research undertaken for the Royal Commission on the Economic Union and Development Practices for Canada, the Macdonald Commission, which reported in the late 1980s. Mansell and Copithorne (in Norrie, Simeon, and Krasnick, 1986), in work for the Royal Commission, provide an overview of economists' thinking about Canadian regional economic disparities. They note that economists have not reached agreement on the explanations for differences in the economic performance of different provinces but that a number of factors are commonly implicated, some related to differences in economic structure and others to differences in the process of economic adjustment. They also remark that disparities in output per capita exceed disparities in per capita disposable income, presumably reflecting a variety of stabilization and equalization programs. They also note that regional mobility of labour and capital has played a role in keeping regional differences from widening. Differences in five aspects of an economy are argued to be most significant in explaining regional income differences: "Capital intensity, labour quality, scale and technology, participation rates and unemployment rates" (Mansell and Copithorne, 1986, p. 31). Presumably similar factors, including the nature of the key industries, relate to the stability of regional income. They note that studies designed to decompose the contribution of various actors to per capita income suggest that differences in the capital intensity of different industries (higher capital intensity yielding a higher capital-to-labour ratio) and in the quality of the labour force are major factors affecting regional income differences. Thus, Alberta's relatively high per capita output reflects, in part, a well-educated labour force and the high capital intensity of the petroleum and agricultural industries.

A third line of research involves the neo-classical modelling efforts of Copithorne (1979, looking at regional economic differences in Canada) and Mansell (1975, and 1981, looking at both migration and the functioning of the Alberta economy; also Mansell and Wright, 1981, and Mansell and Percy, 1990). Copithorne's research suggested that disparities in natural resources are not the main basis of Canadian interregional economic differences, although the functioning of specific resource industries like forestry in British Columbia and the Newfoundland open-access fishery do have lasting structural effects. Rather, his model places emphasis on the mobility of capital and labour and the degree of flexibility in labour and capital markets, with greater rigidity in factor adjustments associated with lower income. Mansell (1975) and Mansell and Wright (1981) also found that Alberta benefited from a greater degree of labour mobility than in some other parts of Canada.

Mansell and Percy (1990, pp. 35*ff*.) report simulations of the Alberta economy using a large econometric model. Within this model, investment spending is found to have been a major driving force (and an increasingly important force) behind the growth of the economy. This is entirely consistent with petroleum-resource booms in the late 1940s and the mid-1970s. In the 1980s, starting in 1982, an economic slowdown is explained by a fall in petroleum investment (argued to be occasioned by the National Energy Program), as well as by high interest rates and a large net financial transfer out of Alberta to the federal government. Throughout, migration into (or out of) Alberta is responsive to relative income differences between Alberta and the rest of Canada.

Mansell and Percy argue that this model places less importance on purely structural aspects of various industries and more emphasis on inappropriate government policies. From a Keynesian perspective, an economy in which investment spending forms a significant part of aggregate demand may be particularly prone to instability. Presumably, in Alberta, the high role for investment reflects both the capital intensity of key industries and the fact that the province has exhibited periods of higher than average growth. (The Keynesian 'accelerator/multiplier' model exhibits just such instability. Investment stimulates economic growth, through a multiplier effect on the economy; this growth in turn attracts increased investment, which accelerates the income growth. However, if any factor stops the growth in investment, then the growth in income tends to stop, and investment falls, which reduces aggregate demand and reduces income, leading to a further drop in investment, and so on.)

A fourth line of research on the Alberta economy, using general equilibrium models, was undertaken for the Economic Council of Canada by Norrie and Percy (1981, 1982, 1983). A general equilibrium approach is designed to capture the wide-ranging effects of changing sectoral growth rates or of specific economic policies, by explicitly looking at the interconnections amongst various sectors of the Canadian and provincial economies. (Much of their work posits a 'Western Economy,' based, for example in the 1982 paper, on Alberta and Saskatchewan. We shall discuss the results as applicable to Alberta.) Norrie and Percy (1981) found that, while Alberta expanded relatively faster than Central Canada through the 1970s, largely due to rising resource prices, there was little evidence of significant structural change in the Canadian economy; for example, little diversification was seen in Alberta. Growth through labour migration did have some effects, including some labour shortages in Alberta, and price effects in markets for non-traded commodities (such as housing, with weaker prices in regions losing labour, and higher prices in regions like Alberta gaining labour).

There is no evidence that Alberta's expansion came at the expense of central Canada. In fact, some 'Dutch Adjustment' effects are evident, in which skilled labour shortages in Alberta make expansion of manufacturing and service industries there less appealing, and imports from Central Canada more appealing. The 1982 paper focuses explicitly on the utilization of resource rents by the provincial government. It finds that if the province uses the revenue to provide additional goods and services to residents, as opposed to passing the rents through in the form of lower taxes, the net benefits to residents on average are reduced, but the provincial economy grows in size and certain local residents (e.g., property owners) experience a net gain. This is a 'province-building' strategy, and it has greater impact if there are regional agglomeration effects.

In conclusion, while the Alberta economy has clearly grown faster than the Canadian economy since 1947, and appears somewhat wealthier but also somewhat less stable, there is little consensus as of yet on the exact nature of the underlying growth processes and whether the economy has become more diversified in the process. Part of the problem is in the difficulty in defining 'diversification'; partly it is in devising an adequate measure of diversity for any specific definition of that term.

Conceptually, the petroleum industry would affect the larger Alberta economy in three major ways: (1) through an increase in the level of petroleum production and associated investment; (2) through an increase in the real price of petroleum; and (3) through increases in productivity. To some extent, all three factors have operated since 1947. Figure 13.10 provided some information on the relative importance of the first two factors, showing the relative changes since 1947 in oil and natural gas output as compared to real prices.

- The period from 1947 through to the early 1970s was driven largely by the rising production, as can be seen in the tables in Chapter Six for oil and Chapter Twelve for natural gas. In this stage, the petroleum industry initially provided diversification away from the heavy reliance on agriculture but left Alberta largely dependent on these two industries.
- From 1973 to 1982, rising energy prices were the key factor, as shown in Figure 13.10. The essential economic effects of higher prices for oil and natural gas are relatively straightforward, although the precise impact depends on how the increased values are utilized. Initially, there is a significant inflow of funds into the province (due to what most economists would call an improvement in Alberta's 'terms-of-trade,' as petroleum prices rise relative to the prices of other goods and services). The higher prices and incomes induce greater spending on goods and services generally and petroleum production in particular. This, in turn, increases imports into the region and drives up local prices, including prices of the skilled labour and other inputs used in the petroleum industry. Longer-run effects begin to operate, including a rise in the inflow of labour and capital into the region, which helps to alleviate the local inflationary pressures. However, rising costs of local inputs also decrease the attractiveness of production for many goods and services. In effect, the resources utilized to produce more of the increasingly valuable petroleum come from two sources: in-migration and resources transferred from other production in the region. The latter effect is a manifestation of the 'Dutch Adjustment' and implies an increased economic reliance on the petroleum industry or a reduction in economic diversification.
- International oil prices fell after 1982, and natural gas prices followed, as seen in Figure 13.10. While petroleum and agriculture have continued to be the mainstay of the Alberta economy, many observers have expressed the feeling that by the turn of the century Alberta had become somewhat more economically diversified, at least in the sense of having attained a relatively large, robust, and growing economy. The sharp fluctuations in international oil prices in the late 1990s and early 2000s seemed to have a somewhat smaller effect than similar real price changes had in the 1970s and 1980s. In 2003, the Toronto Dominion Bank (TD Bank, 2003) issued a report labelling the Calgary–Edmonton corridor one of Canada's four high-growth areas (along with Toronto, Montreal, and Vancouver), describing it as "the only Canadian urban setting to amass a U.S.-level of wealth while preserving a Canadian-style quality of life" (p. 1). They note the high reliance upon the oil and gas sector but suggest that some economic diversification has taken place (p. 9):

> Oil and gas mining production and exploration activity remains the single largest industry in Alberta, at 19 per cent of GDP, followed by finance, insurance and real estate (16 per cent), manufacturing (10 per cent), and construction (8 per cent). However, the past few decades have seen some notable shifts across the sectors in terms of relative importance to the provincial economy. The real GDP shares of oil and gas and public services (including health care and education) have both slipped by 4–5 percentage points since the mid-1980s. In contrast, several industries – such as forestry, chemicals and machinery and equipment, residential construction, transportation services and wholesale trade – have registered above-average growth and rising shares of provincial output. Finally, professional, scientific and technical services and communication services have witnessed among the largest jumps in relative importance over the past two decades, spurred in part by the surge in industrial and consumer demand for information-technologies.

Thus, by the start of the twenty-first century, the Alberta economy appeared to have become more resilient and somewhat less dependent upon the direct activities of the petroleum industry than it had been over the previous five decades.

In addition, as was remarked in Chapter Seven, there have also been changes due to the contraction of conventional oil production and the expansion of non-conventional oil activities. The mining/upgrading approach to the oil sands involves more regionally concentrated (in northeast Alberta) production activities and different labour skills and equipment than conventional oil drilling and lifting. Further, while oil sands and heavy oil output expansion may help to maintain government revenue as conventional oil and gas production declines, the reliance upon profit-sensitive rules for government take may increase the instability of this revenue flow.

3. Alberta Government Policies

The Alberta provincial government has long seen diversification of the provincial economy as important. Following the election of the Progressive Conservatives in 1971, replacing Social Credit, which had been in power since 1935, the government has usually been characterized as pursuing a relatively activist diversification policy, as captured by the term 'province-building.' A key component of this policy was the active encouragement of processing industries using petroleum, especially natural gas; petrochemicals were the main example and were guaranteed access to ethane under favourable conditions.

After the mid-1980s, the official policy has shifted to a more passive diversification policy, generally captured in the phrase the "Alberta Advantage." Mansell (1997) and Emery (2006) provide useful reviews of Alberta's diversification policies. They argue that the 'active' policy pursued by the Lougheed and Getty governments through the 1970s and 1980s was not successful and involved losses of over $2 billion in government funds. The 1991 discussion paper *Toward 2000 Together* set out a variety options but signals this shift quite clearly: "the Alberta Government is committed to building a competitive business environment which encourages private sector growth and strengthens the role of market forces in the Alberta and Canadian economies" (Alberta, 1991, p. 4). While the discussion paper was supposed to allow Albertans to discuss various development strategies, the government's preferred approach seemed to have been decided already. In the same year, the Alberta Department of Economic Development and Trade, in an overview of the Alberta economy entitled "Alberta Industry and Resources," under the heading "Alberta's economic strategy," said:

> Alberta sees the role of Government as one of providing support to, but following the lead of, the private sector. This role serves Alberta well in a rapidly changing and competitive world, where decisions taken by individual entrepreneurs ultimately select the "winners and losers." Once business has established the direction, government policy can support and enhance its competitiveness and encourage further development.

The government has seen the "Alberta Advantage" largely in terms of measures to free up markets (including those for labour), removing regulatory barriers to business activity (partly through fewer, but also through transparent and stable, regulations), the provision of general infrastructure, which can be utilized by any business, and a regime of low income taxes (both personal and corporate). The Toronto Dominion Bank's 2003 study of the Calgary–Edmonton corridor listed three factors as of particular importance to the corridor's economic strength (pp. 9–14): 'low costs' (particularly a low-tax environment); 'a young and diverse population' (including high skill levels); and 'world-class infrastructure' (including transportation, internet communications, and educational facilities). All three are dependent on provincial government policies, but policies of a 'general' nature, rather than activist policies that try to direct economic diversification into specific industries.

Of course, this policy has not been without its critics. Thus, for example, the TD Bank study notes that the reason for the young and skilled Alberta labour force lies largely in the qualities of in-migrants to the province. One of their main suggestions is that the Alberta government should be doing more for education, training, and investment in research and development. A second concern of some observers is the extent to which economic development in Alberta hinges on the ready accessibility of relatively low-cost natural gas. This is obviously important for the petrochemical industry but also for enhanced oil recovery projects for conventional oil and for oil sands production; it also underpins the hopes of some that Alberta might play a lead role in the development of a 'hydrogen economy.' The concern is whether a free market environment will allow Alberta to maintain abundant relatively low-cost natural gas supplies as North American gas markets become more integrated and as existing low-cost Alberta gas pools are drained. (Also see Bradley and Watkins, 2003.) To support the more diversified economic structure of the province, while allowing continued growth, may require a somewhat more activist policy than has been seen recently.

We now turn to very brief discussions of several other issues related to the role of the petroleum industry in the Alberta economy.

D. The Macroeconomic Costs of the National Energy Program and Net Provincial Transfers to the Rest of Canada

In Chapter Nine, we discussed the 'overt' regulation of the petroleum industry in the years 1973–85. This period generally involved joint agreements between the federal government ('Ottawa') and the Alberta provincial government ('Alberta,' and other provincial governments). However, the initial regulations were introduced unilaterally by Ottawa, first in 1973, and then again in October 1980 in the National Energy Program (NEP). It will be recalled that amongst the regulations were policies to hold the price of Canadian-produced oil below world levels, to restrict exports of oil and natural gas, and to transfer a greater share of the industry's economic rent to Ottawa. It has been argued that these policies had detrimental effects on Alberta. Mansell and Percy (1990) note two: (1) inducing an economic downturn, and (2) ensuring that federal fiscal policy was consistently deflationary in Alberta, even during periods of recession when fiscal stimulation would be desirable.

It is apparent that the federal overt petroleum policies did not consistently depress Alberta GDP, since the economy showed strong growth during the years immediately after 1973. However, growth would have been expected to be even faster had oil prices in Canada risen at the same rate as world prices, rather than at the slower controlled rate. After 1981, Alberta's real GDP did decline. Mansell and Percy discuss this period (pp. 30–41) and, as mentioned above, report simulation results of an econometric model of the Alberta economy that finds that "the NEP was the key factor in initiating the downturn, and its negative effects were compounded by the accompanying high interest rates" (p. 37). As Figure 13.3 showed, Alberta GDP remained flat right through to 1993, long after deregulation in 1985. This suggests, as others had argued, that the key factor in the poor economic performance was less the NEP than plunging international oil prices, though the major price decline did not come until 1985. Mansell and Percy suggest that the NEP provoked a recession in Alberta but find that it would likely have occurred after 1985 anyway due to the lower petroleum prices. The NEP, presumably, made the downturn longer than it would otherwise have been, though they find that the adjustments the economy began to make after 1981 helped somewhat in the adjustments to lower prices after 1985.

Mansell and Percy (1990, Appendix A, drawn from Mansell and Schlenker, 1988) show Canadian "Net Federal Fiscal Balances" by year from 1961 to 1985. The Net Federal Fiscal Balance (NFFB) is federal government revenues collected in a region less federal expenditures in that region. This is based on government budget numbers from the Canadian economic accounts with several adjustments. The most significant relates to the oil-pricing policy from 1973 to 1985, in which it is assumed that without Ottawa's policies, Canadian petroleum prices would have followed world prices; the price controls are therefore seen as a federal government tax and transfer scheme, which 'taxed' oil producers on the difference between world and Canadian prices and transferred the difference to Canadian energy consumers. In Canada (with the organizational activities of the federal government concentrated in Ottawa-Hull and a commitment to the Equalization program, which transfers funds from 'have' to 'have-not' provinces), one would expect that different provinces exhibit different NFFBs. In the 1960s, four provinces ran positive NFFBs (revenues collected exceeded expenditures) while the other six provinces and the two territories had negative NFFBs.

From a macro perspective, a positive NFFB is contractionary, and a negative NFFB is expansionary. The four 'have' provinces in the 1960s – those with a positive NFFB – in this regard were Quebec, Ontario, Alberta, and British Columbia, with the first two generally showing the largest NFFBs. However, in 1971, the Quebec NFFB turned negative, as did those of B.C. and Ontario in 1977; from 1977 to 1985, only Alberta had a positive NFFB. Alberta NFFB from 1961 to 1973 is reported to vary between 1 and 8 per cent of 'Market Income,' but from 1974 to 1982 the values ranged from 19 to 52 per cent. (By 1985, the value was back down to 8 per cent, although, as mentioned, Alberta was still the only province with a positive NFFB.) Clearly, the petroleum price controls played a major role in the size of the NFFB. Apart from the rising political resentments of Ottawa seen in Alberta in the 1970s, Mansell and Percy (1990, p. 39) note that the net federal surpluses in Alberta "produced a strong fiscal drag on the provincial economy"; this was particularly true in the 1981–85 NEP period, but "in the absence of a continued rapid escalation in energy prices and energy investment, the exceedingly large federal fiscal surpluses with Alberta as early as the mid-1970s began to exert substantial deflationary effects on the provincial economy."

Mansell et al. (2005) provide revised and updated NFFB calculations, concluding that "for the period from 1961 to 2002 Alberta made a net fiscal contribution of $244 billion, compared to $315 billion for

Ontario and $54 billion for B.C." (p. 2). (Values are in 2004 dollars.) Almost 70 per cent of the Alberta contribution was credited to the 1970s and 1980s, which includes the period when Canadian petroleum prices were regulated, with oil prices held below the international level. Over the entire period, the relative contribution from Alberta is shown as significantly more than would be justified by Alberta's 'have' status; however, in the 1990s, when oil prices were no longer fixed below the world price, this discrepancy is not apparent.

In conclusion, from Alberta's perspective, the overt regulation period imposed, not only the efficiency costs discussed in Chapter Nine, but also significant macroeconomic stabilization costs.

E. Economic Equalizers: Migration and Input Price Changes

Oil and natural gas are highly prized natural resources, seen by many as a route to wealth and power. As discussed above, they served as the prime engine for growth in the Alberta economy after 1947. To understand the full economic impact of the crude petroleum industry, it is necessary to apply a broad framework. The economic models we refer to in this section generally draw on a long-term, general equilibrium perspective that emphasizes that increased wealth as a result of the exploitation of petroleum calls into play dynamic reactions that modify the initial wealth-creating effects. In an increasingly 'globalized' world, these effects operate at the international level, but they are particularly potent in a regional economy such as Alberta, housed in Canada's developed market economy, where labour and capital are highly mobile.

The short-term and long-term effects on Alberta of a rise in the real value of petroleum were suggested above. The immediate effect is a rise in the economic rent earned on the sale of petroleum. Some of this leaves the region in the form of higher payments to non-resident resource owners; this may occur directly as dividend payments or indirectly as an increase in the value of the assets held (e.g., the price of common shares in companies). However, some of the increased value remains in the region as returns to resident owners of the petroleum and as rent collected by the provincial government. If the local economy is operating close to full employment, the immediate increase in local incomes must be translated into higher expenditures on goods and services produced outside the region (that is, imports) or savings (e.g., money held in bank accounts, in banks based in Toronto) and may also be accompanied by local inflation.

The longer-term adjustments are stimulated by two main factors:

First, the increased value of petroleum encourages investment in the oil industry. If the economy is close to full capacity, the oil industry must attract productive inputs from other sources, which is accomplished by increasing the price paid for the input. That is, the wages of the labour needed by the industry will rise, as will the price of specialized inputs such as drilling rigs, steels pipe, etc. These higher prices draw the required inputs to the petroleum industry from three sources: (1) imports from outside the region, including in-migration of workers; (2) the freeing-up of local inputs due to reduced production of other goods and services in the region as a result of the higher costs of hiring labour and purchasing inputs; and (3) absorption of any unemployed local resources, labour, or otherwise. It is often suggested that these effects can be understood somewhat better by dividing the goods and services produced by the economy into two broad classes, the tradable (like petroleum, agricultural goods, steel pipe, lumber, etc, which move easily between regions) and the non-tradable (like land and some personal services, which do not move easily). For tradable goods and services produced by the local economy, the main factor operating is that an increase in production costs reduces production locally because exports fall and/or imports increase (the 'Dutch Adjustment' effect). For non-tradables, the major effect is that an increase in cost reduces the domestic demand for the product.

Second, the way in which the provincial government elects to utilize its share of the increased economic rent from petroleum will affect the nature of the adjustment. The discussion of economic diversification, above, suggested two alternative approaches, although the provincial government is likely to use a mix of both. In an 'active' diversification policy, the government uses its higher revenue to offer support for certain non-petroleum industries in order to maintain their competitiveness. This is typically done to reduce the decline in the non-petroleum tradable good production, and benefits, especially, the producers of those goods; it also shifts some of the adjustment for higher petroleum production onto the other long-term adjustment mechanisms. (These mechanisms include the non-tradable goods and services sector, larger imports of other goods and services, and more in-migration; as discussed above, the latter process is why this use of the higher government revenue is often called a 'province-building' strategy). Alternatively, the government may transfer the funds to local residents, generally through some combination of lower taxes and more public services. These benefit current residents, but also make the region a more appealing place to live, therefore attracting more immigrants.

If there were a one-time rise in petroleum prices, economists suggest that one would expect these long-term adjustments to continue until a new equilibrium is reached. Consider, for example, the in-migration of labour. The primary motivation is an increase in real wages in the region, which will be enhanced by government programs to offer lower tax rates or a higher level of public services than can be found elsewhere in the country. As more workers enter the labour market in the province, the real wage will tend to fall, reducing the incentive to move to the province. The precise path to lower real wages is complicated. New migrants bring their own demands for housing, food, and other goods and services, which puts upward pressure on local prices. The tendency of an increased labour force to put downward pressure on wages – due to diminishing marginal productivity of adding more workers – hinges on inflows of additional capital resources. An equilibrium would be established (the incentive to migrate ceases) where, at the margin, the benefits to a worker of moving into the province (e.g., higher wages, lower taxes, more public services) are just equal to the costs of moving (e.g., dislocation costs of leaving an existing home; higher living costs in the new location; congestion costs in the rapidly growing new location).

We do not explore these factors in any great detail for Alberta but will offer some evidence on two elements. (We must note that the simple graphs we offer, illustrating the relationship between several variables, do not offer the assurance provided by multivariate statistical analysis.)

First, consider population change in the region. Recorded changes in population and migration seem consistent with the theoretical picture we have just drawn. (In the Canadian context, with a particular emphasis on Alberta, Mansell, 1975, and Schweitzer, 1982, are revealing.) One aspect of the model is the supposition that an expansion of the petroleum industry (from either the 'supply' side, through new discoveries, or the 'demand' side through higher prices) stimulates economic expansion, which draws in new people. Figure 13.11 is a visual presentation of the relationship over time between percentage changes in Alberta real GDP and population. The correlation is not perfect, and GDP exhibits much more variability. A part of population change is 'natural,' reflecting the age structure of the resident population, and is relatively independent of GDP changes. Figure 13.11 does not show a clear relation between real GDP growth and population change, apart from the fact that positive growth in production is associated with a rising population; that the percentage change in GDP is generally higher than the percentage change in population reflects, among other factors, increasing productivity of the economy over time. The high rates of increase in GDP after 1973 did see relatively high, and rising, rates of increase in population. And the recession and slowdown of economic growth beginning in 1982 also saw population growth fall.

Net migration data, capturing the actual inflows and outflows of individuals, are only available for years from 1972 on. Figure 13.12, which uses these data, hints at a positive correlation between changes in GDP and migration into Alberta.

Figure 13.13 shows Alberta population changes since 1947 in relation to Alberta per capita GDP relative to the Canadian average. The discussion above suggests that this may be a better measure of one of the main factors that motivates migration, an improvement in the economic return an individual can expect by moving into this region. While the two time series do not exhibit a one-to-one relation, the connection looks somewhat closer than that of Figure 13.11. In particular, there are periods in the 1950s and 1970s in which an increase in Alberta's per capita GDP relative to Canada saw increases in the population growth rate; and the levelling off, and subsequent decline, in Alberta's relative GDP starting in the early 1980s also saw the population growth fall sharply. These broad measures, in other words, are consistent with the economic model we have been describing of the relationships between the petroleum industry and the Alberta economy.

A second characteristic of this model is the suggestion that the impacts of rapid growth in Alberta, occasioned by expansion of the real value of petroleum production, may be particularly pronounced in the prices of non-tradable goods and services. Reflection suggests that the concept of 'non-tradable' is as much conceptual as real, since many immobile goods and services have mobile components. Thus, while land does not move, many of the things that give value to real estate are tradable (e.g., buildings and other

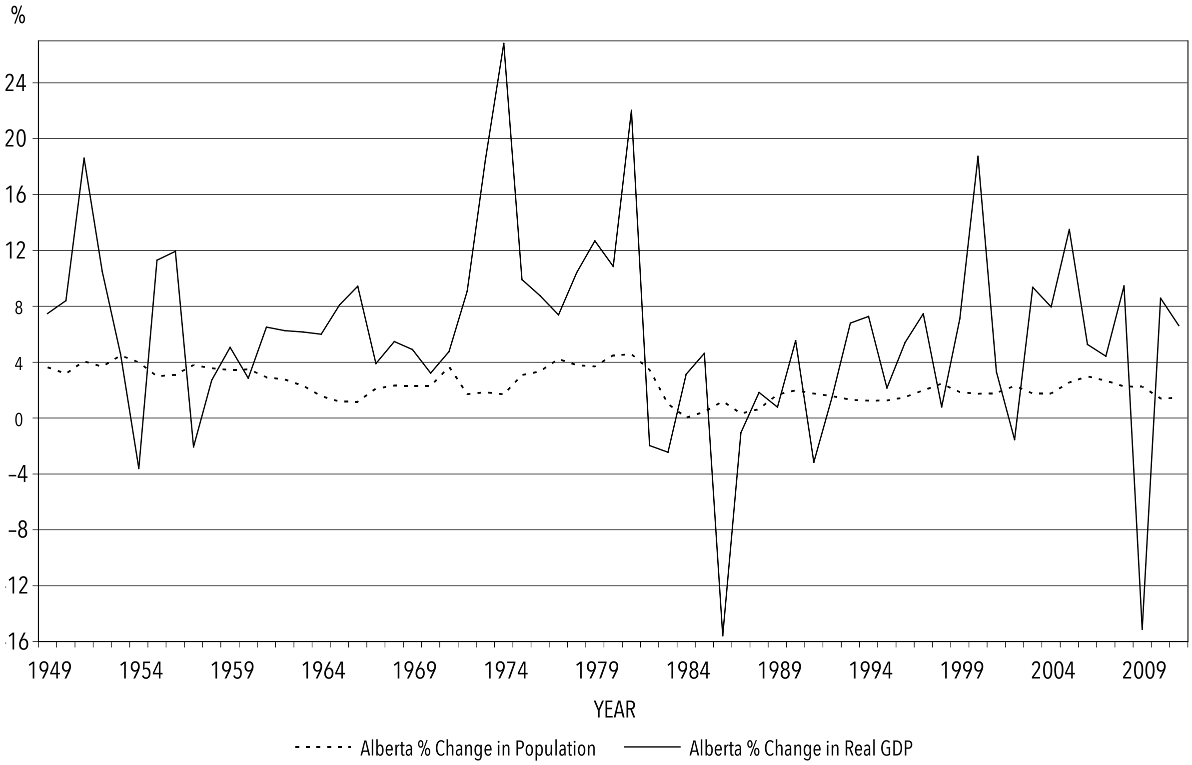

Figure 13.11 Alberta % Changes in Population and Real GDP, 1949–2011

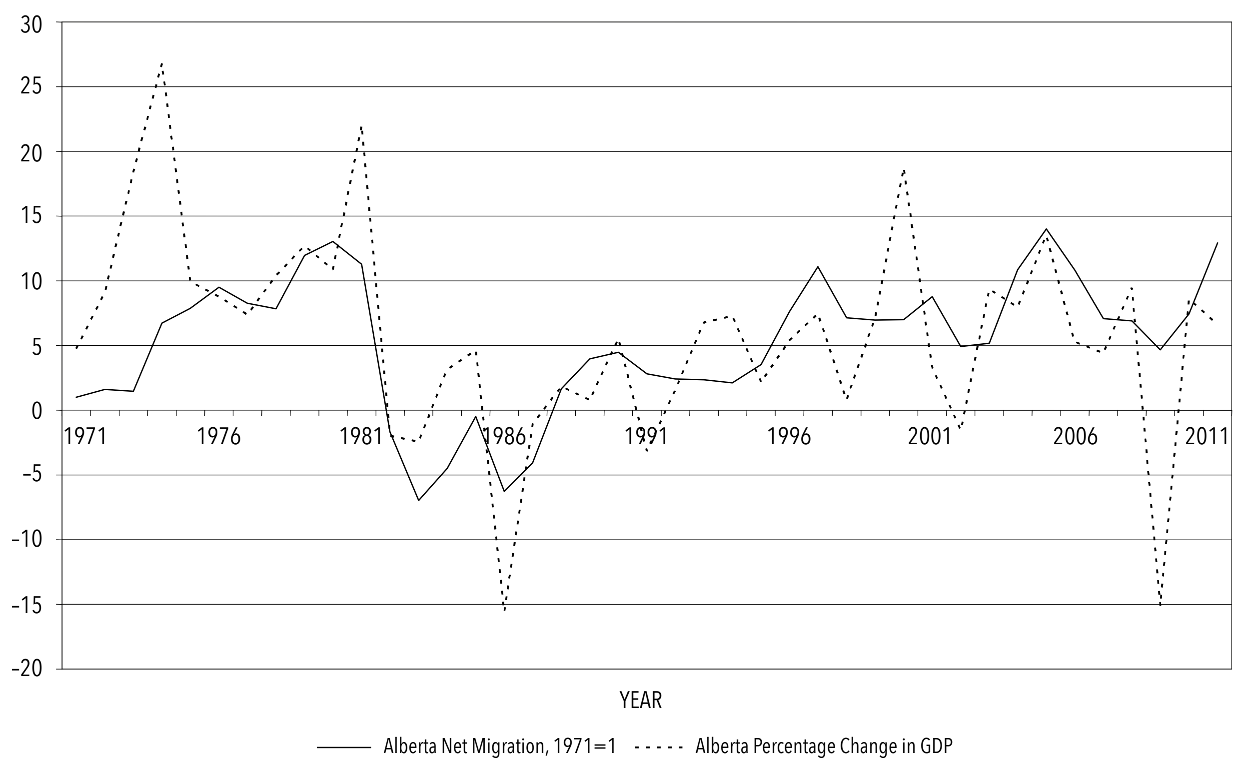

Figure 13.12 GDP Change and Net Migration, 1971–2011

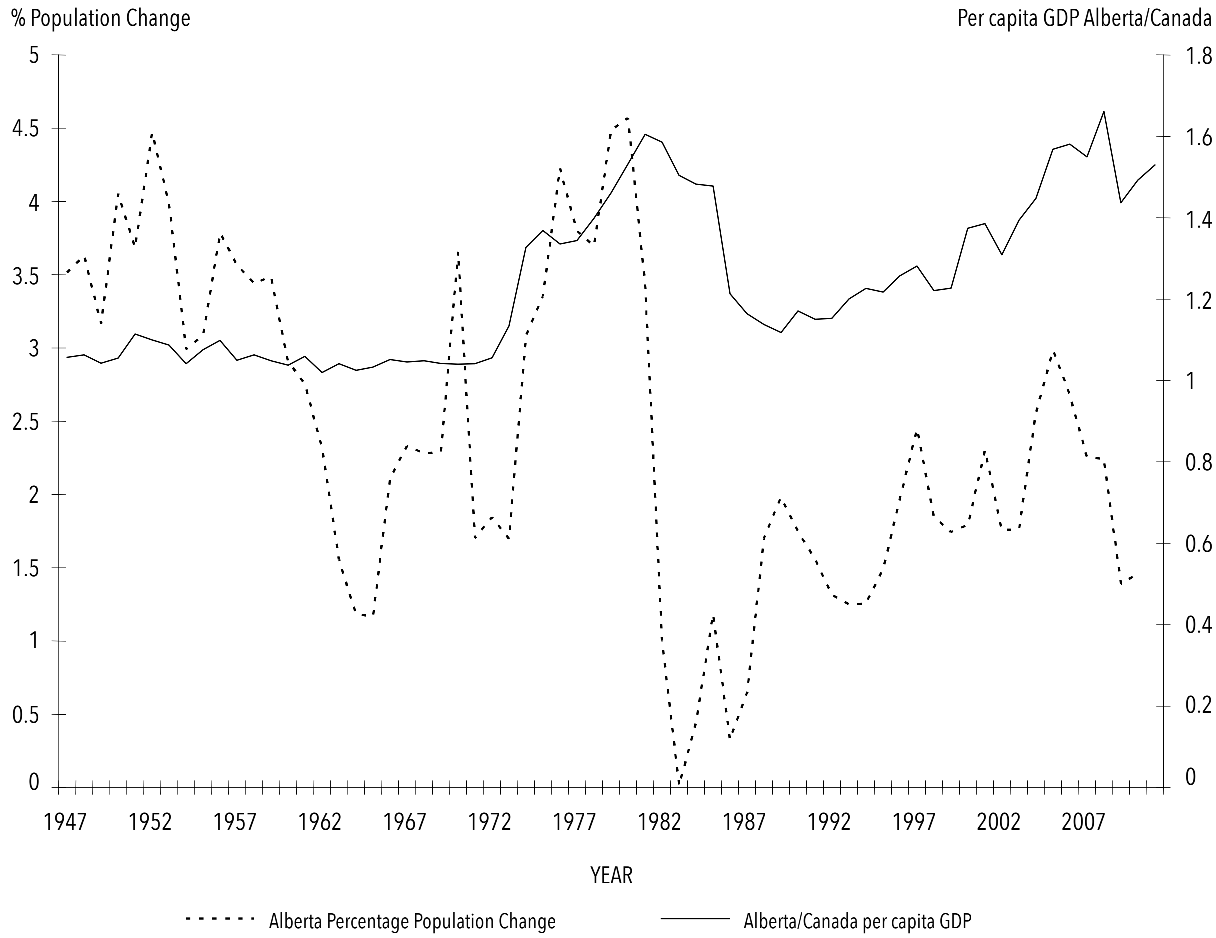

Figure 13.13 Alberta Population Change and per capita GDP, 1947–2011

capital improvements). Similarly, many social and community services are strongly location-dependent, and so not readily tradable across distances, but also draw upon labour and materials that are mobile. In this context, the main non-tradable may be intangibles, such as a sense of belonging and supportive social interaction, which may become scarcer in an environment of rapid growth. On the other hand, recent research, by Richard Florida (2005) suggests that a region's economic vitality is closely connected to its social and cultural diversity, which are likely to increase as the region grows and attracts a greater variety of individuals. One of the readily accessible possible measures of trends in the value of non-tradable goods and services is real estate values. Here the comparison with Saskatchewan may be revealing. In 1947, house prices in Calgary and Edmonton were not much different from those in Regina and Saskatoon. After that, average house prices rose somewhat faster in Alberta than in Saskatchewan, especially after 1973. For April 2004, the Canadian Real Estate Association web site reported the following average housing prices: Regina, $110,593; Saskatoon, $135,550; Edmonton, $178,777; and Calgary, $220,245. The average for the two Alberta cities was over 60 per cent higher than for the two cities from Saskatchewan. (It is not clear whether these values control adequately for differences in the characteristics of houses. It should also be said that, at that time, average housing prices in Victoria, Vancouver, and Toronto were much higher than in Calgary. By the time of final revision, in April 2013, the gap between the Alberta and Saskatchewan cities had narrowed to 29 per cent, reflecting in part the rapid economic growth in Saskatchewan after 2008.)

In conclusion, the development of the petroleum industry in Alberta led to economic growth in the province. It is hardly surprising that rapid expansion of the volume of oil and natural gas produced during the two decades from 1947 brought an increase as well in the population of the province to support higher activity. However, this occurred even after 1973 when the main reason for the GDP growth was not increases in the volume of petroleum produced but higher real prices for crude oil and natural gas. There were strong forces in place that ensured that the higher values of petroleum did not simply translate into higher average incomes in the province. Two of these equalizing forces were immigration into Alberta and inflation in local prices, especially for goods not easily traded.

F. Government Revenues and Expenditures

As earlier chapters demonstrated, the petroleum industry has proven to be the major source of revenue to the provincial government, providing in some years close to 50 per cent of the total annual government expenditures. This has raised several important policy issues, some of which we have touched on in other parts of this chapter.

How should the petroleum revenues be allocated across various possible uses? Earlier, we spoke of the basic distinction between using the funds to support various industries in the hope of gaining economic diversification and using money in a more general way to benefit citizens of the province. Examples include the provision of a greater level of government-produced goods and services (education, health, roads, parks, etc.) and reducing taxes. In the 1990s, one of the priorities of the Alberta provincial government became reducing the provincial debt; this would reduce future debt interest costs and therefore allow higher government spending or lower taxes in the future. Another possibility was for the government to save the money; this was the purpose of the Alberta Heritage Trust Saving Fund, which will be discussed in the next, and last, section of this chapter.

How does the fact that conventional petroleum is an exhaustible natural resource affect the government's utilization of petroleum revenues? (We would remind the reader that the notion of petroleum as an exhaustible resource is not as straightforward as many assume, since we do not know for certain the total amount of petroleum physically available in a region, and the amount that will ultimately be produced is constrained not so much by the physical availability as by economics and technology.) As mentioned in the section above dealing with economic diversification, this concern about depletion of petroleum was one of the reasons that diversification of the provincial economy was assumed to be desirable. The issue at hand can be expressed in somewhat different terms. The government revenue derived from petroleum can be seen as current income received by depleting the petroleum asset. This raises the question of how much of the income should be used up on current consumption and how much of it should be saved to 'replace' (in an economic sense) the depleting petroleum. We will return to this question in the next section.

Since the provincial government's petroleum revenues are unstable, how can the government accommodate this instability in its public finances? The instability in revenues reflects, in part, the variability of bonus bids, which fluctuate with the anticipated profitability of the mineral rights for sale in that year. It also mirrors the instability in oil and gas prices, which has been evident since 1972; conventional oil and natural gas are assessed royalties based directly on the price of the product, and the net profits of oil sands output, on which oil sands and bitumen royalties are based, depend heavily on the oil price as well. Table 11.2 in Chapter Eleven clearly shows the fluctuations in the revenue the Alberta government has derived from the petroleum industry. Bonus bids, for example, over the fiscal years from 1979/80 through 2011/12 varied from over $3.5 billion (2005/6) to as low as $167 million (1992/3). The 2002 Alberta Financial Management Commission of July 2002 reported that (p. 23): "Since 1981/82, annual non-renewable resource revenues have ranged from a low of $1.9 billion to a high of $10.6 billion.… As a share of the province's total annual revenues over the past ten years, resource revenues have varied from a low of 14% of total revenues (in 1998/99) to a high of 41% of total revenues (in 2000/01)."

Fluctuating receipts by the government from the oil industry pose obvious difficulties for the budget process. (For detailed discussion with respect to Alberta, see the papers in Bruce et al., 1997; also Emery, 2006, and Emery and Kneebone, 2009.) Part of the difficulty is in forecasting future revenues and expenditures in order to engage in the responsible determination of expenditure and tax programs. Possible 'irrationalities' in the public decision-making process may exacerbate the problem. Thus, decision-makers may be prone to an 'optimism' bias, in which favourable conditions, such as unusually high petroleum revenues, are expected to continue. Lobbying efforts by special interest groups for new expenditures may be particularly successful in years in which petroleum revenues are unusually high but would generate continuing expenditure commitments. Some public policy analysts have suggested that governments tend to exhibit a 'spending bias,' since the larger the government, the greater the power and prestige of the legislators and bureaucrats. Larger revenues in a particular year, even if not expected to continue, may draw forth increased spending, simply because the money is there. This tendency may be greater just prior to an election!

Instability in petroleum revenues became an even more pressing issue after the Alberta government adopted a balanced budget requirement in the early 1990s. (This commitment is currently housed in the 2009 *Fiscal Responsibility Act* (RSA 15-1, Section 2. The 2013/14 provincial budget proposed a new *Fiscal Management Act* which had not been passed at the time of final editing of this book.) We will not engage in a detailed assessment of the wisdom of such a policy. In brief, the proponents argued that it provided protection against the tendencies of the government to be more willing to increase expenditures than to control expenses and/or increase taxes, thereby leading to perpetual annual deficits. Opponents suggested that the government was giving up its responsibilities for fiscal stabilization policy. Requiring a balanced budget would be countercyclical, since the government would have to reduce its expenditures or raise taxes when economic conditions were bad and the economy needed stimulation. The government was also said to be sacrificing flexibility in its operations and failing to recognize that borrowing is an entirely fair and reasonable way to finance capital investments; since the services of the capital accrue over time, so should payments for capital assets.

In part, a government can attempt to manage fluctuating petroleum revenues through careful longer-term forecasting, rather than basing programs solely on current revenue flows. However, much of the instability in oil and gas prices is impossible to forecast with any degree of accuracy. The key would thus seem to lie in basing the fiscal program on reasonable expectations of average petroleum values over a number of years and introducing some offsetting flexibility in other parts of the revenue or expenditure stream. Since government revenue is generally collected under relatively fixed regulations and virtually all tax sources are subject to their own variability, the required flexibility is more likely to come from the expenditure side of the government's operations. In Alberta, three main avenues of expenditure flexibility have been proposed. One is to make greater use of the Alberta Heritage Savings Trust Fund for revenue stabilization purposes. (See the next section.) The second, which has played a major role, is to use the government's commitment to debt reduction as the major avenue for responding to fluctuating provincial revenues; given various other program-spending commitments, the debt could be paid down more or less rapidly depending on the vagaries of government revenues. By March 2005, the provincial debt (with no allowance for the Heritage Fund assets of over $11 billion) had been reduced to about $3.5 billion, from some $23 billion in 1993. In that year, the government set up a Debt Retirement Account to pay off the remaining debt as it matured; the final payment was made on March 1, 2013. However, the March 2013/14 budget included new borrowing; this budget established a formal distinction between a balanced operating budget and a capital budget, which might rely on borrowing with a clear schedule of repayment.

In the 2003 Alberta provincial budget, a third way of handling instability in petroleum revenues was adopted. This followed the July 2002 report, *Moving from Good to Great*, of the Alberta Financial Management Commission, under the Chairmanship of David Tuer. The commission had been formed in March 2002 with "a broad mandate to explore the province's finances and recommend possible improvements" (p. 14). The 2002 Commission was the second such commission.

The previous commission had reported in 1993, in response to persistent provincial government deficits. This set in motion a major re-evaluation of the Alberta government's fiscal policy, which included a variety of new accounting/accountability measures. The changes also tied into the new policy approach mentioned earlier, which came to be labelled the "Alberta Advantage"; it legislated balanced budgets, lower taxes, debt repayment, and reduced government spending. We are concerned only with the parts of this program that relate to resource revenues. The main provisions related to unstable provincial revenues included the adoption of a three-year budget-planning period, conservative revenue forecasting, and the requirement to set aside, in each budget, an 'economic cushion' of 3.5 per cent of the projected budget revenue. Such a cushion would provide some protection against unexpected revenue shortfalls, as well as leaving a source of funds for unexpectedly high expenditures and emergencies. (For general discussions of the provincial budgeting process, see Bruce et al., 1997, and Kneebone and McKenzie, 1999.)

The Tuer Commission on Alberta Financial Management noted (p. 21) that "the province, like all other natural resource owners had consistently had difficulty accurately forecasting resource revenues. Between 1993 and 2001, the government underestimated resource revenues by a total of close to $12 billion, or an average of almost $1.5 billion a year." (A significant part of this, some $4 billion, came in the 2000–2001 fiscal year.) Underestimation may partly reflect a deliberate 'defensive' budget policy of conservative forecasting, but it seems fair to argue that persistent *underestimation* of resource revenues cannot be solely due to *instability* in the revenues. Moreover, persistent errors must either make government budgeting less than optimally efficient or suit some other political purpose. (The Tuer Commission notes [p. 21] the perception among some Albertans that it served to rationalize lower spending on a variety of social programs.)

The Tuer Commission made an extensive set of recommendations, which relied heavily on changes in the role of the Heritage Trust Savings Fund and which will be reviewed in the next section. One significant change, consistent with the Commission's suggestions, was implemented in the 2003/4 provincial budget. A total of $3.5 billion of non-renewable resource revenue was to enter into the province's general revenue. Any revenue above $3.5 billion would go into a new 'Sustainability Fund,' to be drawn on in later years if resource revenues fell below $3.5 billion. The Sustainability Fund would be allowed to build up to a size of $2.5 billion, after which potential additional contributions might be diverted to a number of specific uses such as debt repayment or disaster relief (but not to general government operating expenses). This measure clearly addressed very directly the problem of unstable resource revenues. In its budgets after 2003, the government increased the amount of non-renewable resource revenue that would go into the operating budget above the $3.5 billion ceiling.

In subsequent years, despite transfers for disaster relief and to other capital funds, the Sustainability Fund grew in size, reaching almost $7.7 billion by September 2007, as a third provincial commission was looking at the government's finances. (By this year, the amount of non-renewable resource revenue applied to general government expenses had risen to $5.3 billion, with the excess going to the Sustainability Fund or other capital funds or capital projects. In 2008, non-renewable resource revenue in excess of about $6.6 billion would go to the Sustainability Fund.) *Preserving Prosperity: Challenging Alberta to Save* was the title of the December 2007 report from the Alberta Financial Investment and Planning Advisory Commission (under the chairmanship of Jack Mintz). The Mintz Commission recommended maintenance of the Sustainability Fund but with a cap of $3.5 billion (in real dollars), which it judged large enough to meet its stabilization objectives; the excess capital in the fund should be transferred to the Heritage Fund (Alberta Financial Investment and Planning Advisory Commission, p. 41). The Commission argued that the objectives of the Sustainability Fund were too broad and undefined, including, as well as provincial government budget stabilization, vague goals related to natural gas price subsidization for Albertans, and meeting the costs of disasters and settlement of aboriginal land claims; the Commission recommended that such subsidiary objectives be dropped.

As of the time of final revision to this chapter (spring 2013) these recommendations had not been acted on. The Sustainability Fund stood at $2.7 billion at the end of the 2012/13 fiscal year; it had been drawn on in the years 2008–13 to offset government deficits. (In 2009, the 'Capital Account,' also established in 2003, had been rolled into the Sustainability Fund.) In its 2013/14 budget, the government forecast that by March 2014, the value of the sustainability fund would be less than $700 million but would increase again after that in the form of a new 'Contingency Account' with a maximum value of $5 billion.

G. The Heritage Fund and Preserving the Income from Depleting Capital Assets

As this chapter has implied, the petroleum industry makes two quite different contributions to an economy. First, production requires factors of production (labour, capital, supplies, and management skills). Second, a resource like petroleum generates economic rent, a surplus of revenue above production costs, which can be used to the benefit of people in the region. These two contributions raise rather different economic issues, which the local government must somehow reconcile.

With respect to the first issue, production of petroleum normally involves economic growth, with both an expansion in population and in real per capita incomes in the region. The rate of expansion is determined in large part by factors outside the control of the regional government (demand for oil and natural gas, world prices, technological changes). However, as discussed in various chapters in this book, domestic government policies also affect the levels of industry activity and production. There is often pressure to think that 'more is better': a larger provincial economy has more influence at the national level; growth allows realization of agglomeration effects and economies of scale, which bring lower costs and greater self-reliance; growth brings a more vibrant and diverse community; growth is necessary to maintain the demand (especially the investment demand) needed to sustain full employment. Against this, however, one must balance the costs of growth, such as personal adjustment costs, congestion effects, higher local inflation, and environmental degradation. Finding an optimal balance is a chimera, especially since a number of the benefits and costs are difficult to measure accurately and because many of the forces affecting the level of petroleum industry activity are outside the control of the provincial government. In the Alberta context, the rate of development of the industry has been affected by such 'market forces.'

The second issue involves an array of factors. One is the efficiency with which the provincial government collects economic rent. The main focus of provincial government policy has been on devising rent-collection mechanisms that transfer a significant share of economic rent to the government while having minimal impact on the behaviour of the petroleum industry. A second component of this issue is that of the 'use' to which economic rents might be put. As discussed in this chapter, this is not transparent, most fundamentally because it is not entirely clear who the beneficiaries of the economic rent should be. At its most extreme, we suggested that one might take a 'descendants' view (the prime beneficiaries should be the 'initial' residents, e.g., Albertans as of 1947 and their families), or a 'successors' view (the prime beneficiaries should be whomever happens to reside in the province). From a political perspective, the reality probably reflects a combination of the two: at any point in time, the government is largely concerned with the interests of current residents (a descendants perspective), but as time passes the population of the province changes, so the government's constituency changes (a successors perspective). However, the absence of any pronounced policies to control the level of petroleum production to one that could be handled largely by the current population implies that policies have been largely 'successor'-based. We would argue that the 'successor' view is the more desirable one in a world in which resources must be flexible to exploit the most efficient economic opportunities and when one values the ability of individuals to make choices freely (including the choice of where to live). As we suggested earlier in this book, at the theoretical level, one of the strongest arguments for a more 'descendant'-based perspective is for a region heavily dependent upon exhaustible resource production, where a clear rising-then-falling life cycle of production is anticipated and there are minimal prospects for other types of economic activity; in this case, policies might favour current residents (and their descendants) rather than others who would be expected to migrate in for a while and then depart again.

Some analysts have suggested that one might provide a better framework for consideration of these complex and controversial issues if petroleum were explicitly seen as a regional asset, as part of the region's wealth. Higher wealth allows higher consumption, but it is not desirable to consume all the wealth in a single year. There are clear analogies to the prevailing neoclassical economic model of an individual's consumption. An individual's life style is predicated on prevailing income (from all sources) and the yet-to-be-realized return on various assets the individual owns or will own. A 'rational' individual would base consumption, not on the maximum possible expenditures in the current period (attainable by liquidating all assets now), but on a life-time consumption-savings plan. If the individual focussed solely on his/her own self, this would mean that assets are liquidated gradually over time, until they disappear when the individual dies. This simple model is not strictly accurate, partly because many individuals have 'self-control' problems that lead them to consume more in the present period than is optimal. In addition, we would not expect people to run their assets down to exactly zero at their deaths. For one thing, at the time of death, there is invariably some probability that the individual might have lived longer, so some assets would still be maintained. More importantly, most individuals also exhibit a 'bequest motivation,' to pass assets on to their heirs. If an individual gives just as much weight to his family and other heirs as to his own wants, then the individual would be inclined to maintain his wealth relatively constant, even at death. This situation is similar to that of a government concerned with the well-being of its citizens through the indefinite future.

This conceptual approach suggests that, as petroleum is produced, the 'income' could be used for current consumption purposes, but the 'principal' or asset value should be saved. In this manner, depletable oil and gas will be transformed into other lasting assets that yield a return over time. (Habib, 2009, provides an interesting perspective on the ethical dimensions of spreading natural resource values across generations.)

There are numerous problems in actually implementing such a policy. To begin with, since the petroleum resource base is not known with accuracy, and since oil and gas prices are constantly changing, the 'true' value of the petroleum asset can never really be known. One might take the 'user cost' of petroleum production as an approximation of the asset value. (See Chapter Four. The user cost is the present value of the future profits given up by lifting a unit of petroleum today, instead of leaving it in the ground, and is therefore a measure of the reduction in the value of the resource due to current production.) However, the user cost cannot be easily measured. There is also the difficulty in building up an alternative capital stock, which could take many forms: industrial diversification in the region; infrastructure in the region; human capital (training, health, and education) in the region; private saving by residents of the region; investments, either direct or indirect, outside the region. Presumably funds should be allocated in such a way that the (risk-adjusted) marginal rate of return is equal in all such uses. This is no easy task!

The literature in 'political economy' also touches on this issue. In particular, there may be a lack of long-term perspective and financial responsibility on the part of governments with a particular interest in shorter-term (electoral) popularity. Politicians may find it hard to resist the temptation to spend unexpectedly large revenue inflows immediately, although prudence would suggest restraint and retaining some revenues for future times when the inflow of funds is reduced. A savings plan might reduce these temptations to spend more when revenues surge.

It is clear that the uses to which Alberta has put its petroleum revenues have aspects of both current consumption and saving, but one particular use ties directly to investment. In 1976, the province created the Alberta Heritage Savings Trust Fund, which was designed with four objectives in mind (Alberta Financial Management Commission [Tuer Commission], 2002, p. 27):

- To function as a savings account that would offset declining resource revenue in the future;
- To provide additional leveraging opportunities for the government, reducing the province's future debt load;
- To improve quality of life for Albertans; and
- To facilitate stability in the economy by providing a fund that could help diversify the economic activity of the province.

Alberta was not the only petroleum-producing region to create such a fund. Davis et al. (2001), with the International Monetary Fund, have studied some such funds, although not Alberta's. They suggest that governments have set up the funds for two somewhat different purposes: savings funds and stabilization funds. The Heritage Fund is an example of the former. (The Stabilization Fund that Alberta created in 2003, discussed above, is an example of the latter.) Davis et al. are not strongly impressed by the conceptual arguments for establishing these funds. They view them as necessary primarily to offset the faulty decision-making of governments who otherwise would fail to handle natural-resource revenues correctly; but if governments would make bad decisions without these funds, they must surely expect that governments, who have sovereign power, would also utilize the funds badly! Davis et al. admit that some countries have made good use of natural-resource funds. Both Norway and Alaska are often seen as examples. In Alaska, for instance, the government has ensured that the fund receives petroleum revenues on an established basis, regulations regarding investment of the funds are carefully set out, part of receipts are reinvested in the fund to maintain its real value in the face of inflation, and the main use of the remaining return on the fund is rebates to Alaska citizens rather than to the state government (Anderson, 2002). Warrack and Keddie (2000) compare the Alaska and Alberta funds.

The Alberta Heritage Fund commenced operations in fiscal year 1976/77, with a contribution from petroleum revenues of $2.1 billion. Thirty per cent of the province's non-renewable resource revenues were to go into the fund. (These values are drawn from p. 13 in the Alberta Heritage Trust Fund 2003 *Annual Report*. A 1980 special issue of *Canadian Public Policy* investigated the Heritage Fund. See Collins, 1980.) Contributions out of petroleum resource payments to the Alberta government continued, at lower levels, for another decade; in the early 1980s, the government reduced the share of resource revenues going into the fund to 15 per cent. A final contribution of $216 million was made in 1986/87. With falling oil prices in 1986, the government decided that all petroleum revenues would go into general government revenues. In all, in this first decade, a total of just over $12 billion built up in the Heritage Fund. Beginning in mid-1982, the government withdrew, into general government revenues, virtually all the net income earned by the fund. (Until that date, earnings were retained, increasing the value of the fund.) This meant that, from 1984 and for over two decades, the size of the fund was stable at about $12 billion. Only in 2005 did the province begin to contribute to the fund once again. (In that year, the government also contributed a special $1 billion to the fund in an 'Access to the Future' account meant to finance advanced education investments.) The 2002/3, 2007/8, and 2008/9 fiscal years were the only ones in which the fund earned a negative return, as did most North American investment funds. As of December 31, 2012, the value of the fund was $16.4 billion, down from its peak of about $17 billion in spring 2008.

The general investment objectives of the fund have changed over its life, consistent with the change noted above in Alberta's industrial policy. Initially, a prime purpose of the fund was to aid actively in the economic diversification of the Alberta economy. This could be done by direct funding of key infrastructure projects in the province and by giving priority to loans to Alberta entrepreneurs for promising projects. The latter mandate probably reflected a presumption that Canadian capital markets focussed on central Canada and discriminated unfairly against projects in the periphery. From 1976 through 1995, the fund spent a total of $3.5 billion on direct capital investments. From its inception, the Heritage Fund maintained a general investment portfolio with a broad mix of investments, including loans to other provinces. (In the politically charged regulatory environment of the late 1970s and early 1980s, when the federal government constrained Alberta's oil and gas prices, and Alberta was arguing for higher prices, such loans may have been one way of persuading other provinces that their interests were allied to some extent with Alberta's. Mumey and Ostermann, 1990, and Smith, 1991, provide assessments of the investment strategies of the Heritage Fund.)

As we discussed above, Alberta government policy changed in the 1990s from an active diversification strategy to a more neutral emphasis on the 'Alberta Advantage.' Consistent with this, a revision of the *Alberta Heritage Savings Trust Fund Act* became effective at the start of 1997. Under this act, the objective of the Heritage Fund is "to provide prudent stewardship of the savings from Alberta's non-renewable resources by providing the greatest financial returns on those savings for current and future generations of Albertans." This clearly establishes the fund's role as an investment fund, rather than an economic diversification fund.

The government's strong commitment to the Heritage Fund was in the period of high oil and gas prices from the late 1970s through to the mid-1980s. For the next two decades, its value was pretty well constant in nominal dollars, so its real value fell. (In contrast, the Alaska Fund is designed to reinvest part of its earnings, in order to retain its real value, before any payouts are made to Alaska citizens.) During its establishment period, the government appears to have felt that an activist policy was needed to help preserve the 'asset' value of Alberta's petroleum. In part, this reflected the perceived necessity of a government-led, and active, diversification policy. It may have also reflected some mistrust in more neutral investment and savings procedures. For example, the government is always under political pressure to spend public funds on current projects, and a commitment to spin some revenue off to a special fund may reduce this. It has also been argued that private decision-makers may be excessively myopic and save less of any income gains than is socially desirable, so a government 'forced savings' plan like the Heritage Fund is preferable to transferring the money to the private sector.

The more passive role for the Heritage Fund after 1995 cannot be taken as evidence that the government has lost interest in an objective of maintaining capital assets in the province as petroleum resources are run down. In fact, the government argues that the 'Alberta Advantage' is designed to make Alberta unusually attractive for new private-sector investment. Instead, the policy change with respect to the Heritage Fund reflects a change in policy: a much greater trust in the efficiency of relatively unregulated markets and a greater disbelief in the necessity for government programs to offset inefficiencies or inequities in market outcomes. From this perspective, the surprising fact is not that the government has chosen to treat the Heritage Fund in a relatively passive manner, letting its value decline through the effects of inflation. It is that the fund has been retained at all: for example, running down the fund over a period of years would permit even lower tax rates and could have been employed for debt reduction, increasing the 'Alberta Advantage.' Maintenance of the fund during this period seems to be due less to a commitment to the principles of such a fund and more to the fact that numerous opinion polls demonstrated that a majority of Albertans want to see the Heritage Fund maintained.

In April 2002, the government released *The Savings Question: A Discussion Paper*, which suggested that most analysts see a desirable role for a special government savings plan when non-renewable resources are a major source of government revenue.

A number of possible uses of the savings that were mentioned included more activist project funding and more passive debt repayment and tax reduction possibilities. None of these were specifically endorsed.

The July 2002 *Report* of the Alberta Financial Management (Tuer) Commission recommended (p. 51):

1. The Alberta Heritage Savings Trust Fund should be retained, strengthened, allowed to grow, and renamed the "Alberta Heritage Fund" with four new purposes:

    - To stabilize the impact of volatile resource revenues on the province's budget;
    - To manage the orderly pay down of existing debt as it comes due;
    - To address the backlog of deferred capital projects in the short term; and
    - To serve as transition to the time when resource revenues decline and as an integral part of the province's strategy for achieving a sustainable economic vision for the future.

2. To provide stable and predictable funding, the Commission recommends that all non-renewable resource revenues should go into the renewed Alberta Heritage Fund on an annual basis. All year end surpluses should also go into the Heritage Fund. A fixed and sustainable amount of resource revenues should be drawn out each year to support the government's budget.

With respect to the part of resource revenues that would be drawn into the general government budget each year, the Commission recommended that: "This fixed amount should be set at a conservative and sustainable level. We recommend the lesser of $3.5 billion (the historical average over the past 20 years excluding the spike in revenues in 2000–2001) or the average of resource revenues for the previous three years." We would note that if several exceptionally good years occurred close together (like 2000–2001 and 2002–2003 or 2005–2008), there could be a significant difference between these two approaches. The Commission expected (p. 53) that the Heritage Fund might, under this policy, more than double its current value by the year 2025. These recommendations would, as the Commission notes, mean a complete change in the role of the Heritage Fund, which would become a key player in the province's finances, and the mechanism through which all petroleum revenues received by the government are managed. The government did not adopt these recommendations, and the Alberta Heritage Trust Savings Fund continued to operate as it had over the past fifteen years, as a relatively passive investment fund with a fixed size of about $12 billion.

Beginning in the 2005/2006 fiscal year, the province began (under the *Alberta Heritage Savings Trust Fund Act*) to reinvest a portion of the fund's annual earnings (or transferred funds from the Sustainability Fund) to offset annual inflation (*Alberta Heritage Savings Trust Fund*, 2008, p. 319). (From 1996 on, there had been some partial compensation for inflation.) In addition, in the years 2006/7 and 2007/8, the provincial government made additional transfers into the fund as petroleum revenues substantially exceeded forecast amounts due to higher than anticipated prices.

The role of the Heritage Trust Savings Fund was a major concern of the Mintz Commission in its December 2007 report. The Commission noted that if one compared the change in the provincial government's net financial position with its resource revenues, just over 30 per cent of resource revenues had been saved on average each year from 1994 to 2007 (Alberta Financial Investment and Planning Commission, 2007, pp. 26–27). Much of this saving came in the form of reductions to the province's debt, with relatively little coming in the form of the increases in the size of the Heritage Fund after 2004. The Commission suggested that the province was saving too little and doing so in an unsatisfactory '*ad hoc*' manner (p. 31). The report, in a 'province-building' framework, argued (p. 3) that government saving was important:

> The government's financial investment and planning policies are extremely important to the long-term stability and growth of the Alberta economy. To put it in clear terms, Alberta's non-renewable resources should provide significant benefits not just to Albertans today, but also for our children and grandchildren. When Alberta sells its resources, it has given up wealth that can either be spent today or saved for the future. When our stock of non-renewable resources dwindles, Alberta's economy will need to rely only on its people – not its natural resources – to create wealth. The government itself will have to rely on investment income from the financial

assets that it has accumulated and taxes paid by future Albertans to fund essential public services needed by a growing and aging population. Alberta should not look like a ghost town in the next century when the resources are depleted. Instead, Albertans want to have a dynamic economy attracting people from around the world to enjoy Alberta's advantages long after the resources are used up. For those reasons, our Commission is proposing a new approach to savings. The approach is designed to simplify the current approach, to make savings a clear and deliberate objective with tangible targets, to provide the necessary fiscal discipline, and to encourage proper stewardship of Alberta's savings to maximize the benefits to Albertans. It is intended to capture Albertans' interest and attention, to renew their commitment to savings, and to hold the government accountable.

The Commission examined Alberta's long-run fiscal position and recommended that the provincial government undertake an active and large savings program, preferring this to an approach that paid 'dividends' to Alberta citizens and let them decide how much to save individually. (Reduced taxes to 'give away' any government revenue surpluses would be equivalent to such a dividend.) The Mintz Commission (agreeing with the Tuer Commission) recommended that the 'Alberta Heritage Savings Trust Fund' be replaced by a reconstituted 'Alberta Heritage Fund.' The Heritage Fund would incorporate most existing government savings programs and would be increased in size annually, to a total of $100 billion by the year 2030. (As discussed above, the Commission recommended continuation of the Stabilization Fund, but with a ceiling size of $3.5 billion, indexed for inflation, solely for the purpose of stabilizing the government budget as fluctuating revenues might require. A 'Heritage Capital Fund' would also exist separately.) To attain this target, the Commission recommended that the government commit to set aside a fixed proportion of revenues each year for the Heritage Fund (pp. 33–34), to contribute at least 75 per cent of any budget surpluses (after topping up the Sustainability Fund, if needed) to the Heritage Fund (p. 40) and to draw on only 4.5 per cent of the value of the Heritage Fund each year for the government's budget (p. 37).

As of April 2013, the government had not acted on these recommendations but the 2013/14 budget incorporated several proposals with respect to the Heritage Fund. Firstly, starting in fiscal 2014/15, a higher share of the fund's earnings would be retained and reinvested, with 100 per cent of earnings retained by the 2016/17 fiscal year. Secondly, again commencing with fiscal year 2014/15, regular contributions to the fund would be made out of non-renewable resource revenues; the amount of investment would start at 5 per cent of the government's resource revenues up to $10 billion in revenue, then 25 per cent of the next $5 billion and 50 per cent of any resource revenues over $15 billion.

4. Conclusion

The economic development of the Alberta economy since 1947 is intimately tied to the development of the petroleum industry. Many economists see this connection from an 'export base' or 'staples' point of view. The external demands for petroleum products are an essential force driving the process of economic growth, while the form that growth takes is affected by the backward and forward linkages of the petroleum industry. The petroleum industry can be seen as affecting the local economy through three mechanisms, which operate jointly: changes in the volume of production; changes in the real value of the products; and increased productivity. The precise dependence of the economy on a specific industry is difficult to measure. Other export industries may have initially developed based on the demands of an export-base industry, and the viability of industries producing largely for the local market may hinge on the growth in demand stimulated by the export-base industry.

Starting in 1947, for the next two decades or so, the levels of petroleum output (crude oil and natural gas) increased dramatically, while prices were relatively stable. This attracted new productive inputs to the economy and reduced Alberta's dependence on agriculture. Gross production in Alberta grew more rapidly than the Canadian average, as did employment and the population. Per capita income also rose, but, over much of the period to the early 1970s, remained quite close to the Canadian average. Alberta depended heavily upon two export industries, petroleum and agriculture.

Beginning in the early 1970s, the real prices of oil and natural gas began to rise dramatically, spurring increased economic growth through to the early 1980s. The higher real value of petroleum increased the relative share of the petroleum industry in the Alberta economy (which some saw as reduced economic diversification); migration into Alberta increased, and the prices of local goods and services were put under upward pressure; even with the in-migration, per capita Alberta incomes rose above the Canadian average. However, oil prices began to soften in the world market after 1981 and then fell dramatically, ushering a period of relative income stagnation in Alberta. Unemployment rose, population growth slowed, and Alberta GDP per capita fell close to the Canadian average. The relative contribution of the petroleum industry to the Alberta economy fell.

Starting in 1993, Alberta population and GDP, in total and per capita relative to the Canadian average, began to increase once again, although still fluctuating as the prices of oil and natural gas changed. There is a feeling that the dependence of the economy on the petroleum industry has lessened somewhat, reflecting such factors as new export industries, import substitution, and agglomeration effects. There has been increased production by sectors of the economy other than the petroleum industry, including manufacturing and a variety of services, such as information technologies and petroleum service companies that sell to customers outside the province. In addition, as the population has grown from barely 800,000 in 1947 to almost 3.9 million by 2013, agglomeration effects and economies of scale have been easier to realize, allowing more varied industrial production for both domestic and export customers.

At the level of economic policy, the desirability of economic diversification has been a persistent focus of attention. On the whole, the process of economic growth has been what naturally occurred in response to market forces. Especially in the later 1970s and early 1980s, the provincial government used some of the resources it gained from the high prices of crude oil and natural gas to actively encourage expansion of new industries, concentrating on those like petrochemicals that further processed crude petroleum. Beginning in the later 1980s, and up to the present, the government's approach has been more neutral, emphasizing lower taxes and the high quality local infrastructure. As mentioned in the previous paragraph, most analysts think that the economy has gained a greater degree of diversification and stability over the past decade. It is important to note that the Alberta economy is still highly dependent on oil and gas prices. And high oil prices are essential to the growing oil sands and heavy oil industry, which provide an increasing share of Alberta's liquid hydrocarbons as conventional production declines. Indeed, by 2002 oil sands output exceeded that from conventional sources. Higher natural gas prices also bring higher government revenues, but some analysts have expressed concern that continued economic growth (especially in industries like petrochemicals and oil sands, which use energy-intensive production processes) may prove difficult if natural gas prices become too high. Accessibility to natural gas may prove an important issue in the future although the fall in prices after 2008 has alleviated immediate concerns.

The petroleum industry has been the key factor underlying the economic development of the Alberta economy for the past four decades. It will continue to do so for the foreseeable future.

CHAPTER FOURTEEN

Lessons from the Alberta Experience

Readers' Guide: In the final chapter, we briefly explore the relevance of Alberta's experience with petroleum to other jurisdictions. This chapter does not involve any empirical comparisons between Alberta and the rest of the world but does offer thoughts on the treatment of the petroleum industry. In addition, it makes some final assessment of the general effectiveness of government regulation of the Alberta petroleum industry.

1. Introduction

Even in this shrinking, increasingly integrated world, the petroleum industry stands out for the scope and breadth of its regional interconnections. In part, this reflects the uneven geographical distribution of the underlying natural resource. The geological realities of the distribution of oil and natural gas in nature bear little relationship to the concentrations of population and economic power that drive energy consumption. As a result, many regions or sub-regions of the world find themselves in a position similar to that of Alberta, rich in petroleum with limited domestic requirements. How is this valuable resource to be developed so as to provide maximum benefit to the region? The purpose of this brief concluding chapter is to examine the Alberta experience with an eye to the possible lessons it might offer to other parts of the world. We do not attempt an empirical comparison of developments in Alberta with those elsewhere. Rather we draw upon the experience, problems, and regulations in Alberta, as discussed in previous chapters of this book, in order to offer suggestions that we feel could be usefully pondered by decision-makers elsewhere in the world. Because this discussion is based on the previous chapters, no references are cited in this chapter. The discussion and suggestions are divided into three broad categories: factors related to the 'physical' realities of petroleum; factors related to the operation of petroleum markets; and factors related to economic rents.

The petroleum industry within a region does not arise in a pristine historical and institutional environment. Hence, several specific characteristics of the Alberta situation need review. First, Alberta is fortunate in being a modern economy, part of the developed western world. Thus the birth of Alberta's oil and natural gas industry occurred within an established and stable political and legal environment. Alberta was ready to participate immediately in the development of petroleum. Industry and government could draw upon a well-educated local population, established business firms, and a responsible and well-trained civil service. Not all petroleum-bearing regions are so fortunate; in war-torn regions such as Sudan or Angola, or in countries such as those of the former Soviet Union undergoing fundamental economic and political transformation, a multitude of problems must be resolved before decision-makers can even begin to consider most of the issues that were important for Alberta.

Second, special problems are created by Alberta's status as part of a federated political system, where the province of Alberta shares jurisdiction with the federal government in Ottawa. Some parts of the world do not have this set of problems to consider (e.g., Qatar), and in others the division of powers are quite different than in Canada, so the responses to interjurisdictional conflicts may also have to be different.

Third, the conventional petroleum industry in Alberta is smaller than that in a number of other parts of the world, small enough that we have generally been satisfied to treat Alberta as a price-taker in the oil market. Thus the issue of the best way to exercise market power, which has been of vital concern to countries belonging to OPEC, has not attracted much attention in Alberta.

Fourth, the majority, although not all, of the petroleum 'in the ground' in Alberta has been under the ownership of the provincial government (the 'Crown'); this has been true in much of the world, but not everywhere at all times. With initial government ownership of petroleum rights, the interactions of the government with the private-sector petroleum industry are in its role as 'landowner,' as well as the governing representative of the people.

2. Factors Related to Physical Aspects of Petroleum

Oil and natural gas typically lie in segregated deposits (pools or reservoirs), invisible from the surface, deep within the earth. Pools differ, not only in the volumes of hydrocarbons held, but in the chemical make-up of the hydrocarbons present and the characteristics of reservoir rock and reservoir pressure. In addition, petroleum is a depletable natural resource in the sense that oil and natural gas do not naturally regenerate themselves within anything like the human time span, nor are they recyclable, like aluminum, after use.
It is accepted that socially optimal development of petroleum calls for a government regulatory framework that recognizes the unique characteristics of the resource. Many of the desirable regulations relate to the environmental impact of the industry and have not been dealt with in this book; this includes such regulations as those regarding the disposal of water produced in conjunction with petroleum, the flaring of natural gas, safety in drilling, sealing of abandoned wells, the environmental impacts of fossil fuel use, etc. We would note that Alberta seems to have a good reputation in many of these areas, especially those related to petroleum engineering, and that many of the regulations have been overseen by the Alberta Energy Resources Conservation Board (ERCB), which is also responsible for a number of the programs that we have discussed in this book. In this section, we will discuss three main issues related to the 'physical' nature of petroleum: uncertainties about reservoir existence and location; the reservoir as a single pressure system; and the meaning of 'depletability' of the natural resource.

A. Uncertainty and Exploration

Estimates may be made at any time of the size of the petroleum resource base within a region, but such estimates, especially in the early days of exploration in a region, are subject to a very wide margin of error. From an analytical perspective, little has been done in economics to integrate five essential components of a theoretical model of petroleum exploration: the extremely wide range of possibilities for the resource base; the precise nature of a social welfare function in such an uncertain setting; the open access nature of the exploration process (where investors may be motivated to undertake rent-destroying early exploration to capture mineral rights); the 'option value' of delaying exploration (waiting until others explore, or exploring more slowly, is likely to reduce the geological uncertainty the investor faces, allowing more profitable investment later); and the joint product nature of exploration (today's exploration activity generates knowledge of significance to both oil and natural gas discoveries, now and into future time periods). To suggest, as has been common in many theoretical models of exhaustible resources, that the key social issue is that of defining the 'optimal depletion path' for the resource, seems to be putting the policy cart in front of the information horse. Rather, we would suggest that one of the key policy issues in a newly developing petroleum region has been to find an efficient way of generating new knowledge in face of the extreme uncertainty involved.

From the early days of industry activity in Alberta, the government elected to address this through a combination of competitive private exploration and careful mineral rights issuance. We think that there is much to be recommended for such an approach, that efficiency arguments favour a reliance on private industry. Since most of the mineral rights are owned by the Crown, it would have been feasible to undertake exploration through a single government-owned 'national' (i.e., provincial) petroleum company. However, it is doubtful that a single company would have been as efficient in generating knowledge within the very uncertain geological environment that characterizes the petroleum industry. Allowing exploration to be undertaken by competing private firms allows for maximum testing of varying geological opinions, something that is likely to be hard for a single company, regardless of its interest in the 'public welfare.' In addition, experience in other parts of the world suggests that it is often difficult for a public petroleum company to generate the level of exploration investment it desires since the government often uses its ownership to appropriate a large share of any 'excess' funds in the company. Possible disadvantages of a reliance on the private sector for all exploration activities must, however, be acknowledged. The main one is the possibility that a large portion of mineral rights will be transferred to private companies with relatively little return to the government. If access to mineral rights is relatively low-cost, or if risk-averse companies are willing to pay little up front for access, or if petroleum discoveries *ex post* (after the fact) turn out to be exceptionally large, or if there is a lack of sufficient competition, the government will find that the majority of the economic rents accrue to the private sector.

Alberta handled this problem in several ways. Issuing mineral rights through competitive bonus bids, in a setting in which a large number of firms were active, ensured that a significant portion of anticipated (*ex ante*) rents would go to the government. Including rental and royalty provisions in the mineral rights meant that the government would share in ongoing rents from successful exploration. Drilling requirements helped to ensure that companies would not sit on land indefinitely and that geological knowledge would be generated. Dissemination of this knowledge was aided by the requirement that companies lodge well core samples with the ERCB, with the samples made public after a period of time (usually one year). Finally, checkerboard relinquishment provisions ensured that, as exploration determined which lands were of most value, the government retained an interest (for later sale) in the regions found to be of highest value. An argument might be made for one additional activity in the early stages of the petroleum industry in a region: given the very high initial uncertainty, the government might undertake, at its expense, an initial exploratory well-drilling program with the results made public knowledge. However, for many countries this would require considerable public expenditure from a relatively poor government (before any revenue flows from petroleum taxation occur). Alberta did not undertake such government drilling; it did, however, allow companies only a short period of time (typically one year) in which the results of their drilling could be retained privately.

It is desirable, from the beginning of petroleum industry activities in a region, to establish policies that are stable, efficient, and equitable and allow important geological knowledge to be generated quickly and made public. Alberta met these standards well.

B. The Reservoir as a 'Natural' Unit

Petroleum production is a deliberate economic act, but it must follow nature's constraints. Private petroleum producers will, of course, be aware of the limitations nature imposes, but this need not ensure that their production practices (investment, output levels, and production techniques) will be socially optimal. Hence governments may be motivated to regulate aspects of petroleum production practices. Many of these regulations relate to producers' uses of 'environmental amenities,' the capabilities of land, air, and water, which are not priced and sold in economic markets and hence are overutilized by profit-oriented companies. As has been mentioned, this book does not deal with such environmental aspects of Alberta petroleum production.

A typical conventional petroleum reservoir is a connected volume of porous rock (bounded by impermeable rock) holding hydrocarbons and water under pressure higher than surface pressure. Production of crude oil and natural gas draws upon the pressure differential between the reservoir and surface. In physical terms, the reservoir is a 'natural' unit of production, and it is sometimes useful to see production as the 'production' of reservoir pressure changes. Depending on the reservoir itself and the number, type, and location of wells, their output rates, and the location and volume of fluids (natural gas, water, CO_2, etc.) injected back into the reservoir, the time path of pressure in the reservoir (and the output of oil and natural gas) will vary. Since oil companies are interested in maximizing the present value of the profits received from the reservoir, one would expect that they would be vitally interested in the responsible management of reservoir pressure. However, they may not develop reservoirs in a socially efficient manner.

Within North America, the most obvious reason for this derived from the sharing of reservoirs by companies and the incentives of the 'rule of capture,' which said that the ownership of oil and gas went to the party that lifted them to the surface. Companies and land owners were often not willing to go to the expenses of time, money, and effort involved in negotiating and monitoring a joint agreement to 'unitize' the reservoir and lift from it as single producer. Instead, there was an incentive to produce competitively to capture petroleum before neighbouring companies could do so. This meant rapid declines in reservoir pressure and output, a smaller reservoir recovery factor, large numbers of wells with high expenses, and a reluctance to invest in pressure maintenance or enhancement. The economically preferred solution would be a compulsory unitization program. Alberta did not adopt this solution, although in certain circumstances (where obvious damage to reservoirs took place) the provincial regulatory board could order it. Instead, Alberta drew on U.S. regulations, with a mix of well-spacing rules (limiting the number of wells that could be drilled), maximum output rates (to avoid undue pressure decline), and 'market-demand prorationing' for crude oil, which limited output to the level that the market was willing to accept (at prevailing prices). Market-demand prorationing was not introduced for natural gas reservoirs. Here the excesses of the rule of capture in Alberta were reduced by the prevalence of long-term contracts that slowed the rate of reservoir depletion.

However, market-demand prorationing brought its own inefficiencies. By controlling output, it blunted the operation of market forces, an impact that was felt at the North American level since the program operated in many of the most important producing regions (especially Texas). It also increased oil production costs by prorating controlled output across all producers, therefore restricting production of low-cost oil in order to make room for higher-cost oil. Finally, regulations often induced producers to drill incremental wells to gain higher output quotas even when existing wells were capable of lifting more; successive revisions of prorationing meant that this incentive was pretty well eliminated in Alberta by the mid-1960s. Market-demand prorationing became gradually less significant in Alberta from the mid-1970s and was entirely removed in the later 1980s. Well-spacing and maximum rate regulation continued, and the advantages of unit operations were now well known to companies, so the excesses of the rule of capture have been blunted to a considerable extent.

In many parts of the world, the rule of capture is not operative, if only because single companies frequently control entire reservoirs. In many of these countries, a different type of insecurity of ownership of oil reservoirs may induce companies to exploit the oil excessively rapidly. This is the case if there is a fixed life of the mineral rights, with oil reservoirs reverting back to the government at the end of the agreement; companies then have no incentive to consider the impact of today's pressure decline on output past the end date of the contract. From the viewpoint of economic efficiency, the most direct way to address this problem would be to allow continuation of the mineral rights until the producer decides to abandon the reservoir, as has been the case in Alberta. Should governments be unwilling to do so (perhaps because it is regarded as politically impossible), then a 'conservation' regime of well-spacing and maximum output rate limitations might be well advised. Here, the Alberta experience might prove instructive, particularly the decision to rely heavily upon a quasi-judicial regulatory board with a highly qualified technical staff and open procedures.

It has been suggested (for instance by some apologists for OPEC) that the petroleum industry always requires market-demand-prorationing regulations for 'conservation' reasons to limit an inducement to excessively rapid production. This argument does not acknowledge the fact that market-demand prorationing arose out of the specific setting of a North American industry in which the rule of capture held in common law and mineral rights holdings covered very small surface areas. In Alberta, in contrast to the continental U.S., where private ownership of initial mineral rights was common, the majority of Alberta's mineral rights are Crown-held, but the government typically issued production leases for relatively small areas. These conditions simply do not hold in much of the world. For most economists, therefore, there is no obvious justification for prorationing as a 'standard' petroleum policy; rather, it appears that those desiring high oil prices are attempting to find a justification for their exercise of market power.

C. The Significance of Depletability

Conservation of petroleum use is another possible reason to limit current production, and is normally justified by reference to the limited resource base for conventional petroleum. It has been suggested that, unless action is taken soon, resource limitations will translate into catastrophic future shortages, although many analysts are quite vague about exactly what the nature of this crisis will be.

Readers of this volume will know that the authors are not sympathetic to this line of argument. There is great misunderstanding about the 'exhaustible' nature of petroleum resources since it is primarily an economic phenomenon, not a physical one. That is, we will 'run out' of crude oil or natural gas when they become too high in cost, relative to market value, to continue with production. In economic terms, as the world turns to more and more costly petroleum, relatively less energy-intensive activities and alternative energy sources will become more attractive, reducing the consumption of petroleum. There is a strong presumption amongst most economists that market forces will, if allowed, handle this transition relatively smoothly, particularly since producers and consumers have a strong incentive to anticipate such an outcome and begin to take action prior to significant price increases. If this is correct, the transition to other energy forms will be relatively smooth and will have resulted from the 'economic' (not physical) exhaustion of our petroleum resources. Not everyone accepts this argument since many feel that economic markets fail to understand the fundamentally limited nature of the underlying resource base. OPEC representatives have often justified their production restraint by a presumed need to conserve scarce resources. However, economists have tended to view this rationale with a high degree of scepticism, since it is clearly in OPEC's immediate interest to force oil prices to high levels.

It is of interest that, in the case of Alberta, there has been a persistent tendency for the relevant government agencies to underestimate future petroleum production and reserves. This is not surprising and is common in studies of other regions as well since forecasts of petroleum availability are necessarily based on current knowledge and future geological plays, economic conditions, and production technologies are impossible to forecast with accuracy. Many studies attempt to make allowance for these uncertainties, but there seems to be a persistent tendency to underestimate their effect on future reserves additions. There is obviously no guarantee that past underestimation of future petroleum producibility will continue through the indefinite future. However, the historical evidence suggests that economists who argue that economic markets adequately recognize the depletability of petroleum are more justified in their argument than those who fear sudden and catastrophic exhaustion.

Those who argue in favour of restricting current petroleum production to generate higher supplies for a future energy supply crisis must recognize the complexity of such a policy. Clearly the approach rejects the idea that petroleum is a product like other products that one is willing to trade in economic markets. The key question is why this is the case. As suggested, it normally reflects a belief that current market forces fail to reflect the future value of petroleum. It also implies that government regulators are better able to determine this future value. (Given the wide range of oil prices over the past fifty years, it seems disingenuous to simply say that the socially optimal value is always higher than observed prices.) The Canadian experience suggests that this faith in regulators may be misplaced: official estimates of future oil and gas prices have been notoriously inaccurate. (So, we should note, have been most private forecasts!)

Prohibition or limitation of exports is often recommended as a way to preserve resource supplies, as was done by Canada from 1973 to 1985. This generates contradictions. After all, the argument is that we are all using the resource stock too quickly, not simply that foreigners are using too much. By itself, restricting exports forces greater supply onto the domestic market, lowers the domestic price, and encourages greater consumption of petroleum at home. Thus we ourselves are using up the natural resource more quickly. It also requires the expense of an effective regulatory program to ensure that domestic petroleum does not leak into the higher-priced foreign market. There is also the contradiction that we usually expect to be able to import, at prevailing international prices, the resources that we ourselves do not possess in abundant quantities. Why should we expect this to continue while our country cuts back petroleum sales to other nations? It is also curious to note that export limitations may appear to generate precisely the outcome that was feared. Reserves additions will be inhibited, but this is not because markets have underestimated the availability of petroleum resources but because lower prices make reserves additions less profitable. Lower domestic prices, as a result of export limits, also induce earlier abandonment of reservoirs, reducing the recovery ratio, and inhibit technological innovations that increase the recoverability of petroleum.

If concerns about resource availability are legitimate, this would suggest that the appropriate policy is to force domestic prices higher to inhibit resource use. Exports would disappear, as domestic supply would be priced out of the international market, and consumption at home would fall. The easiest way to do this would be through a tax on oil that would raise prices to consumers and reduce prices for producers. However, the difficult part of such a policy is determining exactly when and how the future dire scarcities of petroleum will occur and how, at that time, incremental petroleum will be made available to domestic users. As noted, the essence of this argument is that markets fail to recognize the exhaustible nature of petroleum and that at some future date a massive energy crisis is going to occur in the world. Presumably, at that time, this nation would prohibit exports and increase petroleum production; petroleum prices would move below world prices and domestic petroleum users would benefit. Economies elsewhere would suffer from energy shortages, but this country would be protected, at least to some extent. There are, of course, ethical and political implications. Could we justify reserving petroleum use for ourselves alone when people in other parts of the world are going short? Would other powers allow us to withhold supplies of petroleum?

But our main objection to this line of argument is that we view the entire scenario as unlikely and betraying a failure to appreciate the essentially economic nature of resource limitations and the ability of economic markets to signal resource scarcity and induce compensatory actions. Our inclination is to see the essential problem as one of risk (and insurance) rather than resource exhaustibility. Since perfect foresight is impossible, it may be that petroleum resource scarcity will occur faster and more dramatically than is generally expected. It might be judged desirable to have some 'insurance' in the event of this outcome; the insurance could take the form of current subsidization of alternative energy forms and energy conservation, that is, of those activities that will play a prominent role in any smooth adjustment to petroleum depletion. It might take the form of 'strategic petroleum reserves' (SPRs), that is government-owned reserves set aside for later use as needed. This differs significantly from intervention with petroleum sales to retain scarce petroleum assets for domestic use.

3. Factors Related to Petroleum Markets

The discussion in the previous section illustrated a commonly expressed concern: that petroleum markets fail to function in an appropriate manner so that governments are justified in interfering with prices or trade flows. Experience in Canada and Alberta has illustrated many possibilities in this regard. Thus, both Alberta and Canada imposed domestic requirement limitations on natural gas exports; oil imports into Canada were limited from 1962 through 1972, allowing domestic oil to sell at prices in excess of the international level; oil and natural gas export sales were limited from 1973 to 1985, and domestic prices were fixed at levels below those in external markets. We have generally been critical of such policies on the ground that they impose economic efficiency costs on the economy, without clear offsetting gains. Thus, for example, setting prices above the prevailing market level stimulates production of petroleum that costs more than the price of imports and penalizes domestic consumers. Holding prices below the prevailing market level means that higher utilization of oil is stimulated in uses that have a lower value than the amount that foreign buyers are willing to pay for that petroleum, and domestic production is inhibited. The obvious question is whether some additional factor justifies these efficiency losses.

In addition to the arguments related to resource exhaustibility discussed above, several other possible reasons for interfering in the operation of petroleum markets will be briefly discussed, including: second-best considerations; providing a fairer distribution of the benefits and costs of petroleum; generating improved macroeconomic stability and adjustment; and encouraging regional development.

A. Second-Best Considerations

The efficiency advantages that economists see accruing from competitive free markets can be guaranteed, economic theory tells us, only if they are part of an entire system of 'complete and perfect' markets. If the market for one product is effectively competitive, but other associated markets are not, we move from our 'perfect ('first-best') world to a 'second-best' world, and we do live in a second-best world. This does not necessarily mean that we should interfere with the operation of markets, but it may mean that there are efficiency gains that could be attained from such interference. Thus, for instance, we argued in Chapter Nine that the Alberta oil industry was tied in the 1960s to the large U.S. oil market where oil prices were maintained above international levels by the joint operation of state-run market-demand prorationing regulations and the federal oil import quota program. The Canadian National Oil Policy divided the Canadian oil market at the Ottawa River valley, allowing the western part to access the U.S. market at prices above the international level. This benefited western Canadian oil producers at the expense of oil consumers and might normally have been expected to give an efficiency loss. However, if account is taken of the incremental oil export earnings, due to U.S. oil regulations, then the policy generated net gains to Canada.

However, the world oil market currently shows few if any similar examples since pretty well all major participants now operate in the market in a free manner. It is possible that other second-best situations exist, but each of these requires a clear demonstration that there is a gain to be made from interference with petroleum prices or trade flows. We would also suggest that the most plausible of these market failures (such as the failure to adequately 'price' environmental amenities) are more likely to be addressed by tax/subsidy schemes that operate through the market rather than by direct interference in petroleum markets.

B. Fairness

Petroleum price changes impact differently on different individuals in the economy. Oil price rises, for instance, hurt oil users but benefit owners of private oil companies, petroleum industry input suppliers, and governments in oil-producing regions. One of the main reasons that the Canadian federal government fixed oil prices below international levels from 1973 to 1985 was to ensure that the benefits of the increasingly valuable oil was spread across all Canadians, rather than concentrated in the western producing regions, with most other Canadians feeling mainly the higher prices. However, the justification for the policy was less a desire to shelter oil users than it was a reflection of the difficulty in deciding in a federal system what is a fair interregional distribution of the gains (to an oil-exporting economy) from higher oil prices. Moreover, the policy of holding oil prices down had the effects of encouraging more use of oil, discouraging production of oil, and necessitating an increasingly convoluted set of regulations limiting and taxing exports to ensure that foreign consumers did not benefit from the low Canadian prices.

It should be noted that the Canadian evidence does not offer much support for the argument that rising petroleum prices are highly regressive in their impact. Petroleum takes a relatively low proportion of people's income and does not take a much higher share for the poor than the rich. Should such income-distribution effects be of concern, the more appropriate policy would be to combine an effective rent-collection program (see below) with modest tax reform; that is, extra government revenue from the increased profits on higher-priced petroleum could be used to lower personal tax rates on the poor or provide social programs that benefit the less-well-off.

It is tempting for oil-exporting countries to set domestic prices low to ensure that citizens benefit from 'their' petroleum, and many governments have found that such programs become very difficult to remove once in place. Our view, however, is that the argument of the previous paragraph holds for most nations. In fact, in very poor nations, income distribution is often more unequal than in Canada, and the very poorest use little petroleum so benefit very little from low oil prices. Moreover, many of these countries have relatively inefficient public administration systems, so the ability to control illicit trade in subsidized oil is weak. We suspect that it would be more effective to help the poor by exporting more petroleum at higher world prices and using the government revenue gained on programs aimed directly at the poor. In other words, unfairness of the distribution of income is a general societal problem, not best tackled by subsidization of the prices of individual goods or services.

C. Macroeconomic Stability

Rapid changes in petroleum prices, especially, it seems, rapid *rises*, impose adjustment costs on an economy, particularly an oil-importing economy. Many, but not all, economic analysts assign rising world oil prices a significant role in the 'stagflation' starting in the mid-1970s. (Stagflation is the combination of a sluggish economy, or recession, with high inflation.) One of the justifications for the Canadian oil and natural gas price freezes of 1973 was that Canada, as a net oil exporter, could use this policy to reduce macroeconomic adjustment problems. If the oil price rises were temporary, as some expected in 1973, Canada could wait out the blip in prices, and if they were permanent, Canada could make the required adjustments more gradually. However, subsequent economic analysis has cast doubt on this argument. For example, two of the major oil-importing nations (West Germany and Japan) weathered the oil price rises of the 1970s very well. Not all large petroleum price rises seem to have generated strongly stagflationary effects, and some models have suggested that the problem is not so much higher oil prices as the macroeconomic policy response to the higher prices. Further, simulations with several Canadian macroeconomic models did not find much difference in levels of such key economic indicators as the unemployment rate and the Consumers Price Index between cases with immediately higher oil prices and those with more slowly staged price increases. Thus our conclusion is that the macroeconomic benefits from holding petroleum prices below market levels are not likely to offset the efficiency losses of such a policy.

D. Regional Development

A final justification for interfering in the operation of free market forces in oil and natural gas markets is that such a policy might generate regional economic gains by encouraging resource-using industries to establish in the region; that is, export limitations and/or regulated lower prices could generate higher economic growth. It is not an easy argument to assess. This is particularly true if the focus of analysis is on individuals and appropriate attention is given to our personal mobility: the government of Alberta might see a clear benefit in having a petrochemical plant located in the province, but an individual worker may be less concerned about whether the plant is located in Edmonton or Vancouver.

There is also the question of whether the policy instrument (e.g., lower prices that benefit all users) is appropriate to the objective (to support a specific industrial user who otherwise would not locate here). More specialized subsidies might cost less and would be more transparent than intervention in the operation of the petroleum market. Also, policy-makers must recognize that it is difficult for governments to know exactly which new industries to encourage. Presumably this is made easier if there is a temporary factor inhibiting an industry from moving into the area; short-term subsidies then can be designed to last until the new industry establishes itself. For example, if the industry outside the region is dominated by oligopolists not willing to build in the region, despite the ready resource availability, then temporary government support for a new company might be reasonable while it breaks into the market. Or, if the problem is the lack of skilled local labour, temporary encouragement of the new industry could be attractive while the requisite training occurs.

We find little reason to suppose that a policy of holding down petroleum prices or prohibiting profitable exports is justifiable as a way to support regional economic development, given the known inefficiencies of such a policy and the possibility of introducing more finely tuned measures that specifically address the problems inhibiting development.

4. Factors Related to the Sharing of Economic Rent

Issues of taxation are inevitably controversial. Petroleum taxes might be imposed in order to change behaviour in petroleum markets; an example would be a 'carbon tax' designed to reduce utilization of petroleum in order to reduce carbon dioxide emissions. However, the most significant reason for governments to assess charges on the petroleum industry is to capture for the public purse a high proportion of the economic rent generated by the production of oil and natural gas. Economic rent is attractive as a revenue source for governments since it is excess to necessary production costs, so it can, in theory, be taken without inhibiting production. The government incentive to capture economic rent is particularly pronounced where the mineral resources are initially publicly owned. In a region such as Alberta, there are two main sources of this economic rent. First, petroleum reservoirs vary greatly in quality. In a well-functioning market, price must be high enough to cover the costs of the highest-cost supply necessary to meet demand, so higher 'quality' petroleum (in the sense of more productive lower-cost supplies) will earn profits in excess of costs. Second, because oil is seen as a non-renewable resource, most oil and natural gas will command an excess of price above production cost reflecting this general scarcity factor. (In economic theory, this premium is called a user cost, as discussed in Chapter Four.) A third source of profits on petroleum is the deliberate exercise of market power, as has been done by OPEC in the crude oil market. For a region such as Alberta, which takes the price of oil as given by the world market, this means that more oil is commercially viable and oil profits (economic rents) are higher.

Governments typically claim a right to a significant portion of these petroleum rents, often because the underlying natural resource that generates the rents is seen as the property of the people of the region. In the Alberta context, this perception has legal standing because, in over 80 per cent of the area of the province underlain by sedimentary rocks, the petroleum rights are held and issued by the provincial government. Beyond this, economic rent is an appealing source for government revenue from an 'ability to pay' principle of taxation since it represents a surplus of revenues above the essential expenditures to produce the resource. This often leads to the recommendation that governments should 'maximize' their share of economic rents. We have suggested the more modest objective of governments attaining a 'high' share of the rents. Partly this is because it is impossible to define an actual rent-collection scheme that touches only (and 100% of) the rent. At a more abstract level, it seems unlikely to us that there is a clearly defined absolutely 'pure' economic rent (i.e., revenue in excess of necessary production costs) that plays no role whatsoever in encouraging efficient, cost-minimizing production. A 'perfectly effective' government rent-collection scheme, which left no rent in the hands of private companies, would leave little incentive to keep costs to a minimum except on the highest-cost projects, particularly if benefits to the private owner could be disguised as 'costs.'

The task of gathering economic rents for the government is very much complicated by the great uncertainties associated with petroleum industry activities. In our earlier discussion, we framed this in terms of the difference between *ex ante* (expected) and *ex post* (actual) economic rents. It can also be seen in terms of the risk-sharing. Thus, for example, a government might be effective in capturing 100 per cent of anticipated rents, leaving all the risk with the private sector. However, unless the government is highly risk-averse, this would not be seen as desirable. Many have argued that private investors are more risk-averse than governments, implying that the value they place on anticipated economic rents may be less than the value the government places on them. Governments, then, would wish to collect much of their share in the form of ongoing payments as rents actually accrue. It is also noteworthy that early estimates of ultimate recoverable reserves for the world's main petroleum-producing regions have been shown to be conservative; hence estimates of anticipated economic rents when a region is under initial exploration typically fall below actual earned rents. Finally, there are advantages (in terms of economic planning and self-discipline) in a government spreading its petroleum revenues relatively evenly over time. For reasons such as these, governments have generally focussed on gaining a high share of actual rents rather than expected rents.

To capture a share of rents in an economically efficient manner, the methods of raising revenue should, ideally, be neutral with respect to industry activity. Specifically, it would be desirable that the methods of rent-extraction should not: (1) discourage investment in exploration or development; (2) induce earlier abandonment of reservoirs; or (3) change the time path of petroleum production. It has been suggested that this could be accomplished by a 'resource rent tax,' that is a tax upon profits earned (including an allowance for the required return on capital as a cost of doing business). However, the practical implementation of such a tax is difficult. Allowance for exploration costs for individual projects is almost inevitably somewhat arbitrary, and an emphasis on earned profits often entails the notion that the government would not receive any payments until after full 'payout' of costs has occurred. In the 1990s, Alberta introduced a 'generic' tax for oil sands and heavy oil projects that was explicitly based upon an accounting definition of profits, although a minimum *ad valorem* royalty provision was also included. This was largely motivated by the high cost of this oil, with the associated vulnerability to low oil prices.

However, for conventional petroleum industry activities, Alberta has long utilized a mix of rent-collection mechanisms, including competitive bonus bids, royalties, land rentals, and a corporate income tax (applied to all companies, with regulations largely set by the federal government in Ottawa, but with Alberta receiving a portion of the revenue). A royalty has been the traditional method for North American land owners to obtain a share of oil revenues, so was an obvious instrument to use as the government of Alberta issued Crown mineral rights. This is an example of how private landowner leasing arrangements may have affected Crown mineral rights provisions. A major disadvantage of a traditional royalty (based on the gross revenue from oil) is that it fails to distinguish between lower- and higher-cost oil; thus, if set at a level high enough to earn significant revenue, it inhibits oil production. The government of Alberta introduced a variation on traditional flat-rate royalties by setting the royalty rate higher for higher-output wells, which were presumed to have lower per unit costs of production. Under reasonably competitive conditions (there have been many private companies active in the province), the bonus bid can be expected to capture a significant portion of expected rents after companies make allowance for the rentals, royalties, and income tax that they expect to pay.

This approach seemed to work well until the rapid rise in world oil prices (and North American natural gas prices) starting in the early 1970s, when two problems became apparent. First, actual profits on petroleum surged far beyond what anyone had expected, and, under existing royalty regulations, the largest share of the profit increase went to the private sector. Secondly, as economic rents surged, the issue of the appropriate division of rents, particularly between the provincial and federal governments, became red hot. This was particularly critical because the main rent-collection devices that were used by Alberta (competitive bonus bids and royalties) were deductible as costs for the main rent-collection tool of Ottawa (the corporate income tax); Ottawa feared that Alberta would pre-emptively gather all the rent increases before it had a chance to generate more revenue itself.

This complex situation led to a period of political and regulatory instability from 1973 to 1985, characterized by increasingly complex government regulation. Alberta moved to raise royalty rates substantially by making the royalty rate a positive function of the price of petroleum; since higher royalties are a disincentive to production, the government retained the sliding-scale rate based on output. (For example, the royalty rate on oil fell towards zero as output from a well fell to nil.) It also set lower royalty rates on new production which required new investment. Ottawa moved to fix petroleum prices below world levels, to make royalties and bonus bids non-deductible for the (federal) corporate income tax, and, starting with the National Energy Program in 1980, introduced several exclusively federal taxes. (These federal taxes, and price controls, were removed with deregulation in 1985/6.)

Alberta's experience in rent collection offers useful lessons to other jurisdictions. First, it is important in federal government systems that the various levels of government work cooperatively to determine fair rent shares. Second, there is much to be said for Alberta's use of a number of rent-collection mechanisms so that the governments can give weight to a number of different objectives: ensuring a flow of income across time (i.e., with royalties and income taxes); differentiating among heterogeneous projects (i.e., with competitive bonus bids and sliding-scale royalties); and allowing the government a suitable share in risky, fluctuating rents (i.e., with royalties and income taxes that vary with earnings). Third, by electing to use gross royalties and land rentals that are not directly tied to profits earned, Alberta has found it necessary to introduce rather complicated measures, such as sliding-scale royalties and a number of incentive schemes, so as not to unduly inhibit investment in new, higher-cost projects. Rent-collection instruments more directly attuned to private company profits (such as have been used for oil sands ventures) might be somewhat less complex administratively. On the other hand, it is somewhat harder than might be thought to set up a well-balanced and effective profit tax on petroleum because (except for projects such as those in the oil sands) it is not possible to define separate projects clearly (since exploration costs, in particular, are of a joint-product nature, rather than tied to any one project), and it is very difficult to set up regulations that are equitable across different types of companies (e.g., established companies with existing cash flow from which this year's costs can be deducted as compared to new companies with no or low cash flow who must carry current expenditures forward until they have sufficient cash flow to claim them).

On balance, the Alberta petroleum rent-collection scheme in place after the mid-1980s for conventional petroleum seemed to strike a good balance among the objectives of gathering a high share of rent, ensuring some stability in revenue flow to the government, sharing risk with the private sector, and providing stable and relatively low-cost administration. The main difficulties have been in designing a system that is sensitive to sudden increases in profitability due to surges in world oil prices, as had been seen in 1973 and 1980 and occurred again in 2005–2008, and one that minimizes the disincentive effects of *ad valorem* royalties.

5. Conclusion

Alberta has been most fortunate in its petroleum endowments, with extensive conventional oil and natural gas resources plus large volumes of the less-conventional, higher-cost resources (e.g., oil sands and coal bed methane), which are expected to play an increasing role in the future. These resources have spurred rapid economic growth in Alberta and have been the key input in making it the wealthiest of Canadian provinces. The role of government (both the province of Alberta and the federal government in Ottawa) in generating benefits from the petroleum industry has been controversial. The Alberta experience certainly offers a wealth of experience in different types of government programs. Our view is that certain forms of government regulation have been very effective in the Alberta case, others less so.

In Alberta, governments have been effective in establishing a relatively stable and well-defined system of property rights, which encourages risk-taking and long-term planning on the part of petroleum producers. To help offset the negative effects of specific market failures in the operation of petroleum reservoirs, the Alberta government established an independent and powerful regulatory board (now known as the ERCB, the Energy and Resources Conservation Board), which has a well-earned international reputation for careful and honest regulation with respect to the technical aspects of oil and gas production. This board has powers related to many environmental matters (gas flaring, safe drilling and well operation, control of well blowouts, well abandonment, and closures), which are an inevitable part of the physical process of exploring for and lifting petroleum. In addition, it has managed the day-to-day problems associated with the insecurity of property rights over petroleum in the ground generated by the 'rule of capture.'

However, in more recent years the ERCB has been subject to criticism with respect to the fairness and effectiveness of its hearings and judgments with regard to broader health and environmental issues and whether it is giving appropriate attention to the 'public interest.' The decision, in 2012, to transfer many of the board's regulatory powers to a new energy regulator may, in part, reflect these concerns. In this study, we have not considered such important environmental issues as pollution and global warming.

The government of Alberta has also been quite successful in its rent-collection regulations. It has succeeded in establishing regulations that ensure a relatively high proportion of economic rent, both expected rents and unexpected rent changes, accrues to the government, without significantly inhibiting petroleum production.

However, it took an extended period of time for a regulatory regime to be established in Alberta that recognized two key factors. One was largely political, establishing a stable and efficient regulatory framework within the context of a federal state, when both the provincial government and the federal government might reasonably exercise some claim on the benefits from the petroleum resource. As might be expected, these disputes came to a head in the 1970s when world oil prices soared and the value of Alberta's oil and natural gas resources increased dramatically. The eventual resolution, in the mid-1980s (which was undoubtedly aided by falling world oil prices), essentially recognized the primacy of the province and the acceptance of market forces in determining the values of oil and natural gas. The controversial policies of the period from 1973 through 1985 had lead to changes that somewhat increased the rent-collection efficiency of the corporate income tax (accruing largely to the federal government).

A second important factor was devising a regulatory regime that recognized the inevitable uncertainties and risks attendant to the petroleum industry. This included, not just the geological risks of exploration and reservoir performance, but also the economic (and political) uncertainties of the operation of global energy markets. This is very important for rent-sharing; if governments are to capture a large share of the actual rents that accrue, the rent-collection mechanisms must be flexible to changing geological and economic circumstances. A variety of mechanisms have been used, including competitive bonus bids, relinquishment provisions on mineral rights tracts, and royalties that are sensitive to output levels and prices.

It took some time for Canadian governments to agree to adapt to the variability of international energy markets, rather than imposing regulations to 'protect' either Canadian oil producers or consumers from the impacts of uncertain and variable prices. Since the mid-1980s, and with the free trade agreements with the United States and, later, the United States and Mexico, Canada seems willing to allow market forces to establish prices for both oil and natural gas. Previous experiments with price and trade regulations had made it evident that governments were no more successful than the private sector in forecasting future prices, so temporary 'bridging' policies to allow gradual adjustment to price changes were not possible. Policies to control prices interfered with desirable consumption and production adjustments; holding prices below the international level, for instance, encouraged more oil use and inhibited consumption, therefore raising the possibility of increased dependence on expensive imported oil. It was also apparent that the regulations would likely become very complicated. For example, if international oil prices changed frequently, then so must various regulations; holding domestic prices down required limitation on exports of petroleum and/or export taxes; the level of taxes would have to recognize quality differences, etc.

Thus there was an extended period in Alberta in which a distrust of the operation of petroleum markets led to considerable controversy and to experimentation with regulatory programs that entailed real economic inefficiencies. Since the mid-1980s, there has been a willingness to accept the operation of petroleum markets. This is well-justified from an economic point of view. But a part of this desirability stems from the existence by then of a stable and relatively effective regime for sharing economic rents and controlling many of the production externalities generated by the activities of an industry operating in a physical world. In this respect, Alberta can serve as a good example for the rest of the world.