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OIL AND GAS IN CANADA: THE EFFECTS OF DOMESTIC POLICIES AND WORLD EVENTS

John F. Helliwell
Mary E. MacGregor
Robert N. McRae
André Plourde

CTF ACEF
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RESEARCH CENTRE
CANADIAN TAX FOUNDATION



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Foreword

The oil and gas industry in Canada has experienced turbulent times during the past 25 years and particularly since the first oil price shocks in 1973. The extraordinary increases in international oil prices gave rise to a wide range of government policies that were designed to control the prices of crude oil and natural gas and to alter the way energy revenues were taxed.

In October 1980, the federal government unilaterally introduced the national energy program, which outlined a new strategy for replacing foreign oil with Canadian oil in the domestic market. The program generated grievances on the part of the industry and the governments of the producing provinces over the distribution of oil and gas revenues. A number of new policy measures were adopted to address some of these grievances.

Later, as world events unfolded differently from the projections upon which the NEP was based, the federal government and the governments of the producing provinces responded by introducing yet another series of policies, this time designed to buoy up the industry's position. The western accord and the measures aimed at deregulating natural gas markets laid to rest the last vestiges of the NEP.

That the energy scene is dynamic and continuing to evolve is apparent from the recent steep decline and partial recovery in world oil prices, which have drastically altered the environment in which the Canadian oil and gas industry operates.

The authors of this study present an overview of the evolution of Canadian oil and gas policy since the early 1960s and the key developments in world energy markets. They analyze the impacts of those events on the Canadian oil and gas industry and evaluate the actual policy regimes adopted as well as feasible alternatives that might have been introduced instead. They conclude by drawing some lessons from these experiences that should assist government leaders in formulating energy policies for the future.

Several appendices provide extensive data on various aspects of the study.

John F. Helliwell and Robert N. McRae are professors of economics at the University of British Columbia and the University of Calgary, respectively. For most of the period during which this research was conducted, Mary MacGregor and André Plourde were with the Institute for Policy Analysis at the University of Toronto. Ms MacGregor is now with the federal Department of Finance, while Professor Plourde is in the Department of Economics at the University of Ottawa.

Frances Emery edited the manuscript, M.A. Neal verified the references, and Esther Yeoh prepared the index.

The views expressed in this volume are those of the authors and should not be attributed to their employers, the granting agencies that supported related work, or the Canadian Tax Foundation or its members.

D.J. Sherbaniuk
Director
February 1989

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Abbreviations and Acronyms

AGA	American Gas Association
AGTL	Alberta Gas Trunk Line Limited; in 1980 this became known as NOVA, an Alberta Corporation
AERCB	Alberta Energy Resources Conservation Board Note: the AERCB is the present name of the AOCGB, formerly the APGCB
AOGCB	Alberta Oil and Gas Conservation Board
APGCB	Alberta Petroleum and Gas Conservation Board
API	American Petroleum Institute
APMC	Alberta Petroleum Marketing Commission
ARCAN	Atlantic Richfield Canada
bbl/d	barrels per day
BCEC	British Columbia Energy Commission Note: the BCEC was succeeded by the BCUC
BCPC	British Columbia Petroleum Corporation
BCUC	British Columbia Utilities Commission
BTU	British thermal unit
CCA	capital cost allowance
CES	constant elasticity of substitution
CIGOL	Canadian Industrial Gas and Oil Limited
COR	Canadian ownership ratio
COSC	Canadian ownership special charge
CPA	Canadian Petroleum Association
CPI	consumer price index
EMR	Department of Energy, Mines and Resources (federal)
EOR	enhanced oil recovery
FERC	US Federal Energy Regulatory Commission Note: FERC is the successor to the former FPC
FPC	US Federal Power Commission
GCOS	Great Canadian Oil Sands plant, now known as Suncor; in the text it is usually referred to as GCOS (Suncor)
GJ	gigajoule
GNP	gross national product
IFSD	interfuel substitution demand model of EMR
IORT	incremental oil revenue tax
IPAC	Independent Petroleum Association of Canada
IPL	Interprovincial Pipe Line Limited
Kwh	kilowatt-hours

MACE	the model used in the experimental aspects of this study (from MACro and Energy)
mcf	thousand cubic feet
NEB	National Energy Board
NEP	national energy program
NGGLT	natural gas and gas liquids tax
NOP	national oil policy
NORP	new oil reference price
OEB	Ontario Energy Board
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
PEAP	policy and economic analysis program of the University of Toronto's Institute for Policy Analysis
PCC	petroleum compensation charge
PGRT	petroleum and gas revenue tax
PIP	petroleum incentives program
PMA	Petroleum Monitoring Agency
RDP	real domestic product
RTPC	Restrictive Trade Practices Commission
SOQUIP	Société québécoise d'initiatives pétrolières
tcf	trillion cubic feet
TCPL	TransCanada PipeLines Limited
TQ&M	Trans Quebec and Maritimes Pipeline Limited
VRIP	volume related incentive pricing program
WGM	Western Gas Marketing Limited

Preface

In early 1986, the Canadian Tax Foundation invited us to stand back from current events and take a longer view of developments affecting the Canadian oil and gas sector, with special reference to the effects of world prices, domestic regulation, and the various systems of taxes and royalties that have been recommended or applied over the past 25 years. The invitation came at the right time: we were already in the course of a substantial data-gathering and policy analysis exercise sponsored by the Ontario Ministry of Energy, and we had recently completed a new version of the macroeconomic model we use for energy policy analysis.[1] It was an opportunity to update and improve our modelling of energy supply and demand, and to use the newly sharpened tools to provide an overview of the role of oil and gas in Canada.

Dramatic changes in world prices and Canadian policies have occurred over the past 25 years. The aim of our study is to describe these changes in sufficient detail, and with enough comparable supporting data and empirical analysis, to make it possible to assess their separate and combined impact on the pace and structure of oil and gas investment and production in Canada.

The introductory chapter spells out our research plans in more detail. Subsequent chapters discuss the nature of the Canadian oil and gas resources and the pattern of changes in world prices (both in chapter 2); the history of Canadian oil and gas regulation and pricing (chapters 3 and 4); the history of oil and gas taxation in Canada (chapter 5 and two appendixes); the structure and explanation of changes in energy demand in Canada (chapter 6 and two appendixes); investment, costs, and supply of conventional oil and gas (chapters 7 and 8 and an appendix); the role of heavy oil and the oil sands, and of arctic and east coast offshore sources (chapter 9); analysis of the revenue and activity effects of changes in oil and gas prices and policies (chapter 10); and a brief analysis of the macroeconomic consequences of some of the major changes and crises in Canadian oil and gas policies (chapter 11). Our results are summarized in chapter 12. Two more appendixes present the more important of the data series that we have gathered for this study, and the sources of the data used in our many figures.

We hope that the study will be useful to those interested either in the history and effects of oil and gas taxation and regulation, or in the past and likely future development of the oil and gas industry in Canada.

[1] The new version of the model is described in John F. Helliwell, Mary E. MacGregor, Robert N. McRae, André Plourde, and Alan Chung, "Supply Oriented Macroeconomics: The MACE Model of Canada" (July 1987), 4 *Economic Modelling* 318-40.

We acknowledged above the research support of the Ontario Ministry of Energy. We owe an even greater debt to the Social Sciences and Humanities Research Council of Canada: it has provided a series of substantial grants over the past 15 years to support our model-based analysis of energy policies and of the relationship between the energy sector and the rest of the economy. We acknowledge also the efforts of our many co-authors and collaborators on earlier versions of the model used in this study or on parts of the research reported here—especially, Bruce Duncan, Ardo Hansson, Kenneth Hendricks, Michael Margolick, Gerry May, Sanford Osler, Tim Padmore, Anthony Scott, and David Williams. Many graduate and undergraduate students carried out research that contributed to this study. In preparing our latest research results for this book, we have had the cooperation and assistance of Philip Bagnoli, Marlyn Chisholm, Alan Chung, Janet Damery, Sergio Gai, Robert Williams, and Esther Yeoh. Alan Chung, our partner in the development of the macroeconomic parts of our modelling activity, has been an especially important contributor to this and many other related papers. We also thank the three anonymous referees who provided useful comments on an earlier version of the manuscript and Frances Emery who did a marvellous editing job. We are grateful to Douglas J. Sherbaniuk for suggesting this study to us, and to the Canadian Tax Foundation for its financial support of our research and for the preparation of this manuscript.

John F. Helliwell, *Vancouver*
Mary E. MacGregor, *Ottawa*
Robert N. McRae, *Calgary*
André Plourde, *Ottawa*

September 1988

1

Introduction

Background

Much has happened in the 25 years since the Canadian Tax Foundation published *Oil and Gas Production and Taxes*.[1] By the early 1960s, it was already clear that the post-war opening-up of the world economy and the widely foreseen growth of incomes and trade would lead to great increases in the volume of goods and people transported by rail, sea, air, and road. The dominance of the automobile was being consolidated in North America just as it was starting to emerge in Europe and Japan. The jet plane was new on the scene, and the full extent of its impact on modern life was still unknown. For all forms of transport, however, it was reasonable to foresee that petroleum products would be the fuels of choice. At the same time, in homes and industry, coal was rapidly being replaced by cheaper, cleaner fuel oil and natural gas as sources of heat and power (including steam and electricity). Extrapolation of these trends for oil and gas promised growing demands for energy, with a growing share of oil and natural gas in the energy mix.[2]

All of this was being made possible by the massive supplies of crude oil in the Middle East. Despite the impressive growth in world oil demand, these seemingly limitless supplies of low-cost crude oil assured a continuing downward pressure on world crude oil prices and hence on energy prices in general. The main policy issues relating to oil and natural gas in North America involved trading off the desires of energy users to have access to the ever-cheaper supplies of world oil against the desires of the domestic petroleum industry to obtain a secure market for their production of higher-cost crude oil.[3] In both Canada and the United States, as a result, protection against the importation of foreign oil was combined with various tax provisions to encourage investment and production in the domestic petroleum industry.

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[1] Jacques Barbeau, ed., *Oil and Gas Production and Taxes*, Canadian Tax Paper no. 33 (Toronto: Canadian Tax Foundation, 1963).

[2] John Davis forecast these trends in his *Canadian Energy Prospects*, a study of energy for Canada, Royal Commission on Canada's Economic Prospects (Ottawa: Queen's Printer, 1957) ("the Gordon commission"). General trends in energy demand are discussed in chapter 6, below.

[3] These issues were the subject of the Royal Commission on Energy ("the Borden commission"), whose report gave rise to the national oil policy of 1961, which reserved Canadian markets west of the Ottawa Valley for Canadian crude oil. See Canada, Royal Commission on Energy, *First Report* (Ottawa: Queen's Printer, 1958). These policies are described in more detail in chapter 3, below.

Was it possible, at that time, to predict the world oil price shocks of 1973-74 and 1979-80 and the subsequent oil price declines? Probably not. It should, however, have been possible toward the end of the 1960s to see the stage being set for a substantial energy squeeze as demands grew faster than new discoveries and as the margin of idle production capacity for crude oil shrank. In any event, those world price changes and the multitude of policy changes they induced made the subsequent 25 years complex, confusing, and difficult for those producing and using energy as well as for those responsible for its taxation and regulation. These matters were especially complex in Canada, where the regional differences in energy endowments and the division of powers and revenues between federal and provincial governments posed inevitable complications for the design and administration of energy policies.

The fast pace and great complexity of the events and policy responses have meant that even specialists have had a hard time keeping track of what happened, let alone developing a balanced view of why things happened or what might have been the consequences if things had happened differently. Since ignoring the lessons of history usually ensures that its lessons must be relearned the hard way, the purpose of this study is to draw together several key elements of the Canadian experience, to analyze their relative importance, and to sketch some possible lessons for the future.

Scope and Methods of the Study

Following the example of *Oil and Gas Production and Taxes*, we focus special attention on the "upstream" or producing activities of the Canadian oil and gas industry. But because we are concerned with a broad range of policies affecting energy supply, demand, and taxation, we extend our survey and our analysis to include the prices and demands for all main forms of energy. We also consider a much broader set of policies and regulations and deal with oil and gas supply from non-conventional sources (oil from the oil sands, and oil and natural gas from northern Canada and offshore regions) as well as from western Canadian sources.[4]

Four types of information are presented: (1) consistent historical series for prices, revenues, production, drilling, and investment; (2) a fairly complete record of the major features of changes in the taxation and regulation of oil and gas production, especially at the federal level; (3) an empirical analysis of the main factors determining energy demand, investment, and production; and (4) a quantitative assessment of the effects of alternative taxation and regulation policies. Historical data are presented in figures and tables in several chapters of the study. It should be noted that, because of their length and complexity, sources for the figures in chapters 2 through 9 are not given with the figures themselves but are gathered into an appendix,

[4]For the purposes of this book, northern Canada will be thought to consist of the Yukon and Northwest Territories and contiguous offshore areas. Western Canada is defined as the provinces of Manitoba, Saskatchewan, Alberta, and British Columbia.

"Data Sources and Explanations for the Figures." Similarly, raw data on which much of the modelling work, many of the tables, and some of the figures are based are gathered together in a data appendix. Taxation systems and empirical analysis are described generally in the text with, again, supporting detail presented in individual appendixes, numbered to correspond with the chapters to which they relate.

Our method of analysis is primarily economic and quantitative; we tend to explain energy demands by incomes and relative prices, and to explain industry investment by the factors influencing its expected profitability. We impose a high degree of aggregate consistency on our analysis and results by ensuring that we establish complete linkages between the prices paid by energy buyers and the after-tax revenues received by energy producers. We also ensure that the quantities of oil and gas explained by our demand equations are consistent with the quantities produced and traded. Establishing such consistency in our data is difficult and requires a number of adjustments and assumptions, while the explanation of the linkages between producer revenues, government taxes and royalties, and final energy prices paid by users requires rather detailed modelling of what have often been very complex systems of pricing, taxation, transportation, and distribution for oil and natural gas. In addition, because we cannot analyze many of the important regional aspects of the distribution of energy revenues and benefits without explaining energy pricing and demand on a regional basis, our modelling treats energy pricing and demand separately for each of seven regions in Canada.[5]

Establishing a consistent treatment of oil and gas supplies and demands allows a more complete evaluation of the costs and benefits of alternative policy regimes. For example, if price regulations are used in an attempt to redistribute energy revenues between producers and consumers, the resulting effects on energy use can be evaluated (including any efficiency losses caused by pricing at levels different from the opportunity cost of the energy sources) as can the resulting impacts on energy investment, production, taxation, and trade.

In earlier studies, we have also concentrated on the macroeconomic effects of changes in energy prices and policies, making use of the structure of the macroeconomic model in which our energy modelling is embedded. Although the main emphasis of the current study is on the more detailed consideration of energy taxes and regulations, we continue to do all our analysis within the context of our macroeconomic model and will include a chapter describing the macroeconomic effects of alternative energy prices and policies. Macroeconomic analysis of energy policies is worthwhile because of the importance of energy use and production in the Canadian

[5] The four Atlantic provinces (Newfoundland and Labrador, Nova Scotia, Prince Edward Island, and New Brunswick) are treated as a single unit; the three prairie provinces (Manitoba, Saskatchewan, and Alberta), however, are treated separately in our latest analysis, since their energy pricing and use patterns are rather different.

economy and because energy price changes have been so large and rapid in the post-1973 period.

Preview of the Contents

The study is broadly divided into two parts: chapters 2 to 5 describe oil and gas activity levels, prices, and policies in some detail; chapters 6 through 12 attempt to explain the supply and demand conditions for oil and natural gas, and to evaluate the consequences of the actual policies as well as a number of alternatives.

Chapter 2 sets the stage by describing the size and distribution of Canadian oil and gas resources. It then records the extent of drilling activity and the resulting increases in reserves. Finally, it describes the development of the world petroleum market, especially the changes that have taken place in international and North American prices for crude oil and natural gas. The various Canadian activity measures are compared with those in the United States; these comparisons are useful later as we discuss the extent to which Canadian developments have been determined by common causes rather than by domestic policies.

Chapter 3 explains the history and detail of Canadian federal and provincial regulation of crude oil prices and trade, while chapter 4 does the same for natural gas.

Chapter 5 describes in chronological order the structure and main changes in the system of taxation applicable to the production of crude oil and natural gas in Canada. This chapter contains descriptions rather than quantitative measures of taxes and royalties. Two related appendixes present supporting data: itemized descriptions of the main taxation measures in all federal budgets over the past 20 years are found in appendix 5.1; a less detailed outline of related fiscal measures in the three main producing provinces (Alberta, British Columbia, and Saskatchewan) is included as appendix 5.2. The combined effects of taxes and royalties on the net-of-tax prices received by producers are shown by the netback price series presented in this chapter and used in our subsequent analysis.

Chapter 6 begins the explanatory material by first presenting and then explaining the changes in total energy use in Canada, as well as its distribution by fuel and by region. Appendix 6.1 describes part of the material used in this chapter—the energy demand and losses sectors of the MACE model.[6] Since information on fuel prices to final users is often difficult to obtain, appendix 6.2 discusses how our measures of these prices were derived. This appendix also contains a detailed breakdown of the most difficult of these series to construct—user prices for oil products.

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[6]The version of the MACE model used in this analysis is described in John F. Helliwell, Mary E. MacGregor, Robert N. McRae, André Plourde, and Alan Chung, "Supply Oriented Macroeconomics: The MACE Model of Canada" (July 1987), 4 *Economic Modelling* 318-40.

Chapters 7 and 8 analyze investment and supply conditions for conventional oil and natural gas in western Canada. Chapter 7 reviews the historical patterns of investment, and chapter 8 presents our calculations and discussion of exploration and development costs, as well as some tentative explanations of the variations in the pace of exploration and development activity. Appendix 8.1 presents the results of statistical tests of our preferred explanations of exploration activity against a number of alternatives.

In chapter 9, we turn our attention to non-conventional sources and the frontier regions. These high-cost regions and sources need particular explanation because they have frequently been granted special taxation and incentive measures designed to encourage their exploration and development. We describe and evaluate some of the more important of these measures including, among others, superdepletion and the enriched system of petroleum incentive payments for activities on the Canada lands.[7]

In chapters 10 and 11, we present a more aggregate evaluation of the actual policy regimes in place as well as feasible alternatives that might have been adopted instead. We also discuss to what extent the variations in activity, prices, and revenues have been amplified or dampened by the changes in Canadian policies that have accompanied or followed changes in world oil prices and conditions in US export markets for Canadian natural gas. This is done for industry and government revenues in chapter 10 and for macroeconomic variables in chapter 11. Chapter 12 summarizes our observations and draws some general conclusions.

[7]Note that, as with publications issued by the federal government during the late 1970s and early 1980s, we understand "Canada lands" to mean Canadian territory outside the jurisdiction of any of the provinces.

2

Domestic Resources and World Events

Introduction

The distribution of oil and gas resources in Canada is very uneven: about 85 percent of non-frontier oil and gas reserves are located in Alberta; most of the remaining oil is found in Saskatchewan, and the remaining gas in British Columbia. Since the main producing region is in western Canada, with its traditionally resource-based economy, while the main consuming regions are several thousand kilometres away in the industrialized provinces of Quebec and Ontario, transportation becomes a vital issue. Transportation is also a key issue for potential production from Canada's frontier regions. Despite substantial efforts in the last decade, however, new discoveries of oil and natural gas in the arctic and east coast offshore regions have so far been very small in relation to those in western Canada, and they have been achieved at a much higher cost.

Canadian oil and gas reserves grew rapidly from 1947 to 1973. Energy taxation and trade policies actively encouraged development to meet domestic and export demand for oil and gas. In the 1950s, the reserve base in western Canada was viewed as being plentiful enough to warrant the construction of both oil and gas pipelines from western Canada to Ontario and to export markets in the United States. At their peak in 1973, oil exports accounted for about 58 percent of domestic production, and gas exports accounted for about 42 percent. The potential for large export volumes was a great impetus for Canadian oil and gas exploration and development.

The regional distribution of oil reserves and the cost of trans-Canada transportation led to the establishment of an oil market in which oil was imported into eastern Canada (Quebec and the Atlantic provinces), and exported into the US West and Midwest.

The world oil price increases of 1973-74 and 1979-80 and the rapid decline of world oil prices in 1985-86 are the most important external events influencing the recent pattern of development of Canadian oil and natural gas resources. This study begins, therefore, with a description of these movements of world prices and of the related, but sometimes lagged, changes in oil and natural gas prices within the United States and Canada. US domestic prices are especially important for Canadian natural gas, for which the United States is the only economically attractive export market.

We then describe the scale and pattern of oil and natural gas exploration, development, and production. To help put the Canadian experience in perspective, comparable data for the United States are presented. This will facilitate subsequent explanations of how changes in Canadian policies augmented or offset the swings in activity that would otherwise have taken place in response to the large, and mostly unexpected, changes in world market conditions.

Oil Prices: OPEC, the United States, and Canada

The decade following the end of World War II brought both large increases in world demand for oil, and the discovery and development of vast oil reserves in the Middle East and North Africa. These two forces, working in opposition, caused world oil prices to fluctuate but to show no clear trend during most of that decade. From the late 1950s until 1970, Canadian oil prices remained approximately constant in nominal terms. This pattern was also true for oil prices in the United States and for Saudi light crude oil, as figures 2.1 and 2.2 show.[1] All oil prices nudged upward slightly in 1971 as a result of the Tehran-Tripoli agreements.

The first oil price shock of 1973-74 drove up the price for Saudi light from about US$3.00 to about US$10.50 per barrel.[2] Between 1974 and 1978, world oil prices, measured by the official OPEC (Organisation of Petroleum Exporting Countries) price of Saudi light in US dollars, rose in nominal terms but fell in real terms, reaching US$12.70 per barrel in late 1978. At the end of 1978, OPEC agreed to further increases in its official price—to US$14.55—to be phased in quarterly over the next year. But the plans of OPEC were disrupted by the events in Iran. The revolution stopped all oil exports from that country by the end of December 1978. Panic among oil purchasers, most of whom had allowed their inventories to be drawn down to low levels, forced spot prices up dramatically in early 1979—to as high as US$40 per barrel. Official OPEC prices lagged behind movements in spot prices but rose over the course of 1979 and 1980 to US$34 per barrel. Toward the end of 1980, spot prices took another large leap with the beginning of armed hostilities between Iran and Iraq and the resulting reductions in export volumes from those two OPEC countries.

Subsequent overcapacity in world oil production forced spot prices down during 1981. At the beginning of 1982, they fell below the official OPEC price for the first time since late 1978.[3] Excess production capacity, despite

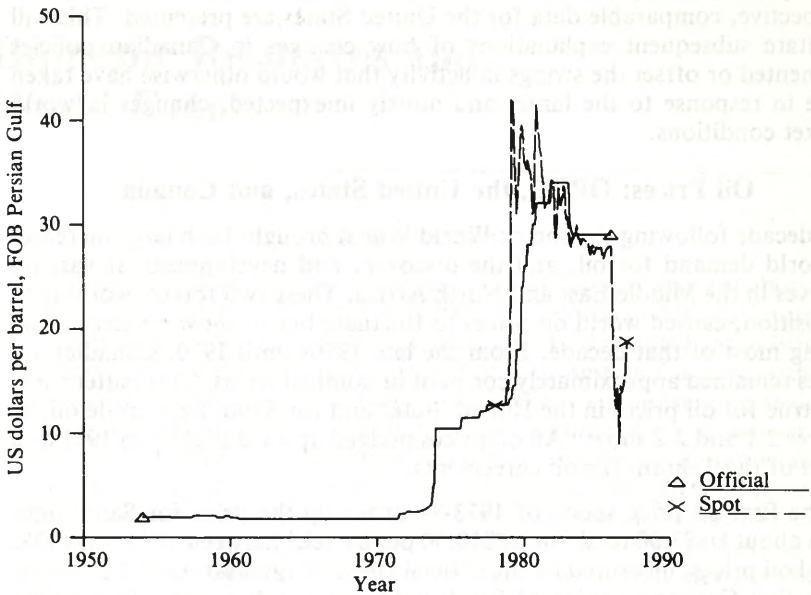
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[1] As with a number of the data series used in this chapter, time series of Canadian, US, and world oil prices are presented in a data appendix. Sources for the data used in the construction of the figures in chapters 2 to 9 are given in an appendix entitled "Data Sources and Explanations for the Figures."

[2] The barrel, of 35 imperial gallons or 159 litres, is the conventional measure for quoting crude oil prices, and we use it throughout this study. There are approximately 6.3 barrels in a cubic metre.

[3] See Albert L. Danielsen, *The Evolution of OPEC* (New York: Harcourt Brace Jovanovich, 1982).

Figure 2.1 OPEC Crude Oil Prices (Saudi Light)
(monthly data)

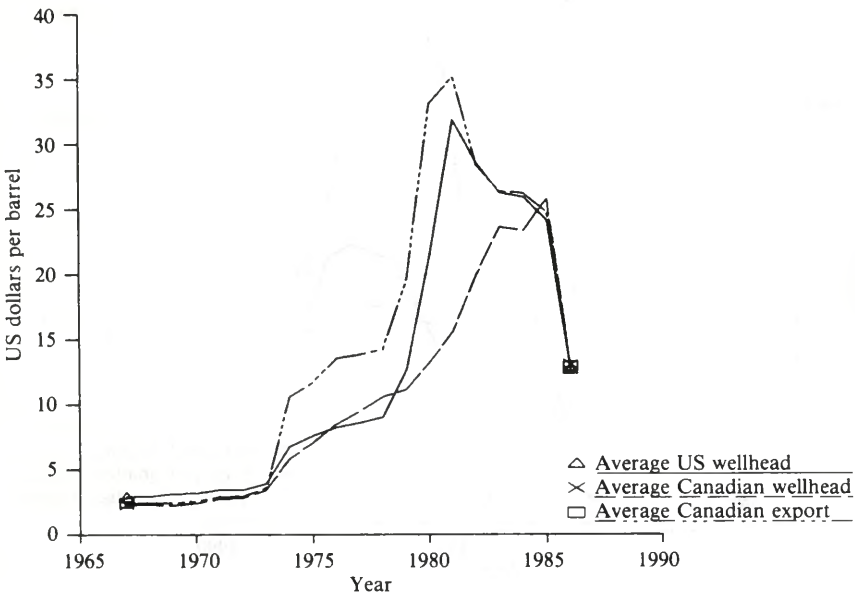


the continuation of the Iran-Iraq war, was brought about by the sharp decline in oil demand because of conservation and substitution as well as by the increase in non-OPEC production. From 1978 to 1983, oil consumption in the non-communist world fell by 12 percent, from 50.6 million barrels per day in 1978 to 44.8 million in 1983. Over that period, oil production from the non-OPEC (and non-communist) countries increased by 24 percent, from 18.7 million barrels per day in 1978 to 23.2 million in 1983.[4] Consequently in March 1983, for the first time in its history, OPEC lowered its official oil price from US$34 per barrel to US$28 per barrel. Spot prices fell even further. The most dramatic drop took place in late 1985 and early 1986, when the oil price fell from about US$27 per barrel at the beginning of December 1985 to a temporary low of about US$9 per barrel in mid-1986. It then rebounded to the US$15 to $18 per barrel range at the end of that year.

OPEC was successful at increasing official oil prices during the 1970s despite the continued excess production capacity of its member countries. The period from 1978 to 1981 was marked by a confusing array of international oil prices and little coordination within OPEC. The rapid rise in official oil prices from 1978 until about the end of 1982 left the general

[4]Data are from British Petroleum, *Statistical Review of World Energy* (London: British Petroleum Company, 1986).

Figure 2.2 Canadian and US Crude Oil Prices
(annual data)

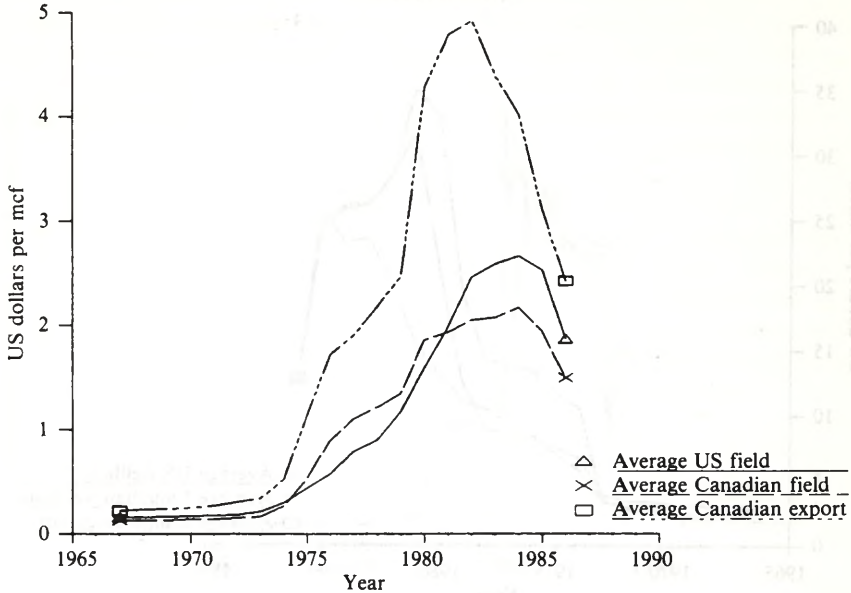


perception in the minds of consumers and producers that oil prices would continue to rise in real terms. But the actual price path taken by world oil prices since 1982 has, in fact, left them below the real 1974 oil price.

Until 1973, the evolution of oil prices in Canada and the United States was very similar to that of prices worldwide. Data for US and Canadian wellhead prices and Canadian export prices, all expressed in US dollars per barrel, are graphed in figure 2.2. Oil exports from Canada to the United States were priced at world-equivalent levels. Until the end of 1980 in the United States, and until mid-1985 in Canada, wellhead prices were controlled by government and regulated at levels lower than prevailing world prices. Overall, Canadian and US prices were quite similar between 1974 and 1979. For the next five years or so, however, US wellhead prices were substantially higher than those in Canada. In 1978—just before the second world oil shock—Canadian oil prices were at 75 percent of world levels, and they did not get this close again until 1983.

Canadian and US field natural gas prices and export prices for Canadian natural gas, all expressed in US dollars per thousand cubic feet, are graphed in figure 2.3. All three prices were similar until 1974, and thereafter export prices rose significantly above field prices. Until 1974, Canadian natural gas prices (export and field) were set to be competitive with US supplies of gas, while US prices for interstate gas were held artificially low by the US

Figure 2.3 Canadian and US Natural Gas Prices
(annual data)



Federal Power Commission (FPC),[5] which was granted control over such prices in 1938. After the OPEC oil price shock of 1973-74, exports of Canadian gas were priced to match more closely the energy-equivalent value of world oil prices. Thus the export price of gas subsequently followed the movements of world oil prices. Canadian and US field prices were controlled by government and set at levels that reflected a discount compared with the energy-equivalent value of oil. Canadian field prices for natural gas were higher from 1975 to 1980, while US prices were higher from 1982 to 1985.

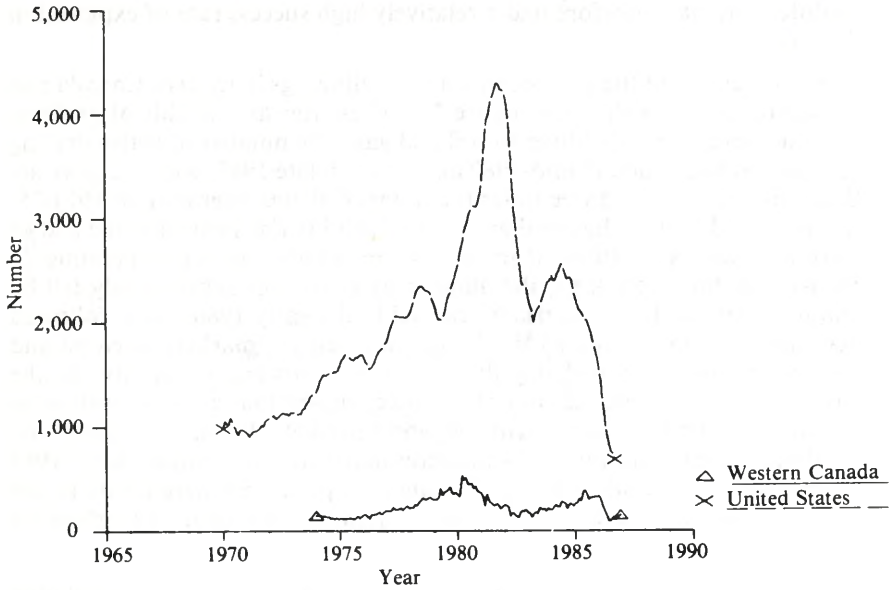
Resource Activity

Exploration

Exploration activity begins with attempts by seismic and geophysical crews to locate the most promising areas for drilling. To drill on Crown land in western Canada, it is necessary to have a licence, which can be purchased at a government-run auction, or to arrange a farm-in with a company already

[5] As explained in chapter 4, below, the FPC became the Federal Energy Regulatory Commission (FERC) in the late 1970s. Note that the period of active regulation by the FPC of US field-prices of natural gas in interstate trade began only in 1954, following a celebrated court decision (the so-called *Phillips* decision). On this, see Richard J. Pierce Jr., "Natural Gas Regulation, Deregulation, and Contracts" (January 1982), 68 *Virginia Law Review* 63-115, at 65-69.

Figure 2.4 Active Drilling Rigs, United States and Western Canada
(monthly data)



holding a licence. Within Alberta, the Crown holds about 81 percent of mineral rights, 10 percent is freehold, and the remainder is in national parks and Indian reserves. Exploration permits for Canada lands are obtained from the federal government.

Exploration activity is aimed at the discovery of replacement oil and gas reserves. The level of activity can be viewed as an industry barometer of the expected long-run profitability. The stock of reserves discovered must be exploited gradually over a long time period—perhaps 20 to 30 years—so that perceptions of future volumes, prices, taxes, and royalties play an important part in profitability calculations.

In western Canada, geophysical, seismic, and drilling activity are concentrated in the winter months; in northern Canada, a significant proportion of the activity is offshore and is therefore concentrated in the summer and fall. The data used to portray these activities in the graphs are monthly or quarterly, and the seasonal patterns are therefore very evident.

Figures 2.4 through 2.15 portray various aspects of the exploration process. How has Canadian drilling activity compared with that in the United States? Exploration drilling for oil and gas in the United States has been less volatile than in Canada. In a relative sense, the level of oil and gas exploration drilling, as measured by the number of completed wells, has been very high in Canada. Oil well completions in Canada were between 25 and 40 percent of those in the United States; gas well completions in Canada were

an even higher percentage of those in the United States—between 30 and 60 percent. Compared with the United States, Canada has been less intensively explored and has therefore had a relatively high success rate of exploration drilling.

A comparison of the number of active drilling rigs in western Canada and the United States is shown in figure 2.4. These rigs are capable of exploration and development drilling for oil and gas. The number of active drilling rigs peaked in Canada in mid-1980 and again in late 1985, with the peak activity involving about three times the number of rigs operating in 1974-75. In the United States, the number of active drilling rigs peaked at the end of 1981 and was also about three times the number of rigs operating in 1974-75. In both countries, the number of active rigs subsequently fell by about 50 percent from the peaks reached in the early 1980s. This followed developments on world and North American energy markets when oil and gas prices either dropped slightly or stopped growing as quickly. In the United States, the deregulation of oil prices meant that activity levels were directly affected by developments on world markets. In Canada, continued regulation resulted in oil prices that continued to grow quickly until 1983 before stabilizing, and even though Canadian producers were aware of the US and world trends, they drilled substantially more relative to their US counterparts in 1984-85.[6]

Figure 2.5, showing the number of active seismic crews, portrays not only seasonal variation but also large variations over time. The sharp increase in seismic activity in the 1966-67 period was the result of the 1965 discovery of the Keg River formation, the last large oil discovery in the western sedimentary basin. Similarly, the sharp increase in seismic activity during 1977-78 was primarily the result of Chevron's discovery of oil in the Pembina area. Effort declined in 1975, partly as a result of the federal government's making provincial royalties non-deductible in order to protect its tax base after provincial royalty rates were raised. By 1976, an accommodation had been reached between the federal and provincial governments about how to handle royalty payments, and investment activity increased. The high level of activity in 1983-1985 was probably a reflection of the relatively high after-tax return on new oil discoveries. The number of active seismic crews, as shown in figure 2.5, accounts for most of the number shown as active geophysical crews in figure 2.6. The latter figure, however, contains separate activity for western Canada, northern Canada, and the east coast offshore region. Although the time under consideration—1976 to 1986—was one of considerable frontier exploration activity, the volume of frontier activity was never of the same scale as that in western Canada.

Figure 2.7 shows western Canadian land sales, measured in millions of hectares. It is interesting that, in physical units, land sales made before the first OPEC price shock in 1973-74 were much higher than those made after-

[6]Comparisons between industry activity levels in Canada and the United States are useful to avoid tunnel vision when observing Canadian data. Most of the rest of this chapter, however, will concentrate on Canada.

Figure 2.5 Active Seismic Crews, Western and Northern Canada
(monthly data)

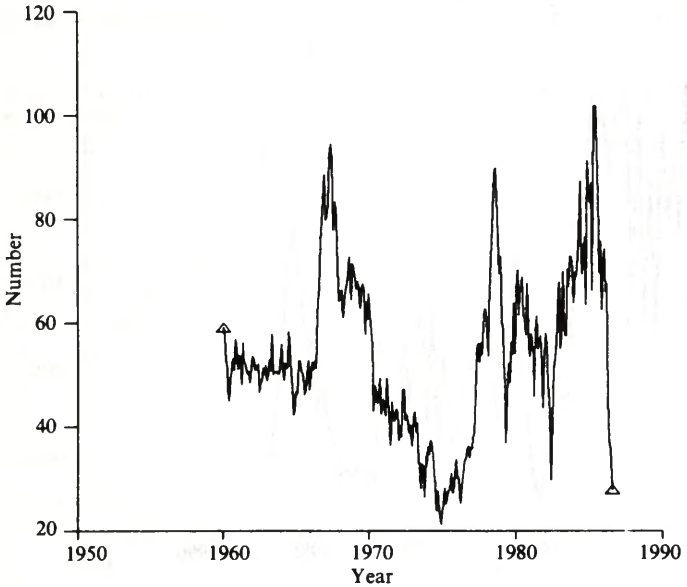


Figure 2.6 Active Geophysical Crews, Canada
(monthly data)

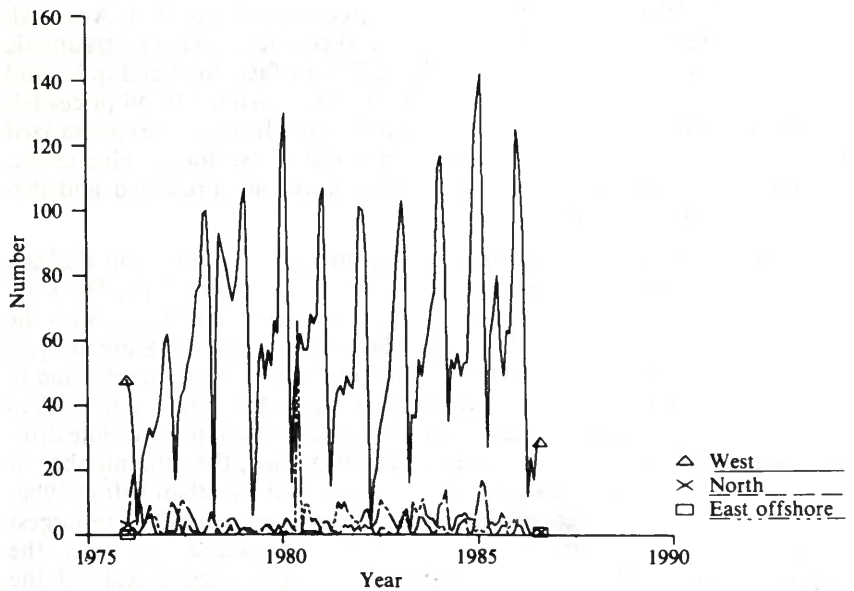
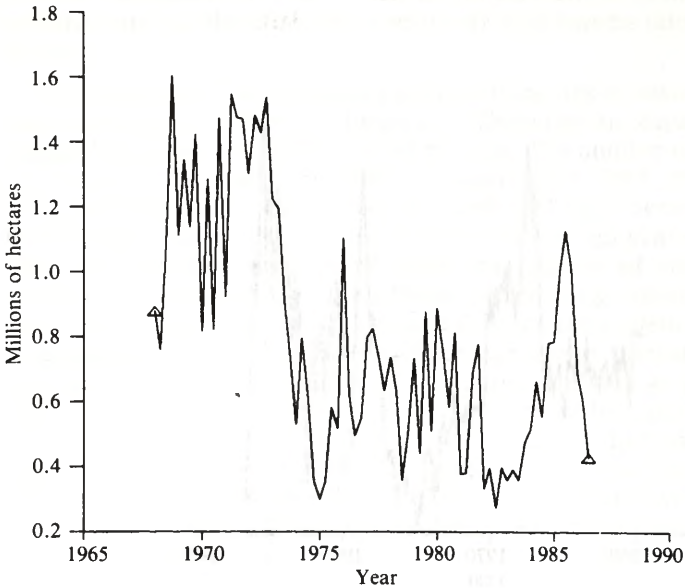


Figure 2.7 Land Sales, Western Canada
(quarterly data)



ward. The 1976 peak is probably related to the Pembina discovery mentioned earlier, and the sharp decline and subsequent increase in 1981 are probably because of the introduction of the national energy program (NEP) at the end of 1980 followed by the energy agreements of late 1981. Although the industry response to the NEP has been to characterize it as a traumatic experience, this is not borne out by figure 2.7. In fact, the buildup in land sales during 1984 and 1985 and the drop in 1986 when world oil prices fell by more than 50 percent were far more substantial. It should be emphasized that the land sales are reported here in physical units, not in value terms. The related investment activity and expenditures are presented and discussed in chapters 7 to 10.

Drilling rig activity in western Canada, northern Canada, and the east coast offshore region is displayed in figures 2.8, 2.9, and 2.10. The total number of drilling rigs represents mainly active rigs and idle rigs, with the remaining few rigs moving and rigging. The most noticeable feature of these figures is the large decline both in the number of drilling rigs in total and in the number of active drilling rigs in western Canada from the end of 1980 to the end of 1981 and the associated large increase in the number of idle drilling rigs over the same period. After a year of decline, the total number of drilling rigs started to increase again, but at a slower rate than before 1980; by 1986 it had almost reached the same number as in 1980. The largest swing in activity occurred over the 1985-1986 period. As with the geophysical crew data, one can observe the relatively small scale of the

Figure 2.8 Total Number of Drilling Rigs, Canada
(monthly data)

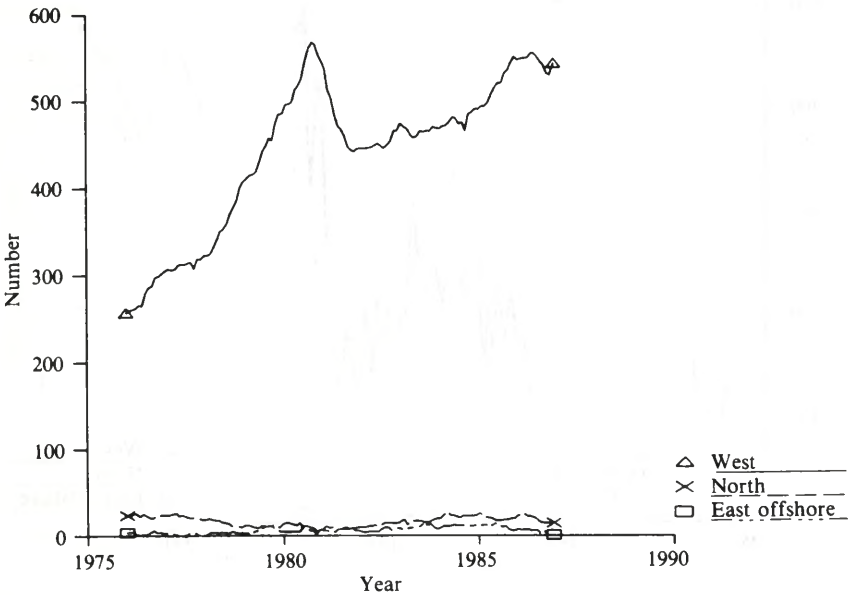


Figure 2.9 Active Drilling Rigs, Canada
(monthly data)

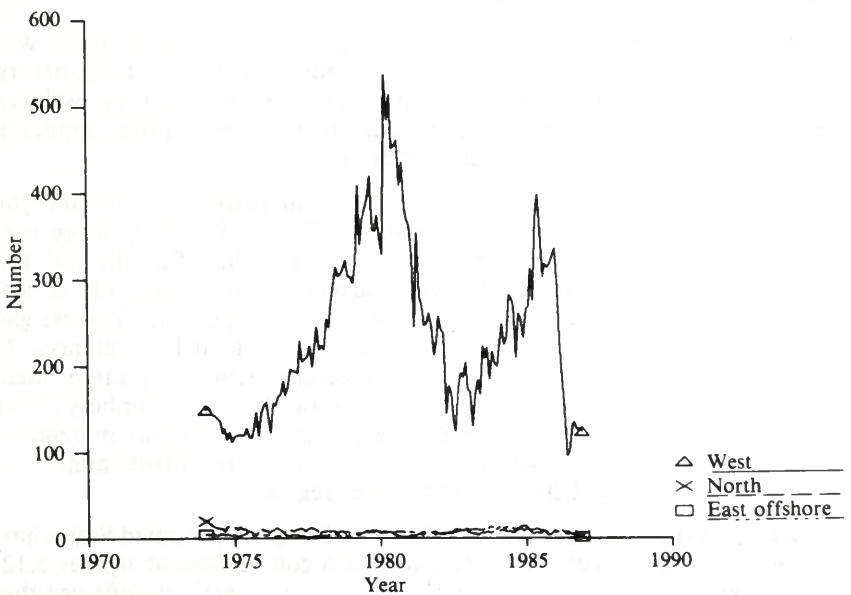
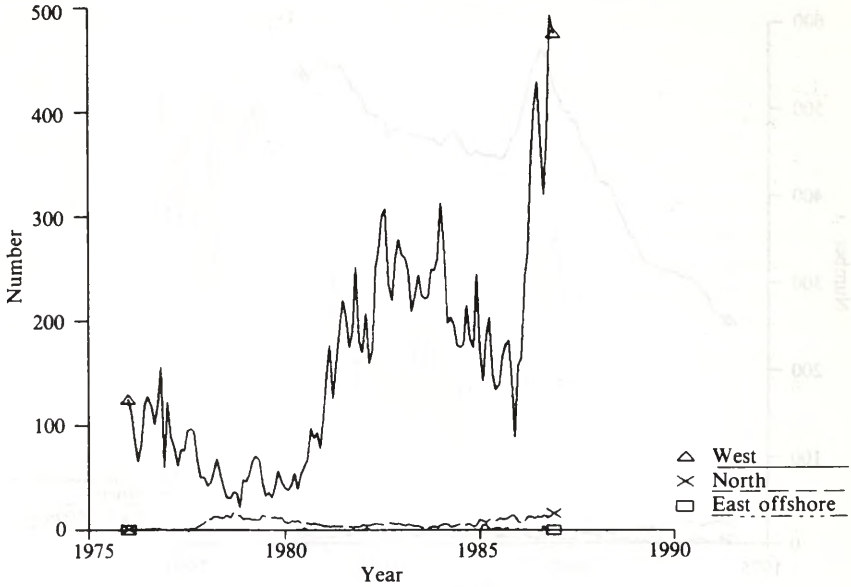


Figure 2.10 Idle Drilling Rigs, Canada
(monthly data)



northern and east coast activity compared with western Canada. As shown in chapter 9, however, drilling costs per well are very much higher in the frontier regions, and the frontiers therefore represent a larger fraction of total expenditures than of activity.

Figure 2.11 shows that the average depth of exploration wells was reduced by almost 25 percent in western Canada from 1965 to 1976, before increasing by almost the same amount from 1976 to 1985. Costs per well are higher for wells of greater depth, and the higher netback prices available after the mid-1970s encouraged deeper drilling.

Figures 2.12 and 2.13 indicate rather different patterns for oil and gas exploration wells completed. From about 1973 to 1981, many more successful exploration wells were completed for gas than for oil; just the reverse was the case from 1981 to 1986. Differences in the ratio of the netback price to marginal costs and changes in the prospects for natural gas export sales will be used in a later chapter to explain such differences. It should be pointed out, however, that exploration firms may target their effort toward oil but discover gas, or vice versa. Thus the numbers of oil and gas exploration wells completed are not exact reflections of relative profitability and marketability. Compared with western Canada, almost no exploration wells were drilled in the frontier regions.

Since 1970, the pattern of oil exploration drilling in the United States has been relatively smoother than in Canada, as a comparison of figures 2.12 and 2.14 would suggest. In particular, the peak in US activity followed the

Figure 2.11 Average Depth of Wells, Western Canada
(annual data)

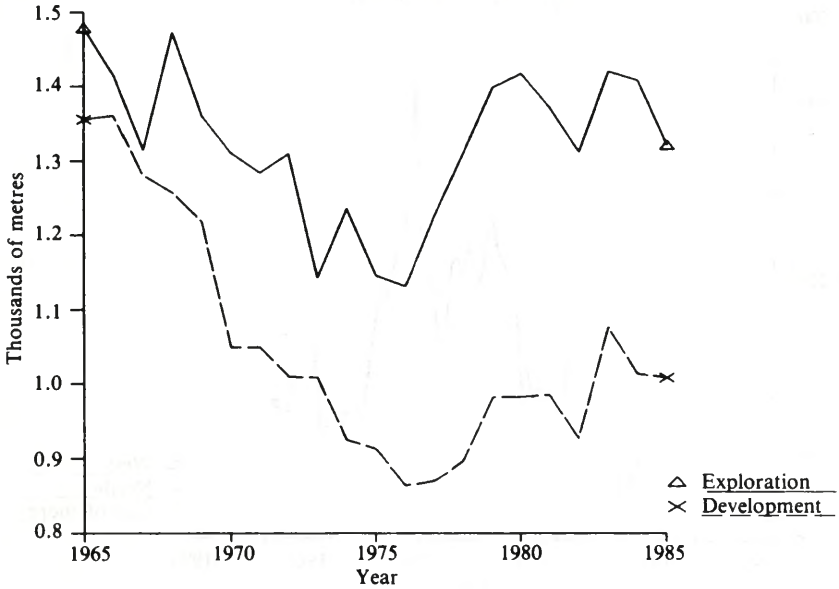


Figure 2.12 Exploration Oil Wells Completed, Canada
(quarterly data)

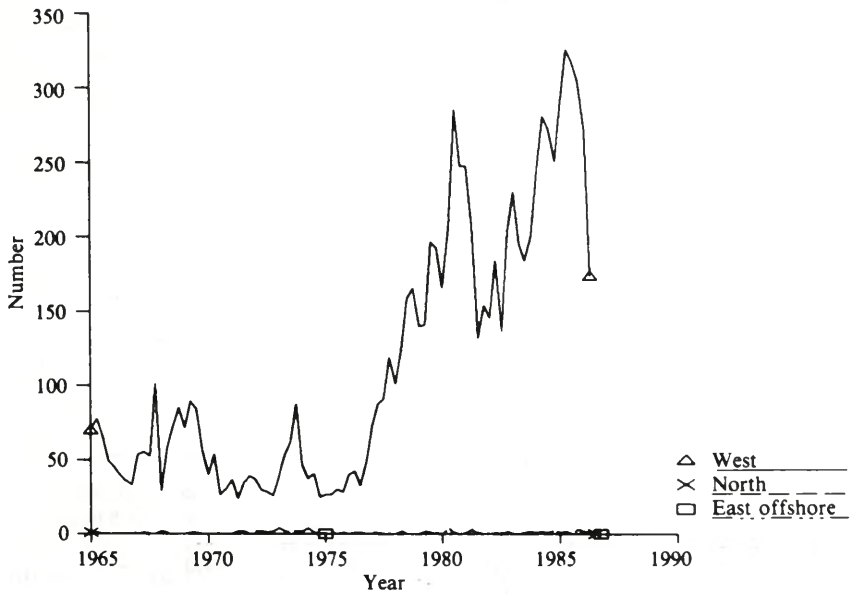


Figure 2.13 Exploration Natural Gas Wells Completed, Canada
(quarterly data)

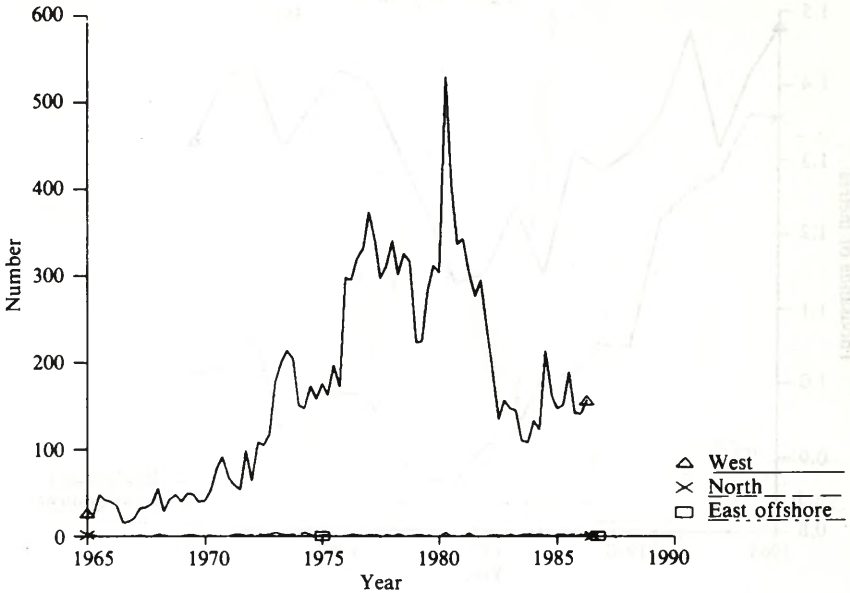


Figure 2.14 Exploration and Development Oil Wells Completed, United States
(quarterly data)

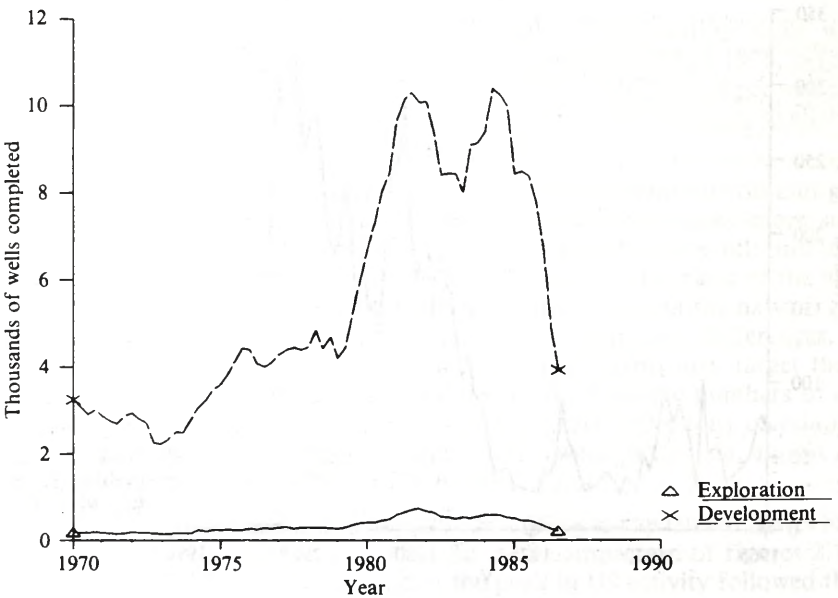
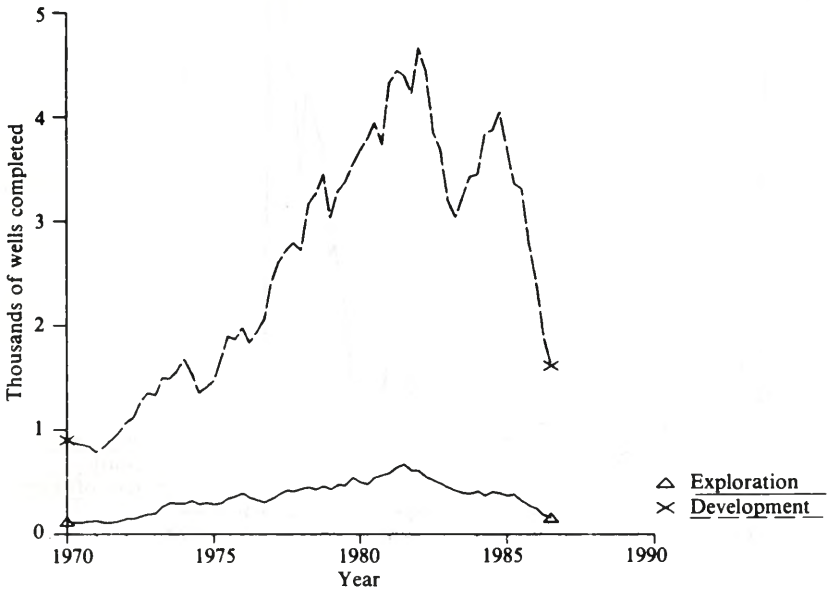


Figure 2.15 Exploration and Development Natural Gas Wells Completed, United States
(quarterly data)



second world oil price shock and the deregulation of the oil industry in that country early in 1981. Similarly, gas exploration activity, as measured by the number of wells completed, has followed a relatively steadier path in the United States. In addition, as figures 2.13 and 2.15 remind us, there was no sharp peak in US activity levels comparable to that which occurred in Canada in 1980, even following the partial deregulation of the US gas industry in 1978.

Development

After exploration activity, the next stage is development of proven reserves to the point where they are ready for production. This involves drilling step-out wells to delineate the size (depth and area) and flow characteristics of discovered reservoirs.

Figures 2.14 and 2.15 also show the number of completed development wells in the United States for oil and for gas, respectively. Figures 2.16 and 2.17 show the same information for Canada. The pattern for oil development drilling is quite different in the United States from that in Canada. US development drilling more than doubled between 1979 and 1981, then declined by about 20 percent in 1982 and 1983 before increasing to the previous (1981) peak in 1984 and then plummeting in 1986. The Canadian pattern shows an approximate doubling of development wells completed during 1979 to 1983 compared with previous years, but the largest increase

Figure 2.16 Development Oil Wells Completed, Canada
(quarterly data)

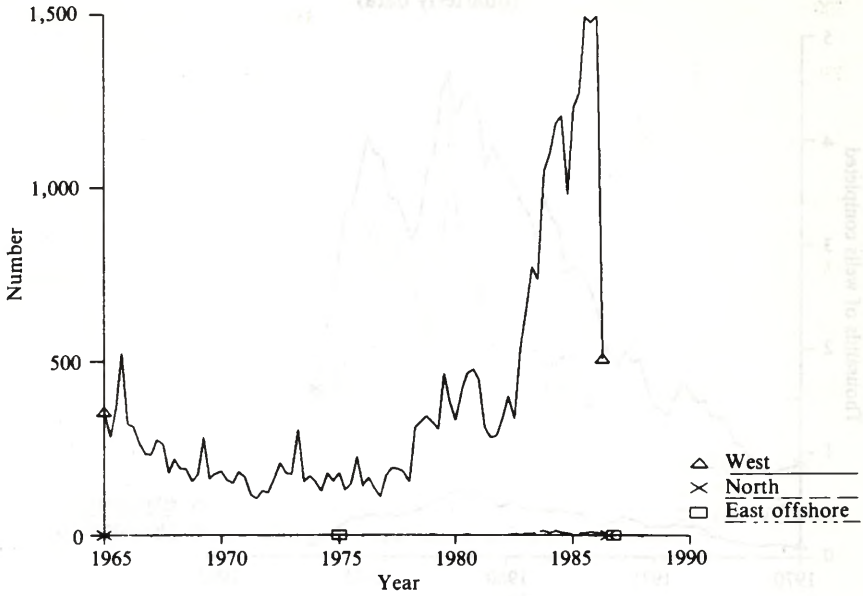


Figure 2.17 Development Natural Gas Wells Completed, Canada
(quarterly data)

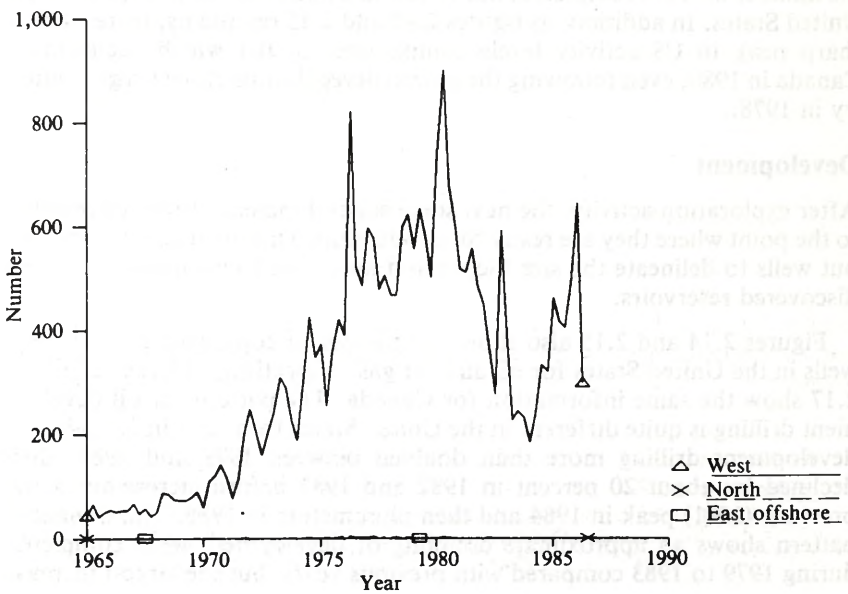
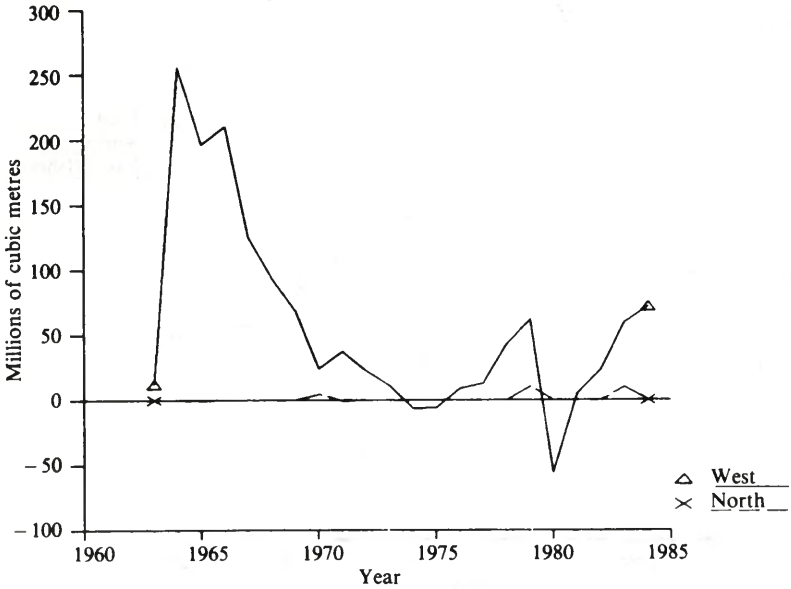


Figure 2.18 Reserve Additions for Crude Oil, Canada
(annual data)

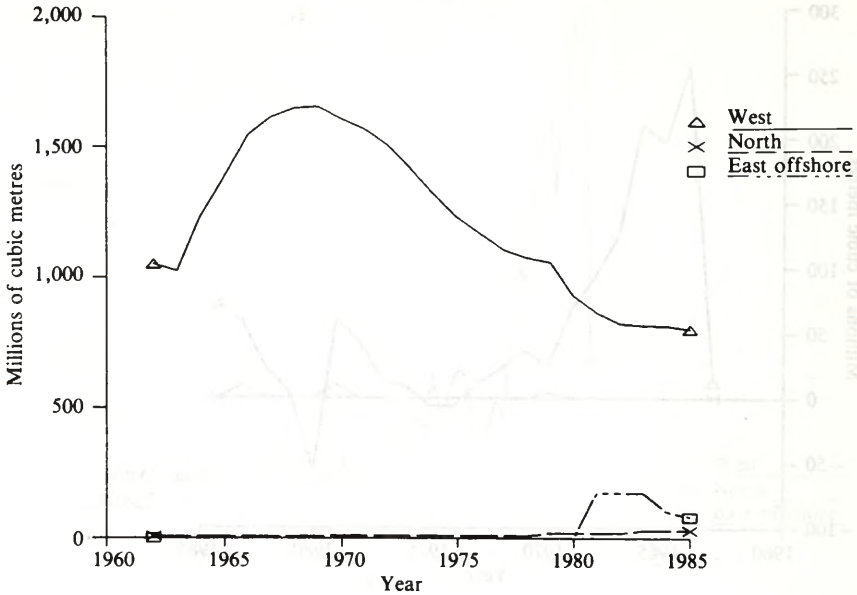


occurred from 1983 to 1985, when the number of development wells increased fivefold before plunging in 1986. The peak oil development activity in Canada was higher, came later, and lasted for a shorter period of time than in the United States. On the other hand, the pattern of gas development wells drilled is quite similar in Canada and the United States. But the peak drilling in Canada increased about fourfold from 1973, whereas it increased about threefold in the United States. As figure 2.4 reminds us, the fact that exploration and development drilling for oil and gas in western Canada moved in opposite directions from 1981 to 1985 helped to keep the number of active drilling rigs fairly stable over this period.

Average well depth for development wells in western Canada declined by about 35 percent from 1965 to 1976, which was a somewhat greater decline than for exploration wells. But the average well depth for development wells increased only marginally (about 10 percent) thereafter, unlike that for exploration wells.

The outcome of development drilling is reserve additions. Figure 2.18 shows the reserve additions for crude oil for western and northern Canada. The only recognized additions for the east coast offshore region have been for Hibernia (discovered in 1979). In western Canada, reserve additions for oil gradually fell over the 1964 to 1975 period but increased thereafter,

Figure 2.19 Remaining Established Crude Oil Reserves, Canada, at Year-End



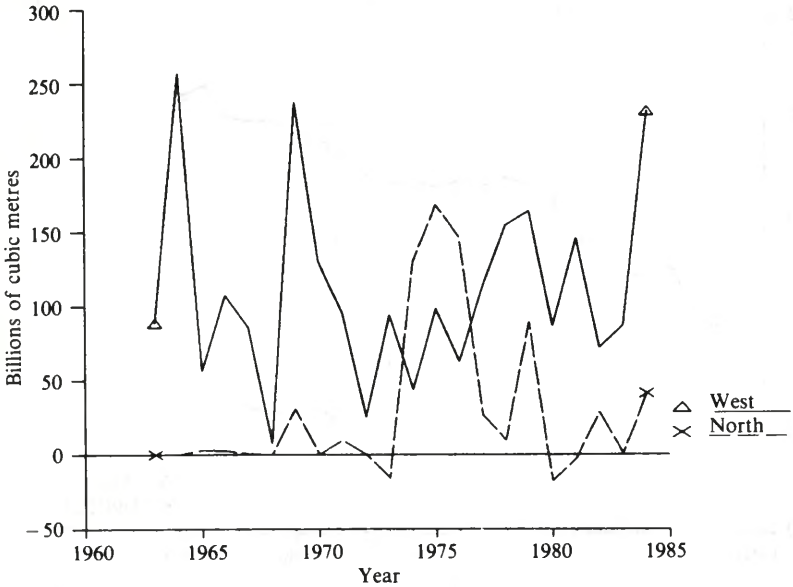
except in 1980 when reserve additions were negative.[7] The large reserve additions in the mid-1960s are mostly the result of the Keg River discovery in 1965. As figure 2.18 shows, that was the last large oil discovery in western Canada.

The annual level of oil reserve additions has not exceeded 75 million cubic metres[8] since the late 1960s, and since this is less than the annual oil production (see figure 2.22 in the next section), remaining established oil reserves have been declining since 1969. The decline in remaining established crude oil reserves is clearly evident in figure 2.19. The level of oil reserve additions in the last few years, in conjunction with declining oil production, has been sufficient to keep the level of remaining oil reserves in western Canada about constant. Recognition of the Hibernia reserves in 1981 provided a relatively large boost to total Canadian remaining oil reserves; it was the first for the east coast offshore area. The drop in the oil reserve estimates for the east coast offshore region in 1984 and 1985 does

[7] Negative reserve additions occur when additions from new discoveries are more than offset by downward revisions to previously estimated reserve additions.

[8] Current industry practice is to use both metric and imperial measures when referring to volumes and prices of natural gas. For example, prices are almost always given in dollars per thousand cubic feet, whereas volumes tend to be given in both metric (for example, billions of cubic metres) and imperial measures (for example, trillions of cubic feet). We have adopted current industry practice in this area. Note that there are approximately 35 cubic feet in a cubic metre.

Figure 2.20 Reserve Additions for Natural Gas, Canada
(annual data)



not represent production but rather the downgrading of the estimated size of Hibernia that was deemed appropriate after the results of delineation drilling had been examined.

Figure 2.20 shows that reserve additions for marketable natural gas in western and northern Canada have been much more erratic than for oil. Also the size of the reserve additions have been larger relative to gas production (gas production is shown in the next section, in figure 2.23), so that the remaining established gas reserves are seen to have been almost continuously increasing. Figure 2.21 shows that remaining established gas reserves have more than doubled between 1962 and 1985. Unlike oil reserve additions, natural gas additions in the frontier regions (especially northern Canada) have been relatively large; in 1985 they were about 30 percent as large as those in western Canada. The frontier regions do not yet include the Sable Island gas discovery in the east coast offshore region because there is still some doubt about its economic viability.

Production

Western Canada's oil production is depicted in figure 2.22. The dip in oil production in the late 1950s was the result of a decline in oil exports to the United States, because Canada was initially included in that country's mandatory import quota program of 1959. This did not last long, however, and by 1960 Canada (along with Mexico) had been granted an "overland exemption." Although this exemption did not give Canadian oil unlimited

Figure 2.21 Remaining Established Gas Reserves, Canada, at Year-End

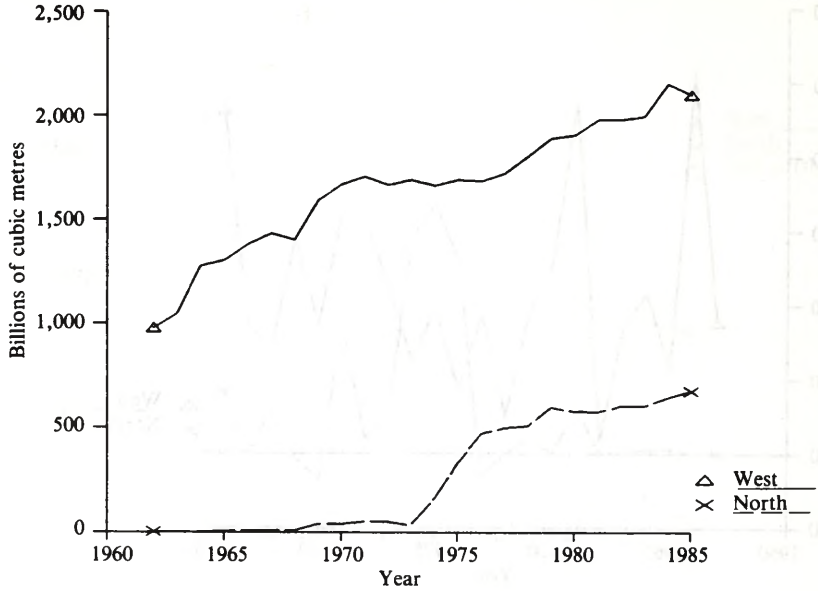


Figure 2.22 Annual Crude Oil Production, Western Canada

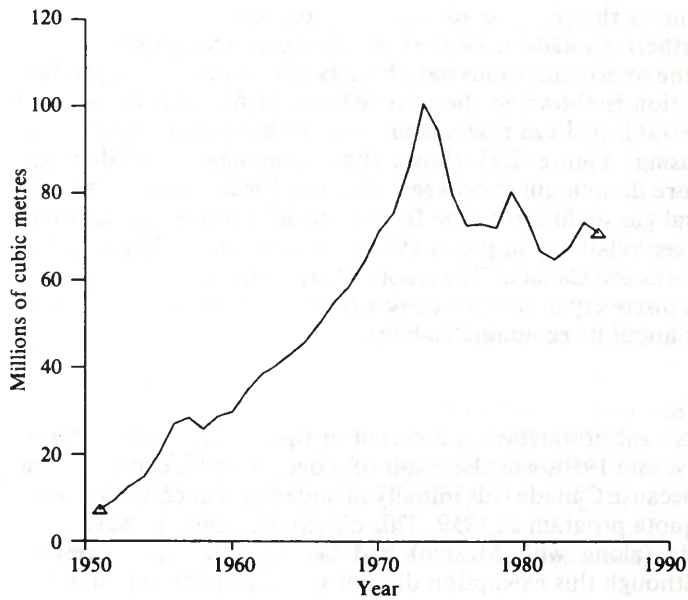
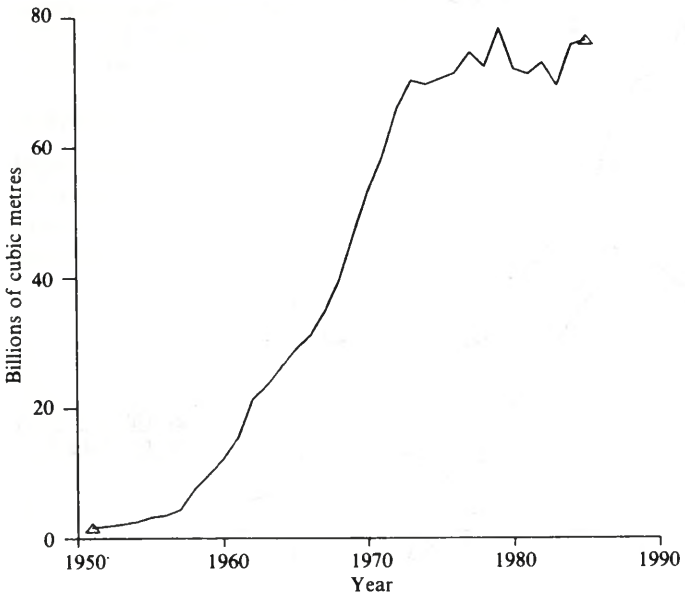


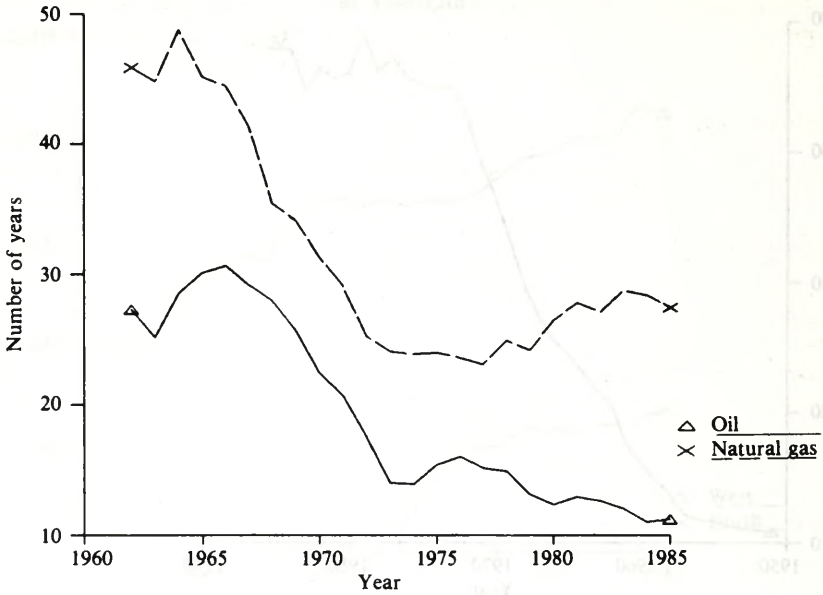
Figure 2.23 Annual Marketable Natural Gas Production, Western Canada



access to the United States, it did allow Canadian export volumes to continue to increase throughout the 1960s and early 1970s. Oil production reached a peak in 1973 and then declined rapidly until 1976 because of Canada's decision to phase out exports of light crude to the United States over the period 1975 to 1977. Oil production from western Canada rose again a few years later in 1978 and 1979 because of the start-up of the Sarnia-to-Montreal pipeline extension. Western Canadian oil production is influenced by many factors: overall level of oil demand, the level of oil imports into eastern Canada (Quebec and the Atlantic provinces), the volume of oil flowing through the Sarnia-Montreal pipeline, the level of export demand, the amount of synthetic oil production, and the capacity of the Interprovincial Pipe Line (IPL) system.

Marketable natural gas production is shown in figure 2.23. Its growth rate was somewhat larger than for oil, partly because natural gas was not available in the large Ontario market until the late 1950s, when the TransCanada PipeLines (TCPL) project was finished. Export markets in the United States were established around the same time, when pipelines were built from Alberta and British Columbia. The growth rate in natural gas production slowed down dramatically after 1973. Part of the explanation for this was a decision by the National Energy Board (NEB) not to issue any new export permits between 1971 and 1978. Of course, both oil and gas production were affected by the conservation effort induced by the increases in oil and gas prices.

Figure 2.24 Life Index for Oil and Gas, Western Canada



The life indices (ratios of reserves to current annual production) for natural gas and oil are displayed in figure 2.24. The life index can be interpreted as the number of years the current reserves will last if there are no additions to reserves and if production continues at the existing level. It is a rough measure of the inventory of reserves held for future consumption.

The life index is much higher for natural gas than for oil, especially before the 1970s. In the 1950s and 1960s, the extraordinarily high life index for natural gas arose because natural gas was found as a by-product of oil exploration, and markets for it had not fully developed. During the 1970s, there was significant debate over the need for gas supplies from the arctic region. Industry submissions to hearings before the NEB painted a picture of looming gas shortages. This was in startling contrast to the optimistic reserve outlook at the end of the 1960s. Arctic gas resources were seen as a necessary source of supply for southern Canada and possibly for the US export market. Lengthy hearings ensued before the NEB in the 1970s regarding domestic supply and demand balances and the feasibility of a pipeline to bring arctic gas to market. With respect to gas from the reserves in western Canada, however, any fear of shortages seems to be unfounded, since the life index remained in the range of 24-30 years throughout the 1970s. When the life index fell below 30 years in 1970, Canada stopped issuing new export permits, since the NEB's exportable surplus test failed to indicate the presence of any gas surplus to Canadian needs.

The life index for oil has remained between 11 and 15 years since 1973. Given the relatively long lead times to bring new oil supplies to production,

especially from non-conventional sources like oil sands, the life index for oil could be cause for concern. At the end of 1984, the life index for oil from OPEC was 72 years and for the whole world, 34 years, so that there is a substantial worldwide inventory of conventional oil reserves.

Synthetic Oil

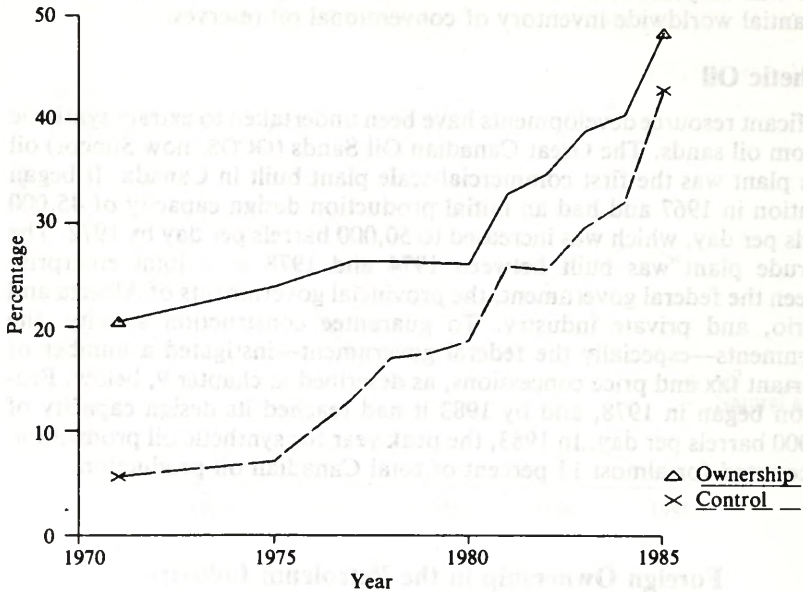
Significant resource developments have been undertaken to extract synthetic oil from oil sands. The Great Canadian Oil Sands (GCOS, now Suncor) oil sands plant was the first commercial-scale plant built in Canada. It began operation in 1967 and had an initial production design capacity of 45,000 barrels per day, which was increased to 50,000 barrels per day by 1972. The Syncrude plant was built between 1974 and 1978 as a joint enterprise between the federal government, the provincial governments of Alberta and Ontario, and private industry. To guarantee construction activity, the governments—especially the federal government—instigated a number of important tax and price concessions, as described in chapter 9, below. Production began in 1978, and by 1983 it had reached its design capacity of 129,000 barrels per day. In 1983, the peak year for synthetic oil production, it accounted for almost 13 percent of total Canadian oil production.

Foreign Ownership in the Petroleum Industry

The degree of foreign ownership and control of the oil and gas industry has had an important influence on Canadian energy policy. One method by which governments have aimed at reducing the level of foreign ownership is by establishing state enterprises that are granted special land rights or that purchase existing assets from foreign-controlled firms. Such firms have been established by provincial governments—for example, Alberta Gas Trunk Line (AGTL) and Alberta Energy Company in Alberta, Saskoil in Saskatchewan, and Société québécoise d'initiatives pétrolières (SOQUIP) in Quebec—and by the federal government (Petro-Canada). Canadianization of the petroleum industry has also been facilitated by the purchase of foreign assets by Canadian firms, like the Dome Petroleum purchase of Hudson's Bay Oil and Gas and the Olympia & York purchase of Gulf Canada.

The change in control and ownership of the petroleum industry on the basis of upstream plus downstream revenues, measured at year-end, is shown in figure 2.25. Canadian control remained at a very low level (7 percent) until 1975 and had increased to only 19 percent by 1980. The largest increase in Canadian control came in 1980, when it increased by about 6 percentage points, and in 1985, when it increased by about 10 percentage points. Throughout the 1970s, the level of Canadian ownership was much higher than the level of Canadian control, rising slowly from about 21 percent to 26 percent. From 1980 to 1985, Canadian ownership followed a pattern somewhat similar to that of Canadian control, but was consistently about 7 to 8 percentage points higher. The Petroleum Monitoring Agency

Figure 2.25 Canadian Ownership and Control of Petroleum, on the Basis of Upstream Plus Downstream Revenues
(annual data)



(PMA)[9] also reports ownership and control using other data—such as upstream revenue only, oil and gas revenue separately, and assets. Generally, Canadian ownership is about 2 to 5 percentage points higher using upstream revenue only, and Canadian control is about 3 to 10 percentage points higher. Hence, Canadian control and ownership are higher in the upstream than in the downstream component of the industry; within the upstream sector, gas-based revenue has a higher degree of Canadian control and ownership than does oil-based revenue. On the basis of total assets, Canadian ownership and control were above 50 percent by 1982.

[9]See Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry: Monitoring Survey* (Ottawa: Supply and Services, various issues).

3

Regulating and Deregulating Crude Oil

Introduction

The Canadian oil industry has been the subject of government intervention almost since its inception: production of crude oil, its allocation between domestic and export markets (and indeed, among different domestic markets), and prices have all been either directly controlled or strongly influenced by government policies at one time or another. This chapter examines how the Canadian crude oil market has evolved, how it has been influenced by the regulatory environment, and how the regulatory environment has changed (or not, as the case may be). First, a brief overview of the pre-1973 system shows how much of the structure of the current marketing system was laid down in this period. We then describe how the first OPEC price shock led to a "made-in-Canada" oil price and dramatically increased the degree of government involvement. The complexities of the two-price system introduced in the 1981 federal-provincial energy agreements are discussed, along with the implications of deregulation for domestic oil prices and the marketing of Canadian crude oil.[1]

Market Protection

The pre-1973 period established many of the institutions and much of the regulatory framework in effect today, and created a tradition of active government involvement in the industry. During the 1950s and 1960s, oil was cheap, plentiful, and dominated by a handful of large multinationals. Probably the most outstanding feature of this period, particularly when compared with the post-1973 period, is the stability of international oil prices (see chapter 2, figures 2.1 and 2.2). The posted price of Saudi light, for example, was almost constant in nominal terms over most of the period. It increased slightly during the Suez crisis of 1956-57 (from US$1.93 to US$2.08 per barrel), but by August 1960 it had dropped to US$1.80 per barrel, where it remained for the next 11 years. Although data on actual transaction prices are sketchy, these prices probably fell during the 1960s as new companies entered the international marketplace and new sources of supply

[1] The following sections have drawn heavily from three sources: André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986,* PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986); G. Bruce Doern and Glen Toner, *The Politics of Energy: The Development and Implementation of the NEP* (Toronto: Methuen, 1985); and Canada, Restrictive Trade Practices Commission, *Competition in the Canadian Petroleum Industry* (Ottawa: Supply and Services, 1986).

were developed.[2] Despite the new entrants, the big multinationals still dominated the world market and controlled about 80 percent of world production by the end of the 1960s.[3]

The multinationals played a key role in the development of the Canadian industry as well. Imperial Oil, a subsidiary of US-owned Exxon, drilled the discovery well at Leduc in 1947, marking the start of the modern Canadian oil industry. Production expanded rapidly, and by 1951 Imperial accounted for around 40 percent of Canadian production.[4] This, plus its dominance of the refining sector,[5] helped establish Imperial as the industry leader.

The rapid expansion in productive capacity was not matched by an equally rapid expansion in available markets. As a result, by 1950 production was running at about 45 percent of capacity. Complaints about marketing problems led to hearings in October 1950 by the Alberta Petroleum and Gas Conservation Board (APGCB).[6] The board's response was to adopt a system of allocating market demand among producers. This system, often called prorationing, was implemented in December 1950, a few months after the APGCB hearings.

Marketing problems were not the sole reason for instituting prorationing. Efficient production was also a consideration, since oil in the ground is a typical common property resource. Because a firm does not own the oil until it is actually produced, each firm with a well in a given reservoir has the incentive to produce as much oil as it can before its competitors get to it. As a result, production rates tend to be too high, which can lead, for a variety of technical reasons, to the recovery of less oil than would be the case with a sole owner. Prorationing is not the only solution to this common property problem. Compulsory field unitization is an alternative, but one that the Alberta government and the APGCB concluded did not lie within their authority.

Under prorationing, the AERCB (or one of its predecessors) set the total allowable production for the province equal to estimated market demand. Demand for Alberta crude was determined from the nominations filed with the board by refiners stating their intended purchases. Over the years, most of the changes to the system have had to do with the method of allocating the total allowable production among producers. Initially, each well received a two-part production quota. The first part, the economic allow-

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[2] In 1967, for example, the Department of National Revenue calculated the fair market value of crude oil as 12 percent less than the posted price. See Canada, Restrictive Trade Practices Commission, supra, at 102.

[3] Ibid., at 96.

[4] Ibid., at 132.

[5] At this point, Imperial owned approximately 50 percent of the refining capacity in Canada. See ibid., at 81.

[6] This board later became the Alberta Oil and Gas Conservation Board (AOGCB) and then the Alberta Energy and Resources Conservation Board (AERCB). It was established to regulate the production of oil and natural gas, and their removal from the province.

ance, was set to a fixed amount, which was graduated according to well depth. After all the economic allowances had been satisfied, the remaining market demand was then allocated according to the productive capacity of each well. In 1957, the system was changed so that the fixed economic allowance was higher for the first seven years after the initial development of a reservoir and then reduced. Changes in 1964 abolished the two-part economic allowance and replaced it with a single, much reduced minimum allowance graduated with well depth. Remaining market demand was then allocated across reservoirs in proportion to reserves, without reference to the number of wells or their productive capacity.

In the early days, prorationing accomplished two main things. First, because it guaranteed a certain minimum production to each well and tended to favour new ones, it made entrance to the industry relatively easy for the newer, smaller firms.[7] Second, because any increase in market demand was spread over all producers, prorationing effectively eliminated direct price competition among producing firms.[8] What did encourage price competition was the overwhelming need to find new markets for the burgeoning domestic production.

Geography and politics made the task of penetrating new markets difficult. A pipeline was the only feasible solution to the problem of the vast distances between the oil in the West and the consumers in the East, but it was more expensive than shipping foreign crude into eastern Canada by tanker. It was not until 10 years after the Leduc discovery that the IPL (Interprovincial Pipe Line Limited) oil pipeline reached Toronto. Expansion into the export market was complicated by increasing protectionism in the United States. Successful lobbying efforts on the part of the US oil industry led to the introduction in the United States of voluntary import controls in 1955 and mandatory controls in 1959.

The need for new markets and the excess production capacity of the Canadian oil industry were two of the main issues addressed in the second report of the Royal Commission on Energy (the Borden commission) released in 1959.[9] In presentations to the commission, the Independent Petroleum Association of Canada (IPAC), a group of small independent companies, lobbied for an extension of the pipeline to Montreal and an expansion of the available domestic market. The major oil companies, on

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[7] As an example, Imperial Oil's share of western Canadian oil production fell from about 40 percent in 1951 to 15 percent in 1978. See Canada, Restrictive Trade Practices Commission, supra footnote 1, at 132.

[8] Two other drawbacks of the prorationing system instituted in Alberta are worthy of notice. First, the pre-1957 system tended to encourage overdrilling since individual producers could obtain a larger share of total production by drilling more wells. Second, prorationing tended to encourage cost-inefficient behaviour since every firm with reserves was guaranteed a share of production, irrespective of production costs. For a more detailed discussion of these and related issues, see G.C. Watkins, "Conservation and Economic Efficiency—Alberta Oil Proration" (March 1977), 4 *Journal of Environmental Economics and Management* 40-56.

[9] See Canada, Royal Commission on Energy, *Second Report* (Ottawa: Queen's Printer, 1959) ("the Borden commission").

the other hand, were in favour of expanding the market by keeping foreign imports out of Ontario and increasing exports to the United States. The latter policy was recommended by the commission and became the basis of the national oil policy (NOP) introduced in 1961.

Between 1961 and 1973, the NOP established a protected market for Canadian crude oil producers. The area west of the Ottawa Valley was reserved for domestic production, while the area east of that was supplied by imported oil. As figure 3.1 shows, deliveries of domestic production to Canadian refineries between 1957 (when the IPL pipeline was extended to Toronto) and 1961 (when the Ottawa Valley line was established) increased less than the overall increase in total refinery receipts. After the introduction of the NOP, domestic deliveries increased steadily. One of the consequences of this policy was the fact that delivered crude oil prices in Toronto were higher than average import prices during the NOP years (figure 3.2).[10] Canadian wellhead prices were roughly competitive with US prices, which in turn were higher than offshore crude prices because of import controls, but the mere existence of a protected domestic market would have created the opportunity for higher prices in any event.

Expansion into the US market, the other main objective of the NOP, had been actively encouraged by both the federal and provincial governments since the early 1950s. In 1953, C.D. Howe, then federal minister of trade and commerce, had advocated marketing surplus Canadian production in the United States, and transporting it by the least-cost routes. Although the federal government enacted the Exportation of Power and Fluids and Importation of Gas Act in 1955, which required prior approval of future energy exports by the federal Cabinet, this appears to have been a response to early experiences with Ontario natural gas exports,[11] rather than to the steadily growing exports of crude oil. The National Energy Board (NEB) was created in 1959 with the authority to regulate exports of crude oil as well as natural gas, but it did not introduce a formal licensing system for crude oil until 1973. It did, however, license natural gas exports and introduce specific surplus test requirements to be met before exports could be authorized.[12] Aside from setting pipeline tariffs, the only action taken by the NEB with respect to oil markets before 1973 was to introduce mandatory gasoline import licences in 1970 as a result of complaints about violations of the Ottawa Valley line.

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[10]Caution should be used in interpreting the price comparisons in figure 3.2 since no adjustments have been made for quality differentials or transport costs. More detailed and exact comparisons are available in Canada, Department of Energy, Mines and Resources (herein referred to as EMR), "Memorandum of Agreement Between the Government of Canada and the Government of Alberta Relating to Energy Pricing and Taxation" (mimeograph, September 1, 1981); and Canada, Restrictive Trade Practices Commission, supra footnote 1, at 81-89.

[11]See Ian McDougall, "The Canadian National Energy Board: Economic 'Jurisprudence' in the National Interest or Symbolic Reassurance?" (1973), 11 *Alberta Law Review* 327-82, at 334-35.

[12]See chapter 4 for a more detailed discussion of these issues.

Figure 3.1 Annual Refinery Receipts of Crude Oil

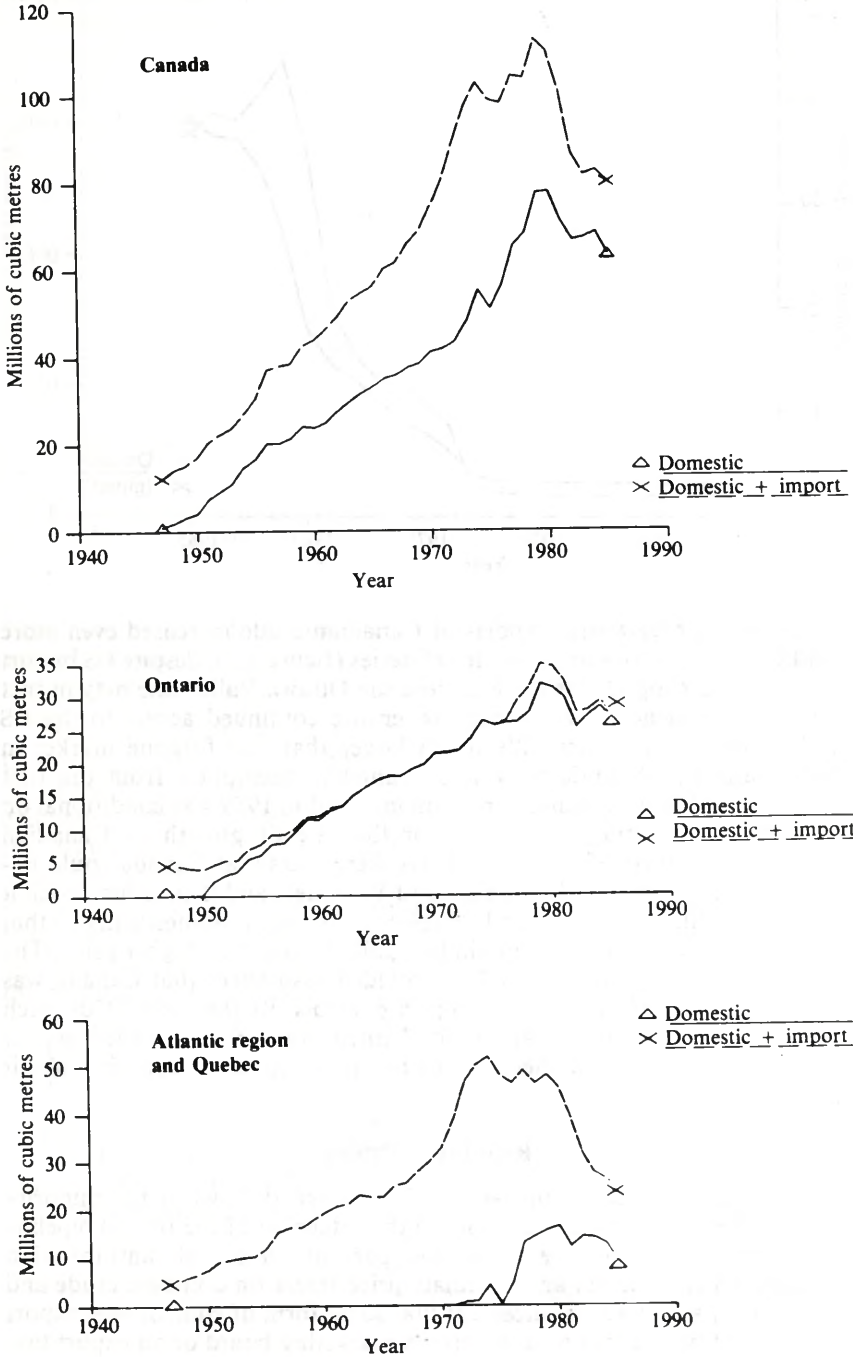
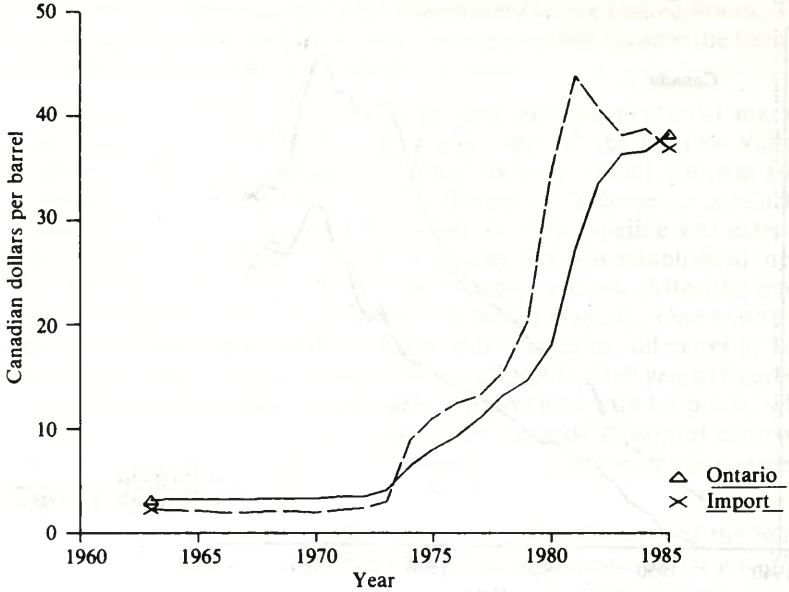


Figure 3.2 Annual Crude Oil Price, Ontario Versus Average Import

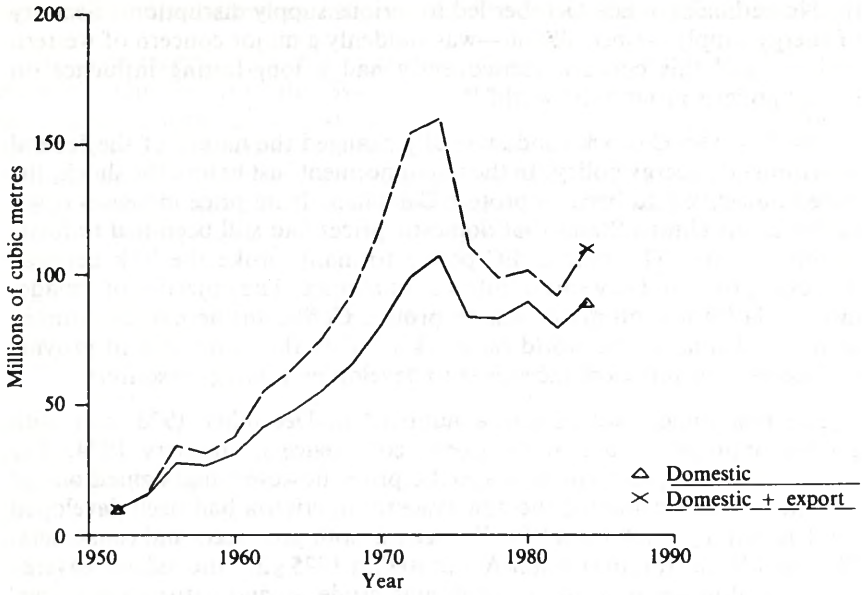


During the NOP years, exports of Canadian crude increased even more rapidly than deliveries to domestic refineries (figure 3.3), despite US import controls. The adoption of the NOP and the Ottawa Valley line may in fact have been influenced by the need to ensure continued access to the US market, which was potentially much larger than the forgone market in Quebec and the Atlantic provinces. Canadian exemption from the first mandatory US import control program imposed in 1959 was conditional on its observing voluntary guidelines for the rate of growth of Canadian exports and imports of crude oil. There were fears that Canada could import cheap oil from the Middle East and Venezuela and then either re-sell it directly to refiners in the United States or substitute it domestically so that more Canadian oil could be sold in the United States at a higher price. The existence of the Ottawa Valley line provided assurances that Canada was not being used to circumvent US import controls. By the early 1970s, such assurances were less important as the United States first loosened import controls and later lifted them altogether in response to concerns about supply shortages.

Regulated Prices

The NOP came to an abrupt end in September 1973 when the minority Liberal federal government announced the extension of the IPL oil pipeline to Montreal. The surprise move was part of an overall anti-inflation package, which included an immediate price freeze on domestic crude and oil products, and the announcement that some form of control over export prices would be sought through either a marketing board or an export tax.

Figure 3.3 Annual Crude Oil Disposition, Canada



The domestic price freeze was originally intended to be in effect until the end of January 1974. During this period, however, the higher costs of imports were to be passed on to eastern Canadian consumers.

This change in policy was the result of rising oil prices offshore and in the United States. Import prices had been edging steadily upward since the signing of the 1971 Tehran-Tripoli agreements between OPEC and the major oil companies. Posted prices in the Middle East had risen by 70 percent since the beginning of 1971,[13] and eastern Canada, completely dependent on imported crude, had experienced price increases of 30 percent in the previous year. Oil prices in the rest of Canada had also risen in response to rising prices in the United States. US prices were under upward pressure because of greater dependence on imports, increasing supply concerns, and the recent decontrol of new crude oil prices. The Canadian federal government wanted some control over export prices so that the supply problems in the United States would not automatically mean higher prices for Canadian consumers.

Barely a month after the new policy was introduced, war broke out in the Middle East, and the first OPEC price shock was under way. In mid-October 1973, OPEC unilaterally raised oil prices from around US$3.00 to US$5.00 per barrel, and in late December prices were raised again to

[13]The posted price of Saudi light, for example, rose from US$1.80 per barrel to US$2.285 in June 1971, and by August 1973 this price had climbed to US$3.066 per barrel. See also chapter 2, under "Oil Prices: OPEC, the United States, and Canada."

US$11.65 per barrel. The Arab oil embargo against the United States (and the Netherlands) in late October led to serious supply disruptions. Security of energy supply—especially oil—was suddenly a major concern of western nations, and this concern subsequently had a long-lasting influence on energy policies around the world.[14]

The first OPEC shock fundamentally changed the nature of the federal government's energy policy. In the announcement just before the shock, the stated objective had been to protect Canadians from price increases originating in the United States, but domestic prices had still been tied to international prices. The post-OPEC policy formally broke the link between domestic prices and any sort of international price. The objective of "made-in-Canada" crude oil prices was to protect Canadians across the country from the whims of the world oil market but at the same time to provide producers with sufficient incentives to develop new energy resources.

The new policy, which was announced in December 1973, met with general approval at a first ministers' conference in January 1974. The failure to reach agreement on a specific price, however, highlighted one of the intrinsic difficulties of the new system: no criteria had been developed for determining what was a "fair" price for both producers and consumers. The Petroleum Administration Act passed in 1975 gave the federal government the ultimate authority to determine crude oil and natural gas prices, with or without provincial agreement, for the purposes of interprovincial and international trade. In practice, prices of oil in interprovincial trade were negotiated between the federal government and the governments of the producing provinces or at first ministers' conferences. As long as OPEC increased world prices in an orderly fashion (as it did until the late 1970s), the system worked relatively smoothly. In 1979-80, however, the second OPEC price shock led to a federal-provincial stalemate and, eventually, to significant changes in the way regulated prices were determined. These changes will be discussed more fully in the following section, "The National Energy Program and Two-Tier Pricing."

The first Canadian oil pricing system, inaugurated early in 1974, had three main components: (1) direct regulation of domestic crude oil prices through federal-provincial agreements, (2) subsidies for imported oil so that consumers in eastern Canada would also benefit from lower prices, and (3) controls over the prices and quantities of crude oil and products in the export market. The relatively ad hoc nature of the initial pricing agreements (see table 3.1) reflected uncertainty about how durable the OPEC cartel would prove to be. By early 1977, however, there was enough confidence in

[14] In January 1974, Canada enacted the Energy Supplies Emergency Act, SC 1973-74, c. 52, which created the Energy Supplies Allocation Board and gave it broad emergency powers. At the end of 1974, Canada signed an agreement with other OECD nations promising cooperation in allocating oil supplies if one of the parties to the agreement experienced significant disruptions in its import supplies. On this, see Glen Toner, "The International Energy Agency and the Development of the Stocks Decision" (February 1987), 15 *Energy Policy* 40-58, and references given therein.

OPEC's stability to negotiate a longer-term, more structured pricing agreement, which raised domestic oil prices $1.00 per barrel every six months.

The only exception to this regulated pricing system was for synthetic crude oil. Output from the Syncrude project was guaranteed the international price at the outset, while the entire output of the GCOS (Suncor) plant received the international price as of April 1979, following a major plant expansion. The federal government subsidized the difference between synthetic and conventional crude oil prices and financed the subsidy through a refinery levy (the so-called Syncrude levy) on all oil refined in Canada.

The oil import compensation program was introduced in January 1974 so that consumers in Quebec and the Atlantic provinces, who were then completely dependent on imported oil, would also be protected against increases in world oil prices. The changes in the program give some idea of the complexity of administering even a relatively simple regulated pricing system. Initially (from January 1974 to June 1975), the import subsidy was equal to the change in the FOB cost of imported oil since November 30, 1973 plus the change in transportation costs. This effectively froze refinery costs at November 1973 levels with the disadvantage that there were no incentives to import the lowest-priced crudes. In July 1975, a flat-rate compensation system was introduced whereby all refiners received the same subsidy regardless of the cost or quality of the crude they imported. This subsidy was equal to the difference between the forecast cost of imported crude and the cost of equivalent-quality domestic oil delivered to Montreal. After April 1982, the volatility of world oil prices and the increased importance of spot markets resulted in changes to the system, so that actual costs, rather than forecasts, were used in determining the subsidy rate.

The federal government also controlled crude oil export prices through the oil export tax set by the NEB. Since the federal government rather than the producers received the difference between the export price and the regulated domestic price, the oil export tax removed any incentive for producers to prefer export over domestic markets. It also provided revenues to help finance the oil import compensation program. Initially, the oil export tax rate was the same for all qualities of crude oil, but complaints that Canadian heavy crudes were being priced out of their export markets led the NEB to allow a different rate for heavy crudes starting in November 1974. Different oil export tax rates for different types of crudes gradually prevailed and became especially important in the early 1980s when US deregulation and soft world oil markets increased the competitiveness of export markets.

In addition to regulating prices, governments became more actively involved in the marketing of Canadian crude oil. Security of supply was a key issue and the main reason why the NEB assumed an active role in allocating Canadian production among domestic and export markets. Mandatory export licences for crude oil were introduced in March 1973 originally because some Canadian refiners were facing shortfalls at the same

Table 3.1 Conventional Crude Oil Pricing Agreements and Proposals

Date	Dollars per barrel	Action taken or proposed
September 1973	3.80	The federal government imposed a price freeze on the price of crude oil produced in Canada.
April 1974	6.50	The first ministers' conference of March 1974 agreed to raise the price to $6.50 per barrel over the April 1974 through June 1975 time period.
July 1975	8.00	The June 1975 federal budget announced an agreement with Alberta to raise prices to $8.00 per barrel through June 1976.
July 1976	9.05	Although no agreement was reached at the May 1976
January 1977	9.75	first ministers' conference, the federal government and the governments of the producing provinces reached the first two-stage, albeit short-term, pricing agreement in late May.
July 1977	10.75	An agreement between the federal government and
January 1978	11.75	Alberta reached in May 1977 originally called for a
July 1978	12.75	further increase to $13.75 per barrel in January 1979.
July 1979	13.75	The Alberta government later agreed to a deferment
January 1980	14.75	of the increase slated for January 1979 and to an additional price hike in January 1980. In November 1979, Alberta and the new federal Progressive Conservative government reached a partial agreement whereby all conventional oil would be given 75 percent of the lesser of the Chicago or world price, with the parity rate rising to 85 percent in 1984. The budget was defeated in the House, as was the government in the subsequent election, and therefore the agreement was never put into effect.
August 1980	16.75	The Alberta government unilaterally raised the wellhead price of production from Crown lands. The price increase was accepted by the federal government.
January 1981	17.75	The NEP originally announced that wellhead prices
June 1981	18.75	would be increased $1.00 per barrel every six months between January 1981 and December 1983; from January 1984 through December 1985, the price would rise $2.25 per barrel every six months; from 1986 on, it would rise $3.50 per barrel every six months until it reached the quality-adjusted oil sands reference price, which was to be the lesser of the international price or $38 in 1981 inflated by the consumer price index. Overall, the weighted average price of Canadian crude oil was not to exceed 85 percent of the lesser of the international price or the average US price.
October 1981	21.25	The 1981 energy agreements created two categories of
January 1982	23.50	oil: (1) conventional old oil (discovered before 1981),
July 1982	25.75	which received the basic wellhead price; and (2) new
January 1983	29.75	oil (discovered after 1980), which received the new oil reference price (NORP) as of January 1982. The

(Table 3.1 is concluded on the next page.)

Table 3.1 Concluded

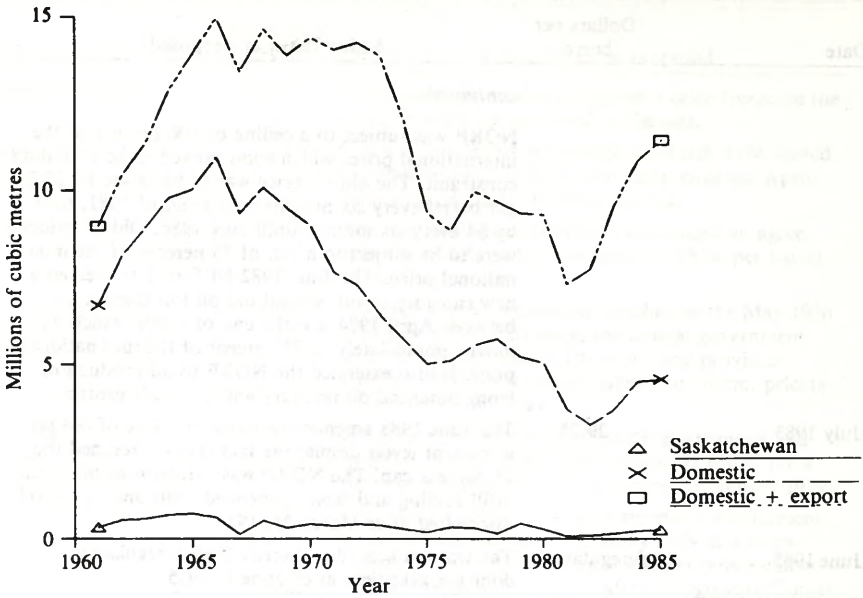
Date	Dollars per barrel	Action taken or proposed
		continued . . .
		NORP was subject to a ceiling of 100 percent of the international price, which soon proved to be a binding constraint. The old oil price was to be raised by $2.25 per barrel every six months to the end of 1982, then by $4 every six months until July 1986. Old oil prices were to be subject to a cap of 75 percent of the international price. The June 1982 NEP update created a new category of oil, special old oil (oil discovered between April 1974 and the end of 1980), which was moved immediately to 75 percent of the international price. It also extended the NORP to all production from enhanced oil recovery and oil sands projects.
July 1983	29.75	The June 1983 amendment froze the price of old oil at current levels despite the fact that it exceeded the 75 percent cap. The NORP was extended to oil from infill drilling and from suspended wells and to old oil discovered after March 31, 1974.
June 1985	deregulation	The western accord of March 1985 deregulated domestic oil prices as of June 1, 1985.

Source: André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986,* PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986), items 73.27; 74.10; 76.7; 77.11; 78.26; 79.36; 80.19; 80.28; 81.22; 82.22; 83.17; and 85.7.

time as export volumes to the United States were reaching record levels. The licence system meant that the NEB would authorize the export only of quantities deemed surplus to foreseeable Canadian requirements. Export volumes had already been cut back, but the OPEC shock and oil embargo increased concerns over security of supply and resulted in further reductions of allowed export volumes as well as emergency measures to transport western crude to eastern markets via the Panama Canal and the Great Lakes.

In its *Report on the Matter of the Exportation of Oil* released in October 1974, the NEB recommended major changes in export policies. Monthly export licences would still be issued, but the criteria for determining the total exportable surplus would become more stringent. Annual exports would be fixed in relation to producibility, domestic requirements, and a conservation factor. The NEB also concluded that domestic requirements would soon exceed non-frontier production and, in the light of this, recommended that exports to the United States be phased out in such a way as to cause minimum inconvenience for US refiners dependent on Canadian oil. Exports, particularly of light and medium crude oils, were phased out over the remainder of the 1970s.

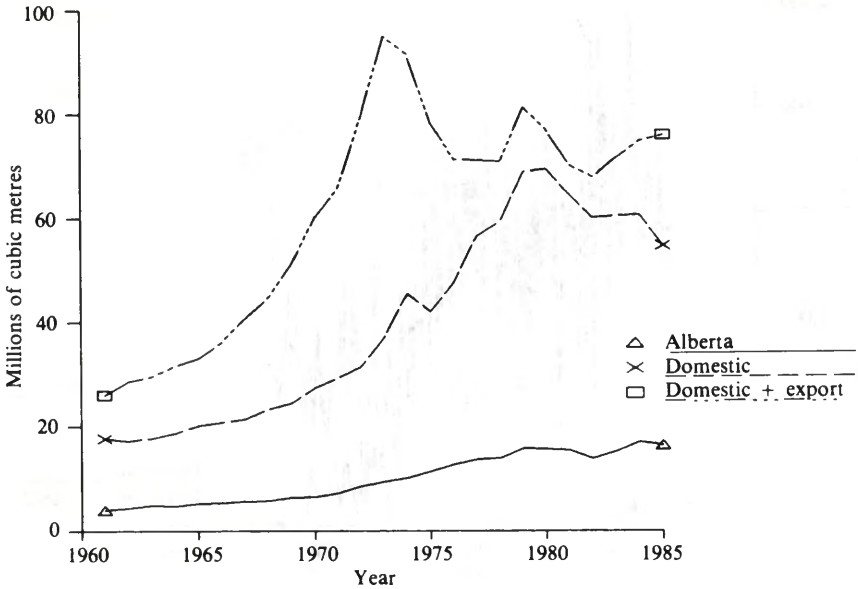
Figure 3.4a Annual Crude Oil Disposition, Saskatchewan



Weakness in the demand for heavy crudes, however, resulted in the NEB's instituting a separate licensing system at the end of 1976 and actively encouraging exports of heavy crudes in order to alleviate shut-in problems. The NEB also instituted a mid-continental export exchange program in 1976 whereby Canadian operators were permitted to export additional volumes of light and medium crudes to US northern-tier refiners, provided that they reimported an equivalent amount somewhere else. In 1979, the exchange program was expanded to include eastern Canada because of the supply shortages brought about by the Iranian crisis. The effects of the change in export policy are clearly shown in figures 3.4a and 3.4b. Exports from both Saskatchewan (figure 3.4a) and Alberta (figure 3.4b) fell sharply after the 1973 controls were implemented. From 1975 through 1979, exports of Saskatchewan production (mostly heavy crude) remained more or less constant, while exports of Alberta production (mostly light and medium crude) continued to decline sharply. Production levels were maintained in Alberta, however, because of increasing domestic use of Alberta crude outside the province.

Federal policies were aimed at encouraging refiners in eastern Canada to use domestic production whenever possible: exports were cut back so that western production was available to domestic refiners; the Montreal pipeline extension was completed in 1976; and the federal government subsidized the Sarnia-Montreal transport costs until August 1980. Problems with shut-in production in 1982 led to the introduction of a new transport

Figure 3.4b Annual Crude Oil Disposition, Alberta



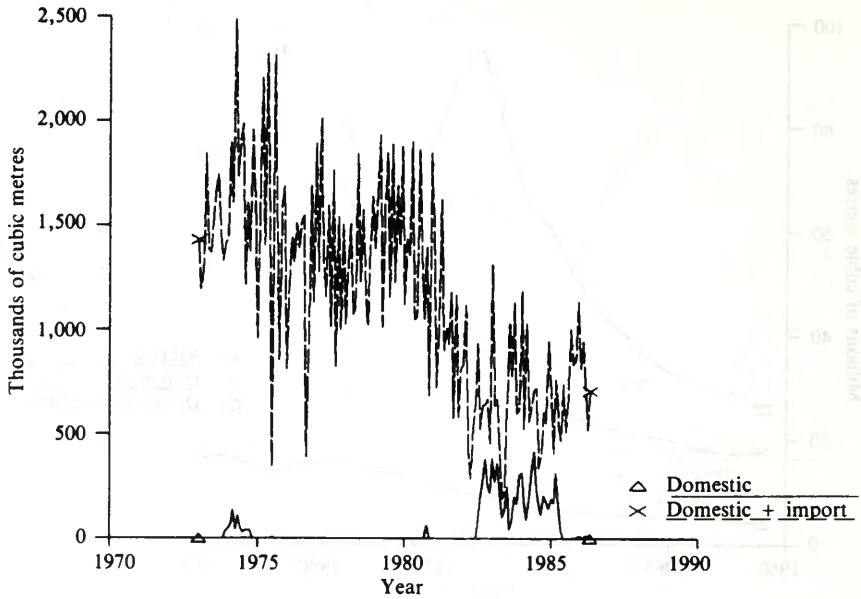
subsidy for western crude moving to eastern Canada,[15] and a request by the federal government that eastern refiners take only the minimum volumes required under their long-term import contracts. No new long-term contracts were permitted, and oil bought on the spot market was subject to a lower import compensation rate.[16]

The federal policies did have an impact, as figures 3.5a and 3.5b show. Atlantic refineries (figure 3.5a) received some domestic crudes during the supply disruptions of the first OPEC crisis but then virtually none until a new transportation subsidy and import-restriction requests went into effect in 1982. The effects are not quite as clear in Quebec (figure 3.5b), since total refinery receipts of crude oil were declining over time. Quebec refineries received some domestic oil through the emergency measures taken during the first OPEC oil crisis, but these were soon phased out. In 1976, the pipeline extension to Montreal was completed, and receipts of domestic oil generally showed an upward trend while the Sarnia-Montreal transport subsidy was in effect. In mid-1980 when the subsidy was removed, receipts of domestic oil declined much more sharply than overall receipts.

[15]The subsidy applied to the transport costs from Montreal to refineries further east or to Alberta oil moving through the eastern export exchange program.

[16]See Canada, EMR, *The National Energy Program: Update 1982* (Ottawa: Supply and Services, 1982), 70.

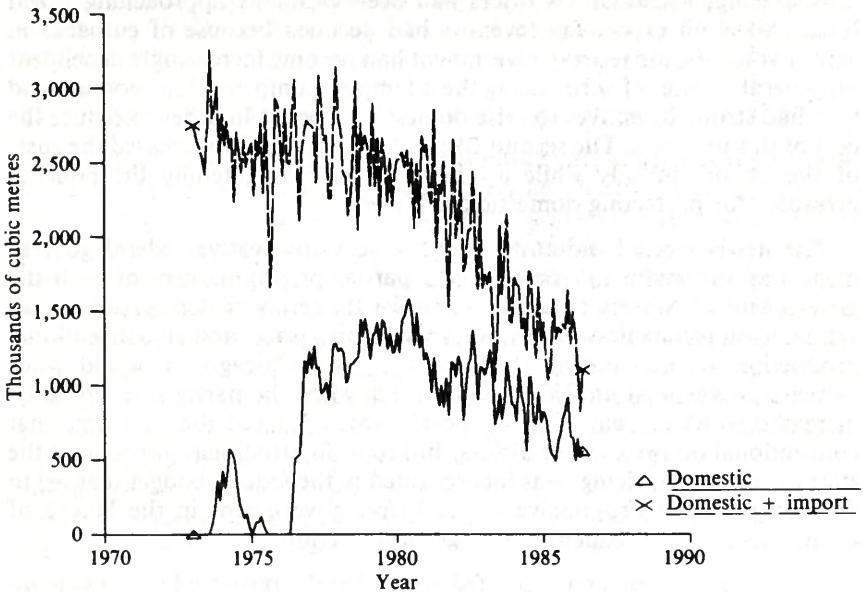
Figure 3.5a Monthly Refinery Receipts of Crude Oil, Atlantic Provinces



With the exception of the production cutbacks ordered by Alberta early in 1981 to protest the national energy program (NEP), the effects of provincial intervention in crude oil markets were more indirect. They were nonetheless pervasive. The role of prorationing was discussed in the previous section and did not in fact change much with the OPEC shocks. During the early 1970s, Alberta had given some consideration to abolishing the prorationing system, since record export levels were making shut-in problems largely irrelevant, but this idea was abandoned in early 1974 because the province was very concerned with maintaining control over its energy resources. In late 1973, the Alberta government created the Alberta Petroleum Marketing Commission (APMC) in an effort to increase the province's control over the disposition of its energy resources. The APMC was given the power to set prices and terms of sale for all petroleum produced from Crown lands and became the sole agent for disposing of both the royalty share of production and the lessee's share. The APMC was also responsible for determining quality-related price differentials for crude oil according to variations in density and sulphur content in such a way as to maintain the average field price set by federal-provincial pricing agreements.

The APMC played an additional role in allocating available production among potential buyers. Between March 1, 1974 (when the APMC started operations) and March 31, 1980, the commission established a list of eligible buyers, but producers were essentially free to enter into private contracts

Figure 3.5b Monthly Refinery Receipts of Crude Oil, Quebec



with any of the potential buyers on the eligibility list.[17] The eligibility list was basically a list of historical buyers of Alberta crude. Even though this procedure prevented new buyers from entering the market, it is not clear how binding this constraint actually was. The objective was to ensure that traditional customers were not crowded out during periods of supply shortages.

In April 1980, the approved-purchaser system was discontinued. All private contracts between producers and buyers on the eligibility list were abrogated, and the APMC became the sole purchaser of crude produced from Crown lands in Alberta. It took over the marketing and handling roles that had previously been undertaken by private agents and offered to do the same for production from freehold lands. It set prices, decided upon buyers, took possession of the crude at the wellhead, and made all the arrangements for its transfer to the buyers. Although the approved-purchaser list had been abandoned, the APMC was still selective in its buyers, refusing, for example, to sell to brokers.[18]

The National Energy Program and Two-Tier Pricing

In 1979-80, the second OPEC shock resulted in a doubling of world oil prices, which in turn led to a federal-provincial stalemate on pricing issues.

[17] In the first 10 months of operations, the producer received the proceeds from the sale and remitted the royalty share to the APMC. After December 1974, this procedure was reversed.

[18] See Canada, Restrictive Trade Practices Commission, supra footnote 1, at 138.

In the years following the first OPEC shock and the introduction of regulated pricing, Canadian oil prices had been gradually approaching world levels. Since oil export tax revenues had declined because of cutbacks in export volumes, the federal government had become increasingly dependent on general revenues for financing the oil import compensation program and thus had strong incentives to raise domestic oil prices in order to reduce the cost of this program. The second OPEC shock drastically increased the costs of the import subsidy while at the same time heightening the political pressures for protecting domestic consumers.

The newly elected, minority Progressive Conservative federal government was successful in negotiating a partial pricing agreement with the government of Alberta in late 1979. Under the terms of this agreement, all synthetic oil production would receive the world price, and all conventional production would receive 75 percent of the Chicago or world price (whichever was less) until the end of 1983, when the parity rate would be increased to 85 percent. This proposal, which marked the first time that conventional oil prices were directly linked to international prices since the start of regulated pricing, was incorporated in the federal budget that led to the defeat of the Progressive Conservative government in the House of Commons and, subsequently, in a general election.

During the campaign, the federal Liberals promised a "made-in-Canada" oil price. Once in office, however, the majority Liberal government was unsuccessful in its attempts to negotiate an agreement with the governments of the producing provinces. The net result, in October 1980, was the unilateral imposition by the federal government of the NEP,[19] which introduced several new energy taxes and a broad range of policy initiatives. The NEP's pricing regime retained the objective of a uniform "made-in-Canada" oil price below world levels, but it differed from its predecessor in two important respects. First, it adopted the principle that although some of the new high-cost sources of oil required higher prices to be economic, these prices did not necessarily have to be as high as the international price. Synthetic oil production would therefore receive the oil sands reference price, which was equal to the lesser of the world price or $38 per barrel escalated annually by the consumer price index.[20] A similar but lower reference price would be paid for oil produced using approved tertiary enhanced recovery methods.

Second, and more important, however, it introduced a refinery levy called the petroleum compensation charge (PCC) to help finance the oil import compensation program and the synthetic and tertiary supplement. Canadian consumers, and not solely the federal government, would help to pay the costs of the program directly. Canadians would thus pay a blended

[19] See Canada, EMR, *The National Energy Program 1980* (Ottawa: Supply and Services, 1980).

[20] Production from the existing GCOS (Suncor) plant, however, would receive the conventional oil price, and only production from the expansion would be eligible for the oil sands reference price. See ibid., at 29.

price equal to the basic wellhead price plus the PCC. Every six months, the wellhead price of conventional oil would be increased by $1 per barrel (until the end of 1983), by $2.25 (to the end of 1985), and by $3.50 thereafter, until it reached the quality-adjusted oil sands reference price.[21] The overall objective of this system, however, was for the blended price never to exceed 85 percent of the lesser of the world price or the average US oil price.

The NEP was not well received by either the industry or the governments of the producing provinces. To protest, Premier Peter Lougheed of Alberta ordered a phased-in series of oil production cuts. In return, the federal government increased the PCC to compensate for the higher level of imports made necessary by the lower domestic production. Eventually, in the fall of 1981, the federal government reached an agreement on energy pricing and taxation with the governments of each of the producing provinces.[22]

The 1981 energy agreements, originally intended to be in effect until the end of 1986, retained the concept of a blended price system. Subsidies for imported oil and supplements to the basic price received by producers for various categories of oil would continue to be financed by the PCC[23] so that consumers, and not the federal government, would bear the full costs of the subsidies. The main innovation of the agreements was the creation of a two-tier pricing system for domestic oil. Oil discovered before the end of 1980 (old oil) would receive the basic old oil price, which would be increased more rapidly than had been planned under the NEP (see table 3.1), and which would be subject to a cap of 75 percent of the quality-adjusted international price. Oil discovered after 1980 (new oil), synthetic oil, and oil produced on the Canada lands would receive the basic old oil price plus a supplement to bring it up to the new oil reference price (NORP),[24] which was subject to a cap of 100 percent of the quality-adjusted international price.[25] A schedule of base prices for the NORP was laid out in the agreements, and provisions were made for gradually rolling the NORP into the international price toward the end of the period covered by the agreements. The NORP schedule would have protected Canadian consumers from major new world

[21] A few months later, the federal government introduced the Canadian ownership special charge (COSC), a new refinery levy, to help finance the Canadianization objectives of the NEP.

[22] See Canada, EMR, supra footnote 10; Canada, EMR, "Joint Statement by the Prime Minister of Canada and the Premier of British Columbia" (mimeograph, September 24, 1981); and Canada, EMR, "Letter of Understanding Between the Government of Canada and the Government of Saskatchewan Relating to Energy Pricing and Taxation" (mimeograph, October 26, 1981).

[23] The PCC rate would be set so as to finance the oil import subsidies and the NORP supplements.

[24] GCOS (Suncor) was to get the NORP, but Syncrude was to get the international price until June 30, 1982, after which there was a complicated formula to adjust the Syncrude price toward the NORP.

[25] The agreements also extended the NORP to production from enhanced oil recovery projects (other than waterflood), experimental crude bitumen, and non-integrated oil sands projects starting after 1980.

price shocks, but the protection proved unnecessary because international prices did not rise as quickly as had been anticipated. The 100 percent cap became a binding constraint from the beginning.

The fact that world prices failed to escalate as rapidly as had been anticipated at the time of the agreements led to a series of modifications to the pricing regime. The NEP update of June 1982[26] extended the NORP to all categories of tertiary and experimental crude oil, regardless of their start-up dates, as well as to wells that had been suspended for three years or more, as long as they qualified for new oil royalty rates. It also created a new category of oil—special old oil (that is, oil discovered between April 1, 1974 and December 31, 1980)—which was moved immediately to 75 percent of the international price. The fall in world prices in the spring of 1983 necessitated further changes to the system because it meant that the old oil price was above the 75 percent cap stipulated in the agreements. The June 1983 amendment[27] froze the wellhead price of old oil at the prevailing level of $29.75 per barrel and extended the NORP to special old oil and oil from infill drilling. It also announced a major review of the methods for calculating quality differentials, to be completed by November 1983.

The 1981 energy agreements had dealt with the issue of quality differentials in some detail. The differentials previously used by the APMC had been based on density ($0.03 per barrel per degree API) and sulphur content ($0.02 per barrel per 0.1 percent sulphur content). This method ensured that the total differential per barrel was a flat rate that did not respond to changes in the overall price level. The 1981 agreements retained the same methodology for calculating price differentials for both the conventional old oil price and the NORP, but the flat-rate differentials were to be increased gradually for old oil as prices rose. The initial differentials for the NORP were much larger and were to rise with increases in that price. The NORP for a particular quality of oil was not intended, however, to exceed consistently the international price of the equivalent-quality crude oil.

The review announced in the June 1983 amendment resulted in the introduction, in January 1984, of major changes to the system for determining the NORP. The original system responded relatively slowly to changes in international prices. The NORP was set on the basis of the average price of imported oil at Montreal in the three most recent consecutive months for which actual data were available. This meant that in April 1983, for example, the NORP was set for the month of May on the basis of prices in the previous November, December, and January.[28] In times of rapid price changes, this had the potential for creating problems. The limited number of international crudes actually being landed in Montreal created even more

[26] Supra footnote 16.

[27] Canada, EMR, "Agreement To Amend the Memorandum of Agreement of September 1, 1981 Between the Government of Canada and the Government of Alberta Relating to Energy Pricing and Taxation" (mimeograph, June 30, 1983).

[28] See Canada, EMR, "Oil Pricing Information Newsletter," Oil Pricing and Compensation Program Branch (mimeograph, May 1983).

problems when it came to determining how relevant the regulated quality differentials were to comparable international prices.

The new system implemented at the beginning of 1984 did away with both the time lag and the arbitrary method of calculating quality differentials. The NORP for each quality block (based on density and sulphur content) was equated directly with the official selling price of international crudes that could be placed in a similar quality block. Although this system was an improvement, in that it directly compared the prices of domestic and international crudes of similar qualities, it too presented problems. Official selling prices were used to set the NORP, but spot prices, which at the time tended to be lower than the official prices (see chapter 2, figure 2.1), were becoming an increasingly important factor in determining actual transactions prices. The other problem with the new system was the fact that many of the international crudes used in setting the quality-adjusted NORPs were not actually imported into Canada. Calculating the theoretical costs of these crudes landed at Montreal led to some anomalous results and required an elaborate smoothing formula to ensure that lower-quality crudes did not receive higher prices than their better-quality counterparts. The net effect was that by the summer of 1984, the NORP received by Canadian producers for various crudes was higher than the price those same crudes were fetching in the export market (figure 3.6). The simple concept of giving Canadian crudes the price of the equivalent international crude proved to be a difficult one to administer.

Deregulation

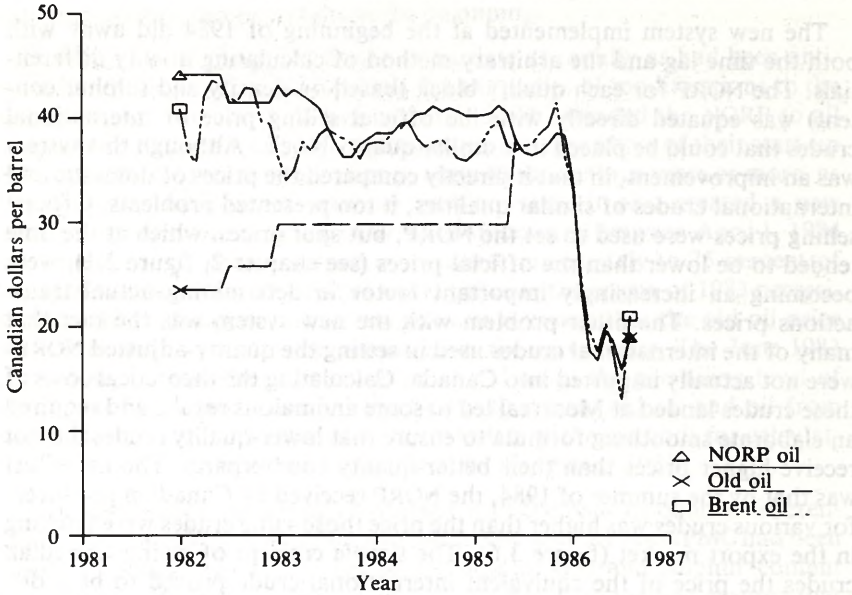
In March 1985, the new majority Progressive Conservative government in Ottawa and the governments of the producing provinces signed the western accord.[29] As far as Canadian crude oil markets were concerned, the accord accomplished two main objectives. It deregulated domestic oil prices, thus abolishing import subsidies, transportation subsidies, the export tax on crude and oil products, and the PCC (the COSC was also dropped);[30] and it also lifted controls on short-term oil exports. The federal government did, however, retain the right to intervene in the event of serious disturbances in the international oil market and to restrict exports if supplies to Canadian consumers were threatened. The provincial governments retained the right to control crude oil production for conservation reasons or to ensure equitable sharing of production in the event of market constraints.

By the time Canadian oil prices were officially deregulated in the spring of 1985, it was clear that the world oil market had undergone a number of

[29]Canada, "The Western Accord: An Agreement Between the Governments of Canada, Alberta, Saskatchewan, and British Columbia on Oil and Gas Pricing and Taxation" (mimeograph, March 28, 1985).

[30]On motive fuels, however, the COSC was effectively replaced by an increase in federal excise taxes (up two cents per litre in September 1985, with an additional one-cent increase in January 1987). The original announcement was made in the May 1985 budget; see Canada, Department of Finance, Budget Papers, Budget Speech, May 23, 1985 (Michael H. Wilson).

Figure 3.6 Light Crude Oil Prices, Edmonton
(monthly data)



significant changes since the last time Canadian producers had operated in a deregulated environment. In the 1970s, OPEC had wrested control of the world market away from the multinationals and had successfully engineered a number of substantial price increases. These price increases eventually led to a reduction in the world demand for crude oil[31] and made higher-cost, non-OPEC sources profitable to develop. In the early 1980s, OPEC began to lose its control over the world oil market,[32] as increased production from non-OPEC sources like the North Sea and Mexico competed for a smaller, less rapidly growing market. The spot market grew more important,[33] and soft world market conditions tended to keep prices on the spot market below official selling prices (see chapter 2, figure 2.1). The availability and quality of price information also improved enormously with the introduction of a futures market for crude oil on the New York Mercantile Exchange in 1983, and this had a large impact on spot market operations as well as on term contracts. Long-term, fixed-price contracts became less attractive under these circumstances, and a trend emerged toward built-in price

[31] This was particularly true during the deep worldwide recession of 1981-82 and was a factor behind the cut in official OPEC prices in early 1983.

[32] OPEC production fell by about 45 percent between 1979 and 1985. See, for example, Canada, Restrictive Trade Practices Commission, supra footnote 1, at 162.

[33] Between 1980 and 1985, the proportion of oil moving through the spot market increased from about 9 percent of all third-party transactions to between one-third and one-half of all transactions. See ibid., at 159.

flexibility and shorter contract terms.[34] Brent, a North Sea crude, and West Texas intermediate, the marker crude of the New York Mercantile Exchange, gradually replaced Saudi light as the world oil price leaders.[35]

With the advent of deregulation in mid-1985, Canadian producers were therefore facing a much more competitive and volatile world oil market than had existed in the 1950s and 1960s. The first month of deregulation saw a drop of just over $2 per barrel in the price of oil that had been receiving the NORP, with a drop of an additional $1 the following month. Data in the *Crude Oil Pricing Report* of the federal Department of Energy, Mines and Resources (EMR) suggest that Canadian posted prices were $1 to $2 per barrel less than either Brent or West Texas intermediate spot prices, once adjustments were made for transportation costs and exchange rate fluctuations. Overall, deregulation did not entail major changes in oil prices for Canadian consumers since higher prices for old oil were offset by lower prices for NORP oil and the removal of the COSC. The average acquisition cost of domestic oil at Canadian refineries dropped slightly immediately after deregulation.[36] After this initial drop, prices remained relatively stable until the pressure of world events took over.

Deregulation also affected the disposition of Canadian crude oil production. With the removal of the federal transportation subsidy, Atlantic refineries stopped using domestic production entirely and imports increased in importance in Quebec (see figures 3.5a and 3.5b). Export markets continued to increase in importance for the disposition of Alberta and Saskatchewan crude, although figures 3.7a and 3.7b do not show a sharp break as a result of deregulation. Problems with shut-in capacity had resulted in looser export restrictions as early as 1982. In April 1982, Canadian producers had been assured that the NEB would take steps to ensure that heavy oil exports to the United States were competitively priced. The NEB had also been instructed to consider heavy crude export licences for terms up to one year instead of on the month-to-month basis used previously, and to look at the possibility of exporting other chronically shut-in oil, such as Saskatchewan light sour.[37] Deregulation, therefore, merely strengthened the trend toward increased reliance on export markets for the disposition of Canadian crude.

Deregulation did not signal the end to the problems with shut-in production that had plagued the industry since the early 1980s, and marketing problems eventually led to significant changes in the Alberta prorationing system. As was discussed in the section on "Market Protection" above, prorationing effectively removes any incentive for direct price competition

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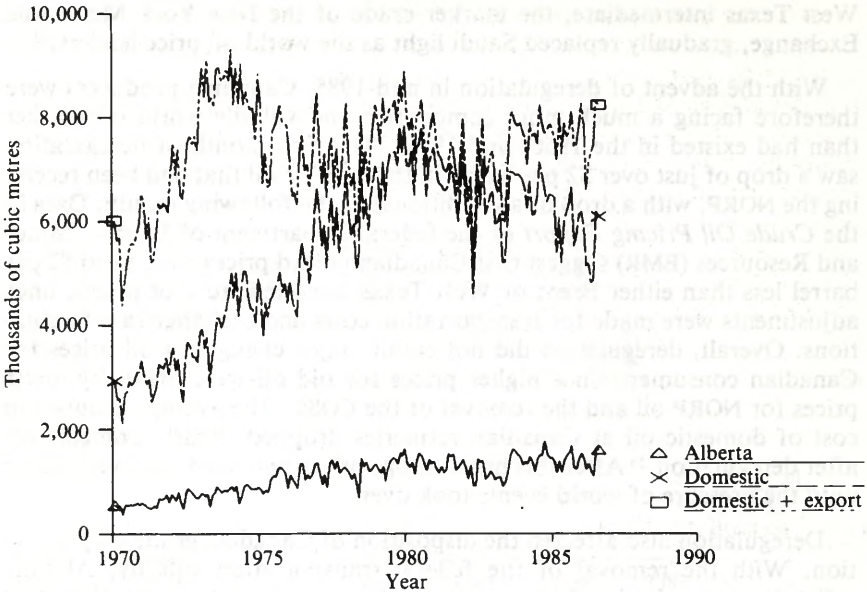
[34] See ibid., at 162.

[35] See Canada, National Energy Board, *1984 Annual Report* (Ottawa: Supply and Services), 26.

[36] The Ontario refinery acquisition cost, for example, dropped from an estimated $39.17 per barrel before deregulation to $37.88 per barrel in the following month, according to EMR estimates.

[37] See supra footnote 16, at 68.

Figure 3.7a Monthly Crude Oil Disposition, Alberta

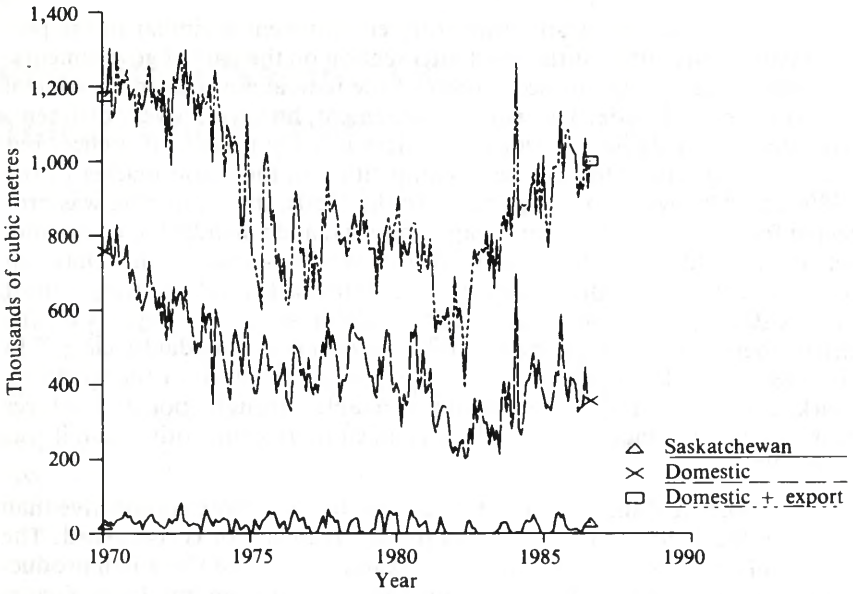


among individual producers, since any incremental sales are effectively spread across all producers. The AERCB first introduced a supplementary market system on a trial basis in October 1985 and then, in the spring of 1987, made in-depth changes to the prorationing system.

The supplementary market program was designed to give producers the opportunity to sell shut-in oil on the spot market if pipeline capacity was available, but it was not intended to undermine sales to primary markets. The AERCB set the monthly allowable production rate for each pool in the province on the basis of the nominations filed with the board. If this was below the maximum allowable rate for that pool (a figure that was based on technical considerations), the producer could offer the difference for sale by public tender on the supplementary market. Prices and terms of sale were then negotiated with buyers in the supplementary market, with the whole arrangement being subject to pipeline capacity constraints. Although limited in size, the supplementary market did provide incentives for price competition since, unlike under the traditional prorationing system, producers offering price discounts also received the benefits from the sale of the incremental production. In the spring of 1987, the degree of competitiveness was enhanced even more when the government of Alberta introduced the modified proration plan. The new system of production allocation is designed to allow producers to sell all available production, subject to limits determined by the AERCB with respect to geologically feasible maximum production rates for each well.

In late 1985 and early 1986, Saudi Arabia increased its production of crude oil in an effort to recapture its market share. The effects were

Figure 3.7b Monthly Crude Oil Disposition, Saskatchewan



dramatic. Crude oil, which had been trading at around US$27 per barrel on the spot market at the beginning of December 1985, dropped to less than US$20 per barrel just a few weeks later. The downward slide continued over the next few months, with spot prices occasionally dipping below US$10 per barrel. Prices recovered somewhat during the second half of 1986 but did not regain their 1985 levels. Canadian prices adjusted rapidly to the change in world prices and tended to track spot prices very closely, as can be seen in chapter 2, figure 2.2.

The price collapse spawned a number of proposals that called for a return to government involvement in the industry: import tariffs, minimum prices, and various income stabilization plans. Interestingly enough, the proposals tended to stress the temporary and limited nature of the assistance, unlike the more-or-less permanent consumer protection that was advocated when prices were first regulated in the 1970s. Although the federal government retained emergency powers of intervention in the event of serious disturbances in the international oil market, it adopted the view that it could not protect producers from a 50 percent drop in world oil prices.[38] Aid by both the federal and provincial governments was confined to various tax relief and incentive programs and did not include price supports.

[38] Patricia Carney, then federal minister of energy, mines, and resources, quoted in "Senate Committee Proposes Floor Price" (June 30, 1986), 37 *Oilweek*, 1 and 11, at 11.

Summary and Conclusions

In some respects, the current regulatory environment is similar to the pre-NOP days of the 1950s: little direct intervention on the part of governments, with the potential, but unused, power of the federal government to control export prices and trade. The world environment, however, is very different. The increased volatility in world oil prices is a significant difference, but over the longer term the increased competition in the world market of the 1980s could be even more important. In the 1950s, the US market was protected from competition from cheaper imports, and a handful of companies set prices and controlled most of the world's production. Data on arm's-length transactions prices (that is, fair market values) were almost non-existent and certainly not readily available as the two reports on the pricing behaviour of the Canadian oil industry make abundantly clear.[39] In the 1980s, a wide variety of groups are actively involved in the world oil market, price information is readily available through spot and futures markets, and the industry as a whole is much more competitive than it was in the 1950s.

The domestic Canadian industry has also become more competitive than it was in the 1950s, at least as far as the upstream sector is concerned. The major oil companies still control a substantial portion of Canadian production, but small, independent companies have become an important factor. Institutional changes, such as the modifications made to prorationing, have also made the industry more competitive.

[39]These reports are Canada, Director of Investigations and Research, Combines Investigation Act, *The State of Competition in the Canadian Petroleum Industry*, vol. 3: *International Linkages: Canada and the World Petroleum Market*, and vol. 4: *The Production Sector* (Ottawa: Supply and Services, 1981); and Canada, Restrictive Trade Practices Commission, supra footnote 1.

4

Regulating Natural Gas Markets and Trade

Introduction

Natural gas, like crude oil, is produced in western Canada and transported to consuming regions in eastern Canada and the United States by a few large pipelines, which are regulated by the National Energy Board (NEB). For most of the last 25 years or so, the NEB has also had the authority to control exports of both oil and natural gas. Despite these similarities between oil and natural gas, the institutional structures for handling the two have developed quite differently. Oil production has traditionally been allocated among firms through prorationing, sold to refiners under short-term, month-to-month contracts, and transported by a pipeline that was a common carrier. Natural gas, on the other hand, has traditionally been sold under long-term contracts (for example, 25 years) between producers and pipeline companies, which have not only transported the gas but also been responsible for selling it at the other end.

Transportation plays a key role in explaining these differences. Natural gas must be transported from the field to the final user by pipeline.[1] In most cases, this means that the distribution of natural gas to the final user is a natural monopoly. This situation has given rise to a highly regulated downstream market. Regulation of the downstream market, which falls under a number of different jurisdictions, has had an influence on the upstream portion of the industry as well.

The logistics of transportation also explain why a world market exists for crude oil but not for natural gas. Because oil can be transported by tanker as well as by pipeline, Canada has easy access to oil supplies from all over the world, and spot markets, futures markets, and posted prices all make price information readily available. But because transportation of natural gas is primarily limited to pipelines, Canadians have ready access only to North American supplies. Spot markets for natural gas do exist in the United States and have grown in importance since the enactment of the Natural Gas Policy Act of 1978, but US natural gas markets remain very complicated and highly regulated so that international market-determined prices are not as readily available for natural gas as for oil.

The remainder of this chapter provides an overview of how the present system has evolved. The next section describes the period leading up to the

[1] Proposals have been put forward to liquefy Canadian-produced natural gas and transport it by tanker, but these have so far not been implemented.

establishment of the NEB in 1959, while following sections look at developments in the 1960s, the period of increasing government intervention and regulation during the 1970s, and the gradual relaxation of government controls during the 1980s. The final section looks at recent efforts to implement a more market-oriented system for natural gas and suggests some of the difficulties encountered and the issues outstanding.

Pipelines and Security of Supply, 1950-1958

At the start of the 1950s, domestic markets for natural gas were limited, and natural gas was frequently flared off as waste, jointly produced with crude oil. Producers tended to concentrate their efforts on finding and developing new reserves of crude oil, which was more easily marketed and far more profitable. Over 85 percent of the wells completed in the Alberta basin between 1948 and 1955 were oil wells,[2] and crude oil reserves increased rapidly. Natural gas reserves also increased rapidly during this period, but with far less fanfare.[3] The huge oil discoveries made in the late 1940s and the emphasis on oil-directed exploration activities no doubt contributed to the concerns expressed about the security of long-term gas supplies by the Dinning commission, among others.

The Dinning commission was set up by the Alberta government in 1948 to make recommendations on the removal of oil and gas from the province. In its report, the commission recommended that removals from the province be authorized only after reserves were deemed adequate to meet future provincial requirements and that other Canadian users be given priority over exports to the United States. The commission was doubtful, however, that current proven reserves were adequate to warrant removals of natural gas from the province, a judgment with which the AOGCB (the successor to the APGCB and the predecessor of the AERCB) later concurred.

Under the Gas Resources Preservation Act of 1949, the AOGCB could authorize removal of gas from the province only if the removal was deemed to be in the public interest with respect to present and future provincial needs. The AOGCB was initially very conservative in its estimates of reserves and in its rulings on what constituted adequate supply. Proven reserves had to be sufficient to meet forecast Alberta requirements (including peak requirements) for the next 30 years as well as previously authorized removals. As time went on, the AOGCB relaxed its requirements and authorized removals on the assumption that some future requirements would be supplied from new discoveries.[4] In the early 1950s, however,

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[2]See Russell S. Uhler (with Peter C. Eglington), *The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin*, a study prepared for the Economic Council of Canada (Ottawa: Supply and Services, 1986), 42, table 5-1.

[3]The Canadian Petroleum Association (CPA), for example, began publishing data on crude oil reserves in 1955, the first year that the predecessor of the *Statistical Handbook* was produced, but natural gas data were not included until 1957.

[4]For a more detailed discussion, see G.C. Watkins, *Canadian Public Policy and the Export of Natural Gas*, Discussion Paper no. 75 (Calgary: University of Calgary, Department of Economics, 1982).

removal permits for gas were refused on the grounds of insufficient reserves.

To a certain extent, the federal government adopted the provincial concerns about security of supply. Natural gas exports had required a licence since 1907,[5] when southern Ontario gas fields became so depleted that domestic requirements could not be met. Under these arrangements, the term of a typical export licence was usually one year, although it could be terminated whenever domestic energy needs were deemed at risk.

In addition to its direct control over natural gas exports, the federal government exerted considerable influence over the development of natural gas markets outside Alberta through its jurisdiction over international and interprovincial pipelines.[6] Under the Pipe Line Act,[7] pipelines first had to be incorporated by an act of Parliament and then the details of the proposal had to be approved (or rejected) by the Board of Transport Commissioners. The proposed route for the pipelines proved to be one of the more controversial details to be settled.

In his 1953 energy policy statement, C.D. Howe argued that "the only reliable supply of natural gas for the provinces of Ontario and Quebec must be from Western Canada by means of an all Canadian pipeline" and that "government policy will require that Canadian gas be used in Canada accordingly." Export permits would be refused until the government was convinced that "there can be no economic use present or future for that gas within Canada."[8] The government did approve two export-oriented pipelines in the early 1950s: one as part of the Korean war effort (Canadian-Montana), and the other (Westcoast Transmission) to supply Vancouver and the US Pacific Northwest. The argument made at the time was that the Vancouver market was too small to support the pipeline on its own and that the built-in export component would ensure its economic viability. Concern over US policies as well as over domestic security of supply may also have played a role in Howe's support of the all-Canadian pipeline route for natural gas. The US Federal Power Commission (FPC) had refused commitments of US gas to future Canadian requirements; it also refused import permits for Westcoast Transmission in 1954 on the ground that US reliance on foreign natural gas supplies was undesirable.[9] Routing gas destined for

[5] This was under the Electricity and Fluid Exportation Act, SC 1907, c. 16. Its successor was the Exportation of Power and Fluids and Importation of Gas Act, SC 1955, c. 14.

[6] The government of Alberta became concerned that federal control over interprovincial and international pipelines would result in federal control over field prices for natural gas as well. The Alberta Gas Trunk Line Limited (AGTL), which became NOVA, An Alberta Corporation in 1980, was set up as a mixed public and private enterprise to transport all gas within Alberta in order to ensure that at least one link in the price chain from the field to the final user would remain under provincial control.

[7] The bill was first introduced in April 1949.

[8] John N. McDougall, *Fuels and the National Policy* (Toronto: Butterworths, 1982), 75-76.

[9] See ibid., at 12; and Ian McDougall, "The Canadian National Energy Board: Economic 'Jurisprudence' in the National Interest or Symbolic Reassurance?" (1973), 11 *Alberta Law Review* 327-82, at 347-48.

Canadian markets through the United States was therefore likely to involve problems with existing US policies.

The west-to-east natural gas pipeline that was eventually approved—the TransCanada PipeLines Limited (TCPL) project—did follow an all-Canadian route but also included an export component to improve its economic viability. It did not take long for TCPL to run into serious financial difficulties. The market for natural gas in eastern Canada differed from that for oil in two important respects. First, and most important, the market had to be developed. Since there were no significant supplies of natural gas in eastern Canada and manufactured gas was very expensive, current consumption levels provided little indication of the potential market. To help build up markets in eastern Canada, the federal government permitted imports of gas from the United States through Niagara Falls starting in 1956. These were completely phased out once TCPL reached the southern Ontario market in 1958.

The other major difference was the degree of vertical integration present in the oil industry: the major oil producers controlled the refining and marketing end of the industry and were also major shareholders in the pipeline. Although three of the largest shareholders in TCPL were gas producers that accounted for over 60 percent of the reserves under contract,[10] the potential buyers were the provincially regulated gas utilities who had no strong connections to either the producers or the pipeline. Building a natural gas pipeline, therefore, involved more risk than building an oil pipeline had a few years earlier, since the end market was more potential than fact, and a key link—the natural gas utilities—was not under the control of the producers or the pipeline.

The need to develop markets and the lack of vertical integration may explain why natural gas pipelines have traditionally bought and sold the gas they carried, while oil pipelines have been common carriers. Because the major oil companies controlled both the producing and refining ends of the industry, they could guarantee "throughput" for the pipeline, and provide assurances of economic viability without explicit long-term contracts with outside companies. The proof of economic viability for natural gas pipelines,[11] on the other hand, rested on the existence of long-term contracts with gas utilities and with producers (to the extent that they were not the same as the pipeline participants).[12] The implicit existence of a long-term contract inherent in a vertically integrated company would also provide oil producers with more assurances of a long-term market than the month-to-month nature of the actual sales contracts would initially suggest, and the

[10] See Cochran Murray and Hay Inc., *Natural Gas in Canada* (Toronto: Cochran Murray and Hay, 1957), 29-31.

[11] Proof of economic viability and of the ability to finance the project was required for approval of pipeline projects by the federal Board of Transport Commissioners. In the case of TCPL, deadlines for these were extended on several occasions.

[12] The AOGCB also had a policy of refusing removal permits unless at least 80 percent of the volumes were under contract.

prorationing system enforced by Alberta would guarantee market access. Long-term contracts with minimum take-or-pay provisions[13] provided the same sort of assurances for natural gas producers.

TCPL's financial problems and the measures the federal government took to assist the company eventually led to the "great pipeline debate" of 1956-57 and the defeat of the Liberal government at the polls. To defuse the political situation, one of the first steps taken by the newly elected Progressive Conservative government was the establishment of the Borden commission to inquire into Canadian energy policy.

The Export Issue, 1958-1971

The main issues facing the Borden commission were summed up by a contemporary observer as improving Canadian access to US oil markets and restricting natural gas exports to the United States in the interest of security of supply.[14] Western Canada was the only reliable source of natural gas for eastern Canada, and in presentations to the commission various consumer groups argued that exports should not be allowed if these would jeopardize future Canadian requirements or force Canadians to rely on the development of more remote or higher-cost reserves. Industry presentations, on the other hand, stressed the importance of export markets (and increased prices) in stimulating the exploration for and development of new reserves and enhancing security of supply in the longer term. Increased export volumes would also reduce transport costs for Canadian consumers, since a high proportion of pipeline costs were fixed, and a higher throughput would reduce the cost of service per unit volume.

The Borden commission recommended that a national energy board be established with the authority to license exports of surplus natural gas under terms that were fair and in the public interest. The commission concluded that it was not reasonable to set aside enough proven reserves to meet all long-term future needs; it suggested rather that some reliance could be placed on supplies that were expected to become available on the basis of past trends in the growth of reserves. With respect to the determination of an export price in the public interest, the commission rejected the regulation then in effect,[15] which stated that such a price should be no less than that charged to Canadian buyers of similar volumes under similar conditions of sale. The commission felt that the technical difficulties involved

[13] Take-or-pay provisions mean that the buyer pays for a minimum contracted volume whether or not the gas is actually taken. Until the late 1970s, TCPL had take-or-pay provisions in both its purchase and sales contracts. Toward the end of the 1970s, take-or-pay provisions in TCPL's domestic sales contract were significantly relaxed. See Canada, Pipeline Review Panel, *A Review of the Role and Operations of Interprovincial and International Pipelines in Canada Engaged in the Buying, Selling, and Transmission of Natural Gas* (Ottawa: Supply and Services, 1986), 70.

[14] Supra footnote 8, at 78-97.

[15] This was under the Exportation of Power and Fluids and Importation of Gas Act of 1955, supra footnote 5.

in making the required comparison were too great but did not suggest alternative criteria.

The recommendations of the Borden commission were mostly adopted when the NEB was created in 1959. The NEB was given the responsibility for monitoring and reporting on all energy matters within federal jurisdiction as well as the regulation of pipelines, energy imports and exports, and utility rates and tariffs. The surplus test for natural gas developed by the NEB used a 30-year time horizon and was similar to but relatively more liberal than the one used by the AERCB.[16] Established reserves had to be sufficient to meet Canadian requirements for the first 21 years, but all increases in demand after the third year and all requirements after 21 years were to be met from future discoveries (so-called trend gas). The NEB held its first set of export hearings in 1960 and approved export licences totalling nearly 7 trillion cubic feet (190 billion cubic metres) over a 25-year period.

Although the NEB quickly developed guidelines for determining allowable export volumes, it was not until 1967 that it developed a set of guidelines for determining whether or not the export price was in the public interest. There were three criteria:

1) the export price should recover all relevant costs incurred;

2) it should not be less than the price charged to Canadian consumers in the adjacent region for comparable volumes and terms of service; and

3) it should not be materially less than the least-cost alternative energy source in the relevant export market.

These guidelines were developed in the course of an NEB ruling on an export application by Westcoast Transmission. In 1954, the FPC in the United States had refused to grant import permits for Westcoast Transmission's sales in the Pacific Northwest. When the FPC eventually approved the imports in 1957, the price approved was less than the price charged by Westcoast Transmission to its Canadian consumers, with no contract provisions for price escalations.[17] In 1966, when Westcoast Transmission attempted to increase export prices above those charged to its Canadian customers, the FPC rejected the application. It judged that the prices negotiated between Westcoast Transmission and the US buyer were too high and suggested that these should be "in line" with those charged to Canadian users. The FPC also ruled out periodic price escalations and renegotiations during the life of the contract. The NEB in turn rejected the revised

[16] In 1966, the NEB adopted the "25A4 rule" whereby the amount of reserves set aside for Canadian needs was equal to 25 times the estimated requirements four years hence.

[17] This arrangement had been approved by the Canadian government before the creation of the NEB. The export price was 22 cents per thousand cubic feet (mcf), while the price to Vancouver residents was 31 cents per mcf; see François Bregha, "Canadian Natural Gas Policy: A Critique" (unpublished paper submitted to York University, Faculty of Environmental Studies, Toronto, 1975), 57. A study done for the Borden commission had in fact concluded that all of the company's profits were gained from its Canadian markets, see Ian McDougall, supra footnote 9, at 348.

application based on the FPC ruling, since the "in line" principle would make the floor price in Canada the ceiling price for exports to the United States, and it denied the notion that the export price should at least approximate the value of the gas in the market served. In the end, the NEB and FPC both accepted a price half-way between the two proposals, which was about 7 percent below the cost of US gas in the same market.[18]

In 1970, the NEB essentially adopted the "in line" pricing principle with its ruling that the export price should not be less than 105 percent of the domestic price in the area next to the export point. Although this ruling was made with respect to a specific export application, it was applied more generally. An application by Alberta & Southern to export a large quantity of gas to California was accepted because it met the first two criteria of the price test, even though the NEB had concluded that the price was significantly below the least-cost alternative in the California market.

Surplus tests were gradually relaxed in the 1960s, and the NEB approved a number of new export licences (table 4.1).[19] Exports (approximately equal to the difference between distributor sales and total marketed production) accounted for a rapidly growing proportion of total marketed Canadian gas production during the 1960s, as figure 4.1 shows. The figure also indicates how rapidly domestic consumption of natural gas grew during the 1960s. By 1970, natural gas accounted for over 18 percent of total Canadian energy consumption as compared with 3 percent in 1950.[20] Although residential and commercial demand showed strong increases, the most rapidly growing portion of the Canadian market was the industrial segment (see figure 6.3 in chapter 6). To meet this growing demand, TCPL proposed a major expansion of its pipeline facilities to Ontario in 1966. Although the NEB approved the proposed route through the United States, the federal Cabinet responded to the storm of protest and overturned the NEB decision. Cabinet approval for the expansion through the United States was eventually obtained on the condition that the existing all-Canadian line be used to transport the bulk of Alberta gas destined for eastern Canada.

By early 1968, there was evidence of strong demand growth in both the export and domestic markets. The FPC had actively been encouraging imports of Canadian gas despite some opposition from industry groups within the United States.[21] Field prices for interstate gas in the United States had been regulated by the FPC since 1954, and by the late 1960s increases in

[18] Supra footnote 8, at 106-13.

[19] See Watkins, supra footnote 4, for a detailed description of these changes. In general, the NEB placed greater reliance on reserves beyond current economic reach and deferred gas. The AERCB relaxed its surplus tests in the 1960s as well, but it was also concerned with providing short-term protection for Alberta consumers.

[20] Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986), section 7, table 4.

[21] See André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986*, PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986), items 65.7, 66.5, 66.10, and 69.16.

Table 4.1 Sales and Transportation of Natural Gas

Year	TCPL[a]		Canadian distributor sales outside Alberta and British Columbia
	Canadian sales	Transported for others	
	billions of cubic metres		
1965	7.96	0.13	9.65
1966	9.07	0.47	10.71
1967	9.93	0.53	12.06
1968	11.01	0.48	13.75
1969	12.71	0.40	15.35
1970	14.97	0.39	16.79
1971	12.71	0.38	18.86
1972	18.86	0.52	22.20
1973	20.92	1.28	22.90
1974	22.38	1.15	25.42
1975	22.32	1.43	24.88
1976	22.89	1.57	26.39
1977	23.20	1.69	26.78
1978	23.78	1.69	26.72
1979	23.30	1.99	27.46
1980	22.40	2.17	26.24
1981	23.37	3.75	26.26
1982	22.99	4.85	25.70
1983	21.96	3.68	25.96
1984	24.46	4.57	27.92
1985	24.40	4.69	29.21
1986	23.75	5.84	29.26

[a]TCPL—TransCanada PipeLines Limited.

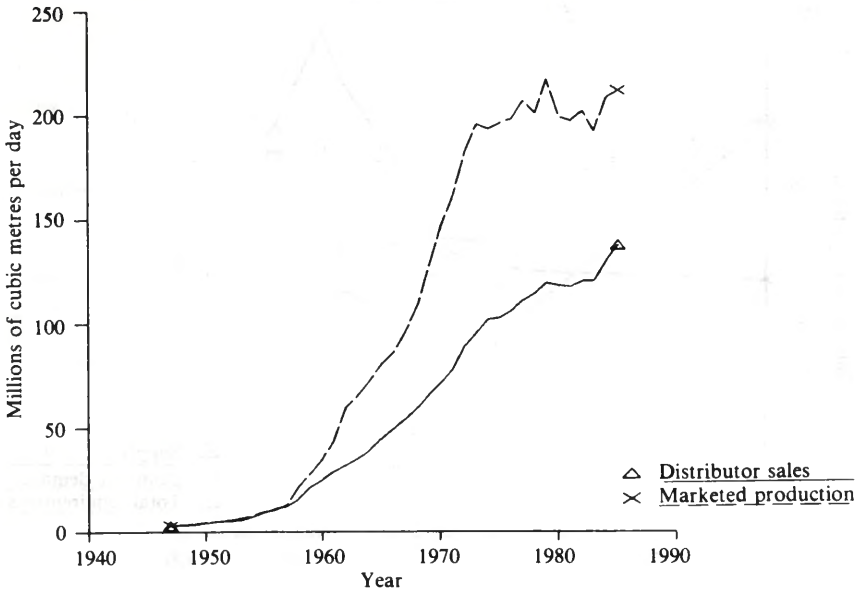
Source: TCPL Canadian sales and gas transported for others are taken from the company's annual reports. Sales of natural gas outside Alberta and British Columbia are taken from the Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986), section 7, table 6.

demand were outstripping reserve additions.[22] TCPL reported upward pressure on export prices as a result. A number of export proposals were put before the NEB in late 1969, but for the first time, the NEB refused to grant all of the additional volumes requested because of inadequate Canadian supplies. For the most part, this entailed a reduction in the term of licences from 23-25 years to 15-20 years, but it also meant the outright rejection of one proposal involving a new pipeline project. Even so, the 6.3 trillion cubic feet (175 billion cubic metres) of additional exports evoked sharp criticism a few years later when supply shortages of natural gas were widely foreseen.[23] Several of the companies involved resubmitted export applications, and in

[22]For example, see Richard J. Pierce Jr., "Natural Gas Regulation, Deregulation, and Contracts" (January 1982), 68 *Virginia Law Review* 63-115. This situation was exacerbated by the fact that, at the time, wellhead prices of intrastate gas were not regulated, so that US producers tended to abandon interstate markets for intrastate ones.

[23]See, for example, Bregha, supra footnote 17.

Figure 4.1 Annual Distributor Sales and Total Marketed Production of Natural Gas



1971, the NEB rejected them all and identified a *deficit* of 1.1 trillion cubic feet (30 billion cubic metres) in meeting future Canadian requirements. This deficit arose despite the fact that the assumed rate of growth of trend gas had been increased from 3.5 to 3.7 trillion cubic feet (100 to 105 billion cubic metres) per year. Earlier projections by the NEB had seriously underestimated the growth in Canadian requirements.[24]

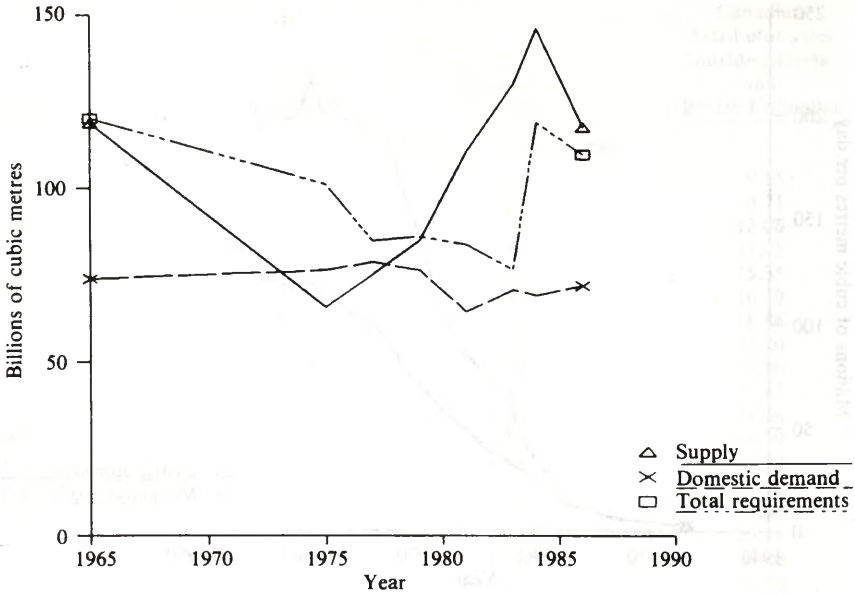
Regulated Pricing, 1971-1979

The early 1970s brought about two radical changes for the natural gas industry: (1) the threat of supply shortages and (2) direct government intervention into pricing. In 1971, the NEB's projection of a deficit came about primarily because Canadian requirements had grown more rapidly than expected and not because of unexpectedly low supply forecasts. Within a few years, however, the NEB had drastically cut back its estimates of future supply capabilities.[25] In 1969, the board had projected that the supply capacity of conventional areas in 1990 would be in the order of 4.2 trillion cubic feet (120 billion cubic metres); by 1975, this projection had fallen to 2.3 trillion

[24] Ian McDougall, supra footnote 9, at 358-65.

[25] In 1973-74, serious waterflooding problems reduced the producibility of northeastern BC gas fields (figure 4.3b gives an indication of the severity of the problem). This probably contributed to the NEB's reduction of its estimate of the future gas supply capabilities of the western sedimentary basin.

Figure 4.2a NEB Natural Gas Supply-Demand Projections for 1990
(annual data)



cubic feet (65 billion cubic metres). Figure 4.2a shows how the NEB projections of conventional productive capacity (supply) and total requirements (domestic plus export demand) for 1990 changed between 1969 and 1986, while figure 4.2b shows the corresponding estimates for 1985.

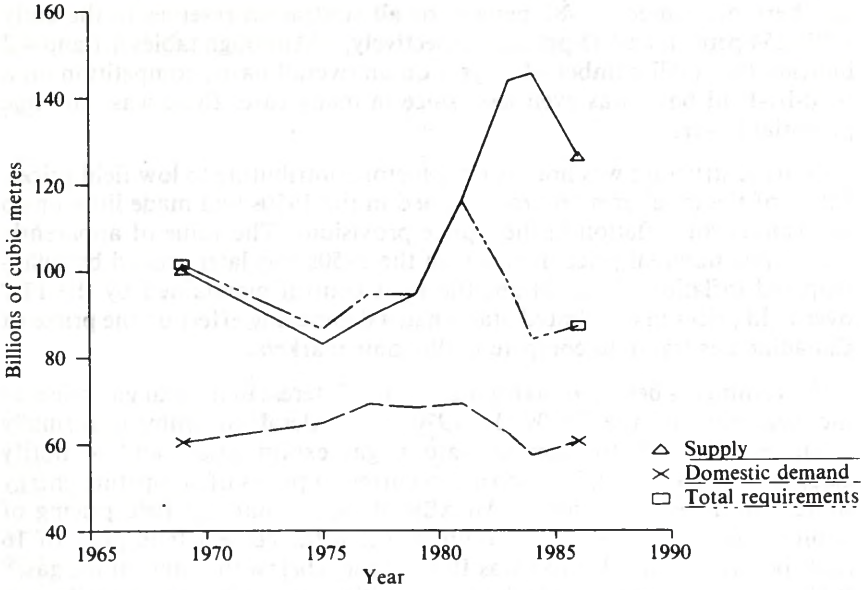
The year 1975 marked the low point in conventional supply projections and the height of interest in building an arctic pipeline to supply Canadian energy needs.[26] Projected shortfalls in conventional gas supplies became even more of a threat when they were coupled with concern over Canada's increasing dependence on imports of foreign oil following the OPEC price shock in 1973. The regulatory delays imposed by the controversy over the environmental and social impacts of the projects had the beneficial side-effect, however, of preventing investments that later forecasts indicated were unnecessary.[27] In the meantime, the threat of supply shortages forestalled new export applications and helped bring pricing issues to the fore.

With the exception of a few export contracts (in particular, the 1967 Westcoast Transmission decision), pricing had not been a particularly controversial issue in either domestic or export markets. Long-term contracts were negotiated between producers and pipelines (or in some cases, domestic utilities) and usually, but not always, provided for periodic price

[26] Chapter 9 provides a more detailed discussion of northern pipeline proposals.

[27] See John F. Helliwell, "Canadian Energy Policy" (1979), 4 *Annual Review of Energy* 175-229, at 191-206, for a more complete discussion.

Figure 4.2b NEB Natural Gas Supply-Demand Projections for 1985
(annual data)



rises and renegotiations.[28] As was evident in chapter 2, figure 2.3, average field prices in western Canada were low in nominal terms during the 1950s and 1960s.

Price competition among potential buyers was limited for out-of-province markets, which accounted for most of the gas produced within Alberta and British Columbia (the other main producing region). TCPL had the only pipeline to eastern Canada, and until 1957, when Alberta & Southern began operating on the export market, TCPL was almost the only buyer of natural gas for sale outside Alberta.[29] As table 4.1 shows, TCPL owned most of the gas it transported (although it did occasionally act as a contract carrier) and accounted for a substantial proportion of the Canadian market. Competition among buyers was also limited in the export market as a breakdown of export licences by company shows (table 4.2). In 1968, Consolidated Natural Gas created some competition for TCPL and

[28] This took into account the fact that pipeline transmission costs per unit volume tended to fall over time as the throughput increased. See A.J. Nixon, *Natural Gas Pricing in Canada: An Economic Analysis*, Working Paper no. 81-2 (Calgary: Canadian Energy Research Institute, 1981), 8-13.

[29] The exceptions were some gas in northern Alberta bought by Westcoast Transmission and a small amount exported by Canadian-Montana from southern Alberta. In British Columbia, Westcoast Transmission was the only buyer of natural gas. See Stanford Research Institute, *The Market Price for Natural Gas from Sources in Western Canada, 1972-1990*, vol. 1 (Menlo Park, CA: the institute, 1972), 223.

Alberta & Southern when it began offering higher prices, prepayments,[30] and shorter contracts for export gas. Even with this, TCPL and Alberta & Southern accounted for 87 percent of all contracted reserves in the early 1970s (54 percent and 33 percent respectively).[31] Although tables 4.1 and 4.2 indicate the small number of buyers on an overall basis, competition on a field-by-field basis was even less, since in many cases there was only one potential buyer.

Market structure was not the only factor contributing to low field prices. Many of the long-term contracts signed in the 1950s had made little or no allowances for inflation in their price provisions. The value of apparently reasonable nominal price increases in the 1950s was later eroded by unanticipated inflation. In addition, the tight control maintained by the FPC over field prices in the United States had a dampening effect on the prices of Canadian gas trying to compete in the same markets.

Governments began to take a more active interest in natural gas prices at the beginning of the 1970s. In 1970, the federal government formally requested the NEB to monitor natural gas export prices and to notify Cabinet when a significant increase occurred in prices of competing energy sources in the export market. An AERCB inquiry into the field pricing of natural gas in Alberta in 1972 estimated that the current field price of 16 cents per thousand cubic feet was 10 to 20 cents below the value of the gas.[32] It blamed the low prices on lack of competition among buyers, the failure of the NEB to grant export licences in 1970 and 1971,[33] and the lags involved in regulating the prices paid by final consumers. Late in 1972, the Alberta government accepted the recommendations of the report, which called for prices to reflect the "field value" of the gas,[34] although provisions were made to protect Alberta consumers from price increases. As a result, the average field price of gas in western Canada increased from 15.8 cents per thousand cubic feet in 1972 to 27.4 cents per thousand cubic feet in 1974.[35]

The rapid increase in world oil prices following the first OPEC price shock in the fall of 1973 soon led to the replacement of government pricing guidelines with outright regulation. British Columbia Petroleum Corporation (BCPC) was set up by the BC government in late 1973 and became the

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[30] Prepayments were essentially interest-free loans designed to aid the exploration for and development of new gas reserves. The FPC allowed the costs of these to be worked into the rate base of US utilities; see supra footnote 28, at 12.

[31] Supra footnote 29, at 224.

[32] The British Columbia Energy Commission (BCEC) soon came to a similar conclusion.

[33] The argument was that the failure to grant export licences meant that the tight market conditions in the United States could not be translated into higher prices for Canadian producers; see supra footnote 28, at 13.

[34] The AERCB conducted a second inquiry into field pricing in 1973 and formally defined a "field value" for the gas based on the value of competing fuels in the market, net of transportation and distribution costs.

[35] Supra footnote 20, at section 6, table 1.

Table 4.2 Natural Gas Exports by Licence Holder

Year	TCPL	Alberta & Southern	Canadian-Montana	Westcoast	Pan-Alberta	Total
			billions of cubic metres			
1960	0.35	—	0.17	2.28	—	2.80
1961	1.68	0.22	0.45	2.44	—	4.78
1962	1.76	3.35	0.80	3.80	—	9.71
1963	1.78	3.63	0.77	3.96	—	10.19
1964	2.02	4.14	0.79	4.10	—	11.11
1965	2.10	4.32	0.83	4.13	—	11.47
1966	2.19	4.70	0.88	4.37	—	12.23
1967	2.39	5.84	0.87	5.33	—	14.54
1968	3.48	6.84	1.04	5.65	—	17.12
1969	4.27	7.48	1.13	6.23	—	19.27
1970	5.77	8.63	1.21	6.32	—	22.10
1971	7.33	10.03	1.26	6.81	—	25.84
1972	7.26	10.87	1.38	8.68	—	28.60
1973	7.32	10.97	1.42	9.01	—	29.12
1974	7.18	10.13	1.36	8.12	—	27.17
1975	7.07	10.77	1.19	7.43	—	26.82
1976	7.12	11.12	1.01	7.40	—	27.01
1977	7.88	11.05	0.81	8.11	—	28.34
1978	6.97	9.77	0.80	7.06	—	24.96
1979	8.19	11.03	0.82	7.90	—	28.16
1980	6.90	8.92	0.63	5.43	—	22.56
1981	5.99	7.40	0.59	4.73	0.28	21.58
1982	4.35	7.19	0.39	3.35	3.07	22.20
1983	2.60	7.05	0.11	3.08	4.23	20.17
1984	3.55	6.58	0.19	3.16	4.55	21.40
1985	4.71	8.56	0.23	3.20	5.89	26.15
1986	3.17	6.94	0.22	2.96	4.63	20.98

Source: Canada, National Energy Board, *Annual Report* (Ottawa: Supply and Services, various years), appendix G.

sole purchaser of natural gas produced within the province.[36] Gas prices in both Alberta and British Columbia were doubled, and in the fall of 1974 the federal government, in consultation with the governments of Alberta and British Columbia, instructed the NEB to increase unilaterally natural gas export prices to $1 per thousand cubic feet. Further increases in export prices were made in early 1975, and all three governments agreed that, unlike oil producers, natural gas producers would receive the benefits of the higher export prices. Initially, the NEB adopted a commodity-value approach to export pricing, where the price was determined by the value of alternative sources in the relevant US market and the replacement value of the gas, but it later moved toward a substitution value concept, where the export price was determined in relation to the price of imported oil.[37]

[36] It also became the means by which the provincial government collected revenues from the gas industry. The difference between BCPC revenues and what it paid producers became known as a "deemed royalty." See appendix 5.2 for more details.

[37] See, for example, Canada, National Energy Board, *1978 Annual Report* (Ottawa: Supply and Services), 20.

Domestic pricing continued to present a problem, however. The Petroleum Administration Act of 1975 gave the federal government the ultimate jurisdiction over natural gas prices in interprovincial trade. The NEB was given the responsibility of achieving a price for natural gas sold outside the province where it was produced that was uniform across Canada except for transportation and service costs. BCPC and the AERCB, however, were unilaterally raising prices of gas removed from the province. An agreement between Alberta and the federal government was eventually announced in the June 1975 federal budget. The price of natural gas delivered to Toronto (the Toronto city-gate price) was to be set equal to $1.25 per thousand cubic feet, or approximately 85 percent of the BTU-parity oil price.[38] The intention was to increase the Toronto city-gate gas price to 100 percent of the BTU-parity oil price over a period of three to five years.

In November 1975, the Alberta government enacted the Natural Gas Pricing Agreement Act and the Natural Gas Price Administration Act and created a two-price system for Alberta gas. All gas sold outside the province received the Alberta border price, which was equal to the Toronto city-gate price less transportation costs. Gas sold within the province received a discount, and the price was set by the province's Public Utilities Board.[39] The other major change made by the regulated pricing system was the creation of the export flow-back system, where the difference between the export price and the border price was divided evenly among all producers, not only the producers who had export contracts with the pipeline companies.

The severe supply shortages experienced in the United States during the winter of 1976-77[40] gave rise to warnings that the country was facing a permanent energy shortage and that the situation was especially critical for natural gas. President Carter's 1977 national energy plan eventually led to the Natural Gas Policy Act of 1978 and a complicated phased-in plan for gas deregulation. This Act and its supporting legislation changed the name of the Federal Power Commission (FPC) to the Federal Energy Regulatory Commission (FERC) and expanded its regulatory powers to include intrastate as well as interstate gas. It then created some 20 categories of natural gas production, each with its own price ceiling and agenda for deregulation. Most of the high-cost gas was to be formally deregulated by November 1979 and much of the rest by January 1985, but gas discovered before 1977 would be regulated until supplies were exhausted.

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[38] The BTU-parity price is the price that would be paid for a quantity of oil that would provide the same amount of heat.

[39] See Michael Crommelin, Peter H. Pearse, and Anthony Scott, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy" (April 1978), 18 *Natural Resources Journal* 337-89. A similar scheme was also adopted in British Columbia.

[40] Periodic supply shortages had been occurring on a regional basis since the early 1970s, and in many states a moratorium had been declared on new gas hookups and priority given to residential customers. On this occasion, however, even high-priority users were faced with curtailed supplies.

The supply shortages combined with the increases in field prices under the new regulatory system in the United States[41] stimulated Canadian interest in the export market. The NEB decision on northern pipelines in 1977[42] was also encouraging for potential Canadian exporters. Although it rejected the Mackenzie Valley pipeline proposal, it did support the Alaska Highway pipeline with a lateral to the Mackenzie Delta.[43] The supply projections that accompanied the decision were more optimistic because of the appreciation of conventional reserves arising from higher prices. In the spring of 1978, the NEB relaxed controls on short-term exports,[44] and the FPC approved large additional imports of Alberta gas as part of the southern Alberta phase of the Alaska pipeline. By the end of 1978, however, the US government was expressing concerns about the large volume of gas imports from Canada, and there were some doubts about the construction of the Alaska segment of the pipeline.[45]

The Gas Bubble, 1979-1984

In Canada, there was growing evidence of a deliverability surplus (an excess of production capacity over domestic and export requirements) for western gas production. TCPL introduced a voluntary prorationing scheme among its suppliers in the spring of 1978, when it was unable to take all its contracted supplies.[46] Even with this in place, TCPL ran into serious financial difficulties with its take-or-pay provisions.[47] Shut-in natural gas became one of the main issues raised during the 1979 hearings held by the AERCB and

[41] In fact, the FERC had increased field prices from US$0.52 to US$1.92 per thousand cubic feet in 1976, before the new system was in effect. The price ceilings that had been in effect under the area-rate system resembled prices prevailing in the late 1950s. See supra footnote 22, at 65-66.

[42] See Canada, National Energy Board, *Reasons for Decision: Northern Pipelines* (Ottawa: Supply and Services, 1977).

[43] On these and related issues, see chapter 9.

[44] Approval of longer-term exports remained on a swap-back basis (that is, exports from Canada would be approved now if reciprocal exports from the United States would be available later in the 1980s). This meant that US supplies could potentially be used to build up a market in the maritime provinces (Nova Scotia, Prince Edward Island, and New Brunswick) for the Trans Quebec and Maritimes (TQ&M) pipeline project, in the same way that a market had been built up in southern Ontario for TCPL.

[45] Supra footnote 21, at item 78.24.

[46] The amount of gas under contract had increased faster than sales in domestic and export markets in part because TCPL had changed its method of contracting from a reserves-based system to an area system based on producibility.

[47] Under the Topgas I program in the spring of 1982, a group of financial institutions advanced producers $1 billion in prepayments and $1.3 billion under take-or-pay obligations incurred in the 1980-81 and 1981-82 contract years in return for a reduction in TCPL's take-or-pay obligations. Another $350 million was extended to producers under Topgas II for take-or-pay obligations for the 1982-83 contract year. See Canada, National Energy Board, *Reasons for Decision: In the Matter of TransCanada PipeLines Limited Availability of Services* (Ottawa: Supply and Services, 1986), 14-21.

the NEB on the determination of exportable surpluses.[48] Natural gas was in short supply in the US market, and expansion of the domestic market to Quebec and the maritime provinces was still in the planning phase.[49] Late in 1979, the NEB approved a number of relatively short-term (five to seven years) natural gas export projects.

Export prices were also considerably higher than domestic prices (see chapter 2, figure 2.3). In 1978, Alberta and the federal government had agreed not to increase the BTU-parity price of domestic natural gas to 100 percent as originally planned, but to maintain the 85 percent rule because of shut-in supplies. The NEB, on the other hand, was essentially using a 100 percent BTU-parity ratio to determine the gas export price on the basis of imported oil prices, which were in turn higher than domestic oil prices. As a result of the second OPEC price shock, Canadian export prices increased from US$1.90 per thousand cubic feet at the beginning of 1979 to US$4.47 per thousand cubic feet in February 1980.[50]

The OPEC price shock of 1979 reinforced expectations that world oil prices would continue to rise in real terms in the future. With the prospects of rising costs for imported oil and a growing surplus of domestic natural gas, encouraging Canadian consumers to switch from oil to gas became one of the main objectives of the 1980 national energy program (NEP), which proposed to do this by reducing the relative price of natural gas.[51] A single wholesale price was established for all gas consumed in eastern Canada, and it was intended that this price would rise by 45 cents per thousand cubic feet over the following three years. Part of the increase would be the natural gas and gas liquids tax (NGGLT), a new flat-rate tax, which would apply to both domestic and exported natural gas.[52] Because of this new tax, producers would not receive any of the increase in the domestic gas price in the first year. In May 1981, wholesale natural gas prices were increased again with the addition of another new federal tax, the Canadian ownership special charge (COSC), which was to be used to finance some of the Canadianization aspects of the NEP.

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[48] Both the AERCB and the NEB moved away from a definition of surplus solely on the basis of stocks to a definition that also incorporated deliverability factors. As well, the AERCB reduced its required protection from 30 years to 25 years. For more details, see Watkins, supra footnote 4.

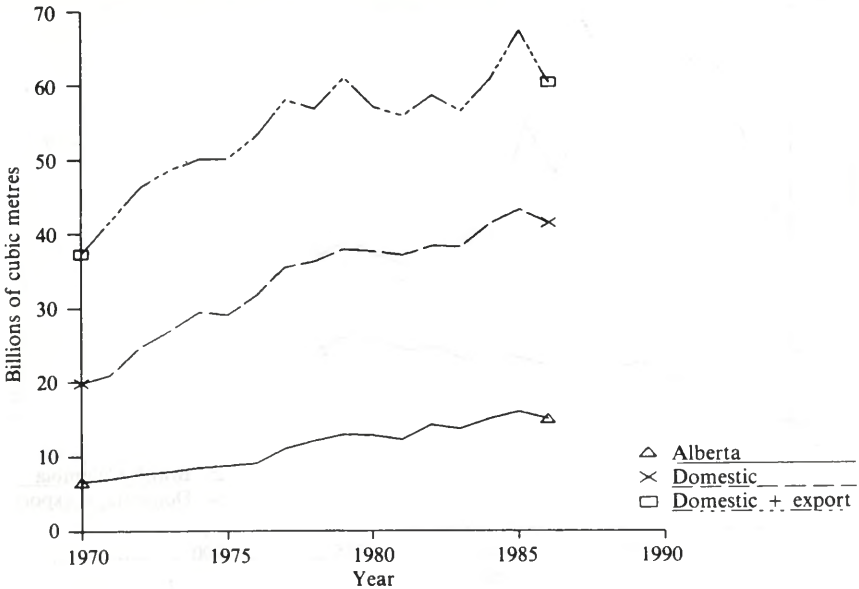
[49] In early 1978, there were two expansion plans being discussed: one, a new pipeline to Quebec and the maritime provinces; the other, an extension of the TCPL system. Hearings on the proposals began in 1979, and the two projects were eventually combined and approved in 1981.

[50] The FERC objected to the new prices on the ground that these were higher than the BTU-equivalent price of residual fuel oil, and hence rejected several import applications. The 1980 Duncan-Lalonde formula continued the import-substitution pricing policy but agreed to delays in implementing price changes.

[51] Several grant programs were also introduced to encourage consumers to switch away from oil.

[52] The NGGLT would not affect export sales for three months, because of an agreement with the US government, and would have to be absorbed by producers instead.

Figure 4.3a Annual Natural Gas Disposition, Alberta

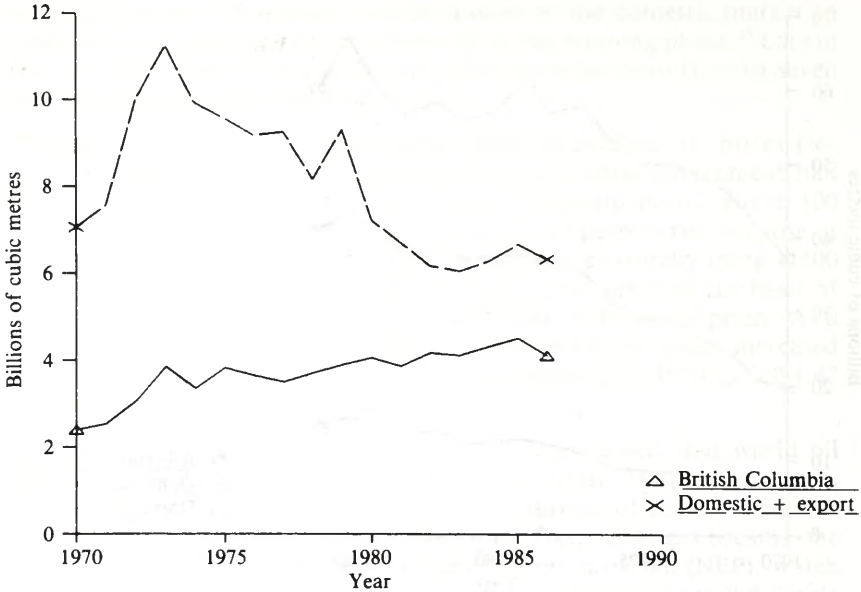


As noted in chapter 3, the controversy arising from the federal government's unilateral imposition of the NEP was eventually resolved with the 1981 energy agreements between the federal government and the governments of the producing provinces. The agreements modified the NEP's natural gas pricing provisions but retained the principle of reducing the relative price of natural gas. The Toronto city-gate price would be maintained at 65 percent of the BTU-parity delivered price of crude oil, and the Alberta border price would be increased 25 cents per thousand cubic feet every six months until the end of 1986. The NGGLT would apply only to domestic sales, but instead of being a flat-rate tax, it would be equal to the regulated Toronto wholesale price net of the COSC, transportation charges, and the Alberta border price. It would thus be the wedge that would permit consumer and producer prices to be determined independently. Government initiatives to develop new natural gas markets were another feature of the 1981 agreements. The federal government was to approve additional exports if surpluses were found, while Alberta agreed to help finance federal initiatives for the development of domestic natural gas markets east of Alberta.[53]

As figures 4.3a and 4.3b indicate, export volumes (especially from British Columbia) fell after 1979. The expected growth in the export market had not materialized, thus increasing the wedge between Canadian production capability and actual production. In 1980, for example, exports were

[53] This was under the market development incentive payments program.

Figure 4.3b Annual Natural Gas Disposition, British Columbia



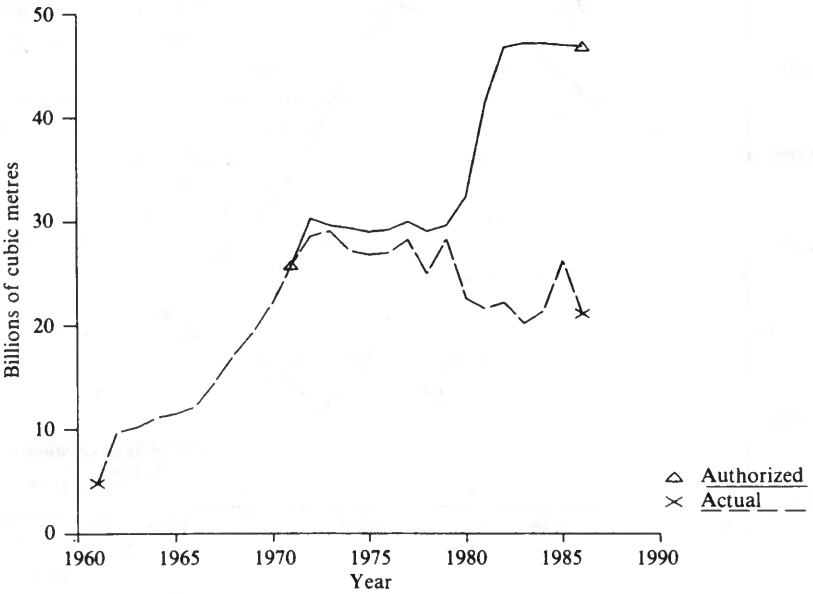
only 70 percent of approved volumes, the first time that they had fallen below 85 percent of approvals. The next year, exports proceeded at only 52 percent of approvals (figure 4.4). The surplus problem became worse in the months following the 1981 agreements. The 1981-82 recession, the worst since the 1930s, had a negative impact on domestic and export sales. In the United States, imported Canadian natural gas was relatively expensive, although the full effects were not felt by consumers as US pipelines rolled in the costs of their more expensive supplies with their supplies of old, low-cost gas. Nevertheless, consumer demand in the United States was hard hit by the 1981-82 recession, and this was reinforced by higher gas prices.

On the domestic front, the recession also had a negative impact on gas sales, especially in the large industrial market (see chapter 6, figure 6.3). Meanwhile, higher field prices stimulated drilling activity and resulted in greatly increased supplies. To alleviate this situation, the NEB sought and, in the fall of 1982, received permission to authorize short-term (less than two years) natural gas exports by order (that is, without holding an export licence hearing).[54] A few months later, in January 1983, the NEB authorized additional long-term exports totalling 11.5 trillion cubic feet (325 billion cubic metres), less than one-half the requested volumes, but the first long-term exports to be authorized since 1970.[55]

[54] The volumes could not exceed 3 billion cubic metres in any given year and could not displace existing volumes.

[55] See Canada, National Energy Board, *Reasons for Decisions: In the Matter of Phase II—The Licence Phase and Phase III—The Surplus Phase of the Gas Export Omnibus Hearings, 1982* (Ottawa: Supply and Services, 1983).

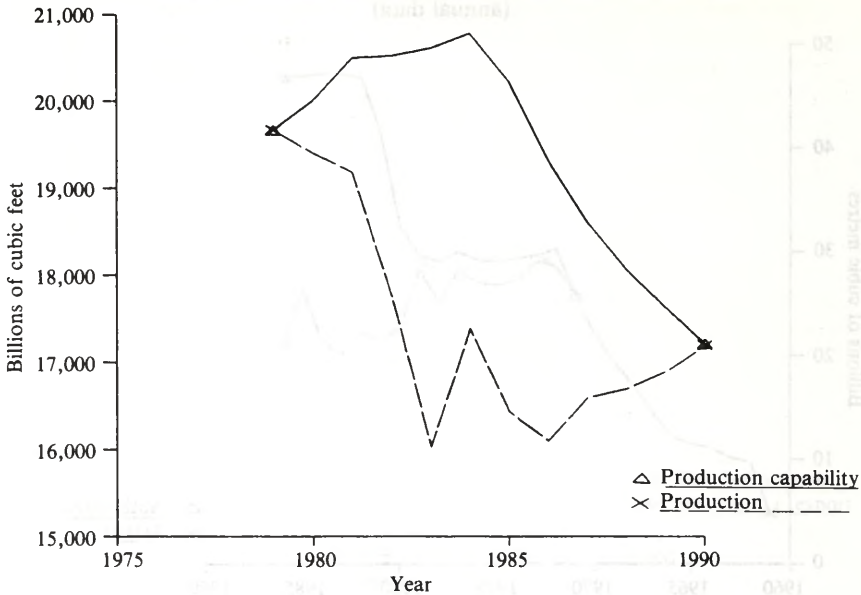
Figure 4.4 Actual and Authorized Natural Gas Exports
(annual data)



Despite the more liberal approach to authorizing exports, actual export volumes to the United States fell in 1983, both in absolute terms and relative to approvals (see figure 4.4). The higher prices in the United States reduced the growth in demand for natural gas, but at the same time stimulated the development of new supplies. Figure 4.5 shows how the deliverability surplus in the United States widened from zero in 1979 to an estimated 3 trillion cubic feet (85 billion cubic metres) in 1983. The gas bubble was initially expected to be a temporary 18-month phenomenon, but in 1986, the American Gas Association (AGA) projected that it might not disappear until 1990.

The drop in world oil prices in 1983 contributed further to the deliverability surplus since many large industrial consumers with dual-burner capacity could shift very quickly from natural gas to residual fuel oil in response to small changes in relative prices. In the spring of 1983, therefore, exports of Canadian gas were competing with both residual fuel oil and vastly increased supplies of US gas. Canadian authorities responded by reducing the export price from US$4.94, where it had been since April 1981, to US$4.40 per thousand cubic feet. In the summer of 1983, when it became evident that actual exports were continuing to run below authorized volumes, the federal government introduced the volume-related incentive pricing (VRIP) program. Under this program, the base export price remained at US$4.40 per thousand cubic feet, but volumes in excess of 50 percent of the licensed authorizations could be sold for US$3.40 per thousand cubic feet.

Figure 4.5 Annual US Natural Gas Production and Production Capability



The 1983 drop in world oil prices created problems for domestic natural gas markets as well. It soon became apparent that it would not be possible to maintain the 65 percent BTU-parity price in Toronto and, at the same time, increase the Alberta border price according to the schedule laid out in the 1981 energy agreements. These agreements were amended in June 1983 so that once the NGGLT fell to zero (which occurred in February 1984), the Alberta border price would be increased in 1984 only to the extent that the 65 percent BTU-parity rule was not breached. After 1984, the 65 percent BTU-parity rule would be breached, if necessary, to allow for the increases in the Alberta border price laid out in the 1981 agreements. As things turned out, the Alberta border price was effectively frozen from August 1984 until deregulation in November 1986.

In the summer of 1983, domestic as well as export markets started to become more flexible. In British Columbia, field prices were to be set under contracts negotiated between buyers and producers, although wholesale and retail prices would continue to be regulated. In early 1984, the government of Alberta and the federal government introduced an incentive pricing scheme to offer discounts to large industrial users in eastern Canada. These moves were complemented by legislative efforts on the part of consuming provinces (especially Ontario) to increase the flexibility of the price regulations affecting large industrial users.

Problems with the natural gas export market continued in 1984. In February, the FERC ruled that US companies would no longer be able to roll take-or-pay costs for imported gas into their rate base. This gave US com-

panies the incentive to shift from Canadian to US sources for which the take-or-pay penalties were still binding. With export volumes still well below 50 percent of approvals, the Canadian government ruled that as of November 1, 1984, producers would have the choice of continuing under the existing VRIP program or of negotiating prices directly with US customers, subject to NEB approval. Although the Toronto city-gate price would be the floor, the negotiated export price had to be equal to or greater than the price of the major competing energy sources in the relevant export market and had to recover its appropriate share of the costs incurred. Contracts also had to include provisions for renegotiating prices, had to provide reasonable assurances that contracted volumes would be taken, and had to show that the terms of the renegotiated contracts were approved by producers and would result in higher economic returns to Canada. These conditions bore a striking resemblance to the ones attached to natural gas export licences in the early 1950s and the criteria developed by the NEB in its 1967 Westcoast Transmission decision. By the beginning of November, the NEB had approved renegotiated contracts that accounted for 80 percent of licensed volumes.

At the time, the desirability of more flexibility in export arrangements seemed to be based on two main premises. First, there was an emerging belief that the (short-run) price elasticity of the demand for Canadian gas in the United States was very large. Daniel, Goldberg, and Weyant, for example, reported estimates of between −3 and −5, while Beltramo, Manne, and Weyant suggested that it might be as high as −11.[56] The post-October 1984 developments lent some support to this notion. Equally important is the fact that both these sets of estimates are much larger (in absolute value) than estimated own-price elasticities of the demand for natural gas in Canada.[57] Second, the importance of spot markets for natural gas in the United States was growing rapidly. Transactions in such markets had been virtually non-existent before the 1980s, but by 1984 about 15 percent of all gas consumed in the United States had been purchased on spot markets,[58] and there was a consensus that this proportion would increase significantly over the next few years, perhaps reaching as high as 50 percent by 1987.[59] The message conveyed by the industry was clear: in order for Canadian gas to maintain its share of the US market, exporters needed a more flexible

[56] See Terrence E. Daniel, Henry M. Goldberg, and John P. Weyant, "Canadian Natural Gas in the United States: A Monopolistic Intertemporal Analysis" (October 1984), 5 *The Energy Journal* 21-34, at 28; and Mark A. Beltramo, Alan S. Manne, and John P. Weyant, "A North American Gas Trade Model (GTM)" (July 1986), 7 *The Energy Journal* 15-32, at 27-29. The second article circulated in discussion paper form beginning in September 1984.

[57] Such estimates tend to be between −0.5 and −1.0, even in the medium run (for example, five years). See Mary E. MacGregor and André Plourde, *An Examination of the Macroeconomic Consequences of Removing the Canadian Ownership Special Charge on Natural Gas (COSC)*, PEAP Policy Study no. 84-6 (Toronto: University of Toronto, Institute for Policy Analysis, 1984), 4, 10-11. See also chapter 6, below.

[58] See "Gas Marketing Robust, but Future Uncertain," *Oilweek*, January 20, 1986, 11.

[59] See, for example, "US Natural Gas Market Evaporates," *The Financial Post*, February 9, 1987, 4.

regulatory environment, one that would allow them not only to modify existing long-term contracts to protect their sales,[60] but also to penetrate short-term markets.

Formulating and Implementing Deregulation

The Western Accord

As the preceding section has shown, the first half of the 1980s saw a progressive relaxation of government controls over natural gas prices and exports. As we have seen in chapter 3, a similar process was moving Canadian oil prices toward world levels during the same period. Despite this relaxation in controls at the beginning of 1985, there were still significant volumes of shut-in production of both crude oil and natural gas. This similarity of excess supply conditions for Canadian oil and gas did not run very deep; market conditions for the two were fundamentally different. As has been argued elsewhere,[61] shut-in oil production followed a period of federal and provincial policy initiatives designed to spur oil exploration and development activities. The resulting increase in domestic production capability created a bottleneck at the transportation stage: there was a chronic shortage of pipeline capacity linking the producing regions in western Canada to the consuming regions in the United States and eastern Canada. Several pipeline expansion projects had been (or would soon be) approved by the NEB, however, and, equally important, prospects for increased crude oil sales were excellent, especially in the United States.

It cannot be argued, however, that in early 1985 pipeline availability constraints were a key factor in explaining the deliverability surplus for western Canadian natural gas. Market opportunities for domestically produced gas had been disappointing since the beginning of the 1980s. As far as domestic markets were concerned, the extension of the pipeline distribution system in eastern Canada had not resulted in as strong a market penetration by natural gas as had been anticipated at the time the pipeline project was first proposed.

The export market situation was also more complicated for natural gas than for crude oil for several reasons. First, since Alberta-produced gas first reached eastern Canadian markets in the late 1950s, both upstream and downstream sectors of the domestic natural gas industry had always been heavily regulated. This, however, was not out of line with the regulatory environment prevailing in the US gas market. Second, as noted earlier, problems associated with transporting natural gas restrict the geographical extent of markets. In the case of Canada, this effectively means that export opportunities for non-liquefied gas are limited to the United States. Third,

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[60] It is probably important to recall that in late 1984, FERC order 380 had effectively brought about the elimination of take-or-pay provisions in long-term export and import contracts, with the exception of contracts relating to the southern Alberta segments of the Alaska Highway pipeline.

[61] See Plourde, supra footnote 21, at section 2.

for more than a decade, exports of gas had accounted for a greater proportion of domestic production than had exports of crude oil.[62] The combination of these two factors meant that the "health" of the Canadian natural gas industry was more closely linked to developments in the United States than that of the domestic oil industry. Finally, as argued in the earlier section "The Gas Bubble, 1979-1984," policy initiatives, market responses, and general economic conditions together created a situation of chronic excess gas supply in the United States.

When the western accord was signed in March 1985, the federal government and the governments of the producing provinces committed themselves to deregulating domestic oil markets and establishing "a more flexible and market-oriented pricing mechanism"[63] in the domestic natural gas market. In terms of concrete action, the western accord froze the Alberta border price at its prevailing value (about $2.90 per thousand cubic feet) and set up a task force designed to produce a federal-provincial agreement on a new pricing regime by November 1, 1985.

The western accord did not modify in any way the Canadian gas export policy in effect at the time. The policy changes of November 1, 1984 had been accompanied by a resurgence of the marketability of Canadian gas in the United States. Thus, export *volumes* between November 1984 and March 1985 were about 23.2 percent higher than they had been one year earlier (10.43 billion cubic metres in 1983-84 against 12.85 billion cubic metres in 1984-85).[64] Canadian gas exporters had quickly taken advantage of the increased price flexibility to renegotiate contracts with their US customers to include lower prices,[65] which in turn boosted sales volumes, at least in the short run.

The Agreement on Natural Gas Markets and Prices

The task force established by the western accord produced a blueprint for deregulating domestic and export markets for natural gas that was agreed to by the federal government and the governments of the producing provinces at the end of October 1985.[66] On the domestic front, the agreement on natural gas markets and prices (herein referred to as "the natural gas agreement") provided for a transition period of one year, beginning Novem-

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[62] For example, over the 1980-1984 period, exports of gas accounted for almost 30 percent of domestic production, while net crude oil exports barely reached 13 percent of production.

[63] Canada, "The Western Accord: An Agreement Between the Governments of Canada, Alberta, Saskatchewan, and British Columbia on Oil and Gas Pricing and Taxation" (mimeograph, March 28, 1985), 3.

[64] These figures were taken from various issues of Statistics Canada, *Crude Petroleum and Natural Gas Production*, catalogue no. 26-006.

[65] See, for example, supra footnote 21, at items 84.21, 84.32, and 85.4. It should also be noted that in October 1984, Mexico suspended gas exports to the United States. At that time, Mexican export volumes equalled about 10 percent of Canadian exports.

[66] See Canada, "Agreement [Among the Governments of Canada, Alberta, British Columbia, and Saskatchewan] on Natural Gas Markets and Prices" (mimeograph, October 31, 1985).

ber 1, 1985, during which both the Alberta border price and the Toronto city-gate price would be frozen at their prevailing values of approximately $2.90 and $4.00 per thousand cubic feet, respectively.[67] The governments party to this agreement, however, stated their intention to honour prices negotiated between buyers and sellers for incremental sales and for arrangements replacing expiring contracts. In addition, so-called competitive market programs, designed to allow gas prices to remain competitive in certain market segments, would also be allowed.

At the end of this transition period, the federal government and the governments of the producing provinces would effectively withdraw from the business of regulating gas prices, and a key component of the administered pricing system would thus be dismantled. As the natural gas agreement stated:

> Effective November 1, 1986, the prices of all natural gas in interprovincial trade will be determined by negotiation between buyers and sellers.[68]

The renegotiation of existing contracts was encouraged, but would not be made compulsory. The natural gas agreement, however, explicitly provided for prices to be determined through arbitration when such renegotiations between individual buyers and sellers proved unsuccessful.

Two important elements of the regulatory system remained. One such element was the regulation of interprovincial and international pipelines. Here, the natural gas agreement deferred any changes to the existing system but requested the NEB to undertake a review of specific aspects of TCPL's operations, and it established a review panel to examine broader questions concerning the role of such pipelines in a deregulated system. Both of these groups were expected to report relatively soon;[69] their findings and recommendations will be discussed later.

The other remaining element of the regulation system concerned the activities of the intraprovincial pipelines and distribution companies. The natural gas agreement[70] recognized that such activities would continue to be regulated by the provinces in which they operate, and that the consuming provinces, which were not party to the agreement, were in no way bound by its terms. The agreement, however,

> *anticipated* that the governments of the consuming provinces who are not signatories to the Agreement will make changes to ensure the effectiveness of the market-sensitive gas pricing regime, including legislative changes and *the provision of direction to provincial agencies to provide consumers with alternative sources of supply* through the availability of

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[67] During this transition period, the Alberta government would absorb the costs of the 11.8 cent per thousand cubic feet increase in TCPL transport tolls authorized earlier by the NEB.

[68] Supra footnote 66, at 1, item 2.

[69] In the case of the review panel, the natural gas agreement (ibid., at 5, item 25) stipulated that its report should reach the federal minister of energy, mines, and resources on July 31, 1986, at the latest.

[70] Supra footnote 66, at 1, item 4.

> transportation services on distribution systems, and to provide distributors with greater flexibility in determining prices of gas sold by them. [Emphasis ours.][71]

The natural gas agreement also continued the relaxation of export regulation begun in 1982. All signatory governments agreed to review their surplus tests, with the ultimate aim of relaxing the constraints on obtaining provincial removal permits and export licences. In particular, this led to a subsequent decision by the NEB to reduce the time horizon of its main surplus test from 25 to 15 years.[72]

The volume restrictions on short-term exports were lifted, and the Toronto city-gate pricing test was replaced by a requirement that export prices be no less than prices charged to Canadian users in the area adjacent to the export point. Finally, the government of Alberta agreed to terminate the province's export flow-back system, a move that was soon followed by the government of British Columbia.

Some early repercussions of the natural gas agreement included the establishment of gas brokers in western Canada and export sales to US brokers.[73] In addition, TCPL created a wholly owned subsidiary, Western Gas Marketing (WGM), that would take over the pipeline's buy and sell functions.[74] Contracts with Alberta producers were renegotiated, take-or-pay provisions eliminated, and a netback pricing scheme implemented.[75]

Consuming provinces, especially Ontario, quickly responded to the natural gas agreement's anticipations about increased flexibility of the regulatory provisions applicable to the downstream sectors of the gas industry. In particular, new legislation was designed to allow distributors to carry gas that had been purchased by industrial users directly from western Canadian gas producers or brokers. Such developments were complementary to the NEB's efforts aimed at opening up TCPL's transmission services to non-system sales (that is, gas not purchased or sold by WGM). As direct sales to eastern Canadian users were made, the NEB ordered TCPL to carry the gas and set the tolls that the pipeline could charge.[76]

In October 1985, the FERC issued order 436, which made it attractive for US gas pipelines to become open-access—that is, contract—carriers in addi-

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[71] Ibid., at 5, item 26.

[72] In March 1987, the AERCB also reduced the time horizon of its main surplus test to 15 years, see *The Globe and Mail*, March 27, 1987, B6.

[73] See, for example, supra footnote 21, at items 85.40 and 86.3.

[74] Such a move had earlier been deemed desirable by the Economic Council of Canada in *Connections: An Energy Strategy for the Future* (Ottawa: Supply and Services, 1985), 67, where it recommended that TCPL be split into two companies, much along the lines chosen by the pipeline company.

[75] Under a netback arrangement, producers share, on a production prorated basis, in sales revenues net of regulated fees, transport costs, Topgas interest charges, and WGM's 1.5 percent administration charge.

[76] On these issues, see supra footnote 21, at items 85.46, 86.2, and 86.8.

tion to their long-standing merchant role. This effectively increased the availability of pipeline transportation services and broadened the scope for direct sales in the United States, thus making it easier for gas to compete with other fuels in most markets. When seen in conjunction with the more flexible rules applicable to gas exports from Canada, this probably increased market opportunities for Canadian gas in the United States.[77] But the earlier elimination of take-or-pay provisions in most export-import contracts no doubt meant that another consequence of FERC order 436 would be to increase the price sensitivity of Canadian gas exports, not only with respect to competing fuels, but also relative to prices of US-produced gas.[78]

The May 1986 NEB Ruling on TCPL Services

In May 1986, the NEB released its decision on issues referred to it by the natural gas agreement—the overall availability of TCPL's transportation services.[79] In it, the NEB formalized a policy that it had effectively been following since the natural gas agreement had been signed: the so-called displacement proviso contained in TCPL's transportation contracts would be removed. This meant that TCPL could no longer refuse to carry non-system gas that displaced volumes originally sold by TCPL—that is, system gas.[80] This decision significantly increased the availability of transportation facilities to eastern Canadian markets and went a long way toward transforming TCPL into a common carrier, with tolls and fees regulated by the NEB.

Two other rulings by the NEB in its May 1986 decision increased the price competitiveness of non-system gas in eastern Canadian markets. The NEB ruled that demand charges, which were essentially fixed costs since they had to be paid by downstream purchasers (that is, distributors) irrespective of whether the gas volumes were actually taken or not, were to be collected only once. Previously, direct purchasers of displacement gas had had to pay demand charges twice: once as a condition of obtaining transportation services from TCPL, and another time as compensation to the distributor whose sales had been displaced.[81] It also suggested that non-system pro-

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[77] A good description of these issues can be found in supra footnote 13, at 77. There are, however, reports that US pipeline companies transporting Canadian gas have been slow to take advantage of the opportunities offered by order 436; see *The Financial Post*, February 9, 1987, 4.

[78] Key provisions of FERC order 436 were subsequently struck down by US courts. It was replaced by order 500, which, at the margin, seems to offer less advantageous incentives for interstate pipelines to become contract carriers. For a more detailed discussion, see André Plourde, "On the Role and Status of Canadian Natural Gas Carriers under Deregulation" (Autumn 1987), 13 *Journal of Energy and Development* 1-25, at 21-23.

[79] The NEB released this decision in its *Reasons for Decision: In the Matter of TransCanada PipeLines Limited Availability of Services*, supra footnote 47.

[80] During the hearings held before the release of the NEB's May 1986 decision, TCPL had expressed its willingness to carry all direct sales gas volumes, subject to a few conditions. See ibid., at 6.

[81] This second collection of demand charges was enforced by rulings of regulatory agencies in consuming provinces. See ibid., at 6.

ducers using TCPL's transportation facilities should pay only approximately 50 percent of the Topgas interest charges over one-half of the pay-back period for the loans.[82]

The NEB's May 1986 decision sought to establish ground rules that would eliminate (or at least significantly reduce) the scope that TCPL's monopoly position in the provision of west-to-east transportation services gave it to frustrate the transition to and implementation of a market-sensitive pricing regime for domestic sales of natural gas. In its June 1986 report,[83] the task force set up by the natural gas agreement to look into the role and operations of interprovincial and international gas pipelines argued along much the same general lines as had the NEB, as far as the provision and regulation of long-distance transportation services were concerned.

The Report of the Pipeline Review Panel

In its report, the pipeline review panel[84] argued that in order for a market-responsive pricing regime to work, there had to be non-discriminatory access to transport services offered by pipeline companies and distributors. Rejecting the contract-carrier approach to gas transportation over long distances adopted in the United States, the panel recommended that transportation-related activities should continue to be federally or provincially regulated, as appropriate. In the United States, most regional gas markets are served by at least two (and often more) pipelines connected to producing regions in the United States, Canada, or Mexico. Such a situation provides some scope for intercarrier competition in the provision of transportation services. Even then, there is evidence that US long-distance carriers possess some degree of market power, which they have exercised with some success.[85]

In Canada, two main pipelines link producing areas in the West with consuming regions in the East; both pipelines are owned by TCPL or one of its subsidiaries. There is effectively, therefore, no scope for intercarrier competition in the provision of transportation services for western Canadian gas destined to Canadian markets east of Alberta. It seems clear that, if TCPL were allowed to operate as an unregulated contract carrier, it would be in a position where it would possess and could exercise some degree of market power.

The option preferred by the panel was to have public regulation of the (long-distance) transportation-related activities of pipeline companies

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[82]The Topgas interest charges were the result of the loans advanced in the early 1980s to cover TCPL's take-or-pay obligations. See the text at "The Gas Bubble, 1979-84," above. An excellent summary of the evolution of the Topgas problem is contained in NEB, *Reasons for Decision: In the Matter of TransCanada PipeLines Limited Availability of Services*, supra footnote 47, especially at sections 3.1 to 3.3. See also supra footnote 13, at 16-18.

[83]Supra footnote 13.

[84]Ibid., at 7.

[85]On this, see Harry G. Broadman, "Elements of Market Power in the Natural Gas Pipeline Industry" (January 1986), 7 *The Energy Journal* 119-38; and supra footnote 13, at 78.

operating in Canada. To facilitate the regulation of only those activities related to transportation, pipeline companies and distributors would be required to separate marketing functions from provision of transportation services, as far as policy-making, management, and accounting are concerned.[86] In addition, it was argued that the services provided by these companies should be "unbundled," so that the cost of individual services could be identified, thus allowing for the desired "bundle" of services to be chosen by customers.[87]

Two other points were emphasized by the panel. First, it strongly endorsed adherence to the principle of the "sanctity of contracts." In other words, the letter and intent of all gas purchase and sales contracts, including those signed before deregulation, should be fully respected.[88]

The second point emphasized by the panel finds no direct correspondence in the provisions of the natural gas agreement:[89]

> Multiple buyers and sellers are necessary at each level of transaction from producer to consumer, *except for the sale of gas by a franchised distributor to its "core" market of residential, commercial and small industrial consumers,* which, from a practical point of view, can only, or may best, be served by the distributor . . . . This means that . . . distributors and large industrial consumers would be free to negotiate and to sell or buy gas for use or resale under conditions which they would negotiate . . . . This would not be the case with sales to the core market served by a franchised distributor, *simply because it would not be practical.* Such customers, individually consuming small quantities of gas, requiring long-term secure supplies, and mostly unwilling and incapable of arranging their own supply, are clearly best served, as now, through a distributor, i.e., through a single seller. [Emphasis ours.]

On the same topic, the pipeline review panel added:[90]

> Gas acquired by a franchised distributor for its core market would continue to be subject to regulatory scrutiny or approval for both the acquisition cost and the resale price.

The panel also encouraged provincial regulatory agencies to require that franchised distributors always have under firm contract gas supplies equal to at least 10 times the current year's requirements of their core markets.[91]

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[86] It is not clear to what extent the TCPL-WGM division of January 1986 meets the panel's proposed guidelines, but it can safely be concluded that it was a step in that direction.

[87] The examples given in supra footnote 13, at 10, 11, and 14 involve the ability of large industrial users to choose to buy gas and transportation, only transportation, or only certain types of transportation services (for example, transmission, compression, or load regulation). The Ontario Energy Board (OEB) later endorsed a similar approach to "unbundling."

[88] See, for example, supra footnote 13, at 8 and 17-18. This principle has also been endorsed by the natural gas agreement and was supported in broad terms by the NEB in its May 1986 ruling.

[89] Supra footnote 13, at 6.

[90] Ibid.

[91] Ibid., at 9.

The most striking implication of the above is that, if strictly implemented, "deregulation" would have virtually no impact on more than 50 percent of the gas market in Canada (see chapter 6, figure 6.3). This amounts to a form of institutionalized price discrimination, wherein some segments of the market are prevented, as a result of regulatory action, from bearing the costs and reaping the benefits of increased intra-fuel competition. It may well be, of course, that such an arrangement would prove to be economically efficient, but no evidence on this score was presented.

Subsequent Developments

Since the completion of the pipeline review panel's report, numerous events have affected the operation of Canadian natural gas markets.[92] Rather than attempt to provide a detailed description and analysis of these developments, the next few pages will seek to describe directions that events and policy changes have taken.

During 1986, it became clear that the marketability of Canadian gas in the United States had been sharply curtailed following the fall in world oil prices in late 1985 and early 1986. The sharp reduction in residual fuel oil prices and the preponderance of dual-burner capacity in the United States vastly increased inter- and intra-fuel price competition, especially in industrial uses and for electricity generation. In part because a similar degree of dual-burner capacity did not exist in Canada, downward pressure on Canadian natural gas prices was not felt as strongly. This meant that the adjacent border pricing rule applicable to gas exports became more of a binding constraint, in the sense that export prices could not fall fast enough to prevent reductions in export volumes. In the first quarter of 1986, for example, Canadian gas exports were 18.9 percent lower than a year earlier (6.49 billion cubic metres against 8.0 billion cubic metres).[93]

These developments led western Canadian gas producers and the governments of the producing provinces (especially Alberta) to call for a loosening of the rules governing exports. In October 1986, the federal government agreed to replace the adjacent border pricing test with a less clearly defined notion of price monitoring, which would chart and compare domestic and export prices of natural gas. An announced objective of this price monitoring system was to ensure that Canadian-produced gas would not be exported at prices below those prevailing in domestic transactions, at least not over some (undefined) period of time. It is not yet clear how this will be accomplished.

During 1987, Canadian regulatory authorities also loosened controls on gas export volumes. In March, the AERCB reduced the term of its surplus

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[92] A more detailed discussion of some of these events can be found in supra footnote 78, at 11-23.

[93] Volumes were about 24.5 percent lower in the second and third quarter of 1986 than during the same period in 1985 (8.21 billion cubic metres against 10.88 billion cubic metres, respectively). These data were taken from 1986 issues of Statistics Canada, *Crude Petroleum and Natural Gas Production*, catalogue 26-006.

test from 25 to 15 years, while the NEB, in September, replaced its 15-year surplus test with a requirement that export sales not create difficulties in meeting foreseeable Canadian requirements. On their own, these modifications of the Canadian regulatory system applicable to natural gas would operate to enhance the accessibility of export markets to Canadian gas producers.

The situation in the United States, however, has tended to exert an opposite influence. So far, the period following the 1981-82 economic recession has been characterized by sluggish growth in US natural gas demand. This has meant that the US gas bubble has not disappeared but threatens to remain at least until the end of the 1980s.[94] In addition, the deregulation process for US natural gas markets has proceeded not only more slowly, but also along somewhat different directions than in Canada. A consequence of this has been that Canadian gas producers have had difficulties in securing the increased access to the interstate pipeline system necessary to boost export sales. Overall, it seems that the regulatory environment prevailing in Canada at the end of 1987 is such that problems of access to US gas markets are not likely to have Canadian roots.

Changes to the regulatory system governing gas exports did not give rise to significant publicly voiced disagreements between the different governments involved. The same cannot be said, however, about changes in the regulatory system applicable to domestic sales. In particular, Manitoba and Ontario have tried to take the system of regulation for sales to final users in directions to which the government of Alberta was opposed. Since the federal government has stayed out of this dispute, at least until the beginning of 1988, the dispute has been manifested largely through pronouncements and decisions by provincial governments and their agencies.

The governments of the consuming provinces have sought to ensure that small individual consumers of natural gas would benefit from the fall in gas prices that followed the 1985-86 drop in world oil prices to an extent roughly similar to that enjoyed by large-scale industrial users. In Manitoba, the government sought to achieve this objective through public-sector intervention. A provincial Crown corporation would replace privately owned, regulated distributors as the sole purchaser of natural gas for consumption by small-scale users in the province, and the privately owned local distribution system would be taken over by the Crown. On the basis of a "sanctity of existing contracts" argument, the NEB refused to allow the Manitoba Crown corporation to proceed with its plans. In the aftermath of this decision, the government of Manitoba decided not to go ahead with its proposal to assume ownership of the local distribution system in the province.

Ontario tried a different method to ensure that small consumers would enjoy wider access to gas supplies. The OEB is seeking to open up the Ontario gas market by allowing brokers and marketers to operate in most,

[94] See figure 4.5.

if not all, submarkets in the province, thus effectively extending deregulation to the downstream sectors of the industry. It has also expressed its distinct lack of enthusiasm for sales contracts between WGM and local distribution companies that specify prices to individual or groups of final users. The OEB felt that the determination of prices in different uses across the province, and thus of price differentials across submarkets, was within its duties and powers as determined by provincial legislation.

The government of Alberta strongly objected to these moves by the governments of consuming provinces, especially Ontario's attempt to extend deregulation to downstream activities. As the pipeline review panel had argued earlier,[95] Alberta maintained that small-scale users (the so-called core market) should continue to be served by a single regulated seller (a franchised monopoly) holding long-term contracts with gas producers. In the environment following the sharp fall in oil prices of 1985-86, these long-term contracts would mean—all else equal—that gas prices to the core market would fall proportionately less than those to large-scale users, who would be allowed to purchase gas on short-term contracts.

Since the government of Alberta cannot, of course, control the actions of the governments of the consuming provinces or their agencies, it has had to rely on indirect measures to try to bring about the desired results. Initially, the method commonly used was for Alberta to impose long delays before issuing permits to allow the removal of gas volumes from the province if the prices provided in the contract were judged to be too low or if the terms of the contract were too short. As the above section, "The Agreement on Natural Gas Markets and Prices," suggests, this behaviour went against the spirit if not the letter of the 1986 natural gas agreement.

In December 1987, the government of Alberta instituted a gas royalty system in which, when the transaction price of the production from an individual well is less than 80 percent of the average price of all production in the province, producers pay royalties based not on the individual transaction price but on a proportion (80 percent) of the average price. Such a royalty system is designed to enforce price discipline by discouraging individual producers and groups of producers from signing sales contracts in which the transaction price is significantly below the provincial average. As of early 1988, it was not yet clear whether the introduction of this new royalty system would be accompanied by a shortening of the delays for the issuance of removal permits.

The deregulation process for domestic gas markets thus remains in a relatively unsettled state, with the consuming provinces (especially Ontario) attempting to extend deregulation (and thus lower prices, at least in the short run) to all downstream sectors, and Alberta resisting these moves, especially as they apply to the core market. Many of the obvious difficulties in implementing a market-sensitive pricing system for natural gas arise from

[95] See the text, above, under the heading, "The Report of the Pipeline Review Panel."

the fact that natural gas must be transported from the field to the final consumer by a pipeline, which is almost always a natural monopoly. This has meant that the downstream portion of the gas industry—unlike the downstream portion of the oil industry—has always been highly regulated. There is also therefore a potential for price discrimination among different submarkets (export versus domestic, industrial versus residential). The regulation of natural gas markets is therefore a much more complicated process than the regulation of oil markets, both definitionally and operationally. The nature of the Canadian Constitution also requires a high degree of consensus and cooperation among the different jurisdictions on the fundamental objectives of regulating natural gas markets in order to achieve those objectives. Such consensus and cooperation are not yet evident in the attempt to deregulate domestic gas markets.

5

Taxation of Crude Oil and Natural Gas

Introduction

The oil and gas industry has never been far from the centre of attention whenever tax reform and tax changes have been under consideration.[1] At the time of the Royal Commission on Taxation in 1967, the oil and gas industry was favourably treated under the federal income tax system, and the main thrust of the royal commission's proposals was to increase taxes in that industry toward the general levels applicable to the rest of the business sector. As a result, the oil and gas industry's arguments at that time took the form of defending the preferential treatment accorded to it. These arguments were fairly effective in the political arena, so that when oil and gas prices rose rapidly in the early 1970s, the federal government received little revenue from the oil and gas industry. These problems were exacerbated by the costs of the federal subsidy to imported oil and by the sharp increases in provincial royalty rates, both of which reduced net federal revenues from oil and natural gas.

The subsequent series of federal tax changes in the 1970s and early 1980s altered the federal tax treatment of oil and gas revenues so markedly that industry arguments took the form of asking for a tax system in which oil and gas revenues would be subject to the same tax regime as applied to other industries. By the early 1980s, when the range and height of federal taxes on oil and gas production were at their greatest, the equal tax treatment that the industry fought against in the aftermath of the royal commission would have looked very attractive from the industry's perspective. By the end of 1986, almost all of the special federal taxes applicable to oil and gas revenues had been removed,[2] and some industry participants were asking for the reintroduction of a broadly based earned depletion allowance as a means of helping firms hard-hit by the 1985-86 fall of world oil prices.

The purpose of this chapter is to recount the main elements of the taxation system in effect before the 1971 federal tax reform and the several

[1]This chapter uses material from John F. Helliwell, Mary E. MacGregor, Robert N. McRae, and André Plourde, *Oil and Gas Taxation in Canada: An Analysis of Developments Since the Royal Commission on Taxation*, PEAP Energy Study no. 87-2 (Toronto: University of Toronto, Institute for Policy Analysis, 1987), sections 2 to 7 (forthcoming in a special issue of the *Osgoode Hall Law Journal*).

[2]The major exceptions relate primarily to offshore exploration, the resource allowance to compensate for the non-deductibility of royalties, and the ability of the consortium operating the Syncrude oil sands plant to deduct royalty payments for federal income tax purposes.

regimes that have been in place since that time. It begins with a brief discussion of the system in place in the mid-1960s, then describes the Royal Commission on Taxation's assessment of that system, its proposals for reform, and the effects of tax reform in the early 1970s on the industry. It ends with a description of the June and December 1987 tax reform proposals for the industry. Described in somewhat less detail are the main changes that have occurred in the provincial system of royalties, taxes, and incentives. Our description of the provincial system concentrates on Alberta, since it accounts for the bulk of Canadian production, and since Saskatchewan and British Columbia, the other two main producing provinces, have tended to follow Alberta's lead in many respects.[3] Chapter 10 presents a quantitative assessment of the alternative systems, including their effects on the distribution of risks and revenues among the industry, provincial governments, and the federal government.

The System Before Tax Reform

During the 1950s and 1960s, the oil and gas industry was subject to stable, relatively favourable treatment by both the federal and provincial tax systems. The corporate tax base was almost the same for both levels of government,[4] and gave the industry a number of special write-offs. Non-tangible exploration and development expenditures could be written off in the year in which they were incurred, as could provincial land payments after April 1962. Provincial royalty payments were also fully deductible. One of the most important provisions affecting the industry, however, was percentage depletion. This allowed firms to deduct automatically a given percentage of oil and gas production profits (33⅓ percent for operators and 25 percent for non-operators). It was originally designed to offset the non-deductibility of certain expenditures related to the acquisition of mineral properties (notably, expenditures to acquire land and production rights), but by the time the Royal Commission on Taxation looked at the issue, these expenditures had become fully deductible.

In addition to corporate income taxes, Alberta revenues from oil and gas came from three main sources: land payments, royalties on the production of oil and gas from Crown lands, and freehold mineral taxes.[5] Land payments were (and are) generally comprised of two components: a fixed annual rental fee, which was more or less nominal in character, and a bonus bid, which gave the operator exclusive drilling or production rights on a given tract of land. Bonus bids tended to be a highly variable component of land payments, as an examination of figure 7.8 in chapter 7 indicates. Pro-

[3] Appendix 5.1 contains a more complete description of the federal elements of the various tax systems that have been proposed or applied to oil and gas income and expenses since 1967. Appendix 5.2 contains further details on the royalty, tax, and incentive regimes implemented (or proposed) by the three main producing provinces.

[4] In fact, Alberta did not levy its own corporation income tax until the 1960s, but received revenues from the federal government instead.

[5] Saskatchewan and British Columbia had similar arrangements.

duction from Crown land was then subject to a maximum royalty rate of 16⅔ percent of sales for oil and 15 percent of sales for natural gas. In 1962, the government of Alberta raised the ceiling on natural gas royalty rates to equal those on oil, but other than this, no significant changes were made to the provincial royalty system until the early 1970s. The freehold mineral tax, levied on oil and gas production from non-Crown land, was similar to but lower than provincial royalties. Freehold production, however, accounts for a relatively small proportion of the total.

The Royal Commission's Approach

The royal commission's approach to resource taxation in general and to the taxation of oil and gas in particular was consistent with its approach to overall tax reform. Indeed, it is one of the strengths of any coherent and integrated approach to tax reform that its principles can be generally applied, without the need for a separate rationale and separate provisions for each industry, type of organization, or class of income. The royal commission's general approach to the taxation of income from business was to treat all industries and types of organizations as equally as possible.

The main aspects of the preferential tax treatment extended to resource industries consisted of percentage depletion, the three-year tax-free period for new mines, and the accelerated write-off of exploration and development expenditures. In volume 4 of the commission's report,[6] and in the related study by Bucovetsky,[7] the pros and cons of these special provisions were considered at some length. By the time the commission was formed, all of the previously non-deductible expenditures had become fully deductible, so that the remaining case for the depletion allowance was based on considerations of abnormally high risks, entailing a higher cost of capital. The report took the view that the possibilities for spreading and diversification of risks were as great in the mining and petroleum industries as elsewhere in the economy and that any tax-based disincentives to risk-taking should be addressed in a way that would be equally applicable to all industries and types of organizations. In particular, the commission argued that if all gains were fully and equally taxable and all losses fully and immediately deductible, "there would be little need for any special concessions to the mining and petroleum industries even if it was felt that they were characterized by greater risks than other industries."[8] The commission went through the various arguments based on regional development, the existence of similar incentives in the United States, the special role of energy in economic development, and the encouragement of domestic ownership in the extractive industries, and it concluded that

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[6]See Canada, Royal Commission on Taxation (the Carter commission), *Report*, 6 vols. (Ottawa: Queen's Printer, 1966) (herein referred to as "the report").

[7]See M.W. Bucovetsky, *The Taxation of Mineral Extraction*, Studies of the Royal Commission on Taxation no. 8 (Ottawa: Queen's Printer, 1964).

[8]Supra footnote 6, vol. 4, at 309.

> the need for special encouragement to mineral and petroleum exploration to compensate for a capital market bias against risky ventures is small, if it exists at all. We are also convinced that there are fiscal methods available that would be as efficient as, or more efficient than, tax concessions in encouraging exploration if this was deemed to be in the public interest.[9]

The royal commission's main proposals were that:[10]

1) The depletion allowance should be withdrawn.

2) Exploration costs (including related depreciable assets) should have a separate capital cost allowance class with a rate of write-off of 100 percent.

3) Development costs (including related depreciable assets) should be included with exploration costs for a transitional period of 5 to 10 years, and thereafter segregated in a separate class subject to write-off at 20 to 30 percent on a declining balance.

4) The cost of acquiring properties should have a separate capital cost allowance class for each property, subject to a high transitional rate of depreciation, but thereafter written off at 10 to 20 percent of the operating income from the property.

5) Losses on the sale of properties should be subject to the same provisions as in other industries, and gains should be fully taxable, also as in other industries.

The White Paper and Bill C-259

In the four years between the release of the royal commission's report in December 1966 and the introduction of Bill C-259 embodying tax reform in 1971, many changes were made to the proposals. Responding to a combination of pressures from the extractive industries and the governments of resource-rich provinces, the Benson white paper

> recognized that the exploration for and development of mineral deposits continue to provide special benefits to Canada and to various provinces by creating or maintaining highly productive industry in areas other than those where rapid urban and industrial growth are already occurring . . . . Just as scientific research and development are believed to warrant some special public support, the government feels that exploration for and development of minerals still warrant some support in a form more directly related to this activity than has been the case with past depletion. It is believed that support on a less-generous scale should suffice for this purpose.[11]

The proposals contained in the white paper can be summarized as follows:

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[9] Ibid., at 327.

[10] Ibid., at 335-36.

[11] Canada, Department of Finance, Edgar J. Benson, *Proposals for Tax Reform* (Ottawa: Queen's Printer, 1969), 64 (herein referred to as the "white paper").

1) Immediate deductibility would be retained for all exploration and development expenses, against all income for those principally involved in resource extraction, and against resource income for others.

2) Full deductibility of the costs of acquiring mineral properties would be retained (subject to the same "principal-business" tests as for exploration and development), but gains from the sale of such properties would be treated as capital gains and hence taxable, under the white paper's general proposals for capital gains, at 50 percent of their actual value.

3) For operators, the 33⅓ percent depletion allowance would be retained, but only if firms "earned" the rights to the allowance by capital expenditures of $3 for every $1 of depletion allowance claimed.

4) Percentage depletion for non-operators would be repealed.

In all major respects, the white paper proposals treated oil and gas production revenues more generously than did those of the royal commission, but they too came under pressure from the extractive industries, especially before hearings held by committees of the Senate and the House of Commons. In the course of hundreds of briefs and scores of meetings on tax reform, the Commons Finance Committee heard once again the arguments favouring special incentives for the extractive industries; it phrased the resulting dilemma thus:

> Is Canada prepared to suffer the possibility of a . . . reduction in the growth and development of its natural resource industries in exchange for the longer term benefits of a more neutral and equitable tax system?[12]

This dilemma is the inevitable consequence of existing advantageous tax treatment for any industry or activity—the removal of the special treatment must generally lead to at least the possibility of either temporary or long-lasting reductions in the pace of that activity. Indeed, one of the primary justifications for the neutral tax treatment championed by the royal commission was the possibility that there would be some redistribution of employment and investment away from the tax-favoured sectors toward those activities with a higher pre-tax return and, therefore, with the potential for making a greater overall contribution to economic well-being. The usual result, at each stage of a reform process, is for the original thrust and consistency of the reforms to be muted by attempts to regain or retain the advantages originally available to the favoured industries or activities. Thus it was predictable that the Commons Finance Committee would accept the white paper modifications of the royal commission's proposals and even offer some further expansion of incentives. This committee suggested that:

1) some consideration be given to permitting tax-free transfers of mineral rights between corporations (even though the cost of these rights

[12]Canada, House of Commons, *Eighteenth Report of the Standing Committee on Finance, Trade, and Economic Affairs Respecting the White Paper on Tax Reform* (Ottawa: Queen's Printer, 1970), 74.

might have been written off previously against taxable income), subject to safeguards against abuse; and

2) the earned depletion base be broadened to include the cost of all mineral properties and expenditures on processing equipment.

Tax reform finally appeared before the House of Commons as a whole when Bill C-259 was introduced on June 18, 1971.[13] With respect to petroleum revenues and expenditures, the Bill followed the white paper fairly closely. The main elements were as follows:

1) Earned depletion was adopted, with eligible expenditures broadened to include expansion of milling capacity for mining (including oil sands) but excluding depreciable property such as production equipment and natural gas plants.

2) Percentage depletion was to remain in force until the end of 1976, with no reduction of the accumulation of eligible expenditures for earned depletion, based on all expenditures incurred after November 7, 1969.

3) Exploration and development expenditures could both be written off at 100 percent against all income for companies meeting "principal-business" tests. Other firms could write off these expenditures at 20 percent of the unclaimed balance against any income, or 100 percent against their resource income.

4) The purchase and sale of oil and gas rights was to be left unchanged, treated as fully deductible expenses and fully taxable income.

By permitting full expensing of all exploration and development expenditures, by extending percentage depletion to the end of 1976, and by allowing all expenditures from 1969 to 1976 to accumulate for the use of post-1976 earned depletion, Bill C-259 left substantially intact the pre-reform system applicable to oil and natural gas revenues. The system put in place at that time was first subjected to major change as a consequence of the rapid rise of world oil prices in 1973-74.

Tax Consequences of the 1973-74 World Oil Price Increases

Starting in 1974, the pace of change in energy taxation and regulation was so fast that only the main elements can be sketched in this chapter.[14] As has already been described in chapter 3, the regulated pricing system imple-

[13] See Canada, Department of Finance, Budget Papers, Budget Speech, June 18, 1971 (Edgar J. Benson).

[14] A full review of the chronology is available in André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986*, PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986); and an update, André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments, September 1986 to May 1987*, PEAP Energy Memo no. 87-2 (Toronto: University of Toronto, Institute for Policy Analysis, 1987). The main stages of the regulation and deregulation of Canadian crude oil prices and trade are described in chapter 3 of the present monograph, and changes in the regulation of natural gas pricing and trade are described in chapter 4.

mented in September 1973 involved the introduction of an oil export tax to collect the difference between domestic and export prices, and in early 1974 the oil import compensation program was introduced to subsidize the difference between the actual and regulated prices for imported oil and products.

During that fall and winter, the governments of all three producing provinces legislated sharp increases in provincial royalties and taxes. Although in 1972 Alberta had given oil producers the option of paying either a reserves tax or increasing their average royalty rate to about 22 percent, these plans had not been implemented and were soon overtaken by the OPEC price shock. The new Alberta royalty system announced in 1974 adopted a two-tier approach.[15] Oil discovered after March 1974 (or gas discovered after 1973) was classified as "new" oil (or gas) and was subject to a lower royalty rate than "old" oil (or gas), which had been discovered before that. The royalty formulas were designed to capture about 22 percent of a low base price[16] for both new and old production and applied a higher marginal rate to the price in excess of that amount. The marginal rate was around 35 percent for new production and 50 percent for old production.[17] Overall, average royalty rates for new oil increased to about 28 percent, while those for old oil rose to about 40 percent.[18]

The federal budget of May 1974[19] proposed a number of measures affecting the oil and gas sector in response to the OPEC price shock and changes in the provincial royalty systems. But the minority Liberal government was defeated in a House of Commons vote on this budget. The ensuing general election returned the Liberals to power, this time in a majority position, and the November 1974 budget[20] reintroduced, with some modifications, the main elements of the May proposals. As enacted, the main tax changes were as follows:

1) Provincial royalties were disallowed as an expense under the federal corporation income tax. In return, an additional 10 points of provincial abatement (for oil and gas profits only) was given on the new national income tax rate of 50 percent on oil and gas profits. Of this 50 percent, 20 percent was considered to be abated to the provinces, leaving the federal rate at 30 percent. The budget also proposed that the federal corporation

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[15] Changes in natural gas royalty rates were announced in January 1974; the changes in oil royalties in March.

[16] The base prices were originally set at $4.40 per barrel for oil and $0.26 per thousand cubic feet for natural gas, which were roughly equal to the prices prevailing early in 1974.

[17] The marginal rate for old oil was 65 percent between $4.40 and $6.50 per barrel, however.

[18] Saskatchewan and British Columbia had already increased their royalty rates, but soon followed Alberta's lead in making the distinction between new and old production and reducing the royalty rates for new production.

[19] Canada, Department of Finance, Budget Papers, Budget Speech, May 6, 1974 (John N. Turner).

[20] Canada, Department of Finance, Budget Papers, Budget Speech, November 18, 1974 (John N. Turner).

income tax rate (net of provincial abatement) applicable to petroleum production profits would be reduced to 28 percent in 1975 and to 25 percent in and after 1976.

2) Percentage depletion was to be replaced immediately by earned depletion.

3) Earned depletion was to be subject to an upper limit of 25 percent of production profits rather than the 33⅓ percent established by the June 1971 budget.

4) A 100 percent write-off was to be retained for exploration expenditures, with a rate of 30 percent to be used for development expenditures, for which the definition was broadened to include land expenditures.[21]

The main purpose of these substantial changes was said to be to prevent the erosion of the federal income tax base by the recent substantial increases in provincial royalties. In his budget speech of November 1974, the minister explained the underlying reasoning as follows:[22]

> I acknowledge that royalties in respect of property rights have traditionally been deductible as a business expense. However, in tax reform we began the process of disallowing certain income royalties in the mineral field and substituting federal tax abatements.[23] Today, it is evident that a royalty is no longer a royalty in the traditional meaning of the word. There have emerged various provincial charges that are thinly disguised income taxes.
>
> Today provincial charges take many forms . . . there are provincial charges that are determined by price, profit and volume . . . . In fact, there are so many kinds of provincial charges and claims that it would be virtually impossible to draft workable legislation which could distinguish between bona fide royalties, traditionally deductible, and other taxes and charges.

The provincial responses to the federal initiative on the tax treatment of royalty payments consisted of changes aimed at maintaining the deductibility of these payments for purposes of the provincial corporation income tax, the introduction of royalty tax credits (especially in Alberta), some decreases in royalty rates, and new incentive measures.[24]

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[21] This is quite similar to what was proposed by the royal commission, except that the commission proposals would have had a lower rate of write-off for land expenditures and would have linked that write-off to income from the property in question. The commission proposals would also have linked these expenditures to different capital cost allowance (CCA) classes, from which claims would have been discretionary. The November 1974 budget continued the practice of making write-offs of exploration and development expenditures automatic for purposes of the corporation income tax. In the May 1974 budget, a 30 percent write-off rate had been proposed for both exploration and development expenditures.

[22] Supra footnote 20, at 13.

[23] The reference to "certain income royalties" was to mining profits taxes, which under Bill C-259 were no longer to be deductible expenses for the federal corporation income tax.

[24] The introduction of royalty tax credits in the provincial corporation income tax system was aimed at compensating firms for the non-deductibility of provincial royalty payments in

(Continued on the next page.)

The federal budget of June 1975,[25] which raised the regulated oil price to $8 per barrel and established regulated pricing for natural gas sold in eastern Canada, also made further changes in the income tax arrangements for the taxation of oil and gas profits. The key changes made at this time were:

1) Effective from January 1, 1976, the general rate of corporation income tax was set at 46 percent, and the additional 15 percentage-point abatement for oil and gas profits was converted to a 25 percent resource allowance on production income net of operating expenditures and capital cost allowances.

2) An investment tax credit of 5 percent of eligible expenditures on tangible assets was introduced, applicable to oil and gas exploration and development activities, to be in effect between June 1975 and June 1977.

The net effect of these budget changes was to lower the rate of federal corporation income tax (net of provincial abatement) below the 30 percent established in the previous budget. The reduction was especially great for firms making substantial investment expenditures.[26]

The next federal budget, in May 1976, continued the new tradition of using the budget as the occasion for announcing increases in the regulated domestic prices of crude oil and natural gas and made some modifications to energy taxation:[27]

1) To encourage energy conservation, the budget proposed a two-year write-off for certain energy-conserving capital expenditures incurred between budget night and 1980. In addition, the federal sales tax was removed on certain non-fossil-fuel energy generators, such as solar furnaces, heat pumps, and wind-powered generators.

2) For similar reasons, the budget proposed special excise taxes on high-energy-consuming motor vehicles and motor-vehicle air conditioners.

3) Between May 1976 and June 1979, all taxpayers (and not just "principal-business" taxpayers) were to be permitted to deduct 100 percent of exploration expenditures against any other income. (This came to be known as the "drilling funds" deductibility.)

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[24]Continued . . .
the calculation of the federal corporation income tax. Alberta further reduced the royalty rates for enhanced oil recovery (EOR) projects in 1976 and for low-productivity natural gas wells in 1978.

[25]Canada, Department of Finance, Budget Papers, Budget Speech, June 23, 1975 (John N. Turner).

[26]The resource allowance is a reduction from taxable income rather than a tax credit. It differs from a change in the tax rate because its base is larger than the corporation income tax base, especially for firms making substantial exploration and development expenditures.

[27]Canada, Department of Finance, Budget Papers, Budget Speech, May 25, 1976 (Donald S. Macdonald).

In the next federal budget,[28] the key energy-related measure was the introduction of "superdepletion," to apply for three years, until March 31, 1980. In addition to regular earned depletion, exploration expenditures above $5 million per well would "earn" an additional depletion allowance of 66⅔ percent. The combination of depletion and superdepletion meant that well expenditures above $5 million gave rise to a 200 percent write-off, comprising the 100 percent immediate exploration write-off, the 33⅓ percent earned depletion allowance, and the 66⅔ percent superdepletion allowance. The combination of depletion allowances of this size with the provision of the May 1976 budget that permitted anyone to obtain the 100 percent exploration write-off meant that 200 percent of well costs could be written off against resource income or 166⅔ percent against any other income. The growth in the number of drilling funds subsequently made these write-offs available to many individual taxpayers with tax rates over 50 percent, creating a perverse form of negative taxation whereby a more costly well (to do the same job) could make the investor better off, since the value of the tax reductions exceeded the costs of the drilling. Under these circumstances, it was not surprising that frontier wells became more numerous and much more expensive.[29]

The next two federal budgets aimed to reduce the effective tax burden on marginal projects such as heavy oil upgraders, oil sands plants, and enhanced oil recovery (EOR) ventures.[30] In addition, the November 1978 budget not only extended the drilling funds deductibility to the end of 1981, but it also indefinitely extended the availability of the investment tax credit. At the same time, the general rate of tax credit was raised from 5 to 7 percent, with higher rates for designated regions, including Saskatchewan and the northern parts of Alberta and British Columbia.[31]

The Second World Oil Price Shock, 1979-80

In early 1979, world oil prices began to rise rapidly once again, starting another series of tense and difficult federal-provincial negotiations about

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[28] Canada, Department of Finance, Budget Papers, Budget Speech, March 31, 1977 (Donald S. Macdonald).

[29] "For example, as a result of the 200-per-cent deduction now available, a taxpayer subject to a combined federal and provincial marginal tax rate of 62 per cent receives tax benefits of $124 for every $100 invested in the frontier" (Canada, Department of Finance, Budget Papers, Supplementary Information [on the Budget], December 11, 1979, 69—John S. Crosbie). This question is discussed in more detail in chapter 9, below.

[30] Canada, Department of Finance, Budget Papers, Budget Speech, April 10, 1978 (Jean Chrétien); and Canada, Department of Finance, Budget Papers, Budget Speech, November 16, 1978 (Jean Chrétien).

[31] As noted in chapter 3, in August 1978 the federal government introduced a refinery levy on all oil refined in Canada. This levy, often referred to as the "Syncrude levy," was used to raise the funds necessary to extend the world price to the output of the Syncrude oil sands plant when it came on stream toward the end of August. In December 1974, the federal government had guaranteed the Syncrude participants that the plant would receive the world price for its output.

energy prices and taxes. In December of that year, federal Finance Minister John Crosbie introduced the budget proposals of the new minority Progressive Conservative government.[32] In the absence of an agreed federal-provincial resolution of energy pricing and taxation issues, some aspects of the energy proposals were deliberately vague, such as the form of a proposed new tax intended to collect for the federal government "roughly half of the returns from oil and gas price increases that exceed $2.00 per barrel and 30 cents per thousand cubic feet per year."[33] The proposed energy price strategy was to move Canadian prices for crude oil gradually toward 85 percent of the lesser of US or international prices, and to let prices for natural gas rise in concert with oil prices.

To encourage conservation, the budget also proposed to replace the 7 cent per gallon excise tax on gasoline with a 25 cent per gallon tax on all transportation fuels, to be partially offset by an income-tested refundable energy tax credit in the personal income tax. In addition, the budget proposed to extend superdepletion at a much reduced rate (6⅔ percent) to the end of 1980, and then to let it expire. The write-off rate for the purchase prices of Canadian oil and gas properties, which had been 30 percent, was to be reduced to 10 percent.[34] But the minority Progressive Conservative government was defeated on the budget in the House of Commons, principally as a result of opposition to the excise tax on transportation fuels.

After an election campaign that was heavily oriented to energy issues, a majority Liberal government was elected, having promised a "made-in-Canada" oil price as well as an increase in the Canadian ownership share of the petroleum industry. This platform achieved heavy electoral support in central Canada but almost none in the western provinces. It was therefore not entirely surprising that the next federal budget,[35] presented jointly with the NEP on October 28, 1980, contained several controversial energy taxes. Against a background of sustained rapid increases in world oil prices, federal-provincial negotiations aimed at increasing Canadian oil prices had been unsuccessful, and Alberta had unilaterally increased wellhead prices of crude oil produced in the province by $2.00 per barrel, to $16.75. The gap between Canadian and world oil prices was growing significantly; one result of this was rapidly rising federal subsidy payments covering the expenditures made necessary by the oil import compensation program.[36]

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[32] Canada, Department of Finance, Budget Papers, Budget Speech, December 11, 1979 (John S. Crosbie).

[33] Ibid., at 4.

[34] This measure would be enacted in April 1980 by the new Liberal government. See Canada, Department of Finance, Notice of Ways and Means Motion To Amend the Income Tax Act, April 21, 1980 (Allan J. MacEachen).

[35] Canada, Department of Finance, Budget Papers, Budget Speech, October 28, 1980 (Allan J. MacEachen).

[36] See chapter 3, under "Regulated Prices."

The National Energy Program and Its Aftermath

As noted in chapter 3 in "The National Energy Program and Two-Tier Pricing," one of the centrepieces of the NEP was a schedule of "made-in-Canada" prices to be paid for different categories of crude oil, with the costs to be paid by Canadian consumers through the petroleum compensation charge (PCC). Aside from the PCC, itself a quasi-tax, the main tax and subsidy elements of the NEP were the following:

1) The natural gas and gas liquids tax (NGGLT) was introduced, starting at $0.30 per thousand cubic feet and rising to $0.75 per thousand cubic feet by 1983. This tax was to be levied on all gas and gas liquids produced in Canada.

2) The petroleum and gas revenue tax (PGRT) was introduced, at 8 percent of petroleum and natural gas production revenues net of operating costs. This new tax was not to be deductible from the income base for the corporation income tax.

3) The NEP proposed to replace earned depletion allowances with a system of cash payments under the new petroleum incentives program (these payments were usually known as PIP grants).[37] These grants varied between exploration and development and between regions, and were higher for firms with higher degrees of Canadian ownership. With the exception of exploration activities on the Canada lands, no PIP grants were payable to firms with less than 50 percent Canadian ownership. The maximum rate payable on provincial lands was 35 percent for exploration by firms with more than 75 percent Canadian ownership. On the Canada lands, the maximum rate payable was 80 percent for exploration by firms with more than 75 percent Canadian ownership. The PIP grants were not taxable, but they correspondingly reduced the expenditure that could be deducted from taxable income or used to earn depletion allowances, or that would be eligible for the investment tax credit.[38]

4) The revenues from the continuing federal oil export tax were to be shared equally with the producing provinces.

5) Several features related to the ownership and taxation of oil and gas rights on the Canada lands. Most important were:

a) the retroactive right granted to the Crown to acquire a 25 percent back-in interest, at accumulated cost, on any production licence on the Canada lands; and

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[37] The main exceptions to this were exploration activities by corporations on the Canada lands, and in non-conventional sources, including tertiary oil projects and heavy oil upgraders. In these cases, earned depletion was to remain at 33⅓ percent, with PIP grants also available. Superdepletion had been allowed to expire on April 1, 1980, however, as scheduled in the March 1977 budget introducing this form of exploration incentive.

[38] As noted in appendix 5.1, section 16, some departures from these proposals emerged when the measures were enacted.

b) the planned introduction of a separate profits-related royalty system (the progressive incremental royalty or PIR) for production on the Canada lands.

6) The NEP also envisaged the imposition of a tax on oil products to be used to finance government acquisitions of producing companies. Such a levy, labelled COSC (Canadian ownership special charge), was introduced in May 1981 with the aim of covering the costs of Petro-Canada's acquisition of the Canadian assets of Petrofina. This levy, effectively a consumption tax, was set at $1.15 per barrel for oil products and $0.15 per thousand cubic feet for natural gas.

The reaction of the governments of the producing provinces to the NEP was strongly negative. Two days after the introduction of the NEP, the government of Alberta announced a series of phased cutbacks of allowed conventional oil production and halted the approval process for new oil sands plants. These measures, the provincial government stated, would remain in effect until the sharp differences in energy policy were resolved in a manner acceptable to Alberta.[39] As noted in chapter 3, above, the resulting stalemate lasted until September-October 1981, when agreements on energy pricing and taxation were signed between the federal government and the governments of the three main producing provinces. These agreements were unusual for the detail and degree of commitment by both levels of government, each of which agreed not to alter tax and royalty rates in such a way as to reduce aggregate revenues flowing to the other level of government or to the oil and gas producing industry. They were originally intended to last for five years, until December 31, 1986.

The main features of the 1981 energy agreements were:

1) The pattern of regulated oil and gas prices was to be linked more closely to world oil prices, with synthetic oil and "new" oil (that is, crude oil produced from pools discovered after 1980) getting the world price, while a price schedule limited to 75 percent of the cost of world oil would apply to "old" oil (that is, crude oil produced from pools discovered before 1981).[40] These prices were, on average, substantially higher than the NEP or pre-NEP prices for both producers and consumers.[41]

2) The federal government agreed to drop the NGGLT on gas exports but proposed to raise the rate of this tax to make the Toronto city-gate price of

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[39] For a quantitative analysis of the NEP and the Alberta response, see John F. Helliwell and Robert N. McRae, "The National Energy Conflict" (Winter 1981), 7 *Canadian Public Policy* 15-23.

[40] It should be noted that these definitions of "old" and "new" are not the same as those used by producing provinces for purposes of determining royalties; see the earlier section entitled "Tax Consequences of the 1973-74 World Oil Price Increases."

[41] For example, the 1982 wellhead price for new oil, net of all taxes and royalties, was $7.10 per barrel under the NEP and $14.60 per barrel under the agreements. For more detailed quantitative analysis of the agreements, see John F. Helliwell and Robert N. McRae, "Resolving the Energy Conflict: From the National Energy Program to the Energy Agreements" (Winter 1982), 8 *Canadian Public Policy* 14-23.

natural gas equal to 65 percent of the delivered price of crude oil with an equal heating value.

3) The PGRT, originally 8 percent, was to be raised to 16 percent, but a 25 percent resource allowance was introduced to reduce the effective rate of this tax to 12 percent.

4) The federal government was to introduce a new incremental oil revenue tax (IORT), which equalled 50 percent of the incremental revenues on old oil, where the incremental revenues were defined by the difference between the conventional oil prices established in the NEP and those in effect under the agreements. Provincial royalties were deductible for the purpose of IORT, which was essentially a substitute for the corporation income tax.

5) Within Alberta, the PIP was to be administered and paid for by the provincial government, but it was to be left in the federal charge elsewhere.

The net effect of these new taxes and higher prices was to increase revenues, relative to the NEP, for the producing industry and for both levels of government. The new federal taxes envisaged by the agreements were part of the federal budget of November 12, 1981,[42] and came into effect on January 1, 1982. World oil prices had stopped rising, however, so that the agreement prices, which were limited by world prices, soon fell below the "made-in-Canada" prices envisaged by the NEP. Thus the new taxes—the IORT, NGGLT, and PGRT—produced much less revenue than originally forecast.

In response to stagnant world oil prices, the governments of the producing provinces introduced a number of incentive packages and reductions in royalty rates. In 1982, for example, Alberta reduced the marginal royalty rate from 50 to 45 percent for old oil and gas, and increased the par (or base) price.

The federal government also responded to the lower than expected world oil prices and released an update to the NEP in June 1982 in which the main tax changes announced were:

1) the suspension of the IORT from June 1, 1983 (this suspension was subsequently renewed until the tax was removed entirely, and the IORT was thus only in effect for the first half of 1982);[43]

2) a reduction in the effective rate of PGRT from 12 to 11 percent for a one-year period starting June 1, 1982;

3) the reduction of the effective rate of PGRT for oil sands production to 8 percent for a two-year period ending December 31, 1984; and

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[42] Canada, Department of Finance, Budget Papers, Budget Speech, November 12, 1981 (Allan J. MacEachen).

[43] As noted in appendix 5.1, section 18, the IORT was levied on the production of the GCOS (Suncor) oil sands plant for a longer period.

4) the granting to all producers of a credit of $250,000 per year against PGRT payments with the aim of eliminating the tax entirely for the smallest producers.

The overall intent of the Alberta changes was to increase industry cash flows by $5 billion over the 1982-1986 period covered by the 1981 energy agreements, while the NEP update changes were expected to add $2 billion to industry cash flows over the same period. The effects on the producing industry of the drop in actual and expected oil prices between September 1981 and June 1982 were thus expected to be slightly more than fully offset by the combined provincial and federal changes.[44]

The federal budget of April 1983[45] renewed the IORT suspension for another year and proposed to change the PGRT for tertiary oil recovery projects so as to eliminate liabilities under this tax until all capital costs from the projects were recovered. The indefinite continuation of the COSC was also announced in this budget.

In the November 1984 economic and fiscal statement,[46] the lower rate of PGRT for oil sands production was extended, and there was an increase in the small producers' credit against the PGRT. In addition, it was announced that the narrowing gap between Canadian and world oil prices had lessened the justification for subsidy programs designed to cut oil use by conservation or substitution and that such subsidies would be phased out or consolidated. The statement also foreshadowed changes designed to reduce and simplify the extent of energy taxation and regulation, including the system of PIP grants.

The Western Accord and the Current Tax System

By the time the western accord was signed in March 1985 by the governments of Canada, Alberta, British Columbia, and Saskatchewan, Canadian crude oil prices were at or close to world levels, and the various special taxes and charges introduced as part of the NEP were producing little revenue, with the exception of the PGRT. Under the accord, PIP grants and the PGRT were both to be phased out; the IORT, the NGGLT, and the COSC[47] were to be withdrawn immediately; and deregulation was promised for both crude oil and natural gas. Moving to world prices for crude oil meant that the oil

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[44] These calculations are reported in John F. Helliwell, Mary E. MacGregor, and André Plourde, "The National Energy Program Meets Falling World Oil Prices" (September 1983), 9 *Canadian Public Policy* 284-96.

[45] Canada, Department of Finance, Budget Papers, Budget Speech, April 19, 1983 (Marc Lalonde).

[46] Canada, Department of Finance, *Economic and Fiscal Statement*, November 8, 1984 (Michael H. Wilson).

[47] As noted in chapter 3, above, on motive fuels, the COSC was effectively replaced by an increase in federal excise taxes (up two cents per litre in September 1985, with an additional one-cent increase in January 1987). The original announcement was made in the May 1985 budget; see Canada, Department of Finance, Budget Papers, Budget Speech, May 23, 1985 (Michael H. Wilson).

export tax, the PCC, and the oil import compensation program were redundant, and they were accordingly dismantled.[48] Shortly after the western accord was signed, the government of Alberta announced a phased-in reduction in oil and gas marginal royalty rates of 5 percentage points over the next three years, an increase in the royalty tax credit, and adjustments to other incentive programs.[49]

It was envisaged, and has been the case, that deregulation would proceed faster and further for crude oil than for natural gas. The tight links between domestic and international oil prices, which were made effective by providing for virtually unrestricted exports and imports of crude oil and products, meant that the post-accord reductions in world oil prices drove down taxes and industry cash flows alike and created substantial pressure for accelerated removal of the PGRT. The immediate elimination of the PGRT was announced, outside the normal budget process, in September 1986, to be effective October 1. Shortly thereafter, the government of Alberta announced a reduction in oil and gas royalty rates, and extensions of royalty holidays (for periods as long as five years) to eligible wells.[50]

In March 1987, the federal government announced a program of incentive grants to oil and gas exploration and development activities. Under this program, eligible expenditures would earn incentive grants at a rate of 33⅓ percent, up to a maximum of $10 million per firm. At the same time, the government extended tax advantages to the oil and gas industry by allowing certain of its activities to be financed through the issue of flow-through shares. (Tax advantages for flow-through shares had previously been available in the mining industry.)

In June and December 1987, the federal government put forward its proposals for a major overhaul of the personal, corporate, and sales tax systems.[51] The principal measures affecting the corporate sector included a phased-in reduction in corporate tax rates and a broadening of the corporate tax base through changes to CCAs. The proposed changes called for a reduction in the CCA rates for a number of classes. The largest change was the switch from a three-year write-off for manufacturing and processing equipment (which includes natural gas plants) to a 25 percent declining balance. The CCA rate applicable to resource extraction assets and drillships and offshore platforms was also reduced from 30 to 25 percent. Special

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[48] For a quantitative examination of the potential impact of the western accord and related developments, see John F. Helliwell, Mary E. MacGregor, Robert N. McRae, and André Plourde, "The Western Accord and Lower World Oil Prices" (June 1986), 12 *Canadian Public Policy* 341-55.

[49] See Alberta, "Statement by Premier Lougheed and Energy Minister Zaozirny on Oil and Gas Incentives" (mimeograph, June 24, 1985).

[50] See Alberta, "Oil and Gas Activity Incentives" (mimeograph, October 29, 1986).

[51] Canada, Department of Finance, *Tax Reform 1987: Income Tax Reform* (Ottawa: the department, June 18, 1987); and Canada, Department of Finance, *Supplementary Information Relating to Tax Reform Measures* (Ottawa: the department, December 16, 1987) (Michael H. Wilson).

measures for the oil and gas industry were essentially confined to the phasing out of earned depletion for investment in oil sands and EOR projects (earned depletion for the rest of the industry had been previously phased out under the NEP) and the phasing out of the exploration and development incentive program introduced in March 1987.

In early 1988, provincial royalties are levied on an ad valorem basis against all oil and gas production from Crown land (with the exception of some oil sands production), while a freehold mineral tax is imposed on production from non-Crown land. Land payments take two forms—rentals and bonus bids— and a number of incentive programs have been extended to the oil and gas industry by the producing provinces. The principal remaining special features of oil and gas taxation are as follows:

1) Exploration expenditures can be written off immediately; development expenditures are written off at a rate of 30 percent; and 10 percent is the rate applicable to land expenditures.

2) Provincial royalties are non-deductible for purposes of the federal income tax.[52] This non-deductibility is intended to be offset by the resource allowance, which reduces resource income by 25 percent. This offset is more or less complete depending on whether royalty rates are less or more than 25 percent of production income.[53] This treatment of provincial royalties amounts to a federal subsidy to oil and gas extraction whenever royalty rates are below 25 percent of production revenues. Whether the combined federal and provincial system is non-neutral as between industries and as between classes or grades of deposits depends almost entirely on the structure of the provincial royalty system and on the extent to which royalty rates at the margin are less for higher-cost deposits.[54] In general, an efficient combination of royalties and bonus bids has a substantial royalty component (including possible allowances for actual or best-practice costs of development) to share the risks between owner and developer, and a significant bonus bid value to permit competition among developers and to

[52] As noted under "Tax Consequences . . . " above, provincial royalty payments are fully deductible for the purposes of the provincial corporation income tax, and the producing provinces have adopted measures aimed at compensating firms for the non-deductibility of royalties for the purposes of the federal corporation income tax.

[53] The details of the resource allowance are described in appendix 5.1, section 9.

[54] The efficiency effects of alternative systems for taxation of extractive industries are spelled out in Robert D. Cairns, "Extractive Resource Taxation in Canada," in Wayne R. Thirsk and John Whalley, eds., *Tax Policy Options in the 1980s*, Canadian Tax Paper no. 66 (Toronto: Canadian Tax Foundation, 1982), 255-88; and Terry Heaps and John F. Helliwell, "The Taxation of Natural Resources," in Alan J. Auerbach and Martin S. Feldstein, eds., *Handbook of Public Economics*, vol. 1 (Amsterdam: North-Holland, 1985), 421-72. A theoretical examination of the efficiency effects of the corporation income tax in non-renewable resource markets is undertaken in Gérard Gaudet and Pierre Lasserre, "Capital Income Taxation, Depletion Allowances, and Nonrenewable Resource Extraction" (March 1986), 29 *Journal of Public Economics* 241-53. A more applied discussion of aspects of the Canadian corporation income tax system can be found in Robin Boadway, Neil Bruce, Ken McKenzie, and Jack Mintz, "Marginal Effective Tax Rates for Capital in the Canadian Mining Industry" (February 1987), 20 *Canadian Journal of Economics* 1-16, and references mentioned therein.

guard against royalty rates so high as to cause economically attractive deposits to appear uneconomic from the point of view of the royalty-paying developers.

3) The rate of corporation income tax is higher for oil and gas extraction than for manufacturing and processing (including the operation of gas processing plants).

4) The oil and gas exploration and development incentive program offered by the federal government is to be in effect until the end of 1989.

5) Flow-through shares receive special tax treatment and can be used by the oil and gas and the mining industries to finance some of their activities.

Aside from these issues of unequal treatment among industries, there is the possibly more important issue of the instability over time of the Canadian system of taxation of production revenues from oil and gas. There have been very large and rapid swings in the rates and structure of taxation, ranging from subsidies exceeding 100 percent of costs in the high-flying days of superdepletion, to marginal tax rates reaching 100 percent during some of the federal-provincial struggles for larger shares of revenues when oil prices were rising rapidly in the aftermath of the 1973-74 and 1979-80 world oil price shocks.

How can the consequences of the changes be assessed? In principle, it is likely that a rapidly changing system would act to increase investor uncertainty and thus reduce the attractiveness of oil and gas investments. It is also possible, however, that the changes in the level and structure of oil and gas taxation have served to make actual net-of-tax revenues less variable and more predictable than they would have been in the absence of these changes. The latter possibility is perhaps less likely in recent Canadian history, when the major changes have been triggered by competition for revenue shares more than by any intent to stabilize net industry returns. Some rough empirical judgments about this issue can be made by comparing the rates of return and their variability under the actual regime of fast-changing rules with those that would have obtained under several alternative and more stable tax regimes. The size and variability of rates of return under alternative tax systems are compared in chapter 10, while their macroeconomic effects are analyzed in chapter 11.

6

Energy Demand

Introduction

This chapter starts with a historical overview of energy demand in Canada. After actual trends in energy consumption have been presented, the theoretical determinants of energy demand are discussed. Empirically estimated demand systems for Canada are then briefly examined, and finally, the demand system used in this study is described.

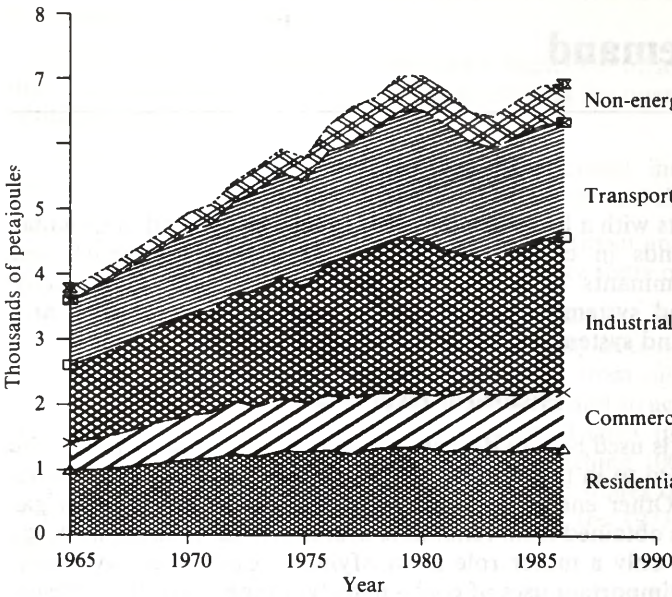
Historical Overview

The term energy is used here to describe the aggregate of energy fuels. The main fuels referred to in this chapter are oil products, natural gas, electricity,[1] and coal. Other energy fuels are coke, coke oven gas, natural gas liquids, and fuels obtained from renewable sources. Within the main energy fuels, coal plays only a minor role in satisfying secondary energy needs. Two of the most important uses of coal—namely, in the generation of electricity and as an input into the production of steel—are not included in the statistics for secondary energy. The former is excluded because it does not involve consumption by final users; the latter is excluded because in this process coal is not used as a fuel. Secondary energy refers to energy consumed by final users, in contrast with primary energy which refers to all energy consumed, including energy used by final users, intermediate uses such as transforming coal to electricity, and energy used in supplying and transporting the fuel to end-users. For instance, primary electricity is generated from hydro and nuclear power, and secondary electricity includes electricity generated by using coal, oil, and natural gas in boilers.

Energy fuels are consumed for many reasons. Energy statistics are not disaggregated by use, however, but rather by end-use sector. The main end-use sectors are residential, commercial, industrial, and transportation. Other categories are non-energy (for example, petrochemical feedstock, asphalt, greases, and lube oil) and own-use. The main sectors are usually further disaggregated—transportation, for example, into road, rail, air, and marine. Within an end-use sector, energy can be used for a variety of purposes—energy in the residential sector, for example, is used for space heating, hot water heating, household appliances, lighting, and many other purposes.

[1] Electricity demand is discussed in this chapter because it is a potential substitute for oil and natural gas, even though we are not discussing electricity supply, taxation, or policy. It should be considered as one of the components in the energy choice set.

Figure 6.1 Total Energy Consumption by Sector, Canada
(annual data)

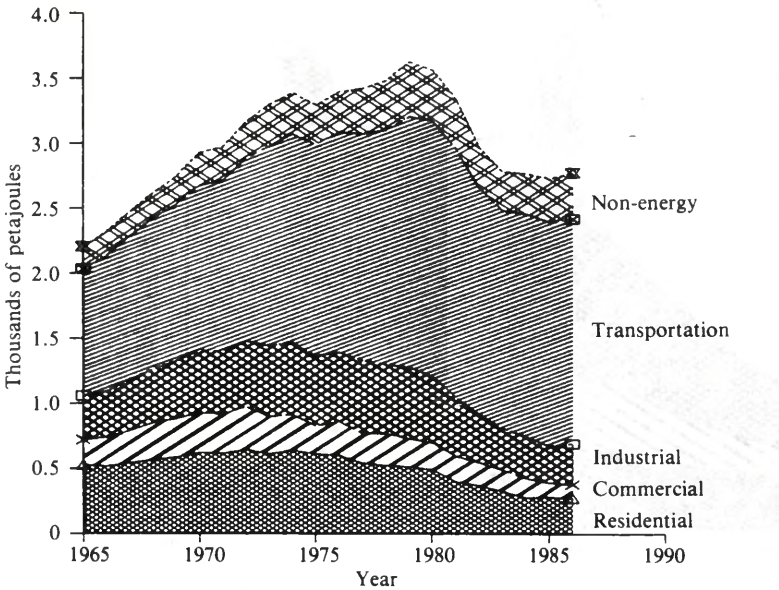


The change, over time, of total energy consumption in Canada, disaggregated by end-use sector, is shown in figure 6.1. With the exception of 1975, total energy consumption continued on a steady growth path from 1965 to 1979. Energy consumption remained virtually the same in 1980 as in 1979 and then fell for the next three years before rising again in 1984. The pattern of total energy consumption in Canada is similar to that in the western world, except that energy demand in Canada rose more rapidly before 1980 and fell faster after 1980 than in the rest of the western world. Canadian energy demand grew by about 26 percent between 1973 and 1980 and fell by about 9 percent between 1980 and 1983, whereas in the western world, energy demand grew much more slowly (by 10 percent) and fell less rapidly (by 2.4 percent) over the respective periods.[2]

In 1986, the industrial and transportation sectors were the largest energy-using sectors in Canada, accounting for about 34 and 25 percent, respectively, of total energy consumption. Although the 1986 share of the transportation sector was the same as it had been in 1965, the share of the industrial sector rose by 2 percentage points over that period. The share of the commercial sector increased slightly, from 11 percent of total demand in 1965 to 13 percent in 1986. On the other hand, the residential sector's share of total energy demand fell from 27 to 19 percent over the same period.

[2]These data are from British Petroleum, *Statistical Review of World Energy* (London: British Petroleum Company, 1986).

Figure 6.2 Oil Consumption by Sector, Canada
(annual data)

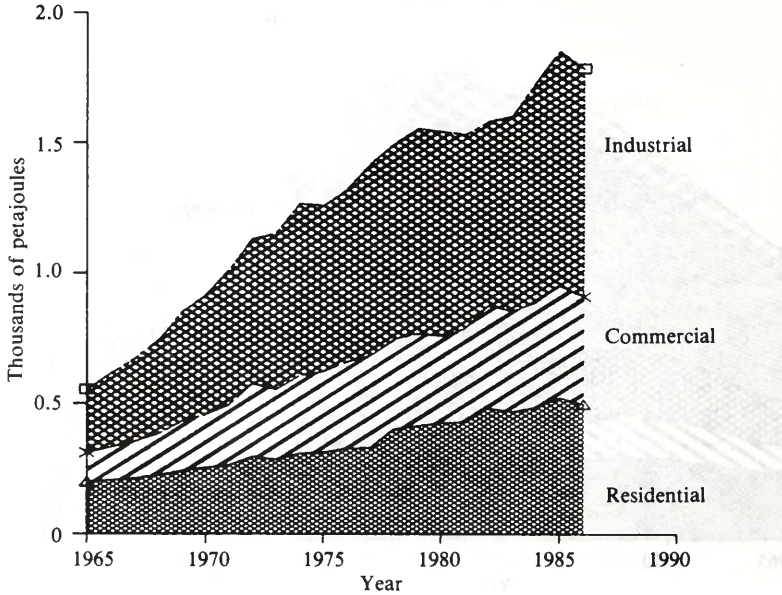


Figures 6.2 to 6.4 provide information on the type of energy fuels that underlie the aggregate energy total in figure 6.1. Figure 6.2 contains a sectoral breakdown of oil use over time;[3] figures 6.3 and 6.4 show the same for natural gas and electricity, respectively. As figure 6.2 shows, most of the oil is consumed in the transportation sector.[4] In fact, transportation use amounted to 62 percent of oil consumption in 1986, dwarfing industrial and residential uses, which accounted for only 11 and 10 percent, respectively. The residential and industrial shares of oil consumption have fallen since 1965, whereas the transportation share has risen. Between 1965 and 1986, the residential share declined by about 14 percentage points and the industrial share by about 4 percentage points, while the transportation share rose by about 18 percentage points. Oil consumption declined rather substantially from 1979 to 1986, with the industrial and residential end-use sectors experiencing the largest relative decline compared with the transportation sector—as one would expect, given the lack of substitute fuels in transportation.

[3] Oil consumption can be broken down by petroleum product: in 1984, for example, motor gasoline accounted for 36 percent; aviation fuels, 5 percent; light fuel oil and kerosene, 11 percent; diesel fuel, 19 percent; heavy fuel oil, 11 percent; asphalt, 3 percent; and others, 15 percent.

[4] Within the transportation sector, road transport accounts for about 80 percent of consumption.

Figure 6.3 Natural Gas Consumption by Sector, Canada
(annual data)



In 1986, the industrial sector had by far the largest share—49 percent—of domestic natural gas sales; residential and commercial sales accounted for about 28 and 23 percent, respectively (see figure 6.3). Between 1965 and 1986, the residential share fell by 8 percentage points, whereas the commercial share increased by 3 percentage points and the industrial share by over 5 percentage points. From 1965 to 1979, total domestic natural gas sales grew more rapidly than oil sales; unlike oil consumption, however, natural gas consumption dropped only slightly from 1979 to 1981 and rose again subsequently.

Electricity consumption (see figure 6.4) has continued to grow throughout the time period, except for temporary declines in 1975 and 1982. Both declines occurred only in the industrial sector and in recessionary years. In 1986, the industrial sector was by far the largest user of electricity (46 percent), followed by the residential sector at 31 percent and the commercial sector at 24 percent. Between 1965 and 1986, the growth in electricity consumption was faster in the residential and commercial sectors than in the industrial sector. Over that period, the residential sector's share rose by 8 percentage points and that of the commercial sector by 6 points, while the industrial sector's proportion of total electricity consumption fell by 14 percentage points.

The division of aggregate energy demand among fuels is shown in figures 6.5 and 6.6 (as opposed to the division by end-use sectors shown by the pre-

Figure 6.4 Electricity Consumption by Sector, Canada
(annual data)

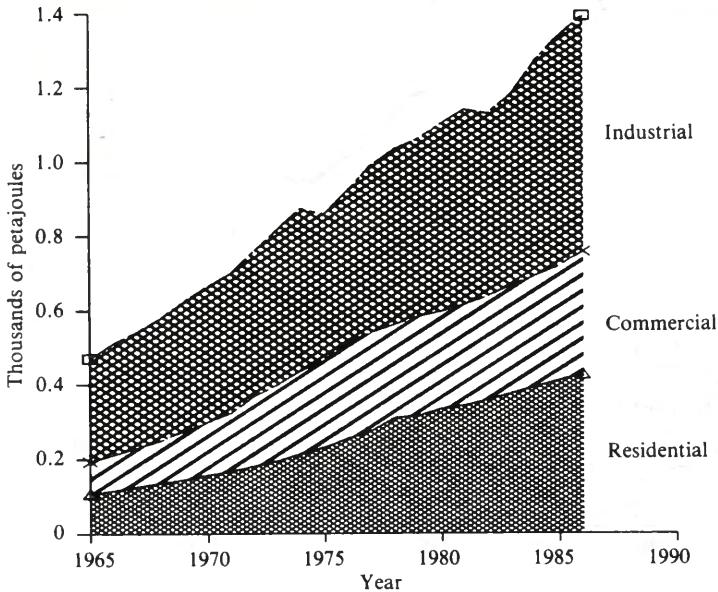


Figure 6.5 Energy Consumption by Fuel, Canada
(annual data)

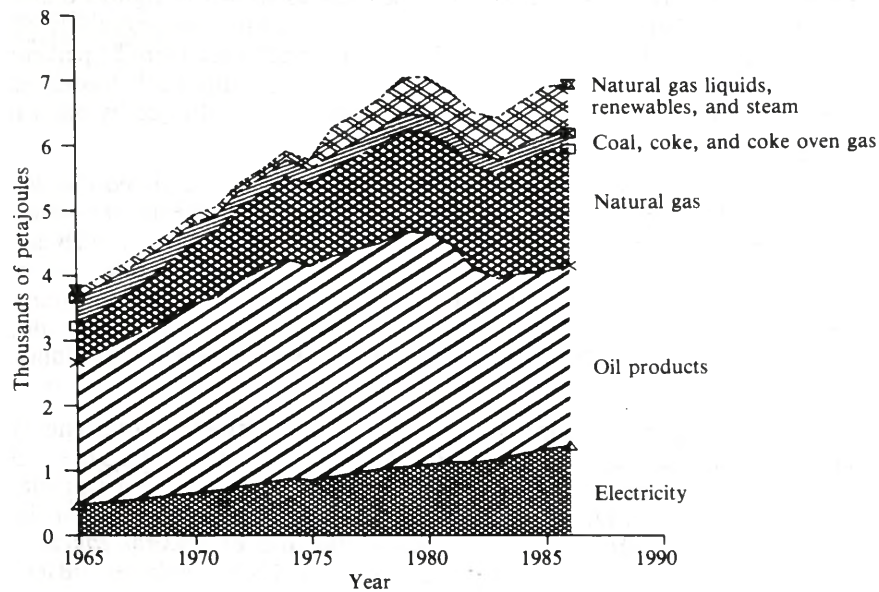
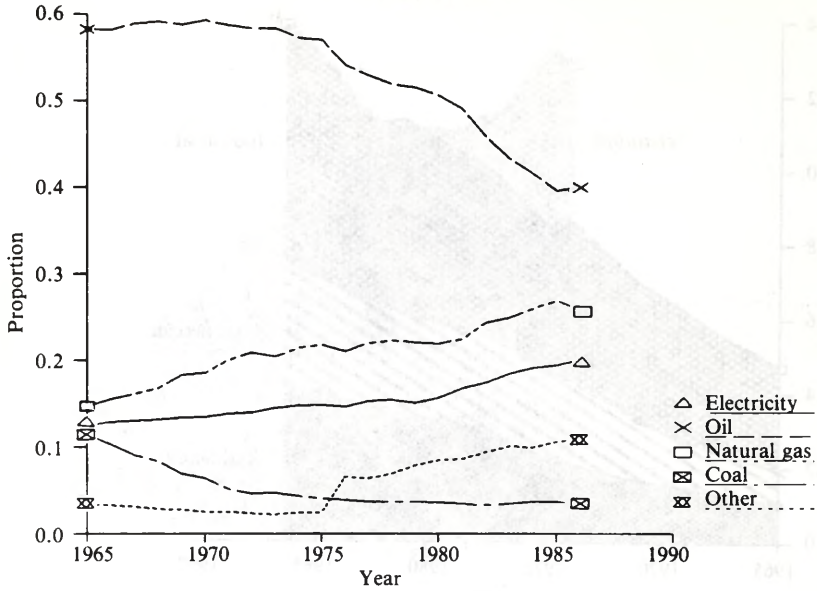


Figure 6.6 Energy Fuel Shares, Canada
(annual data)



vious three figures). The large decline in the oil share since 1975, the continuous increase in the natural gas share over the whole period, and the increase in electricity's share—especially since 1979—all confirm the observations on relative growth rates for these fuels as shown in figures 6.2 to 6.4. The most significant change in energy demand since the first world oil price shock of 1973-74 has been the decline in the oil share from 57 percent in 1975 to 40 percent in 1986. In 1986, however, oil products still accounted for the largest share of Canadian energy consumption, followed by natural gas at 26 percent and electricity at 20 percent.

The foregoing discussion about energy demand has considered Canada as a whole. Sectoral shares, fuel shares, and energy growth rates, however, differ across the regions of the country, because not all energy fuels are available in all regions of Canada, and because relative energy prices differ across regions. Information on 1986 energy fuel shares and total consumption, disaggregated by province, is presented in table 6.1. For comparison, similar data are provided for 1977, except that the provinces in the Atlantic region are grouped together.

In 1986, Ontario accounted for 35 percent of Canada's total energy consumption; Quebec accounted for 20 percent; western Canada, 39 percent; and the Atlantic provinces, 6 percent. Within western Canada, Alberta is by far the largest energy user, accounting for 21 percent of the Canadian total. This is primarily because the use of natural gas as a petrochemical feedstock is included in the data; this use is large and has

Table 6.1 Distribution of Secondary Energy Consumption

Canada and provinces, 1986

Province	Coal	Oil[a]	Natural gas	Electricity[b]	Total energy
		percent			*peta-joules*
Newfoundland	4.9	65.5	0.0	29.6	120
Prince Edward Island	0.8	86.4	0.0	12.8	17
Nova Scotia	4.0	79.4	0.0	16.5	174
New Brunswick	0.9	70.8	0.0	27.5	151
Quebec	1.6	46.4	13.3	38.7	1420
Ontario	7.6	42.7	30.2	18.3	2508
Manitoba	1.1	43.0	31.2	24.5	239
Saskatchewan	1.4	43.0	42.6	13.0	331
Alberta	0.1	32.9	58.6	8.4	1493
British Columbia	1.3	45.0	29.2	24.5	726
Yukon and Northwest Territories	0.0	69.7	19.5	10.8	32
Canada	3.4	43.7	31.3	21.1	7210

Canada and regions, 1977

Region	Coal	Oil[a]	Natural gas	Electricity[b]	Total energy
		percent			*peta-joules*
Atlantic	2.9	82.1	0.0	15.0	536
Quebec	1.6	69.8	5.7	22.9	1597
Ontario	7.8	50.3	27.4	14.5	2445
Manitoba	1.7	49.3	31.2	17.9	249
Saskatchewan	1.2	51.1	38.2	9.5	306
Alberta	0.2	42.5	49.6	7.8	808
British Columbia	1.2	54.5	24.0	20.4	679
Yukon and Northwest Territories	0.0	86.0	1.4	12.5	24
Canada	3.7	57.2	22.9	16.2	6644

[a]Oil includes liquid petroleum gases. [b] Electricity is measured at 3.6 megajoules per kilowatt-hour.

Source: Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada*, catalogue no. 57-003, 1977, 4-5 (net domestic consumption); and ibid., 1986:IV, 4-5 (net domestic consumption).

increased substantially since 1977, when Alberta's share of Canadian consumption was only 12 percent. Consequently, the greatest change in overall regional consumption between 1977 and 1986 has been the increase in energy demand in western Canada and the decline in all other regions. If the increase in energy consumption in Alberta were subtracted from the 1986 total, there would have been slightly less energy consumed in Canada in 1986 than in 1977.

Natural gas is not available in the Atlantic region, and the oil share there is very large; but as in every other region, the oil share in the Atlantic region

fell between 1977 and 1986. In Quebec, natural gas was not important in 1977, unlike oil, which accounted for 70 percent of total energy consumption. An enormous shift in energy use occurred in Quebec between 1977 and 1986: the natural gas share more than doubled (to 13 percent), the electricity share almost doubled (to 39 percent), and the oil share fell (to 46 percent). Natural gas is relatively more important in Ontario and western Canada, although only Alberta has a natural gas share as large as 59 percent. The fuel shares for Ontario and western Canada do not differ from the national averages as much as do the shares for Quebec and the Atlantic region.

What are the salient features to note from the historical overview? Oil demand fell after 1979; it fell sharply enough to drag down overall energy demand from 1980 to 1983. Oil products still, however, account for the largest energy fuel share, nationally as well as for all provinces except Saskatchewan and Alberta. From 1965 to 1986, natural gas and electricity continued to increase their market share. Up until 1974, this increase was at the expense of coal; after 1974, it was at the expense of oil. With respect to end-use sectors, it is worth noting that the transportation sector has accounted for between 50 and 62 percent of the oil consumed during the last decade. In 1986, the industrial sector used by far the largest amount of natural gas and electricity, at 49 and 45 percent of Canadian usage, respectively. The combined residential and commercial sectors accounted for slightly more natural gas and electricity consumption than the industrial sector alone. Finally, aggregate energy consumption and fuel shares are quite different across the provinces.

Theoretical Determinants of Energy Demand

No attempt was made in the previous section to explain why total energy consumption and fuel shares changed over the historical period. This section contains a brief discussion of the major theoretical determinants of energy demand.[5]

At an elementary level, we can consider an energy fuel to be just like a typical non-durable consumer good, the demand for which ought to be determined by a combination of factors—its own price, the prices of substitutable and complementary goods, some measure of economic activity or income level, and other socioeconomic factors. Later, we will explain the importance of the technology embodied in the energy-using capital equipment, thus demonstrating that energy is not, in fact, a typical non-durable good. To assist in visualizing the changes over time in these primary factors affecting energy demand, figures 6.7 to 6.13 show average nominal fuel prices for oil products, natural gas, and electricity by region—the Atlantic provinces, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia (data for the Yukon and Northwest Territories are in-

[5] For a detailed discussion, see Douglas R. Bohi, *Analyzing Demand Behavior: A Study of Energy Elasticities* (Baltimore: Johns Hopkins University Press for Resources for the Future, 1981).

Figure 6.7 Fuel Prices for the Atlantic Provinces
(annual data)

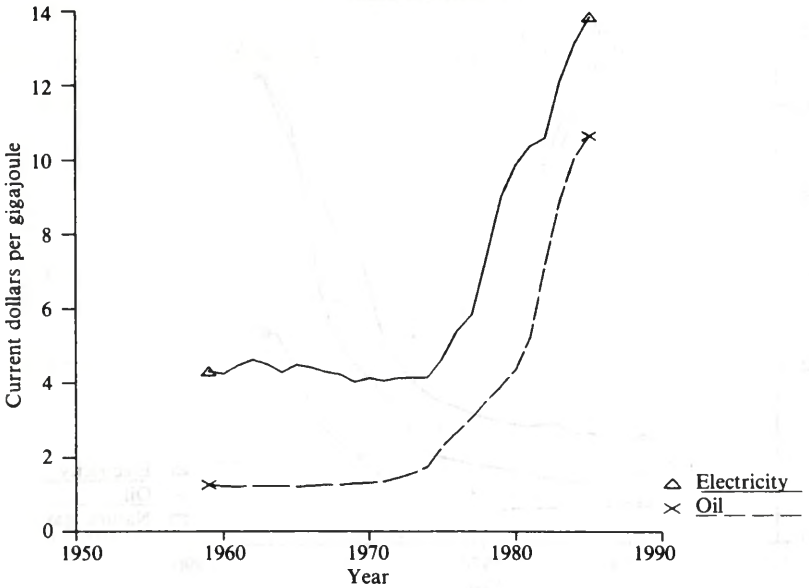


Figure 6.8 Fuel Prices for Quebec
(annual data)

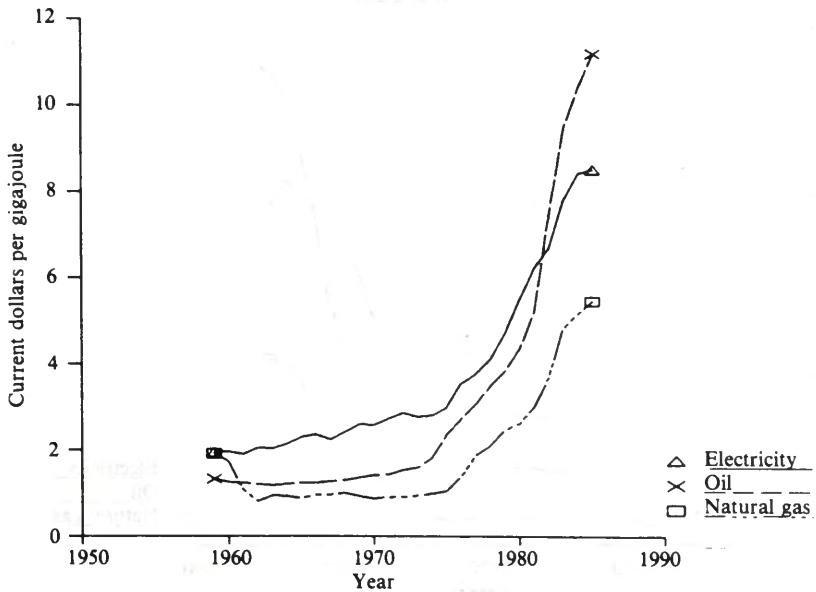


Figure 6.9 Fuel Prices for Ontario
(annual data)

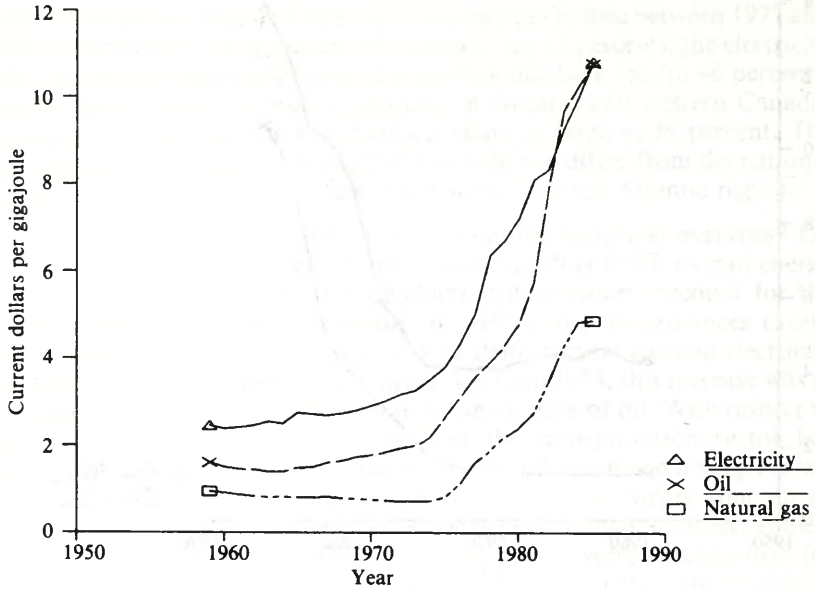


Figure 6.10 Fuel Prices for Manitoba
(annual data)

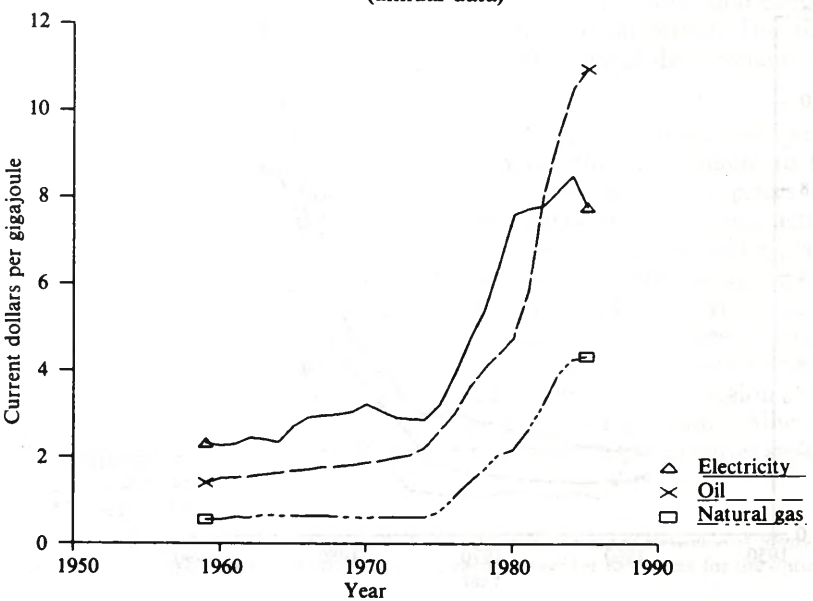


Figure 6.11 Fuel Prices for Saskatchewan
(annual data)

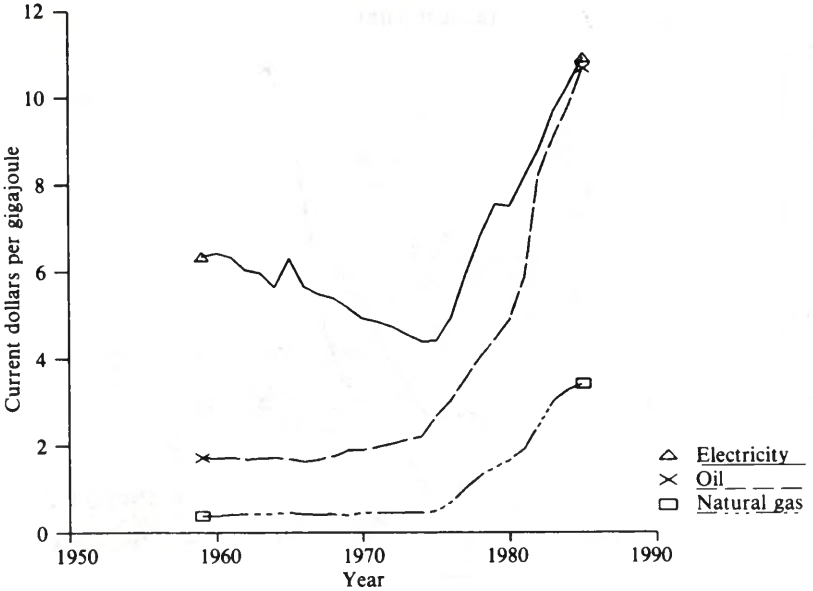


Figure 6.12 Fuel Prices for Alberta
(annual data)

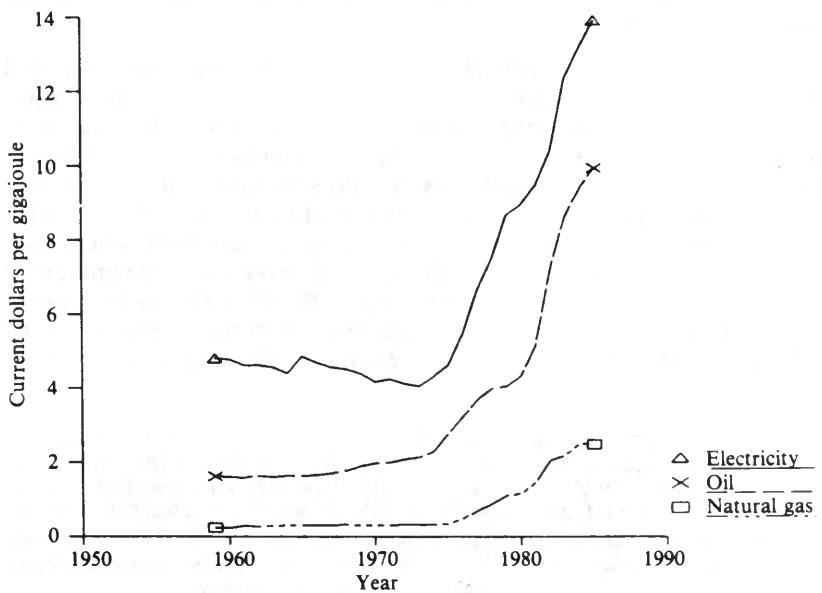
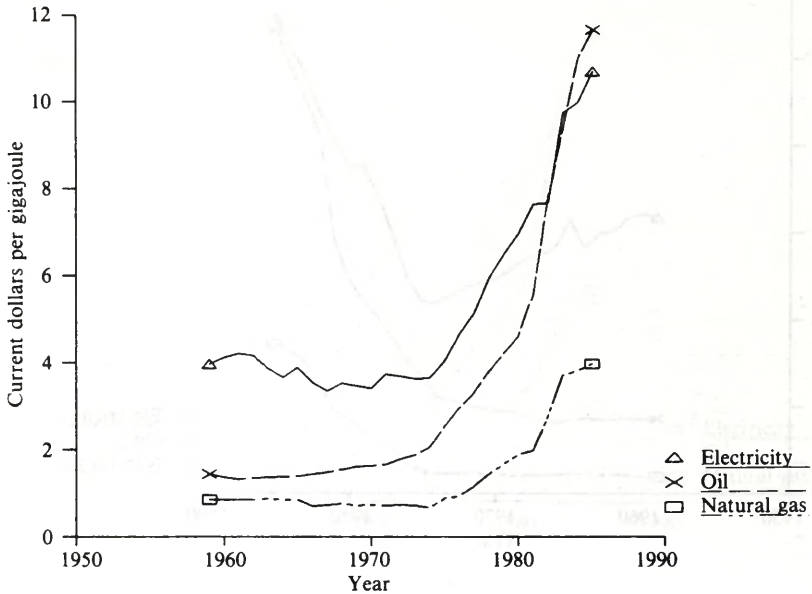


Figure 6.13 Fuel Prices for British Columbia, the Yukon, and the Northwest Territories
(annual data)



cluded with British Columbia). The regional real domestic product (RDP), a proxy for the level of economic activity that drives energy demand, is shown in figures 6.14 and 6.15.

In all regions, the prices of electricity, oil, and natural gas remained approximately constant from 1958 to 1973 and rose sharply thereafter. Prices of natural gas have followed similar paths in each of the regions, as have oil prices. Electricity prices, however, have behaved very differently across regions, both before and after the 1973-74 world oil price shock.[6] The reason for this is that electricity rates are set by provincially controlled utilities, and there is not much interprovincial electricity trade, whereas oil and gas prices have been regulated to various degrees over time and differ across regions chiefly by transportation costs.[7] With only a few exceptions, all regions have the same ordering of fuel costs, such that, when measured on a heat-content basis, natural gas is the cheapest fuel and electricity is the

[6] The pattern of electricity prices is quite different by region. To illustrate the difference in price levels, the following are the regional electricity prices for 1983: Atlantic, $14.52 per gigajoule (GJ); Quebec, $9.30 per GJ; Ontario, $11.06 per GJ; Manitoba, $9.41 per GJ; Saskatchewan, $11.36 per GJ; Alberta, $14.58 per GJ; and British Columbia, $11.06 per GJ.

[7] Details about the oil and gas price regulations are contained in chapters 3 and 4. As noted in chapter 4, under "Regulated Pricing, 1971-1979," some of the producing provinces adopted a policy of discounting prices for natural gas used within these provinces.

Figure 6.14 Real Domestic Product by Region and for Canada
(annual data)

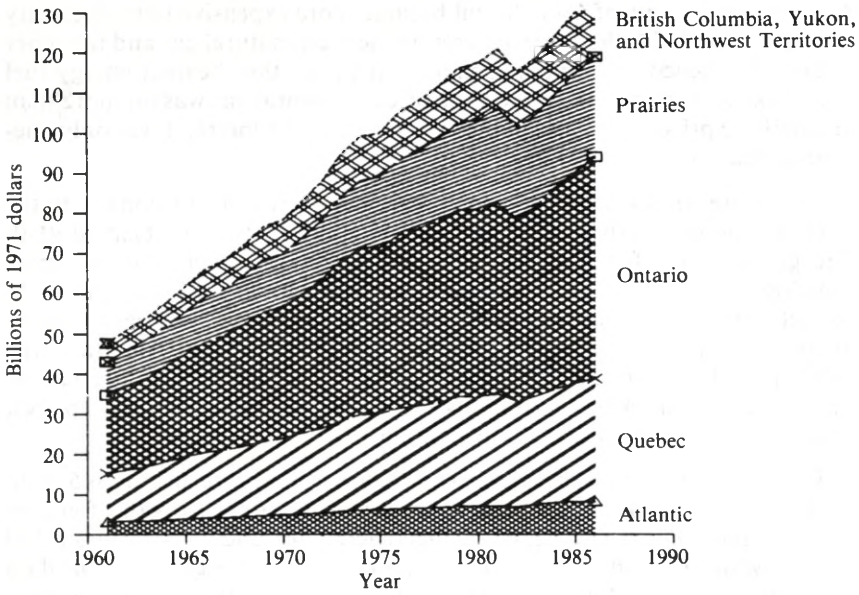
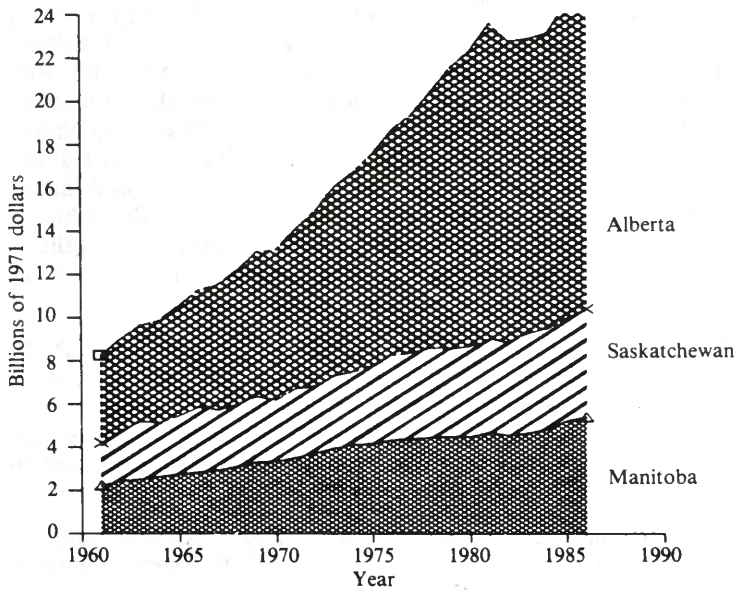


Figure 6.15 Real Domestic Product for the Prairie Provinces
(annual data)



most expensive.[8] The sharp rise in oil prices after 1980 narrowed the price gap between oil and electricity in the Atlantic provinces, Saskatchewan, and Alberta; for the rest of Canada, oil became more expensive than electricity after 1981. By 1984, the price differential between natural gas and the other fuels had widened substantially, making it by far the cheapest energy fuel (on a heat-content basis). In fact, the price of natural gas was no more than one-half the price of oil, and in the extreme case of Alberta, it was only one-quarter that of oil.

Aggregate energy demand in each region is likely to be responsive to the level of economic activity, and figures 6.14 and 6.15 portray regional RDP. The growth path for RDP has been fairly smooth except for moderate slowdowns in 1970 and 1975, and the large downturn in 1982. As figure 6.15 indicates, most of the growth of RDP in the prairie region has been because of the growth in Alberta. The booming energy industry in Alberta in the 1970s helped it avoid the 1975 recession that struck the rest of the country. The impact on the Alberta economy of the 1985-86 fall in world oil prices, however, can also be discerned in figure 6.15.

By comparing total energy demand shown in figure 6.1 or 6.5 with national RDP shown in figure 6.14, one can observe the growth of energy per RDP and see that from 1965 to 1980 energy demand grew by about 100 percent while RDP grew by about 85 percent. The energy and RDP data from 1980 to 1986 show the uncoupling of the energy-economic growth ratio, as the two series moved in different directions.

By combining energy usage with some measure of output, like RDP, one can calculate the energy intensity, which is the ratio of energy consumption to output. Data on energy intensity for various countries are shown in table 6.2, energy intensity by sector for Canada in table 6.3, and energy intensity by region in table 6.4. Canada has the highest energy intensity of the countries mentioned in table 6.2. The United States follows closely behind, with European countries and Japan substantially lower than Canada. Among the reasons for North America's higher energy intensity are the colder climate, larger distances for intercity transportation, less public transportation, automobiles that are less fuel-efficient, proportionately more (and larger) single-family dwellings, and an industrial structure that includes a higher proportion of energy-intensive industries; but some of these factors themselves arise from the fact that energy has been cheaper in North America than in Europe and Japan.

Since 1973, there have been substantial reductions in the energy intensity of Canadian activity. Table 6.3 shows how energy intensities have fallen in all end-use sectors from 1973 to 1982—by 13 percent in residential use, 9 percent in commercial, 7 percent in industrial, and 23 percent in transportation. These changes are substantial, and they are in line with changes in

[8] One must be cautious when comparing energy fuel prices. These fuels may have different efficiencies depending upon end-use, which often are not reflected in the conversion to a standard unit.

Table 6.2 Index of Secondary Energy Consumption per Unit of Output, 1979

Country	Index
Canada	100
United States	98
United Kingdom	88
Italy	76
Sweden	67
West Germany	57
France	57
Japan	53

Source: Economic Council of Canada, *Connections: An Energy Strategy for the Future* (Ottawa: Supply and Services, 1985), 106.

Table 6.3 Energy Intensity by Sector for Canada, 1973 and 1982

End-use sector	Energy intensities 1973	1982	Change, 1973-1982
	gigajoules per household		*percent*
Residential	184	160	−13
	megajoules per 1971$ of real output		
Commercial	16.9	15.4	−9
Industrial	62.8	58.7	−7
	gigajoules per automobile		
Transportation: automobile	116	89	−23

Source: Economic Council of Canada, *Connections: An Energy Strategy for the Future* (Ottawa: Supply and Services, 1985), 110.

other developed countries with the exception of the industrial sector, which has not changed as much in Canada as it has elsewhere. The same story of increased energy efficiency can be observed by region between 1973 and 1984 in table 6.4.

The data presented in figures 6.7 to 6.15 provide a general picture of the main determinants of regional energy demand. Economic theory indicates the desirability of explaining energy demand by end-use sector (as the best approximation to end use), and therefore energy fuel prices and measures of economic activity need to be specific to each end-use sector.

A feature of energy demand that distinguishes it from a typical non-durable consumer good is that energy is consumed in conjunction with some form of capital equipment, such as a furnace, automobile, boiler, or light fixture. In general, this capital equipment will have a long life. With changes in an economic variable, like a fuel price, the consumption of the fuel is often closely tied to the energy efficiency embodied in the capital equipment, so that the short-run response is constrained to changes in use

Table 6.4 Energy Intensity by Region, 1973 and 1984

Region	Total secondary energy, megajoules per 1971$ of RDP		Industrial energy, megajoules per 1971$ of industrial output
	1973	1984	1984
Atlantic	80	61	91
Quebec	59	49	59
Ontario	48	47	46
Manitoba	55	47	37
Saskatchewan	72	62	75
Alberta	83	76	46
British Columbia, Yukon, and Northwest Territories	57	59	102
Canada	58	54	57

Sources: The regional total secondary energy consumptions used in the energy intensity calculations are from Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada*, catalogue no. 57-003, 1984:IV; and *Detailed Energy Supply and Demand in Canada*, catalogue no. 57-207, 1973. The regional RDP data are from the MACE model database. The column showing the industrial energy intensity for 1984 is from Canada, NEB, *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services, 1986), 24.

of the existing equipment. In the intermediate run, retrofitting of existing capital can sometimes occur, which allows some improvement in energy efficiency. Only in the long run is there complete freedom to adjust to the desired level of energy demand by choosing new capital equipment. Energy demand is therefore less responsive to changes in energy prices in the short run than it is in the long run.

Energy demand is often estimated in a two-stage, so-called top-down approach, where aggregate energy demand is explained first and then the total is disaggregated into specific fuels. This procedure guarantees consistency in that the aggregation of individual energy fuels will equal total energy use.[9] Within this type of framework, the demand for an individual energy fuel will have a higher elasticity than aggregate energy, because there are more substitutes for a specific fuel than for aggregate energy. The alternative—the so-called bottom-up or engineering approach—incorporates technical detail about the capital stock and its energy-output ratio to determine total energy use.

Factors other than fuel prices and economic output (or income) affect energy demand. In the residential sector, the weather and the number and type of households are important; in the industrial sector, other factors of production—like labour and capital—are important; and in the transportation sector, the characteristics of the automobile stock (including its embodied fuel efficiency) are important. The inclusion of many of the

[9]It should be noted, however, that such an approach also makes some rather strong assumptions about aggregation and substitution possibilities across fuels, and about the relationship between energy use and the rest of the economy.

Table 6.5 Estimates of Long-Run Price and Income Elasticities of Energy Demand in Canada

	Elasticities	
	Price	Income
Total energy	−0.30 to −0.59	0.96
By sector		
Residential	−0.32 to −0.60	0.15 to 0.47
Commercial	−0.40 to −1.06	1.16
Industrial	−0.21 to −1.00	0.93
Transportation		
road	−0.70	1.10
rail	−0.10	0.30
marine	−0.20	0.90
air	−0.20	3.70
By energy source		
Oil products	−0.68	0.91
Electricity	−0.57	0.80 to 1.70
Natural gas	−0.33	—[a]

[a]Not reported.

Source: Economic Council of Canada, *Connections: An Energy Strategy for the Future* (Ottawa: Supply and Services, 1985), 106.

above factors attempts to capture the sector-specific capital equipment used and its embodied energy-efficient technology.

Empirically Estimated Demand Responses

How responsive has energy demand been in Canada to the dramatic changes in energy fuel prices? Using the data contained in the previous two sections, one is certainly tempted to draw the conclusion that aggregate energy demand and fuel shares have been affected by fuel prices. Table 6.5 summarizes the long-term price and income elasticities of energy demand gleaned from a number of studies.[10] Almost without exception, the price elasticities are less than one in absolute value, which implies that demand is price inelastic. Demand is most price inelastic in the transportation sector, where few fuel substitutes exist. The price elasticities show the largest potential variation in the commercial and industrial sectors. With respect to individual fuels, the responsiveness of demand to changes in prices is the largest for natural gas and the smallest for oil products. The income[11] elasticity shows a much wider dispersion than the price elasticities, from an estimated low of between 0.15 and 0.47 for the residential sector to an

[10]These studies are discussed in Economic Council of Canada, *Connections: An Energy Strategy for the Future* (Ottawa: Supply and Services, 1985), 106.

[11]The term "income" is here used in a generic sense to refer to an appropriate measure of economic activity for the end-use sector in question, like real domestic product, real industrial product, or real disposable income.

estimated high of 3.7 for air transport. The income elasticity for overall energy demand is estimated to be 0.96, indicating an almost equiproportionate response of energy demand to economic activity.

None of the studies that were the sources of the elasticities reported in table 6.5 used post-1980 data, and given the demand responses evident from figures 6.1 to 6.6, this is a weakness. Many of the studies also used fairly rudimentary methods of accounting for the dynamic adjustment of energy demand. To provide details of the underlying models would take too long; the elasticities are therefore to be used only as a guideline to the order of magnitude one can expect.

One use to which estimated demand elasticities are put is to forecast future energy demand. In this regard, as a test of forecast accuracy, the projected demands for total energy, oil, and natural gas published by the NEB since the mid-1970s are presented in table 6.6. The 1985 forecast value, given in all NEB reports over the last decade, is used as the reference point in measuring the forecast accuracy. It was not until the NEB's 1977 report[12] that energy demand was considered in a "top-down" approach, where aggregate energy is subsequently disaggregated into fuels, as opposed to a partial approach, where individual demands for energy fuels are estimated in isolation. Before that report, the NEB overestimated the demand for oil and gas; and subsequent reports continued to overestimate oil demand. With the exception of the NEB's 1981 report,[13] the other post-1977 NEB reports were remarkably accurate in projecting total energy and gas demand. Figures 6.2 to 6.4 show how the demand for oil, unlike that for gas and electricity, changed drastically over the period under consideration, making it much more difficult to forecast accurately.

Energy Demand in MACE

Since the MACE (for MACro and Energy) model is used to forecast the outcome of some policy experiments in chapters 10 and 11, more detail of that model's energy demand system is provided in this section. The MACE model uses a two-sector approach to represent the Canadian economy. The energy-producing sector is modelled as using capital, labour, and natural resources to bring energy from the "ground" to the consumer, while the energy-using sector uses energy in combination with labour and capital to produce everything else.[14] The production function of the energy-using sector is of the nested variety, with the inner level containing energy and capital in a vintage, constant-elasticity-of-substitution (CES) framework. The

[12]Canada, National Energy Board, *Reasons for Decision: Northern Pipelines* (Ottawa: Supply and Services, 1977).

[13]Canada, National Energy Board, *Canadian Energy: Supply and Demand 1980-2000* (Ottawa: Supply and Services, 1981).

[14]This means that the output of the energy-using sector is equal to real gross domestic product plus net energy imports. A more detailed description of the MACE model can be found in John F. Helliwell, Mary E. MacGregor, Robert N. McRae, André Plourde, and Alan Chung, "Supply Oriented Macroeconomics: The MACE Model of Canada" (July 1987), 4 *Economic Modelling* 318-40.

Table 6.6 Forecasts of 1985 Primary Energy Demand for Canada by the National Energy Board

NEB report[b]	Primary demand[a] for		
	Total energy	Oil	Natural gas
	petajoules		
1	n.a.[c]	n.a.	2895 (+41%)[d]
2	n.a.	5167 (+69%)	n.a.
3	n.a.	4224 (+38%)	n.a.
4	10824 (+6%)	4401 (+44%)	2169 (+5%)
5	10245 (0%)	4117 (+34%)	1988 (−3%)
6	10450 (+2%)	4058 (+33%)	1966 (−4%)
7	11787 (+15%)	3894 (+27%)	2425 (+18%)
8	9961 (−3%)	3019 (−1%)	1908 (−7%)
9	10239	3061	2056

[a]Unless otherwise stated, the demand is a base-case forecast. The total primary energy demand reported in (9), below, converts hydro electricity at 3.6 gigajoules (GJ) per megawatt-hour (Mwh) and nuclear electricity at 12.1 GJ per Mwh, whereas in all the previous NEB studies both hydro and nuclear were converted at 10.5 GJ per Mwh. To make a consistent comparison, the total primary energy figure of 8461 petajoules (PJ) was recalculated to be equal to 10,239 PJ using the previous conversion factors.

[b]See sources, below, for full citations of National Energy Board publications represented by numbers in this column.

[c]n.a. means not available.

[d]The percentage in parentheses below each forecast is the forecast error, using the actual demand data reported in (9), below.

Sources: All are Canada, National Energy Board (Ottawa: Supply and Services), with titles, dates, and page numbers as follows: (1) *Canadian Natural Gas Supply and Requirements* (1975), 17, medium case; (2) *Canadian Oil Supply and Requirements* (1975), 109, conservation case; (3) *Canadian Oil Supply and Requirements* (1977), 149; (4) *Reasons for Decision: Northern Pipelines* (1977), 2-39; (5) *Canadian Oil Supply and Requirements* (1978), 95; (6) *Canadian Natural Gas Supply and Requirements* (1979), 46; (7) *Canadian Energy: Supply and Demand 1980-2000* (1981), 28, middle demand case; (8) *Canadian Energy: Supply and Demand 1983-2005* (1984), A-190; (9) *Canadian Energy: Supply and Demand 1985-2005* (1986), 160, actual demand.

outer-level CES production function contains the output of the energy-plus-capital inner function as well as labour measured in efficiency units. An implication of this modelling strategy is that energy demand is determined on an economy-wide basis and not by end-use sector.

In MACE, a distinction is made between "normal" output and the actual level of output. "Normal" output is generated with the long-run production function, using actual employment and the current value of capital-plus-energy; it yields the level of output that would be produced under

normal utilization rates. Over the sample period, the normal factor demands associated with the long-run production function are assumed to be consistent with cost minimization, although this does not hold from year to year because of changes in factor utilization. The actual level of output is modelled as a utilization-rate decision, which depends upon the deviation of sales from normal output, a measure of profitability, and a measure of unintended inventory accumulation. The desired levels for factor demands, including energy, are derived from the production function for normal output and hence are a function of relative factor prices and the expected level of output.

Energy and capital are closely linked in MACE, and a brief description of the investment component is therefore necessary to understand the derivation of energy demand. Capital investment is based on a modified "putty-clay" model. All new capital investment uses energy at the optimal rate based on current relative factor prices. New investment is not, however, the only capital that is malleable, because the MACE model estimates the rate of retrofitting of previously installed capital. Hence, the energy requirements from the vintage capital stock are based on both the old vintage capital and the sum of the newly installed capital and the retrofitted capital.

This structure makes MACE very much a supply-oriented model. One of its underlying (and controversial) assumptions is that firms are not on their production function at each observation point, but rather are so only on average over the sample period. The treatment of energy and capital jointly, in the above fashion, takes specific account of the theoretically important dynamic adjustment component of energy demand mentioned earlier in this chapter, under the heading "Theoretical Determinants of Energy Demand."

As noted above, MACE estimates aggregate energy demand for Canada as a whole. A separate component of the model disaggregates total national energy demand into regional energy demands, and within each region, into demands for each fuel type.[15] Regional energy demand is estimated using the ratio of regional RDP to the national total, a weighted moving average of regional energy prices relative to national energy prices, and national energy demand.

Regional energy demand is disaggregated into fuel demand by estimating regional quantity fuel share equations, which are a function of relative average energy fuel prices,[16] the number of natural gas pipeline distribution

[15] As noted earlier, the regions are the Atlantic provinces, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia (including the Yukon and Northwest Territories). The regional fuel share equations are for oil, electricity, and natural gas.

[16] Prices to final users in each province (or region) were used in the estimation of the fuel demand equations. As will become clear in chapter 8, wellhead prices of crude oil and field prices of natural gas are endogenous variables in MACE. These prices, in conjunction with crude oil import prices, are the first building blocks for our user price series. In the case of oil, the sum of the wellhead price (or the import price, as appropriate) and the relevant transportation tariffs defines the city-gate crude oil price for each province (or region). User prices for oil

(Continued on the next page.)

kilometres (as an indication of the availability of natural gas), and lagged shares. To be specific, the form of the estimated equations is as follows:

$$\ln(SO/SL) = a1 + b*\ln(PO/PL) + c1*GPKM + d*\ln(lag(SO)/lag(SL)) + u$$

$$\ln(SG/SL) = a2 + b*\ln(PG/PL) + c2*GPKM + d*\ln(lag(SG)/lag(SL)) + v$$

$$SL = 1 - SO - SG,$$

where SO, SG, and SL are quantity shares for oil, gas, and electricity, respectively; PO, PG, and PL are the average nominal fuel prices for oil, gas, and electricity, respectively; GPKM is the number of gas distribution pipeline kilometres; ln indicates the natural logarithm operator; lag represents a one-period lag; a1, a2, b, c1, c2, and d are parameters to be estimated; * (asterisk) represents the multiplication operator, and u and v are stochastic error terms. This functional form for fuel demand equations has been used previously by Baughman and Joskow.[17] The regional fuel demands are obtained by multiplying the fuel shares by the aggregate regional energy use. The regional demands for fuels are not disaggregated by end-use sector, except for fuels used in electricity generation, which are estimated separately. The fuels used in electricity generation are estimated with an equation system similar to that just described.[18] The estimated coefficients, statistical properties, and exact equation structures[19] are contained in appendix 6.1.

[16]Continued . . .
are then defined as the sum of the city-gate price and a province-specific markup. These markups include refining, distributing and retailing costs, and profit margins, as well as provincial and federal taxes on oil consumption. A similar approach was adopted for the determination of natural gas user prices. The sum of the field price, the relevant transmission tariffs, and, between 1981 and 1984, the NGGLT determines delivered (or city-gate) prices in each province. User prices are the sum of delivered prices, the COSC (between 1981 and 1984), and province-specific markups consisting of distribution costs and margins. Obviously, the calculations were modified for the years between 1975 and 1985 to take into consideration the fact that delivered prices of natural gas were then regulated, as noted in chapter 4. To allow for some responsiveness of the markups when simulating the MACE model under alternative assumptions about the behaviour of other variables, we estimated, and included in the model, fairly rudimentary equations with the markups as dependent variables. In all, 13 such equations were estimated, one each for oil and gas in each of the seven provinces or regions included in the model (no gas markup equation was estimated for the Atlantic provinces, where that fuel is not consumed). User prices for electricity were calculated directly from data maintained by Statistics Canada. Delivered electricity prices were simply assumed always to equal 75 percent of user prices in all provinces or regions. A more detailed discussion of the derivation of our user price series can be found in appendix 6.2, where our estimates of per-barrel prices of oil products to final users are also presented.

[17]See Martin L. Baughman and Paul L. Joskow, "Energy Consumption and Fuel Choice by Residential and Commercial Consumers in the United States" (1976), 1 *Energy Systems and Policy* 305-23.

[18]The differences between the structure used in the main demand system and that of the thermal demand system are as follows: aggregate fuel demand is a function of the residual electricty, determined by subtracting from total electricity demanded the supply of hydro and nuclear generated electricity; gas distribution pipeline kilometres are not used; and coal replaces electricity in the fuel share equations.

[19]Not all fuels are used in all regions; the equation structure for each region therefore reflects the actual fuel mix. For instance, natural gas is not used in the Atlantic provinces, and coal is not used to generate electricity in Quebec or in British Columbia.

Table 6.7 Estimated Long-Run (Short-Run) User Price Elasticities for Canada

	MACE model			
	Oil	Gas	Electricity	Energy
Oil	−0.71 (−0.15)	−0.21 (−0.05)	−0.11 (−0.02)	−0.42 (−0.12)
Gas	0.01 (0.02)	−0.40 (−0.20)	0.01 (0.01)	−0.09 (−0.02)
Electricity	−0.09 (−0.04)	−0.11 (−0.07)	−0.61 (−0.22)	−0.17 (−0.04)
	Thermal electricity sector of MACE model			
	Oil	Gas	Coal	
Oil	−1.38 (−0.02)	0.05 (0.01)	0.19 (0.05)	
Gas	0.01 (0.01)	−1.99 (−0.65)	0.17 (0.03)	
Coal	1.64 (0.16)	2.66 (0.68)	−0.41 (−0.37)	

Source: Authors' calculations based on the results of alternative simulations of the MACE model.

The estimated price elasticities for overall energy demand and thermal energy demand in the MACE model are listed in table 6.7. The short-run (one-year) price elasticities are included in parentheses beside the long-run (five-year) elasticities for each of the fuels. The own-price elasticities for energy fuels are all less than 1.0 in absolute value. A comparison of table 6.7 with table 6.5 indicates that these own-price elasticities are similar to those obtained from other models. The oil, natural gas, and electricity price elasticities in MACE are virtually identical to the ones reported in table 6.5. Many of the cross-price elasticities are negative because the relatively large negative total energy elasticities swamp the positive cross-price elasticities that would prevail if aggregate energy were left unaffected by the price changes. For example, an increase in the price of oil would imply a substitution of electricity for oil. But the increase in the price of oil would also increase the overall price of energy and lead to a fall in total energy consumption. In the case of electricity, the decline in total energy consumption outweighs the substitution effect.[20]

Summary

The pattern of energy fuel consumption in Canada has gone through a radical transformation, especially since 1979. This chapter has examined the changes that have taken place in various end-uses for aggregate energy demand and for specific energy fuels. Total energy was broken down into components, and the changes in energy fuel shares nationally and by region were compared. The most significant change has been the decline in oil consumption, in absolute terms and as a share of aggregate energy. The magnitude of this decline has been large enough to drag down aggregate

[20]This is similar to the income and substitution effects of microeconomic price theory.

energy demand. Regional energy fuel prices and economic activity, theoretically important variables in determining energy demand, were examined.

The overall energy intensity in Canada was compared with that in other countries; within Canada, this was seen to have declined significantly over time in all end-use sectors. The responsiveness of energy demand to changes in fuel prices and economic activity was discussed in the context of elasticity measurements. It was observed that most demand models, including MACE, found the long-run response of energy demand to own-price changes to be inelastic, and the income (economic activity) elasticity to be around unity.

7

Investment Patterns in the Oil and Gas Industry

Introduction

In the next three chapters, we turn our attention to investment in the oil and gas industry. Before discussing the costs and supply of conventional reserves (chapter 8) or frontier reserves (chapter 9), we set the stage with an overview of investment patterns within the industry as a whole. Trends in oil and gas investment are compared with those in the rest of the energy sector and the rest of the Canadian economy. We then look at how investment within the industry has shifted between oil and natural gas, between exploration and development, and finally, between frontier and non-frontier activities.

Macroeconomic Perspectives

During the 1960s, aggregate investment in Canada grew rapidly—more rapidly than investment in either the upstream oil and gas industry or the energy sector as a whole (see figure 7.1). The energy sector (defined here as oil and gas wells, petroleum and coal products, coal mines, pipelines, electric power, and gas distribution) averaged around 22 percent of aggregate investment, while the upstream portion of the oil and gas industry accounted for around 5 percent. In the late 1970s, oil and gas investment increased sharply as did investment in both the energy sector and the rest of the economy. The steep drop in aggregate investment during the severe 1981-82 recession was not, however, shared nearly to the same extent by the oil and gas industry. In level terms, upstream oil and gas investment declined slightly during the early 1980s (see figure 7.1); nevertheless, it continued to account for a steadily increasing proportion of aggregate investment (see figure 7.2).

Some idea of the increasing importance of the upstream oil and gas sector can be obtained by comparing its relative share of aggregate investment with that of the manufacturing industries. Much of the comparison obviously depends on how broadly the oil and gas industry is defined—whether it includes retail gasoline outlets, for example, as well as oil wells. We have chosen a fairly narrow definition of the industry, one that concentrates on exploration and production (or upstream) activities as opposed to refining and marketing (the downstream segment), since the upstream portion of the industry has been the primary focus for many of the policy changes initiated. As figure 7.2 shows, the manufacturing industries played a much more important, though more volatile, role in

Figure 7.1 Real Investment in the Energy and Non-Energy Sectors
(annual data)

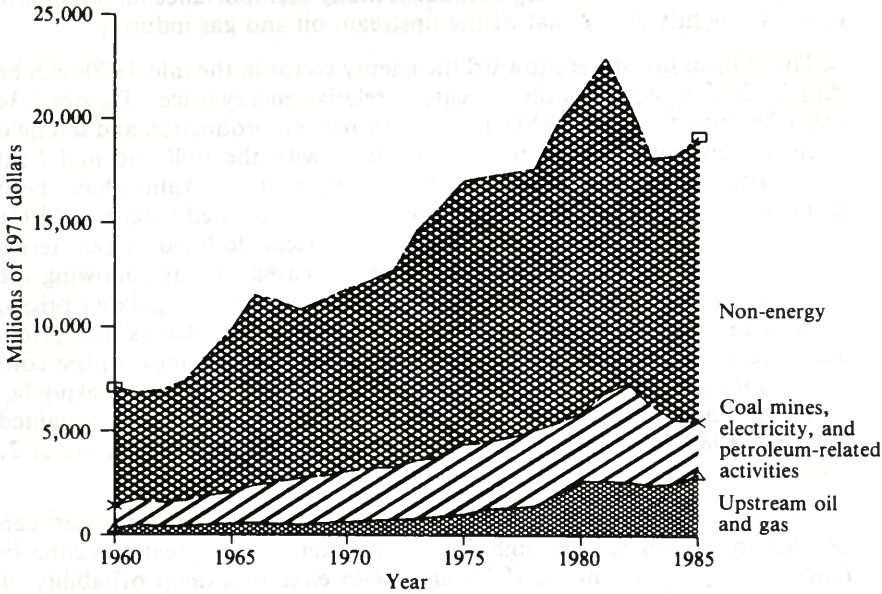
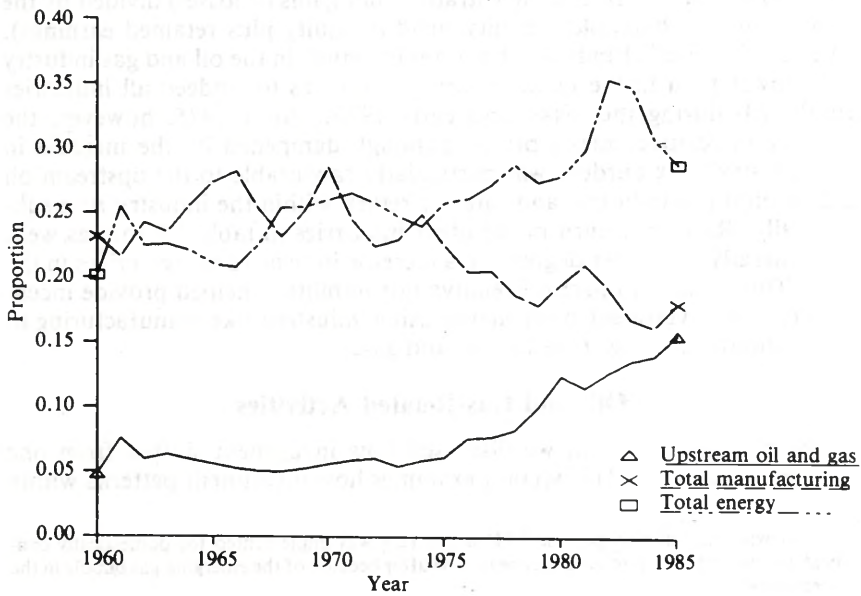


Figure 7.2 Investment by Industry as a Proportion of Total Real Business Investment
(annual data)



determining aggregate investment until the mid-1970s. From the mid-1970s through 1985, manufacturing declined steadily in importance until its share was only slightly above that of the upstream oil and gas industry.

The shift in investment toward the energy sector in the mid-1970s can be explained in large part by the increase in relative energy prices. Figures 7.3a and 7.3b show the gross wellhead price for new oil production and the field price of new natural gas production, along with the wellhead and field prices after all taxes and royalties have been paid. All values have been deflated by the absorption price deflator and are expressed in terms of 1971 dollars. As is evident from the figures, oil prices declined in real terms throughout the 1950s and 1960s and then increased rapidly following the OPEC price shock of 1973-74, despite the imposition of regulated prices. Natural gas prices showed a somewhat different pattern. Gross field prices increased in real terms during the 1950s and then remained more or less constant until after the first OPEC oil price shock. Prices increased sharply between 1973 and 1980, fell slightly in real terms in 1981,[1] and then remained flat until 1985, when export prices dropped sharply again (see chapter 2, figure 2.3).

The impact of these changes on the nominal prices paid by final users can be seen in figures 6.7 through 6.13 in chapter 6. The steady decline in relative energy prices in the 1950s and 1960s enhanced the profitability of energy-using industries compared with the energy-producing ones, which shows up in a comparison of the relative rates of return. Table 7.1 compares the average annual rates of return on an equity basis for the oil and gas industry, the petroleum and coal products industry, total manufacturing, and finally, all industries combined. Rates of return are here calculated as net after-tax profits (including extraordinary gains or losses) divided by the book value of shareholder equity (paid-in equity plus retained earnings). The data in table 7.1 indicate that rates of return in the oil and gas industry were lower than in the manufacturing industries (or indeed all industries combined) during the 1960s and early 1970s. After 1975, however, the increase in relative energy prices, although dampened by the increase in the industry's tax burden, was particularly favourable to the upstream oil and natural gas industry, and rates of return within the industry rose substantially. Rates of return in the other industries in table 7.1 rose as well, but generally to a lesser degree. This increase in relative energy prices in the mid-1970s, and its impact on relative profitabilities, helped provide incentives to shift investment from energy-using industries like manufacturing to energy-producing industries like oil and gas.

Oil- and Gas-Related Activities

In the preceding section, we discussed how investment shifted from one industry to another. This section examines how investment patterns within

[1] This was when the 65 percent BTU-parity rule was implemented for domestically consumed gas, and when export revenues began to suffer because of the emerging gas bubble in the United States.

Figure 7.3a Gross and After-Tax Wellhead Prices for New Crude Oil Production
(annual data)

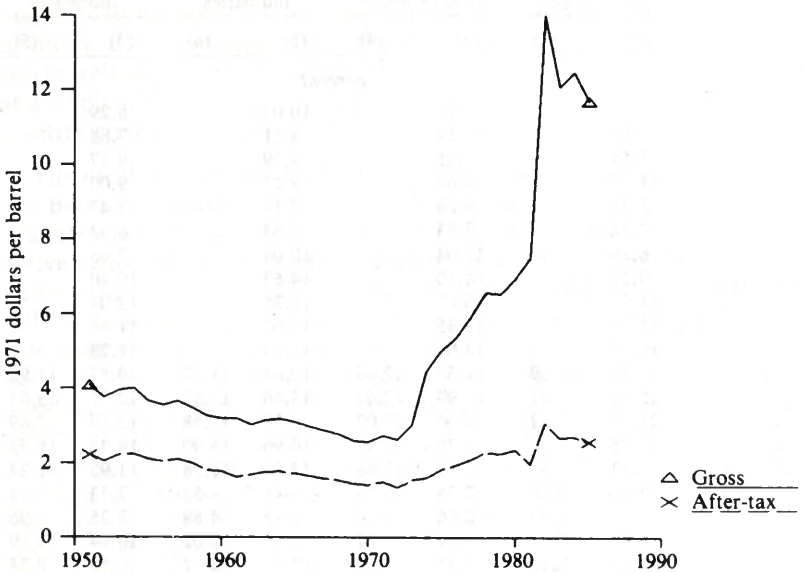


Figure 7.3b Gross and After-Tax Field Prices for New Natural Gas Production
(annual data)

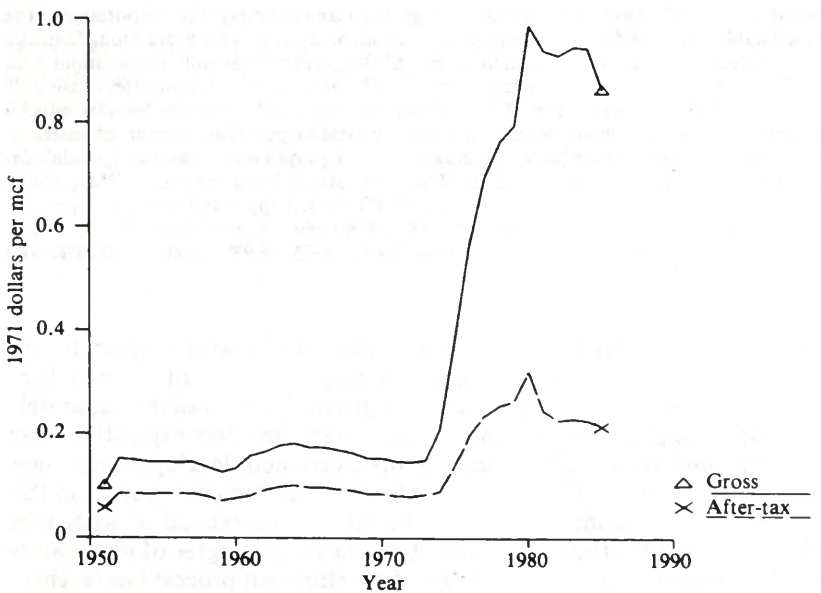


Table 7.1 Comparisons of Annual Rates of Return

Year	Oil and gas		Petroleum and coal products		Manufacturing industries		All industries	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				percent				
1966	6.67		8.71		10.04		8.29	
1967	7.65		7.54		8.51		7.88	
1968	7.59		9.05		9.29		9.17	
1969	11.25		4.63		9.28		9.00	
1970	5.35		9.09		7.18		7.47	
1971	6.52		9.63		8.83		8.93	
1972	6.29		11.04		10.04		7.66	
1973	9.31		14.10		14.63		10.40	
1974	11.11		16.83		16.25		13.04	
1975	15.78		13.45		12.65		11.40	
1976	16.46		14.05		11.61		11.28	
1977	17.29	20.09	12.37	12.86	10.63	11.57	10.83	11.92
1978	15.51	19.61	10.99	12.63	13.46	13.50	12.77	13.63
1979	21.36	24.42	16.00	21.02	16.18	17.58	15.19	17.89
1980	18.15	19.80	14.78	22.56	14.96	16.90	14.37	16.52
1981	7.93	10.53	12.10	11.68	13.25	11.58	11.90	11.24
1982	8.49	9.04	7.74	6.79	4.18	4.53	7.33	5.71
1983	8.00	3.90	2.56	6.40	7.93	8.88	8.25	7.96
1984	11.40	8.81	9.84	11.57	12.65	12.02	10.44	10.59
1985	9.00	9.10	8.55	9.89	10.47	10.57	9.50	9.74
1986	n.a.	−12.80	n.a.	6.88	n.a.	10.02	n.a.	8.51
1987	n.a.	6.35	n.a.	9.27	n.a.	9.34	n.a.	8.10

Notes and sources: n.a. means not available. Rates of return have been calculated as net after-tax profit (including extraordinary gains or losses) divided by total shareholder equity. Data in columns 1, 3, 5, and 7 are from Statistics Canada, *Corporation Financial Statistics*, catalogue no. 61-207, and include the entire Statistics Canada universe of corporations. The latest available data are for 1985. The data in columns 2, 4, 6, and 8 are from Statistics Canada, *Industrial Corporations*, catalogue no. 61-003, and include only corporations with $10 million or more in total assets. These quarterly data are available on a consistent basis only from 1977, and do not include the oil and gas industry separately from the broader mineral fuels category. The Petroleum Monitoring Agency (PMA) published similar estimates of upstream rates of return on the basis of average capital employed using Statistics Canada's *Industrial Corporations* quarterly publication. Their estimates as listed in Canada, PMA, *Canadian Petroleum Industry: Monitoring Survey 1986* (Ottawa: Supply and Services), appendix A-10, and *Canadian Petroleum Industry: 1987 Monitoring Report*, appendix A-13 are: 1981—7.2%; 1982—7.8%; 1983—8.1%; 1984—8.4%; 1985—6.9%; 1986—(−0.8)%; and 1987—6.7%.

the industry have changed over time, particularly with respect to the distribution of activity between oil and natural gas. One of the problems with such a task is that investment data are generally not available separately for oil and natural gas (with a few obvious exceptions, like expenditures on natural gas plants). In many cases, the discovery and development of new oil and gas reserves is a joint process. The random element involved in this process means that companies cannot be certain beforehand of what they will find when the investment is made. Obviously, the degree of uncertainty depends on which stage the discovery and development process has reached.

The outcome is far more certain for development than for exploration, and during the exploration process there is far more uncertainty during the preliminary stages, when the geological and geophysical work is undertaken, than during the later stages, when drilling is under way. The degree of uncertainty also depends on the level of aggregation. The outcome for a single well may be highly uncertain, but for the western sedimentary basin as a whole, there are clearly oil-prone and gas-prone regions, and firms have a better chance *on average* of finding what they are looking for.

The ideal way of allocating investment between oil and gas would be on the basis of company intentions, but since these data are not usually available, other means must be found.[2] Figure 7.4 shows a number of alternative measures of intent ratios: exploration wells completed, development wells completed, exploration metres drilled, and finally, total metres drilled. Arguments can be made that measures based on metres drilled provide a more accurate allocation of costs than ones based on the number of wells, or that development drilling is a more accurate reflection of intentions than is exploration, since the end-product is more certain. Measures based on exploration alone (whether metres drilled or wells completed) tend to have the lowest oil intent ratios, while development-based measures show the highest. Despite these differences, the overall pattern is similar for all four measures. Oil investment accounted for the bulk of investment until the mid-1960s (over 80 percent). It fell sharply through the late 1960s and early 1970s and then recovered in the second half of the 1970s and the early 1980s.

The shift from oil-related to gas-related activities is one of the most prominent features of the 1970s, and although a more detailed quantitative assessment is given in chapters 8 and 9, some preliminary observations can be made here. As chapters 3 and 4 have shown, the market prospects were much better for oil than for natural gas during the 1950s, and natural gas was frequently flared off as a waste product. Data on reserve prices calculated by Uhler[3] suggest that reserve prices for natural gas in Alberta were in fact negative until the 1960s; it is not surprising therefore that producers concentrated their efforts on finding and developing crude oil reserves. In the 1960s, natural gas prices improved somewhat and by-products like sulphur and natural gas liquids became important sources of revenue.[4]

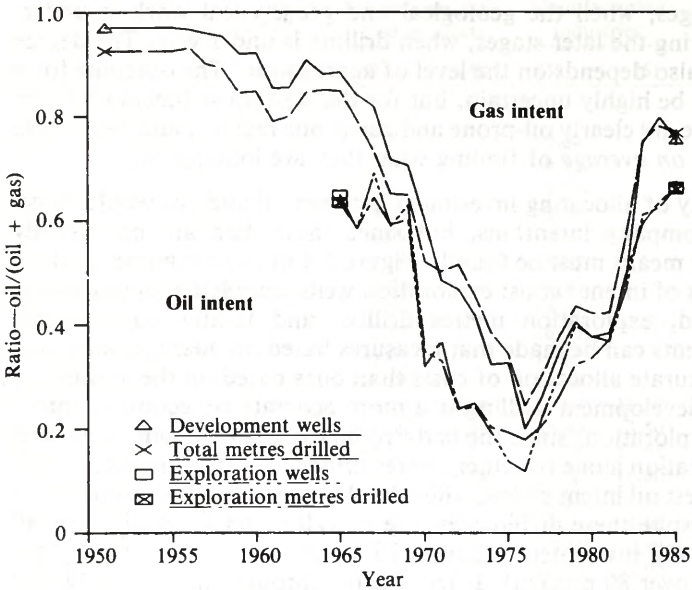
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[2] It should be noted that if the discovery and development of oil and gas is truly a joint process, then *any* ex post allocation of investment between oil and gas will be arbitrary.

[3] See Russell S. Uhler (with Peter C. Eglington), *The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin*, a study prepared for the Economic Council of Canada (Ottawa: Supply and Services, 1986), 58-60, tables A-1 and A-3. Reserve prices are equal to the discounted flow of expected future revenues net of all costs and taxes per unit of reserves. The after-tax producer prices in figures 7.3a and 7.3b form part of the calculation, but reserves prices also take into account capital and operating costs, along with expected increases in future prices.

[4] Ibid. Uhler has incorporated these into his reserve price estimates, but they are not included in our series for field prices in figure 7.3b.

Figure 7.4 Intent Ratios
(annual data)



As outlined in chapter 4, threatened natural gas shortages in the United States in the late 1960s created opportunities for Canadian exports. The concern in the early 1970s over potential supply shortages in Canada (see chapter 4, figures 4.2a and 4.2b) and the NEB's refusal to authorize more long-term exports also provided a stimulus for gas-directed activities even though field prices were relatively flat in real terms during this period. Although the proportion of industry activity directed toward natural gas reached its peak in 1976 (the year after the NEB released its most pessimistic forecast of future supply conditions), the number of exploration and development gas well completions continued to climb in the late 1970s and far outstripped oil completions (see chapter 2, figures 2.12, 2.13, 2.16, and 2.17).

The prospects for expanded natural gas markets appeared buoyant in the late 1970s. In 1978, the US Federal Power Commission (FPC) approved large increases in imports of western Canadian gas in conjunction with the construction of the southern Alberta segment of the proposed Alaska natural gas pipeline. In addition, proposals were put forward to expand the domestic market by extending the natural gas pipeline from Montreal to the maritime provinces.

Natural gas prices also increased relative to crude oil during this period: export prices increased sharply during the 1970s (and the benefits flowed through to producers, which they did not do in the case of oil), and domestic gas prices rose. Between 1972 and the peak of the upstream investment boom in 1980, the average wellhead price of crude oil in western

Canada increased by 264 percent in real terms, compared with a real increase of 670 percent in the field price of natural gas.

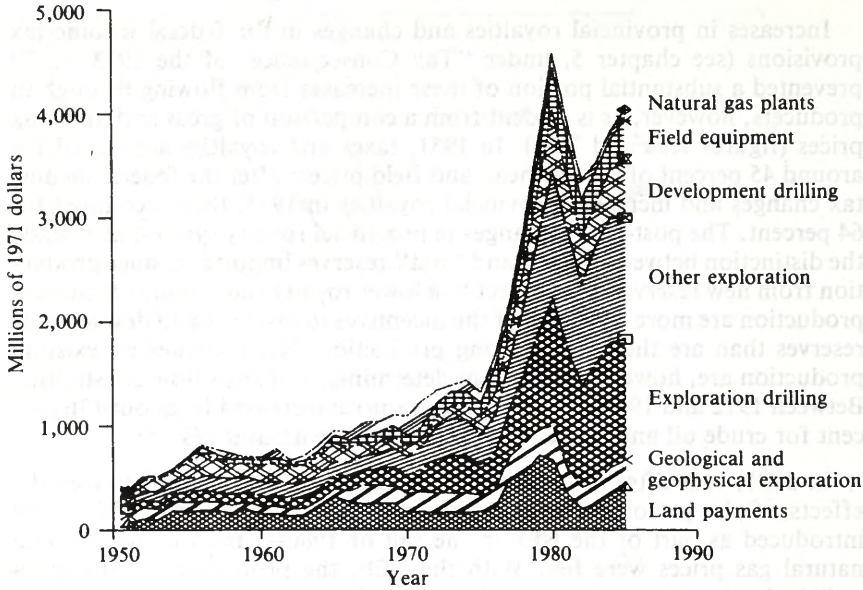
Increases in provincial royalties and changes in the federal income tax provisions (see chapter 5, under "Tax Consequences of the 1973 . . .") prevented a substantial portion of these increases from flowing through to producers, however, as is evident from a comparison of gross and after-tax prices (figures 7.3a and 7.3b). In 1951, taxes and royalties accounted for around 45 percent of the wellhead and field prices; after the federal income tax changes and increased provincial royalties in 1975, they accounted for 64 percent. The post-OPEC changes in provincial royalty systems also made the distinction between "new" and "old" reserves important, since production from new reserves was subject to a lower royalty rate; returns from new production are more reflective of the incentives to discover and develop new reserves than are those for existing production. Net revenues on existing production are, however, important determinants of cash flow constraints. Between 1972 and 1980, the real after-tax price increased by about 176 percent for crude oil and by nearly 400 percent for natural gas.

In 1981, real after-tax prices fell for both oil and natural gas as the effects of the petroleum and gas revenue tax (PGRT)—which had been introduced as part of the NEP in the fall of 1980— and the drop in real natural gas prices were felt. With the NEP, the proportion of the gross wellhead price going to taxes and royalties increased to about 74 percent. The pronounced 1981-82 recession in economic activity compounded these effects, and total development and exploration expenditures both fell sharply in these two years (figure 7.5). Despite this fall in expenditures, the share of oil and gas investment in relation to aggregate investment actually increased, as was shown in figure 7.2. Although oil exploration completions in western Canada dropped in 1981, the decline in development expenditures was not as steep. Virtually all of the decline in development expenditures, as well as most of the decline in exploration completions, was attributable to natural gas.

One of the objectives of the NEP was to provide consumers with incentives to shift from oil products to natural gas. This was to be achieved in part through the lowering of relative natural gas prices. The formal introduction of the 65 percent BTU-parity pricing rule in the 1981 energy agreements reinforced this off-oil policy, while the introduction of the new oil reference price (NORP) at the end of 1981 further enhanced the attractiveness of new oil production relative to natural gas. At the same time, natural gas producers were facing serious marketing problems. The pipeline proposal to eastern Canada was scaled down in the early 1980s and, even more important, natural gas exports to the United States were being severely squeezed. Export volumes fell both in absolute terms and relative to their authorized levels as the effects of natural gas deregulation in the United States began to take hold.

The drop in natural gas exploration activity and development expenditures in the early 1980s was clearly a key factor behind the industry

Figure 7.5 Capital Expenditures by Category
(annual data)



downturn, and when activity began to recover in 1982-83, oil—not natural gas—was the driving force. After falling sharply from their 1980 peak, completions of natural gas exploration wells remained more or less constant from early 1982 through 1986. Oil exploration completions, on the other hand, increased steadily and, by 1983, outnumbered gas completions. Development activity showed an even more pronounced shift from natural gas to oil. Starting in early 1983, development completions of oil wells in western Canada far outstripped natural gas completions.

The sharp fall in world oil prices at the beginning of 1986 appears to have had a greater impact on oil-related activities than on natural gas, judging by the drilling data presented in chapter 2, figures 2.12 through 2.17. Exploration completions dropped sharply for oil in early 1986 but remained more or less constant for natural gas. Although natural gas export prices were strongly influenced by the drop in world oil prices, domestic prices were frozen at 1984 levels for most users as a result of the 1985 natural gas agreement (see chapter 4, under "The Agreement on Natural Gas Markets and Prices"). Development completions, however, dropped sharply for both oil and natural gas.

Disaggregation of Investment Expenditures

Investment patterns within the industry have changed with respect not only to their division between oil and natural gas but also to their division among different categories of expenditure, as figure 7.5 shows. The broad division

between total exploration (including land payments, which are not considered investment expenditures under national accounts definitions) and development expenditures shows that the proportion of exploration expenditures tended to be higher in the 1950s, when the industry was just getting under way, dropped somewhat in the 1960s, and then rose again following the OPEC price shock of 1973-74.[5] This tendency is even more pronounced if the frontier regions are excluded, because exploration expenditures in western Canada (excluding land payments) fell from around 55 percent of total upstream expenditures in the mid-1950s to as low as 30 percent in the early 1970s.

Land payments have been among the most volatile components of exploration-related expenditures. They dropped as a proportion of exploration expenditures during the 1960s, increased in the late 1970s, and then fell sharply in 1981. The relative importance of geological and geophysical expenditures has tended to decline over time, while drilling costs have accounted for an increasingly large proportion of exploration spending. Drilling costs accounted for more than one-half of total development spending in the 1950s but then declined somewhat in relative importance until the late 1970s. Expenditures on field equipment, on the other hand, have grown steadily in importance.

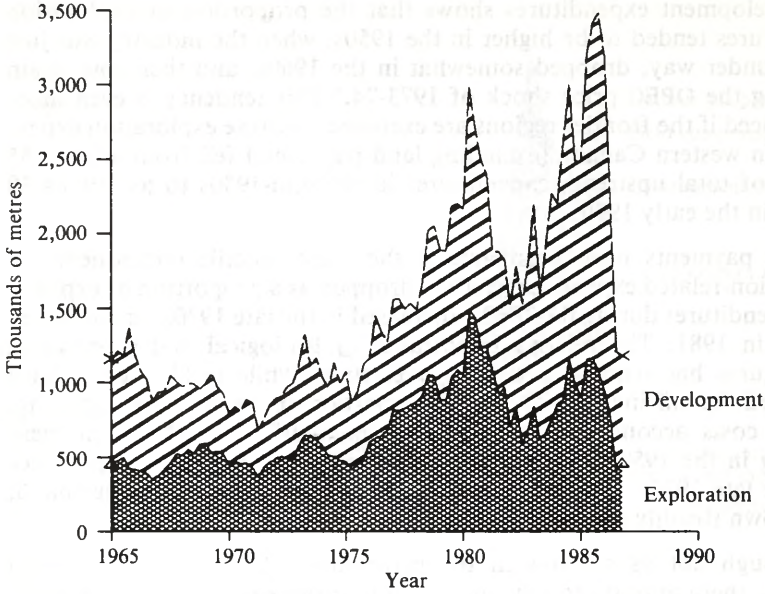
Although not as obvious in the expenditure data as in the drilling statistics, there appears to have been a shift from exploration to development activity in western Canada in the 1980s. On average, development expenditures accounted for 45 percent of total expenditures between 1973 and 1981, but this increased to 50 percent in the 1982 to 1985 period. A comparison of the exploration and development metres drilled in western Canada shows an even more pronounced shift toward development activity starting in late 1982 (figure 7.6).

During this period, both the federal and provincial governments introduced incentives for enhanced oil recovery (EOR) projects: the NORP was extended to all such projects in the 1982 NEP update, and the PGRT was eliminated on new EOR projects until capital costs had been recovered. In addition to these incentives, Alberta royalties on EOR projects were about 5 percent compared with the roughly 30 percent payable on conventional new oil. High-cost oil that had been discovered in previous years was now profitable to develop. In mid-1983, the amendment to the 1981 energy agreements extended the NORP to oil produced from infill drilling in old pools, providing even more incentives for drilling development oil wells.

With deregulation and the phasing out of the PGRT, the western accord modified the relative value of some of these incentives. Nevertheless, the trend toward development-related activities continued after the accord. Total development expenditures increased much more rapidly than total exploration spending between 1984 and 1985 (32.9 percent versus 5.9 per-

[5]The pattern is similar if land payments are excluded from exploration expenditures.

Figure 7.6 Exploratory and Development Metres Drilled, Western Canada
(quarterly data)



cent), and development drilling activity remained strong. Completions of development wells had averaged around 60 percent of the total in western Canada from the mid-1970s to the early 1980s. In the last quarter of 1982, development completions jumped up to 70 percent of the total and remained at about that level until early 1986, when the effects of the collapse in world oil prices were first felt. The proportion of oil completions peaked at 78 percent in the last quarter of 1983, fell back to around 66 percent in the third quarter of 1984, and then remained at that level until early 1986.

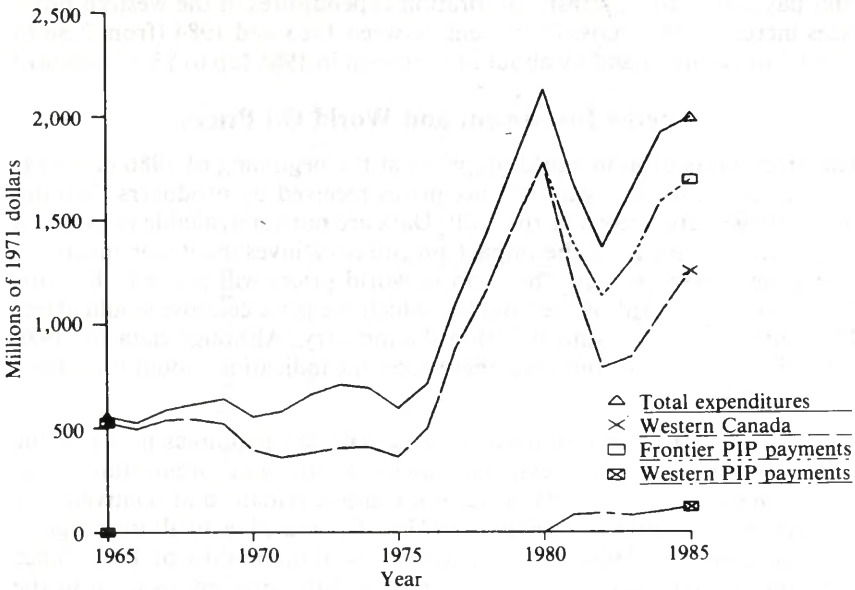
Investment in the Frontier Regions[6]

The location of industry activity has also changed significantly over time, especially for exploration, as western Canada has continued to account for 90-95 percent of all development expenditures. Until the mid-1960s, virtually all exploration was carried out in western Canada, but in the early 1970s, there was a shift away from the western sedimentary basin toward the frontiers (figure 7.7). Interest in northern Canada reached a high point in the early 1970s with the proposed Mackenzie Valley gas pipeline and predictions that Canada would require arctic gas by the 1980s. By the time the Berger inquiry recommended a 10-year moratorium on the construction of such a pipeline in 1977,[7] exploration expenditures in northern Canada

[6]These and related issues are discussed in more detail in chapter 9.

[7]See Thomas R. Berger, *Report of the Mackenzie Valley Pipeline Inquiry: Northern Frontier and Northern Homeland*, 2 vols. (Ottawa: Supply and Services, 1977).

Figure 7.7 Real Exploration Expenditures by Location
(annual data)



had dropped from their peak of over 30 percent of total expenditures on oil and gas exploration in Canada to just under 17 percent. The introduction of superdepletion in 1977, however, acted to moderate this fall in exploration activity in northern Canada and in frontier areas generally.

Figure 7.7 shows that exploration expenditures on the Canada lands started to increase in 1981, even though total exploration expenditures were down. The rise in world oil prices following the second OPEC price shock had certainly increased the potential profitability of frontier production, and the implementation of the petroleum incentives program (PIP) significantly reduced the costs of frontier exploration for Canadian-owned companies. This program, which replaced the previous tax-based incentives with a system of cash grants, was designed to favour exploration by Canadian-owned companies in frontier areas and provided for grants of up to 80 percent of eligible exploration costs. As the figure also shows, the federal government, through the PIP, made a significant contribution to frontier exploration expenditures.

In the light of this, the western accord's announcement that PIP grants would be phased out could well be expected to reduce frontier activity levels, although the full impact might be delayed as companies tried to fulfill existing drilling commitments before the program was phased out. There was no obvious drop in drilling activity in northern Canada or in the east coast offshore region between 1984 and 1985, but exploration expenditures in these two regions fell by over 14.5 percent (from 2.43 to 2.08

billion dollars). The drop is particularly severe for expenditures on preliminary exploration work—geological and geophysical operations, and land payments. By contrast, exploration expenditures in the western provinces increased by almost 25 percent between 1983 and 1984 (from 2.36 to 2.94 billion dollars) and by about 21.5 percent in 1985 (up to $3.57 billion).[8]

Energy Investment and World Oil Prices

The precipitous drop in world oil prices at the beginning of 1986 had a far greater impact on the real after-tax prices received by producers than did either the western accord or the NEP. Data are not yet available to permit a complete assessment of the impact on industry investment nor indeed to determine how permanent the drop in world prices will prove to be. One issue to arise from this is the extent to which the price collapse would affect different types of investment within the industry. Although data for 1986 are preliminary and incomplete, there are some indications about the effects on the industry.

Bonus bids and exploration drilling activity are two areas in which the industry tends to respond relatively quickly to changing circumstances. As figure 7.8 shows, bonus bids in western Canada remained at relatively low levels before shooting up rapidly in 1977.[9] After reaching an all-time high in the first quarter of 1980, they fell sharply until the middle of 1983. Since then, bonus bids have increased steadily until the precipitous drop in the first quarter of 1986 (from $233 million in the fourth quarter of 1985 to $112.8 million in the first quarter of 1986) as companies responded to the fall in world oil prices.

Table 7.2 shows the actual and intended investment expenditures for different sectors within the upstream oil and gas industry between 1980 and 1986. Each year, Statistics Canada conducts two surveys to determine industry investment intentions. One is conducted in the late fall and early winter to obtain preliminary estimates of investment intentions for the coming year. The second is conducted in late spring to obtain revised estimates of investment intentions for the current year and preliminary actuals for the previous year. The data therefore provide estimates of what capital expenditures companies were planning to undertake in 1986, before the impact of the world price collapse made itself felt, and they give some indication of the importance of the price collapse to investment in 1986. The data in table 7.2 suggest that, if the 1986 preliminary investment intentions of companies had been realized, capital expenditures in that year would have been lower than 1985 levels by about 4.5 percent over all (in nominal terms). Furthermore, this fall in oil and gas investment would have been broadly based since all upstream sectors, with the exception of non-conventional crude oil, would have shown decreases.

[8]The data are from Statistics Canada, *The Crude Petroleum and Natural Gas Industry*, catalogue no. 26-213, 1984 and 1985.

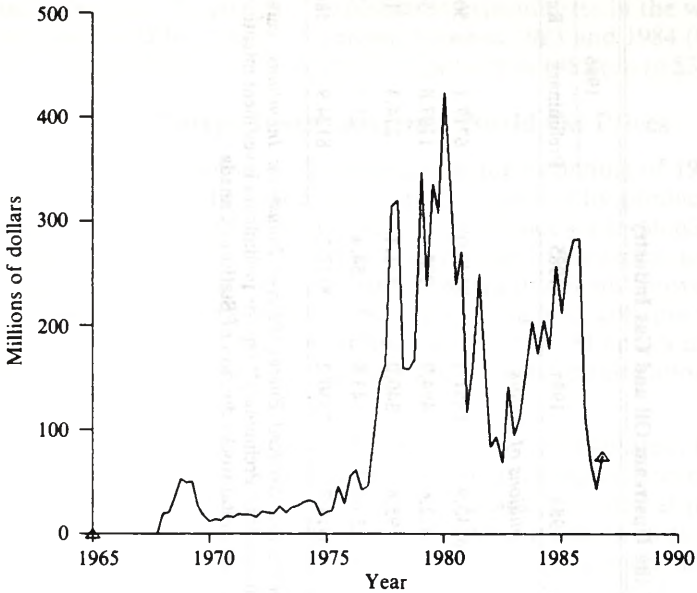
[9]This jump in the series is probably related to a 1976 change in Alberta's policy on the allocation of exploration and production rights on Crown land.

Table 7.2 Investment in Different Sectors of the Upstream Oil and Gas Industry

	1980	1981	1982	1983	1984	1985	1986 Preliminary	1986 Revised
				millions of dollars				
Conventional crude oil and natural gas production	5323.7	5903.8	6357.3	6140.9	6451.5	7140.0	6717.1	5060.9
Non-conventional crude oil	420.5	541.1	386.1	422.6	494.9	993.4	1107.8	548.6
Natural gas processing plants	311.5	311.6	522.8	195.8	340.0	331.4	274.3	165.8
Drilling contractors	197.7	274.9	173.5	155.4	43.8	54.4	25.7	26.1
Total upstream	6253.4	7031.4	7439.7	6914.7	7330.2	8519.2	8124.9	5801.4

Source: Statistics Canada, *Investment Statistics—Manufacturing Sub-Industries and Selected Energy Related Industries: Intentions*, catalogue no. 61-214. Figures reported for 1980 to 1985 are for actual investment; the column headed "Preliminary" reports preliminary investment intentions for 1986. Revised intentions for 1986, under "Revised," were obtained directly from the capital stocks division of Statistics Canada.

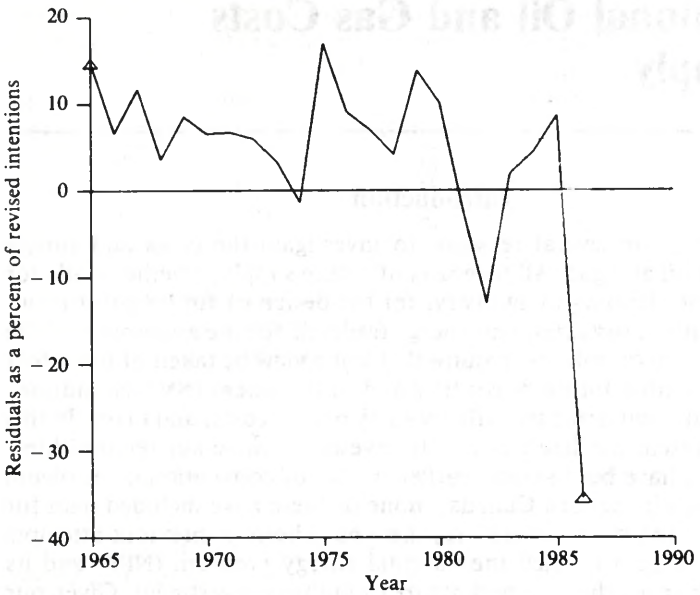
Figure 7.8 Land Sale Bonuses, Western Canada
(quarterly data)



The difference between the Statistics Canada preliminary and revised investment intentions for 1986 provide an indication of the impact of the collapse in world oil prices. These estimates, reported in table 7.2, suggest a drop of nearly 25 percent in expenditures in the conventional oil and gas sector, more than 50 percent in the non-conventional sector, and almost 40 percent for natural gas processing plants. It should be noted, however, that preliminary investment intentions are usually subject to revisions. In order to assess the importance of this under normal conditions, we have regressed the revised investment intentions on preliminary intentions over the 1965 to 1986 period and graphed the residuals in figure 7.9. On average, the revised intentions are about 97 percent of the initial intentions, but in 1986 the revised intentions are only 71 percent of the initial. As is evident from figure 7.9, the error of the equation in 1986 far outstrips anything within historical experience, including the effects of the NEP or the 1981-82 recession.

In the next chapter, we present some of our attempts to assess the determinants of industry investment. They tend to support the notion that higher prices increase oil and gas investment, not only by increasing the incentives to invest, but also because the new higher-cost sources require more investment, on average, than did past discoveries.

Figure 7.9 Regression Residuals: Revised Versus Preliminary Investment Intentions, Oil and Gas
(annual data)



8

Conventional Oil and Gas Costs and Supply

Introduction

It is important, for several reasons, to investigate the costs and supply conditions for oil and gas. All forecasts of future supply, whether made for the purposes of planning by industry, for the design of future government policy for taxation, royalties, and energy trade, or for the assessment of the consequences of past policies, require that some view be taken of the extent and cost of potential future discoveries and of the extent to which industry investment and discoveries are influenced by prices, costs, and taxes. In this chapter, we present our latest efforts to investigate these key relationships. Although there have been several earlier studies of conventional petroleum supply and costs in western Canada,[1] none of these have included data for the first half of the 1980s. Therefore, there have been no previous attempts to assess the extent to which the national energy program (NEP) and its aftermath influenced the pace and nature of industry investment. Given our need to explain investment and discoveries separately and consistently for crude oil and natural gas, our treatment is more integrated and aggregate than in other studies, which often consider individual regions or plays in order to deal with more clearly defined discoveries and geological structures.[2]

The major problem that researchers face in estimating the costs of oil and gas supply is that a large element of luck is involved in the search for deposits, especially at the exploration stage. This is complicated by the fact that significant discoveries in new exploration regions, which may be separated from other deposits by distance or depth, often lead to waves of

[1]Many of these studies are listed and compared by A.J. MacFadyen and Ken Foat, "Modelling Conventional Crude Oil Supply: Complexity in an Uncertain World," in A.J. MacFadyen and L.W. Copithorne, eds., proceedings of the conference *Strategy for Energy Policy* (Calgary: University of Calgary, Faculty of Continuing Education, 1985), 43-48.

[2]Some studies have emphasized the difficulties involved in applying geologically based models of cost and supply to aggregate data. See, for example, Russell S. Uhler, "Forecasting Petroleum Supply: Methods and Aggregation Bias," in Don Seastone and George Linder, eds., proceedings of the conference *The Economics of Oil and Gas Self-Sufficiency in Canada* (Calgary: University of Calgary, Faculty of Continuing Education, 1975), 49-54; and John R. Livernois and Russell S. Uhler, "Extraction Costs and the Economics of Nonrenewable Resources" (February 1987), 95 *Journal of Political Economy* 195-203. There are few options for us, however, as we need results at the aggregate level, but we shall flag any problems that are likely to arise from our use of aggregate relations. ("Play" is the term used in the oil and gas industry to refer to the extent of a petroleum-bearing formation.)

additional investment and discoveries in their wake. Thus the attempt to identify the extent to which longer-run costs of supply are rising as the resource base is exploited will be complicated by periodic surges of low-cost discoveries as new plays are identified. After a series of major plays, there may be a long period in which there are no important discoveries, giving rise to fears that there are no more large plays to be discovered. An additional complication, although a fortunate one, is that there is substantial though uneven technical progress in the discovery process, especially in the ability to obtain and analyze information from geophysical and seismic work. This technical progress may, like a run of favourable exploration luck, offset or obscure the longer-run increases in costs as the resource base is more fully explored and developed.

To deal with this situation, we have adopted a two-stage strategy. In the first stage, we estimate simple cost equations on the basis of a long series of data from the early 1950s until the mid-1980s, explaining the marginal real costs of additions to reserves in terms of cumulative discoveries. Although we expect that this relationship will explain only a small part of the year-to-year variation in discoveries, we hope that it provides a fairly robust measure of the extent to which costs are rising as the discovery process goes on.

In the second stage, we make use of these estimated marginal costs to specify and estimate a model of the exploration and development investment decisions of the oil and gas industry. In this model, we explain expected discoveries (which are defined as actual investment spending divided by the estimated marginal costs of reserve additions) by the variations in the expected profitability of discoveries (defined as the ratio of the net-of-tax wellhead or field value of new reserves to the amortized after-tax marginal cost of exploration, development, and production). The influence of other factors, such as cash flow constraints and the expected lag between discovery and extraction, is also tested. We then develop some preferred alternatives that establish causal links from land payments to subsequent exploration and development investment.

Each of these two stages will be the focus of a separate section of the chapter. After these results have been presented, we shall use the same model to explain the year-to-year changes in bonus bids and other land payments made by producers to obtain exploration and production rights. Although these bonus bids and other land payments are quite properly considered by firms as part of their costs in obtaining oil and gas reserves, they are not part of the physical costs of exploration and discovery and hence do not appear in the cost equations estimated earlier. They are needed for our analysis, however, because the vast majority of the oil and gas deposits in western Canada belong to the provinces, and these land payments are an important and highly variable component of the oil and gas revenues of the provincial governments. Modelling these payments should be an important part of the analysis of any major changes in taxes and royalties, because changes in tax and royalty revenues may be largely offset by changes in land

payments, since expected taxes and royalties influence the bids that are submitted to the periodic auctions held by the governments of the producing provinces.

After presenting the evidence on costs, investment, and land payments, we continue with a brief description of our attempts to explain operating costs to complete the description of our quantitative evidence on the economic determinants of the supply of crude oil and natural gas from western Canada. These relationships will then be used, in conjunction with the demand modelling already described in chapter 6, to analyze the consequences of alternative tax and royalty policies, as well as the effects of alternative price paths, in chapters 10 and 11.

Estimating the Costs of Reserve Additions

The two panels of figure 8.1 show the actual and estimated unit costs of reserve additions for crude oil and natural gas in western Canada plotted against cumulative reserve additions.[3] The costs are in constant (1971) dollars per barrel of crude oil, or per thousand cubic feet (mcf) of natural gas, and are equal to total expenditures on exploration, development, and geophysical work.[4] The reserve additions comprise new discoveries plus revisions and extensions of discoveries previously recorded. Although some studies "credit back" revisions and extensions to the years in which the initial exploration work was done, we think it more appropriate to match the reserve additions to the subsequent exploration and development drilling that led to their recognition.[5] The measured costs vary a great deal from year to year, partly because there have been important swings in investment

[3] We choose to call these "marginal" costs to emphasize the fact that we are using aggregate data, and that these represent the unit costs of reserve additions *in each year*, not weighted averages of such costs over time.

[4] To simplify the terminology, these costs will be referred to as "exploration and development" or "capital" costs. Please note that the deflator used here is the economy-wide price of final demand (or absorption). Increases in the marginal costs shown in the figure can thus be due to either increases in the volume of drilling or the relative price of drilling services.

[5] The "crediting back" procedure, without allowance for the expected appreciation of reserves discovered in recent years, is used by John R. Livernois and David L. Ryan, "Testing for Non-Jointness in Oil and Gas Exploration: A Variable Profit Function Approach" (mimeograph, University of Alberta, Department of Economics, Edmonton, 1987, and in a forthcoming issue of the *International Economic Review*); and John R. Livernois, "Estimates of Marginal Discovery Costs for Oil and Gas," (May 1988), 21 *Canadian Journal of Economics* 379-93. One complication raised by our procedure is that in some years the revisions and extensions have been negative and occasionally larger in size than new discoveries. If special precautions were not taken, this would produce the anomalous result that the costs of reserve additions appeared negative, since positive investment would be divided by negative reserve additions. The problem was reduced by using the data of the Alberta Energy Resources Conservation Board (AERCB) for reserve additions in Alberta, and combining these series with Canadian Petroleum Association (CPA) data for reserve additions in other provinces. We dealt with the remaining negative observation, for crude oil in 1976, by leaving it out of the data sample used for estimating the marginal cost equation for crude oil. The actual data and methods are described in the data appendix and the appendix on data sources and explanations for the figures.

Figure 8.1a Marginal Costs for Crude Oil
(annual data)

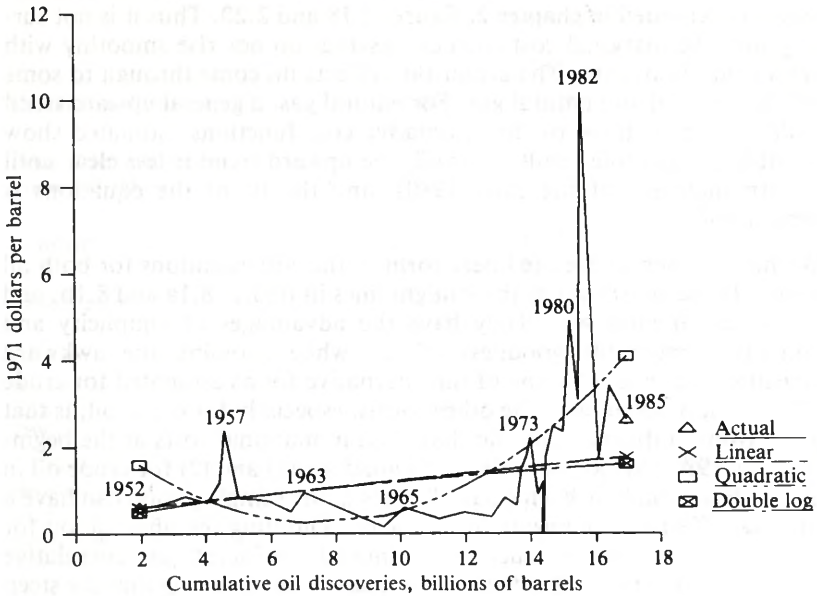
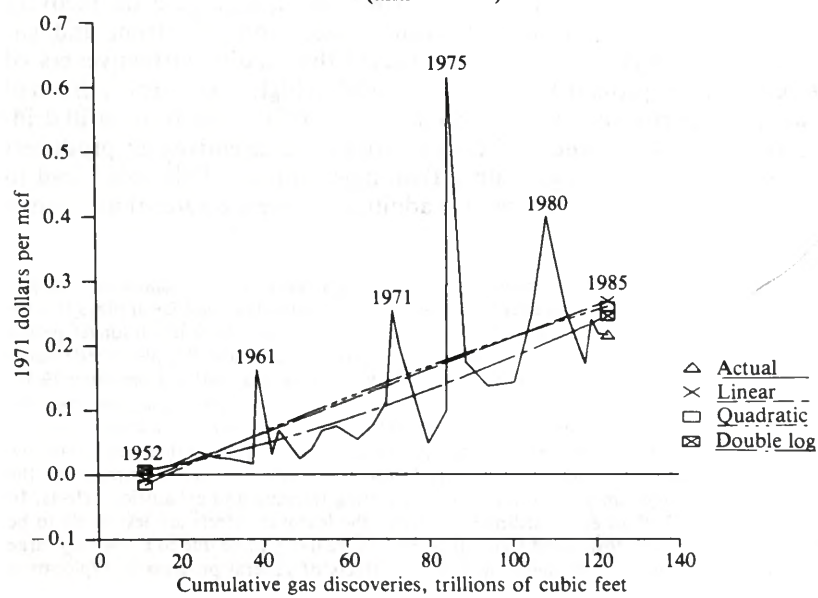


Figure 8.1b Marginal Costs for Natural Gas
(annual data)



(as recorded in chapter 7), but more importantly because, for the reasons discussed above, there have been large variations in the net additions to reserves, as recorded in chapter 2, figures 2.18 and 2.20. Thus it is not surprising that the marginal costs of new reserves do not rise smoothly with accumulated discoveries. The exhaustion effects do come through to some extent for both oil and natural gas. For natural gas, a general upward trend is evident, and all three of the alternative cost functions estimated show reasonably comparable results. For oil, the upward trend is less clear until the sharp increases of the early 1980s, and the fit of the equations is extremely poor.

We have chosen to use the linear form of the cost equations for both oil and gas.[6] These are shown as the straight lines in figures 8.1a and 8.1b, and are reported in table 8.1. They have the advantages of simplicity and reasonably comparable goodness of fit, while avoiding the awkward forecasting properties of some of the alternative forms estimated for crude oil. The main problem with the other forms, especially for crude oil, is that they are overly influenced by the sharp rise in marginal costs at the beginning of the 1980s. As a comparison of equations (1) and (2) for crude oil in table 8.1 shows, making even small changes in the sample period can have a substantial effect on the results for crude oil. Omitting the observation for 1982, an obvious outlier, cuts the estimated coefficient on cumulative discoveries by one-third. Are there other reasons for thinking that the steep rise in observed costs in the early 1980s may overstate the costs of finding and developing new reserves?

In chapter 7, we discussed the boom in oil development drilling that occurred in the early 1980s. Several of the 1982 policy changes—the extension of the new oil reference price (NORP) to all enhanced oil recovery (EOR) projects, lower provincial royalty rates, and petroleum and gas revenue tax (PGRT) concessions—increased the relative attractiveness of EOR projects and provided incentives to develop high-cost reserves that had already been discovered. The extension of the NORP to oil from infill drilling in old oil pools in June 1983 created even more incentives for producers to invest in existing reserves rather than new supplies. This could lead to higher observed costs for new reserve additions, since a greater-than-normal

[6]The use of the linear form implies that, at the aggregate level, "exhaustion" effects outweigh "learning" effects. Research has shown that for individual geological plays there is often an initial stage where the learning effect dominates, followed by a much longer period where exhaustion effects dominate. See Russell S. Uhler, "Costs and Supply in Petroleum Exploration: The Case of Alberta" (February 1976), 9 *Canadian Journal of Economics* 72-90. The quadratic form graphed in figure 8.1a shows a substantial drop in marginal costs over the first 8 billion barrels of cumulative discoveries, followed by a several-fold increase over the next 8 billion barrels. We think that the shape of this curve is too much influenced by the low discoveries and negative revisions of the early 1980s to provide reasonable estimates of the relative importance and timing of the possibly offsetting learning and exhaustion effects. In addition, at the level of an entire sedimentary basin the learning effects are less likely to be applicable, and the early downward trend of costs is more likely to be due to a few very large discoveries, as described in chapter 2, and to the effects of general progress in exploration technology.

Table 8.1 Regressions Explaining Marginal Capital Costs for Crude Oil and Natural Gas

	Crude oil			
	(1)	(2)	(3)	Natural gas
Cumulative discoveries	0.1681	0.1156	0.07807	0.002454
	(2.80)	(3.45)	(1.51)	(5.05)
Price differential between new and old oil	—	—	16.067	—
			(4.42)	
Constant	−0.10964	0.1937	0.4517	−0.03457
	(0.16)	(0.51)	(0.80)	(0.96)
Sample period	1952-75, 1977-85	1952-75, 1977-81, 1983-85	1952-75, 1977-85	1952-85
$\bar{R}^2$	0.1757	0.2601	0.4846	0.4267
SEE	1.6823	0.9219	1.3302	0.0978
DW	1.6521	0.9800	1.4215	2.0695

Notes: In all of these equations, the dependent variable is real expenditures on exploration, development, and geophysical work per unit of reserve additions. The absorption price was used as deflator. Linear forms of the equations were used in estimation. t-statistics are in parentheses. SEE and DW are estimation statistics: SEE—standard error of the estimate; DW—Durbin-Watson statistic.

Sources: The key data series that went into the construction of all variables used here are reproduced in the data appendix. See also the notes to figures 8.1a and 8.1b in the appendix containing data sources and explanations for the figures.

proportion of the investment would be directed at existing reserves, rather than new additions. Beginning in 1982, we have represented the proportion of the observed capital costs associated with existing reserves by the relative price differential between new and old oil.[7] As equation (3) for crude oil in table 8.1 shows, the addition of this variable to the basic equation cuts the coefficient on cumulative discoveries by one-half (compared with the original equation), and substantially improves the fit of the equation.

In figures 8.1a and 8.1b, table 8.1, and the data appendix, we show the data and the estimation results of alternative specifications of the equations. In doing so, we seek to emphasize the uncertainty that must surround any estimates of marginal costs when there is so much uncertainty in the exploration process, and where the numbers for reserve additions are themselves uncertain and subject to much revision, even after the drilling results are known.

[7] As shown in chapter 3, figure 3.6, this differential was largest in 1982, the first year the NORP was introduced, and then decreased substantially in 1983 as old oil prices rose and the NORP fell. It was eliminated entirely when Canadian oil prices were deregulated in the spring of 1985.

Investment and Expected Discoveries

In studies of investment spending, it is quite common to develop some model of the desired capital stock and then to find some way of representing the process of adjustment whereby firms invest so as to close the gap between actual and desired capital stocks. Matters are more difficult when one is modelling investment in reserves of crude oil and natural gas, partly because it is less easy to derive a desired stock from a clearly defined model, and partly because the additions to reserves vary much more widely than the investment activity designed to achieve them. To deal with the problem of large random variation in reserve additions, we have defined a series, which we call expected reserve additions (or expected discoveries), equal to the actual level of investment spending[8] (in real terms) devoted to reserve additions divided by the estimated marginal costs of reserve additions based on the linear equations shown in table 8.1. The dimension of the resulting series is thus in terms of physical units of expected reserve additions, measured in millions of barrels for crude oil and trillions of cubic feet for natural gas.

As discussed in the previous section, it appears that the estimated marginal costs for crude oil reserve additions were strongly affected by a number of policies that tended to encourage investment in existing reserves but that are not a good reflection of the anticipated costs of new additions. Accordingly, in defining our expected reserve additions series for crude oil, we use a measure of the "adjusted" capital costs of new discoveries that excludes the costs of this extra investment.[9] The ratio of the total estimated capital costs (the fitted values from the relevant equations in table 8.1) to the adjusted capital costs of new reserves additions is then added to our estimated equation for expected crude oil reserve additions. If our cost equation from the previous section perfectly captured this extra investment, we would be able to remove this from our observed investment series to arrive at a "true" measure of expected reserve additions.[10] In practice, however, our estimate of the magnitude of this extra investment is not likely to be very precise, and therefore we allow the ratio of estimated to adjusted costs to enter the equation for expected crude oil discoveries independently, to account directly for the proportion of investment that is directed at existing reserves.

Our series for expected reserve additions of crude oil and natural gas differ from the conventional series for investment spending because our figures show a smaller upward trend, since they show the effects of marginal costs rising as discoveries accumulate. We show our expected discovery series in the two panels of figure 8.2. The predicted values are

[8] We use the same sum of exploration, development, and geological expenditures, measured in constant 1971 dollars, that we used to measure marginal costs in the previous section.

[9] This is equal to the fitted value from the estimated marginal cost equation in the preceding section minus the coefficient on the price differential term multiplied by the differential between new and old oil prices.

[10] This is equivalent to restricting the coefficient on the ratio of estimated to adjusted costs to be equal to 1.0.

Figure 8.2a Investment and Expected Discoveries: Crude Oil
(annual data)

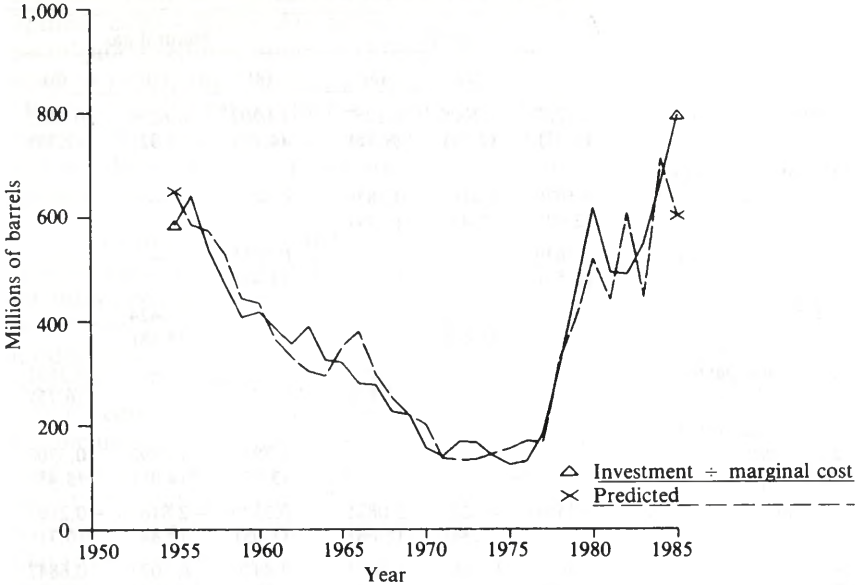


Figure 8.2b Investment and Expected Discoveries: Natural Gas
(annual data)

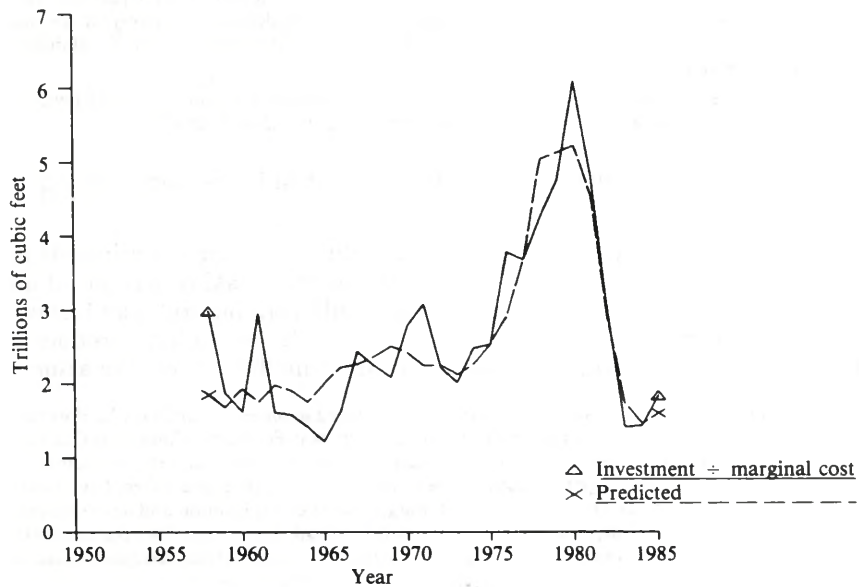


Table 8.2 Regressions Explaining Expected Discoveries for Crude Oil and Natural Gas

	Crude oil			Natural gas		
	(1)	(2)	(3)	(4)	(5)	(6)
Profitability ratio	1.7287	1.7006	1.1957	1.0202	0.6259	0.4165
	(4.42)	(7.32)	(9.88)	(4.43)	(2.92)	(2.39)
Ratio of estimated to adjusted capital costs	0.5070	0.4191	0.4839	—	—	—
	(2.92)	(2.42)	(5.59)			
Level of production	0.1639	—	—	0.7255	—	—
	(0.56)			(4.43)		
Cash flow	—	0.2045	—	—	0.6424	—
		(1.60)			(4.48)	
Lagged land payments	—	—	0.5585	—	—	0.3631
			(7.88)			(6.75)
Actual to authorized export ratio	—	—	—	0.7859	1.2890	0.6708
				(3.07)	(4.48)	(3.48)
Constant	4.9503	4.5242	3.0821	−0.5379	−2.8161	−0.2195
	(3.54)	(5.34)	(8.66)	(1.05)	(2.84)	(0.71)
$\bar{R}^2$	0.6921	0.7141	0.9053	0.4970	0.5023	0.6847
SEE	0.3047	0.2936	0.1690	0.3001	0.5023	0.2377
DW	0.7479	0.6617	1.5897	1.0380	1.0858	1.5678

Notes: In all of these equations, the dependent variable is the logarithm of expected discoveries. These series are defined as (the logarithm of) real expenditures on reserve additions (exploration, development, and geophysical work) divided by the fitted values from the marginal cost equations in table 8.1 for both crude oil (equation 3 in table 8.1) and natural gas. The absorption price was used as deflator. Double logarithmic forms of the equations were used in estimation. The profitability and export variables are defined as three-year moving averages. t-statistics are in parentheses. SEE and DW are estimation statistics: SEE—standard error of the estimate; DW—Durbin-Watson statistic.

Sources: The key data series that went into the construction of all variables used here are reproduced in the data appendix. See also the notes to figure 8.3 and table 8.1.

from the estimated equations, which are described below and reported in table 8.2.

Most other studies explain the desired additions to reserves primarily in terms of the expected after-tax value of the reserves, taking account of all taxes, royalties, exploration, development, and operating costs, and allowing for the fact that the revenues will accrue only over a long producing life.[11] We follow a similar approach, with some modifications. We assume

[11] Brian L. Scarfe, and Edwin W. Rilkoff, in their paper *Financing Oil and Gas Exploration and Development Activity*, Discussion Paper no. 274 (Ottawa: Economic Council of Canada, 1984), use real investment spending as their measure of industry activity, and then explain it by a measure of netback and one of output relative to reserves. Our procedure differs from theirs by developing and using an explicit measure of marginal cost of exploration and development, which is then used to transform investment data into expected discoveries. This permits us to define a profitability variable based on the ratio of the expected after-tax wellhead value of reserves to the marginal costs of exploration, development, and production.

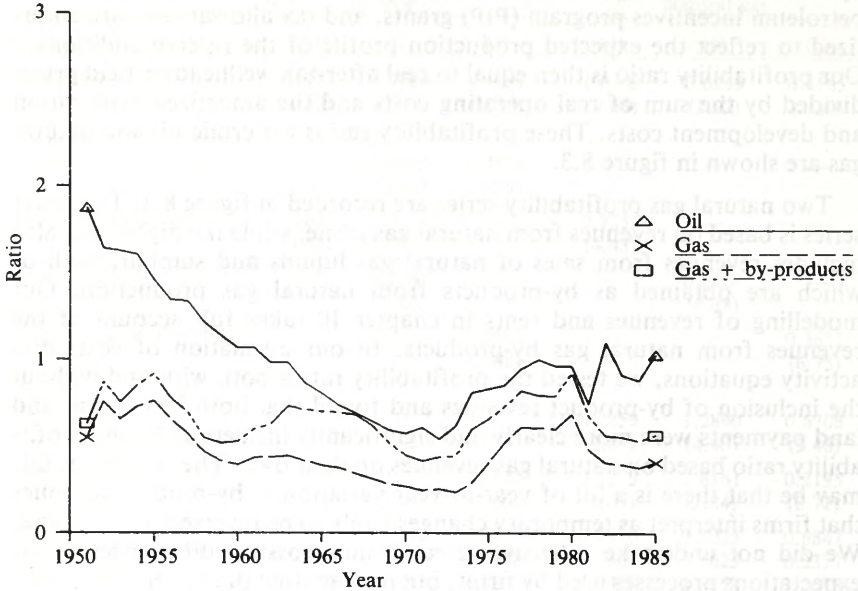
that producers expect future after-tax wellhead or field prices and operating costs to remain at their current levels in real terms.[12] Exploration and development costs—taking due account of the various investment incentives, petroleum incentives program (PIP) grants, and tax allowances—are amortized to reflect the expected production profile of the reserve additions.[13] Our profitability ratio is then equal to real after-tax wellhead or field prices divided by the sum of real operating costs and the amortized exploration and development costs. These profitability ratios for crude oil and natural gas are shown in figure 8.3.

Two natural gas profitability series are recorded in figure 8.3. The lower series is based on revenues from natural gas alone, while the higher one also includes revenues from sales of natural gas liquids and sulphur, both of which are obtained as by-products from natural gas production. Our modelling of revenues and rents in chapter 10 takes full account of the revenues from natural gas by-products. In our estimation of costs and activity equations, we tested the profitability ratios both with and without the inclusion of by-product revenues and found that both investment and land payments were more clearly and significantly influenced by the profitability ratio based on natural gas revenues on their own. The reason for this may be that there is a lot of year-to-year variation in by-product revenues that firms interpret as temporary changes likely to be reversed in the future. We did not undertake extensive research into possible differences in the expectations processes used by firms, but instead used the better-fitting profitability series for natural gas alone, thereby assuming that firms expect by-

[12] Some other studies have attempted to divide the historical period into subperiods during which future oil prices were expected to be stable or to grow at different rates. For example, Uhler assumes that investors making drilling decisions up to 1973 expected future nominal crude oil prices to be constant, whereas investors in 1974 and 1975 expected them to grow at 5 percent per annum, and from 1976 to 1981 (the end of his sample period) at 10 percent per annum. Producers are thus assumed to forecast future nominal oil prices and then discount them using a nominal rate to determine the present value of future production. See Russell S. Uhler (with Peter C. Eglington), *The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin*, a study prepared for the Economic Council of Canada (Ottawa: Supply and Services, 1986). By contrast, we have producers implicitly forecasting the future real value of crude oil and natural gas and then calculating their present values using a constant expected value for the real cost of capital. In choosing this option, we follow evidence indicating that firms making capital expenditures tend to treat the real cost of capital as a constant when deciding on the optimum level of the capital stock. Some of this evidence is reported in Timothy C.G. Fisher, Alan Chung, and John F. Helliwell, *A Translog Model of Aggregate Production and Variable Factor Utilization*, Discussion Paper no. 86-41 (Vancouver: University of British Columbia, Department of Economics, 1986).

[13] It is assumed that new crude oil reserves can be connected in the year of discovery. Once connected, these reserves are assumed to be produced at a constant rate (one barrel per day for every 5,000 barrels of new reserve additions) for 8 years, with production then declining at 15 percent per year over the remaining 15 years of production life. In the case of natural gas, however, it is assumed that new gas reserves cannot be connected until the year following their discovery. Once connected, these reserves are assumed to be produced at a constant rate (1 billion cubic feet per day for each 7,300 billion cubic feet of new reserve additions) for 14 years, with production then declining at 15 percent per year for the remaining 14 years of production life.

Figure 8.3 Profitability Ratios for Oil and Gas Net Wellhead Revenue Divided by Marginal Cost
(annual data)



product revenues on average to be equal to their historical mean value of about 40 percent of direct revenues from sales of natural gas.

Comparison of the profitability ratios for crude oil and natural gas is interesting but plagued with difficulties. The pattern shows high but declining profitability for crude oil until 1973, followed by subsequent increases. The ratios for natural gas are initially lower than for crude oil, with a slight declining trend until 1973; thereafter they show substantial increase until 1980. Difficulties are created by the need to allocate costs between crude oil and natural gas, which we do on the basis of the number of metres of development drilling for oil and natural gas, respectively.[14] As argued in chapter 7, most of the alternative methods of allocating costs between these two products would give similar results. There are two main reasons why the profitability ratio for natural gas is much lower than that for crude oil

[14] A parallel problem is posed by the fact that crude oil and natural gas are often joint products of the exploration process, in which case there is no straightforward way of allocating costs between the two products. The jointness arises in part because gas is often associated with crude oil in the same deposit, and in part because oil and gas deposits are often found in similar geological structures, so that either may be found in the course of a search for the other. Livernois and Ryan, supra footnote 5, however, present some statistical results showing, at least for their data and functional forms, that the hypothesis of non-jointness in the discovery processes for crude oil and natural gas could not be statistically rejected. Nonetheless, caution is warranted when making comparisons between our separate measures of profitability and investment for oil and gas.

from 1950 until the late 1960s. The primary reason, as explained in chapter 4, is that many of the early gas deposits were found in the process of searching for oil, and that much of the early production was of gas associated with oil. In the early days, this gas was often flared off, in the absence of pipeline access, and before it became more common to reinject gas to maintain pressure in oil reservoirs. Since natural gas was a by-product for which there were few alternative markets or uses, it is not surprising that its sales revenues did not cover the allocated costs of exploration, development, and production. A second reason for the lower profitability ratio is that by-product revenues are much more important for natural gas than for crude oil, as shown by the difference between the two gas profitability ratios in figure 8.3.

An additional complication is posed by the fact that there is sometimes an excess supply of crude oil or natural gas reserves, in the sense that current reserves are being produced at a lower rate than their owners would like.[15] As noted earlier, the profitability ratios are constructed on the assumption that reserve additions could have been brought into production within the first few years following their discovery. We therefore need to make some separate allowance for any expected further delays between discovery and market access, in the case of natural gas, or of the extent of market prorationing, in the case of crude oil.[16] We have considered three different ways of taking possible excess supply into account, in addition to whatever effect it might have on the market price. The first variable we considered was one measuring the ratio of production to the stock of reserves.[17] The disadvantage of this approach is that this ratio approaches infinity as the reserves approach exhaustion.

An alternative measure is provided by the level of production, which would represent desired additions to reserves if the reserve stocks at the beginning of the year had represented the levels that the producing firms wished to maintain. This procedure has the advantage that desired discoveries will eventually run down to zero as the reserves in the region approach exhaustion. We therefore use the current production level as our measure of the extent to which the profitability variable needs to be

[15] This has typically come about through the process of market prorationing for crude oil, as described in chapter 3, or through the lack of pipeline access or available markets, which has been more usually the case for natural gas, as described in chapter 4.

[16] A more desirable alternative would have been to incorporate the expected delays between discovery and production directly into the profitability ratio, but data limitations prevented us from doing so.

[17] These series are the inverses of the reserve life indices for crude oil and natural gas shown in chapter 2, figure 2.24. The reserve life indices are the ratios of reserves to production. Scarfe and Rilkoff, supra footnote 11, suggest that this is an appropriate way of capturing, in conjunction with a measure of profitability, the behaviour of firms aiming to maintain target stocks of reserves. These target stocks are defined in terms of current production levels and optimum ratios of reserves to production (with these optimum ratios being determined by a measure of profitability), while the actual ratios indicate the adequacy of the current stock of reserves. The analogy is thus made between the reserves targets of oil and gas firms and the inventory targets of firms in other industries.

adjusted for disequilibrium between actual and desired production (and between actual and target inventory stocks).

A further complication exists for natural gas, where the export market has traditionally provided the main outlet for production from new discoveries. To capture the potential impact of export market disequilibrium on the expectations of those making investment decisions, we use a variable measuring the ratio of actual exports to those authorized by the National Energy Board (NEB).[18]

In addition to the profitability of new discoveries, and the likely wait before new reserves can be brought into production, some firms may find their current exploration and development expenditure plans constrained by their current cash flow. This constraint may arise either if investment spending (and hence borrowing) is very large in relation to cash flows or if cash flows are so large as to weaken normal constraints and payback rules used to measure the desirability of new investments.

We have not yet addressed the issue of the timing of the effects of profitability and other variables on the pace of industry activity. It is to be expected that investment decisions will be essentially forward-looking, since it takes many months to plan, execute, and evaluate a drilling program, and drilling itself needs to be preceded by geological, geophysical, and seismic work, and requires the prior acquisition of drilling rights. Furthermore, successful discoveries take time to bring on stream, even if pipeline access is already close at hand, and the producing life of most oil and gas wells extends over a 20- to 30-year period.

In dealing with this issue, we have adopted the simplest possible procedure. We first define the profitability ratios using current prices, royalties, tax rates, and costs, and then we use alternative combinations of current and previous values of the ratios in our estimating equations. We permit lagged values of the profitability ratios to enter the equations for two possible reasons: first, because firms take time to decide if current changes are likely to be permanent enough to justify investment in an asset with a long producing life, and second, because it takes time to alter investment plans. In reality, both of these effects are likely to be important. To guard against the possibility that unusual observations should unduly influence our final choice of lag structures, we restricted our choice to the same lag pattern for both oil and gas. The final choice involved a three-year moving average, with equal weights on the current and two preceding years. The crude oil equation would have preferred the current value to be eliminated entirely and more weight to be placed on the second-year lag, while the natural gas results were less affected by the form of the lag structure for profitability and provided some evidence of current-year effects.

There was strong evidence that conditions in export markets had long-lasting effects on natural gas investment. The natural gas activity equation

[18]The component series are shown in figure 4.4. Before 1972, authorized exports are assumed to equal actual exports. Given the history of Canadian gas exports, this is not a controversial assumption.

preceding years with equal weights) to either the current value alone or a two-year moving average. The reasoning in support of this result is that knowledge about the existence and longevity of the so-called gas bubble in the United States accumulated only slowly in Canada: the implications of the drop in export sales (which was thought at one stage to be chiefly due to regulatory difficulties in Canada, as described in chapter 4) were only slowly digested, therefore, and their effects on drilling decisions followed behind.

The results of our activity equations are shown in table 8.2[19] and in the two panels of figure 8.2. What do they show? First, there is strong and consistent evidence that investment activity in both crude oil and natural gas is influenced by expected profitability. Second, it appears likely that the crude oil cost equation overestimates the proportion of observed capital costs due to investment in existing reserves. If the estimate were accurate, the coefficient on the cost ratio in the expected reserve additions equation would be very close to 1.0. Since the coefficient was only about 0.5 in the three cases reported in table 8.2, this suggests that the adjusted capital costs of new additions were somewhat lower than implied by our cost equation. Third, as the results for equations (1) and (2) in table 8.2 show, neither production nor cash flow were significant factors in explaining discoveries for crude oil, although both had a strong influence on expected natural gas discoveries—equations (4) and (5).

We then considered the possibility that total land payments should play a direct role in explaining subsequent investment activity, both because drilling rights must be acquired before most investment can take place, and because the acquisition of drilling permits usually entails obligations to maintain a certain pace of subsequent drilling. As equations (3) and (6) of table 8.2 reveal, the expected discovery equations estimated with land payments in the previous year included as additional explanatory variables[20] perform far better than either the production or the cash flow models. Cash flow and production were insignificant in the natural gas equation when land payments were included and have therefore been dropped from our final equations. When land payments were included in the oil equation, the cash flow variable became marginally significant, but since the coefficient on the profitability variable increased substantially (leading to some undesirable simulation properties), and since cash flow could not be included in the natural gas equation, it was excluded from the oil equation as well.

In our final equations—(3) for crude oil and (6) for natural gas—the elasticity of expected discoveries with respect to profitability is much higher for crude oil (1.20) than for natural gas (0.42). The elasticity with respect to total lagged land payments is also higher for oil than for natural gas (0.56

[19] All equations are estimated in double logarithmic form, so that the estimated coefficients represent elasticities. Cash flow is defined as production revenues less current operating costs, royalties, and taxes. The absorption price was used as deflator.

[20] The equations were also tested using current land payments and those lagged two years, but these alternatives were dominated by the version reported in table 8.2.

compared with 0.36). For natural gas, the ratio of actual exports to their authorized level has a significant effect, with a short-run elasticity of about 0.2 building up to 0.67 at the end of three years.

So much for what the equations do explain. It is perhaps more interesting to consider what they don't explain—for example, the gaps between the actual and estimated levels of expected discoveries in figure 8.2. The crude oil equation tends to overestimate the value of expected discoveries from 1974 through 1978 and to underestimate it from 1979 through 1981. Thus the prospects for profitable oil discoveries were perceived less optimistically by the industry than by our model in the middle to late 1970s, as shown by lower-than-predicted levels of expected discoveries. One reason for the industry pessimism in the mid-1970s may have been the general perception, which was echoed in the several NEB reports surveyed earlier, that the western sedimentary basin was "played out," and that all important new production would have to come from synthetic oil or from the frontier regions. This is illustrated by the low price elasticity of supply evident in the various industry submissions to NEB hearings during that period. The higher-than-predicted levels of expected oil discoveries in the post-1978 period may be partly due to the 1979-80 OPEC price shock. Even though domestic prices were well below world levels at this point, there was considerable pressure on the federal government to raise prices toward world levels, as noted in chapter 3. Some high-cost oil (for example, synthetic) was already receiving world-equivalent prices, and the industry may well have been forming investment plans on the basis of world prices, rather than on the then-current, domestically regulated price. Following the introduction of world-equivalent pricing for new oil at the beginning of 1982, the equation is reasonably successful in capturing movements in expected discoveries.

The natural gas expected discoveries series shows a big boom between 1975 and 1980 and a sharp drop after 1980. Both the sharp increase and the sharp decrease are well captured by the model. The sharp increase was due to the combined effects of the profitability variable (which was increasing even faster for natural gas than for crude oil) and the continued strong markets for natural gas exports. The post-1980 drop in activity is entirely due to changes in export demand, acting primarily through the ratio of exports to authorizations, but also showing up to some extent through a declining profitability ratio, as predicted marginal costs continued to rise and expected revenues were squeezed by the lower export volumes and prices. The effects of specific tax changes will be considered in chapter 10, but they are not the primary reason for the changes in the pace of natural gas investment, as can be seen by comparing the relatively slight decline of profitability, shown in figure 8.3, with the sharp decline in expected and estimated natural gas investment and discoveries in figure 8.2b.

Land Payments

Land payments are a large and highly variable part of the oil and gas revenues of the provincial governments in western Canada. Before asking

for areas to be posted for auction, and before deciding what bids to submit, firms in the oil and gas industry perform the kinds of profitability calculations described in the previous section, adjusted for their estimates of future changes in prices and demand conditions in domestic and export markets. The cash flow model also suggests an additional influence, to some extent substitutable for the profitability and production effects, of current cash flow. The bids submitted, and thus the total land payments eventually received by the provincial governments, therefore depend on factors similar to those that govern the activity equations already estimated. But because the bonus bids reflect payments out of any surplus remaining between the present value of expected wellhead and field revenues, net of taxes and royalties, and the costs of developing and producing new reserves, we would expect that land payments would be more volatile than investment activity, and that they might respond proportionately more to changes in profitability and cash flow.

As Watkins[21] and others have emphasized, if there is enough competition at the stage of bidding for leases and production rights, land payments will fluctuate enough to absorb any differences between expected returns and expected costs, after allowing for a rate of return on capital of the average value for investments of an equivalent degree of risk. Watkins calculated, for sales of five Crown leases in the late 1960s in the Rainbow area of Alberta, that the successful bids were at a high enough level to obtain for the province of Alberta a high share of the surplus value expected to accrue from the deposits in question. He notes, however, that the system does not require bidding for all production rights and hence does not collect an equally high proportion of the potential revenues. In addition, if there are unexpected changes in prices or costs after the land payments have been made, then supernormal or subnormal returns will be achieved by the producing firm, subject to whatever tax and royalty system is in place when production is undertaken.

Our land payments equations,[22] like those for expected discoveries, are estimated in logarithmic form and thus do not permit easy calculation of the extent to which land payments in the aggregate respond to absorb expected surplus value from prospective drilling rights. Some evidence on this score will be available from the model simulations to be reported in chapter 10,

[21] See G.C. Watkins, "Competitive Bidding and Alberta Petroleum Rents" (June 1975), 23 *Journal of Industrial Economics* 301-12. As noted in our appendix 5.2 and chapter 7, however, there have been some changes in the Alberta system of land regulations since this article was written. For a more recent discussion, see G.C. Watkins and R. Kirby, "Bidding for Petroleum Leases: Recent Canadian Experience" (July 1981), 3 *Energy Economics* 182-86.

[22] As an anonymous referee pointed out, the total value of land payments depends not only on the expected profitability, but also on the total quantity of land put up for bid. The amount of land put up for bid, however, depends both on requests by the industry and on policy decisions on the part of the provincial (or federal, in the case of the Canada lands) governments, and cannot be considered an exogenous variable. Although initial efforts to separate total land payments into a price component (dollars per hectare) and a quantity component (total hectares) were less satisfactory than our equations for total land payments, we think that separate treatment of the two components remains a promising line for future work.

Figure 8.4a Land Bonus Bids for Oil Exploration
(annual data)

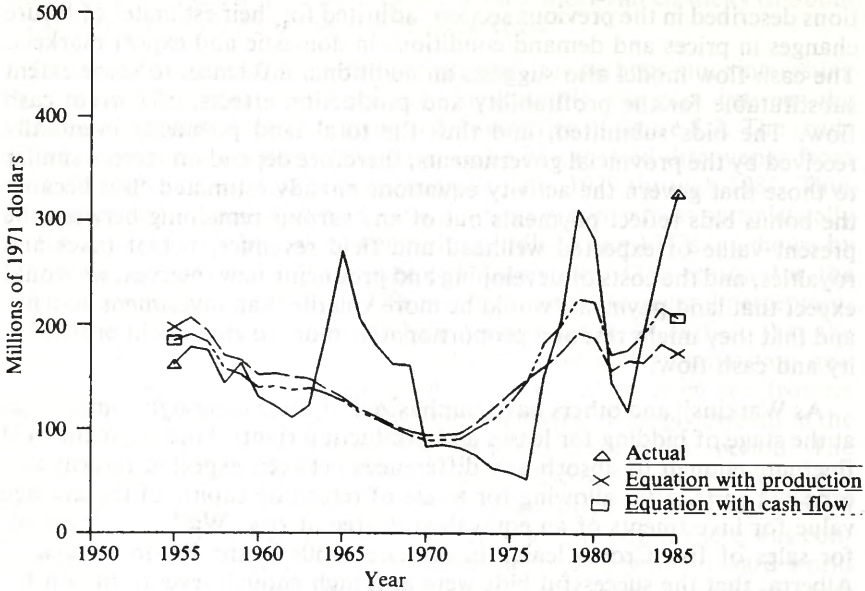


Figure 8.4b Land Bonus Bids for Gas Exploration
(annual data)

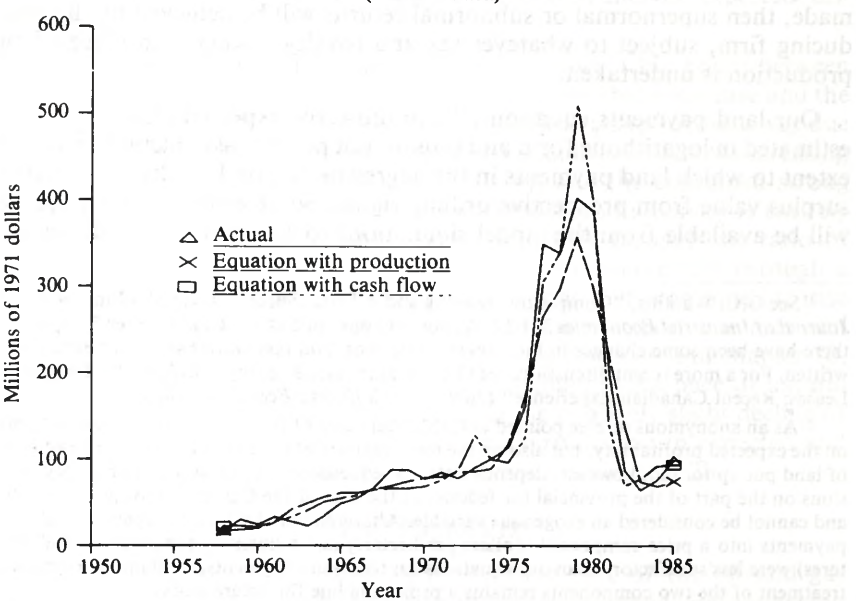


Table 8.3 Regressions Explaining Land Payments for Crude Oil and Natural Gas

	Crude oil		Natural gas	
	(1)	(2)	(3)	(4)
Profitability ratio	1.1422	1.3834	0.4589	1.5134
	(3.75)	(2.69)	(2.58)	(6.85)
Level of production	—	0.4626	—	1.3320
		(1.45)		(14.08)
Cash flow	0.4168	—	2.0165	—
	(2.73)		(16.99)	
Actual to authorized export ratio	—	—	1.9528	1.3542
			(8.05)	(5.09)
Constant	2.2714	2.4343	−8.8060	−3.8076
	(2.22)	(1.34)	(10.74)	(5.89)
$\bar{R}^2$	0.3098	0.1870	0.9193	0.8447
SEE	0.4051	0.4397	0.2428	0.2932
DW	0.5303	0.5436	1.0775	0.8447

Notes: In all of these equations, the dependent variable is the logarithm of real land payments. The absorption price was used as deflator. Double logarithmic forms of the equations were used in estimation. The profitability and export variables are defined as three-year moving averages. t-statistics are in parentheses. SEE and DW are estimation statistics: SEE—standard error of the estimate; DW—Durbin-Watson statistic.

Sources: The key data series that went into the construction of all variables used here are reproduced in the data appendix. See also the notes to figure 8.3 in the appendix containing data sources and explanations for the figures.

where it will be possible to calculate the size and distribution of actual revenues and costs and to assess the relative importance of land payments in distributing total revenues between producers and provincial governments.

In the meantime, we can examine the size and determinants of real aggregate land payments,[23] as shown by the two panels of figure 8.4 and by the equations in table 8.3. Although land payments are not recorded separately for oil and gas, we have divided the total by the same splitting ratios used for investment spending, and have estimated equations similar to those tested for the corresponding expected discovery equations.

We find that the cash flow version of the land payments equations—(1) for crude oil and (3) for natural gas—fits better than the version with production. This is especially true for crude oil, although the fit is not particularly good for either equation. In both alternative models, and for both crude oil and natural gas, profitability has a significant effect on land payments. The effects of cash flow changes are more significant and larger than in the corresponding expected discovery equations. This suggests that some significant proportion of tax changes that influence either expected profita-

[23] These have been converted to constant 1971 dollars using the economy-wide absorption price deflator.

bility or current cash flow may be offset by induced changes in land payments.[24] The likely size of these offsetting effects will be assessed in chapter 10.

Operating Costs

To complete the representation of the exploration, development, and production of oil and gas reserves used in the simulation exercises of chapters 10 and 11, we need to estimate equations for operating costs. These costs, measured in 1971 dollars per barrel for crude oil and 1971 dollars per thousand cubic feet for natural gas, are shown in figure 8.5, and the estimated values from the equations are reported in table 8.4. For both crude oil and natural gas, real operating costs showed a steady decline until the early 1970s, followed by fairly steady increases since then. The key factors responsible for this, according to our equations, are cumulative production and remaining reserves; for crude oil, the profitability ratio also matters.

The long rise in per-unit operating costs since the early 1970s is captured by the ratio of cumulative production to remaining reserves. As cumulative production rises, increasing use is made of lower-quality and farther-flung deposits that entail higher per-unit operating costs. As remaining reserves fall, there is less freedom for producers to select lower-cost deposits for production, and real operating costs therefore may be expected to rise. There is an additional cost-increasing effect likely to follow from the fact that, for typical deposits, the production profile is flat for several years and then follows a long decline. During the declining portion of the production profile, per-unit operating costs are likely to rise, because the costs of tending the related gathering systems and processing plants have to be spread over a decreasing volume of production. Statistical tests show that both the cumulative production and remaining reserves parts of the variable are significant determinants of real per-unit operating costs.

The additional positive impact of the profitability ratio, which was apparent for crude oil but not evident in the case of natural gas, probably has two causes. On the one hand, the higher net value of crude oil justified closer monitoring of production activities as well as greater use of both labour and capital in enhanced recovery projects. In addition, boom times in the industry are likely to raise the relative costs of supplies and services and lead to less attention to cost control within firms when revenues and profits are high.[25] Typical examples include the use of helicopters rather

[24] We re-estimated these equations to take into account the 1976 change in Alberta land policy. (See figure 2.7 of chapter 2.) These results suggested that the policy change did not cause a structural break in the relationships. We thus opted to stay with the equations reported in table 8.3.

[25] As with our treatment of land payments and exploration and development costs, our measures of constant-dollar operating costs are obtained by dividing the current-dollar figures by the economy-wide price of absorption. Increases in the prices of oil industry services relative to goods and services purchased in the economy as a whole will therefore show up as increases in real operating costs.

Figure 8.5a Operating Costs for Crude Oil
(annual data)

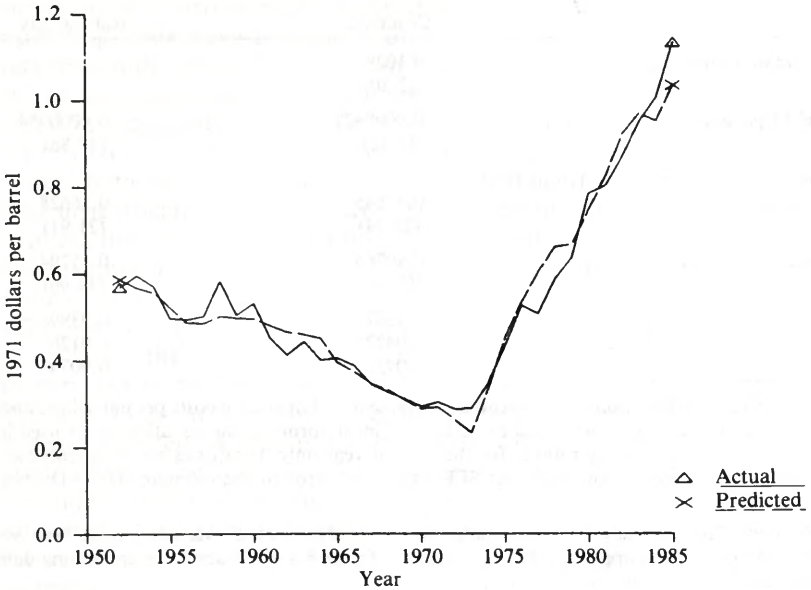


Figure 8.5b Operating Costs for Natural Gas
(annual data)

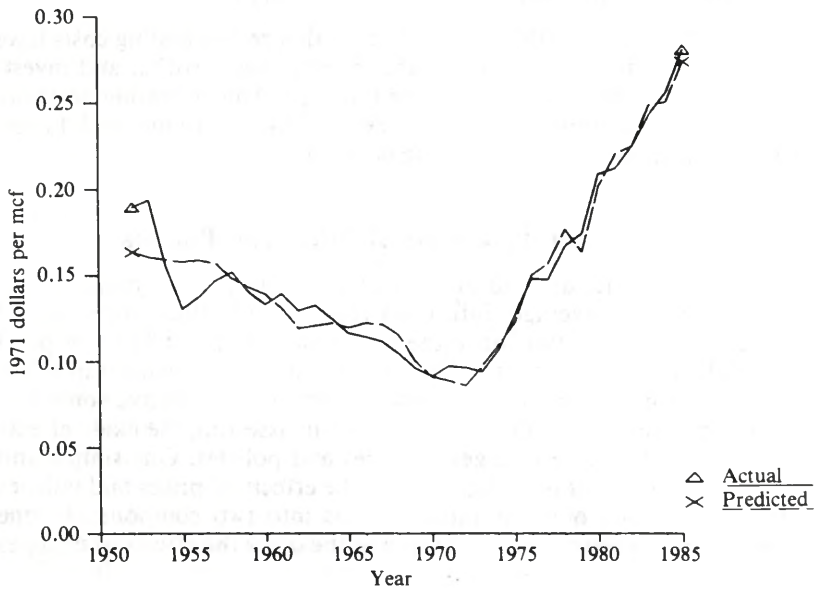


Table 8.4 Regressions Explaining Operating Costs for Crude Oil and Natural Gas

	Crude oil	Natural gas
Profitability ratio	0.1029	—
	(2.30)	
Level of production	−0.0007822	−0.0000954
	(7.42)	(17.86)
Ratio of cumulative production to stock of remaining reserves	0.37685	0.56628
	(23.74)	(21.91)
Constant	0.40768	0.15294
	(5.81)	(39.96)
$\bar{R}^2$	0.9602	0.9399
SEE	0.0427	0.0120
DW	1.0720	0.9074

Notes: In these equations, the dependent variable is real operating costs per unit of production. The absorption price was used as deflator. Linear forms of the equations were used in estimation. The profitability ratio is for the current year only. t-statistics are in parentheses. SEE and DW are estimation statistics: SEE—standard error of the estimate; DW—Durbin-Watson statistic.

Sources: The key data that went into the construction of all variables used here are reproduced in the data appendix. See also notes to figure 8.3 in the appendix containing data sources and explanations for the figures.

than trucks to deliver parts and personnel when times are good, and the greater attention to on-time maintenance and advance ordering of parts and supplies when times are tough and every dollar counts.

It is likely that the post-1985 data will show that real operating costs have dropped substantially in response to the lower prices, profits, and investment in 1986 and 1987. Over the longer term, per-unit operating costs are likely to resume an upward trend as deeper, farther-flung, and lower-quality deposits play an increasing role in production.

Disentangling the Effects of Prices and Policies

We have thus far estimated all our equations under the assumptions that firms expect that, on average, future tax regimes and future prices will be like those in the current year or in the recent past, and that firms respond equally to all changes in after-tax returns, whether due to changes in prices or policies. These assumptions may not be correct, and deserve some further testing before we put our results to work in assessing the likely effects of past or possible future changes in prices and policies. One simple and convenient way of assessing independently the effects of prices and policies would be to separate our profitability ratios into two components—one representing chiefly the effects of prices and the other the effects of changes in policies.

The details of these experiments are shown in appendix 8.1. Generally, the results for the oil equations are quite good. In the unrestricted equation, prices have a strong positive effect on investment; pre-tax capital and operating costs have a negative impact on investment that is somewhat larger than the price effects although the differences are small. The effects of the tax factors are statistically weaker, but the constraint that they are equal in magnitude to the effects of prices and costs is not rejected. The unrestricted equation suggests, however, that the effects on costs of the tax system (and the PIP) are not well captured, since the coefficient is positive (but insignificant). This may arise in part because our treatment implicitly assumes that all firms are in a fully taxable position. For wellhead revenues, this assumption is probably a reasonable approximation because, during the estimation period, the bulk of the taxes on these revenues—royalties and the PGRT—were payable regardless of whether or not the firm was in a taxable position for the purposes of the corporation income tax. The value of the capital cost write-offs, however, is far more dependent on whether or not the firm is in a fully taxable position. The other implicit assumption made concerning after-tax costs is that a tax write-off has the same effect as a cash grant in reducing the cost of capital to the firm. Although this may be reasonable for a firm in a fully taxable position, it is likely that a firm that is not taxable will place far more value on an up-front cash grant than on a future tax write-off. Some preliminary efforts to separate the effects of PIP payments from the normal tax write-offs offered some support for this hypothesis. The coefficients on costs and the associated tax factors were similar in magnitude and both were negatively signed, but the coefficient on the PIP payments was unstable. At this stage, these results are highly tentative in nature, and further work is required before more definitive conclusions can be drawn.

For natural gas, our tests indicate that all of the components of the profitability ratio are relatively weak, and it makes very little difference whether tax factors are included or not. Perhaps the most disconcerting features of the unrestricted equation are the negative coefficient on prices and the positive sign on costs. This may be partly because we have not included the revenues from natural gas by-products in our modelling or because of the fact that in many instances natural gas was found as a by-product in the search for crude oil, particularly during the early years of our sample period. Market constraints have also been far more important in the development of natural gas reserves than they have been for crude oil. Our equation incorporates these effects for the export market, but does not deal with constraints (or perceived opportunities) for domestic markets.

Separating our profitability ratio into its components also allows us to test the hypothesis that firms differ in how quickly they respond to changes in prices and costs, as opposed to changes in taxation and other policy factors. One might expect, for example, that firms would be slow to respond to changes in prices and costs, since it may take some time before they are certain that the changes are permanent in nature. Changes in tax and royalty regimes, on the other hand, might be expected to have an imme-

diate impact. We have tested our basic equations for expected discoveries and land payments for this type of phenomenon, and it does not appear to have been an important factor, at least over our sample period.

When our profitability ratio was constructed using a three-year moving average of all prices and costs, but current tax and royalty rates, the fit of the equations deteriorated somewhat. The differences were very slight for the expected discoveries equations and a bit more pronounced for the land payments equations. This result may have arisen because firms were no more certain about the permanence of changes in the tax and royalty regime than of changes in prices and costs. Until the 1970s, the tax and royalty regime facing the industry was extremely stable and underwent very few changes. The 1970s ushered in a period of rapid changes by both the federal and provincial governments (and a substantial amount of controversy), so that it is perhaps not surprising to find some evidence that the industry was slower to respond than might have been expected.

Despite these problems, our tests indicate that for both oil and natural gas, not only prices and costs, but also the various changes in taxes, royalties, and incentives have had an effect on the size and timing of investment expenditures. In the case of oil, prices and costs appear to have had comparable but opposite effects. Further work is required, however, on the effects of the tax system on costs and of differences between tax incentives and cash grants. For natural gas, all of the components of the profitability ratio appear to have relatively weak effects and to have been overshadowed by market developments.

9
The Frontiers and Energy Megaprojects

Introduction

The term "megaproject" was coined in the early 1980s "to denote the large capital projects proposed or planned for the 1980s and 1990s."[1] Although "large" was most often defined as a minimum investment value of $100 million,[2] a number of oil- and gas-related projects proposed during that time (for example, the Alsands oil sands plant) involved capital expenditures far in excess of that figure. In retrospect, a number of earlier proposals by the Canadian oil and gas industry, both those that were stillborn (for example, the Mackenzie Valley pipeline projects) and those subsequently undertaken (for example, the Syncrude oil sands plant), also involved capital expenditures greater than $100 million. For simplicity of exposition, all oil- and gas-related projects requiring large capital outlays will be referred to as megaprojects, irrespective of when they were first proposed.

In what follows, two types of frontiers are distinguished. In general, the technological frontier refers to oil and gas sources for which some aspect of the production technology is not well established. Over the last few decades, the dominant example of this has been non-conventional oil deposits such as the Athabasca oil sands. As time and research have proceeded, this frontier has been pushed back, so that projects proposed in the late 1970s and early 1980s have been technologically more sophisticated than those first discussed in the 1960s. With this in mind, we treat projects and proposals as they were perceived when first introduced.

Sources of oil and gas situated in remote areas such as the arctic and offshore regions, or more generally the Canada lands, will be thought of as the geographical frontier.[3] An example of this is the Venture gas field located

[1] G. Bruce Doern, "The Mega-Project Episode and the Formulation of Canadian Economic Development Policy" (Summer 1983), 26 *Canadian Public Administration* 219-38, at 219.

[2] See, for example, Canada, Department of Regional Industrial Expansion, *Major Projects Inventory—October 1985—Issue 3* (Ottawa: Supply and Services, 1985), 3; and earlier publications in that series.

[3] Between 1971 and the mid-1980s, a ban on exploration activities offshore from Canada's West Coast was in effect. See André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986*, PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986), items 71.1 and 86.23. In the light of this, the discussion of the geographical frontier will be concerned only with the arctic and east coast offshore regions.

offshore from Sable Island. In some cases, proposals for developing deposits in remote areas are also on the technological frontier, since some aspects of the proposed extraction technology are essentially untried. A prime example of this is the Hibernia oil field, situated offshore from Newfoundland. In this case, the seasonal presence of icebergs in the vicinity of the field is a problem that has never before been tackled in the development and production of an oil deposit.

If, as the above argument implies, the demarcation between geographical and technological frontiers is blurred, why is it useful to distinguish between the two? The most compelling reason has little to do with economics and a lot to do with the nature of the Canadian federation. Non-conventional sources of oil and gas (that is, those on the technological frontier) are almost exclusively located in areas under provincial jurisdiction, whereas the geographical frontier is under federal jurisdiction. The remaining parts of this chapter take this distinction into consideration. A general discussion of frontier oil and gas projects follows in the second section. Then issues relating to oil and gas from non-conventional sources are discussed in the third section. The discussion of the geographical frontier is broken down into two components: the fourth section addresses issues related to arctic and northern developments, while the fifth is concerned with offshore areas. The sixth, and last, section offers an overview and a summary of the key issues.

General Characteristics of Frontier Oil and Gas Projects

At first glance, it is not clear why frontier developments and megaprojects would be closely linked. Nonetheless, a general characteristic of frontier oil and gas projects is that these have tended to be highly capital intensive and to involve capital outlays well in excess of $100 million. Two types of arguments are most often made to explain these facts. First is that the scope and design of these projects are sufficient to make them large scale and capital intensive. For example, *any* pipeline linking arctic energy sources to markets in Canada and the United States would be classified as a megaproject simply because of the distances involved. Furthermore, any such project would be highly capital intensive because it would require very little labour to operate once construction was completed.

The second type of argument suggests that there are significant economies of scale to be exploited. In such cases, the argument goes, large-scale projects are more attractive than smaller-scale ones because they would be characterized by much lower total per-barrel costs. Feick,[4] among others, argues that this applies to mineable oil sands projects. Overall, therefore, it is argued that geography and economics combine to make megaprojects out of most proposals for developing frontier oil and gas resources.

[4]John E. Feick, "Prospects for the Development of Mineable Oil Sands" (September 1983), 9 *Canadian Public Policy* 297-303, at 299-302.

Another characteristic of frontier projects follows directly from the above: such projects tend to have long lead times. This applies both for the study and design stage, and for the construction period. For example, the Alsands proposal incorporated an 11-year lead time—planning began in 1977, but production start-up was not expected before 1988, when the project was cancelled in 1982.[5]

In addition, most frontier oil and gas megaproject proposals made since the early 1960s have been ex ante marginally profitable propositions, in the sense that the potential social and, especially, private net benefits from these projects were frequently shown to be small or even negative under a relatively wide range of assumptions about key variables. A number of these proposals that proceeded beyond the design stage and were actually constructed and operated also proved to be marginally profitable ex post. An example of this is the GCOS (Suncor) plant before the period of rapid increases in oil prices.[6]

The above discussion suggests that a typical frontier oil and gas project proposal would involve large capital expenditures and a long lead time, and would exhibit questionable economic viability. The combination of these three factors means that frontier projects are high-risk propositions. They are risky not only in the sense that some relevant information is uncertain in key respects, but also in the sense that they may potentially unbalance participating firms' portfolios of projects and leave these firms more highly exposed to the risk of default and bankruptcy.[7]

Why then have frontier projects continued to be part of the Canadian energy policy agenda during the last few decades? From an economic perspective, two general reasons suggest themselves.[8] First is the notion that such projects would have large positive indirect and induced effects on the economy. Their large size usually means many direct and indirect jobs, at least during the construction phase. It has elsewhere been argued, however,[9]

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[5] When Alsands was cancelled, construction activities were expected to begin in 1982, thus leaving a six-year gap between the beginning of construction and the first barrels of synthetic crude production.

[6] Larry Pratt, in *The Tar Sands—Syncrude and the Politics of Oil* (Edmonton: Hurtig Publishers, 1976), 47, argues that between 1967—when the plant came on stream—and 1974, GCOS was remitted $7.1 million in Alberta royalties and about $6 million in federal sales taxes. During most of this period, daily plant production averaged less than 40,000 barrels, and oil prices were below $3 per barrel.

[7] Observed behaviour supports this type of argument: most, if not all, frontier megaprojects are initiated as joint ventures involving several distinct corporate entities.

[8] For readers unfamiliar with the types of arguments discussed below, a reading of the following two papers could prove useful: Earle Gray, "Why Canada Needs the Arctic Gas Pipeline," in Peter H. Pearse, ed., *The Mackenzie Pipeline: Arctic Gas and Canadian Energy Policy* (Toronto: McClelland and Stewart, 1974), 33-46; and John Helliwell, Peter H. Pearse, Chris Sanderson, and Anthony Scott, "Where Does Canada's National Interest Lie? A Quantitative Appraisal," in ibid., at 197-227, especially section D.

[9] See Mary E. MacGregor and André Plourde, *Investment Trends and Changing Policies in the Canadian Oil and Gas Industry*, PEAP Energy Study no. 87-1 (Toronto: University of Toronto, Institute for Policy Analysis, 1987), section 4.

that these job-creation effects may be only temporary and may cause bottlenecks in the supplying industries. Furthermore, there is no reason to believe that positive macroeconomic impacts are restricted to oil- and gas-related projects, or that such projects are the most effective way of generating these impacts, if desired. We shall return briefly to these issues in chapter 11.

Events associated with the first OPEC oil price shock of 1973-74 resulted in Canada's becoming a net importer of crude oil and products. In addition, there was a growing expectation that non-frontier sources of natural gas would soon prove insufficient to meet domestic requirements. These effectively led to the crystallization of a second type of argument—that of energy self-sufficiency on its own merits. This type of argument tends to be based on the proposition that a market economy left to its own devices would tend to underestimate the value of the domestic production of commodities like oil and gas. This, in turn, suggests that public policies aimed at accelerating the pace of oil- and gas-related activities could result in the attainment of a higher level of social welfare. Not only was this type of argument propounded by the oil and gas industry, it also effectively became part of the federal government's energy policy objectives.[10] When combined with the argument that the potential for Canada's conventional non-frontier sources to yield the requisite quantities of additional oil and gas reserves was virtually non-existent, there remained one feasible alternative—the frontiers and, hence, megaprojects.

Although the empirical and theoretical significance of such arguments was not firmly established, they nonetheless became part of the conventional wisdom of the Canadian oil and gas industry and a strong influence on public policy. Thus, for the decade or so that followed the first OPEC oil price shock, the focus of Canadian energy policy moved to the frontiers. An early manifestation of this was the creation of Petro-Canada with its initial mandate of accelerating the pace of activities on both technological and geographical frontiers.[11]

The federal government and the governments of the producing provinces (especially Alberta and Saskatchewan) also attempted to deal with issues specific to frontier oil and gas activities by adopting fiscal regimes that were much more sensitive to the profitability of frontier projects than the regimes applicable to conventional non-frontier activities. Frontier fiscal regimes, especially those applicable in areas under federal jurisdiction, have tended to contain incentive, royalty, and taxation components. Although these

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[10] See, for example, Canada, Department of Energy, Mines and Resources (EMR), *An Energy Policy for Canada—Phase 1, Volume 1: Analysis* (Ottawa: Information Canada, 1973); Canada, EMR, *An Energy Strategy for Canada: Policies for Self-Reliance* (Ottawa: Supply and Services, 1976); and Canada, EMR, *The National Energy Program 1980* (Ottawa: Supply and Services, 1980).

[11] For a more detailed discussion of Petro-Canada's frontier activities, see Paul Halpern, André Plourde, and Leonard Waverman, *Petro-Canada: Its Role, Control, and Operations*, a research study prepared for the Economic Council of Canada (Ottawa: Supply and Services, 1988), especially chapter 2.

systems were flexible enough to accommodate a number of frontier projects, they still left many others unprofitable from the private participants' perspective. More generally, it was argued that some significant part of most individual frontier projects was unique, and that this uniqueness should be reflected by the applicable fiscal provisions.[12] This led to an increased willingness on the part of governments to negotiate specific fiscal terms with individual project proponents. At times it appeared that government policy in this area was not to have a policy, but rather to have as many policies as there were proposals.

Although there have been some changes in emphasis, we would argue that the above accurately characterizes the essence of Canadian policy initiatives toward frontier developments, especially since the beginning of the 1970s. We now turn to more detailed examinations of key areas of concern in frontier oil and gas activities.

Non-Conventional Sources

Since the early 1960s, the story of non-conventional oil and gas resources in Canada has essentially been that of bitumen, synthetic crude, and heavy oil upgraders.[13] Non-conventional crude is basically heavy oil so viscous that it will not flow to the surface in its natural state. The western sedimentary basin contains huge deposits of this type of bitumen, and two types of technology have been applied to its production. The first is open-pit mining. If the deposits are located relatively near the surface (usually less than about 75 metres), it is possible to mine the bitumen. This is the production method used by Canada's two integrated oil sands plants, GCOS (Suncor) and Syncrude. These two plants are much more than open-pit mining ventures, however, since they also include refining and upgrading facilities that produce a synthetic crude oil of slightly better quality than the average western Canadian conventional crude.

An alternative way of extracting bitumen is through thermal recovery methods. The joint BP Canada–Petro-Canada Wolf Lake project, for example, uses a two-stage steam injection process. After wells have been drilled into the formation, periods of steam injection are followed by periods of bitumen production, the ambient temperature of the bitumen having been increased by injections of steam, thus allowing it to flow to the surface. Esso Resources' Cold Lake project, on the other hand, uses an in situ process, whereby residual bitumen is ignited and combustion is enhanced by injections of air or oxygen, reducing the viscosity of the bitumen, which then flows to the surface through production wells. Although early proposals concerning the Cold Lake project included refin-

[12] See, for example, G. Bruce Doern and Glen Toner, *The Politics of Energy: The Development and Implementation of the NEP* (Toronto: Methuen, 1985), 362.

[13] Exceptions to this have been coal liquefaction proposals. See, for example, Canada, National Energy Board, *Canadian Energy: Supply and Demand 1980-2000* (Ottawa: Supply and Services, 1981), 144. These, however, have yet to proceed beyond the design stage and have been ignored in the following discussion.

ing and upgrading operations, these were later cancelled or indefinitely suspended. Indeed, none of the western Canadian thermal recovery projects currently in operation include any refining or upgrading of the extracted bitumen, which is sold on markets for heavy oil.

Since the mid-1970s, an increasing proportion of Canadian crude oil production is at the heavy end of the spectrum, as figure 9.1 shows. By 1986, about 31.7 percent of Canadian production was either conventional heavy crude or non-upgraded bitumen, an increase of about 60 percent in the relative importance of heavier crudes in domestic production since 1965. Since heavy oil as produced cannot be used as feedstock by Canadian refineries other than those at the two integrated oil sands plants, market opportunities for these types of crude are mainly limited to asphalt production and exports to the United States. Such a state of affairs has led to proposals to build heavy oil upgraders in Alberta and Saskatchewan. These upgraders would use the heavy oil as feedstock, and produce an upgraded crude that could then be used by all Canadian refineries.

Since the early 1960s, the governments of the producing provinces (especially Alberta for oil sands developments, and Saskatchewan for upgraders) have been strong supporters of the proposed megaprojects. The arguments made to express that support have tended to be versed in terms of the landlord's desire to realize the value of his or her property; but they have also stressed the potential for positive regional economic effects of the type discussed in the previous section. After the first OPEC oil price shock, non-conventional megaprojects were encouraged by the federal government mostly because these were perceived as means of reducing Canada's dependence on foreign sources of oil, thus moving the country toward a greater degree of oil self-sufficiency.[14]

Since much has already been written about non-conventional megaprojects,[15] our discussion here can be succinct. Early efforts by provincial

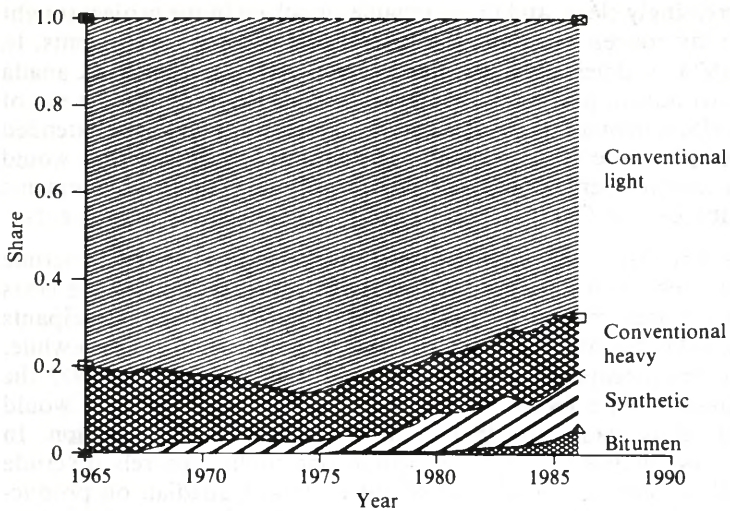
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[14]Western Canadian conventional oil producers at first opposed the construction of oil sands plants because of concerns that the output of these would compete with conventional production in markets until then reserved for the latter. These objections progressively disappeared as the prospects for market expansion in eastern Canada and the United States improved. By the end of the 1970s, there was a high level of support for megaprojects in the Canadian oil and gas industry.

[15]See the following references for further discussion. ***On oil sands in general***: G.W. Brandie, R.H. Clark, and J.C. Wiginton, "The Economic Enigma of the Tar Sands" (Spring 1982), 8 *Canadian Public Policy* 156-64. ***On GCOS (Suncor)***: G.W. Govier, "Alberta's Oil Sands in the Energy Supply Picture," in K.J. Laidler, ed., *Symposium on Energy Resources* (Ottawa: Royal Society of Canada, 1973), 55-70; and Pratt, supra footnote 6, at chapter 3. ***On Syncrude***: John Helliwell and Gerry May, "Taxes, Royalties, and Equity Participation as Alternative Methods of Dividing Resource Revenues: The Syncrude Example," in Anthony Scott, ed., *Natural Resource Revenues: A Test of Federalism* (Vancouver: University of British Columbia Press, 1976), 153-80; and Pratt, supra footnote 6. ***On Alsands***: Gordon W. Douglas and James A. MacMillan, *Alsands Energy Ltd. Impact Study* (Calgary: Canadian Energy Research Institute, 1981); Peter Eglington and Maris Uffelmann, *An Economic Analysis of Oilsands Policy in Canada: The Case of Alsands and Wolf Lake*, Discussion Paper no. 259 (Ottawa: Economic Council of Canada, 1984), section 2; and John F. Helliwell, Robert N. McRae, Paul Boothe,

(Continued on the next page.)

Figure 9.1 Shares of Canadian Crude Oil Production
(annual data)



governments to devise fiscal systems applicable to these high-cost projects typically involved a low, flat-rate royalty on output, as well as some form of additional royalty or profit sharing once capital expenditures had been recovered. After about four years of production, however, the GCOS (Suncor) plant continued to operate at a loss, and the royalty rate was halved by the Alberta government. In retrospect, this probably gave the signal to proponents of such projects that provincial governments seemed willing to alter the terms negotiated and agreed to by the parties involved, if they could be convinced that the economics of individual projects were proving less favourable than had been anticipated at the time the negotiations took place, and that the projects might be cancelled in the absence of some tax or other concession. A similar process soon applied at the stage of the initial negotiations in the hopes of securing a more favourable (from the proponents' perspective) royalty and tax treatment of individual projects. Two examples of this are the Syncrude project and the Alsands proposal.

As table 9.1 suggests, when the first set of AERCB hearings into the Syncrude project were held, the proposal called for the construction of an 80,000 barrels-per-day plant requiring capital expenditures of about $200 million. By the time operations began in 1978, design capacity had increased about 55 percent, to 125,000 barrels per day, but capital expenditures of

[15] Continued . . .
Ardo Hansson, Michael Margolick, Tim Padmore, André Plourde, and Reg Plummer, "Energy and the National Economy: An Overview of the MACE Model," in Anthony Scott, ed., *Progress in Natural Resource Economics* (Oxford: Clarendon Press, 1985), 17-85, especially section 10. ***On heavy oil upgraders***: André Plourde and Mary E. MacGregor, *Heavy Oil Upgrading in Canada: An Economic Perspective*, PEAP Policy Study no. 86-4 (Toronto: University of Toronto, Institute for Policy Analysis, 1986).

over $2 *billion* had been incurred, more than 10 times the original estimate. As construction proceeded, the magnitude of the cost underestimate became increasingly clear, and the companies involved in the project sought royalty and tax concessions from the federal and Alberta governments. In December 1974, a 30 percent equity participant—Atlantic Richfield Canada (ARCAN)—withdrew, placing the project in serious jeopardy. By the end of February 1975, a number of royalty and tax concessions had been extended to the project, the federal government had guaranteed that Syncrude would receive world-equivalent prices for its output, and three governments (federal, Alberta, and Ontario) had agreed to become equity participants.[16]

Helliwell and May[17] have shown that the net effect of the Syncrude arrangements was to bring about a significant redistribution of the costs and risks associated with the project—away from the private participants and toward governments, especially the federal government.[18] For a while, it appeared that megaprojects would flourish, and in September 1975 the National Energy Board (NEB) forecast that by the mid-1990s there would be eight oil sands plants and two in situ megaprojects in operation. In aggregate, these would produce more than one million barrels of crude per day and account for about 70 percent of total Canadian oil production.[19] Although a number of other non-conventional megaprojects were announced around that time (table 9.1), the bloom wore off somewhat as the growth in world prices proved sluggish in the years following the first OPEC shock, the magnitude of capital expenditure requirements became clearer, and governments developed a more cautious attitude toward such projects. Several proposals quietly disappeared, but two remained actively in consideration: Alsands and Esso Resources' Cold Lake in situ proposal.

Both of these projects went through a negotiation process similar to that which had applied to Syncrude. Following the second world oil price shock, the federal government's interest in megaprojects was rekindled, partly because the frontiers were seen by the national energy program (NEP) as key future domestic supply sources, and also because of a recently developed economic growth policy that centred on megaprojects in general.[20] As other participants in the Alsands project withdrew, the federal and Alberta governments once again offered to become equity participants, but the remaining private-sector sponsors ultimately cancelled the project in 1982, citing a lack of consistency in government policy as the key factor underlying this

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[16]The federal government's share was transferred to Petro-Canada in 1976. The Ontario government sold its interest to a private-sector firm before the end of 1978, and the Alberta government sold 50 percent of its interest in 1979. See Plourde, supra footnote 3, at items 74.34 and 79.24.

[17]Helliwell and May, supra footnote 15.

[18]Plourde and MacGregor, supra footnote 15, make a similar point about the redistribution of risk associated with the proposed Husky upgrader.

[19]See Canada, National Energy Board, *Canadian Oil Supply and Requirements* (Ottawa: Supply and Services, 1975), 25-31.

[20]See Doern, supra footnote 1; and Doern and Toner, supra footnote 12, at 363-65.

Table 9.1 Description of Selected Non-Conventional Megaprojects

Project	Proposal			When commissioned or cancelled			
	Date	Capacity, barrels per day	Turnkey cost (as spent), $ millions	Date	Capacity, barrels per day	Turnkey cost (as spent), $ millions	Estimated cost,[a] thousands of 1985 $ per design capacity barrel
Mineable oil sands							
GCOS (Suncor)	1960	31,500	110	1967[b]	45,000	260	22.3
Syncrude	1968	80,000	200	1978[b]	125,000	2,200	37.4
Shell—Shell Explorer (later, Alsands)	1974	100,000	700+	1982[c]	140,000	13,000+	94.6
Athabasca Oil Sands	1974	125,000	850	1976[c]	125,000	2,000+	26.0
Home Oil—Alminex	1975	103,000	1,000+	1976[c]	103,000	2,000+	31.6
Canstar	1980	140,000	10,000	1982[c]	140,000	10,000+	72.8
Bitumen (thermal recovery)							
Cold Lake	1977	140,000	4,000	1982[c]	140,000	12,000	87.4
Peace River	1979	135,000	2,000+	1982[c]	135,000	15,000	113.2
Wolf Lake	1983	7,000	150	1985[b]	7,000	110	16.4
Upgraders							
Plains	1981	40,000	1,000	1983[c]	40,000	1,000+	26.0
NewGrade	1983	50,000	700	[d]			14.6
Husky	1983	46,000	1,400	[e]			31.7

[a] These were calculated by the authors using only capital expenditures. Arbitrary six-year expenditure profiles were assumed for all the projects except GCOS (Suncor) and Wolf Lake, where four-year and three-year profiles, respectively, were used. Similar three-year profiles were used for all three upgrader projects examined. With the exception of the NewGrade and Husky upgraders, cost estimates at the time of commissioning or cancellation were used. The absorption price was used as deflator. [b] Commissioned. [c] Cancelled. [d] Under construction; expected to be commissioned late in 1988. [e] Fate undecided as of September 1988.

Sources: The primary data for this table were taken from numerous government publications, and issues of *Oilweek*.

decision. It seems reasonable to presume, however, that the progressive realization that world oil prices would not keep rising in real terms, at least in the short to medium run, must also have been a factor in bringing about the cancellation.

By the end of 1984, it was quite clear that expectations about the role of non-conventional megaprojects in ensuring Canada's medium-term supply of crude oil had been adjusted downward. For example, the NEB projected that only the equivalent of one additional Syncrude plant would come on stream by the end of the 1990s.[21] Similarly, the equivalent of one-half of the proposed Cold Lake development was seen as proceeding by the early 1990s. Two years later, the dramatic fall in world oil prices led the NEB to update its forecast,[22] which now did not include any additional oil sands plants or large thermal recovery projects in its domestic supply picture to the end of this century.

The estimates of real capital expenditures per design capacity barrel reported in table 9.1 do not show any indication of the significant economies of scale that larger mineable oil sands plants were supposed to be able to realize. At about 22.3 thousand 1985 dollars per design capacity barrel, capital expenditures for the smallest plant—GCOS (Suncor)—are the lowest of all plants built and proposed. To be fair, differences in output mixes probably account for some part of this, as does some quasi-rent captured by relatively scarce inputs. In addition, Feick[23] argues that economies of scale are also important at the operation stage. More recent work, however, suggests that the optimal size for a mineable oil sands plant is about one-half as large as the estimates offered in the early 1980s (70,000 versus 140,000 barrels per day).[24]

The Cold Lake megaproject was cancelled at about the same time as Alsands. Esso Resources decided later, however, to undertake the development of their bitumen reserves using a smaller-scale modular approach. As table 9.1 shows, in 1983 BP Canada and Petro-Canada decided to undertake a relatively small-scale development project at Wolf Lake.[25] Even though this project does not involve any refining or upgrading of the bitumen, table 9.1 shows that the sum of its real per-barrel capital expenditures and those of *any* of the proposed upgraders is still less than 55 percent of the per-barrel capital expenditure estimates for either of the proposed Cold Lake or Peace River megaprojects.

As figure 9.1 suggests, several other smaller-scale thermal recovery projects have been undertaken since the early 1980s. The fact remains,

[21] See Canada, National Energy Board, *Canadian Energy: Supply and Demand 1983-2005* (Ottawa: Supply and Services, 1984), 76-78.

[22] See Canada, National Energy Board, *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services, 1986), 83-84.

[23] Supra footnote 4.

[24] Supra footnote 21, at 76-77.

[25] For a more detailed discussion of the Wolf Lake project, see Eglington and Uffelmann, supra footnote 15, at section 3.

however, that these are high-cost sources of oil, which, as appendixes 5.1 and 5.2 remind us, have benefited from a number of royalty and tax concessions. Nonetheless, these efforts have shown that economies of scale in thermal recovery projects are not as large as originally believed,[26] which in turn suggests that in the future we shall probably see more smaller-scale projects and fewer megaprojects of the scale of the original Cold Lake and Peace River proposals, at least in this area. This, in turn, should reduce the bankruptcy risk associated with these projects. On a similar note, the proposed upgrader projects have been relatively less ambitious than the megaprojects cancelled in the early 1980s. The technology here, however, remains less well developed.

The Arctic Region

As the 1960s progressed, it became increasingly clear that total US oil and gas production from existing fields would soon start to decline. The general feeling at the time was that the best prospects for large discoveries rested with the "frontiers"—Alaska in particular. There followed a rapid build-up of exploration activity on the north slope of Alaska, which resulted in the 1968 discovery of the huge Prudhoe Bay oil field. This "north fever" was not confined to Alaska but had also spread to the Canadian arctic region. The exploration program in that region was set on a sturdier footing late in 1967 when the federal government agreed to acquire a 45 percent share of Panarctic Oils, an exploration consortium active in the Canadian Arctic. In the course of the following few years, several oil and gas discoveries were made in Alaska. In the Canadian Arctic, however, discoveries were less impressive and consisted mainly of gas fields.[27]

An obvious question arose as soon as the importance of the Prudhoe Bay discovery was confirmed: how was Alaskan oil to reach markets in the lower 48 states? Although a number of alternatives were advanced, two types of proposals emerged as serious contenders. One involved a pipeline from Prudhoe Bay to the south shore of Alaska, from where the crude would be loaded onto tankers, and transported to the main US markets. The other involved an all-land route: a pipeline from Prudhoe Bay to northern Canada, and from there down to the United States.

From the outset, the government of Canada was a strong supporter of the all-land route, seeing in it an important means of furthering the economic development of the Canadian arctic region. It quickly became clear, however, that the potential for environmental damage stemming from the construction and operation of pipelines in such regions was not negligible. This led the federal government to issue in 1970 a series of

[26] See supra footnote 22, at 83; and Jack Ruitenbeek, "Economics of In-Situ Oilsands Production: Some Implications for Public Policy" (July 1985), 11 supplement *Canadian Public Policy* 407-14.

[27] See chapter 2, figures 2.18 and 2.20.

guidelines on the construction and operation of oil and gas pipelines in the Yukon and Northwest Territories.[28]

These guidelines envisaged the construction of two pipelines—one each for oil and gas—situated close to one another. This so-called energy corridor concept was designed in the hope of minimizing environmental damage and other unwanted disruptions to northern lifestyles. Natural gas acquired a higher profile in discussions of arctic developments following the NEB hearings and decisions on natural gas exports in 1970 and 1971. Since these issues have already been discussed in chapter 4, suffice it to say that in its 1971 decision, the NEB identified a deficit of 1.1 trillion cubic feet in meeting projected Canadian gas requirements, not to mention contracted exports, from domestic non-frontier sources. Early in 1973, the focus of northern pipeline proposals effectively shifted to natural gas when US President Richard Nixon announced that the pipeline-tanker option had been chosen to transport Alaskan oil to the lower 48 states.

As the number of pipeline proposals grew, so did concerns over the effects of such projects. In 1974, the federal government set up the Berger inquiry to look into the potential environmental and socioeconomic effects of northern pipelines. The NEB also elected to conduct its own inquiry into northern gas pipeline proposals. Helliwell[29] and references therein offer an overview of the events that led to the Berger inquiry's 1977 recommendation of a 10-year moratorium on the construction of any pipeline down the Mackenzie River valley and an outright ban on the construction of lateral lines linking northern Alaska to the Mackenzie Delta.[30]

A few months later, the NEB recommended that a specific gas pipeline proposal—Foothills' Alaska Highway pipeline—be accepted.[31] This recommendation was made conditional on the proponents' agreeing to modify the project from an "express line" for Alaskan gas destined for US markets, to one including a connection to Canadian gas reserves in the Mackenzie Delta, the so-called Dempster spur. Shortly thereafter, the project ran into difficulties in the United States, where it was becoming increasingly clear that Alaskan gas would not be needed to meet US requirements in the foreseeable future. As noted in chapter 4, under "Regulated Pricing: 1971-1979," a similar process was taking place in Canada: the imminent need projected in the early 1970s for frontier gas reserves to meet Canadian requirements would not be realized. In particular, as chapter 4, figures 4.3a and 4.3b suggest, the NEB forecasts made between 1970 and 1977 were

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[28] These guidelines were subsequently modified and expanded in 1972. See Canada, Department of Energy, Mines and Resources, *An Energy Policy for Canada—Phase 1, Volume 2: Appendices* (Ottawa: Information Canada, 1973), 343-53.

[29] John F. Helliwell, "Canadian Energy Policy" (1979), 4 *Annual Review of Energy* 175-229, at 199-206.

[30] See Thomas R. Berger, *Report of the Mackenzie Valley Pipeline Inquiry: Northern Frontier and Northern Homeland*, vol. 1 (Ottawa: Supply and Services, 1977).

[31] Canada, National Energy Board, *Reasons for Decision: Northern Pipelines* (Ottawa: Supply and Services, 1977).

shown to have underestimated gas deliverability from domestic non-frontier areas, which was precisely the point made by some independent researchers in the course of the Berger inquiry hearings and those held by the NEB during this period. These and other related issues later led to the cancellation or the indefinite deferral of other northern gas-related megaprojects, such as arctic liquefied natural gas projects and the Polar Gas consortium's plans to bring Canadian arctic gas to domestic and export markets by pipeline.

Eventually, the US government decided not to go ahead with the construction of the Alaska segment of the proposed gas pipeline. This, in conjunction with the fact that Canadian arctic gas reserves would not be necessary to meet domestic requirements in the foreseeable future, effectively made unnecessary the Canadian segment of the pipeline north of Calgary. In 1980, the federal government therefore approved the construction of only the southernmost segments of the Alaska Highway pipeline (the so-called prebuild), which then became another export project for Alberta-produced gas.

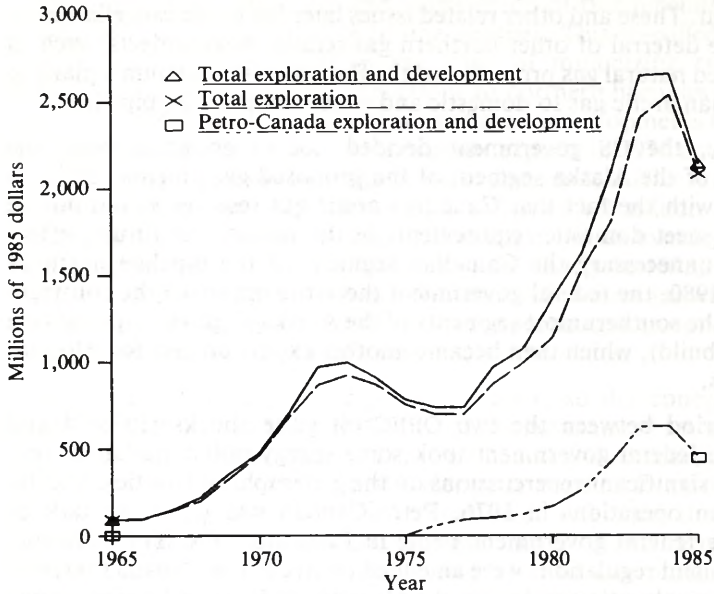
In the period between the two OPEC oil price shocks (1973-74 and 1979-80), the federal government took some energy policy initiatives that were to have significant repercussions on the geographical frontier. Shortly after it began operations in 1976, Petro-Canada was given the task of assuming the federal government's role in Panarctic Oils. The following year, federal land regulations were amended to give Petro-Canada preferential access to exploration rights on the Canada lands when foreign-owned holders of such rights renegotiated permits with the federal government. Petro-Canada soon became an important participant in oil- and gas-related activities on the geographical frontier,[32] as figure 9.2 shows. A closer examination of the available information, however, reveals that the Crown corporation played a relatively more important role in the east coast offshore area.[33] In the light of this, further discussion of Petro-Canada's activities will be deferred to the next section.

Two other policy initiatives also had a strong impact. As appendix 5.1 shows, the federal budget of March 1977 instituted a new kind of exploration incentive. "Superdepletion" allowed corporations and individuals to earn an additional depletion allowance of 66⅔ percent of eligible exploration expenditures in excess of $5 million per well incurred before April 1980. Table 9.2 reveals that, although the legislation did not *explicitly* treat activities in different regions of the country differently, it *effectively* did so, since only wells on the geographical frontiers approached the necessary minimum expenditure level of $5 million.

[32] As noted in the introduction to this chapter, there was a ban on exploration activities in the west coast offshore region for most of the period under consideration. Overall, expenditures in that region account for less than 2 percent of exploration and development expenditures on the geographical frontier.

[33] See Halpern, Plourde, and Waverman, supra footnote 11, at 10-27, and charts 2.1 and 2.2.

Figure 9.2 Petro-Canada's Contribution to Exploration and Development Expenditures in the Arctic, Eastern, and Western Offshore Areas
(annual data)



Seven months after superdepletion expired, the federal government introduced the NEP, in which activities in different regions of the country were *explicitly* treated differently. An adjunct objective of encouraging greater participation in frontier activities by Canadian-owned firms was pursued through the institution of preferential treatment for these firms. Section 16 of appendix 5.1 provides details of the various grant-based incentives offered for exploration and development. Of special interest to us now is the fact that exploration incentive and earned depletion rates were higher for activities on the geographical frontier (for example, the Canada lands) undertaken by firms with a high Canadian ownership ratio (COR). For example, in 1983 eligible exploration expenditures incurred on the Canada lands by a firm with a COR of at least 69 percent would earn a grant of 80 percent and a depletion allowance of 20 percent of expenditures net of grants. This compares with a 35 percent rate of incentive payment and an earned depletion allowance of 10 percent of net expenditures in Alberta.

Even though the rate of incentive payment fell sharply with the COR, this did not prove to be a constraint on the geographical frontier because firms were very successful in negotiating intercorporate arrangements, ensuring that almost all eligible expenditures incurred qualified for grants at the highest rate.[34] During this first six years (1981 to 1986) of the program, a

[34] It should be noted that not all frontier exploration expenditures were deemed eligible for PIP grants. Land acquisition costs, for example, were not eligible expenditures.

Table 9.2 Average Drilling Cost of Exploration Wells

Year	North[a]	East offshore	West[b]	North[a]	East offshore	West[b]
	millions of current dollars			*millions of 1985 dollars*		
1965	0.73	n.a.	0.06	2.87	n.a.	0.25
1966	0.38	n.a.	0.07	1.42	n.a.	0.27
1967	0.21	n.a.	0.08	0.75	n.a.	0.30
1968	0.27	n.a.	0.08	0.94	n.a.	0.28
1969	0.59	5.90	0.07	1.97	19.82	0.25
1970	0.65	1.49	0.08	2.09	4.82	0.25
1971	1.06	1.66	0.07	3.30	5.16	0.23
1972	1.93	2.69	0.09	5.73	8.01	0.26
1973	2.06	1.96	0.09	5.68	5.40	0.23
1974	3.49	2.86	0.12	8.47	6.94	0.28
1975	4.87	6.29	0.12	10.55	13.64	0.25
1976	10.03	4.82	0.13	19.94	9.59	0.25
1977	15.44	11.90	0.17	28.33	21.84	0.32
1978	37.40	9.94	0.26	63.58	16.90	0.43
1979	23.34	34.03	0.43	36.38	53.05	0.67
1980	40.73	41.81	0.53	57.24	58.76	0.75
1981	62.05	43.14	0.58	77.86	54.14	0.73
1982	65.64	91.17	0.54	74.64	103.67	0.61
1983	81.98	66.26	0.59	87.99	71.12	0.63
1984	34.56	68.52	0.48	36.08	71.51	0.50
1985	20.82	42.32	0.50	20.19	42.32	0.50
1986	12.47	40.29	0.62	12.10	39.09	0.60

Notes: n.a. means not available. [a]North refers to the Yukon and Northwest Territories, and contiguous offshore areas. [b]West refers to Manitoba, Saskatchewan, Alberta, and British Columbia. The absorption price was used as deflator.

Source: Authors' calculations using data from Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986), sections 1 and 4, and its predecessors.

total of $6.97 billion in federal incentive payments were made. Of this amount, $6.41 billion, or about 92 percent, was paid to firms with CORs high enough to qualify for 80 percent grants. Even if we assume that *all* of the $511 million in federal grants for expenditures incurred in areas under provincial jurisdiction outside of Alberta qualified for PIP grants at the highest rate, still more than 90 percent of federal grants to activities on the Canada lands ($5.90 of $6.46 billion) were triggered by expenditures incurred by firms qualifying for incentive payments at an 80 percent rate.[35] Although this may be interpreted as suggesting that the PIP program was very successful in attaining one of its key objectives—that of increasing the participation of Canadian-owned firms in frontier exploration activities—it must also be reconciled with the fact that during this period several foreign-

[35]This was computed with information contained in Canada, Petroleum Incentives Administration, *Annual Report* (Ottawa: Supply and Services), various years, as follows: 1981-1983, 16, tables 4 and 7; 1984, 17, table 6, and 18, table 8; 1985, 16, table 7, and 17, table 9; 1986, 17, table 7, and 19, table 9. Over this period, development incentive grants accounted for less than 3 percent of total grants to activities in frontier regions.

owned firms were active in these areas (for example, Gulf and Esso Resources in the Beaufort Sea, and Mobil in the east coast offshore region).

Table 9.3 reports the results of simulated corporation income tax calculations and PIP grant allocations. These calculations replicate the provisions of the relevant legislation as closely as we could model them. During the 12-year period from 1965 to 1976, (undiscounted) total real exploration expenditures in northern Canada amounted to 4.74 billion 1985 dollars. Of this amount, we estimate that tax expenditures[36] were 2.08 billion 1985 dollars. On this basis, the corporate contribution to the expenditure program would have reached 2.66 billion 1985 dollars—about 56 percent of the total. In the nine years between 1977 and 1985, exploration expenditures of about 7.53 billion 1985 dollars were incurred, of which we estimate 1.28 billion (or about 17 percent) were borne by firms. In such a case, the rest—about 6.25 billion 1985 dollars (or 83 percent)—would have been borne by the public sector in the form of tax expenditures and grants.

The data underlying table 9.2 reveal that in the 1965-1976 period, the average real cost of drilling an exploration well in northern Canada was about 4.74 million 1985 dollars.[37] This rose more than eightfold, to 44.50 million 1985 dollars, during the 1977-1985 period.[38] The comparable figures for the western sedimentary basin are 257 and 575 *thousand* 1985 dollars, respectively. This represents an increase in real average drilling costs of about 120 percent—less than one-sixth the increase experienced in northern Canada. Our estimates thus suggest that between 1977 and 1985 it was about 77 times more expensive to drill an average exploration well in northern Canada than it was to do so in the western sedimentary basin.

The data underlying figure 9.3 (about which a caution similar to that found in the previous footnote applies) show a similar, though less extreme, pattern in average drilling depths. Between 1965 and 1976, exploration wells in northern Canada averaged about 1,930 metres. This rose by about 43 percent—to 2,760 metres—during the 1977-1985 period. Comparable figures for the western sedimentary basin are 1,245 and 1,325 metres, respectively—an increase of about 6.5 percent. During the 1977-1985 period, an average exploration well drilled in northern Canada was thus more than twice as deep as one drilled in western Canada.

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[36]This is taken to mean the value to the corporation of tax deductions, and hence is a measure of forgone tax revenues for the government.

[37]We do not have information on individual wells. The Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986) and its predecessors, however, report total expenditures on exploration drilling and number of well completions by region, on an annual basis. To the extent that expenditures on individual wells are incurred in a different year than these wells are completed, our annual estimates of average drilling costs will be inaccurate. Over longer periods of time, however, this type of inaccuracy will be much less important.

[38]The lack of information on individual wells made it impossible to design reliable statistical tests for differences in the means of the two subperiods.

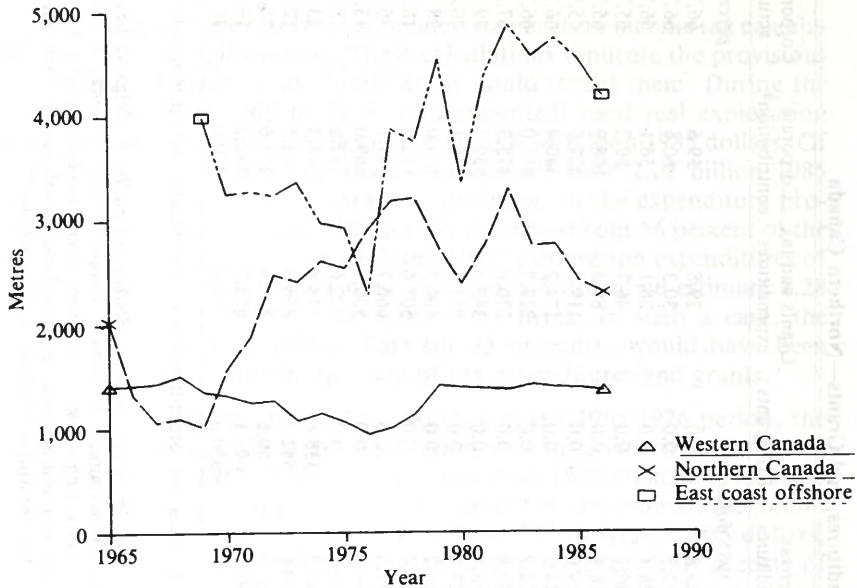
Table 9.3 Exploration Expenditures, Tax Expenditures, and Grants—Northern Canada

Year	Actual expenditures	Earned depletion	Superdepletion	Other tax expenditures	PIP grants	Grants and tax expenditures	Corporate contribution[a]	Corporate/ actual
				millions of 1985 dollars				*percent*
1965	89.4	0.0	0.0	29.8	0.0	29.8	59.6	66.7
1966	91.0	0.0	0.0	30.3	0.0	30.3	60.6	66.7
1967	84.2	0.0	0.0	28.1	0.0	28.1	56.1	66.7
1968	135.8	0.0	0.0	46.7	0.0	46.7	89.2	65.7
1969	257.3	0.0	0.0	88.4	0.0	88.4	168.9	65.7
1970	346.5	0.0	0.0	119.0	0.0	119.0	227.5	65.7
1971	514.7	0.0	0.0	174.2	0.0	174.2	340.4	66.2
1972	667.6	0.0	0.0	222.7	0.0	222.7	445.0	66.7
1973	706.1	0.0	0.0	230.8	0.0	230.8	475.3	67.3
1974	687.6	60.1	0.0	288.4	0.0	348.5	339.1	49.3
1975	589.2	73.4	0.0	277.8	0.0	351.2	238.1	40.4
1976	568.2	86.0	0.0	318.2	0.0	404.2	164.0	28.9
1977	619.6	93.9	76.3	337.4	0.0	507.6	112.0	18.1
1978	715.7	108.4	191.0	377.8	0.0	666.7	49.1	6.9
1979	639.0	96.4	154.9	294.0	0.0	550.1	89.0	13.9
1980	640.4	101.4	114.6	305.1	0.0	522.6	117.8	18.4
1981	937.1	94.7	0.0	285.3	338.8	718.8	218.3	23.3
1982	975.8	53.2	0.0	160.6	642.4	856.3	119.5	12.3
1983	1048.4	46.9	0.0	235.3	550.6	832.8	215.6	20.6
1984	1080.9	17.6	0.0	177.0	694.1	888.7	192.2	17.8
1985	874.0	0.0	0.0	153.4	550.0	703.4	170.6	19.5

Notes: These calculations assume that all activities were undertaken by principal-business corporations in a fully taxable position. [a]Includes Petro-Canada and other Crown corporations.

Source: Data on expenditures and number of wells were taken from the Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986), sections 1 and 4, and its predecessors. PIP grants were taken from Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry: Monitoring Survey* (Ottawa: Supply and Services, various issues). Details concerning the tax system were taken from appendix 5.1. For ease of computation, it was assumed that for a given year during the period when superdepletion was available, each exploration well cost the same amount to drill. This average cost was allowed to vary across years, as indicated by the data. The absorption price was used as deflator.

Figure 9.3 Average Depth of Exploration Wells
(annual data)



What do we have to show for this massive investment of public funds in exploration for oil and gas in northern Canada? As shown in chapter 2, figures 2.18 to 2.21, since 1977, total reserves of about 300 billion cubic metres (10 trillion cubic feet) of natural gas and much less than 50 million cubic metres (300 million barrels) of oil have been discovered in this region.[39] The only significant increase in oil or gas production from northern Canada to have occurred during this period resulted from Esso Resources' 1983-1985 expansion of its Norman Wells facilities, and the construction of a pipeline linking the field to Zama, Alberta. Although early in 1987 Gulf Canada publicly discussed the possibility of a $4.6 billion development of the Amauligak oil field in the Beaufort Sea,[40] results in Eglington and Uffelmann[41] suggest that such developments would be uneconomic from society's perspective without a significant and sustained increase in real world oil prices from the levels prevailing in mid-1988.

The East Coast Offshore Region

Until the end of the 1970s, exploration efforts offshore from Canada's East Coast were concentrated in three areas: the Labrador coast, the Grand

[39] Another benefit generated by these activities is information regarding the size and quality of the reserve base in frontier areas.

[40] See *The Globe and Mail*, May 4, 1987, B1.

[41] See Peter Eglington and Maris Uffelmann, *An Economic Analysis of Hydrocarbon Developments in the Beaufort Sea*, Discussion Paper no. 258 (Ottawa: Economic Council of Canada, 1984).

Banks of Newfoundland, and Sable Island. Years of disappointing results on the Labrador coast, the discovery of the Hibernia oil field on the Grand Banks, and the attempts to delineate the Venture gas field offshore from Sable Island have meant that over the last 10 years or so the focus of activity in this region has gradually shifted toward the last two.

It was initially thought that most of the gas eventually produced from the Venture field would be absorbed by markets in the northeastern United States. But the continuing US natural gas deliverability surplus has effectively caused this plan to be shelved, at least in the short to medium run. As a result, even though a formal development plan for the field was submitted to the NEB early in 1984, the absence of a ready market for the gas has meant that interest in proceeding with development and production of the field has been quite low in recent years. This, in turn, has meant that the focus of attention on east coast offshore activities has centred on the Grand Banks of Newfoundland, where a few oil deposits have been found.

To date, the most important discovery on the Grand Banks is that of the Hibernia oil field in 1979. In 1985, Mobil Oil, acting on behalf of all corporate participants, proposed a multi-billion dollar development plan for the field.[42] The main technological barrier to unfettered production remains the seasonal presence of icebergs in the vicinity of the field. Project participants, however, express confidence that the proposed fixed gravity base system could withstand the impact in the event of a collision with an iceberg. In the limit, oil produced from Hibernia could be sold on world markets, so that the marketability problems plaguing the Venture gas field are not shared by the Grand Banks oil fields. The price fetched by the oil is, however, a crucial factor in determining the commercial viability of such projects. The sharp fall in world oil prices that occurred in late 1985 and early 1986 has definitely dampened enthusiasm for the early development and production of Hibernia. Notwithstanding this, early in 1987 Petro-Canada announced that it intended to proceed with the development of another Grand Banks oil field—Terra Nova—at an estimated cost of between $0.5 and $1 billion.[43]

Eglington and Uffelmann[44] are slightly more optimistic than Plourde[45] in their assessment of the economic viability of the Hibernia field. Nonetheless, both studies suggest that at world oil prices similar to those prevailing in mid-1988 the development and production of Hibernia would, at best, exhibit questionable economic viability. In addition, since these two

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[42] See Mobil Oil Canada, *Hibernia Development Project Environmental Impact Statement*, 6 vols. (n.p.: n.p., 1985).

[43] See "A Week of Billion Dollar Decisions," *Oilweek*, March 16, 1987, 22-23.

[44] Peter Eglington and Maris Uffelmann, *An Economic Analysis of the Venture Development Project and Hibernia*, Discussion Paper no. 261 (Ottawa: Economic Council of Canada, 1984), section 3.

[45] André Plourde, "Modelling the Economic Implications of Offshore Oil: The Case of Hibernia" (PhD dissertation, University of British Columbia, Department of Economics, Vancouver, 1985), chapters 4 to 6.

studies have been completed there has been a reduction in the estimate of the volume of recoverable oil thought to be contained in the field. On average, this suggests that, all else constant, these two studies have probably overestimated the revenues and underestimated the per-barrel costs of development and production.

The Canadian Petroleum Association has yet to recognize any east coast offshore gas discovery as commercially viable, as chapter 2, figures 2.19 and 2.21 show. On the oil side, only the Hibernia discovery has so far been deemed commercial. What summary information can we offer on the exploration activities that led to these reserves additions? The information reported in table 9.4 reveals that between 1967 and 1976, exploration expenditures of about 1.28 billion 1985 dollars were incurred in the east coast offshore region. Our estimates suggest that of this amount, 556 million 1985 dollars translated into tax expenditures. As was the case in northern Canada, approximately 56 percent of exploration expenditures (722 million 1985 dollars) would thus have been ultimately met by the firms active in this area. Between 1977 and 1985, however, tax expenditures and grants accounted for more than 5.1 billion 1985 dollars, or about 79 percent of total exploration expenditures of 6.5 billion 1985 dollars. Therefore, our estimates suggest that during this period, the net corporate contribution to the financing of the exploration activities was approximately 21 percent (1.4 billion 1985 dollars).

The data that went into the construction of table 9.2 reveal that between 1967 and 1976 the average drilling cost for an exploration well in the east coast offshore region was about 7.02 million 1985 dollars. In the 1977-1985 period, this increased more than 700 percent, to 57.70 million 1985 dollars. During this period, it was on average about 100 times more costly to drill an exploration well in the east coast offshore region than to drill one in western Canada.

As with the data for northern Canada, a similar pattern emerges from calculations of average depths of exploration wells. In the first subperiod, the average well depth in the region was about 3,140 metres; it reached 4,440 metres during the second subperiod, an increase of approximately 40 percent. Between 1977 and 1986, an average exploration well drilled in the east coast offshore region was thus about 60 percent deeper than one drilled in northern Canada and more than three times as deep as an average exploration well in western Canada.

As chapters 3 and 7 make clear, the period corresponding to enhanced incentives for frontier exploration—and particularly the years during which the federal PIP was in effect—witnessed a relative shift of Canadian oil and gas exploration activities from western Canada to the North and to the east coast offshore region. One conclusion that emerges from the evidence presented in this chapter is that there was also a relative reallocation of exploration expenditures within the geographical frontier—namely, from northern Canada to the east coast offshore region. Between 1967 and 1976, for example, expenditures in northern Canada accounted for about 78 per-

Table 9.4 Exploration Expenditures, Tax Expenditures, and Grants—Offshore Eastern Canada

Year	Actual expenditures	Earned depletion	Superdepletion	Other tax expenditures	PIP grants	Grants and tax expenditures	Corporate contribution[a]	Corporate/ actual
				millions of 1985 dollars				*percent*
1967	35.0	0.0	0.0	11.7	0.0	11.7	23.3	66.7
1968	28.2	0.0	0.0	9.7	0.0	9.7	18.5	65.7
1969	54.7	0.0	0.0	18.8	0.0	18.8	35.9	65.7
1970	114.2	0.0	0.0	39.2	0.0	39.2	75.0	65.7
1971	161.0	0.0	0.0	54.5	0.0	54.5	106.5	66.2
1972	198.8	0.0	0.0	66.3	0.0	66.3	132.5	66.7
1973	215.6	0.0	0.0	70.5	0.0	70.5	145.2	67.3
1974	178.2	15.5	0.0	76.0	0.0	91.4	86.8	48.7
1975	163.5	20.3	0.0	78.3	0.0	98.6	65.0	39.7
1976	128.7	19.3	0.0	76.2	0.0	95.5	33.2	25.8
1977	77.8	11.5	11.6	51.5	0.0	72.6	5.2	6.7
1978	156.6	23.1	28.0	86.6	0.0	137.7	18.9	12.1
1979	354.3	53.9	93.5	163.0	0.0	308.0	46.3	13.1
1980	496.5	79.2	15.1	238.0	0.0	331.9	164.6	33.2
1981	584.0	53.2	0.0	160.0	249.7	462.8	121.1	20.7
1982	827.9	58.1	0.0	174.8	463.9	696.8	131.0	15.8
1983	1352.6	52.8	0.0	264.1	793.1	1110.0	242.6	17.9
1984	1454.6	30.4	0.0	304.5	793.2	1128.2	326.4	22.4
1985	1204.9	0.0	0.0	286.4	598.0	884.4	320.5	26.6

Notes: These calculations assume that all activities were undertaken by principal-business corporations in a fully taxable position. Data are not available before 1967. [a]Includes Petro-Canada and other Crown corporations.

Source: Data on expenditures and number of wells were taken from the Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986), sections 1 and 4, and its predecessors. PIP grants were taken from Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry: Monitoring Survey* (Ottawa: Supply and Services, various issues). Details concerning the tax system were taken from appendix 5.1. For ease of computation, it was assumed that for a given year during the period when superdepletion was available, each exploration well cost the same amount to drill. This average cost was allowed to vary across years, as indicated by the data. The absorption price was used as deflator.

cent of the combined real spending levels (4.56 billion of 5.84 billion 1985 dollars). In the second subperiod, however, expenditures in northern Canada accounted for slightly less than 54 percent of the combined total (7.53 billion of 14.04 billion 1985 dollars). In other words, the relative importance of the east coast offshore region as an oil and gas exploration target (as measured by relative real expenditure levels) doubled during the second subperiod, going from 22 percent between 1967 and 1976 to 46 percent between 1977 and 1985. This shift occurred even though for most of this period jurisdiction over certain key areas of the region was the subject of disagreement between federal and provincial governments (mainly Newfoundland and Labrador, but also Nova Scotia).[46]

The optimism generated by the Venture and Hibernia discoveries is no doubt partly responsible for this development. But it would appear that another important factor was the role played by Petro-Canada.[47] Halpern, Plourde, and Waverman[48] argue that Petro-Canada was the company most active in exploration activities offshore from Canada's East Coast between 1978 and 1984. Their chart 2.1 shows that this statement would also clearly apply if the period were defined to include 1977 and 1985. During this period, the Crown firm participated in more than 85 percent of the exploration wells drilled in that region.

Even though between 1977 and 1985 Petro-Canada participated in about as many northern exploration wells as it did on the East Coast, chart 2.2 in Halpern, Plourde, and Waverman shows that it was a relatively smaller player in northern Canada.[49] During that time, Petro-Canada was a participant, either on its own or as a member of the Panarctic consortium, in fewer than 50 percent of the wells drilled in the region.

Overview and Summary

Canada's foray into the oil and gas frontiers has proven to be an expensive proposition. Mineable oil sands production has never achieved the levels anticipated in the mid-1970s. The dramatic cost escalation documented in table 9.1—both across projects, and between proposal stages and commissioning or cancellation stages for individual projects—is a key factor in understanding why no mineable oil sands project has proceeded since Syncrude. Although some tax provisions of the NEP no doubt made such projects less attractive from a private-sector perspective, a few oil sands plant proposals had been cancelled before October 1980, and, as the ill-fated negotiations surrounding the Alsands project showed, the federal and Alberta governments were willing to extend significant royalty and tax con-

[46] For example, in 1977 a jurisdictional dispute between the federal and Newfoundland governments led an important exploration consortium to cancel its drilling program for the Labrador coast. See Plourde, supra footnote 3, at item 77.5.

[47] These two factors are not likely to be independent since Petro-Canada is a participant in both the Venture and Hibernia drilling programs.

[48] Supra footnote 11, at 29.

[49] Ibid.

cessions to such projects. The realization that the future did not promise oil prices that would forever grow in real terms also reduced the attractiveness, to both society and potential project sponsors, of what would be multi-billion dollar megaprojects that exhibited, at best, uncertain prospects for profitability. It thus seems quite likely that in the absence of significant net subsidies by governments, no additional oil sands projects will be constructed in the short to medium term.

The same does not apply to bitumen production through thermal recovery methods. As figure 9.1 shows, bitumen production as a proportion of total Canadian crude oil production doubled between 1982 and 1986. Although most of these projects can still be classified as megaprojects according to the definition given at the beginning of this chapter, they involve capital expenditures of a few hundred million dollars each—a far cry from the expenditure levels associated with oil sands plants. Granted that thermal recovery projects produce a fraction of the output and a lower-quality product than do integrated mineable oil sands projects, nevertheless, the risk of default associated with the former is significantly lower than that applicable to the latter. Still, thermal recovery projects remain propositions that require a series of royalty and tax concessions to be made privately profitable.

Activities in the geographical frontier have tended to be different from those relating to non-conventional oil sources (the technological frontier). The location and approximate size of the main bitumen deposits were known before the GCOS (Suncor) proposal was made in 1960; such information was not available for the Canada lands. Therefore, even though megaprojects proposed for the geographical frontier were related to development, production, and transportation, the main focus of activities in these areas has been exploration. As the discussion in the two preceding sections shows, this has also been an expensive proposition.

Between 1965 and 1985, about 20 billion 1985 dollars were spent on exploration activities in northern Canada and the east coast offshore region. About 70 percent of this was spent after the introduction of enhanced frontier exploration incentives in 1977 (tables 9.3 and 9.4). This massive investment program did not generate much in the way of recognized reserve additions, as figures 2.18 to 2.21 in chapter 2 show. Figures 2.14 to 2.17 reveal that this surge in investment was not accompanied by any significant increase in the number of wells drilled. Rather, as was argued above, increases in average depth and average cost of wells on the Canada lands after 1976 for outstripped the increases experienced in western Canada.[50] Granted that technological changes may have contributed to the emergence of these trends, nevertheless, the sharp fall in the share of expenditures borne by the firms doing the exploration must also have played a very important role.

[50]For an early discussion of these issues, see John F. Helliwell, "The Interaction of Tax Policy and Energy Policy," in *Report of Proceedings of the Thirty-First Tax Conference*, 1979 Conference Report (Toronto: Canadian Tax Foundation, 1980), 7-20, especially at 16-18.

The estimates reported in tables 9.3 and 9.4 suggest that the public-sector cost of the 1977-1980 superdepletion program was about 685 million 1985 dollars. This is almost certainly an underestimate of the actual magnitude, however, since superdepletion deductions could be claimed against any income by individuals with marginal tax rates greater than the assumed corporate rate of 46 percent. Between 1981 and 1985, PIP grants of about 5.7 billion 1985 dollars were made to exploration activities in northern Canada and the east coast offshore region. The net public-sector contribution in the form of tax expenditures and grants was, however, proportionately slightly smaller under the PIP than under superdepletion, because the provisions of the former were such that commensurate reductions in tax expenditures accompanied the grants.

The role played by Petro-Canada in the push to the geographical frontier should not be underestimated. As figure 9.2 suggests, between the introduction of the PIP in 1981 and 1985, the Crown firm accounted for about 21 percent of (undiscounted) real exploration and development expenditures on the Canada lands. It should not be surprising to learn that Petro-Canada and its subsidiaries received about 22 percent of all federal PIP grants made during that time.[51] As Halpern, Plourde, and Waverman argue, in pursuing an aggressive exploration program on the geographical frontier, Petro-Canada was fulfilling aspects of the mandate given by the federal government to the firm at the time of its creation in 1975.[52]

One aspect of this push to the geographical frontier remains a bit of a puzzle. Chapter 7 documented a shift in activity (measured in terms of real expenditure levels) from the western sedimentary basin to the geographical frontier. Petro-Canada, as noted above, clearly played a part in bringing this about, especially after 1981, but were there other contributing factors as well? The results of illustrative corporation income tax calculations are shown in table 9.5 for three specific years: 1976, when there were no special frontier exploration incentives; 1978, when superdepletion was in effect; and 1983, when the PIP, with its higher incentive payment rate for frontier activities, was in effect. At the margin, the net cost to firms in 1976 of an additional dollar in exploration expenditures was approximately the same whether the activities were undertaken in Alberta (37 cents) or the east coast offshore area (39 cents).[53]

After 1976, however, there was a marked change in this relationship. By 1983, the net cost to firms of each additional dollar's worth of exploration activity in Alberta had gone down by about 6 cents (to 31 cents). After 1976,

[51] This information was drawn from the annual reports of the Petroleum Incentives Administration for the years in question. Dome Petroleum and its subsidiaries received about 17.5 percent of total federal PIP grants. No other single corporate entity collected more than 10 percent of all federal grants made between 1981 and 1985.

[52] Supra footnote 11, at 5-31.

[53] This is likely an underestimate for the east coast offshore area since it is based on the assumption that the expenditures are claimed against income earned outside all provinces. Total corporate tax rates are higher for income earned within the boundaries of any province.

Table 9.5 Illustrative Tax Calculations
Additional $1 Spent on Drilling an Exploration Well[a]

	Alberta (A)			Offshore east (OE)		
	1976	1978	1983	1976	1978	1983
(1) Eligible expense ..... [$1 – (6)]	1.00	1.00	0.65	1.00	1.00	0.20
(2) Earned depletion ..... [76 & 78: 0.33 * (1) 83-A: 0.10 * (1) 83-OE: 0.20 * (1)]	0.33	0.33	0.07	0.33	0.33	0.04
(3) Superdepletion ..... [78-OE: 0.67 * (1)]	0.00	0.00	0.00	0.00	0.67[b]	0.00
(4) Tax rate ..... [fed. + prov.]	0.36 + 0.11	0.36 + 0.11	0.36 + 0.11	0.46	0.46	0.46
(5) Tax expenditures ..... [((1) + (2) + (3)) * (4)]	0.63	0.63	0.34	0.61	0.92	0.11
(6) PIP grants[c] ..... [83-A: $1 * 0.35 83-OE: $1 * 0.80]	0.00	0.00	0.35	0.00	0.00	0.80
(7) Total ..... [(5) + (6)]	0.63	0.63	0.69	0.61	0.92	0.91

[a]To abstract from complications relating to royalty holidays, it is convenient to think of this as a dry hole, not a discovery well. These calculations apply to principal-business corporations, and specifically not to individuals. The corporations are assumed to be in a fully taxable position. [b]Applies to wells costing in excess of $5 million to drill. [c]Applies to corporations with Canadian ownership rates in excess of 68 percent.

Source: Authors' calculations based on information contained in appendixes 5.1 and 5.2.

this net cost also fell on the Canada lands but by about 30 cents, to approximately 8 or 9 cents. Given that, the observed reallocation of exploration expenditures toward the Canada lands should be less of a surprise. It is also interesting to note that, *overall*, the provisions of the PIP on the geographical frontier had virtually the same marginal effect on net costs to firms of exploration activities as did superdepletion. One of the key differences between these two incentive programs was that superdepletion was a tax-based system, while the PIP was based on cash grants. The switch from a tax-based to a grant-based system was hailed at the time as a means of getting cash-constrained firms (especially Canadian-controlled firms) into frontier exploration. We have little to offer on this, except to reiterate that over 90 percent of all federal PIP grants were made to firms with high CORs. Petro-Canada and Dome between them, however, received almost 40 percent of all federal PIP grants in the 1981-1985 period. Overall, the top four recipients during that period accounted for more than 55 percent of federal grants made. This suggests that a relatively small number of firms captured a large portion of the benefits offered by the program.

The main conclusions that emerge from the discussion in this chapter are that since the early 1970s, Canadian energy and tax policy has not only

sought to encourage frontier megaprojects, which displayed, at best, questionable profitability ex ante, but also encouraged a shift in the focus of exploration activity from lower-cost regions in western Canada to higher-cost ones on the geographical frontier. These have been expensive experiments, and ones that have thus far produced disappointing results.

From the private sector's perspective, a key implication of the policy thrust since the early 1970s has been a reallocation toward the public sector of the risks involved in frontier projects. This trend, begun by the first two mineable oil sands projects, was extended to the geographical frontier and institutionalized by the advent of superdepletion and its subsequent replacement by the PIP.

In October 1985, the federal government announced a new policy for exploration (and subsequent development) activities on the geographical frontier.[54] A 25 percent exploration tax credit is extended to all eligible expenditures in excess of $5 million per well. For non-taxpaying investors, this tax credit is refundable at a 40 percent rate. Expenditures per well up to $5 million earn a 25 percent credit against royalties to be levied against any future frontier production. This policy combines elements of the two systems that have been in effect since 1977. For firms in a fully taxable position, the tax credit is similar in its overall impact to superdepletion at a rate of approximately 56 percent. For non-taxpaying firms, the refund provisions are similar to PIP grants at a rate of about 10 percent. Additional royalty and tax expenditures relating to frontier exploration activities are then tied to subsequent development and production. Overall, this marks a return to greater reliance on the tax system to provide incentives to exploration activities on the geographical frontier. The evidence presented in this chapter suggests that this type of incentive system could well prove costly to the public purse, while continuing the trend of having the public sector assume a large proportion of the risks associated with frontier oil and gas activities. In addition, the idea of tying expenditure and revenue streams from specific projects for the purposes of taxation seems desirable from the perspective of improving the efficiency of the royalty and tax system. It should also be noted, however, that this will likely increase the pressure for concessions by proponents of projects exhibiting questionable economic viability ex ante, in order to allow them to proceed with development and production and thus realize the full value of the benefits "earned" by the exploration activities. If the federal government were to yield to such pressures, an even greater proportion of the risks associated with oil and gas megaprojects on the geographical frontier would end up being borne by the public.

[54] See Canada, Department of Energy, Mines and Resources, *Canada's Energy Frontiers: A Framework for Investment and Jobs* (Ottawa: Supply and Services, 1985).

10

Evaluation of Alternative Policies: Effects on Revenues and Rents

Introduction

Since the early 1970s, so many oil and gas policy regimes have come and gone that even specialists lose track of what provisions were in place during which years.[1] Not only were changes in the tax and royalty system frequent (see chapter 5), but they were also accompanied by the creation of a complicated system of price regulations for both crude oil (see chapter 3) and natural gas (see chapter 4) as well as the implementation of tighter export controls in response to concerns about security of supply. It has been suggested that these rapid and often unpredictable policy changes have caused needless political tensions and created an uncertain planning environment for oil and gas producers.

In this chapter, we ask whether a stable policy regime would have been better able to cope with the fluctuations in world market conditions. The interactions among the tax and royalty regimes, the regulated pricing system, export policies, and changes in world market conditions are complex. We first separate the effects of the regulated market system from changes in tax and royalty regimes; then we compare the effects of two stable alternative tax and royalty systems with the actual pattern of tax and royalty changes. For this, we use the MACE model of the Canadian economy,[2] which incorporates the energy demand model described in chapter 6 and the oil and gas supply model developed in chapter 8, to compare five main policy regimes:

1) The actual pattern of changing tax structures and rates, with historical pricing policies ("historical prices and taxation policies" or "ACTUAL" in the text, tables, and figures). Although they were not "actual" at the time of assessment, we incorporate the changes proposed in

[1] This chapter draws from and extends the analysis in John F. Helliwell, Mary E. MacGregor, Robert N. McRae, and André Plourde, *Oil and Gas Taxation in Canada: An Analysis of Developments Since the Royal Commission on Taxation*, PEAP Energy Study no. 87-2 (Toronto: University of Toronto, Institute for Policy Analysis, 1987), sections 8 and 9 (forthcoming in a special issue of the *Osgoode Hall Law Journal*).

[2] The version of the MACE model used in this analysis is described in John F. Helliwell, Mary E. MacGregor, Robert N. McRae, André Plourde, and Alan Chung, "Supply Oriented Macroeconomics: The MACE Model of Canada" (July 1987), 4 *Economic Modelling* 318-40.

the federal government's June 1987 tax reform package and confirmed by the December 1987 detailed proposals.[3]

2) The actual pattern of changing tax structures and rates, with unregulated oil and natural gas prices ("price deregulation" or "PDEREG").

3) A "complete" deregulation case, where price deregulation is accompanied by deregulated export volumes as well ("EXPORT").

4) The tax system and royalty rates that were in place before oil prices and royalty rates started to rise in the early 1970s ("the pre-reform system" or "PREREF").

5) The current tax regime, involving somewhat higher royalty rates than in the early 1970s, with royalties being non-deductible for federal income tax purposes, but with a resource allowance ("the current system" or "CURRENT"). It also includes the lower federal tax rates and capital cost allowance (CCA) changes announced in the 1987 tax reform package.[4]

All assessments are made using the actual pattern of world oil prices, but in all cases except the historical one (ACTUAL), we assume that Canadian oil and natural gas prices were unregulated and therefore rose and fell in concert with movements in world prices. In the analysis of the actual system, we compare the actual results with what they would have been had domestic energy prices been unregulated (PDEREG) or what they would have been if both prices and export volumes had been deregulated (EXPORT). This shows the relative importance of price and export regulation in determining the changing size and distribution of energy revenues.

The main objectives of the assessment are to see to what extent the actual pattern of complex energy taxes and regulations sheltered Canadian energy users and producers from changes in world markets, and to assess the extent to which the distribution of energy revenues, energy industry activity, and energy demand would have been different under any of the alternative systems under review. The results reported in all the figures and tables in this chapter are based on simulations of the MACE model of the Canadian economy.

Historical Prices and Taxation Policies (ACTUAL)

The pattern of regulated prices and tax changes that evolved during the 1970s and early 1980s was largely a response to a rapidly changing world oil market. Regulated domestic prices insulated both Canadian consumers and producers from the full effects of changes in world oil prices. Despite this insulation, Canadian energy prices still rose more rapidly than did the overall price level in the economy. Domestic requirements for crude oil generally declined, while the demand for natural gas increased. Real invest-

[3] In particular, our modelling does not include the provisions of the December 1, 1987 changes in Alberta natural gas royalties described in chapter 4, under "Subsequent Developments," and in appendix 5.2.

[4] The exception noted in the previous footnote also applies here.

ment in the energy industry[5] more than doubled between 1974 and 1985. Net government energy revenues, particularly those from the upstream oil and gas industry, increased steadily.

Part of the increase in government revenues was due to increases in wellhead prices of crude oil and field prices of natural gas, but a large part was attributable to increases in provincial royalty rates and the introduction by the federal government of special industry taxes or tax provisions when world oil prices were increasing rapidly. The average wellhead price of crude oil, for example, increased sixfold between 1974 and 1985; the after-tax prices received by producers for new oil increased by a factor of five. Rates of return for the upstream oil and gas industry increased from around 10 percent in 1974 to a maximum of just under 18 percent in 1980, as shown in figure 10.1.[6] Rates of return for crude oil increased sharply in the early 1980s with the introduction of world-equivalent pricing on new oil production in 1982. This was more than offset, however, by the decreased rate of return on natural gas production. The combined rate of return falls sharply in 1986 with the drop in world oil prices from around US$27 per barrel in 1985 to US$15 per barrel in 1986. We have assumed that the recovery apparent in world oil prices at the beginning of 1987 will be sustained,[7] and this accounts for the gradual recovery in the overall rates of return to around 8 percent, which is still below the levels prevailing during the 1970s.

An indication of how the net economic benefits from Canadian crude oil and natural gas production are distributed among producers, consumers, and governments under the historical pricing and taxation policies is found in figure 10.2. These annual flows have been converted to 1971 dollars in order to facilitate year-to-year (and later, case-by-case) comparisons.[8] As is evident in the figure, the provincial governments tended to reap most of the

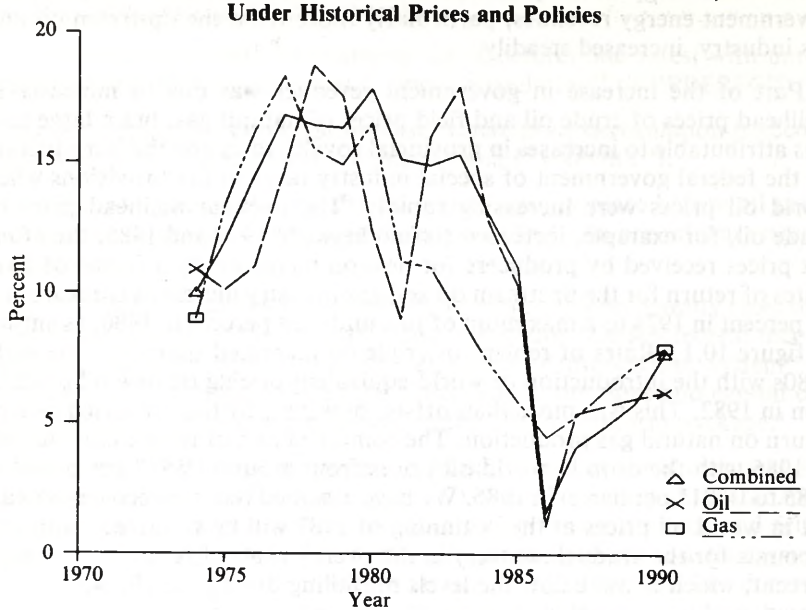
[5] This is defined to include electricity generation in addition to the oil and gas industry.

[6] The total rate of return shown in figure 10.1 includes oil sands, while the rate of return for crude oil is for conventional production only. This is why the combined rate of return does not always lie between the rates for natural gas and oil.

[7] In our projection period, we assume that 1987 world oil prices will average US$18 per barrel, and that they will grow at the US rate of inflation thereafter. We also assume that domestic natural gas prices will be equal to 85 percent of the BTU-parity oil price, starting in 1987.

[8] Economic rents to consumers are the compensated consumer surpluses accruing between domestic and opportunity prices. Opportunity prices are defined as the equivalent world price, plus transportation adjustments, plus non-tax markups, plus an indirect tax opportunity cost equal to the rate prevailing in the non-energy sector. Producer rents are equal to wellhead (or field, as appropriate) revenues net of operating costs, all taxes and royalties, land payments, economic depreciation, and an after-tax charge on unamortized capital. Rents to provincial governments are equal to revenues from income taxes, royalties, land payments, and the equity interest in Syncrude, net of incentive payments, royalty abatements, and a real tax opportunity cost of about 1 percent of invested capital. They also include excise tax revenues (for both producing and consuming provinces) over and above those that would have been collected by the provinces at the indirect tax rates prevailing in the rest of the economy. Rents to the federal government are defined as the sum of income and other taxes on the oil and gas industry, consumer taxes on oil and natural gas, less subsidy and incentive payments and a real tax opportunity cost of about 2 percent of invested capital. Federal excise tax revenues have been adjusted to take account of the opportunity cost of indirect taxes as well.

Figure 10.1 Rates of Return for Oil, Gas, and Combined, Under Historical Prices and Policies

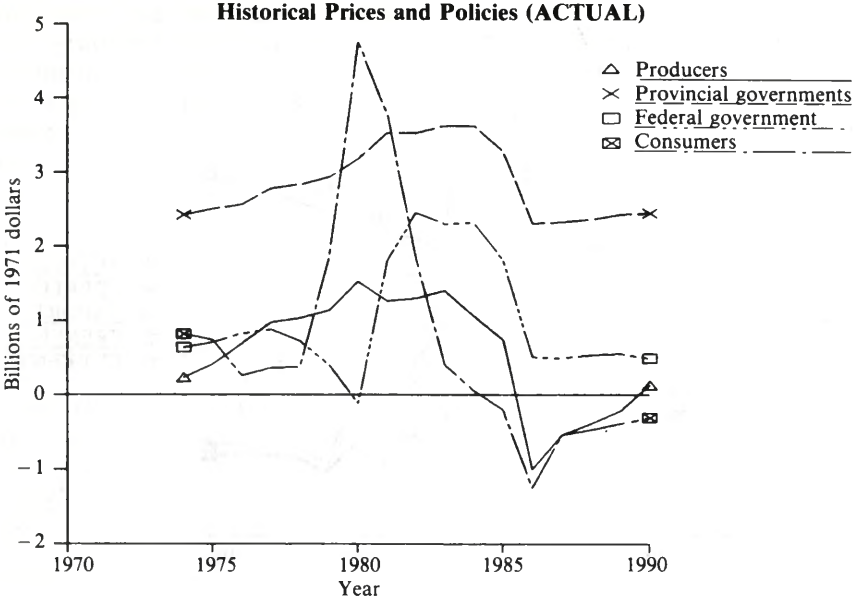


economic benefits from oil and natural gas production and consumption during the 1970s. They benefited not only from increased revenues from the industry (mainly in the form of royalties and land payments), but also from the higher-than-average indirect tax rates prevailing on oil and natural gas consumption. These higher-than-average excise taxes mitigate the positive impact for consumers of keeping oil prices below domestic levels; although consumer rents show a sharp peak in 1980, they fall sharply and become negative (because of higher-than-average indirect taxes) when domestic prices reach world levels. Excise tax revenues also help to offset the costs of the oil import subsidy program for the federal government, so that federal rents are generally positive, except during the height of the second OPEC oil price shock. Rents to the federal government also rise during the early 1980s with the introduction of a number of special taxes on the industry as part of the national energy program (NEP) and 1981 energy agreements. Producer rents rise gradually during the 1970s, but plunge sharply in 1986 as a result of the fall in world prices.

Price Deregulation (PDEREG)

In our price deregulation case, we have assumed that all domestically produced oil would receive the equivalent of the world price, and that the delivered price of natural gas in eastern Canada would be equal to 85 percent of the BTU-equivalent delivered oil price. Natural gas export prices are also assumed to equal 85 percent of the BTU-equivalent world oil price. Although our oil price assumptions are not controversial, our assumptions about natural gas prices under price deregulation are more precarious.

Figure 10.2 Flow Rents from Oil and Gas, Under Historical Prices and Policies (ACTUAL)



Given the highly regulated nature of the natural gas market, the past swings from expected shortfalls to large surpluses, and the uncertainty as to the effects of price deregulation in the future, our assumptions about what deregulation would have meant in the past should be viewed mainly as illustrative of how a market-sensitive pricing system might have functioned.

In this case, we assume that, except for prices, everything would have remained the same as in our historical base case. By assuming that taxes, royalty rates, export volumes, and other policies are unchanged, we can separate the effects of historical pricing policies from the many changes in taxes and royalties that accompanied price regulation. This will later allow us to compare the effects of the historical pattern of tax changes with several more stable regimes in order to assess how they contributed to or subtracted from the stability of industry revenues and investment.

The most obvious outcome of our deregulation pricing system is the higher prices producers would have received for both oil and natural gas during the 1970s and the first half of the 1980s. Average wellhead prices for crude oil would have been anywhere from 15 to 111 percent higher, and field prices of natural gas would have been from 7 to 250 percent higher.[9]

[9]The differences in oil prices are strictly a function of how far domestic prices were below world levels and of any resulting differences in the exchange rate. Natural gas prices, however, are a function of both changes in the BTU-parity pricing rule and higher oil prices. Lower BTU-parity pricing rules were in effect before 1976 and after 1980 when the NEP and 1981 energy agreements lowered the BTU-parity ratio from 85 percent to 65 percent. There are also big increases in natural gas export prices, especially in 1974, because of the assumption of a constant 85 percent BTU-parity pricing rule.

Figure 10.3 Ratio of After-Tax Prices to After-Tax Costs, Oil

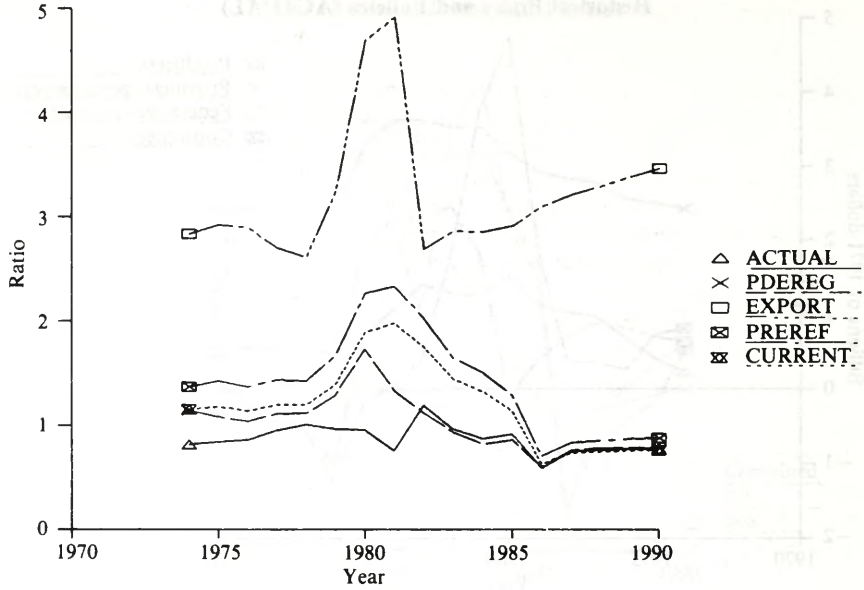
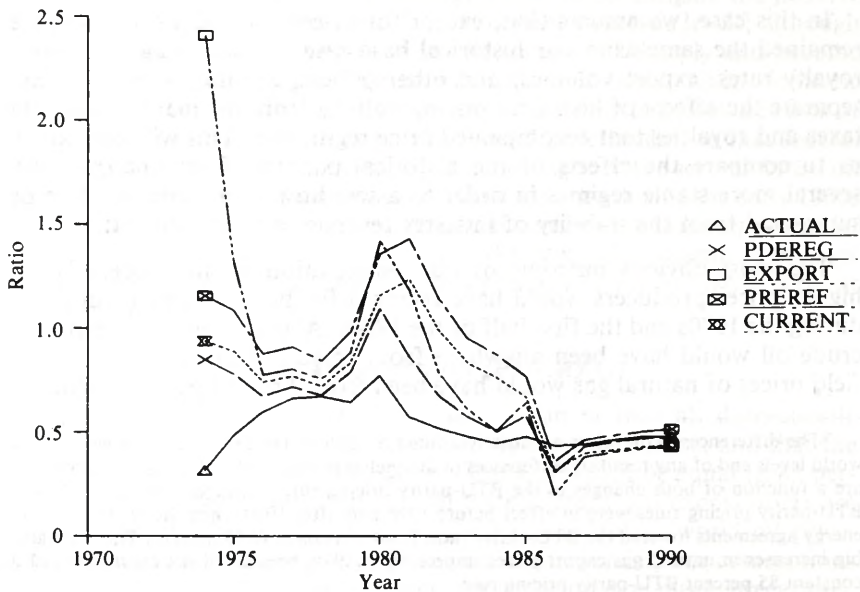


Figure 10.4 Ratio of After-Tax Prices to After-Tax Costs, Gas



In our expected-discoveries model developed in chapter 8, changes in oil and natural gas investment are driven by changes in the after-tax profitability ratio averaged over three years, and changes in land payments, which are themselves driven by changes in the after-tax profitability ratio.[10] The increases in producer prices outweigh the increases in producer-borne costs under deregulation (see figures 10.3 and 10.4),[11] so that oil and gas investment, discoveries, and indeed the ultimate stock of recoverable reserves all would have been much higher in the price deregulation case. Real energy investment would have been around 5.7 percent higher on average between 1974 and 1985, although, as table 10.1 suggests, these differences become smaller as prices approach world levels.

Although higher wellhead and field prices result in increased investment and productive capacity for both oil and natural gas, actual production levels tend to be lower. As explained in chapter 8, production of conventional oil and natural gas is endogenous in MACE. If the maximum productive capacity from previously connected reserves is not sufficient to meet domestic requirements[12] plus export commitments, additional reserves (if available) are connected and put into production. Connected reserves may also be produced at less than the maximum rates if total requirements are less than the maximum productive capacity. This is in fact what happens in the price deregulation case, since exports are held at their historical levels, and domestic demand falls because of higher consumer prices. This is especially important for natural gas. Overall energy prices to consumers are up by 17 percent on average over the 1974 to 1985 period, and at the peak of world prices in 1980 they are 40 percent higher. Canadian crude oil requirements are down an average of 7 percent (reducing oil imports by 25 percent), while the demand for natural gas is down an average of 17 percent. The price increases for users are much larger for natural gas than for oil products. Over the 1974 to 1985 period, prices to final users are up an average of 52 percent for natural gas compared with 16 percent for oil products.

Consumers are clearly worse off in our price deregulation case. What of producers and governments? Revenues to both increase as a result of price deregulation, but have net economic rents also increased? The changes in flow rents to producers, consumers, and the federal and provincial governments are shown in figure 10.5. Obviously, price deregulation results in a shift in the net economic benefits from oil and gas consumers to producers and governments.

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[10] See chapter 8 for a more detailed description.

[11] PIP grants, investment tax credits, etc., reduced the proportion of costs that were borne by producers.

[12] For crude oil, domestic requirements are equal to the demand for crude oil in the four western provinces plus the throughput of the Montreal pipeline. For natural gas, they are equal to total domestic demand.

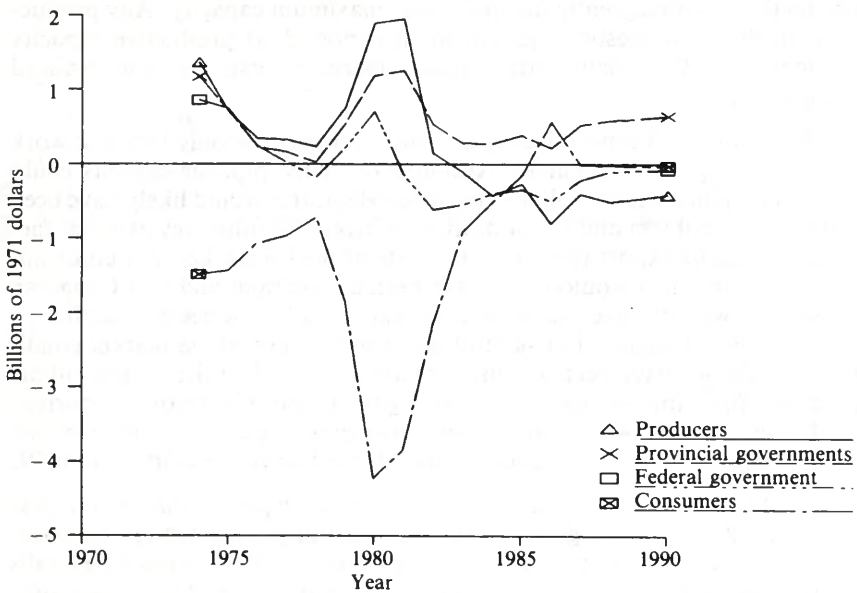
Table 10.1 Effects of Deregulating Prices and Export Volumes, PDEREG and EXPORT
(percentage change from ACTUAL)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1990
Real energy investment													
PDEREG	2.21	4.35	8.07	6.07	5.10	5.55	11.86	15.14	7.93	2.77	−0.71	0.16	1.56
EXPORT	2.32	4.60	13.28	14.37	11.22	15.26	17.33	21.70	14.85	8.44	2.77	2.27	2.30
All-government energy balance (level differences in billions of dollars)													
PDEREG	2.53	2.34	1.08	0.96	0.20	3.03	9.02	7.17	1.87	0.24	0.10	0.18	2.24
EXPORT	3.02	3.96	3.31	3.38	3.91	4.09	14.59	15.68	7.10	2.37	1.77	1.30	−0.04
Energy trade balance (level differences in billions of dollars)													
PDEREG	0.77	0.41	0.08	0.05	−0.07	0.43	0.89	2.53	1.16	0.74	0.93	2.56	4.22
EXPORT	1.30	2.50	2.69	3.03	4.08	2.91	6.95	10.98	7.63	5.87	4.85	4.62	0.66
Production of crude oil													
PDEREG	−0.47	−1.67	−3.12	−3.45	−3.62	−4.34	−7.15	−3.23	−7.28	−5.13	−3.96	3.76	29.84
EXPORT	2.10	22.56	30.33	24.97	23.95	17.92	29.26	46.50	36.98	30.95	22.95	18.77	6.72
Production of natural gas													
PDEREG	−7.99	−10.89	−10.15	−9.32	−8.49	−9.23	−12.89	−14.46	−15.02	−14.62	−12.69	−10.66	−2.36
EXPORT	3.94	2.77	2.09	8.50	28.37	−8.76	−12.25	−13.64	−14.03	−13.54	−11.69	−9.72	−0.56

Note: The base case used here is ACTUAL, the historical pattern of prices and taxes.

Source: Authors' calculations based on results of simulations of the MACE model.

Figure 10.5 Changes in Flow Rents from Oil and Gas Under Price Deregulation (PDEREG)
(level differences from ACTUAL)



Price Deregulation and Endogenous Exports (EXPORT)[13]

The results of the preceding section suggest that if Canadian oil and gas prices had been allowed to track world prices during the 1970s, more conventional reserves would have been discovered, but that in the presence of export controls, the reduction in Canadian energy demand would have resulted in somewhat lower production levels. What would have happened if export volumes as well as prices had been unregulated and Canadian producers had been free to sell their surplus production in the United States?

[13] A reading of the main provisions concerning trade in oil and natural gas in the proposed Canada-US free trade pact suggests that, at least in the short run, its implementation would not likely have much impact on the institutional setting for oil and gas trade. In the post-western-accord world, Canadian producers are free to export whatever volumes of crude oil they wish to, at negotiated prices. This type of market-responsive behaviour is captured adequately by our EXPORT case. As far as natural gas is concerned, however, our treatment of Canada-US trade is less likely to provide an accurate depiction of the post-natural-gas-agreement, post-border-pricing-test, post-NEB-surplus-test world. This is primarily due to the implications of the continuing surplus of productive capacity in Canada and the United States and to the fact that US gas supply, demand, and prices are not modelled in MACE. Technological and other non-institutional barriers, however, will continue to prevent Canadian producers from selling their gas outside of the North American market. The provisions of the proposed free trade agreement are outlined in Canada, Department of External Affairs, *The Canada-US Free Trade Agreement* (Ottawa: the department, 1987). A discussion of the possible effects of this agreement on the Canadian energy sector can be found in Canada, Department of Energy, Mines and Resources, *The Canada-US Free Trade Agreement and Energy: An Assessment* (Ottawa: Supply and Services, 1988).

In our deregulated export case, we effectively assume that there is no shut-in productive capacity created by the higher prices. Except for a safety cushion,[14] new reserve additions are connected as they are discovered, and production is subsequently maintained at maximum capacity. Any production surplus to domestic requirements is exported. If productive capacity declines, or Canadian requirements increase, exports are reduced accordingly.

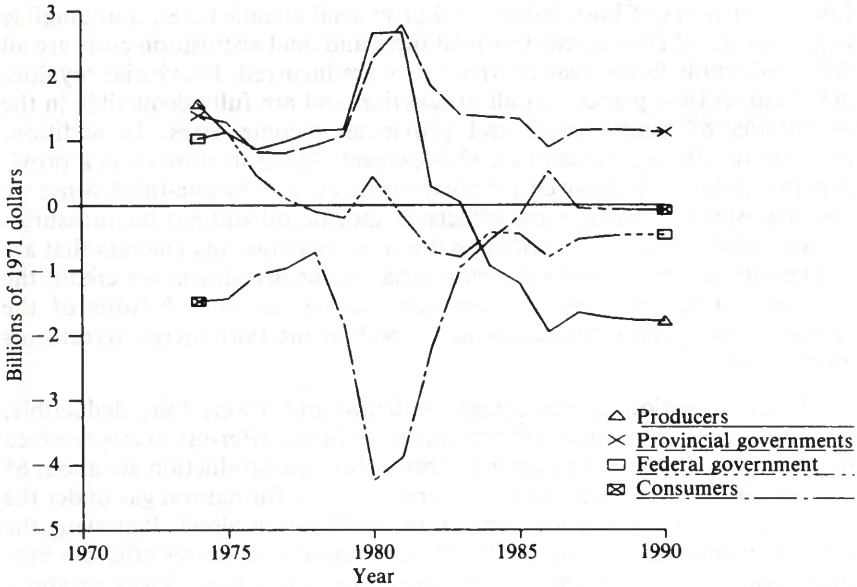
Obviously, NEB export licence decisions were not the only factor at work in determining export volumes. Although restricted pipeline capacity could have constrained export volumes to some extent, this would likely have been a short-run problem and is not dealt with here. The other key external factor constraining export volumes is the state of the US market. For crude oil, we assume that this would never have been a constraint and that Canadian producers would have been able to export all production surplus to domestic requirements. For natural gas, we assume that US market conditions would not have been a constraint until 1979, when the US gas bubble made its first appearance and natural gas exports fell below authorized levels (see chapter 4). In our deregulated export case, we therefore set natural gas export volumes equal to their historical values starting in 1979.

On the whole, the effects of deregulating export volumes are less pronounced for natural gas than for oil. Natural gas production increases by less than 10 percent on average during the pre-1979 period and then falls below base-case levels as export volumes return to their historical levels. Conventional crude oil production, on the other hand, is 25 percent higher on average during the 1974-1985 period. Although the deregulated export volumes are substantially higher than historical levels (by a factor of four in 1981, for example), they never exceed the 1973 peak. Instead of the large cutbacks observed in the historical series, the deregulated export volumes are relatively constant over most of the simulation period, averaging about 260 million barrels per year during the 1974-1985 period and then falling gradually. The effects on the energy trade balance are quite large in some years—an improvement of $11 billion in 1981, for example, compared with an improvement of $2.5 billion for price deregulation alone.

Deregulating export volumes as well as prices almost doubles the effects of price deregulation on real energy investment. The effects on the after-tax profitability ratios are almost the same, but the extra cash flow generated by the additional export volumes boosts land payments and therefore subsequent exploration and development expenditures, according to our model. As figure 10.6 shows, the additional production also increases the rents flowing to producers and both levels of government compared with the case involving only price deregulation. There is almost no difference in consumer rents between the two cases.

[14] This safety cushion is approximately equal to the stock of unconnected reserves at the start of the simulation.

Figure 10.6 Changes in Flow Rents from Oil and Gas Under Deregulation Export Volumes (EXPORT)
(level differences from ACTUAL)



These results highlight the importance of developing markets for Canadian production as well as the importance of finding and developing new productive capacity. Whether the additional export sales would actually have taken place if export volumes had been unregulated is another question entirely. We have made the very strong assumption that any new reserve additions could have been immediately connected and produced at maximum capacity, and the excess sold in the US market. Canadian producers must compete with a number of other potential suppliers in the US market, therefore the US demand for Canadian exports is likely to be substantially more elastic than its overall demand for oil and gas. Transportation costs and the availability of existing pipeline capacity are also important factors in determining how well Canadian production can compete in US markets. Since MACE does not model the US demand for Canadian exports, we use our export deregulation case to highlight the potential importance of the export market, but assume that exports are equal to their historical values for the remainder of the analysis. Therefore, in the remainder of this chapter, we concentrate on comparing the historical pattern of tax and royalty changes with two stable alternatives, assuming the same deregulated pricing system in all three cases.[15]

[15] In the following two sections, effects will thus be measured as deviations from the results obtained under our price deregulation case.

The Pre-Reform System (PREREF)

Our first alternative is essentially the system that was in place before tax reform was introduced in 1971, referred to herein as the pre-reform system. For the purposes of both federal and provincial income taxes, non-tangible exploration and development expenditures and land acquisition costs are all fully deductible in the year in which they are incurred. Provincial royalties are equal to 16⅔ percent on all production and are fully deductible in the calculation of both federal and provincial income taxes. In addition, resource profits are subject to a 33⅓ percent depletion allowance, a provision that reduces effective corporate income tax rates by one-third. Since we are interested primarily in the effects of specific oil and gas tax measures, we have maintained the historical pattern of corporate tax changes that are not specific to the oil and gas sector—that is, the investment tax credit, the half-year CCA, and general corporate income tax rates.[16] None of the special industry taxes introduced in the NEP or the 1981 energy agreements are in effect.

The combination of percentage depletion and lower, fully deductible, provincial royalties results in large increases in the after-tax prices received by producers. In the 1970s, after-tax prices for new production are about 65 percent higher for crude oil and 73 percent higher for natural gas under the pre-reform system compared with price deregulation alone. Removing the petroleum and gas revenue tax (PGRT) substantially increases after-tax producer prices in the early 1980s: in the pre-reform case, these prices are about 140 percent higher in 1981 but only 80 percent higher in 1980 (when the PGRT was not in effect).

The constant-dollar values of capital and operating costs also show increases of 20 to 40 percent, however, moderating the effects of the rise in after-tax prices. Increasing the volume of discoveries increases the capital costs of finding new reserves since, in our model, the marginal costs of new reserves increase with cumulative discoveries because of depletion effects. The other, and perhaps more important, factor in the increase in after-tax costs is the fact that the value of the investment tax deductions is reduced under this set of policies. Depletion is no longer tied to the level of investment, so that percentage depletion merely reduces the effective tax rate rather than increasing the write-off available for a given level of investment. The lower effective tax rate also reduces the value of tax write-offs in general. Despite the increases in after-tax costs in this case, the ratios of after-tax prices to costs show substantial increases compared with price deregulation alone, especially during the early years (see figures 10.3 and 10.4). Real energy investment is increased by over 20 percent on average between 1974 and 1985 as a result of the increases in oil and gas investment.

Not surprisingly, net government revenues from oil and gas are down compared with price deregulation alone. The pre-reform taxation system, as

[16]The exception here is in 1974 and 1975, when the federal corporate tax rate for oil and gas has been changed to that prevailing in the rest of the corporate sector.

Figure 10.7 Changes in Flow Rents from Oil and Gas Under the Pre-Reform System (PREREF)
(level differences from PDEREG)

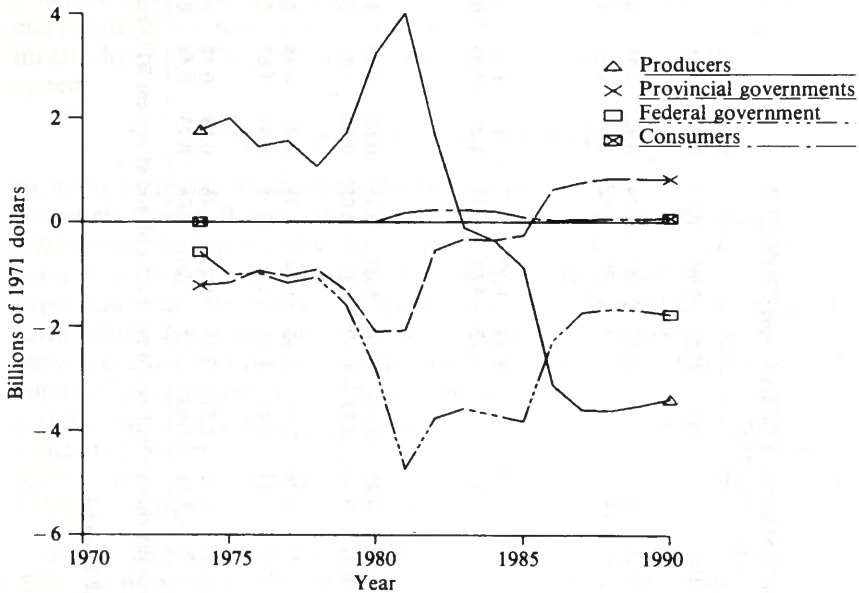


figure 10.7 indicates, results in a transfer of rents from both levels of government to producers. Provincial governments tend to lose more with oil than with natural gas, since oil-related land payments do not increase as much. Furthermore, since land payments are deductible for corporate income tax purposes, the larger increases in land payments for natural gas also mean that rents to the federal government drop more for gas than for oil. Consumer rents are almost unaffected compared with price deregulation alone, but they increase slightly after 1980 with the removal of the Canadian ownership special charge (COSC).

After 1985, however, producers do not fare nearly as well under the pre-reform system as under price deregulation alone, while provincial governments fare better. Under the pre-reform system, producers invest more than they would have under the historical tax system (even with deregulated prices, as table 10.2 indicates), so that when world oil prices fall in 1986, they are holding greater stocks of reserves and face a higher opportunity cost of doing so. Provincial governments, on the other hand, benefit from higher income tax revenues with the elimination of the royalty tax credit (which was increased in 1985) and generally higher production levels. Higher after-tax prices for producers also result in higher land payments

Table 10.2 Effects of Alternative Taxation Systems, PREREF and CURRENT
(percentage change from PDEREG)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Real energy investment																	
PREREF	1.53	16.05	27.54	18.42	17.51	18.46	27.66	29.84	28.69	24.24	19.23	23.41	13.59	6.14	4.58	4.51	4.81
CURRENT	0.32	7.56	12.76	8.50	7.20	6.55	9.38	11.07	13.98	12.56	10.87	13.39	8.62	3.01	1.77	1.60	1.60
All-government energy balance (level differences in billions of dollars)																	
PREREF	−1.10	−1.17	−1.70	−1.16	−1.75	−1.70	−2.59	−4.97	−9.26	−9.18	−8.99	−8.97	−4.77	−2.29	−1.93	−1.24	−0.91
CURRENT	−0.78	−0.74	−0.80	−0.40	−0.81	−0.45	−0.32	−1.17	−5.13	−5.16	−5.47	−4.67	−3.53	−1.41	−0.89	0.01	0.62
Energy trade balance (level differences in billions of dollars)																	
PREREF	0.00	−0.01	−0.04	−0.08	−0.12	−0.17	−0.29	−0.30	−0.43	−0.48	−0.14	−0.08	0.15	0.60	1.13	1.51	1.86
CURRENT	0.00	0.00	−0.02	−0.04	−0.06	−0.07	−0.12	−0.12	−0.16	−0.21	−0.10	−0.08	0.05	0.39	0.85	1.17	1.44
Production of crude oil																	
PREREF	0.00	0.13	0.53	1.02	1.38	1.52	1.78	2.15	2.56	2.57	2.42	1.84	1.38	2.75	4.85	5.88	6.83
CURRENT	0.00	0.05	0.24	0.46	0.63	0.66	0.72	0.87	1.11	1.24	1.31	1.15	0.95	2.47	4.63	5.61	6.44
Production of natural gas																	
PREREF	0.02	0.12	0.37	0.64	0.88	0.99	1.20	1.74	2.46	2.74	2.17	1.77	1.46	0.88	0.38	0.03	−0.18
CURRENT	0.00	0.05	0.17	0.30	0.41	0.43	0.50	0.75	1.08	1.40	1.35	1.20	1.08	0.75	0.44	0.19	0.04

Note: The base case used here is PDEREG, the actual pattern of tax and royalty changes with world pricing for oil and 85 percent BTU-parity pricing for natural gas.

Source: Authors' calculations based on results of simulations of the MACE model.

under the pre-reform system.[17] In addition, royalty revenues are lower under the pre-reform system than under price deregulation, but after 1984 the differences become less pronounced. This is because the price deregulation case incorporates the effects of the 1985 and 1986 reductions in provincial royalty rates, so that by the end of the simulation period, these rates are much closer to the constant royalty rates prevailing in the pre-reform system.

The Current System (CURRENT)

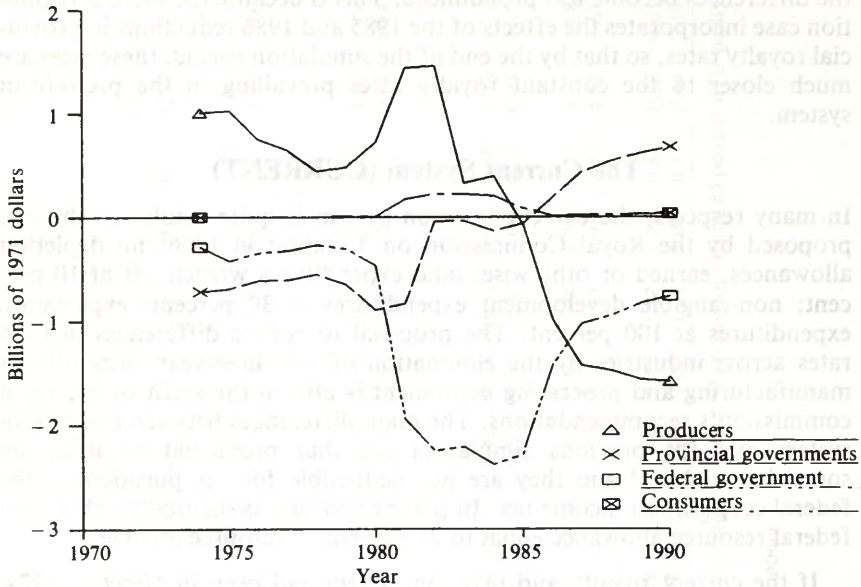
In many respects, the current taxation system is quite similar to the one proposed by the Royal Commission on Taxation in 1966: no depletion allowances, earned or otherwise; land expenditures written off at 10 percent; non-tangible development expenditures at 30 percent; exploration expenditures at 100 percent. The proposal to reduce differences in CCA rates across industries by the elimination of the three-year write-off for manufacturing and processing equipment is also in the spirit of the royal commission's recommendations. The main differences between the current system and the previous simulation are that provincial royalties are somewhat higher,[18] and they are not deductible for the purposes of the federal corporation income tax. In place of royalty deductibility, there is a federal resource allowance equal to 25 percent of resource income.

If the current royalty and taxation system had been in effect in 1974, after-tax prices to producers would have been larger than under price deregulation with the historical tax policies, but the differences are only about two-thirds as large as under the pre-reform system. The increase in after-tax costs tends to be somewhat smaller than under the pre-reform system because of the earlier introduction of the half-year CCA rule and the lower CCA rates. Income tax rates would also be lower and reduce the value of any available write-offs. The differences between the price deregulation case and our CURRENT case are small toward the end of the simulation. The increases in real energy sector investment, therefore, are more moderate than under the pre-reform system (see table 10.2). As figure 10.8 suggests, the current policies would have increased rents flowing to producers during the initial part of the simulation period, mainly because of the lower royalty rates in effect. After 1985, royalty rates are roughly the same in this simulation and the price deregulation case, but production levels are higher (particularly for oil) and result in an increase in provincial royalty revenues. Land payments are also higher than in the price deregulation case, so provincial rents increase after 1986. The increases are not as large, however, as

[17] In the flow rent equations, land payments are written off as reserves are produced, and unit land costs are expressed as the unamortized stock of land payments per unit of current production. Since land payments increase proportionately more than production in the pre-reform case, the unamortized stock of land payments per unit of current production is much larger.

[18] In this case, we have used the provincial royalties that will be in effect once the changes announced in 1985 and 1986 have been fully implemented. They also include the effects of royalty reductions for low productivity wells and various provincial incentive systems.

Figure 10.8 Changes in Flow Rents from Oil and Gas Under the Current System (CURRENT)
(level differences from PDEREG)



in the pre-reform case. Rents to the federal government also rise because of the earlier elimination of earned depletion and the lower CCA rates.[19]

Taxation and Risk Sharing

The final issue to be addressed is the extent to which instability in the tax system contributed to instability in the operating environment for the industry. Table 10.3 shows the average rates of return for conventional crude oil, natural gas, and the two (including oil sands) combined over the 1974 to 1985 period and the 1974 to 1990 period, along with the standard deviations for each period. The actual pattern of prices and policies consistently gives the lowest average after-tax rate of return, while the pre-reform system gives the highest. Deregulating export volumes as well as prices has a relatively small impact on rates of return for gas, compared with price deregulation alone. The effects for oil are larger, but not as large as for either of the two stable tax and royalty regimes.

An interesting feature of these results is that the stable taxation policies tend to provide the most variable rates of return for the industry. Part of the increase in variability is due to the higher variability in returns when domestic oil prices respond fully to changes in world oil prices. The stable tax regimes also tend to have lower marginal tax rates, however, and thus

[19] The federal corporate income tax rates at the end of the simulation period are the same in both cases.

provide the highest pass-through to producers of the effects of any change in world prices. These tax systems yield the highest investment responses during the boom time of 1979-1981 and lead to lower rates of return after the slump of 1986. The actual pattern of prices and taxes had the lowest level of investment and therefore the highest rates of return in the period after 1983 (this is even more true of the post-1985 period) when world oil prices began to fall.

This result does not mean that a constantly changing tax policy provides the most certain environment for investment planning, but it does illustrate that investor uncertainties about future tax policies may in part offset the uncertainties caused by the variability of future prices for oil and gas. This will be so if the general pattern of the changes is to raise tax rates when oil prices are high and to lower them when oil prices are low. In our model, investors are assumed to respond to recent prices and costs when making their current investment decisions. This is no doubt oversimplified, because wise investment planners may not want to alter their plans substantially in response to what may be temporary changes in prices and tax rates. It is probably true, however—as indicated by, among other things, the big cycles in the bid prices paid for drilling rights sold at auction—that the cycles of optimism and pessimism about net returns exaggerate the effects that current prices will in fact have on the present value of revenues from oil and gas wells with production lives extending 30 or more years into the future.[20]

Changing tax policies impose another cost that is difficult to quantify: if tax policies are thought to be subject to change under political pressure, then it becomes rational for industries to invest substantial resources in political efforts designed to improve the position of their own industry or activity relative to other industries and activities. From the point of view of the system as a whole, however, the political volatility of the tax system imposes a real cost, since the efforts of each taxpayer group to increase its own benefits require real resources. This offers the prospect of a tax system that has substantial non-neutralities that lower the efficiency with which the nation's resources are allocated among alternative industries and activities.

Our results do seem to show that the taxation system as it evolved in response to changing external conditions—increasing the tax burden in the boom times and backing off when times got rough—served to dampen the investment swings that are perhaps the inevitable consequence of a highly volatile world market. There is also no doubt that without the collapse in world prices in 1986, the historical policies that retarded investment would not have looked nearly as attractive as they do today.

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[20]The short horizon for expectations, and hence the overresponse to current policies, events, and market conditions, may be due in part to similar behaviour on the part of institutional investors. Evidence of the myopia of share-market expectations may be found, for example, in Robert J. Shiller, "Do Stock Prices Move Too Much To Be Justified by Subsequent Changes in Dividends?" (June 1981), 71 *American Economic Review* 421-36; and S.J. Nickell and S.B. Wadhwani, *Myopia, the "Dividend Puzzle," and Share Prices*, Discussion Paper no. 155 (London: Centre for Economic Policy Research, 1987).

Table 10.3 Average Rates of Return Under Alternative Taxation and Pricing Systems

	ACTUAL	PDEREG	EXPORT	PREREF	CURRENT
			percent		
Oil (excluding oil sands)					
1974-1985	13.4	17.7	22.3	25.8	24.5
	(3.4)	(5.3)	(7.7)	(10.0)	(8.0)
1974-1990	10.9	14.2	16.6	19.2	18.6
	(5.0)	(7.3)	(11.1)	(13.4)	(11.5)
Gas					
1974-1985	12.4	15.6	16.7	19.5	16.4
	(4.0)	(8.4)	(10.9)	(16.7)	(11.0)
1974-1990	10.6	12.0	11.7	13.7	11.9
	(4.4)	(9.1)	(12.0)	(16.7)	(11.6)
Oil and gas (including oil sands)					
1974-1985	14.4	17.1	18.7	21.7	19.8
	(2.4)	(5.8)	(7.7)	(12.6)	(9.0)
1974-1990	11.6	13.2	13.3	15.7	14.6
	(5.1)	(8.0)	(10.7)	(14.2)	(11.1)

Note: Numbers in parentheses are standard deviations.

Source: Authors' calculations based on results of simulations of the MACE model.

Our results, and the history of oil and gas taxation in Canada, show that there is another important element to this issue that comes to the fore when an industry operates in an environment of uncertain and highly variable prices. In these circumstances, a tax system, to be politically viable, must produce a distribution of revenues that is perceived to be fair, not just on average over a 30-year horizon, but over a much shorter period. In Canada, as in most countries, the oil and gas taxation systems that were designed and applied in an environment of oil costing less than US$3 per barrel were not sustainable with oil at US$30 per barrel. Similarly, the systems brought in with oil at US$30 per barrel generally required many changes when oil prices dropped to US$10 or US$15 per barrel.

In a federal structure of government with resource ownership in the hands of the provinces, it is probably more efficient if the federal tax structure is kept as equal as possible among industries, with the political viability and return-stabilizing features of the tax and royalty system being designed and implemented by the provincial governments, in the case of resources located in lands under provincial jurisdiction. If the resulting interregional variations in tax and activity levels pose political and efficiency problems, as they have done almost continuously in the Canadian context, then the remedy is probably better found in more robust systems for general fiscal equalization, and not in industry-specific tax provisions.

11

Evaluation of Alternative Policies: Macroeconomic Effects

Introduction

This chapter discusses the main ways in which changes in the energy sector, originating either in Canada or in world markets, have had macroeconomic effects on the Canadian economy. All of the quantitative analysis undertaken in this chapter is based on the results of MACE model simulations. We consider first the consequences of domestic energy pricing and taxation policies. We then consider comparable evidence on the consequences of changes in world oil prices. The ensuing section deals with macroeconomic effects of changes in the prices and quantities of Canadian energy exports. We then consider the macroeconomic effects of energy megaprojects, making the distinction between the construction and operations phases, with the effects of the operations phase being akin to those of an increase in energy exports, or a reduction in energy imports. The final section discusses the macroeconomic aspects of a major theme of our entire study: the interactions between the effects of domestic policies and world events. In that section we assess the extent to which changes in domestic policies have either offset or amplified the macroeconomic effects of changes in world oil prices.

Macroeconomic Effects of Domestic Policies

The main Canadian policies relating to the domestic pricing of oil and natural gas were the outcome of a complex process, described in chapters 3 and 4, whereby Canadian oil and natural gas prices were held down by federal government regulation during the late 1970s and early 1980s. Through these policies, the government of Canada sought to achieve two broad objectives: that of mitigating the short-term macroeconomic effects of rapidly rising energy prices, and that of transferring some of the economic benefits from the energy-producing to the energy-consuming regions of the country.

There is much evidence and analysis to suggest that the 1973-74 and 1979-80 rises in the world price of crude oil played an important role in raising overall inflation rates and reducing the real rate of economic growth. This combination of lower growth and higher inflation has come to be known as "stagflation." For oil-importing countries, the stagflationary effects of higher crude oil prices can arise from either the direct or the indirect effects of the higher prices. The direct effects have been analyzed either with reference to the role of energy as an important input to the

domestic production process, or by emphasizing the effect of oil prices on the terms of trade of oil-importing countries. The former analysis, which has been extensively studied by Bruno and Sachs[1] and others, emphasizes that any increase in the price of an imported raw material diminishes the margin between the available price for output and the wage rate. Firms respond to these pressures, which are analogous to the effects of a slowdown or reversal of technical progress, by raising their final output prices, reducing their output, and attempting to substitute other factors for the import whose price has risen. If the possibilities of substituting capital, labour, or other materials for the imported oil are very great, then the stagflationary effects are correspondingly reduced.

The analysis based on the terms of trade is similar to the above, despite what appear to be important differences.[2] The rise in the price of imports raises the average absorption (or spending) price (and hence puts a squeeze on the real wage as perceived by wage and salary earners) but does not increase the price of domestic output or GNP (the GNP deflator).[3] What happens next depends a great deal on how wages and salaries are set. If wages and salaries respond fully to changes in the spending price,[4] then there will be an increase in the wage rate relative to the price of domestic output, leading firms to hire fewer workers and to produce less output. If, by contrast, the wage bargain depends more on the output price than on changes in spending prices, then the wage rate will rise less, and employment and output will fall by less, reducing the stagflationary effects of the higher oil prices. This analysis emphasizes that the higher oil price imposes a terms-of-trade loss on oil-importing countries. In these circumstances, real incomes measured in terms of spending prices must fall if the economy is not to suffer induced stagflation on top of the required drop in real incomes.

The parallel between the two analyses of direct effects arises because in both cases there is a need for a drop in the wage rate relative to the final spending price if employment and output levels are to be maintained. In both cases, the analysis suggests that wage flexibility in response to changes in the terms of trade, or in response to increases in the unemployment rate, will reduce the amount of stagflation that an oil-importing country will suffer in response to an increase in the world price of oil. An important qualification to this conclusion is that sharp reductions in real wages that

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[1] Michael Bruno and Jeffrey Sachs, *Economics of Worldwide Stagflation* (Cambridge, MA: Harvard University Press, 1985).

[2] This point is emphasized in John F. Helliwell, "Comparative Macroeconomics of Stagflation" (March 1988), 26 *Journal of Economic Literature* 1-28.

[3] The analysis here is for the case of a country that does not produce any of the commodity whose price has risen. We consider later how things are different for a country like Canada, which produces more energy than it consumes, and hence has a terms-of-trade gain rather than a loss when the price of oil rises.

[4] The consumer price index (CPI) is the specific spending price that is usually used for wage indexation and in discussions about the extent to which wages have kept up with or exceeded changes in the cost of living.

might be triggered by an increase in the price of imports could themselves increase unemployment through the drop in disposable personal income, leading to lower levels of consumer spending.[5]

The above lines of reasoning both involve some indirect and direct stagflationary effects, because the wage responses and consequent employment changes are in response to the changes in the price of imported oil. There is a much broader class of indirect effects that has important implications for countries, like Canada, that are not net importers of energy. These broader indirect effects arise because there is international transmission of stagflation, since the reductions of income and employment in the oil-importing countries induce a reduction in the growth of world trade and hence of the volume of exports of most countries. For Canada, these were the most important of the stagflationary effects of the oil price increases of 1973-74 and 1979-80.

Putting aside these indirect effects flowing through the volume of world trade, is there any reason why oil-producing countries like Canada should suffer stagflation in the face of higher oil prices? The simplest reasoning would suggest that oil exporters must be receiving a terms-of-trade gain that is the counterpart of the terms-of-trade loss faced by oil importers, and that real incomes, real spending, and possibly real output might be correspondingly increased. In addition, a country like Canada with a number of exploitable new sources of energy might also find that investment levels are increased, first in the energy industry itself, and then in other industries that directly or indirectly supply the goods and services used in the new energy projects. These lines of influence are indeed important and have been seen most obviously in the regions or countries (for example, Alberta or Norway) that have the largest gains in income and the greatest amount of induced investment in response to increases in oil prices. Similarly, when oil prices fall, the terms-of-trade losses and the effects of cancelled investment projects are seen most clearly in the regions and countries that are heavily specialized in the petroleum industry.

Does this mean that for Canada as a whole there is not likely to be stagflation in response to higher oil prices (putting aside the important indirect effects acting through the volume of world trade)? As our results show, an important factor offsets, and sometimes dominates, the activity-increasing effects for Canada of increases in oil prices. To explain this factor, it is important to distinguish the producer prices of oil and gas from the prices paid by Canadian users. If there is an increase in the price paid to producers, but not paid by domestic consumers, then the macroeconomic effects are similar to those of a change in the price or volume of energy trade (this is discussed below, under the heading "Macroeconomic Effects

[5] The reason for this is the generally higher propensity to spend for wage and salary income than for profits and taxes. Hence, any redistribution of income away from wages and salaries can cause a short-term reduction in income and employment. This possibility lay at the centre of many discussions in the 1930s—as it still does today—about the macroeconomic effects of large drops in wage levels as a means of fighting stubbornly high levels of unemployment.

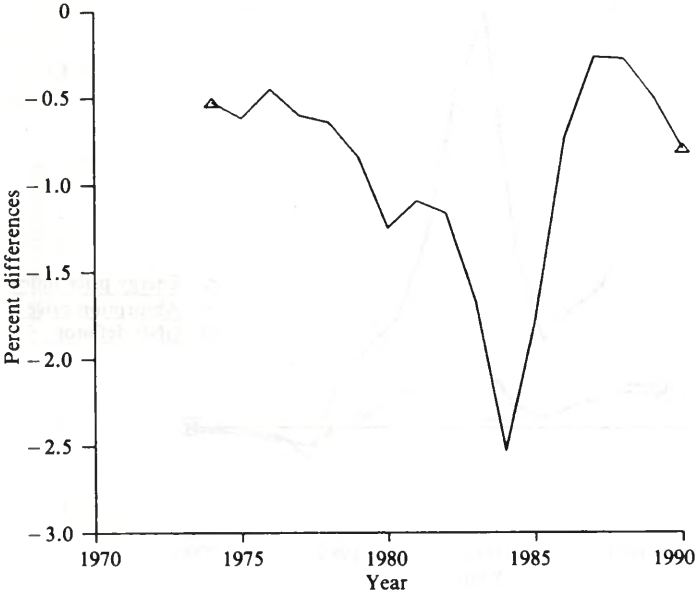
of Energy Trade"). In such cases, the possibility for stagflation arises from the induced increase in the real exchange rate, which "crowds out" output and employment in other industries.

In this section, we consider instead the possible stagflationary effects of increases in energy prices paid by domestic energy users. In this case, there is a change in the terms of trade among industries and regions within the country, with the producing industry and regions better off and the consuming regions worse off. In general, there is no reason to suppose that this should cause reductions in the overall level of activity, except for two main possibilities. The first is that unexpected changes in relative prices might cause disruptions in the plans of households and firms, with the extra spending by the unexpected winners being less than the cuts in spending by the losers. This possibility has already been discussed at the world level and must be considered as realistic and possibly applicable to unexpected declines as well as to unexpected increases in oil prices.

The second possibility for stagflationary effects arises because of the distribution of the revenues from higher oil and gas prices. In Canada, as in most energy-producing countries, most of the revenues from higher oil prices are paid by widely spread energy users and received by relatively few governments and energy-producing firms. The higher revenues of governments are especially important, since oil and gas resources in most countries are either owned directly by some level of government or are subject to high levels of marginal taxes or royalties. This means that much of the change in energy revenues takes the form of induced changes in taxes and royalties, so that increases in the prices paid by the users are largely in the form of tax increases. The macroeconomic effects are therefore similar to those of any increase in indirect taxes: in the short run, there is an increase in the price level (because of the higher price of the taxed goods) and a decrease in the levels of output and employment. Output falls because the higher taxes reduce the real incomes of consumers and induce households to reduce their real expenditures, with resulting effects on the aggregate level of income and employment. These possible stagflationary effects serve to offset, in part or even entirely, the expenditure-increasing effects flowing from the terms-of-trade gains of an oil-exporting country, and the increased investment activity in the oil and gas industry. To establish the net effects, it is necessary to have a model—like MACE—that can estimate simultaneously the likely increases in energy investment, the induced responses in energy demand, the effects of energy prices on overall prices and wages, and the effects of changes in energy trade on the exchange rate and hence on activity in other sectors.

In this section, we present some results from the latest version of the MACE model, dealing first with the effects of increases in domestic energy prices for given world energy prices, and then with the effects of changes in energy taxes. Figure 11.1 shows the effects on the level of real GNP of Canadian energy prices that follow world energy prices continuously (the PDEREG case, discussed in chapter 10), rather than following their actual paths. The corresponding effects on the levels of the energy price index, of

Figure 11.1 The Effects on Real GNP of Canadian Energy Prices Following World Levels (PDEREG)
(percentage differences from ACTUAL)



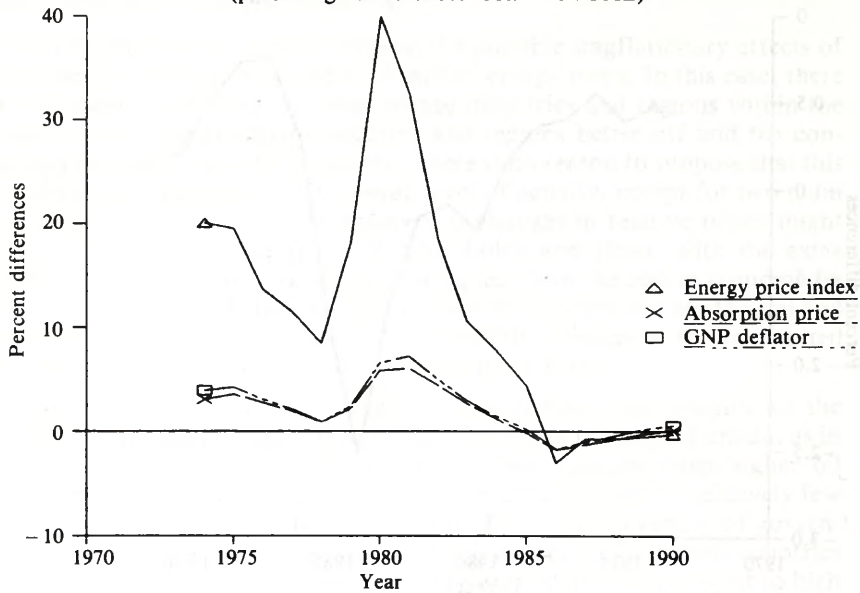
the absorption or spending price, and of the implicit price of GNP are shown in figure 11.2. The results show that after each of the world oil price shocks Canada was protected to some extent from the resulting stagflation by the slowness with which Canadian prices approached world levels. Over the longer term, of course, there are efficiency costs in holding domestic prices below world levels; and in any event, the actual policies brought domestic prices rapidly toward world levels in the early 1980s, just as world prices were starting to weaken.

The three price indices show that the actual policies, relative to continous market linkage of Canadian prices to world levels, had the most impact on the energy price index,[6] with much smaller, and fairly similar, effects on the absorption (or spending) price and the price of GNP. The last two effects are fairly similar, since the actual policies held down prices to both consumers and producers. Prices to producers were held down slightly more, but Canada is a net exporter of crude oil and natural gas, so that these two differences were offsetting.

Deregulating export volumes as well as prices (the EXPORT case discussed in chapter 10) gives substantially different macroeconomic effects. On the whole, the positive effects of increasing energy exports are enough to

[6]There was even more effect on the prices of oil and gas, because electricity prices were not directly affected by the regulation of domestic prices for crude oil and natural gas.

Figure 11.2 The Effects on Domestic Prices of Canadian Energy Prices Following World Levels (PDEREG)
(percentage differences from ACTUAL)



offset the negative effects of higher energy prices on real GNP, as shown in figure 11.3. The differences are particularly pronounced in the early 1980s, when world oil prices were at their peak and Canadian oil exports were cut back sharply. When energy export volumes are allowed to rise, the Canadian dollar appreciates steadily throughout the simulation period, slightly moderating the increase in energy prices compared with price deregulation alone. Higher energy investment, however, and real GNP growth produce general inflation rates that are higher in the EXPORT case (see figure 11.4).

To show the macroeconomic effects of alternative tax and royalty structures, we present figures 11.5 and 11.6 for the pre-reform tax and royalty system (PREREF), and figures 11.7 and 11.8 for the current system (CURRENT). These are the same cases analyzed in chapter 10. In both cases, the figures show by how much the variables would have differed if energy prices had been deregulated, with either the pre-reform or the current tax and royalty system in place throughout the simulation period.[7]

Relative to the actual pattern of taxes and royalties, either of the stable tax systems (the pre-reform system and the current tax regime) would have led to slightly higher GNP over the past 15 years and to lower energy prices in the early 1980s, when the actual system moved to world prices coupled with increases in indirect energy taxes, like the introduction of the Canadian

[7]See chapter 5 and its two related appendixes.

Figure 11.3 The Effects on Real GNP of Deregulated Exports (EXPORT)
(percentage differences from ACTUAL)

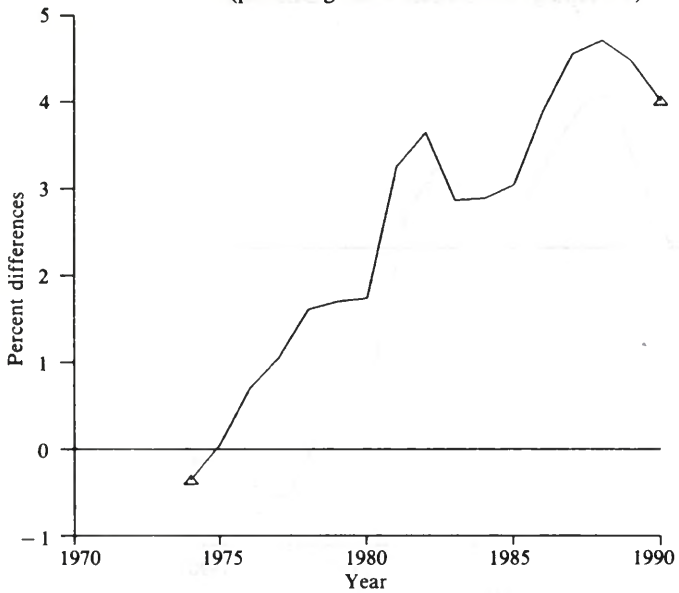


Figure 11.4 The Effects on Domestic Prices of Deregulated Exports (EXPORT)
(percentage differences from ACTUAL)

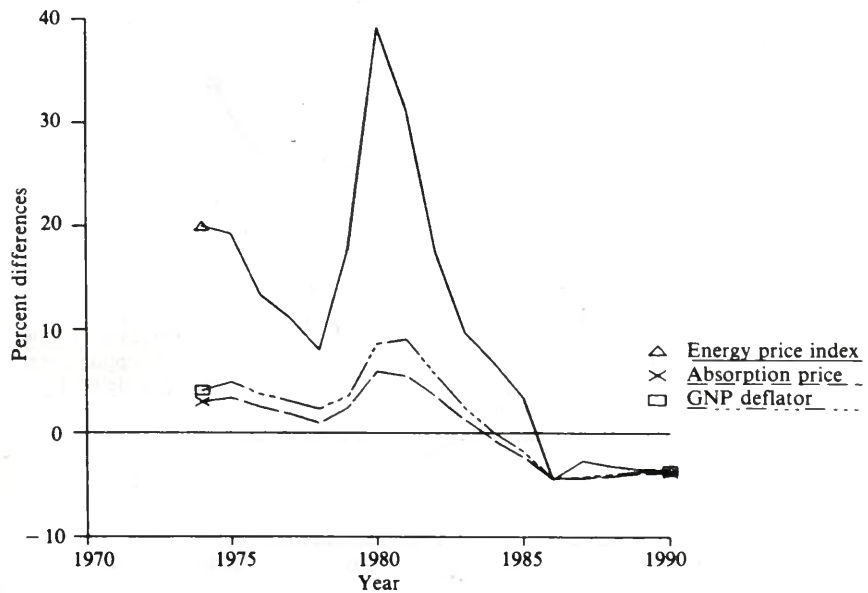


Figure 11.5 The Effects on Real GNP of Pre-Reform Taxes (PREREF)
(percentage differences from PDEREG)

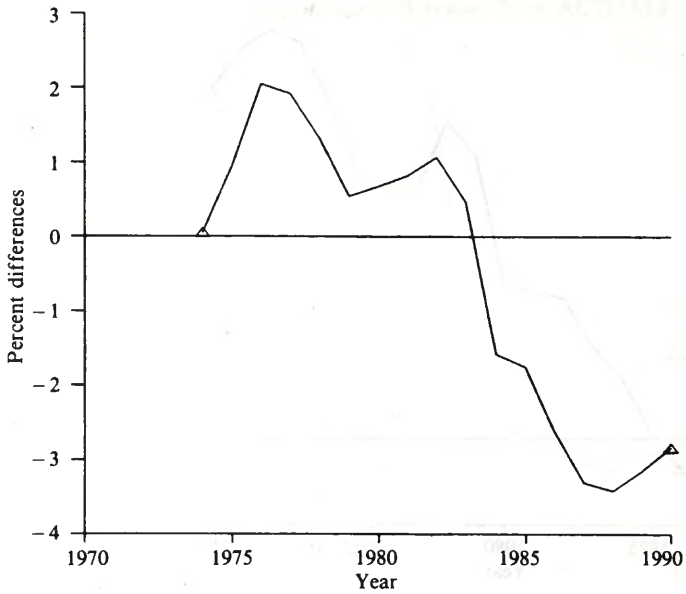


Figure 11.6 The Effects on Domestic Prices of Pre-Reform Taxes (PREREF)
(percentage differences from PDEREG)

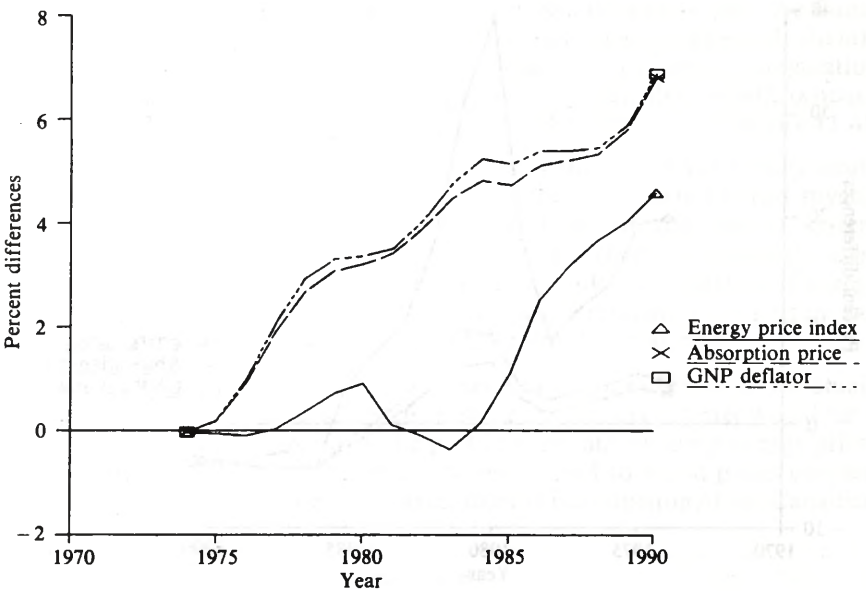


Figure 11.7 The Effects on Real GNP of Current Taxes (CURRENT)
(percentage differences from PDEREG)

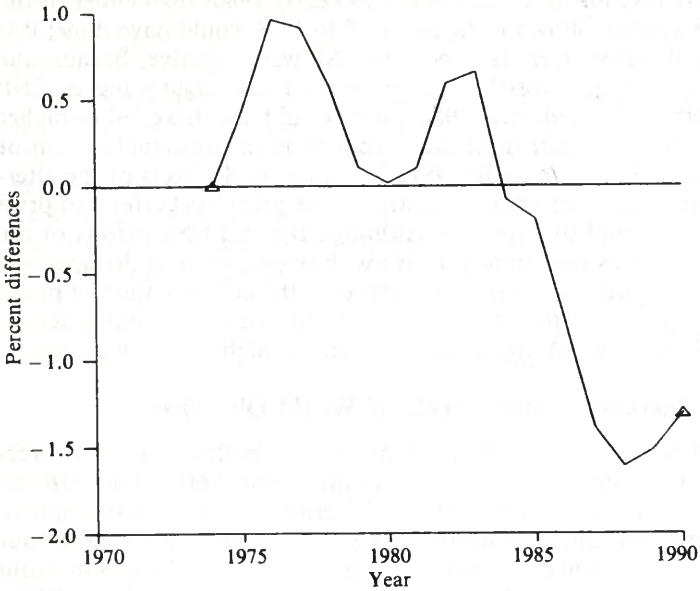
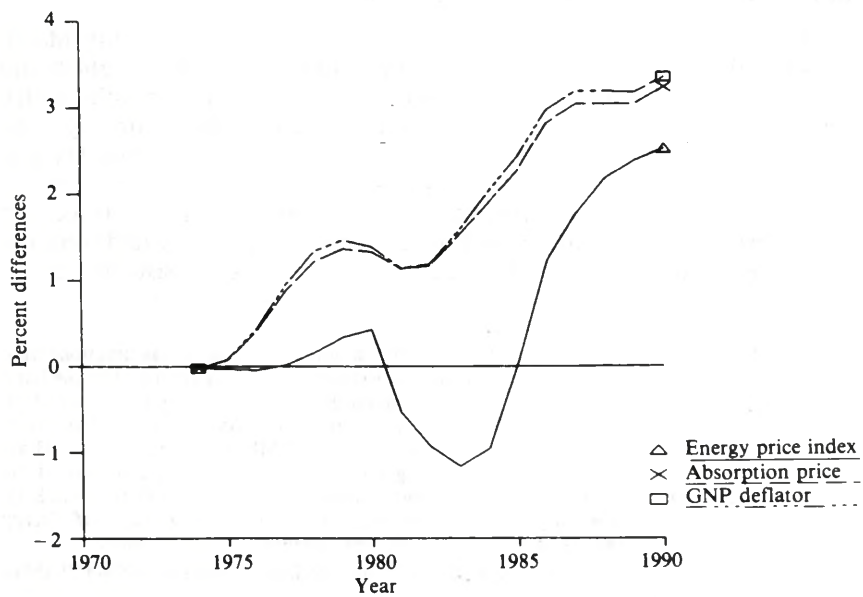


Figure 11.8 The Effects on Domestic Prices of Current Taxes (CURRENT)
(percentage differences from PDEREG)



ownership special charge (COSC). As shown in chapter 10, the actual system raised more tax revenue in the late 1970s and early 1980s than either of the two stable tax systems shown in figures 11.5 to 11.8 would have done; it is not surprising therefore that its effects on GNP were negative. Because the two stable tax regimes assessed would have produced slightly higher GNP levels in the late 1970s and early 1980s, they would also have led to higher general price levels, at least until the introduction in the actual system of increased indirect energy taxes in 1981. The price level effects of the alternative tax systems are even smaller relative to the price level effects of price deregulation, as would be expected. Although the real GNP effects of the two stable tax systems tend to be positive with respect to price deregulation alone, they are generally negative with respect to the actual pattern of prices and taxes. The positive effects of higher energy investment are not generally strong enough to outweigh the negative effects of higher energy prices.

Macroeconomic Effects of World Oil Prices

As we have shown, changes in world oil prices have both direct and indirect effects on the Canadian economy, and the size of these effects depends on the extent to which the changes in world prices are passed through to domestic energy users and producers. In this section, we review some of our earlier studies and present our findings about the effects of changes in world oil prices. In these earlier studies, the MACE model was run under different assumed paths for world oil prices and, in some cases, with different paths for the rates of growth of income, prices, and trade in other countries. One of the studies is based on results from models of other countries, to give some direct guidance about the size of the indirect effects flowing through direct effects on other countries' real growth and inflation.[8]

One of the most ambitious of the studies began by running MACE through the 1970s under the assumption that all world variables and national policies were either stationary or on consistent growth paths, which gave a resulting base case of steady growth for the Canadian economy.[9] The various changes in world events and domestic policies were added sequentially, resulting finally in a model solution that took all actual world events and policies into account. Although even the final simulations showed that there were important features of Canadian economic history that were not fully explained by the model, they did provide a consistent way of

[8] The MACE results that were prepared using internationally comparable assumptions from Stanford University's Energy Modeling Forum project are reported in John F. Helliwell and Mary E. MacGregor, "Energy Prices and the Canadian Economy: Evidence from the MACE Model," in Bert G. Hickman and Hillard G. Huntington, eds., *Macroeconomic Impacts of Energy Shocks: Contributions from Participating Modelers*, EMF Report no. 7, vol. 3 (Palo Alto, CA: Stanford University, Energy Modeling Forum, 1987), 329-58. A summary of the overall project design and the results from US and multinational models can be found in B.G. Hickman, H.G. Huntington, and J.L. Sweeney, eds., *Macroeconomic Impacts of Energy Shocks*, EMF Report no. 7, vol. 1 (Amsterdam: Elsevier Science Publishers, 1987).

[9] John F. Helliwell, "Stagflation and Productivity Decline in Canada, 1974-82" (May 1984), 17 *Canadian Journal of Economics* 191-216.

establishing the relative importance of the various changes that were simultaneously buffeting the Canadian economy.

The results depend to some extent on the order in which the events and policies are evaluated, as will be discussed in the final section of this chapter. In that study, starting from a steady growth path, we first assessed the effects of the changes in world events, holding constant the structure of the Canadian energy taxation system and letting world oil price changes be reflected immediately in the prices paid by Canadian energy users and received by Canadian energy producers. In these circumstances, the 1973-74 and 1979-80 increases in world oil prices both led to immediate increases in Canadian energy prices, thereby spurring increases in energy investment, inducing substantial increases in government taxation and royalty revenues (even with the unchanged tax and royalty rates), and raising the Canadian inflation rate. The results were initially stagflationary, even taking into account the terms-of-trade gains on Canada's net energy exports, and before taking into account the induced or simultaneous economic recessions occurring in other countries. By adding in first the changes in world prices and then the actual growth rates of world income and trade, we discovered that the main inflationary effects flowed from the direct effects of the oil price increases, while the loss of growth of GNP was chiefly due to the slower growth of income and output in other countries. Between them, these changes in world events seemed to explain most of Canada's lower growth of real GNP and higher growth of prices over the 1973-1982 period.

Macroeconomic Effects of Energy Trade

It is an interesting feature of political economy that almost any event that changes the economic relationships between industries or groups is often seen as bad by both parties, even aside from the costs of the adjustments made necessary when unexpected changes occur. One might otherwise have thought that the increases in world energy prices that occurred in the middle and late 1970s might have been considered good news at least by the energy-exporting countries. In many of the energy-rich industrial countries, however, there was much attention to the difficulties posed by what became known at the "Dutch disease" (because the classic example revolves around the consequences of the development and export of natural gas from the Netherlands sector of the North Sea).[10] This "disease" starts with an otherwise benign increase in the quantity or prices of energy exports. The typical economic analysis of this problem by-passes any employment-generating effects of the energy extraction investments themselves, either because the facilities are assumed to be already in place with excess capacity in hand, or because the producing facilities are purchased on a "turn-key" basis from

[10]See Michael Ellman, "Natural Gas, Restructuring, and Re-Industrialization: The Dutch Experience of Industrial Policy," in Terry Barker and Vladimir Brailovsky, eds., *Oil or Industry? Energy, Industrialization, and Economic Policy in Canada, Mexico, the Netherlands, Norway, and the United Kingdom* (London: Academic Press, 1981), 149-66.

foreign suppliers.[11] Alternatively, the analysis can safely by-pass the investment requirements if the rise in export revenues occurs because of an increase in the price rather than in the volume of energy exports.

The increase in energy export revenues then leads to an increase in the value of the domestic currency, which may render uncompetitive the manufacturing and other industries that were previously depending on export sales or that were facing active import competition. This is a normal part of the economic adjustment process that takes place when new products are substituted for old.

Two special features of energy exports, at least in the cases of the main industrial countries with important energy exports[12] are (1) the impermanence of such exports, and (2) the generally low labour requirements in the operating stages of oil and gas production and export. The impermanence of energy exports is important because it is often feared that manufacturing industries driven out of world markets during the years of high energy exports will find it difficult to re-establish a presence when the oil is gone. This issue arises with special emphasis in relation to conventional oil and gas production in the North Sea, where the producing lives of deposits are rather short, and where there are not expected to be new discoveries on anything like the scale of those currently being exploited. For countries with very large reserves in relation to their current population and GNP—Norway being the sole example among the industrial countries—it is possible to achieve a long producing horizon by deliberately choosing a slow rate of development of the known deposits, thus ensuring a producing life extending 100 years or more. For most other countries, there are greater pressures to develop the available reserves as soon as current markets appear profitable.

The second point—low labour requirements—is important because the shift from industry to oil tends not to provide as many jobs in the new activity as there were in the old for the same value of output. The economic answer to this, in a world where all resources are scarce, is that the additional labour freed up can be employed to raise the level of GNP and average incomes, whether in manufacturing, services, or elsewhere. The issues raised on both sides of this question are rather similar to the issues raised by technological progress generally, and especially by the use of robotized or mechanized processes that achieve the same level of output with far fewer direct employees. The required adjustments are feasible but not always easy to achieve, as illustrated by the rapid technical progress in agriculture that reduced the agricultural labour force to a fraction of its size

[11] We consider the macroeconomic repercussions of large energy investment projects in the next section.

[12] The industrial countries faced with the choice between "oil or industry" were considered to be the United Kingdom, Norway, the Netherlands, Mexico, and Canada. Taking into account the strong links between the prices and export prospects for coal and crude oil, Australia might well be included in the list, although its exports of raw materials, like Canada's, cover a much wider range than just hydrocarbons. See Barker and Brailovsky, supra footnote 10.

of 40 years ago, while permitting increases in real agricultural output as well as in total employment and real GNP.

If these are some of the macroeconomic issues relating to energy exports, how do they relate to Canada? Our results from an earlier version of MACE show that for Canadian energy exports there is not much evidence of the "Dutch disease," since increased energy exports, although they provide little additional employment in the production stages, do not lead to increases in the unemployment rate.[13] Although there are exchange-rate-induced reductions in non-energy exports, the overall levels of spending and employment are kept up by the higher real incomes of Canadians. This effect is supplemented by the strength of the Canadian dollar, which then leads to a lower price level and lower interest rates, which in turn encourage further spending. Thus, while there is no reason in principle to favour energy exports over any other sort, the MACE modelling of the Canadian economy does not suggest that the low labour content of energy exports is enough to lead to higher unemployment in response to increases in energy exports.

Macroeconomic Effects of Megaprojects

Versions of MACE and its predecessor models have been used to analyze the macroeconomic implications of different energy megaprojects ranging from the Mackenzie Valley natural gas pipeline proposal of the early 1970s,[14] through the Syncrude[15] and Alsands[16] oil sands projects, to the proposed development of the east coast offshore Hibernia oil field.[17] As described in these papers and more briefly in chapter 9, the typical megaproject involves a stream of capital expenditures, often with a high imported content but generally also with substantial local requirements for construction labour and materials. The expenditures usually build up over several years to a peak and then decline toward the completion of the project. By the usual multiplier process, there are induced income changes elsewhere in the economy, as the incomes generated in construction are spent elsewhere. There may also be induced investment spending in other sectors, following the so-called accelerator principle, if producers in other industries need to increase their facilities to provide for the project, or if they expect high current sales to indicate higher sales in the future.

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[13]See John F. Helliwell, Robert N. McRae, Paul Boothe, Ardo Hansson, Michael Margolick, Tim Padmore, André Plourde, and Reg Plummer, "Energy and the National Economy: An Overview of the MACE Model," in Anthony Scott, ed., *Progress in Natural Resource Economics* (Oxford: Clarendon Press, 1985), 17-85, at 57-61.

[14]See John F. Helliwell, "Impact of a Mackenzie Pipeline on the National Economy," in Peter H. Pearse, ed., *The Mackenzie Pipeline: Arctic Gas and Canadian Energy Policy* (Toronto: McClelland and Stewart, 1974), 143-82.

[15]See Gerry May, "Syncrude and the Oil Sands: An Economic Evaluation" (MA thesis, University of British Columbia, Department of Economics, Vancouver, 1976).

[16]See Helliwell, McRae, et al., supra footnote 13, at section 10.

[17]See André Plourde, "Modelling the Economic Implications of Offshore Oil: The Case of Hibernia" (PhD dissertation, University of British Columbia, Department of Economics, Vancouver, 1985).

Whether the investment phase is accompanied by a higher or a lower value for the Canadian dollar depends on the extent to which the project uses imported materials and imported capital: the higher the share of foreign financing and the lower the share of imported materials and equipment, the higher the value of the Canadian dollar is likely to be. The result also depends on the amount by which Canadian activity and price levels rise as a result of the extra investment, and on the extent to which the Bank of Canada expands the money supply in order to accommodate the higher incomes. The greater the monetary accommodation, the less likely the Canadian dollar is to rise. The results reported in an earlier paper show that for the Alsands project, with monetary policy following a typical pattern, the Canadian dollar would rise during the construction phase, thus moderating the real GNP and inflation effects of that phase.[18] After the construction phase, there would be an inevitable slump in activity as the multiplier-accelerator influences operate in reverse.

During the operations phase, as described in the previous section, there is usually little by way of direct employment, given the high capital intensity of most energy megaprojects. The macroeconomic effects are thus dominated by the effects of the change in export revenues, acting indirectly on the economy through changes in the exchange rate, the interest rates, and the price level.

When energy megaprojects are considered in comparison with other investment projects, they have little to recommend them over the alternatives. The three main difficulties they pose flow from their large size: (1) it increases the likelihood of local bottlenecks; (2) it increases the extent to which there is a build-up and run-down of project-specific employment and activity; and (3) it usually decreases the extent to which investment spending is responsive to unexpected changes in demands and costs. This last problem is especially important for energy projects, because they typically take a long time to construct, and because energy markets have changed rapidly and unpredictably over the past two decades.

Even though megaprojects tend to increase the instability and decrease the flexibility of the macroeconomy, our research also suggests that their effects are not so large as to make them indigestable, or even to pose a strong macroeconomic case against any such projects that would otherwise be more economic than their alternatives. As shown in chapter 9, however, most of the megaprojects have been substantially more costly than alternative energy sources, so that both microeconomic and macroeconomic considerations weigh against them.

Interaction Between Domestic Policies and World Events

In the previous sections, we have assessed some of our findings about the macroeconomic effects of world oil prices and domestic policies. The general nature of these results is that world prices have been much more

[18] See Helliwell, McRae, et al., supra footnote 13, at 55-57.

important than Canadian policies in determining the variations of the rates of growth of income, employment, and inflation in Canada. Within the range of Canadian policies, the policies regulating the linkages between Canadian and world energy prices have tended to be more important than the changes in tax structure and rates. In this section, we look for the macroeconomic evidence on the question addressed previously in chapter 10: have the various changes in Canadian policy tended to amplify or to reduce the fluctuations that Canada would have felt from the changes in world energy prices over the past 15 years? To do this, we first set up a hypothetical control solution, SMOOTH, in which world oil prices grow at the same rate as the overall spending price in the United States. In this control solution, Canadian oil prices are also assumed to follow this smooth path and natural gas is again priced at 85 percent BTU-parity with crude oil, while historical royalty and tax policies are assumed to prevail. As we have already seen, these assumptions will not remove all, or perhaps even most, of the stagflationary world effects of the oil price increases, but will provide an understandable and fairly simple way of depicting an important part of those effects. We then show, in figures 11.9 and 11.10, the extent to which the actual world oil prices caused Canadian real GNP and the GNP price level to deviate from the levels they might have taken had world oil prices been less volatile. One line shows the effects of historical domestic prices and policies (ACTUAL), while the other three show the consequences of applying the actual world prices in Canada under three alternative tax systems: (1) the historical tax system (PDEREG), (2) the pre-reform system (PREREF), and (3) the current system (CURRENT).[19]

As is evident from figures 11.9 and 11.10, the effects of the OPEC price shocks in the 1970s far outweigh the effects of domestic energy policies. In 1984, the year with the peak impacts, the historical pattern of taxes with deregulated pricing (PDEREG) would have reduced real GNP by 4.6 percent in a world with the OPEC price shocks compared with one without. World pricing and either of the stable tax regimes (PREREF and CURRENT) would have somewhat improved the negative impacts of higher world prices until the mid-1980s[20] through a boost to energy investment, but the difference between the two stable tax regimes and the historical regime is not nearly as large as the effect of the OPEC price shocks themselves. Nor are the stable tax regimes as effective in reducing the negative GNP effects as were the actual energy pricing policies. Holding domestic prices below world levels reduced the peak negative real GNP effects to 2.1 percent.

The price effects of all three world pricing policies are very similar and peak in 1981, the year before the peak in official world oil prices. Domestic pricing policies (ACTUAL) substantially reduced the immediate inflationary

[19]Note that the ACTUAL, PDEREG, PREFEF, and CURRENT cases are defined here in exactly the same way as they were defined in chapter 10.

[20]Starting in 1984, the two stable tax and royalty systems both result in lower real GNP levels than price deregulation alone, since they are associated with higher inflation and a deterioration of the exchange rate.

Figure 11.9 The Effects on Real GNP of Alternative Pricing and Taxation Policies
(percentage differences from SMOOTH)

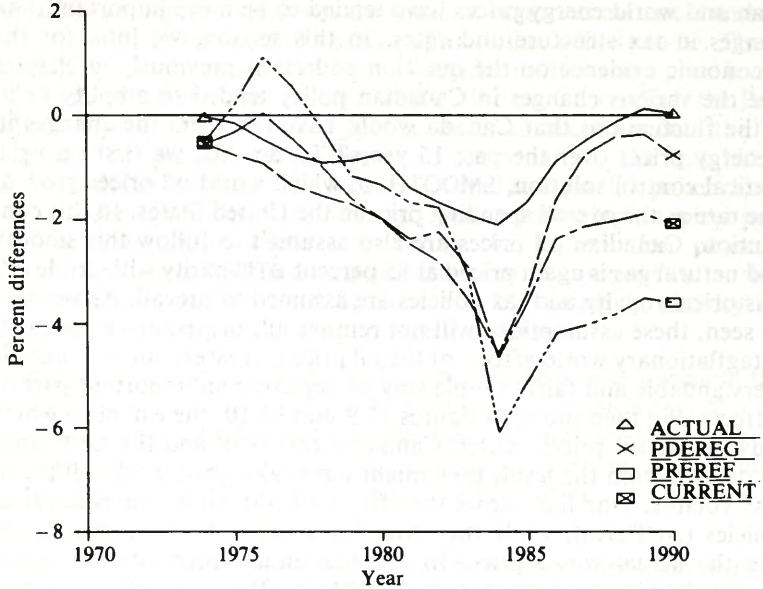
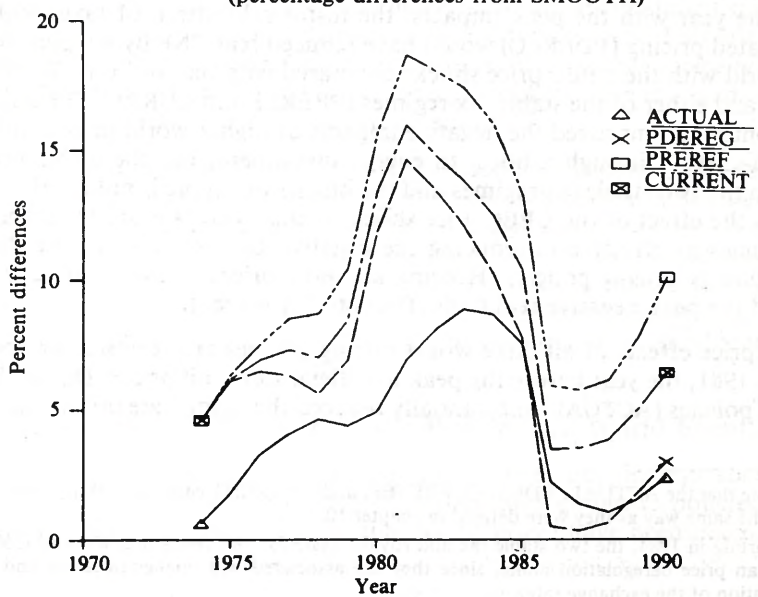


Figure 11.10 The Effects on the GNP Deflator of Alternative Pricing and Taxation Policies
(percentage differences from SMOOTH)



effects of the OPEC shocks: in 1980, the GNP deflator was 3.9 percent higher than it would have been without the OPEC shocks, compared with 10 percent in the world pricing case (PDEREG). Figure 11.10 suggests, however, that domestic pricing policies delayed, rather than prevented, the world price increases from being fully passed through to Canadians.

Overall, the results suggest that domestic policies—especially domestic pricing policies—were successful in moderating to some extent the impact of the OPEC price shocks in the 1970s. The historical tax regime, which generally increased the industry tax burden during or following the price shocks, tended to have a negative effect on energy investment and amplified the negative effects of the shock, at least relative to a more stable tax regime. The results also indicate, however, that domestic policies had far less impact on the economy than the price shocks themselves.

12

Summary

Overview

This concludes our fairly detailed review of the production, investment, taxation, and trade of Canada's oil and gas industry over the past 25 years. The industry has grown substantially in relative importance over this period, principally in terms of its share of national investment, but also in terms of the extent to which energy prices and taxation have been at the centre of regional, national, and international disputes and economic disruptions.

The structure and growth of the industry were documented in chapter 2, with the investment activity described more fully in chapter 7 and explained in chapter 8. Chapter 7 also documented the increase in the relative size of energy investment, and chapter 8 reported the results of our equations showing the substantial extent to which the increased investment was in response to higher prices and changing market conditions. The latter element was most important for explaining the dramatic drop in natural gas investment in the early 1980s, as export demands fell well below the authorized export levels, even at progressively lower prices.

Since direct regulation of oil and gas prices and trade has been such an important part of the Canadian experience over the past 25 years, two separate chapters were needed to describe the structure and changes in the regulatory environment—chapter 3 for crude oil, and chapter 4 for natural gas. In both chapters, there were seen to be tight links between the structure of trade and the nature of price regulation. Close linkage between domestic and world prices has occurred only when there was freedom of access to world markets, both for consumers and producers.

Under the national oil policy of 1961, the Canadian market west of the Ottawa Valley was reserved for Canadian producers, so that prices were higher there than in parts of Canada with access to imported oil. After 1973, by contrast, Canadian prices were held below world levels, by amounts that grew each time world prices shot up. Over the succeeding years, this wedge between domestic and world prices was gradually eliminated by federal-provincial agreement and legislation. In the late 1980s, oil prices are deregulated to a greater extent than ever in the past 25 years, because both producers and consumers are free to find sources and markets both at home and abroad.

For natural gas, the process of deregulation has been slower and more difficult, principally because the need for pipeline shipment and the conse-

quent lack of offshore competition mean that it is difficult for final users to make market contact with competing suppliers.

Nevertheless, for both crude oil and natural gas, the main pressures have been to move domestic prices toward world levels, and thereafter to abandon most of the long-established mechanisms for official regulation of prices. During the late 1970s and early 1980s, there were so many unpredicted changes in prices that regulated prices came under considerable pressure, requiring more rapid and flexible adjustment than the regulatory system was capable of providing. Since deregulation, the oil and gas industry is now in a position much more like that of other natural resource industries, with a slightly more stable domestic market and the opportunity to compete in world markets at variable and often unpredictable prices.

Even though domestic energy prices were initially shielded to some extent from the rapid increases in world prices, domestic energy prices did rise substantially. Although there was a prevailing view in the energy industry and among policy-makers that energy was sufficiently necessary that its demand would be largely unaffected by price changes, research has continued to show, as reported in chapter 6, that rising energy prices played an important role in the post-1973 drop in the growth of energy demand. These price-induced changes in energy demand were especially great for oil products because their prices rose substantially faster than did the prices of natural gas and electricity.

Our research, including some as early as the mid-1970s, has continually shown significant responses of energy demand to changes in energy prices. If these demand responses had been more widely foreseen by the industry and government, there would probably have been an earlier commitment to link Canadian energy prices to world prices, and less attraction to the various megaprojects, such as arctic energy developments, offshore oil and gas, and the oil sands and heavy oil; these projects often proved to be much more expensive and difficult to achieve than price-induced reductions in demand and increases in conventional supply would have been. In chapter 9, we described the range of megaprojects and documented the extent to which public funds have been used to subsidize them relative to other forms of energy supply and investment in other industries. Our general conclusion from this evidence is that an earlier move toward higher prices and less direct use of public funds in frontier energy developments would have increased the efficiency and timeliness of Canadian energy supplies.

In chapters 10 and 11, we used the analysis presented in earlier chapters to undertake some new experiments and to build on evidence from earlier studies, to assess the effects of both world events and domestic policies on the level, pattern, and efficiency of Canadian energy demand and supply and on the size and distribution of energy revenues. In chapter 10, we emphasized the effects on the pattern of activity in the energy industry and on the distribution of energy revenues, while in chapter 11 we dealt mainly with the impact of energy prices and taxation on macroeconomic variables such as the levels of output and employment, and the overall rate of infla-

tion. In this summary, we pick up a frequent theme of our study by dividing our review of the findings to deal first with the effects of world events and then with the effects of domestic policies; in both cases we consider both industry-level and aggregate effects.

The Effects of World Prices

All our evidence, as well as that from earlier studies by ourselves and others, attaches great importance to world prices as the primary determinants of energy supply and demand in Canada, despite the periodic use of policies that dampened or delayed the extent to which world prices were directly applicable to domestic supply and demand. Canada is an open economy, so that the overall level of output, and hence the level of energy demand, is importantly affected by world growth and trade. Perhaps the greatest effect of the world oil price shocks on the Canadian oil and gas industry, and certainly the macroeconomic effects, flowed indirectly through their influence on incomes and prices in other countries. For all the attention that has been focused on them, Canadian policies influenced only the timing of the impact of world prices on Canadian prices, so that the changes in world prices and trade conditions remained the fundamental influences on the activity of the oil and gas industry and on the pattern and size of Canadian energy demand.

The exact nature of the channels of influence differed for crude oil and natural gas. In both cases, the reductions in net exports in the mid-1970s were a response to Canadian policies rather than to changes in world markets, which could easily have absorbed more output. By the end of the 1970s, when it was more widely understood that there was no immediate supply crisis for either crude oil or natural gas in Canada, Canadian exports came to depend more directly on world markets. It was then that the differences between crude oil and natural gas became more obvious, since there was always a market for Canadian crude oil production—barring short-term limitations from policy or from lack of pipeline capacity—either by replacing imported oil in eastern Canada or by export to the United States. For natural gas, however, there are virtually no imports, and the only available export market is overland to the United States, where a parallel excess supply of natural gas was building up at the same time as in Canada. Since Canadian supplies are often the last to be sought and the first to be cut by US natural gas users, in part for regulatory reasons, the so-called gas bubble in the United States proved to be of fundamental importance to the market prospects for Canadian gas producers. The lack of immediately foreseeable markets for new discoveries, as represented by the continuing buildup of the ratio of reserves to production, documented in chapter 2, has been the single biggest factor leading to the drop in Canadian natural gas investment in the 1980s; this is shown by our investment equations in chapter 8.

Thus, while both oil and natural gas have been heavily influenced by events outside Canada, for crude oil the primary force has been movements in world oil prices, including their effects on world income and inter-

national trade, whereas for natural gas the main impact has been through the US gas market, which has been itself affected by world oil prices, by US supply and demand conditions, and by numerous changes in the US regulatory environment, as described in chapter 4.

The Effects of Domestic Policies

In chapter 10, we analyzed the extent to which changes in domestic policies influenced oil and gas demand, production, revenues, and investment. In chapter 11, we investigated the extent to which these same policies had macroeconomic impacts. Both types of evidence consistently showed that domestic policy changes to some extent moderated the impact of the changes in world prices and events, with the price regulation policies tending to have somewhat larger effects than did the changes in tax rates and tax structure.

The price regulation policies smoothed somewhat the immediate stagflationary effects of the 1973-74 and 1979-80 oil price increases, with little direct impact on longer-run performance. If the price regulation had not been seen to be temporary, or if there had not been such efforts, at least since 1980, to ensure that new discoveries would receive world-level prices, the efficiency costs of the price regulation could have been substantially higher without any corresponding benefit from increased economic stability. A particular feature of the Canadian history of regulated oil prices is that during some periods they represented policies that were negotiated and agreed to by the federal and provincial governments, whereas at other times, especially during 1980 and 1981, they were unilaterally set by the federal government.

Another important feature of the Canadian experience is the extent to which there was official policy support, particularly from the federal government and to some extent from the governments of the producing provinces, for switching the focus of new investment from conventional sources to the frontiers and unconventional sources. As described above, this was probably due in large measure to mistakenly pessimistic forecasts about the extent to which domestic demand and conventional supplies would respond to higher energy prices. To some extent, the high costs of the government support programs for energy megaprojects can be treated as an indirect cost of the price-smoothing policies, since the latter delayed the responses of supply and demand that would have demonstrated the costliness of the megaprojects relative to the alternatives (this is documented in chapter 9). Our simulations cannot take account of that indirect influence, because we do not know to what extent more rapid demand and conventional supply responses would have reduced the likelihood of superdepletion, frontier PIP grants, and other high-cost support programs for frontier investment.

We were, however, able to estimate the extent to which the actual policies influenced the pattern of investment and supply, and also to distinguish between the effects of pricing and taxation policies. When we made this

distinction, we found that taxation policies had as strong an effect on energy investment as pricing policies. But in many instances the effects were mitigated because tax increases were often accompanied by measures designed to maintain or increase the profitability of new investment and discoveries.

One of the accidental benefits of the low domestic prices and high taxes at the beginning of the 1980s was that the oil and gas investment boom was more muted in Canada than in the United States, which meant that there was a slightly less painful adjustment to the sharply lower world prices and deflated demand expectations of the mid-1980s. Thus, as shown in chapter 10, the actual tax policies produced a smaller excess supply of natural gas than would have existed had a more stable tax system been in place. A more general feature of the changes in taxes and tax rates is that they have generally been counter-cyclical in nature and effects, so that industry revenues and investments have been slightly more stable than they would have been under an unchanging tax system. On the other hand, it is perhaps unlikely that oil and gas firms would have accurately projected the changes in taxes, or would even have guessed that the tax changes would have muted the effects of the swings in world prices and export markets. Thus the overall efficiency effects of variable tax systems are hard to assess. As we argued in chapter 10, there is an additional advantage to keeping the tax system stable rather than altering it frequently as circumstances change. If the system is always changing, it is difficult to understand, and participants are likely to use scarce resources in learning about the new system and in trying to have the system changed or interpreted in their favour. The resulting higher costs of administration and compliance do not show up directly in our calculations, but they are probably substantial and deserve an important weight when alternative systems are being considered.

Implications for the Future

Although we have spent some time dealing with the broader macro-economic context, our main aim has been to lay out enough detail of the actual history of activity, events, and policies to permit the fast-changing events of the 1970s and 1980s to be remembered and understood more easily.

There is too much detail to permit easy summary or the drawing of strong implications for the future. If there is a single striking feature of the period of history we have assessed, it is that major changes in the external environment were far-reaching and found domestic oil and gas producers, consumers, and policy-makers largely unprepared. If we are right to infer that the future for world oil prices remains uncertain, then there seems an advantage to being prepared. What would better preparations require? For policy-makers, a fast-changing external environment makes it impossible to design and administer any system of detailed price regulation, as was seen from the Canadian experience from 1973 to 1985. On the other hand, if price regulation is not available as a means of distributing the benefits and

costs of rapid changes in the market environment for oil and gas production, it is important to have a tax and royalty system in place that is robust enough to withstand large changes in prices and demand.

What does a robust system require? First, it needs to distribute the revenues from unpredicted changes in a way that maintains the basic investment incentives intact and responsive to market opportunities, while redistributing windfall gains and losses in a way that is seen to be both fair and efficient. These last characteristics are especially important if the system is to be politically stable—that is, able to withstand almost irresistible political pressure for change every time oil prices rise or fall. If the gains as well as the losses are generally perceived to be reasonably distributed, then even the current losers are likely to reduce their demands for subsidies or compensation, keeping their peace in the hope that the future will eventually alter circumstances in their favour.

The current tax and royalty system is probably more even in its impact across types of investment and among different industries than any other system in place over the past 40 years.[1] This equality of treatment is, of course, one of the objectives of any tax reform, in order to achieve the efficiency gains that are possible if all forms of organization and types of activity face approximately the same tax rates.

It is important to note that the equality needed for allocative efficiency does not mean that combined royalty and tax rates for oil and gas should be the same as the tax rates in other industries—for the royalties, and even some of the taxes, are intended to be part of the price by which the government that owns or controls the deposits charges for the right to extract and sell them. The needed equality is of the tax system itself, even if it is often difficult to separate the sharing of resource rents from the main structure of taxation. This latter difficulty arises partly through constitutional complications peculiar to the Canadian situation, but more fundamentally because efficient methods for resource owners to develop their deposits frequently involve royalty contracts that share net benefits and costs among the owners and the developers in a way that resembles a tax system.

Under the Canadian Constitution, where resources in the provinces belong to those provinces, this ambiguity between taxes and royalties need affect only the provincial governments; the federal government is free to treat all industries and activities in an equal manner.

[1] As noted earlier, our modelling does not include the provisions of the December 1987 changes in Alberta natural gas royalties described in chapter 4, under "Subsequent Developments," and in appendix 5.2.

Appendix 5.1

Federal Taxation of Oil and Gas Income Since 1967

This appendix to chapter 5 contains a more complete description of the federal elements of the various tax systems that have been proposed or applied to oil and gas income and expenses since 1967.[1]

1. Outline of the System in Effect in 1967

• *Corporation income tax rate.* The rate is 21 percent on the first $35,000 of taxable income, then 50 percent on the balance.

• *Provincial tax abatement.* The system allows for a reduction of 10 percentage points in the federal tax rate applicable to the taxable income from activities undertaken within the boundaries of any of the provinces; provincial royalties are fully deductible from income.

• *Exploration and development expenses.* Such expenditures may be deducted by *principal-business taxpayers* at a rate of 100 percent against any income in the year incurred or any subsequent year. *Non-principal-business taxpayers* may deduct such expenses only from mining and petroleum income, but also with unlimited carryforward.[2]

• *Depletion.* A depletion allowance of 33⅓ percent of production profits can be claimed by *operators*. *Non-operators* receiving income relating to oil and gas production are entitled to a 25 percent depletion allowance. *Shareholders* of certain companies are allowed to exclude from income between 10 and 20 percent of dividends received.

• *Capital cost allowances.* Expenditures on tangible assets are cumulated in a number of asset classes and are deductible at a fixed percentage of the unclaimed balance. In the case of upstream oil and gas activities, almost all

[1] In compiling this appendix, we referred extensively to budget documents as well as to the following: Canada, Department of Energy, Mines and Resources (EMR), "Petroleum Fiscal Systems in Canada: A Summary" (mimeograph, October 1983); Canada, EMR, *Petroleum Fiscal Systems in Canada*, 2d. ed. (Ottawa: EMR, Financial and Fiscal Analysis Branch, 1986); E. Nicolaas Holland, G. Richard Schulli, and Ronald M. Kemp, *Canadian Taxation of Oil and Gas Income: An Analytical Evaluation* (Don Mills, Ont.: CCH Canadian, 1979); André Plourde, *Oil and Gas in Canada: A Chronology of Important Developments—1941-1986*, PEAP Energy Study no. 86-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1986); various issues of *The National Finances* (Toronto: Canadian Tax Foundation); and various issues of the *Canadian Income Tax Act with Regulations* (Toronto: CCH Canadian).

[2] Holland, Schulli, and Kemp, supra, at 120, argue that before May 7, 1974, proceeds from the disposition of property whose cost had been an exploration and development expense had no well-defined tax status.

tangible assets are deductible at 30 percent of the unclaimed balance; natural gas plants (and oil refineries), however, are depreciable at 20 percent of the unclaimed balance. New wells in an existing mine are eligible for a 100 percent write-off. Net proceeds from sales of assets eligible for capital cost allowances (here defined as the costs of such assets at the time of their initial acquisition by the seller) are applied against the unclaimed balance of the individual classes in question; all excesses of these proceeds over unclaimed balances are treated as income.

• *Oil and gas rights.* Since April 10, 1962, costs of acquiring such rights (for example, land bonus payments) are fully deductible, and the proceeds from their sale are treated as income.

• *Miscellaneous.* Income from new mines (for example, oil sands mining) is exempt from taxation for the first three years of operation.

2. Changes in the November 1967 Budget[3]

• *Corporation income tax rate.* A surtax of 5 percent on individuals is proposed. In March 1968, however, a modified proposal is to be enacted; it will establish a surtax of 3 percent on both individuals and corporations, to be levied in 1968 and 1969.

3. Changes in the June 1969 Budget[4]

• *Corporation income tax rate.* The 3 percent surtax on corporations is extended to the end of 1970.

4. Changes in the December 1970 Budget[5]

• *Corporation income tax rate.* The 3 percent surtax on corporations is extended to the end of 1971.

5. Changes in the June 1971 Budget[6]

• *Corporation income tax rate.* This rate is 50 percent in 1972, to be reduced by one percentage point annually to 46 percent in 1976; the 3 percent surtax on corporations is eliminated as of June 30, 1971. Beginning in 1972, the tax rate applicable to the first $50,000 of business income earned in each year by a small business[7] is to be 25 percent (15 percent, net of provincial abatement), until accumulated post-1971 taxable income reaches $400,000.

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[3]Canada, Department of Finance, Budget Papers, Budget Speech, November 30, 1967 (Mitchell Sharp).

[4]Canada, Department of Finance, Budget Papers, Budget Speech, June 3, 1969 (Edgar J. Benson).

[5]Canada, Department of Finance, Budget Papers, Budget Speech, December 3, 1970 (Edgar J. Benson).

[6]Canada, Department of Finance, Budget Papers, Budget Speech, June 18, 1971 (Edgar J. Benson).

[7]A small business is here considered to be a Canadian-controlled private corporation.

• *Exploration and development expenses.* As of January 1, 1972, *non-principal-business taxpayers* are to cumulate these expenses in a separate asset class and deduct annually the *greater* of income from mining and petroleum (including royalties) *or* 20 percent of the unclaimed balance.

• *Depletion.* The present system for *operators* and *non-operators* is to continue until the end of 1976; thereafter, depletion deductions will be earned at a rate of 33⅓ percent of eligible expenditures (defined as all exploration and development costs incurred after November 7, 1969). Earned depletion deductions are to be claimed at a maximum rate of 33⅓ percent of production profits, but can be carried forward. As of January 1, 1972, depletion deductions for *shareholders* are eliminated.

• *Capital cost allowances.* With the introduction of the capital gains tax on January 1, 1972, the full proceeds from the sale of tangible assets will enter into consideration; for example, if such proceeds exceed the original costs of the assets, then amounts equal to these costs will be deducted from the undepreciated stocks of the relevant asset classes, and any excesses will be treated as capital gains, one-half of which are to be brought into income.

• *Oil and gas rights.* These are to be included in exploration and development expenses as of January 1, 1972, but will earn no depletion. The proceeds from the sale of any such property acquired after April 10, 1962 continues to be treated as income.

• *Miscellaneous.* The three-year tax exemption for income from new mines is repealed as of December 31, 1973. Beginning in 1974, higher capital cost allowance rates will be extended to some asset classes (for example, mines acquired before November 7, 1969 were not eligible for capital cost allowances; expenditures incurred after that date for the development of new mines will earn capital cost allowances at a rate of 30 percent of the unclaimed balance).

6. Changes in the May 1972 Budget[8]

• *Corporation income tax rate.* As of January 1, 1973, the tax rate applicable to manufacturing and processing (which includes natural gas plants and oil refineries but not oil sands plants) is reduced to 40 percent; the tax rate on small businesses in manufacturing and processing is reduced to 20 percent (10 percent, net of provincial abatement; subject to the limits introduced by the June 1971 budget).

• *Capital cost allowances.* For tangible assets in manufacturing and processing acquired between May 9, 1972 and December 31, 1974, the depreciation rate is increased to 50 percent, to be applied according to a straightline method.[9]

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[8]Canada, Department of Finance, Budget Papers, Budget Speech, May 8, 1972 (John N. Turner).

[9]This fast write-off rate applies to machinery and equipment, but not to structures.

• *Miscellaneous.* A given portion of manufacturing and processing profits is to be deductible from federal tax payable; that portion is to be 9 percent in 1973, 8 percent in 1974, 7 percent in 1975, and 6 percent in 1976 and subsequent years.

7. Changes in the May 1974 Budget[10]

• *Corporation income tax rate.* As of May 6, 1974, the tax rate applicable to oil and gas income is increased to 50 percent, the standard provincial abatement of 10 percentage points continues to apply, and a new resource profit abatement of 10 percentage points (15 points for oil sands mining) is introduced. The resource profit abatement is designed to compensate for the budget's termination of the deductibility of provincial royalties in the calculation of taxable income. As of May 6, 1974, the lower tax rate available to small businesses will apply to the first $100,000 of business income earned in each year, until cumulated post-1971 taxable income reaches $500,000.

• *Exploration and development expenses.* For all taxpayers, expenditures incurred after May 6, 1974 are to be cumulated and deducted at a rate of 30 percent of the unclaimed balance. Proceeds from the sale of property whose cost was an exploration and development expense are to be deducted from the unclaimed balance, and any excess is to be treated as income.

• *Depletion.* The system of earned depletion announced in the June 1971 budget is to begin on May 6, 1974, with the modification that the maximum rate of claim for earned depletion allowances is to be set at 25 percent of production profits.

8. Changes in the November 1974 Budget[11]

• *Corporation income tax rate.* The 10 percentage point resource profit abatement introduced in the May budget is increased to 12 points in 1975, and to 15 points in 1976 and subsequent years.

• *Exploration expenses.* The rate of deductibility is restored to 100 percent as of May 7, 1974. The proceeds from the sale of a property whose cost was an exploration expense is to be deducted from cumulative exploration expenses, and any excess is to be treated as income.

• *Development expenses.* The reduction in the rate of deductibility announced in the May budget is maintained. Oil and gas land costs (for

[10]Canada, Department of Finance, Budget Papers, Budget Speech, May 6, 1974 (John N. Turner). The minority Liberal government was defeated in a House of Commons vote on this budget. The ensuing general election returned the Liberals to power, this time in a majority position. The budget introduced in November 1974 included many of the changes proposed in the May budget. Since the November measures were enacted retroactively to May 7, changes first proposed in May are discussed here, and only modifications of these proposals and changes first proposed in November are discussed in the next section.

[11]Canada, Department of Finance, Budget Papers, Budget Speech, November 18, 1974 (John N. Turner).

example, land bonus payments) are effectively treated as development expenses. Proceeds from the sale of a property whose cost was a development expense (including the sale of oil and gas rights) are to be deducted from the unclaimed balance of development expenses, and any excess is to be treated as income.[12]

• *Capital cost allowances.* The fast write-off for tangible assets in manufacturing and processing, introduced in the May 1972 budget, is extended indefinitely.

9. Changes in the June 1975 Budget[13]

• *Corporation income tax rate.* As of January 1, 1976, this tax rate is reduced to 46 percent. Although the 10 percentage point provincial abatement is maintained, the resource profit abatement is replaced by a 25 percent resource allowance of resource profits (to be calculated as gross resource income after operating expenses and capital cost allowances, but before interest expenses, exploration and development expenses, and earned depletion).[14]

• *Investment tax credit.* Expenditures on tangible assets purchased between June 23, 1975 and July 1, 1977 will be eligible to receive a 5 percent investment tax credit against federal corporation income tax payable. This credit will not be allowed to exceed $15,000 plus one-half of the taxpayer's federal tax payable in excess of that amount. Any unclaimed balance can be carried forward for five years. The amounts received in tax credits will be deducted from the relevant asset classes' unclaimed balances for purposes of calculating capital cost allowances.

10. Changes in the May 1976 Budget[15]

• *Corporation income tax rate.* Effective at the beginning of 1976, the lower tax rate available to small businesses is to apply to the first $150,000 of business income earned in each year, until cumulated post-1971 taxable income reaches $750,000.

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[12]Some phasing-in rules are adopted for the treatment of the proceeds from sales of oil and gas rights acquired before 1972; these are designed to shift the treatment of such proceeds away from income, toward the same treatment as that given to oil and gas rights acquired after 1971.

[13]Canada, Department of Finance, Budget Papers, Budget Speech, June 23, 1975 (John N. Turner).

[14]It should be noted that "resource profits for resource allowance" differs from "resource profits for earned depletion." The latter is defined as resource profits for resource allowance *minus* the 25 percent resource allowance, royalties, interest expenses, exploration expenses, and development expenses. Earned depletion is then deductible to a maximum of 25 percent of "resource profits for earned depletion."

[15]Canada, Department of Finance, Budget Papers, Budget Speech, May 25, 1976 (Donald S. Macdonald).

• *Exploration expenses.* The 100 percent deductibility of exploration expenses is extended to all taxpayers for such expenses incurred between May 25, 1976 and July 1, 1979.[16]

• *Miscellaneous.* The rate of capital cost allowance for offshore drilling platforms is increased to 30 percent (from 15 percent). The budget clarifies the notion that no federal tax is payable on provincial incentive payments.

11. Changes in the March 1977 Budget[17]

• *Depletion.* Exploration expenditures incurred between March 31, 1977 and April 1, 1980 will earn additional depletion entitlements of 66⅔ percent of single-well drilling costs in excess of $5 million.[18] These entitlements can be claimed against *any* income (not just to the extent of 25 percent of resource profits, as is the case with all other earned depletion allowances).

• *Investment tax credit.* The program is extended to July 1, 1980. The general rate of credit remains at 5 percent, but it is increased to 7.5 percent in Saskatchewan, Manitoba, northern Alberta, northern British Columbia, northern Ontario, and parts of Quebec (a rate of 10 percent is to apply in the Gaspé area and the Atlantic provinces) effective April 1, 1977. The program is also extended to all research and development expenditures to be incurred between March 31, 1977 and July 1, 1980.[19]

• *Miscellaneous.* This budget also addresses a historical anomaly: during the 1960s, Saskatchewan sold oil and gas rights not through a bonus bidding system but rather through a royalty bidding system, whereby companies whose bids had been successful would pay a basic royalty plus whatever additional royalty they had bid; the May 1974 budget made *all* Crown royalty payments non-deductible from income for purposes of calculating federal tax payable. This budget effectively restores the deductibility of these additional royalties and treats them as expenditures on oil and gas rights, retroactive to May 7, 1974.

12. Changes in the April 1978 Budget[20]

• *Corporation income tax rate.* Effective January 1, 1978, the Northwest Territories enter the corporation income tax field, and the provincial abatement is to apply there as well.

• *Supplementary depletion.* Effective in 1978, the earned depletion rate on enhanced oil recovery equipment is increased to 50 percent. The max-

[16]This came to be known as the "drilling funds" deductibility.

[17]Canada, Department of Finance, Budget Papers, Budget Speech, March 31, 1977 (Donald S. Macdonald).

[18]This new source of deductions came to be known as "superdepletion."

[19]For these purposes, some expenditures on pilot projects and other experimental projects in the oil and gas industry are treated as research and development expenditures.

[20]Canada, Department of Finance, Budget Papers, Budget Speech, April 10, 1978 (Jean Chrétien).

imum rate of claim is increased to 50 percent of total income (not just production profits) for enhanced oil recovery equipment and oil sands depreciable property.

• *Investment tax credit.* An additional deduction from taxable income will be allowed for research and development expenditures incurred after 1977 and before 1988. This will equal 50 percent of the difference between current and capital expenditures on research and development in any given year and the average of such expenditures over the previous three years.

• *Miscellaneous.* As of April 10, 1978, heavy oil upgrading plants are to be treated as manufacturing plants and thus eligible for a 50 percent, straightline calculation of capital cost allowances as well as for the lower tax rate (that is, 40 percent) available to manufacturing and processing activities.

13. Changes in the November 1978 Budget[21]

• *Exploration expenses.* The "drilling funds" deductibility is extended to December 31, 1981.

• *Development expenses.* As of November 17, 1978, well recompletion costs will be considered as development expenses and will earn depletion deductions.

• *Investment tax credit.* The program is extended indefinitely. As of November 17, 1978, the basic credit rate is increased from 5 to 7 percent (rates applicable to investments made in certain regions of the country are increased from 7.5 to 10 percent, and from 10 to 20 percent).[22] In addition, small businesses can now claim an additional tax credit of 25 percent of all research and development expenditures.

• *Miscellaneous.* As of November 17, 1978, expenditures incurred for the development of new mines will be deductible at a rate of 100 percent.

14. Proposals in the December 1979 Budget[23]

• *Corporation income tax rate.* A surtax of 5 percent of tax payable is to be in effect from December 12, 1979 to December 31, 1981.

• *Depletion.* Superdepletion is extended to the end of 1980. The rate at which superdepletion deductions are earned is reduced to 6⅔ percent (from 66⅔ percent) for eligible expenditures incurred between April 1, 1980 and December 31, 1980.

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[21] Canada, Department of Finance, Budget Papers, Budget Speech, November 16, 1978 (Jean Chrétien).

[22] See the discussion on the March 1977 budget, above.

[23] Canada, Department of Finance, Budget Papers, Budget Speech, December 11, 1979 (John S. Crosbie). The minority Progressive Conservative government was defeated in a House of Commons vote on this budget. The ensuing general election brought to power a majority Liberal government. As noted in the next section, this government adopted, in April 1980, some of the measures proposed in the December 1979 budget.

• *Oil and gas rights*. The cost of acquiring oil and gas resource properties, including land bonus payments, will now be deductible at 10 percent declining balance.

• *Miscellaneous*. This budget also proposes to levy a new federal tax on oil and gas production revenues. The objective is to capture for the federal treasury one-half of the revenues from annual price increases in excess of $2 per barrel for crude oil and $0.30 per thousand cubic feet for natural gas. Details concerning the exact nature of this tax and its implementation are not spelled out.

15. Changes in the Notice of Ways and Means Motion of April 1980[24]

• *Corporation income tax rate*. The proposals concerning the surtax in the December 1979 budget are adopted.

• *Depletion*. Superdepletion is allowed to expire at the end of March 1980, and the proposals concerning its extension in the December 1979 budget are not adopted.

• *Oil and gas rights*. The proposals in the December 1979 budget are adopted. A new asset class will be created for oil and gas properties acquired after December 11, 1979. Proceeds from the disposition of such properties are to be applied first against any unclaimed balance in this new asset class; any excess of proceeds is then to be applied against unclaimed development expenses; only if the balance for this class can also be reduced to zero will any remaining proceeds be brought into income.

• *Miscellaneous*. Proposals concerning a new tax on oil and gas production revenues in the December 1979 budget are not adopted.

16. The National Energy Program and the October 1980 Budget[25]

• *Corporation income tax rate*. Activities relating to heavy oil upgrading will be treated as resource activities, not manufacturing and processing, effective in 1981.

• *Corporation income tax rate*—non-budget item. The Yukon Territory enters the corporation income tax field, and the provincial abatement is to apply there as well, beginning in 1980.

• *Exploration expenses*. These expenses are now to exclude drilling and related costs incurred after 1980 other than costs incurred in respect to a well drilled in an area where a commercial accumulation was not previously known to exist, and only if the well is abandoned within 12 months of its completion, or if it is the first well in the area capable of commercial production. Costs incurred in drilling all other wells are to be treated as

[24]Canada, Department of Finance, Notice of Ways and Means Motion To Amend the Income Tax Act, April 21, 1980 (Allan J. MacEachen).

[25]Canada, Department of Finance, Budget Papers, Budget Speech, October 28, 1980 (Allan J. MacEachen).

development expenses.[26] After 1980, exploration expenses for federal tax purposes will be net of all government grants, subsidies, or other assistance received. A separate measure indefinitely extends the "drilling funds" deductibility.

• *Development expenses.* After 1980, development expenses for federal tax purposes will be net of all government grants, subsidies, or other assistance received.

• *Overhead expenses.* After 1980, overhead expenses will not earn depletion. These will form a new category in the calculation of "resource profits for resource allowance" and will be deductible at a rate of 100 percent.

• *Depletion.* Overall, the tax-based system of exploration and development incentives is replaced by a grant-based system called the "petroleum incentives program." *Individuals* will not be eligible to earn depletion allowances after 1980; instead, Canadian individuals will receive cash grants of 80 percent of their exploration costs on Canada lands, 35 percent of their exploration costs elsewhere in Canada, and 20 percent of all their development costs. After 1980, *corporations* will not be eligible to earn depletion allowances for development costs (exceptions to this are prescribed projects, which will continue to earn depletion at a rate of 33⅓ percent of eligible expenditures, but now net of cash grants received, as described below). After 1980, the rate of earned depletion for exploration costs on Canada lands will remain at 33⅓ percent, while that applicable elsewhere in Canada will fall from 33⅓ percent until the end of 1981 to 20 percent in 1982, 10 percent in 1983, and zero in subsequent years. Corporations with a Canadian ownership ratio (COR) of at least 75 percent will receive cash grants relating to exploration and development costs according to the same rates as for Canadian individuals. Corporations with a COR between 50 and 75 percent will receive cash grants for exploration costs as follows: on Canada lands, 35 percent in 1981, 45 percent in 1982 and 1983, and 50 percent thereafter; elsewhere in Canada, zero in 1981, 10 percent in 1982 and 1983, and 15 percent thereafter. Corporations with a COR between 50 and 75 percent will receive cash grants for development costs as follows: everywhere in Canada, zero in 1981 and 10 percent thereafter. Corporations with a COR below 50 percent will receive cash grants only for post-1980 exploration costs on Canada lands at a rate of 25 percent.[27]

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[26] This measure was not implemented. See the discussion of the November 1981 budget, below.

[27] As implemented, the petroleum incentives program differed somewhat from the original version described above. The main differences relate to the COR for corporations. As noted above, three categories were originally proposed (at least 75 percent, between 50 and 75 percent, and below 50 percent). Modifications to some of the boundaries were made, and a fourth category was added. The top category will include corporations with a COR of at least 65 percent in 1981, 67 percent in 1982, 69 percent in 1983, 71 percent in 1984, 73 percent in 1985, and 75 percent in 1986 and subsequent years. The new category would include corporations with a COR of at least 60 percent in 1981, 61 percent in 1982, 62 percent in 1983, 63 percent in 1984, 64 percent in 1985, and 65 percent in 1986 and subsequent years. No changes were made to the other two categories. Corporations in the new category would earn cash grants of 65 percent of

(Continued on the next page.)

• *Supplementary depletion.* The supplementary depletion earned at a rate of 50 percent of the cost of enhanced oil recovery machinery and equipment, and 33⅓ percent of the cost of oil sands equipment, will continue until the end of 1980. After 1980, such costs (incurred by corporations only) will earn supplementary depletion at a rate of 33⅓ percent on prescribed projects (including enhanced oil recovery, oil sands, and heavy oil upgrader projects). All such depletion earned after 1980 will be deductible up to a maximum of 25 percent of resource profits.

• *Capital cost allowances.* For machinery and equipment relating to heavy oil upgrading acquired after 1980, these will be calculated according to a 30 percent, declining-balance method instead of according to a 50 percent, straightline method.

• *Investment tax credit.* After 1980, the amount of cash grants received will reduce the cost of properties eligible for this tax credit.

• *Petroleum and gas revenue tax.* As of January 1, 1981, this tax will be levied at a rate of 8 percent on production revenues net of operating costs.

17. Changes in the November 1981 Budget[28]

• *Corporation income tax rate.* The surtax introduced in the December 1979 budget is extended for two years. The rate of surtax will remain at 5 percent in 1982, but will fall to 2.5 percent in 1983. Small businesses are to be exempt from the surtax in 1982 and 1983. Effective in 1982, the lower tax rate on small businesses will apply to the first $200,000 of business income, until cumulated post-1971 taxable income reaches $1 million.

• *Exploration expenses.* Wells drilled for information purposes in *known* pools and capped for at least 12 months will be treated as development wells as of the end of 1981; such expenses will thus be deductible at 30 percent declining balance instead of 100 percent. Application of this change to gas wells is delayed for one year.[29]

• *Depletion.* Earned depletion deductions of 33⅓ percent of eligible expenditures on new oil sands plants, prescribed enhanced oil recovery projects, and heavy oil upgrading plants in Saskatchewan are retained. For new oil sands plants, depletion allowances will now be deductible up to a maximum of 25 percent of *any* income (instead of up to 25 percent of resource profits). Earned depletion deductions for exploration expenses on

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[27] Continued . . .
exploration costs on Canada lands, 25 percent of exploration costs elsewhere in Canada, and 15 percent for development costs everywhere in Canada.

[28] Canada, Department of Finance, Budget Papers, Budget Speech, November 12, 1981 (Allan J. MacEachen). This budget also implements the terms of the 1981 energy agreements between the federal government and the governments of the producing provinces. It should be noted that, as part of these agreements, the government of Alberta undertook to finance the petroleum incentives program within the boundaries of that province.

[29] A variant of these measures was first proposed in the national energy program. Its application was delayed a number of times; see the discussion of the February 1984 budget, below.

the Canada lands are to be phased out according to the following schedule: from 33⅓ percent until the end of 1982 to 20 percent in 1983, 10 percent in 1984, and eliminated thereafter.

• *Capital cost allowances.* For tangible assets acquired after November 12, 1981, the first-year capital cost allowance is reduced to one-half of its normal annual value. The two-year, straightline write-off for manufacturing and processing assets becomes a three-year (25-50-25) straightline write-off.

• *Miscellaneous.* It is made clear that income from new oil sands plants, from major extensions of such projects, or from the proposed Saskatchewan heavy oil upgrader is not to be sheltered by deductions stemming from expenditures unrelated to the specific project in question.

• *Petroleum and gas revenue tax.* The basic tax rate is increased to 16 percent as of January 1, 1982; however, a 25 percent resource allowance will be extended, which means that the effective tax rate will equal 12 percent. A special allowance is made for the proposed Alsands, Cold Lake, and Saskatchewan upgrader projects whereby the tax rate would equal 8 percent until project payout.

• *Incremental oil revenue tax.* Effective January 1, 1982, this special tax will be levied on oil production revenues from pools discovered before 1981. The difference between actual revenues and revenues at prices provided in the national energy program (NEP) (both net of provincial royalties) will be taxed at a rate of 50 percent; income subject to this tax will not be subject to the corporation income tax; 75 percent of the production from the GCOS (Suncor) oil sands plant will be subject to this tax.

18. Changes in the National Energy Program: Update 1982[30]

• *Petroleum and gas revenue tax.* The effective rate of this tax is reduced to 11 percent for the period between June 1, 1982 and May 31, 1983. A further reduction of 3 percentage points (to 8 percent) in this rate will apply to the production from oil sands plants over the period extending from January 1, 1983 to December 31, 1984. An annual credit of up to $250,000 against the tax liability of corporations on their annual production revenue will be available from June 1, 1982.[31]

• *Incremental oil revenue tax.* This tax is suspended for the period between June 1, 1982 and May 31, 1983; the only exception (until 1985) is the GCOS (Suncor) oil sands production, which will continue to be subject to this tax.

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[30] Canada, Department of Energy, Mines and Resources, *The National Energy Program: Update 1982* (Ottawa: Supply and Services, 1982).

[31] There is an extended delay in the implementation of this last measure; see the discussion of the economic and fiscal statement of November 1984, below.

19. Changes in the April 1983 Budget[32]

• *Investment tax credit.* For investments made after April 19, 1983, taxpayers will be able to use this tax credit to reduce their federal tax payable without limit. Previous limitations will continue to apply to investments made before that date. Credits earned before April 20, 1983 can be used to reduce federal tax payable to the full extent possible under the "old" rules, and any remaining tax may be reduced further by credits available under the "new" rules. Carrybacks will be allowed for credits earned after April 20, 1983.[33] This is to be phased in over two years according to the following schedule: credits earned in 1983 can be carried back two years (to 1981); credits earned in 1984 and subsequent years can be carried back three years. It will be possible to carry forward credits earned after April 19, 1983 for a period of seven years (up from five years under the old rules). A portion of the credits earned on investments made between April 19, 1983 and May 1, 1986 can be refunded directly *in cash* to taxpayers who cannot fully use these credits to reduce their federal taxes; the refund rate is 40 percent for small businesses and a few other categories of taxpayers, and 20 percent for all other taxpayers.

• *Petroleum and gas revenue tax.* This tax is not to be payable by enhanced oil recovery projects receiving provincial royalty relief until eligible capital costs (defined as expenditures on well equipment and expenditures eligible for earned depletion) have been recovered. This is to apply to expenditures made after December 31, 1982.[34]

• *Incremental oil revenue tax.* This tax is suspended for another year, to May 31, 1984.

20. Changes in the February 1984 Budget[35]

• *Miscellaneous.* Changes in the treatment of expenditures on wells drilled in known pools first discussed in the NEP are delayed for two more years, to January 1, 1986.

• *Incremental oil revenue tax.* This tax is suspended for another year, to May 31, 1985.

21. Changes in the November 1984 Economic and Fiscal Statement[36]

• *Miscellaneous.* A number of tax changes dating back to as early as 1982 (for example, the enhanced oil recovery capital-cost offsets for the

[32]Canada, Department of Finance, Budget Papers, Budget Speech, April 19, 1983 (Marc Lalonde).

[33]Credits earned after that date can thus be used to reduce taxes assessed in previous years.

[34]There are delays in the implementation of this measure; see the discussion of the economic and fiscal statement of November 1984, below.

[35]Canada, Department of Finance, Budget Papers, Budget Speech, February 15, 1984 (Marc Lalonde).

[36]Canada, Department of Finance, *Economic and Fiscal Statement* (Ottawa: the department, November 8, 1984) (Michael H. Wilson).

petroleum and gas revenue tax) will be enacted, retroactive to the time these were originally to apply.

• *Petroleum and gas revenue tax.* The lower tax rate for oil sands production is extended for one year. The threshold level of the small producers' tax credit is doubled to $500,000, effective January 1, 1985.

• *Incremental oil revenue tax.* This tax is suspended for the production of the GCOS (Suncor) oil sands plant, effective January 1, 1985.

22. Changes in the May 1985 Budget[37]

• *Corporation income tax rate.* A 5 percent surtax on the tax payable by corporations is to be levied between July 1, 1985 and June 30, 1986. Small businesses are exempt from this surtax.

• *Investment tax credit.* The credit rate for current (but not capital) expenditures on research and development activities by small businesses is increased to 100 percent of those eligible expenditures incurred after May 23, 1985; other research and development provisions relating to tax credits will be allowed to expire on April 30, 1986.[38] There is a general tightening of the definition of "eligible expenditures" for the research and development aspects of this tax credit.

• *Petroleum and gas revenue tax.* This tax is to be phased out according to the following schedules: effective rates payable on conventional oil and gas production net of operating expenditures—from 12 percent until the end of 1985 to 10 percent in 1986, 8 percent in 1987, 6 percent in 1988, and eliminated beginning in 1989 (changes effective on January 1 of each year); effective rates on synthetic oil production revenues net of operating expenditures—from 8 percent until the end of 1985 to 6 percent in 1986, 4 percent in 1987, 2 percent in 1988, and eliminated in 1989 (again, changes effective on January 1 of each year). Production from wells on which drilling began on or after April 1, 1985 is exempt from this tax (a similar provision applies to some production resulting from post-March 1985 application of waterflooding and tertiary recovery methods). Existing enhanced oil recovery production, however, does not qualify for this exemption *if* participants elect to take advantage of the capital-cost recovery provision of this tax.[39] Companies will be allowed to reduce payments for this tax with unused corporation income tax deductions. Eligible exploration and development expenses (net of government assistance) incurred after March 31, 1985 will be deductible at 30 percent of the write-off rates allowed for corporation income tax purposes; however, these credits will be available only in the year the expenditures are incurred (also, the credits will be repayable to the federal government when the taxpayer claims the offset

[37] Canada, Department of Finance, Budget Papers, Budget Speech, May 23, 1985 (Michael H. Wilson). This budget also implements the terms of the western accord.

[38] See the discussion of the April 1983 budget, above.

[39] Again, see the discussion of the April 1983 budget.

amounts as normal federal corporation income tax write-offs in future years). The first $10,000 of an individual's annual oil and gas income is to be exempt from this tax after December 31, 1985.

• *Incremental oil revenue tax*. This tax is repealed as of June 1, 1985.

• *Petroleum incentives program*. This program will be terminated as of March 31, 1986; however, provisions for grandfathering some outstanding investment commitments will apply until the end of 1987.

23. Changes in the February 1986 Budget[40]

• *Corporation income tax rate*. This tax rate is to be reduced according to the following schedules: basic rate—from 36 percent in 1986 to 35 percent in 1987, 34 percent in 1988, and 33 percent in 1989 and subsequent years; manufacturing—from 30 percent in 1986 to 28 percent in 1987, 27 percent in 1988, and 26 percent in 1989 and subsequent years; small business—from 15 percent in 1986 to 14 percent in 1987, and 13 percent in 1988 and subsequent years; small business, manufacturing and processing—from 10 percent in 1986 to 8 percent in 1987 and subsequent years (these rates are to be effective on July 1 of each year and are net of provincial abatement). The surtax on corporate income is extended to December 31, 1986.[41] A surtax of 3 percent on *all* business income is imposed, effective January 1, 1987.

• *Investment tax credit*. This tax credit is to be phased out according to the following schedules: for investments currently earning a 7 percent credit—5 percent in 1987, 3 percent in 1988, and eliminated in subsequent years (effective January 1 of each year); investments currently earning a 10 percent credit will also see its elimination; but those qualifying for a 20 percent credit will continue to do so. Effective February 26, 1986, the east coast offshore region will qualify for a credit rate of 20 percent (up from 7 percent). The provisions for a cash refund of a portion of the unused credits are to be extended to December 31, 1988.

• *Exploration tax credit*. Exploration expenditures incurred between December 1, 1985 and December 31, 1990 (and not eligible for petroleum incentive payments) will earn tax credits at a rate of 25 percent of eligible single-well costs in excess of $5 million. These credits will be refundable at a rate of 40 percent for companies in a non-tax-paying position.

• *Petroleum and gas revenue tax*—non-budget measures. In April, the federal government suspends the petroleum and gas revenue tax (PGRT) for oil sands production until the end of 1986. In September, this tax is abolished for all oil and gas production, effective October 1, 1986.

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[40] Canada, Department of Finance, Budget Papers, Budget Speech, February 26, 1986 (Michael H. Wilson). This budget also implements some of the provisions of the government's new frontier energy policy, discussed in chapter 9. Our coverage here is limited to the implications of the new policy for the corporation income tax system.

[41] Small businesses continue to be exempt from this surtax.

• *Exploration and development incentives*—non-budget measure. In March, the federal government announces a new oil and gas exploration and development incentive program: subject to some conditions, all exploration and development expenditures on projects beginning after April 1, 1987 will qualify for a 33⅓ percent incentive payment, up to an annual maximum of $10 million per firm.

• *Miscellaneous*—non-budget measure. In conjunction with the introduction of exploration and development incentives in March, the federal government extends tax write-offs to oil and gas investors in the form of flow-through shares.[42]

24. Tax Reform Proposals of June and December 1987[43]

• *Corporation income tax rate.* As of July 1988, this tax rate is to be reduced as follows: basic rate—from 35 to 28 percent; small businesses—from 15 to 12 percent. The following phased reduction is to apply to manufacturing: from 30 percent in 1987 to 26 percent in 1988, 25 percent in 1989, 24 percent in 1990, and 23 percent in 1991 and thereafter.

• *Depletion.* The rate at which eligible expenditures earn depletion deductions is to be changed according to the following schedule: from 33⅓ percent in 1987 to 16⅔ percent after June 1988, and zero after December 1989.[44]

• *Capital cost allowances.* Resource extraction assets, drillships, and offshore platforms will be written off on a 25 percent declining balance rather than 30 percent, starting in 1988. Manufacturing and processing assets will be converted from a three-year straightline method to a 25 percent declining-balance method over the 1988 to 1991 period. During the phase-in period, new assets will be written off on a 40 percent declining-balance basis in 1988, 35 percent in 1989, 30 percent in 1990, and 25 percent in 1991 and subsequent years.

• *Investment tax credit.* After 1988, eligible expenditures undertaken in the east coast offshore region will qualify for a 15 percent credit (down from 20 percent).

• *Exploration and development incentives.* The program announced in March 1987 is to be phased out by December 31, 1989 according to a

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[42] With these shares, the value of the incentive grants is allowed to flow through to the investor, who also earns a tax deduction for the remaining value of the investment. Such a mechanism had previously been available to the mining industry.

[43] Canada, Department of Finance, *Tax Reform 1987: Income Tax Reform* (Ottawa: the department, June 18, 1987) (Michael H. Wilson); and Canada, Department of Finance, *Supplementary Information Relating to Tax Reform Measures* (Ottawa: the department, December 16, 1987) (Michael H. Wilson).

[44] Since the early 1980s, eligible expenditures for the purpose of earned depletion consisted of heavy oil upgrading costs and expenditures on exploration, development, and equipment for oil sands mining and enhanced oil recovery. See the discussions of the national energy program and the October 1980 budget, section 16, and the November 1981 budget, section 17, above.

schedule similar to that applicable to earned depletion: the rate of incentive payment will fall from 33⅓ percent in 1987 to 16⅔ percent after October 1988 and zero after December 1989.

• *Miscellaneous*. Mechanisms for allowing individuals to claim expenditures incurred by corporations (in particular, flow-through shares) will be retained, but definitions of which types of instruments qualify will be tightened.

Appendix 5.2

Selected Changes to Provincial Royalties, Incentive Programs, and Regulations

1949

The government of Alberta enacts a ceiling on royalty rates for oil and gas production from Crown lands. The maximum royalty rate on crude oil is set at 16⅔ percent and that on natural gas at 15 percent of production.

1949 July

Alberta enacts the Gas Resources Preservation Act, which empowers the Alberta Oil and Gas Conservation Board (AOGCB) to regulate the removal of natural gas from the province, subject to the approval of the Alberta government. Specific criteria for regulating gas removals are not specified in the Act but are later developed by the AOGCB. Over time, two key criteria emerge: (1) removals of gas are to be authorized only if there exists a demonstrable surplus of reserves over the province's gas requirements (an initial 30-year protection period is replaced in 1979 by a 25-year period and, in 1987, by a 15-year period); and (2) most of the gas volumes sought for removal are to be under contract before granting of authorization (a measure of 80 percent eventually comes into use). Although this Act is frequently amended, its basic intent and purpose are not altered.

1950 December

The AOGCB introduces an oil prorationing plan. It assigns a two-part production quota to each oil well. First, a fixed part (called economic allowance) is graduated with well depth. A variable part is then calculated by allocating the remaining market demand (after all economic allowances have been satisfied) in proportion to the productive capacity of each well. Market demand, in turn, is determined through a nominations system, by which purchasers of Alberta oil file each month with the AOGCB the volumes that they intend to buy.

1962 June

Maximum royalty rates on oil and gas production in Alberta are set at 16⅔ percent. Although this represents an increase in gas royalty rates (up from 15 percent), oil rates are unchanged.

1964 July

After hearings held by the AOGCB during 1963, the Alberta government approves major changes to the province's oil prorationing system. Full implementation of the new plan is to be achieved by January 1, 1969. The two-tier economic allowance is abolished and replaced by a single, and substantially reduced, minimum allowance which will continue to be graduated with well depth. Market demand is to be allocated among reservoirs in proportion to reserves, without any reference to well capacity or the number of wells in a reservoir. Within each reservoir, demand is to be distributed in proportion to well acreage, subject to the minimum allowance.

1966 June

The AOGCB announces changes in the calculation of natural gas available for removal from the province. Although the method used to determine the surplus becomes more complicated, the net effect is to encourage removals from the province.

1969 October

The AOGCB adopts a more liberal way of determining the quantity of gas that can be removed from the province. More reliance is placed on reserves yet to be discovered to meet future requirements.

1972 March-April

The Alberta government announces that it is undertaking a comprehensive review of the province's oil and gas royalty system. In April, Premier Peter Lougheed says that because of the nature of long-term production leases, it will be difficult for the province to get more royalty revenues. Instead, the premier suggests that a special tax on oil may be levied. Later in April, the Alberta government announces that it proposes to institute a tax on Crown and freehold oil and gas reserves. To offset the impact of the tax on exploration activity, the government plans to offer all discovery wells a royalty and reserves tax holiday, to last until the end of 1977. An implementation date of July 1972 is initially proposed. Delays and the government's willingness to explore alternatives to the reserves tax, however, are soon announced.

The Alberta Energy Resources Conservation Board (AERCB)[1] announces changes to Alberta's oil prorationing scheme, effective June 1. A discovery allowance is introduced, and the minimum allowance is increased.

1972 August

Numerous changes to Alberta's proposed reserves tax are announced. Changes in the royalty regime applicable to gas are delayed indefinitely. Oil

[1] This is the new name of the former Alberta Oil and Gas Conservation Board (AOGCB).

producers are offered a choice: they can opt for either a reserves tax or increased royalty rates (the average royalty rate would rise from 16⅔ percent to about 22 percent). Producers are given until January 1, 1973 (this is later extended to July 1, 1973) to choose between the two options. Initial plans are for the new royalty and reserves tax system to be in effect until December 31, 1977, at which time changes in the royalty and tax rates, or even the system itself, may be enacted. The Alberta government also introduces an exploration incentive package that includes a combination of tax credits for drilling expenses and tax holidays for new oil discoveries. A key part of this package is the provision that all new field discovery wells drilled between May 1, 1972 and December 31, 1977 are to be eligible for a five-year royalty and reserves tax holiday. (This royalty and reserves tax holiday is designed to apply to fewer wells than the holiday proposed in April: only new field discovery wells are to be eligible. The later proposal is more generous toward those wells that are eligible, however: these are to get a five-year royalty and reserves tax holiday, irrespective of when drilling occurred.)

The AERCB releases its *Report on Field Pricing of Gas in Alberta*, a study undertaken at the request of the Alberta government. The main finding is that wellhead prices of natural gas are currently much too low, and have been for some time. The AERCB estimates that current wellhead prices of 16 cents per thousand cubic feet are between 10 and 20 cents too low. A doubling of wellhead prices seems to be in order. Three main reasons are given: (1) insufficient competition among buyers, (2) the failure of the National Energy Board (NEB) to grant export licences for all the quantities sought in 1970 and 1971, and (3) the existence of regulatory lag preventing gas prices to consumers from rising as quickly as the prices of competing fuels. The AERCB recommends that all purchase contracts include base prices consistent with the field value of the gas at the time each contract is negotiated. In addition, contracts should have provisions for annual price escalation of 3 to 4 percent.

1972 November

The Alberta government announces its endorsement of the AERCB's recommendations. Existing contracts are to be revised. The government, however, also announces its intention to institute a two-tier pricing system to protect Alberta residents from increases in gas prices.

1973 February

The government of British Columbia announces a large increase in crude oil royalty rates: effective April 1, the highest rate goes from 16⅔ percent to 40 percent.

1973 October

The Alberta government announces major changes in the province's crude oil royalty system. The reserves tax is repealed; royalty rates are increased

(from 16⅔ percent to about 23 percent, on average) and made to depend on oil prices. The Alberta government states that these moves are in response to the federal government's September oil price freeze and the introduction of the oil export tax.

1973 November

British Columbia Petroleum Corporation (BCPC) is established by the government of British Columbia. The new Crown corporation is to assume all of Westcoast Transmission's gas purchase contracts. Shortly thereafter, BCPC becomes the sole purchaser of natural gas, and the price it pays producers is to be net of royalties. Instead, the provincial government is to collect revenues on the production of natural gas through BCPC. This becomes known as the "deemed royalty" system. A portion of the incremental revenues from the higher-priced gas export sales is to be retained by BCPC. The remaining portion is to be distributed among the province's gas producers. This is an early version of the so-called export flow-back system.

1973 December

The Saskatchewan government introduces legislation aimed at collecting a greater portion of oil and gas revenues. In return, some incentives for oil and gas exploration are announced. One of the key aspects of this new legislation is the introduction of a mineral income tax and a royalty surcharge to collect the difference between Canadian and world-equivalent wellhead oil prices. (In February 1974, the constitutionality of these aspects of the legislation are challenged by a producer, Canadian Industrial Gas and Oil Limited—CIGOL—later renamed Norcen Energy Resources. Although a provincial court first finds in favour of Saskatchewan, the Supreme Court of Canada eventually, in November 1977, finds the legislation to be ultra vires.)

1974 January

The Alberta Arbitration Act is modified so that the energy-equivalent value of natural gas is now to serve as a key criterion in renegotiations of natural gas purchase contracts.

The government of Alberta unveils new royalty and incentive systems for natural gas. Royalty rates will differ for "new" and "old" gas, according to when the discovery occurred. These rates will also vary according to a sliding scale tied to field prices. Overall, average royalty rates go up significantly (maximum rates are 65 percent for old gas and 35 percent for new gas). The government also announces that changes in the province's oil royalty system will be forthcoming in March.[2] The incentive program in

[2]It should be noted that for purposes of provincial royalties, "old" oil refers to crude oil produced from pools discovered before April 1, 1974; "old" gas refers to gas produced from fields discovered before January 1, 1974. Crude oil and gas from pools or fields discovered after these dates are called "new" oil and gas. The same distinction soon applies in the determination of royalty rates in British Columbia and Saskatchewan. This is in contrast to the

(Continued on the next page.)

place since August 1972 is modified by the adoption of a broader definition of oil wells eligible for a royalty holiday. The new oil incentive program is to be in place for five years, until December 31, 1978. In addition, a two-year royalty holiday for new gas wells is announced.

1974 March

The Alberta government announces sharp increases in royalty rates for crude oil. Effective April 1, average royalty rates are to rise from about 23 percent to 40 percent for old oil and 28 percent for new oil. As with the gas royalty system introduced a few months earlier, the new oil royalty rates are to vary according to a sliding scale tied to wellhead prices. Well productivity is also to play a role in determining oil royalty rates.

1974 April

The Saskatchewan government announces a new exploration incentive program: tax credits are offered, as is a reduction in royalty rates applicable to new oil discoveries.

1974 May

The government of British Columbia increases oil royalty rates substantially, especially on wells producing 1,000 and 4,000 barrels per day, for which the rates go up by as much as 30 percentage points. The government also increases rentals and introduces land regulations that require greater work commitments.

1974 December

The Alberta government announces the petroleum exploration plan, which reduces oil and gas royalty rates, introduces a royalty tax credit, and extends new drilling incentives to oil producers. These measures are presented as an attempt to reduce the impact on the industry of the recent federal decision to disallow the deductibility of provincial royalty payments in the calculation of taxable income. The overall intent of Alberta's measures is to retain the deductibility of royalties for the purposes of the provincial corporation income tax, and to extend some compensation to producers (through the royalty tax credit) for the federal move. Similar responses are soon made by the governments of both Saskatchewan and British Columbia.

1975 February

The Saskatchewan government announces additional incentives for oil exploration.

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[2]Continued . . .
definitions of "new" and "old" used in the 1981 energy agreements. On this, see chapters 3 and 5, under "The National Energy Program and Two-Tier Pricing" and "The National Energy Program and Its Aftermath," respectively.

1975 March

The Alberta government introduces new seismic and other geophysical incentives, retroactive to January 1. These are to be in place until March 31, 1978.

1975 July

The government of Alberta effectively sets a maximum royalty rate of 50 percent on a recently announced domestic crude oil price increase. This is done by modifying the existing formula to calculate royalties.

1975 October

The net differential between domestic and export prices of natural gas is to be distributed by the Alberta government to all gas producers in the province. (As noted above, a similar measure was introduced in British Columbia in November 1973.) Previously, the transmission companies had returned the differentials only to producers under contract with them.

1975 November

Modifications to BC crude oil royalties are announced: a distinction between old and new oil is now to be made, and a general reduction in average rates is to be effected. A system of oil exploration incentives is also introduced, whereby the province will refund as much as 75 percent of exploration expenditures. The refund rate, however, is to fall over time, to reach zero by 1979.

The Saskatchewan government announces a simplification of its oil royalty system and a reduction in average rates from about 55 percent to 50 percent. To spur oil exploration activity, the royalty rate on new oil is to be reduced to 60 percent of that on old oil for a period of six years. A few additional incentive measures are also announced. The announcement also stipulates that similar changes to the gas royalty system are to be enacted in 1976. Further reductions in oil royalty rates will be announced in February 1976.

1976 July

Alberta enacts stricter land regulations. For existing leases, the new regulations call for increased drilling requirements. New leases are to be issued for five years (renewable for three one-year extensions, if certain conditions are met). Leases issued until then had terms of 10 or 21 years.

1976 September

The government of Alberta extends lower royalties to enhanced oil recovery projects.

1976 November

The government of British Columbia announces that average royalty rates are to fall from about 40 percent to 22 percent for old oil, and from about 57 percent to 28 percent for new oil.

1977 August

The Alberta government announces that its exploration drilling incentive program, scheduled to end on December 31, has been extended until March 31, 1981. No other significant changes to the program are made. The geophysical incentive program is curbed, but extended by two years from its previously announced termination date of March 31, 1978. This program was subsequently extended for another year, to end on March 31, 1981.

1977 December

The Saskatchewan government introduces legislation to replace part of its royalty system declared ultra vires by the Supreme Court of Canada (in re the *CIGOL* case). The legislation is to apply retroactively to January 1974, and is designed to generate the same amount of provincial revenue as did the elements of the royalty system that were struck down.

1978 July

The Alberta government reduces royalty rates on low-productivity gas wells. The new rates are to be determined according to a sliding scale based on production and price. The minimum rate falls from 22 percent to 5 percent.

1979 December

The AERCB announces a series of changes in the methodology used to determine the volumes of gas available for removal from the province. In particular, the 30-year protection for Alberta requirements is reduced to 25 years. Other changes result in a more optimistic view of Alberta's future gas supply situation, which in turn also encourages greater gas removals from the province.

1980 February

A formal review process for exports of natural gas, oil, and electricity is established by the BC government. Two basic principles are to drive this process: (1) export prices must at least equal the long-term value of the fuel, and (2) the province's immediate and future energy needs must be protected before exports can be allowed.

1980 October

As a response to the national energy program (NEP), the Alberta government announces a 15 percent (180,000 barrels per day) cut in crude oil pro-

duction, phased in over three periods of three months, beginning on March 1, 1981.

1981 June

Retroactive to April 1, 1981, the Alberta government extends the exploration and geophysical incentive programs for a period of two years.

1981 September

As part of the federal-provincial agreement on oil and gas pricing and taxation, the government of Alberta agrees to administer the petroleum incentives program (PIP) within the boundaries of the province.[3] The oil production cuts announced in October 1980 are ended.

1981 October

Retroactive to September 1, the Alberta government doubles the rate of the royalty tax credit (from 25 percent to 50 percent) and its annual maximum (from $1 million to $2 million).

1982 January

The Saskatchewan government first reduces the royalty rates on old oil, then reduces royalty rates on most heavy crude production.

1982 April

The Alberta government unveils the Alberta oil and gas activity program. At an estimated cost of $5.4 billion, this program is designed to increase revenue flows to the industry for 1982-1987. The main elements include a permanent reduction in the marginal royalty rate for old oil and old gas (down to 45 percent from 50 percent) and increases in the base price for all oil and gas production. Other shorter-term measures include the enrichment of royalty tax credits (to 75 percent of royalties up to an annual maximum of $4 million, to be in effect between September 1, 1981 and the end of 1983) and royalty holidays for some natural gas production (one-year holiday for exploration wells drilled between April 15, 1982 and December 31, 1982; two-year holiday for wells drilled during 1983). Unless otherwise stated, these measures are in effect as of April 1.

The government of Saskatchewan announces a new tax and royalty regime for enhanced oil recovery. Overall, average royalty rates are reduced, and royalties may now be levied on either gross or net operating revenues, whichever yields the most revenue for the province.

1982 July

An extensive series of changes to Saskatchewan's oil and gas royalty and tax system is announced. It includes royalty holidays for new exploration and

[3]For details concerning the PIP, see section 16 of appendix 5.1.

development wells, reductions in royalty rates for old oil, a number of royalty and tax reductions for heavy oil, and lower effective royalty rates for enhanced oil recovery. One-year royalty holidays are to apply to all wells that qualify for the new oil reference price (NORP), to be drilled between June 1, 1982 and December 31, 1983. In addition, deep exploratory wells drilled during the same period are to receive a five-year royalty holiday, while deep development wells are eligible for a three-year holiday. The royalty holidays for development wells are deemed a first in Canada.

1982 October

The Alberta government introduces a series of incentives for enhanced oil recovery projects. The net effect of these measures is to reduce effective royalty and tax rates on these projects.

1983 January

A number of changes are made to Saskatchewan's oil royalty system. The main changes have to do with the extension of royalty holidays for shallow wells drilled after 1982.

1983 April

The Alberta government's exploration drilling and geophysical incentive programs, due to expire March 31, are extended for a period of one year.

1983 September

Plans for a number of fundamental changes in British Columbia's gas production and marketing system are announced by the provincial government. The deemed royalty system is to be abandoned and replaced by a royalty pricing system, as in Alberta. The role of BCPC is to be sharply curtailed as most future contracts are to be between producers and purchasers. Current BCPC contracts are to be renegotiated to allow for the new pricing system. Westcoast Transmission is to become a common carrier for future contracts.

1983 December

Some changes are made to Alberta's geophysical incentive system and to the Alberta PIP regulations. These changes are designed to make both programs slightly less generous toward the industry.

1984 January

The Alberta government announces reductions in the province's royalty rates by increasing basic well rates, thus making wells less productive for purposes of calculating royalty payments. These measures are to be in effect as of February 1.

1984 March

Some minor modifications to Saskatchewan's oil royalty and incentive system are announced.

A 12-month royalty holiday for all exploration oil wells is declared in Alberta, effective April 1. The maximum holiday is set at $1 million per well. The more selective five-year royalty holiday for some oil exploration wells (introduced in August 1972) is extended to March 31, 1985, but a maximum holiday of $2 million is now to apply. The royalty holiday on exploration gas wells is also extended for one year, with a maximum holiday of $2 million. Exploration drilling and geophysical incentives are also extended for one year.

1985 March

The Alberta geophysical, exploration, and drilling incentive programs are extended for four months, to July 31. The same applies to the one-year royalty holiday for exploration oil wells.

1985 June

The government of Saskatchewan extends its oil royalty holiday for one year. The program was originally introduced in 1982 and had been due to end in December 1985.

The Alberta government announces major changes in royalty rates and a number of incentive programs. Over a two-year period, marginal royalty rates on all oil and gas production are to fall by 5 percentage points, beginning on August 1 (down to 40 percent for old oil and gas, and 30 percent for new production). As of April 1, 1986, the royalty tax credit is to be increased from 50 percent of royalty obligations up to a maximum of $2 million, to 75 percent of royalty obligations up to a maximum of $3 million per eligible investor. This coincides with the termination of the Alberta PIP. The exploration drilling and geophysical incentive programs are to expire on July 31. As of June 1, a one-year crude oil royalty holiday is available for eligible wells. As of August 1, a one-year royalty holiday is to be available for eligible gas wells. Both programs are to end on May 31, 1988. In addition, a royalty holiday program for deep gas is implemented as of June 1.

1985 July

A new production-sensitive gas royalty is introduced in Saskatchewan. On average, the new system is characterized by slightly higher royalty rates.

1985 August

The government of British Columbia announces an oil royalty incentive program, retroactive to June 30. All exploration wells are to be eligible for a

three-year holiday and all development wells for a two-year holiday. The program is to be in effect until June 30, 1989.

1985 October

As part of the federal-provincial agreement on natural gas markets and prices, the government of Alberta agrees to abolish the province's export of flow-back system for natural gas, as of November 1, 1986.

The AERCB sets up a program of supplementary market allocations for crude oil, on a trial basis. Oil producers can offer their shut-in production for sale by public tender. Such sales, of course, are subject to deliverability constraints (that is, pipeline capacity). In the months that follow, supplementary production is used to take advantage of unforeseen availability of pipeline capacity.

1986 March

The government of British Columbia eliminates the flow-back system for export sales of BC-produced gas.

1986 April

The Alberta government enhances the province's royalty tax credit program (the credit rate is increased to 95 percent from 75 percent) and extends a 50 percent royalty credit to exploration wells. These two measures are to apply to activities undertaken between April 1 and December 31, 1986. The royalty credit, however, can be claimed against royalties payable after April 1, 1987, up to a maximum of $3 million or until the end of 1987, whichever comes first.

1986 May

The government of Saskatchewan provides a number of temporary relief measures for the oil industry. The two main temporary measures are: (1) a program under which 40 percent of qualified well maintenance expenditures will be deductible against royalties and taxes, up to a maximum of $6 million; and (2) a sharp reduction in Crown royalties and freehold taxes for all oil production. These measures are to be in place from the beginning of May to the end of July. (Shortly before they are due to end, these relief measures are extended to October 31.) In addition, a permanent reduction in the effective royalty and tax rates for enhanced oil recovery is then introduced.

1986 June

The government of Alberta announces a summer aid package to the oil and gas industry, at an expected cost of $200 million. The relief program is to be in place from the beginning of June to the end of September. The main elements of this aid package are assistance programs for development drilling, well servicing, and geophysical activities.

1986 September

The Alberta government extends some of its incentive programs to the end of December 1986 (they had originally been intended to end on September 30).

1986 October

The Alberta government announces adjustments to its incentive programs, royalty reductions for oil and gas, and royalty holidays for certain wells. Overall, average royalty rates for both old and new oil and gas fall by about 12 percent to 31 percent for old oil, 25 percent for old gas, 23 percent for new oil, and 19 percent for new gas. A five-year royalty holiday is extended to eligible wells on which drilling began between October 1, 1986 and November 1, 1987. A three-year royalty holiday is extended to eligible wells on which drilling began between November 1, 1987 and November 1, 1988. A number of other incentive programs are extended until the end of December 1986 (they had originally been intended to end on September 30).

1987 January

Effective Januray 1, Saskatchewan royalty rates on oil production are reduced, and rates are tied to prevailing oil prices. Development wells drilled before June 30, 1988 are also to be eligible for a three-year royalty and tax holiday. Wells drilled during the following calendar year are to be eligible for a two-year holiday. After June 30, 1989, a one-year holiday will be earned if oil prices are above US$20 per barrel, while a two-year holiday will continue to apply if prices are below US$20 per barrel.

1987 February

The government of Saskatchewan introduces a new royalty and tax regime, which is sensitive to prices, productivity, and vintage.

1987 March

Alberta announces that the AERCB will implement, effective June 1, 1987, a modified system of production allocation for light and medium crude oil. This profoundly changes the prorationing system first enacted in December 1950. The intention of the new system is to allow producers to sell all available production, subject to limits determined with respect to maximum production rates for each well. The new system, initially to be in effect for a seven-month trial period, is extended indefinitely in November 1987.

The AERCB moves to a 15-year protection for Alberta's residential, commercial, and small industrial (or core) users in its calculation of the volumes of gas available for removal from the province.

1987 May

The government of British Columbia announces a royalty holiday for gas wells. Effective June 1, eligible development and exploration wells will

qualify for a 12-month royalty holiday. Some exploration wells will qualify for a holiday of between 12 and 36 months, depending on how far the well is from producing areas, the difficulty of the terrain, and drilling depth.

1987 December

The government of Alberta modifies the royalty system applicable to natural gas production. Under this system, instead of being payable on transaction prices of the production from individual wells, royalties are to be payable on 80 percent of the average price of all production in the province when transaction prices for individual producers are below 80 percent of the province-wide average.

Appendix 6.1

Description of the Demand and Losses Sectors

Demand Sector

The demand sector is responsible for disaggregating total national energy demand (E), obtained in the macroeconomic model, into regional energy demands (FUEL.reg), and within each region, into demands for each type of fuel (QO.reg, QG.reg, QL.reg). The regions are Atlantic (AT), Quebec (QU), Ontario (ON), Manitoba (MN), Saskatchewan (SK), Alberta (AL), and British Columbia (BC). The regional fuel share equations are for oil, electricity, and natural gas.

Regional energy demand (FUEL.reg) is estimated using the ratio of regional real domestic product (RDP) to the national total (RDP.reg), a weighted moving average of regional energy prices relative to national energy prices (PE.reg), and national energy demand (FUEL.CA). FUEL.CA, measured in trillions of input BTU, is proportionally related to the macroeconomically determined energy demand (E), measured in billions of 1971 dollars.

Regional energy demand (FUEL.reg) is disaggregated into fuel demand (QO.reg, QG.reg, QL.reg) by estimating regional quantity fuel share equations, which are a function of relative average energy fuel prices, the number of natural gas pipeline distribution kilometres (as an indication of the availability of natural gas), and the lagged shares. To be specific, the form of the estimated equations is as follows:

$$\ln(SO/SL) = a1 + b * \ln(PO/PL) + c1 * GPKM + d * \ln(\text{lag}(SO)/\text{lag}(SL)) + u$$

$$\ln(SG/SL) = a2 + b * \ln(PG/PL) + c2 * GPKM + d * \ln(\text{lag}(SG)/\text{lag}(SL)) + v$$

$$SL = 1 - SO - SG,$$

where SO, SG, and SL are quantity shares for oil, gas, and electricity, respectively; PO, PG, and PL are the average fuel price for oil, gas, and electricity, respectively; GPKM is the number of natural gas distribution pipeline kilometres; ln is the natural logarithm operator; * is the multiplication operator; lag is a one-period lag; u and v are stochastic error terms; and a1, a2, b, c1, c2, and d are parameters to be estimated. The regional fuel demands are obtained by multiplying the fuel shares by the aggregate regional energy usage.

The regional demands for fuels are not disaggregated by end-use sector, except for fuels used in thermal electricity generation, which are estimated separately and also reported in this appendix. The fuels used in thermal

electricity generation are estimated with an equation system similar to that just described. The differences between the structure used in the main demand system and the thermal demand system are as follows: (1) aggregate energy demand (FUELSL.reg) is a function of thermal electricity generation (QSL.reg), which is residually determined by subtracting from total electricity demanded (QL.reg) the supply of hydro- and nuclear-generated electricity (QHL.reg); (2) gas distribution pipeline kilometres are not used; and (3) coal replaces electricity in the fuel share equations.

Not all fuels are used in all regions; therefore the equation structure for each region reflects the actual fuel mix. For instance, natural gas is not used in the Atlantic region, and coal is not used to generate electricity in Quebec or in British Columbia.

The equation structure follows. A complete list of variables and symbols is found at the end of each section.

Calculate the total fuel expenditure by region, millions of dollars:

```
T$AT = PO.AT * QO.AT + PL.AT * QL.AT
T$QU = PO.QU * QO.QU + PG.QU * QG.QU + PL.QU * QL.QU
T$ON = PO.ON * QO.ON + PG.ON * QG.ON + PL.ON * QL.ON
T$MN = PO.MN * QO.MN + PG.MN * QG.MN + PL.MN * QL.MN
T$SK = PO.SK * QO.SK + PG.SK * QG.SK + PL.SK * QL.SK
T$AL = PO.AL * QO.AL + PG.AL * QG.AL + PL.AL * QL.AL
T$BC = PO.BC * QO.BC + PG.BC * QG.BC + PL.BC * QL.BC
T$ = T$AT + T$QU + T$ON + T$MN + T$SK + T$AL + T$BC
```

Calculate a user price index for energy by region, dollars per million input BTU:

```
PEN.AT = T$AT/(QO.AT + QL.AT)
PEN.QU = T$QU/(QO.QU + QG.QU + QL.QU)
PEN.ON = T$ON/(QO.ON + QG.ON + QL.ON)
PEN.MN = T$MN/(QO.MN + QG.MN + QL.MN)
PEN.SK = T$SK/(QO.SK + QG.SK + QL.SK)
PEN.AL = T$AL/(QO.AL + QG.AL + QL.AL)
PEN.BC = T$BC/(QO.BC + QG.BC + QL.BC)
PE.CA = T$/(FUEL.CA)
```

Calculate the weighted moving average fuel prices by region:

```
R1TOT = (1.0 - 0.18) + (1.0 - 0.18) ** 2 + (1.0 - 0.18) ** 3 + (1.0 - 0.18) ** 4
W1 = (1.0 - 0.18)/R1TOT
W2 = (1.0 - 0.18) ** 2/R1TOT
W3 = (1.0 - 0.18) ** 3/R1TOT
W4 = (1.0 - 0.18) ** 4/R1TOT
```

```
PE.AT = W1 * (PEN.AT/PE.CA) + W2 * (lag(1,PEN.AT)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.AT)/lag(2,PE.CA)) + W4 * (lag(3,PEN.AT)/lag(3,PE.CA))

PE.QU = W1 * (PEN.QU/PE.CA) + W2 * (lag(1,PEN.QU)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.QU)/lag(2,PE.CA)) + W4 * (lag(3,PEN.QU)/lag(3,PE.CA))

PE.ON = W1 * (PEN.ON/PE.CA) + W2 * (lag(1,PEN.ON)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.ON)/lag(2,PE.CA)) + W4 * (lag(3,PEN.ON)/lag(3,PE.CA))

PE.MN = W1 * (PEN.MN/PE.CA) + W2 * (lag(1,PEN.MN)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.MN)/lag(2,PE.CA)) + W4 * (lag(3,PEN.MN)/lag(3,PE.CA))

PE.SK = W1 * (PEN.SK/PE.CA) + W2 * (lag(1,PEN.SK)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.SK)/lag(2,PE.CA)) + W4 * (lag(3,PEN.SK)/lag(3,PE.CA))

PE.AL = W1 * (PEN.AL/PE.CA) + W2 * (lag(1,PEN.AL)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.AL)/lag(2,PE.CA)) + W4 * (lag(3,PEN.AL)/lag(3,PE.CA))

PE.BC = W1 * (PEN.BC/PE.CA) + W2 * (lag(1,PEN.BC)/lag(1,PE.CA))
      + W3 * (lag(2,PEN.BC)/lag(2,PE.CA)) + W4 * (lag(3,PEN.BC)/lag(3,PE.CA))
```

Calculate the correspondence of aggregate fuel demand with macro E:

```
FUEL.CA = 555.27 * E + TEMP(FUEL.CA)
           (110.1)
ols, 1958-1982; R2 = 0.9796; SEE = 186.66; DW = 0.17
```

Calculate regional energy demand (net of thermal), trillions of input BTU:

```
FUEL.AT = EXP(-2.0781 + ln(FUEL.CA) + 0.14138 * ln(RDP.AT)
               (-2.00)                 (0.37)
              -0.33274 * ln(PE.AT) + TEMP(FUEL.AT))
               (-4.81)
non-linear system, 1961-1984; DW = 0.33

FUEL.QU = EXP(1.5346 + ln(FUEL.CA) + 2.0445 * ln(RDP.QU)
               (5.53)                 (10.51)
              - 0.33274 * ln(PE.QU) + TEMP(FUEL.QU))
                (-4.81)
non-linear system, 1961-1984; DW = 0.57

FUEL.ON = EXP(- 0.43457 + ln(FUEL.CA) + 0.66809 * ln(RDP.ON)
                (-3.83)                 (5.24)
              - 0.33274 * ln(PE.ON) + TEMP(FUEL.ON))
                (-4.81)
non-linear system, 1961-1984; DW = 1.60

FUEL.MN = EXP(0.53856 + ln(FUEL.CA) + 1.1702 * ln(RDP.MN)
               (1.76)                 (12.10)
              - 0.33274 * ln(PE.MN) + TEMP(FUEL.MN))
                (-4.81)
non-linear system, 1961-1984; DW = 1.04

FUEL.SK = EXP(- 1.2965 + ln(FUEL.CA) + 0.54205 * ln(RDP.SK)
                (-4.64)                 (6.29)
              - 0.33274 * ln(PE.SK) + TEMP(FUEL.SK))
                (-4.81)
non-linear system, 1961-1984; DW = 0.81
```

FUEL.AL = FUEL.CA − FUEL.AT − FUEL.QU − FUEL.ON − FUEL.MN
− FUEL.SK − FUEL.BC

FUEL.BC = EXP(− 0.77699 + ln(FUEL.CA) + 0.63771 * ln(RDP.BC)
(−3.89) (6.85)
− 0.33274 * ln(PE.BC) + TEMP(FUEL.BC))
(−4.81)
non-linear system, 1961-1984; DW = 1.68

Calculate the regional demand for each fuel, trillions of input BTU:

RSOL.AT = EXP(0.080706 − 0.19881 * ln(PO.AT / PL.AT)
(0.81) (−3.12)
+ 0.84403 * ln(lag(1,SO.AT) / lag(1,SL.AT)) + TEMP(RSOL.AT))
(10.80)
ols, 1960-1984; RB2 = 0.9852; SEE = 0.0377; DW = 1.20

SO.AT = RSOL.AT / (1.0 + RSOL.AT)

SL.AT = 1.0 − SO.AT

QO.AT = SO.AT * FUEL.AT

QL.AT = SL.AT * FUEL.AT

RSOL.QU = EXP(0.52085 − 0.37685 * ln(PO.QU / PL.QU)
(4.90) (−4.94)
− 0.000068578 * GPKM.QU + 0.54444 * ln(lag(1,SO.QU) / lag(1,SL.QU))
(−2.24) (8.89)
+ TEMP(RSOL.QU))
sys (iterative Zellner), 1960-1984; R2 = 0.9603; SEE = 0.0623; DW = 0.78

RSGL.QU = EXP(− 1.3963 − 0.37658 * ln(PG.QU / PL.QU)
(−5.11) (−4.94)
+ 0.00017668 * GPKM.QU + 0.54444 * ln(lag(1,SG.QU) / lag(1,SL.QU))
(3.21) (8.89)
+ TEMP(RSGL.QU))
sys (iterative Zellner), 1960-1984; R2 = 0.8566; SEE = 0.1116; DW = 1.26

SO.QU = RSOL.QU / (1.0 + RSOL.QU + RSGL.QU)

SG.QU = RSGL.QU / (1.0 + RSOL.QU + RSGL.QU)

SL.QU = 1.0 − SO.QU − SG.QU

QO.QU = SO.QU * FUEL.QU

QG.QU = SG.QU * FUEL.QU

QL.QU = SL.QU * FUEL.QU

RSOL.ON = EXP(0.60790 − 0.15804 * ln(PO.ON / PL.ON)
(5.60) (−4.22)
− 0.000010798 * GPKM.ON + 0.67085 * ln(lag(1,SO.ON) / lag(1,SL.ON))
(−6.61) (11.58)
+ TEMP(RSOL.ON))
sys (iterative Zellner), 1960-1984; R2 = 0.9924; SEE = 0.0218; DW = 2.04

RSGL.ON = EXP(− 0.16261 − 0.15804 * ln(PG.ON / PL.ON)
(−1.92) (−4.22)
+ 0.0000064050 * GPKM.ON + 0.67085 * ln(lag(1,SG.ON) / lag(1,SL.ON))
(2.36) (11.58)

```
            + TEMP(RSGL.ON))
sys (iterative Zellner), 1960-1984; R2 = 0.9862; SEE = 0.0263; DW = 2.88

SO.ON = RSOL.ON/(1.0 + RSOL.ON + RSGL.ON)

SG.ON = RSGL.ON/(1.0 + RSOL.ON + RSGL.ON)

SL.ON = 1.0 - SO.ON - SG.ON

QO.ON = SO.ON * FUEL.ON

QG.ON = SG.ON * FUEL.ON

QL.ON = SL.ON * FUEL.ON

RSOL.MN = EXP(0.16442 - 0.12897 * ln(PO.MN/PL.MN)
                 (7.26)      (-3.96)
          + 0.80776 * ln(lag(1,SO.MN)/lag(1,SL.MN)) + TEMP(RSOL.MN))
            (45.03)
sys (iterative Zellner), 1960-1984; R2 = 0.9757; SEE = 0.0388; DW = 1.31

RSGL.MN = EXP(- 0.048468 - 0.12897 * ln(PG.MN/PL.MN)
                  (-1.15)     (-3.96)
          + 0.80776 * ln(lag(1,SG.MN)/lag(1,SL.MN)) + TEMP(RSGL.MN))
            (45.03)
sys (iterative Zellner), 1960-1984; R2 = 0.9466; SEE = 0.0620; DW = 1.71

SO.MN = RSOL.MN/(1.0 + RSOL.MN + RSGL.MN)

SG.MN = RSGL.MN/(1.0 + RSOL.MN + RSGL.MN)

SL.MN = 1.0 - SO.MN - SG.MN

QO.MN = SO.MN * FUEL.MN

QG.MN = SG.MN * FUEL.MN

QL.MN = SL.MN * FUEL.MN

RSOL.SK = EXP(0.10482 - 0.061611 * ln(PO.SK/PL.SK)
                 (1.90)      (-3.00)
          + 0.88970 * ln(lag(1,SO.SK)/lag(1,SL.SK)) + TEMP(RSOL.SK))
            (28.16)
sys (iterative Zellner), 1960-1984; R2 = 0.9837; SEE = 0.0577; DW = 1.39

RSGL.SK = EXP(- 0.0015509 - 0.061611 * ln(PG.SK/PL.SK)
                  (-0.04)     (-3.00)
          + 0.88970 * ln(lag(1,SG.SK/lag(1,SL.SK)) + TEMP(RSGL.SK))
            (28.16)
sys (iterative Zellner), 1960-1984; R2 = 0.9646; SEE = 0.0427; DW = 2.02

SO.SK = RSOL.SK/(1.0 + RSOL.SK + RSGL.SK)

SG.SK = RSGL.SK/(1.0 + RSOL.SK + RSGL.SK)

SL.SK = 1.0 - SO.SK - SG.SK

QO.SK = SO.SK * FUEL.SK

QG.SK = SG.SK * FUEL.SK

QL.SK = SL.SK * FUEL.SK

RSOL.AL = EXP(0.040139 - 0.091869 * ln(PO.AL/PL.AL)
                 (0.73)      (-1.70)
          + 0.90883 * ln(lag(1,SO.AL)/lag(1,SL.AL)) + TEMP(RSOL.AL))
            (19.12)
sys (iterative Zellner), 1960-1984; R2 = 0.9830; SEE = 0.0441; DW = 1.20
```

RSGL.AL = EXP(− 0.080541 − 0.091869 * ln(PG.AL/PL.AL)
(−1.11) (−1.70)
+ 0.90883 * ln(lag(1,SG.AL)/lag(1,SL.AL)) + TEMP(RSGL.AL))
(19.12)

sys (iterative Zellner), 1960-1984; R2 = 0.9028; SEE = 0.0852; DW = 2.05

SO.AL = RSOL.AL/(1.0 + RSOL.AL + RSGL.AL)

SG.AL = RSGL.AL/(1.0 + RSOL.AL + RSGL.AL)

SL.AL = 1.0 − SO.AL − SG.AL

QO.AL = SO.AL * FUEL.AL

QG.AL = SG.AL * FUEL.AL

QL.AL = SL.AL * FUEL.AL

RSOL.BC = EXP(0.25631 − 0.19123 * ln(PO.BC/PL.BC)
(1.60) (−2.44)
+ 0.0000054607 * GPKM.BC + 0.58441 * ln(lag(1,SO.BC)/lag(1,SL.BC))
(0.47) (5.65)
+ TEMP(RSOL.BC))

sys (iterative Zellner), 1960-1984; R2 = 0.8717; SEE = 0.0490: DW = 1.69

RSGL.BC = EXP(− 0.71668 − 0.19123 * ln(PG.BC/PL.BC)
(−2.99) (−2.44)
+ 0.000047973 * GPKM.BC + 0.58441 * ln(lag(1,SG.BC)/lag(1,SL.BC))
(3.08) (5.65)
+ TEMP(RSGL.BC))

sys (iterative Zellner), 1960-1984; R2 = 0.9414; SEE = 0.0634; DW = 2.46

SO.BC = RSOL.BC/(1.0 + RSOL.BC + RSGL.BC)

SG.BC = RSGL.BC/(1.0 + RSOL.BC + RSGL.BC)

SL.BC = 1.0 − SO.BC − SG.BC

QO.BC = SO.BC * FUEL.BC

QG.BC = SG.BC * FUEL.BC

QL.BC = SL.BC * FUEL.BC

Calculate the regional demand for thermal electricity as a residual after considering hydro and nuclear supply, trillions of input BTU:

QSL.AT = QL.AT + A(1922) * LOSSL.AT − A(1922 * QHL.AT

QSL.QU = QL.QU + A(1922) * LOSSL.QU − A(1922) * QHL.QU

QSL.ON = QL.ON + A(1922) * LOSSL.ON − A(1922) * QHL.ON

QSL.MN = QL.MN + A(1922) * LOSSL.MN − A(1922) * QHL.MN

QSL.SK = QL.SK + A(1922) * LOSSL.SK − A(1922) * QHL.SK

QSL.AL = QL.AL + A(1922) * LOSSL.AL − A(1922) * QHL.AL

QSL.BC = QL.BC + A(1922) * LOSSL.BC − A(1922) * QHL.BC

Calculate the regional demand for fuels to generate thermal electricity, trillions of input BTU:

FUELSL.AT = EXP(1.8626 + 0.79122 * ln(QSL.AT) + TEMP(FUELSL.AT))
(23.67) (31.28)

ols, 1959-1984; RB2 = 0.9751; SEE = 0.0778; DW = 0.40

FUELSL.QU = EXP(1.3410 + 0.86061 * ln(QSL.QU) + TEMP(FUELSL.QU))
(28.14) (17.17)
ols, 1959-1984; RB2 = 0.9216; SEE = 0.2063; DW = 0.54

FUELSL.ON = EXP(1.4746 + 0.89863 * ln(QSL.ON) + TEMP(FUELSL.ON))
(37.12) (93.03)
ols, 1959-1984; RB2 = 0.9971; SEE = 0.0552; DW = 0.62

FUELSL.MN = EXP(1.4692 + 0.86986 * ln(QSL.MN) + TEMP(FUELSL.MN))
(39.04) (18.84)
ols, 1959-1984; RB2 = 0.9340; SEE = 0.1916; DW = 1.21

FUELSL.SK = EXP(1.8215 + 0.83439 * ln(QSL.SK) + TEMP(FUELSL.SK))
(51.15) (60.58)
ols, 1959-1984; RB2 = 0.9932; SEE = 0.0390; DW = 1.24

FUELSL.AL = EXP(1.8513 + 0.80544 * ln(QSL.AL) + TEMP(FUELSL.AL))
(41.19) (62.95)
ols, 1959-1984; RB2 = 0.9937; SEE = 0.0526; DW = 1.44

FUELSL.BC = EXP(0.35809 + 1.1848 * ln(QSL.BC) + TEMP(FUELSL.BC))
(1.34) (9.27)
ols, 1959-1984; RB2 = 0.7728; SEE = 0.3313; DW = 0.33

Calculate the quantity of fuels used to generate thermal electricity:

SOCL.AT = EXP(− 1.9163 − 0.80604 * ln((PCGO.AT / A(1921)) / (PC.AT / A(1924)))
(−2.75) (−4.21)
+ 0.74206 * ln(lag(1,SOL.AT) / lag(1,SCL.AT))
+ 0.032967 * RTIME + TEMP(SOCL.AT))
(3.14)
ols, 1960-1984; RB2 = 0.9104; SEE = 0.2360; DW = 0.95
Note: the coefficient 0.74206 restricted to be equal to its estimated value for Ontario.

SOL.AT = SOCL.AT / (SOCL.AT + 1.0)

SCL.AT = 1.0 − SOL.AT

QOL.AT = SOL.AT * FUELSL.AT

QCL.AT = SCL.AT * FUELSL.AT

SGOL.QU = EXP(− 2.4008 − 2.3832 * ln(PCGG.QU / (PCGO.QU / A(1921)))
(−2.84) (−1.09)
+ 0.43160 * ln(lag(1,SGL.QU) / lag(1,SOL.QU)) + TEMP(SGOL.QU))
(2.35)
ols, 1960-1984; RB2 = 0.2192; SEE = 2.0794; DW = 2.12

SGL.QU = SGOL.QU / (SGOL.QU + 1.0)

SOL.QU = 1.0 − SGL.QU

QGL.QU = SGL.QU * FUELSL.QU

QOL.QU = SOL.QU * FUELSL.QU

SGCL.ON = EXP(− 0.44322 − 1.6746 * ln(PCGG.ON / (PC.ON / A(1926)))
(−1.71) (−2.45)
+ 0.74206 * ln(lag(1,SGL.ON) / lag(1,SCL.ON)) + TEMP(SGCL.ON))
(8.34)
sys (iterative Zellner), 1960-1984; R2 = 0.8002; SEE = 0.502; DW = 1.14

SOCL.ON = EXP(− 0.14665 − 1.6746 * ln((PCGO.ON / A(1921)) / (PC.ON / A(1926)))
(−0.33) (−2.45)
+ 0.74206 * ln(lag(1,SOL.ON) / lag(1,SCL.ON)) + TEMP(SOCL.ON))
(8.34)
sys (iterative Zellner), 1960-1984; R2 = 0.0770; SEE = 0.8105; DW = 2.23

SGL.ON = SGCL.ON / (SGCL.ON + SOCL.ON + 1.0)

SOL.ON = SOCL.ON / (SGCL.ON + SOCL.ON + 1.0)

SCL.ON = 1.0 − SOL.ON − SGL.ON

QGL.ON = SGL.ON * FUELSL.ON

QOL.ON = SOL.ON * FUELSL.ON

QCL.ON = SCL.ON * FUELSL.ON

SGCL.MN = EXP(− 1.6767 − 0.46076 * ln(PCGG.MN / (PC.MN / A(1927)))
(−4.27) (−1.11)
+ 0.33817 * ln(lag(1,SGL.MN) / lag(1,SCL.MN)) + TEMP(SGCL.MN))
(2.40)
sys (iterative Zellner), 1960-1984; R2 = 0.3248; SEE = 1.084; DW = 2.12

SOCL.MN = EXP(− 0.40845 − 0.46076 * ln((PCGO.MN / A(1921)) / (PC.MN / A(1927)))
(−0.80) (−1.47)
+ 0.33817 * ln(lag(1,SOL.MN) / lag(1,SCL.MN)) + TEMP(SOCL.MN))
(2.40)
sys (iterative Zellner), 1960-1984; R2 = 0.0287; SEE = 0.8133; DW = 1.89

SGL.MN = SGCL.MN / (SGCL.MN + SOCL.MN + 1.0)

SOL.MN = SOCL.MN / (SGCL.MN + SOCL.MN + 1.0)

SCL.MN = 1.0 − SOL.MN − SGL.MN

QGL.MN = SGL.MN * FUELSL.MN

QOL.MN = SOL.MN * FUELSL.MN

QCL.MN = SCL.MN * FUELSL.MN

SGCL.SK = EXP(− 0.027570 − 0.30057 * ln(PCGG.SK / (PC.SK / A(1927)))
(−0.43) (−2.53)
+ 0.82739 * ln(lag(1,SGL.SK) / lag(1,SCL.SK)) + TEMP(SGCL.SK))
(11.96)
sys (iterative Zellner), 1960-1984; R2 = 0.9183; SEE = 0.2671; DW = 2.03

SOCL.SK = EXP(− 0.21169 − 0.30057 * ln((PCGO.SK / A(1921)) / (PC.SK / A(1927)))
(−1.12) (−2.53)
+ 0.82739 * ln(lag(1,SOL.SK) / lag(1,SCL.SK)) + TEMP(SOCL.SK))
(11.96)
sys (iterative Zellner), 1960-1984; R2 = 0.9215; SEE = 0.4169; DW = 1.62

SGL.SK = SGCL.SK / (SGCL.SK + SOCL.SK + 1.0)

SOL.SK = SOCL.SK / (SGCL.SK + SOCL.SK + 1.0)

SCL.SK = 1.0 − SOL.SK − SGL.SK

QGL.SK = SGL.SK * FUELSL.SK

QOL.SK = SOL.SK * FUELSL.SK

QCL.SK = SCL.SK * FUELSL.SK

SGCL.AL = EXP(0.21826 − 0.44385 * ln(PCGG.AL / (PC.AL / A(1927)))
(1.12) (−1.98)
+ 0.83390 * ln(lag(1,SGL.AL) / lag(1,SCL.AL)) + TEMP(SGCL.AL))
(12.53)

sys (iterative Zellner), 1960-1984; R2 = 0.9697; SEE = 0.2030; DW = 2.11

SOCL.AL = EXP(− 0.022796 − 0.44385 * ln((PCGO.AL / A(1921)) / (PC.AL / A(1927)))
(−0.09) (−1.98)
+ 0.83390 * ln(lag(1,SOL.AL) / lag(1,SCL.AL)) + TEMP(SOCL.AL))
(12.53)

sys (iterative Zellner), 1960-1984; R2 = 0.9111; SEE = 0.5432; DW = 1.82

SGL.AL = SGCL.AL / (SGCL.AL + SOCL.AL + 1.0)

SOL.AL = SOCL.AL / (SGCL.AL + SOCL.AL + 1.0)

SCL.AL = 1.0 − SOL.AL − SGL.AL

QGL.AL = SGL.AL * FUELSL.AL

QOL.AL = SOL.AL * FUELSL.AL

QCL.AL = SCL.AL * FUELSL.AL

SGOL.BC = EXP(− 0.33423 − 0.10000 * ln(PCGG.BC / (PCGO.BC / A(1921)))
(−2.26)
+ 0.21971 * ln(lag(1,SGL.BC) / lag(1,SOL.BC)) + TEMP(SGOL.BC))
(1.07)

ols, 1960-1984; RB2 = −0.0155; SEE = 0.6402; DW = 2.01

Note: coefficient −0.10000 restricted to take that value.

SGL.BC = SGOL.BC / (SGOL.BC + 1.0)

SOL.BC = 1.0 − SGL.BC

QGL.BC = SGL.BC * FUELSL.BC

QOL.BC = SOL.BC * FUELSL.BC

Aggregate fuels (coal, oil, gas, electricity) in Canada, trillions of input BTU:

QE.COAL = QCL.AT + QCL.ON + QCL.MN + QCL.SK + QCL.AL

QE.OIL = QO.AT + QO.QU + QO.ON + QO.MN + QO.SK + QO.AL + QO.BC
+ QOL.AT + QOL.QU + QOL.ON + QOL.MN + QOL.SK + QOL.AL
+ QOL.BC

QE.GAS = QG.QU + QG.ON + QG.MN + QG.SK + QG.AL + QG.BC
+ QGL.QU + QGL.ON + QGL.MN + QGL.SK + QGL.AL + QGL.BC

QE.ELEC = QL.AT + QL.QU + QL.ON + QL.MN + QL.SK + QL.AL + QL.BC

Explanation of the Symbols and Variables

Symbols

The symbols used in the foregoing equations are identified below:

* is the multiplication operator

** is the exponentiation operator

ln is the natural logarithm operator

EXP is exponentiation to the power e

lag(i,x) is the value of variable x lagged i periods

TEMP is an array containing the estimation residuals

ols, sys (iterative Zellner), and non-linear system are estimation techniques

R2, RB2, DW, and SEE are estimation statistics

the number in parentheses under each estimated coefficient is its t-statistic

Variables

Nearly all variables are defined for each of the seven regions: Atlantic (AT), Quebec (QU), Ontario (ON), Manitoba (MN), Saskatchewan (SK), Alberta (AL), and British Columbia (BC). The mnemonics for the regional variables are VAR.reg, where reg stands for the regions mentioned above.

E	total energy demand in Canada, as determined in the macroeconomic part of the MACE model, billions of 1971 dollars
FUEL.reg	total fuel demand, trillions of input BTU
FUEL.CA	total fuel demand in Canada, trillions of input BTU
FUELSL.reg	fuels used to generate thermal electricity, trillions of input BTU
GPKM.reg	amount of natural gas distribution pipeline, kilometres
LOSSL.reg	losses and adjustments for electricity, billions of kilowatt-hours
PC.reg	price of coal, dollars per ton
PCGG.reg	city-gate price of natural gas, dollars per thousand cubic feet
PCGO.reg	city-gate price of oil, dollars per barrel
PE.CA	price index for energy, Canada, dollars per million input BTU
PEN.reg	price index for energy, dollars per million input BTU
PE.reg	weighted average fuel price index
PG.reg	user price of natural gas, dollars per million input BTU
PL.reg	user price of electricity, dollars per million input BTU
PO.reg	user price of oil, dollars per million input BTU
QCL.reg	quantity of coal used to generate electricity, trillions of input BTU
QE.COAL	coal used to generate electricity in Canada, trillions of input BTU
QE.ELEC	aggregate electricity used in Canada, trillions of input BTU
QE.GAS	aggregate natural gas used in Canada, trillions of input BTU
QE.OIL	aggregate oil used in Canada, trillions of input BTU

QG.reg	quantity of natural gas demanded, trillions of input BTU
QGL.reg	quantity of natural gas used to generate electricity, trillions of input BTU
QHL.reg	quantity of hydro and nuclear power available, billions of kilowatt-hours
QL.reg	quantity of electricity demanded, trillions of input BTU
QO.reg	quantity of oil demanded, trillions of input BTU
QOL.reg	quantity of oil used to generate electricity, trillions of input BTU
QSL.reg	quantity of thermal electricty demanded, trillions of input BTU
R1TOT	weight used in the calculation of the regional moving average fuel prices
RDP.reg	regional share of national real 1971 dollars of domestic product
RSGL.reg	ratio of the share of natural gas to the share of electricity
RSOL.reg	ratio of the share of oil to the share of electricity
RTIME	index with 1958 = 58, and so on
SCL.reg	quantity share of coal used to generate electricity
SG.reg	quantity share of natural gas
SGCL.reg	ratio of share of natural gas to share of coal used to generate electricity
SGL.reg	quantity share of natural gas used to generate electricity
SGOL.reg	ratio of share of natural gas to share of oil used to generate electricity
SL.reg	quantity share of electricity
SO.reg	quantity share of oil
SOCL.reg	ratio of share of oil to share of coal used to generate electricity
SOL.reg	quantity share of oil used to generate electricity
T$	total expenditure on energy in Canada, millions of dollars
T$reg	total expenditure on energy, millions of dollars
W1, W2, etc.	weights used in the calculation of the regional moving average fuel prices

Coefficients

The coefficients used in the foregoing equations are as follows:

A(1921) =	5.803	conversion factor for oil, millions of input BTU per barrel

A(1922) = 3.412 conversion factor for electricity, millions of input BTU per thousand kilowatt-hour

A(1924) = 25.183 conversion factor for Atlantic coal, millions of input BTU per ton

A(1926) = 25.417 conversion factor for Ontario coal, millions of input BTU per ton

A(1927) = 14.419 conversion factor for Manitoba coal, millions of input BTU per ton

A(1927) = 14.419 conversion factor for Saskatchewan coal, millions of input BTU per ton

A(1927) = 14.419 conversion factor for Alberta coal, millions of input BTU per ton

Note: the conversion factor for natural gas is taken to be 1.0 (that is, one million input BTU per thousand cubic feet); no explicit mathematical operation is thus necessary to convert natural gas volumes into their energy contents.

Losses Sector

The losses, adjustments, and energy-industry use for oil, gas, and electricity must be estimated to enable one to link user demands to supplies. For each fuel, the "losses" are assumed to be directly related to consumer use, as measured by final user demand. The only exception is for natural gas losses in the producing provinces of Alberta and British Columbia, where losses are directly related to production. This is necessary to allow for the high energy-industry use of natural gas.

The electricity losses are estimated for each region, whereas the oil losses are estimated for two regions (Atlantic and Quebec combined, and the rest of Canada), and the gas losses are estimated for two regions (Alberta and British Columbia combined, and the rest of Canada).

The equation structure follows. A list of variables and symbols is found at the end of the section.

Losses for electricity are a proportion of regional sales:

LOSSL.AT = −2.1840 + 1.4820 * ln(QL.AT / A(1922)) + TEMP(LOSSL.AT)
(−7.48) (12.91)

ols, 1959-1984; RB2 = 0.8689; SEE = 0.3322; DW = 0.51

LOSSL.QU = −23.128 + 7.1795 * ln(QL.QU / A(1922)) + TEMP(LOSSL.QU)
(−9.77) (12.82)

ols, 1959-1984; RB2 = 0.8673; SEE = 1.0822; DW = 1.39

LOSSL.ON = −11.035 + 4.2426 * ln(QL.ON / A(1922)) + TEMP(LOSSL.ON)
(−8.28) (13.31)

ols, 1959-1984; RB2 = 0.8757; SEE = 0.6585; DW = 1.52

LOSSL.MN = −2.2167 + 1.6945 * ln(QL.MN / A(1922)) + TEMP(LOSSL.MN)
(−7.14) (11.42)
ols, 1959-1984; RB2 = 0.8380: SEE = 0.2813; DW = 0.60

LOSSL.SK = 0.018620 + 0.48992 * ln(QL.SK / A(1922)) + TEMP(LOSSL.SK)
(0.28) (12.25)
ols, 1959-1984; RB2 = 0.8563; SEE = 0.1314; DW = 1.18

LOSSL.AL = −0.44160 + 0.77509 * ln(QL.AL / A(1922)) + TEMP(LOSSL.AL)
(−4.90) (20.22)
ols, 1959-1984; RB2 = 0.9422; SEE = 0.1451; DW = 1.58

LOSSL.BC = −4.3464 + 2.0118 * ln(QL.BC / A(1922)) + TEMP(LOSSL.BC)
(−7.29) (11.03)
ols, 1959-1984; RB2 = 0.8284; SEE = 0.3912; DW = 1.88

Losses for crude oil are a proportion of regional sales:

EASTO = (QO.AT + QO.QU) / A(1921)

EASTO1 = (lag(1,QO.AT) + lag(1,QO.QU)) / A(1921)

AUTOEO = 0.89282 * (lag(1,LOILEAST) − 2.6894 * ln(EASTO1))
(9.91)

LOILEAST = 2.6894 * ln(EASTO) + AUTOEO + TEMP(LOILEAST)
(12.25)
Cochrane-Orcutt, 1960-1984; RB2 = 0.8753; SEE = 1.4098; DW = 1.25

WESTO = (QO.ON + QO.MN + QO.SK + QO.AL + QO.BC) / A(1921)

WESTO1 = (lag(1,QO.ON) + lag(1,QO.MN) + lag(1,QO.SK) + lag(1,QO.AL)
+ lag(1,QO.BC)) / A(1921)

AUTOWO = 0.77998 * (lag(1,LOILWEST) − 3.8362 * ln(WESTO1))
(6.23)

LOILWEST = 3.8362 * ln(WESTO) + AUTOWO + TEMP(LOILWEST)
(10.34)
Cochrane-Orcutt, 1960-1984; RB2 = 0.7046; SEE = 2.5303; DW = 1.59

Natural gas losses are a proportion of sales for Quebec, Ontario, Manitoba, and Saskatchewan, but are a proportion of production for Alberta and British Columbia:

EAST = QG.QU + QG.ON + QG.MN + QG.SK

EAST1 = lag(1,QG.QU) + lag(1,QG.ON) + lag(1,QG.MN) + lag(1,QG.SK)

AUTOE = 0.82357 * (lag(1,LOSSG.E) − 7.9694 * ln(EAST1))
(7.11)

LOSSG.E = 7.9694 * ln(EAST) + AUTOE + TEMP(LOSSG.E)
(5.82)
Cochrane-Orcutt, 1961-1984; RB2 = 0.7990; SEE = 8.7863; DW = 1.61

AUTOW = 0.68296 * (lag(1,LOSSG.W) − 3.6248 * ln(365. * lag(1,GASPRO)))
(4.58)

LOSSG.W = 3.6248 * ln(365. * GASPRO) + AUTOW + TEMP(LOSSG.W)
(4.15)
Cochrane-Orcutt, 1961-1984; RB2 = 0.5335; SEE = 10.939; DW = 2.27

Explanation of the Symbols and Variables

Symbols

The symbols used in the foregoing equations are identified below:

* is the multiplication operator

** is the exponentiation operator

ln is the natural logarithm operator

lag(i,x) is the value of variable x lagged i periods

TEMP is an array containing the estimation residuals

ols and Cochrane-Orcutt are estimation techniques

RB2, DW, and SEE are estimation statistics

the number in parentheses under each estimated coefficient is its t-statistic

Variables

Some of the variables are defined for each of the seven regions: Atlantic (AT), Quebec (QU), Ontario (ON), Manitoba (MN), Saskatchewan (SK), Alberta (AL), and British Columbia (BC). The mnemonics for the regional variables are VAR.reg, where reg stands for the regions mentioned above.

AUTOE	a statistical creation to facilitate the representation of the equation for Canadian natural gas losses outside Alberta and British Columbia
AUTOEO	a statistical creation to facilitate the representation of the equation for oil losses in the Atlantic region and Quebec
AUTOW	a statistical creation to facilitate the representation of the equation for natural gas losses in Alberta and British Columbia
AUTOWO	a statistical creation to facilitate the representation of the equation for Canadian oil losses west of Quebec
EAST	Canadian natural gas consumption outside Alberta and British Columbia, billions of cubic feet
EAST1	same as EAST, but lagged one year
EASTO	oil consumption in the Atlantic region and Quebec combined, millions of barrels
EASTO1	same as EASTO, but lagged one year
GASPRO	natural gas production for Canada, billions of cubic feet per day
LOILEAST	losses for oil in Atlantic and Quebec, millions of barrels
LOILWEST	losses for oil in Ontario and Western Canada, millions of barrels

LOSSG.E	losses for natural gas in Quebec, Ontario, Manitoba, and Saskatchewan, billions of cubic feet
LOSSG.W	losses for natural gas in Alberta and British Columbia, billions of cubic feet
LOSSL.reg	losses and adjustments for electricity, trillions of kilowatt-hours
QG.reg	quantity of natural gas consumed, trillions of input BTU
QL.reg	quantity of electricity consumed, trillions of input BTU
QO.reg	quantity of oil consumed, trillions of input BTU
WESTO	Canadian oil consumption west of Quebec, millions of barrels
WESTO1	same as WESTO, but lagged one year

Coefficients

The coefficients used in the foregoing equations are as follows:

A(1921) = 5.803	conversion factor for oil, millions of input BTU per barrel
A(1922) = 3.412	conversion factor for electricity, millions of input BTU per thousand kilowatt-hours

Note: the conversion factor for natural gas is taken to be 1.0 (that is, one million input BTU per thousand cubic feet); no explicit mathematical operation is thus necessary to convert natural gas volumes into their energy contents.

Appendix 6.2
Fuel Prices to Final Users

In the MACE model, the prices of electricity and of natural gas to final users in each province (or region, in the case of the Atlantic provinces) are taken from, respectively, Statistics Canada, *Electric Power Statistics, volume 2, Annual Statistics*, catalogue no. 57-202; and Statistics Canada, *Gas Utilities: Transport and Distribution Systems*, catalogue no. 57-205. Since they are readily available, these series will not be reproduced here.

In the case of oil, however, there is no single, convenient source for user prices. These were constructed on the basis of information about the prices of individual oil products. We relied in particular on Statistics Canada, *Consumer Prices and Price Indexes*, catalogue no. 62-010 for motor gasoline and light fuel oil prices, and Statistics Canada, *Consumption of Purchased Fuel and Electricity by the Manufacturing, Mining, Logging, and Electric Power Industries*, catalogue no. 57-208 for the prices of most products in industrial uses; we have also used unpublished data made available to us by officials of Statistics Canada. Prices of diesel fuel and heavy fuel oil were taken from the database for EMR's inter-fuel substitution demand (IFSD) model. A time series of representative per-barrel prices for each province (or region) was then constructed using quantity information for each oil product from Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada*, catalogue no. 57-003; from its predecessor, *Detailed Energy Supply and Demand in Canada*, catalogue no. 57-207; and from EMR's IFSD database.

The additional complication for oil has to do with the numerous indirect taxes on oil products that have been imposed over time. Information about these various taxes was taken from Statistics Canada, *Principal Taxes and Rates*, catalogue no. 68-201, last issue published in 1978; various years of Canadian Tax Foundation, *The National Finances* (Toronto: the foundation); various years of Canadian Tax Foundation, *Provincial and Municipal Finances* (Toronto: the foundation); and Millie Goodman, *Tax Developments*, Tax Memos (Toronto: Canadian Tax Foundation, various years); as well as from the relevant federal and provincial statutes. Using the product-specific prices, quantities, and indirect taxes described above, we constructed two series of per-barrel taxes for each province (or region): one representing provincial taxes and the other, federal taxes. Note that in the case of the Atlantic provinces, information about oil product prices and taxes for Nova Scotia was taken to be representative of those for the entire region.

For each province (or region), the refining, distributing, and retailing costs and margins, or non-tax markups, were simply defined as the differ-

ence between the calculated user prices and the sum of provincial taxes, federal taxes, and delivered prices. In the MACE framework, it is important to proceed as we did because it allows us to create an unbroken (endogenous) chain going from wellhead and import prices to the prices paid by final users.

The following pages report our constructed series of user prices for oil, and their key components, for each province or region.

User Prices and Components: Oil

Year	Delivered oil price	Provincial taxes	Federal taxes	Non-tax markup	User price
		current dollars per barrel			
Atlantic					
1958	2.980	1.376	0.251	3.037	7.644
1959	2.700	1.376	0.341	3.020	7.437
1960	2.600	1.376	0.344	3.104	7.425
1961	2.630	1.487	0.350	2.989	7.456
1962	2.710	1.598	0.344	2.814	7.466
1963	2.680	1.598	0.344	2.911	7.533
1964	2.640	1.598	0.329	2.803	7.370
1965	2.540	1.598	0.322	3.004	7.465
1966	2.460	1.598	0.322	3.266	7.646
1967	2.440	1.598	0.366	3.285	7.689
1968	2.500	1.598	0.367	3.409	7.873
1969	2.470	1.598	0.386	3.585	8.040
1970	2.370	1.708	0.379	3.809	8.266
1971	2.740	1.766	0.409	3.937	8.852
1972	2.940	1.780	0.432	4.413	9.565
1973	3.400	1.780	0.491	5.003	10.673
1974	6.460	1.780	0.604	5.121	13.966
1975	8.040	1.780	1.081	5.388	16.289
1976	9.310	1.780	1.594	6.042	18.725
1977	11.070	1.780	1.526	7.068	21.447
1978	13.190	1.780	1.341	7.627	23.938
1979	14.230	1.780	1.294	9.318	26.621
1980	17.940	1.780	1.609	10.676	32.005
1981	27.960	1.780	2.044	11.829	43.613
1982	33.650	2.581	2.352	15.569	54.153
1983	36.390	3.083	2.582	19.204	61.259
1984	36.770	3.243	2.739	22.044	64.797
Quebec					
1958	3.080	1.399	0.300	3.278	8.057
1959	2.800	1.399	0.374	2.000	7.573
1960	2.700	1.399	0.347	3.017	7.464
1961	2.730	1.399	0.347	2.857	7.333
1962	2.810	1.434	0.341	2.524	7.108
1963	2.780	1.598	0.332	2.637	7.347
1964	2.740	1.652	0.341	2.746	7.478
1965	2.640	1.738	0.331	2.814	7.523
1966	2.560	1.760	0.337	3.012	7.669
1967	2.540	1.760	0.374	3.191	7.864

(Table is continued on the next page.)

User Prices and Components: Oil, Continued

Year	Delivered oil price	Provincial taxes	Federal taxes	Non-tax markup	User price
			current dollars per barrel		
1968	2.600	2.040	0.361	3.182	8.183
1969	2.570	2.124	0.374	3.473	8.541
1970	2.470	2.124	0.379	3.737	8.709
1971	2.840	2.124	0.414	3.939	9.317
1972	3.040	2.124	0.415	4.039	9.618
1973	3.500	2.142	0.483	4.869	10.993
1974	6.460	2.142	0.645	4.970	14.216
1975	8.040	2.142	1.253	5.017	16.451
1976	9.310	2.142	1.895	5.261	18.608
1977	11.070	2.142	1.857	6.174	21.242
1978	13.190	2.142	1.604	6.407	23.342
1979	14.230	2.142	1.535	8.612	26.519
1980	17.940	2.222	1.834	9.674	31.671
1981	27.960	3.282	2.282	11.651	45.175
1982	33.650	5.873	2.635	15.406	57.564
1983	36.390	7.413	2.676	16.897	63.376
1984	36.770	6.435	2.905	21.892	68.002
Ontario					
1958	3.330	2.066	0.433	3.966	9.795
1959	3.020	2.066	0.521	3.606	9.213
1960	2.970	2.066	0.501	3.359	8.896
1961	3.030	2.066	0.493	3.208	8.796
1962	3.000	2.066	0.479	3.061	8.606
1963	3.160	2.066	0.456	2.876	8.558
1964	3.190	2.352	0.480	3.090	9.112
1965	3.190	2.385	0.492	3.110	9.176
1966	3.200	2.505	0.527	3.587	9.819
1967	3.200	2.536	0.587	3.781	10.103
1968	3.210	2.812	0.596	3.980	10.598
1969	3.210	2.881	0.607	4.220	10.918
1970	3.240	2.881	0.634	4.570	11.325
1971	3.470	2.881	0.660	4.873	11.884
1972	3.500	3.005	0.665	5.058	12.229
1973	4.150	3.036	0.721	5.495	13.402
1974	6.460	3.036	0.906	5.767	16.170
1975	8.040	3.036	1.772	6.132	18.980
1976	9.310	3.036	2.656	6.749	21.752
1977	11.070	3.036	2.560	7.210	23.876
1978	13.190	3.036	2.212	7.699	26.138
1979	14.230	3.388	2.120	9.551	29.289
1980	17.850	3.401	2.541	11.364	35.156
1981	27.680	4.144	3.143	13.425	48.392
1982	33.470	5.315	3.518	16.792	59.095
1983	36.190	5.483	3.612	17.243	62.527
1984	36.570	5.744	3.800	19.550	65.663

(Table is continued on the next page.)

User Prices and Components: Oil, Continued

Year	Delivered oil price	Provincial taxes	Federal taxes	Non-tax markup	User price
		current dollars per barrel			
Manitoba					
1958	2.960	1.756	0.466	3.394	8.576
1959	2.830	1.756	0.694	3.919	9.199
1960	2.780	1.756	0.650	4.133	9.319
1961	2.840	2.030	0.620	3.948	9.438
1962	2.810	2.296	0.613	4.048	9.767
1963	3.000	2.296	0.638	4.113	10.047
1964	3.030	2.443	0.627	4.186	10.286
1965	3.030	2.882	0.598	3.921	10.431
1966	3.040	2.896	0.636	4.211	10.783
1967	3.040	2.882	0.712	4.263	10.897
1968	3.050	2.882	0.732	4.451	11.115
1969	3.050	2.882	0.755	4.769	11.455
1970	3.080	2.882	0.779	4.943	11.683
1971	3.310	2.882	0.823	5.194	12.209
1972	3.350	2.882	0.857	5.471	12.560
1973	4.000	2.882	0.930	5.777	13.589
1974	6.360	2.724	1.141	5.805	16.030
1975	7.790	2.913	2.070	5.624	18.398
1976	9.100	3.157	3.069	6.799	22.125
1977	10.860	3.219	2.991	7.713	24.783
1978	12.900	3.219	2.624	8.055	26.798
1979	13.900	3.219	2.537	9.451	29.108
1980	17.490	3.392	3.034	11.701	35.617
1981	27.250	4.772	3.775	13.391	49.187
1982	32.900	5.537	4.244	14.772	57.453
1983	35.570	6.311	4.621	17.730	64.232
1984	35.940	6.528	4.791	19.570	66.829
Saskatchewan					
1958	2.810	1.772	0.603	5.375	10.560
1959	2.680	1.772	0.799	5.201	10.452
1960	2.630	1.772	0.793	5.395	10.591
1961	2.690	1.772	0.752	5.108	10.322
1962	2.660	1.940	0.765	5.076	10.441
1963	2.860	2.109	0.753	4.796	10.517
1964	2.890	2.109	0.737	4.646	10.381
1965	2.890	2.109	0.731	4.281	10.011
1966	2.900	2.227	0.749	4.435	10.310
1967	2.900	2.256	0.847	4.762	10.766
1968	2.910	2.549	0.868	5.261	11.589
1969	2.910	2.602	0.871	5.265	11.648
1970	2.940	2.889	0.878	5.322	12.029
1971	3.170	2.934	0.919	5.525	12.548
1972	3.210	2.934	0.967	5.933	13.044
1973	3.860	2.934	0.999	5.753	13.546
1974	6.220	2.303	1.306	6.598	16.427
1975	7.640	1.928	2.179	6.818	18.565
1976	8.930	2.378	3.014	7.379	21.700

(Table is continued on the next page.)

User Prices and Components: Oil, Continued

Year	Delivered oil price	Provincial taxes	Federal taxes	Non-tax markup	User price
			current dollars per barrel		
1977	10.690	2.921	2.884	8.147	24.641
1978	12.720	3.027	2.573	8.860	27.180
1979	13.710	3.057	2.515	10.622	29.905
1980	17.300	3.063	3.131	12.291	35.786
1981	27.050	4.305	4.008	14.965	50.329
1982	32.670	1.875	4.589	16.202	55.336
1983	35.310	0.571	5.018	18.806	59.704
1984	35.670	1.059	5.462	22.698	64.890
Alberta					
1958	2.610	1.902	0.626	4.737	9.875
1959	2.480	1.902	0.839	4.553	9.774
1960	2.430	1.918	0.824	4.560	9.733
1961	2.490	1.943	0.850	4.742	10.025
1962	2.460	2.315	0.802	4.198	9.774
1963	2.650	2.315	0.767	4.231	9.963
1964	2.680	2.315	0.761	4.304	10.059
1965	2.680	2.315	0.763	4.306	10.063
1966	2.690	2.315	0.804	4.640	10.448
1967	2.690	2.315	0.902	4.948	10.855
1968	2.700	2.702	0.937	5.272	11.611
1969	2.700	2.959	0.950	5.469	12.078
1970	2.730	2.959	0.957	5.578	12.224
1971	2.980	2.959	1.010	5.784	12.733
1972	3.020	2.959	1.055	6.015	13.050
1973	3.670	3.046	1.162	6.149	14.028
1974	6.030	2.342	1.504	7.071	16.947
1975	7.450	2.095	2.715	7.350	19.611
1976	8.740	2.095	3.865	7.904	22.604
1977	10.456	2.095	3.683	8.095	24.329
1978	12.540	0.644	3.201	8.384	24.770
1979	13.540	0.161	3.100	9.649	26.450
1980	17.120	0.161	3.691	10.510	31.482
1981	26.850	0.161	4.650	12.332	43.993
1982	32.430	0.161	5.322	14.803	52.716
1983	35.050	0.161	5.713	16.355	57.279
1984	35.410	0.161	6.079	18.792	60.442
British Columbia (*including the Yukon and Northwest Territories*)					
1958	3.010	1.271	0.491	4.047	8.818
1959	2.880	1.352	0.623	3.504	8.359
1960	2.830	1.448	0.569	3.306	8.154
1961	2.890	1.646	0.561	3.203	8.300
1962	2.860	1.845	0.542	3.168	8.415
1963	3.050	1.845	0.537	3.042	8.474
1964	3.080	1.845	0.537	3.114	8.575
1965	3.080	1.845	0.551	3.407	8.882
1966	3.090	1.845	0.568	3.600	9.103
1967	3.090	1.845	0.653	3.914	9.502

(Table is concluded on the next page.)

User Prices and Components: Oil, Concluded

Year	Delivered oil price	Provincial taxes	Federal taxes	Non-tax markup	User price
		current dollars per barrel			
1968	3.100	1.845	0.675	4.253	9.873
1969	3.100	1.845	0.679	4.410	10.033
1970	3.130	1.845	0.690	4.527	10.191
1971	3.380	2.212	0.728	4.719	11.039
1972	3.420	2.303	0.763	5.074	11.561
1973	4.070	2.303	0.838	5.446	12.657
1974	6.430	2.303	1.045	5.714	15.492
1975	7.850	2.692	1.799	5.740	18.082
1976	9.220	2.762	2.597	5.635	20.213
1977	11.000	2.762	2.531	6.904	23.197
1978	13.090	2.762	2.227	7.617	25.696
1979	14.110	2.762	2.089	9.178	28.139
1980	17.670	2.761	2.679	10.812	33.923
1981	27.440	4.433	3.384	12.343	47.600
1982	33.120	5.563	3.814	14.702	57.200
1983	35.810	6.031	4.233	21.034	67.108
1984	36.180	6.055	4.510	24.171	70.916

Appendix 8.1

Tests of the Expected Discoveries Equations

In this appendix, we present tests of the preferred forms for the expected discoveries or investment equations against some more general and some specific alternatives. The basic form of the expected discoveries equations has, as dependent variable, the logarithm of the ratio of real investment expenditures to the estimated marginal cost of new discoveries. The data for investment expenditures are divided between oil and gas by the procedures described in chapter 7, and the data for expected marginal costs are obtained from the marginal cost equations described in the body of chapter 8.

The basic driving variable is the ratio of the after-tax wellhead (or field, as appropriate) price of reserve discoveries to the amortized after-tax marginal cost, and there are auxiliary variables that might influence the ways in which the profitability calculations of investing firms might differ from the observed price and tax data. The key auxiliary variables for expected natural gas discoveries are the current level of production and the ratio of actual to authorized export volumes. Both are intended to capture producer expectations about the length of time they will have to wait before new discoveries can be brought into production. To improve the dynamics of the specifications, we considered the hypothesis that since land payments reflect the outcome of a specific investment decision, and since the acquisition of land must precede major drilling and itself implies subsequent drilling commitments, the previous year's land investment might be used to augment the current determinants of investment spending. This hypothesis was fairly strongly supported by the results reported in chapter 8.

This basic equation is already a restricted model, because it presupposes the same expectations processes for expected revenues as for costs, and the tax factors are assumed to be subject to the same static expectations and to have equal weight with the price and cost terms. In this appendix, we present some test results indicating the strength, or lack of strength, of the empirical evidence supporting the final forms chosen for the equations. We do this by computing F-statistics on the restrictions required on the most general model to obtain the preferred equation, and also the statistics on the restrictions imposed by some of the alternative models that we and others have previously considered.

When setting up the restrictions, we recognize that the dependent variable can be treated as the logarithm of real investment spending by bringing the logarithm of estimated current marginal cost over to the right-hand side and then restricting its coefficient to be equal to 1.0 for our

preferred form. A more traditional form of investment equation, which does not include any allowance for changes over time in the relation between real investment spending and discoveries, can be estimated by restricting the coefficient on the current expected cost variable to be equal to zero. Even in the conventional form, of course, expected marginal cost continues to play its usual role in the definition of the moving average variable for expected profitability. By setting up our preferred equations and conventional investment equations as alternative restricted cases of the same general model, we can make more precise tests of the strengths of the two versions.

Another complication arises in establishing a general model within which the various alternatives could be tested as restricted, or "nested," special cases. We found that the cash flow variables generally took the wrong sign in the general model, so that we have used instead a slightly less general model that excludes the cash flow variables. The general model we have fitted therefore has the logarithm of real investment spending as the dependent variable, with the independent variables being the logarithms of current expected marginal cost, the four separate components of the profitability variable, the level of production, and the level of land expenditures in the previous year. For natural gas, a three-year average of the ratio of authorized to actual export volumes is also included, and for oil, the ratio of estimated to adjusted exploration and development costs. As was discussed in chapter 8, several policies were introduced in the early 1980s that provided incentives for firms to invest in existing reserves rather than new additions. If our cost equation accurately captured these effects, we would expect the coefficient on this ratio to be equal to 1.0. This will be tested further below.

Tables A8.1 and A8.2 show the results for oil and natural gas, respectively. In each table, the estimates of the general model are followed by those of 12 nested special cases. The coefficients and equation statistics differ for two reasons from those reported in chapter 8. In this appendix, we define the dependent variable as the logarithm of investment, and include expected marginal cost on the right-hand side. Since investment and expected marginal cost both have positive trends, the equations in the appendix show higher coefficients of determination, but the same standard errors, for the cases where current expected marginal cost is constrained to have a coefficient of 1.0. The second reason for differences is that in this appendix we have used geometric rather than arithmetic moving averages for the components of the profitability index. This permits a precise disaggregation of the four components, in the double logarithmic form used for estimation. This changes the coefficients only in the third or fourth decimal place and has no material impact on the conclusions or implied properties.

For each of the restricted models, we show, in addition to the usual regression statistics, an F-statistic that tests the statistical acceptability of the restrictions imposed by that equation, relative to the general model shown at the top of the table. A single asterisk marks rejection of the

restrictions at a 95 percent confidence level, and two asterisks mark rejection at a 99 percent level.

Each table contains 12 numbered equations. For crude oil, the basic restricted equation is indicated solely by a number. For the basic version with the additional restriction that the coefficient on the cost ratio is equal to 1.0, the number is followed by the letter "a." The 12 basic restricted equations are divided into three groups of four equations each. In the first group, the coefficient of current expected marginal cost is restricted to be equal to zero, so that these equations follow the traditional form for investment equations. In the second group, the coefficient of current expected cost is unrestricted, while in the third group the coefficient is restricted to be equal to 1.0, as required by our assumption that expected discoveries respond to changes in the ratio of the expected value of discoveries to the expected marginal cost.

It is clear from table A8.1 that the restriction on the coefficient on the cost ratio is strongly rejected. The coefficient is significantly less than 1.0 in all the equations, indicating that our marginal cost equation overestimates the proportion of exploration and development expenditures directed at existing reserves.

The results in tables A8.1 and A8.2 suggest that the differences between our preferred expected discoveries form and the more traditional investment form are small. The traditional investment form, however, results in a negative coefficient on the ratio of actual to authorized export volumes for natural gas, and tends to worsen the fit of the oil equations when production is excluded.

Within each group of four equations, the first equation constrains all four components of the profitability variable to have the same coefficients, with positive signs for the revenue elements and negative signs for the cost components. The tax factors are defined as 1.0 minus the relevant weighted average tax rates. Higher values for the price tax factor therefore reflect higher net revenues for producers, and higher cost tax factors reflect greater net costs for producers. The top two equations in each group contain unrestricted coefficients on the level of production, while the second pair restrict the coefficient on production to be equal to zero. Within each pair, the upper equation includes all four components of the profitability variable, while the lower one includes only the pre-tax price and cost terms, with the coefficients on the tax factors constrained to be equal to zero, and the coefficients on the price and cost terms constrained in all cases to be equal but of opposite sign.

The results for crude oil support the hypothesis that the tax and price variables have the same coefficients. The coefficients on the tax factors in the unrestricted equation are much weaker than the coefficients on the price and cost variables, and the coefficient on the marginal cost tax factor is positive (but insignificant). The constraints on the price, cost, and tax factors are accepted nonetheless.

A general feature of the natural gas results is that the overall importance of the profitability effects is so small, relative to the demand effects captured by the export ratio, that the data do not strongly reject any definition of profitability in favour of any other. The roles of all components of the profitability variable are relatively weak, so that either including or excluding the tax factors is acceptable.

For both crude oil and natural gas, the preferred equations are equation 11, which includes the tax factors, excludes production levels, and constrains the coefficient of expected marginal costs to equal 1.0. For oil, these restrictions are all statistically acceptable, and for natural gas they are acceptable at the 1 percent level. The remaining variables all have significant coefficients of the expected sign and reasonable magnitudes. In particular, the plausible and highly significant coefficients on the land variables offer strong evidence in favour of the inclusion of lagged land payments as a separate variable.

The above results, while satisfactory in several respects, do not suggest that better investment models need not be developed. In particular, the results with respect to the cost tax factors suggest that more work needs to be done in analyzing the links between tax rules and the expectations used by firms in making their investment decisions. For example, our calculations of the tax factors assume that the representative firm is in a taxable position, whereas many firms have actually had sufficient backlogs of unclaimed deductions that they were not likely to be in a taxable position for several years in our sample period. This would tend to reduce the effect of changes in income tax rates, but it would not influence so much the effect of changes in the rates of royalty or of taxes—like the petroleum and gas revenue tax (PGRT)—that apply to a base that does not permit a wide range of deductions. The cost tax factor also includes the effects of petroleum incentives program (PIP) grants, and here, too, the effect of a cash grant as opposed to a tax write-off is likely to vary substantially with the taxable position of the firm. Preliminary experiments that separated the effects of PIP grants from the overall cost tax factor suggested that tax write-offs could have very different effects from cash grants. The sign on the cost tax factor (excluding the effects of PIP grants) was negative, and the estimated coefficient was of approximately the same magnitude as the other components of the profitability ratio, but the coefficient on PIP grants was very unstable.

Table A8.1 Tests of Oil Expected Discoveries Equations

Equation	LINFOX	LMCCOL71	LPOIL3	LTFPO3	LMCOL3	LTMCOL3	LPRO	LLOLAND	CONST	RB2	SEE	DW	n	d	F
Unrestricted	0.1234	0.7202	1.2403	0.1501	−2.1708	0.5966	0.6260	0.5976	0.4025	0.9197	0.1497	1.6285			
	(0.691)	(0.722)	(1.92)	(0.120)	(1.61)	(0.700)	(1.91)	(5.79)	(0.199)						
1	0.5354	—	1.4976	1.4976	−1.4976	−1.4976	0.8682	0.6506	−2.1626	0.9097	0.1588	2.0572	4	22	1.81
	(5.90)		(7.28)	(7.28)	(7.28)	(7.28)	(6.71)	(9.76)	(2.64)						
1a	1.0000	—	1.1015	1.1015	−1.1015	−1.1015	0.5742	0.6085	−0.3431	0.8255	0.2208	1.9912	5	22	7.33**
			(4.16)	(4.16)	(4.16)	(4.16)	(3.56)	(6.61)	(0.334)						
2	0.1623	—	0.8927	—	−0.8927	—	0.3743	0.6023	0.6186	0.9265	0.1433	1.6223	4	22	0.45
	(1.53)		(8.42)		(8.42)		(5.12)	(9.85)	(1.10)						
2a	1.0000	—	0.3082	—	−0.3082	—	0.0901	0.6135	2.2591	0.7586	0.2596	1.4748	5	22	11.8**
			(2.24)		(2.24)		(0.780)	(5.54)	(2.38)						
3	0.8056	—	0.3464	0.3464	−0.3464	−0.3464	—	0.6277	2.8540	0.7626	0.2575	1.0920	5	22	11.6**
	(6.11)		(1.88)	(1.88)	(1.88)	(1.88)		(5.81)	(5.27)						
3a	1.0000	—	0.3431	0.3431	−0.3431	−0.3431	—	0.60908	2.9169	0.7527	0.2628	1.3505	6	22	10.7**
			(1.83)	(1.83)	(1.83)	(1.83)		(5.57)	(5.29)						
4	0.4282	—	0.6357	—	−0.6357	—	—	0.5534	3.0735	0.8579	0.1992	1.0845	5	22	5.16**
	(3.34)		(4.90)		(4.90)			(6.59)	(7.52)						
4a	1.0000	—	0.2855	—	−0.2855	—	—	0.5968	2.8726	0.7620	0.2578	1.4481	6	22	10.2**
			(2.14)		(2.14)			(5.53)	(5.46)						
5	0.4946	0.3542	1.4979	1.4979	−1.4979	−1.4979	0.6419	0.6194	−0.7736	0.9081	0.1602	1.9232	3	22	2.20
	(4.63)	(0.740)	(7.22)	(7.22)	(7.22)	(7.22)	(1.93)	(7.80)	(0.377)						
5a	1.0000	−0.8131	1.1808	1.1808	−1.1808	−1.1808	1.1532	0.6888	−3.8955	0.8327	0.2161	2.2490	4	22	8.04**
		(1.47)	(4.46)	(4.46)	(4.46)	(4.46)	(2.72)	(6.54)	(1.49)						
6	0.1823	−0.2281	0.9017	—	−0.9017	—	0.5231	0.6213	−0.2893	0.9243	0.1454	1.6790	3	22	0.52
	(1.60)	(0.519)	(8.28)		(8.28)		(1.77)	(8.63)	(0.157)						
6a	1.0000	−1.2952	0.4384	—	−0.4384	—	0.9736	0.7196	−3.1190	0.7779	0.2490	1.7263	4	22	12.5**
		(1.83)	(2.92)		(2.92)		(2.96)	(5.94)	(1.01)						

(Table A8.1 is continued on the next page.)

Table A8.1 Continued

Equation	LINFOX	LMCCOL71	LPOIL3	LTFPO3	LMCOL3	LTMCOL3	LPRO	LLOLAND	CONST	RB2	SEE	DW	n	d	F
7	0.4274	1.2036	1.3673	1.3673	−1.3673	−1.3673	—	0.5418	3.1300	0.8985	0.1684	1.5501	4	22	2.72
	(4.02)	(6.09)	(6.63)	(6.63)	(6.63)	(6.63)		(7.52)	(8.76)						
7a	1.0000	0.5820	0.8337	0.8337	−0.8337	−0.8337	—	0.5515	3.1096	0.7931	0.2404	1.7025	5	22	9.51**
		(2.52)	(3.23)	(3.23)	(3.23)	(3.23)		(5.37)	(6.10)						
8	0.1395	0.5235	0.8497	—	−0.8497	—	—	0.5545	2.9175	0.9182	0.1512	1.4798	4	22	1.12
	(1.20)	(4.57)	(7.80)		(7.80)			(8.70)	(9.35)						
8a	1.0000	0.0609	0.2899	—	−0.2899	—	—	0.5995	2.8426	0.7544	0.2619	1.4554	5	22	12.1**
		(0.366)	(2.13)		(2.13)			(5.46)	(5.26)						
9	0.4201	1.0000	1.4985	1.4985	−1.4985	−1.4985	0.2291	0.5624	1.7592	0.9052	0.1627	1.6112	4	22	2.17
	(4.52)		(7.11)	(7.11)	(7.11)	(7.11)	(1.73)	(8.23)	(2.10)						
9a	1.0000	1.0000	1.0040	1.0040	−1.0040	−1.0040	−0.1378	0.5099	4.0305	0.7722	0.2522	1.5921	5	22	10.9**
			(3.32)	(3.32)	(3.32)	(3.32)	(0.748)	(4.85)	(3.44)						
10	0.0743	1.0000	0.8536	—	−0.8536	—	−0.2780	0.5193	4.5985	0.9045	0.1633	1.3363	4	22	2.23
	(0.616)		(7.07)		(7.07)		(3.33)	(7.45)	(7.17)						
10a	1.0000	1.0000	0.2077	—	−0.2077	—	−0.5920	0.5316	6.4113	0.6998	0.2895	1.2706	5	22	15.8**
			(1.35)		(1.35)		(4.60)	(4.30)	(6.07)						
11	0.4914	1.0000	1.1946	1.1946	−1.1946	−1.1946	—	0.5564	3.0833	0.8982	0.1686	1.6067	5	22	2.44
	(5.69)		(9.92)	(9.92)	(9.92)	(9.92)		(7.87)	(8.69)						
11a	1.0000	1.0000	1.1860	1.1860	−1.1860	−1.1860	—	0.5096	3.2479	0.7758	0.2502	1.5559	6	22	9.36**
			(6.63)	(6.63)	(6.63)	(6.63)		(4.89)	(6.19)						
12	−0.1232	1.0000	1.0444	—	−1.0444	—	—	0.5556	2.7756	0.8687	0.1914	0.9383	5	22	4.42**
	(1.00)		(8.38)		(8.38)			(6.88)	(7.06)						
12a	1.0000	1.0000	0.3564	—	−0.3564	—	—	0.6409	2.3809	0.4839	0.3796	0.6837	6	22	26.3**
			(1.81)		(1.81)			(4.03)	(3.07)						

Notes: t-statistics are given in parentheses; **indicates restrictions rejected at the 99 percent level.

(Table A8.1 is continued on the next page.)

Table A8.1 Continued

Guide to Restrictions Imposed in Table A8.1
Dependent Variable: LINFO

Equation	LINFOX	LMCCOL71	LPOIL3	LTFPO3	LMCOL3	LTMCOL3	LPRO	LLOLAND
Unrestricted								
1		0.0	= +	= +	= –	= –		
1a	1.0	0.0	= +	= +	= –	= –		
2		0.0	= +	0.0	= –	0.0		
2a	1.0	0.0	= +	0.0	= –	0.0		
3		0.0	= +	= +	= –	= –	0.0	
3a	1.0	0.0	= +	= +	= –	= –	0.0	
4		0.0	= +	0.0	= –	0.0	0.0	
4a	1.0	0.0	= +	0.0	= –	0.0	0.0	
5			= +	= +	= –	= –		
5a	1.0		= +	= +	= –	= –		
6			= +	0.0	= –	0.0		
6a	1.0		= +	0.0	= –	0.0		
7			= +	= +	= –	= –	0.0	
7a	1.0		= +	= +	= –	= –	0.0	
8			= +	0.0	= –	0.0	0.0	
8a	1.0		= +	0.0	= –	0.0	0.0	
9		1.0	= +	= +	= –	= –		
9a	1.0	1.0	= +	= +	= –	= –		
10		1.0	= +	0.0	= –	0.0		
10a	1.0	1.0	= +	0.0	= –	0.0		
11		1.0	= +	= +	= –	= –	0.0	
11a	1.0	1.0	= +	= +	= –	= –	0.0	
12		1.0	= +	0.0	= –	0.0	0.0	
12a	1.0	1.0	= +	0.0	= –	0.0	0.0	

Note: Blank spaces represent cases where no restrictions on the values of the coefficients were imposed in estimation. In the case of LLOLAND, for example, restrictions on the value of its coefficient were never imposed.

Mnemonics (All Variables for Western Canada, Logarithmic Form)

LINFO real capital cost, defined as real expenditures on exploration, development, and geophysical work (excluding land payments)—oil, millions of 1971 dollars

LINFOX ratio of estimated to adjusted capital costs—oil

LMCCOL71 real predicted marginal cost—oil, 1971 dollars per barrel

LPOIL3 three-year moving average of the real wellhead price—oil, 1971 dollars per barrel

LTFPO3 three-year moving average of the tax factor for prices—oil

LMCOL3 three-year moving average of the real capital plus operating cost—oil, 1971 dollars per barrel

LTMCOL3 three-year moving average of the tax factor for costs—oil

LPRO production—oil, millions of barrels

LLOLAND previous year's real land payments—oil, millions of 1971 dollars

CONST a constant term

(Table A8.1 is concluded on the next page.)

Table A8.1 Concluded

RB2	adjusted R-square
SEE	standard error of the estimate
DW	Durbin-Watson statistic
n	degrees of freedom of numerator
d	degrees of freedom of denominator
F	F-statistic

Table A8.2 Tests of Gas Expected Discoveries Equations

Equation	LMCCG71	LPGAS3	LTFPG3	LMCG3	LTMCG3	LGPRW	LRAUTA3	LLGLAND	CONST	RB2	SEE	DW	n	d	F
Unrestricted	−1.6250	−0.7934	−1.5066	5.4487	1.5754	−0.5013	2.8407	0.4242	7.2100	0.9466	0.1922	2.4709			
	(1.49)	(1.65)	(0.770)	(2.72)	(0.686)	(0.759)	(1.98)	(2.31)	(1.01)						
1	—	0.0900	0.0900	−0.0900	−0.0900	0.2617	−0.1707	0.6922	0.9124	0.9278	0.2235	2.1384	4	19	3.02*
		(0.319)	(0.319)	(0.319)	(0.319)	(1.32)	(0.702)	(4.98)	(1.26)						
2	—	0.1092	—	−0.1092	—	0.2773	−0.0652	0.6728	0.8719	0.9282	0.2228	2.1200	4	19	2.98*
		(0.495)		(0.495)		(1.56)	(0.179)	(4.86)	(1.28)						
3	—	−0.2120	−0.2120	0.2120	0.2120	—	−0.3835	0.8627	1.7854	0.9256	0.2269	2.2785	5	19	2.89
		(1.27)	(1.27)	(1.27)	(1.27)		(2.08)	(16.8)	(6.08)						
4	—	−0.1525	—	0.1525	—	—	−0.5035	0.8718	1.8424	0.9240	0.2293	2.2475	5	19	3.03*
		(1.04)		(1.04)			(2.13)	(15.8)	(6.38)						
5	−0.1444	0.1033	0.1033	−0.1033	−0.1033	0.3511	−0.2500	0.7059	−0.0924	0.9245	0.2284	2.1510	3	19	4.02*
	(0.131)	(0.338)	(0.338)	(0.338)	(0.338)	(0.494)	(0.382)	(4.00)	(0.012)						
6	−0.2087	0.1241	—	−0.1241	—	0.4047	−0.1689	0.6927	−0.5757	0.9251	0.2276	2.1403	3	19	3.95*
	(0.190)	(0.520)		(0.520)		(0.584)	(0.256)	(3.94)	(0.075)						
7	0.3765	0.0223	0.0223	−0.0223	−0.0233	—	0.0129	0.6751	3.6279	0.9270	0.2247	2.1285	4	19	3.10*
	(1.22)	(0.088)	(0.088)	(0.088)	(0.088)		(0.035)	(4.16)	(2.36)						
8	0.4086	0.0536	—	−0.0536	—	—	0.0940	0.6539	3.8035	0.9272	0.2244	2.1022	4	19	3.08*
	(1.44)	(0.264)		(0.264)			(0.198)	(4.08)	(2.74)						
9	1.0000	−0.0021	−0.0021	0.0021	0.0021	−0.3575	0.3787	0.5973	7.8723	0.9243	0.2288	2.0291	4	19	3.40*
		(0.007)	(0.007)	(0.007)	(0.007)	(1.76)	(1.52)	(4.20)	(10.64)						
10	1.0000	0.0374	—	−0.0374	—	−0.3333	0.4320	0.5776	7.8089	0.9244	0.2287	2.0000	4	19	3.39*
		(0.165)		(0.165)		(1.82)	(1.16)	(4.06)	(11.1)						
11	1.0000	0.4105	0.4105	−0.4105	−0.4105	—	0.6695	0.3644	6.6797	0.9177	0.2386	1.5625	5	19	3.60*
		(2.34)	(2.34)	(2.34)	(2.34)		(3.46)	(6.76)	(21.6)						
12	1.0000	0.3519	—	−0.3519	—	—	0.9588	0.3385	6.6425	0.9170	0.2395	1.5420	5	19	3.65*
		(2.29)		(2.29)			(3.88)	(5.88)	(22.0)						

Notes: t-statistics are given in parentheses; *indicates restrictions rejected at the 95 percent level.

(Table A8.2 is concluded on the next page.)

Table A8.2 Concluded

Guide to Restrictions Imposed in Table A8.2
Dependent Variable: LINFG

Equation	LMCCG71	LPGAS3	LTFPG3	LMCG3	LTMCG3	LGPRW	LRAUTA3	LLGLAND
Unrestricted								
1	0.0	= +	= +	= −	= −			
2	0.0	= +	0.0	= −	0.0			
3	0.0	= +	= +	= −	= −	0.0		
4	0.0	= +	0.0	= −	0.0	0.0		
5		= +	= +	= −	= −			
6		= +	0.0	= −	0.0			
7		= +	= +	= −	= −	0.0		
8		= +	0.0	= −	0.0	0.0		
9	1.0	= +	= +	= −	= −			
10	1.0	= +	0.0	= −	0.0			
11	1.0	= +	= +	= −	= −	0.0		
12	1.0	= +	0.0	= −	0.0	0.0		

Note: Blank spaces represent cases where no restrictions on the values of the coefficients were imposed in estimation. In the case of LRAUTA3 and LLGLAND, for example, restrictions on the values of their coefficients were never imposed.

Mnemonics (All Variables for Western Canada, Logarithmic Form)

LINFG	real capital cost, defined as real expenditures on exploration, development, and geophysical work (excluding land payments)—gas, millions of 1971 dollars
LMCCG71	real predicted marginal cost—gas, 1971 dollars per thousand cubic feet
LPGAS3	three-year moving average of the real field price—gas, 1971 dollars per thousand cubic feet
LTFPG3	three-year moving average of the tax factor for prices—gas
LMCG3	three-year moving average of the real capital plus operating cost—gas, 1971 dollars per thousand cubic feet
LTMCG3	three-year moving average of the tax factor for costs—gas
LGPRW	production—gas, billions of cubic feet
LRAUTA3	three-year moving average of the ratio of actual to authorized gas exports
LLGLAND	previous year's real land payments—gas, millions of 1971 dollars
CONST	a constant term
RB2	adjusted R-square
SEE	standard error of the estimate
DW	Durbin-Watson statistic
n	degrees of freedom of numerator
d	degrees of freedon of denominator
F	F-statistic

Data Appendix

The primary sources for the data series reported below are the Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986); Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada*, catalogue no. 57-003; and its predecessor, *Detailed Energy Supply and Demand in Canada*, catalogue no. 57-207. All of these series are available either on the energy data banks maintained at the Institute for Policy Analysis, University of Toronto,[1] or the MACE model database maintained at the University of British Columbia. Fuel prices to final users are given in dollars per gigajoule, and fuel consumptions are in petajoules. There are approximately 0.95 gigajoules in 1 million BTU (and one million gigajoules in 1 petajoule). One barrel of crude oil converts to approximately 5.8 million BTU; one thousand cubic feet of natural gas represents about 1 million BTU; and electricity was converted using a relationship of about 0.0034 million BTU per kilowatt-hour. The calculation of fuel prices to final users is described in appendix 6.2.

[1] These data banks are described in Mary E. MacGregor and André Plourde, *Documentation for Data Banks on Canadian Oil and Gas Activity*, PEAP Energy Study no. 86-3 (Toronto: University of Toronto, Institute for Policy Analysis, 1986); and Mary E. MacGregor, André Plourde, and Robert Williams, *Update of PEAP Energy Study no. 86-3: Changes to Data Banks and Mnemonics*, PEAP Energy Memo no. 87-1 (Toronto: University of Toronto, Institute for Policy Analysis, 1987).

Crude Oil Prices

Year	Average US wellhead	Average western Canadian wellhead	Average Canadian export
	US dollars per barrel		
1967	2.920	2.271	2.437
1968	2.940	2.274	2.449
1969	3.090	2.238	2.409
1970	3.180	2.365	2.543
1971	3.390	2.713	2.859
1972	3.390	2.786	2.919
1973	3.890	3.410	3.580
1974	6.740	5.828	10.578
1975	7.560	7.049	11.657
1976	8.190	8.468	13.516
1977	8.570	9.450	13.812
1978	9.000	10.547	14.201
1979	12.640	11.115	19.477
1980	21.190	13.180	33.007
1981	31.770	15.523	35.094
1982	28.520	19.883	28.353
1983	26.190	23.572	26.294
1984	25.880	23.273	26.173
1985	24.080	25.726	24.740
1986	12.650	13.030	12.848

Natural Gas Prices

Year	Average US field	Average western Canadian field	Average Canadian export
	US dollars per thousand cubic feet		
1967	0.160	0.133	0.224
1968	0.164	0.134	0.236
1969	0.167	0.132	0.241
1970	0.171	0.142	0.253
1971	0.182	0.146	0.273
1972	0.186	0.154	0.307
1973	0.216	0.169	0.341
1974	0.304	0.273	0.526
1975	0.445	0.534	1.134
1976	0.580	0.894	1.719
1977	0.790	1.105	1.899
1978	0.905	1.218	2.180
1979	1.178	1.348	2.465
1980	1.590	1.858	4.278
1981	1.980	1.935	4.784
1982	2.460	2.050	4.916
1983	2.590	2.076	4.385
1984	2.660	2.170	4.010
1985	2.530	1.942	3.103
1986	1,870	1.498	2.422

Fuel Prices to Final Users by Region

Year	Electricity	Oil	Natural gas
	Canadian dollars per gigajoule		
Atlantic region			
1959	4.308	1.251	—
1960	4.243	1.218	—
1961	4.466	1.215	—
1962	4.614	1.221	—
1963	4.500	1.222	—
1964	4.277	1.233	—
1965	4.493	1.207	—
1966	4.423	1.222	—
1967	4.305	1.252	—
1968	4.236	1.259	—
1969	4.014	1.289	—
1970	4.127	1.316	—
1971	4.060	1.353	—
1972	4.130	1.449	—
1973	4.149	1.566	—
1974	4.135	1.747	—
1975	4.633	2.286	—
1976	5.369	2.667	—
1977	5.839	3.066	—
1978	7.377	3.511	—
1979	8.990	3.919	—
1980	9.863	4.358	—
1981	10.374	5.240	—
1982	10.580	7.140	—
1983	12.108	8.865	—
1984	13.108	10.029	—
1985	13.814	10.628	—
Quebec			
1959	1.927	1.319	1.900
1960	1.943	1.240	1.720
1961	1.886	1.222	1.064
1962	2.031	1.201	0.798
1963	2.027	1.164	0.941
1964	2.128	1.203	0.921
1965	2.281	1.224	0.874
1966	2.347	1.232	0.950
1967	2.225	1.255	0.950
1968	2.411	1.287	0.988
1969	2.584	1.340	0.921
1970	2.571	1.398	0.865
1971	2.717	1.426	0.893
1972	2.848	1.525	0.902
1973	2.755	1.574	0.931
1974	2.791	1.800	0.978
1975	2.964	2.327	1.036
1976	3.529	2.693	1.368
1977	3.758	3.046	1.862
1978	4.114	3.477	2.099
1979	4.718	3.821	2.460
1980	5.500	4.341	2.603

(Table is continued on the next page.)

Fuel Prices to Final Users by Region, Continued

Year	Electricity	Oil	Natural gas
	Canadian dollars per gigajoule		
1981	6.215	5.185	2.987
1982	6.662	7.396	3.660
1983	7.780	9.424	4.790
1984	8.393	10.375	5.140
1985	8.482	11.149	5.436
Ontario			
1959	2.468	1.603	0.950
1960	2.391	1.508	0.921
1961	2.421	1.456	0.874
1962	2.463	1.440	0.845
1963	2.546	1.409	0.817
1964	2.500	1.401	0.826
1965	2.749	1.492	0.817
1966	2.729	1.502	0.817
1967	2.703	1.608	0.836
1968	2.735	1.654	0.798
1969	2.811	1.735	0.779
1970	2.924	1.787	0.760
1971	3.039	1.854	0.741
1972	3.189	1.945	0.731
1973	3.276	2.002	0.722
1974	3.526	2.194	0.731
1975	3.801	2.647	0.826
1976	4.333	3.107	1.121
1977	5.034	3.561	1.605
1978	6.355	3.909	1.871
1979	6.701	4.279	2.194
1980	7.229	4.795	2.403
1981	8.108	5.755	2.745
1982	8.349	7.922	3.445
1983	9.252	9.674	4.252
1984	9.985	10.236	4.844
1985	10.811	10.768	4.871
Manitoba			
1959	2.329	1.404	0.551
1960	2.274	1.506	0.551
1961	2.300	1.526	0.608
1962	2.442	1.545	0.598
1963	2.422	1.599	0.655
1964	2.351	1.645	0.646
1965	2.714	1.684	0.646
1966	2.926	1.708	0.646
1967	2.970	1.765	0.646
1968	2.995	1.784	0.627
1969	3.051	1.820	0.608
1970	3.235	1.875	0.598
1971	3.065	1.913	0.608
1972	2.922	1.999	0.617
1973	2.889	2.056	0.617
1974	2.873	2.225	0.617

(Table is continued on the next page.)

Fuel Prices to Final Users by Region, Continued

Year	Electricity	Oil	Natural gas
	Canadian dollars per gigajoule		
1975	3.234	2.624	0.741
1976	3.919	3.012	1.064
1977	4.737	3.622	1.425
1978	5.403	4.057	1.700
1979	6.465	4.387	2.052
1980	7.605	4.765	2.175
1981	7.737	5.831	2.610
1982	7.809	8.052	3.176
1983	8.152	9.405	3.875
1984	8.493	10.515	4.252
1985	7.785	10.962	4.333
Saskatchewan			
1959	6.342	1.729	0.389
1960	6.415	1.711	0.389
1961	6.325	1.734	0.418
1962	6.042	1.690	0.427
1963	5.961	1.709	0.437
1964	5.645	1.722	0.437
1965	6.296	1.700	0.456
1966	5.659	1.639	0.437
1967	5.477	1.688	0.418
1968	5.386	1.762	0.427
1969	5.167	1.897	0.408
1970	4.918	1.907	0.456
1971	4.844	1.969	0.456
1972	4.720	2.054	0.456
1973	4.549	2.135	0.465
1974	4.382	2.218	0.456
1975	4.399	2.689	0.503
1976	4.925	3.039	0.703
1977	5.945	3.553	1.036
1978	6.812	4.034	1.311
1979	7.543	4.450	1.510
1980	7.492	4.896	1.672
1981	8.160	5.858	1.938
1982	8.783	8.239	2.476
1983	9.663	9.059	3.041
1984	10.251	9.774	3.283
1985	10.892	10.646	3.418
Alberta			
1959	4.806	1.617	0.238
1960	4.784	1.600	0.238
1961	4.621	1.593	0.275
1962	4.623	1.641	0.266
1963	4.569	1.600	0.285
1964	4.394	1.631	0.294
1965	4.866	1.647	0.304
1966	4.700	1.647	0.304
1967	4.564	1.711	0.304
1968	4.525	1.777	0.314

(Table is concluded on the next page.)

Fuel Prices to Final Users by Region, Concluded

Year	Electricity	Oil	Natural gas
	Canadian dollars per gigajoule		
1969	4.398	1.901	0.304
1970	4.185	1.977	0.294
1971	4.244	2.001	0.304
1972	4.120	2.085	0.314
1973	4.057	2.136	0.314
1974	4.316	2.296	0.314
1975	4.619	2.774	0.342
1976	5.446	3.210	0.484
1977	6.667	3.700	0.694
1978	7.504	3.983	0.883
1979	8.673	4.055	1.102
1980	8.940	4.330	1.159
1981	9.457	5.154	1.453
1982	10.368	7.202	2.045
1983	12.343	8.630	2.180
1984	13.156	9.377	2.503
1985	13.894	9.922	2.476
British Columbia *(including the Yukon and Northwest Territories)*			
1959	3.980	1.444	0.865
1960	4.123	1.368	0.865
1961	4.218	1.335	0.865
1962	4.169	1.359	0.855
1963	3.868	1.378	0.883
1964	3.672	1.387	0.865
1965	3.900	1.404	0.855
1966	3.544	1.454	0.712
1967	3.355	1.490	0.741
1968	3.529	1.556	0.779
1969	3.470	1.616	0.731
1970	3.421	1.642	0.741
1971	3.741	1.668	0.722
1972	3.700	1.807	0.741
1973	3.639	1.893	0.731
1974	3.659	2.072	0.684
1975	4.043	2.536	0.893
1976	4.642	2.960	0.941
1977	5.141	3.309	1.169
1978	5.954	3.798	1.454
1979	6.472	4.207	1.672
1980	6.967	4.607	1.900
1981	7.634	5.553	1.991
1982	7.676	7.793	2.745
1983	9.737	9.364	3.714
1984	9.983	10.986	3.821
1985	10.688	11.638	3.983

Fuel Consumption by Region

Year	Electricity	Oil	Natural gas
		petajoules	
Atlantic region			
1958	13.9527	129.1423	—
1959	14.9381	141.0796	—
1960	15.4038	158.3128	—
1961	15.9378	164.0113	—
1962	17.4377	177.0356	—
1963	19.7470	183.3673	—
1964	22.7311	202.1841	—
1965	26.0315	217.9775	—
1966	28.1773	217.6496	—
1967	30.2972	243.3384	—
1968	33.8873	269.4832	—
1969	36.6599	284.5559	—
1970	40.4708	311.9403	—
1971	43.4314	336.2873	—
1972	48.0573	371.9990	—
1973	53.0604	375.6926	—
1974	56.9988	375.7889	—
1975	58.1958	352.7011	—
1976	64.7611	359.6502	—
1977	67.7889	366.8581	—
1978	70.2851	374.5397	—
1979	71.6383	376.6738	—
1980	74.7513	374.1534	—
1981	76.0701	344.9398	—
1982	73.0827	313.5923	—
1983	76.6309	296.5382	—
1984	86.1711	299.7938	—
Quebec			
1958	116.2421	353.6458	2.9017
1959	121.1120	393.6970	5.1209
1960	138.5770	401.3947	12.1770
1961	137.2262	418.0713	24.2104
1962	137.7789	467.2326	22.7913
1963	140.0565	501.0200	27.1610
1964	154.4803	551.6871	33.1134
1965	162.3860	589.4264	31.2351
1966	175.8688	641.2611	32.4848
1967	182.6580	695.8128	32.2598
1968	189.4953	736.5858	44.0820
1969	202.6527	778.8311	50.7157
1970	218.9542	833.0514	50.6471
1971	220.2617	819.7422	55.2888
1972	239.1959	859.8334	58.1466
1973	256.5527	912.2972	64.1320
1974	283.2448	903.9223	80.1220
1975	272.7351	889.8790	82.2720
1976	281.8732	909.2912	80.3700
1977	317.1577	853.4716	81.4880
1978	338.9365	844.2396	86.7613
1979	333.6672	854.6241	97.5326

(Table is continued on the next page.)

Fuel Consumption by Region, Continued

Year	Electricity	Oil	Natural gas
		petajoules	
1980	360.4379	836.2314	103.0381
1981	377.4979	747.5564	112.6899
1982	368.1640	648.2671	104.8088
1983	387.7967	584.6847	129.3486
1984	422.0958	556.8888	151.3821
Ontario			
1958	96.6111	472.1826	50.3200
1959	106.8574	511.8484	82.2817
1960	112.3442	530.3803	102.7637
1961	115.8650	545.1315	124.0226
1962	122.5549	566.9711	147.3583
1963	129.4236	605.6556	166.5955
1964	139.8596	624.5815	192.8610
1965	152.1087	678.2268	216.8072
1966	165.5560	698.1746	237.2963
1967	175.8337	740.2591	277.5339
1968	189.3292	789.5510	304.7741
1969	201.5192	804.3120	346.1423
1970	216.4259	844.8953	397.4521
1971	227.9810	855.4260	440.6711
1972	245.5575	904.8119	496.4083
1973	263.2116	914.0601	513.2500
1974	278.3465	952.3617	569.0940
1975	274.8786	950.0672	552.5900
1976	295.6501	954.4531	615.0930
1977	309.9297	970.5459	602.3310
1978	320.3551	981.8809	621.6594
1979	333.4785	998.4096	636.4774
1980	337.4405	971.1332	641.4402
1981	346.5463	901.7694	641.5610
1982	339.4998	801.9659	617.4146
1983	351.7997	769.6409	628.8589
1984	376.5367	781.1209	671.3949
Manitoba			
1958	12.2542	80.4517	3.2799
1959	13.4904	82.2764	6.1986
1960	14.3314	78.4915	9.3409
1961	15.4117	75.5392	13.6665
1962	16.6055	77.0313	16.0202
1963	17.9673	80.5590	20.1807
1964	18.5319	82.2498	25.4882
1965	18.4896	83.7918	30.3646
1966	19.3392	84.0262	34.4250
1967	20.3369	85.4236	37.3918
1968	21.9300	88.6088	40.7534
1969	24.3426	90.1184	44.9589
1970	26.5433	91.7279	47.1681
1971	29.1880	92.9480	51.3559
1972	30.0655	102.1351	61.4837
1973	32.2536	106.0614	59.2410

(Table is continued on the next page.)

Fuel Consumption by Region, Continued

Year	Electricity	Oil	Natural gas
		petajoules	
1974	34.4568	110.9127	63.7820
1975	34.7734	106.7050	60.1400
1976	36.2849	110.0371	60.7980
1977	37.1871	106.4961	60.5420
1978	38.1584	109.4168	64.1540
1979	40.0796	112.7757	68.0037
1980	39.7935	106.9085	62.8780
1981	38.4404	102.0712	59.6367
1982	39.7604	99.4516	63.8857
1983	40.6649	96.4947	61.7176
1984	43.6944	95.5904	63.8885
Saskatchewan			
1958	3.8648	76.2045	14.6733
1959	4.4626	78.9920	21.7083
1960	4.7447	78.9743	23.3998
1961	5.3367	77.6206	27.6131
1962	5.8963	83.7422	30.3305
1963	6.9209	87.3421	33.5347
1964	7.6255	88.3362	38.1834
1965	9.5799	96.0767	48.1664
1966	10.8420	99.1184	53.6461
1967	11.8915	97.8435	55.4306
1968	13.5774	99.7507	63.9677
1969	15.2592	98.5991	66.7263
1970	16.0715	101.0563	65.0240
1971	16.7577	104.4306	68.5723
1972	19.0959	107.2981	72.8941
1973	21.2827	107.3050	74.4430
1974	22.4946	115.2331	80.4940
1975	21.8989	126.7532	82.2730
1976	22.5294	128.0850	82.3110
1977	24.5302	129.0976	86.4440
1978	27.1879	132.9818	88.7922
1979	28.9694	137.8843	91.0300
1980	29.4741	135.5108	88.2218
1981	30.7797	129.5863	85.3577
1982	30.8520	126.0612	89.6788
1983	32.9590	127.2758	88.3634
1984	37.2563	124.8986	94.3739
Alberta			
1958	7.9940	97.6962	86.4014
1959	9.0172	100.8653	100.2493
1960	10.0132	104.9993	106.6612
1961	10.9136	103.1866	112.5786
1962	11.8813	107.5770	122.3204
1963	12.9663	114.7288	122.1696
1964	14.4874	114.9530	132.3249
1965	16.9286	121.4191	145.0714
1966	18.4975	131.1806	153.1671
1967	19.7360	133.5547	157.6027

(Table is concluded on the next page.)

Fuel Consumption by Region, Concluded

Year	Electricity	Oil	Natural gas
		petajoules	
1968	22.2640	143.2767	164.4431
1969	25.7985	148.4710	194.7895
1970	28.4302	154.5944	193.5892
1971	31.1969	158.9575	212.7948
1972	36.4821	172.6160	240.0103
1973	40.6588	189.8672	226.1910
1974	44.1192	208.1925	241.7100
1975	46.3391	228.5947	247.4670
1976	49.8234	238.4099	284.7290
1977	52.8188	253.0764	380.1950
1978	59.8147	271.9785	408.5608
1979	67.6380	307.4920	423.3752
1980	72.4401	326.7630	402.7405
1981	80.6637	323.7965	387.9264
1982	87.1068	306.8636	443.8356
1983	93.2348	296.0718	380.6234
1984	98.8385	292.8241	418.8336
British Columbia *(including the Yukon and Northwest Territories)*			
1958	38.2192	134.9522	10.4708
1959	39.7945	143.7502	18.7483
1960	43.6791	147.3428	24.1586
1961	43.0509	148.0618	26.5155
1962	47.1791	155.8744	28.8810
1963	49.6661	159.7850	31.2352
1964	56.4887	178.9860	35.1973
1965	61.0304	187.8449	35.3529
1966	68.8303	200.0961	53.3412
1967	73.7060	214.7081	55.5395
1968	78.8479	221.9328	63.6207
1969	85.4791	247.7365	78.4093
1970	82.6827	253.4994	79.7234
1971	93.5864	267.5897	95.4776
1972	100.4254	288.3580	107.3287
1973	107.1129	300.3087	117.3610
1974	107.1112	324.5032	124.0990
1975	103.6354	312.7631	120.2520
1976	119.6841	321.5396	134.3950
1977	126.1021	334.9579	132.1370
1978	128.4735	332.2963	135.7940
1979	132.7069	359.4575	141.0981
1980	138.9366	372.4017	146.2780
1981	138.7894	371.7506	142.6379
1982	140.6504	335.3186	155.0194
1983	146.6657	295.8424	162.9477
1984	146.2250	293.9366	166.4874

Discoveries and Investment, Western Canada, Crude Oil

Year	Cumulative discoveries	Reserve additions	Real investment
	millions of barrels		*millions of 1971 dollars*
1952	1941.51	529.09	326.534
1953	2448.57	507.06	333.276
1954	2880.12	431.54	317.521
1955	3367.81	487.70	417.886
1956	4061.93	694.11	491.943
1957	4428.56	366.63	427.543
1958	4587.25	158.69	380.060
1959	5013.03	425.78	343.852
1960	5469.91	456.88	366.526
1961	5936.44	466.53	352.599
1962	6615.51	679.07	344.525
1963	7027.68	412.17	389.318
1964	9454.88	2427.20	387.202
1965	10117.59	662.72	398.376
1966	11178.95	1061.36	370.046
1967	11966.48	787.53	384.975
1968	12803.97	837.50	327.906
1969	13197.86	393.89	325.392
1970	13561.09	363.23	235.680
1971	13704.66	143.56	214.150
1972	13849.16	144.50	258.191
1973	13965.71	116.55	257.592
1974	14204.95	239.23	220.131
1975	14368.42	163.47	194.819
1976	14281.44	– 86.97	204.558
1977	14447.09	165.64	292.087
1978	14653.67	206.58	507.632
1979	14974.20	320.53	751.862
1980	15179.60	205.40	1007.842
1981	15444.54	264.94	815.986
1982	15524.62	80.08	811.781
1983	16059.91	535.29	934.056
1984	16398.20	338.30	1152.163
1985	16929.59	531.39	1404.096

Discoveries and Investment, Western Canada, Natural Gas

Year	Cumulative discoveries	Reserve additions	Real investment
	trillions of cubic feet		*millions of 1971 dollars*
1952	11.2198	3.5203	29.929
1953	14.2714	3.0516	28.790
1954	16.6237	2.3523	29.759
1955	18.9985	2.3748	43.317
1956	21.5840	2.5855	64.023
1957	24.2536	2.6696	92.839
1958	28.2516	3.9980	103.961
1959	31.6848	3.4332	81.320
1960	37.3990	5.7142	93.092
1961	38.4859	1.0869	176.255
1962	42.0261	3.5402	110.783
1963	43.7267	1.7006	115.224
1964	48.7262	4.9995	120.638
1965	51.5992	2.8730	112.361
1966	53.9813	2.3821	160.880
1967	57.4894	3.5081	260.337
1968	62.5383	5.0489	267.634
1969	66.1152	3.5769	266.494
1970	69.5042	3.3890	378.635
1971	71.2116	1.7074	431.150
1972	72.8402	1.6286	320.398
1973	79.6793	6.8391	324.878
1974	84.0530	4.3737	426.509
1975	84.7725	0.7196	440.294
1976	88.7710	3.9985	693.347
1977	94.0805	5.3095	721.386
1978	100.4371	6.3566	902.510
1979	104.6894	4.2523	1054.394
1980	108.2204	3.5311	1405.042
1981	112.8761	4.6557	1162.954
1982	117.2791	4.4029	750.633
1983	118.8143	1.5352	365.683
1984	120.5438	1.7295	373.453
1985	122.8267	2.2828	490.955

Production, Western Canada

Year	Crude oil	Natural gas
	millions of barrels	*billions of cubic feet*
1951	47.0767	57.576
1952	60.6549	64.142
1953	80.0972	73.673
1954	95.1350	89.735
1955	128.2938	112.187
1956	170.6389	121.965
1957	180.0140	152.677
1958	163.4032	263.169
1959	182.1533	344.326
1960	188.1307	429.648
1961	218.9614	546.813
1962	242.4307	754.417
1963	256.2102	825.090
1964	272.6952	924.533
1965	289.9353	1021.293
1966	317.4943	1096.943
1967	348.5767	1225.191
1968	371.6054	1395.695
1969	405.5193	1645.273
1970	450.4442	1878.436
1971	476.4931	2067.897
1972	540.5456	2324.818
1973	634.3594	2477.036
1974	595.0972	2456.208
1975	502.4790	2488.085
1976	458.0574	2516.537
1977	459.9451	2628.936
1978	454.5339	2552.826
1979	507.1980	2759.196
1980	472.4663	2537.329
1981	421.1864	2509.654
1982	409.8608	2573.195
1983	425.8424	2450.524
1984	462.9653	2671.473
1985	448.3616	2696.170

After-Tax Profitability Ratios

Year	Crude oil	Natural gas	Gas, sulphur, and gas by-products
1951	1.877091	0.5485750	0.6308449
1952	1.641285	0.7584589	0.8703351
1953	1.626836	0.6556128	0.7566244
1954	1.604789	0.7292069	0.8520553
1955	1.460620	0.7641333	0.9173014
1956	1.343856	0.6563895	0.7826286
1957	1.335530	0.5744270	0.7004024
1958	1.213779	0.4676638	0.5496590
1959	1.141338	0.4183520	0.5216883
1960	1.068105	0.3944387	0.5282294
1961	1.067472	0.4366060	0.5993860
1962	0.9816357	0.4386139	0.6269328
1963	0.9818929	0.4448099	0.7332875
1964	0.8648018	0.4180661	0.7107874
1965	0.8062151	0.3906221	0.7009925
1966	0.7384577	0.3760547	0.6976826
1967	0.6920531	0.3451562	0.6807073
1968	0.6442280	0.3132037	0.6204418
1969	0.5933719	0.2841270	0.5183755
1970	0.5767162	0.2715320	0.4506919
1971	0.6089533	0.2482386	0.4158677
1972	0.5411228	0.2534247	0.4397580
1973	0.6166007	0.2381519	0.4450589
1974	0.8105810	0.2901592	0.5996152
1975	0.8325372	0.4077449	0.6598111
1976	0.8548884	0.5267762	0.7324331
1977	0.9486777	0.6132779	0.8214233
1978	1.003404	0.6095884	0.7959517
1979	0.9662805	0.6012196	0.7919834
1980	0.9641322	0.6848401	0.9249614
1981	0.7479981	0.4829308	0.6769927
1982	1.099517	0.4085221	0.5645408
1983	0.9122818	0.3992208	0.5562614
1984	0.8819747	0.3793144	0.5340549
1985	1.032125	0.4098880	0.5689331

Land Payments in Western Canada and Gas Export Ratio

Year	Crude oil	Natural gas	Ratio of actual to authorized gas exports
	millions of 1971 dollars		
1951	66.1428	5.4078	1.000
1952	97.8407	7.9994	1.000
1953	94.6313	7.7370	1.000
1954	170.3109	13.9245	1.000
1955	162.0057	13.2455	1.000
1956	178.4199	13.1781	1.000
1957	175.2700	19.3447	1.000
1958	143.6488	17.6438	1.000
1959	163.1513	30.0575	1.000
1960	130.8916	23.6567	1.000
1961	122.0212	32.4008	1.000
1962	111.2429	27.8977	1.000
1963	122.5902	22.3258	1.000
1964	191.2503	33.8480	1.000
1965	270.9993	48.3381	1.000
1966	207.0242	54.4988	1.000
1967	180.8538	66.8572	1.000
1968	162.4584	86.8792	1.000
1969	161.2379	87.0802	1.000
1970	83.7288	77.2077	1.000
1971	85.1833	84.4167	1.000
1972	82.4555	77.4845	0.940
1973	75.0147	89.8636	0.980
1974	62.6422	100.1874	0.930
1975	59.2958	113.5178	0.920
1976	52.2970	161.8945	0.920
1977	151.0857	349.0489	0.940
1978	204.7931	338.5688	0.860
1979	311.2688	402.6833	0.960
1980	281.9424	387.0394	0.700
1981	145.8214	198.9752	0.520
1982	117.1859	87.0739	0.480
1983	196.4131	64.7120	0.430
1984	271.5512	76.4129	0.450
1985	327.2759	98.8979	0.550

Correlation Matrix of Variables

(1) KIROW2	1.0000							
(2) INFO	0.43740	1.0000						
(3) OPRW	0.92005	0.19272	1.0000					
(4) DISO	−0.21411	0.77456	−0.41078	1.0000				
(5) OLAND	0.20890	0.72493	−0.01634	0.62017	1.0000			
(6) PROFLA3	−0.79572	0.06814	−0.84455	0.65302	0.14417	1.0000		
(7) CASH71	0.85757	0.68197	0.75993	0.16172	0.49355	−0.44384	1.0000	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	

(1) KIRGW2	1.0000							
(2) INFG	0.78410	1.0000						
(3) GPRW	0.95553	0.77198	1.0000					
(4) DISG	−0.26045	−0.10293	−0.24280	1.0000				
(5) GLAND	0.63606	0.89207	0.67221	−0.07852	1.0000			
(6) PRFG3	−0.29926	0.08923	−0.42255	0.30937	0.14153	1.0000		
(7) RAUTA3	−0.75277	−0.39827	−0.56852	0.10210	−0.17521	0.00147	1.0000	
(8) CASH71	0.93654	0.81655	0.89486	−0.20853	0.78273	−0.11018	−0.68489	1.0000
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)

Mnemonics (All Variables for Western Canada)

KIROW2	cumulative discoveries—oil, millions of barrels
INFO	real investment—oil, millions of 1971 dollars
OPRW	production—oil, millions of barrels
DISO	expected discoveries—oil, millions of barrels
OLAND	real land payments—oil, millions of 1971 dollars
PROFLA3	three-year moving average of the after-tax profitability ratio—oil
CASH71	real after-tax cash flow, millions of 1971 dollars
KIRGW2	cumulative discoveries—gas, billions of cubic feet
INFG	real investment—gas, millions of 1971 dollars
GPRW	production—gas, billions of cubic feet
DISG	expected discoveries—gas, billions of cubic feet
GLAND	real land payments—gas, millions of 1971 dollars
PRFG3	three-year moving average of the after-tax profitability ratio—gas
RAUTA3	three-year moving average of the ratio of actual to authorized gas exports

Data Sources and Explanations for the Figures

The main source for the data used in the construction of the figures in chapters 2 to 9 is a series of energy data banks maintained at the University of Toronto's Institute for Policy Analysis.[1] In the following descriptions, these are referred to as "the University of Toronto database." In most cases, the database mnemonics for the various series used are given. Figures in chapter 10 and 11 are based on the results of alternative simulations of the MACE model. Note that "*" represents the multiplication operator.

Chapter 2

Figure 2.1

The official OPEC price (POPECO) is the posted price for Saudi light crude oil in US dollars per barrel, FOB the Persian Gulf. The spot OPEC prices (POPECS) are available only from January 1978 to December 1985. During 1986, OPEC sold oil on a netback arrangement, and the spot OPEC data are not available; for 1986 spot prices, therefore, we use those for Brent crude oil (BRENTNS). All data are monthly and taken from the University of Toronto database.

Figure 2.2

The average wellhead prices for crude oil in the United States (PWOUS) are available annually from 1967 to 1986, whereas the wellhead price in Canada and the Canadian export price are available from 1955. The US-Canada exchange rate is used to convert Canadian dollars to US dollars, so that all data can be reported in US dollars per barrel. The US data are from the University of Toronto database and are preliminary for 1986. The Canadian data are from the MACE database. All series are reported at an annual frequency.

Figure 2.3

The average field prices for natural gas in the United States (PWGUS) are available annually from 1967 to 1986, whereas the field price in Canada and the Canadian export price are available from 1955. The US-Canada exchange rate is used to convert Canadian dollars to US dollars, so that all data can be reported in US dollars per thousand cubic feet. The US data are

[1] These data banks are described in Mary E. MacGregor and André Plourde, *Documentation for Data Banks on Canadian Oil and Gas Activity*, PEAP Energy Study no. 86-3 (Toronto: University of Toronto, Institute for Policy Analysis, 1986); and Mary E. MacGregor, André Plourde, and Robert Williams, *Update of PEAP Energy Study no. 86-3: Changes to Data Banks and Mnemonics*, PEAP Energy Memo no. 87-1 (Toronto: University of Toronto, Institute for Policy Analysis, 1987).

from the University of Toronto database and are preliminary for 1986. The Canadian data are from the MACE database. All series are reported at an annual frequency.

Figure 2.4

The number of operating rigs in the United States (SMRIGUS) and the number of rigs drilling in western Canada (ARIGDW) are available in monthly frequency from the University of Toronto database.

Figure 2.5

Total active seismic crews in western and northern Canada (ASCRWNS) are available from the University of Toronto database in monthly frequency, seasonally adjusted.

Figure 2.6

Total number of active geophysical crews are available for western Canada (ACREWW), northern Canada (ACREWN), and the east coast offshore region (ACREWE) in monthly frequency from the University of Toronto database.

Figure 2.7

Total land sales in western Canada (ALHW) are available in quarterly frequency from the University of Toronto database.

Figures 2.8, 2.9, and 2.10

Drilling activity in western Canada, northern Canada, and the east coast offshore region is measured with data on total number of rigs (ARIGW, ARIGN, ARIGE), number of rigs drilling (ARIGDW, ARIGDN, ARIGDE), and the number of idle rigs (ARIGWW, ARIGWN, ARIGWE). All series are available in monthly frequency from the University of Toronto database.

Figure 2.11

Series for the average depth for exploration and development wells in western Canada (AADEPEW and AADEPDW) are available in annual frequency from the University of Toronto database.

Figures 2.12 and 2.13

The number of oil (AEWCOW, AEWCON, and AEWCOE) and natural gas (AEWCGW, AEWCGN, and AEWCGE) exploration wells completed in western Canada, northern Canada, and the east coast offshore region are available in quarterly frequency from the University of Toronto database.

Figure 2.14

The number of US exploration oil wells completed (SQCUSEO) and the

number of US development oil wells completed (SQCUSDO) are seasonally adjusted, quarterly data from the University of Toronto database.

Figure 2.15

The number of US exploration natural gas wells completed (SQCUSEG) and the number of US development natural gas wells completed (SQCUSDG) are seasonally adjusted, quarterly data from the University of Toronto database.

Figures 2.16 and 2.17

The number of oil (ADWCOW, ADWCON, and ADWCOE) and natural gas (ADWCGW, ADWCGN, and ADWCGE) development wells completed in western Canada, northern Canada, and the east coast offshore region are available in quarterly frequency from the University of Toronto database.

Figures 2.18 and 2.20

Reserve additions for oil and natural gas in western Canada and northern Canada are available in annual frequency from the University of Toronto database. Oil reserve additions (ADON) and gas reserve additions (ADGN) for northern Canada are available directly in annual frequency from the University of Toronto database. Reserve additions for western Canada were obtained for oil as the difference in initial established oil reserves (KIROW-lag(KIROW)), and for gas as the difference in initial established gas reserves (KIRGW-lag(KIRGW)).

Figure 2.19

Remaining established reserves at year-end for crude oil are available for western Canada (KRROW), northern Canada (KRRON), and the east coast offshore region (KRROO) in annual frequency from the University of Toronto database.

Figure 2.21

Remaining established reserves at year-end for natural gas are available for western Canada (KRRGW) and northern Canada (KRRGN) in annual frequency from the University of Toronto database.

Figures 2.22 and 2.23

Annual crude oil production (OPRW) and natural gas production (GPRW) for western Canada are available from the University of Toronto database.

Figure 2.24

The life indexes for oil and gas in western Canada are obtained by dividing the remaining established reserves (KRROW in figure 2.19 and KRRGW in figure 2.21) by average annual production (OPRW in figure 2.22 and GPRW in figure 2.23).

Figure 2.25

Ownership and control in the petroleum industry is based on upstream plus downstream revenues and is available from various issues of Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry: Monitoring Survey* (Ottawa: Supply and Services) (herein referred to as PMA *Monitoring Surveys*). Data are available only for 1971 and 1975, and from 1977 onward; a linear trend line is drawn between the 1971 and 1975 values, and between the 1975 and 1977 values.

Chapter 3

Figure 3.1

Total refinery receipts of domestic crude oil for Canada (QOD), Ontario (QODON), and the Atlantic provinces plus Quebec (QODAT + QODQU) are available annually from 1947 to 1985. Receipts of imported crude oil for Canada (QOM), Ontario (QOMON), and the Atlantic provinces plus Quebec (QOMAT + QOMQU) are also available from 1947 to 1985. All series are from the University of Toronto database.

Figure 3.2

The import price of oil (PMO) is available monthly from January 1963 (converted to an annual basis and to Canadian dollars per barrel). The price of crude oil delivered to Toronto, in Canadian dollars per barrel, is available annually (POILONT) from 1962. Both series are from the University of Toronto database.

Figure 3.3

Annual crude oil disposition for Canada—domestic (QOD) and export (QOXT)—are available from the University of Toronto database.

Figure 3.4a

"Saskatchewan" is the annual disposition of Saskatchewan-produced crude oil within that province (this variable is called QOSKSK in the University of Toronto database). "Domestic," the annual disposition within Canada of Saskatchewan crude oil production, is the sum of QOSKSK, QOSKQU, QOSKON, and QOSKMN (disposition to Saskatchewan, Quebec, Ontario, and Manitoba, respectively). "Domestic + export" is the sum of "Domestic" and QOSKUT (total Saskatchewan production shipped to the United States). All of these series are available annually from 1961 from the University of Toronto database.

Figure 3.4b

"Alberta" is the annual disposition of Alberta-produced crude oil within that province (this variable is called QOALAL in the University of Toronto database). "Domestic," the annual disposition within Canada of Alberta

crude oil production, is the sum of QOALAT, QOALQU, QOALON, QOALMN, QOALSK, QOALAL, and QOALBC (disposition to the Atlantic provinces, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia, respectively). "Domestic + export" is the sum of "Domestic" and QOALUT (total Alberta production shipped to the United States). All of these series are available annually from 1961 from the University of Toronto database.

Figures 3.5a and 3.5b

Receipts of refineries in the Atlantic provinces—domestic (QODAT) and imports (QOMAT)—are available monthly from 1973. QODQU and QOMQU are similarly available for Quebec. All series are from the University of Toronto database.

Figure 3.6

The series for new crude oil—"NORP oil"—is available monthly from 1982. This series, available from the University of Toronto database (PNORPL), is originally from Canada, Department of Energy, Mines and Resources, "Crude Oil Pricing Report." The series "Old oil" consists of the price of old crude oil (POLD) for January 1982 to May 1985, and NORP from June 1985. POLD is available in monthly frequency from January 1954 to May 1985. This series is originally from *The Petroleum Economist* to 1977, and PMA *Monitoring Surveys* thereafter. Brent North Sea crude oil spot prices (PBRENTNS) are available monthly and are originally from *The Petroleum Economist* and EMR's "Crude Oil Pricing Report." Both POLD and PBRENTNS are available from the University of Toronto database.

Figure 3.7a

"Alberta" is the monthly disposition of Alberta-produced crude oil within that province (this variable is called MQOALAL in the University of Toronto database). "Domestic," the monthly disposition within Canada of Alberta crude oil production, is the sum of MQOALAT, MQOALQU, MQOALON, MQOALMN, MQOALSK, MQOALAL, and MQOALBC (disposition to the Atlantic provinces, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia, respectively). "Domestic + export" is the sum of "Domestic" and MQOALUT (total Alberta production shipped to the United States). All of these series are available monthly from January 1970 from the University of Toronto database.

Figure 3.7b

"Saskatchewan" is the monthly disposition of Saskatchewan-produced crude oil within that province (this variable is called MQOSKSK in the University of Toronto database). "Domestic," the monthly disposition within Canada of Saskatchewan crude oil production, is the sum of MQOSKQU, MQOSKON, MQOSKMN, and MQOSKSK (disposition to Quebec, Ontario, Manitoba, and Saskatchewan, respectively). "Domestic

+ export" is the sum of "Domestic" and MQOSKUT (total Saskatchewan production shipped to the United States). All of these series are available monthly from January 1970 from the University of Toronto database.

Chapter 4

Figure 4.1

Annual distributor sales for natural gas in Canada are taken from the Canadian Petroleum Association, *Statistical Handbook* (Calgary: the association, updated to 1986) (herein referred to as the CPA *Statistical Handbook*), section 7, table 2; and total marketed production is taken from ibid., at section 3, table 10. The difference between these two series includes exported marketed production and transmission losses.

Figures 4.2a and 4.2b

Projections are taken from the following Canada, National Energy Board (NEB) publications: *Energy Supply and Demand in Canada and Export Demand for Canadian Energy, 1966-1990* (Ottawa: Information Canada, 1969), 63, case A; *Canadian Natural Gas Supply and Requirements* (Ottawa: Supply and Services, 1975), 21 and 59; *Reasons for Decision: Northern Pipelines* (Ottawa: Supply and Services, 1977), 2-42, table 2-8, and 2-82, table 2-16; *Canadian Natural Gas Supply and Requirements* (Ottawa: Supply and Services, 1979), 141; *Canadian Energy: Supply and Demand 1980-2000* (Ottawa: Supply and Services, 1981), 426, table SD-13, appendix 5; *Reasons for Decisions: In the Matter of Phase II—The Licence Phase and Phase III—The Surplus Phase of the Gas Export Omnibus Hearings, 1982* (Ottawa: Supply and Services, 1983), 32, table 3-14; *Canadian Energy: Supply and Demand 1983-2005* (Ottawa: Supply and Services, 1984), A-108, table A6-20; and *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services, 1986), 226, table A5-8, low price case. Unless otherwise specified, the cases used are the "base case," the "most probable case," or the "medium case."

Figure 4.3a

"Alberta" is the annual disposition of Alberta-produced natural gas within that province (this variable is called MQGALAL in the University of Toronto database). "Domestic," the annual disposition within Canada of Alberta natural gas production, is the sum of MQGALAL, MQGALQU, MQGALON, MQGALMN, MQGALSK, and MQGALBC (disposition to Alberta, Quebec, Ontario, Manitoba, Saskatchewan, and British Columbia, respectively). "Domestic + export" is the sum of "Domestic" and MQGALUT (total Alberta production shipped to the United States). All series are available annually from 1970 from the University of Toronto database.

Figure 4.3b

"British Columbia" is the annual disposition of BC-produced natural gas within that province (this variable is called MQGBCBC in the University of Toronto database). "Domestic + export" is the sum of "British Columbia" and MQGBCUT (total BC production shipped to the United States). Both series are available annually from 1970 from the University of Toronto database.

Figure 4.4

Actual exports are available annually from 1961, but the NEB has published a formal series on authorized exports only since 1972. Both series are available from the University of Toronto data base.

Figure 4.5

These data series were made available to us by the American Gas Association (AGA). They are estimates to 1986, and AGA projections thereafter.

Chapter 6

Figure 6.1

Data for total secondary energy consumption by end-use sector are from Canada, NEB, *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services, 1986), 141-42, table A3-1. Non-energy use includes petrochemicals. The series have been updated to 1986 on the basis of unpublished information made available to us by the NEB.

Figure 6.2

Data for oil consumption by end-use sector are from ibid., at 300-1, table A6-15. Non-energy use includes petrochemicals. The series have been updated to 1986 on the basis of unpublished information made available to us by the NEB.

Figure 6.3

Data for natural gas consumption by end-use sector are from ibid., at 259, table A5-3. "Industrial" is the sum of "petrochemicals" and "other industrial." "Transportation" is not included because it has been reported as zero throughout the period. The series have been updated to 1986 on the basis of unpublished information made available to us by the NEB.

Figure 6.4

Data for electricity consumption by end-use sector are from ibid., at 220, table A4-2. "Transportation" is not included because it has been virtually zero throughout the period. (It was in fact reported as zero until 1978.) The series have been updated to 1986 on the basis of unpublished information made available to us by the NEB.

Figures 6.5 and 6.6

Data for energy consumption by fuel are from ibid., at 177, table A3-4. The energy fuel shares are calculated as the ratio of "fuel consumption" to "total energy consumption." The series have been updated to 1986 on the basis of unpublished information made available to us by the NEB.

Figures 6.7 to 6.13

The regional end-use fuel prices for oil products, electricity, and natural gas are available from the MACE database, and are used in estimating the demand equations reported in this chapter.

Figures 6.14 and 6.15

The regional figures for real domestic product (RDP) are available from the MACE database, and are used in estimating the demand equations. The original sources for the RDP data are the Conference Board of Canada, *Provincial Economies* (Ottawa: the board, updated to 1984); and *Provincial Outlook* (Ottawa: the board, various issues).

Chapter 7

Figure 7.1

The bottom line of the graph represents investment in the upstream oil and gas industry: oil and natural gas wells and related facilities, oil extraction from sands or shale, natural gas processing plants, and contract drilling for petroleum and natural gas. It excludes, however, geological and geophysical expenditures. The second line from the bottom is the sum of upstream oil and gas investment, investment in petroleum-related activities (petroleum and coal products, pipelines, and gas distribution), and investment in coal mines and electricity generation. The top line represents total investment in non-residential construction and machinery and equipment according to national accounts definitions.

The overall energy sector is therefore defined here as mineral fuels (coal mines plus oil and natural gas wells), petroleum and coal products, pipelines, electric power, and gas distribution. Nominal investment in coal mines was taken from Statistics Canada, *Coal Mines*, catalogue no. 26-206; and *Investment Statistics—Manufacturing Sub-Industries and Selected Energy Related Industries: Intentions*, catalogue no. 61-214. Nominal investment in oil and gas wells is taken from the University of Toronto's disaggregated supply side models (DSS) project database,[2] which uses unpublished calculations of the capital stocks division of Statistics Canada. The DSS database was used to the end of 1982; values for subsequent years

[2]This database is described in David Fujimagari, *Input-Output Database*, DSS Technical Paper no. 85-3 (Toronto: University of Toronto, Institute for Policy Analysis, 1985); and Peter Dungan and David Fujimagari, *The DSS Models Database: Annotated Catalogue and Aggregation Specifications (Version 1.0)*, DSS Technical Paper no. 85-5 (Toronto: University of Toronto, Institute for Policy Analysis, 1985).

were taken from Statistics Canada, catalogue no. 61-214. Real 1971 dollar investment for these two industries was calculated using the investment deflator for mines, quarries, and oil wells. This deflator is very close to the economy-wide absorption deflator, which we have adopted in our regression analysis of investment. Comparison of the unpublished Statistics Canada values for 1971 dollar investment in the oil and gas industry with the values using the mines, quarries, and oil wells deflator showed that the two were very similar. The latter was chosen since the DSS database goes only up to 1982. The remaining components of real investment are from Statistics Canada's "CANSIM" computer accessible university dababase.

Figure 7.2

Curve 1 is the ratio of real (1971 dollar) investment in the upstream oil and gas industry to real total business investment. Curve 2 is the ratio of real investment in total manufacturing to real total business investment. Curve 3 is the ratio of real energy-sector investment to real total business investment. See notes to figure 7.1 for sources.

Figures 7.3a and 7.3b

Gross Prices

Oil

POIL71 = POIL/PA,
where
POIL = POILW/6.292.

POILW is the average wellhead price for crude oil in western Canada (dollars per cubic metre). This is converted to dollars per barrel. PA is the absorption price deflator (1971 = 1.0).

Gas

PGAS71 = PGAS/PA,
where
PGAS = PGASW/35.301.

PGASW is the average field price for natural gas in western Canada (dollars per million cubic metres). This is converted to dollars per thousand cubic feet. PA is the absorption price deflator (1971 = 1.0).

After-Tax Prices

Oil

PONET71 = POILNET/PA,
where
POILNET = POIL * (1 − RTFE * (1 − RR * RRO) − RRO
− RTPE * (1 − RRO)) − RTPGRT * (POIL − COPO).

The calculation for nominal operating costs (COPO) is defined below; see figure 8.5a.

Gas

PGNET71 = PGASNET/PA,

where

PGASNET = PGAS * (1 − RTFE * (1 − RR * RRG) − RRG
− RTPE * (1 − RRG)) − RTPGRT * (PGAS − COPG).

The calculation for nominal operating costs (COPG) is defined below; see figures 8.5a and 8.5b.

Variables

The variables used to define the above tax factors are derived as follows:

Define royalty rates

1. Oil

RRO = 1/6

IF(YEAR ≥ 72) RRO = 0.229

IF(YEAR = 74) RRO = 0.28

IF(YEAR ≥ 75) RRO = (0.229 * 4.40 + 0.35 * (POIL − 4.40))/POIL

IF(YEAR ≥ 82) RRO = (0.229 * 6.50 + 0.35 * (POIL − 6.50))/POIL

2. Gas

RRG = 0.15

IF(YEAR ≥ 62) RRG = 1/6

IF(YEAR ≥ 74) RRG = (0.0854 + 0.35 * (PGAS − 0.36))/PGAS

IF(YEAR ≥ 82) RRG = (0.22 * 0.50 + 0.35 * (PGAS − 0.50))/PGAS

Define effective income tax rates

1. Resource allowance

RA = 0.0

IF(YEAR ≥ 76) RA = 0.25

2. Deductibility of royalties

RR = 1.0

IF(YEAR = 74) RR = 0.25

IF(YEAR > 74) RR = 0.0

Define depletion allowances

DEP is percentage depletion; EDEP is earned depletion for exploration; and EDEPD is earned depletion for development:

DEP = 1/3

IF(YEAR > 73) DEP = 0.0

EDEP = 0.0

```
IF(YEAR >73) EDEP = 1/3
IF(YEAR = 82) EDEP = 0.20
IF(YEAR = 83) EDEP = 0.10
IF(YEAR >83) EDEP = 0.0
EDEPD = EDEP
IF(YEAR >80) EDEPD = 0.0
```

Define marginal income tax rates including depletion, resource allowance

```
RTFE = RTF * (1 − RA) * (1 − DEP)
RTPE = RTP * (1 − DEP),
```

where RTF and RTP are, respectively, the relevant federal and provincial corporate income tax rates.

Define PGRT rates

```
RTPGRT = 0.0
IF(YEAR = 81) RTPGRT = 0.08
IF(YEAR = 82) RTPGRT = 0.12 * (5/12) + 0.11 * (7/12)
IF(YEAR = 83) RTPGRT = 0.12 * (7/12) + 0.11 * (5/12)
IF(YEAR >83) RTPGRT = 0.12
IF(YEAR = 85) RTPGRT = 0.05
```

The POIL, POLD, and PGAS series are available from the University of Toronto database.

Figure 7.4

The intent ratios are obtained by dividing the relevant oil categories by the sum of the oil and gas categories. In this figure, the categories are (1) development wells, (2) exploration and development metres drilled, (3) exploration wells, and (4) exploration metres drilled. The calculations for the intent ratios are as follows:

- Curve 1: OS = AADWCOW/(AADWCOW + AADWCGW), where OS is the ratio of oil to oil and gas development wells, and where AADWCOW is the number of oil development wells completed in western Canada, and AADWCGW the number of gas development wells completed in western Canada, both at annual frequency;

- Curve 2: OSM = (oil exploration + development metres drilled)/(oil and gas exploration + development metres drilled), where OSM is the ratio of oil to oil and gas exploration and development metres drilled;

- Curve 3: OSE = AAEWCOW/(AAEWCOW + AAEWCGW), where OSE is the ratio of oil to oil and gas exploration wells, and where AAEWCOW is the number of oil exploration wells completed in western Canada, and AAEWCGW the number of gas exploration wells completed in western Canada, both at annual frequency;

• Curve 4: OSNEB = (oil exploration metres drilled)/(oil and gas exploration metres drilled), where OSNEB is the ratio of oil to oil and gas exploration metres drilled.

The data for (1) and (3) are obtained from the University of Toronto database; (2) is obtained from the CPA *Statistical Handbook*; and (4) from Canada, NEB, *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services, 1986), 258, table A5-2, and 288, table A6-4.

Figure 7.5

- Curve 1: land payments = EELART/PA;
- Curve 2: geological and geophysical = EEGAGT/PA;
- Curve 3: exploration drilling = EEDRIT/PA;
- Curve 4: other exploration = (EETT − EELART − EEGAGT − EEDRIT) / PA, where EETT is total exploration expenditures;
- Curve 5: development drilling = EDDRIT/PA;
- Curve 6: field equipment = EDFEQ/PA;
- Curve 7: natural gas plants = EDNGP/PA.

All variables, originally in millions of current dollars, are deflated by PA, the absorption price deflator. All expenditure variables are available from the University of Toronto database and are originally from the CPA *Statistical Handbook*.

Figure 7.6

These quarterly series have been seasonally adjusted and are from the University of Toronto database.

Figure 7.7

This graph is constructed by stacking the different types of exploration expenditures one on top of the other. The top line represents total real exploration expenditures, while the dashed line shows real exploration expenditures in western Canada. Real frontier exploration expenditures are therefore represented by the distance between the two. The contribution of PIP grants to exploration expenditures in western Canada and in frontier regions can be determined in a similar manner.

Total exploration expenditures for British Columbia, Alberta, Saskatchewan, and Manitoba are taken from the CPA *Statistical Handbook* and are converted to 1971 dollars by dividing by the mines, quarries, and oil wells investment deflator.

The proportion of western Canadian exploration expenditures financed by PIP payments is taken from the PMA *Monitoring Surveys* and applied to

total real western Canadian exploration expenditures to obtain the 1971 dollar value of PIP payments in this region.

The proportion of frontier exploration expenditures financed by PIP payments is also obtained from the PMA *Monitoring Surveys* and applied to real exploration expenditures in frontier regions to obtain the 1971 dollar value of PIP payments in those regions. Exploration expenditures in the Yukon and Northwest Territories, Hudson Bay, west coast offshore, and east coast offshore regions are taken from the CPA *Statistical Handbook* and deflated by the mines, quarries, and oil wells deflator.

Figure 7.8

These are unadjusted quarterly numbers from the University of Toronto database. The primary source is *Oilweek*.

Figure 7.9

Statistics Canada, *Private and Public Investment in Canada: Revised Intentions*, catalogue no. 61-206, contains preliminary and revised investment intentions for the current year, and preliminary actual investment figures for the previous year. Preliminary investment intentions for the year are determined from a survey carried out over the November-December period of the previous year (with some spillover into January). Revised intentions are from a survey carried out over the April-June period of the current year. The residuals are from an ordinary least squares regression of revised intentions on initial intentions:

Revised intentions = 0.9683644 * initial intentions

1965-1986; RB2 = 0.9451; SEE = 207.65; DW = 1.52.

Chapter 8

Figure 8.1a

- Curve 1: the actual marginal costs for conventional crude oil in western Canada are defined as real investment divided by reserve additions (MCCO = INFO/ADDO2);

- Curves 2-4: (MCCOL71, MCCOQ, MCCOLOG) are the predicted values from the linear, quadratic, and double logarithmic regressions of cumulative discoveries (KIROW2) on marginal costs (MCCO). The linear regression also includes the price differential between new and old oil (PRATD) as an explanatory variable. (MCCO71 is the predicted value from the linear regression, but MCCOL71, which leaves out the contribution of PRATD, is used instead in most of our subsequent analysis.)

The main data series described above are maintained on the University of Toronto database, and are reported in annual form in the data appendix.

Figure 8.1b

The descriptions are as for figure 8.1a, but for natural gas. The variable PRATD does not apply in this case.

Figure 8.2a

- Curve 1: real investment divided by predicted marginal costs (DISO = INFO/MCCOL71);
- Curve 2: represents expected discoveries for western Canada and is the predicted value from a double logarithmic regression with DISO as dependent variable and using the ratio of estimated to adjusted capital costs (MCCO71/MCCOL71), a three-year moving average measure of profitability (PROFMA3), and lagged land payments (OLAND) as explanatory variables.

All variables are constructed with data available from the University of Toronto database.

Figure 8.2b

The descriptions are as for figure 8.2a, but for natural gas. Curve 2 here includes an additional explanatory variable (RAUTA3), a three-year moving average of the ratio of actual to authorized exports. The ratio of estimated to adjusted capital costs does not apply to gas.

Figure 8.3

These three curves represent profitability (or profit) ratios:

- Curve 1: oil = POILNET/MCOL;
- Curve 2: gas = PGASNET/MCG; and
- Curve 3: gas + by-products = (1.0 + X) * PRFG;

where X = (YNGL + YSUL)/YGAS, and YNGL, YSUL, and YGAS are the values of producer sales for natural gas liquids, sulphur, and natural gas, respectively; POILNET = POIL * (tax factor for oil price—as defined for figure 7.3); MCOL = (adjusted marginal costs + operating costs) * (tax factor for oil costs); PGASNET and MCG are defined as above, but for natural gas. All variables are constructed with data available from the University of Toronto database.

Figure 8.4a

- Curve 1: actual total land bonus bids for oil are defined as the intent ratio for oil multiplied by land acquisition and rentals divided by the absorption price deflator;
- Curves 2-3: these represent predicted land bonus bids for oil and are the predicted values from double logarithmic regressions with real bonus bids as dependent variable; both use a three-year moving average of profitability

(PROFMA3) as explanatory variable, although curve 2 includes production (OPRW), while curve 3 includes real cash flow (CASH71) as additional explanatory variables.

All variables are constructed with data available from the University of Toronto database.

Figure 8.4b

The descriptions are the same as for figure 8.4a, but for natural gas. Curve 2 here includes an additional explanatory variable (RAUTA3), a three-year moving average of the ratio of actual to authorized exports.

Figure 8.5a

- Curve 1: actual operating costs for crude oil (COPO71) are defined as nominal costs (COPO) deflated by the absorption price deflator; the calculation for nominal operating costs is as follows:

$$\text{COPO} = \text{OSPRO} * (\text{EOTW} - \text{EONGPW})/\text{OPRW},$$

where OSPRO = (OPRW/6.292)/((OPRW/6.292) + (GPRW/35.301)); 6.292 and 35.301 are conversion factors from cubic metres to barrels and thousand cubic feet (mcf), respectively; EOTW is total annual operating expenditures; EONGPW is annual operating expenditures for natural gas plants (both for western Canada); OSPRO is the splitting ratio for oil to oil and gas activity; OPRW is the level of crude oil production; and GPRW is the level of gas production.

- Curve 2: the predicted operating costs for oil come from the linear regression of real operating costs (COPO71) on the profitability ratio (PROFL), the level of production (OPRW), and the ratio of lagged cumulative production to the stock of remaining reserves (KOPRR).

Note that KOPRR is defined as follows:

$$\text{KOPRR} = \text{lag(KOPRW)}/\text{lag(KRROW2)},$$

where KRROW2 = KIROW2 − KOPRW; KIROW2 is annual initial established reserves for crude oil in western Canada. All of the original variables are available annually from the University of Toronto database.

Figure 8.5b

The descriptions are the same as in figure 8.2a, but for natural gas, and the profitability ratio (PRFG) is not included as an explanatory variable.

Chapter 9

Figure 9.1

The series in level form are taken from various issues of Statistics Canada, *The Crude Petroleum and Natural Gas Industry*, catalogue no. 26-213, tables 5 or 7; and Statistics Canada, *Crude Petroleum and Natural Gas Pro-*

duction, catalogue no. 26-006, December 1986; and supplemented with information from Canada, NEB, *Canadian Energy: Supply and Demand 1983-2005* (Ottawa: Supply and Services, 1984), A-109, table A7-1.

Figure 9.2

Petro-Canada's expenditures are based on information contained in Paul Halpern, André Plourde, and Leonard Waverman, *Petro-Canada: Its Role, Control, and Operations*, a research study prepared for the Economic Council of Canada (Ottawa: Supply and Services, 1988), chapter 2. Frontier expenditures are from the CPA *Statistical Handbook*, section 4. The absorption price from the MACE database was used as deflator.

Figure 9.3

These series are calculated using data on metres drilled and number of wells completed, which are taken from the CPA *Statistical Handbook*, section 1.

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