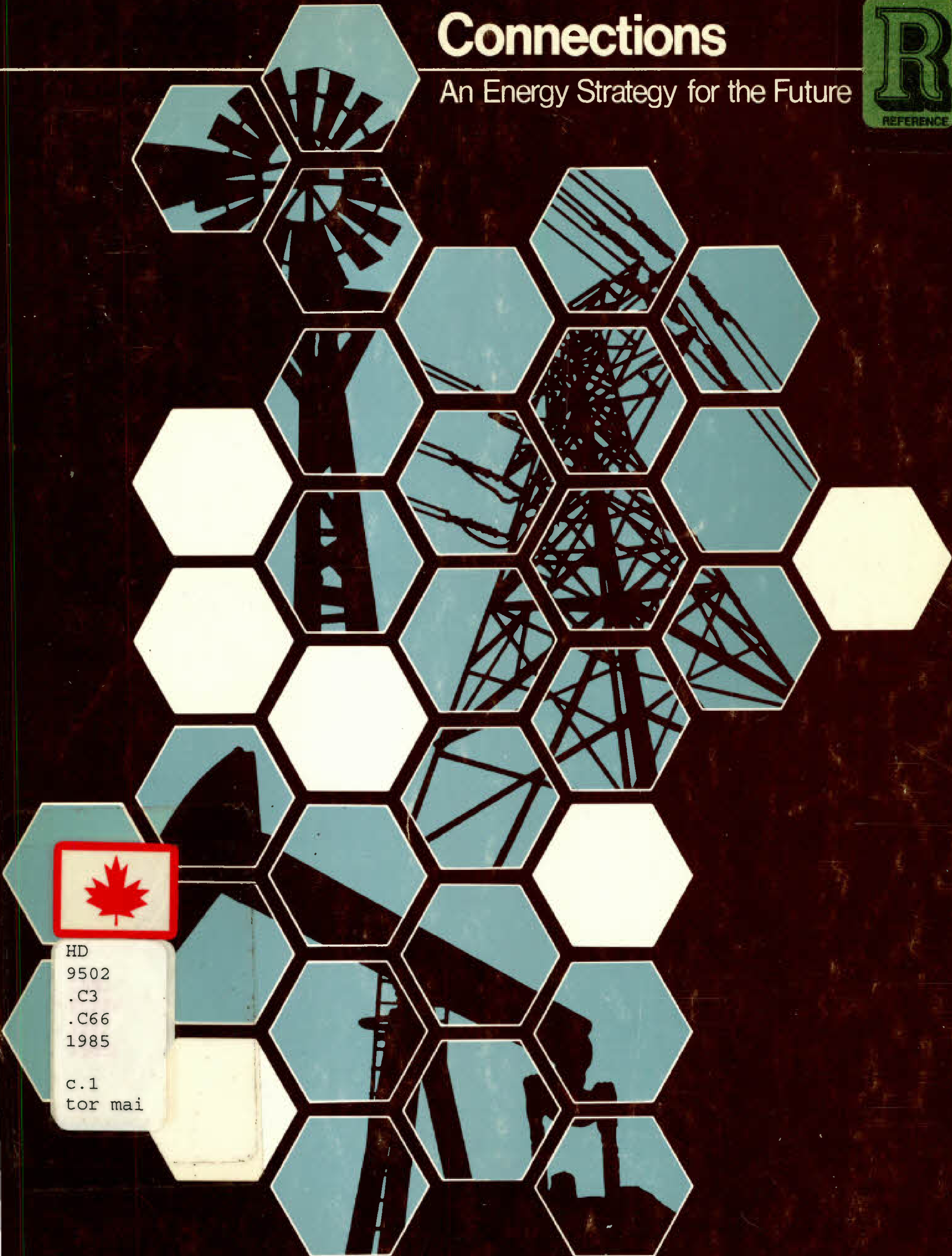
Connections

An Energy Strategy for the Future



Economic Council of Canada

1985

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ECONOMIC COUNCIL OF CANADA

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Contents

This report reflects the views of the Members of the Economic Council of Canada. However, dissenting comments by Mrs. Bellemare appear after Chapter 8.

Members of the Economic Council of Canada

Reader's Note

The reader should note that various conventional symbols similar to those used by Statistics Canada have been used in the tables:

--	amount too small to be expressed
-	nill or zero
..	figures not available
...	figures not appropriate or not applicable
x	data confidential, to meet the secrecy requirements of the Statistics Act.

Details may not add up to totals because of rounding.
In Charts 6-2 and 6-3, amounts smaller than 0.5 per cent have not been shown.

Symbols and Conversion Factors

Symbols:

m^3	=	cubic metre
bbl	=	barrel
J	=	joule
BTU	=	British thermal unit
Wh	=	Watt-hour
mcf	=	thousands of cubic feet

Prefixes:

kilo	(k)	=	10^3
mega	(M)	=	10^6
giga	(G)	=	10^9
tera	(T)	=	10^{12}
peta	(P)	=	10^{15}
exa	(E)	=	10^{18}

Conversion factors:

1 m^3 of oil	=	6.29287 bbl
1 m^3 of natural gas	=	37.3147 cubic feet
1 m^3 of oil	=	38.49 GJ
1 m^3 of natural gas	=	37.24 MJ
1 kWh of electricity		
primary	=	10.5 MJ
secondary	=	3.6 MJ
1 Wh	=	3,600 J
1 kJ	=	0.94821 BTU
1 mill	=	$0.001

Acronyms

CANDU	Canada Deuterium and Uranium (reactor)
CNG	Compressed natural gas
COGLA	Canada Oil and Gas Lands Administration
COSC	Canadian ownership special charge
EMR	Energy, Mines and Resources Canada
EOR	Enhanced oil recovery
GSC	Geological Survey of Canada (an EMR agency)
IEA	International Energy Agency (an OECD agency)
IORT	Incremental oil revenue tax
MDIP	Market-development incentive payments
MES	Minimum economic scale
MSW	Municipal solid waste
NEB	National Energy Board
NEP	National Energy Program
NGGLT	Natural gas and gas liquids tax
NOP	National Oil Policy
NORP	New-oil reference price
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PGRT	Petroleum and gas revenue tax
PIP	Petroleum incentives program
PIR	Progressive incremental royalty
TCPL	TransCanada Pipelines Limited

Preface

The Economic Council of Canada has a broad mandate to analyze and advise on national and regional economic issues. Over the past decade, the Council has, in its Annual Reviews and other reports, commented on energy-related questions as these have become increasingly important in national affairs. Today, at the end of Canada's first decade of high energy prices and on the eve of a new round of federal-provincial consultations on oil and gas prices and taxation, the Council believes that there is a need to examine in greater detail the economic, political and strategic issues that surround the making of energy policy.

Much has been said and done in the area of energy in recent years. What has emerged clearly out of the public debate is that there are at play a diversity of objectives and interests among regions and groups in the country. The Council's decision to undertake its own study stemmed from the realization that national differences must be reconciled and a consensus must be achieved in order for Canadians to draw maximum advantage from their energy resources and to share in the ensuing benefits. To this end, we have sought to lay out fundamental principles – but neither the rules nor the formulas – that should guide policy makers in the management of the nation's energy resources, taking account of the domestic political and economic realities and of Canada's international and continental economic and political relations.

It became obvious to us, during the preparation of our report, that energy supply is, in a very basic way, characterized by integration. Not only is this suggested by the oil and gas pipeline networks and electric power grids, but, more fundamentally, the production and distribution of energy require energy. For example, many electrical generation stations are powered by oil, and electrical power is a major input in oil and gas extraction and refining activities. In addition, the expressions "upstream" and "downstream" illustrate the continuity of operations within the petroleum sector. Interdependence in the energy area is also demonstrated by the considerable influence that the world price of oil has on the prices of other energy products and resources. In Canada, public policy – especially in the area of taxation – has an equally decisive impact on energy supply and demand. Finally, the priorities of energy policy must be united in a consistent strategy that reflects various concerns – the security of energy supply, economic efficiency, sustained economic growth, and increased Canadian ownership and control of the energy industry, among others. The title of our report, *Connections,* is meant to reflect all of these interrelationships.

Our study is national in scope and is concerned with different forms of energy, such as electricity and alternative sources, in addition to oil and gas, which have attracted most of the public attention since 1973 and thereafter, in particular after the adoption of the controversial National Energy Program in 1980. Energy issues are many, often complex, and generally intertwined with other aspects of economic and social policy. However, we have focused on those issues which we perceive to be the most fundamental for the next 10 to 15 years.

A number of subjects have not been addressed in this report. Among the topics that have not been covered are the "downstream" energy industries, such as petroleum refining, petrochemicals and natural gas distribution; the nuclear industry; environmental issues; and the question of native land claims. Some issues were excluded from this report because they have recently been – or will soon be – covered in other Council reports; a major part of the nation's coal industry and an important part of its uranium industries were analyzed in a recent report entitled *Western Transition*; the role of Crown corporations in the energy sector, such as Petro-Canada and the provincial electric utilities, is currently under examination as part of a broad study of government enterprises. In addition, a study on the taxation of capital, many facets of which are of relevance in the energy sector, is currently in progress at the Council.

In the course of this report on energy, the Council and its staff have consulted with numerous individuals within the federal and provincial governments, the oil and gas industry, the electrical utilities and other groups; a list is appended to the report. The Council is grateful to these individuals and organizations for their kind cooperation and assistance, but it naturally assumes full responsibility for the perspective, analysis, conclusions and recommendations of the report.

Connections

1 Introduction

There are many energy-deficient countries in this world that would gladly exchange their problems for ours. We in Canada are, after all, in possession of remarkable energy resources. And though we have exploited some of these resources rather heavily – perhaps carelessly at times, in the eyes of those less well endowed – we are for the time being in a position of overall energy surplus. We also enjoy the relative luxury of being able to focus our energy-management attentions less on an anxious present than on a promising future – both near and distant.

From this perspective, our energy problems have a typically Canadian flavour, often involving divided jurisdiction over unequally distributed resources. They also involve the essentially political question of how best to capitalize on our national advantages in ways that will ensure the protection of the "public interest," which in this case involves efficient resource management, economic development, maximum social benefit and national security.

It is the consensus of the Economic Council of Canada that the public interest in this country is not especially well served by the current policies applying to various energy sectors at both senior levels of government. Those policies have a rather wide range of goals, including the development and use of resources, income redistribution, increased Canadian ownership, healthy public finance, job creation, regional development and the struggle against inflation. As important as each of these national objectives will always be in the broader context of social and economic policies in Canada, it is the Council's view that the time has come to assign greater prominence to the goals of economic growth and development in the setting of energy policies. This alternative approach to energy policy would direct it more consistently at the efficient management, development and use of Canadian energy resources – including alternative energy supplies and conservation – while recognizing other domestic policy requirements and Canada's position in a dynamic world economy.

The design of such alternative policies requires a look at the historical experience of socioeconomic and policy development. Our review of the past in this report has demonstrated the necessity to recognize three economic realities:

- The effects of domestic oil pricing flow through to all areas of industry and have an important impact on the deployment of labour and capital, international trade and international financial flows – indeed, on the whole economy.

- Energy markets are highly responsive to economic factors such as prices; they respond slowly, but they *do* respond. Energy demand decreases when consumers face higher costs, and energy supply increases when producers receive higher returns.

- Resource management is complex, involving the ordering and pacing of development, as well as the measurement and sharing of resource revenues.

Past experience suggests that current policies do not pay sufficient attention to these realities. Under the alternative approach recommended by the Council for the next 10 to 15 years, the cornerstone of energy policy would be to allow domestic energy prices to reflect economic values to a much greater extent, together with sensitive adjustment of other policies to pursue other worthwhile objectives. This means that Canadian prices for crude oil, natural gas, coal and even electricity should be more aligned with the world price of crude oil, subject to the specific supply and demand situation of each energy form. The deregulation of oil and gas prices and a more effective regulation of electricity prices would induce increased energy production, on the one hand, and energy conservation and the choice of least-cost energy fuels by consumers, on the other. The need to resort to expensive grant and subsidy programs would be reduced. It is also important that energy policy be resilient enough, through mutual consultation and fundamental agreements between governments, to sustain oil price shocks and provide for the sharing of the costs and benefits of energy development among Canadians.

The principal objective of such an energy strategy is the same as that of any drive for greater economic growth and development – in this case, to make the maximum contribution that energy policy can be expected to make towards raising the per-capita income of Canadians. More efficient resource management would make that contribution by encouraging investment, stimulating energy supply, curbing energy consumption and favouring the development of alternative energy sources. More economic growth and better resource management could make the resolution of Canada's social and political problems easier and less costly.

Certainly, the development of such an energy policy will not be easy; there are important political, regional and institutional considerations, not the least of which is the public impatience bred by the intense politicization of energy affairs in Canada over the past several years. Few would reject the view that the National Energy Program of 1980 and its subsequent revisions represent one of the more contentious political issues ever faced by Canadians. Moreover, the program is characterized by fairly long-run commitments – federal-provincial deals extending to 1986, frontier exploration agreements that last to 1988 and beyond, and several conservation and other energy initiatives whose horizons extend to the end of this decade.

Nevertheless, the Council believes that a new energy strategy for oil, natural gas and electricity can reconcile the economic goals of energy policy with institutional and political factors, through the restoration of consensus, a sense of national purpose, and determination. One essential requirement now is that all concerned – governments, producers, distributors and consumers – give more consideration to longer-term economic goals in plotting a new course for Canadian energy policy over the next decade or so.

In assessing such an approach, it is important to recognize that the Council is not advocating a strategy based purely on the functioning of economic forces – international and domestic – in the markets for energy. Although we envisage that market forces would be allowed to operate much more effectively than at present, there would still be a necessity for government action in a number of areas. Consumer protection requires, among other things, the continued regulation of electrical utilities and pipelines, as well as more general policies to ensure competition and stability in the delivery of various energy products and services. Because government is ultimately responsible for the security of energy supplies, there is a need, as well, to continue to control exports in the national interest, to employ measures in selective markets aimed at shifting demand from one form of energy to another, to induce conservation, to stimulate production in certain areas, to promote research and development in new energy technologies, and so on. Such intervention is consistent, in the Council's view, with a policy in which more efficient resource management – and thus maximum economic growth and development – is the central thrust.

It is our purpose in this report to explore this approach and to propose specific recommendations for the reformulation of energy strategies for Canadians. To this end, we first review the historic policy settings in Chapter 2 and discuss in Chapter 3 the political and regional realities that have shaped the current policy stance. In Chapters 4 to 7, we then set out the implications of these developments and our approach for oil, gas and electricity supply, as well as the outlook for energy demand and conservation and for alternative energy technologies. The final chapter presents the approach recommended by the Council and indicates how this proposed new strategy can be reconciled with constitutional, political, regional and international considerations.

2 The Historical Legacy

At the best of times, energy policy making in Canada is a difficult business, involving an interplay of contending ideas – such as the broad socioeconomic goals of stability, security and equity – and no small measure of regionalism, nationalism and continentalism.

The potential benefits from improving energy policy are very large. The energy-producing industries – primarily oil and gas, hydroelectricity, coal, and uranium – form a substantial part of the nation's economy, delivering some 43.2 billion dollars' worth of energy to Canadians and exporting some 12.8 billion dollars' worth in 1982, with domestic investments reaching about $20 billion that same year.

In addition to its role in the economy, the social importance of energy – energy in general, and oil in particular, having a strategic value in modern societies – has led governments to seek some degree of control over its supply and distribution, either through regulation or through direct government ownership. The role of oil in transportation alone sustains the everyday functioning of twentieth-century society in times of peace; and oil has been termed "as necessary as blood" in times of war. Historically, therefore, energy policy has attempted to balance the issues of economic efficiency and development with the issue of control and with the many other issues of concern, including the problem of regional fiscal disparities in Canada.

Whatever else might be said about the present set of policies, including the National Energy Program (NEP), they have not paid enough attention to economic considerations. While various goals such as increased Canadian participation in the petroleum (i.e., oil and natural gas) industry have been well served, the goal of long-term economic growth that for so many years had implicitly or explicitly guided Canadian resource development was, in this instance, overwhelmed by more immediate requirements for political and fiscal accommodation.

As necessary as that posture may have appeared, given the problems of oil and natural gas at the time, the results are unfortunate. Where accord was sought, substantial division remains. Where simplicity was needed, complexity prevails. Where basic economic forces were developing in a way that could have been expected to encourage supply and discourage demand, we now have a wide and costly array of grants and subsidies existing alongside administered prices and several types of taxation. Where regulation of the petroleum industry was once confined to resource conservation, environmental protection, and safety, we now have a whole range of regulatory devices and agencies.

When it comes to direct government involvement in pricing policies, Canadianization and general public ownership, the electricity sector in Canada has nothing to learn from recent initiatives in oil and gas. Unlike the petroleum sector, the electricity sector is characterized by significant economies of scale and natural monopolistic elements, which have prompted government action since its early days. While it was not until 1955 that public ownership of electricity production and distribution in Canada surpassed private ownership, the move in that direction began many years earlier. It is traceable mainly to a series of provincial government actions that began in Ontario at the turn of the century.

Developments in the electricity sector have been characterized by the replacement over the years of foreign private ownership with Canadian public ownership and control in most provinces, as well as by a progressive movement towards the integration of the sector at the provincial and regional levels; the pursuit of provincial self-sufficiency and security of supply where at all feasible; and the use of electricity to promote regional economic development – for example, through pricing policies favouring industrial customers, low-cost access to hydraulic sites by large users and promotion of the use of provincial resources in electricity supply.

A federal power policy designed to encourage exports and interprovincial ties was articulated in 1963. This policy was reiterated in the NEP Update in 1982, but for the most part electricity policy remains a provincial domain.

Today, the electricity sector has achieved structural maturity in all provinces. With the recent expansion of electricity exports to over $1 billion, this has induced the provincial governments, perhaps belatedly, to show a growing concern for the efficient regulation of their utilities. While the provincial governments are involved in electricity price setting, many have not undertaken to regulate prices systematically.

To gain some understanding of these central issues of energy policy, it is useful to back up briefly and review the historical development of both petroleum and electricity policy in Canada. History suggests that the long-run economic goals of petroleum policy – especially with respect to oil – have recently been overshadowed by other issues. Electricity policy, on the other hand, is seen as maturing from a period of adolescence. Provincial economic development goals have continued to be important, both domestically and in exploiting export markets, but serious concern is now being raised about the economic efficiency of the present domestic pricing of electricity.

Oil and Gas Policies[1]

For decades, economic growth was at least one consideration – not always well expressed, seldom the only consideration, but nonetheless usually apparent – in the formulation of petroleum policies in Canada. Many other social and political goals were intertwined with the goal of economic growth in those policies, which were designed primarily to develop the infrastructure of the nation. That posture traces its ancestry to Sir John A. Macdonald's National Policy. It gave an active role to the state in economic life, combining tariff policy, immigration policy and transportation policy to promote commercial links between central and eastern Canada with the West as an act of nation-building. It was political defiance of the north-south economic axis, and it contributed to Canada's development as a state stretching from east to west across the width of the continent.

No matter what view is held on the effectiveness of the National Policy, there is no doubt that there were strong regional forces at work within Canada, as well as a marked continental pull on Canadian trade and economics. The underlying strength of the regional interests finally won the western provinces primary control of natural resources in 1930. And the North American realities began to emerge: coal is now imported to Ontario; electricity is exported to the northern United States; and for much of the early oil era Canada was heavily dependent on oil imports from the United States. Our early oil export markets – and later our major natural gas export markets – emerged in the U.S. West and mid-West.

Notwithstanding these realities, the National Policy had a lasting influence on the future course of the politics of resource development. Its endurance was to be demonstrated years later, in the 1950s, when C. D. Howe, minister of Trade and Commerce in the St. Laurent government, repeatedly likened the building of the TransCanada natural gas pipeline to the centrepiece of Macdonald's policy, the Canadian Pacific railway. The gas pipeline, Howe argued, was as essential to the building of an east-west economy in Canada as was the railway; it would carry a Canadian resource across Canadian soil to Canadian consumers. This combination of logic and sentiment so commended itself to the Commons that the original bill of incorporation, which contained no reference to exports, met with virtually no dissent. It was only later, when the project was refashioned and refinanced in a way that would tie Canada more tightly into the North American energy market, that it became the object of intense political debate.

The Postwar Period

The realization in the late 1940s of the size of the Alberta oil fields precipitated a round of constitutional jockeying for authority over, and management of, natural resources. Alberta's desire to provide effective management of oil and gas resources and to ensure primary access by Albertans to provincial gas supplies led the province to enact the Gas Resources Preservation Act in 1949. It moved that same year to strengthen its constitutional jurisdiction over the regulation of the removal of gas from the province by establishing the Petroleum and Natural Gas Conservation Board, later renamed the Energy Resources Conservation Board.

Also in 1949, the federal government, asserting its jurisdiction over interprovincial and international trade, brought in legislation requiring the federal incorporation of companies proposing to transmit Canadian oil and gas to markets outside the producing province. The same legislation required the companies to obtain approval by the Board of Transport Commissioners of the details of each project, including the pipeline route to be followed.

The Alberta government argued that federally incorporated pipelines could, by extending their gathering lines across the province's borders into its major gas fields, also extend Ottawa's jurisdiction into the province and give the federal authorities wellhead control over Alberta's gas. This in turn could be used by Ottawa – or so went the argument – to undermine Alberta's emphasis on provincial priority in determining supply and price, and thus give eastern or U.S. consumers cheap gas. In 1954, the Alberta government created Alberta Gas Trunk Line (now NOVA) as a single gas-gathering system – a common carrier inside the province that would also distribute the pooled gas to export companies at the provincial border.

It was against this background that the great national debate on the TransCanada pipeline had its beginning. Initially, the primary focus was on resource management and economic efficiency issues, including such questions as pipeline routes, the volume and price of exports and the cost of transmitting Canadian fuels. The debate was eventually expanded to embrace broader political and social issues, such as foreign ownership, Canadian-American relations, north-south continentalism versus east-west nationalism, security, public versus private enterprise – and those most hardy perennials, federal-provincial jurisdiction and revenue-sharing.

For example, concern about national integration and self-sufficiency in fuels was reflected in the objective of preserving exclusive Canadian jurisdiction over transmission systems by ensuring that they were built entirely within Canada. "All-Canadian" routes had the advantage of being free from the U.S. interference that could result from the delivery of Canadian oil and gas to Canadian markets across U.S. territory. Moreover, they would shield Canada against pressure for excessive exports to the United States. This concern about exclusive Canadian regulatory control, however, often clashed with the equally important concept of economic efficiency, which in this case was reflected in the objective of reducing the cost of transmitting Canadian fuels to Canadian markets – across U.S. territory, if necessary – and thereby improving their competitive position. Much later, the related issue of ownership and control of corporations in the petroleum industry gained prominence.

Of interest in Howe's 1953 approach was that the attitude of the government towards oil pipelines differed from that towards gas pipelines. The major concern with oil was to move it "from the source of production to refineries within economic distance in the cheapest possible way," and "to arrange for markets for that portion of Canadian output that cannot be economically used in Canadian refineries in the market that offers the highest return to the producer."[2] The logic of this attitude was reflected in both the Interprovincial and Trans Mountain pipelines. In fact, the Interprovincial line was built south of the Great Lakes through the United States in order to serve markets in both the midwestern states and central Canada.

For natural gas, on the other hand, Howe applied the logic that governed policy with respect to the other major energy source, electricity. It was government policy, he claimed, to refuse permits to move natural gas by pipeline across the border until the government was convinced "there can be no economic use present or future for that gas within Canada."[3] The Westcoast and Canadian-Montana pipelines were to be the only exceptions. The TransCanada pipeline was seen as the classic example of nation-building in action.

This differentiation in policy attitude towards gas and oil prevails to the present day. It has had a lot to do with the nature of contracting for natural gas supplies and the financing of gas pipeline infrastructure, as well as the relative inflexibility of gas transportation.

The National Oil Policy

One of the key issues addressed by the Royal Commission on Canada's Economic Prospects (the Gordon Commission) in its 1957 report was the impact of foreign direct investment on Canada's economic growth. The Commission was optimistic about the growth prospects of the oil and gas industry but pessimistic about the potential for reducing its high level (roughly 80 per cent) of foreign ownership. The Commission concluded that foreign-owned subsidiaries, mainly because of their access to parent-company financial resources, had the wherewithal to finance large-scale capital investments, to engage in competitive bidding for land for exploration and development, to generate revenues at many or most stages of the integrated industry and, perhaps most important, to satisfy most of their needs for expansion capital from retained earnings, thereby decreasing the need to involve Canadian equity ownership. The Gordon Commission made a number of recommendations: greater reliance on foreign capital in the form of bonds or mortgages; a minimum of 20 to 25 per cent Canadian owernship of companies operating in Canada; greater use by foreign-owned firms of Canadian engineering, professional and service personnel; more Canadian sourcing of supplies, materials and equipment; and the requirement of Canadian participation in future oil and gas exploration permit and leases. These recommendations, however, had little impact on the politicians and officials in the federal government or in the producing provinces. Twenty-three years were to elapse before those issues were addressed more directly – in the 1980 NEP.

Meanwhile, in 1961 there was further explicit acceptance of the continental energy reality in the Diefenbaker government's announcement of the National Oil Policy (NOP). In the years leading up to that decision, the issue had arisen whether to extend the Interprovincial oil pipeline to Montreal, so that Alberta crude could displace the Venezuelan imports (which were cheaper) at the multinationals' Montreal refineries. In accord with the recommendations made by the Royal Commission on Energy (the Borden Commission) only a year earlier, the government rejected the idea. The National Oil Policy drew a line along the Ottawa Valley and retained the system of imports to the east and domestic supply to the west of that line. It was a compromise in the Canadian tradition. Western Canadian oil got its "natural" market for expansion – the U.S. mid-West – and was protected from cheaper-oil competition in the Ontario market. Quebec and the Atlantic provinces retained oil supplies that were somewhat cheaper than if they had come from Alberta. The country gained the advantage of exporting "expensive" oil west of the Ottawa Valley and importing "cheap" oil east of it. Ontario may have paid a little more for its oil, but at the same time a large refining and petrochemical industry developed in the province.

Supported as it was by the Liberal opposition, the NOP was surprisingly noncontroversial, in part because it accommodated a number of interests. Moreover, it was not a statutory policy and could be interpreted as having been arrived at in a quasi-voluntary way. Markets were being "regulated," but almost without regulations. The NOP also satisfied the multinationals and the U.S. government, and it contributed to increased continental integration of the Canadian and U.S. oil markets. It is important to note as well that the NOP also won the support of the provinces affected and that it benefited from this large degree of consensus. Agreement was perhaps made easier by the fact that these policies evolved in a period of relatively strong economic growth. Moreover, despite the political compromise, the central objective of energy policy retained a strong element of economic efficiency while pursuing the expansion of production and increased oil (and gas) exports to the United States.

There followed about 10 years of rapid expansion of petroleum production, together with quiet regulatory consolidation. The NOP was working to protect the domestic oil industry. The establishment in 1959 of the National Energy Board (NEB) had the effect of depoliticizing the energy issue by shifting decisions on pipelines, export volumes and prices out of Parliament to an expert, quasi-independent regulatory agency.

One problem that emerged later involved the uncertainty of oil and gas supply forecasts, for which the NEB relied almost entirely upon the oil companies. So buoyant where those assessments that in 1969 the minister of Energy (J. J. Greene) was encouraging Washington to consider his ideas of a continental energy arrangement. Within three years, however, the industry was telling Ottawa that Canada was running out of gas and oil. Shaken by its reliance on the industry and its own limited policy instruments, the federal government strengthened the Department of Energy, Mines and Resources and purchased a controlling interest in Panarctic Oils, whose task was to explore in the high Arctic – one of the earliest initiatives linking energy policy with northern development policy.

The Oil Price Shocks

If not too little, such action was too late: the federal government was caught by the 1973 oil embargo imposed by the Organization of Petroleum Exporting Countries (OPEC) and by the subsequent increase in oil prices without any means for gathering information and with only limited means for digesting it. Ottawa sought to respond by announcing, in quick succession, oil export controls, similar controls over the export of refined products, extension of the Interprovincial oil pipeline to Montreal, a freeze on domestic oil prices, an export tax on crude oil and an oil-import compensation scheme to protect consumers who were dependent on imported oil. It also considered, but rejected, both oil rationing and the acquisition of a subsidiary of one of the multinational oil companies.

In December 1973, the federal government announced its decision to establish Petro-Canada as a national oil company. It was a reflection of the government's growing frustration over a number of factors, including the lack of control over the security of supplies, the lack of solid information on reserves and industry practices and procedures, and a growing apprehension about having to rely for such information on a largely foreign-owned industry.

Many of these moves were seen by the producing provinces as an intrusion into traditional areas of provincial responsibility. They brought in new legislation to further secure their constitutional control over the production, regulation, marketing and pricing of oil within provincial boundaries. The provinces also raised their royalties on resources that were now more valuable, and thus they were further dismayed when the May 1974 federal budget disallowed the deductibility of provincial royalties for purposes of federal corporate income tax. For its part, the federal government was concerned that as oil prices rose – and, with them, the royalty payments to the producing provinces – its own share of oil revenues would decline, while the requirement to finance equalization payments would increase. The federal government also felt that after years of offering tax incentives for exploration research and development, all Canadians should share in the benefits to be derived from higher production revenues.[4] In 1975, Ottawa gave itself broad powers over oil and gas pricing through the Petroleum Administration Act, signaling its intention to set the price of oil in interprovincial trade if agreement with the provinces could not be reached.

It was a volatile period. Federal-provincial disputes heightened. The consensus that had underpinned the NOP was shattered. One effect of the federal intervention was to hold Canadian prices well below world levels. It is worth noting, however, that after initially resisting Alberta's call for world prices, the federal government let Canadian oil prices rise to within \$3 a barrel of the international price (about Can\$16) by mid-1978.[5] Then, in the wake of the 1979 revolution in Iran, the world price doubled to about Can\$37 a barrel, and the federal government renounced its policy of linking the Canadian price to the world price. Canadian prices were left far below world levels, and as a result the relations between the federal government and Alberta deteriorated further.

Meanwhile, the second half of the 1970s saw Petro-Canada expand to the point where it became Canada's sixth largest oil and gas producer, having absorbed the federal government's interest in Panarctic and Syncrude, and having subsequently acquired Atlantic Richfield Canada and Pacific Petroleum. It was, in part, on the "privatization" of this growing state enterprise that the Progressive Conservative party successfully campaigned during the 1979 general election. The Conservatives' energy policy also included the general goal of oil self-sufficiency by the 1990s, the general concept of promoting Canadianization through tax and investment incentives, and the theme that federal-provincial relations could be restored through a less centralist approach.

Seven months later, the Conservative government was defeated on a budget dominated by energy policy – a budget that included an excise tax increase of 18 cents a gallon on gasoline, an energy-related income tax credit, the intention to levy a windfall-profits tax to finance government energy programs, and special incentives for frontier drilling. The budget was predicated on the government's hope of concluding an agreement with Alberta that would let oil and gas prices rise at "a measured pace" towards 85 per cent of world or U.S. price levels.

The Liberal party was returned to power in the February 1980 general election after campaigning in defence of Petro-Canada, "made in Canada" prices and a goal of 50 per cent Canadian ownership of the oil and gas industry.

Meanwhile, there was a widespread assumption that world prices would continue to rise, and there was the belief that huge revenues could be generated by the stroke of a pen that would bring Canadian prices closer to world levels. Industry profits were high, and a fourfold increase in the federal oil-import compensation payments contributed to a deficit that approached $10 billion, while Ottawa collected less than 10 per cent of petroleum revenues – not even enough to offset the compensation payments. The stage was set for the National Energy Program, presented in the budget of October 1980.[6]

The NEP set a new pricing regime for oil, created a new revenue-sharing scheme to increase Ottawa's take through several new taxes, and launched a large energy-conservation and oil-substitution program. In addition, the NEP began a Canadian-ownership drive, partly through direct acquisition and partly through an exploration and production incentive program. The emphasis was shifted from a tax-based to a grant-based system favouring Canadian ownership and participation in the "frontier" areas administered by the federal government, now designated "Canada Lands."

Reactions were swift and strong. While the public response was generally positive, especially in the East, in Alberta the provincial government charged that Ottawa had "without negotiation, without agreement, simply walked into our home and occupied the living room."[7] It reacted by announcing a progressive reduction in oil shipments to eastern Canada (which it proposed to implement over a period of nine months), a delay in approval of new oilsands and heavy-oil projects, and a challenge to the constitutional legality of the federal tax on exports of provincially owned natural gas. Equally concerned, British Columbia responded by withholding the flow-through of revenues from the new federal tax on natural gas and gas liquids.

The larger foreign-owned firms reacted by significantly cutting their exploration budgets for the coming year and by putting pressure on their "home" governments in the United States, Britain and the Netherlands to persuade the Canadian authorities that the NEP ran counter to international conventions. In Washington, the Reagan Administration in 1981 began a campaign against the NEP through the GATT (General Agreement on Tariffs and Trade) negotiating mechanism and through the International Energy Agency of the Organisation of Economic Co-operation and Development (OECD). The U.S. industry generally also reacted angrily to a few high-profile takeovers, or attempted takeovers, of U.S.-owned companies by Canadian firms that were encouraged by the Canadianization provisions of the NEP.

Among Canadian firms, reactions were mixed. The larger oil companies responded favourably to the opportunity to expand and were strongly supported by the Canadian banks in their takeover moves. Some of the smaller Canadian firms opposed the NEP, however, partly on ideological grounds, partly because they saw it cutting their cash flow and partly because they were unprepared to shift into frontier exploration. They reacted by curtailing their drilling programs and by shifting part of their exploration activity to the United States, where the Reagan Administration had announced the deregulation of oil and its intention to deregulate natural gas prices. Ottawa's response was that such drilling in the Western Canada Sedimentary Basin had not proven significant new reserves in any event, that Canada already had a large surplus of natural gas and that what the country needed now were large new oil discoveries on the Canada Lands in the north and offshore.

While the federal government itself developed the administrative apparatus – including legislation – for the new regime, Petro-Canada moved to acquire

Petrofina, a Belgian company, for $1.46 billion; and the Canada Development Corporation, partly owned by the federal government, acquired the French company Elf-Aquitaine for $1.6 billion. In 1981, however, some concessions were made by the federal government in the name of international relations and balance-of-payments considerations: the banks were asked to slow down the rate of loans for Canadian takeovers (essentially in order to relieve the downward pressure on the dollar); the industrial-benefits legislation was amended to ensure competitive conditions for foreign suppliers; and federal compensation was offered for the 25 per cent Crown interest in frontier exploration.

Moreover, in a document accompanying the November 1981 budget,[8] the government rejected the idea of NEP-style Canadianization of other sectors of the Canadian economy dominated by foreign-owned firms. The main emphasis of that document was on the role that the development of a number of then-proposed energy megaprojects was supposed to play in solving a myriad of economic ills. First, the megaprojects were supposed to provide the federal government with substantial revenues, based on the assumption that world oil prices would continue to rise. Second, these projects were to provide substantial economic spinoffs, thereby helping to further alleviate the problems of regional economic disparity. Quebec, Nova Scotia and New Brunswick, for example, were to get jobs for their ailing shipbuilding industries by constructing the ice-reinforced supertankers required to transport oil out of the Beaufort Sea. Newfoundland, together with the other Atlantic provinces, was to develop all kinds of marine and petroleum supply industries, including work for its shipyard at Marystown. British Columbia was to supply drilling platforms and icebreakers for the Beaufort projects. The proposed Alsands and Cold Lake oilsands plants in Alberta were to purchase huge inputs of steel and equipment from industries in Ontario and Quebec. The prospect of northern pipelines would give work to Interprovincial Steel and Pipe in Saskatchewan and Alberta. Alberta was expected to experience a greater industrial boom than it could handle. Third, all the capital inflows needed to finance this activity were expected to make the Canadian dollar buoyant. Ultimately, huge exports of oil and gas would generate export revenues to repay the foreign debt acquired to finance a large part of this expansion – and hence would maintain the strength of the balance of payments in the long run. To combat inflation, oil prices would be held down by direct controls. There was hardly a facet of macroeconomic and regional economic policy that would remain untouched by the harnessing of energy megaprojects.

A few weeks earlier, in September 1981, after months of political brinkmanship, the federal and Alberta governments had reached an agreement on energy pricing and taxation.[9] Lacking consensus on objectives, national energy policy was reduced to a prescription of detailed and complex price schedules, rules and regulations. This agreement mixed instruments of resource management with government aspirations for more revenue – to the detriment of both, as it turned out. The agreement had a major flaw: it assumed that real world prices would continue to rise substantially over the next several years. It defined the prices of both "new oil" (i.e., oil discovered after 1980) and "old oil," which were linked with the world level – the former being tied to that level, the latter to no more than 75 per cent of it. Within 18 months, however, the agreement, designed to last until the end of 1986, was in difficulty.

In the spring of 1982 a number of factors dampened the short-term outlook for the industry: continued high interest rates; the deepening of the worldwide recession; the softening of the demand for oil in Canada and abroad, along with the growing realization that the emerging oil glut on world markets might be more than a short-term condition; the maturation of many of the conservation and substitution programs put in place since 1973 in the western consuming world; the subsequent softening of world prices as a consequence of recession; and the growing dissension within OPEC. All of these developments combined with the higher royalties and higher taxes provided for in the September 1981 agreement to squeeze the industry's cash flow and profits.

To alleviate the industry's plight, both the federal and Alberta governments made adjustments to cut back their share of the take from petroleum revenues. In April 1982, the Alberta government announced a $5.4 billion program to increase revenue flows to the industry in 1982-83 through royalty reductions and the provision of special grants and credits. At the end of May, the federal government unveiled the NEP Update.[10] It included a $2 billion assistance plan designed primarily to aid the Canadian "junior" oil companies. In combination, the events of 1981 and 1982 were putting extraordinary pressure on the Canada-Alberta September 1981 agreement, and in June 1983, a new 18-month deal was struck, this time without the acrimony of the 1980-81 negotiations.[11]

Since 1973, petroleum policy in Canada, in response to the world oil price shocks, has gone through a period of intense change, reflecting the extraordinary events of the decade. Although the world oil price has been unstable in the past, notably between 1900 and the 1930s, nothing like the upward swings of 1973-74 and 1979-80 had been seen for a century. The past decade has been an unusual time that has bred dramatic shifts in policy.

In many ways, Canada is a microcosm that reflects the world oil dilemma, particularly with its current oil production being largely concentrated in one province with a relatively small population. Moreover, the long-run economic foundations of petroleum policy have yielded to short-term conflicts of interest. Detailed agreements have been hammered out and subsequently revised, item by item, to meet changing circumstances. Hopefully, lessons have been learned, so that we will be better able to roll with the punches in the event of any future surprises in the world oil market.

Electricity Policies

While many of the issues and government initiatives at the provincial level in the electricity sector predated by many years the recent circumstances at the national level in the case of oil and gas, that sector was also affected by the events of the 1970s. This was reflected particularly in the fact that, as a result of the slowdown in economic growth, the growth in demand for electricity fell considerably short of earlier projections – which had formed the basis for expanding the supply capacity – with the result that there has developed in recent years a significant excess in the generating capacity that had been put in place. Unlike the developments in the petroleum sector, however, little friction between the federal government and the provinces occurred in this area as potential revenue increases from hydraulic resources were less visible. There were times in earlier years, however, when electrical generation was the object of severe clashes within individual provinces.

There are several notable differences between the electricity sector and the oil and gas sector. For example, electricity is characterized by significant scale economies and natural monopolistic elements; as a consequence, the history of that sector has essentially been one of increasing dominance by large public corporations, whereas the oil and gas sector has witnessed the birth of small Canadian-owned private companies alongside the large foreign and domestic firms. The movement towards Canadianization, public ownership and provincial integration of the electricity sector has generally been a process of evolution rather than a distinct event. It often occurred in stages, at different times and different rates in the various provinces, sometimes in small steps and sometimes in bold measures. The process, which began in Ontario at the turn of the century, was subsequently repeated under various guises in most of the other provinces.

Consolidation of the Provincial Utilities[12]

In 1903, there was something of a public uproar in Ontario over electricity. A strike in the Pennsylvania coal mines led to the closing of many Ontario factories and the doubling of coal prices; at about the same time, there was mounting concern that Canadian hydroelectric power at Niagara was being developed mainly to serve foreign and local monopoly interests at the expense of Ontario's industrial and household consumers. Several Ontario municipalities urged the Liberal government of G. W. Ross to study the feasibility of a provincewide, municipally operated electrical system; the government responded by setting up the Ontario Power Commission to examine the question.

Before the Commission had a chance to report, however, the Conservative party under J. P. Whitney swept into power, and the new Premier quickly set the political tone of the long debates that ensued:

> [T]hese powers should be as free as air not only to the monopolist and the friends of the government as it used to be, but every citizen under proper conditions should be free to utilize the powers that the Almighty has given to the province.[13]

Premier Whitney set up a second commission chaired by Adam Beck, and both bodies reported around the same time – the Ross Commission urging that municipal cooperatives build and operate transmission lines, and Beck recommending a provincewide commission with the power to regulate private companies. Public pressure for some kind of action mounted – there was a march on Queen's Park – and in 1906 the legislature created the Hydro Electric Power Commission of Ontario, later to become Ontario Hydro. As its chairman, Adam Beck dominated the utility's development and heavily influenced provincial politics until his death in 1925. By the end of 1910, the utility was transmitting power to 10 municipalities; and, in the early 1920s, with the completion of the Sir Adam Beck No. 1 station at Niagara Falls, public ownership overtook private ownership in Ontario.

The Ontario pattern was to be repeated in other provinces, typically with the same kind of political intensity. The process of public ownership often began with the creation of a provincial government commission – usually a commission of inquiry. There was the Quebec Streams Commission in 1910, the Nova Scotia Water Power Commission in 1914, a commission of inquiry in New Brunswick in 1918, the Manitoba Power Commission in 1919, the Saskatchewan Power Resources Commission in 1927 and the Lapointe Royal Commission in Quebec in 1934. The latter concluded that, given the monopolistic nature of the industry, government must control and regulate it in the public interest, but the Commission did not propose public ownership.

The next steps, usually several years later, involved authorizing the commission or another board to participate actively in the sector and granting it power to distribute and/or generate electricity. The commission was sometimes given a start through a takeover of one or more private or municipal utilities. The Nova Scotia Power Commission did not become involved in generation until 1929; the New Brunswick Electric Power Commission, which was established by statute in 1920, began operations in 1923. The Manitoba Power Commission was established in 1919 to distribute power to rural areas, but it was only in the early 1950s that the Manitoba Hydro-Electric Commission, created in 1949, became deeply involved in generation on the Winnipeg River, partly through the acquisition of the Winnipeg Electric Company. The Saskatchewan Power Commission was created in 1929, following the recommendation of the inquiry commission, with powers to purchase, manufacture, distribute and sell electricity, as well as to expropriate land and other electrical systems in the province. By the end of the Depression, it had grown quite notably; and it expanded still further in the early postwar period with the takeover of three major companies.

In Quebec, the government did not act until about a decade after the Lapointe Commission reported. When Montreal Light and Power Consolidated failed to cooperate with the government by reducing rates, it was expropriated in 1944 and replaced by Hydro-Québec. British Columbia's move to public involvement began at about the same time with the establishment of the British Columbia Power Commission in 1945 to serve rural and remote areas of the province. In Newfoundland, the move to major provincial public ownership only began in 1954 with the creation of the Newfoundland Power Commission to serve and assist rural areas. Ten years later, the Commission was authorized to begin development of Bay d'Espoir and was given the authority to develop all the other hydro-electric sites on the island.

As the development of the utilities began at different times and proceeded at different paces, the structure of the various provincial sectors also reached its current status at different times. In 1949, 20 years after its creation, the provincial utility in Saskatchewan was reorganized into the Saskatchewan Power Corporation, but only in the 1960s did it overcome local resistance in some of the cities and purchase utilities in Moose Jaw, Weyburn and Regina. The New Brunswick Commission took over the distribution facilities of the Moncton Electricity and Gas Company only in 1959.

In 1961, the Manitoba Power Commission was amalgamated with the Manitoba Hydro Electric Board into Manitoba Hydro. That same year, the provincial government in British Columbia acquired control of B.C. Electric, a major private utility, and made it a Crown corporation in order to initiate the simultaneous development of the Peace and Columbia Rivers. The following year, the Crown corporation was amalgamated with the B.C. Power Commission into the B.C. Hydro and Power Authority. Over the next decade, B.C. Hydro acquired over a dozen small utilities within the province.

In Quebec, the nationalization of the private electric companies became a campaign issue in the 1962 election and was presented partly as the means whereby francophones could become more involved in their own economic development. The following year, Hydro-Québec acquired the assets of eight privately owned utilities. The takeovers followed the recommendation of a committee consisting of representatives of Hydro-Québec, the government and the financial community, with Hydro-Québec making offers that the shareholders of the companies accepted. Hydro-Québec also made offers to acquire the 46 cooperatives formed under the Rural Electrification Act, and by 1964 all but one had accepted. Various municipal systems were also acquired when agreement could be reached.

The process of consolidation in Nova Scotia reached a major turning point in 1972 with the purchase of Nova Scotia Light and Power by the Nova Scotia Power Commission. Since then, two other municipal utilities have been taken over. It was only in 1975 that Newfoundland and Labrador Hydro was created. The corporation was given the majority interest in Churchill Falls (Labrador) Corporation, as well as the water rights in Labrador, which had recently been purchased from Brinco by the provincial government. The province's majority interest in the Gull Island Power Company, which was created in partnership with the federal government in 1978, was given to the Crown corporation.

While the process of consolidation generally culminated with the domination of public ownership, numerous mergers and acquisitions also occurred in the private sector at the same time. For example, at various times there were over 100 electric companies in Nova Scotia, many of which became part of Nova Scotia Light and Power before it was purchased by Nova Scotia Power Corporation. In Prince Edward Island, integration was realized by the private companies, of which there were as many as 30 at one point in time.

The process of increasing provincial government involvement should not obscure the continuing role of municipal and private utilities in Canada. There are municipal utilities – some of them with power-generating facilities – in Ontario, Manitoba, Alberta and Prince Edward Island. There are only a few private utilities in Canada, mainly in Alberta and Newfoundland; small private utilities also operate in New Brunswick, Quebec, Ontario and British Columbia.

The process of consolidation, provincial ownership and regulation of the electric utilities appears to have been founded on a number of political and economic considerations. First, there was the drive to curtail the monopolies – which were often foreign-controlled – and to gain control of hydraulic resources. The objective was to promote the integration of the electrical system and exploit the potential scale economies in order to provide cheap power. In fact, average real revenues for electricity – used here as a proxy for prices – declined almost everywhere in Canada until the mid-1970s. Second, reflecting their economic development goals, most provinces sought to use this cheap power to encourage rapid industrial growth and broad access to the new, electrically based technology in the home – both urban and rural. All the provinces became involved in rural electrification in the postwar period, in one way or another. Closely related to the widespread use of electricity was the desire of the provincial authorities to reduce disparities in rate levels within their province.

Another factor behind government involvement was the desire to develop indigenous expertise in the electrical sector, as this was viewed as essential for economic development. In the early stages, hydroelectric developments were largely financed, and often initiated, in the United States, with considerable British direct investment. Even when large hydroelectric developments were undertaken in Canada by the provincial utilities in the 1950s and 1960s, foreign-based engineering, technology and construction management continued to play a major role. Canadian engineering firms were often subsidiaries of foreign enterprises. Regardless of the source of expertise, however, the major hydro projects undertaken in Canada often represented outstanding engineering achievements, as well as "firsts" by world standards.

The development of indigenous expertise and management in the electrical sector was perhaps most explicit in the 1963 takeovers in Quebec. Even before then, however, Canadian engineers, with major support from the federal government in cooperation with the Ontario government, initiated efforts that culminated in the development of the CANDU nuclear system. Today, some of the provincial public utilities undertake much of their own engineering design work, employ their own construction staff and have active research and development programs. Moreover, Canadian expertise in the electrical sector is highly valued abroad.

The final factor behind the involvement of the provinces stemmed from the fact that a Crown-owned utility, unlike a private company, is exempt from federal income taxes. This factor was used as an additional rationale in support of the public takeovers in British Columbia and Quebec in the early 1960s.

Pricing Policies

Early on, Adam Beck had recognized the potential for scale economies in the electrical industry, and he argued repeatedly that the adoption of prices aimed at promoting increased sales would result in lower per-unit costs. To increase sales, the innovative "promotional rate" structure was introduced. Under this system, customers were charged lower rates for each succeeding block of power purchased. The system was very attractive to large industrial customers and led many municipal utilities in Ontario to hook into the provincial grid.

Such attractive rates and rate structures were used in most, if not all, provinces to lure industrial customers. Similar rate structures have also been used in the residential market to develop the space- and water-heating markets in competition with other energy sources. In addition, the provincial governments have fostered industrial development by providing large industrial companies with free or low-cost access to hydraulic resources, particularly in the forestry- and mineral-based industries. In fact, the history of the growth of the industry in Canada and the reduction in real prices until the mid-1970s reflected the mutual reinforcement of increasing sales and scale economies.

The uniformity of prices, or at least the reduction of price differences, within provinces has also been an objective of all provincial governments. For example, one of the goals sought in creating Ontario Hydro was to equalize costs for all municipalities. Recently, Ontario Hydro has been instructed to hold rural rates to no more than 15 per cent above the municipal rates, which it regulates. Newfoundland and Labrador Hydro wholesales power at the same rate throughout the island. Hydro-Québec standardized rates across most of the province immediately after the 1963 takeover. In 1982, the Alberta government created the Electrical Energy Marketing Agency, which purchases all electricity at the wholesale level and sells it back to the utilities at uniform rates for distribution throughout the province. The provincial government has been providing subsidies on a five-year declining basis in order to reduce the impact on customers whose rates will be rising.

To summarize, through direct and indirect provincial government participation in electrical utilities in most provinces, domestic electricity prices have been held as low as feasible by a variety of means. The consolidation of Crown corporations and promotional pricing have characterized the evolution of the industry in Canada, but significant concern is now being raised about pricing policy in relation to economic efficiency under today's circumstances. The rapid rate of growth experienced in earlier decades is unlikely to be repeated in the foreseeable future. Electricity is now available almost everywhere, and some major sources of scale economies may be reaching their limit.

The electrical sector now accounts for an important share of the capital stock in the nation, raising questions about the return to capital invested in that sector. In addition, the growing importance of electricity exports raises questions about how profits on these exports will be allocated and about the opportunity value of electricity in export markets, compared with prices in domestic markets. While regulatory bodies have evolved in all provinces, there is concern that insufficient emphasis is being placed on economic efficiency in the operation and development of the electrical sector.

Conclusions

This historical outline of Canadian petroleum and electricity policy indicates consistent economic themes – growth, development and efficiency – whose relative importance has shifted over time, according to the circumstances and political attitudes of the day.

Other issues emerge as well – the constitutional dilemma, the pursuit of energy security and economic stabilization at both the national and the provincial levels, the uncertainty of energy supply and demand forecasting, as well as international factors and foreign ownership. At the national level, however, history suggests that the economic objectives of petroleum policy – those related to growth, development and the efficient management of resources – were, for the most part, the primary priorities in the energy field in the years preceding the 1973 OPEC crisis, but not thereafter.

Throughout that early period, petroleum policy was developed by consensus. There were, to be sure, winners and losers, but the losses and gains were reconciled to serve a generally accepted national interest, which made for basic federal-provincial agreement. Moreover, that consensus was vital to industry and investor confidence, and thus to the building of an increasingly important petroleum sector. It is beyond dispute that the consensus was seriously weakened in later years, as the dominant issues in the formulation of oil and gas policy during the energy crisis years of the 1970s became those of economic stabilization and the sharing of energy revenues. The goals of economic growth, development and efficiency were simply overshadowed by the pressing political concerns arising from the two OPEC price shocks.

Until recently, provincial policies in the electrical field have largely addressed the need for restructuring the utilities into the present-day provincial Crown corporations. Provincial policies now have more room to focus on such issues as economic efficiency in electricity pricing, investment decisions and the development of profitable export markets.

In essence, Canadian energy policy in recent years has tried to juggle too many issues. Its aims should be kept within reasonable bounds; it should be shifted back to its economic underpinnings, its objective being the achievement of longer-term economic growth and stability. That, however, will require the integration of the many political, regional, economic and international considerations that are faced by the policy maker.

3 The Policy Setting

When the chips are down, energy policy is an amalgam of numerous interests – a balancing of concerns, benefits and costs. These reflect not only the divided federal/provincial jurisdiction, but also the different provincial and regional aspirations and attitudes, the issues surrounding energy security and foreign ownership, the outlook in world oil market in general and in the U.S. market for energy in particular, and – not least – the degree to which a host of recent contractual and other agreements in petroleum policy leave room for early policy change. Without intending to resolve in this chapter just how all of these issues might be balanced in a new policy approach, we shall examine them here as background to the analysis of possible solutions that will be developed later.

Federal-Provincial Overlap

There are few hard rules in the Canadian constitution to determine the respective roles of the federal and provincial governments in the management and taxation of energy. Bargaining will always be necessary, as each level of government seeks to exercise what it considers to be a legitimate influence over the energy industry – and thus over economic development generally – and to collect its fair share of revenues from actual and potential resource development. Moreover, such bargaining may also be difficult, simply because the federal and provincial constitutional powers overlap.

The exclusive federal power over interprovincial and international trade restricts provincial control over the natural resources that cross the borders of the producing provinces. This is particularly true for oil and natural gas, which are sold mostly outside the producing provinces, with the prices then being set by the federal government. While the federal government can regulate the production leaving a province, however, normally it has no control over the production that remains within the province. The provinces, as owners of the natural resources within their jurisdiction, can limit the production from provincial Crown lands that leaves the province. The provincial power over property rights also enables the producing provinces to apply general conservation measures on both public and private lands.

Taxation is another source of controversy. The federal government can raise money by any mode or system of taxation, including import tariffs and export taxes. This taxation power is limited, however. For example, royalties, being a payment to the owner of the resource, cannot be levied as such by the federal government, except on lands that it owns. The federal taxation power is also limited by section 125 of the British North America Act (renamed the "Constitution Act, 1867" in 1982), which disallows the taxation of provincial properties. (Resorting to this clause, Saskatchewan has argued that the federal government cannot tax provincial Crown corporations, as it intended to do under the National Energy Program; however, the two governments have agreed to set the issue aside until the end of 1986.) The Supreme Court's June 1982 decision that the federal government cannot tax exported natural gas, which remains the property of the producing province until it reaches its border, also limits federal taxation powers.

The "Constitution Act, 1982" gave the provinces the power to raise money by any mode or system of taxation on most natural resources, provided that their taxes do not differentiate between production exported to another part of Canada and production staying within the province.

With such wide taxation powers at both levels of government, the room for overlap and potential dispute in the energy area is substantial. Electricity, however, has not been a source of major conflict between the federal and provincial governments to date. In most provinces, electrical power is produced by provincial Crown corporations and is not subject to federal taxation. In the few cases where electricity is produced and/or distributed by private utilities, the federal government remits to the province 95 per cent of the corporate income tax collected. In the past, electricity exports were subject to a federal export tax, but this ceased in 1963.

The major disputes have been over oil and natural gas, which are subject to numerous levies at both levels of government. The producing provinces collect bonuses and royalties on production from provincial Crown lands. They tax oil and gas on freehold land and collect corporate income tax.

Until the fall of 1973, when the federal government began to tax oil exports, corporate income taxes were its only source of revenue from the primary production of oil and gas. Ottawa has since implemented a whole range of taxes that have never been fully accepted by the provinces. Included are the petroleum and gas revenue tax, the incremental oil revenue tax, the oil export tax and the natural gas and gas liquids tax.

Another federal tax measure that was contested by the provinces was the nondeductibility of provincial royalties for federal corporate income tax purposes, announced in the May 1974 budget, which was allegedly aimed at preventing the federal share of petroleum revenues from being eroded by provincial levies. The provinces argued at the time that this was an indirect way for the federal government to collect royalties. The federal government subsequently replaced that provision with another that permitted a special deduction of 25 per cent of operating revenues, called the "resource allowance," which broke the deadlock. The resource allowance is, however, only a partial substitute for the full deductibility of royalties that had previously been increased by the provinces.

Hand in hand with these federal-provincial disputes over taxation are the tensions that have arisen over conflicting objectives in such areas as the pace and direction of resource development, the sharing of resource revenues and the sharing of some of the resultant costs of policy. The federal line of argument regarding the sharing of oil and gas revenues, spelled out in the National Energy Program, is twofold: first, the government needs the funds to finance its various energy programs and other activities; second, the funds are needed to provide for sharing among all Canadians of "windfalls" that would otherwise go largely to only one part of the country.[1]

At the time, the NEP foresaw "no discernible end" to the "unprecedented, and welcome, prosperity in the three westernmost provinces" that resulted from the oil and gas resource boom.[2] Alberta's per-capita income had risen from slightly below the national average in 1970 to some 9 per cent above the average in 1980; and net in-migration to the province in 1980 was running at some 66,000 people per year. Such developments reinforced the perception by the federal government that the centrifugal forces of an enduring westward shift in wealth, activity and population could jeopardize Canadian unity. The federal government also fell victim to the existing structure of the Equalization Program during that period. This thrust an additional financial burden on the government's shoulders because the huge petroleum revenues of the producing provinces increased the total amount of the equalization entitlements. Accordingly, the equalization formula was revised. Although a wide range of federal taxes were introduced in the NEP, it must be stressed that most of the sharing of energy wealth among all Canadians up until recently was accomplished not through such fiscal measures but through the pricing of domestic oil at less than the world price.

Over the last two years, however, the unemployment rate in Alberta has come closer to the national average and has even surpassed it in some months, and there has been a reversal in migration trends, with 21,000 net exits being recorded in 1983. The changes made to the formula for equalization payments in 1982 had the effect of excluding Alberta from the calculation of the payments standard. Thus oil and gas revenues in Alberta essentially no longer affect equalization, and as a result the federal financial burden has been reduced accordingly.

The Diversity of Provincial Interests

The Alberta government has been at the centre of the clash between the oil- and gas-producing provinces and the federal government over the past decade. It would like to see the Canadian oil price move as rapidly as possible towards the world level. It also supports market-oriented pricing for natural gas. The Alberta authorities have specifically supported the move towards the more flexible export-pricing arrangements announced by the federal government in mid-1984, following a detailed study of this issue by a federal-provincial task force in consultation with industry. As for taxes, while the Alberta government has accepted the argument that the federal government has a claim to a share of oil and gas revenues, it remains opposed to any federal levy similar to a wellhead tax. Alberta has also opposed export taxes on oil and gas, particularly if no similar tax is imposed on other energy products.

The Alberta economy suffers when exploration and development by the oil and gas industry in the province stagnate or decline, and the provincial government must act to counter such downturns in activity. Accordingly, it introduced a program of incentives for geophysical and exploration drilling when federal measures to constrain revenue increases were imposed in the latter part of 1973; and there have been numerous policy changes since then, including the April 1982 announcement of royalty reductions and special grants to soften the effects of the September 1981 agreement with the federal government. At the same time, the Alberta government continues to pursue diversification of the provincial economy, particularly through the establishment of a number of large-scale petrochemical plants and other, more recent initiatives.

For Alberta, the single most important issue – and it is hardly a new one – boils down to retaining control over its natural resources. The province perceived the NEP as a takeover of its resources. While forced to accept certain tax measures, such as the petroleum and gas revenue tax, in order to obtain an agreement with the federal government in 1981 that avoided some of the most disliked features of the NEP, the province is obviously prepared to go to some length to retain control over the pace of development of its energy resources. It took over the distribution and administration of payments made under the "petroleum incentives program" in Alberta and probably would have been prepared to assert ownership of all natural gas wells in the province if the federal government had imposed a tax on gas exports.

The major consuming provinces, Ontario and Quebec, have differed with Alberta, as well as among themselves. Ontario, concerned with the depressing impact of increased oil prices on the provincial economy, was initially reluctant to favour a move to the world oil price and supported the idea of a blended price. The authorities of Queen's Park were also concerned about a situation where a relatively small province received a large share of oil and gas price increases, as this could lead to substantial disparities in fiscal capacity between the provinces, which in the long run could pose a threat to the stability of the Canadian federation. In addition to a limit on price increases, Ontario proposed a reinvestment plan for revenue increases, with part of the funds to be used to protect industries and consumers against sudden oil and gas price increases and to assist them in adjusting to higher prices.

Quebec, on the other hand, supported the move to raise oil prices in Canada to the world level, as this would lessen the demand for oil. It was concerned that federal intervention in oil and gas pricing and in the handling of resource revenues might set a dangerous precedent for Quebec's hydroelectric resources. The province was less concerned with the increase in fiscal disparities that accompanied increases in Canadian oil and gas prices.

National Economic Concerns

At the same time as it has been exposed to these differing provincial positions, the federal government has been wrestling with a number of more general problems. In the late 1970s and early 1980s, Canada faced strong inflationary forces – fueled by the doubling of world oil prices – that refused to yield to monetary restraint for many months. Interest rates reached record levels by mid-1981. Economic activity had begun to level off and then plunged into severe recession; real GNP dropped by 4.4 per cent in 1982 – more than in other OECD countries. Other economic problems predated the recession: Canada's rate of productivity increase was very slow during the 1970s; and even before the sharp economic downturn, slow rates of economic growth were resulting in rising unemployment.

These broader economic issues merged with developments in the energy sector at the beginning of the 1980s and heavily influenced both the nature and timing of the National Energy Program. The federal government had been running a substantial deficit, though it was not inordinately high in relation to GNP. The system of taxes and levies on oil was designed to balance the subsidies on imported oil and domestic synthetic crude production, with the result that the latter exerted little pressure on the government's fiscal resources. However, with the reduction in Canadian oil exports and the prospect of increased oil imports by mid-decade, coupled with the 1979-80 doubling of OPEC prices, the federal government faced the prospect of much larger deficits. At the same time, provincial budgets, especially in Alberta, were perceived to be producing increasing surpluses. As this Council pointed out in 1979, such fiscal imbalances were placing the federal government "in a poor position to continue to play its major role in economic management, equalization of provincial revenues, and the conduct of major national policies."[3]

Not only was the federal government facing an accumulation of problems, but it was rankled by its extreme exposure to the actions of the other players in the energy sector. For most of the preceding decade, it had been obliged to adjust its policies to their moves. At the international level, there was also considerable politicization of the energy sector, arising from the activities of the OPEC cartel and the general development of state oil companies throughout the world. This generated additional constraints on the federal government's margin for manoeuver.

Concern about regional economic development has weighed heavily on the development of federal energy policy, and it continues to do so. The provinces have long employed energy policy in general, and policies with respect to their electric power utilities in particular, to foster local and regional economic growth and development. At the federal level, within a year after the NEP was launched, the government had focused on energy megaprojects (the oilsands and Beaufort Sea projects, among others) as an essential element of the economic recovery during the balance of the 1980s. That was, of course, before the world price of oil, which had been forecasted to climb steadily in real terms, underwent an unanticipated decline.

The Search for Energy Security

One of the legacies of the 1970s that deserves special attention is the notion of self-sufficiency, which typically focused on oil but which was frequently broadened to include all forms of energy. However that goal is expressed, it is not easy to define. Over a number of years after 1973, the federal authorities became increasingly concerned about the fact that imports of crude oil into eastern Canada were steadily outstripping oil exports from the western region. The consequence of this trade imbalance was a growing transfer of income from Canadians to the oil-exporting countries. Only recently – as the result of a decline in domestic demand – has this country regained its position as a net exporter of oil, although Canada has continued to enjoy a surplus in its balance of trade in all forms of energy taken together throughout the period since 1973, as it had for many years before.

In 1976, the federal government suggested the objective of achieving energy self-reliance.[4] Such self-reliance was to be measured by the degree to which Canada was independent of imported oil from insecure sources. Vulnerability could be lessened by reducing oil imports as much as possible in the context of our general economic, environmental and social objectives. Energy security could also be enhanced by ensuring that we maintain a sufficient degree of emergency preparedness to withstand any possible supply curtailments with minimal economic and social consequences.

As oil exports continued to decline in the late 1970s and as net imports rose, energy self-reliance came to be presented in terms of Canada producing sufficient oil to meet all of its own requirements. The NEP set oil self-sufficiency as a target to be met by 1990.

For an energy-surplus province like Alberta, the desire to have oil self-sufficiency as a component of federal policy is understandable; but that objective has been strongly supported by other provinces as well. Should a major world crisis leave Canada unable to import oil, the Canadian economy could be severely affected, and Canadian oil production might have to be shared more widely among the provinces, as well as with other countries, as part of prearranged emergency supply allocations.

The Ontario government, for example, has taken a number of steps to contribute to increased Canadian oil supply through its participation first in Syncrude, then in Suncor and in frontier oil and gas exploration by means of the investments made by the Crown-owned Ontario Energy Corporation in Trillium Exploration Corporation. Despite the currently soft world oil market and the excess supplies of natural gas and electricity, Ontario still believes that Canada should not rely on oil imports as a secure source of supply over the long run.

Ontario has set a target of increasing the proportion of energy provided from provincial sources from 26 per cent in 1980 to 37.5 per cent by 1995. This would entail reductions in total energy consumption per unit of output in all sectors, as well as a reduction in the share of oil in the energy consumption of the residential, commercial and industrial sectors to 10 per cent by 1990 – also a target of the NEP. Increased use of electricity plays a central role in the Ontario targets; and energy from renewable sources and from waste is targeted to rise from 2 to 5 per cent as a share of primary energy needs by 1995.

Ontario's concern with the security of its electricity supply predates the 1973 OPEC crisis by many years. The lack of additional low-cost hydro sites and the dependence on U.S. coal, together with the possibility of using local uranium and developing a nuclear industry, were major factors underlying Ontario's interest in nuclear generation. More recently, the province has diversified its energy sources by purchasing more western coal, its primary purpose being to reduce its dependence on U.S. sources.

In Quebec, energy autonomy is a principal objective of government policy. Originally, the policy had two dimensions, both emphasized in the provicial government's 1978 White Paper: increased conservation in the utilization of energy, and a doubling of the share of energy derived from provincial sources by 1990. The conservation aspect has hardly been mentioned in the last year or two, however. A rapid increase in the proportion of electrical energy was envisaged as a way to achieve energy autonomy, with specific increases targeted for each sector. Concurrently, however, the province has had an objective of rapid expansion in the market share of natural gas. Recent developments encouraging the use of natural gas may reflect something of a shift from the objective of autonomy to that of secure access to energy supplies – to which less stress had been given in the White Paper. In any event, the competition between electricity and natural gas and the restructuring of the oil refinery sector now pose major issues for Quebec policy.

In the Atlantic provinces, which depend heavily on imported oil to meet their energy requirements, security of supply has been a major concern. In Nova Scotia, electricity production has been shifted away from oil-fired generation and will be almost completely derived from coal by the end of 1984. In New Brunswick, the off-oil shift in electricity generation is being met mainly by the Point Lepreau nuclear power plant. The Atlantic provinces have also been active participants in energy conservation programs, some of which have supplemented federal schemes; under New Brunswick's "home energy conservation loan program," for example, low-interest loans are extended to homeowners to improve energy efficiency.

Prince Edward Island, which already had the highest electricity prices among the provinces in 1973, was hit particularly hard by the rise in oil prices, given its dependence on oil-fired generation. The province now imports nearly all of its power from New Brunswick, partly from facilities in which it shares ownership, although the price of imported power remains high. Prices are also quite high in the Northwest and Yukon Territories, with many communities being dependent on isolated generators using fossil fuels.

While Newfoundland has well-developed hydro generation on the island, the province is concerned that it will remain dependent on oil-fired generation for expansion of the system unless hydro power from Labrador can be brought to the island. Quebec will not allow Newfoundland to use more power from Churchill Falls, and the proposed development on the Lower Churchill would be economically viable only if some of the power could be exported from the province – which, in practical terms, requires agreement with Quebec.

Self-sufficiency in electricity has been an important consideration in most provinces. Most provincial utilities and governments would prefer to rely on capacity and energy resources within the province, and most would be willing to pay a cost premium if necessary. When significant purchases of power from other provinces were planned in the past, as in the case of the purchases of electricity from Churchill Falls by Quebec, they were secured with tight, long-term contracts.

The assurance of sufficient reserve capacity to meet contingencies is a concern shared by all electric utilities, given the long lead times in construction and the uncertainties involved. Most utilities and provincial governments are reluctant to become dependent on capacity in other jurisdictions. The fear of having to cut back on supplies in peak periods because of a shortage in capacity is pervasive, and it has led to periodic debates on the appropriate reserve levels that the utilities should maintain.

For the federal government, the search for energy security has led to a number of conservation and off-oil conversion programs for households and businesses, incentive grants to stimulate increased exploration, increased Canadianization, and special roles for Petro-Canada and other Crown corporations. With the holding-down of the domestic oil price, Ottawa was forced to introduce a wide variety of programs entailing large expenditures in grants and subsidies. A specific target of the NEP was to reduce oil demand in the residential, commercial and industrial sectors of every province to no more than 10 per cent of the total energy used in those sectors.

The federal government has also implemented the measures outlined in the NEP to extend the use of natural gas. As well as setting the price of gas at a 65 per cent parity with the oil price, grants are being provided under the "distribution system expansion program" (DSEP) to finance the cost of expanding natural gas distribution systems to new areas in British Columbia, Saskatchewan, Manitoba, Ontario and Quebec. Under a special program, the federal government is also providing up to $500 million to Quebec to finance the construction of laterals (branch lines) and to cover their operation and maintenance costs for five years. This followed an agreement with the Quebec government to remove its sales tax on natural gas. Substantial support has also been given to two Quebec natural gas distributors to promote the rapid expansion of new markets in that province under the "gas marketing assistance program." Funds for this program and for the DSEP are obtained partially from the "market-development incentive payments," for which provision was made in the September 1981 agreement; they involve contributions by Alberta natural gas producers and are conditional on increased sales of Alberta natural gas. Heavy federal subsidization may also be required for natural gas distribution systems in the Atlantic provinces, as well as in British Columbia to build a gas pipeline to Vancouver Island.

A major program reflecting the federal government's concern with security of supply and Canadianization is the petroleum incentives program (PIP), which gives grants replacing the fiscal incentives that were provided under a previous program operated through the corporate tax system. The largest grants are available to Canadian companies operating on the Canada Lands (up to 80 per cent of approved exploration expenditures). If the program results in an increase in the amount of proven reserves of oil in the areas under federal jurisdiction, it will not only help to alleviate the problem of oil insecurity, but it will also provide the federal government with a larger role in the development of oil supplies. The PIP scheme is proving to be very expensive, however, now requiring the payment of about $1.6 billion annually in grants. This caused the federal government to move early in 1984 to tighten its control over expenditures to some degree.

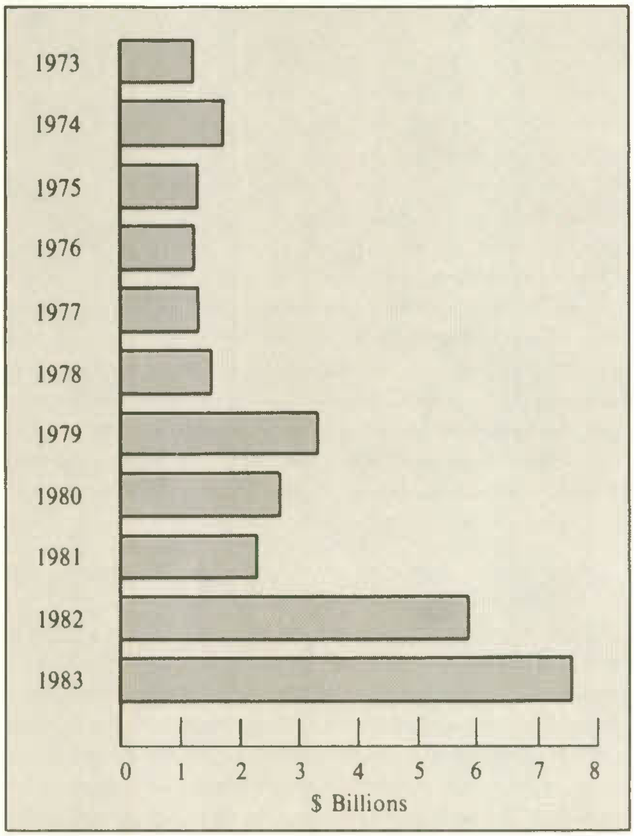
Energy Exports and Imports

Canada's overall energy trade balance has improved substantially since 1973 from some $1 billion to the present $8 billion (Chart 3-1). Natural gas exports have risen from close to $1 billion to around $4 billion, even though current exports are running at little more than 40 per cent of authorized volumes. Electricity exports have also increased – over 10 times in the same period – to the present value of around $1.2 billion.[5] The remaining net energy exports in 1983 included about $2.2 billion of refined petroleum and coal products, and about $200 million for crude oil.

Clearly, energy exports have become a significant activity in the Canadian economy. In net terms, they represented in 1983 more than half of Canada's total

Chart 3-1

Energy Trade Balances, Canada, 1973-83



SOURCE Based on data from Statistics Canada.

balance for all merchandise trade, which was valued at about $15 billion. Furthermore, Canada is at present a net exporter of almost all energy commodities. The overall energy trade picture has become extremely bright, largely as a result of energy price changes since 1973, which have helped to open up this opportunity for economic development based on Canada's energy resources.

The security of our oil supply remains a concern, however. Over the years, the net trade balance in crude oil has fluctuated much more than that for other energy sources. In 1981, the crude oil balance was in deficit by some $5.4 billion, but it turned positive in 1983 for the first time since 1974, to the tune of $183 million (Table 3-1). These swings have reflected both Canada's oil export policies and the impact of the changing world oil price on the value of imports, among other factors. At present, Canada is a net exporter of heavy crude but a net importer of light crude. Oil balances in the future could tip one way or the other, and the politicization and volatility of the world oil situation (including the impact on world prices) mean that oil supply issues will remain a prominent factor in Canadian energy security.

World Oil Markets

The possibility of oil shortages and escalating prices has dominated energy policy discussions for much of the past decade. What are the prospects for world oil markets in the years ahead? While there is still the risk of a supply upset followed by a sharp rise in prices, conditions in the 1980s are very different from those of the 1970s.

A longer-term examination of oil price changes brings out a number of points. Throughout the past hundred years, oil production and pricing have been wholly or partially controlled by cartel arrangements – by the petroleum companies in the early years, by the Texas Railroad Commission after the early 1930s and by OPEC since the beginning of the 1970s. From 1870 to 1945, there was an extremely high degree of price variability, after which prices stabilized somewhat.

The period from 1946 to 1972 was characterized by a decline in the preponderance of the United States and by the emergence of a more dominant position by the Middle East. Prices increased in the late 1940s and then declined in real terms till the early 1970s. They showed little year-to-year variability, with an average annual swing of only 4 per cent. From 1973 to the present, the real oil price has increased about fourfold, but since 1980 it has dropped by 7 per cent a year.

In attempting to draw inferences from the long-term price changes and the accompanying degree of variability, it is impossible to discern whether the long-term trend of oil prices is upward, as would be implied by the hypothesis that the world is running out of oil resources, or stable, as would be implied by taking into account the reduction in oil demand, the potential for new discoveries, technological change and the availability of energy substitutes (Chart 3-2).[6]

When seen in the longer-run context, the degree of variability of oil prices during the 1970s is perceived as having been unusually high. Underlying the price developments of the past decade are a number of factors.[7] The quadrupling of real oil prices in the 1970s caused reductions in the use of oil. Between 1979 and 1982, the total world demand for oil declined by 4 per cent a year, with all of the reduction being accounted for by the developed market economies. Of this reduction, probably half or more was the result of the slower growth of the world economy. The reduction in oil demand caused by the price increases was also substantial, however. More than 40 per cent of the decline resulted from energy conservation and from the substitution of other energy sources for oil. There are both short- and long-run price effects, the former being

Table 3-1

Canadian Trade in Energy and Related Products,[1] 1973-83

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
						($ Millions)					
Exports											
Crude petroleum	1,482	3,420	3,052	2,287	1,751	1,573	2,405	2,899	2,505	2,729	3,457
Other refined petroleum and coal products[2]	477	930	1,132	1,120	1,300	1,528	2,721	3,258	3,789	3,807	4,129
Natural gas	351	494	1,092	1,616	2,028	2,190	2,889	3,984	4,370	4,755	3,958
Electricity	109	175	104	162	377	479	729	773	1,123	1,120	1,228
Radioactive ores	64	51	47	57	75	207	379	231	179	359	63
Total	2,483	5,070	5,427	5,252	5,532	5,977	9,122	11,145	11,966	12,769	12,835
Imports											
Crude petroleum	941	2,646	3,304	3,273	3,243	3,466	4,497	6,919	7,861	4,979	3,274
Other refined petroleum and coal products[2]	375	676	852	769	922	1,013	1,260	1,499	1,715	1,794	1,887
Natural gas	8	6	8	9	—	—	—	—	1	1	—
Electricity	6	5	13	9	15	2	1	3	6	5	2
Radioactive ores[3]	x	x	x	—	70	12	73	67	131	127	112
Total	1,331	3,333	4,176	4,060	4,250	4,494	5,831	8,489	9,715	6,906	5,276
Balances											
Crude petroleum	541	774	-252	-986	-1,493	-1,894	-2,093	-4,020	-5,356	-2,251	183
Other refined petroleum and coal products[2]	102	254	280	351	378	515	1,461	1,759	2,074	2,013	2,241
Natural gas	343	488	1,084	1,608	2,028	2,190	2,889	3,984	4,369	4,754	3,958
Electricity	103	169	92	153	362	477	728	770	1,117	1,114	1,226
Radioactive ores[3]	64	51	47	67	5	195	306	164	48	232	-49
Total	1,153	1,737	1,251	1,192	1,281	1,484	3,291	2,656	2,252	5,863	7,559

1 On a customs basis.
2 Includes coal and other crude bituminous substances, fuel oil, lubricating oil, coke of petroleum and coal, and other petroleum and coal products.
3 Imports for 1973 through 1975 are confidential, but values are considered negligible.
SOURCE Based on data from Statistics Canada and the CANDIDE database.

quite modest and the latter being much larger. It took many years for the effects of the 1973 price shock to be felt fully, and those of the 1979-80 rise have almost certainly not yet been registered fully, even though there has been a drop in prices recently. Meanwhile, the share of oil in the energy requirements of the industrial countries dropped from 51 per cent in 1973 to 44 per cent in 1981.

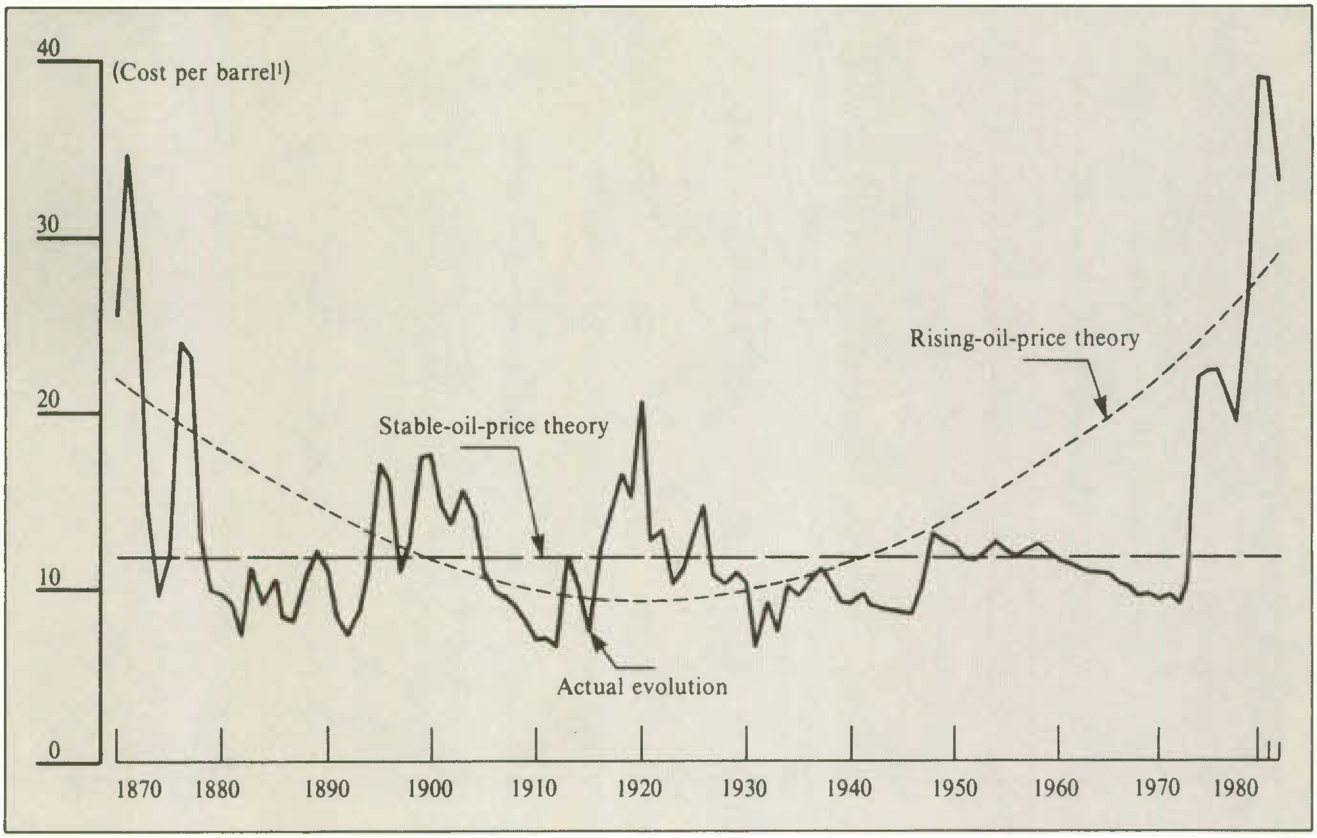
The world demand for oil in the future is unlikely to increase at anywhere near the rate of 7 per cent a year that it reached over the decade from 1963 to 1973; in fact, the increase is unlikely to average much above 1 or 2 per cent a year. Thus the world oil shortages that were envisaged several years ago as occurring in the 1980s and that were more recently projected for the 1990s are unlikely to occur.

Nevertheless, there remain problems arising from the oil market structure and the location of excess oil supplies. The world oil market can be viewed as comprising four groups of countries: the industrialized countries of North America and Europe, and Japan; the centrally planned economies; the OPEC countries; and the less-developed countries and others. For each country or group of countries there is an oil demand and an oil supply, and their balances constitute net imports or exports in the world oil market (Table 3-2). By maintaining control over surplus supply, OPEC is the "price maker" in the world oil market, with the least costly oil being concentrated in the OPEC countries of the Middle East. Other producers – both those providing supplies to the world market, such as Mexico, and those supplying their own domestic markets, such as the United Kingdom, the United States and Canada – are "price takers."

The net world demand for OPEC oil has been declining in recent years. The slowdown in the growth of demand and the increased production by some non-OPEC countries have left OPEC with 32 per cent of world oil production in 1984, compared with 53 per cent in 1973. If the centrally planned economies are excluded from the calculation, OPEC's share of world production drops from 66 to 42 per cent over the same period. Given OPEC's dominant share of proven oil reserves, however, one cannot preclude the possibility that its share of total production could rise again.

Chart 3-2

World Prices of Crude Oil, 1870-1982



1 Measured in constant 1982 U.S. dollars.
SOURCE Bourque, "Évolution du prix international du pétrole."

Table 3-2

World Oil Demand and Supply Balances, 1973 and 1984

	1973			1984		
	International demand	International supply	Net balance[1]	International demand	International supply	Net balance[1]
			(Millions bbl/day)			
North America	19	13	-6	18	12	-6
Europe	14	—	-14	12	4	-8
Japan	5	—	-5	5	—	-5
Less developed countries	7	3	-4	8	8	—
OPEC	2	31	+29	3	19[2]	+16
Centrally planned economies	10	11	+1	13	15	+2
Other	1	—	-1	1	2	+1
Total	58	58	—	60	60	—

1 A minus sign indicates imports; a plus, exports. For simplicity, inventory changes have been ignored.
2 Sustainable productive capacity in OPEC would be much higher than this, probably in the order of 30 million barrels per day.
SOURCE Estimates by the Economic Council of Canada, based on data from Energy, Mines and Resources Canada.

Whether or not the current cartel arrangements are maintained, price stability requires that some excess supply be kept off the world oil market. At present, excess capacity appears to be between 20 and 25 per cent of total world demand, with Saudi Arabia and Kuwait playing a central role because their proven and potential reserves and their substantial production capabilities are so large. A reduction in the surplus capacity of these countries would make further upward oil price shocks a possibility. A ratchet effect would be more likely than a gradual upward movement because OPEC producers (such as Saudi Arabia, Kuwait, Qatar and the United Arab Emirates) would be likely, as in the past, to take advantage of upward movements in spot prices by restricting output in order to support a higher price level for long-term contract sales.

Reinforcing this process has been the inclination of holders of inventories to increase stocks in times of uncertainty.[8] This amplifies the ratchet effect by increasing the demand in the world oil market, leading to further strength in spot prices. The Director of the International Energy Agency (IEA) has urged the oil-importing countries to use their oil stockpiles in such circumstances, so as to prevent minor supply disruptions from causing price increases to escalate.[9]

Canada joined with 20 other major industrial oil-consuming countries within the OECD to form the IEA in November 1974. Their aim was to reduce the risk of further shocks to the oil market and to improve their response capability should a new oil-suply crisis develop. The IEA carries out cooperative programs to reduce dependence on oil through conservation, the development of alternative energy sources, and energy research and development. It also attempts to encourage cooperation between producing and consuming countries to develop a stable oil trade.

The IEA has an emergency plan that can be put into operation when a member nation or one of its regions, or the members of the Agency collectively, experience a reduction in total supplies of at least 7 per cent. The three major measures in the plan are to: 1) restrain demand; 2) draw down from emergency stocks, which are to be kept at a level equal to at least 90 days' supply of net imports; and, 3) share available oil supplies. Under the plan, all countries are to give up an equal proportion of their total supplies in the case of a supply shortage. This implies that a country like Canada, which is relatively less dependent on imports than other members, would suffer a greater reduction relative to its imports. The plan allows oil stocks in excess of the required minimum emergency supplies to be used as a substitute for demand restraint. "Standby" oil production in excess of normal quantities can also be used as a credit towards emergency stocks.

The United States, along with other countries that are more dependent than Canada on foreign oil supplies, has built up strategic reserves in addition to the levels committed to the IEA. These reserves are currently contributing to the stability of oil prices. To date, this option has not been pursued in Canada. The inventories of crude oil and oil products held by the industry in 1983 averaged about 100 days of total domestic requirements. Since somewhere between 50 and 60 days of inventories are required to maintain the supply system, there was about 45 days' domestic supply being carried as excess inventories, which was equivalent to over 200 days of imported supply. There is some question, however, about the extent to which industry supplies can be relied upon in crisis situations.

Canada has also stabilized its crude-oil import risk by diversifying its sources of supply. Of the share of domestic demand accounted for by imports – 17 per cent in 1983 – only about one-fifth originated in the Middle East. This compares with close to 40 per cent of its imports coming from that area in 1973, when imports accounted for about 50 per cent of domestic demand. Canada also has signed a long-term, state-to-state supply contract (through Petro-Canada) with Mexico.

Everything considered, it can be concluded that through economic forces and countervailing political action in the face of moves by OPEC, the world oil price should be less explosive in the future than it was in the 1970s. On the other hand, the sources of price instability remain. The oil cartel is intact, and world oil reserves are still largely concentrated in the politically volatile Middle East. As a result, the future path of world oil prices will continue to be difficult, if not impossible, to predict.

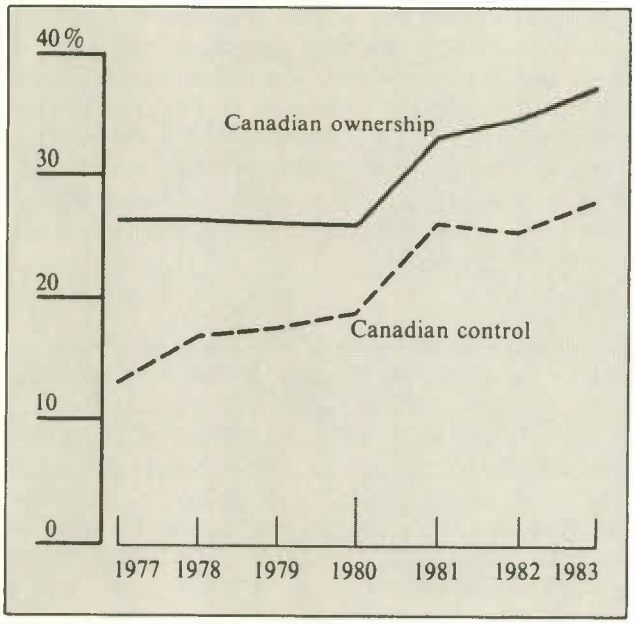
The longer-term trends of real prices, starting from today's level, may be upward or downward over the next 20 years, and the risk of short-term shocks will remain. In our view, assuming a trend of rising real prices in the future is not a sound basis for policy making. It is the *instability* of oil prices that is the essential policy problem. The only reasonable basis for oil price forecasting, therefore, is to consider both upward and downward shocks or trends, relative to a middle case of constant real prices. Policy must be formulated, however, in such a way as to be able to withstand various price eventualities.

Ownership and Control

Closely related to the search for energy security has been the desire of the federal government "to give Canadians a greater opportunity to participate in the energy industry, directly and through the spin-off benefits associated with a rapidly growing sector."[10] The Canadian oil and gas industry is largely foreign-owned or foreign-controlled (Chart 3-3),[11] and this has been a source of concern for Canadian policy makers, particularly since the mid-1970s. There have been three major reasons for this concern. First, the domestic oil and gas industry has become a net exporter of capital since 1974; during the period from 1975 to 1979, cash outflows exceeded inflows by some $3.7 billion.[12] The outflow has been exacerbated since 1980 (Table 3-3). Second, foreign ownership has been seen as limiting the participation of Canadians in the development of their resources because larger shares of research and development, management recruitment and the purchasing of goods and services tended to be done outside Canada. Finally, the control of the industry by foreigners has raised strategic issues because the setting of priorities and investment plans could be in conflict with Canadian interests, particularly in periods of crisis.

Chart 3-3

Ownership and Control of the Petroleum Industry, Based on Petroleum-Related Revenues, Canada, 1977-83



SOURCE Based on data from the Petroleum Monitoring Agency.

Table 3-3

International Flow of Funds Related to Long-Term Investment by the Canadian Petroleum Industry, 1980-82[1]

	1980	1981	1982
		($ Millions)	
Interest	-45	-210	-470
Dividends	-457	-530	-570
Business service payments	-131	-200	-150
Transactions[2]	+223	-4,340	+860
Total	-410	-5,280	-320

1 A minus sign indicates capital outflows; a plus sign, capital inflows. The data show only the direct flow of funds within the energy industry and do not include transfers via other sectors of the Canadian economy — e.g., financial institutions.

2 Represent investment items, such as a parent company's investment in a foreign subsidiary.

SOURCE Based on data from the Petroleum Monitoring Agency.

Prior to the NEP, the flag of Canadianization was carried essentially by Petro-Canada. The company, created in 1975, was given a number of objectives. It was to serve as a "window" on the petroleum industry and to acquire better knowledge of Canada's oil and gas resources. Another important mandate called for Petro-Canada to act as a "catalyst" in exploration and development in the frontier regions and to encourage the participation of small companies in long-term, capital-intensive projects. The company inherited the federal government's shares in the Panarctic consortium, which had previously been set up to sustain exploration in the high Arctic. It also participated, as the federal government's representative, in the Syncrude project. By 1980, acquisitions had enabled Petro-Canada to become involved in the downstream activities of refining and marketing, thus making it one of the largest oil and gas companies in Canada.

The provincial governments also recognized the economic and strategic advantages of participating in the petroleum sector. As far back as 1954, the Alberta government had set up the Alberta Gas Trunk Line (now NOVA). The province created the Alberta Energy Company as a vehicle for its citizens to invest in the development of energy resources and as an instrument of economic development. Similar objectives motivated the creation of the Saskatchewan Oil and Gas Corporation (Saskoil) by the Saskatchewan government in 1978. Quebec also moved in this area by forming the Société québécoise d'initiatives pétrolières (SOQUIP) in 1969.

Partly because of the growing public-sector involvement, Canadian control of oil and gas companies increased during the 1970s. Between 1977 and 1980, the share of industry revenues accruing to Canadian-controlled companies rose from 13 per cent to nearly 19 per cent.

In 1980, with energy prices and the profits of the oil and gas companies rising, the federal government took steps through the NEP to accelerate the Canadianization process, especially with respect to activity on the Canada Lands. It was recognized that foreign-owned companies held most of the exploration permits in the frontier regions, which meant that they would dominate future oil and gas activity on the Canada Lands. It was believed that in periods of rising prices, the outflow of capital would accelerate and the assets of foreign companies would grow to the point where it would become impossible for Canadians to take them over, rendering the ownership problem permanent. Moreover, an industry monitoring survey in 1979 indicated that the larger foreign-owned oil and gas companies were gradually extending their activities into nonenergy sectors.[13]

The NEP outlined three goals with respect to Canadianization: 1) to achieve at least 50 per cent Canadian ownership of oil and gas production by 1990; 2) to encourage Canadian control of a significant number of the larger oil and gas firms; and 3) to enlarge rapidly the share of the oil and gas sector owned by the Canadian government.

The program outlined various ways of achieving these objectives. The PIP system, by adjusting the amount of eligible grants in relation to the "Canadian ownership rate" of the claiming company, was designed to favour Canadian companies. The federal government also indicated its intention to claim a 25 per cent interest in oil and gas rights on the Canada Lands, at the time of project development; the right would be exercised by Petro-Canada or another Crown corporation. In addition, 50 per cent Canadian ownership would be required for the production of oil or gas from the Canada Lands, along with guarantees by the developing companies that substantial industrial and employment benefits would accrue to Canadians.

The NEP also introduced a temporary "Canadian ownership special charge" (COSC) to finance future acquisitions of large energy corporations by the federal government. The proceeds of that tax, which has been applied since May 1981 to all Canadian sales of oil and gas, were first used to cover the costs of the purchase of Petrofina by Petro-Canada, which took place that year, at a cost of $1.5 billion.

Finally, the NEP expressed the government's intention to monitor closely the activities of foreign companies through the Foreign Investment Review Agency, for the purpose of discouraging those companies from buying Canadian energy companies or expanding into nonenergy activities.

The NEP achieved immediate success in raising the level of Canadian ownership and control in the oil and gas sector. Within a year, Canadian control of revenues rose from 19 to 25 per cent. Increases occurred in both public and private participation, but growth in Canadian public ownership and control was sharper, going from about 4 to 8 per cent between 1980 and 1981. A series of takeovers took place that included, apart from the Petrofina deal, the purchase of Elf-Aquitaine by the Canada Development Corporation, which later also acquired Texas Gulf's interests in Canada to form a new corporation, Canterra; and the acquisition of a portion of Suncor by the Ontario Energy Corporation.

The targets of the federal government, as well as the other steps taken to achieve increased Canadian ownership and control of the oil companies, represented an attempt to gain greater domestic control over events in the energy sector. The measures also reflected the concern of the government that Canadian firms had less access to capital than the large international oil companies and thus could not compete actively in areas such as frontier and offshore development and production unless special policies were introduced. To achieve these and other goals, a series of complex arrangements were put into place.

The Constraint of Present Petroleum Agreements

Over the past few years, federal energy legislation has been completely overhauled. In addition, a host of new federal-provincial agreements have been concluded. A wide variety of programs have been instituted under both the legislation and the agreements, entailing commitments that run many years into the future. Any consideration of policy change would therefore require an examination of the scheduled life of these programs.

The relevant federal legislation consists of the new Canada Oil and Gas Act, proclaimed in March 1982, and the eight other pieces of legislation implementing the NEP that became law in mid-1982. The latter legislation covers such matters as authority for new taxes and the proportions of eligible expenses that are to be subsidized by the PIP grants, in relation to specified levels of Canadian ownership. There have also been some recent initiatives, one of which was proposed in early 1984, to permit the COSC to be used for purposes other than to finance increases in Canadian public ownership in the oil and gas industry.

Under the new legislation, the Canada Oil and Gas Lands Administration has been renegotiating existing exploration agreements on the Canada Lands and entering into some new ones. On the Scotian Shelf, such agreements come under the auspices of the Canada-Nova Scotia Offshore Oil and Gas Board, which was established under the long-term agreement signed in March 1982 between the federal and Nova Scotia governments. The exploration agreements are for various terms extending to 1990 at the latest.

With the extension of exploration into the North, the process of settling native land claims will have to be carried through. In addition, the environmental impact in the Canada Lands, both in the North and offshore, must be assessed – a process that in some cases can be lengthy, involving public hearings. To support that process, two revolving funds were launched in 1983 – a northern fund and a southern fund, each financed by industry but administered by the federal government. Early in 1984, the federal government also announced a seven-year "northern oil and gas action program" to lay the groundwork for the commercial production and transportation of oil and gas from Canada's far North. A preference was indicated for small-scale demonstration projects in the early stages.

Other programs that are part of the NEP also extend well into the future. In March 1984, the coverage of "Canadian home insulation program" was expanded to include all homes built prior to September 1977; the "super energy efficient home program" was extended for another seven years in February 1984; both the "Atlantic energy conservation investment program," initiated in 1981, and the "solar domestic hot water demonstration program," begun in 1983, run for five years; and ENERDEMO-Canada, a program of demonstration projects relating to alternative energy and conservation, will last five years from 1984.

There are also commitments to off-oil conversion programs that extend for several years. The "propane vehicle grant program," initiated in 1981, has a target of 100,000 vehicles by 1985; the "compressed natural gas vehicle conversion program," begun in 1983, runs to 1987; the "Canada oil substitution program" applies to the conversion of household heating undertaken before the end of 1990; and the "industrial conversion assistance program" will remain in effect until 1987. The "forest industry renewable energy program," providing incentives to use wood residues, as well as municipal, agricultural or industrial wastes, and peat and other forms of biomass fuel, was started in 1978 and currently runs to 1986.

Beyond these commitments of the federal government are those which are embodied in agreements with the provinces, of which a number pertain to research and development. One of these is a five-year agreement with Saskatchewan, signed in 1984, which is aimed at expanding the development and use of that province's fossil-fuel resources through research and development and the demonstration of new technologies, with special emphasis on the recovery and utilization of heavy oil.

The agreements signed in the fall of 1981 (and amended in 1983) with the oil- and gas-producing provinces are of major significance because they cover pricing and taxation and impinge on many aspects of energy policy. The original agreement of September 1981 between the federal government and the province of Alberta established a schedule of price changes for oil and gas that extended to the end of 1986. It also established tax rates. Within the first year of the agreement, reductions were made in both taxes and royalties. In 1983, the agreement was amended to extend the definition of "new oil" to oil produced between 1974 and 1980, thus allowing it to qualify for the world price. In addition, the amendment established a freeze on natural gas price increases from August 1983 to the end of 1984. The wellhead prices of old oil were also frozen at Can$29.75 for this period. In 1985, the 1981 agreement will again become effective unless other arrangements are made by then.

Similar agreements were also made with Saskatchewan and British Columbia in 1981; these expire at the end of 1986 as well. There are also arrangements for pricing and taxation in the 1982 Canada-Nova Scotia offshore oil and gas agreement, with the wellhead price to be set by the federal government after consultation with Nova Scotia. The agreement specifies that Nova Scotia is to receive all provincial-type resource revenues, as well as the federal PGRT, until it reaches a certain level of fiscal capacity and economic activity.

The federal administered prices currently in effect for oil and natural gas sold in the domestic market are summarized in Appendix A. These complex price arrangements are governed by the agreements with the western producing provinces. The actual calculations of oil prices are even more complicated than is revealed by the tables, however, because they incorporate quality differentials and a number of other factors that are not shown.

Under the 1981 agreements, the Canadian wellhead price for new oil cannot exceed the world price, and it has remained tied at that level since the beginning of 1982. As for the wellhead price for old oil, it will not increase unless the world oil price rises. Should that occur, it is not to rise to more than 75 per cent of the world price. While the provisions governing the pricing of oil may seem arcane, those governing natural gas prices are even more complex.

The outcome of the September 1981 agreement for natural gas prices is especially telling with respect to the failure of recent energy policy to deal with the basic longer-run issues. In order to clinch a negotiated agreement, the federal government concurred in the establishment of an Alberta "border price" by the provincial government at the upstream end of the TransCanada pipeline, while the federal government would establish the Toronto wholesale price at 65 per cent of the oil-equivalent price at the downstream end of the pipeline. This extraordinary arrangement, whereby the price of gas is administered under separate and different criteria at each end of the main transmission system, is wholly without precedent, to the best of our knowledge. Historians will marvel at the complexity of the negotiations, but they will also see in this arrangement the source of the policy conflict between Ottawa and Edmonton.

The present pricing arrangement for natural gas has been maintained in the short term by the federal government reducing its natural gas and gas liquids tax and by Alberta agreeing to lesser increases than originally agreed in the border price arrangement. Ottawa also modestly subsidizes the TransCanada pipeline toll by a subsidy to distributors under the "transportation assistance program." In addition, there are payments by the Alberta government out of the producers' netback to provide funds for the market-development incentive payments in central Canada. This kind of administered adjustment and readjustment will be possible for a brief period, but the basic problem caused by disassociating the price of gas from demand and supply conditions cannot be suppressed for long. At present, the gas market is in substantial excess supply, with about 11,000 gas wells remaining idle ("shut-in"). Unless some of the controls on gas pricing are relaxed in order to bring market forces back into play, the situation is likely to worsen.

It should be noted that the same wholesale rates, including the pipeline toll, apply throughout the "eastern zone," which stretches from southwestern Ontario to Quebec City. (In the NEP, the federal government announced that it would also set Halifax prices at the same level.) Under the June 1983 amending agreement, these prices are to stay in effect until the end of 1984. For natural gas exports, the price is currently based on a two-tier price system: base volumes are sold at a uniform border price of US$4.40 per million BTUs, but an incentive price of US$3.40 prevails for additional amounts. As noted previously, the federal government announced that it was prepared to consider exports from 1 November 1984 at prices negotiated between buyers and sellers, provided they were no lower than Toronto "city gate" prices under the same terms and they were recommended as meeting the public interest by the National Energy Board.

Conclusions

This cursory review makes it clear that many elements go into the setting of Canadian energy policy. They include the ambiguities and overlap in jurisdiction over the oil and gas industry; the centrifugal forces of regional disparities; the wide diversity of provincial interests; national concerns about economic stabilization and regional economic development; the provincial and national search for energy security; the instability of world oil prices and the politicization of the world oil scene; foreign ownership of Canada's oil and gas companies; and, finally, the constraining drag of the existing petroleum agreements upon policy change. The number and variety of these factors are sufficient to indicate that energy policy must integrate a wide variety of political, social and regional concerns. While the guiding light of policy should be the realization of Canada's economic potential, there are obviously many other interests that must also be weighed in the balance.

Although electricity is largely a provincial affair, many (if not all) of these considerations also have to be brought into play in developing a satisfactory electrical policy.

From the foregoing review, it is evident that both the supply and demand sides of oil and natural gas in Canada are currently governed by a plethora of government programs and agreements that tend to be rigid in nature and unresponsive to market forces. What is necessary, as a first requirement, is the replacement of this detailed set of rules, regulations and pricing formulas by a strategy aimed at facilitating flexible adjustment of prices to changing conditions in the market place. To implement such a strategy, it is essential that continuing consultation be maintained between all of the many groups concerned with petroleum policy – consumers, industry and government – to establish consensus in policy formulation.

Getting that strategy right will require, first and foremost, the realization of the economic potential by a policy that encourages both efficiency and entrepreneurship in developing our substantial oil resources.

4 Oil Supply

Oil is one of Canada's major energy sources. Not only does it represent an important share of this country's energy supplies, but the price of oil has a major impact on the prices of other energy sources, in both the domestic and the export markets.

Policy developments over the past decade have had a considerable influence on the oil supply situation in Canada. From our perspective in this report, the fundamental issue to be considered is whether current government policies make it possible for Canada to maximize its potential economic performance from the development of its oil resources. To bring that issue into focus, it is necessary, first, to consider a number of factors that have a bearing on the present and prospective state of Canadian petroleum development. This requires a brief outline of the evolution of oil supply over the past few decades and of the latest projections of future supply.

Of particular concern are the key geological, technological and economic factors that affect exploration, development and production – the three main stages of oil supply. Some understanding of these factors is required in considering whether Canada is producing as much oil as is economically beneficial, given the nature and costs of its resources and given their value, as established by the international price of oil.

One of the critical questions that must be addressed is whether changes in domestic oil policy would bring about a response by the industry in the form of changes in oil supply. Accordingly, a number of policy issues are analyzed in this chapter, such as the pricing of oil, the balancing of incentives between different sources of oil involving different costs of recovery, and the broad question of the collection of economic rents by governments in the form of royalties, taxes and other levies.

While there are many inherent uncertainties, our research leads us to conclude that oil supply is, indeed, responsive to policy – a conclusion that is examined here in the context of existing and prospective oil sources in Canada. It is our view that policy changes that would provide for the pricing of domestic oil at world levels and for the establishment of a more efficient tax and incentive structure, could result in a significant increase in Canadian oil production on a cost-effective basis. That, in turn, would make a positive contribution to the growth of output and employment in the economy generally.

The Situation in 1983

Canada's oil production averaged nearly 232,000 cubic metres a day (m^3/d) in 1983 (Table 4-1). This output included conventional light and heavy crude oil, synthetic oil from the Athabasca oilsands, as well as pentanes plus and experimental heavy oil. (Together, these items can be grouped under the label "crude oil and equivalents," or simply "oil.")

Table 4-1

Production and Estimated Productive Capacity[1] of Crude Oil and Equivalent, Canada, 1983

	Production	Estimated capacity
	(Thousands m^3/d)	
Conventional light oil	154.8	165.1
Conventional heavy oil	33.1	34.2
Synthetic oil	25.4	25.4
Pentanes plus	14.5	14.5
Experimental heavy oil	4.0	4.0
Total	231.7	242.5

1 Production figures are actual, whereas productive capacity is estimated.
SOURCE Based on data from the National Energy Board.

Virtually all of this production came from western Canada. There was no production from the frontier areas in the North and offshore; and, except for the Norman Wells field in the Northwest Territories (scheduled to begin production in 1985), none is expected before the 1990s.

Conventional light oil was produced mainly from primary and secondary recovery. There was also some tertiary recovery, or "enhanced oil recovery" (EOR).

Most of the production of conventional heavy crude oil in 1983 also came from primary and secondary recovery. None of this output was subsequently "upgraded" into lighter oil, a process that requires sizable capital investments; heavy-oil upgraders are presently forecast by the National Energy Board to come on stream in 1988 and 1989, but it is doubtful that they will actually be operative before the 1990s.

The Terminology of Oil Supply

Light crude oil – A term applied to crude oil having a low density – for example, less than 900 kilograms per cubic metre.

Heavy crude oil – Crude oil having a high density – for example, more than 900 kilograms per cubic metre.

Conventional crude oil – As used in this report, crude oil (light and heavy) from conventional producing areas, excluding oilsands, pentanes plus and experimental heavy oil.

Bitumen – A natural viscous mixture, composed mainly of hydrocarbons heavier than pentanes, that is not recoverable at a commercial rate through a well.

Synthetic oil – Crude oil produced by treating bitumen in upgrading facilities designed to decrease its viscosity and sulphur content.

Oilsands – Deposits of sand, sandstone or other sedimentary rocks, containing crude bitumen.

Pentanes plus – A liquid composed primarily of pentanes and heavier hydrocarbons; generally a by-product of the processing of natural gas.

Crude oil and equivalent – A term referring to the sum of light and heavy crude oil, synthetic oil and pentanes plus.

Primary recovery – The recovery of crude oil through natural depletion processes only; yields about 20 per cent of the oil in place.

Secondary recovery – The recovery of crude oil through pressure-maintenance schemes, such as waterflooding or gas injection; yields an additional 15 per cent or more of the oil in place

Tertiary recovery – The recovery of crude oil through a process other than primary or secondary – for example, through miscible-flood processes; involves the injection into the formation of a fluid that will readily mix with the remaining oil and permit its recovery from the porous rock; increases the total recovery by about 10 or 20 per cent.

Enhanced recovery – Generally refers to the sum of secondary and tertiary recovery. As used in this report, however, refers mainly to tertiary "miscible-flood" recovery.

Miscible-flood recovery – Incremental recovery of crude oil by flooding a reservoir with miscible fluids – fluids that mix readily with crude oil (generally natural gas liquids) – either following or replacing waterflooding and/or gas injection.

In situ recovery – The process of recovering crude bitumen from oilsands by processes other than surface mining.

Productive capacity – The estimated rate at which crude oil can be produced from a well, a pool or any other entity, unrestricted by demand, taking into account reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling, the availability of field facilities, and potential losses due to mechanic breakdown.

"Shut-in" capacity – Unused productive capacity.

Adapted from NEB, *Supply and Demand 1983-2005.*

The production of synthetic (mostly light) oil came from the two commercial Athabasca plants that separate bitumen from the mineable oilsands and process or refine it. There was no *in situ* production being upgraded into synthetic light oil from the deeper oilsands deposits. The large experimental *in situ* plants (at Cold Lake and Wolf Lake) announced recently will produce a heavy crude oil for special markets.

Some 4,000 m^3/d of the production of pentanes plus in 1983 was used as a diluent for facilitating the movement of heavy oil through pipelines. (Diluents are generally included with heavy, rather than light oil.)

Finally, the production of experimental heavy oil is mainly from thermal EOR processes, which involve techniques other than the more common miscible-gas flooding.

The total production rate of oil in 1983 was less than the estimated productive capacity (Table 4-1). There was "shut-in" conventional light oil in the first months of the year, due to a slowdown in domestic markets. In response, the NEB authorized additional sales abroad of some 4 million m^3 of light crude for the year.[1]

In 1983, for the first time since 1974, Canada was a net exporter of crude oil (Table 4-2), the trade surplus arising from the net exports of heavy oil. This country exports most of its production of heavy oil because it does not have the refineries necessary to process or upgrade it. On the other hand, Canada continues to import net amounts of light oil. Heavy-oil upgraders have been proposed as a means of achieving a better overall supply/demand balance for crude oil in Canada, but the viability of such investments has not yet been proven.

Table 4-2

Trade of Crude Oil and Equivalent, Canada, 1983

	Exports	Imports	Net exports
	(Thousands m^3/d)		
Light oil	9.5	23.2	-13.7
Heavy oil	31.7	11.4	20.3
Total[1]	41.1	34.6	6.5

1 The total figures do not include exchanges of crude oil with the United States, which amounted to 4,700 m^3/d in 1983. Refined petroleum products have not been accounted for in the total amounts. In 1983, net exports of petroleum products amounted to about 12,000 m^3/d.
SOURCE Based on data from Energy, Mines and Resources Canada.

The Evolution of Oil Supply

Even if the present supply and demand situation were considered satisfactory, Canada's short-run oil supply has often been a poor indicator of the long-run trend. New discoveries have tended to excite excessive optimism, while a lack of discoveries has led to undue pessimism. Notwithstanding the spurts and sputters in new petroleum discoveries, most of the period of development in the Western Canada Sedimentary Basin (or, simply, "Western Basin") has been marked by a surplus of oil capacity relative to the domestic market west of the Ottawa Valley. As a consequence, a main element of policy before 1973 was the desire to expand exports to the United States.

The origins of the Canadian oil industry in Petrolia, Ontario, coincided with the development of the U.S. industry, which began in Pennsylvania in the 1860s. At that early stage, Canada was a net importer of oil from its southern neighbour. While Alberta's oil potential was recognized as early as 1913, with the discovery of the Turner Valley oil field, Alberta did not become a major oil-exporting province until after the discovery of the Leduc field in 1947. Since then, the Canadian oil industry has evolved to its present position through cycles of exploration, development and production activity focused mainly on conventional sources in the southern part of the Western Basin – primarily in Alberta and, to a lesser extent, in Saskatchewan, with some production also occurring in British Columbia and Manitoba. Beginning in the 1960s, exploration began to gather momentum in the Mackenzie Delta and the Beaufort Sea, in the Arctic Islands region, as well as off the East Coast.

Following the Leduc discovery, intensive exploration in the western provinces resulted in a number of significant discoveries – at Redwater (1948), Fenn Big Valley (1950), Bonnie Glen (1951), Pembina (1953), Swan Hills (1957), Mitsue (1964), Nipisi (1965) and Rainbow (1965). Oil production increased by as much as 40 per cent a year, rising from 3,400 m^3/d in 1947 to 56,700 m^3/d in 1955 (Table 4-3). Alberta became the predominant producing province, accounting for about 85 per cent of Canada's annual production over the past decade.

In the years immediately following the Leduc discovery, production was unregulated. By 1950, substantial surplus reserves existed, prompting the industry to request that the Oil and Gas Conservation Board initiate a regulatory scheme. A system of "prorationing" production to market demand was introduced in 1950. Under this system, allowable production from each pool is determined by the reserves in the pool as a proportion of total industry reserves, and total industry production is determined by market demand.[2]

Exploration continued during the early 1960s, but discoveries were generally few and small. The industry's efforts began to shift towards proving up through further development the large reserves previ-

The Terminology of Oil Reserves

Established reserves – The oil or gas reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing and production – plus that portion of contiguous recoverable reserves that is believed to be present with reasonable certainty, on the basis of geological, geophysical or similar information.

Initial established reserves – The established reserves before deduction of any production.

Remaining established reserves – The initial established reserves less the cumulative production.

Reserve additions or "booked reserves" – The incremental changes to established reserves over a period of time, resulting from the discovery of new pools or extensions of existing pools – for example, following enhanced oil recovery – and/or revisions to previous reserve estimates.

Ultimate potential – An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, taking into account the geological prospects of the area and anticipated technology and economic conditions. The ultimate potential is the sum of the initial established reserves and the estimated future additions.

Adapted from NEB, *Supply and Demand 1983-2005.*

Canadian Geology and Oil and Gas Resources

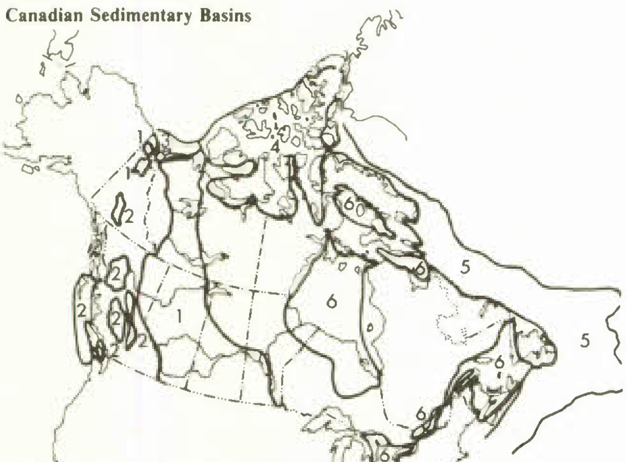
Canada is well endowed with natural resources, including oil and natural gas, because of the complex and varied nature of the geology of its landmass and flooded continental borders. Three major geological settings comprise the framework of Canadian geology. The most complex and oldest rocks are exposed in the vast central regions known as the Precambrian Shield and underlie the geologically stable region known as the craton. The craton was covered by shallow seas over much of geological time, and the sediments deposited in these seas now constitute the sedimentary basins of Canada. The habitat of oil and gas exists primarily in the sedimentary cover of the craton and its margins. Geological characteristics such as age and structure allow the organization of the sedimentary basins into six major petroleum regions – the Western Canada Sedimentary Basin, the Cordilleran Basin, the Beaufort Sea/Mackenzie Delta region, the Arctic Islands, the Eastern Canada Offshore and the Paleozoic Basins of eastern Canada.

Historically, the Western Canada Sedimentary Basin (or "Western Basin") has been the most important source of hydrocarbons in Canada. It comprises close to 70 per cent of all the oil and gas resources discovered to date.

The layers of a basin are separated into eras and periods (or "horizons"). A review of oil supply can be done by looking at the basins, horizons and/or any other supply unit. In this report, we focus our analysis on four of the basins – the Western Basin, the Beaufort Sea/Mackenzie Delta, the Arctic Islands and the Eastern Canada Offshore. In examining the responsiveness of oil supply, we have also considered specific horizons of the Western Basin to provide a more disaggregated assessment of the supply potential.

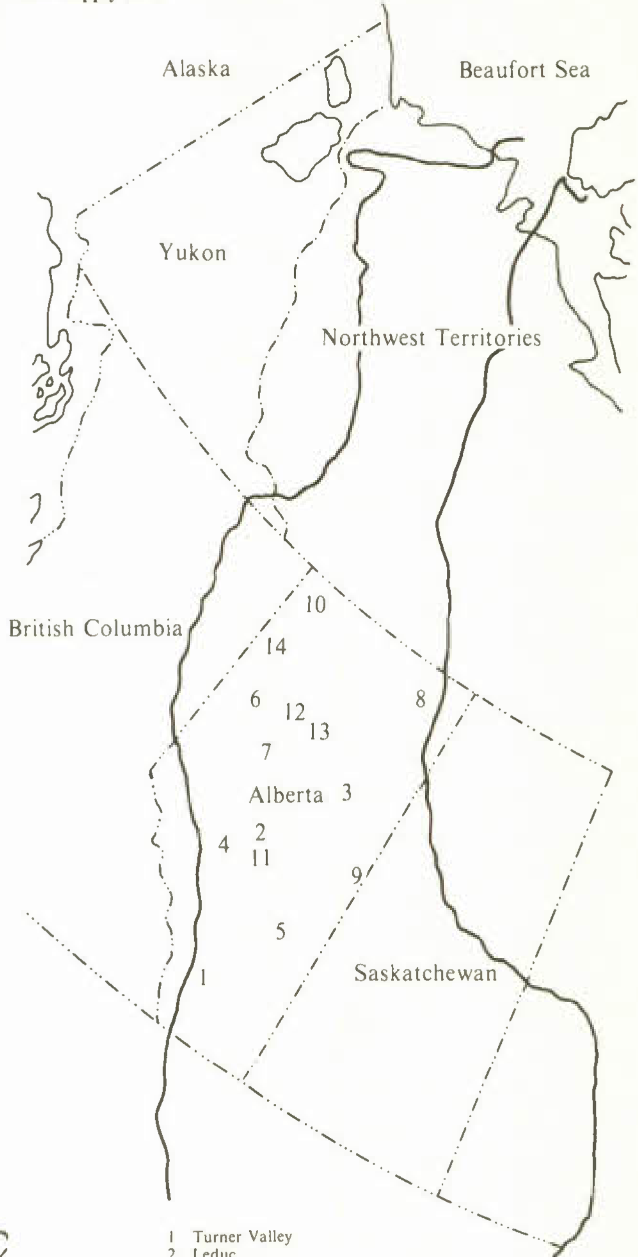
Adapted from Procter, Taylor and Wade, *Oil and Natural Gas Resources of Canada.*

Canadian Sedimentary Basins



1 Western Canada Sedimentary Basin
2 Cordilleran Basin
3 Beaufort Sea/Mackenzie Delta
4 Arctic Islands
5 Eastern Canada Offshore
6 Paleozoic Basins of Eastern Canada

Western Canada Sedimentary Basin: Major Oil Discoveries and Supply Sites



1 Turner Valley
2 Leduc
3 Redwater
4 Pembina
5 Fenn Big Valley
6 Peace River
7 Swan Hills
8 Athabasca (Fort McMurray)
9 Lloyminster
10 Zama
11 Bonnie Glen
12 Nipisi
13 Mitsue
14 Rainbow

Table 4-3

Production of Crude Oil and Equivalent, Canada, by Producing Region, 1947-82

	Northwest Territories	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Canada
				(Thousands m³/d)			
1947	0.1	–	3.0	0.2	–	0.1	3.4
1950	0.1	–	12.0	0.5	–	0.1	12.7
1955	0.2	..	49.6	4.9	1.8	0.2	56.7
1960	0.2	0.7	58.5	22.6	2.1	0.4	84.6
1965	0.3	6.3	91.6	38.3	2.2	0.6	139.2
1970	0.4	11.5	167.3	39.1	2.6	0.5	221.4
1975	0.4	6.8	215.2	25.8	1.9	0.3	250.5
1980	0.4	5.9	209.3	25.6	1.5	0.3	243.1
1982	0.5	6.1	183.5	22.3	1.6	0.2	214.2

SOURCE Based on data from the Canadian Petroleum Association.

ously discovered, so that additional reserves could be "booked" with the provincial regulatory authorities. New oil-transportation systems – the Trans Mountain pipeline to British Columbia and the state of Washington, inaugurated in 1953, and the extension of the Interprovincial pipeline to Toronto in 1957 – allowed crude oil to move out of Alberta to new markets. Production increased to some 100,000 m³/d in the early 1960s, but growth was slower than during the first decade of industry activity.

The National Oil Policy (NOP) of 1961, which guaranteed western producers the Canadian market west of the Ottawa Valley and encouraged exports, triggered a new period of intensified production and development. In less than 10 years, production doubled to reach 220,000 m³/d in 1970. By that time, some 50 per cent of Canadian production was destined for export markets, up from about 25 per cent in the early 1960s.

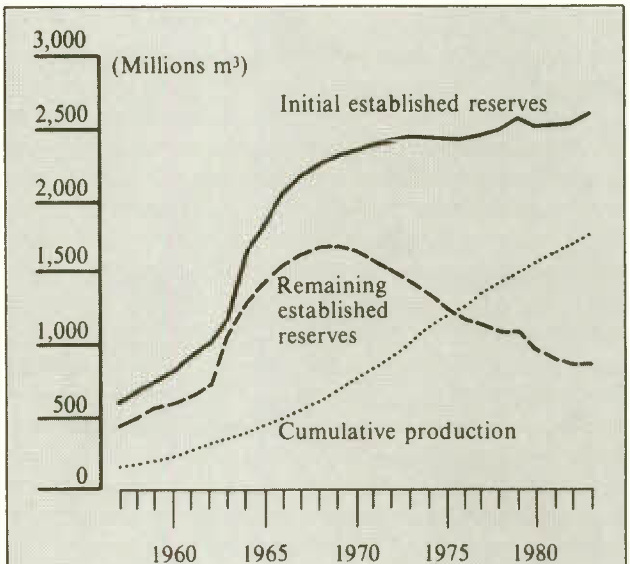
One significant development of the 1960s was the daring decision by Sun Oil to go ahead with the construction of the Great Canadian Oil Sands Plant at Fort McMurray in 1967. The Fort McMurray plant was the smallest oilsands project considered to be economic at that time; it produced some 2.5 million m³ of synthetic crude in its first three years of operation. It showed that some techniques could be applied to mine the oilsands, although those techniques were not profitable at that time.

With the exception of the pinnacle reefs at Keg River (1965) and Zama (1967), few large discoveries were made in the 1960s. The major companies began to move to the Canada Lands (lands under federal control in the territories and offshore), focusing at the same time on increasing the recovery of oil from the reserves that had already been established. Thus the additions to the established reserves during the 1960s were more from secondary recovery than from new discoveries.

Since 1970, the additions to the established reserves of crude oil – including new discoveries, re-evaluation of previous discoveries, and secondary oil recovery but excluding oilsands and pentanes plus – have not kept pace with production in most years. Hence Canada's remaining established reserves of crude oil have been declining fairly steadily (Chart 4-1).

Chart 4-1

Established Reserves and Cumulative Production of Conventional Crude Oil, Canada, 1957-83



SOURCE Based on data from the Canadian Petroleum Association.

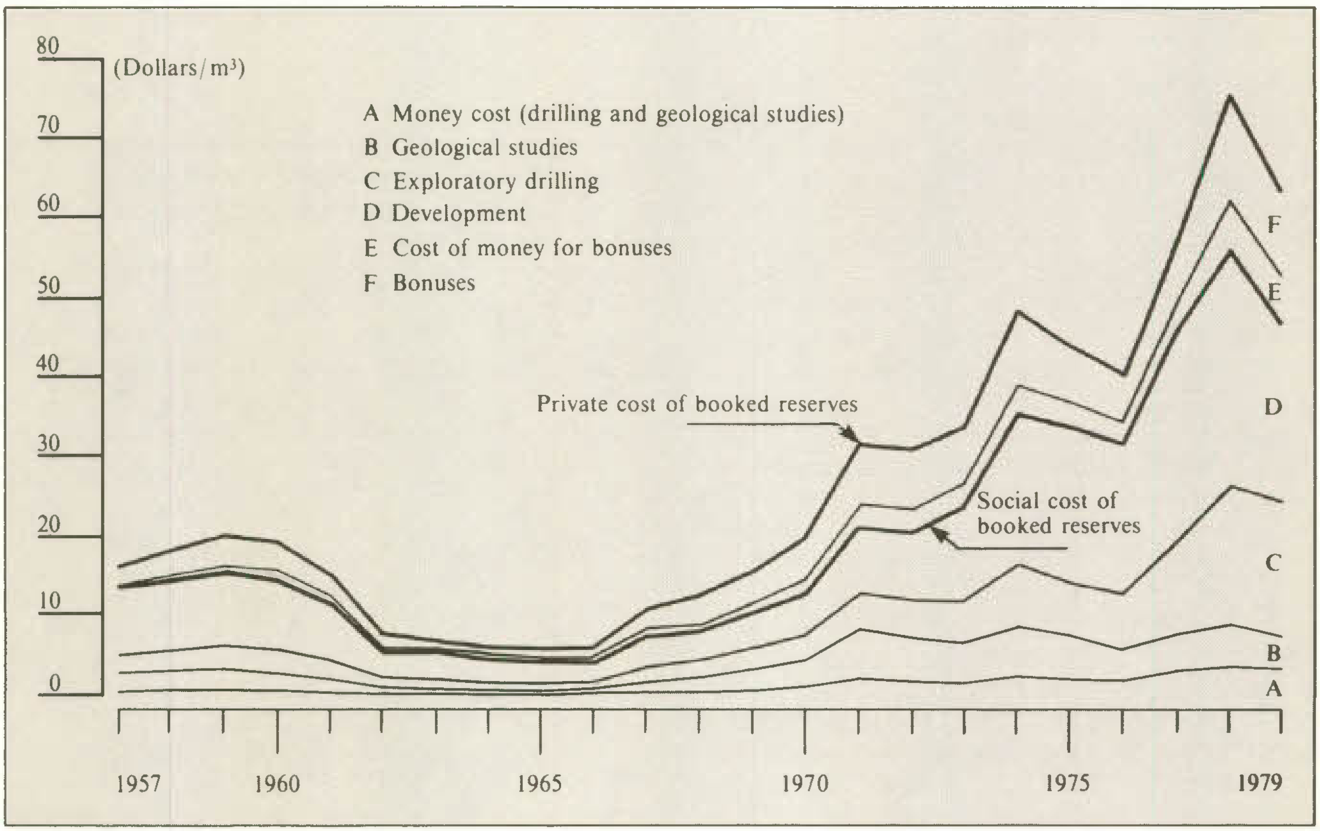
A factor affecting the level of exploration activity in western Canada during the late 1960s and the 1970s was the increasing cost of finding new conventional oil pools. A review of industry expenditures between 1960 and 1979 shows that while year-to-year cost variations were erratic, there was indeed a clear upward trend (Chart 4-2). The "social" cost of booked reserves – the cost to industry, excluding net payments to government – increased from some $5/m^3$ in the mid-1960s to a range between $30/m^3$ and $60/m^3$ in the late 1970s. (The costs are smoothed over five-year periods and expressed in 1983 dollars per cubic metre of oil in the ground.)[3] Increases in the "private" costs – the costs to industry, including net payments to government – have been of the same order. There were increases in all cost components – geological activities, exploration drilling, cost of money, development and bonuses paid to government (Chart 4-2). The costs of exploration drilling increased the fastest (Table 4-4), reflecting the more costly efforts needed to discover oil. More recently, however, the rising trend in costs has slowed down.

The higher costs of finding oil, combined with changes in government policy, have limited the incentives to look for the "black gold." After 1974, with domestic oil prices below world levels and with changes in domestic and export gas pricing and other policies, for the first time it became more profitable to drill for gas. As a result, exploration in the Western Basin in the latter half of the 1970s was targeted mainly at finding gas rather than oil. Moreover, the decline in discoveries of conventional crude oil, associated with the lack of incentives to explore for oil, led policy makers to be pessimistic about Canada's potential to establish new reserves of conventional oil. In short, policy stimulated gas supply in circumstances that, by the late 1970s, called for additional oil.

Not only did oil exploration activity decrease during the 1970s, but so did production. Production reached its peak in 1973, with more than half going to exports, but the federal government's decision to conserve Canadian oil by reducing exports and to maintain domestic oil prices below world levels contributed to a

Chart 4-2

Cost Components for Booked Reserves of Conventional Crude Oil in Alberta, 1957-79[1]



1 Costs (expressed in 1983 dollars) are averaged over five-year periods.
SOURCE Eglington and Uffelmann, "Oil and Gas Reserves in Alberta."

Table 4-4

Component Costs[1] of Booked Reserves of Crude Oil in the Ground, Alberta, 1960 and 1979

	1960		1979	
	Cost	Distribution	Cost	Distribution
	(Dollars/m³)	(Per cent)	(Dollars/m³)	(Per cent)
Bonuses	4.01	20.5	10.84	17.1
Geological and geophysical activities	2.29	11.7	3.58	5.7
Exploratory drilling	2.82	14.4	17.42	27.5
Development drilling	8.90	45.6	22.42	35.5
Cost of money	1.52	7.8	8.98	14.2
Total	19.53	100.0	63.24	100.0

1 In 1983 dollars. The costs for each year have been averaged (or "smoothed") over five-year periods in order to show more clearly the overall trend in the cost series. The erratic nature of the costs that have not been averaged is a result of the variation in annual success ratios and discovery sizes and tends to make the upward trend in costs less evident.

SOURCE Eglington and Uffelmann, "Oil and Gas Reserves in Alberta."

30 per cent decline in production – from 312,100 m³/d in 1973 to a low of 217,600 m³/d in 1982 (Chart 4-3).

The rising world oil prices improved the prospects for mining the tarsands, but the oilsands projects were still subject to considerable economic uncertainty. With provincial and federal government participation, the only new project to come on stream after the Great Canadian Oil Sands Plant was the large-scale Syncrude plant at Fort McMurray in 1978, which resulted in synthetic crude production increasing from 7,200 m³/d in 1977 to 19,100 m³/d in 1982. A third mining project, the Alsands megaproject, proposed in 1977, was projected to produce 219 million m³ of synthetic crude over a life of 29 years. In April 1982, however, after some five years of planning, the Alsands consortium announced the suspension of its activities.

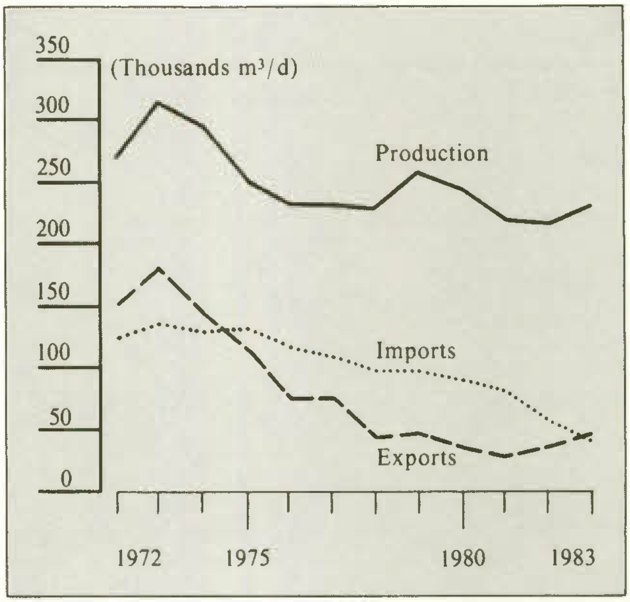
In the years that have elapsed since the introduction of the National Energy Program (NEP) in October 1980 and the federal-provincial agreements signed in 1981, industry activity has changed considerably. With the new-oil reference price (NORP) being based on world oil prices, it became more profitable once again to drill for oil than for gas, especially in view of the emerging excess supply of natural gas in Canada and the United States. In recent years, the greatest share of exploration funds has been spent in Canada Lands, where Canadian companies receive grants equivalent to up to 80 per cent of exploration costs through the PIP scheme.

Throughout its development, the Canadian petroleum industry has been characterized by a very distinct industry structure. Foreign control and ownership of the industry have been particularly high in comparison with other sectors of the energy industry. During the 1960s, the level of foreign control in the industry hovered around 90 per cent, while foreign ownership was in a range between 75 and 80 per cent. By the late 1970s, a decline in the level of foreign control was evident, and in 1982 the level was about 74 per cent. It was not until the introduction of the PIP grants in 1980 that the foreign-ownership level showed any significant decline; by 1982, the level was about 66 per cent.[4]

Industry activity is carried out, in part, by a number of small independent companies involved in exploration

Chart 4-3

Production and Trade of Crude Oil and Equivalent, Canada, 1972-83



SOURCE Based on data from Energy, Mines and Resources Canada.

and production. Of the hundreds of companies in the industry, fewer than 10 are fully integrated operations, involving exploration, production, transportation and marketing. The major shareholders of most of the integrated firms are foreign.

In summary, the recent evolution of the Canadian oil industry points to three important trends. First, with few exception over the past decade, oil production has been declining: 10 years ago, Canada was producing at a rate about one-third higher than today's level. Second, the remaining established reserves of conventional crude oil have been reduced because additions to the reserves have not kept up with production. And, third, the cost of finding oil has been rising.

Future Outlook

Under the present circumstances and policy, the observed trends in oil supply, particularly the lowering of both the reserves and the production of conventional oil, are expected to continue as we approach the mid-1980s. The most recent forecast by the NEB shows that future Canadian production of light oil will be below domestic demand, except for a brief period following the assumed initiation of production in the frontier areas in 1993.[5] That forecast implies a continuing need for small imports of light oil, whereas the production of heavy oil is expected to exceed domestic requirements and provide an exportable surplus.

The NEB foresees major shifts in the composition of Canadian oil supply (Table 4-5). The productive capacity of conventional oil is expected to decline rapidly, although the drop would be partially offset by increased production from the oilsands and from the frontier areas in the early 1990s. In total, Canadian productive capacity would fall by 20 per cent by 1990 but would return to close to its present level in 1995.

Conventional Light Oil

The productive capacity of conventional light oil is expected by the NEB to drop by about half between 1983 and 1995. The forecast starts from a 1983 level of remaining established reserves of conventional light crude oil of 617 million m^3. These reserves, largely concentrated in the Western Basin, are equivalent to some 11 years of supply at current production rates. The NEB estimates that the ultimate potential for additions to the reserves is about 684 million m^3 (Table 4-6), mainly from new discoveries and from enhanced recovery from known reserves.

The potential additions to the established reserves from new discoveries are estimated by the NEB to be no more than some 280 million m^3 – about five years' worth of supply. The Board also forecasts that these additions will occur at a rapidly declining rate and will be surpassed in the early 1990s by additions from secondary and tertiary EOR. A significant EOR potential of some 319 million m^3 is forecast; additional recoverable reserves are expected to show up in the near future as a number of currently planned miscible-flood projects become a reality.

Overall, the NEB forecast of potential supply additions of conventional light oil suggests that the Western Basin is currently over 50 per cent depleted and that limited supply – a maximum of some 25

Table 4-5

NEB Forecast of Productive Capacity of Light and Heavy Oil, Canada, 1983-95

	Light oil				Heavy oil				Total			
	1983	1985	1990	1995	1983	1985	1990	1995	1983	1985	1990	1995
	(Thousands m^3/d)											
Conventional crude oil	165.1	157.0	109.1	81.7	34.4	36.5	29.4	27.1	199.5	193.5	138.5	108.8
Established reserves	165.1	153.1	80.0	44.9	34.4	34.7	18.7	10.1	199.5	187.8	98.7	55.0
Reserve additions	–	3.9	29.1	36.8	–	1.8	10.7	17.0	–	5.7	39.8	53.8
Pentanes plus	9.0	8.2	8.4	3.2	5.5	7.2	8.7	11.0	14.5	15.4	17.1	14.2
Synthetic crude and experimental heavy oil[1]	23.5	25.0	28.5	38.5	4.0	7.0	17.0	25.0	27.5	32.0	45.5	63.5
Frontier production	–	–	1.9	44.0	–	–	–	–	–	–	1.9	44.0
Upgraders[2]	–	–	14.0	15.0	–	–	–16.0	–17.0	–	–	–2.0	–2.0
Total	197.6	190.2	161.9	182.4	43.9	50.7	39.1	46.1	241.5	240.9	201.0	228.5

1 Light synthetic crude from the Athabasca oilsands and heavy oil from experimental thermal EOR projects.
2 The amount of heavy oil being upgraded appears under "heavy oil"; the resulting amount of light oil appears under "light oil"; and the net loss occurring in the process appears under "total."
SOURCE Based on data from the National Energy Board.

Table 4-6

Ultimate Potential for Conventional Light and Heavy Crude Oil, Canada

	Light crude	Heavy crude
	(Millions m³)	
Initial established reserves[1]	2,055	366
Cumulative production	1,438	247
Remaining established reserves	617	119
Potential additions	684	521
Discoveries	280	140
Secondary recovery from established pools	85	100
Tertiary EOR	319	281
Thermal EOR (Lloydminster area)	. . .	216
Other	. . .	65
Total ultimate potential	2,739	887

1 At 31 December 1982.
SOURCE Based on data from the National Energy Board.

years' worth, at present supply rates – will be available through recovery from the existing remaining reserves, plus new reserve additions, for future production. As a consequence, the NEB foresees a continuing decline in the productive capacity of conventional light oil, which suggests that there will be a growing need to obtain additional light oil from either the frontier areas, the mineable oilsands or the upgrading of heavy oil.

Conventional Heavy Oil

In the case of conventional heavy crude oil, productive capacity is forecast by the NEB to decrease by some 20 per cent between 1983 and 1995 (Table 4-5). A considerable portion of future production is assumed to be used as feedstock for two proposed heavy-oil upgraders expected by the Board to come on stream in 1988 and 1989, respectively.

The Western Basin has a very large resource base of conventional heavy crude oil. At the beginning of 1983, however, the remaining established reserves were 119 million m³ – only some nine years of supply, at current rates. The NEB estimates a potential for additions from new discoveries of 140 million m³ (Table 4-6), with an additional 381 million m³ potentially coming from secondary recovery and tertiary EOR (mostly from the Lloydminster thermal-recovery projects). As in the case of light oil, the rate of additions from EOR would gradually surpass new discoveries.

Synthetic Light Oil from Oilsands

The NEB forecasts that the productive capacity of synthetic light oil from the oilsands plants will increase by about 15,000 m³/d between 1983 and 1995 (Table 4-5). This is based on the assumption that Syncrude will undergo a 3,500 m³/d expansion by 1988 and that production of 10,000 m³/d from an additional oilsands plant will occur by 1992.

Overall, the remaining established reserves of mineable oilsands are estimated to exceed 5 billion m³ – enough to supply the equivalent of more than 50 years of Canadian light oil demand, at current rates.[6] However, the established reserves of synthetic oil associated with the two operating mineable-oilsands plants are only about 200 million m³, measured in terms of the plants' productive capacity and assumed 25-year economic life.[7] A substantial number of additional plants would therefore be required to exploit the remaining volume of mineable oilsands.

Frontier Oil

The NEB forecast for the frontier areas includes production from the Hibernia offshore field and from the Beaufort Sea, assumed to start in 1993 in both cases. The productive capacity from those sources would reach 44,000 m³/d by 1995. No production is assumed from the Arctic Islands region, where oil reserves have also been discovered.

While there is no "connected" productive capacity (i.e., deliverable to markets) in the frontier areas, the Geological Survey of Canada[8] has defined the following reserves as "best current estimates" of discovered reserves: Beaufort Sea, 117 million m³; Arctic Islands, 76 million m³; and East Coast Offshore (including Hibernia), 225 million m³. Best current estimates are commonly based on a single well per discovery, plus the best available geological-engineering judgment. Established reserves, on the other hand, are viewed as rigorously quantified amounts of oil that can be produced with a high degree of certainty under current and anticipated economic conditions. The NEB concluded in 1981 that sufficient drilling had been done in the Jeanne d'Arc Basin, which forms part of the Hibernia field, to justify the inclusion of 50 million m³ of recoverable crude oil in the established reserves.[9] Additional drilling since 1981 has pushed the delineation of the Hibernia field further, and the established reserves are now estimated by the operator to be 160 million m³.

Overall Prospects

Conventional oil supply in Canada has never unfolded in a smooth succession of discoveries and development. The Leduc discovery occurred after a series of over 100 drillings by Imperial Oil. The West Pembina discoveries in 1977 surprised everybody, except of course the companies that were investing in the exploration. These ups and downs – the uncertainty of exploration – complicate supply forecasting and oil supply policy. That is particularly true today, after such radical shifts have occurred in the potential economics of oil supply. We have noted that the remaining established reserves of conventional oil declined in the 1970s and early 1980s – a trend that is likely to continue, according to the NEB. At the same time, exploration and development costs have been rising. But are these trends irreversible? Exploration and production technology is continually improving, and the potential economics of supply, given current prices, are better than in 1970.

In our view, the NEB forecast of conventional light oil provides a rather bleak outlook for the Western Basin. This may reflect recent government policy, which was inclined to focus on nonconventional megaprojects and the frontier areas. The heavy-oil reserve potential is less uncertain than that for light oil, but the markets for heavy oil are limited. Should economic considerations prevent the upgraders from coming on stream as forecast, it seems doubtful that the productive capacity from heavy oil would increase as much as expected.

The forecast establishment of a new, large-scale oilsands mining plant by 1992 could be optimistic. These mining plants have been seen as providing a "backstop" supply. Earlier forecasts tended to assume that they could be put in operation in sequence, to fill the predicted gaps between oil supply and demand. For example, the NEB predicted in 1974 that the daily production from the oilsands by 1993 would be about 184,000 m^3/d, but its current forecast is only 38,500 m^3/d – a huge reduction in expectations, particularly in view of the increase in the world oil price since 1974.

Current knowledge about the oil resources in the frontier areas is only rudimentary. While the NEB has been cautious in the past when forecasting the start-up of frontier production, three of the major companies estimated, in a submission read at a 1975 NEB hearing, that Mackenzie Delta/Beaufort Sea production would commence by 1984.[10] The current NEB forecast assumes that frontier production will not begin before 1993, which appears to be about the earliest date that could be expected, given the regulatory, engineering and financial requirements to be met.

A significant constraint on the development of productive capacity in the frontier areas is the long lead time involved. The normal pace of exploration and development is greatly slowed by the difficulties of the environment. There has yet to be a "threshold" commercial discovery in the Beaufort Sea, although exploration activities have been carried out in that region for nearly 30 years. The Hibernia oil field, discovered in 1979 after a decade of exploratory activity, is considered to have commercial potential, but there are a number of technological and regulatory uncertainties that will prevent production for some time. The same is true of the Arctic Islands region, where a great deal of exploration activity has taken place since the first "wildcat" discovery in 1962, but where the date of initial large-scale production is still very uncertain.

In summary, oil supply forecasting is not the easiest of tasks, particularly because of the uncertainty present at most stages of the supply process and because prices, costs and policies have a substantial impact on industry activity. The present NEB forecast, which reflects the prospective impact of recent government policy, shows a reduction in conventional light-oil supply from the Western Basin. Our own research suggests that more conventional oil could be produced economically if adequate changes were made in policy. The mineable oilsands, frontier oil and the heavy-oil upgraders can play their part, but alongside conventional production rather than as a replacement for it.

The Process of Oil Supply

The complexity of oil supply and, therefore, of supply policy begins with a fundamental characteristic of the oil pool itself – its nonrenewability. As oil is produced, the reservoir is depleted; and, ultimately, the economically recoverable oil will be used up. While any given oil pool will be depleted, however, the aggregate remaining established reserves in all the discovered and developed pools in the industry can be sustained by adding new reserves through exploration or through an improvement in the rate of recovery from the reserves already discovered. For this to happen, there must be an economic incentive – at least a normal return to the exploration or development investment involved.

The Supply Cycle

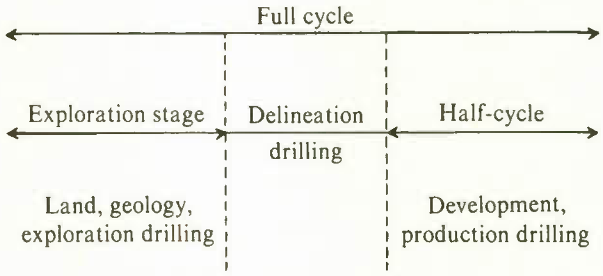
Therefore, the overall supply process can be viewed as including several stages – exploration, discovery, development and production – in a cycle that lasts some 20 to 30 years. If the level of production is to be maintained over the long run, each cycle must be followed by more cycles, commencing with new exploration, long before the first pools are totally depleted.

Each stage in the full cycle has its own set of uncertainties and costs. Activity begins with exploration, which includes geological and geophysical surveys to identify potential oil-bearing structures. If an exploratory well drilling results in a discovery, follow-

The Cycles of the Supply Process

The *full cycle* of the oil and gas supply process includes all activities from the beginning of the exploration stage to the time that the production of the developed reserves terminates. The so-called *half-cycle* (i.e., the development partial cycle) does not include exploration activities, but its starting point is not always clear: reserve delineation may or may not be included. It is generally accepted that the half-cycle begins when the decision is made to proceed with development, but some further delineation drilling may be required. In our cost analysis, delineation activities are included in the half-cycle for the Beaufort Sea and Hibernia developments. They are not included in the Venture gas half-cycle.

The costs of the full-cycle activities are the most relevant with respect to judging a project's profitability and the economics of alternative sources of oil and gas. Policy can be properly set only if the full-cycle economics of alternative projects are considered.



up delineation wells are drilled to determine the size of the pool and of the undeveloped reserves. Coincidentally, the reserves are partially developed. At year's end, the reserves are booked with the appropriate government authority, showing the estimated initial reserves in place and the initial established reserves.

The sum of the costs incurred during the exploratory stage is known as the "finding costs" of undeveloped reserves. The social finding costs comprise not only the cost of successfully drilled discovery and delineation wells, but also the cost of dry holes drilled in the process of locating the reserves.

The second stage of the process is development. It comprises development drilling – drilling the number of wells required for efficient production – and the installation of field equipment. During development drilling and production, additional information and re-evaluation may lead to a change in the established reserves that will subsequently be booked.

The sum of the social costs incurred up to this point – that is, all exploration and development costs, including the cost of money – is the social cost of the developed reserves *in the ground*. It can be converted to a cost of reserves *per unit of production at the wellhead* by the use of a factor that takes into account the value of money over time and the production rate during the productive life of the reservoir. This "levelized exploration and development cost," as we call it, becomes the total exploration and development component of the cost of supply.

The final stage of the supply process is production. Generally, it involves the primary and secondary recovery of oil from established reserves, but it can also, in some cases, involve the tertiary phase of enhanced oil recovery. The costs during production include all of the operating and other costs for lifting the oil from the reservoir.

The total costs associated with the three stages of the supply cycle are referred to as the "full-cycle costs"; they are the costs that have to be covered for the production of new supplies to be economically justifiable. By comparison, the "half-cycle costs" comprise only development and production and, in some cases, delineation drilling. In terms of a company's sequential decision making, once reserves have been found and exploration costs have already been incurred, only the half-cycle costs would have to be covered for development and production to be economically justifiable. But unless the full-cycle economics are positive, the reserves would not be replaced and future production would not be sustained.

Social and Private Costs

We refer often to the costs of oil and natural gas supply as being either "social" or "private."

The *social* supply costs refer to the total costs to industry before any payments to government and any receipt (subsidy) from government. The social costs are measured in real (constant) dollars per unit of supply – in this chapter, generally, in 1983 dollars per cubic metre of oil. They are given by dividing total discounted costs by total discounted production, using an appropriate discount factor – 10 per cent in this chapter.

The *private* supply costs are calculated in an analogous manner but they include the discounted costs of bonus, royalties and taxes, net of subsidies, paid to government.

Payments to governments are not included in social costs because they are considered to be transfers. However, they are costs incurred by the private producer.

In reality, many complications that tend to obscure the full-cycle process could arise. For example, exploration can lead to an oil discovery, a gas discovery, a well producing both oil and gas, or a dry well. This joint-product aspect of oil and gas supply requires that costs be assigned to the various resources or that they be lumped together as "barrels of oil equivalent." In this report, we have assigned costs whenever feasible.[11] More complications arise in the assessment of oil supply costs because of the lead times that elapse before the investment payoff and of the uncertainty about future costs.

In fact, uncertainty and incomplete information are inherent parts of the oil business. The geological uncertainty involves the degree of probability that exploration will lead to new discoveries – an uncertainty that the petroleum industry takes in stride as it considers the risks involved and the historical success ratios. Technological uncertainty arises with respect not only to exploration methods but also to development. It may, for example, relate to methods for extracting reserves that would be unrecoverable under normal production methods, or to the complex production systems needed for the offshore fields and the far North. Such technological development is risky and expensive, and it is characterized by long lead times that greatly complicate the formulation of effective supply policy. Moreover, both geological and technological uncertainties must be considered in relation to such factors as pricing and taxation over time.

Economic uncertainty – which involves such elements as future prices, costs and interest rates – is sometimes compounded by the adoption by governments of erratic and complex fiscal policies. This is known in some quarters as "political risk." The oil and gas companies are concerned not only with expected gains but also with the full range of possible financial outcomes. Each investment presents both a downside risk (i.e., things may deteriorate unexpectedly) and an upside risk.

The exploration process itself is comparable to industrial research and development, the outcome of which is also uncertain. Most oil pools are difficult to locate, and drilling is required to verify their existence; in addition, they range enormously in size and productivity. As in research and development, a company's expectations of success motivate the investment, and positive results will reinforce and sustain the effort.

The total costs incurred by industry to find, develop and produce oil – the private costs – are generally higher than the social supply costs because they include bonuses, royalties and taxes (less subsidies). The contrary can also be true, however, in the case where a project receives net subsidies in the form of tax credits or grants. (The taxes and royalties that comprise the Canadian petroleum fiscal system are summarized in Appendix B.)

The Profitability Issue

The incentive for industry to invest at any stage of the supply cycle is the expected profitability; in other words, the expected private costs must be less than the expected revenues attributable to each stage. The stages are interdependent, however. The expected profitability of production is an important determinant

Levelized Exploration and Development Costs

By using a conversion factor, it is possible to relate the costs for a stock of reserves in the ground to an equivalent levelized cost for a flow of oil or gas produced. Because significant capital outlays for exploration and development must be made upfront before a unit of gas or oil is produced, the objective in establishing such a cost relationship is to assign investments made for the exploration and development of reserves in the ground (dollars per cubic metre in the ground) to a barrel of production (dollars per cubic metre produced). In other words, we want to determine the amount that must be charged to each unit of oil or gas produced in order to recoup the costs of the investment necessary to undertake exploration and development. This cost is referred to here as the "levelized exploration and development cost."

The levelized cost is determined by the investment, the cost of money and the anticipated output profile. The expenditures for exploration and the development of reserves are assigned to the units that are produced in later time periods; thus the costs recovered from the units produced must be discounted to the present. The anticipated output can be approximated by the rate of output in the initial period and the rate of production decline. The production decline rate accounts for the fact that as gas and oil are produced in each period, the amount that remains to be produced declines and, therefore, so does production capacity.

The calculated value for the conversion factor for January 1983 was 2.12; we have applied that factor to both oil and gas costs in this report. The levelized costs are obtained by multiplying the 2.12 factor by the cost of reserves in the ground.

The cost of money assumed for both oil and gas is given by the McLeod Young Weir bond rate, augmented to take into account the debt/equity position of the petroleum industry. The cost of money is expressed in real terms. An 8 per cent production decline rate was used for both oil and gas.

of the profitability of development; and the latter, in turn, is a determinant of the expected profitability of exploration. A reduction in production royalties, for example, will therefore lead a producer to increase the amount he is willing to pay for reserves in the ground, and this will improve the expected profitability of exploration.

The profitability issue can best be illustrated by referring to the current situation with respect to the expected average profitability of new oil exploration in western Canada for large companies (Table 4-7). Naturally, the use of averages should not obscure the fact that some large companies have had much better exploration success than others and – depending on their exploration targets, the regions in which they are exploring and their cost levels – there may be wide variations between them in expected profitability.

It can be seen that the expected half-cycle (development and production) profitability is $53/m³. That is the amount that is available to pay for the exploration

Profitability and the Economic Rent

Few definitions of the economic rent are satisfactory, because the concept is blurred by the uncertainties and dynamics of the real world. Consequently, economists use David Ricardo's definition of *pure economic rent* as a starting point. Ricardo's pure resource rent refers to payments to landlords for the use of the "original and indestructible powers of the soil." The soil, or land, is considered both nonaugmentable and nondepletable; therefore, its receipts as a factor in production are simply a residual "scarcity payment," determined by the revenues from production after the costs of the other production factors have been taken into account. It is supposed that any residual payment greater than zero to the fixed quantity of land would call forth its use; even huge payments would not call forth any greater quantity of any particular piece of land. Consequently, the residual payment to a factor of production could be taxed away without altering the supply of that factor and, as a consequence, without altering the supply of the product.

There is a big step from this abstract concept to the uncertain real world of petroleum (and other mineral) supplies. For one thing, oil reserves are individually and collectively depletable as a result of production, and the supply of known oil reserves is augmentable through exploration. Therefore, while it is useful to begin with Ricardo's concept, it must be augmented to incorporate the effects of exploration and depletion. It is useful to distinguish between the economic rents earned by a natural endowment, like land or oil resources, and the quasi-rents that are earned by those involved in development and exploration.

The oil supply process can be viewed as including a number of stages, and one can speak of economic rents in the context of each of these stages: exploration, development and production. Such rents are better called *quasi-rents*, because apparent economic rents – for example, those accruing in the development and production half-cycle – have to be partially earmarked by the producer to pay for reserves either by purchase or through exploration. These rents are, therefore, partly pure resource rents and partly quasi-rents. Over the full cycle, any economic rent retained by industry would appear as profits above a normal return on investment. Presumably, such "excess profits" could be taxed away without depressing industry activity below its existing level.

Considerable difficulty arises for governments from the fact that the profitability of supply varies widely. Given the differential in the potential rents, the collection of the right amount of rent at the right time and place becomes a difficult task.

The collection of economic rent by government at the production stage is generally accomplished through royalties (or taxes) on production, often taken in-kind and viewed as capturing the pure resource rent. Such royalties should be geared to the short-run profitability of production, so that marginal wells, or pools, will not be "shut in" and the more profitable ones will pay the bulk of the royalties. To accomplish this, royalties are related to well productivity and to the level of prices as a rough means of relating them to profitability. However, it is important to note that not all of the apparent economic rents at the production stage – the production quasi-rents – should be taken by government (the landlord), because some of this profit is needed for replacing, by exploration or otherwise, the reserves that are used up in the process of production.

The main counterpart to royalties at the production stage are bonus payments at the exploration stage and sometimes at the development stage. Bonus payments are bids, made by industry at a government land auction, for exploration or development permits covering certain lands. Their level can, therefore, be seen as equivalent to the expected present value of the profitability from an exploration or development program, after taking into account the expected future prices and costs, including all production royalties and taxes. Bonus payments thus reflect the expected economic rent beyond that which will be captured at the production stage.

Bonus payments are a useful component of the fiscal system because they are like a shock absorber that will contract, if production royalties or taxes are increased, down to the point at which it will not appear worthwhile to bid. Alternatively, if production royalties are reduced, the size of the bonuses will increase, other things being equal. Bonuses, together with royalties, also provide for the sharing of risks by government and industry in the collection of the economic rent, with bonus receipts going early to government and royalty receipts going later.

To summarize, an efficient rent-collection system should be based both on bonuses and on flexible, profit-related production royalties or taxes.

Table 4-7

Approximate Expected Profitability (Social and Private) of New Oil Production for a Large Producer in Western Canada, 1983[1]

	(Dollars/m³)
Wellhead price	224
Less: Operating costs	28
Development costs	48
Production quasi-rent	148
Less: Provincial royalties (net incentives)	43
Federal PGRT	23
Income taxes	29
Available to pay for exploration	53
Less: Exploration costs	52
Available for exploration bonus payments	1
Summary	
Total revenue	224
Less: Full-cycle social supply cost (28 + 48 + 52)	128
Total economic rent available (148 – 52)	96
Less: Total royalties and taxes (43 + 23 + 29)	95
Available for bonuses	1

1 In 1983 dollars. The detailed calculations and explanations for this table appear in Appendix C.
SOURCE Eglington and Uffelmann, "Oil and Gas Reserves in Alberta"; and data from Energy, Mines and Resources Canada.

needed to find the reserve, involving costs such as drilling and bonus payments. At present, the average exploration costs are running around $52/m³, leaving only $1 to bid as bonuses. (These costs are examined in detail in Appendix C.)

Traditionally, royalties are aimed at collecting resource rents, but the interplay of the royalty and tax measures is a key factor. None of the royalty or tax instruments (the income tax and the petroleum and gas revenue tax – PGRT) can be viewed as purely aligned with resource rents, the income of capital, or any other base. The instruments interact, and one useful way to view them is in relation to the total economic rent available. As shown in Table 4-7, however, royalties and taxes at the production level take almost all the available economic rent. Consequently, on the basis of these averages, there is only a marginal incentive for large companies to undertake oil exploration activities in western Canada, because their expected costs, other than bonuses, are essentially equal to the expected revenue from a discovery.[12]

Bonus payments are generally an important "shock absorber" in the whole fiscal system, because they take up the slack from the effects of all the other factors – including taxes, royalties, expected prices, incentive payments, interest rates, the state of the market for the product, and so forth. In the full cycle, bonuses reflect the industry's perception of profitability and therefore will adjust, with some lags, to push the average rate of return on capital in the industry towards its opportunity cost – i.e., towards a "normal rate of return." At the present time, however, the scope for exploration bonuses to cushion the system is minimal.

If royalties or production taxes were reduced, bonus payments would tend to increase. In fact, this is an important method for sharing the risks between government and industry. Tilting the fiscal regime towards upfront bonus payments reduces the risks borne by government relative to those faced by the industry, while a tilt towards production royalties reduces relative industry risks, particularly if the royalties are tuned to the actual half-cycle profitability of production. Having royalties related to half-cycle profitability is important to ensure that oil wells will not be prematurely abandoned and that projects such as tertiary EOR will go ahead – i.e., that all possible marginal oil will get produced. It also ensures that any unanticipated cost or price shocks will be accommodated by the fiscal regime.

We conclude that industry activity and the consequent oil supply are largely based on expectations of profitability at the different stages of the supply process, and especially at the exploration stage. Thus the supply of oil is partly responsive to economic factors, and that relationship can be quantified. The profit equation in exploration compares the costs of land, geological activities, drilling and so on with the expected value of discoveries. The expected value of a discovery is obtained by multiplying its size by the "reserve price." This explains why estimates of the responsiveness of supply focus on the reserve price as the basic variable on the revenue side of the equation. On the cost side, the most important element is drilling.

Estimating the Supply Response

The complexities, uncertainties and time lags in oil supply make the estimation of supply responsiveness to expected profitability or to policy a difficult task. It is widely observed that the volume of oil and gas supply does respond to increasing economic incentives, but the systematic measurement of response through the estimation of an elasticity of supply is tricky. A first difficulty is that the reserve base is never static over time. It is continually being depleted by production and augmented by exploration and development. When a price or policy shock is imposed upon this fluid situation, its effects are difficult to separate from the impact of other changes.

Despite such difficulties, a number of empirically based estimates of supply response have been made, both in Canada and elsewhere. Before the OPEC price hikes, it was widely believed that there was little relationship between oil prices, exploration and the supply of reserves. Consequently, it was more important to demonstrate any positive connection rather than try to arrive at a single estimate. One study concluded that the short-run reserve-price elasticity for oil was about 1.0.[13] This finding was qualified, however, by stressing that short-run elasticities are not expected to remain constant as an oil reservoir is depleted. In the case cited above, a 1 per cent change in price would produce a similar change in the reserves. Some alternative estimates were also presented, showing the difficulty of measuring the supply response – a task made especially onerous at that time by the fact that oil price changes had been minimal during the two decades up to 1970. It was also estimated that the approximate elasticity between wellhead oil prices and "new field wildcat" exploratory drilling was about 1.7 during the period of analysis. (This implied that a 1 per cent change in wellhead prices would result in a 1.7 per cent change in expenditures on exploratory drilling.)

A more recent study of supply responsiveness has attempted to bridge the approaches of geology, engineering and economics by examining potential reserves at the disaggregated level of particular geological horizons in Alberta.[14] Engineering-type performance equations relating reserve additions to wells drilled were specified, and the subsequent economics of drilling were estimated on the basis of drilling costs, prices and taxes. Through this approach, long-run reserve-price elasticities were estimated for those geological horizons and areas in which oil and gas had previously been discovered and for which there was, therefore, a statistical drilling history. These are the "mature" horizons and areas of the province. There are other horizons and areas in Alberta that are considered by industry to have a high potential for yielding additional oil reserves but that have only a limited history of drilling, if any, and could not, therefore, be analyzed by this method.

The incentive, on the basis of the existing fiscal regimes, to explore and develop new oil reserves in many of the geological horizons that were examined was, in fact, found to be low. The two horizons that were found to be promising, with respect to significant additional reserves, were the Upper Devonian and the "Viking and Equivalent" sediments in the Lower Cretaceous.

The responsiveness of potential additions of primary reserves of conventional light oil was assessed on the basis of an assumed decrease in taxes leading to a higher reserve price. The resulting long-run elasticity of about 0.4, being based on mature geological horizons, is probably lower than the actual average for the Western Basin. Nevertheless, we conclude that a reserve-price elasticity of at least 0.4 is a reasonable estimate for policy decisions that affect exploration and development for conventional oil reserves in the Western Basin.

Our analysis of individual EOR projects, described more fully below, suggests an even stronger relationship between economic incentives and supply response. This seems to be more widely accepted today by industry and policy makers. In the recent past, a number of estimates of EOR reserve-price elasticity have been published, ranging from 0.8 to as high as

Measuring Supply Responsiveness

The two measures of supply responsiveness that we use are the "reserve price elasticity" and the "production price elasticity."

The "reserve price" is defined as the price that a private interest would be willing to pay to acquire reserves that are in the ground. In effect, it measures the worth of these reserves, given expectations about future prices and costs.

The *reserve price elasticity*, upon which we rely mainly in this report, measures the impact of a change in the reserve price on the volume of economically recoverable reserves. The reserve price elasticity is calculated as the percentage change in reserve additions that results from a 1-percentage-point change in the reserve price. When the reserve price elasticity is positive, an increased reserve price leads to an increased amount of additions to reserves.

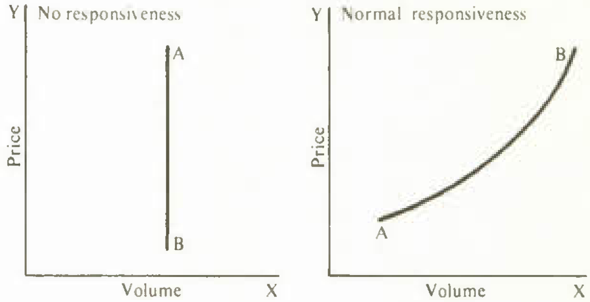
The *production price elasticity* measures the impact on production of changes in the "netback" on oil, defined as the wellhead price of oil less taxes, royalties and operating costs.

The production price elasticity is calculated as the percentage change in the rate of production resulting from a 1-percentage-point change in the netback. The empirical values of the production price elasticities are usually positive, but they may vary considerably, depending on whether they are estimated for one pool, a few pools in a small region, many pools in a large region, and so on. It is also important to realize that the nonrenewability of the single pool is an important determinant of the production price elasticity, but it is not a paramount characteristic in the supply response for a large region. In addition, the larger the region being considered, the more stable over time and over any range of prices would be the production price elasticity.

about 3.1, depending upon various assumptions and upon the level of prices that was considered.[15] The overall conclusion is that the EOR projects – and the subsequent oil supply – are estimated to be highly responsive to economic incentives.

Another study took an aggregate-expenditure approach to the estimation of the linkage between economic incentives and industry activity.[16] In this approach, the response of industry expenditure levels to the reserve price was used in place of reserve additions. The estimated results for oil and gas show that a change in the reserve price is almost fully matched by a proportionate change in total exploration expenditures (Table 4-8). Both exploratory and development drilling expenditures actually increase more than proportionately, with the price elasticity of expenditures reaching 1.53 for exploratory drilling. The elasticities for drilling expenditures are greater than for other expenditure categories because, as incentives improve, new reserves are discovered and become available for drilling; in addition, more intensive drilling is likely to take place on existing reserve holdings. This study also found that, although the reserve price was the primary determinant, the available cash flow helped to explain a change in expenditures. The importance of cash flow is evidence of the financial considerations that partially drive industry activity. The authors concluded that the potential economic rents that may accrue to new oil discoveries are a major motivation behind exploration activity.

All of these findings point in the same direction: oil (and gas) supplies are responsive to economic incentives. As for other commodities, the supply of oil will increase if Canadians are willing to pay more for it. To be sure, there are complexities and delays in the process, but these results dispel the notion, which seemed to underlie policy in the 1970s, that productive oil capacity in the Western Basin would not increase in response to higher economic incentives. In terms of a supply curve for conventional oil, it was mistakenly viewed as being essentially vertical, meaning that no new capacity would emerge from higher net prices. By contrast, a more realistic depiction of the supply relationship is an upward-sloping supply curve. This relationship shows that a higher net price, achieved by raising the reserve price (and increasing the cash flow), will indeed lead to an increase in productive capacity.



As a further indication of the potential responsiveness of oil supply to policy changes, we note the gradual upward revision of past NEB forecasts of potential additions of light oil from EOR (in this case, including waterflooding) that have followed changes in pricing and fiscal policy. The estimated potential increased from 156 million m^3 in 1977 to the current figure of 404 million m^3. The forecasts of potential additions from discoveries have also been increased by the NEB over the same period, from as low as 76 million m^3 in 1977 to the present 280 million cubic metres.[17]

Finally, it is important to reiterate that the expected full-cycle profitability is the main incentive that sets in motion an expansion of exploration, development and (eventually) production activity. In this context, the expected full-cycle profits may not be fully realized if costs rise and more money is paid for bonuses, but the expectations serve to drive up the level of activity and, consequently, to increase supply. The fiscal regime is, therefore, seen as the throttle that controls industry activity.

In summary, we conclude that oil supplies are indeed responsive to policy and that government control of the fiscal regime – that is, government control over industry profitability – is the means by which policy can affect the level of oil supply.

Table 4-8

Long-Run Expenditure Elasticities[1] for Oil and Gas, Alberta

Exploration	
Geological and geophysical activities	0.57
Drilling	1.53
Land acquisition and rental	0.74
Total	0.93
Development	
Drilling	1.12
Field equipment	0.43
Secondary recovery	0.41
Natural gas plants	0.36
Total	0.46

1 Weighted average reserve price for oil and gas. For exploration, the undeveloped reserve price is used; for development, the developed reserve price is used. The expenditure elasticity is defined as the long-run percentage change in the level of expenditure, divided by the percentage change in the weighted reserve price.

SOURCE Scarfe and Rilkoff, "Financing Oil and Gas Exploration."

Supply Costs

The potential supply responsiveness to policy change can also be revealed by a look at the broad picture of costs, prices and profitability of this country's sources of oil supply. The situation varies considerably between supply sources because there are wide variations in costs and in the degree to which taxes and royalties are attuned to profitability. There are, as a consequence, priority goals that can be identified.

Conventional Crude Oil

The wide variations that can occur in the costs of conventional oil supply result from a number of factors, including year-to-year fluctuations in the cost of finding and developing reserves, in the productivity of discoveries and in development costs. In 1979, the five-year moving average social supply cost of crude oil reserves *in the ground* was about \$47/m³, while the private supply cost was \$63/m³. (Unless specified otherwise, all social and private supply costs in this section are expressed in 1983 dollars.) The difference, about \$16/m³, is the cost of the bonuses paid to the provincial government, plus the estimated cost of money associated with those payments (see Chart 4-2).

The equivalent levelized social supply cost per cubic metre of oil *production* is approximately \$100. When the cost of bonus payments is added, the levelized private cost becomes approximately \$134/m³ – the amount that the producer would have to recover in production in order to cover his investment in finding and developing the reserve. The other levelized supply cost component is the operating cost of production; in Alberta, it averaged about \$28/m³ in 1983.[18]

Adding all of the social costs in the supply process yields a total average social cost of new oil production in Alberta in 1983 of approximately \$128/m³. This can be compared with a wellhead value of about \$224/m³ that year (Table 4-7).

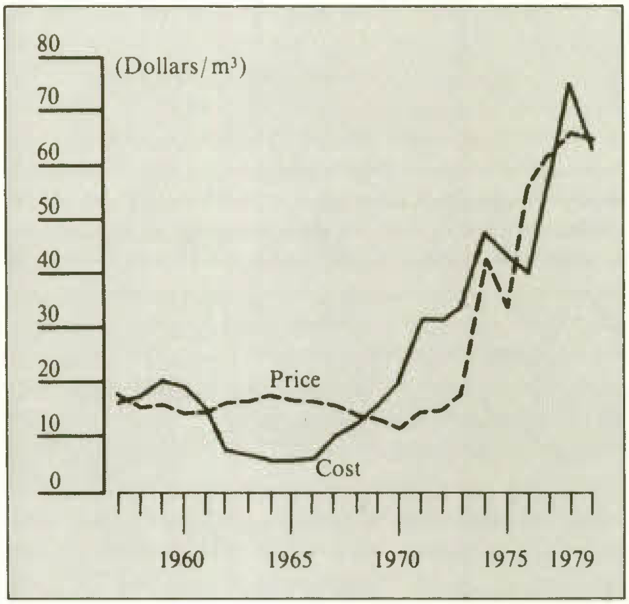
Thus it can be seen that the average real social cost of finding, developing and producing new reserves of conventional oil in western Canada, although it has risen in the past, is still far below the wellhead value, which is based on world prices. In the social sense, it is economically worthwhile, therefore, to encourage exploration, development and production of conventional light oil.

At this point, it is necessary to turn to a consideration of wellhead prices in relation to private costs, which – unlike social costs – involve payment to government of royalties, taxes and bonuses, less any subsidies received from government. To get a sense of the long-run private profitability of new conventional-oil supplies, we first go back a step to look at a comparison of the private cost of booked reserves and the price of developed reserves in the ground. Historically, the cost of finding and developing reserves tended to be below the estimated reserve prices until the late 1960s (Chart 4-4). In the early 1970s, costs shot ahead of prices; they have since remained somewhat higher or about the same. The approximately parallel course of private costs and prices in recent years was to be expected because rising reserve prices signal an increase in expected exploration profitability to the explorer. That, in turn, sets a number of responses in play. First, more active bonus bidding for exploration and development permits will occur, involving both higher bids for reserves already under consideration and bids for reserves previously considered uneconomic. Second, other exploratory activities (such as seismic surveying and drilling) will increase, and they will also be directed towards more remote reserves. Greater exploratory effort also puts upward pressure on the cost of inputs into the industry. Meanwhile, it takes time for reserve additions to materialize. As a result of these factors, private costs and reserve prices tend to move in step, although lags may occur.

We estimate that in the recent past, the exploration, development and production of new conventional-oil supplies provided, on average, a somewhat less-than-

Chart 4-4

Average Price and Cost[1] of Developed Oil Reserves in the Ground in Alberta, 1957-79



1 Private cost, including bonuses, in 1983 dollars. Costs are averaged over five-year periods.

SOURCE Uhler, with Eglington, "Potential Supply"; and Eglington and Uffelman, "Oil and Gas Reserves in Alberta."

normal rate of return to the investment involved, taking into account the new-oil reference price, the applicable federal and provincial taxes and royalties (including bonuses), and the available incentives (including the provincial PIP payments). This outcome of poor average full-cycle profitability also existed in 1982, prior to the Canada-Alberta amending agreement. But it also reflects, in part, what may have been overly optimistic bonus payments by industry, although the existing level of production taxes and royalties does not appear to leave much room for bonuses.

We conclude that while economic prospects are very good, in the social sense, large companies *on average* have little incentive, on the basis of private costs, to maintain exploration for conventional oil and none to expand it. In other words, the level of existing taxes and royalties at the production stage is such that the expected profitability over the full cycle is at best a normal rate of return, provided that bonuses are kept to a minimum. A continuation of these fiscal conditions will tend to slow the pace of exploration.

Light-Oil Tertiary Recovery

To assess the costs of oil supplies recoverable by enhanced oil recovery through the miscible-flood process, four projects in Alberta were analyzed.[19] Three of the projects – located at Swan Hills, Fenn Big Valley and Nipisi Gilwood – are in operation, the miscible-flood injection having commenced in 1982-83. The fourth project, in the Pembina field, has not yet proceeded beyond the study stage.

All four projects have previously been subjected to secondary recovery by waterflooding. In the case of the three EOR projects currently under way, the miscible fluid used is a natural gas liquid, which is obtained primarily from natural gas processing plants. The process has been developed and tested in pilot projects; large field projects have only been operating for a few years, however, and it is too early to determine whether the recoveries will meet expectations.

The capital investment required by these particular projects is relatively low. It involves drilling additional development wells to handle the increased production and the wells required to inject the miscible fluid. The operating costs, however, are higher than those of conventional oil production.

Based on the technical data available at present, the three operating projects appear to involve social supply costs ranging between $82 and $125 per cubic metre of production. If the projects can operate at the anticipated recovery rates, these supply costs for additional oil will remain attractive.

The proposed fourth project is small in scale and involves low production rates and a 40-year project life. It is probably representative of many potential EOR projects in Alberta that could eventually provide access to large quantities of oil. The estimated social supply cost is around $161 per cubic metre of production – still below the world price.

Our calculations show that the actual or potential private profitability of the four projects ranges from marginal – which involves just earning a normal rate of return – to very high. The variation in costs translates into a significant variation in expected profitability.

The EOR projects are an important factor in the future supply of oil, in view of the fact that the resource has already been discovered and developed. Considering the risk that industry is taking with the new recovery technologies, the sharing of this risk that governments have undertaken in the form of royalty and PGRT adjustments illustrates the type of cooperation that is needed between government and industry in other areas. There is still room for some improvement, however, in devising fiscal regimes that are appropriate for marginal projects. Given that the social costs of developing these additional reservoirs, which are in a range between $80 and 160/m^3, are less than the cost of oil imported from abroad, it is in Canada's interest to encourage the recovery of this domestic oil.

Enhanced Recovery of Heavy Oil

The recovery of heavy oil by primary production methods seldom exceeds 5 per cent of the original oil in place. Because secondary recovery by waterflooding is not very effective, tertiary EOR methods are generally needed to achieve better results.

To get a measure of the cost of enhanced heavy-oil recovery, we have examined a small experimental project in one section of the Lindbergh field in Alberta, involving the recovery of 0.9 million m^3 of oil. Based on the technical data available, the social supply cost of recovered heavy crude oil is approximately $166/m^3. As this is an experimental project, the cost for a larger commercial operation might be lower. Again, the social costs are lower than the wellhead price of heavy oil, which was about $190/m^3 (based on the NORP) at the beginning of 1984.

Under present fiscal arrangements, there is a sharing of potential profits and risks between industry and government. This approach appears to be quite reasonable, as it provides a sufficient incentive to continue research through this experimental project into technologies to recover more heavy oil from the large number of fields of this type in Saskatchewan and Alberta.

Oilsands

To gauge the potential costs of supply from the Alberta oilsands, two projects were assessed – a mining megaproject, that has not gone ahead, and an experimental *in situ* project that is proceeding.[20]

The mining project, Alsands, was to produce about 21,000 m^3/d of synthetic light crude from the Athabasca field.[21] The total capital cost was estimated to be $14 billion (as spent dollars) and the project's life was to be 29 years. A large portion (90 per cent) of the capital cost was to be spent during the preproduction years for mining equipment and site preparation, extraction, upgrading, an electrical generation plant and on-site facilities for administration and operation. The remaining 10 per cent was to be invested after the start of production, primarily for the replacement of mining equipment during the life of the project.

On the basis of the Alsands capital and operating cost data, it is estimated that the social supply cost of synthetic oil would be approximately $315/$m^3$. Therefore, the project would not be economically viable, given the plant-gate price of some $240/$m^3$, based on the 1984 world price level. Since the social costs would be higher than the world price, a large Alsands-type project would be attractive to industry only with heavy government support – even heavier than was included in the final offer made to the Alsands consortium. The rejection of that offer by the consortium in 1982 illustrates the degree of uncertainty that is associated with this type of project and its marginal chance of economic success, at least given the present outlook for flat real world oil prices. It is suggested today that a plant comparable to Alsands could be put in place for less than the original estimated cost of Alsands, but the economics would still be doubtful.

Attempts to develop supply from the oilsands in smaller increments are preferable at this time. The Cold Lake and Wolf Lake projects are examples of such efforts, which are designed to develop techniques for the recovery of bitumen from the oilsand deposits *in situ* – i.e., where they are located underground, because the sands are too deep to be surface-mined economically.[22]

We focus here on the Wolf Lake project, whose planned life is 25 years and which is designed to produce 1,100 m^3/d of oil. There will be 192 wells drilled at the beginning of the project, with 50 more wells to be drilled each year to offset production decline. Over the project life, 1,200 wells will be drilled, each with a life of five to ten years. A great deal of the research will involve experimental drilling to determine the well pattern that would optimize bitumen recovery. The bitumen in place is estimated to consist of 51 million m^3, and the recovery factor forecast for this project is 18 per cent.

It is estimated that the total capital expenditures over the project life will reach $550 million (1983 dollars). Approximately $200 million of this amount will be spent in preproduction costs in preparation for the start-up in 1985. The operating costs are estimated to average about $35 million per year, 40 per cent being for natural gas fuel. The levelized operating cost is equivalent to about $80 per cubic metre of production.

The total social supply cost for Wolf Lake bitumen production is approximately $180/$m^3$ – only slightly below the wellhead value of about $190/$m^3$ for heavy oil at the beginning of 1984. As this is an experimental project involving a considerable amount of drilling and process research, a future larger commercial venture might have lower costs per cubic metre of production.

At the current scale, the Wolf Lake project is likely to be approximately a break-even investment. The estimated profitability will just about pay back the cost of the investments, but the existing fiscal regime is capable of preserving the project's viability. While there is no expected economic rent at the current scale, we presume that a greater spread between the social supply cost and the wellhead price is expected for larger-scale *in situ* projects. The attractiveness of this type of project, if it is socially economic, rests on the huge *in situ* reserves available as a future source of supply. It should be recalled, however, that the market for heavy oil is limited and uncertain and that the cost of upgrading heavy oil is high.

Frontier Oil

The most attractive prospects, at the present time, for frontier oil exploitation in Canada are in the Beaufort Sea/Mackenzie Delta region and off the East Coast.[23] While the Arctic Islands and other frontier regions show long-run potential, their supply possibilities for the medium term are more limited.

The Beaufort Sea/Mackenzie Delta Area

The Beaufort Sea and Mackenzie Delta area is of particular interest in the unfolding of Canada's oil-supply prospects because, geographically, it is the northward extension of the Western Canada Sedimentary Basin. With the Norman Wells project scheduled to come on stream in late 1985, a first step is being taken towards linking Canada's northern petroleum resources with their potential market by joining them to the North American pipeline system. The number of discoveries in the Mackenzie Delta and the Beaufort Sea is encouraging, given the relatively small number of wells that have been drilled. Between the early 1960s (when exploration began to pick up momentum) and 1982, some 180 wells had been drilled in the area at a cost of about $2 billion. Drilling has resulted in 12 oil discoveries, 11 gas discoveries, and four oil and gas finds; reserves of close to 159 million m^3 of oil and about 255 million m^3 of gas have been identified.

Further delineation will be required, however, to establish whether sufficient reserves are available to meet the threshold volumes required to ensure the economic viability of specific production and transportation plans.

The Mackenzie Delta has been compared with the great hydrocarbon delta basins in other parts of the world. It has been, and still is, tantalizing to exploration companies. Remoteness and weather conditions, however, have restricted the pace of exploration to a few wells a year – usually fewer than 10 or so, either onshore or offshore. The lead times are correspondingly longer than elsewhere, and the required exploration investment is substantial.

From the start of exploration, the companies have been searching for oil rather than gas. Land-based exploration has led mainly to gas discoveries, however, and the focus of the search for oil is now the Beaufort Sea. The search is not only to determine the oil prospects but also to find large oil reservoirs. The question that arises, in view of the large investments made by the lead companies and their investment partners, and of the heavy subsidies granted by the federal government, is whether the endeavour is likely to be worthwhile. We review here some of the factors involved in answering that question.

First, we consider the minimum oil reserve size – the minimum economic scale (MES) – that would allow the development of a discovery to be economically viable, including the production and transportation of the oil to Montreal. In other words, we are interested in the minimum scale at which the development of Beaufort Sea oil will break even, assuming a price of $\$252/m^3$ for oil in Montreal. (All prices and costs in this section are expressed in 1983 dollars.) We further assess the impact on the MES of different reservoir parameters, which ultimately affect the required production systems.

An estimate of the MES provides a sense of the riskiness of Beaufort Sea development from an economic point of view, because small reserves are more likely to be discovered than large ones, even if the oil-bearing structures are themselves large. Further, the MES is of interest because smaller-scale pilot development, which is environmentally less risky and socially more acceptable, could pave the way to larger-scale development.

For a "single-island" (or single-platform) development offshore, with water depths of about 50 metres, the MES is estimated by Dome Petroleum to be in a range between 35 and 55 million m^3, with a middle value of 44 million m^3, based on the present Canada Lands fiscal regime and constant real oil prices in the future. Without taxes and royalties, the MES (based on social costs) is estimated to be 34 million m^3. These estimates are based on the assumption that tankers will be used to deliver the oil to southern markets.

The assumed oil price has a marked effect on the MES estimate. If oil prices are assumed to increase at 5 per cent annually, the private MES is reduced by about 45 per cent, from 44 to 24 million m^3. The effect is opposite and even greater with declining real oil prices, an annual decline of 5 per cent leading to a 70 per cent jump in the MES. The MES in both the private and social cases increases if an overland pipeline from the Mackenzie Delta is assumed to deliver the oil to southern markets.

For single-island development in shallower water (around 20 metres), the minimum economic scale is estimated to be about 25 per cent less, with a middle value of about 33 million m^3 (with taxes and royalties) or about 27 million m^3 (without taxes and royalties). Imperial Oil has said that it would need about 48 million m^3 of reserves in one pool or in several small pools, either onshore or in the shallow areas of the Beaufort Sea, for development to be commercially economic.[24]

An approximation of the private MES, assuming reservoir conditions that necessitate multi-island development (i.e., five islands), is in the neighbourhood of 100 million m^3, or about two to three times the estimate for a single-island development. In this case, transportation is assumed to be by an overland pipeline.

A second consideration, in addition to the minimum economic scale, is the potential for relatively low-cost oil from the Beaufort Sea, assuming very favourable physical and economic conditions – although these are unlikely to occur. The analysis assumes that adequate reserves will have been discovered, so that production will be optimized and costs will be minimized. An analysis of the potential for relatively low-cost oil enables us to investigate the likelihood of developing such supplies in the Beaufort Sea at a unit cost that is comparable with, or lower than, that of other sources of oil in Canada. This, in turn, helps us to judge whether the Beaufort Sea exploration effort might eventually be worthwhile. While the probability is small that all of the factors involved in such an undertaking – geological formation, engineering resources, project management and so on – will be favourable, such an outcome is believed to be possible. The estimated cost of supply represents a minimum above which the world oil price must remain for the development of Beaufort Sea projects to be economic from the point of view of social costs.

A half-cycle social supply cost of around \$95 per cubic metre of production (\$15/bbl) to produce and deliver oil to Montreal is estimated for low-cost oil, corresponding to a high-productivity reservoir of about 160 million m^3 that could be accessed through a single-island development. This means that, with reasonably favourable conditions and with existing world oil prices, the development of the Mackenzie Delta/Beaufort Sea field could eventually become economic for Canada. The oil is assumed to be transported to southern markets by an overland pipeline.

Notwithstanding the reserve potential, the costs of development will be substantial. The single-island production system for a middle-sized reservoir of 64 million m^3 is estimated to have a total investment cost of $3.6 billion. This investment includes 69 wells ($1.5 billion) and production facilities (almost $1.4 billion). The operating costs amount to about $1.6 billion over the life of the project, which comes to an average levelized operating cost of approximately $24 per cubic metre of production.

The costs for a reservoir of 100 million m^3 with five production islands are markedly higher. The total investment cost is about $7.8 billion, which includes: the construction costs for the five islands, amounting to $1.5 billion; about $3.8 billion for the production facilities; and $2 billion for 80 development wells. The operating costs over the 19-year production life amount to $6.1 billion. The per-unit levelized operating cost is about $58/m^3$.

In terms of expected private-sector profitability, a multiple-island development – given a reservoir of 100 million m^3 and the existing world oil price – would leave the producer with a return that would be somewhat less than a normal rate. The available economic rent would be marginal. On the other hand, the single-island cases, assuming that the reserves are larger than the amount equivalent to the social MES, would provide production quasi-rents, some of which should be retained by industry to pay for exploration.

East Coast Offshore Area

Our estimates of the economics of potential oil supply from the East Coast are based on the Hibernia discovery on the Grand Banks, about 300 km southeast of St. John's, Newfoundland.[25] The Hibernia field covers an area of about 8,000 hectacres at a depth of 3,500 metres, and the reservoir interval is about 88 metres. The estimated recoverable reserves are some 230 to 290 million m^3.

Since the discovery of Hibernia in 1979, nine evaluation wells have been drilled, producing the first reserves of oil in Canada's frontier areas to be recognized by the NEB as established. To date, no decision has been made with respect to the choice of a production system. The occasional severe weather in the area can cause high winds and high waves, and the presence of icebergs and flow ice creates exceptionally difficult operating conditions. The production and cost data in our analysis assume the adoption of a production system fixed to the ocean floor.

The capital costs (in 1983 dollars) are estimated to total $5,400 million;[26] the operating costs are expected to be about $190 million annually (1983 dollars). At a peak production rate of just under 40,000 m^3/d, that would be equivalent to a levelized operating cost of about $20 per cubic metre of oil produced.

On the basis of this data, the half-cycle social supply cost for East Coast oil is approximately $85 per cubic metre of production at the wellhead and approximately $93 per cubic metre delivered to Montreal. A great deal of uncertainty surrounds these cost estimates, however, because of the engineering problems to be overcome in the design of a suitable production platform. On balance, we conclude that the Hibernia oil field has potential for low-cost oil for Canada, provided that the final production system is not significantly more costly than is currently estimated.

Summary

Table 4-9 summarizes the social costs and profitability of supply for Canada's major potential new oil sources. It illustrates, first, that there is a wide variability of costs not only among the sources, but also among individual projects within each source. Bearing in mind the comparative outlays and the comparative risks involved in exploration, we find that western Canada conventional oil is the least costly. This remains true even in the case of oil produced by enhanced recovery, part of which can be acquired at costs that are considerably below the world price. For Beaufort Sea and Hibernia oil, the information is necessarily much less reliable because it deals only with hypothetical projects; moreover, exploration costs are not included. The estimates nonetheless suggest that, although there are risks involved, oil could eventually be produced from these sources at costs comparable with those attached to production in the Western Basin.

On the other hand, although geological uncertainty is small, the mineable oilsands would appear to be the most costly source of oil. Long lead times – about eight to ten years – are involved in such developments, and investors have only limited means of diversifying their financial risk.

The assessments of profitability also vary among the sources of supply. The variations result in part from the observed cost differentials, but they also point to difficulties with the present policy. Canada's fiscal regimes are not encouraging the development of all the reserves that could be economically worthwhile. The

Table 4-9

Social Costs and Profitability of Oil Supply, by Source, Canada

Source of new oil supplies	Comments	Social supply cost[1]	Private-sector profitability
		(Dollars/m³)	
Western Canada conventional light oil	Estimated average full-cycle costs	130	Low, based on average performance
Western Canada light oil EOR	Range of costs of four projects	80 to 160	Low to good, depending on project
Western Canada heavy oil EOR	Experimental project	165	Low
Mineable oilsands synthetic oil	Alsands data	315	None
In-situ oilsands bitumen	Wolf Lake data; experimental project	180	Low, possibly good, depending on achieving larger scale
Beaufort Sea light oil (assumes a commercial discovery)	Delivered to Montreal	75 to 250	Potentially good but more likely low because of high exploration risk
Hibernia light oil (uncertain platform costs)	Delivered to Montreal	95	Potentially good but with high development and technological risk
Approximate value of oil at wellhead, based on world oil price (at the beginning of 1984)		240 (light) 190 (heavy)	

1 In 1983 dollars, rounded to the nearest $5. All cost estimates refer to the half-cycle (development and production), except for conventional light oil from western Canada.

SOURCE Estimates by the Economic Council of Canada.

main imbalance arises in the Western Basin, where production taxes and royalties tend to take too much of the production quasi-rent, thereby leaving the large companies in the industry, on average, with minimal room to bid for exploration permits through bonuses. The structure of taxes also detracts from the development of some projects.

Supply Responsiveness

We know, on the basis of our analysis and of historical experience, that there would be a response in oil supply – i.e., that oil production could be brought on at a cost less than the world price – if the incentives to explore and to develop reserves were increased. While we discussed a range of estimates of this responsiveness for conventional oil, our research, which is based on the mature regions and geological horizons in Alberta, suggests an elasticity of reserve additions of at least 0.4 with respect to the reserve price. Based on this estimate, how might a change of policy translate into additional cubic metres of oil from western Canada?

The NEB forecast of oil supply included some 605 million m^3 of light- and heavy-oil reserve additions from discoveries, infill drilling, and waterflooding (but not tertiary EOR). As this forecast assumed a continuation of the present policy, we can argue, on the basis of our estimate of the reserve-price elasticity, that a decision to raise the reserve price would increase reserve additions above that forecast. For example, using the base elasticity estimate of 0.4, a change of 50 per cent in the reserve price would lead to an expansion of conventional reserve additions by 20 per cent, or some 121 million cubic metres.[27]

The NEB forecasts of conventional oil production suggest that the Western Basin is over 50 per cent depleted. By contrast, our research indicates that an increase in the rate of reserve additions could be realized if the proper incentives were in place to increase the netbacks on new oil over the next few years. To achieve this, however, policy would have to be more aligned with the full-cycle profitability of exploration, development and production.

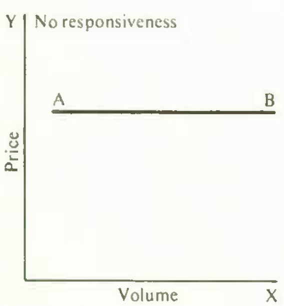
Our study of the enhanced recovery of light and heavy oil leads us to concur with the NEB in the view that there are substantial reserves to be brought on stream by tertiary methods. The key to realizing the forecast potential of reserve additions through EOR is the attention paid in policy making to the half-cycle marginal project. Recent policy adjustments have, in fact, gone a long way in this direction. As mentioned earlier, the estimates of the reserve-price elasticity for EOR have generally been higher than 1.0, which means that there is estimated to be a significant responsiveness of reserve additions to the potential profitability of EOR projects.

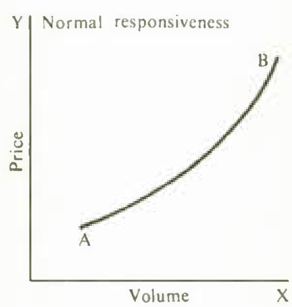
The viability of increased additions of heavy oil, whether from discoveries or EOR, will depend upon the existence of export markets and upgrading facilities. Currently, the NEB's forecast includes two upgraders. While upgrading seems like a good idea, it only makes economic sense if the final social cost of the upgraded crude is less than the wellhead value, based on world prices.

In reviewing both *in situ* and mineable oilsands in Canada's future oil supply, we must ask whether the tarsands can be regarded as a limitless backstop supply, accessible economically only to strong-willed companies and governments, or whether they are like other oil supplies, varying in cost from project to project. Although they are free from exploration uncertainty since the reserves are known, they are still subject to technological and economic uncertainties.

Unlike most of the petroleum industry's activities, the mineable oilsands plants are indeed mining operations. As in all other mining sectors, there is a wide variation in costs with respect to existing and potential projects. For tarsands plants, the variation in costs depends on the extent of the oil saturation of the sands, their continuity, the depth of the overburden, the accessibility to water and other utilities, the remoteness of the site and so on.

Perhaps because operations such as Syncrude or the now-abandoned Alsands project include an upgrading plant, these projects seem to have been viewed less as mines and more as manufacturing plants that could be replicated in series, leading to the notion of an essentially infinite supply of oil being available at a certain price. Unfortunately, that is not the reality. In our discussion of the supply of conventional oil from the Western Basin, we argued that the supply curve for that oil is commonly, but wrongly, believed to be vertical. By contrast, the common conception of a supply curve for mineable oilsands is that it is horizontal.



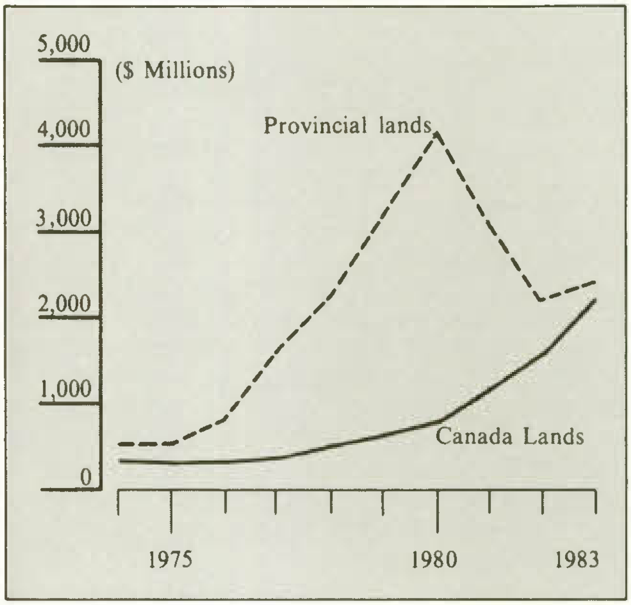


In our view, the supply of oil from conventional sources (including that from EOR), as well as from mineable and *in situ* oilsands projects, is characterized at any given time by an upward-sloping supply curve, which means that additional oil supplies will become available at higher netbacks to the producers. It follows, then, that the supply of oil from the oilsands, either *in situ* or surface mining, is responsive to policy, but within the limits determined by the relatively high costs of production. Over the longer term, technological breakthroughs will still be needed; and this is an area where government can usefully maintain and enhance its support of research and development, including experimental projects.

We are unable to estimate statistically the responsiveness of frontier oil supplies to policy changes because there has yet to be any actual production. Exploration expenditures, including the federal PIP payments, have increased rapidly in recent years (Chart 4-5), and the active participants in the Mackenzie Delta/Beaufort Sea area are becoming more certain that commercial reserves exist. However, the threshold reserve of some 34 to 44 million m^3, considered necessary for these areas to be connected to the market, has not yet been established. Until discoveries can be developed and moved to the market, the expected full-cycle profitability is bound to be poor. Moreover, these expectations are not improved by the present Canada Lands fiscal regime.

Chart 4-5

Oil Exploration Expenditures, Canada Lands and Provincial Crown Lands, 1974-83



SOURCE Based on data from the Canadian Petroleum Association

Assessing the Existing Policy

For oil, policy today is largely a reflection of the National Energy Program of 1980, the 1982 NEP Update and the federal-provincial agreements. Our research has shown that supply from various oil sources in Canada is responsive to policy, given various costs and various risks. Fiscal policy, both federal and provincial, must address some of the basic elements of efficient resource management, however, if Canada is to achieve its potential at the least social cost. The first fundamental step towards efficient supply policy is to establish oil pricing in a way that will assist in resolving supply difficulties. Second, the balancing of incentives for all sources of oil, with due regard for risks, is an essential ingredient of a sound policy aimed at developing oil supplies at the least social cost. Third, increased attention should be paid by governments to devising a more uniform and efficient system of taxation.

Pricing

A central tenet of the National Energy Program was that the price of conventional oil was to remain below world levels. It was stated that "the government is determined that the price of Canadian oil will not be linked to world prices, but rather will be 'made-in-Canada'."[28] This was not a wholly new direction for policy, since the 1970s had witnessed a widening gap between Canadian and world oil prices.

While the NEP held down wellhead prices for conventional oil, there were provisions that reflected an attempt to price nonconventional oil according to the costs of the sources of supply. To encourage oilsands development, there was an oilsands reference price, set at more than twice the price of conventional oil. There was also a price for oil recovered by tertiary EOR, more or less half-way between the two other prices.[29]

Oil pricing has been revised considerably since the NEP was introduced four years ago, and it is now determined by two subsequent agreements between the governments of Canada and Alberta, as well as by agreements with the other producing provinces. The present arrangements distinguish between "old" and "new" oil. Old oil – which has been redefined as oil discovered prior to 1974 – remains underpriced in relation to the world price, but the new-oil reference price (NORP) now applies to some 45 per cent of domestic production, including oil discovered since 1974, oil from infill drilling, synthetic oil, oil from EOR processes and frontier oil.

While the implementation of the NORP has redressed some of the pricing problems that emerged in the 1970s, thereby re-establishing some incentive to find and develop new oil supplies, complications have inevitably arisen as a result of the price distinction between old and new oil. A bias is imparted to industry investment decisions towards producing known oil reserves as new oil – for example, through infill drilling or EOR. In effect, the tendency is to attempt to reduce production classified as old oil and to increase production deemed to be new oil, so as to meet a given oil demand, even if this incurs somewhat higher costs. As a result, oil is not produced at the least possible social cost. In this respect, the old/new price distinction becomes counterproductive in terms of enhancing supply and directing investment towards least-cost oil. Achieving Canada's oil-supply potential would require that oil be priced at its opportunity value – the world oil price – irrespective of any distinction between old oil and new oil. This could require adjusting the oil royalties as part of a new federal-provincial agreement.

Certainly, one alternative that should be ruled out is any attempt to price oil on the basis of wellhead costs. This approach, reflected in the NEP, is plagued by technical difficulties that arise from the variability of costs between operations and over time. Are prices best set according to short-run marginal costs, long-run costs or average costs? Should they reflect full-cycle costs (with an allowance for the dry holes)? The complexities are endless. Indeed, there is a compelling message for Canadians in the attempt – and failure – of the U.S. Federal Power Commission to price U.S. natural gas according to its apparent cost for so many years. The outcome was a supply crisis in 1978, followed – after partial deregulation – by the present oversupply of natural gas.

Because Canada's pricing policies have reflected many concerns other than oil supply, they have, over the last decade, drifted away from the principles of efficient resource management. Keeping domestic prices down prior to the introduction of the NORP limited the industry's incentive to find and develop new supplies, and the subsequent distinction between old oil and new oil has distorted supply. As a result of the wide variety of special fiscal provisions for different supply projects, the industry tends to concentrate production on oil that offers the greatest profitability, after full account is taken of fiscal measures, rather than on the production of oil that is the least costly.

Balancing Oil-Supply Incentives

A primary goal of the NEP was to encourage the discovery and development of oil in the frontier areas, with some consideration also being given to the development of oilsands and enhanced recovery processes. The pricing and taxation policies that applied to oil supply from the conventional producing areas (principally Alberta) were of concern, but more in relation to the collection of revenues than as elements of a coherent oil-supply policy.

The priorities of the federal government were reflected in its revision of the incentive system for oil and gas. Previously, the Income Tax Act allowed taxpayers to claim deductions against taxable income for so-called depletion allowances, which were generally equal to one-third of oil and gas exploration and development expenditures and of certain capital expenditures related to oilsands plants. Under the NEP, the depletion allowances were to be gradually reduced and eventually eliminated except for the oilsands. Acknowledging that changes to the depletion-allowance system would cut heavily into the incentive to invest, the NEP introduced an entirely new system of incentives in the form of outright grants under the PIP scheme.

The PIP grants are direct subsidies for exploration and development, designed to promote both the Canadianization of the oil and gas industry and the tilting of investment towards the Canada Lands. The proportion of a company's exploration and development expenses that is eligible for PIP grants increases in relation to the firm's "Canadian ownership rate." The lower rate of PIP grants for investments on provincial lands relative to the Canada Lands results in less incentive for developing conventional supplies from the Western Basin, other factors being equal (Table 4-10).

Table 4-10

COR-Related Incentives Payments as a Proportion of Eligible Expenditures, Canada Lands and Provincial Lands, March 1984

	Canadian ownership rate (COR)[1]			
	A	B	C	D
	(Per cent)			
Canada Lands				
Exploration	25	50	65	80
Development	–	10	15	20
Provincial lands				
Exploration	–	15	25	35
Development	–	10	15	20

1 COR levels are as follows:
A = less than 50 per cent COR;
B = between 50 per cent COR and level C;
C = 63 per cent COR in 1984, increasing 1 per cent per year to 65 per cent in 1986;
D = 71 per cent COR in 1984, increasing 2 per cent per year to 75 per cent by 1986.

SOURCE Price Waterhouse Chartered Accountants, *Oil and Gas Taxation* (Toronto, 1984).

The impact of the Canadianization incentive on the Canada Lands is revealed in the trend of new exploration agreements. The large foreign companies have encouraged the "farm-in" of Canadian firms as joint-venture participants in their projects on the Canada Lands, thus raising their eligibility for federal subsidies. The foreign-owned companies are able to drill without having to use their own funds, because Ottawa pays for most of the drilling operations under the exploration agreements.

In our view, such direct subsidies for investments in the petroleum industry are not the most efficient way to encourage Canadian participation. Because they represent up to 80 per cent of exploration costs in the frontier areas, they invite wasteful expenditures as a result of the assumption of excessive risks or overpayment for drilling services. They also invite the "scrambling" of intercompany arrangements to gain access to the grants.

In addition to our concern about the efficient use of public funds, the important policy issue here is not so much the level of activity on the Canada Lands, but whether that activity is happening at the expense of other oil and gas activities or other productive investment in the economy that could facilite lower-cost and less risky oil supplies at an earlier date. Frontier activities will not, in the medium term, solve any of Canada's energy problems, but eventually Canada Lands oil supplies will take their place alongside production from the western provinces. The present Canada Lands policy, by deploying such large grants in the face of the geological, technological and economic uncertainties of frontier oil exploration, is extremely risky. The heavy gamble involved in promoting Canada Lands exploration to the present extent seems to be an unbalanced strategy. Incentives for exploration should be better balanced between regions and types of investment.

We suggest that more consideration be given to improving the economic incentives for exploration and development activities in the Western Basin. At present, there appears to be too little recognition of the implications of full-cycle costs. While it is reasonable to encourage activity in the Canada Lands over the longer term, the government should reassess the costs of providing the present high level of subsidies. The incentives pertaining to the Canada Lands should be scaled to better match the likely benefits and the time frame in which those benefits are likely to begin to be realized.

Collecting the Economic Rent

By controlling the collection of economic rent, governments control the existing and expected profitability of industry to a considerable extent. Given what we understand now about the responsiveness of supply to changing levels of profitability, governments can, within limits, control the rate of oil and gas exploration and development and, consequently, oil supply.

Provincial bonuses and royalties are the primary mechanism for collecting economic rents on provincial lands. The royalties are assessed on a well-by-well basis, in order to account for variable productivity levels and costs for the wells in a given pool. Royalty rates are, therefore, related by proxy to the profitability of each well, in that the percentage of gross revenues taken by the royalty is closely correlated with the profitability of a given oil field. In Alberta, oil royalties are a function of both well productivity and prices. Distinctions are also made between old and new oil. The royalty schemes that have evolved in the other producing provinces are similar.

At the federal level, the petroleum and gas revenue tax, one of the instruments intended to collect oil resource revenues, appears less effective than the provincial royalties. The PGRT was introduced in the National Energy Program as a flat-rate tax on net operating revenues – prices less operating costs – from all oil and gas production in Canada. Its effective rate is now 12 per cent, and only in the cases of tertiary EOR and other, negotiated special oil-recovery projects is it applicable after investment payback. In all other cases, it is imposed when production begins. The tax is not deductible for income tax purposes. At the time of its introduction, hostility arose for a number of reasons, including the added burden on the producer, which resulted in reduced profitability and reduced cash flow. The provinces objected that the PGRT was an intrusion into provincial taxation territory, the tax being similar to a royalty on production. In addition to the controversies over the justification of the PGRT, its design is also a contentious matter, because it is not as efficient as a tax on profits.

Because the PGRT only allows the deduction of operating costs, which generally represent some 10 per cent of the full-cycle private supply costs, in effect it skims off part of the gross production revenues, irrespective of the half-cycle or full-cycle profitability. The basic difficulty is that it does not relate closely enough to actual or expected profitability. Development projects with low profitability are overtaxed, and those with above-normal profits are undertaxed. The design of this tax should therefore be revised.

An obvious way in which the PGRT could be made more profit-sensitive would be to allow the deductibility of certain capital costs, as in the case of the present relief measures applicable to EOR projects until investment payback. This modification of the PGRT would make it more like a tax on corporate profits than on revenues. It would be valuable to the producer and would offer some protection on the downside and would, therefore, be more efficient in terms of fostering oil production.

These observations also apply to production from the Canada Lands. There, the fiscal regime includes the PGRT, a 46 per cent federal income tax and two types of federal royalties, plus the PIP grants. At the heart of the royalty regime is the progressive incremental royalty (PIR), which applies to the above-normal profits from a defined ("ring-fenced") field. The revenue base for this royalty is net of operating and investment costs, income tax payable, the PGRT and the 10 per cent basic royalty. The PIR is, therefore, aligned with profitability, but both the PGRT and the basic royalties appear less than effective. In addition, the present Canada Lands policy does not include bonus bidding, a system that efficiently balances risks between industry and government.

In our view, the private-sector supply of oil from the oilsands is certainly responsive to policy, but within the limits set by the relatively high costs of production. The fiscal policies for the oilsands can be aligned with the profitability of the projects, as has been the case for the individual arrangements for the smaller *in situ* developments such as Wolf Lake, Cold Lake and Elk Point. Policy should recognize more clearly the incremental nature of supply from the oilsands – i.e., the upward slope of the supply curve. We also believe that it should provide profit-oriented tax and royalty regimes that are explicit and stable. A clear assurance from governments that oilsands production will not be shut in – i.e., prorated along with production from other sources – seems essential.

Conclusions

Canada has a significant petroleum resource base. At present, it underutilizes this potential because of policy weaknesses created by a decade of adjustment to sharply rising world oil prices. If one objective is to achieve the economic potential of this country's oil resources, there is no doubt that the price of domestic oil supplies should be based on the prevailing world price. This relates to Canada's fundamental options in oil supply: either we develop our own oil resources or we buy oil on the world market. In reality, we will likely always do both, depending on transportation costs, oil quality and other factors.

Our evidence has shown that the supply of oil – particularly in the Western Basin, but also in all oil regions – is responsive to economic incentives and can be affected by policy. Supplies from the Western Basin – from discoveries, the further proving-up of existing reserves, and EOR – will be of great importance until well into the 1990s, particularly in view of the high cost of new oilsands supplies. Moreover, except for the Norman Wells project, we are unlikely to see any large production from the Canada Lands until later in the 1990s. In general, policy should not attempt to promote one source of supply over another but rather to provide a decentralized framework of incentives for industry to explore and develop those sources whose social supply costs are below the world oil price.

Throughout our analysis, we have suggested that recent perceptions of where our supplies will come from, in the medium term, have leaned towards nonconventional and frontier sources. In our view, conventional oil supplies from the Western Canada Sedimentary Basin will have to be – and should be – depended upon to a greater extent than is generally believed, until well into the 1990s. Moreover, our analysis has shown that such a reliance is quite feasible as there remains a significant conventional-oil potential in the Western Basin, given adequate economic incentives.

5 Natural Gas Supply

We frequently speak of "oil and gas" as if great similarities existed between these two forms of hydrocarbons, and certainly that is true: they are often found together; and exploration, development and production at the wellhead are similar, for the most part.

Nevertheless, great differences also exist between the two resources. The production process for gas is more involved, requiring a more complex infrastructure, as well as a more expensive transportation system since gas cannot be transported by truck and transportation by tanker is very costly. Longer lead times also characterize the gas production process. These features necessitate the existence and accessibility of sufficiently large gas reserves and longer-term contracts to secure the viability of gas production and delivery. Moreover, the gas industry is highly regulated – more so than the oil sector. As a result, the market for gas is more rigid. The markets for gas and oil also differ in scope. The gas market is mainly continental, owing to the difficulties of transporting gas worldwide, whereas a well-defined international market exists for oil. Consequently, the pricing of oil and gas presents somewhat different problems. Finally, the importance of exports with respect to the health of the industry has been much greater in recent years for gas than for oil. It is because these differences have significant implications in the analysis of supply and in policy formulation for gas and oil that we have devoted a separate chapter to gas.

Perhaps the most obvious characteristic of the natural gas market at the moment is the current imbalance that exists between supply and demand. This is compounded by the fact that Canada's established natural gas supplies are about twice as large as its established oil supplies, in energy-equivalent terms, although the domestic demand for oil is about twice as large as the demand for gas. Currently, there is a significant excess supply of gas relative to demand, not only in Canada but throughout the North American market.

While the surplus reveals a severe imbalance within the market, its existence also provides a number of opportunities for Canadians. If natural gas prices were to be deregulated in this country, they would likely decline initially, at least in relation to oil, and Canada would have an opportunity to achieve a better balance between gas supply and demand. Moreover, in the short to medium term, deregulation would provide a chance for Canadian consumers to enjoy lower natural gas prices, as well as to further off-oil goals. In the medium term, as gas use increased, the current network of pipelines could be expanded to serve those needs, but in so doing Canadians would also be able to prepare better for their longer-term requirements.

The gains that could accrue to Canadians through lower energy prices would be made possible by the present natural gas surplus. The surplus itself is the culmination of the high level of gas exploration and development over the past decade. Canada's ability to take advantage of the existing situation is reinforced by the massive long-term gas potential that exists in the Western Canada Sedimentary Basin and in the frontier areas.

It is sometimes suggested, in reference to natural gas and other nonrenewable resources, that in order to maximize long-term benefits Canada should aim at limiting production and keep in the ground as much of its resources as possible, in anticipation of future needs and price increases. It has to be kept in mind, however, that production today can generate net revenues, that can be reinvested in the economy to trigger a chain of investment and income generation over time, including investment aimed at replenishing the resource base. In other words, the benefit of resource revenues earned and invested today can be greater than that from production at some distant point in the future, depending on the rate of increase in the price of the resource over time.

What remains to be seen is whether it will be possible to realize the opportunities from the present surplus, while at the same time preserving and even enhancing Canada's long-term potential. Policy will be a determining factor in this regard, because the pricing mechanism, the structure of taxes and royalties, and the degree of regulation are the features that will determine whether the gas market can respond effectively to the forces of supply and demand, in both the short and the long term.

The existence of the present surplus and the fact that it is expected to persist for some time strongly suggest that present gas policy is not in step with the current market situation. The policy is unduly rigid, and until more flexibility is added, Canadians will be unable to take advantage of the opportunities that are facing them. If the current gas policy does not enable them to make these gains, then they must ask themselves what changes have to be made to redress that situation. There is no doubt that policy adjustments over the past two years, which have facilitated the domestic expansion of gas use and the adaptation to the export conditions, have been in the right direction and have been made in recognition of the existing market imbalances. They appear, however, not to have gone far enough.

Present Gas Supply

Canada's present established capability of supplying marketable gas is assessed in much the same way as oil supply capability, looking first to the remaining established recoverable reserves and then to the potential production from those reserves. The production of gas is usually called "gas deliverability," which may refer to either the expected or the potential rate of production.

Gas Definitions

Raw natural gas – Unprocessed natural gas.

Nonassociated gas – Natural gas not in contact with crude oil in the reservoir.

Associated gas – Natural gas, commonly known as "gas cap gas," that overlies, and is in contact with, crude oil.

Marketable natural gas – Natural gas that meets given specifications for end use.

Natural gas liquids (NGLs) – The hydrocarbons, such as ethane, propane, butane and pentanes plus, or a combination thereof, obtained from the processing of raw natural gas.

At the end of 1982, the remaining established reserves of marketable natural gas in Canada were 2,658 billion m^3 (Table 5-1), most of which was "nonassociated" gas; an estimate of reserves at the end of 1983 was 2,645 billion m^3. Given the current domestic consumption level (about 45 billion m^3),[1] those reserves will be sufficient to meet domestic requirements and currently licensed exports until well into the next century.

The conventional areas – primarily the Western Basin – account for over 80 per cent of the remaining established reserves. The gas reserves recognized as "established" in the frontier regions include some 150 billion m^3 in the Mackenzie Delta and some 322 billion m^3 in the Arctic Islands; none of the resources discovered off the East Coast are yet included in the

Table 5-1

Remaining Established Reserves and Reserve Additions of Marketable Natural Gas, Canada, by Region, 31 December 1982

	Remaining established reserves	Reserve additions
	(Billions m^3)	
Conventional regions		
British Columbia	260	13
Alberta	1,861	76
Saskatchewan	46	1
Others	8	1
Subtotal	2,175	90
Frontier regions		
Mainland territories	11	2
Beaufort Sea/Mackenzie Delta	150	–
Arctic Islands	322	–
Subtotal	483	2
Total	2,658	92

SOURCE Based on data from the National Energy Board.

established reserves. In 1982, the additions to the established reserves from discoveries, revisions and extensions totaled 92 billion m^3, all of which were recorded in conventional areas. For 1983, the additions are estimated to be in the order of 60 billion m^3.

The potential annual deliverability of marketable gas from conventional areas was estimated at 135.2 billion m^3 in 1983.[2] Given that the annual production that year was 65 billion m^3, the gas industry was operating at only 48 per cent capacity.[3] Domestic demand accounted for just over two-thirds of the annual production. The remainder – 20.2 billion m^3 – was exported to the United States; this represented only 43 per cent of the maximum allowable exports licensed by the NEB for 1983.[4]

The surplus is certainly evident. The shut-in wells and the excess capacity in the export market, which has resulted in weak and falling export prices, both reveal an overall gas market where supply is well in excess of demand and an imbalance prevails. A number of developments have contributed to the creation of this surplus.

Evolution of the Industry

Although natural gas was produced in Canada as early as the 1880s, the first significant events in the history of the domestic gas industry were the Leduc oil discovery of 1947 in Alberta and the subsequent surge in exploration activity in the Western Basin. At the time, gas finds were mainly the by-product of the search for oil. Explorers showed little interest in finding and developing gas resources because of the delays and investments necessary to transport the gas to potential markets. The gas reserves that were found, whether associated with oil or not, were shut-in, flared or consumed within the vicinity of the wells by industrial or residential users.

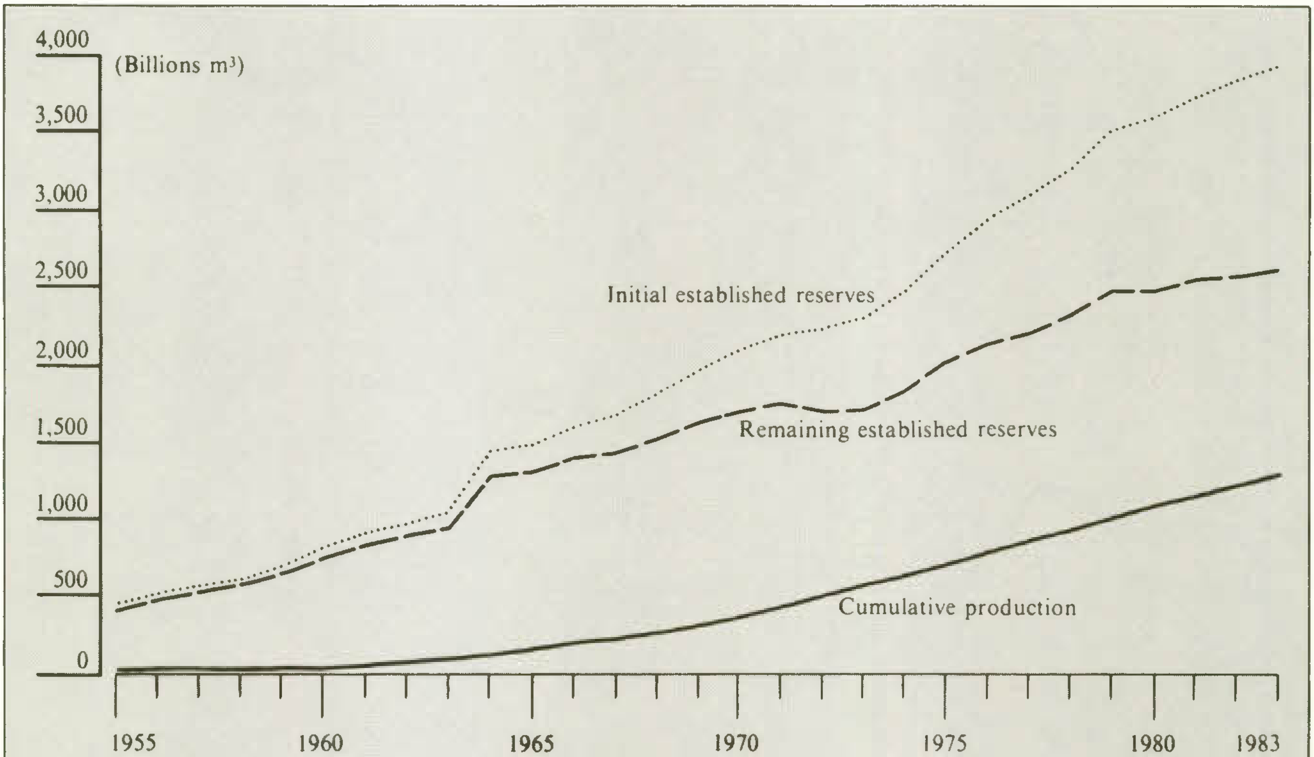
But the cumulative discoveries of gas grew to be significant over time. By 1957, the level of the remaining established reserves had reached 500 billion m³, or the equivalent of some 20 per cent of the current established reserves (Chart 5-1).[5] This level of reserves was clearly ample in relation to domestic and export requirements at the time. Substantial new discoveries made since then have been sufficient to support the expansion of the gas industry to the present day.

The major breakthrough for the Canadian gas industry occurred in the late 1950s and early 1960s with the establishment of a transmission infrastructure connecting the producing fields to the domestic and export markets. Westcoast Transmission Company completed the construction of a pipeline to serve British Columbia and the northwestern United States in 1957; TransCanada PipeLines provided the link to the eastern market and to selected border points by 1958; and a pipeline to California was in operation by 1961. Within Alberta, an integrated gathering system had gradually developed to move the gas from the wells to the plants and to the main transmission lines. The pipeline systems, together with the routes of a number of proposed new systems, are shown in Figure 5-1.

Between 1960 and 1973, the domestic gas industry enjoyed rapid growth, with annual production increasing at an average rate of 14 per cent to reach 71.3 billion m³ by 1973. While Alberta remained by far the largest producer, the gas industry in British Columbia also developed substantially over the period, achieving a production of 13.1 billion m³ in 1973, or 18 per cent of total domestic production (Table 5-2).

Chart 5-1

Established Reserves and Cumulative Production of Marketable Natural Gas, Canada, 1955-83



SOURCE Based on data from the Canadian Petroleum Association.

Figure 5-1

The Natural Gas Pipeline System and TCPL Tariff Zones

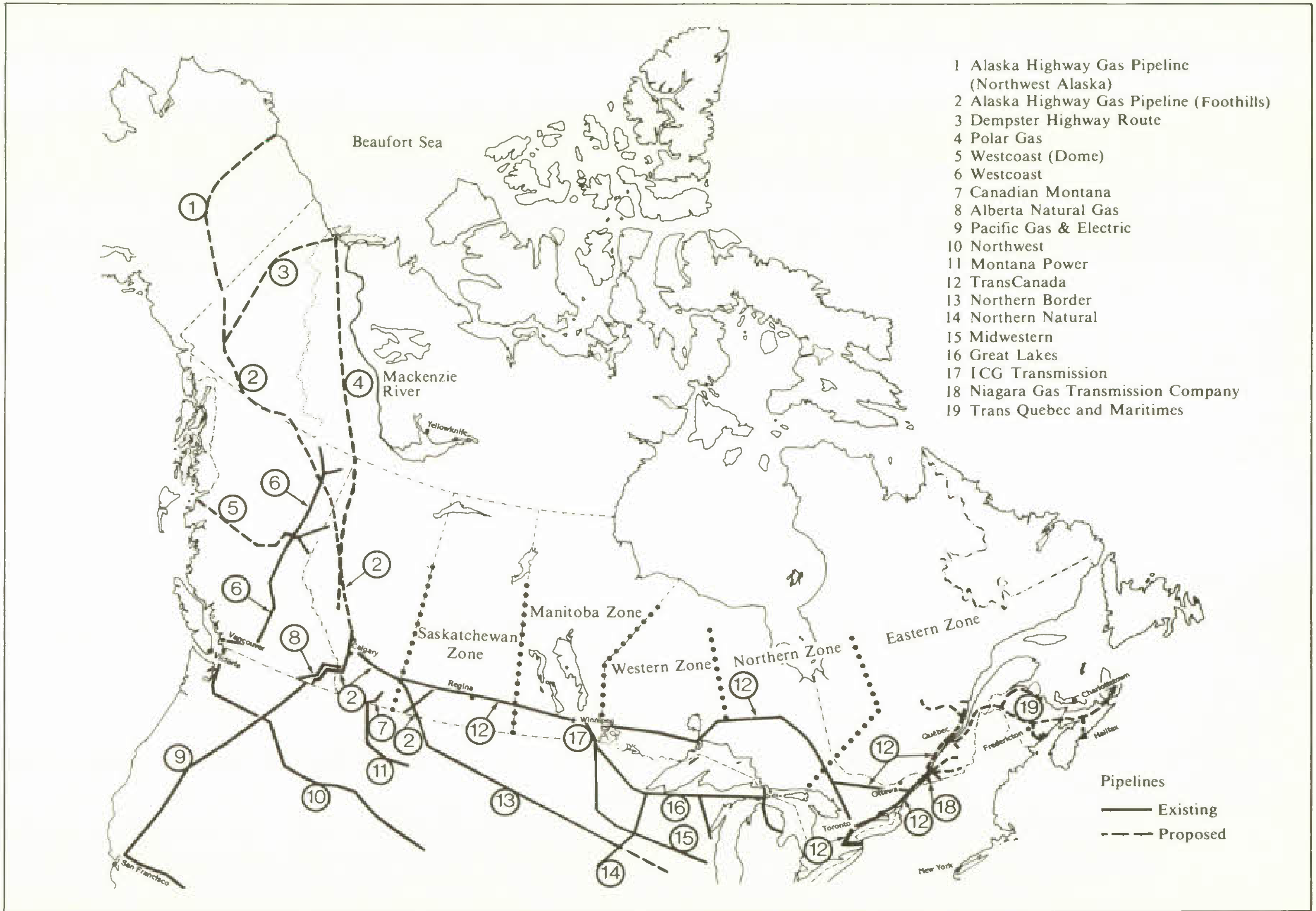


Table 5-2

Regional Distribution of the Production of Marketable Natural Gas, Canada, 1955-82

	1955	1960	1965	1970	1973	1975	1980	1982
				(Billions m³)				
Alberta	3.0	9.1	24.0	42.9	55.5	58.1	62.1	64.1
British Columbia	--	2.2	3.9	8.9	13.1	10.8	8.6	7.5
Saskatchewan	0.2	0.9	1.0	1.4	1.6	1.5	1.2	1.3
Territories	-	-	-	-	0.8	0.8	0.4	0.2
Eastern Canada	0.3	0.5	0.4	0.5	0.3	0.3	0.4	0.4
Total	3.5	12.7	29.3	53.7	71.3	71.5	72.7	73.5

SOURCE Based on data from the Canadian Petroleum Association.

The development of the Canadian natural gas industry has depended in large part upon the state of the U.S. market. Throughout the industry's history, a significant portion of production has been bound for that market. In the 1960s and early 1970s, the market for gas expanded at a steady pace in all connected regions, with the U.S. export market showing the fastest growth. In 1973, some 50 per cent of total domestic production flowed south of the border, mostly to the western states, while the markets in western and eastern Canada accounted for 26 and 24 per cent, respectively (Chart 5-2).

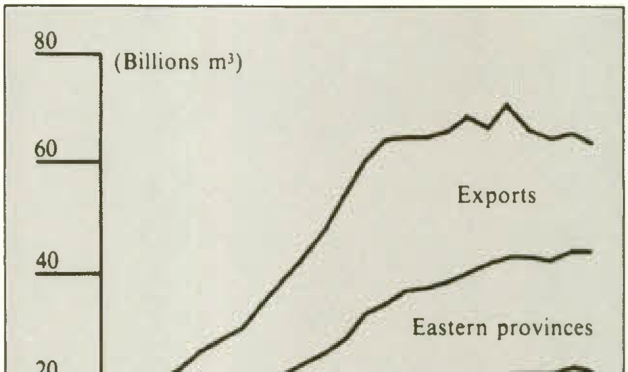
Despite the growth in gas markets during the 1960s, the interest of the exploration industry remained focused primarily on oil, with only an estimated 30 per cent of the drilling effort being directed specifically at finding gas. The inclination towards oil persisted partly because the gas producers faced low field prices and significant delays in finding market outlets, partly because of the high costs incurred by the pipeline companies for transmission and distribution of the gas, as well as other marketing costs related to the penetration of new markets.

A sharp turnaround in the gas supply situation was to occur in the mid-1970s. Because of the OPEC price shocks and of changes in government policy, the average wellhead price of gas increased dramatically from $6/thousand m³ in 1973 to as much as $56/thousand m³ in 1979.[6] This provided ample incentive for the industry not only to intensify gas exploration but, because gas prices increased faster than oil prices, to actually shift the emphasis of exploration from oil towards gas. The established gas reserves increased at an average annual rate of 6 per cent over the 1973-79 period, bringing them to a level of 2,500 billion m³ by 1979. These reserve additions included discoveries in the Mackenzie Delta and the Arctic Islands in the early and mid-1970s.

By contrast, demand began to stagnate around 1979, following some years of substantial expansion; increases in demand moderated and were accompanied by a gradual decline in exports. Despite this, the value of natural gas exports as a proportion of total merchandise exports rose over the 1973-79 period as a result of sharp increases in export prices. The total annual production fluctuated around 70 billion m³ – less than half the average rate of reserve additions over the period. The combined effect of increased reserves and reduced demand served to lift the ratio of reserves to production to about 35 years – well above a level that would indicate a supply/demand balance on the market.

Chart 5-2

Destination of Canadian Natural Gas, 1960-83



SOURCE Based on data from the Canadian Petroleum Association.

The Gas Reserve Price

The determination of the reserve price requires that one work backwards from the wellhead price. The valuation of unprocessed gas at the wellhead is done by imputing to production the value of all production emerging from the gas plant. After the deduction of gas plant costs, one is left with the composite price of gas at the wellhead. One then works backwards from this value to determine netbacks and reserve prices as defined in Chapter 4.

Since 1979, the fear of a gas supply shortage has been eliminated, at least for a decade or so, as the result of a gradual build-up of the present, very large, excess potential deliverability. Naturally, this development has moderated the industry's interest in finding and developing new gas reserves in the Western Basin, and it has sharply reduced interest in frontier gas. Consideration of new exploration and development projects remains important, however, because of the potential profitability of large gas developments for the 1990s and of the need to secure supplies for the more distant future.

History has shown that gas development is cyclical, being characterized by a number of ups and downs. Supply and demand adjustments take time, but eventually they do respond to economic incentives. The surplus is partly a result of policy initiatives that were intended to ward off the threat of a gas shortage, but the end result is a situation where reserve additions greatly exceed consumption.

While Canada added to its potential throughout the period 1960-79, the cost of these additions is increasing (Table 5-3). Finding and developing costs rose from between \$6 and \$8/thousand m^3 in the early 1960s to over \$25/thousand m^3 in 1979 (in 1983 dollars). However, the trend of gas cost increases has not been accelerating, as it has for oil. Moreover, while gas costs appear to be quite variable from one source to another, there is less variation than for oil. The five-year moving average costs reveal the trends in the annual costs, while the unaveraged costs reveal extreme variability over time. Although there are some gaps between the reserve prices and finding costs as reserves were being booked, costs have tended to track the value of new gas reserves (Chart 5-3).

Table 5-3

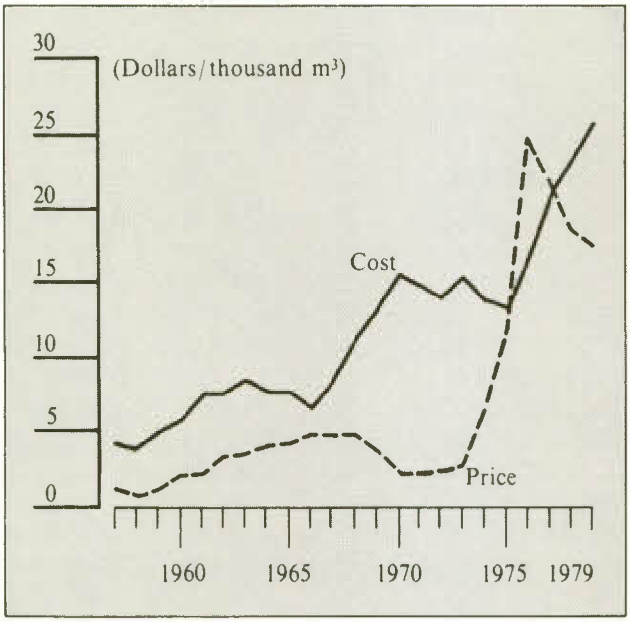
Private and Social Costs[1] of Finding and Developing Gas in the Ground, Alberta, 1960-81

	Five-year moving average costs		Without five-year moving average	
	Private	Social	Private	Social
	(Dollars/thousand m^3)			
1960	5.79	4.46	3.31	2.38
1961	7.45	5.84	43.46	37.74
1962	7.45	6.01	8.69	6.59
1963	8.28	6.83	12.83	10.35
1964	7.45	6.19	4.55	3.85
1965	7.45	6.27	4.55	3.86
1966	6.62	5.52	12.00	10.49
1967	8.28	6.99	10.35	8.82
1968	11.17	9.58	6.21	5.00
1969	13.24	11.50	10.35	8.68
1970	15.73	13.79	26.49	23.57
1971	14.90	13.51	31.04	28.35
1972	14.07	12.99	26.90	23.98
1973	15.31	14.39	5.79	5.64
1974	13.66	12.99	8.69	8.27
1975	13.24	12.73	66.22	63.45
1976	16.56	15.83	19.04	18.31
1977	21.11	20.05	15.73	15.12
1978	23.18	21.59	14.90	14.08
1979	25.66	23.68	24.01	22.56
1980	..	..	41.80	37.85
1981	..	..	33.52	30.49

1 In 1983 dollars. The private costs of finding and developing gas in the ground include bonus payments for land exploration and development rights but exclude all other payments to government. The social costs exclude all fiscal payments to government, including bonus payments for land rights.
SOURCE Eglington and Uffelmann, "Oil and Gas Reserves in Alberta."

Chart 5-3

Price and Private Cost[1] of Developed Gas Reserves in the Ground, Alberta, 1957-79



1 Five-year moving averages in 1983 dollars. The private cost includes bonuses.

SOURCE Uhler, with Eglington, "Potential Supply"; and Eglington and Uffelmann, "Oil and Gas Reserves in Alberta."

The average real-dollar costs of finding and developing new gas reserves in Alberta have been particularly erratic, but the trend shows an increase. The annual variation in costs reflects annual variations in discovery sizes and success rates. Again, the cyclical nature of gas supply development is evident. On the basis of these historical reserve booking costs, it can be calculated that in 1983 the social supply cost (without bonuses) for new developed reserves of conventional gas in the ground was approximately \$23/thousand m³ (in 1983 dollars). The total social cost of a thousand cubic metres of gas produced at the plant gate amounted to approximately \$63. This full-cycle cost level was still substantially below the wellhead price of \$92.50/thousand m³, indicating the presence of a substantial amount of economic rent from gas production, although the available rent in 1983 was somewhat lower than that in the mid-1970s.

The historical review of gas costs provides one further lesson. While Canada's gas potential has been growing, it has been doing so at increasingly higher real costs. Coinciding with rising costs have been rising wellhead gas prices – which until the mid-1970s had remained relatively flat – as well as rising government revenue takes through taxes and royalties.

On the basis of our estimates, the full-cycle private costs under the present fiscal arrangements are between \$100 and \$115/thousand m³, depending on the size of the producer and on whether the gas is classified as old or new. Provincial incentives are included in these estimates. Given that the price for natural gas was about \$100/thousand m³ in the spring of 1984, we conclude that currently the industry on average has little incentive to search for and develop new natural gas reserves. The available economic rent is more than adequately captured by governments. As a consequence, major exploration for new reserves has virtually ceased, although some development continues to be undertaken by gas producers to fulfil existing supply contracts. The situation, of course, also reflects the excess supply of gas in North America in general and the shut-in reserves in western Canada in particular. In the face of the present surplus situation, this may not be a very urgent matter, but the continuation of poor incentive levels for new exploration could lead to trouble in the future.

Future Gas Supply

The long-term gas potential of each of the various "gas-prone" regions was assessed recently by the National Energy Board. Assessments of reserves have also been made by other groups – in particular by the Geological Survey of Canada (GSC).

Western Canada Sedimentary Basin

According to the NEB forecast for natural gas deliverability from the conventional areas[7] and on the basis of the current pricing and fiscal policies and the current rate of domestic consumption and export commitments, Canada's long-term outlook is indeed favourable (Table 5-4). The potential deliverability from the established reserves is forecast to increase slightly until 1986, reflecting the current surplus; beyond 1986, it will decline to the end of the forecast period. The supply from reserve additions will show a steady increase to the year 2000. On balance, Canada's total supply capability is forecast to rise over the short term as a result of the excess gas supply, but a steady decline is envisaged for the long term.

Looking to the forecast of potential gas supply, the southern part of the Western Basin is estimated to have an ultimate potential of about 5,000 billion m³ of natural gas, recoverable at present netback levels (Table 5-5). To the end of 1981, approximately 3,200 billion m³, or 64 per cent, had been discovered and recorded as initial established reserves, implying an additional potential of 1,800 billion m³ from added reserves. In 1983, the NEB forecast that approximately 1,200 billion m³ of reserve additions will be recorded to the year 2000.[8] Consequently, 4,400 billion

Table 5-4

Projected Natural Gas Deliverability from Conventional Areas, 1983-2000

	From established reserves	From reserve additions	Total capability
		(Billions m^3)	
1983	134.9	0.3	135.2
1984	135.6	1.2	136.8
1985	135.9	2.7	138.6
1986	131.8	5.2	137.0
1987	128.4	8.3	136.7
1990	110.6	19.5	130.1
1995	71.2	37.7	108.9
2000	38.7	45.2	83.9

SOURCE Based on data from the National Energy Board.

Table 5-5

Ultimate Potential and Initial Established (or Discovered) Reserves of Natural Gas, Canada, by Producing Region

	Ultimate potential	Initial established reserves	Discovered reserves[2]
		(Billions m^3)	
Western Canada Sedimentary Basin	5,000	3,200[1]	...
Beaufort Sea/ Mackenzie Delta	1,865	–	286
Arctic Islands	2,257	–	361
Eastern Canada Offshore	2,423	–	245
Total	11,545	–	4,092

1 The cumulative production to 1981 in the Western Basin was about 1,200 billion m^3.

2 Discovered reserves are defined in terms of "best current estimates" of discoveries, rather than the conventional terminology of established reserves. Less-than-complete assessment of the reservoirs has taken place. The ultimate potential for the frontier areas is the "average-expectation" potential.

SOURCE Based on data from the National Energy Board and from the Canadian Geological Survey.

m^3 of reserves, or 88 per cent of the ultimate potential, should have been discovered by then.

To the end of December 1981, the natural gas produced since production first began in western Canada amounted to about 1,200 billion m^3, or 24 per cent of the ultimate potential for the region. It is apparent that the Western Basin alone has the capability of supplying Canada's needs for many years to come.

Nonconventional Gas in Alberta

Natural gas from very low permeability reservoirs is often referred to as "tight gas" and requires special stimulation before commercial rates of production can be achieved. To date, only a nominal quantity of reserves of tight gas has been booked by the NEB and the Alberta authorities, but there are estimates suggesting that there are great quantities of gas in the Alberta deep basin.

Frontier Areas

The Geological Survey of Canada estimated in 1983 that approximately 900 billion m^3 of gas had been discovered to date in Canada's frontier areas. The potential was estimated to be an additional 2,700 billion m^3 at a high confidence level and an additional 6,500 billion m^3 at an average expectation level. A higher probability is assigned to the estimated potential at the high confidence level than at the average expectation level. While these discovered and potential reserves are substantial, the amount that may be commercially viable will depend on natural gas prices, market availability and progress in the development of the technology required to produce and transport frontier supplies.

The three frontier areas where significant discoveries have been made are the Beaufort Sea/Mackenzie Delta, the Arctic Islands and the Eastern Canada Offshore region. The discoveries in these areas are defined in terms of the best current estimates of the discovered reserves, rather that the conventional terminology of the established reserves. This is due to limited delineation drilling and, consequently, to less-than-adequate assessment of the reservoirs.

In the Beaufort Sea/Mackenzie Delta region, the discovered gas resources are estimated by the GSC to be about 300 billion m^3, while the average-expectation potential is estimated to be about 1,900 billion m^3. The major gas discoveries have been in the gas-prone, onshore Delta area, where three fields totaling 85 billion m^3 have been discovered. The gas from this area will be ready for commercial development when market demand justifies the investment in production and gas transmission facilities.

In the Arctic Islands, the discovered gas resources account for approximately 360 billion m^3, while the average-expectation potential is estimated by the GSC to be about 2,250 billion m^3. The major potential for natural gas in the Arctic Islands is in the Sverdrup Basin, where three of the discoveries range between 50 and 100 billion m^3; none of the pools, however, have been fully delineated. The gas reserves from the Arctic Islands are generally shallow and potentially highly productive. Because of transmission difficulties, however, it is too early to judge whether gas from the high Arctic could contribute significantly to the supply capability before the next century.

The discovered gas resources in the Eastern Canada Offshore region are considered to be about 250 billion m^3 and the average-expectation potential is approximately 2,400 billion m^3. The area has only been lightly explored in relative terms, but currently the gas potential is estimated to be greatest in the Labrador Shelf and Scotian Shelf areas.

In the Scotian Shelf area, the average-expectation potential for gas is estimated to be approximately 500 billion m^3. This is in addition to the discovered resources to date, which amount to approximately 110 billion m^3. The Venture gas field in the Scotian Shelf area near Sable Island is currently under study as a possible source of natural gas for new domestic markets in the Atlantic provinces and new export markets in the northeastern United States.

In the area of Newfoundland, the Hibernia oil field has associated gas reserves that are estimated to be about 60 billion m^3 in terms of discovered resources. Although the gas would likely be reinjected initially when the oil field comes on production, this would probably be a short-term measure; eventually the gas should be marketed, perhaps as liquefied natural gas and gas liquids.

While these areas are not expected to contribute to the overall Canadian gas supply until well into the 1990s, by that time their contribution could be important. The commercial development of the frontier natural gas resources will depend on firm gas prices, new markets and long-term demand in the current markets in Canada and the United States. Transportation systems will also play an important role when commercial development is undertaken.

Currently, the transportation systems are not developed; their costs will in many cases be very high, and there is still an intense debate over their impact on the environment. A great deal of study has already been undertaken with regard to linking up some of these proposed systems with existing natural gas pipelines in Canada,[9] but more research needs to be done.

Over the past decade, a number of proposals for the construction of major systems to transport gas from the Arctic to southern markets have been put forward (Figure 5-1). Most, however, have subsequently been abandoned or set aside until market conditions improve. Both the Canadian Arctic Gas plan for a pipeline running from Prudhoe Bay, in Alaska, eastward along the North Slope to the Mackenzie Delta and southward along the Mackenzie Valley, and the all-Canadian Maple Leaf line to tap Canadian gas only lost out to the proposed Alaska Highway Gas Pipeline project, proposed by the Foothills (Yukon) Group. While the southern segments of the latter project have been built and are currently transporting surplus Canadian gas to markets in the western and midwestern United States, the construction of the northern segment, from Prudhoe Bay south to Fairbanks and then southeast along the Alaska Highway corridor, has been deferred indefinitely as a result of the recent upheavals in the U.S. gas market. A proposed branch line (the Dempster Lateral) to transport Canadian gas from the Mackenzie Delta/Beaufort Sea area to connect with the main line at Whitehorse is, of course, also being held in abeyance.

For want of progress in firming up their plans, the application by the proponents of the Arctic Pilot Project (APP) was dismissed early in 1984 by the National Energy Board. Initially, this project involved moving liquified natural gas from Melville Island by tanker to a Canadian port on the East Coast, where it would be regasified and marketed in Canada, thus releasing an equivalent volume of Alberta supplies for export to the United States. When the potential U.S. market began to slip away, the backers of the APP turned to Europe, but markets there proved to be just as elusive as those in the United States.

Some years ago, the proponents of the Polar Gas project, which involved the construction of a gas pipeline from the Arctic Islands southward to the west of Hudson Bay, submitted but later withdrew their application to the NEB. Subsequently, they raised the possibility of building a "Y" line to provide access to gas from the Mackenzie Delta/Beaufort Sea area as well as from the Arctic Islands. In mid-1984, however, Polar Gas submitted an application to the Board for a pipeline running south from the Mackenzie Delta, which was similar in concept to the earlier proposal for the Maple Leaf line. A subsequent line to connect with the Arctic Islands gas reserves was contemplated only as a future, second-stage undertaking.

In summary, it can be concluded that the frontier areas will provide a long-term source of natural gas, but the vital question remains: At what cost? The answer is that the discovery of further reserves in the future will likely come at higher costs. Essentially, all of the gas discoveries to date have occurred as a result of the search for oil, which was the primary goal of exploration. With the exception of the Mackenzie Delta and some areas in the Scotian Shelf and, to a limited extent, in the Arctic Islands, very little drilling has been done with the intent of discovering or delineating gas.

The estimated full-cycle social supply cost for conventional gas supplies in the Western Basin is about \$65/thousand m^3 (in 1983 dollars). The half-cycle costs of nonconventional (tight gas) supplies in the basin are expected to be high, perhaps in a range between \$70 and \$140/thousand m^3. Given the current price situation, these supplies are generally uneconomic. On the basis of the information presently available, we do not expect frontier production to occur until at least the mid-1990s. The earliest development might be in the Venture gas field, which could be economic if real costs are reduced by the "proving-up" of additional reserves.[10] Current estimates place the real cost of Venture gas around \$135/thousand m^3. Firm marketing contracts with the northeastern United States would be needed to make the project economically viable. Gas from the Mackenzie Delta and the Arctic Islands has yet to be connected to southern markets and is currently uneconomic.

In its latest forecast, the NEB brings together its forecasts of the future deliverability of natural gas and of gas demand. They reveal that the deliverability from the established reserves and the reserve additions is more than sufficient to serve Canadian domestic requirements and existing export commitments until well into the next decade. The established reserves alone are sufficient to meet these requirements until the end of the 1980s, at which time the deliverability from the reserve additions is forecast to become increasingly important.

In 1983, Canada earned \$4 billion through net gas exports, which amounted to half of the overall energy trade balance. On the basis of the NEB's method for authorizing new exports (see Appendix D) and of the 1983 decision to license an additional 322.5 billion m^3 of gas exports, we conclude that the current producing areas of Canada can supply domestic needs and meet the authorized exports to the year 2000.

Except for the proposed production from the Venture field to supply new markets in Canada's Atlantic region, gas supplies from the frontier areas will not be required to serve the domestic market for many years. Frontier gas supplies could, however, provide for new exports to the United States or be shipped to other markets in liquefied form. The economic benefits to Canada from gas exports are substantial; in all likelihood, they will continue to be an important component of this country's international trade for many years.

It can be concluded from the foregoing discussion that Canada does have more than sufficient natural gas to meet its present needs, as well as a significant long-term potential. The existence of the present surplus affords Canadians an opportunity to make a number of gains in the short term. Excess-supply pressures would likely cause gas prices to fall – at least in relation to oil prices – if they were to be deregulated. In addition to the obvious benefits accruing to gas users from lower overall energy costs, lower gas prices would encourage increased gas use, restoring a closer balance between supply and demand. That, in turn, would provide for a more stable gas market, which would ultimately be of benefit to both users and producers.

Lower gas prices relative to oil prices would enable Canadians to accelerate the substitution of gas for more costly forms of energy. Our research suggests that, under the current system of fixed gas/oil price ratios, there is limited scope for increasing the domestic-market share for natural gas, even if one assumes that oil prices will rise. There exists at present an opportunity to stimulate the substitution of gas for oil and other energy sources through lower gas prices. This offers an alternative to the present system of subsidies as a means of achieving off-oil targets. The expansion of gas transportation and distribution systems into areas and sectors that are currently more dependent on other fuels – as in the case of industrial users of heavy fuel-oil in some parts of Ontario and Quebec, for example – could be realized through lower prices.

Finally, lower export prices would contribute to increased sales of natural gas in the United States as new markets are penetrated. In particular, the northeastern states are generally believed to hold greater long-term potential for Canadian gas than any other U.S. region. By establishing a position in these markets, Canadian producers will be able to benefit later when conditions firm up south of the border. Market conditions in the United States are such, however, that Canadian gas exports will have to be price-competitive in order to maintain and expand their position in that country.

In view of the current gas surplus and the possibility of enjoying lower energy prices, we must ask whether this is consistent with the preservation of Canada's long-term potential. The answer to this question lies in the flexibility of fiscal and marketing arrangements for natural gas. The short term calls for lower prices, and the long term may call for higher prices. We have seen that, while substantial additions to reserves have occurred in the past, they have only been possible at increasingly higher costs, which will apparently continue to be the case in the future. Furthermore, the profitability of new gas from the Western Basin under present conditions has been found to be marginal; it is certainly insufficient for the development of nonconventional and frontier gas sources. Natural gas supply policy, therefore, requires more flexibility not only in pricing but also in the fiscal measures adopted by governments.

Responsiveness of Supply to Policy

What is required of natural gas policy is the flexibility to adapt faster to the realities of the market than it has in recent years. If supply and demand are out of kilter, policy must enable prices to change accordingly, so that the necessary market responses can be triggered. The present surplus position therefore requires that gas prices have sufficient downward flexibility to stimulate demand and pave the way for immediate gains in the short term. To ensure simultaneously that the long-term potential is preserved, the structure of government taxes and royalties must also contribute to the flexibility of the system. To do so, taxes and royalties must be aligned with the profitability of the activities of the gas industry. Should gas prices decline through deregulation, the tax and royalty load ought to be reduced accordingly, in order to maintain the incentives to continue the long-run development of the gas potential.

At present, natural gas prices in Canada are administered through federal-provincial agreements. As a result, they tend to lag far behind the realities of the market place. When prices should be decreasing, thereby stimulating gas consumption and slowing down gas exploration, they are held too high. Consumers do not benefit, and the gas industry builds up surplus capacity quickly. Conversely, when there is a shortage of gas, prices should respond quickly by rising to induce conservation in the market place and to promote additional supplies. In other words, policy must generally take into account the responsiveness of supply.

The underlying cost structure of gas supplies within given geological formations suggests that the supplies are inherently elastic over a wide range of volumes, and our research indicates that they are substantially responsive to policy.[11] In assessing the short-term supply potential of gas reserve additions, the geological formations examined for oil in the preceding chapter have also been analyzed for natural gas. These are the formations in Alberta for which sufficient statistical drilling histories exist and that are considered to be representative of the Western Basin.[12]

The definition of the price of gas reserves is similar to that for oil, as is the method for deriving the gas reserve price. However, there are some special features of the latter that warrant mention. First, the value of the wellhead product (raw gas) is viewed as including the net value of the various by-products that emerge from the gas plant. Second, for gas, there are often significant delays between discovery and initial production, whereas this has not typically been the case for oil in the Western Basin.

We have shown that the reserve price is essentially a discounted netback. The discount factor accounts for the fact that reserves in the ground are assets that necessarily generate revenues slowly over time as they are exploited. A delay in production and thus in the realization of revenues therefore reduces the value of the reserves in the ground; in other words, it reduces the reserve price. Conversely, a reduction in delay will tend to increase the gas reserve price. As with oil, we view the reserve price as a key factor in driving the gas supply effort, and this delay feature becomes important for natural gas policy. Reductions in the wellhead price of gas do not necessarily translate into lower reserve prices, as would be the case for oil. If lower wellhead prices for gas result in expanding markets and shorter delay times between discovery and production, the value of the gas reserves in the ground could be sustained.

How responsive are the supplies of conventional natural gas to policy? It would appear that substantial amounts of additional natural gas reserves may be expected from Alberta. Research undertaken for the Council indicates that the reserves from the Mannville and Viking geological horizons, together with some from both the Upper and Lower Devonian horizons, are likely to be responsive to price and fiscal regimes. The Milk River and Medicine Hat horizon in southeastern Alberta is also promising, as are many others, but these were not considered in our research.

With a price of \$15/thousand m^3 for developed gas reserves in the ground – close to the average value of new gas reserves in the early months of 1984 – the Mannville and Viking horizons hold out the prospect of containing a significant potential for additional nonassociated gas reserves. The estimates for the additional potential in the Mannville horizon range between 297 and 309 billion m^3; in the "Viking and Equivalent" geological horizon, they range between 62 and 106 billion m^3. The lower estimates result from an assumption of full directionality in drilling, while higher estimates result from an assumption of no directionality.[13] As for oil, these are extreme assumptions, and the true potentials likely fall somewhere between the two estimates.

By considering a change in the price of developed gas reserves in the ground, the degree to which additions of natural gas reserves would respond to policy can be estimated. For example, a higher reserve price of \$25/thousand m^3 – an increase of \$10/thousand m^3 – is assumed. The potential additions in the Mannville horizon are estimated to increase from 297 to 399 billion m^3 in response to the higher price. In the Viking horizon, the potential additions would rise from a previous estimate of 62 billion m^3 to 85 billion m^3. Thus, under this assumption, the combined increase in the potential for gas reserve additions in the two formations is 125 billion m^3.

The reserve-price elasticity, in this range of prices, is about 1.2, revealing significant supply responsiveness. Based on our findings for gas and oil, we conclude that the response of reserve additions to a price increase is greater for gas than for oil. This result tends to be consistent with the generally held belief that the Western Basin is gas-prone and can therefore provide a significant additional supply of natural gas reserves in response to policy.

An historical review of the NEB's forecasts of potential gas deliverability in the Western Basin reveals an implicit recognition of this elasticity of gas supply. In 1975, the NEB forecast potential deliverability for the year 1995 to be about 49 billion m^3. That estimate rose steadily over the years to a level of 109 billion m^3 in the 1984 forecast.[14] The increases, while caused by a number of factors, clearly reflect the impact of the higher gas netbacks that came about in the mid-1970s.

Our analysis has focused on conventional gas activities in the Western Basin because there has been little or no production in the frontier areas or from nonconventional reserves. There is no reason to believe, however, that activity and natural gas production would respond differently in these other sources of supply.

This evident and potential responsiveness of natural gas supply shows that Canada is not faced with some fixed stock of gas that might run out during a long winter. On the contrary, Canadians have the resources and the industry, so that flexible prices and fiscal arrangements can serve to safeguard deliveries to domestic consumers. This can be the case for both the short and the long term.

Current Policy

The current natural gas policy focuses on three areas: gas pricing at the wellhead, the consumer city gate and the export border point; gas royalties and taxes at various levels in the production and distribution chain; and the promotion of natural gas in both domestic and export markets.

To realize fully the potential from increased domestic natural gas sales, there is a need for prices and government fiscal measures to be more flexible, as we have already noted. In addition, there is also a need to untangle some of the institutional constraints that tend to prohibit responsiveness in the industry.

Pricing

The value of a barrel of oil at a given time and place can be fairly easily determined from its price on the world market, adjusted for transportation and quality. Whether the price will be set at that value in any given transaction will depend mainly on the nature of any government intervention in the market place.

In the natural gas market, however, there are no worldwide indicators of value. The international trade in liquefied natural gas is still too small to serve that purpose. In Canada, the present pricing policy has evolved from a series of more or less successful attempts by industry or government to measure the value of gas over time (see Appendix E). For Canadian consumers, the domestic price of gas sold interprovincially is currently determined by the federal requirement that the valuation at the Toronto "city gate" be approximately 65 per cent of the equivalent price of oil; in early 1984, the corresponding Toronto wholesale price was some \$145/thousand m^3. The prices paid to producers, however, are determined on the basis of the Alberta "border price," which is essentially set by Alberta in keeping with the terms of the agreements with the federal government; the Alberta border price at the beginning of 1984 was some \$105/thousand m^3. The difference between the consumer wholesale price and the producer price is made up of federal taxes, transportation tariffs and the moderate federal subsidy paid for the TransCanada pipeline.

Despite successive adjustments, the gas-pricing system currently in place has continued to be inadequate over the past year or two, which is reflected in the growing surplus of gas supply. The administered gas prices are above market-clearing levels – where supply equals demand – reflecting a lack of policy responsiveness to the conditions of supply and demand.

Since the early 1970s, gas prices have moved from being negotiated between producers and large pipeline companies to being the fully administered, fixed ratios of the oil price that they are at present. This evolution has been driven by the desire of the federal and provincial governments to exercise greater control over gas prices. While it would appear that the current method is somewhat awry, the gas/oil price relationship in the consumer market still requires consideration.

Recognition of the gas market imbalance was evident in the National Energy Program. The gradual decline in the gas/oil price ratio from 80 to 65 per cent at the Toronto city gate can be seen as an attempt to address the surplus. Clearly, the changes were in the right direction, although they were perhaps not large enough. The present-day arrangement, whereby the ratio is fixed at around 65 per cent, is the result of policy changes subsequent to the NEP. The gas surplus persists, however, and it is difficult to envision its rapid reduction at the current ratio.

The problems – and opportunities – in the gas industry are too complicated to be dealt with simply by lowering the administered price. Not only is the level of prices out of whack, but the overall structure of the administered-pricing system tends to be contradictory.

In both Canada and the United States, history has shown that it is difficult, if not impossible, for governments to prescribe market-clearing gas prices because of the many factors that must be taken into account. From the point of view of supply, the deliverability potential, the established reserves and potential additions, and the cost of present and future supplies are important factors. On the demand side, consideration must be given to conditions in the domestic and export markets, including the level of economic growth and the price of natural gas substitutes, such as oil and electricity. Over the long term, the effect of each factor on the value of gas varies, with the result that no simple formula can be relied upon to administer prices. The efforts of governments to derive such formulas in the past have been unsuccessful, leading, sooner or later, to costly market imbalances.

Another feature of the current gas-pricing arrangement also detracts from the efficiency of the system. The NEP provided that the Toronto city gate price, which applied throughout the eastern zone of the TransCanada pipeline system, would also apply throughout the whole area served by domestic gas in eastern Canada. The result is that all consumers east of Toronto in effect pay the same mainline transportation tariff as do Toronto consumers. This arrangement does not accurately reflect actual transmission costs. Added to the basic rigidity of the gas-pricing mechanism is this artificial means of stimulating the eastern market.

The structure of the gas transmission and distribution industry also presents obstacles to the establishment of competitive prices within the parameters permitted by the regulatory framework. For a price-deregulated system to lead to competitive price setting, it will be necessary to ensure that a sufficient number of producers and buyers of gas have access to the market. On the producer side, gas production is reasonably competitive. Structural changes on the buyer side of the market might be necessary, however, since the main buyers are also the transmission companies.

This is the case, for example, with TransCanada PipeLines (TCPL), the largest buyer of Alberta gas. It resells the gas that it purchases to Canadian regional distributors east of Alberta and to U.S. customers. The company also owns and operates the only transmission system moving gas from the West to eastern domestic markets and export points. This places TCPL in a conflict-of-interest position. The company is reluctant to transport gas that it does not own, particularly in view of the fact that its "take-or-pay" contracts with producers have forced it to buy large volumes of gas that it has been unable to market in recent years and that still lie idle in the ground. Naturally, it is in TCPL's interest to assign priority to the sale of the gas that it has paid for but not taken.

Natural Gas Take-or-Pay Contracts

Most contracts between gas producers and buyers, whether on the domestic or the export market, include what are known as "take-or-pay" clauses. These clauses stipulate that the gas purchaser must guarantee payment for some predetermined share of contracted sales amounts, regardless of whether the gas is actually taken by the purchaser. The take-or-pay payments are intended to ensure the producer with recovery of the cost of "dedicating" gas reserves and/or deliverability potential to a specific customer. When the gas is paid for but not taken, it becomes the property of the buyer; the buyer can claim the gas at a later date, subject to the conditions of the contract, including its duration. Some sales agreements provide for an extra period of one year or so at the end of the contract for delivery of gas paid but not taken.

Efficient price deregulation would require, however, that TCPL and other pipeline companies be asked to compete with other buyers – for example, regional distribution utilities or large industrial users of natural gas – for the purchase of gas from producers. This, in turn, would require that TCPL agree to transport, for a regulated tariff, gas that it does not own – that is, to become a "contract carrier." While TCPL could continue to purchase and sell gas to honour its present contracts and eventually dispose of its accumulated stock of gas, the operator of the pipeline should be a neutral party. A possible solution would be to split TCPL into two companies – a gas-buying and gas-selling company (in effect, a broker), and a regulated pipeline company acting as a contract carrier. This could apply both to gas marketed domestically and to gas sold into the export market. The contract carrier could serve all buyers who are prepared to negotiate directly with producers and who have been allowed to do so under provincial laws. The broker company would take over TCPL's take-or-pay obligations. Similar conditions might apply to other pipeline companies, such as Westcoast Transmission in British Columbia, which would be in keeping with the recommendations made by a provincial task force.[15]

Full price deregulation would have to be phased in over a period of a few years to allow time for the renegotiation of the existing contracts. With the gradual expiry of contracts between producers and major pipeline companies, more buyers would bid for gas and prices would be established at competitive levels.

All of the pricing schemes, including the negotiated contracts under which prices were set before 1975, have demonstrated inadequacies. The most general criticism is that they have not adequately responded to market realities. Because Canadian gas prices have not adjusted well to supply and demand conditions over time, the developed reserves have moved from rapid depletion to overabundance. Before 1975, the rigidity of gas pricing stemmed mainly from inadequate renegotiation provisions within private contracts. Since 1975, new problems have arisen because of government difficulty in administering prices that would clear the market, especially in view of the importance of gas exports. Since 1981, even more difficulties have been introduced by setting different prices at both ends of the TransCanada transmission system – the Alberta border price and the Toronto city gate price.

All this experience indicates the failure of overly detailed pricing formulas. While our ultimate goal is the establishment of an effective system for ensuring competitive prices within the framework of an agreed regulatory system, we recognize that some transitional arrangement needs to be adopted. Given our proposal to deregulate oil prices, we believe it would be appropriate to link the Toronto city gate price of gas to the price of oil, provided that the ratio were subject to adjustment at least annually, if not semi-annually. This periodical adjustment would be based on market conditions. In addition, the Alberta border price would be calculated as a simple netback after deduction of the transmission costs. In this way, prices could be adjusted to the apparent supply and demand conditions. They could then be deregulated.

The inflexibility of past and present pricing mechanisms has contributed to the development of the current gas surplus. If gas prices remain inflexible, Canadians will be unable to benefit from the solution to the surplus – lower gas prices.

Taxation and Incentives

Taxation and incentives in the gas industry parallel those described for the oil industry in Chapter 4. The petroleum and gas revenue tax applies to the revenue from gas production, including the export flowback, as well as from oil production. Policies concerning exploration, development, and production on Canada Lands are also similar to those prevailing for oil. Likewise, the income tax system and the PIP scheme are the same for both oil and gas activities.

The current system of taxation is insufficiently aligned with the profitability of gas development, just as is the case for oil. That fact has particular implications in view of our concern that lower gas prices over the short term should not be at the expense of Canada's long-term potential. At present, the fiscal system lacks sufficient built-in mechanisms to adjust to declining prices.

Taxation

The natural gas and gas liquids tax (NGGLT) is unique to the gas industry. Introduced in the National Energy Program, the tax was originally intended to apply to all domestic and export sales of natural gas and gas liquids. For natural gas, the tax was to be determined at the Toronto city gate, together with the Canadian ownership special charge. It was set in 1980 at \$10.43/thousand m³, reducing producers' anticipated revenues, and it was initially scheduled to increase to as much as \$26.44/thousand m³ by 1982. (Meanwhile the tax-inclusive wholesale price of gas in Toronto was to go from \$102.42 to \$139.66/thousand m³.) Since its introduction, however, the tax has gone through successive adjustments; first, it was set at zero on natural gas exports (in the September 1981 agreement); then, as a result of decreases in the oil price and of the federal government's commitment to maintain a 65 per cent ratio of gas-to-oil prices, it was brought down to zero in February 1984 on domestic sales as well. The tax is still in place, however, and upward adjustments could occur in the event of rising oil prices.

There is a tax on gas production that is not paralleled on the oil side: the natural gas and gas liquids tax (NGGLT). The extent to which the NGGLT might be considered a burden on the producer depends upon the manner in which the Alberta border price is determined. As established in the National Energy Program, the tax reduced producer netbacks because the Alberta border price was determined as the net sum of the Toronto city gate price less transportation tariffs, the NGGLT and the Canadian ownership special charge. Any change in the NGGLT would clearly change the Alberta border price and therefore affect producer netbacks. This provision was modified in the September 1981 agreement, however. The Alberta border price became a prescribed price, to be set by the province while the federal government would set the Toronto city gate price, both subject to agreement. A problem arises, however, with two governments controlling prices at either end of the pipeline. The arrangement has separated the forces of demand from those of supply, and the present surplus, coincident with production delays and consequent reductions in the gas price, has in effect been the mechanism serving to equilibrate market forces. This is wasteful because capital is tied up in shut-in gas reserves.

Domestic Market Penetration

Prior to the 1980s, governments in Canada had been involved only indirectly in the expansion of the domestic gas market. Apart from the regulation of pipeline companies and distributors, the most significant intervention had come in the latter part of the 1950s, with the granting of financial assistance by Ottawa to TransCanada PipeLines Limited.

But in 1980, with the emerging gas supply surplus and the growing concern over the security of energy supply, the federal government expressed its intention to participate more directly in the development of new gas markets in Canada. Various initiatives were announced in the NEP and, subsequently, in the September 1981 agreement and the NEP Update of 1982. The measures concerned all aspects of gas marketing, from the extension of the pipeline system to programs of financial incentives for consumers converting to natural gas (see Appendix F).

In recognition of the importance of the eastern gas market, the gas producers and provincial government of Alberta contribute to the federal market-development incentive payments (MDIP) fund. These payments, which amount to 30 per cent of the Alberta border price, apply to new gas volumes supplied to the provinces east of Alberta. The net effect of this program is that gas producers and the Alberta government assist in the subsidization of domestic market expansion.

While the programs mentioned above can help to enlarge the market for gas, they are a costly way to achieve what could be obtained, at least in large measure, if gas prices were lowered to reflect the present excess supply. This would make gas more attractive to potential new users and provide them with natural incentives to adopt the fuel, which would facilitate the task of distribution utilities prepared to extend their networks.

Export Market

The U.S. market has been a major element in the development of the Canadian gas industry. In the early years, the pipeline companies used exports to generate a much needed cash flow and to ensure or improve the profitability of the new lines. The additional flow of gas through the pipeline system also enabled the companies to charge lower transportation tariffs for gas destined for Canadian markets than would have otherwise been possible. Partly on the basis of the estimated net economic benefits, the NEB in 1983 granted new export licences for a total volume of 322.5 billion m^3, covering a period of up to 18 years.

The export of natural gas from Canada is under federal jurisdiction, and it is administered under the National Energy Board Act. The NEB can authorize gas exports (subject to the approval of the Governor in Council) if it is able to "satisfy itself that the quantity of natural gas proposed to be exported does not exceed the surplus remaining after due allowance for the reasonably foreseeable requirements for use in Canada." The industry has expressed particular concern that one of the criteria applied by the NEB in determining the gas export surplus – that the volume of reserves must exceed 25 times the present annual consumption (the "25A1 test" – see Appendix E) – constitutes a considerable cost. This calculation of the gas surplus available for exports is, however, less stringent than it may at first appear. It is used only for *new* export licences, the result being that once the exports begin, the surplus does not have to be sustained. Also, the protection afforded to Canadians by the surplus-determination formula is considerably less than 25 years once the average annual rate of production decline and the annual growth rate in domestic demand are considered. In fact, the 25A1 test typically provides assurance of deliverability to Canadian distributors of about five to eight years, depending on these factors. The NEB also uses deliverability tests, which include an estimate of future additions, to assess the export surplus. In addition, the Board has the responsibility for advising the government on the prices to be charged for export sales.

For many years, keeping the export price of natural gas higher than the domestic price has been a matter of policy. As a consequence, for any export sale the producer first receives a price equivalent to the average domestic price. The wellhead difference between the export price and the domestic price is collected by the Alberta government and returned to all gas producers in the province on a prorata basis, regardless of whether their production is destined for domestic or export markets. Called an "export flowback," this revenue ensures that producers have as much incentive to sell gas in Canada as in the United States. As we move towards deregulated domestic gas prices, and in view of the Canadian government's July 1984 export-pricing policy, which provides for negotiated prices within limits, it will become necessary to adjust the export-flowback system in order to keep incentives in line with the goals of maximizing the revenues from export sales and avoiding underpricing in the domestic market.

The new export-pricing policy provides for Canadian exporters to participate in the growing U.S. market for spot or short-term direct sales, which seems a useful change that should not only assist in expanding export sales but also make prices more responsive to continental market conditions.

Since the beginning of the 1980s, the export market for Canadian natural gas has deterioriated, mainly as a consequence of the persistent surplus of indigenous gas supply in the United States. A number of observers agree that the U.S. market is not likely to improve before the late 1980s; and even then market pressures will require Canadian gas to be more competitively priced.

In view of the U.S. market situation, the prospects for increasing sales exist even though short-term export revenues may decline temporarily. For the longer term, the NEB has expressed optimism about new export sales. It has identified the northeastern U.S. region as a future target market and estimated that further penetration could be achieved in the north-central regions of the mid-West. The NEB has noted, however, that the growth areas in the gas market are generally remote from Canada's western fields, which could lead to lower netbacks, particularly if the policy of uniform border prices were maintained. In its report, the Board also welcomed the proposal by Dome Petroleum to export liquefied natural gas to Japan as an opportunity for the Canadian gas industry to diversify its markets.

The recent decisions in export policy are in the right direction and the improvements that remain to be implemented basically involve doing more of the same. In particular, we believe that the export price should remain subject to some regulatory control because export transactions at the border cannot be viewed as taking place within a competitive market. Canada has relatively few marketers of gas exports, and the export quantities are regulated both by the provinces and by the NEB so as to ensure that sufficient gas supplies are available to meet domestic requirements. In the United States, the market is split among a few buyers and is regulated by federal and state agencies. Totally free negotiations of export sales are not likely, therefore, to yield competitive and fair prices for Canadian exporters.

Completely unregulated export prices could both lead to a loss of export revenues and cause inefficiencies in the domestic market – the latter because the deregulated domestic prices would be influenced by the export market. Therefore, there should be some degree of price regulation on the export side. In this sense, the constraints imposed on the export price become guidelines for domestic pricing.

Conclusions

In the economic sense, oil and gas share a great number of similarities; and, generally speaking, the underlying objective for effective gas supply policy is the same as for oil: the gas industry should contribute the largest economic benefit possible to Canada at the least cost. However, there are many differences between the markets for the two resources: a high level of regulation and costly transportation for gas; the pricing of gas is based on the continental supply/demand situation for gas rather than on the world market; gas supplies respond to economic incentives; and gas exports play an important role. Consequently, the policy for gas cannot be a replica of the oil policy.

At present, the Canadian natural gas market is characterized by a significant excess supply. While the imbalance reveals a market that is constrained by excessive regulation and is slow to adjust, it also offers Canadians the opportunity to enjoy lower energy prices over the short to medium term and to increase gas use. However, these opportunities will only be possible under a more flexible gas policy, which should include provision for deregulated domestic gas prices.

We have mentioned that, under the present fiscal arrangements, the profitability of exploration and development of new gas supplies in western Canada is currently not sufficient to maintain a healthy level of activity. Moreover, additions to the gas potential have only been possible in the past under steadily rising costs. This will apparently continue to be the case in the future. The prospect of declining gas prices, therefore, calls for more flexible fiscal regimes.

Some of the policy changes adopted within the past few years – widening the gas/oil price gap, lowering the export price, increasing export licences and expanding the domestic market – all address the present market imbalance. These changes have been in the right direction, but they may not have been large enough. The gas market is still characterized by a great deal of rigidity, including that associated with the traditional role of the major gas transmission systems. In our view, greater interaction between buyers and sellers in the domestic market, in parallel with the recent changes in export policy, would afford better use of Canada's natural gas potential over both the short and long terms.

6 Electricity Supply

The electrical industry in Canada has grown rapidly since its inception (see Chapter 2 for a brief historical survey of the industry). The domestic markets for electricity have expanded steadily, except for a recent slowdown attributable to sluggish economic growth and to energy conservation in response to rising prices. In addition, Canada's exports of electricity to the United States have risen sharply since 1970. In the process, the electricity sector has become one of the most important in the Canadian economy, representing nearly one-fifth of the book value of the net fixed assets of all industrial corporations and about 2.5 per cent of gross domestic product at the beginning of the 1980s.

Goals and Problems

As pointed out earlier in this report, the electrical industry has some monopolistic elements and, for the most part, is now publicly owned and regulated. It has developed not only as a supplier of energy, concerned with the efficient management of resources, but also as an instrument of social and economic development. Beginning in the early 1900s, government-owned utilities were being established to make electricity available in homes, businesses and factories as a public service at an affordable cost. Electrification proceeded first in urban areas and later in rural regions to stimulate growth and enhance standards of living. Fundamental to an understanding of the issues involving electricity, therefore, is an awareness of the dichotomy of objectives that has shaped the industry throughout its history: economic efficiency has usually been a genuine concern, but it has often had to make way for other social and economic goals of governments.

Today, the management and regulation of the electric utilities continue to reflect a sense of social purpose. Electricity is viewed by many as a motor of modern technology and industry and thus continues to be perceived as a primary instrument of economic development. Canada benefits from a comparative advantage in electricity supply. Our natural resources, primarily hydraulic, and our experience and engineering potential place us in a favourable position in this respect. In a number of provinces, the strategies for economic development aim at capitalizing on these advantages and are targeted at industries that rely heavily on electricity – metal transformation, pulp and paper, and chemicals, among others – and that can possibly attract spinoff activities as a means of gradually diversifying the industrial base. Since electricity is viewed as playing an important role in determining the location of these industries, governments attempt, through their utilities, to promote regional development and to achieve a number of other objectives.

The principal means of promoting the consumption of electricity has been, and remains, pricing policy. The official mandate of most electric utilities in Canada is to price electricity as low as possible without jeopardizing their financial integrity. While this approach has been widely accepted as the norm by the industry and, indeed, by the public at large, more and more concern has been voiced in recent years about its adequacy from the point of view of maximizing the net benefits from the use of scarce resources. Objections to current policies centre on the contention that electricity is being sold at prices that are below its real cost, leading to distortions in the market place. Artificially low electricity prices lead to overconsumption and to a waste of valuable resources – including capital, which earns a significantly lower rate of return in the electrical sector than in most other areas of Canadian economic activity.

With the supply infrastructure well in place, and with an energy environment that appears to have stabilized, the time seems to be right for a reassessment of Canadian pricing and investment strategies in electricity.

The problem of electricity pricing is complex, especially when considered in a dynamic perspective. Among other complicating factors, there is now an oversupply of electricity in many provinces. Although long-run considerations may suggest that higher electricity prices are desirable, the present reality of the market suggests that domestic prices should be held down and exports should be promoted in order to get rid of excess supplies.

The management of electrical supply relies heavily on proper forecasting. Long lead times – up to 10 or 15 years – are involved in the planning, construction and integration into the transmission system of new supply facilities, with investment commitments being made for as long as 100 years.

The supply-planning problem is made more acute by the fact that, over any given period, industry is required to meet not just average demand but peak demand as well. Any such planning exercise is subject to error. An overestimation of demand leads to the installation of costly facilities that remain underused. The underestimation of demand has historically been considered a more serious risk because of its perceived effect in crippling economic growth. The belief that electricity demand is largely insensitive to price – an erroneous claim, as we shall show in the next chapter – has contributed to an exaggerated perception of this risk, limiting efforts to "manage" demand as a means of achieving market balance.

The tendency to overshoot demand in planning has been partly offset in recent years by increased exports of surplus electricity. In the future, however, firm power contracts are expected to represent a larger share of Canada-U.S. trade. This would require dedication of specific amounts of generating capacity to the export market and possibly the prebuilding of facilities to serve that market initially and, ultimately, the domestic market. At present, the net revenues accruing from export sales are applied against the cost of supply in order to reduce domestic prices – a procedure that amounts to returning export profits to the domestic consumers of electricity. This approach can be questioned in terms of economic efficiency, because it induces extra domestic consumption of electricity at the expense of other energy sources or of energy conservation. More generally, the net revenues from exports might be used for other purposes elsewhere in the economy. By contrast, some argue that the stimulative effect of low electricity prices for export industries, for example, results in even greater net benefits to Canadians.

The complexity and interrelationship of the concerns involving electricity have brought about extensive government involvement in the industry. Changes in electrical supply policy could therefore involve changes in the legislative mandates of the utilities and in the structure and extent of regulation, and they could call for changes in other government policies affecting the industry. We believe that there is a need for governments to attach greater importance to the criterion of economic efficiency and to seek strategies that are best for the economy as a whole rather than to focus exclusively on the interests of electricity consumers. This would require step-by-step adjustments consistent with the dynamic nature of the market, while integrating other public concerns for regional development, security of supply, public safety and environmental impacts.

Structure of the Industry

The Supply Profile

In 1982, the production of electricity in Canada amounted to some 380,000 gigawatt-hours (Table 6-1). This was the equivalent in energy terms of close to 100,000 m^3 of oil per day – somewhat more than 40 per cent of Canada's domestic oil production.[1] The domestic consumption of electricity accounted for 83 per cent of production; exports (from Ontario, Quebec, British Columbia, Manitoba and New Brunswick), for 9 per cent; transmission and distribution losses largely accounted for the remaining 8 per cent. Imports were marginal, representing less than 1 per cent of domestic consumption.

Table 6-1

Electrical Energy Generation, Trade, Consumption and Losses, Canada, by Province, 1982

	Total net generation	Imports	Exports	Interregional trade: Net in	Interregional trade: Net out	Consumption	Losses
				(Gigawatt-hours)			
Newfoundland	44,340	–	–	–	35,779	7,576	985
Prince Edward Island	35	–	–	478	–	450	62
Nova Scotia	6,568	–	–	83	–	6,054	597
New Brunswick	8,435	71	3,029	3,053	–	7,556	973
Quebec	100,037	7	8,530	26,453	–	108,409	9,558
Ontario	110,439	404	11,168	6,775	–	98,816	7,634
Manitoba	20,790	214	5,255	–	1,485	11,771	2,494
Saskatchewan	9,846	31	60	419	–	8,919	1,317
Alberta	27,112	2	–	256	–	25,319	2,052
British Columbia	48,363	2,118	6,171	–	253	39,645	4,411
Territories	841	–	–	–	–	786	55
Canada	376,805	2,848	34,214	37,517	37,517	315,301	30,139

SOURCE Based on data from Statistics Canada.

Growth in the production of electricity has averaged some 6.6 per cent during the 1960s and early 1970s; over the last decade or so, however, it has slowed down to some 4 per cent per year. Generally, supply has been targeted to meet domestic requirements, but over the past decade, exports have become more and more important in relation to total production.

The potential electrical capacity at any point in time is measured in megawatts (MW) of *power*. In principle, each megawatt of capacity makes possible the supply of 8.8 (1 x 365 x 24 ÷ 1,000) gigawatt-hours (GWh) of *energy* per year. This distinction between power and energy is critical to a clear understanding of a number of issues involving electricity. In terms of the installed capacity of equipment in place, this potential in Canada amounted to 85,547 MW in 1982 (Table 6-2). Installed capacity, however, can overestimate the effective supply capability for various reasons: some equipment may not be in service; not all equipment is capable of operating at full installed capacity; it might not be possible for all equipment to be put into operation at the same time because of constraints with respect to transmission facilities; and variations in water conditions may have a direct effect on the supply capability of hydroelectric generators. Taking these various factors into account, it is estimated that the actual supply capability in Canada in 1982 was 78,023 MW, or over 91 per cent of installed capacity.

Supply capability can be compared with annual peak demand. The difference between the two is defined as reserve capacity. The reserve provides the utilities with safeguards against possible equipment failure, unexpectedly cold weather, unforeseen changes in water conditions or errors in forecasting demand. The targets for the ratio of reserves to peak demand – which provides a measure of the balance between supply and demand – for Canadian electrical utilities are in the range of 11 to 25 per cent, depending on the configuration of supply (for example, on the type of generation and the size of the units). The lower end of this range applies to hydro-based utilities because of the greater reliability of hydraulic facilities.

In 1982, the noncoincident peak demand – the total of individual utility peaks – was 62,417 MW, compared with an estimated actual capacity of 78,023 MW. Hence the reserves amounted to 15,606 MW, providing a relatively high ratio of reserves to peak demand of 25 per cent. Overcapacity was, and remains, severe in Manitoba, British Columbia, Ontario and Quebec, although the reserves/peak-demand ratios appear to be more

Table 6-2

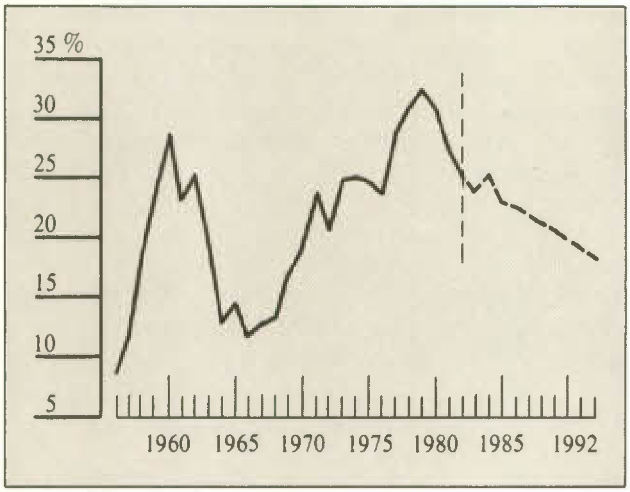
Installed Electrical Generating Capacity, Net Supply Capability and Peak Demand, Canada, by Province, 1982

	Installed capacity[1]	Net supply capability[2]	Firm power peak demand	Reserves	Ratio of reserves to peak demand
			(Megawatts)		
Newfoundland	6,963	2,949	1,606	1,343	0.84
Prince Edward Island	118	131	100	31	0.31
Nova Scotia	1,865	1,678	1,244	434	0.35
New Brunswick	3,469	2,462	1,664	798	0.48
Quebec	22,762	23,918	21,674	2,244	0.10
Ontario	26,272	22,937	18,820	4,117	0.22
Manitoba	4,144	4,216	2,743	1,473	0.54
Saskatchewan	2,322	2,292	2,055	237	0.12
Alberta	6,427	6,155	4,525	1,630	0.36
British Columbia	10,886	11,013	7,835	3,178	0.41
Territories	284	272	151	121	0.80
Canada	85,547[3]	78,023	62,417[4]	15,606	0.25

1 The nominal generating capacity of the operational facilities.
2 The expected available power to meet one hour-long firm peak load, taking into account interregional exchanges of firm power, the expected water conditions at peak, the impossibility of placing all pieces of equipment in operation at same time, and so on.
3 Includes 35 MW of power not allocated across provinces.
4 The published peak for Canada is noncoincident (the arithmetic sum of the provincial peaks regardless of time of occurrence) and may be equal to, or greater than, the coincident peak load for the provinces.
SOURCE Based on data from Statistics Canada.

Chart 6-1

Electricity Reserve Capacity as a Proportion of Peak Demand, Canada, 1956-92



SOURCE Based on data from Statistics Canada.

acceptable in the two latter provinces. Ontario has mothballed a number of coal-fired generating stations, while Quebec, despite a relatively low surplus during peak periods, has immense surpluses from hydroelectrical generation in off-peak hours. Capacity is excessive in the Atlantic region, but this is mainly explained by the gradual transition away from oil-fired generation, which leads to temporary overcapacity as the new coal-fired and nuclear-power generating stations are brought into service.

Supply capability, peak demand and reserves have all increased steadily over the past 25 years. The rates of growth have differed from time to time, however, and thus so has the reserves/peak-demand ratio. The ratio has moved in cycles, and overcapacity has periodically been a problem. As reserves diminish in relation to peak demand, large new units of additional capacity are put into place, creating temporary surpluses. When demand increases, the excess is gradually used up, and more capacity additions are eventually required. The highs and lows of the cycle are determined largely by the accuracy of capacity planning. The present supply surplus, for example, has been attributed, among other factors, to an overestimation of demand in forecasts made during the early to mid-1970s.

The reserve/peak-demand ratio is at present on the high side of the cycle (Chart 6-1). With more aggressive marketing, the utilities expect to re-establish the supply/demand balance gradually, predicting that the annual growth in peak demand will average 3.6 per cent over the decade 1982-92, while capacity is forecast to grow at about 3.0 per cent over the same period (Table 6-3), largely as a result of the completion of facilities whose construction commenced in the 1970s.

Table 6-3

Actual and Projected Total Net Capability and Within-Province Firm Power Peak Demand, Canada, by Province, 1982 and 1992

	Total net supply capability		Within-province firm power peak demand		Average annual compound change, 1982-92	
	1982	1992	1982	1992	Capability	Demand
	(Megawatts)				(Per cent)	
Newfoundland	2,949	3,779	1,606	2,312	2.5	3.7
Prince Edward Island	131	131	100	126	0.0	2.3
Nova Scotia	1,678	2,001	1,244	1,770	1.8	3.6
New Brunswick	2,462	2,733	1,664	2,206	1.0	2.9
Quebec	23,918	34,676	21,674	32,311	3.8	4.1
Ontario	22,937	30,942	18,820	23,298	3.0	2.2
Manitoba	4,216	4,628	2,743	4,006	0.9	3.9
Saskatchewan	2,292	3,016	2,055	2,639	2.8	2.5
Alberta	6,155	9,529	4,525	8,881	4.5	7.0
British Columbia	11,013	13,946	7,835	11,273	2.4	3.7
Yukon Territory	103	124	61	95	1.9	4.5
Northwest Territories	169	180	90	161	0.6	6.0
Canada	78,023	105,685	62,417	89,078	3.0	3.6

SOURCE Based on data from Statistics Canada.

The CANDU Nuclear Reactor

The CANDU reactor is a Canadian technology that has not only proven itself in the domestic market but that is also considered to be one of the most efficient nuclear reactors in the world. Seven CANDU reactors have been sold (or donated) to other countries – three to India, and one each to Pakistan, Taiwan, Argentina and South Korea. At the end of 1981, seven of the world's top 10 power reactors, in terms of their lifetime capacity factor, were CANDU units operated by Ontario Hydro. The success of the CANDU reactor is attributable to a number of technical and economic factors. First, the CANDU reactor uses natural uranium rather than enriched uranium. Second, it uses less uranium than other types of reactors to produce equal amounts of energy. These two advantages are made possible because the CANDU reactor uses heavy water (deuterium oxide) as a moderator. Furthermore, CANDU reactors have proved themselves to be safer than most other reactors, and they can be charged and maintained while in operation.

Although the record is generally good, some Canadian reactors have not performed well, if at all – such as the Gentilly I unit in Quebec and the reactor in Pickering, Ontario, during certain years. CANDU capital costs are higher than some light-water reactors, and these costs have risen rapidly in the 1970s. There have been numerous "accidents," none of them serious. The problem of long-term storage of nuclear fuel waste remains unresolved. Public support has been mixed.

Regardless of its past success, the current status of the Canadian nuclear industry looks somewhat bleak; Ontario Hydro has experienced some problems with existing plants. The Pickering B reactor is scheduled to begin operation in 1985, and eight more reactors are scheduled to be put into place in Ontario by 1992 – four at the Bruce B site by 1987 and four at Darlington thereafter. Accidents at Pickering A (the rupturing of pressure tubes containing uranium) in August and November 1983 resulted in a public outcry, even though emergency procedures were not required to shut down the reactors. The tubes in reactors I and II are scheduled to be changed, and operation will resume in 1987. The cost for repairs has been estimated to be $700 million, including $300 million to replace the energy produced from the nuclear plant with coal-fired generation. Ontario Hydro has no fixed plans to install nuclear plants beyond Darlington.

Outside Ontario, the possibilities foreseen for new nuclear reactors are limited to a second reactor at Point Lepreau in New Brunswick; two plants are under construction in Romania. The prospects for the nuclear industry and its satellite industries (uranium mines, heavy-water production, equipment manufacturing and engineering consulting) depend heavily on new orders for the CANDU reactor.

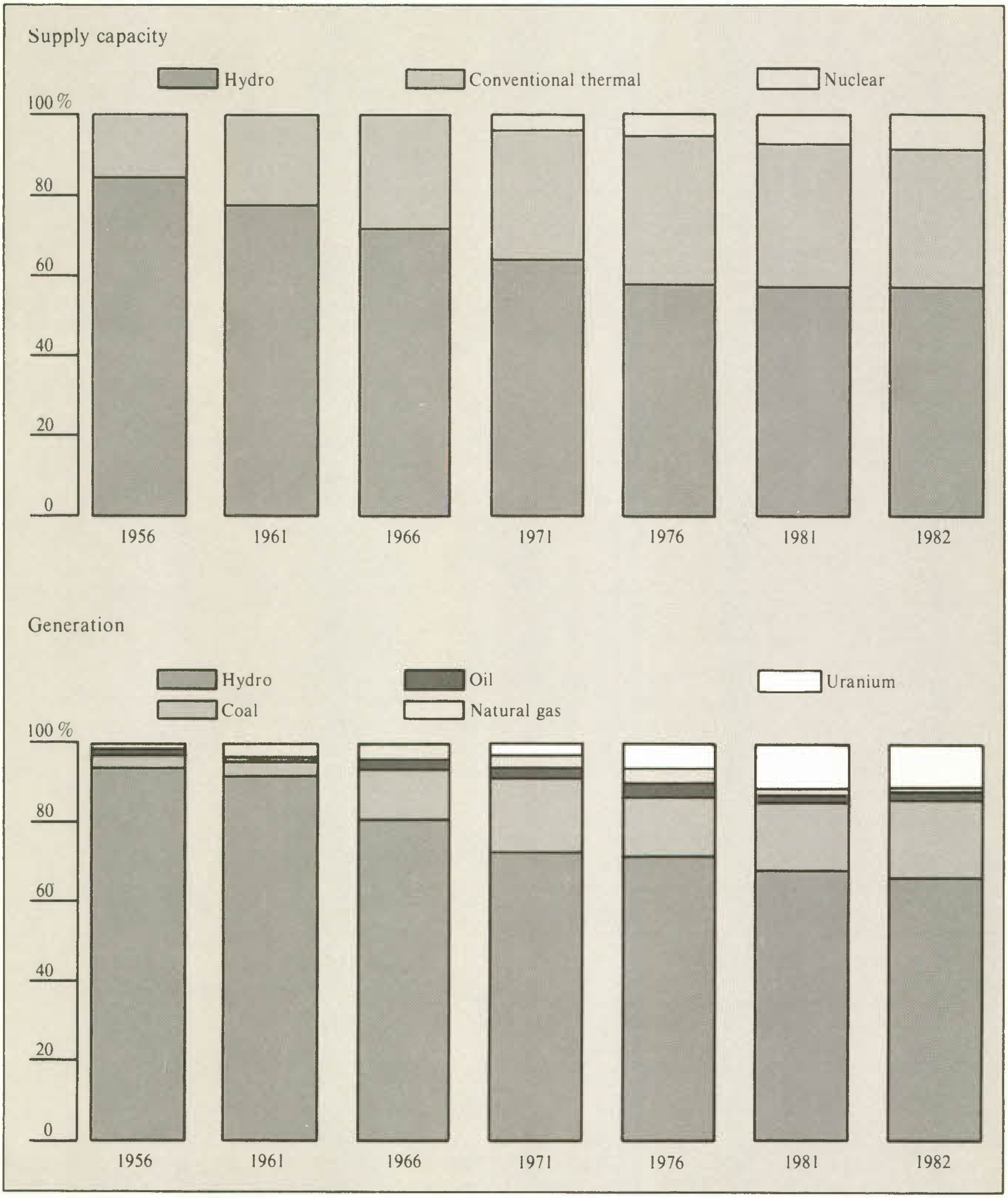
Hydraulic power has been the primary means of electrical generation in Canada since the early 1900s, when it gradually replaced small and dispersed thermal generating units. Between 1920 and 1956, hydro represented more than 90 per cent of total electrical energy generation, and 85 per cent of total capacity. These shares have since declined to 68 and 58 per cent, respectively (Chart 6-2). The country has diversified its energy sources, using more coal, natural gas and oil in the first half of the 1960s, and then turning more to nuclear power. Conversion to new sources of energy for electric-power generation was encouraged during this period by the unavailability or increasing cost of major new hydraulic sites in many provinces and, later, by the global petroleum crisis, which prompted many utilities to switch away from oil. In Ontario, the introduction of nuclear-generating technology was motivated by concerns about energy self-sufficiency and economic development. This alternative was favoured because it utilized a local energy resource (uranium) and because it fostered the development of a domestic industry that offered state-of-the-art technology in the form of the CANDU heavy-water, nuclear-generating reactor, first constructed in Ontario in 1962. Between 1966 and 1982, Ontario built 10 such reactors. Two more were constructed in Quebec – one of which is now permanently shut down – and one in New Brunswick. In 1983, nuclear reactors accounted for about 9 per cent of installed generating capacity and about 12 per cent of electricity generation in Canada.

Despite the movement away from coal in Ontario, this energy source has increased its share of national electricity generation in more recent years and contributed some 19 per cent of total electrical energy supply in 1982. Oil- and gas-fired generation represented 2 and 1 per cent, respectively. In terms of capacity, conventional thermal facilities – coal, oil and gas – account for about 34 per cent of the Canadian total.

The types of installed production capacity and generation vary considerably from one province to another (Chart 6-3), reflecting the different economic and strategic incentives that lead the provinces to rely on local resources where possible. Hydroelectric capacity is most important by far in Newfoundland, Quebec, Manitoba, British Columbia and, to a lesser degree, the territories. Prince Edward Island, on the other hand, has oil-fired thermal capacity exclusively,

Chart 6-2

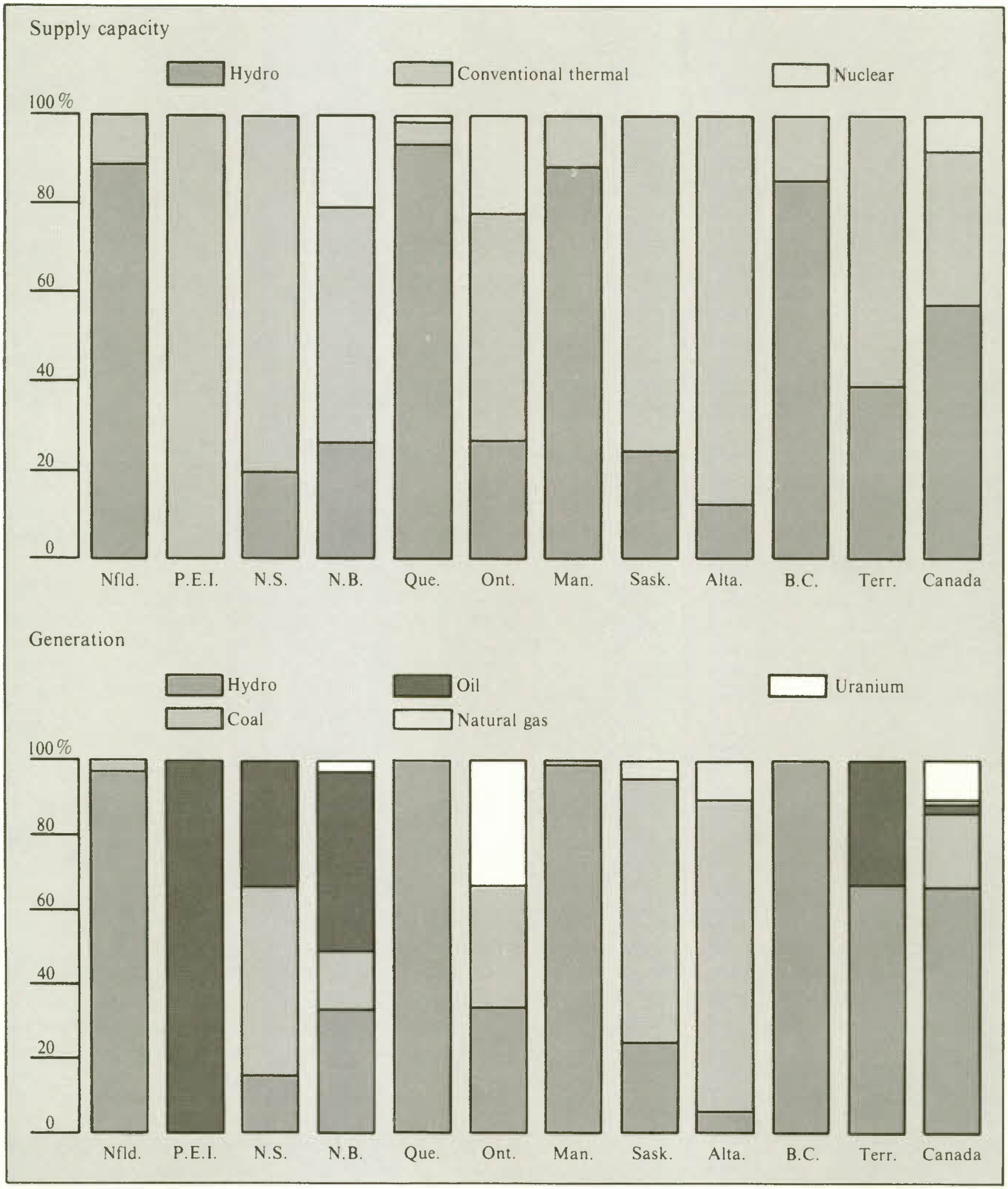
Electricity Supply Capacity and Generation, by Type, Canada, 1956-82



SOURCE Based on data from Statistics Canada.

Chart 6-3

Electricity Supply Capacity and Generation, by Type, Canada, by Province or Territory, 1982



SOURCE Based on data from Statistics Canada.

with most of its electrical energy requirements – over 90 per cent in 1982 – now being met by purchases from New Brunswick. Another province with low hydroelectric capacity is Alberta (less than 20 per cent in 1982), where producers rely mainly on coal and, to a lesser extent, natural gas. The structure of Saskatchewan energy production is similar, although hydroelectricity represents a larger share of electricity production there than in Alberta. New Brunswick and Nova Scotia depended heavily on oil for the generation of electricity in 1981. Since that time, New Brunswick has diversified into nuclear power and Nova Scotia has made increasing use of its coal resources. In Ontario, production is divided more or less equally between nuclear, hydroelectric and coal-fired generation.

It is expected that the share of hydro power in total electricity generating capacity in Canada will remain close to its current level of about 60 per cent until the early 1990s. Nuclear power will expand with the construction of new reactors in Ontario and possibly in New Brunswick, and its share could reach 15 per cent over the next 10 years. Conventional thermal generation will decline; in particular, oil-fired generation will likely be phased out almost entirely over the medium term, except in those remote communities where there are few, if any, alternatives to oil.

Organization Structure

The electrical industry in Canada is highly concentrated. Except in Prince Edward Island and Alberta, it is dominated by provincial Crown corporations that oversee the generation, transmission and, to varying degrees, the distribution of electric power. In Prince Edward Island, the supply function is split between a privately owned company (Maritime Electric Company) and a municipal utility (in Summerside). The industry is more fragmented in Alberta, where production is, for the most part, in the hands of two privately owned companies – TransAlta Utilities Corporation and Alberta Power, accounting for about 80 per cent of electrical capacity in the province; two municipal utilities, in Edmonton and Medicine Hat, also generate electricity. All are linked by a transmission network largely owned by TransAlta Utilities. In addition, there are about 10 municipalities in Alberta that buy and distribute electricity on an exclusive basis.

Some of the other provinces also have utilities that are primarily concerned with distribution. Newfoundland Light and Power, a privately owned utility, is the primary retailer of electricity on the island, purchasing most of its power from Newfoundland and Labrador Hydro but also operating a few hydraulic facilities of its own. In Manitoba, Winnipeg Hydro retails to the city and still operates a few generating stations. In Ontario, the structure of the industry is unique among the provinces, with over 300 municipal utilities distributing power purchased from Ontario Hydro. The provincial utility itself retails to rural customers and sells directly to about 100 large industrial users. In Nova Scotia, New Brunswick, Quebec, Saskatchewan and British Columbia, however, only a small part of the electricity produced is distributed by utilities other than the major publicly owned corporations.

In most provinces, there are also industrial establishments – aluminum smelters, pulp and paper plants, and mineral smelting and refining industries – that produce their own electricity, most of it hydro-generated. About 10 per cent of electrical generation in Canada is accounted for by these establishments, which are found in every province except Prince Edward Island. In some cases, such as Bowater in Newfoundland, Inco in Ontario and Cominco (through West Kootenay Power) in British Columbia, they also service local communities. In British Columbia and Quebec, industrial establishments accounted for as much as 24 per cent and 17 per cent, respectively, of provincial electricity generation in 1982.

Some remote communities are served by diesel-fired generators or small hydroelectric installations that are not tied to a central system. This is common in the territories, Newfoundland, Manitoba, British Columbia and, to a lesser extent, Alberta and Saskatchewan.

In summary, the provincial public electric utilities held about 93 per cent of the net fixed assets of all electric utilities in 1982. The latter, in turn, accounted for almost 90 per cent of electricity produced in the nation that year, the remainder having been generated by industrial establishments.

An Historical Perspective

Policies

Both economic and political considerations have shaped the Canadian electrical industry over the years (see Chapter 2). The involvement of government was partly motivated by the monopolistic nature of the industry, but an equally compelling factor was the widespread perception of electricity as a public service and as a key to social and economic development.

The electrical industry has been characterized by important economies of scale, which arise when average costs decrease as output increases. Thermal and hydroelectric generating stations exhibit scale economies in their fixed and operating costs and in their bulk transmission facilities. Scale economies can also be realized in administration, planning, operation and maintenance. Up to a certain size, larger and more integrated systems require less reserve capacity to achieve the desired level of reliability than smaller systems. Moreover, in view of the diversity of customer demands, less capacity is needed to serve a large aggregate of customers than to supply small groups separately. Scale economies are also present in the distribution of electricity.

Under these conditions, a competitive market is impossible to maintain. By gaining a larger market share, a producer benefits from increasing scale economies – a situation that tends to lead to a breakdown of competition. It becomes costly and inefficient to have two or more suppliers in a given geographical area. A monopoly, it can be argued, is the only form of organization that permits efficient supply.

The monopoly question led governments to become involved in the electricity sector through regulation and/or ownership. In Quebec, for example, a royal commission in 1934 concluded that, given the monopolistic nature of the industry, government must control and regulate it in the public interest.[2] Regulation or public control is undertaken to prevent excess profits and to ensure that supply will be sufficient to meet demand reliably and at low cost. Most, if not all, of the activities in Canada that tend to be monopolistic – communications, oil and gas pipelines, and so on – are regulated, and several Crown corporations have been set up to provide service in these sectors. Regulation of private monopolies and public ownership are two approaches that have been employed to pursue economic efficiency in such circumstances.

From the very beginning, legislators were aware of the importance that electricity assumed in the eyes of the public because of its promise of enhanced standards of living, and in the eyes of business because of its potential to increase productivity. Public pressure was felt strongly during hydro development in Ontario in the early 1900s. Intense struggles took place between a coalition of small manufacturers and local politicians who sought access to cheap and abundant energy, and financial interests intent on developing the new resource for export markets and for their own profit. Little by little, public sentiment swung in favour of publicly owned facilities to make electricity available to all at a reasonable cost. This movement largely contributed to the formation in 1906 of the first publicly operated electric utility in Canada – the Hydro-Electric Power Commission of Ontario, now Ontario Hydro.

Electricity today remains, potentially, a political issue as much as an economic one. The availability of cheap electricity is considered a right, not a privilege, and rate increases are strongly opposed by various pressure groups, who view them as socially detrimental.

Following the same line of argument, one of the reasons for government consolidation of the industry in the past was rate standardization – cross-subsidization among customers – which was considered necessary from the point of view of equity. For example, in the creation of Ontario Hydro, one of the objectives was the equalization of costs for all the municipalities served by the utility. In all of the provinces today, the vast majority of consumers pay the same rate, or very similar rates, for the same kind of service. In 1982, a body was established in Alberta to standardize rates among the customers of the various utilities. The Alberta Electrical Energy Marketing Agency has been buying electrical energy from the utilities at a separate price for each individual company and reselling it to them for distribution at average rates. More recently, Prince Edward Island has proposed the uniformity of prices in sales between provinces.

A related political motivation for government intervention was the electrification of rural areas, a program that accelerated in the 1950s. It was a priority of provincial governments because it granted a measure of economic and social benefits to a large segment of the population. In itself, however, this would not have justified public ownership of the industry. Indeed, the Prince Edward Island and Alberta governments successfully achieved rural electrification through existing private electrical utility companies and rural cooperatives.

The growth in demand for electricity during and after the Second World War made governments aware of the importance of long-term planning for the generation and transmission of electric power. They considered it essential to have adequate forecasting of future requirements and coordination between companies in order to avoid shortages of power. This was viewed as a particularly critical problem in view of the long lead times required to bring additional generating capacity on stream and of the extensive operating life of facilities in the electrical industry. Hence governments have turned to Crown corporations or to the regulation of private utilities in order to influence the planning functions, not only within the electrical sector itself but also with respect to their larger concerns for economic development.

One of the incentives for establishing public ownership of the power industry within the provinces was that the federal government taxed the net earnings of privately owned electric utilities in the same way as it did those of any other private business. This was a sore point for the provinces, which felt that federal levies on a provincial resource were unwarranted and that Ottawa was discriminating in favour of the publicly owned utilities that did not have to pay federal income tax. This argument was one of the factors cited by the governments of British Columbia and Quebec in taking over the industry within their provinces. Since 1966, however, the federal government has refunded 95 per cent of the income taxes collected from private utilities to their respective provincial governments. Generally, the rebates are passed on to the private utilities and, ultimately, to consumers.

Historically, hydroelectric developments have occurred on land and waterways owned by the provincial governments, and they have often had important effects on the environment with respect to land use, the creation of lakes, irrigation, the alteration of landscape and so on. These factors, which do not directly involve the electric power market, have a very direct impact on other sectors of the economy – agriculture, fishing and recreation, to name only a few. The construction of transmission lines is subject to similar considerations, often involving the expropriation of land. The operation of nuclear facilities gives rise to other kinds of environmental concerns, for example with respect to nuclear-waste disposal. Because of such external economic and environmental factors, government involvement in the electrical industry has been, and continues to be, substantial.

In summary, the present structure of the industry reflects a mix of governmental interests. While it has been shaped in part as a means of achieving economic efficiency, it also reflects the desire of government to utilize the industry as a means of helping to achieve other objectives (such as energy self-sufficiency and economic development) and to address social concerns. Overall, one of the primary objectives of the provincial governments has been to ensure the lowest possible rates for the residents and industries of the province.

Evolution of Prices

Integration through mergers and nationalization, reinforced by technological advances in generation and transmission, as well as other government policies all worked in the direction of declining prices. The only major rise in average real revenues per kilowatt-hour received for residential service occurred in the early 1930s, presumably because very weak demand forced the electric companies to cover their fixed costs over a small volume of sales. Thereafter, revenues per kilowatt-hour dropped quite steadily in real terms until the mid-1970s (Chart 6-4). The decline was steep until the early 1950s, continuing at a more moderate pace thereafter. Since 1975, however, the averages have stopped falling or have even risen in real terms. While this is perceived as a sign that economies of scale have reached their limit, it is by no means clear that they have, in view of some of the other factors that have put upward pressure on electricity prices during the same period, such as fuel costs and interest rates.

The problem has to be analyzed on a province-by-province basis. In hydro-based systems, for example, real costs are probably on the rise, since new sites generally cost more in real terms than sites developed in the past, despite the application of technological advances. In thermal-power generation, the technical limits to scale economies may have been attained, but not all thermal-based systems in Canada have actually reached that point. Moreover, fuel cost savings and greater system reliability can be achieved by interchanges between utilities with different demand and supply profiles. Indeed, some movement towards interconnection in Canada has been evident in recent years. There have been studies of a possible link-up between the three Prairie provinces, and for some time the Maritime provinces have been discussing the possibility of greater coordination in operating and planning their power systems. Exchanges with utilities in the United States provide additional opportunities to lower the cost of electricity supply, for example, because peak demands on the States usually occur in the summer, while winter peaks are the rule in Canada. Further reductions in the real cost of electricity should not be ruled out. At the same time, however, it should be noted that the environmental cost of expanded electricity supply, which was often neglected in the past, has become a more prominent issue in recent years.

The Mandate and Regulation of the Utilities

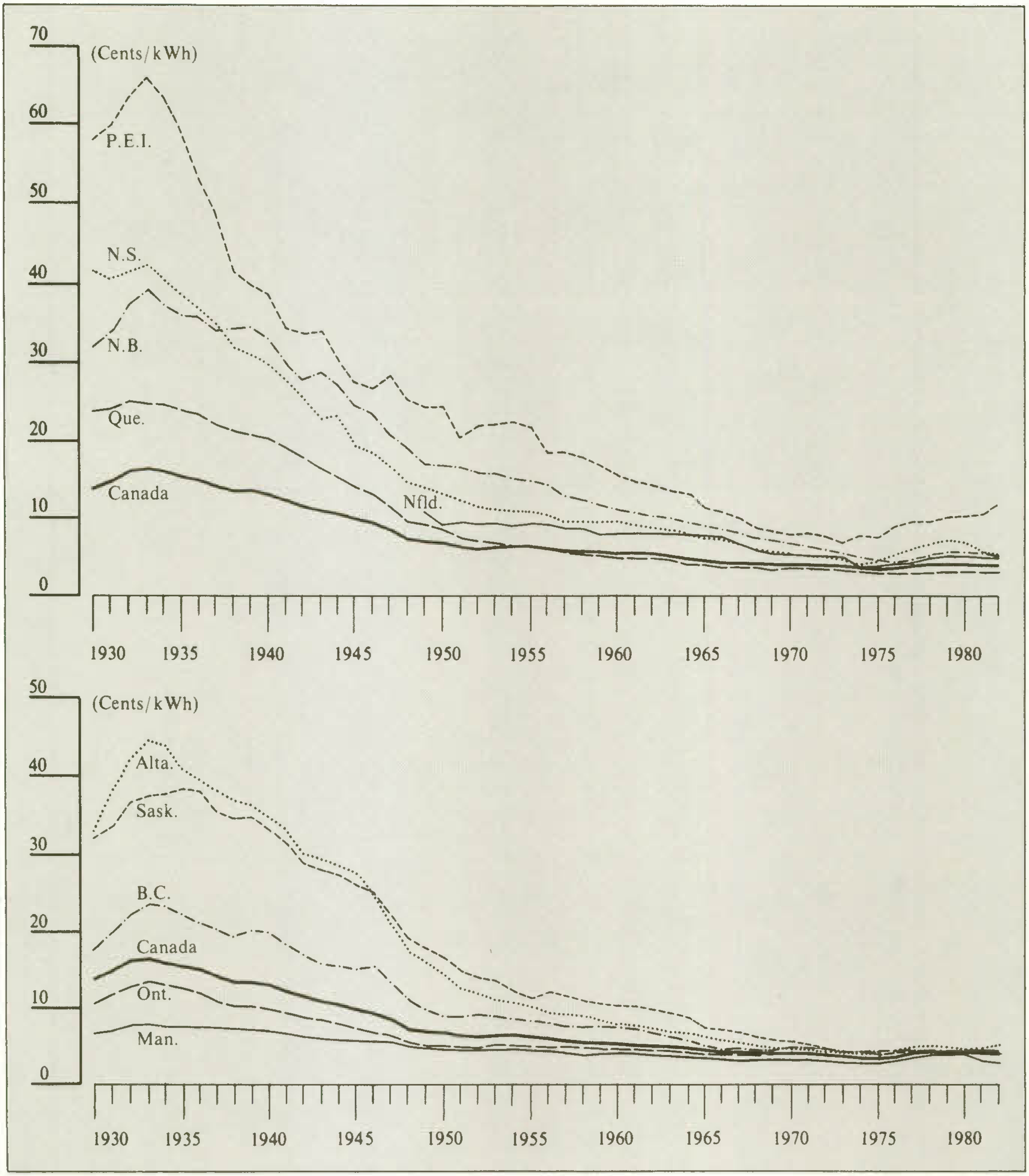
The general mandate of electric utilities in Canada is to ensure the supply of power at the lowest possible rate compatible with sound financial management.

Occasionally, this mandate is tempered somewhat by other objectives – for example, the promotion of energy conservation. In this regard, Quebec's is an interesting case. The Hydro-Québec Act was amended in late 1981 so as to modify the role of the utility, requiring it not necessarily to supply electricity at the lowest possible rates but, rather, to use the rates to control demand and stimulate energy conservation. This important change in policy has not yet been fully reflected in practice, however, presumably because of the prevailing surplus of electricity in the province.

To ensure the fulfilment of the utilities' mandates and to assess the external factors related to electricity supply, most governments have set up regulatory bodies to oversee the management and operation of electric companies. There is no systematic structure of regulation, however. The areas, and degree, of supervision vary from province to province, reflecting differences in past and present policy. The major activities of the industry that are subject to review are rate setting, the building of new facilities (with respect to their environmental impact, in particular) and, at the federal level, nuclear-plant operation and electricity exports (Figure 6-1).

Chart 6-4

Average Electricity Revenues,[1] Canada, by Province, 1930-82



1 For residential and farm services. Figures in 1982 constant dollars.
SOURCE Based on data from Statistics Canada.

Figure 6-1

Regulatory Framework for the Major Electric Utilities in Canada

		Building of new facilities						Rate setting	
	Ownership	Requirement	Costs	Issue of debt	Environmental impact	Nuclear plants[1]	Electricity exports[2]	Recommended by:	Approved by:
Newfoundland and Labrador Hydro Commission	Public			C	C	F	F	Newfoundland Public Utilities Board	C
Newfoundland Light and Power Company	Private				C	F	F		Newfoundland Public Utilities Board
Maritime Electric Company	Private	B				F	F		Prince Edward Island Public Utilities Commission
Nova Scotia Power Corporation	Public		B	C	C	F	F		Board of Commissioners of Public Utilities of Nova Scotia
New Brunswick Electric Power Commission	Public	C		C	C	F	F/C		C
Hydro-Québec	Public			C	C	F	F/C		Parliamentary Commission
Ontario Hydro	Public	C		C	C	F	F/C	Ontario Energy Board (public hearings)	Ontario Hydro Board of Directors
Manitoba Hydro-Electric Board	Public			C		F	F/B[4]	Manitoba Public Utilities Board	C
Saskatchewan Power Corporation	Public			C	C	F	F		Saskatchewan Public Utilities Review Commission
Alberta Power Limited	Private	B[3]			C	F	F		Alberta Public Utilities Board
TransAlta Utilities Corporation	Private	B[3]			C	F	F		Alberta Public Utilities Board
B.C. Hydro and Power Authority	Public	B	B	C	C	F	F/B		B.C. Utilities Commission

C = provincial cabinet
B = provincial utilities board
F = federal government

1 Regulated by the Atomic Energy Control Board.
2 Regulated by the National Energy Board.
3 Energy Resources Conservation Board (of Alberta).
4 Manitoba Energy Authority, comprising government and utility representatives.

The provincial governments are generally involved in one way or another in the process of rate setting. In most cases, the regulatory boards set up to oversee the activities of the companies are empowered to approve rate changes. In New Brunswick, Quebec and Manitoba, however, it is the provincial Cabinet itself that reviews the applications for rate changes. An important difference between the agency process and Cabinet decisions is that in the former case, public hearings are held; in the latter, there are no public hearings. The procedure is different in Ontario: the Ontario Energy Board holds public hearings whenever the provincial utility submits an application to change the rates paid by the municipalities, but the company's directors have the final authority to set rates. Ontario Hydro also determines the rates that the municipalities charge their customers.

The mandate of the regulatory boards set up by the provincial governments, insofar as rate setting is concerned, can be summarized simply as ensuring fair and reasonable rates. A board must make sure that prices do not favour one group over another for the same type of service. It has the responsibility to ascertain what is fair and reasonable. It must also allow, in the case of a private utility, for an equally fair and reasonable return on investment.

The regulation of the electric power industry goes beyond rate setting. The construction of new generating stations and transmission facilities must also be approved. The process of putting a new generating plant into operation involves several steps, including the preparation of studies and applications to the government. These cover the need for more capacity, cost evaluations and environmental impact studies. In general, however, construction projects are not reviewed as systematically as proposed changes in electricity rates.

In particular, the costs involved in building new generating plants are not closely monitored. Only the boards overseeing Nova Scotia Power and B.C. Hydro appear to have a responsibility in this regard. On the other hand, the financing of new projects almost always involves the undertaking of new debts, which for all Crown corporations requires the approval of the provincial government. Thus there is some degree of control over the funds required for the construction of a new generating station.

Since the mid-1970s, legislation has been passed in most provinces to set up procedures to assess the environmental impact of the construction of a new generating station or new transmission installations, to ensure that environmental concerns are taken into account throughout the entire planning process. In one way or another, all provinces require that the environmental effects of proposed projects be studied.

The federal government also has authority in certain areas. The construction and operation of nuclear power stations and heavy-water plants have been under federal control since 1946, with licences being required from the Atomic Energy Control Board.

In addition, the regulation of electricity exports and international transmission lines falls under the authority of the National Energy Board, subject in certain areas to the concurrence of the Governor in Council. The Governor in Council may, under a recent amendment to the National Energy Board Act, extend the Board's jurisdiction to cover designated new intraprovincial lines. To date, no such line has been designated.

The export of electricity requires the approval of the federal Cabinet if the quantities to be exported are greater than 50 MW or 250 GWh per year. The process involves public hearings, leading to recommendations by the NEB; if the export amounts are small, or if the demand for exports arises from emergency situations in the United States, the Board may authorize exports without public hearings or government approval. As far as the prices of electricity exports are concerned, the NEB has developed benchmarks in assessing export applications. In some provinces, electricity exports also require the approval of the provincial government or one of its agencies.

The construction of an international power line in Canada requires a certificate of public convenience, which is issued by the NEB with the approval of the Governor in Council. The process requires public hearings if the capacity of the line is to be greater than 5 MW. The joint approval of the members of the International Boundary Commission is also necessary for an international transmission line.

Neither Canada nor the United States exercises any systematic control over imports of electricity, although in Canada the NEB may regulate imports to some degree if they are part of an arrangement that also involves exports. In the United States, several federal and state bodies have authority over transmission facilities. These multiple levels of regulation can, in certain circumstances, inhibit Canadian electricity exports to markets south of the border.

Electricity Pricing: The Revenue Requirement

While electricity pricing policy is responsive to a number of government objectives, the fundamental problem, from the point of view of economic efficiency, is the regulation of prices for a natural monopoly. The aim is to avoid situations of excess monopoly profits and to create the market conditions that will maximize the total benefits to the economy in the form of investment, production and consumption.

The proper regulation of monopoly prices generally involves two steps. First, regulators determine the "revenue requirement," which is the amount of revenue that is sufficient to cover reasonable costs of production and yield a "fair" return on assets at the same time. In theory, the recovery of costs through prices is not a necessary condition for economic efficiency – in some cases, subsidies could be considered – but the revenue requirement is universally accepted as the most practical starting point for price regulation.[3] As a second step, the costs are allocated across sales and a "rate structure" is designed to meet the revenue requirement.

Measuring the Revenue Requirement

The revenue requirement is a major point of attention for regulators, as it determines the average consumer price and the profit of the producer. While the details of the calculation of the revenue requirement vary from case to case, some principles apply generally.

The revenue requirement comprises, as a first item, the costs of production legitimately incurred by the producer in carrying out his business. This includes operating, maintenance and administration costs; fuel costs; the cost of purchased electricity; depreciation costs; and certain other costs, within the bounds consistent with efficient management.

The second item, a fair return on assets, is often more contentious. Generally, regulators rely on determining a "rate base" that approximates the value, after depreciation, of all prudently invested assets that are used and useful. The value can be assessed on either a historical-cost or a replacement-cost basis, or by some other means. The approach predominantly used at present is based on historical costs.

The "fair" rate of return on the rate base is another matter that involves judgment. It is generally made to approximate the average cost of financial capital in the market place, with reasonable weights being assigned to debt and equity capital. For example, if an efficient financial structure for the regulated enterprise is deemed to be 60 per cent debt and 40 per cent equity, and if the average costs of debt and equity in the capital funds market are 10 and 15 per cent, respectively, then the "fair" return on the rate base can be considered to be 12 per cent.

Of course, there is no easy way to determine a reasonable revenue requirement; each case presents its own problems, and the rules are complex. For example, what exactly should be included in the rate base or what constitutes an efficient debt/equity structure? The case of Canadian electric utilities is no exception. For the private enterprises in Alberta and Prince Edward Island, the process of determining the revenue requirement is much the same as that described above and appears to work relatively well, although some questions remain concerning the allocation of the cost of assets over time, for example. However, the regulatory treatment of embedded debt-interest costs raises tricky problems. In inflationary times, for example, the benefits of old, low-cost debt can be passed on to consumers through lower prices or, alternatively, to shareholders through higher returns. At present, the regulators tend to favour the consumer.

The determination of the revenue requirement for public utilities raises some fundamental issues. The points of debate concern all aspects of the revenue requirement. A widespread view among economists is that the revenue requirement, as calculated for the public utilities, generally undervalues the true cost of electricity. The situation stems in part from the fact that neither the regulators nor the utilities have sought to achieve competitive returns on assets. Rather, they set targets for the debt-to-equity or interest-coverage ratios, at levels sufficient to maintain or enhance their credit rating, while holding electricity price levels down.[4] The returns on public-utility assets are typically lower than those on private-utility assets because debt costs to the provincial utilities are reduced by government guarantees – which also encourage relatively high debt/equity ratios – and because the return on equity is low as a result of the government policy of holding down electrical rates. Also, the accounting practices of the utilities can cause the assets themselves to be undervalued, making the overall question of the costing of assets (depreciation plus return) even more significant. Moreover, provisions for income tax are not made in assessing the return on assets because public – and, to a great extent, private – utilities are exempt from provincial and/or federal income tax. Their positions are thus distorted in relation to that of many other areas of economic activity.

There can also be undercalculation of operating costs in the determination of revenue requirements. Not only have questions been raised about the measurement of the cost of assets, but public electric utilities – and, for that matter, private ones as well – pay few royalties for the use of natural resources, particularly water used in electricity generation. In addition, the profits earned from sales outside a province – and, in some cases, government subsidies – are applied against the cost of domestic service.

Altogether, the major point of difference between the present determination of the revenue requirement in the industry and its determination in the context of economically efficient regulation, in the theoretical sense, arises from the distinction between *accounting costs* – the costs to the utilities as they see them – and what can be referred to as the *social opportunity costs* of the resources employed. In a number of cases, the latter can be significantly higher. For example, the costs that form part of a utility's revenue requirement can be lower than the opportunity costs if the government does not collect the rent on natural resources such as gas, coal and water. More importantly, the embedded accounting cost of financial capital can be below its opportunity cost if it is largely made up of low-cost debt.

The present practice of focusing on accounting costs results in a low revenue requirement and, hence, in low electricity prices – the objective sought by provincial governments. However, the principles of economically efficient regulation, as generally applied in other sectors of the economy, suggest that all legitimate costs should be taken into account and that a fair return should be earned on properly valued assets.

In summary, the economic-efficiency argument is not paramount in practice because it does not address other concerns of governments, such as regional development or social policy. However, an analysis from the perspective of economic efficiency must be undertaken as a means of evaluating present pricing and supply policies in order to identify the trade-offs involved between these various considerations.

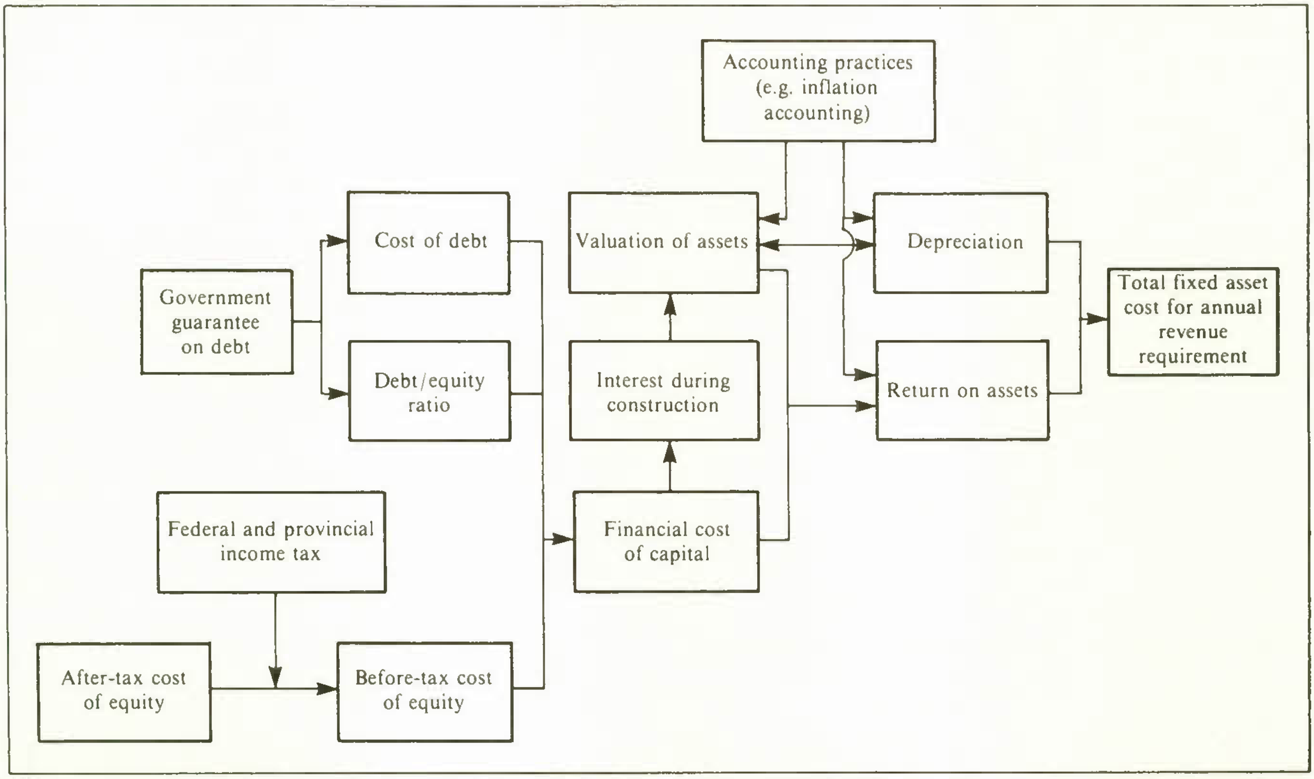
Capital Costs

The cost of assets for an electric utility comprises two basic items (Figure 6-2). There is, first, the return on assets, which can be calculated by looking at the costs of debt and equity capital, and at the mix of debt and equity in the capital structure of the utility. Second, there is depreciation – the annual levy made by the utility to recover the value of its assets over their lifetime, which depends on the accounting methods used to value the assets over time.

A review of the many aspects of the calculation of assets in public utilities in Canada suggests that real costs are being underestimated. The return on assets is generally low in relation to what is earned in either privately owned utilities or other private sectors of the economy. There are problems, as well, with the valuation of assets and the setting of annual depreciation charges. This situation stems largely from the preferences that are extended to the public utilities by their government owners.

Figure 6-2

Relationship between Factors in the Costing of Assets in Canadian Public Electric Utilities



Cost of Debt

A first factor is the government guarantee of the securities of public utilities – which, by reducing risk, facilitates their easy access to low-cost financing. In 1982, 88 per cent of the debt of provincial public electric utilities was guaranteed by the provincial governments. Debt guarantees have the effect of improving the credit rating of the public utilities and/or allowing them to maintain a higher proportion of debt in their capital structure. Indeed, statistics show that the public electric utilities have a much higher ratio of debt to total capital than regulated private utilities in the electricity industry or in other sectors of the economy (Table 6-4).

Table 6-4

Ratio of Long-Term Debt to Total Capitalization[1] for Major Public and Private Electric Utilities, and Other Sectors, Canada, 1982

Public electric utilities	
Newfoundland and Labrador Hydro	0.80
Nova Scotia Power Corporation (31 March 1983)	0.97
New Brunswick Electric Power Commission (31 March 1983)	0.87
Hydro-Québec	0.74
Ontario Hydro	0.84
Manitoba Hydro (31 March 1983)	0.97
Saskatchewan Power Corporation[2]	0.86
B.C. Hydro and Power Authority (31 March 1983)[3]	0.88
Private electric utilities	
Newfoundland Light and Power Company	0.47
Alberta Power Limited[4]	0.31
TransAlta Utilities Corporation	0.39
Other sectors (1981)	
Pipelines	0.52
Communications	0.48
Gas distribution	0.44
Transportation	0.40
All nonfinancial industries (excluding electric power)	0.28
All industries	0.41

1 Ratio of long-term debt to long-term debt plus total equity.
2 Includes gas distribution operations.
3 Includes gas, rail freight and other operations.
4 Result for Canadian Utilities Limited, for which Alberta Power's total assets represented 44.6 per cent.
SOURCE Based on the annual reports of Canadian electric utilities and on data from Statistics Canada.

Commenting on Canadian electric utilities, Standard & Poor's International, an organization that assigns credit ratings, noted that "if a government owns a utility and guarantees its debt ... these utilities can be regulated to meet economic policy objectives with much less emphasis upon external financial constraints."[5] It went on to say that "the availability of reliable electric power at rates a fraction of those prevailing in the U.S. contributes to economic development" but that "these benefits must be weighed against the contingent liability created by the utility ... in assessing the overall impact of the utility on the province's debt rating." The article concluded that "in every case the utility's debt rating is higher than it would be without the provincial guarantee."

The total guaranteed debt of the provincial public electric utilities represented 36 per cent of the provincial long-term direct and guaranteed debt outstanding in 1982. The benefits of their preferred access to debt capital, in the form of lower electricity rates, are quite visible. This preferred access may induce them to borrow more than they otherwise would, adding to the total debt load of the provincial governments and, conceivably, increasing the rate of interest that the latter are required to pay on their own direct debt. The provincial public electric utilities also accounted for as much as 26 per cent of all foreign-currency bonds outstanding in 1980. While they would be difficult to isolate there could be indirect negative impacts on investments and exports – and thus on the production of goods and services in other sectors of the economy. The provincial governments and the public utilities, however, have generally argued to the contrary.

Cost of Equity

The second aspect relating to the question of the return on assets is the rate of return on equity. While the regulation of the private electric utilities generally provides a competitive rate of return to shareholders, that is usually not the case for their public counterparts. The absence of common shares in the publicly owned companies makes comparisons of price/earnings ratios impossible. But taking the ratio of profits to the book value of equity as an indicator of the rate of return on equity capital, we note that the return, on either a before- or an after-tax basis, has for the most part been lower in the electric-power sector than in the nonfinancial sector in Canada in recent years (Table 6-5).

Because both debt and equity capital receive a lower return in the public utilities than elsewhere in the economy, and because debt in relation to total investment is greater, it follows that the total return on assets is lower in the public utilities than in other sectors.

Table 6-5

Profit Before and After Tax as a Proportion of the Book Value of Equity,[1] Electric Power and Nonfinancial Industries, Canada, 1972-81

	Profit before tax		Profit after tax	
	Electric power[2]	Other nonfinancial industries	Electric power[2]	Other nonfinancial industries
	(Per cent)			
1972	6.9	13.0	6.6	8.4
1973	6.9	17.8	6.5	11.7
1974	6.7	20.5	6.7	12.9
1975	3.5	17.4	3.0	11.3
1976	5.6	16.2	5.1	10.8
1977	7.5	15.3	7.0	10.1
1978	8.2	17.7	7.1	12.3
1979	11.2	21.7	9.6	15.0
1980	8.7	20.9	7.5	14.4
1981	9.8	16.9	9.4	11.5

1 Equity includes amounts due to shareholders and affiliates.
2 Excluding municipal electric utilities.
SOURCE Based on data from Statistics Canada.

Valuation of New Assets

A factor that relates to both the return on assets and the calculation of depreciation in the electrical sector is the valuation of new assets. The question at issue here is the possible undercalculation of the costs of money tied up in assets not yet brought into service.

It can take 10 years or more to construct a large nuclear or hydraulic power-generating facility. During that time, much of the invested capital sits idle, providing no return. At the same time, costs are incurred for the borrowed funds or the equity used to finance the construction. The imputed cost of these funds to the utility is referred to as the "interest charged to construction work in progress" or the "interest during construction" (IDC) for short.[6]

Because assets under construction are not yet providing service to existing customers, neither the cost of the funds employed to finance construction nor other construction expenditures are normally included as expenses in the revenue requirement until the assets are in use.[7] Instead, the IDC is capitalized each year, along with the construction expenditures. The value of the assets eventually brought into service is equal to the expenditures on labour and materials plus the accumulated IDC.

For a project with a long construction period, the real interest rate used to calculate interest during construction is, of course, a most important factor in determining the magnitude of the IDC and, therefore, the ultimate value of the assets.[8] For example, for an 11-year project with a usual pattern of expenditures over the construction period, a real interest rate of 10 per cent results in a final asset value that is 63 per cent greater than the outlays for labour and materials, while a 3 per cent real interest rate yields a value that is only about 16 per cent above the costs of labour and materials (Table 6-6).

The provincial electric utilities in Canada generally calculate the IDC on the basis of an interest rate that reflects their bond rates – which is sufficient if the cost to be ultimately recovered through the revenue requirement is the accounting cost of debt. The bond rate, however, may be perceived as an inadequate measure of the opportunity cost of the invested capital because it is a preferential rate on debt granted to the utilities that is below the average rate of return on assets in the Canadian economy. The true economic cost of the assets brought into service is, therefore, underassessed in the utilities' accounting process. As a consequence, the real return on assets in the industry may be even lower than is apparent from indicators based on the book value of the assets.

Allocating Capital Costs Over Time

A final issue that is often raised concerning the costing of assets in the electricity sector has to do with the allocation of costs over time. The setting of annual depreciation charges for assets in place and the subsequent assessment of the rate base and the rate of return involve questions of both fairness and efficiency – fairness, because the costs of the assets are borne by

Table 6-6

Valuation of a New Asset in the Electrical Industry for Various Construction Profiles and at Various Interest Rates for Interest During Construction (IDC)

	Final capital cost per dollar of construction expense at a real interest rate of:			IDC as a proportion of final capital cost at a real interest rate of:		
	3%	7%	10%	3%	7%	10%
	(Constant dollars)			(Per cent)		
Construction period (in years)						
5	1.07	1.16	1.23	6.2	13.8	19.0
7	1.09	1.23	1.35	8.6	18.9	25.8
9	1.13	1.32	1.48	11.2	24.2	32.7
11	1.16	1.41	1.63	13.6	28.9	38.6

SOURCE Estimates by the Economic Council of Canada, based on data from F. Rahnama, *Coal and Nuclear Electricity Fuels: A Regional Analysis*, Study 15, Canadian Energy Research Institute (Calgary: CERI, 1982).

different customers over the life of the asset; and efficiency, because the allocation of costs over time has an impact on prices and investment.

The electric utilities in Canada often employ the "straight-line" method of calculating depreciation, based on the cost of the assets at the time they were placed in service. For example, if the useful life of an asset is considered to be 25 years, 4 per cent of the original cost would be allocated for depreciation expenses each year.

The use of historical costs to determine the revenue requirement can be viewed as less than appropriate when the rate of inflation is high. This is particularly true in the case of long-lived assets, because the use of historical costs can result in a significant distortion in the allocation of costs, heavily charging earlier customers to the benefit of later customers, who pay lower amounts in real terms for the service of the same facilities. At any point in time, therefore, there can be an underestimation or overestimation of asset costs.

Various methods have been advanced to reduce this distortion by providing a different profile of asset cost recovery over time. One proposed method involves escalating both the depreciation and the value of the assets each year by a replacement cost index.[9] Under rate-of-return regulations, a real rate of return is then allowed on the "trended" value of the net fixed assets that is determined by the application of this cost index. The return to the investment would, therefore, be taken partly in the form of changes in the valuation of the assets, which would moderate the effect on prices of rapid changes in inflation rates. It would result in a decline over time in the real asset charges – but much less so than in the case of the historical-cost method – with the result that the revenue requirement for each asset would become more level, in real terms, over time. A second proposed method would involve the levy of a fixed asset charge in constant-dollar terms to recover the value of the assets – a kind of annuity charge.[10] This method would result in lower rates in the early years and higher rates in later years than in the case of the first method (Chart 6-5). Because under these trended methods earnings would be lower in early years, it has been suggested that their implementation might require new financial instruments – an indexed bond, for example.[11]

Income Taxes

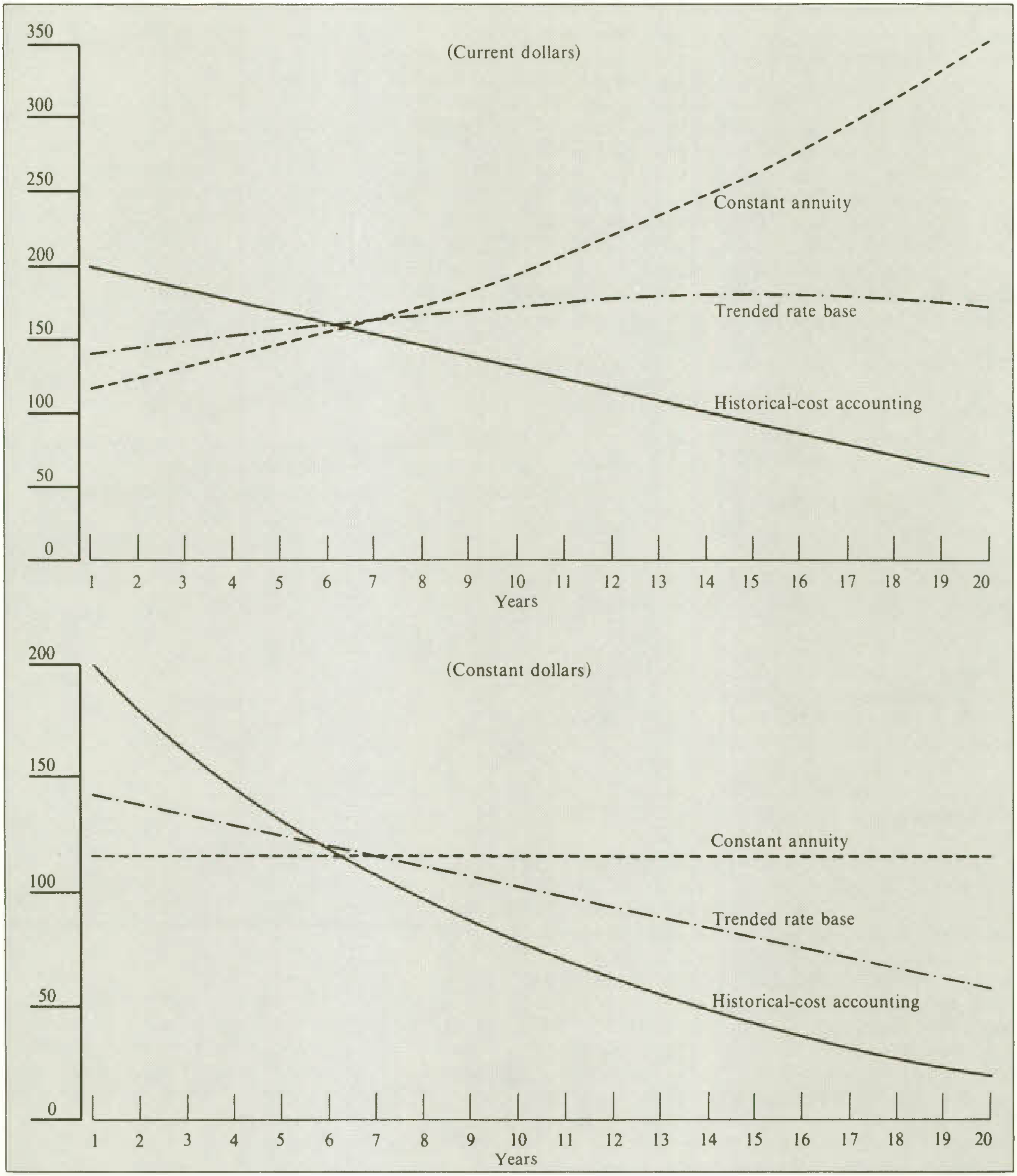
Another important factor that contributes to a lower revenue requirement in relation to total assets in the Canadian electric power sector is that little or no provision needs to be made for income taxes. Under the BNA Act, provincial Crown corporations were not required to pay federal income tax, and this exemption has been maintained in the "Constitution Act, 1982." For reasons of equity, this preferential treatment had been extended to private electric utilities in 1966-67, with the passage of the Public Utilities Income Tax Transfer Act. The Act provides for a rebate to the provinces of 95 per cent of the income tax paid to the federal government by the private electric utilities. The government of Alberta and Prince Edward Island subsequently return the rebate to the tax-paying utilities. Consistent with the provincial policy of maintaining low electricity prices, the public electric utilities also do not pay provincial income tax.

Implications for Investment Decisions

In summary, an important issue is raised by the implications of the policies currently in place. In particular, what is the effect of a low return on the

Chart 6-5

Revenue Requirement for Cost of Assets Under Alternative Regulatory Methods[1]



1 Assuming a $1,000 investment, a 6 per cent rate of inflation, a 9 per cent real rate of return and a 20-year useful life.

assets in the public electric utilities? First, there is the question of the link between the revenue requirement and electricity rates: a low return on assets plays in favour of lower rates; this curtails the development of energy conservation and alternative energy sources in the private sector, where higher, more competitive, rates of return must be earned. But there are also implications from the point of view of investment decisions in both the nonelectricity and the electricity sectors. As noted previously, the preferential access to financial capital provided to the provincial public electric utilities could indirectly increase the cost of borrowing for other sectors of the economy. Within the electricity sector itself, a low cost of assets has a number of effects on investment decisions. It tends to favour facilities that are relatively more capital-intensive and have longer construction lead times and longer useful lives.[12] These characteristics are usually associated with larger – and probably less flexible – projects. In the face of uncertainty in the evolution of demand, fuel prices and technological change, investments having these characteristics increase the probability that costly investment errors will be made.

As a means of determining whether the benefits related to investments in public electric utilities exceed their social costs, it has been proposed that investments be assessed by using the social opportunity cost (or social discount rate) of capital, which would amount to a competitive and fair return on assets. Combined with a better valuation of the rate base and depreciation expenses, the use of the social discount rate would provide a more accurate representation of the costs of capital to be used in determining the revenue requirement and, ultimately, in setting price levels.

Economic Rent on Natural Resources

As indicated earlier, another important benefit is bestowed on consumers of electricity because governments keep prices low by not assessing and collecting the potential economic rent on the resources used in the generation of electricity. In the past, this has also been the case for both natural gas and coal used in electricity generation, but the evidence today is mixed. The potential economic rent on natural gas and coal consumed in electricity generation is dwarfed, however, by the potential rent on hydraulic resources. The economic rent has been estimated by a proxy method – as the cost saving made possible by the availability of hydroelectric generation compared with the least-cost alternative method of thermal generation. The rent estimates for the utilities in the four major hydro provinces – British Columbia, Manitoba, Ontario and Quebec (including the electricity purchased from Churchill Falls), which together account for about 93 per cent of hydraulic generation by utilities nationally – ranged from about $2.6 billion to $4 billion for 1979.[13]

This estimate of the potential economic rent compares with a total revenue for electric utilities of about $7.4 billion actually received that year. The provincial governments have been collecting only a fraction of this potential economic rent – a total of about $241 million in the form of water power rentals; in addition, $60 million in the form of dividends was paid by Hydro-Québec to the Quebec government in 1983. Most of the benefits are currently passed on to domestic consumers in the form of low rates. Indeed, a comparison of electricity prices across Canada's provinces shows that those with high proportions of hydraulic generation generally enjoy lower electricity rates (Table 6-7).

Table 6-7

Average Electricity Rates and Hydro Share of Electrical Generation, Canada, by Province, 1982

	Average rate	Hydro generation
	(Cents/kWh)	(Per cent)
Prince Edward Island	12.2	–
Alberta	4.9	5.9
Nova Scotia	5.9	15.6
Saskatchewan	4.0	24.0
New Brunswick	5.1	31.4
Ontario	3.6	34.1
Territories	11.8	65.0
Newfoundland[1]	3.6	85.5
British Columbia	3.8	95.4
Manitoba	2.9	98.6
Quebec[2]	3.1	99.8

1 Excluding Churchill Falls sales to Quebec.
2 Including Churchill Falls purchases from Newfoundland.
SOURCE Based on data from Statistics Canada.

The question that arises is whether the present policy should continue or whether the value of hydraulic resources should be collected by provincial governments through water rentals or a similar assessment. If some or all of the potential revenue were collected, electricity prices would have to increase substantially in some provinces, leading to a reduction in demand. Governments could recycle the collected rent through lower taxes, thus increasing demand generally for other goods and services, or through programs of economic and regional development. Depending on the evolution of the present excess supply of electricity, changes of this nature could be phased in over a number of years.

Profit on Exports

Currently, any net revenue from external sales by electric utilities is applied against costs to reduce the revenue requirement for domestic customers. The effect, again, is to lower rate levels and encourage demand, thus creating the need for more facilities. This phenomenon arises because the utility operates under its net revenue requirement for its own customers. A company not subject to such a constraint would not necessarily allocate the profits derived from one category of customers to reduce the costs to the other categories. These reductions in domestic electricity rates made possible by the net revenues from external sales constitute a subsidy to domestic customers. It is arguable whether such subsidization should take place, in whole or in part. If exports and interchanges grow in importance, continued subsidization could result in the dissipation of the potential net economic benefits through the wasteful domestic overconsumption of electricity.

As an alternative to this cross-subsidization, export profits might be collected by the provincial governments and used for other purposes. As exports have grown and changed from being essentially relatively small sales of interruptible energy to longer-term sales of significant blocks of firm power, the cross-subsidization of domestic prices has become an increasingly important issue.

The provincial governments reduce the revenue requirements of the utilities – and hence electricity prices – in several other ways. From time to time, they have provided operating subsidies to the electric utilities; these subsidies amounted to about $47 million in 1981.

In summary, on the grounds of economic efficiency – and setting aside the external costs and benefits associated with electricity supply – we are drawn to the conclusion that the manner in which the revenue requirement of Canadian public electric and, in some cases, private utilities is calculated could be revised in a number of ways. The cost of assets, both in total and over time, could be better assessed; the economic rents on natural resources could be fully collected; the profits from export sales could go into provincial revenues rather than serve to reduce domestic prices; and other forms of subsidization could be limited to exceptional circumstances. These changes would result in bringing electricity rate levels more in line with the true economic costs of electricity supply; they would also lead to a more balanced consumer market, stimulate conservation and the market performance of other energy forms, and free capital for use in other sectors of the economy.

But if policy changes were made abruptly, there would also likely be certain adverse effects on those consumers – households, businesses and industries – who have come to depend on a reliable supply of cheap energy. The current provicial economic development strategies could be weakened by reducing the attraction for certain types of industrial investment. There are other short-term constraints that have to be considered. Because the present market climate is not conducive to an immediate move to raise prices, it would seem that prudence is warranted. On balance, electricity prices will have to rise over the long term, but the changes in policies will have to be gradual enough for consumers to adjust and for governments to realign economic development policies. Changes in the structure of electricity prices – as distinct from changes in price levels – can play an important role in the process.

Electricity Pricing: Rate Structures

In addition to the question of the level of prices, as determined by the revenue requirement, there are important issues within the electricity sector concerning the detailed structure of prices for different customers or markets. Rate setting involves a clash of interests: the utilities wish to improve their financial performance and increase their share of certain markets, whereas consumers want to keep rates low and reduce their share of the revenue requirement, and environmental groups want to limit demand.

A number of objectives are pursued in setting the price structure of electricity, the most important of which are: fulfilment of the revenue requirement; understandability and feasibility of application; stability over time; fairness, or the avoidance of undue discrimination among customers; the efficient use of resources; and economic and regional development.

Some of these objectives could be in conflict. For example, economic development could involve price discrimination in favour of industry, and the pursuit of the efficient use of resources could conflict with the goal of price stability over some period of time. In general, however, all price structures initially aim at meeting the revenue requirement.

Given the revenue requirement, there are many alternative price structures that can be implemented, some of which are more consistent with economic efficiency than others. The problem is to determine the rate structure that is the most compatible with economic efficiency.

Multipart Tariffs

To achieve economic efficiency, the price charged for the last unit of electricity produced must be sufficient to cover the marginal cost of producing that unit. Within that margin, however, there is room for some adjustment of prices to cover the production of other, so-called "inframarginal" units. Take, for example, the typical situation in which the average production costs of electricity decrease with increases in the volume of electricity produced. Under a two-part tariff structure, provision can be made for a lump-sum charge to cover connection (or hook-up) costs, together with a further unit charge for each unit of electricity consumed, based on the marginal cost of power production. Under such a tariff structure, the lump-sum charge necessary to meet the revenue requirement could be so high as to discourage customers from buying electricity at all. To circumvent this problem, an alternative that could be adopted is that of a multiblock declining tariff. Under this approach, the hook-up charges would be reduced. The unit price for electricity would be established in blocks according to the volume consumed. The unit price of the first block would be set significantly above the marginal cost level, but the unit price of each successive block consumed would be progressively less. The rate for the last (so-called "tailing") block would be set at the marginal cost of producing electricity.[14]

This approach, modified to provide for different factors applying to different customer classes, is the one generally used in practice for a number of reasons. In the residential market, for example, the charges for market segments that are less price-responsive, such as lighting and appliances, can be relatively higher than those for more price-responsive segments, such as space heating. The nature of the costs of serving a customer conforms to a two-part tariff structure, since there are lump-sum costs involved in connecting and metering customers, regardless of consumption levels. Moreover, this approach affords the utilities greater flexibility in pricing electricity in such a way as to make it competitive and to expand its share of certain markets. There is, however, concern that too much emphasis on market expansion could lead to undue price discrimination and less efficient use of resources.

The monthly residential rate structures in effect for various Canadian cities in April 1984 was reasonably similar, regardless of the quantities consumed beyond minimal levels (Table 6-8). Thus it conforms closely to a two-part tariff, although there are a few mildly declining block structures (where unit costs decrease with increasing consumption) – in Fredericton and Vancouver, for example. Hydro-Québec is the only utility with a rising (or "inverted") block rate, which is appropriate for a utility that faces increasing costs for future hydraulic installations.

All things considered, a two-part tariff structure with a lump-sum charge offers a number of advantages. If the revenue requirement can be met with only minor deviations of the lump-sum charge from actual costs while the second part of the tariff is set at, or close to, the marginal cost, then the resulting tariff structure is a simple one and can promote efficiency. If

Table 6-8

Monthly Residential Electricity Rate Structures, Major Cities, Canada, 15 April 1984

	Monthly energy consumption in kWh				
	0-250	250-500	500-750	750-1,000	1,000-5,000
			(Mills/kWh)[1]		
St. John's	86.8	52.8	52.8	52.8	52.8
Charlottetown	141.6	111.3	111.3	111.3	111.3
Halifax	89.6	58.4	58.1	56.7	56.7
Fredericton	93.0	56.5	53.3	40.7	40.7
Montreal	67.1	33.3	33.4	35.8	39.5
Toronto	56.9	43.6	43.6	43.6	43.6
Winnipeg	60.9	32.4	32.4	32.4	29.8
Regina	55.8	45.2	45.2	45.2	43.0
Edmonton	64.2	43.0	43.0	43.0	43.0
Vancouver	75.7	45.0	43.1	43.1	43.1
Yellowknife	103.4	95.2	95.2	95.2	95.2
Whitehorse	81.2	64.0	60.0	60.0	60.0

1 The incremental cost per kWh includes sales tax, discounts, subsidies and other costs.
SOURCE Based on data from Energy, Mines and Resources Canada.

the revenue requirement necessitates large deviations from cost for the lump-sum charge, then adjustments can be made to the second part of the rate. Furthermore, such a tariff structure can easily be extended to rates that are differentiated by time of use.

Time-Differentiated Rates

An important feature of electricity demand is that it is highly variable at different hours of the day and different seasons of the year.[15] For example, consumption on a typical weekday is generally highest in the morning and early evening, and lowest at night. In Canada, consumption is generally highest in winter months, when heating requirements are high; the peak hourly demand during the year usually occurs on a very cold winter day. Because there are generally only limited possibilities for storing electricity in a cost-effective manner, most of the electricity must be produced at the time it is consumed.

Peak demand is the maximum amount of electrical energy that must be supplied by a utility at any point in time within the year. It is a critical variable for planning purposes, because in the absence of reliable imports, the utility must have sufficient generating capacity to meet this peak demand. Because of the long construction period and long useful lives of generating facilities, the utility must base its system on a forecast of peak demands for many years into the future. In addition, it will maintain reserve capacity in excess of its projected peak demand.

The variability of electricity use on a daily and seasonal basis presents formidable problems for electric utilities as they attempt to minimize costs and, at the same time, meet peak demands. This means that they must maintain some generating facilities that will be utilized for only a small number of hours in the year. They attempt to minimize their overall costs by drawing upon a variety of power-generating technologies to meet different demand levels (see Appendix G).

The characteristics of demand, generation, transmission and distribution are such that the costs of delivering electrical energy differ by time of use. Although there are some exceptions in the case of hydraulic generation, for the most part costs tend to be higher in peak periods. Thus overall costs can be reduced over the longer term by shifting demands towards off-peak periods or, more generally, towards lower-cost periods.

One way to encourage this shift is to set prices that differentiate between higher- and lower-cost periods. The current rate structures in Canada, however, do not encourage the shifting of demand from peak to off-peak periods. Electrical energy charges are not differentiated by time of use; and the power charges levied for larger customers are based on peak demands regardless of when they occur.

There are several justifications for levying time-of-use rates. The first is fairness, or the avoidance of undue discrimination. To the extent that the prices charged do not reflect the real costs incurred, prices that are not differentiated according to the time of consumption are discriminatory: some consumers pay more than they should, while others pay less. The second reason involves a general concern for the efficient use of resources – a concern that applies not only in the electricity sector but also with respect to close substitutes, such as oil and gas, as well as complementary facilities, such as the electric heat pump. Where costs differ according to the time of use, time-differentiated rates could yield a better matching of the benefits received and costs incurred by consumers. Closer matching would result in the shifting of demands to lower-cost periods and in the increased adoption of conservation and more efficient energy-supply technologies. Progressively, capacity requirements could be lowered, less use would be made of higher-cost generation and higher capacity-utilization rates could be achieved.

The experience with time-differentiated tariffs in Europe and the United States indicates that they can play a key role in demand management (see Appendix H). This objective is achieved directly by encouraging customers voluntarily to shift demands away from higher-cost periods and indirectly by allowing the utilities to undertake active load-management practices.

Canadians are most familiar with the application of time-of-use rates for long-distance telephone calls and certain transportation services (airlines and trains, for example). These industries are similarly characterized by peak load problems, and discounts are offered and favourably received for service in off-peak periods. Similarly, seasonal rates have been in effect in the case of natural gas distribution. To date, however, no electric utility in Canada has implemented time-of-use rates on either a voluntary or a mandatory basis, although Ontario Hydro is currently experimenting with this approach, following investigation of this issue by the Ontario Energy Board. In 1979, the Board recommended, among other things, that "the concept of time-differentiated rates be introduced at both the bulk power and retail levels," based mainly on the argument "that time-differentiated rates are in principle fairer than non-time differentiated rates."[16] Some of the factors to be considered in selecting rating periods are outlined in Appendix I.

In Canada, more emphasis has been placed on other load-management techniques than on systematic time-of-use pricing. Canadian utilities have made use of interruptible sales to large industrial customers and have undertaken conservation programs involving advice and/or financial incentives to customers. More recently, some utilities have provided financial incentives to encourage residential customers to adopt hybrid heating systems, using electricity to provide basic heating and oil or gas to meet peak requirements.

Marginal-Cost Pricing

Time-of-use pricing can be based on various costing methods – for example, by extending the current accounting approach or by using the principle of marginal-cost pricing. The application of this principle has perhaps been the most controversial issue in electricity pricing in recent years. Over the past decade or so, this issue has been hotly debated among economists and utility officials before a number of regulatory boards in the United States and, in Canada, before the Ontario Energy Board.

The marginal-cost pricing approach aims at setting electricity rates – over time and across regions and customer classes – in a manner that reflects the corresponding incremental or marginal cost of production rather than the average costs, as is generally the case at present. In any given market and at any point in time, the marginal cost can be lower or higher than the average cost, which means that the adoption of marginal-cost pricing would amount to changes in the distribution of utility sales revenues. In the aggregate, the prices based on marginal costs can be adjusted in order to meet a given revenue requirement.

The difficulties with marginal-cost pricing are many, however, involving problems of measurement and application (see Appendix J). There is no unanimity on its potential use in Canada. The Ontario Energy Board has stated that "marginal-cost pricing became little more that a catchword, without completeness, stability, or consistency. There is no clear, practical definition of marginal costs and no clear, practical way of reconciling these costs with the revenue requirement. These obstacles are insurmountable. The Board therefore recommends that *marginal-cost-based rates be rejected*." The Board urged instead that "Ontario Hydro continue its present method of using accounting costs, adjusted to a future test period, for rate design purposes."[17]

Yet, in France the national electric utility (Électricité de France) introduced rates based on marginal costs over 20 years ago. Since then, similar approaches has been followed in Britain and in other European countries.[18] Faced with evidence similar to that presented at the Ontario Energy Board hearings, some regulatory commissions in the United States arrived at different conclusions. A number of U.S. utilities have been required to conduct marginal-cost studies for rate hearings, and some have introduced time-differentiated rates based on marginal-cost concepts.[19]

Judgment is clearly required in applying marginal-cost pricing to electricity rates – perhaps more, and certainly different, judgments than in the case of rates based on accounting costs. The fact is, though, that system operators and planners use these concepts as an integral part of their cost-minimization efforts. The fundamental question is whether prices should be based more on the cost of the resources that will be required to meet additional consumption than on the cost of the resources that are already in place.

Intraprovincial Price Variations

Other things being equal, the unit costs for distribution increase with the distance from supply and decrease with the size and density of the load. Consequently, distribution costs are generally higher for remote and sparsely settled rural areas and communities. In some cases – in British Columbia, Manitoba, Newfoundland and the territories, in particular – the potential distribution costs are so high that remote commmunities are not connected to the grid at all but are served by costly diesel-fired units.

In most provinces, there has been a general trend towards the reduction of price differences between urban and rural areas over time. While cost differences would justify higher rates for more remote and less densely populated areas, the trend towards a narrowing of the differentials is likely to be irreversible. Where cost differentials are not great, the impact on remote areas is not significant; where the cost is significantly higher, however, any additional charge for it would likely be considered unacceptable. In any case, the efficiency losses from urban/rural cost differentials are probably small in relation to those from other costing and pricing issues.

In general terms, however, the rate structure is an aspect of electricity supply policy that should be examined more closely by the regulators. From the point of view of efficiency in resource allocation, it is as critical an issue as the revenue requirement. In particular, we see a need to pursue the application of time-of-use rates, which could provide for greater equity among consumers and, over the long term, reduce capacity requirements and increase capacity utilization rates, thus reducing the average real costs of electricity supply.

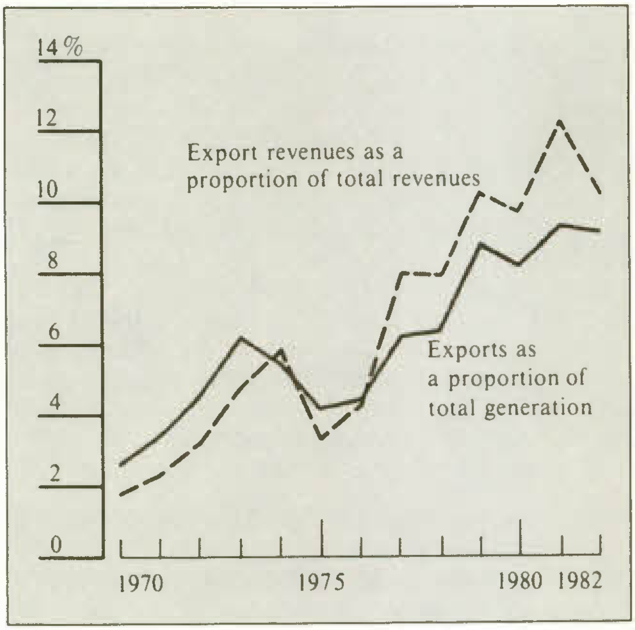
Canada-U.S. Electrical Trade

There is a long history of electricity trade between Canada and the United States. The benefits to both countries are many and varied, and transmission-line capacity and export volumes have grown steadily in order to capture those benefits. (Some of the advantages and disadvantages of electrical exchanges generally are discussed in Appendix K.)

Over the last 25 years, Canada has rarely been a net importer of electricity. Canadian exports have risen sevenfold since 1970 and are about 10 times as high as imports. In 1982, net exports reached close to 10 per cent of the electricity generated in Canada (Chart 6-6). Net export revenues have grown even more dramatically than the volume of trade, reaching about $1.2 billion in 1983 – more than 10 times the value a decade earlier and representing close to 10 per cent of the total revenues of Canadian electric utilities.

Chart 6-6

Electricity Exports and Export Revenues, Canada, 1970-82



SOURCE Based on data from Statistics Canada.

At the end of 1983, there were over 65 major transmission lines crossing the U.S.-Canada border. The power-transfer capability of the major interconnections was about 9,600 MW, with close to two-thirds of that capability being in eastern Canada. Lines capable of transmitting an additional 2,700 MW are under construction or at the planning stage.

Reflecting the generally larger distances and the lower potential benefits to be realized, the interprovincial transmission capability has been less than the international capacity. The major exceptions are the lines from Churchill Falls to Quebec, which account for 5,225 MW of the approximately 8,900 MW of installed interprovincial connection capacity in Canada. Additional lines between British Columbia and Alberta, and between Quebec and New Brunswick, providing a capacity of 1,300 MW, are expected to be in service by 1986.

Early in the century, major portions of hydroelectric developments were committed by long-term contract to U.S. markets at fixed prices. At the same time, Canadian governments at all levels took action to ensure that hydroelectric facilities would also support economic growth in Canada. At the federal level, the Exportation of Power and Fluids and Importation of Gas Act of 1907 established federal jurisdiction over exports of electricity and provided support for the development of hydraulic resources for domestic use. The Act required that a licence be obtained for exports, that only power in excess of Canadian needs be eligible for export and that export prices be equal to, or greater than, the price charged to Canadians "under similar conditions of sale." To make the Canadian market more attractive for producers at Niagara Falls, the federal government imposed an export tax, beginning in 1925, at a fixed amount of 0.3 mills per kWh.

The National Energy Board was created in 1959. The Board's jurisdiction in electricity matters was limited at the time to the regulation of power lines crossing the international border and to the licensing of exports. The Exportation Act of 1907 was repealed, but the criteria for exports were maintained and set under the authority of the NEB.

The first major statement of national electricity policy in subsequent years came with the National Power Policy of 1963.[20] In contrast to the previous restrictive measures, the policy encouraged interconnections and sales to the United States as well as between the Canadian provinces. The export tax was removed in order to realize the potential benefits from increased sales. The policy particularly encouraged early development of large power sources – many of them remote – by promoting firm exports.

More recently, the National Energy Program Update of 1982 reaffirmed the strategy of building capacity in advance of domestic requirements to expand the export market, provided there was "an equitable distribution of the risks and financial burdens between buyers and sellers, and satisfaction of appropriate environmental standards."[21]

The changes in export policy over the years have reflected changing concerns and priorities. With the slowdown in the growth of the domestic market, the achievement of goals such as rural electrification and the emergence of excess supply, the emphasis of the utilities has shifted towards more aggressive export strategies. This trend will likely be reflected in expanded trade in coming years, given the projections for continued slow growth of domestic sales and

Canada's apparent cost advantage over the United States.

Existing and potential new sources of electric power supply are available for increased exports to the United States within the next two decades. The major possibilities include: the untapped hydraulic reserves of the Lower Churchill Falls in Labrador; tidal power in the Bay of Fundy; nuclear units in New Brunswick; current excess and additional hydraulic resources in Quebec; coal-fired and nuclear-powered generation in Ontario; the "prebuilding" of hydraulic installations in Manitoba and Alberta; and hydro facilities in British Columbia.

A recent study found that there was a potential export market for Canadian electricity in the United States of between 84,000 MW and 188,000 MW by the end of the century.[22] By the year 2000, these exports could result in annual gross revenues of $4 billion (in 1980 dollars) – about four times the 1981 value – with potential net revenues of about half that amount.

Obviously, the export of electricity could be a very profitable business for Canada; hence marketing efforts in this direction should continue. Generally, we believe that these efforts should be pursued by the utilities, with governments limiting their role to ensuring a favourable environment for the contract negotiations. There remain, however, questions of policy that need to be addressed.

First, the increased share of utility revenues accruing from exports raises the issue of the growing impact of policy decisions regarding the redistribution of these revenues. It will become increasingly inappropriate to pass on the export profits to domestic consumers in the form of reduced rates. Should that policy continue, the resulting subsidization would become out of proportion with the costs of generation and would lead to outright waste in domestic consumption.

One means of separating domestic and export accounting would be for the public utility to create a separate subsidiary charged solely with the external marketing of electricity. The subsidiary would buy power or energy from the parent company at comparable domestic prices and resell the electricity to out-of-province customers at the best possible prices. The profits could be retained by the subsidiary, transferred to the parent company or passed on to government, depending on provincial policy. Generally, we favour turning the greater part of the profit over to government, although a return of funds to the parent company to build up equity might also be advantageous, depending on provincial government priorities. We would not encourage the use of export profits to lower domestic prices.

Conclusions

Historically, electricity supply policy in Canada has addressed a number of objectives that are not necessarily related to economic efficiency. They have included social development, regional development and energy security. As a matter of policy, electricity prices have been kept as low as possible; in many provinces, they appear to be lower than would be warranted from the strict point of view of economic efficiency.

With electricity taking a growing share of the domestic energy market and with exports increasing, the issues surrounding electricity pricing become increasingly important. Electricity supply is mainly a matter of provincial responsibility; hence many policy questions will need to be addressed by each province.

In our judgment, there is a need for more comprehensive regulation of electricity, particularly with respect to the public utilities. While a number of regulatory boards and commissions are already in place, there are important functions of the utilities that receive less than adequate attention from these regulators. Some large producing provinces, like Quebec and Manitoba, do not hold public hearings to review electricity rate setting. In Ontario, public hearings are held, but the final word on pricing remains in the hands of the provincial corporation. Generally, public utilities are not fully accountable to the public for their forecasting and investment decisions. Hence the costs and risk associated with future investment may not be fully understood by the legislators and the public.

The electrical industry in Canada is now mature and is a major force in the energy market. Its growing exports mean that its role in the economy will become increasingly important. It should, therefore, be the object of tighter control and become more accountable to the public. Formal regulatory bodies should be established in every province, with a mandate to review and determine electricity prices – including rate levels and structures – and to monitor capital investment. Both pricing and investment should be the object of public hearings as a means of achieving broader consensus on electrical supply management. In the process, we would like to see more emphasis being placed on economic efficiency. Priority should go towards bringing the revenue requirement more in line with a more competitive return on capital and other resources devoted to electricity supply.

In the past, public legislators and regulators have been concerned mostly with maintaining low rates. It would appear that some of the real economic costs of electricity generation, transmission and distribution, which are not necessarily reflected in the financial statements of the utilities, have been overlooked in the process. We are concerned that the return on the massive amount of assets employed in the industry is too low as a result of the provincial policies pertaining to both debt and equity capital. We are also concerned that the preferential treatment extended to the utilities – through the exemption from income taxes and the collection of low rents on natural resources, for example – excessively distorts the energy market, overly stimulates electricity demand, restricts the implementation of alternative sources of electricity generation and ultimately leads to waste and inefficiency.

No general rules can apply to all provinces at all times, however. It will be the task of regulators and provincial governments to assess the trade-offs and to elaborate strategies that will integrate the many considerations pertaining to electricity supply. As a first step, the mandate of the utilities could be amended to reflect a long-term, dynamic approach to supply *and* demand management. The pricing of electricity at the lowest possible cost, as costs are currently measured, does not necessarily ensure the maximum potential benefit to Canadians.

There are other steps that policy makers might consider as a means of gradually transforming electricity supply policy in order to promote efficient resource management. One possibility, in the case of asset management, is for government to recommend a target rate of return for investment decisions. Ultimately, the revenue requirement and the rate levels could be based on this discount rate. More efficient management could also include the requirement that the utilities obtain debt capital on their own behalf without any provincial guarantee, except perhaps in special circumstances. At present, some provincial public utilities might find the cost of pursuing this course unacceptable because of their high debt/equity ratio. The first requirement, therefore, would be to improve the capital structures of the utilities so that they may be able, as soon as possible, to compete on their own for debt funds at a favourable cost.

With respect to price structures, initial steps in introducing time-of-use rates could be taken, beginning in those markets where the net benefits would be clearly positive. This should occur not only for those utilities that do not have much excess capacity, but also for those that do. Even in an excess-capacity situation, it still makes sense to encourage the use of lower-cost rather than higher-cost energy. The presence of excess capacity offers an opportunity to introduce time-of-use rates in a slow but deliberate fashion without arousing concern that additional capacity could be required if the expected effects of reducing peak demand are not fully achieved. Because the differential between peak and off-peak rates would tend to be smaller in the face of excess capacity, the impact on customers would also be more gradual.

No general prescription with respect to time-related rates can be laid down because each utility faces circumstances that are somewhat unique. As a rule, one would expect the process to begin with large industrial customers, where the net benefits would likely be greatest, and to proceed to smaller customers as long as net benefits can be achieved.

Based on European and U.S. experience to date, several options for the introduction of time-of-use rates are possible, including initial experimentation, mandatory rates or voluntary rate schedules where the nature and extent of the net benefits may not be clear-cut or may vary within customer classes. The process should be closely monitored for its impact on both the utility and its customers and it should lead to the building-up of a body of knowledge that could be used to improve and change the rate structure, as well as for forecasting purposes. The applicability of marginal-cost principles and the extension of time-of-use rates where warranted should be considered as part of this monitoring exercise. Load-management techniques should be further employed, with or without time-of-use rates, where benefits can be obtained. Furthermore, there should be an active program of interchange of Canadian and foreign experience among utilities. The Canadian Electrical Association is a natural mechanism through which such interchange could be supported.

Finally, we wish to emphasize that there is a growing need for policy makers to integrate export policy and domestic supply policy. Electricity exports to the United States, as well as interchanges between provinces, will likely increase in importance in the future. Under current practices, the subsidy accruing to domestic consumers as a result of net profits on external sales will likely increase in relative terms. Domestic demand could then grow above the level justified by the costs of the resources required to meet that demand. If this is to be prevented, the profit will have to be taken by the provincial governments, either directly or indirectly – through water power rentals, royalties, lump-sum taxes or dividends, for example – and not used to reduce the revenue requirements for domestic customers.

7 Energy Demand, Conservation and Substitution

Until recently, it was widely believed that the demand for energy in Canada was essentially fixed by our lifestyles, our climate, our large automobiles and the need to travel long distances, as well as by other aspects of our environment. Energy prices and policies appeared to have a limited role in the shaping of our energy markets.

In the 1950s and 1960s, there was little reason to challenge this view. Energy prices were relatively stable, and the demand for energy grew roughly in line with economic growth. Greater wealth implied greater energy use; and, somehow, greater energy use seemed to imply greater wealth.

While there is still much to be understood about energy demand and its links with the economy, it is now recognized that energy demand in industry, in buildings and in transportation is significantly responsive to the price of energy and that it can be responsive to policy. Canadians have learned, in effect, that energy demand is malleable.

The demand for energy is derived from demands for energy "services" – for example, heat, light and motion. Energy is combined with other inputs or factors – capital and labour – to meet those needs. As a consequence, changes in prices or incomes can trigger changes in the demand for energy in two ways. First, there may be a response in the demand for the energy service itself; if energy becomes more expensive, for example, households may lower thermostats to reduce their demand for heat. But there may also be adjustments in the manner in which users meet their demand for the energy service. If energy prices rise, the demand for heat may remain the same but the homeowner may choose to use less energy and invest in insulation or a more efficient furnace. This second type of response implies that energy demand will also respond to technology, which defines the options open to users to meet their needs.

In addition, there are interactions in the economy that have indirect effects on energy demand. Consider, for example, the effect of rising industrial energy prices. If the cost increase is not fully compensated by a realignment of the production process – as is likely to happen – then the price of industrial output will increase. Not only will this, in most cases, reduce real incomes, but it will alter the relative prices of goods and services, favouring those that are less energy-intensive. Households, of course, will adjust their demand for goods and services accordingly.

Finally, while the total demand for energy is responsive over time to a variety of factors – particularly prices – the demand for individual energy sources (e.g., oil products, natural gas or electricity) is even more sensitive because, subject to technological limits, one source can be substituted for another without necessarily changing the quantity of energy use. For example, depending on relative energy prices, industry can switch from heavy fuel-oil to natural gas; or households can switch to electricity or gas from heating oil.

The adjustments in energy demand can be slow, however. In industry, lags arise from committed investments in machinery and equipment or from contractual obligations for purchases of material and labour services. The demand of households is similarly slow to adjust: homes, heating systems, appliances and cars cannot be changed overnight. The short-run demand for energy is thus less flexible – less "elastic" – than the long-run demand.

Over the past 10 years, Canadians have witnessed significant changes in energy demand, as generally higher prices have stimulated conservation and changing relative prices have encouraged substitution away from oil. There has been an inclination towards energy diversification in order to improve the security of energy supply and to achieve greater resilience in response to potential price shocks. The responses to the changing energy environment have been uneven because of differences in technology and relative prices among regions, sectors and applications. For example, energy substitution in transportation has been slower than in industry because there are fewer competitive options in that sector.

The role of policy in the process of demand adjustment has been important. Federal and provincial programs of energy conservation and substitution – involving grants, loans, provision of information and so on – have influenced demand patterns and demonstrated the significance of "demand management" in the design of energy policy. At the same time, however, the role of prices and pricing policy remains paramount in shaping energy demand and achieving energy conservation and substitution objectives.

Primary and Secondary Energy

Primary energy refers to an estimate of the energy resources extracted and/or used by an economy over a period of time. It includes crude oil, natural gas, liquid petroleum gases obtained from natural gas plants (such as propane and butane), hydro and nuclear energy, as well as other raw energy resources (such as wood and solar or windpower).

Secondary energy refers to the heat content of energy commodities consumed in the end-use sectors (residential, commercial, industrial and transportation). These commodities include refined petroleum products, natural gas, liquid petroleum gases obtained from gas plants and refineries, electricity (from all sources), wood, and other forms of energy used by energy consumers before any transformation into other energy commodities.

Energy Consumption in Canada, 1982

	(Petajoules)	(Per cent)
Secondary energy	5,920	64.1
Losses in electricity generation		
Thermal	624	6.8
Nuclear	228	2.5
Hydro	1,567	17.0
Losses in electricity transmission	109	1.2
Losses and consumption in pipelines	79	0.8
Other consumption by energy producers	249	2.7
Nonenergy uses	458	5.0
Total (primary energy)	9,233	100.0

In other words, primary energy is the initial resource, while secondary energy is the end-use product. There is a notable statistical difference between the two, which arises mainly from the losses that occur in the process of producing and delivering secondary energy commodities to the consumer. The most significant losses occur in electricity generation. For thermal plants, only about one-third of the primary energy input – oil, gas or coal – is converted to electricity; the remainder is dissipated in waste heat streams. Similar heat losses occur in nuclear electricity generation.

There are also energy losses in hydraulic generation, but those are generally defined more arbitrarily. Ideally, the estimates of primary hydro would refer to the energy potential of the water flow in the turbines; about 90 per cent of that energy does become secondary electricity. The convention adopted by several statisticians, however, is to assign a primary hydro value based on the amount of fossil fuel that would be necessary to produce electrical output equivalent to that achieved from hydro. This approach gives a much higher estimate of primary energy and implies conversion losses of about two-thirds in going from primary to secondary energy. Of course, most of those losses are fictitious. In statistical terms, we say, using this approach, that hydro is valued at 10.5 megajoules (MJ) of primary energy per kilowatt-hour (kWh) of electricity; secondary electricity, on the other hand, is always measured at 3.6 MJ/kWh – the actual heat content of the commodity. There is debate over whether the use of the 10.5 MJ factor provides a good representation of primary energy use. It has been introduced mainly to facilitate comparisons of primary energy consumption between countries with varying degrees of reliance on hydro, in relation to total electricity generation. It has been argued, however, that in effect, more distortions arise with the use of the 10.5 MJ factor.

In any event, here we follow the convention and use 10.5 MJ/kWh for primary hydro energy. (The factor is also used for primary nuclear energy.) Apart from the energy losses in electricity generation, the difference between primary and secondary energy includes losses in electricity transmission and pipelines, other consumption of energy by energy producers, and energy consumption for nonenergy uses – e.g., asphalt from crude oil.

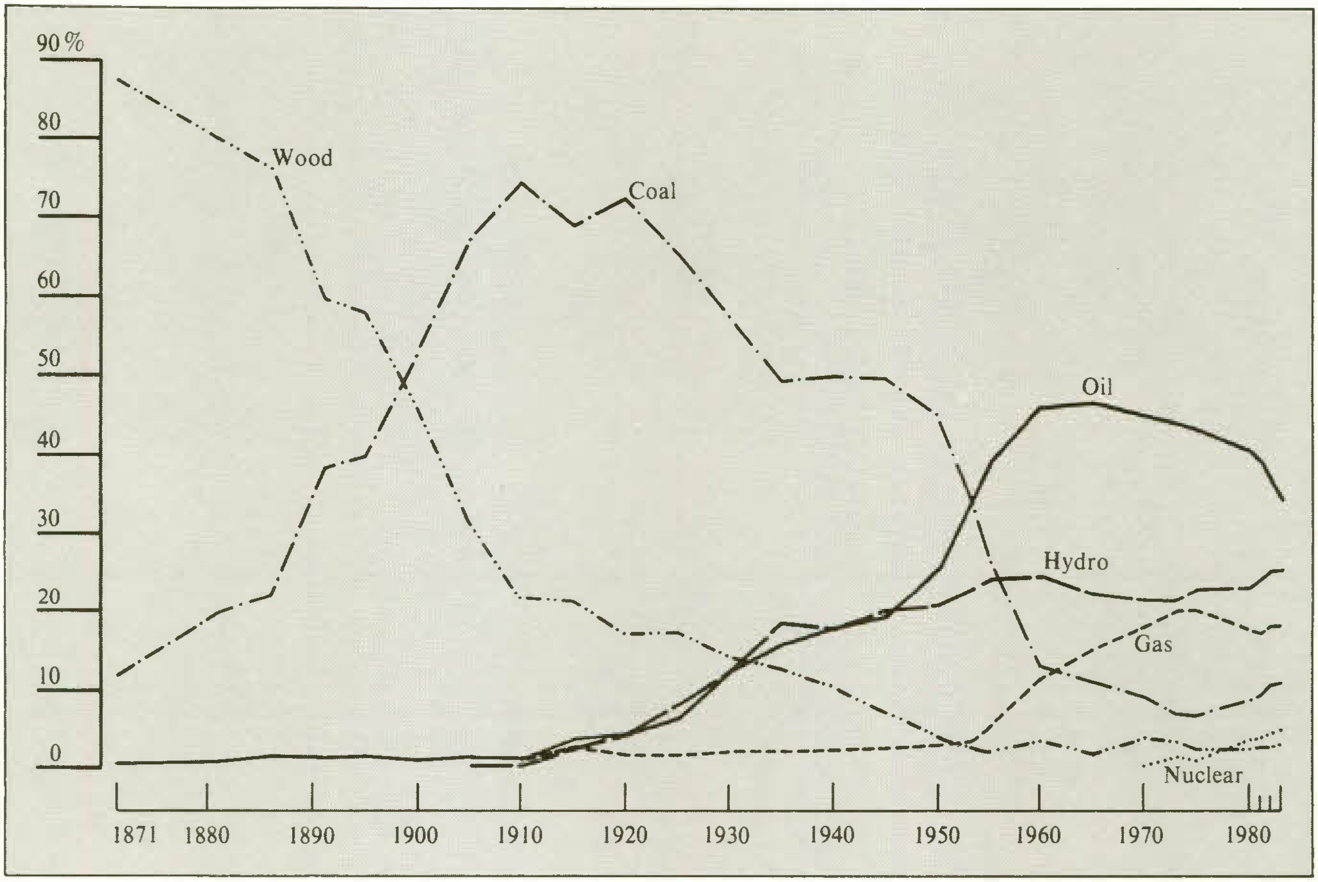
We indicated in previous chapters that there have been inadequacies in energy pricing policy in Canada. Because demand and supply are both responsive to prices, these inadequacies have caused imbalances in energy markets. We believe, however, that revised pricing, together with increased consumer awareness and more selective and efficient government intervention, could re-establish the balance. In the process, energy conservation and substitution could be stimulated, energy costs could be reduced and energy security could be improved.

The Evolution of Energy Demand

Long before the first oil crisis of 1973, the Canadian energy market was adjusting to changes in technology and relative prices. Indeed, in less than a century the market was successively dominated by three fuels – wood, coal and oil. Coal replaced wood as the dominant energy form in the early 1900s (Chart 7-1). Some 50 years later, with the first major oil and gas discoveries, the building of the pipelines and low prices for imported oil, coal rapidly lost ground. Its market share dropped below that of oil in 1954 and below the steadily increasing shares of hydroelectricity and natural gas in the late 1950s and early 1960s, respectively. Coal was replaced not only because relative prices became more favourable to the other forms of energy but also because of the convenience and comparative efficiency of oil, gas and electricity for most energy applications. Coal remained, and remains today, competitive in only two major sectors – elec-

Chart 7-1

Shares of Primary Energy by Source, Canada, 1871 to 1983



SOURCE F. R. Stewart, "Energy Consumption in Canada since Confederation," *Energy Policy* 6, no. 3 (September 1978), and data from Statistics Canada and from Energy, Mines and Resources Canada.

tricity generation, where it is used generally close to the production sites and in large amounts; and pig-iron production, where manufactured coke is used as both a feedstock and an energy source.

Since 1973, the changes in energy demand patterns have been of two kinds. First, the rate of growth in demand has declined as a result of lagging economic growth and general increases in energy prices. The demand for "primary" energy grew at an average rate of 2.0 per cent between 1973 and 1980, compared with between 5 and 6 per cent in the 1960s and early 1970s (Table 7-1). Since then, demand has actually declined some 2.4 per cent a year, on average, to 9,190 petajoules (PJ) in 1983 – the equivalent of some 650,000 m^3 of oil per day. This level of demand is only about 7 per cent greater than that of 1973.

The second major shift in the Canadian energy market, as in the markets of all oil-importing nations, has been the substitution of other energy sources for oil. As oil became relatively more expensive in relation to other fuels, market forces, combined with government initiatives, brought down the oil share of total primary energy from 45 per cent in 1973 to 35 per cent in 1983. Even at this reduced level, though, oil remains Canada's predominant energy source.

Of course, the drive to replace oil has led to increased demands for other energy sources. Hydro and nuclear energy use has increased and now accounts for over 30 per cent of Canada's primary energy needs. Coal has resurfaced in some markets, mainly for electricity generation in eastern Canada. In 1982, it showed a share of primary energy above 10 per cent for the first time since 1970; the 1983 share was 11.4 per cent. On the other hand, the natural gas share

Table 7-1

Distribution of Primary-Energy Consumption by Major Energy Source, Canada, 1960-83

	1960	1970	1973	1980	1981	1982	1983[1]
				(Per cent)			
Coal	13.4	9.6	7.7	9.4	9.9	11.0	11.4
Oil[2]	46.3	45.5	44.5	41.4	39.7	36.9	34.6
Natural Gas	11.5	18.5	20.3	18.1	17.8	18.6	18.6
Hydro[3]	25.1	21.9	21.8	23.8	25.0	25.8	26.0
Nuclear[3]	–	0.1	1.7	3.8	4.1	3.8	5.3
Others[4]	3.7	4.4	4.0	3.5	3.5	4.0	4.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0
				(Petajoules)			
Total energy consumption	4,218	7,402	8,629	9,874	9,631	9,223	9,190
				(Per cent)			
Average annual growth rate		5.8	5.3	1.9	–2.5	–4.3	–0.4

1 Preliminary figures.
2 Includes liquid petroleum gases.
3 Hydro and nuclear electricity measured at 10.5 MJ/kWh.
4 Wood wastes and spent pulping liquor used in industry, and steam energy produced from nuclear sources.
SOURCE Based on data from Statistics Canada and from Energy, Mines and Resources Canada.

Table 7-2

Production and Consumption of Primary Energy, Canada, by Province, 1982

	Production[1]		Consumption[1]		Ratio of production to consumption
	Volume	Distribution	Volume	Distribution	
	(Petajoules)	(Per cent)	(Petajoules)	(Per cent)	
Newfoundland	453	4.5	162	1.8	2.8
Prince Edward Island	–	–	20	0.2	–
Nova Scotia	100	1.0	233	2.6	0.4
New Brunswick	45	0.4	204	2.3	0.2
Quebec	1,048	10.4	2,216	25.0	0.5
Ontario	791	7.9	3,013	34.0	0.3
Manitoba	238	2.4	345	3.9	0.7
Saskatchewan	489	4.9	407	4.6	1.2
Alberta	5,687	56.7	1,231	13.9	4.6
British Columbia	1,165	11.6	999	11.3	1.2
Territories	13	0.1	35	0.4	0.4
Canada	10,029	100.0	8,865	100.0	1.1

1 Hydro and nuclear electricity measured at 10.5 MJ/kWh.
SOURCE Based on data from Statistics Canada.

of primary energy has declined slightly, from around 20 per cent in 1973 to some 19 per cent in 1983. Growth in gas demand was slower than in the 1960s because of a firming-up of prices in the mid-1970s, followed by a more or less systematic linking to the rapidly increasing oil price in subsequent years.

Published statistics show no increases in the consumption share of "other" forms of energy, which are estimated to represent some 4.1 per cent of primary energy. These energy forms include the energy from wood wastes and spent pulping liquor used in the wood and pulp and paper industries, and the steam energy produced from nuclear sources;[1] there are, however, no published estimates of wood use in the residential sector – an increasingly popular option in some regions of the country. The remaining energy sources – solar and wind energy, energy from municipal solid wastes and so on – are not significant at present from an overall perspective.

The Regional Picture

Looking at the energy picture in Canada from a national perspective is deceiving because there are regional variations in both requirements and resources. It is necessary only to note that 66 per cent of total energy consumption is accounted for by the eastern and central provinces, while the West contributes 76 per cent of the total production of primary energy (Table 7-2). The availability and cost of resources has molded the patterns of demand. In the Atlantic provinces and the territories, the developed resources are relatively scarce, and oil, which is purchased from outside sources, accounts for more than 50 per cent of the market (Table 7-3). In Quebec, Newfoundland, British Columbia and Manitoba, the hydroelectric potential has been put to work and meets significant shares of total energy demand. In Alberta and Saskatchewan, natural gas and coal occupy a strong position because they are relatively cheap. Ontario, on the other hand, shows a more diversified demand structure, comprising important amounts of oil, natural gas, hydroelectricity, nuclear electricity and coal.

The problem of oil dependency in the Atlantic provinces has long been a matter for concern among energy policy makers. In 1973, at the time of the first oil price shock, oil represented close to 80 per cent of primary energy in that region. The market share of oil has since declined considerably – to 68 per cent in

Table 7-3

Distribution of Primary-Energy Consumption by Major Energy Source, Canada, by Region or Province, 1973 and 1982

	Coal	Oil[1]	Natural gas	Hydro-electricity[2]	Nuclear[2]	Total[3]	Total consumption[3]
			(Per cent)				(Petajoules)
1973							
Atlantic provinces	6.7	79.5	–	13.8	–	100.0	693
Quebec	1.2	55.6	3.1	40.1	–	100.0	2,142
Ontario	15.3	40.2	22.7	19.7	2.0	100.0	2,867
Manitoba	4.2	39.6	24.3	31.9	–	100.0	330
Saskatchewan	13.1	38.0	42.6	6.4	–	100.0	347
Alberta	8.9	31.9	57.5	1.6	–	100.0	981
British Columbia and Territories	1.0	40.0	25.8	33.2	–	100.0	924
Canada	8.1	46.4	21.1	23.8	0.7	100.0	8,284
1982							
Atlantic provinces	12.1	67.7	–	19.7	0.5	100.0	619
Newfoundland	1.5	51.0	–	47.5	–	100.0	162
Prince Edward Island	2.5	72.8	–	24.7	–	100.0	20
Nova Scotia	23.2	71.9	–	5.0	–	100.0	233
New Brunswick	8.9	75.6	–	14.1	1.4	100.0	204
Quebec	0.8	38.3	5.1	55.8	–	100.0	2,216
Ontario	18.0	35.0	22.9	12.8	11.4	100.0	3,013
Manitoba	1.8	34.1	21.6	42.5	–	100.0	345
Saskatchewan	23.8	38.4	30.7	7.1	–	100.0	407
Alberta	22.0	32.9	43.5	1.6	–	100.0	1,231
British Columbia	0.3	37.6	18.1	43.9	–	100.0	999
Territories	–	82.5	1.1	16.3	–	100.0	35
Canada	11.4	38.4	19.4	26.9	3.9	100.0	8,865

1 Includes liquid petroleum gases.
2 Hydro and nuclear electricity measured at 10.5 MJ/kWh. For Prince Edward Island, hydro represents imports from New Brunswick. This electricity is mostly produced from coal, included in primary energy for New Brunswick.
3 Excludes energy from wood wastes and spent pulping liquor, and steam energy from nuclear sources, which explains why the figures for 1982 are different from those in Table 7-1.
SOURCE: Based on data from Statistics Canada.

1982 – but the region still faces a problem of energy security, since most of the crude oil it consumes is imported.

Only limited energy resources are available to cope with that problem in the short term. Newfoundland, which produces some 17 per cent of Canadian hydroelectricity, has a large hydro potential, but there are few sites left to be developed on the island; most of the remaining potential is in Labrador and not readily accessible to meet Newfoundland's own requirements. Nova Scotia, for its part, has moved to replace oil by indigenous coal for its electricity production. In New Brunswick, coal is also used, but a nuclear reactor has been brought into operation for both domestic use and export. Other resources available in the Atlantic provinces include wood, now used in many homes for heating, and other renewable energy sources. There are greater expectations for the future with respect to the development of alternative energy sources, including the possible exploitation of hydrocarbon resources offshore and of tidal power in the Bay of Fundy. Another possible source of energy for Nova Scotia and New Brunswick would be gas brought in from the western provinces by extending the TQ&M pipeline.

It is in Quebec that perhaps the most significant results, in terms of energy substitution, have occurred over the past decade. There, the oil share of primary-energy demand dropped from 56 to 38 per cent between 1973 and 1982, compensated by an almost symmetrical increase in hydroelectricity, whose share rose from 40 to 56 per cent. However, there has been less success in the province with respect to natural gas. Although the pipeline to Montreal was completed more than 20 years ago, gas still represents only some 5 per cent of primary-energy consumption in that province. Gas transportation costs are largely responsible for this situation. The effects of government efforts to improve the gas potential in the province – the inclusion of Quebec in the eastern tariff zone, the granting of subsidies to distributors and the removal of provincial sales tax – are not noticeable from the 1982 statistics. The federal government and the government of Quebec, however, expect increases within the next few years.

Ontario, the largest consuming province, produces only some 30 per cent of its energy requirements but benefits from access to a variety of energy sources. It buys oil and gas from the West; its electric-power sector and steel industry use imported and/or western coal; its hydroelectric potential is well developed; and, since the early 1970s, nuclear energy has taken an important share of total energy. The Ontario market is, therefore, in a position to respond well to changes in energy prices.

As we move westward to the Prairies, the degree of energy self-sufficiency given by the ratio of primary production to consumption increases. It is 0.7 in Manitoba, which produces mainly hydroelectricity; 1.2 in Saskatchewan, a producer of coal and oil; and 4.6 in Alberta. British Columbia has a ratio of 1.2, arising mainly from the production of hydroelectricity and coal. Consumption patterns in each province are generally parallel with production patterns, but there are exceptions. For example, Alberta uses less oil, in relative terms, than any other province; it exports most of its production outside its own borders and uses natural gas (and coal in the power sector) to meet most of its needs. Similarly, British Columbia, which accounts for some 30 per cent of Canada's total coal production, uses marginal amounts of its coal production and exports almost all of it.

The territories are dependant on oil for more than 80 per cent of their primary-energy requirements and it is doubtful whether a major change can occur in the foreseeable future. Oil is one of the only reliable energy options for the distant regions, as it is easily transported and stored. In some cases, local resources – mostly small hydro stations, but also wood and wind energy – can be useful and economic; their potential, however, is limited.

A Sectoral View

Turning now to the end-use consumption of energy – secondary energy – we distinguish between the residential, commercial, industrial and transportation sectors. Energy use is more or less evenly split between those sectors, ranging from a low of 16 per cent for commercial users to a high of nearly 35 per cent for industrial consumers (Table 7-4). Historically, the distribution of energy among the sectors has not changed much, although the commercial sector (which includes government and institutions) has gradually become more important – a change that reflects structural changes in the Canadian economy.

The sectoral breakdown of energy use by source identifies the kind of energy substitution that has taken place between 1973 and 1982. The more pronounced changes occurred in the residential, commercial and industrial sectors, where the share of oil products in the consumption of secondary energy declined from 37 to 26 per cent. There was sizable growth in electricity and natural gas consumption in the three sectors, with the sharpest increases occurring in the residential sector. There has been, in the process, a decline in the use of coal. As for wood wastes and other alternative sources of energy, which are used in industry, they have retained a relatively stable, and important, share of secondary energy in that sector – now 19 per cent.

Table 7-4

Distribution of Secondary-Energy Demand by Sector and by Major Energy Source, Canada, 1973 and 1982

	Coal[1]	Oil[2]	Natural gas	Electricity[3]	Others[4]	Total	Total demand	Distribution by sector
			(Per cent)				(Petajoules)	(Per cent)
1973								
Residential	0.7	57.6	24.8	16.8	–	100.0	1,154	20.7
Commercial	0.2	37.2	34.3	28.3	–	100.0	785	14.1
Industrial	11.8	26.3	26.5	19.1	16.3	100.0	2,098	37.6
Subtotal	6.4	37.4	27.5	20.2	8.5	100.0	4,037	72.4
Transportation	0.3	99.7	–	–	–	100.0	1,541	27.6
Total	4.7	54.6	19.9	14.6	6.1	100.0	5,578	100.0
1982								
Residential	0.3	35.9	36.7	27.1	–	100.0	1,318	22.3
Commercial	0.1	30.2	40.7	28.9	0.1	100.0	964	16.3
Industrial	9.7	18.7	29.0	23.8	18.8	100.0	2,057	34.7
Subtotal	4.7	26.4	33.9	26.0	8.9	100.0	4,339	73.3
Transportation	–	99.8	–	0.2	–	100.0	1,581	26.7
Total	3.5	46.0	24.9	19.1	6.5	100.0	5,920	100.0

1 Includes coke and coke oven gases.
2 Includes refined petroleum products and liquid petroleum gases.
3 Electricity measured at 3.6 MJ/kWh.
4 Wood wastes, spent pulping liquor and steam energy.
SOURCE Based on data from Statistics Canada.

On the other hand, the transportation sector remains almost totally dependent on oil products. It accounts for about one-half of Canadian consumption of petroleum products, and there is little substitution in progress. Propane is used in some motor vehicles and compressed natural gas is being introduced in some provinces. However, oil products – gasoline and diesel – may remain the best option for automobiles for some time. Similarly, in other modes of transportation – air, rail and navigation – oil products generally have a competitive edge over other potential energy sources.

The Responsiveness of Demand

The changes that have occurred in recent years within the different regions and sectors are evidence that the demand for energy is responsive to prices – as well as to policy, inasmuch as it affects prices directly and indirectly – and to incomes and, more generally, to the level of economic activity. By tracing the history of energy demand and of prices and incomes, it is possible to measure demand responsiveness – in terms of either price or income elasticity – across energy forms, regions and sectors as a means of gaining a better insight into the dynamics of the energy market.

Demand elasticity is expressed as the change in demand that arises from a 1 per cent change in a so-called "independent" variable – here, price or income. The elasticity is positive if demand tends to move in the same direction as the independent variable; it is negative if the contrary is true. Price elasticity is typically negative, because increasing prices translate into decreasing demand; income elasticity, on the other hand, is generally positive.

An elasticity greater than or equal to 1.0 (in the case of income) or less than or equal to –1.0 (in the case of prices) suggests considerable demand responsiveness, whereas an elasticity in the neighbourhood of 0.5 or –0.5 implies a less strong, though still significant, response. When elasticity is zero, demand is unaffected by changes in the independent variable.

Because the market reaction to a change in prices or incomes is not instantaneous, the elasticity of demand can be measured at different points of time – for example, one to two years after the price or income change (short term); three to five or ten years after the change (medium term); or 10 to 25 years after the change (long term). The following discussion focuses on long-term elasticities. Whatever the elasticity, it is important to understand that there can be variation in the measurement of elasticities because different estimation methods can be used and because elasticities can change over time or over price or income intervals. Hence one should, as much as possible, look at ranges of elasticities rather than point estimates.[2]

First, consider total energy demand. Past experience indicates that, over the short term, price changes have a marginal effect on user demands. Over the long term, however, price elasticity is estimated to be in a range between –0.3 and –0.6 (Table 7-5).

Table 7-5

Estimates of Long-Term Price and Income Elasticities of Energy Demand in Canada

	Elasticities	
	Price	Income[1]
Total energy	-0.30 to -0.59	0.96
Sectors		
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 (gasoline)	-0.70	1.10
Rail	-0.10	0.30
Marine	-0.20	0.90
Air	-0.20	3.70
Energy sources		
Oil products	-0.68	0.91
Electricity	-0.57	0.80 to 1.70
Natural gas	-0.33	..

1 Income refers more generally to selected indicators of economic activity – for example, real domestic product, real industrial output (industry), or real disposable income (residential sector).

SOURCE Compiled from various sources by the Economic Council of Canada.

When energy demand is disaggregated by sector of activity or by type of energy, the elasticities are generally higher. This results from the transfers of consumption that occur between sectors or energy sources over time, following changes in relative prices and other market factors. Such transfers cancel out in the calculation of total energy elasticities.

There are several estimates of price elasticity in the end-use sectors. A study done for the Economic Council[3] shows elasticities of about –0.6 in the residential sector; between –0.4 and –0.8 in the commercial sector; and between –0.5 and –1.0 in the industrial sector. In the transportation sector, the price elasticities vary by mode because each mode differs with respect to technology, fuel and fuel prices. Estimates provided by the staff of the NEB show low price responsiveness in marine, air and rail transportation, but an elasticity of around –0.7 in road transportation (gasoline demand).

There are regional differences in the price elasticities of the demand for individual fuels, reflecting the variety of energy resources and needs across the country. In the Atlantic region, the price elasticity of oil is low, because there are limited substitution possibilities. In Quebec, it is generally close to the national average (–0.7), but it reaches –1.0 in the commercial sector, where competition from gas and electricity is strong. Similarly, oil demand is quite elastic in Ontario and the western provinces.

Income elasticities are determined by relating energy demand to selected indicators of economic activity. For total demand, elasticity is generally measured in terms of changes in the domestic product and is estimated to be close to 1.0 in the long run. This is consistent with the fact that, historically, growth in energy demand has been more or less in line with economic growth.

In the residential sector, income elasticity, which reflects the responsiveness of demand to changes in personal disposable incomes, is comparatively low, because heat and light are necessities for all households. Demand is more responsive in the commercial and industrial sectors, where the long-term elasticity – which relates sectoral energy consumption to the corresponding level of economic output – is around 1.0. While the historical relationship suggests that a doubling of output in those sectors would double energy demand, it is generally agreed that with new energy-efficient technologies, growth could be achieved in the future with a less-than-proportional increase in energy demand.

In the transportation sector, the response of demand to the level of economic activity varies from one mode to another. For road and marine transportation, elasticity is estimated to be around 1.0. Energy demand in air transportation is considerably more responsive because air traffic is largely determined by income levels. By comparison, rail is a less responsive sector and its elasticity, in relation to the output of key economic sectors, is some 0.6.

Historically, electricity is the source of energy that has shown the greatest response to economic growth; its income elasticity is generally found to be greater than unity. In periods of economic growth, therefore, the demand for electricity has tended to grow more rapidly than the demand for other fuels.

In sum, a review of the empirical measurement of demand responsiveness confirms that changes in prices and incomes have at least long-term effects on energy users. For some sectors and some fuels, the demand responses can be quite marked. The implication, as in the case of supply, is that policy can influence the market through prices. In most cases, therefore, prices are an efficient means to achieve balance in the market, to stimulate the efficiency of energy use – energy conservation – and to encourage the growth of the most economic forms of energy through substitution.

The review of elasticities also confirms that there is no single equilibrium point in the energy market. The market is in perpetual transition, moving with changes in relative prices, incomes, technology and other market factors. Hence we expect changes to occur in the structure of future markets regardless of the assumptions that are initially set out.

Energy Demand Scenarios

In view of its responsiveness, energy demand is difficult to forecast because there is considerable uncertainty over the future path of prices and incomes. Few forecasters in the past have come close to predicting accurately the present-day situation or the current trends. Energy demand forecasts need to be revised periodically, based on new information relating to both international and domestic markets.

Forecasts of future energy demand are generally based on econometric models used to estimate future demand on the basis of historical data and various "exogenous" assumptions about the economy and government policy. While econometric models are useful tools in helping to predict future demand, they play perhaps an even more important role in helping to identify certain underlying trends and to study the behaviour of demand and its potential reaction to future changes in prices, incomes and other factors.

In order to gain a better understanding of the dynamics of energy demand, we have used the Inter-fuel Substitution Demand (IFSD) model of the federal department of Energy, Mines and Resources. We have attempted to trace general trends in demand by developing three scenarios. For simplicity, all three scenarios assume the continuation of present policies – e.g., made-in-Canada oil prices (set at 75 per cent of the world price in the case of conventional old oil), natural gas prices set in keeping with current agreements (i.e., at a 65 per cent price parity with oil),[4] electricity prices in line with present costing and pricing practices, and so on. However, we consider three different paths for future oil prices. In the reference scenario, we assume that the international price of oil will not change in real terms; the two other scenarios are based on the hypotheses that the price of oil will rise by 5 per cent a year in real terms until the year 2000, or that it will fall by the same proportion. In all three scenarios, economic growth over the period averages 3.0 per cent a year, and inflation is assumed to be 4 per cent a year.

The reference scenario suggests that primary energy demand will be approximately 15,900 petajoules by the year 2000 (Table 7-6), indicating a growth rate of 3.3 per cent a year. Admittedly, this is a relatively high estimate of future demand, but one that is generally consistent with recent EMR projections.[5] We note that part of the growth rate arises from increases in the hydro share of total energy, implying relative increases in the fictitious heat losses imputed to hydroelectric generation. Secondary energy, which excludes these and other conversion losses, grows by 2.8 per cent a year.

If the international price of oil is assumed to rise by 5 per cent a year in real terms, primary demand by the year 2000 is about 11 per cent lower than the level in the reference scenario. Higher prices encourage energy conservation and substitution, but the process is a slow one. This reflects the time required to replace durable goods, improve technology and let markets adapt to new prices.

In the decreasing-price scenario, primary demand in the year 2000 is only 6 per cent above the level in the reference scenario. This limited response shows the continuing effects of price increases in the late 1970s.

The simulations show that substitution among the different forms of primary energy will continue. In our reference scenario, the use of oil declines from 35 per cent in 1983 to 28 per cent by the year 2000. With rising oil prices, the decline is, of course, sharper and the oil market share drops to 25 per cent. With falling oil prices, energy users would have less incentive to move away from oil, but we still find a slight decrease in the relative demand for oil.

The diminished importance of oil in total energy consumption will inevitably lead to greater market shares for one or more of the competing sources of energy. It would appear, however, that if the 65 per cent gas/oil price parity is maintained, there will be little expansion of the market for natural gas: all three scenarios show a relatively constant market share of about 20 per cent. There are certainly technological and economic impediments to the penetration of natural gas in some markets, but we would expect it to perform better if prices were established in the market place.

If the present policies are maintained, the shift is in the direction of more hydro and nuclear electricity. The proportion of these two sources together in

Table 7-6

Energy Demand and Energy Market Shares Under Alternative Scenarios, Canada, 1983 and 2000

	1983[2]	Oil price changes to the year 2000[1] Low-price scenario	Reference scenario	High-price scenario
			(Petajoules)	
Total demand				
Primary energy[3]	9,190	16,910	15,900	14,140
Secondary energy[4]	5,890	10,580	9,350	7,820
			(Per cent)	
Average annual growth rate, 1983-2000				
Primary energy	...	3.6	3.3	2.6
Secondary energy	...	3.5	2.8	1.7
Primary energy fuel shares				
Coal	11	10	10	10
Oil	35	34	28	25
Natural gas	19	20	21	20
Hydro	26	22	25	28
Nuclear	5	11	13	14
Others	4	3	3	3
Total	100	100	100	100
Secondary energy sector shares				
Residential	22	16	16	17
Commercial	16	15	16	16
Industrial	35	37	40	42
Transportation	27	31	28	25
Total	100	100	100	100

1 The low-price scenario assumes a drop of 5 per cent a year in real terms, whereas the high-price scenario assumes a rise of 5 per cent a year in real terms. The reference scenario assumes no change in real oil prices. For electricity prices, the reference scenario assumes a decline of 0.8 per cent a year in real terms; the corresponding figure is 1.1 per cent in the scenario based on declining oil prices, but the real price of electricity is assumed to rise by 0.3 per cent a year in the high-oil-price scenario.
2 Preliminary figures.
3 Hydro and nuclear electricity measured at 10.5 MJ/kWh.
4 Electricity measured at 3.6 MJ/kWh.
SOURCE Estimates by the Economic Council of Canada.

primary energy then rises from 31 per cent in 1983 to a range between 33 and 42 per cent by the year 2000. The increase in hydroelectricity is contingent upon oil prices remaining constant or increasing, but nuclear-generated electricity takes a greater share of primary energy regardless of the oil price, rising from 5 per cent in 1983 to between 11 and 14 per cent by the year 2000. The results are based on the estimation that real electricity prices will decline slightly in real terms over the forecast horizon, under continuation of current policies.

There are also changes to be expected over the next few years with respect to the sectoral distribution of secondary energy demand, which would grow from 1.7 to 3.5 per cent a year, on average. In all three scenarios, the residential sector becomes less important in terms of total demand, while the share of the industrial sector increases from 35 per cent to a range between 37 and 42 per cent, showing its responsiveness to the assumed economic growth rates. There are relatively small changes in the shares of the commercial and transportation sectors.

The analysis of the simulations leads us to reiterate that the energy market is dynamic. The changes in demand occur gradually, sometimes with considerable lags, but generally the market responds to new prices and a new economic environment. At present, the major trend is to move away from oil, because oil products have become relatively expensive in most markets. While gas would appear to be an ideal candidate for replacing oil in most sectors and regions, we emphasize that its market development will be difficult if no revisions are made to gas pricing. In that context, electricity would be in a better position to achieve gains.

Energy Conservation in Canada

Canada is an energy-intensive country. It consumes considerably more primary energy per unit of domestic product than do other developed nations – 12 and 23 per cent more than the United States and the United Kingdom, respectively, and twice as much as Japan, West Germany or France (Table 7-7). This situation, which has prevailed for many years, appears to imply that Canadians are wasteful consumers of energy and that there is much progress to be achieved in energy conservation. Several factors, however, must be taken into account when making international comparisons of energy intensity. Climate and population density immediately come to mind: those two factors alone would explain higher consumption in Canada relative to a number of other countries. Other considerations are the structure of the energy industry and that of the economy as a whole, which is determined in part by the cost of energy.

Table 7-7

Index of Primary and Secondary Energy Consumption Per Unit of Output, Eight Industrialized Countries, 1979

	Primary energy	Secondary energy
Canada	100	100
United States	89	98
West Germany	49	57
France	48	57
United Kingdom	81	88
Italy	63	76
Japan	48	53
Sweden	65	67

SOURCE Bobbi Cain, "International Energy Comparisons: A View of Eight Industrialized Countries," Discussion Paper 222, Economic Council of Canada, Ottawa, December 1982.

Consider, first, the energy supply industry. For the most part, Canada extracts or produces and transforms the energy commodities that it requires; it is also a net exporter of energy. In the process, it uses a good deal of energy. Moreover, there is a relatively large quantity of hydroelectricity produced and consumed in Canada that, when converted to a thermal-energy equivalent – as is done in comparisons of primary energy – implies huge amounts of fictitious heat losses. Most other developed countries import more energy than Canada in relation to their total requirements and/or use considerably less hydro power. Comparisons of primary energy are therefore not fully adequate.[6] If secondary energy per unit of output is used for international comparisons, Canada remains the most energy-intensive country, but the differences with other countries are narrowed.

Canada's high energy intensity is also explained, in part, by the abundance of its resources. Historically, energy has been available at a relatively low cost in this country and the Canadian economy has developed accordingly. The energy-intensive sectors – for example, the pulp and paper industry and the mining and metals sectors, which account for some 50 per cent of Canada's total industrial requirements – represent a major segment of the economy. Moreover, large amounts of goods produced by the energy-intensive industries are destined for foreign markets. Hence a considerable portion of the Canadian consumption of energy is ultimately embodied in goods that are not consumed in Canada but that are exported.

Low-cost energy has also meant that it was not profitable – or that it was less profitable than elsewhere – to conserve energy, to use less energy-intensive machinery, to insulate homes better, to use smaller cars and so on. In this sense, the differences in energy use between Canada and other countries are seen to arise from normal market factors. In those cases, though, where the cost of energy in Canada has been subsidized – for example, in the holding-down of oil prices below world levels and of electricity prices below real costs – it is safe to say that there has been a "waste" of resources. That, however, is a problem caused by policy, not by market behaviour.

Since 1973, there has been an on-going adjustment in Canada, as in most other countries, to higher energy prices. Demand has been lowered and more energy-efficient technology has been introduced. Overall, the consumption of primary energy per unit of economic output (as measured by the real domestic product) dropped by an average of 1.3 per cent a year between 1973 and 1982 (Table 7-8). Energy conservation intensified in all regions of Canada, but to varying degrees. In the Atlantic provinces, a special effort was made because energy conservation is often the only alternative to oil consumption; there, the indicator of energy intensity dropped by 3.1 per cent a year. In the other provinces, with the exception of Alberta, the annual decline in energy intensity has been between 1.0 and 1.5 per cent. In Alberta, the drop was sharper – 2.8 per cent – presumably because of structural changes in the economy.

Table 7-8

Primary Energy Consumption Per Unit of Real Domestic Product, Canada, by Province, 1973-82

	Energy intensities		Average annual decline
	1973	1982	1973-82
	(Megajoules/dollar)[1]		(Per cent)
Atlantic provinces	119	90	3.1
Quebec	95	84	1.4
Ontario	72	66	1.0
Manitoba	83	76	1.0
Saskatchewan	104	91	1.5
Alberta	112	87	2.8
British Columbia and Territories	84	73	1.5
Canada	87	77	1.3

1 In 1971 dollars.
SOURCE Estimates by the Economic Council of Canada, based on data from Statistics Canada and from the Conference Board of Canada.

The measures taken to conserve energy and the results that have been achieved have been different across sectors. Looking, first, at the residential sector, conservation steps have included simple housekeeping measures – more economic use of appliances and lights, the lowering of thermostats, air-tightening of windows and other openings and so on. There have also been more tangible investments in insulation or furnace replacements, paid in part by federal grants provided to homeowners through the Canadian home insulation program (CHIP) and the Canada oil substitution program (COSP). Between 1973 and 1982, those measures added up to a reduction of some 13 per cent in the average energy consumption of Canadian households (Table 7-9).

In the commercial sector, conservation measures have also been mostly concerned with heating, cooling and lighting. Improvements in energy management have been made with technical and financial support from various government programs. To set an example, the federal government reduced its own energy consumption by 18 per cent between 1975 and 1981.[7]

It is difficult, however, to assess energy conservation in the commercial sector because there are no obvious indicators of energy intensity. Using energy per dollar of commercial output as an indicator – others could be energy per square metre of floor surface or per employee – we estimate that a drop of some 9 per cent occurred between 1973 and 1982.

In the industrial sector, energy is used primarily to generate process heat and efforts have focused on the conservation and recycling of that heat. Industrial managers cooperated with government through various industrial task forces to set goals and disseminate information on new technologies and processes. Joint federal-provincial energy audit programs have also been set up to carry out inspections of building insulation and heating and cooling systems. However, energy consumption per dollar of industrial output has fallen by only some 7 per cent since 1973. Most of this saving has been achieved through "quick-fix," inexpensive energy measures. While there is room for more improvements of this kind, there is, apparently, some hesitation on the part of industry to undertake additional investments of a more expensive nature aimed at achieving significant new reductions.

Finally, the oil price increases have had a particularly strong effect on energy demand in transportation. In the automotive sector, for example, easy measures such as speed reduction and car pooling were taken early on; over the longer term, there has been a movement towards smaller, lighter and more energy-efficient vehicles. On average, the drop in energy consumption per vehicle has been 23 per cent.

Clearly, then, while Canadians use relatively more energy than most other nations, their consumption patterns are essentially related to prices and other

Table 7-9

Indicators of Energy Conservation by Sector,[1] Canada, 1973 and 1982

	Energy intensities		Change
	1973	1982	1973-82
	(Gigajoules per household)		(Per cent)
Residential	184	160	-13
	(Megajoules per dollar of real output[2])		
Commercial	16.9	15.4	-9
Industrial[3]	62.8	58.7	-7
	(Gigajoules per automotive vehicle)		
Transportation – automotive sector	116	89	-23

1 Based on secondary-energy consumption.
2 In 1971 dollars.
3 For the industrial sector, the comparison is between the years 1973 and 1981. In 1982, an abrupt decline in industrial output, together with the normal lag in the corresponding demand response, caused the indicator of industrial energy intensity to return temporarily to its 1973 level.
SOURCE Estimates by the Economic Council of Canada, based on data from Statistics Canada.

market factors and do not necessarily reflect wasteful behaviour. Since 1973, prices have increased and energy use has consequently declined; it continues to decline as homes, cars and factories are upgraded or replaced. However, we are still concerned that there may be in the market place problems causing consumers to use still too much energy or to use energy sources that are not the most economic.

The Potential for Conservation and Substitution

Some observers claim that sizable portions of the economic potential for energy conservation and alternative energy sources, in this country and elsewhere, remain unexploited and that this will continue to be the case unless proper policy initiatives are taken.[8] They argue that the barriers to the development of new energy options include not only distortions in the pricing of conventional energy, but obstacles to an effective functioning of the market arising from institutional constraints and lack of information.

To gain a better sense of the economic potential for conservation and alternative energy supplies and to identify the conditions necessary to realize this potential, we have examined the residential, industrial and transportation markets and selected, within each, a set of technologies capable of displacing conventional forms of energy.[9] We have considered space-heating devices for homes, industrial cogeneration, waste heat recovery, energy-from-waste and alternative automotive fuels (diesel, propane, compressed natural gas and methanol).

We have analyzed the competitiveness of these technologies from a social perspective over an investment horizon beginning *in* 1995 – in contrast with other parts of this report, where the horizon is *to* 1995. We find it useful, in this case, to peer into the more distant future because of the time required for the emerging technologies to mature and penetrate the market. Possibly, steps can be taken today to facilitate the timely introduction of these technologies.

By focusing on the social costs, we have excluded taxes and other transfer payments from our calculations. Those are introduced in the discussion, however, when we relate the long-term potential of the technologies to their current market performance.

The cost competitiveness of new energy options in 1995 will be determined largely by the social cost of the traditional forms of energy. The world oil price, in particular, will play a key role. For the investment period under consideration, we use a reference scenario of flat world oil prices in real terms. The assumed price – $\$215/m^3$ in 1981 Canadian dollars – is only slightly higher than the mid-1984 price.[10] We also discuss, in general terms, the effect of increases in the

Space Heating for Homes

Fuel oil, natural gas and electricity are the most widely used forms of energy for space heating in Canadian homes. Wood is also used in an increasing number of homes as a primary or supplementary source of heat.

The *oil* or *gas furnaces* commonly used in our homes are 50 to 75 per cent efficient, which means that on a seasonal average, 50 to 75 per cent of the oil or gas energy will be converted to useful heat. The *condensing gas furnace* is a more energy-efficient device that has only recently become available on the market. It operates at levels of efficiency of up to 95 per cent by condensing and recuperating the flue gases that would otherwise dissipate through the chimney. The condensing gas furnace also uses electrical ignition rather than a pilot flame, to minimize energy losses between combustion periods.

The *heat pump* is another relatively new addition to the residential heating market. It is distinct itself from other heating devices because of its capacity to provide year-round space comfort and of its very high level of energy efficiency. The heat pump is an electrical device that creates a flow of energy by extracting heat from one air source and releasing it to another. In the winter, heat is extracted from the outside air and distributed within the home. The system is reversed in the summer to act as an air conditioner. The heat pump is particularly efficient in the heating cycle because it ultimately delivers more energy than it consumes in electrical input. It will work best in milder climates and is, therefore, better suited for a home in Toronto than in Winnipeg, for example. The heat pump requires a supplementary oil, gas or electric heating unit as a back-up in very cold temperatures. The all-electric heat pump uses an electric heating system as a back-up.

The *central wood furnace* is a third alternative to conventional oil, gas or electric heating. Unlike the wood stove, it is a device designed to take on the larger fraction of the home heat load, although a back-up source – for example, an electric plenum heater – will generally be added on. The use of wood for space heating currently involves some inconvenience, but it could become more practical with improvements in the technology. For example, recently developed furnaces use wood chips or pellets rather than firewood, to allow for a much easier distribution and loading of the fuel. The new systems are at present more expensive, but they are still at a relatively early stage of development. Future cost reductions are likely to materialize with more research and development.

world oil price on the competitiveness of the technologies examined.

We assume that the future value of gas after 1995 will be at an 85 per cent parity with the oil price, compared with the 65 per cent ratio currently used to establish gas prices.[11] Thus we implicitly assume that the present excess supply of gas will have been "drawn down" as a result of lower prices in the interim period but that eventually Canadian gas exports to the United States will pick up, thus firming up prices in the mid-1990s.

The future social cost of electricity depends upon a variety of region-specific supply and demand conditions. At present, the marginal cost is low in several provinces because of a surplus of supply; but demand is increasing, and the situation is likely to change. In Chapter 6, we suggested that the true cost of electricity will be higher than present prices in the long run. Here, we rely on two sets of future regional electricity costs – one corresponding to the present market prices, and the other to the present market prices plus 30 per cent. The analysis assumes a 10 per cent real social discount rate.

Space-Heating Devices for Homes

Among the many options open to homeowners to reduce their energy bills are three alternative space-heating devices: the condensing gas furnace, the electric heat pump and the central wood furnace. The first two are of interest because of their high level of energy efficiency. Wood heating, on the other hand, is mainly considered as a means to displace oil or electricity in rural parts of the country; wood is currently the only viable alternative to the predominant energy options in Canadian homes, with solar energy and geothermal energy showing little promise for the residential sector, at least in this century.

The condensing gas furnace, the heat pump and the central wood furnace compete against conventional oil, natural gas and electric heating. The competitiveness of the different options vary between regions because of the differences in heat load and energy costs (Table 7-10). The supply costs of the competing options include capital, maintenance and energy costs, levelized over the assumed 20-year service life of the investments.

The condensing gas furnace is an option that appears economically promising, with a high cost-saving potential in the Prairie provinces, Quebec and Ontario ranging between 20 and 35 per cent of conventional oil-heating costs and between 10 and 12 per cent of conventional gas-heating costs. The potential for savings is lower in British Columbia (Vancouver) because there the heat load is low and does not justify the additional investment in the more efficient furnace.

The condensing gas furnace seems to be the least-cost option in the Prairies. In Quebec and Ontario, however, there could be competition from electric heating. Electric resistance heating is one option that is used extensively at present in those two provinces. We find, however, that if the social costs of electricity in

Table 7-10

Social Supply Costs[1] of Home Space-Heating Options for 1995, Five Canadian Cities

	Halifax	Montreal	Toronto	Regina	Vancouver
	(Dollars per gigajoule)				
Conventional heating					
Heating oil	16.10	15.70	15.80	14.80	17.20
Natural gas	–	13.60	13.50	10.70	12.40
Electricity					
At current prices	14.40	11.70	11.90	10.50	12.30
At current prices + 30 per cent	18.00	14.50	14.70	13.00	15.00
Condensing gas furnace	–	12.10	12.20	9.50	12.50
Heat pump					
At current electricity prices	11.90	11.40	10.80	10.30	11.90
At current electricity prices + 30 per cent	13.70	13.10	12.10	12.10	13.00
Central wood furnace[2]	14.70	15.40	16.30	13.80	18.30

1 In 1981 dollars. Supply costs include capital, maintenance and energy costs. The initial cost of the heat pump includes a $1,500 credit, approximating the value of a central air conditioner.

2 Costs apply to the rural areas surrounding the five cities.

SOURCE Estimates by the Economic Council of Canada, based on data from Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies."

1995 are higher than present prices – a likely situation – conventional electric heating will be more expensive than natural gas heating – by perhaps some 20 per cent, in the case of the condensing furnace. In this context, and looking at the long term, one would, therefore, favour gas over electric resistance heating, where gas is available.

The electric heat pump can be competitive only if the homeowner is prepared at the outset to invest in air conditioning; our supply costs assume a $1,500 credit off the initial cost of the heat pump to account for such an investment. Under this condition, we identify some potential for the heat pump mainly in southern Ontario (Toronto), where even with electricity costs 30 per cent above present prices, it would be competitive with the condensing gas furnace. There may also be opportunities in some areas of the Atlantic provinces, where the heat pump can be cheaper than oil, and in Quebec, where it is close to natural gas in saving potential.

In rural areas, wood used for home heating is cheaper than oil and potentially cheaper than electricity over the long term. If energy costs rise in the future, wood will become more and more advantageous – provided, of course, a rational use is made of forest resources.

Our research suggests that there are not only long-term, but immediate advantages for homeowners and new home buyers to turn to the condensing gas furnace and, in more narrow segments of the market, to heat pumps and wood heating. Yet the conventional, less efficient gas furnaces continue to go into new homes or to be chosen to replace older furnaces. In some provinces, electric resistance heating and add-on plenum heaters are other favoured options that would appear to be more expensive than the more energy-efficient alternatives in the long run. There could be an argument in favour of the electric plenum heater for the short run in those provinces where there is a surplus supply of electricity and where plenum heaters can be added on to oil furnaces in order to enhance the security of supply. The long-term costs of this strategy, however, in terms of meeting both future energy and load capacity demand, may offset its short-term advantages.

In general terms, the market success of efficient conservation and substitution options for the home appears lower than it could be. We believe that the problem is generally attributable to a lack of information or awareness within the market. Because reliable information can be hard to obtain, consumers are hesitant to put money into investments – such as the condensing gas furnace – that are perceived to be risky, with respect to whether the promised savings will actually materialize, and essentially irreversible. Despite positive signs in the market in recent years, for many homeowners there is doubt that energy conservation investments are duly capitalized in the value of the home. They will often seek very rapid payback on a furnace replacement, rather than lower costs over the longer term. There is a similar attitude on the part of some builders who choose to limit energy-related expenditures in new homes.

Cogeneration

Process steam and heat are required by industry for a wide variety of purposes. For example, hot water and low-temperature steam are used by the food and beverage industries, and medium to high temperature steam and direct heat are used by the pulp and paper, industrial chemicals and primary metals industries. In a typical plant, low-pressure boilers generate steam to meet the requirements of the plant.

Industrial firms also require electrical energy for a number of applications, including motive power and lighting. The electrical energy is typically purchased from a utility.

Cogeneration is a method by which the supply of steam and electricity is combined in an energy-efficient manner. A cogenerating industrial plant generally uses a high-pressure boiler to generate steam that is passed directly through a turbine to generate electricity. The steam ejected by the turbine is then used in the industrial process. Since the steam and electricity demands of the cogenerating plant are rarely matched, a surplus or deficit of electricity supply within the plant generally prevails. Agreements with the local utility are therefore negotiated for the sale or purchase of the net power and/or energy balance.

Cogeneration is a flexible and energy-efficient technology. The cogeneration boiler can use a variety of fuels (natural gas, diesel fuel, waste) and requires a relatively low incremental cost for the generating portion of the equipment. The system converts up to 82 per cent of the energy supplied as fuel to steam and electrical energy for the plant. This compares favourably to a noncogenerating thermal power plant, which will operate at a level of efficiency of about 35 per cent.

Cogeneration will generally be considered by large industrial steam users. For example, the data base used in our study is limited to plants requiring at least 45,000 kilograms of steam per hour. There are fewer than 500 such plants in Canada.

Consumer information is one area where government has taken an active part in recent years. Informational programs will continue to be necessary if we are to take full advantage in the future of opportunities to reduce energy costs. In the residential sector, information can be provided, for example, by suggesting to homeowners and builders energy targets that would show the economically efficient levels of heat losses, depending on the size and location of the home. This could complement, or replace, eventual revisions to the building code. We believe that if the market is well informed and if the price signals are right, consumers will make the right choices. Moreover, programs of direct subsidies to consumers such as COSP and CHIP could eventually be dropped. Some of the funds could be reallocated to research and development or could be used to assist entrepreneurs in the early commercialization of promising technologies. This strategy could also be applied to other markets where, with improved information and improved price signals, consumers could be expected to adopt more readily on their own alternatives to conventional energy supply.

Industrial Cogeneration

In North America, the cogeneration technology has steadily declined in importance since the 1880s, when 60 per cent of the total power requirement was generated in industrial power plants and half of this was cogenerated. At present, the fraction of total electricity produced from cogeneration in Canada is about 1.5 per cent.

The economic viability of a cogeneration project is generally assessed when industrial boilers are to be replaced. Its determination involves a comparison of the cost of a plant with and without the cogeneration facility. Our evaluation of the technology is based on a sample of such data in Canadian industry. The costs of cogeneration vary with the choice of fuel used to supply the incremental energy required in the boilers to produce electricity. In our calculations, we have assumed that natural gas is the fuel used.[12]

The total technical potential for cogeneration in Canadian industry is estimated at some 4,150 MW of power and 29,450 GWh of annual energy (Table 7-11). These measures correspond to 4.9 and 7.8 per cent, respectively, of the total electric power and energy supply in Canada in 1982. Only some 800 MW and 4,900 GWh of the technical potential are currently in place in industry.

Under our assumptions on future gas costs, some 97 per cent of the technical potential for cogeneration could be realized at a supply cost under 4.5 cents per kWh of electricity production; 85 per cent could be supplied for less than 3.5 cents per kWh (Chart 7-2). The competitiveness of the projects depends on the future cost of electricity produced by conventional means. Using present prices as a measure of future electricity costs, only some 20 per cent of the technical potential would be economically viable, which is roughly equal to the potential currently in place. If, however, we assume that electricity costs in 1995 will

Table 7-11

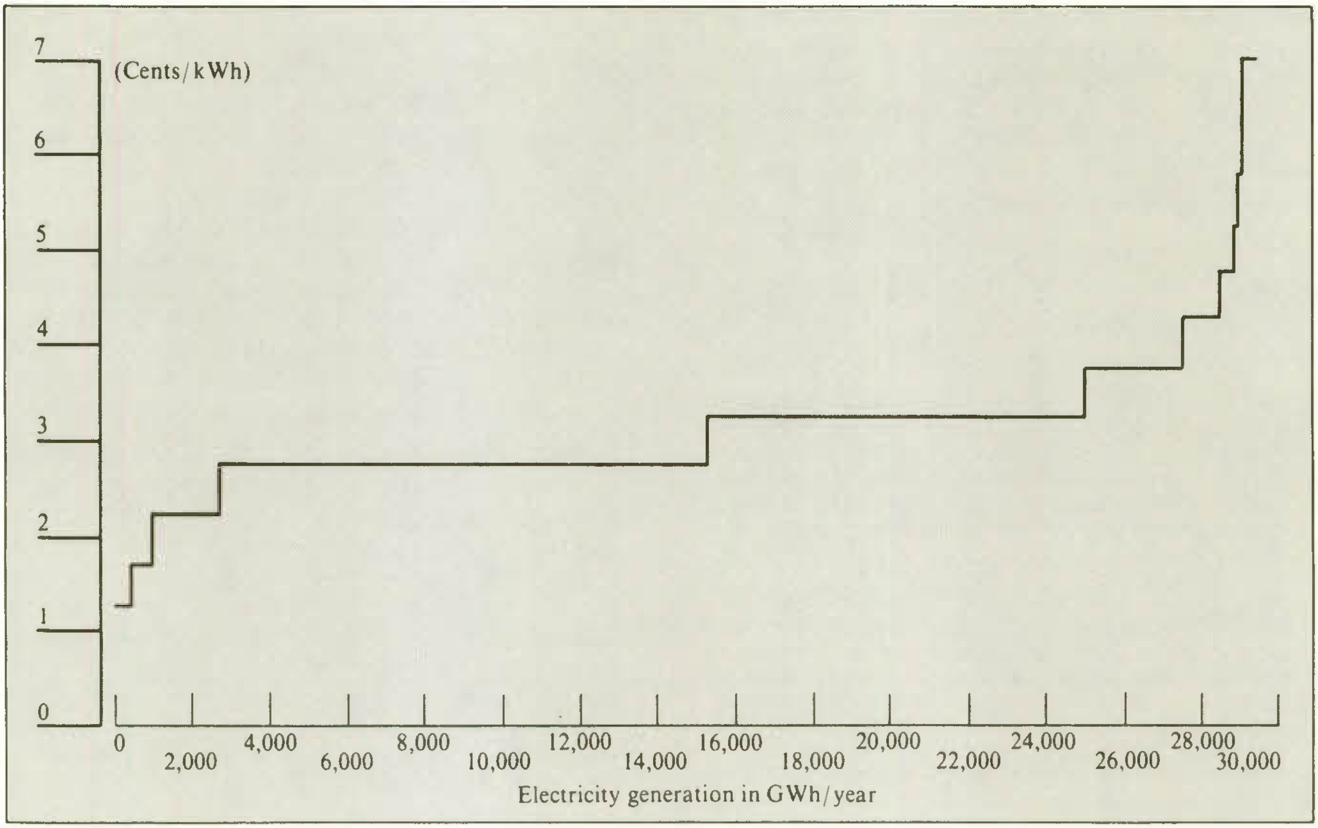
Long-Term Cogeneration Potential, Canada, by Province

		Cogeneration potential					
		At present electricity prices[2]		At present prices + 30 per cent		Total	
	Present electricity price in industry[1]	Power	Energy	Power	Energy	Power	Energy
	(Cents per kWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
Nova Scotia	3.6	220	1,420	220	1,460	220	1,510
New Brunswick	3.3	100	650	130	850	140	900
Quebec	2.6	60	450	560	3,740	670	4,920
Ontario	2.8	190	1,480	1,130	8,600	1,510	10,880
Manitoba	1.9	–	–	–	–	60	450
Saskatchewan	3.0	20	130	40	330	50	360
Alberta	2.4	210	1,730	370	2,970	450	3,280
British Columbia	2.4	40	290	900	6,190	1,050	7,150
Canada[3]	. . .	840	6,150	3,350	24,140	4,150	29,450

1 In 1981 terms; representative mid-1983 prices.
2 Natural gas is assumed to be the incremental fuel for electricity cogeneration.
3 Excluding Newfoundland and Prince Edward Island.
SOURCE Estimates by the Economic Council of Canada, based on Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies."

Chart 7-2

Long-Term Potential Supply and Cost of Cogeneration,[1] in Canada



1 Natural gas is assumed to be the incremental fuel.
SOURCE Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies."

be some 30 per cent higher than at present, the economic potential for cogeneration jumps to about 80 per cent of the technical potential – or 3,350 MW and 24,140 GWh per year. The incremental potential could be phased in over a cycle of industrial boiler replacements – roughly 15 to 20 years.

Under higher oil and gas prices, cogeneration becomes relatively less attractive because it is a fuel-intensive process for generating electricity. Nevertheless, we believe that cogeneration could meet an increasing share of electricity demand in the long run. Of course, the short-term prospects are less favourable because of the prevailing surplus of electricity in most regions. Not only is industry getting relatively cheap power but the utilities are reluctant to buy surplus power from cogenerators – sometimes a necessary condition for the commercial viability of the projects. The market should adjust over time if the surpluses of the utilities are used up and if the prices of electricity increase. The potential will not be fully realized, however, unless investors become well aware of the technology, costs and benefits of cogeneration. The active cooperation and involvement of the utilities will be essential in this regard, as they will be for the set-up of the projects and their connection to the grid. The provincial governments could intervene through their regulatory agencies to ensure that the necessary steps are taken.

A concerted effort by industry, the utilities and government could encourage the adoption of cogeneration technology with a view to increasing the flexibility of supply by the addition of smaller, decentralized generating facilities. We find that similar considerations apply to other, promising small-scale methods of electricity generation, such as small hydroelectric plants. We cannot expect cogeneration or small hydro plants to provide a major share of total electricity supply, but in specific circumstances they can adequately meet the needs of the energy user and should therefore be encouraged.

Waste-Heat Recovery

It is estimated that up to 180 PJ of annual energy used in industry, and subsequently released into the atmosphere in the form of waste heat, could be usefully recovered with existing technology for applications in industry or in other end-use sectors. This is a significant resource, of which a considerable portion is very competitive in price. Indeed, a number of waste-heat recovery projects have already been implemented in virtually all sectors of industry.

Waste-Heat Recovery

Waste-heat recovery refers to the methods designed to capture and put to use the heat streams released from industrial processes. It includes a variety of technologies and applications dispersed across all sectors of industry. The many potential waste-heat recovery projects may be classified as "in-plant" and "interplant" projects.

The *in-plant* projects are the most widely applicable and have the greatest potential to reduce the consumption of energy in industry. They include such measures as steam traps to recover energy as steam condensate for return to the boiler; heat exchanges, including boiler economizers to preheat the combustion air and water supplied to the boiler; vapour recompression; heat pumps to extract heat energy from waste steam or water for low-temperature applications; and cogeneration.

The *interplant* methods of waste-heat recovery are far less common, because they typically face institutional and locational difficulties and/or economic hurdles in the form of high-cost transportation of waste-heat streams. A typical project would be the recovery of heat losses from a thermal or nuclear power plant to provide low-temperature process heat to an industrial manufacturer.

We have evaluated a sample of projects covering a wide range of industries and applications. The typical project is characterized by a low investment cost and correspondingly high energy savings. The average supply cost is as low as $0.84/GJ – well below even the present prices of oil and gas in industry, which range between $1.90/GJ for gas in Alberta to $4.80/GJ for heavy fuel oil in the Atlantic provinces (Table 7-12). The largest fraction of the investments sampled yield supply costs of less than $1/GJ, while the remaining projects are below $5/GJ, a value that may still be less than the cost of oil or gas over the long term. Since the costs of the waste-heat recovery projects are not tied to the level of energy prices, the competitiveness of the projects improves with increases in the price of oil and gas.

We have not attempted to extrapolate the results of our analysis for Canadian industry as a whole. We believe, however, that an important fraction of the technical potential for waste-heat recovery could be economic today and that an even greater proportion could be economic in the long run.

The technology for waste-heat recovery appears sufficiently competitive in the market place today to attract investors. Surprisingly, however, it is often observed that profitable energy conservation investments are overlooked by industry. The adoption of projects is sometimes delayed because managers apply financial criteria that are too stringent. For example, payback requirements ranging from one to three years are often mentioned for energy conservation investments, which is less than would generally be expected from other types of business investments.

Because waste-heat recovery is a well-developed and competitive technology, it would not be reasonable for government to subsidize its introduction into industrial plants. At the same time, however, it appears necessary to take some measures to encourage industry to exploit this low-cost energy potential. Thus we are back to the question of information: it needs to be stressed that conservation investments can be highly profitable and that they should be treated equally with other forms of industrial investment. In our view, information now has to be geared to the financial managers in business who evaluate and select investments and arrange the necessary financing.

As an extension to this, managers might be interested in new financing schemes offered by banks or other institutions. Recently, "incentive financing" packages have been established, whereby loans are granted to industrial investors, subject to a set of conditions, with the provision that annual loan repayments must not exceed the value of the energy saving resulting from the implementation of the project. The object of this condition is to reduce or eliminate the risk perceived by the industrial manager.[13]

Energy-from-Waste

Several types of fuels can be used by industry for the production of process steam. Oil and gas are the most common choices, but electricity and coal are also used in selected regions and industries. In the pulp and paper and wood industries, the use of different forms of biomass – including bark, sawdust, shavings, logging residues and other wastes – has intensified in recent years, with the result that these industries have become virtually self-sufficient in energy.

Municipal solid waste (MSW) is another potential source of energy for steam production but it has been largely ignored until now. The waste generated annually in Canadian urban centres is estimated to hold

Table 7-12

Energy Prices and Costs[1] in Industry, Canada, by Region or Province, 1983 and 1995

	Present prices[2]		Assumed 1995 costs[3]	
	Oil	Gas	Oil	Gas
	(Dollars/gigajoule)			
Conventional energy				
Atlantic provinces	4.80	–	5.30	–
Quebec	4.10	4.00	4.60	5.60
Ontario	4.30	3.80	4.60	5.10
Manitoba	4.10	3.00	4.60	4.60
Saskatchewan	4.10	2.70	4.60	4.00
Alberta	4.10	1.90	4.60	3.80
British Columbia	3.40	2.70	3.80	4.30
Waste-heat recovery[4]				
Supply cost range:	$0.02 – $4.86			
Average supply cost:	$0.84			
Municipal solid waste				
Tipping fee[5]	Supply cost			
$4	$3.75			
$8	$3.50			
$12	$3.00			

1 In 1981 dollars.
2 Representative mid-1983 prices.
3 Based on an oil price of $215/m³, in 1981 dollars, and an 85 per cent gas/oil price parity.
4 Sample of 31 projects.
5 The value of waste disposal per tonne of waste.
SOURCE Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies."

some 170 PJ of primary energy – equivalent to close to 12,000 m³ of oil per day.

The incentives to implement energy-from-waste technology are not only energy-related. The use of municipal solid waste as a fuel is also an alternative to traditional waste landfilling or incineration, which pose environmental problems and are becoming increasingly expensive. In the evaluation of an energy-from-waste plant, the value of waste disposal, or "tipping fee," becomes an important item, entering as a credit in the total costs of the project.

We have considered a prototype MSW plant designed to process 180 tonnes of waste per day. This quantity of waste is typically generated by a population of about 100,000 and is sufficient to meet the steam-energy requirements of a medium-sized industrial user. For a tipping fee of $12/tonne, the estimated supply cost is about $3/GJ. The supply cost increases to about $4/GJ if the value assigned to waste disposal is only $4/tonne.

The supply costs of energy-from-waste are lower than our assumed oil and gas costs for 1995 in most regions, indicating that there is substantial scope for implementation of MSW projects. This will be even more so if oil and gas prices increase. We estimate that by 1995, 120 MSW plants with a daily capacity of 180 tonnes could displace up to 60 PJ per year of oil or gas. A limited number of additional plants, burning wood wastes or other forms of biomass, could also be implemented in the less populated regions, but at a higher cost.

While some technological problems will have to be solved before the energy-from-waste potential can be developed fully, we believe that there are real incentives today to get the technology going. There are, however, institutional factors to address.

One of the potential difficulties with energy-from-waste projects is that they involve a number of parties not necessarily familiar with the technology. The planning and implementation of a steam plant require the cooperative participation of municipal and regional governments, provincial and federal ministries of energy and the environment, equipment suppliers, ratepayer groups and industrial-steam customers. While all parties may express interest in MSW projects, none stands out as a dominant project promoter. For example, municipal and regional governments are responsible for solid-waste management but are hesitant to enter the business of industrial-steam production. Even more hesitation is shown by industry,

Energy-from-Waste

Energy from municipal solid wastes or from other wastes can be used in a variety of ways. Generally, steam is generated in a furnace and then either passed through a turbine for electricity production or directly used as process heat for industry; the two applications can, of course, be combined as cogeneration. In this chapter, we consider the production of process heat.

The technologies available to convert waste to steam energy vary in their form of treatment and combustion of the waste.

In a *mass-burning* plant, the unprepared waste is directly fed into a high-temperature furnace where a grate conveyor system operates during combustion. This technology is most suitable for processing large volumes of solid waste.

Shredded burning is an alternative system that requires the prereduction of waste to particles less than 2.5 cm in size. The shredded waste is blown into the furnace, where it is partially burned in suspension.

A third alternative, *controlled-air incinerator* technology, is designed to process smaller quantities of waste. It is characterized by a two-stage combustion of the waste, with combustion in a primary chamber serving to dry and decompose ("pyrolize") the raw waste. The combustible gases are extracted and passed to a secondary chamber, where the combustion proceeds to completion. The controlled-air system is considered to be the most applicable. It is the system assumed for the prototype plant evaluated in this chapter.

Several other energy-from-waste systems have been developed and successfully implemented in the recent past. The technology is further progressing as research in the area, as in all areas of biomass-energy technology, is intensively pursued in Canada and abroad.

which will often avoid technologies that have not been fully proven.

A possible means of overcoming both the technical and institutional difficulties facing the development of the energy-from-waste potential could be the acceleration of demonstration projects promoted by a multipartite task force dedicated to energy-from-waste technology and project planning. Pilot projects could be financed by governments, but eventually the private sector could take over as experience demonstrated the technical and economic viability of the projects.[14]

Alternative Automotive Fuels

In 1982, the consumption of gasoline amounted to 88 per cent of the total energy demand in road transportation. It also accounted for close to 40 per cent of the Canadian demand for refined petroleum products in the end-use sectors – a fraction that is increasing steadily as the conversion away from oil in the road-transportation sector is proceeding at a slower pace than in the residential, commercial and industrial sectors.

The predominance of gasoline in road transportation is due not to the absence of substitutes but to the lack of competitiveness of the substitutes over the years. Interest in such alternatives as propane, compressed natural gas (CNG) and methanol has grown in recent years, however, following the successive increases in the price of gasoline. Diesel fuel has also been given more attention as an energy-saving alternative to gasoline.

There are many attributes that determine the competitiveness of an automotive fuel. Setting aside the questions of taxes and subsidies, there are the cost of the fuel at the pump, the capital and maintenance costs incurred by the vehicle owner for the use of the fuel (the use of any one of the gasoline substitutes will result in a more or less significant increment in the initial cost of the vehicle), the energy density of the fuel and the efficiency of the related engine. The competitiveness of the fuels also depends on the annual distances driven. For example, the supply costs of gasoline substitutes are generally lower in relative terms for fleet automobiles than for private automobiles because the higher mileage allows for a better amortization of the initial cost of conversion.

We have reviewed the comparative costs of gasoline, diesel, propane, CNG and methanol. Our results shows that, if flat real oil prices are assumed, the conversion of a private automobile to either one of the gasoline substitutes is not economic. The social supply costs (including capital costs) of diesel and propane are 10 to 20 per cent higher than the supply cost of gasoline, which ranges from 30 to 34 cents per litre (Table 7-13). The supply costs for CNG and methanol exceed a level of 40 cents per litre of gasoline equivalent.

The situation, however, is different for fleet automobiles. Diesel is the least-cost fuel in all regions, with supply costs as low as 25 to 28 cents per litre of gasoline equivalent – a 15 to 20 per cent advantage

Automotive Fuels

There are several possible substitutes for gasoline in automotive vehicles. The alternatives vary considerably in their physical properties, costs and levels of development and commercialization.

Diesel fuel is a substitute that is already widely used in heavy transportation. It is an oil product that offers the advantage of being extractable from a heavier cut of the refining process than gasoline. As a consequence, its imputed refining cost is lower than that of gasoline – in our evaluation, we assume 15 per cent lower – and its energy content per unit of volume is higher. The diesel engine is also relatively efficient, with the result that volume savings of some 35 per cent can be achieved over the corresponding volume of gasoline. The diesel advantages are weighed against the additional cost of a diesel vehicle.

Propane is a by-product of natural gas and oil that has recently achieved some level of market penetration as a transportation fuel. On a volume basis, liquefied propane is cheaper than gasoline, but its energy content is lower. At present, most propane vehicles use retrofitted gasoline engines: metal cylinders containing liquid propane are added-on in the trunk of the vehicle, the fuel system is adjusted and the car becomes operational on the new system. (Usually, the retrofitted vehicle can use either propane or gasoline.) Over the next few years, it is expected that vehicles specifically designed for propane will become more common.

Compressed natural gas (CNG) is another gasoline substitute recently introduced on the market. It is natural gas, supplied from the existing network, which is compressed at pressures similar to those used in scuba-diving tanks. The distribution of CNG to the vehicle can take different forms, depending on the needs of the users. The systems currently available in selected Canadian cities use a large compressor and a bank of high-pressure containers to allow for a fast refueling of the vehicles. Another approach, suitable for fleets, uses slow refueling directly from a small compressor. A third alternative, designed for individual homes, is unlikely to be successful in the foreseeable future. The use of CNG currently requires an engine retrofit; vehicles specifically designed for CNG have yet to be produced.

Methanol is a fuel that can be obtained from a variety of substances, including natural gas, coal and wood. It is at present produced in fairly large quantities, but mainly for applications in the chemical industry. Its use as a transportation fuel in North America is limited to selected regions, where it is added to gasoline as an octane enhancer. Methanol is a relatively cheap fuel, but its energy density is only half that of gasoline. This is only partly compensated by the higher efficiency of the methanol engine, with the result that the driving range of the vehicle is more limited. The technology to produce and use methanol is well known. The timing of its introduction on the market, either as an octane enhancer or as a full gasoline substitute, is basically a question of comparative costs.

The other potential substitutes for gasoline are less proven or are considered more expensive. They include, among others, synthetic gasoline, ethanol (a product similar to methanol but produced from a potentially wider range of sources) and hydrogen.

over gasoline. In some of the western provinces, propane and/or CNG are also cheaper than gasoline but more expensive than diesel.

We have assessed the effect of a 50 per cent increase in the price of oil in 1995 relative to 1983, adjusting the supply costs of all fuels. If we first consider private automobiles, an increase in oil prices would favour diesel over gasoline. In view of the relative efficiency of the diesel engine, the diesel supply costs would fall below the increased gasoline supply costs, at levels of 41 to 44 cents per litre of gasoline equivalent. Propane supply costs would fall within the same broad range and would also be lower than those of gasoline. Methanol and CNG supply costs would come closer to gasoline costs, but they would be considerably higher than diesel costs. For fleet automobiles, the ranking of the fuels would remain mostly unchanged under higher oil prices, with diesel remaining the least-cost fuel.

The tax-exclusive evaluation of automotive fuels suggests that diesel has a distinct advantage as a potential substitute for gasoline; it can displace gasoline in fleet automobiles on a cost-effective basis and, under a scenario of increased oil prices, in private automobiles as well. Given the present market situation, however, the owners of fleet vehicles are generally turning to CNG and propane as substitutes for gasoline. Though these fuels may be cheaper than gasoline in some cases, we find them generally more expensive than diesel from the point of view of comparative supply costs.

The current market trend is largely determined by the structure of taxes and subsidies. At present, federal and provincial government policies favour propane and CNG. Grants are available for the conversion of vehicles to either of the two fuels, and fuel taxes are waived in most provinces. By contrast, owners who opt for diesel receive no financial assistance and incur fuel taxes that are at least as high as those on gasoline. In fact, in several provinces diesel is taxed more heavily than gasoline because road taxes are aligned to mileage per unit of volume, which is higher for diesel.[15] The consequence is that the price signals established by

Table 7-13

Supply Costs of Transportation Fuels Under Two Scenarios,[1] Canada, by Region or Province, 1995

	Gasoline		Diesel		Propane		CNG		Methanol	
	A	B	A	B	A	B	A	B	A	B
	(Cents per litre of gasoline equivalent)[2]									
Private automobile										
Atlantic provinces	34	49	37	44	39	47	–	–	46	54
Quebec	32	47	36	43	39	46	47	56	44	52
Ontario	30	45	34	41	36	43	44	54	40	47
Prairie provinces	32	47	36	43	36	43	39	48	41	48
British Columbia	32	47	36	43	40	48	41	50	41	48
Fleet automobile										
Atlantic provinces	34	49	28	35	35	43	–	–	45	52
Quebec	32	47	27	34	35	42	38	47	43	50
Ontario	30	45	25	32	32	40	35	45	39	46
Prairie provinces	32	47	27	34	32	39	30	39	30	46
British Columbia	32	47	27	34	36	44	32	41	39	46

1 A – Reference case; assumes flat real oil prices of \$215/m³ (in 1981 dollars) and an 85 per cent gas/oil price parity.
B – High-oil-price scenario; assumes real oil prices 50 per cent higher than in the reference case; the gas/oil price parity is kept at 85 per cent.
2 In 1981 cents.
SOURCE Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies."

governments at the pump limit the penetration of an efficient fuel – diesel – at the expense of fuels that appear more costly in the social sense.

The present policies can be justified in terms of the objective to reduce gradually the consumption of oil in all sectors of the economy. In the case of CNG, it can also be justified in view of the present excess supply of natural gas. For example, assuming a 50 to 60 per cent gas/oil price parity at Toronto (instead of 85 per cent) for the short term, the supply cost of CNG drops some 6 cents per litre of gasoline equivalent. This makes it competitive with gasoline *and* diesel for fleet vehicles, particularly in the Prairie provinces.

Still, we believe that a reassessment of fuel taxes and conversion incentives is necessary to re-establish a more cost-oriented balance in the market. In effect, subsidies for fuel conversions could be dropped if the relative fuel prices indicated to consumers the more economic options. The emphasis of government programs could be shifted to the longer term, where there may be more sustainable advantages to move away from gasoline or diesel not only in fleet automobiles, but eventually in private automobiles as well. CNG and methanol, in particular, hold promise over the longer term because of the abundance of potential supply. (Methanol is also an attractive option because it can be introduced gradually, first as a blend in gasoline, then on its own.) Some of the funds currently allocated to the commercialization of propane and CNG could, therefore, be better utilized in research programs aimed at longer-term prospects.

Policy Issues

Our analysis of a selection of energy markets has revealed that there are promising energy conservation and substitution technologies in Canada. Many of these technologies already provide attractive investment opportunities for energy users. Several others exist, in all sectors, to displace conventional forms of energy in a cost-effective manner. There are signs, however, that the markets do not always adopt least-cost energy solutions. Problems arise because present energy prices do not always reflect actual costs; because consumers, in a number of markets, are not properly informed; and because institutional barriers or externalities curtail the introduction of promising technologies.

In our opinion, historical distortions in relative prices have been the biggest source of confusion in the market place. Because of pricing policies in Canada – for example, the setting of oil prices below world levels – the incentives for Canadians to move away from traditional forms of energy and towards effective alternatives have been less than they should have been. Adequate pricing, including balanced taxation at the retail level – for example, in the case of transportation fuels – should therefore be our primary concern.

The question of pricing introduces the broader question of market information. Markets can function properly only if sufficient and adequate information is available for the evaluation of competing investments. This condition is not always satisfied in Canadian markets. For example, homeowners are only beginning to be aware of the energy-saving potential of the condensing gas furnace or heat pump. Industrial managers are seemingly neglecting real opportunities to reduce energy costs. The lack of reliable information leads to risk aversion – which, in the case of some projects, can be the major barrier to implementation. In recent years, positive steps have been taken by governments to improve the quantity and quality of information for decision makers. We believe that continued efforts in this direction are required.

We see pricing and information as the priority items in energy conservation and substitution policy. But there are, in some cases, other concerns. The development of some technologies can be difficult because of institutional barriers or other forms of market breakdown. For example, energy-from-waste technology holds considerable promise, but delays are likely to arise because of the number of parties involved and because there are no natural project promoters or coordinators.

In such circumstances, it might be worthwhile for government to introduce different types of incentives. Depending on the stage of development of the technologies, the incentives can take the form of R&D grants, equity investments in demonstration projects, tax write-offs, subsidies and/or lending of capital funds. Assistance, however, needs to be directed only at those technologies which, in selected regions, demonstrate a real economic potential but fail to achieve an adequate level of market penetration. Assistance should also be limited over time and be phased out as markets effect the desired adjustments.

Conclusions

The responsiveness of energy demand to technological, economic and policy factors has been demonstrated throughout Canada's history. Changes in output and income gradually raised the magnitude of energy demand; technological growth and changes in relative prices triggered such movements as the displacement of wood by coal in the early 1900s, and of coal by oil in the late 1950s; and policy initiatives facilitated the penetration of natural gas in many regions of Canada.

But the flexibility of energy demand was perhaps never recognized and understood as much as it is today, 10 years after the first oil price shock. Over the past decade, erratic price fluctuations, varying rates of economic growth, continuing technological advances and the growing intervention of government have brought impressive changes to the patterns of energy demand in all sectors and regions of Canada.

Between 1973 and 1983, the rates of growth in Canada's total energy demand, which had previously fluctuated around 6 per cent a year, showed an average of less than 1 per cent a year. The energy intensity of economic activities declined – for example, by 13 per cent in homes and 7 per cent in industry. Oil became a less dominant part of the energy picture, with a market share declining from 45 per cent in 1973 to 35 per cent in 1983, to the benefit of electricity, gas and other sources of energy.

The concern over the security of energy supply and the cost of energy also drew attention to the many constraints facing energy consumers. In selected areas and sectors, the constraints were severely felt. In the Atlantic provinces, the substitution away from oil proceeded very slowly because the options open to consumers were limited and costly. The situation was similar in the transportation sector, where, despite the many oil price increases, the market share of gasoline and other oil products remained stable. Because of the technological and economic constraints, changes in demand occurred very gradually, even in the climate of crisis caused by the sharp increases in oil prices. The demand adjustments to the price shocks of the 1970s are, in fact, still continuing today, as homes, cars and factories are gradually being replaced or upgraded and as the technology adapts to new economic conditions.

Finally, the experience of the past 10 years has confirmed the ability of government policy to effect changes in consumer attitudes and choices. Massive programs have contributed to the replacement of oil by natural gas, electricity or some alternative energy source in homes and industry, and to energy conservation in all sectors of economic activity. But, in part, government programs have played a role that could have been left to the market if prices had reflected the real cost of the competing energy options. For example, extra efforts were necessary to convince energy users to conserve energy, because prices were kept artificially low in order to meet other government objectives. It is likely that a policy taking greater account of the responsiveness of demand to prices would, to a large extent, have achieved the desired results at a lower cost to government and, in the long run, to consumers as well.

There is certainly a role to be played by government in the molding of energy demand. Markets can work too slowly, sometimes because of a lack of information, sometimes because our institutions have developed in such a way that supply and demand are biased towards certain energy options. Government policy can, therefore, be an efficient factor in leading consumers towards economic energy options. The dissemination of technical and financial information within the markets can be stimulated; financial assistance can be provided, in selected cases, to accelerate the introduction of emerging technologies; and research and development in the many areas of conservation and alternative energies can be supported.

But much of the conservation and substitution potential could be realized without direct government involvement if markets were allowed to function properly – by letting prices adjust to supply and demand conditions and letting consumers, in turn, adjust their demand to prices. A first requirement for policy, therefore, is to recognize fully the capacity of the market to adjust to a changing environment. Government programs can then be implemented, where they can be of economic benefit, to complement or stimulate market response.

Although the future is uncertain, more changes in energy demand will inevitably occur in the years ahead. Oil, gas and electricity will continue to dominate the market for some time, but changes will take place in relative market shares. The demand for oil will tend to decline as natural gas and/or electricity – depending on future prices and policy – penetrate new markets. We also expect that energy conservation and alternative energy supplies – such as cogeneration, municipal solid waste and wood – will play a growing role in the development of a more diversified, more decentralized and more secure energy supply. In the process, government should gradually back off, limit the costly subsidization programs and focus more closely on specific markets and on specific obstacles that may inhibit the response of consumers. The desired changes in energy demand will take place over time. We are convinced that, in the long run, the benefits to Canadians will be greater.

8 The Design of a New Strategy

All of the discussion so far in our report points to one basic conclusion: Canada's immense energy resources, together with the industries that are available to develop them, represent an enormous economic potential for this country. In addition to the reserves presently developed in the Western Canada Sedimentary Basin, there are substantial oil resources remaining to be discovered, developed and produced there, as well as in the North and in the offshore areas. While the costs today are higher than in the past, they generally remain at levels below the present price of world oil. There is an even larger resource base of natural gas that provides long-term economic opportunities in both the domestic and the export market. There is, at present, excess deliverability of gas, but that situation offers opportunities to penetrate new markets, diversify energy use and reduce energy costs. Although extensive hydroelectric development has occurred in the past, Canada still has an impressive volume of hydraulic resources remaining to be harnessed for the production of electricity, both for domestic consumption and for export. Canada also has a very large resource base in coal. Finally, there are opportunities to introduce energy conservation technologies and new forms of energy in a broad range of sectors and applications so as to improve the efficiency of energy use for the benefit of all Canadians – producers and consumers alike.

As suggested in Chapters 4 to 7, a reorientation of energy policies would enable Canadians to take greater advantage of their energy potential, achieve a more efficient allocation of resources and, as a consequence, increase the contribution that energy can make to the development of the country's economy. We have shown that the supply of oil and gas is responsive to the level of financial return that is determined by government. It follows that positive signals provided to industry by government could result in greater investment, discovery, development and production of resources at a cost below their value as established in international markets. In the case of electricity, governments largely act through the management of the large public utilities and the regulation of the private utilities. Through prices, taxes, royalties and a variety of incentive programs, governments can have a substantial influence on both energy demand and supply. Among other things, their actions can have an effect on the level of exploration and development, the intensity of conservation efforts, and the rate of development and adoption of new energy technologies. In addition, policy determines the ground rules for energy exports, which currently provide revenues of almost $13 billion for Canada and a net trade balance of $8 billion. The critical challenge confronting governments, however, is to devise an energy strategy and implement policy measures that, after taking full account of the existing constraints, will result in the most beneficial utilization of Canada's energy and other resources.

The Broader Policy Context

The Canadian economy is quite open in relation to the rest of the world. It is closely linked to the forces of international supply and demand in respect of many goods and services, capital flows and the international transfers of personnel, equipment, expertise and technology that are particularly prevalent in the energy industries. At the same time, Canada is a relatively small trading nation – a situation that has both advantages and disadvantages but that is, in any event, an inescapable reality that Canadian energy policy must take into account. The advantages of openness can be substantial, but difficulties can also arise – especially in the form of instability. This was demonstrated by the adverse side effects generated by the two world oil price shocks and by the exodus of drilling rigs and investment capital from Canada after the announcement of the National Energy Program. Although the abrupt shifts in world energy prices during the 1970s at first put Canadians on the defensive, it has since become clear that, in view of the large net exports of energy, the present world price levels have strengthened Canada's comparative advantage in energy resources. Canadians now have an opportunity to enhance their economic growth in the future by taking advantage of their secure energy supply to develop the domestic market and to exploit the additional potential for energy exports to foreign markets.

An important consequence of Canada's international position is that it is a "price taker" in the world market for oil: neither domestic policies nor domestic oil supply or demand will have a noticeable effect on the world oil price. The real value of Canadian oil production, imports and exports is, therefore, unavoidably defined in the world market. Another important consequence of that fact is that Canada competes with other countries to attract the investment – domestic and foreign – that is required to develop its resources. The mobility of both capital and technical expertise must be taken into account in the design of policy.

Moreover, the fact that Canada shares a border with one of the world's largest consumers and producers of energy is of considerable importance for its energy resources, some of which are more easily tradable in the continental market than on the world scene. This is the case with electricity and, currently, with natural gas as well: their export or import prices are determined primarily by market conditions in the United States. Thus there is a continental, as opposed to a world, context within which the value of gas and electricity is determined. Historically, the United States has been a major market – as well as a major source of capital – for Canada's energy industries, and there is certainly a potential for this exchange to continue. It is necessary, therefore, for Canadian policy to take full account of the prevailing market circumstances in the United States and to respond to those circumstances as they change, in order to achieve the greatest possible benefits from Canada's situation on the North American continent.

While high international energy prices tend to favour this country's comparative trade advantage, government has to face up to the considerable degree of uncertainty that surrounds many aspects of energy supply and demand. A primary consideration is the instability of the world oil market, which results in the risk of sharp price movements – either up or down – and of short-term supply interruptions. There are other sources of uncertainty on both the supply and the demand side, related to the rate of economic growth, the success of exploration for oil and gas, and technological changes in production and consumption. The energy industries generally must cope with long lead times and rely on forecasts that are inevitably imperfect. This can put pressure on the political process, which may be called upon to react as events unfold to take account of the gains and losses to various groups.

As we have seen in Chapter 7, in the past Canada's comparative advantage in energy has been a factor contributing to a high per-capita energy consumption. By itself, this fact has influenced the direction of economic development towards energy-intensive industries. It has also influenced many aspects of the way of life of Canadians – the size of their homes, the design of their cities, their means of transportation and so forth. Their energy resources have significantly contributed to the improvement in their level of income. While they have found in recent years that it is economically and technically feasible to reduce the proportion of energy that is utilized in undertaking many different economic activities, they will continue to require a healthy supply of different forms of energy as the country's economy continues to develop and to enhance their standards of living. Public policy must, therefore, respond to domestic energy requirements and, at the same time, seek to ensure that those demands are met at the lowest possible overall social cost.

Exploiting Canada's energy resources, as we have noted, is not without problems, many of which stem from the divided jurisdiction between the federal and provincial levels of government and the unequal distribution of resource wealth among the country's regions. There is a potential conflict between the principal producing and consuming provinces over prices and between the federal and provincial governments over the management of resources and the sharing of potential resource revenues. While these political circumstances are common, to a greater or lesser degree, to all resources, oil and gas have been singled out because of the high level of economic rent that they have provided in recent years and because of their economic and strategic importance to the economy.

The Strategic Goals

With these realities in mind, the aims of a new energy strategy for Canada become clearer. First and foremost is the objective that has underlined much of the discussion in this report – namely, that policy should enable Canada to realize the greatest possible benefits from its energy potential. In other words, we should seek to manage our resources efficiently. At the same time, there is a heritage from the past that often delineates the scope and/or objectives of public policy. There are, therefore, other goals that have to be integrated in the setting of a Canadian energy strategy. First, policy should aim to achieve a consensus among the many interests of society. In particular, a fair sharing of potential revenues and a clarification of the respective management roles of the federal and provincial governments are necessary conditions. Agreements and protocols setting the rules of the game will require the joint acceptance of a set of principles and the establishment of improved fiscal mechanisms and better means of consultation.

While economic efficiency should be the paramount objective of policy, another important goal that must be taken into account is that of security of supply. Although these two elements are not necessarily in conflict, a high degree of security of supply may be obtainable only at the price of reduced economic efficiency. There are, therefore, trade-offs that must be weighed in the balance. It may be possible to achieve total security of supply only at an unacceptably high cost. On the other hand, it is only prudent to be prepared to absorb such additional costs as may be necessary to reduce the possible impact on the

Canadian economy of a major international oil crisis. Finally, the ownership of the Canadian energy industry is an important consideration of policy. The petroleum industry in this country is largely foreign-owned, which in recent years has led to the adoption of measures aimed at encouraging the participation of Canadians in the development of their oil and gas resources. We believe that increased Canadian participation should remain a policy objective. While maintaining a fair regime for foreign-owned corporations, special incentives should continue to be made available to foster greater Canadian ownership and control.

There are bound to be some conflicts between these objectives, and in implementing policies Canadians must strive for a fair balance between them. The Council believes, however, that in today's circumstances substantial improvements can be made across a broad front in the achievement of these multiple goals. In our judgment, economic growth and development for the benefit of all Canadians – keyed to efficient resource management – should be the primary objective of energy policy in Canada. But the other goals – the security of energy supply, a greater Canadian participation in the energy industries and the sharing of some of the benefits and costs of energy policy among all Canadians – can also be achieved simultaneously. And, although we view the efficient management of resources as the most important issue to be addressed, we are convinced that the question of resource-rent sharing, consistent with the setting of such a management system, has to be examined first.

Sharing the Resource Rents

We all know that Canadian federalism works best in those cases where it has been possible to achieve a reasonable degree of consensus with respect to the formulation and implementation of policy. Because of the division of jurisdiction between them, neither the federal government nor the provinces acting individually are in a position to formulate and implement a comprehensive and cohesive energy policy for Canada. A prerequisite for the achievement of such a policy is the establishment by mutual consent of a framework both for the appropriate sharing of costs and revenues and for the efficient management of resources. Even if such a framework were in place, however, there would still be a need for a forum through which both levels of government can consult periodically on other energy matters. For that reason, we will propose the establishment of a mechanism for an on-going dialogue so as to foster further cooperation between the two levels of governments and possibly between government and other parties interested in energy matters.

The extent to which the economic rent from oil and gas resources should be shared among governments – and, ultimately, among the Canadian people in one way or another – has been a major source of conflict with respect to energy policy in Canada over the past decade. This might not have been a major problem if, at the same time, it had been possible to maintain the efficient management of the energy sector. As our analysis in this report indicates, however, this has not been the case. We believe that the resource rents generated by the exploitation of all natural resources (such as oil and gas, coal and other minerals, hydro power, the forestry, the fishery and so forth), whether owned by the provinces or by the federal government, should be shared among all Canadians. Indeed, it has long been the conviction of this Council that the sharing of costs and benefits is one of the major foundations of Canadian nationhood. Sharing in this country encompasses many activities involving individuals and corporations and takes place quite apart from government activities. What concerns us here is the extent to which the benefits provided by natural resources owned by either the federal government or the provinces should be shared, as well as the type of mechanism that might be developed to provide for such allocation.

Because of the magnitude of the economic rent from the petroleum resources in Canada over the past decade, this issue has unfortunately focused on that sector to the exclusion of other energy resources such as hydroelectricity and of the other natural resources in general. In our view, this single-minded concern over the allocation of oil and gas rents has impeded the development of a cohesive energy policy, curtailed adequate consideration of the broad principles involved in the allocation of resource rents generally and impaired the management of the economy as a whole. In considering these issues, however, it is necessary to view them not just in the context of energy policy but against the much broader background of federal-provincial fiscal relations.

The issue at hand involves two principal elements. The first concerns equity among Canadians across the country with respect to taxation and to the provision of services by their provincial governments. To a considerable extent, these concerns are met through the Equalization Program. The second element pertains to the participation of all Canadians in financing the cost of the nation. This raises the issue of distributing among them, directly or through their respective provincial governments, the taxes required by the federal government to meet its responsibilities and to provide services across the country.

The Equalization Program has become such a central element of federal-provincial fiscal relations that its purpose has recently been enshrined in the Constitution. The stated objective is "to ensure that provincial governments have sufficient revenues to provide reasonably comparable levels of public services at reasonably comparable levels of taxation." The program is meant to address the reality that in Canada all provincial governments do not necessarily have comparable access to revenues because of regional differences in resource endowments and in income levels.

The idea for the Equalization Program originated in the Rowell-Sirois Commission's 1940 report, which recommended "national adjustment grants" from the federal government to certain provinces.[1] While there were elements of equalization built into the tax agreements signed between the federal government and the provinces during the Second World War and the decade that followed, it was not until 1957 that a separate and distinct Equalization Program was introduced. In recognition of provincial sovereignty and diversity, the equalization payments are provided unconditionally: there is no compulsion for the provincial governments to actually provide comparable services. Theoretically, at least, the funds could be used by a provincial government to reduce taxes.

Since its inception, the Equalization Program has been renewed every five years, and it is now part of the Fiscal Arrangements Act, which encompasses other matters, such as federal transfers to the provinces for health and postsecondary education. The program has undergone significant changes in design over the years. Initially, only three revenue sources – personal income tax, corporate income tax and succession duties – were taken into account. In 1962, provincial resource revenues were included. In 1967, the "representative" tax system was adopted as the full range of provincial "own-source" revenues were included. Under the program, the capacity of a province to raise revenue from each of these sources is compared to a standard measure. A province with a lower revenue capacity overall would receive sufficient payments to bring its revenues up to the standard. Since the creation of the program, the trend has been to expand the revenue sources that are taken into account, while lowering the standards. On balance, total payments have increased substantially in real terms over the years.

The program became quite controversial during the 1970s because of the large payment increases resulting from the much greater oil and gas revenues of the producing provinces. To reduce its commitments, the federal government made several *ad hoc* changes designed to reduce the extent to which the equalization payments rose in response to increased provincial natural resource revenues. As a result, questions arose regarding the principles that should underlie the program, particularly with regard to the equalization of natural resource revenues.

In a 1982 report, this Council outlined the broad principles that it believed should inspire the design of the Equalization Program.[2] It agreed that the purpose of the program was to equalize among the provinces the net benefits arising from the fiscal activities of provincial governments. Because natural resources are distributed unevenly among the provinces and because the benefits from provincially owned resources are therefore not available equally to all provinces, the Council concluded that, in principle, these benefits should be taken into account in the Equalization Program when they are received by provincial residents "directly in the form of goods and services and/or tax relief, or indirectly in the form of subsidized prices."[3] Recognizing the provincial ownership of natural resources, the Council proposed the adoption of a second principle:

> [T]he amount of provincial natural resource revenues that is subject to equalization should approximate the federal taxes that would be paid, on average, if resource revenues were distributed to provincial residents and treated as personal income.[4]

In the same year that the Council's report was published, the Equalization Program was changed in several ways by the federal government, in consultation with the provinces. First, the national average standard was changed to a five-province standard that excluded Alberta at the upper end and the four Atlantic provinces at the lower end. Second, most local government revenues were included for equalization. And, third, all revenues from natural resources were once again equalized in full. The first two modifications had the effect of increasing the equalization payments arising from sources other than natural resource revenues. While oil and gas revenues in Alberta are subject to *de jure* equalization by the third change, *de facto* they are not equalized by virtue of the exclusion of Alberta from the standard.

The move to a five-province standard from a national average standard can lead to widely different equalization payments because of the different measures of revenue capacity that can result from the inclusion or exclusion of a particular province in the calculation of the equalization standard. In an extreme case, for example, any increase in oil and gas revenues in one of the Atlantic provinces would result in a roughly dollar-for-dollar reduction in its equalization payments unless the increase were offset by other factors.[5] The Council believes that, in order to address these problems, a return to a national average standard, together with the equalization of only a portion of natural resource revenues, should be considered when the program comes up for renegotiation in 1987.

It is important to understand that while the program has always been financed by the federal government, this need not be the case in order to achieve the objective. In West Germany, for example, transfers are conducted primarily between the governments of the

Länder, and various forms of direct revenue-sharing among the provinces have been suggested for Canada.[6] But if equalization payments are to continue to be financed by the federal government, as they are now, and if, as we recommend, natural resource revenues should play a role in determining the magnitude of the payments, then we believe that the federal government should have access to some share of the provincial government revenues from natural resources in order to achieve the intended redistribution of income among the provinces.

We now turn to the second element that we wish to raise for consideration, that of the distribution among Canadians of the financial costs of the federal government. While the federal government assumes responsibility for the financing of equalization payments, the program is aimed at reducing the disparities between the provincial governments in their capability to provide to their residents the services for which they are responsible. The federal government, however, also has responsibilities for providing other types of services to Canadians. Furthermore, the federal government has the constitutional power to levy any tax to meet its various responsibilities. But this latter power is limited by the section of the Constitution that provides for the mutual exemption of provincial and federal governments from taxation by each other. As a consequence, provincial resource income is exempt from federal taxation; however, the federal government also has authority to set prices in interprovincial and international trade. In such circumstances, the question of what constitutes equity among Canadians across the country seems to require clarification.

In summary, we see two rationales for access by the federal government to provincial resource revenues. The first is to ensure that the federally financed equalization payments brought about as a result of provincial resource revenues will have the desired redistributive effect among the provinces. The second is to ensure that the costs of federal services and activities will be distributed fairly on the basis of ability to pay among Canadians. Therefore,

1 **We recommend that, as part of the discussions leading to the revision of the federal-provincial fiscal arrangements in 1987, the federal and provincial governments enunciate principles and establish mechanisms for the sharing of government revenues from all natural resources.**

What might be involved in such an arrangement? Without either limiting or unnecessarily expanding the matters to be covered, we believe that these discussions should encompass the sharing of economic rents – defined here as the surplus revenues that may be available beyond those sufficient to recover all of the investment and operating costs of the producers, including an adequate rate of return to capital – from all natural resources that have an economic value. It is clear that some resources are more valuable than others at this time, although this relative importance is likely to change in the future. We expect that a revenue-sharing arrangement would have to be brought to maturity step by step, over a period of time, as has been the case with the existing Equalization Program. We would expect the process to start with the most valuable natural resources and to go on progressively to the others.

With respect to the amount of provincial government resource revenue to be taken into consideration in the sharing mechanism, we consider that the yardstick should be the potential revenues – i.e., the pure economic rent – available to the government owning the resources and not necessarily the actual revenues collected. A province, for example, could use any form of levy it chose to collect resource rents and distribute some or all of those revenues as it saw fit; or, alternatively, it could decide not to tap any particular resource revenue source at all. The Council believes that, the resource rent should be collected by the owner. Nevertheless, we also believe that the federal government should have access to an agreed share of these rents, regardless of the policies of the provincial governments with respect to their collection and distribution.

Because rent collection is a major instrument of resource management, such an arrangement would also have the merit of giving the provinces greater latitude to manage the resources that they own as they see fit. While there would be a commensurate reduction in the influence of federal fiscal measures on the management of provincial resources, the access of the federal government to revenues would continue to be protected under the approach we are proposing. Recall that one of the major reasons that led the federal government to eliminate the deductibility of provincial oil and gas royalties – which had been increased by Alberta in 1974 – was that the increase resulted in an erosion of the federal taxbase. The alternative approach that we recommend would give the parties greater freedom to act within their respective areas of responsibility.

Just as we believe that there should be some sharing of provincial resource rents with the federal government, so we believe that there should also be some sharing of federal resource rents from the Canada Lands with the neighbouring provinces and perhaps, the territorial governments. Moreover, the extent to which potential federal revenues from the Canada Lands might be shared with the other provinces as well in a direct fashion, rather than through other federal fiscal measures, could also be addressed in these discussions.

How should the size of these intergovernmental transfers be determined? What principles should govern the appropriate arrangements and what circumstances should be taken into account? We have identified two elements that need to be taken into account: the federal requirement to finance equalization payments, and a fair distribution of federal taxation across the country. Thus the share of provincial resource rents that should be available to the federal government cannot be calculated as a lump sum but as an amount that would vary in relation to the potential rent from the resources involved. In addition, consideration should be given to allowing offsets for certain government costs associated with resource exploration and development and for the enhancement of resource productivity. Moreover, any revenue-sharing agreement must necessarily recognize the interrelationships between the equalization system and the federal and provincial personal and corporate income tax systems. It is, however, beyond our role to articulate fully the factors to be considered; such matters must be left to negotiation by the parties concerned.

We recognize that, given the range of issues to be covered and the need to define principles and procedures, these discussions would take time. It is important to take a long view and, at the outset, to establish reasonable goals with respect to the natural resources that should be included in the discussions as well as to the amounts that should be shared. Initially, at least, there should be a willingness to settle for "rough justice." It is essential, in our view, to bear in mind how the Equalization Program evolved over the years and to consider the time and effort required to collect the data and adjust the procedure over time.

Because of the period that will likely be required to implement fully the new approach that we are proposing, later on we shall outline various changes to the existing fiscal levers of the federal government in the oil and gas sector that might be adopted as an interim measure. The proposed new arrangement should eventually replace these interim measures and should operate in addition to the usual provincial and federal-provincial programs and policies. For example, the provincial governments would retain their existing powers, not only over the collection of resource revenues but also over corporate taxation, while the federal government would continue to exercise its power over international and interprovincial trade and corporate taxation.

We see the prime benefit of the proposed rent-sharing arrangement as being a more resilient and systematic fiscal shock absorber between the federal and provincial governments than is available currently. With this kind of agreement in place, for example, there should be no need for the federal government to resort to other mechanisms – such as the pricing of oil below its economic value – as a means of distributing economic rent across the country nor for a province to acquiesce to such a measure. Thus, as the value of provincial natural resource rents and economic potential shifted over time, the federal government's access to revenue and its capability to finance adjustment programs would move in phase. The provinces whose economies fared less well than others as a result of international changes in natural resource prices would benefit from the federal government's improved capability to undertake regional stabilization and adjustment measures.

As stated above, we are under no illusion as to the considerable period of time that would be required for the full implementation of our proposed approach to resource-rent sharing. In the pages that follow, we outline a number of measures that, in our view, could and should be adopted in the near future to promote greater efficiency in the development of Canada's energy resources. They are measures that we believe to be fully consistent and compatible with the longer-term rent-sharing arrangements that we are recommending.

Resource Management

It is perhaps the area of resource management that is currently most closely intertwined with revenue matters. We foresee that over the longer term a revenue-sharing accord could facilitate a clearer delineation of roles between the two levels of government in the management of natural resources, particularly in the case of oil and gas resources on provincial lands. But improvements in the framework for resource management should begin now.

The sharing of resource rents through intergovernmental transfers is a question that can be dealt with independently of the issues associated with the management of the resources and the ways in which the revenues are collected. It is much more difficult to draw a line between resource management and both the extent and manner in which resource revenues are collected. The concept of resource ownership conveys a responsibility not only for the management of natural resources but also for the institution of appropriate mechanisms to collect the economic rent that may be available from the use of the resources for the purpose of maximizing and distributing fairly the potential benefits among current and future generations. In most cases, the oil and gas resources on which current production is based are owned by provincial governments, although in the case of the Canada Lands the federal government is the owner. In the case of hydro-electricity, the provincial governments, acting directly or through their agencies, oversee the operation and development of their hydraulic resources by both public and private utilities.

The provincial governments recognize and accept responsibility for the management of the natural resources that they own. In the case of oil and gas, for example, the producing provinces have, over the years, developed sophisticated management regimes that evolved in response to changing circumstances and to a growing understanding of the development process. Alberta, the largest oil- and gas-producing province, has created institutions – such as the Energy Resources Conservation Board and the Petroleum Marketing Commission – to establish rules and procedures designed to guide the development of its energy resources. The Board has responsibilities for such matters as the preparation of biennial reviews of oil and gas reserves, the determination of exportable surpluses, the regulation of well spacing and of rates of production to ensure efficient recovery, and monitoring operations to ensure that pollution standards are met and risks of accident are minimized. The federal government recently established the Canada Oil and Gas Lands Administration (COGLA) to undertake similar functions with respect to the management of territorial and offshore areas under its jurisdiction.

As an integral part of managing their oil and gas resources for the benefit of their constituents – present and future – the provincial governments have developed systems for the collection of at least a portion of the economic rent available from the use of those resources. Some part of the rent is passed on to consumers if a resource is sold below its market value. In order to capture the rents that are available to them or that they choose to collect, governments have, in most cases, established fiscal regimes that often involve a system of bonus bids for exploration rights and royalties on production. These regimes are usually tailored to match the varying degrees of profitability involved in different resource developments, recognizing the inherent risks that surround such undertakings and the desirability of encouraging the exploitation of all economically recoverable reserves.

It is clear, as we emphasized in Chapter 4, that any taxes or royalties levied by the federal government or the provinces inevitably affect the rate and distribution of resource development activities and that, as a result, they are instruments of resource management. Although the functions of resource revenue collection and resource management can be distinguished conceptually, revenue collection is, in practice, an integral part of resource management. The reality is that through their respective systems of taxation and royalties, both levels of government have an impact on the management of oil and gas resources within provincial lands.

In our judgment, the owner of any given resource should control the fiscal levers established to collect the pure rents available from that resource. The government with primary responsibility for the management of the resources is in the best position to design and implement an appropriate system – bonus bids and royalties for oil and gas resources, royalties for coal production, water rentals for hydroelectric generation sites, or any other regime. Since most of the natural resources found within provincial boundaries are either owned by the provincial governments or subject to their control, the provinces should collect the resource rents. At the same time, however, both levels of government remain free to levy traditional types of taxes on the income going to the other factors of production – capital and labour. This was essentially the situation that existed before 1973, when stable prices prevailed. However, the respective roles of the two levels of government subsequently became blurred as a result of the upheaval caused by the large price shocks that followed. To sum up our proposal,

2 We recommend that the federal government and the provinces clarify the appropriate areas of responsibility associated with natural resource ownership.

We suggest that, except in emergency circumstances, the government owning the natural resources should have the ultimate responsibility for managing their exploitation and development. This responsibility should encompass the collection of surplus revenues through charges such as bonus bids, royalties and production taxes.

In making this recommendation, it is not our intention to preclude the possibility of the resource owner choosing to share or delegate some or all of its management responsibilities. Rather, we consider that one of the essential elements of our recommendation is that governments should work towards the development of one management authority and one consistent set of rules and regulations. More than one government, however, might be involved in setting and administering such a regime. In fact, we see a number of possible benefits arising from joint participation in management, an example of which is found in the 1982 Offshore Oil and Gas Agreement between Canada and Nova Scotia. We would hope that the governments of Newfoundland and Canada could also conclude an agreement covering the management of the relevant offshore oil and gas resources at an early date.

The Consultation and Policy Process

While the Council believes that a clearer delineation of management responsibilities between the two levels of governments could go a long way towards reducing the areas of contention, there are matters of possible conflict or mutual interest that should be addressed on a continuing basis in the formulation of energy policies. It is clear, as we have shown in Chapters 2 and 3, that under the Constitution the federal government has the authority to exercise powers that ultimately have an impact on provincial resource development in such areas as international and interprovincial trade, the overall state of the economy – as reflected in the level of unemployment, the rate of economic growth and price stability – regional economic balance and national security. In addition to these concerns, the provincial governments must also recognize the national commitments to the international community that are undertaken by the federal government on behalf of all Canadians.

In the crisis atmosphere of the 1970s, the federal government was bound to intervene increasingly in energy policy in an effort to serve what it viewed as the national interest. But that, of course, begs the question as to what form such intervention should have taken. The exercise of federal powers in the national interest can lead to conflict with provincial government resource policy, but it can just as easily serve a mutuality of objectives that could be reinforced by cooperative action. In either case, we see a need for adequate consultation as a prelude to action, whether to minimize conflict or to maximize the benefit from cooperative efforts.

The past decade has, in our view, witnessed a breakdown in the process of consultation between the federal and provincial governments with respect to energy policy generally and to oil and gas policy in particular. Undoubtedly, the spectre of petroleum insecurity around the globe, the perception of an almost endless upward spiral in real oil prices and the shocks that had been administered to Canada's economic and fiscal system by these developments contributed to severe strains on the consultation process. Whatever the cause, these difficulties had devastating effects on federal-provincial relations and on public confidence. We can, and must, do better in the future.

Throughout this past decade, formal channels of consultation existed between the two levels of governments, as well as with industry representatives. In January 1974, a conference of First Ministers dealing largely with energy matters resulted in a new Canada-wide arrangement for oil pricing that superseded the National Oil Policy. A subsequent First Ministers' conference in April 1975 failed to reach agreement on a further increase in domestic oil prices, following the additional hikes in international prices that had been instituted by OPEC. A later increase in domestic oil prices authorized by the federal government encountered a freeze in Ontario. Although regular consultations had taken place between federal and provincial energy ministers during the period 1975-78, that process was allowed to lapse and gave way to bilateral negotiations on specific policy issues. Until 1979, the National Advisory Council on Petroleum (NACOP) brought together senior petroleum company executives for meetings under the chairmanship of the federal minister of Energy, Mines and Resources. Beyond these avenues, a number of other forums existed – many of them long-standing – that provided an opportunity for discussions between federal and provincial authorities at various levels with respect to various forms of energy. None of these processes, however, adequately served the purpose of providing for the close and continuing consultations that should have been held between the two levels of government. In our judgment, it is essential that a mechanism be put into place that will make it possible to re-establish formal federal-provincial consultations on a continuing basis. Therefore,

3 **We recommend that a Council of Federal and Provincial Energy Ministers be established and that it hold formal conferences on at least an annual basis as a means of improving cooperation.**

While informal consultations between the two levels of government have been re-established recently, we consider that all sectors of Canadian society with an interest in energy issues should have an opportunity to contribute to the process of policy formulation. Governments can and do consult from time to time with various groups within their jurisdiction. In order to facilitate the consultation process, however, the proposed council might consider the establishment, for a trial period, of an on-going secretariat to coordinate consultations with other interest groups.

The breakdown in communications between governments and between the public and pivate sectors over the past decade compounded the problems created by the flow of events at home and abroad. Just what impact these forces would have on the oil and gas industries in Canada was, at the time, a matter of considerable uncertainty for all concerned – producers, consumers and governments. The inadequacy of the discussions and consultations among those involved exacerbated that uncertainty. Of even more serious consequence was the fact that drastic changes in policy were frequently introduced without proper consultation, without an adequate understanding of their possible ramifications for the petroleum industry and without provision for an adequate transition period to allow for orderly adjustment to these new measures. Among other consequences, this manner of conducting public affairs heightened the perceived degree of risk under which the industry was operating. This, in turn, added to economic costs because opportunities were forgone or because greater returns or safeguards were demanded as part of the price of undertaking new developments in such an environment. Because of the confrontational atmosphere in which energy policy was being formulated and the lack of trust that was engendered, there was a perceived need to specify all aspects of prospective agreements in great detail. As a result, the policies that were put in place lacked the inherent flexibility necessary to respond to changing circumstances and fostered the creation of an incredibly complex system that entailed excessive administrative and compliance costs. In short, the policy framework did not possess some of the fundamental characteristics that, in our view, should underlie desirable policy formulation.

Looking to the future, we have noted that there is now in place an extensive array of new policies, programs and agreements, some of which are to run for several years. In addition, the oil market appears to be more stable than in the 1970s, although the possibilities of upward or downward price shocks and of supply interruptions have not been eliminated. Moreover, the lessons of the past are fairly clear to all. While the atmosphere has improved in recent years, our concern remains that these shortcomings of the past not be repeated. We suggest that high priority be given in the future to the development of resilient policies that will allow for adjustment to changing circumstances. In addition, adequate transition periods should be provided so that the affected parties can adjust smoothly to the new policy measures and that attempts can be made to implement fiscal regimes and other mechanisms that are as simple and as easy to understand as possible.

Promoting Canadian Ownership and Control

In our review of the history of the energy industry, we have seen that the level of Canadian ownership and control has been of continuing concern in this country for many years. In the electrical sector, Canadian ownership has been achieved primarily through the provincial ownership of the utilities. In the oil and gas sector, the issue of Canadian ownership was first addressed in a major way by the federal government through the creation of Petro-Canada. More recently, under the National Energy Program, the federal government set a target of at least 50 per cent Canadian ownership by 1990 and, as one means of achieving this goal, provided more favourable incentives for exploration on the Canada Lands by firms with higher rates of Canadian ownership. Through the Canadian ownership charge on oil and gas, funds have also been made available to Petro-Canada to expand its operations.

The arguments for increased Canadian ownership and control have economic, social and political dimensions. There has been a concern that Canadian resources and resource development were predominantly under the control of foreign-owned companies whose priorities could be in conflict with Canadian interests. During the insecure and uncertain periods that characterized the international oil market in the 1970, the Canadian government felt that it lacked the instruments it required to provide adequate security of supply for its citizens. At the same time, it lacked the type of accurate information on the oil industry that was relevant to an analysis of petroleum developments and the formulation of policy responses. There has also been a concern that the economic rents from Canadian-owned resources were accruing to foreigners and were subsequently being sent out of the country in the form of increased dividends or that they were being used by the foreign owners to expand either their domination of the oil and gas sector or their ownership and control of assets in other sectors. In other words, it was felt that Canadians lacked the opportunity to participate adequately in the development of their own resources. What was evident was that only government action could change the structure of ownership in the industry in any major way.

It has been argued that increased Canadian ownership is not essential to address many of these concerns. For example, the leakage of economic rent to foreign-owned firms could be minimized by improved fiscal regimes. Canada, as a mature state with well-developed institutions and legislative mechanisms, could ensure that the necessary information is made available by the industry and that the industry conducts its affairs in the national interest. Through their governments, Canadians already own most of the oil and gas resources in the nation and many question the wisdom of purchasing existing productive facilities and equipment in Canada rather than investing in new endeavours.

The level of Canadian ownership and control has indeed risen (see Chapter 3), but it must be recognized that this increase has not been without a price, at least in the short run. The available evidence suggests that the growth of Canadian ownership of the oil and gas industry in recent years has involved a shift of foreign obligation from equity to debt. In addition, many foreign-owned companies came into Canadian hands at a time when equity prices were high and the industry outlook was extremely promising. By 1982 and 1983, however, the detrimental impact of declining oil prices and rising government levies was being severely felt by the purchasing companies. A number of their acquisitions had been made with the help of substantial loans from Canadian banks. These financial requirements had exerted upward pressure on domestic interest rates, which were already on the rise, and downward pressure on the Canadian dollar. Direct interest payments from Canadian industry (mainly the oil and gas sector) to foreign lenders increased tenfold between 1980 and 1982; over the short to medium term, they will most likely exceed the value of the dividend payments that would otherwise be paid to foreign shareholders. Many of the buying companies have encountered severe difficulties in meeting debt payments, and a number of them are still struggling to keep afloat. The nationalistic tenor of the NEP also had the effect of discouraging further foreign investment in the energy sector, ultimately contributing to an overall reduction in industry activity.

In considering these issues, the Council is bound to take account of the mandate it received from Parliament, which states that it must study "means of increasing Canadian participation in the ownership, control and management of industries in Canada." For us, therefore, the central question is how best to achieve this objective under the current circumstances. We see a role for Crown corporations, not only in this regard but also as an instrument for the achievement of other objectives, such as the exercise of increased control in emergency situations and the stimulation and support of frontier exploration and development. More generally, Crown corporations – such as Petro-Canada, the Alberta Energy Company, the Saskatchewan Oil and Gas Company and the Société québécoise d'initiatives pétrolières – can directly strengthen the arm of government and at the same time fully represent Canadians. Some question whether Crown corporations can be as efficient as private companies – a subject that is currently being studied by the Economic Council. It is, however, our preliminary and tentative view that there are a number of advantages to having a Crown corporation such as Petro-Canada operating in the petroleum sector.

Other means could be provided to enable Canadians to participate more fully in the energy sector through private companies. To date, this objective has been fostered through higher rates of grant in the petroleum incentives program (PIP) – a measure that appears to have had mixed results. The high incentive rates are not conducive, in our opinion, to the most efficient use of these funds; moreover, the program discriminates against foreign investment. Perhaps most important, because it is more or less automatic the PIP grant system does not provide a well-developed mechanism that would influence the allocation of this preferential access to Canadian capital to the more successful companies.

If Canadianization through the private sector is to be pursued further, it would be preferable to provide incentives for greater Canadian ownership and participation in the major foreign-owned companies operating in Canada, as well as in Canadian corporations. The purpose of such incentives would be to encourage all Canadians to invest in the equity of any petroleum company operating in Canada and to provide a built-in mechanism that would favour the more successful firms. For example, the federal government currently provides a tax credit for dividends paid by companies incorporated in Canada, as well as a number of other incentives to support Canadian equity investment in firms incorporated in Canada. Dividend tax credits, however, do not provide a strong incentive in the case of start-up or relatively new ventures. Recently, several provincial governments have been offering tax credits for equity capital provided to firms in their provinces. Similarly, the federal government could provide tax credits to Canadians purchasing new equity shares for companies operating in the Canadian petroleum sector. Over the medium term, such a policy would appear to be a reasonable component of any program aimed at achieving greater Canadian ownership of the oil and gas sector. We would hope that the companies involved would take advantage of this measure and support its objective – the foreign-owned companies, by significantly increasing their Canadian ownership; and the Canadian-owned companies, by raising new equity in Canada. We believe that this type of mechanism is preferable to the variable grants for investment that are now available under the PIP scheme. Accordingly,

4 **We recommend that if the policy aimed at increasing Canadian ownership in the oil and gas sector is pursued further, it be supported by incentives for Canadians to invest in the equity of any petroleum company operating in Canada.**

Depending on the mechanisms that are put in place, there is the possibility that this measure would result in the easier access of foreign-owned firms to Canadian equity capital, with no significant increase in the proportion of Canadian ownership and control. Should this turn out to be the case, after a reasonable period of time the federal government should restrict this measure to Canadian companies only. On the other hand, should the program be successful, it could be considered part of a broader policy to promote increased Canadian equity participation in Canadian industry generally.

Under the National Energy Program, the federal government retains a Crown share of 25 per cent in oil and gas activity on the Canada Lands. In the case of exploration expenditures after 1980, this interest is meant to be commensurate with the minimum PIP grant of 25 per cent for exploration, which is available to all companies operating on the federally administered lands. Under the Canada Oil and Gas Act (which applies to the Canada Lands), the minister of Energy, Mines and Resources may, prior to the authorization of a production system, transfer this interest to a Crown corporation such as Petro-Canada or dispose of it by public tender to a Canadian or to a Canadian corporation having a Canadian-ownership rate of at least 75 per cent. In the former case, the Crown corporation can convert this interest into a working interest within 30 days of authorization and thus assume a corresponding share of all subsequent costs. If this conversion option is not exercised by the Crown corporation, then the interest reverts to the federal government and the minister must, as in the case discussed above, dispose of it by public tender as soon as possible.

The Act also requires that a company wishing to obtain and hold a production licence on the Canada Lands be Canadian-owned to the extent of at least 50 per cent, whether by private or public interests (including the 25 per cent Crown share). If this ownership requirement cannot be met at any time, the shortfall may be reserved for the Crown and is to be disposed of by public tender, as above. In the latter case, the overall 50 per cent Canadian-ownership rate for production need not apply.

The Crown share seems to be a reasonable component of the Canada Lands fiscal package and provides the federal government with an option for the active sharing of costs and benefits with private-sector participants. As long as the government carries its share of costs without undue delay in assuming of a working interest, the Crown share appears to be a reasonable and fair way to promote Canadian participation in activity on the Canada Lands. There are, however, several areas where greater clarification is needed and greater flexibility might be warranted with regard to the Canadian-ownership criterion.

An incentive for the purchase of new equity shares, as we have proposed, could increase the availability of Canadian equity capital beyond the stages to which PIP grants currently apply. However, it is not clear what would occur if the Canadian ownership participation, with or without the federal share, were not forthcoming. As a last resort, under the Act the Governor in Council could, for any purpose and under any condition, withdraw the application of the Act to any part of the Canada Lands. The Act does not state what criteria, rules and regulations regarding ownership and other matters to which the Act pertains would then apply. Greater flexibility would be needed within the other sections of the Act so as to avoid forcing the federal government to provide financing – even where, given its other priorities, it might not wish to – in order to meet the ownership criterion for production. On the other hand, greater flexibility could also be introduced into the Act by making it possible for the federal government to reduce its 25 per cent share should financing from other sources be sufficient to meet the 50 per cent Canadian-ownership criterion.

The 25 per cent Crown share provision also applies retroactively to pre-1981 expenditures for exploration in fields declared significant by 1983. The industry was particularly dismayed by the possibility that the federal government might "back in" retroactively on projects where discoveries had been made prior to the NEP and, therefore, prior to the legislation containing the "back-in" provision. This is an issue that the federal government might wish to reconsider.

Security of Supply

The achievement of energy security is an important objective for all governments in Canada. While the security issue is one of the cornerstones of the NEP, it is not a new concern of government energy policy. One of the responsibilities imposed on the National Energy Board when it was established in 1959 was to ensure that the security of domestic energy supply would be fully taken into account before the export of energy resources under the Board's jurisdiction was authorized. In Chapter 3, we also indicated that the theme of oil self-sufficiency in the NEP emerged from the earlier policy goal of energy self-reliance in Canada.

It is with respect to oil that the problem of energy security has the greatest relevance, at least for the next 10 to 15 years. While recent government policy has focused on oil self-sufficiency, the underlying issue – as we see it – is the security of Canada's oil supply and, ultimately, the security of the Canadian economy in general. An overemphasis on the achievement of oil self-sufficiency could lead to costly and unproductive investments if it were to result in the development of petroleum resources that do not yield a net economic benefit for Canada. We believe that the primary goal should be to develop those oil supplies which can be expected to make the maximum contribution to the incomes of Canadians.

The issue of security of supply relates both to short-term interruptions and to possible shortfalls over the longer term. In the short term, the difficulty – to the extent that one exists – arises mainly in the eastern provinces, which are heavily dependent on imported oil supplies.

At present, the amounts of oil involved are relatively small. Not only has the Canadian demand for crude oil decreased, but this country has diversified its sources of international oil supply in the past decade, with the result that only a small proportion of the demand – about 5 per cent, currently – comes from the more insecure supply areas, compared with 20 per cent in 1973. In addition, by 1983 excess inventories equivalent to about 200 days' supply of imports had been built up by industry in Canada.

Moreover, the world oil market is quite different today from what it was a decade ago. There is a substantial excess capacity for oil production within OPEC, and oil stockpiles have been built up in the United States and elsewhere. These circumstances should serve to limit any upward price shocks and compensate for any short-term supply interruptions that might result from political instability abroad.

The Canadian government's emergency planning encompasses the operation of the Energy Supplies Allocation Board (ESAB), which has developed plans, in conjunction with industry, for restraining demand and expanding the availability of domestic supplies to the eastern provinces in the event of import reductions. In an emergency, more oil could be shipped to the Atlantic provinces from Montreal; alternatively, oil could be shipped from the eastern United States in exchange for increased supplies to the midwestern states from western Canada. Prior to the extension of the oil pipeline from Sarnia to Montreal in 1976, Montreal refineries received all of their supplies from abroad, mainly through a pipeline from Portland, Maine. Although about two-thirds of Montreal's supplies are currently obtained from the West, the capacity of the Sarnia-to-Montreal pipeline is, in fact, sufficient to meet Quebec's total needs. The imports through the Portland-to-Montreal line are now maintained at the minimum necessary to keep it operational, as its continuing availability is considered essential to retaining flexibility in the supply system.

In 1979, the Department of Energy, Mines and Resources undertook an internal study of various options for enhancing the short-term security of oil supply.[7] The study concluded that a policy of maintaining shut-in productive capacity in the Western Basin for use during an emergency appeared to be relatively costly. Another option considered was that of increasing domestic oil production during an emergency; the study concluded that production could be increased to above-normal levels for 30 or 40 days but that this could be costly over the longer term because there could be a loss of oil reservoir performance. A storage policy was estimated to be the least costly option. Based on the EMR study, the storage in salt caverns in the Strait of Canso of a full year's supply of oil imports – with imports amounting to nearly 20 per cent of domestic demand – would require a price premium of about 2 per cent on all oil products sold in Canada. A 90-day supply would require a surcharge of only about 0.5 per cent. With the closing of some refineries in eastern Canada, however, the existing storage facilities might be utilized at a lower cost.

To the extent that there is concern over the short-term security of oil supply in eastern Canada, we believe that this problem can best be resolved through the storage of a relatively small volume of oil. Therefore,

5 **We recommend that if additional security against short-term oil supply interruptions is considered desirable, a modest program of storage be instituted, utilizing existing facilities, where possible, in order to reduce costs.**

While such a policy could ensure that there would be no shortage of oil – or, at most, only a minimal one – during an interruption, Canadians should be aware that, as the experience of the past decade has shown, their economy cannot be insulated fully from major supply disruptions or from major fluctuations in the world price of oil. Because Canada is, and will remain, an integral part of the world economy, the most appropriate way to address the problem of the insecurity of international oil supplies in the longer term is to deal with it directly by furthering international cooperation between producing and consuming nations. We urge the federal government to make use of Canada's position as a member of the International Energy Agency to continue to encourage greater cooperation between the consuming nations and the major oil-producing countries, with a view to providing greater stability to the world oil market.

While Canadian oil refining is based mainly on light and medium oil, most of the domestic production of heavy crude oil is exported. Improving the economics of upgrading heavy crude into light oil would also contribute to the enhancement of security of supply. Looking to the longer-term supply potential within Canada, the Council believes that it is in the national interest to continue to encourage exploration for oil supplies that can be economically developed in the frontier regions. We emphasize, however, that this activity should not be at the expense of environmental protection, the safety of workers, the social impact on native peoples or the potential exploitation of less costly oil supplies in the Western Basin. Over a period of several years, the federal government has spent billions of dollars to support exploration activity directed at economically recoverable oil and gas reserves in areas off the East Coast and in the northern frontier regions. We believe that it should, in the national interest, continue these efforts but at a level involving a more moderate investment of public funds. Consequently,

6 **We recommend that over the next five years the federal government continue to provide moderate incentives towards the exploration for oil and gas reserves on the Canada Lands and that the desirability of further incentives be reassessed at the end of this period.**

In considering the means of achieving the objective of the security of oil supply and of energy supply in general, it is important, in our view, to strike a proper balance between the measures aimed at increasing the available petroleum reserves and those aimed at reducing the demand for oil either through conservation or through the substitution of alternative energy sources. In many cases, it is less costly to reduce demand than to increase supply, particularly since such a reduction can represent a continuing source of saving in energy requirements. In the case of oil, the Canadian government has sought to enhance the security of supply by encouraging both conservation and substitution. While the full economic potential for reducing energy demand and using least-cost energy sources should be exploited, we believe that this potential could be realized at a lower social cost than is currently the case.

With the security of energy supplies reasonably assured, Canada would be in a position to develop its export potential in energy. Currently, net energy exports are running at about $8 billion annually. This constitutes a sizeable contribution to Canada's trade balance and to its economy. The positive effects of the energy trade are felt in the form of increased government revenues from royalties and taxation, for example, and in the form of the additional industry output and employment that result from increased levels of activity in many sectors and regions.

The production of energy entails costs other than those involved in producing and delivering energy commodities. For example, costs may be incurred if the rate of depletion of nonrenewable energy resources is accelerated. As these resources are utilized by way of domestic consumption or export, the less costly reserves that make up the resource base are depleted. In the process, the costs that future generations will face in meeting their own energy requirements may be increased, depending in part on future technological advances. Additionally, there are often environmental costs involved in accelerating the production of energy supplies. A major consideration that must be taken into account, with respect to the sale abroad of oil and gas, is whether the economic benefits of such exports outweigh the possible longer-term costs associated with the accelerated depletion of the resource. The problem can be viewed as involving the allocation of energy costs among generations, given the present and projected future costs of energy supply. More fundamentally, the real question is whether production and exports now will provide greater overall benefits than production at a later date.

The issue is made even more complex – particularly in the case of oil and gas – by the unpredictability of future prices. Generally, if resource prices tend to increase more rapidly than the social rate of return that can be achieved by reinvesting the resource revenues – then the resources are better left in the ground in anticipation of higher real benefits in the future. On the other hand, if the social rate of return that can be achieved by reinvesting the resource revenues from current production is greater than the expected increase in real prices, then producing and exporting those resources now would increase Canada's material wealth today and for future generations.

At present, Canada's established reserves of natural gas, as well as the potential additions to those reserves, considerably exceed its own reasonable requirements for many years into the future. In the case of electricity, exports have been rising steadily, and there appear to be many opportunities for further long-term exports at favourable prices. As well, there are continuing opportunities over the medium term for the export of heavy oil, much of which cannot be economically used in Canada. Given the potential of the frontier regions, further opportunities for the export of oil and gas in excess of reasonable Canadian needs may also be available over the longer term.

Canada, a trading nation, is fortunate in having nearby markets to which its valuable energy resources can be exported and in possessing energy resources that can potentially be developed for less than the price received. While we can never be certain, the possibility over the medium term of a major increase in the price of energy seems remote. The benefit that can be obtained from export income, therefore, would seem to outweigh the potential benefit to be gained from the increased value of these resources in the future. In these circumstances, Canadians would be remiss if they did not exploit their export potential in order to provide productive employment opportunities, directly and indirectly, for the many among them who are unemployed.

Before moving on to our recommendations dealing with the oil and gas sector, the electricity sector and the issues of energy conservation, substitution and alternative supplies, we should note that, as part of our deliberations, we had the benefit of an analysis of the interrelationships between the oil and gas sector, the fiscal regimes applying thereto and the economy as a whole. This analysis was based on the MACE model, developed by a team of researchers at the University of British Columbia.[8] The model takes into account many detailed elements with respect to energy demand, oil and gas supply and the set of fiscal measures pertaining to these sectors. All of these components, in turn, are linked to a small model of the economy as a whole, to provide some indication of the mutual interaction between the energy sector and the economy. Using this model, we undertook a wide range of policy simulations pertaining to the oil and gas sector, some of which are reported in Appendix L.

The main lesson suggested by this analysis is that it is possible to strengthen both the economy as a whole and the outlook for domestic oil supply by deregulating the prices of oil and gas and revising the fiscal regimes that currently apply to those resources. It is possible to achieve greater economic growth, less unemployment, lower inflation, a shift in demand from oil to the more plentiful natural gas, increased oil supply – and thus reduced oil imports – all without jeopardizing the level of federal or provincial revenues from this sector. Moreover, most, if not all, of these benefits can be achieved regardless of the future trend of real oil prices – i.e., whether they remain relatively flat or whether they rise or fall.

We recognize that results based on an econometric model inevitably have their limitations. Bearing this constraint in mind, we have also taken a great many other factors into account in formulating the recommendations that follow.

The Oil and Gas Sector

In our review of oil and gas supply in Chapters 4 and 5, we identified as the fundamental issue whether current government policies enable Canada to realize its full economic potential from the development of these resources. While there are many inherent uncertainties, we concluded that policy changes providing for the pricing of domestic oil at world levels, more flexible pricing of natural gas and the establishment of more efficient tax and incentive structures could result in significant increases in Canadian oil and gas production on an economic basis. Our macroeconomic analysis suggested, as well, that these developments could also make a positive contribution to the growth of output and employment in the economy generally, without adversely affecting the revenues from this sector of either the federal government or the producing provinces.

During the 1970s, the increasing cost of finding oil and the restrictive policies adopted by government combined to limit the incentive to industry to explore for new reserves. It was not until the introduction of the "new-oil reference price" (NORP) in 1981 and the subsequent reductions in the levies imposed by the federal and provincial governments that the position of the petroleum industry began to improve. At the same time, however, the structure of PIP grants also had an impact in that it shifted exploratory activity away from the Western Basin to the frontier areas.

As a result of these policies and of the underlying geological and technical conditions in the Western Basin, conventional light oil production over the past decade has been declining, as have the remaining established reserves of conventional crude oil, because the additions to the reserves have not kept pace with production. Under current circumstances and policies, these trends are expected to continue as we approach the mid-1980s. Our own studies suggest, however, that significantly more conventional oil could be produced economically than is currently forecast if some appropriate changes were made in government fiscal policies.

Our review of the oil and natural gas sectors demonstrated that – within the limits of geological, technological and economic uncertainties – the levels of industry activity and of the subsequent output are largely based on expectations of profitability at each stage of the supply process, but especially at the exploration stage. Thus the supply of oil and natural gas is markedly responsive to the fiscal regime in place, which is one of the major ways in which government can affect the level of supply. The fiscal policy of governments can, therefore, significantly improve the potential supply by allowing adequate returns for exploration, development and production.

After examining a number of sources of oil and natural gas, we concluded that there is a wide variation in costs, not only between sources but between individual projects within each source. Bearing in mind the relatively lower outlays required for exploration and the relatively lower risks involved, we found that conventional oil from western Canada is generally the least costly. For the Beaufort Sea and the Hibernia field, our cost estimates are necessarily much less reliable, but they suggest nonetheless that, although the risks would be higher, these sources might eventually yield oil production at unit costs comparable to those of the Western Basin.

We also concluded in Chapters 4 and 5 that the first fundamental step towards the institution of an efficient supply policy was to provide for prices to be established in a way that would encourage the resolution of supply problems. The same theme, with respect to pricing oil and gas at their opportunity values, was central to our policy position in Chapter 7 on energy demand and conservation. Our analysis also led us to suggest that increased attention be paid by government to developing a more efficient system of incentives and taxation.

Pricing

Our views on the pricing of the various forms of energy have been expounded in the preceding chapters. The federal government has authority to establish prices for those energy commodities which move beyond provincial boundaries. Under this authority it has, over the past decade, set prices for oil as well as for natural gas.

The Pricing of Oil

As we have emphasized, the market for oil is international in scope and, ultimately, all energy markets are directly or indirectly tied to the world oil price. Crude oil is easily transported around the globe and can be widely used in many applications. Crude oil is now the price setter in energy markets and will continue to play that role for any practical planning period. Regardless of how Canadians feel about the international price of crude oil and how they perceive it to be determined – i.e., whether by market forces or by cartel arrangement – it is the price that Canadians must pay when purchasing oil on the world market and that they can obtain when selling domestically produced oil on that market.

This Council has consistently recommended in the past that Canadian prices of crude oil be brought up to world levels. We do not believe that crude oil should be sold at home at a price below the international level because such an approach is ultimately costly for the Canadian economy as a whole. It detracts from the prudent use of oil and it reduces the potential contribution that increased oil supplies can make to the economy. Moreover, whatever the reasons may have been for instituting administered prices in the past, they are, in our view, much less relevant today in three important respects. First, while the possibility of short-term supply interruptions has not disappeared, the adequacy of the world oil supply seems likely to preclude a repetition of the price shocks of the 1970s. Second, the federal government now has greater access to oil and gas revenues. Third, users have had several years – and the benefit of generous government financial incentives – to reduce, if not eliminate, oil use in many applications.

A significant element of current pricing policy is the distinction between "old" oil – oil discovered before 1974 – and "new" oil. Such a distinction is inconsistent with the principle that commodities should be priced at their economic value. Quality differences aside, a barrel of oil is essentially a barrel of oil, regardless of its "age of discovery." The distinction between old and new oil becomes counterproductive in terms of least-cost supply as firms concentrate on trying to produce new oil simply to increase their returns, even though the social costs of such supplies may be higher than those of old oil. The distinction can only be sustained at unwarranted administrative and economic costs.

In conclusion, we urge that the present arrangements for administered pricing be discontinued at an early date so as to facilitate the responsiveness of energy demand and supply to the conditions of the energy markets as they evolve. Furthermore, the time is particularly propitious for such a move, because deregulation now would lead to only a marginal increase in Canadian oil prices.

The deregulation of oil prices by the federal government would likely require the cooperation of the producing provinces, particularly Alberta. At present, the Alberta Petroleum Marketing Commission (APMC) markets crude oil production from the province. It purchases almost all oil from producers and acts as an agent for the government's "royalty oil" (royalties received in kind).

In light of the above,

7 **We recommend that cooperative steps be taken by the federal and provincial governments to decontrol the prices of all crude oil as soon as possible and that the present distinction between the wellhead prices of "new" and "old" oil be eliminated.**

We are convinced that a consensus could be reached in support of the deregulation of oil prices if such a move were accompanied by the phased deregulation of natural gas prices – a move that we recommend below. In all likelihood, a marginal increase in the price of oil would be more or less matched, in the medium term, by a reduction in the price of gas. On balance, many consumers would be better off and, where possible, further substitution of gas for oil would be encouraged.

The Pricing of Natural Gas

The current surplus of gas in Canada that is available for delivery to markets at home or abroad is evidence that pricing is the most pressing problem with respect to gas policy. Clearly, the existing system of administered prices is no longer appropriate, and lower gas prices would help to re-establish a situation closer to market equilibrium.

While the lowering of administered prices would be a step towards solving the present problems of the gas industry, more fundamental changes in pricing policy are necessary. We believe that a more responsive and efficient price structure for the domestic market would likely emerge if an opportunity were provided for intensified interaction between the market players. Gas prices should once again be determined by the producers and buyers of gas through contract negotiations.

The deregulation of gas prices should be phased in, with the government continuing to set them over a transition period of about two years, as this would enable the producers and buyers of gas to adjust to the new marketing system and to negotiate the necessary new contracts. This first phase of the gas deregulation policy should be initiated in 1985, when the June 1983 "amending agreement" between the federal government and the Alberta government expires. The gas prices to be set for the period 1985-87 should, as much as possible, reflect the situation of gas supply and demand, as well as the future contract prices that would be negotiated.

In moving to deregulate the price of gas across the country, the price at the Alberta border should not be determined separately but should simply result from the wholesale prices "downstream," after deducting transportation costs. Alberta should be willing to accept such market-sensitive pricing at its border, provided that the federal government move forward to the retail level any taxes, such as the natural gas and gas liquids tax (NGGLT) and the Canadian ownership special charge (COSC), that presently apply between the current Toronto wholesale price and the price at the Alberta border. To sum up the first phase of our proposal, 8 **We recommend that the price of natural gas in Canada be decontrolled and that, through cooperation between the federal government and the provinces, this be done on a phased basis over a period of a few years in order to enable the producers and buyers of gas to negotiate the necessary contracts for the new marketing system.**

The second phase of our gas pricing proposal involves the full deregulation of domestic prices. For a deregulated system to lead to competitive price setting, it will be necessary to ensure that sufficient numbers of producers and buyers have access to the gas market and that pricing at the wholesale level is determined rationally for each distribution point along the transmission system. Structural changes on the buyer side of the market will also be necessary, since the main buyers of gas at present are the transmission companies – one of the most notable being TransCanada PipeLines Limited (TCPL).

Efficient price deregulation requires that TCPL and other pipeline companies compete with many other buyers for the purchase of gas from producers; such other buyers could be regional distribution utilities or, possibly, large industrial users of natural gas. This, in turn, would require that TCPL, which at present owns and operates the only pipeline to the eastern market, transport gas under a regulated tariff on behalf of other buyers. While TCPL could continue to purchase and sell gas in order to honour its present contracts and, eventually, to sell its accumulated stock of gas, the operator of the pipeline should be a neutral party. One practical solution that could be envisaged would be the splitting of TCPL – as well as other pipeline companies – into two companies: a company that would buy and sell gas, and a company that would serve as a contract carrier of gas. The contract carrier could serve all of the authorized buyers who are prepared to negotiate directly with the producers. We encourage governments to examine this possibility as it may take several years for the desired changes to take effect. Accordingly,

9 **We recommend that, in the interest of fostering a more competitive natural gas market, governments consider severing the gas transmission operations of TransCanada PipeLines Limited (as well as other companies in a similar position) from its other activities, or that they consider any other possible changes that would contribute to that objective.**

Full price deregulation would have to be phased in to take into account the existing or renegotiated contracts; and it might come into effect in 1987 or 1988. In addition, we believe that price flexibility would be enhanced by rationalizing the tariff zoning system for natural gas transmission. In particular, as noted in Chapter 5, under the NEP the same tariffs apply in the immense eastern zone, which extends from Georgian Bay to Quebec City and, potentially, to Halifax. The National Energy Board, as part of its responsibility to regulate interprovincial natural gas pipelines, would normally have established tariff zones that tended to reflect relative transmission costs. Even if transmission tariffs were, in fact, more in line with the costs of the pipeline companies, however, the capital cost subsidies granted under the NEP would result in low pipeline tolls east of Montreal. The most economical way to achieve market expansion would then be to allow gas prices to fall in order to reflect the current excess supply. This would make gas more attractive to consumers, providing them with the incentive to adopt it as a fuel and facilitating the task of the distribution utilities that are prepared to extend their networks. Consequently,

10 **We recommend that the federal government, in concert with the National Energy Board, take steps to rationalize the natural gas pipeline tariff system, with special attention to be paid to the problem of the very large eastern zone.**

Federal Government Taxation

The federal government currently levies a series of taxes that spans the entire oil and gas sector – from exploration, production, refining and processing to the retail level. Besides corporate income taxes, there are two major categories of federal taxes: production taxes – which are different for provincial lands than for the Canada Lands – and excise taxes.

Provincial Lands

We have already expressed our conviction that natural resource revenues should be shared among governments and, in particular, that the federal government should have access to some of the revenues from provincial oil and gas production. Pending the conclusion of the kind of sharing arrangement between the two levels of government that we have proposed, the federal government will have to continue to exercise its taxation powers directly.

Given our understanding of the responsiveness of oil and gas supply to changing levels of industry profitability, the ultimate test of an efficient petroleum taxation system is its ability to collect the available economic rents while maintaining sufficient incentives for industry to bring on the maximum supply under conditions of profitability and at the least social cost. Striking just exactly the right balance between these objectives is, of course, not an easy matter. As a minimum, it requires that the fiscal system be relatively simple, explicit and stable and, in addition, that it be as neutral as possible with respect to different types of investment and different sources of supply. Taxes and royalties on resource output should be based on the anticipated profitability of production.

An efficient fiscal system is one that ensures that all projects capable of producing oil or gas at a social cost less than the market-determined wellhead price will go ahead. Such a fiscal system should not undertax profitable projects nor overtax projects with a marginal profitability. If no economic rent exists, the system should recognize that fact and it should be geared accordingly; where resource rents do occur, however, they should be collected by the owner.

Generally, the oil- and gas-producing provinces have developed fiscal systems that, although not perfect, have gone a long way towards meeting the objectives we have just outlined. In Chapter 4, we explained why the inclusion in the fiscal system of bonus bidding for the rights to petroleum lands was extremely useful. This competitive auction process adds an element of resilience to the fiscal regime, especially in view of the uncertainties that surround the full cycle of petroleum activity – exploration (perhaps two years), drilling (another year or two), delineation and development (a few more years) and production (perhaps 20 to 30 years or more). We noted, however, that the oilsands policy might be more explicit and stable. The multitude of special fiscal arrangements for *in situ* oilsands extraction and enhanced oil recovery would also seem to conflict with our criteria of simplicity and stability.

Earlier in this chapter, we suggested that the resource owner should levy royalties, taxes and bonuses that apply to production or land rights and that traditionally serve as a means of collecting resource rents. However, the federal government is currently involved in this type of resource revenue collection on oil and gas production on provincial lands and will probably continue to be until a revenue-sharing arrangement of the type we have proposed is put in place. It is essential, therefore, that the federal government collect revenue in a way that is compatible with efficient production, preferably in cooperation with the governments of the producing provinces.

At present, the main federal taxes at the production level on provincial lands are the petroleum and gas revenue tax (PGRT), the incremental oil revenue tax (IORT) and the corporate income tax.

As it is currently structured for conventional oil and gas production, the PGRT is a rather blunt instrument. It does not fully take into account the differences in cost between the various oil and gas sources, although these differences reflect fundamental geological and economic differences in petroleum supply. As a consequence, the PGRT fosters a misallocation of development efforts among the various sources of supply. Moreover, it inhibits the exploration and development of economically recoverable reserves. As pointed out in Chapter 4, the interaction of increasing supply costs and current federal and provincial fiscal regimes in place in Alberta provides little incentive, on average, for large firms to engage in competitive bidding to obtain land rights for conventional oil exploration. We estimated that investment in the exploration, development and production of conventional new oil in the recent past has provided, on average, a somewhat less-than-normal rate of return. And yet, conventional oil is among the least costly sources of supply available in Canada. The consequence is that conventional oil reserves that could be brought into production at a social cost much lower than the world price remain unexploited. Furthermore, our research has shown that improved returns to the industry would result in increased supplies.

Clearly, then, there is a compelling need for the federal government to restructure the PGRT, particularly as it applies to the supply of conventional oil. A modified PGRT should allow for deductions applying to capital as well as operating costs and thus take account of potential profitability to a much greater extent than is the case at present. In this context, it should be noted that the PGRT has already been modified significantly in its application to enhanced oil recovery projects, including *in situ* oilsands production. The tax is levied only after the eligible capital expenditures on these projects have been recovered from "production revenue." The federal government will have to decide the range of capital cost deductions that is the most appropriate – after consultation, especially with the producing provinces, and after consideration of its revenue objectives, the associated tax rates required and their effect on oil and gas production from the Western Basin.

With a modified PGRT on conventional oil production designed to better reflect relative profitability, there would likely be little need for the IORT. This tax was introduced on 1 January 1982, but its application has since been suspended until 31 May 1985 (except for some oilsands production). The IORT was designed to provide some additional revenue to the federal government, arising from the fact that the price of old oil under the September 1981 agreement was higher than had originally been scheduled in the NEP. Thus the IORT implies a continued distinction between old and new oil. For both of these reasons, we suggest that this tax be eliminated.

What we are suggesting is that, as an interim step, the federal government should modify its system of taxing oil and gas production from provincial lands until the system has been replaced by a general agreement with the provinces on resource-rent sharing. Such a change could best be undertaken with the cooperation of both levels of government. The federal government should seek to adopt a modified tax system that is as efficient as possible; given the reality of federal intervention, this would be in the interest of both the producing provinces and the petroleum industry. To sum up our proposal,

11 We recommend that, as a means of improving the efficiency of the federal system for the taxation of oil and gas production from provincial lands, the incremental oil revenue tax be eliminated. As an interim measure, we recommend that the petroleum and gas revenue tax, as it applies to conventional oil and natural gas production, be modified to provide for the deduction of capital costs as well as operating costs so that it will more closely represent a tax on profitability.

In accordance with our recommendation about crude oil prices, the application of the world oil price to old oil, given the existing royalty structures, would have the effect of increasing the revenues available to both the industry and the producing provinces. But it would also result in an increase of federal revenues from what is now termed old-oil production. However, our proposed modification of the PGRT, by providing for capital cost deductions, would reduce the tax base and tend to reduce federal revenues as well. On balance, depending on the capital cost deductions allowed and on the effect that a more profit-sensitive tax would have in terms of increasing supplies, it may be necessary to provide for a modest increase in a modified PGRT rate in order to maintain federal revenues at the levels that would have prevailed under the current system.

A modified PGRT could also serve an additional purpose over the interim period until our proposed revenue-sharing agreement became a reality. Should a new sharp increase in the world oil price occur during this interval, it would be appropriate for the federal government, in agreement with the provinces, to increase the rate of a modified PGRT as a means of securing a share of the unanticipated windfall revenues. Conversely, in the case of a sharp decline in the world oil price, the rate of a modified PGRT could be lowered, as could the provincial take. In either case, the modified PGRT could serve as a shock absorber to smooth out the excessive instability in the financial position of the industry stemming from fluctuations in the world price. The general price conditions under which such changes would apply should preferably be set ahead of time through agreement between the federal government and the governments of the producing provinces. Accordingly,

12 We recommend that the federal government and the governments of the oil- and gas-producing provinces together determine the general conditions under which the rate of the modified PGRT would be changed in response to major changes in the international price of oil.

With these modifications to the PGRT and with the necessary cooperation of the producing provinces, the federal government should be able to maintain a satisfactory access to oil and gas production revenues in the event of a significant increase in prices. On the other hand, should petroleum prices fall significantly, both the federal and provincial governments must be prepared to accept a balanced reduction in revenues.

In addition to these changes, we believe that consideration should, in the interest of simplicity, efficiency and fairness, be given to progressively eliminating "double taxation" and to avoiding it in the future. Currently, double taxation occurs in the oil and gas sector because both the PGRT and the provincial royalties are not deductible for federal income tax purposes, although the federal government allows the fixed-rate "resource allowance" as a substitute for the deductibility of royalties. As pointed out in Chapter 4, all of the taxes and royalties interact in their impact on industry. The problem of double taxation should be resolved in order to achieve a more efficient system of government levies, aimed at maximizing economically feasible oil and gas development.

Canada Lands

On the basis of the information currently available, the onshore and offshore frontier areas under federal jurisdiction appear to offer considerable potential for oil and gas supplies over the long term. But we see this potential as being complementary to that of the Western Basin rather than a substitute. According to our estimates of possible oil supply costs for the Beaufort Sea and the East Coast (see Chapter 4), the prospects for securing relatively low-cost oil from those areas seem to be reasonably good, although considerable uncertainties remain. On balance, both of these areas should eventually serve to enhance Canada's security of oil supply and, perhaps, also provide for the export of light crude oil in the future.

Progress in developing these supplies will inevitably be slow, however, because of the formidable difficulties posed by drilling in the frontier areas and because of certain engineering problems that remain to be overcome. But the on-going accumulation of information and the continuing advance of technology spur on the effort for the longer term. While the oil potential appears to be significant, the unavoidable delays and costliness of exploration and development necessarily have a profound effect on the potential economic payoff from these activities, whether they are undertaken by private firms or by government. Consequently, the underlying economic conditions are quite uncertain.

Coupled with this problem of intrinsically uncertain economics, which is compounded by the long lead times involved in frontier exploration, has been a degree of ambiguity with respect to the priorities of northern energy policy. In considering the possible course of development of the onshore and offshore frontier areas, there are a number of important considerations to be taken into account. These include the protection of a fragile environment, the minimization of any potentially adverse socioeconomic impact on local residents, the need to develop knowledge about the resource potential of the area, and the pace at which "industrialization" of the frontier areas should be permitted to progress – an issue that cannot be considered without reference to the priority attached to the development of different regions. It is important, therefore, that the federal policy governing these various issues with respect to the Canada Lands be clarified, as should the associated priorities, with an appropriate weight being attached to economic efficiency.

In this latter connection, we believe that the adoption of a number of changes in the fiscal regime that currently applies to oil and gas on the Canada Lands would foster a more competitive and efficient process of petroleum exploration and development. At present, companies are given the right to explore for oil and gas within these territories under federal jurisdiction in accordance with the terms of the agreements negotiated with COGLA on behalf of the federal government. Given the considerable advantages that are attached to the bonus bidding system currently operated by the producing provinces, we believe it would be desirable, at least by the end of this decade, to replace the existing system of negotiated agreements by such a system for the Canada Lands. In the past, it might not have been practical to institute a bonus system of this type, but as more information becomes available it also becomes increasingly feasible and appropriate to adopt it as a means of linking the whole fiscal regime to the realities of the industry estimates of the reserve potential and its expected profitability. Bonuses also have the advantage of providing a means for the early collection of resource revenues by the federal government.

The current taxation regime applying to the Canada Lands consists of a basic royalty of 10 per cent, a progressive incremental royalty (PIR), the PGRT and, of course, income tax. The PIR is currently designed to reflect the profitability of the production from a given oil or gas field, and that makes it an efficient royalty, according to the criteria developed in Chapter 4. The effectiveness of the PIR as a collector of potential economic rent would, however, be hampered by the parallel application of the PGRT and the basic royalty. In addition, while the PGRT may be required for the federal government to collect revenue on oil and gas production from provincial lands where there are provincial revenue-collection regimes in place, it is not essential as a separate tax on production from the Canada Lands, where the federal government has full control of revenue collection. As the PIR is well designed to reflect profitability, there is no need to have a separate PGRT. The 10 per cent basic royalty could hinder the development of economic but marginal reserves, although the application of this royalty is already at the discretion of the Minister. Taking into account all of the foregoing,

13 We recommend that, with regard to the resource revenues from oil and gas activities on the Canada Lands, the federal government:

- **introduce a competitive bonus bidding system for exploration and development leases as soon as the information available and the number of potential companies permit; and**
- **eliminate the PGRT and utilize the progressive incremental royalty as the major instrument for the collection of resource revenues from oil and gas production.**

The federal income tax would, of course, continue to apply to corporate profits.

Excise Taxes

In conjunction with the administered prices of oil and gas under the NEP, the federal government introduced a number of excise taxes on oil and gas and related products at the wholesale level. Effective 1 February 1984, the NGGLT was reduced to zero as a means of maintaining the Toronto city gate price of natural gas at the 65 per cent parity with oil prices provided for in the September 1981 agreement. The petroleum compensation charge is levied on all oil, domestic or foreign, processed or consumed in Canada, as a means of subsidizing the cost of oil at the refinery above the blended domestic price. With the price of crude oil deregulated, the tax would no longer be required for this purpose.

The special charge on all crude oil and prescribed oil products and on natural gas and gas liquids consumed in Canada – the COSC – was introduced to fund the acquisition of some of the Canadian operations of large foreign-controlled petroleum corporations. In February 1984, the minister of Energy, Mines and Resources introduced legislation designed to make the revenues from these taxes available for general purposes; this legislation was not passed, however. The federal government has every right to levy an excise tax on oil and gas and related products to raise revenues for general purposes. Moreover, if Canadianization measures are to be pursued in the national interest, we believe there is no reason why their cost should not be borne by all Canadian taxpayers rather than by just the consumers of oil and gas.

With deregulated oil and gas prices and an appropriately designed PGRT to secure federal revenues from production, there would be little need for the imposition of federal excise taxes at the wholesale level. Indeed, there would be a number of benefits to be gained from imposing taxes at the retail level or as close to it as possible. First, taxes imposed at the wholesale level will, in a deregulated environment, be borne, at least in part, by those who make use of oil and gas as part of the production process. In the case of industrial consumption – and particularly in the case of the petrochemical industry, where oil and gas account for a major proportion of the cost of production – this will reduce the international competitiveness of producers. Second, a tax at the retail level can serve as a relatively efficient charge in the case where benefits are roughly in line with consumption. For example, a federal or provincial tax on motor fuels could be used to support the construction and maintenance of roads, while such a tax would not be appropriate for heating fuels. Third, it should be noted that taxes at the retail level can be adjusted to influence the relative rates of consumption of various products in line with other objectives of public policy – such as shifting consumption from oil towards natural gas, for example.

Generally speaking, moving taxation away from the wholesale level and closer to the retail level might tend to raise administrative costs because more sales units would tend to be involved. But as some of the federal excise taxes already in effect are close to the retail level, the proposed removal of the taxes at the wholesale level would likely result in reduced administrative costs.

In the event of a compelling need by the federal government to intervene in order to influence the oil and gas markets at some future time, hopefully for only a relatively short period, these retail-level taxes, together with the PGRT and the income tax at the production level, could serve as a set of instruments for such intervention. For example, if oil prices were to fall precipitously, the federal government could, during an uncertain period, prevent consumer prices from falling at the same rate by increasing retail-level taxes. Industrial users could, however, remain competitive with foreign producers. At the same time, the federal government's increased revenue at this level could offset the reductions in the PGRT and income tax that would be required to maintain adequate returns to domestic oil and gas producers. Similarly, if oil prices rose notably, retail taxes could possibly be lowered somewhat to soften the impact, and the increase in PGRT and income tax revenues could be used to finance adjustment programs, for example, in part through temporary tax credits to low-income households. In light of the foregoing,

14 We recommend that, in conjunction with the deregulation of oil and gas prices, the federal government move forward to, or towards, the retail level any and all excise taxes designed to collect revenue from the producers or industrial users of oil and gas and related products.

Federal Exploration Incentives

Ideally, government policies should not attempt to promote one source of oil or gas supply over another; rather they should allow geological and economic realities to dictate the allocation of exploration, development and production activity. Recognizing that the risk in exploration can be very great and that there are benefits for the whole country from enhancing domestic supplies, the federal government for many years has chosen to share some of this risk by providing exploration incentives. At the time of the National Energy Program, one of these incentives was referred to as the "depletion allowance" and took the form of an additional percentage deduction of qualifying capital cost for income tax purposes.

Revenues from current production must be available in order for the maximum benefit of this form of incentive to be realized. The government was concerned that the extent of the benefit available through the tax system depended on the corporate taxable position – and thus, predominantly, on revenues from current oil and gas production. As a consequence, already established large producers, mainly foreign-owned, were being favoured over newer and smaller Canadian-owned companies that lacked sufficient taxable income to take full advantage of such tax incentives. It was for this reason that the depletion allowance was phased out for exploration and development and that it was ultimately replaced by direct grants under the PIP scheme, introduced in the NEP. As noted previously, the PIP system involves variable grant rates that favour exploration on the Canada Lands over provincial lands and that favour companies with greater rates of Canadian ownership. We have already dealt with the latter aspect and now address the question of federal exploration incentives.

Provincial Lands

Just as the form and level of taxation by the federal government as it applies within the provinces will inevitably influence the pace and allocation of industry activity, so will the federal government's exploration incentives also influence exploration and, in all likelihood, the subsequent development and production. Therefore, these incentives also influence the management of provincial oil and gas resources.

While a bonus bidding system provides a mechanism for governments to obtain resource revenues in advance of production and, in this way, to shift the risks to explorers, exploration incentives, on the other hand, involve a sharing of costs and risks by governments and thus tend to increase the rate of exploration activity. Since the bonus bids act as a shock absorber, it can also be expected that where there is a competitive bidding process, a part of the benefits from exploration incentives may simply be reflected in the value of the bonus bids. As a result, the provision of federal exploration incentives may result partially in a government-to-government transfer in the case where bonus bids for land rights go to provincial governments. This is one reason why the federal government reduced the maximum annual rate of deduction of land acquisition costs from 30 to 10 per cent for income tax purposes in 1979. In any case, federal incentive programs have direct implications for resource management; it is for this reason, among others, that the government of Alberta operates and funds its own PIP scheme within the province.

We recognize that the federal government, through the income tax system and a host of other policies, has an impact on provincial oil and gas developments. Thus our recommendations on management and consultation were designed to disentangle resource management responsibilities and to encourage cooperation in those policy areas which inevitably interact. Consistency with this approach raises the question whether the federal government should be involved, in a general and continuing way, in the provision of special incentives for oil and gas exploration and development on provincial lands. By special incentives, we are referring to incentives, such as grants, tax credits or favourable income tax rates, that are not generally provided to other sectors – particularly those having similar characteristics – and to the allowance for income tax purposes of deductions above and beyond those representing reasonable costs incurred for the earning of income.

We also recognize, however, that the federal government may have a specific interest in promoting the development of certain sectors, regions or new technologies and that it may deem it desirable to provide support in cooperation with the provincial governments. The latter would likely welcome such support, particularly if the financial requirements involved were beyond their capability.

We would suggest, therefore, that the federal government and the provinces consider an approach whereby the latter would be the primary level of government involved in the funding of special oil and gas exploration and development incentives that are widely available on their own lands. It would follow from such an approach that the federal PIP scheme on provincial lands other than in Alberta would be phased out, that the existing grants would be "grandfathered" and that after some predetermined period, no new federal grants would be provided for activity on provincial lands. The federal government would have to consider some corresponding reduction in its revenue from that sector.

In line with this approach, the federal government would limit its special incentives for activities on provincial lands to cases involving special interests, such as regional development or certain technologies, or to situations that might be beyond the financial capability of provincial governments. Federal support should preferably be undertaken in cooperation with the provincial government concerned. All governments should be aware that if they are not prudent with respect to the level of incentives they provide, they could be assuming an excessive proportion of costs and risks, while accelerating activity beyond its economically viable level, with consequent costs to the economy.

Canada Lands

In recommendation 6, we suggested that the federal government should, at least for the next five years, continue to provide exploration incentives on the Canada Lands. As pointed out previously, the grants available under the PIP scheme for activities on the Canada Lands – up to 80 per cent of exploration costs for companies with the required degree of Canadian ownership – are very high, both in absolute terms and in relation to the level of grants available for exploration on provincial lands. We believe that this has tilted activity excessively towards higher-cost and riskier sources of supply and led to very large expenditures by the federal government. As we have recommended that the incentive for increased Canadianization ownership be provided through means other than the PIP grants, the rates of the latter could fall to a uniform level – perhaps the minimum percentages that are now offered for activity on the Canada Lands regardless of ownership.

There have been complaints about the form of the incentives available under the PIP system. Some have argued that the incentives should again be given in the form of a tax deduction. As mentioned above, the federal government was concerned that this form of incentive has a built-in bias against new entrants and smaller firms. While this problem can be alleviated through "flow-through" financial instruments that permit the tax deduction benefits to be passed along to other investors with taxable income, such arrangements are not guaranteed and can be cumbersome. Thus we agree that, when all of these factors are taken into account, an incentive system based on tax deductions is not the preferred form of incentive for oil and gas exploration and development activity on the Canada Lands at this time.

It has also been argued that the grant system involves excessive government intrusion and control. In fact, until the system was modified recently to require prior approval in the case of very large expenditure projects, the grants had been more or less automatic. No one should expect to receive public funds without some reasonable degree of scrutiny to determine eligibility, appropriateness, etc.

A refundable tax credit could achieve essentially the same incentive effect at an administrative cost that would probably be lower while ensuring a reasonable degree of public scrutiny. The tax credit could be set as a percentage of the eligible capital expenditures, as is the case with the PIP grants, and it could be claimable as a credit against the income tax owing. Its refundable feature means that the amount of the credit could exceed the amount of the tax owing, in which case the claimant would receive a "refund" from the federal government. Refundable tax credits are also similar to grants in that they are easily accounted for in public accounts – a more difficult task in the case of tax deductions. The rate should be set at a more modest level, as we have already suggested, so as not to encourage wasteful activities and to reflect a reasonable degree of cost and risk for the federal government. The existing grants should, of course, be "grandfathered"; and some delay would have to be provided in order to achieve a smooth transition. Accordingly,

15 **We recommend that, after a specified transition period, the federal government shift the form of the incentives available under the petroleum incentives program for exploration on the Canada Lands, from a grant to a refundable tax credit, at a moderate rate that would apply uniformly to all applicants.**

Oil and Gas Exports

The circumstances and factors affecting oil and gas exports in both the short and the long run are somewhat different for oil and natural gas. The oil market is international in scope, while gas trade is currently limited to the continental market and involves less flexibility because of the need for costly pipelines and distribution systems, which, once installed, are essentially fixed. For that reason, the longer-term assurance of pipeline "throughput" is generally required in the case of gas to ensure that the investment costs will be recovered.

The National Energy Board is responsible for regulating the volume and price of hydrocarbon exports, which must generally have the approval of the Governor in Council. In considering major exports, the Board undertakes surplus tests to determine the exportable surplus, as well as benefit/cost analyses, but because the forecasting of prices and of resource availability and costs is fraught with uncertainty, a good deal of caution and discretionary judgment is required. The terms of export licences vary, typically being shorter for oil and longer for natural gas. In the case of prices, one test that the NEB has long applied and that remains reflected in current policy is that oil export prices should be no less than the prices of domestic sales made under similar terms and conditions.

With respect to export volumes, the Board has developed certain criteria for determining exportable surplus – that is, the volume of oil or gas beyond the requirements for domestic security of supply. In the case of natural gas, for example, there are several tests, including the 25A1 test, which has come under a lot of criticism from producers (see Chapter 5). This test stipulates that the exportable surplus be that portion of the remaining established reserves which is above 25 times the current rate of domestic demand, after allowing for licenced exports. When a reasonable growth rate of domestic demand and reasonable decline rates in production are taken into account, however, the 25A1 test theoretically provides secure deliverability from the established reserves to meet domestic requirements for less than 10 years under most conceivable conditions. Nevertheless, the benefit of security of supply involves a cost. In this case, some of the costs of the export quantity restrictions, when they are binding, are borne by producers.

In the short run, Canada's supply of, and demand for, oil are roughly in balance. We do not expect major surpluses of light oil to be available for export in the foreseeable future. In the case of oil export licences, we believe that the NEB should provide sufficient flexibility to alleviate imbalances and, in particular, to avoid the build-up of shut-in capacity. Shut-in capacity is not an economical way to provide security of supply, and we see no useful purpose being served under the present circumstances by maintaining such capacity as a matter of policy.

Since the beginning of the 1980s, the export market for Canadian natural gas has deteriorated, not so much as a result of export-pricing policies but as a consequence of the persistent surplus of indigenous gas supply in the United States. There is widespread agreement that the U.S. market is not likely to improve before the late 1980s, and even then market pressures will require Canadian gas to be competitively priced.

To meet present export difficulties and gradually prepare for future opportunities in the U.S. gas market, the Canadian government, acting in concert with the National Energy Board, has recently taken a number of steps aimed at instituting a more responsive and more flexible export policy. The base price of gas for the export market has been cut; an incentive price has been provided for the portion of sales over a certain threshold; buyers and sellers have been given the opportunity to negotiate individual pricing arrangements, subject to certain conditions; the gas surplus calculation has been adjusted to provide a more flexible determination of exportable surplus; and provisions for the allocation of short-term export licences by the NEB have been actively brought into play.

We believe that all of these shifts in gas export policy go in the right direction and that further improvements will require a continuation of this policy thrust. As we explained in Chapter 5, however, the competitive situation for gas is such that totally free negotiations are unlikely to yield a fair price for Canadian exports, which leads us to the conclusion that the export price of Canadian gas should continue to be partially regulated.

If, as we have recommended, a movement is launched towards the deregulation of natural gas prices in Canada, domestic prices should begin to more closely reflect the circumstances in the United States as well as in this country. For that reason, domestic prices should be less of an artificial barrier to gas exports than may be the case at present, while ensuring that gas is not exported at a lower price than that paid by Canadians. With the rationalization of the pipeline tariff zone system in Canada, the prices in each zone could serve as domestic reference prices for exports to the U.S. regions directly south of each zone.

If our recommendations regarding prices, taxation and incentives in the oil and gas sector are implemented, Canada will be in a position to achieve a more economically efficient set of supply policies and reduce the degree of friction between the federal government and the provinces, while at the same time the federal government will be able to have continued access to a reasonable share of resource revenues. The simulation in Appendix L, which are used to assess the effects of deregulated oil and gas prices and changes in taxes, indicate that the combined impact would be to lower inflation, reduce unemployment and increase the rate of growth in the Canadian economy over the next several years. These policy changes would help to reduce oil imports by reducing consumption and stimulating domestic oil exploration, development and production, while increasing the demand for natural gas. In addition, therefore, these changes would also support the goal of energy security. Finally, the proposed policy changes need not have any adverse effects on government deficits because they could result in an increased flow of revenue to the federal government and the governments of the producing provinces, as well as to the petroleum industry. Moreover, our recommendations can provide adequate mechanisms for the federal government to adjust its production and excise taxes, as well as its corporate income tax, in the event of dramatic price shocks.

The Electricity Sector

In our review of the electricity sector (see Chapter 6), we noted the many considerations that have shaped its development over the years. Electricity is now available almost everywhere in Canada, although it is much more expensive in some parts of the country than in others. Over the last decade or so, circumstances in the industry have changed. In contrast to the steady decrease in real prices exhibited previously, average rates began to level off and even rise in real terms in the 1970s. Increased fuel prices, higher real interest rates and the exhaustion of some sources of scale economies appeared to be the major contributing factors. In addition, the efforts undertaken by the electrical industry to tackle the problem of the adverse environmental impacts resulting from certain forms of power generation, which became a source of growing protest from some segments of society during the past decade, added to electricity supply costs. The rate of growth of electricity demand also slowed noticeably, relative to previous decades, in response to rising prices and to slower economic growth during the 1970s. The time lags in the perception of these changed trends and in the planning process led to the build-up of excess supply capability that still exists today in a number of provinces. Fortuitously, the opportunity for exports to the United States was enhanced during this same period, with sales south of the border growing more than tenfold over the past decade. Finally, the electricity sector is extremely capital-intensive, accounting for a very large share of the total capital stock in the economy, and is dominated by public – mainly provincial – ownership.

The Regulatory Environment

It was once considered that, by itself, the creation of Crown corporations could completely replace the need for regulation in the electricity sector. Our review of that sector indicated that there is a growing recognition that this is not the case. A Crown corporation could not hope to reflect and respond to all of the various interests involved in the electricity sector. Consequently, we see a need for regulating the sector, even where Crown corporations are involved, in order to ensure that the electrical utilities can be responsive to a range of public interests and concerns. This is a requirement that the provincial governments have increasingly come to recognize. Regulatory boards have recently been established in British Columbia and Saskatchewan; and one of the recommendations made by the Royal Commission on Electric Power Planning in Ontario in its 1980 report was that the role of the Ontario Energy Board be upgraded and expanded.[9] A review of the current status of regulation shows that it varies quite widely among the provinces. While in a federal state one should neither expect nor require uniformity in this regard, we believe that more systematic regulation would be beneficial in all the provinces. Accordingly,

16 We recommend that there be provincial regulatory boards with broad authority over matters in the electricity sector in all provinces in Canada.

We believe that the mandate of these regulatory bodies should encompass rate levels and structures and that they should have at least the authority to gather information and make recommendations to government with respect to investment decisions in the electrical sector. As part of their regulatory powers in these areas, the boards should have responsibility for regulation pertaining to capacity reserve margins, taking into account the cost of additional capacity and the additional benefits to customers of increased reliability of supply. Additionally, the boards should have authority in matters relating to the assessment and implementation of load-control techniques, viewed as one type of method for improving reliability and reducing overall supply costs. We consider it important that these regulatory bodies also be mandated to regulate in the case of supply of electricity from nonutility producers within their respective provinces, as well as to consider available out-of-province sources of supply in order to ensure that all economic sources are fully explored. Furthermore, the major utilities should be required to submit timely, systematic and fairly comprehensive data on their operations and plans. For the most part, major regulatory decisions should be based on the record of evidence submitted during the course of public hearings conducted to consider such issues.

One of the major functions of a regulatory body is to provide a mechanism to set fair and reasonable prices for the consumer while sustaining the economic viability of the utility. As such, regulatory bodies act to resolve conflicts between groups and individuals, some of which would otherwise be resolved by the market. A second function of a regulatory board is to assure that economic waste is avoided. Thus one of the major objectives of the provincial regulatory bodies in the electricity sector should be to ensure that electricity is supplied to the extent and in a manner that meets the demands of provincial customers at the least overall cost, taking into account all resources employed or affected. Therefore,

17 We recommend that, within the framework of provincial government policies pertaining to the electricity sector, the regulatory bodies be mandated by the provincial governments to give due consideration to the economically efficient use of resources in the supply of, and demand for, electricity.

As part of the continuing efforts to improve efficiency in the electric power sector in a dynamic environment, the regulatory bodies should be given the mandate to examine cost-effective changes to the institutional structure of the industry. They should have the power to institute some limited changes, at least on an experimental basis, and to advise the minister responsible with respect to more extensive changes that may be beyond their own authority or may require legislative action.

Pricing Policy

Turning now to certain specific issues related to electricity pricing, we are concerned that the public electrical utilities have been overly protected from market forces with respect to the availability and cost of capital. The provincial governments generally guarantee the debt of their electrical utilities, which greatly facilitates their ability to raise capital on favourable terms; at the same time, the governments do not appear to require a reasonable rate of return on investment in these corporations. In light of the possible economic consequences of these policies, we believe that they need to be reviewed. Accordingly,

18 We recommend that consideration be given to the reduction of the proportion of debt in the capital structure of the provincial public electrical utilities over the next decade, so that they may be in a position to obtain debt financing at acceptable cost without the guarantee of the provincial governments.

One of the important effects of government financing assistance is the absence of any real market guideline with respect to an appropriate cost of capital used by the public electrical utilities. Given the extreme capital intensity of the industry, the cost of capital is perhaps the single most important variable affecting the development of the electrical sector. In view of the large investments that are often involved in the sector, we consider it important that a more appropriate measure of the cost of capital be adopted for the initial purpose of assessing investment decisions; for the subsequent determination of the cost of funds tied up in construction work in progress that are later capitalized and eventually recovered from customers; and for setting an appropriate guideline for return on investment for the purpose of determining the revenue requirement.

One way to provide a market-determined indicator of the cost of equity capital would be for the provincially owned electrical utilities to issue some amount of equity for purchase by the public. We see no reason why this could not be done, although this matter would require some detailed consideration by the provincial governments. In the absence of market forces, we believe it is a responsibility of the provincial governments to determine the appropriate cost of capital that their electrical utilities and regulatory bodies should employ with respect to investments and the revenue requirements. Therefore,

19 We recommend that the provincial governments consider the costs and benefits to the provincial economy that could result if their electrical utilities were to issue some equity shares. Alternatively, the provincial governments should state explicitly the target real cost of capital to be used by their public utilities.

We noted in Chapter 6 that both the public and the private electrical utilities pay little or no provincial or federal income tax. We see no reason why this situation should be maintained; in fact, there may be good reasons, involving the efficient use of capital, why all utilities should pay income taxes. Because the Council is currently engaged in studying government enterprises and the taxation of capital income in two separate research projects, however, we forbear from making any recommendations on the taxation of utility income at the present time.

Earlier, we reviewed briefly the issue of inflation accounting in the electricity sector – a problem that affects other regulated sectors in the economy. While this matter has also been discussed in other countries, no clear consensus has yet emerged. We believe, however, that the issue merits attention and we urge the various regulatory bodies in the electricity sector to examine this matter further, with a view to instituting possible changes that would provide for a more efficient and equitable allocation of capital costs over time.

We noted that time-of-use rates for electricity have been in place in Europe for quite a few years and are becoming more common in the United States. We also saw that such rates have been applied in other sectors in Canada, such as transportation and communications, that have characteristics similar to those of the electrical sector. While the technical difficulties involved in applying electricity time-of-use rates may be somewhat more complex and more costly than in other sectors, new, lower-cost technologies (e.g., for metering) are being developed all the time. We believe it is important for improved efficiency and greater fairness in electricity pricing that Canadian utilities begin to gain some experience in the application of time-of-use rates. A variety of approaches to implementation are possible, ranging from initial experimentation to one or more voluntary rate structures, to mandatory rates. Accordingly,

20 We recommend that time-of-use rates for electricity be implemented gradually and with full discussion by the parties involved.

In our review of the electricity sector, we indicated that the question of applying marginal-cost principles to the pricing of electricity is also extremely difficult and complex. Nevertheless, this concept has been applied in other jurisdictions and we believe that it warrants continuing consideration in Canada. However, much more work is required to determine whether the concept, or some of its aspects, could be beneficially applied in this country. We see this as a matter for review by the regulatory bodies that we proposed earlier. As one means of approaching this issue, the regulatory bodies might request the electric utilities to provide information on incremental costs based on various concepts, the implications of such concepts for various pricing structures and the potential impact of the implementation of marginal cost-based pricing on customers, the utilities and the economy as a whole. Therefore,

21 We recommend that all provincial regulatory bodies investigate the applicability of marginal-cost principles to the pricing of electricity within their jurisdiction.

The matter of the economic rent on hydroelectric resources is a very sensitive issue, particularly in view of the energy price increases in recent years. Currently, most of the rent benefits – and we believe that significant benefits do exist – are distributed mainly to consumers through the sale of electricity at prices below its real value rather than being collected by the provincial governments through royalties, taxes, dividends or other means. The distribution of these benefits in this way has implications both for efficiency and for equity between provinces. The economic rents from hydroelectricity are no different than those arising from government levies on oil and gas resources; they should therefore be subject to intergovernmental sharing on the same basis. We pointed this out with respect to the Equalization Program in an earlier report, in which it was also noted that the failure to collect these rents and to take them into account in the program could create distortions in the interregional allocation of resources.[10]

The decision of the provincial governments with respect to collecting all or part of the economic rent can also have an impact within the provinces. Commodity taxes and income taxes have relatively high costs in terms of economic efficiency, and the provincial governments could, for example, replace a portion of these taxes with royalties on water power, which carry relatively minor efficiency costs. The matter of equity arises out of the fact that the benefits from hydraulic resources are currently distributed roughly on the basis of electricity consumption; in other words, the more electricity that is consumed, the greater the benefits received. The provincial governments can exercise little control over this distribution because they have little control over relative rates of consumption. The collection of these rents and their distribution through provincial budgets could allow for their allocation in a manner that would be more compatible with the economic development and social objectives of the provincial governments.

There are administrative costs involved in measuring and collecting economic rents, although we believe that they are likely to be relatively small in the case of hydroelectric resources. Relatively few producers are involved, and the provinces already have in place water power rentals or a dividend system, although their levels – and probably their structures – appear to be in need of reassessment. There are conceptual problems in attempting to measure the rents on hydroelectric resources, as underlined by the disparate estimates that have been developed to date. It should be noted, however, that the oil- and gas-producing provinces did not develop their fiscal regimes overnight. It took them many years to do so, and their fiscal structures are still in a state of evolution. We hope that these issues – the collection of economic rent on hydroelectric resources and the sharing of resource revenues among governments – will be fully aired in the discussions on these matters that we have recommended be undertaken. In the interim,

22 We recommend that, over the next few years, provincial governments consider a policy of collecting economic rents from the resources used to generate electricity, particularly hydroelectricity. Water power rentals, equivalent royalties, taxes and dividends should be examined as instruments to collect the resource rents.

The export of electricity can be a very profitable business for Canada; hence the marketing efforts aimed at further expanding sales to the United States should continue. Generally, we believe that these efforts should be pursued by the utilities, with governments setting a favourable environment for contract negotiations and ensuring that Canadian interests are protected.

We believe that current federal and provincial policies, together with the regulatory oversight provided by the National Energy Board, are helping to maintain such an environment. On the other hand, the policies and regulatory structures in the United States do provide some major constraints for Canadian exports. Other than applying what moral suasion they can with federal and state authorities south of the border, there is little that Canadian governments can do to reduce these constraints. The United States has undertaken an extensive reassessment of its policies and regulatory framework in this sector, a review that will likely proceed for a number of years. Throughout this period, we would expect Canadian exports to proceed and increase, and the potential benefits that can be obtained south of the border could provide further incentive for the U.S. authorities to remove or reduce the existing impediments.

There remains, however, the issue of provincial policy with respect to the distribution of the profits from out-of-province sales. As pointed out in Chapter 6, the use of export profits to reduce the revenue requirement for provincial electricity consumers constitutes a subsidy. We believe that such general subsidization should be reconsidered, particularly now that exports constitute such a large – and, we expect, increasing – proportion of electricity sales. To some extent, the issues of the hydro rents and of the subsidies from the gains made on external sales are integrally related because export profits are derived, in many instances, from the economic rent on hydraulic resources. A further point that should be made is that the regulation of the electrical utilities by provincial agencies should focus primarily on the monopolistic aspects of their operations that involve service to the public within the province. Different regulatory scrutiny is required in the case of electricity marketed beyond provincial boundaries, where conditions are generally more competitive. The separation of the regulated components of companies from those which are more subject to competition has occurred in Canada in a number of sectors – for example, in transportation and telecommunications. We believe that such separation should take place in the electricity sector as well, in order to ensure its effective management. It would be facilitated by the establishment of subsidiaries to handle all aspects of the out-of-province sale of electricity. Therefore,

23 We recommend that the electrical utilities involved in out-of-province sales establish subsidiaries to manage and keep account of those transactions. We also recommend that provincial governments consider using the net profits on out-of-province electricity sales for purposes other than the general reduction of electricity prices for customers within the province.

We believe that a structure of this type can also provide a fuller and clearer accounting of the cost of electricity exports and, consequently, a better measure of the ensuing benefits.

The nuclear sector in Canada has received substantial public financial support over many years and can no longer be classified as an infant industry. In recent years, almost all federal support for electricity research and development has been directed to nuclear generation – to the tune of about $200 million in 1982. Federal support does not end there, as the industry has received additional financial support to assist it to penetrate domestic and international markets. Ultimately, the industry must stand on its own if its potential economic contribution to Canada is to be realized.

Currently, the prospects for expansion are limited both at home and abroad, but circumstances could well improve in the years ahead. We have not undertaken a thorough investigation of the Canadian nuclear industry, of its costs and benefits, of its prospects for the future and of the possible improvements in the structure of public and private involvement. Such an investigation should be considered by the federal government, perhaps as part of its general efforts to improve its long-term fiscal position. In the absence of an investigation of this type, and bearing in mind the time it would likely take to ultimately affect public policy, we believe that it would be premature to abandon all support for the industry. Accordingly,

24 We recommend that, over the next five years, federal government support for the nuclear electric power industry be sufficient to maintain the viability of the CANDU nuclear technology. Continued support should be reassessed at the end of that period, based on the conclusions of a thorough inquiry into costs and benefits, the prospects for the future and the respective roles of the public and private sectors in the industry.

Our recommendations about the electrical sector are motivated primarily by our concern that efficiency in resource allocation be given greater attention in the management of that sector. Our simulations in Appendix M attempt to estimate the implications that various changes in a number of the financial policies applying to electricity – such as the removal of the government guarantee on debt, a higher equity/capital ratio, a higher rate of return on equity and the collection of economic rent on hydroelectric resources – would have in terms of an increase in electricity prices by the year 2000. The primary purpose of these simulations was to estimate the maximum impact on real prices that could result if all of those measures were fully implemented. For the four provinces that were analyzed – Ontario, Saskatchewan, Nova Scotia and British Columbia – our simulations indicate that the price increases in relation to a control solution based on the continuation of current policies could range from 30 per cent in Nova Scotia to as much as 65 per cent in Ontario in the year 2000. Most, if not all, of the additional revenues would accrue to provincial governments, however, and thus they would be available for other purposes, such as a reduction in taxes or debt, or an increase in services or in economic development expenditures.

We are aware that other public concerns are involved and that there is room for debate about what does or does not constitute subsidization of electricity prices. There are complex conceptual and empirical matters at issue. In addition, governments should bear in mind that there are effective means, other than the direct subsidization of electricity prices, that could be employed to support their objectives. As indicated by the simulation results, the increase in the revenues of electrical utilities resulting from higher rate levels would more or less be accounted for by higher provincial revenues. Thus the provincial governments would have greater flexibility in promoting economic development or in pursuing other objectives, where the potential benefits might not be related at all to the quantity of electricity consumed. In our view, a general direction for public policy in this sector is that users should be charged all of the economic and noneconomic costs incurred to meet their demands for electricity. Therefore,

25 We recommend that, over the next decade or so, the general subsidization of domestic electricity prices be gradually eliminated.

In making this final and overall recommendation, we clearly recognize that there are long lags in the electricity sector with respect to both supply and demand and that the proposed changes cannot occur overnight. The problem is also complicated by the degree of excess supply that currently exists. Furthermore, we recognize that there are specific situations where the social benefits of subsidizing electricity consumption could exceed the social costs involved. In those cases, however, we believe that subsidization should come directly and specifically from the provincial government and that other electricity consumers should not bear the cost of the subsidies in their electricity prices.

Demand, Conservation and Substitution

In our review of Canadian energy demand (see Chapter 7), we stressed that demand, as well as supply, is responsive to prices, incomes, technology and other factors. While there remains much to be understood about energy demand and its links with the economy, it is now recognized that users do adjust their consumption patterns as changes occur in the economic environment. They generally turn to those energy options which are perceived to be the most economic, in the direction of a least-cost mix of energy – conservation being treated here as one of the available "sources" of energy supply . This is confirmed in part by the notable changes in demand that have occurred over the past 10 years. There has been a substantial reduction in the rate of growth of demand as a result of the growing economic benefits to be derived from energy conservation. There has also been a sizeable drop in the oil share of primary-energy demand.

There is also some evidence, however, that energy consumption today still does not reflect a least-cost mix of energy sources. This is not unexpected, as there are always lags in the response of energy users. Moreover, we are just emerging from a decade of adjustments to unprecedented changes in the general level of energy prices and the relative price levels of particular energy sources, and it could be said that we are still in the process of transition.

But there are other factors that have contributed to the market imbalances. The incentives for Canadians to move away from certain conventional energy sources and towards other, lower-cost sources have been less than they could have been because of the pricing policies. There have also been market shortcomings, such as a lack of information and the presence of so-called institutional barriers, that have limited the penetration of efficient conservation and alternative energy technologies.

The role of policy on the demand side of the energy equation should be to alleviate such difficulties and stimulate response in the direction of a least-cost energy future. Our first concern, in this regard, is the implementation of coherent pricing policies along the lines that we have already suggested in this chapter. In conjunction with such pricing policies, there is still a need for some degree of government intervention, although we believe that the current policies require some adjustment.

The present strategy at the federal and provincial levels of government is based largely on programs that overlap in part, involving the distribution of grants and subsidies for energy conservation and substitution. In our view, that strategy is relatively costly. As an alternative, we propose an approach based primarily on improving the availability and reliability of the information provided to the public about the relative costs of energy and of various energy conservation methods. The provision of such information should be supplemented by a more limited financial participation of governments in some conservation and alternative-energy projects and by their support for research and development in selected energy-related areas.

In reviewing a selection of energy technologies, we argued that an important impediment to the conservation or substitution of energy is the lack of reliable information within the market. We observed that there are promising home-heating devices and, more generally, profitable energy-conservation investments for the home that appear to be realizing less than their full market potential. There is, also, an economic potential for waste-heat recovery that remains unexploited, presumably because the financial benefits of the necessary investments are not fully appreciated. There is a cost in time and money to the acquisition of information that tends to bias the decisions of energy consumers towards the status quo. There can also be misconceptions, or incorrect information, that will further mislead decision making. Efficient government programs aimed at reducing the cost of information can, therefore, be of considerable benefit. As one recent study put it, they act in such a way that "relative prices are left unchanged but perceived benefits are altered in the direction of verifiable fact."[11]

There are a number of means available to governments for stimulating the flow of information; in fact, there are already a variety of programs in place at different levels of government. First, there can be programs to encourage, or compel, manufacturers or suppliers of services to provide certain energy-related information to their customers in a simple, standardized format. At present, these include the Energuide program, which oversees the labeling of energy-efficiency ratings on certain home appliances, and the "voluntary motor vehicle fuel consumption program" of Transport Canada, which performs similar functions in the new-automobile market. The advantages of such programs are twofold: they make the job of product screening easier for the consumer, and they provide additional incentives for suppliers to become more competitive in terms of energy efficiency. While the approach is not practical for all sectors and for all energy-related products, there are new areas where it could be potentially successful. An example is the home furnace market, where product labeling could make homeowners more confident in investing in high-energy-efficiency devices, such as the condensing gas furnace.[12] The labeling of new homes to provide a measure of energy efficiency levels is much more difficult, but conceivable.

A second approach is for government to provide a considerably broader and more detailed range of information to decision makers. Information on energy matters can be made available in published form in an effort to provide more sophisticated guidance – case studies of successful projects, catalogue-form description of available equipment and processes, and so on. There can also be a direct interface with energy users, as is the case currently with EMR's "energy bus" program, which offers energy audits of industrial plants and, subsequently, technical advice on potential energy-saving investment. Programs of direct interface are generally the most expensive – requiring, among other things, the training of personnel – but they are a very effective means of stimulating consumer response. New programs, targeted towards new groups, can be envisaged. In homes, for example, walk-through audits performed by skilled technicians could provide homeowners with important tips on the best mix and sequencing of energy conservation investments. Similarly, contacts with financial managers in industry could be of benefit as a means of providing a follow-up on energy audits. This could apply particularly well to waste-heat recovery investments, an area where competitive technology is available but where the adoption of projects is sometimes delayed because managers apply excessively stringent financial criteria.

As noted previously, payback requirements ranging from one to three years are often mentioned for conservation investments, suggesting that socially desirable opportunities are being overlooked.

As a third approach, government can set up means of consultation between parties concerned with energy-conservation and alternative-energy investments. A successful example was the creation of a number of industrial task forces by the federal government to stimulate the exchange of information between different industries. Such instruments could possibly be used in the future – for example, to bring together industry and electrical utilities for discussions on the means to promote and implement small-scale sources of electricity supply, such as cogeneration.

There are, of course, several other means to bring information to the attention of decision makers. For example, third parties such as consumer associations can be subsidized to report on energy-related products and services. We did not, in our studies, compare the potential costs and benefits of the different policy options. We believe, however, that the experience gained in the past through the implementation and subsequent evaluation of government programs can be considerably useful for that purpose. Discussions at different levels of government and consultation with industry and consumer groups could lead to improved effectiveness. Presumably, some of the existing programs could be expanded; others could be revised or simply discontinued; and new programs could be targeted towards groups that have received less attention in the past.

Markets can be expected to function properly only if sufficient and adequate information is available for the assessment of competing investments. In recent years, positive steps have been taken by governments to improve the quantity and quality of information for decision makers. We believe that continued efforts are required to accelerate the dissemination of information and to improve the operation of markets. Therefore,

26 **We recommend that, in consultation with representatives of industry and the various interest groups concerned with energy conservation and alternative energy supplies, governments identify the most effective means to inform decision makers of the benefits of conservation and substitution investments, implementing the necessary programs by taking maximum advantage of existing programs and structures.**

Over the past few years, especially since the introduction of the NEP, government policies for increasing efficiency in energy use have been largely dominated by programs designed to offer grants or other forms of subsidies to energy users in order to promote conservation or substitution. At the federal level, the major programs have been the "Canada oil substitution program" (COSP), the "Canadian home insulation program" (CHIP) and the "forest industry renewable energy" (FIRE) program. The provincial governments and the electric and gas utilities have also taken initiatives. The provision of subsidies necessarily had an impact in the market place, because subsidies alter the relative prices of the available energy options and because energy users are responsive to such price changes. But subsidies can also create new market distortions.

In the automotive sector, for example, our evaluation indicates that oil-based fuels such as gasoline and diesel oil enjoy a distinct advantage over other fuels. While future changes in the price of oil could affect the competitiveness of gasoline and diesel, they are not likely to create real opportunities for alternative fuels such as propane, compressed natural gas (CNG) or methanol. At present, however, federal and provincial policies favour propane and CNG, which appear to be more costly in the social sense, although diesel would be preferable in that respect. The owner of a fleet vehicle may take advantage of federal and provincial subsidies to convert his vehicles to propane use, whereas an increased investment in diesel-powered vehicles, which are not eligible for the subsidies, could provide greater net social benefit.[13] The present policies are aimed at reducing the consumption of oil and increasing the use of natural gas and other alternatives. Nonetheless, we believe that the grants have to be reassessed with a view to reducing distortions. For example, some of the funds currently allocated to the immediate commercialization of propane and CNG could be better utilized in research programs aimed at supporting the longer-term opportunities for replacement of oil-based fuels in transportation.

A second example of distortions is provided by homeowners in central or eastern Canada who may use COSP grants to switch from oil to electricity in instances where a less expensive furnace upgrade could have been as effective. Subsidy programs also have the disadvantage that they may invite fraud and deceptive market practices. Moreover, they can result in price increases and indirect subsidies to suppliers when the technologies concerned are sufficiently competitive on their own. Therefore, while we agree that subsidies can, in some instances, yield net social benefits, we suggest that large subsidy programs of the kind that are currently in place be avoided.

There are, however, promising technologies that may fail to realize their full market potential even if the prices are right and if the information is sufficient. Problems of this kind can arise when there are special institutional factors at play. For instance, a potential barrier to the future development of energy-from-waste technology is that there are no obvious project promoters among the many parties that should be involved; at the same time, coordination of planning and construction can be difficult and may appear excessively costly. While this participation could take a variety of forms, we would generally favour administrative and/or financial assistance for demonstration projects, possibly supported by multipartite task forces. By showing the costs and risks – and possible benefits – of new projects, governments can accelerate their implementation and trigger a learning process that will gradually improve the commercial potential of the technologies. The programs should focus on specific markets and energy applications and they should have a time limit. Accordingly,

27 **We recommend that governments redirect their strategy for active support of energy conservation and alternative energy supplies from extensive subsidy programs towards limited administrative and/or financial participation in demonstration projects. The programs should be aimed at economically promising technologies that face specific, clearly identified market barriers.**

Commodity taxes represent another factor that can result in distortions in the prices facing users. At the retail level, taxes should be balanced so as to maintain relative prices in line with relative costs. In Chapter 7, we showed how distortions in the structure of taxes can move consumers away from cost-effective energy solutions. For example, differential taxes are another factor currently favouring the penetration of propane and compressed natural gas at the expense of diesel. We are concerned that exaggerated tax differentials may confuse the real economic trade-offs. Consequently,

28 **We recommend that excise taxes on energy products be reasonably balanced in order to encourage consumption decisions that better reflect the real relative costs of competing energy options.**

Last, but certainly not least, we believe it is important to stimulate research and development in selected areas of energy conservation and alternative energy supplies. Support to researchers in government, industry and universities should reflect the important role of energy in our economy. Special encouragement should be given to research aimed at filling immediate gaps in the technology of energy supply and conservation – for example, biomass technology, including energy-from-waste recovery techniques and wood furnaces for homes. Longer-term opportunities should also be explored: methanol and CNG for vehicles are promising energy sources for the future, even if they are, at present, economically less viable than the currently available alternatives.

Assistance to research and development in energy-related fields is already available, but the Canadian commitment should be further reinforced. Therefore,

29 **We recommend that governments at all levels continue to actively support research and development in the field of energy conservation and alternative energy supplies.**

In summary, energy conservation and substitution should be encouraged as a means of working towards economic efficiency. Although much has been achieved in this area in recent years, there is evidence that further opportunities remain to be exploited. The dissemination of technical and financial information within the market should be stimulated; research and development in the many areas of conservation and alternative energy supplies should be supported; and financial assistance should be provided, in selected cases, as a means of accelerating the introduction of emerging technologies and thus achieving the use of energy in the most cost-effective manner.

Conclusions

Our study has revealed that Canada has the potential to reap major economic benefits across the full breadth of its energy sector in both the short and the longer term and in both the domestic and the export market. There are unexploited economic oil supplies in the Western Basin and more costly, but promising reserves in the frontier regions. Canada has a short-run excess deliverability of natural gas that can be utilized to penetrate new markets in the United States and at home, and it has abundant resources for many years to come. Hydroelectric resources offer similar opportunities over the next decade and beyond. Finally, there are many unexplored opportunities for reducing economic costs in energy consumption through a better mix of conventional energy forms, more extensive conservation measures and the use of new energy sources.

Recognizing the economic realities with respect to Canada's international and continental relationships, we believe the objectives are to achieve this potential through the efficient management of energy resources while providing for a fair and flexible sharing of benefits and costs among Canadians, improved energy security and increased participation of Canadians in the energy industry.

The Council has presented in this concluding chapter the initiatives, changes in current government policies and programs, and institutional arrangements that can best, in its view, meet the fundamental objectives of the energy sector within the overall economic, social and political fabric of Canada. We have clearly recognized that the energy sector is closely connected with the economic, social and political dimensions of Canadian society. But we have emphasized our view that it is possible to develop an energy strategy for the future that can integrate both economic and noneconomic objectives without sacrificing any one of them in a major way. In fact, we believe that our proposals can contribute, to a significantly greater extent than current policies, to the achievement of efficient resource management, the functioning of fair and resilient mechanisms for the sharing of resource revenues across the country, increased Canadian participation in the oil and gas sector, greater energy security and stronger economic development in the short and longer term.

The true test of our advice is whether, over the medium and longer term, it will produce tangible benefits for all Canadians. We are confident that our proposals, with the goodwill and trust of all Canadians and their governments, will pass this ultimate test.

Dissent and Comment

Diane Bellemare

It is common knowledge that today energy is vital to a healthy economy; indeed, as a factor of production, energy is as important as labour. Events in the 1970s have shown that an interruption, or even a reduction, in the flow of energy supplies (such as oil) can have serious effects on the economy, leading not only to a new round of inflation, but more importantly to decreased production and higher unemployment. Given the importance of energy for the economy as a whole, the various sources of energy and their role in the economy cannot be dealt with in the same way as are most other goods and services. It is from this perspective that I wish to express my disagreement with two aspects of the main thrust of the report. The specific recommendations about which I have reservations will be discussed in detail later on.

The starting point for the analysis and recommendations contained in the report is the concept of efficiency. Obviously, there can be no objection in principle to any intervention that promises more efficient management of the economy. According to economic theory, a policy can be considered efficient if it results in increased production of a good or in increased personal welfare *without* having adverse effects on the production of other goods or on the welfare of other individuals. Unfortunately, few policies can be said to meet this criterion. Generally speaking, every economic policy works to the advantage of some and the disadvantage of others, and losses are not always compensated. In this context, the task is to decide who will gain and who will lose. Efficiency-based criteria are of no help in making that decision; it can only be made on the basis of value judgments. Not surprisingly, then, the recommendations contained in the report involve winners and losers. For example, Appendix Table L-5 indicates that the implementation of all proposed policies concerning the deregulation of energy prices and the taxation of oil and gas revenues would lead to increased industry and government revenues, and consequently to lower incomes for energy consumers; this is true of all the scenarios explored, except for the case based on the assumption of declining world oil prices. Thus it is clear that from a strictly theoretical and logical standpoint, the proposed policies cannot be justified simply in terms of efficiency, since they will have a significant impact on income distribution.

Furthermore, the concept of efficiency as used in this report seems inappropriate for several reasons. In the first place, the report states that in order to improve efficiency, the prices paid for the various forms of energy must reflect market prices. As far as economic theory is concerned, this is true only when markets are operating in conditions of perfect competition, when no indivisibilities or externalities exist, and when returns are not on the rise. Under these circumstances, an economic system can indeed be said to be efficient when the prices of its goods and services are market-determined. If even one of these four conditions is not met, however, it cannot be assumed that market prices are a guarantee of efficiency. In the case of energy, it often happens that one or more of these conditions is absent.

Further, this report treats all forms of energy as though they were the same. But is this an accurate view? Oil and gas, for example, are nonrenewable resources, while hydroelectric resources are renewable. The report demonstrates that the supply of oil and gas is elastic relative to price. But for how long? In addition, the development of different forms of energy involves quite different processes. For instance, one need only look at the high degree of uncertainty involved in oil and gas operations, a factor that influences both prices and the financial incentives for producers. And energy consumers may feel greater uncertainty about oil prices than about the price of electricity simply because the oil market is international in scope while the electric power market is more restricted.

Moreover, the report as a whole ignores the fact that energy as a commodity is much more essential than others. Energy is required for national production as well as for consumption at home. A country that cannot rely on a stable supply of energy at reasonable prices cannot develop economically. Thus an energy-producing country that is preoccupied with exporting its energy at the best possible prices in the short term should not expect its economy to grow automatically as a result. Do the member nations of OPEC, which sell their oil abroad, automatically experience strong economic growth? In several cases, their levels of development suggest otherwise.

Finally, the report fails to mention, particularly in Chapter 7, that the use of various forms of energy often involves costly complementary goods. This is one reason why the elasticity of the demand for energy is stronger in the long term than in the short term. The size of the investments needed to switch from one type of energy to another is another reason why price stability is so important to consumers. It can be more profitable, in the long run, to make capital investments in a currently more expensive type of energy, simply because its price is more stable.

When these four points are taken into consideration, it can be seen that the current energy policies of the various governments in Canada have followed a logical pattern that is based on a *broader definition of efficiency* than is used in the report. While mistakes have no doubt been made along the way – mistakes that need correcting – overall this logic should not be dismissed, founded as it is on the pursuit of economic development. Is it not legitimate to assume that, on a national level, an economic policy is efficient if it supports economic development?

The second major aspect of the report with which I am in disagreement is the question of the division of revenues between the federal and provincial governments. According to the Constitution, the provinces have full authority over the management of their resources; they may administer these resources as they see fit and take advantage of any profits that may result. In my opinion, the report does not put forward any valid reason why it should be otherwise. Thus I do not understand how the federal government could legitimately assume fiscal control over natural resources.

The report suggests that the system of equalization payments justifies the federal government taking a share of the revenues generated by natural resource development. In fact, it is correct to include resource revenues when calculating equalization payments, since these revenues, along with personal income taxes and indirect taxes, enable a province to finance its public services. This does not automatically mean, however, that the federal government has a right to impose taxes on resource revenues. Ottawa can always find other means to finance equalization payments. The equal participation of all Canadians in financing federal government expenditures does not allow the federal government to tax "potential" resource revenues. In order to achieve this goal, the federal government can always make use of personal and corporate income taxes, adjusting them according to the non-monetary benefits enjoyed by individuals and corporations who pay less than the national average for their energy needs (oil, gas and electricity). In this way, the fiscal burden of federal expenditures can be divided equally among all Canadians. The profits generated by natural resources can be shared through provincial equalization payments and through personal and corporate income taxes. The report contends, on the other hand, that all Canadians are entitled to a share of the economic rent from resources. But the concept of economic rent is abstract, and difficult to include in calculations. Its level depends, among other things, on what is considered a normal rate of return. But is this not the crux of the problem?

From my comments on the sharing of resource revenues, it should be clear that I disagree with the first recommendation.

As far as the deregulation of oil and gas prices is concerned, this may well be a wise course to follow. I do not think, however, that the reasons cited in the report are the best ones. Because of the uncertainty involved in oil price determination, it may be that a rise in the world price would be advantageous, in that it would encourage more Canadians to conserve energy and to switch from oil to forms of energy with more stable prices. This would have been revealed by using a broader analytical framework than that used in the report.

In reference to Recommendations 11, 12 and 14, I feel that insofar as the federal government undertakes to stabilize and standardize oil and gas prices, it should have control over certain taxes in order to be able to rapidly set up security measures to cushion unforeseen increases in resource prices and to maintain gas transportation.

I have very strong objections to the recommendations of the report on the electricity sector. In particular, I feel that Recommendations 17, 18 and 19 are based on too narrow a definition of efficiency. In the case of Recommendations 18 and 19, the provinces are entitled to manage their electric power production as they see fit. Thus, in a period of high unemployment, a provincial government may decide to institute public works projects designed to increase electric power capacity, and it must have the freedom to finance these undertakings as it likes.

Recommendation 20 seems premature to me. Before proposing a special rate system based on time-of-use, the redistributive effects of such a course of action must be examined. Electric power use is, *a priori*, so different from telephone and transportation that the proposed changes to the rate system could lead to higher costs to subscribers. Individuals and businesses have much less freedom to choose the most opportune moment to use electricity than they do in their use of communications media. Heat is needed when it gets cold, and light when it gets dark.

I also disagree with Recommendations 22, 23 and 25. Each province has the right to decide in what way its citizens should benefit from resource revenues. The provinces can elect to distribute them through domestic price reductions. There are other ways besides price management to encourage consumers to save energy – information campaigns, for example. The recommendations on electricity rates needlessly cut into the provinces' room for manoeuvre as far as economic development is concerned.

Finally, it seems necessary to me to qualify Recommendation 27. It may be that subsidies are necessary to encourage people to use more efficient forms of energy. Without them, consumers may not be able to afford the investment needed to conserve or switch from one form of energy to another, either because their levels of earnings are too low or because they feel that sooner or later prices will drop back to more attractive levels.

I would like to end these comments by repeating that it is unfortunate that this report neglected to carry out an in-depth analysis of the problems connected with two objectives pursued in the past by Canadian governments as part of their energy policies – namely, energy price stability and security of supply. There is certainly reason to believe that stability and security in these areas are essential to maintain economic growth and development. Unfortunately, some of the report's recommendations, if implemented, could lead to greater price instability by introducing into price-setting mechanisms certain variables whose behaviour cannot be predicted. The same recommendations, because they suggest cutting grants and relying instead on relative prices, will encourage energy consumers to return to a reliance on oil, leading to greater insecurity of energy supplies.

Appendixes

A Tables for Chapter 3

Table A-1

Prices of Old Oil and New Oil, Canada, February 1984

	Price	
	Per cubic metre	Per barrel
	(Dollars)	
Old oil		
Wellhead price	187.21	29.75
+ Canadian ownership special charge	7.25	1.15
+ Transportation from Alberta to Toronto	10.47	1.66
+ Petroleum compensation charges[1]	23.64	3.76
Consumer blended crude-oil price at Toronto[2]	228.57	36.32
New oil		
Actual world price at Toronto[3]	251.99	40.04
- Transportation from Alberta to Toronto	10.47	1.66
Wellhead price	241.52	38.38

1 These charges are as follows (per barrel): import levy, $1.36; new-oil reference price levy, $1.64; Syncrude levy, $0.76.

2 The consumer blended price is now at least 92 per cent of the world price at Toronto.

3 Based on 36-40° API oil (D2S2).

SOURCE Estimates by the Economic Council of Canada, based on data from Energy, Mines and Resources Canada.

Table A-2

Calculation of Blended Oil Price[1] and Petroleum Compensation Charge, Canada, First Quarter 1984

	($ Millions)
Volume of old oil produced × old-oil price delivered at Toronto (140,000 m^3/d @ $205.02/$m^3$)	28.70
+ Volume of new oil produced × average weighted new-oil reference price (80,000 m^3/d @ $250.02/$m^3$)	20.00
+ Volume of synthetic crude produced × average weighted price for synthetic crude (20,000 m^3/d @ $265.02/$m^3$)	5.30
+ Volume of imports × import oil price (40,000 m^3/d @ $247.02/$m^3$)	9.88
Total	63.88
	(Dollars/m^3)
÷ Total domestic consumption (280,000 m^3/d, including imports) to give the approximate blended price at Toronto	228.14
- Canadian ownership special charge	7.25
- Transportation from Alberta to Toronto	10.47
- Old-oil wellhead price	187.21
Approximate petroleum compensation charge (PCC)	23.21[2]

1 Basically, the blended oil price is the average price of oil consumed by Canadians; it is based on an average of the fixed old-oil price and the floating world prices for imported oil and for new oil.

2 This estimated PCC is equivalent to $3.69/bbl - some $0.07/bbl less than the actual PCC shown in Table A-1.

SOURCE Estimates by the Economic Council of Canada.

Table A-3

Gasoline Price, Ontario, February 1984

	Price		
	Per cubic metre	Per barrel	Per litre[1]
	(Dollars)		(Cents)
Consumer blended crude-oil price at Toronto	228.57	36.32	22.86
+ Dealer and refiner margins	136.70	21.72	13.67
+ Ontario sales tax	80.00	12.71	8.00
+ Federal sales tax	30.00	4.77	3.00
+ Federal excise tax	15.00	2.38	1.50
Price at the pump	490.27	77.90	49.03

1 Average product cost for regular leaded gas.
SOURCE Estimates by the Economic Council of Canada, based on data from Energy, Mines and Resources Canada.

Table A-4

Natural Gas Price, Ontario, February 1984

	(Dollars/GJ)
Average field price in Alberta	2.95
- Export flowback	0.43
- Market-development incentive payments	0.06
Average field price in Alberta for domestic sales	2.46
+ Transmission in Alberta (NOVA)	0.33
Alberta "border price"	2.79
+ TransCanada pipeline toll	0.94
- Transportation assistance program	0.01
+ Natural gas and gas liquids tax (now zero)	-
+ Canadian ownership special charge	0.14
Toronto wholesale price	3.86
+ Distribution margin	1.08
Average price at the burner tip	4.94

SOURCE Estimates by the Economic Council of Canada, based on data from Energy, Mines and Resources Canada.

B The Canadian Petroleum Fiscal System

Income from oil and gas production is subject to a number of taxes and royalties that are imposed at both the federal and provincial levels. The royalty and tax bases vary depending upon geographical location, date of discovery, size of producer, method of production, productivity, and so on. Figure B-1 lists the current rates. (For a thorough description of Canada's oil and gas fiscal systems as of March 1984, see Price Waterhouse, *Oil and Gas Taxation.*)

Figure B-1

Summary List of Oil and Gas Taxes and Royalties

	Basic charge	Base
Federal:		
Income tax	46%, with a 10% abatement for income earned in a province	- imposed on taxable income from all sources - allows deductions for exploration, development and capital expenses, as well as a resource allowance - no Crown royalty deduction federally, but most producing provinces have some form of rebate
Petroleum and gas revenue tax	16%	- levied on revenues minus operating costs and, for eligible taxpayers, a 25% resource allowance
Incremental oil revenue tax	50%	- suspended until 31 May 1985 - levied on difference between amount received and NEP prices less associated incremental royalties, for oil discovered before 1981
Incremental resource royalty tax	50%	- currently suspended - levied on incremental resource royalties from oil discovered before 1981
Natural gas and gas liquids tax	varies with type of gas liquid; currently set at zero for marketable pipeline gas and natural gas liquids	- on marketable pipeline gas consumed in Canada or exported from Canada Lands and on gas liquids, whether consumed in Canada or exported - levied at the gas-processing plant
Petroleum compensation charge	specific; varies as needed; capped at $75/m^3$	- imposed on all domestic crude as it enters the refinery and on all imported oil
Canadian ownership special charge	$7.25/m^3$ on oil $0.14/GJ on gas	- imposed on all domestic crude oil as it enters the refinery, all imported oil, all marketable gas and gas liquids at the point at which the NGGLT is levied, and all imported gas and gas liquids
Export charge	rates vary from month to month	- on bulk exports of oil and oil products
Provincial:		
Income tax	16% Newfoundland 15% Nova Scotia 13% Quebec 15% Ontario 16% Manitoba 14% Saskatchewan 11% Alberta 16% British Columbia 10% Northwest Territories 10% Yukon	- based essentially on the provisions contained in the federal Income Tax Act, with some exceptions

Figure B-1 (Concl'd.)

	Basic charge	Base
Royalties	rates and structure vary from province to province and, with some exceptions, depend on price, quantity produced, discovery date, method of extraction, etc.	- on oil and gas production in a province - most provinces give low productivity allowances
Canada Lands:		
Basic royalty	10%	- gross revenue from production on Canada Lands
Progressive incremental royalty	40%	- net profit defined as gross revenue minus basic royalty, PGRT, an income tax abatement, operating costs, a capital allowance and an allowed return on investment

C Profitability Calculations

In Table 4-7, all revenues and costs are "expectations" and are based on the existing average price and cost performance of the industry. The costs are calculated to include a "normal" return to capital of 10 per cent in real terms. Provincial royalty estimates are net of incentives, including the Alberta petroleum incentive program (APIP) payments. Income taxes are based on effective rates. (See Appendix B for a description of the federal and provincial fiscal regimes.) The wellhead price is based on the new-oil reference price. The figures in Table 4-7 are derived on the basis of an inflation rate of 10.8 per cent in 1981-82 and 5.8 per cent in 1982-83. A conversion factor of 6.293 barrels per cubic metre is used; the cost of reserves in the ground is converted to a levelized cost of a barrel of production by using a factor of 2.12. The figures in Table 4-7, which have been rounded, have been derived as follows (in 1983 dollars):

	(Dollars/m^3)
Wellhead price for new oil = \$35.55/bbl =	223.72[2]
Operating costs = \$4.52/bbl =	28.44[2]
Development costs for reserves in the ground =	22.42[1]
Development costs of production (levelized cost) = \$22.42/m^3 × 2.12 =	47.53
Provincial royalties = \$10.74/bbl =	67.58[2]
Estimate of provincial incentives[3] = 36% of royalty payment =	24.33
Net provincial royalties (less incentives) = \$67.58/m^3 – \$24.33/m^3 =	43.25
Federal PGRT = \$3.60/bbl =	22.65[2]
Income taxes (federal and provincial, based on effective rates) = (\$3.79 + \$0.76)/bbl =	28.63[2]
Exploration costs for reserves in the ground = private exploration costs less bonuses less cost of money for bonuses = [\$5.54 – \$1.47 – \$0.75] = \$3.32/bbl (1981 dollars) =	24.49
Exploration costs of production (levelized costs) = \$24.49/m^3 × 2.12 =	51.92

1 Eglington and Uffelmann, "Oil and Gas Reserves in Alberta."
2 EMR, *Energy Handbook*, Update 86.
3 This estimate is an approximation for incentive payments, as the latter are not available on a per-unit basis. The estimate of incentives is based on the value of the total incentives paid by the province of Alberta in 1983 as a percentage of total oil and gas Crown royalty payments. See Energy, Mines and Resources Canada, "Detailed Revenue Sharing and Netback Assumptions, Canada/Alberta Amending Agreement," Ottawa, 1983, p. 21.

D Natural Gas Exports

The contracts governing the sale of gas to the United States are drawn between producers and buyers. They include the specification of term volumes, annual and daily maximum levels, and the buyer's take-or-pay commitments. The contracts require the approval of the NEB in Canada and several regulatory bodies in the United States.

Export licences are approved according to the NEB's surplus determination. The calculation of the surplus shows the remaining quantity of established gas reserves from which domestic requirements (represented as 25 times the present requirements – the "25A1" test) and existing export approvals are subtracted to identify quantities that are in excess of Canadian needs. An example is shown in Table D-1.

The export price of natural gas is higher than the domestic price. Since 1975, it has been set by government; and, since 1977, it has, at least in theory, been related to the gas "substitution value," defined as the price of imported crude oil in Canada on a per-unit-of-energy basis, adjusted for transmission costs. In fact, market condition have been such that actual export prices have seldom been as high as the substitution value. The historical export prices are shown in Table D-2. The base price, which now is US\$152.69/thousand m^3, is applied at the Canada-U.S. border and is the same at all border points. The revenue at the wellhead is the border price less the transportation charges to the border. It therefore varies depending on the point of export.

Table D-1

NEB Calculations of the Exportable Surplus of Gas

	(Billions m^3)
Remaining established reserves	2,170
− Deferred reserves[1]	35
− One-half of reserves beyond economic reach[2]	21
− Reprocessing shrinkage[3]	150
Total supply	1,963
Canadian sales[4]	1,133
+ Authorized export sales[5]	336
Total requirements	1,469
Reserve surplus	494

1 The total deferred reserves in Alberta are estimated to be 115 billion m^3, with 81 billion m^3 expected to be connected within 25 years.
2 The Reserves beyond economic reach are estimated to be 40 billion m^3 in Alberta and negligible in British Columbia.
3 Reprocessing shrinkage is calculated on the basis of testimony that the capacity to reprocess all volumes leaving Alberta would be available.
4 Canadian sales include pipeline fuel and losses but not fuel used for exports. They are 25 times the 1982 demand of 45 billion m^3.
5 Export sales reflect the maximum quantities considered exportable under existing licence conditions; they include an allowance of 13 billion m^3 for fuel used in Canada to export those quantities.
SOURCES Based on data from the National Energy Board.

Table D-2

Natural Gas Export Prices, Canada, 1973-83

	Average price per thousand m^3	
	(U.S. dollars)	(Canadian dollars)
1973	12.21	12.21
1974	19.23	18.81
1975	40.94	41.65
1976	58.49	57.68
1977	67.26	71.54
1978	74.98	85.49
1979	88.63	103.83
1980	151.05	176.58
1981	167.28	200.45
1982	171.32	211.36
1983	157.88	194.55
1984 (first half)	152.69	194.53

SOURCE Based on data from Energy, Mines and Resources Canada.

For any export sale, the producer first receives a price equivalent to the average domestic price. The wellhead difference between the export price and the domestic price is collected by the Alberta government and returned to all gas producers in the province on a prorata basis, regardless of whether their production is destined to domestic or export markets. Called an "export flowback," this revenue ensures that producers have as much incentive to sell gas in Canada as in the United States.

The Canadian gas industry and the government have been observing the U.S. gas market with great concern over the past two to three years. In 1983, gas exports to the United States reached their lowest level since 1970, amounting to 20.2 billion m^3 – roughly 43 per cent of the volumes authorized by the NEB. The decline is due partly to Canadian export-pricing policies and partly to a surplus in the United States resulting from abrupt changes in U.S. government policy and in market conditions. An estimated 16 per cent of the U.S. gas is presently "shut in."

The present gas situation in the United States contrasts sharply with that in the late 1960s and early 1970s, when a shortage of gas was developing because of systematically depressed prices that stimulated demand but discouraged exploration and development. In 1972, the "life" of U.S. gas reserves had dropped to as low as 11 years. The demand for Canadian gas increased rapidly at a time when Canadian reserves were also declining steadily. No additional export licenses were issued by the NEB between 1971 and 1976.

Supply/demand conditions in the export market have completely turned around, over a period of less than 10 years, from a situation where the demand for Canadian gas was larger than the available supply to one where Canadian producers have to "shut in" productive capacity because of the depressed U.S. market.

The turning point in the U.S. gas market occurred in 1978 with the adoption by Congress of the Natural Gas Policy Act (NGPA). This legislation radically changed the U.S. gas supply situation in two ways. First, it allowed gas supplies previously trapped in the intrastate market of the producing states to compete on interstate markets, where supplies had become increasingly deficient. This first provision of the NGPA freed some 20 to 30 billion m^3 of gas and caused what was then believed to be a temporary surplus of gas – or "gas bubble." Second, the NGPA established a new schedule of gas prices that was to provide an incentive for gas producers to find, develop and produce "new" gas.

Other events coinciding with the passage of the NGPA were to contribute to the situation of excess supply. Since 1976, gas demand in the United States has decreased steadily at an average rate of 1 per cent per year. This is the combined result of the slowdown in economic growth, intensified energy conservation, competition from other energy sources and federal restrictions on oil and gas use in industry.[1] Since 1981, the downward pressures on gas demand have continued, partly because of the decline in oil prices and partly because of the continuing increase in gas prices provided for by the NGPA.

The U.S. gas market is still in transition. The NGPA calls for a gradual deregulation of prices between 1985 and 1987, which in the medium term should increase competition and lower prices. At present, average prices tend to increase as the high-priced new gas gradually replaces the low-priced old gas. This poses problems for Canadian exporters, who in the past could benefit from the ability of U.S. distributors to "roll in" the expensive Canadian gas with the old domestic gas, thus maintaining an acceptable competitive position. It is generally believed that as a consequence of the declining portion of old gas in the overall U.S. supply, Canadian gas exports will be required to meet competition in a more aggressive manner in the future. This prospect has already put pressure on the Canadian government to soften its export-pricing policies.

In response to the continuing decline in gas export volumes, the federal government has taken a number of steps in the recent past to provide more flexibility and responsiveness to its gas export policy.

The first significant decision was taken in April 1983, with the lowering of the export price from US$171.32 to US$152.69/thousand m^3. In July 1983, the government established a so called "incentive price" of $118/thousand m^3, which was to apply, in any contract and for a period of two years, on the volume taken that exceeds the lesser of 50 per cent of the licensed amount for each group of licences or the previous year's sales volume under a given group of licences. The effect of the price changes has been unclear as U.S. market conditions have continued to deteriorate, causing declines in both the volumes and value of exports between 1982 and 1983.

A second set of policy changes came into effect in May 1982, with the publication of the first-phase report of the NEB's gas-export hearings. The report outlined the amendments that the Board intended to make to its method for determining exportable surplus. The changes essentially provided for a less restrictive means of determining the exportable surplus; this, in turn, provided more flexibility to the Board in its allocation of export licences. The new provisions included the consideration of gas supplies that are licensed for exports but deemed nonexportable (because of the market constraint) as part of the existing reserves.

In November 1982, the NEB obtained the mandate to authorize, by order, the export of natural gas for terms of two years or less without the need for public hearings. Short-term exports, not to exceed 3 billion m^3 per year in total, remain subject to the Board's assessment of exportable surplus.

Finally, in July 1984, the federal government announced a new gas export price that allows for free negotiations between gas exporters and their customers. The implementation of the new pricing arrangement went into effect on 1 November 1984. Under the new arrangement, exporters can continue to sell at the existing two-tiered administered price or they can negotiate a price that will be subject to review by the NEB. The export price cannot fall below the Toronto city gate price. Export contracts must provide for adjustments that reflect the changes in market conditions. Because of the necessary review by the NEB and because of the Toronto city gate floor price, the export price remains, in effect, partially regulated.

Under the new policy arrangements, short-term (or spot) sales must meet the general criteria set out for negotiated prices, but in addition the spot sales must be truly incremental, causing no displacement of other Canadian gas sales. The sales must also be on an interruptible (or "best-efforts") basis, to ensure that there will be no pre-emption of longer-term export sales or capacity to meet Canadian requirements.

E Gas Pricing and the Fiscal Regime

Domestic gas-pricing arrangements in Canada have always demonstrated a certain rigidity, for a variety of reasons. This was the case of the pre-1975 system, under which prices were negotiated between producers and the pipeline companies. Although the contracts contained price-escalation, redetermination and so-called "favoured-nation" clauses,[1] the process of bringing about change in gas prices was generally a lengthy one. This became a problem in 1973 and 1974 with the jump in oil prices. At a time when it was generally believed that oil and gas should be priced at an equivalent level, perhaps with even a premium for gas, the ratio of gas prices to oil prices at the Toronto city gate had slipped to nearly 50 per cent by 1974. The producers and both levels of government recognized the need to correct the situation.

In December 1973, the Alberta legislature passed the Arbitration Amendment Act, which effectively defined the commodity value of gas in the market. It was the intention of the Alberta government that the concept of commodity value be used as the fulcrum for the pricing of natural gas. On that basis, the Alberta Energy Resources Conservation Board set target "field" prices that allowed for an adequate cost of service charges – although these targets were not necessarily adhered to. Subsequent arbitration decisions had the effect of raising natural gas prices to some 63 per cent of the prevailing domestic oil price, on an energy-equivalent basis, by 1975 (Table E-1). Although the Alberta government has indirectly participated in the pricing of natural gas since 1973, direct government involvement in gas pricing did not take place before the June 1975 budget of the federal government, which spelled a new policy for determining gas prices, effective 1 November 1975.

Table E-1

Gas Price in Relation to Oil Price, Canada, 1970-83

	Gas price	
	At Toronto city gate[1]	As a proportion of domestic oil price at Toronto[2]
	(Dollars/thousand m³)	(Per cent)
1970	15.27	75
1971	15.64	72
1972	17.13	79
1973	16.76	66
1974	20.48	52
1975	30.54	63
1976	46.18	82
1977	54.75	81
1978	65.92	82
1979	71.51	80
1980	84.92	77
1981	106.52	63
1982	132.22	65
1983	143.76	65

1 Prices are annual averages; since 1980, they include the NGGLT and the COSC.
2 Based on the yearly average Toronto "refiners acquisition cost."
SOURCE Based on data from Energy, Mines and Resources Canada.

At that time, under the Natural Gas Pricing Agreement between Canada and Alberta, the Toronto city gate price of gas was set closer to 85 per cent of the domestic oil price. The agreement touched all interprovincial sales of gas, with the different regional prices being set on the basis of relative transportation tariffs, as regulated by the NEB. The producing provinces had jurisdiction to set intraprovincial sales prices. The export price, under federal jurisdiction, was also administered directly for the first time in 1975; two years later, it was decided to relate the export price to the "substitution value" of gas, defined as the price of imported crude oil in eastern Canada.

When the new domestic-price regime was implemented, the federal government expressed its intention to ensure that the remaining gap between gas and oil prices at Toronto would be closed over a period of three to five years. Although this never materialized – the gas/oil price ratio never exceeded 82 per cent, on average, in subsequent years – the domestic gas price did increase substantially over the period, in response to the rising oil price. Between 1973 and 1980, the Toronto price rose from \$16.76/thousand m^3 to \$84.92/thousand m^3. Combined with an even faster increase in the export price, this lifted the average wellhead price from \$6/thousand m^3 in 1973 to \$77/thousand m^3 in 1980. The new price regime brought forth a growing supply of natural gas but restricted demand growth.

By 1980, another major revision of the domestic gas-pricing system was introduced as part of the National Energy Program. The two objectives of this revision were: first, that the pricing system provide sufficient incentive to the gas industry to find and develop new sources of gas supply; and, second, that the prices of natural gas in the end-use sectors be sufficiently attractive both to encourage energy consumers to convert away from oil and towards gas and to facilitate the penetration of gas into new markets. This second objective contrasted with the previously held view that the gas price should be set in such a way as to let gas be just competitive with other energy commodities, including oil.

The NEP's initial price schedule provided for a gradual widening of the gap between oil and gas prices. The gas/oil price ratio (after taxes) at the Toronto city gate was to fall from 80 to 67 per cent over a period of three years. Because the domestic oil price was projected to increase considerably over the period, the Toronto city gate price of gas was expected to rise from about \$92/thousand m^3 in October 1980 to about \$140/thousand m^3 in August 1983 (Table E-2). The price increases were designed in part, however, to provide for two new federal taxes on gas, the natural gas and gas liquids tax (NGGLT) and the Canadian ownership special charge (COSC) – the latter also applicable to oil – as well as for increases in transportation tariffs. The netback from domestic sales at the Alberta border was to decline and then return to more or less its original level over the two- to three-year period. The NEP also imposed a common price for Toronto and all centres eastward. The costs of distribution within the "eastern zone" was to be blended and equally allocated to all consuming centres.

Since the introduction of the NEP, two agreements between the federal government and the Alberta government have altered the oil and gas pricing schedule. The September 1981 agreement stipulated

Table E-2

Canadian Natural Gas Prices and Taxes – Figures Set by the NEP and Actual Figures, 1980-83

	Alberta border price	TransCanada pipeline tariff	NGGLT	COSC[1]	Toronto city gate price
			(Dollars/thousand m^3)		
National Energy Program					
31 October 1980	68.16	23.84	–	–	91.99
1 November 1980	68.16	23.84	10.43	–	102.42
1 July 1981	58.47	27.93	16.01	5.21	107.64
1 January 1982	54.75	31.66	21.23	5.21	112.85
1 February 1982	60.34	31.66	21.23	5.21	118.44
1 August 1982	65.55	31.66	21.23	5.21	123.65
1 January 1983	61.45	35.75	26.44	5.21	128.86
1 February 1983	66.67	35.75	26.44	5.21	134.08
1 August 1983	72.25	35.75	26.44	5.21	139.66
Actual prices and taxes					
31 October 1980	68.16	23.84	–	–	92.00
1 November 1980	66.16	23.84	10.43	–	100.42
1 July 1981	66.13	24.12	15.64	5.21	111.10
1 January 1982	63.37	26.88	15.64	5.21	111.10
1 February 1982[2]	72.05	27.92	23.46	5.21	128.64
1 August 1982[2]	80.73	28.34	23.46	5.21	137.74
1 January 1983[2]	80.73	32.78	23.46	5.21	142.18
1 February 1983[2]	89.41	32.90	16.76	5.21	144.28
1 August 1983[3]	98.09	34.90	5.59	5.21	143.79
1 February 1984[3]	103.91	34.56[4]	–	5.21	143.68

1 The COSC was introduced in the NEP, but the rates were set only in May 1981.
2 Determined under the September 1981 agreement.
3 Determined under the June 1983 amending agreement.
4 The actual toll charged by TransCanada Pipelines is \$34.90/thousand m^3; however, under the June 1983 amending agreement, the effective toll used to calculate the Alberta border price cannot exceed \$34.56/thousand m^3. The federal government therefore subsidizes transportation by \$0.34/thousand m^3, out of the COSC.
SOURCE Based on data from Energy, Mines and Resources Canada.

that the federal government would set the NGGLT with the intention of keeping a 65 per cent gas/oil price ratio at Toronto and a fixed schedule of domestic prices at the Alberta border. In doing so, the setting of prices was shifted from Toronto to the Alberta border. Note that the commitment was towards consumers and not towards Alberta, which had been guaranteed a price. Having established prices at both ends of the pipeline, with the Toronto gas price varying with the oil price, the federal government was left with the NGGLT and the COSC as tools for reconciling its pricing policy with Alberta's border-price aspirations. A decreasing oil price would reduce the Toronto gas price and force the federal government to squeeze out the NGGLT and COSC in order to maintain the agreed schedule of prices at the Alberta border. Increasing oil prices would imply the opposite, again holding producer revenues to the agreement. As a result of the September 1981 agreement, therefore, producer revenues from domestic gas sales would have become insensitive to the oil price and other market conditions – a position that was not realistic in view of the considerable market changes that were to occur.

The declining world oil price had put downward pressures on the domestic oil price and had made it increasingly difficult for Ottawa to maintain its Alberta-border-price commitments, while at the same time keeping the consumer gas price at a 65 per cent parity with oil. The June 1983 "amending agreement" provided that the scheduled fixed price increases in the Alberta border price ($8.83/thousand m^3 every six months) provided for in the September 1981 agreement would be trimmed down if it became impossible for the federal government to maintain the 65 per cent gas/oil price ratio, even if the NGGLT were held at zero. The COSC was maintained, but at the same time, an upper limit was put on future effective transportation tariffs between Alberta and Toronto. Excessive increases in transportation costs would be subsidized by the federal government and, as a consequence, would cut into the COSC instead of the Alberta border price. This arrangement brought the Alberta border price closer to being a netback than the September 1981 agreement had provided for.

In February 1984, in line with the June 1983 amending agreement, the Toronto price was set at $143.68/thousand m^3, the NGGLT was brought down to zero and the transportation cost between Alberta and the East became subsidized for the first time, but only by some $0.34/thousand m^3.

F Government Initiatives for the Expansion of Domestic Gas Markets

A first step that the federal government judged essential to its market policy under the National Energy Program was the determination of a unique city gate price for gas in eastern Canada. The price in all major centers of the "eastern zone" was to be equal to the price at the Toronto city gate, where it has been set at a comparative advantage with respect to oil since 1981 – at a 65 per cent parity. This was designed to stimulate the market penetration of gas.

With respect to pipelines, the NEP announced that the federal government was prepared to set aside $500 million as a contribution to a pipeline to Vancouver Island and to the extension of the TransQuebec and Maritimes (TQ&M) pipeline from Quebec to Halifax. The Vancouver Island project has since been delayed, and only recently has the provincial government announced its approval of a B.C. Hydro plan in preference to a competing proposal by Westcoast Transmission; the eventual participation of the federal government in the project is not defined at the moment. As for the TQ&M pipeline, the NEP Update provided that the extension of the line to Halifax would depend on further examination of the Sable Island gas reserve, which could provide an alternative source of gas for the Atlantic provinces. At the moment, the status of both the TQ&M pipeline and the Sable Island project is unclear.

More definite policy steps were taken by the federal government with respect to pipeline laterals. In May 1982, with the delays in the TQ&M and Vancouver Island projects, Ottawa announced that the $500 million fund would be used for construction of lateral lines in the province of Quebec. The responsibility for construction of the lines was transferred from TQ&M to regional distributors, relieving upward pressures on the West-East transportation tariff that takes into account all investment costs incurred by TQ&M. Because regional distributors are regulated under provincial jurisdiction, the decision was taken in agreement with the Quebec government, which in turn agreed to eliminate its 9 per cent sales tax on natural gas.

Further programs were aimed at assisting gas distribution utilities in the extension of the supply network and the marketing of gas in new markets. The Alberta government and gas producers agreed to contribute to such programs through the market-development incentive payments (MDIP) program. The payments, amounting to 30 per cent of the revenues from incremental gas sales to eastern Canada, are to be made between 1981 and 1987. In fiscal year 1982-83, the payments totaled close to $30 million (Table F-1).

Table F-1

Costs of Federal Programs for Gas Market Development and MDIP Payments from Alberta, 1982-85

	Actual 1982-83	Forecast 1983-84	Estimate 1984-85
		($ Millions)	
Natural gas laterals program	4.8	110.0	235.0
Distribution system expansion program	34.8	59.9	60.0
Gas marketing assistance program	4.8	23.0	27.0
Industrial conversion assistance program	–	3.6	6.8
Compressed natural gas fueling stations program	–	0.4	3.1
Natural gas for vehicles assistance program	0.3	0.6	5.9
Total	44.7	197.5	337.8
Market-development incentive payments from Alberta to Ottawa	28.6	11.8	26.3

SOURCE Based on data supplied by Energy, Mines and Resources Canada to the Treasury Board.

The federal programs that receive MDIP funds include the distribution system expansion program (DSEP), aimed at the expansion of the supply network of the distribution utilities, with an annual budget in the order of $60 million; the gas marketing assistance program (GMAP), designed to assist the distribution utilities in the promotion of natural gas within new markets, at a cost of between $20 and $30 million per year; and the industrial assistance conversion program (ICAP), which pays to industrial energy consumers a sum equivalent to 50 per cent of the cost of a fuel conversion from oil to gas, at a cost of less than $10 million per year.

There are, in addition, two programs aimed at stimulating the use of compressed natural gas (CNG) as an automotive fuel. The CNG fueling stations program and the natural gas for vehicles assistance program provide subsidies for the start-up of fueling stations and the conversion of vehicles, respectively. The two programs combined will cost about $10 million in 1984-85.

Finally, we can mention the Canadian oil substitution program (COSP), which provides subsidies to homeowners and businesses who decide to convert their heating systems from oil to either gas, electricity, wood or propane.

G Implications of Demand Characteristics for Electricity Generation Costs

Chart G-1 illustrates a typical "annual load curve" for an electric utility, showing demands measured in megawatts (MW) chronologically throughout the year. The area under the annual load curve is the total energy demanded in the year, measured in megawatt-hours (MWh). To determine how to meet these variable demands at least cost, system planners reorder the approximately 8,760 hourly demands from the highest to the lowest. The result is an "annual load duration curve," which clearly identifies the number of peak and off-peak hours (Chart G-2). The annual load factor is defined as the ratio of the average of hourly demands in the year to the peak hourly demand. The lower the load factor, the sharper the peak of the annual load duration curve. Typically, the annual load factor for a large Canadian electric utility is in the range of 0.55 to 0.70. This means that the peak hourly demand is between 43 and 80 per cent higher than the annual average.

Chart G-1

A Typical Annual Load Curve for an Electric Utility

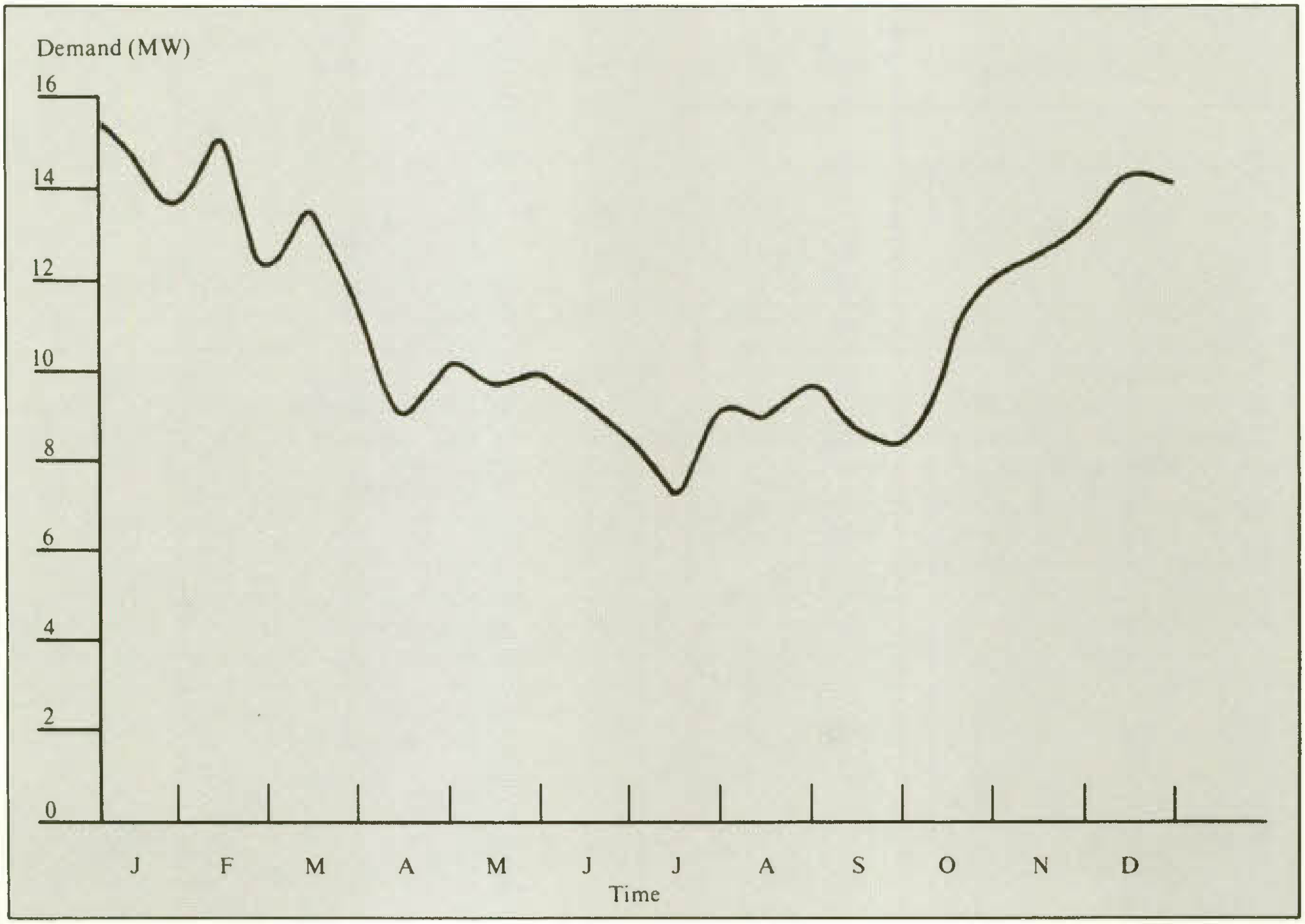
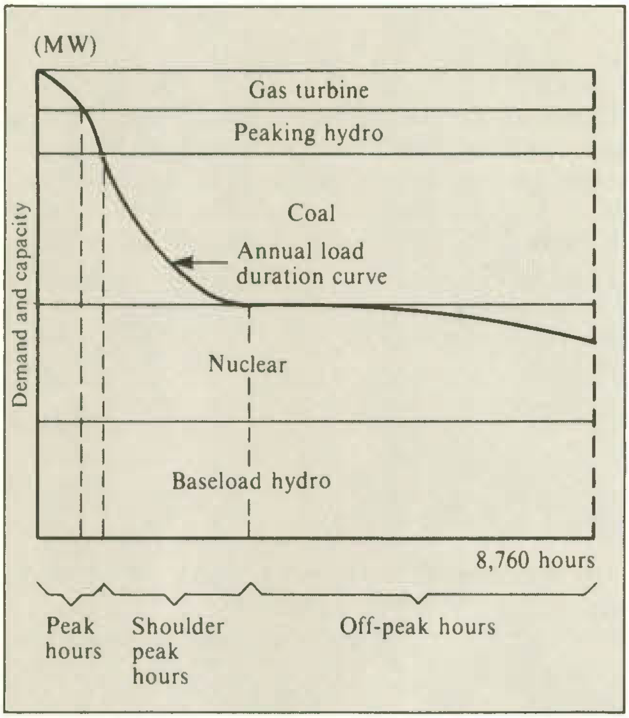


Chart G-2

A Typical Annual Load Duration Curve and Generation Cost Minimization for an Electric Utility



The differences in cost explain why different types of production technologies are used to meet the demands associated with specific annual load duration curves. The generation costs are determined by fixed costs, which are mainly capacity-related, and by variable costs, which are related mainly to energy generation. One important distinguishing feature among the various technologies is the relative difference between fixed costs and variable costs. A second one is "start-up" and "shut-down" costs, which affect the cost of changing output levels over a short period of time.

For base loads that occur on a regular basis over the year, costs will be minimized by using large-scale facilities with relatively high fixed costs and relatively low variable costs. Thus nuclear, coal-fired and large hydraulic installations are generally used for base loads. At the other extreme, facilities with relatively low capital and start-up costs but relatively high variable costs will be used for peak loads occurring intermittently for relatively few hours during the year. For example, gas turbines burning costly fossil fuels are used for peaking demands. Technologies with intermediate capital, operating and start-up costs – such as coal- and oil-fired units – will be used to meet intermediate loads.

In a hydraulic system, the so-called "energy-limited" facilities drawing upon seasonal water flows, reservoirs or pumped storage installations are operated during intermediate or peaking loads. Such facilities have the advantage of having capital costs that are lower than large hydro dams, as well as very low variable cost, but they can only be used for limited periods of time, depending on the water flow or the size of the reservoir.

Keeping in mind the principle of minimizing generation costs by using various technologies, some conclusions can be drawn on the factors that influence generation costs:

- A given quantity of energy demand characterized by a low load factor requires more capacity and a lower average rate of utilization compared with a demand with a smoother load duration curve – i.e., a higher load factor.
- Since variable costs increase as one moves from base load to peak load in a thermal system, the incremental cost of meeting additional demands is higher in peak periods than in other periods. For example, considering energy costs only, the cost per MWh for fuel oil used to operate gas turbines in Ontario was about $61 in 1981, compared with about $23 for coal and $2.90 for nuclear fuel.
- In the case of a predominantly thermal system, the incremental costs will vary mainly in relation to time-of-day and seasonal variations in demand. In large hydro-based systems, the storage in reservoirs can be used to offset daily variations in demand. But water flows vary seasonally and cyclically. Thus, in a hydro-based system, costs will tend to vary mainly seasonally and cyclically, while daily cost variations will be less important than for thermal systems.

Within limits, considering maintenance requirements and the seasonal variations in water flows – and allowing for adjustment in capacity over the longer term – it is concluded that generation costs could be reduced by shifting demands towards off-peak periods.

H Time-Differentiated Electricity Rates in Europe and the United States

European Utilities[1]

Électricité de France was the first European utility to offer time-of-use rates. Its so-called "green tariff," introduced in 1958, offered such rates to high-voltage customers on an optional basis. Some time later, it was made standard for high-voltage customers. Over the years, many European utilities have introduced time-of-use rates for various customer classes on a mandatory or voluntary basis. In some cases, more than one tariff structure may be offered. Some utilities levy a demand charge on residential customers, based on the size of the main fuse or circuit breaker. It should be noted that seasonally differentiated rates need not require any change in meters for residential and commercial customers who are charged only on the basis of the energy consumed.

Table H-1 summarizes some of the characteristics of time-differentiated tariffs in six European countries during the second half of the 1970s. To a great extent, the different rate structures reflect the cost variations experienced by the utilities arising from their mix of hydraulic and thermal generating facilities.

In addition to time-of-use rates, European utilities also employ active load-management techniques to further reduce costs and prevent shortages. Various methods are employed, depending on the nature of the variations in costs over time and on the extent to which customers are willing to yield control over their consumption to the utility. For example, interruptible sales contracts may allow the utility to cut off demand for several hours during the day in thermal-based systems or for longer periods of time seasonally in hydro-based systems. Such techniques are attractive because they allow the utilities to reduce demand by

Table H-1

Structure of Some High-Voltage Tariffs in Six European Countries, 1975 to 1977

	Variation in rates			
	By season for:		By time-of-day for:	
	Peak load	Energy	Peak load	Energy
United Kingdom – Southeastern Electricity Board (1976)	x			x
Finland – Helsinki Electricity Works (1977)	x			x
France – Électricité de France (1976)	x	x	x	x
Norway – Water Resources and Electricity Board (1975)		x		
Sweden – State Power Board (1976)		x		
– Stockholm Energy Works (1975)				x
West Germany – Westphalian Utility (mid-1970s)[1]		x		x

1 Tariff structure for medium-voltage, high-utilization customers.

large amounts, while dealing with only a small number of customers. Interruptible sales are particularly effective in reducing unpredictable requirements, such as weather-related peak demands.

Where costs differ significantly over the course of the day, the utilities may encourage customers to employ appliances or adopt hybrid systems that enable electric loads to be controlled. For example, the utilities may take over the active control of supply to space or water heaters, using various remote-control techniques or direct controls, such as staggered time-clock settings. Such techniques applied to storage devices and the use of alternative fuel sources can allow temporary reductions in peak-period demands for generation and in the demands placed on specific links in the distribution system, without serious inconvenience to customers.

Unless customers are willing to yield all control of their appliance and energy consumption decisions to the utility, the use of such load-control techniques will likely require financial incentives in order to make them attractive to customers.

U.S. Utilities[2]

In the 1970s, public utility commissions in California, Michigan, New York and Wisconsin ordered that time-of-day pricing be implemented for the largest industrial and commercial customers and that meters allowing for time-of-day rates in the future be installed for smaller commercial and industrial users. Beginning in 1974, an extensive report on rate design and load control (referred to collectively as "load management"), eventually involving over 100 individual studies, was prepared at the request of the National Association of Regulatory Utility Commissioners and sponsored by a number of major organizations concerned with electricity matters. By 1977, 22 state public utility commissions had either held generic rate hearings, ordered utilities to submit time-of-day rates or received time-of-day rate proposals.

The Public Utility Regulatory Policies Act, passed by the U.S. Congress in 1978, requires state regulatory authorities and utilities to consider voluntary rate design and regulatory standards to determine whether they promote conservation, efficiency and equity. The Act stipulates that rates should not discriminate against qualifying cogenerator or small power producers. The Federal Energy Regulatory Commission rules implementing the Act and subsequent court decisions have specified that such rates must equal "avoided cost" – that is, the additional costs that would otherwise be incurred by the purchasing utility. As a result, there has been an increase in generation by cogenerators and small hydro facilities in recent years.

By the end of 1981, many U.S. electric utilities had implemented time-differentiated rates for some customer classes on a mandatory or voluntary basis, and a number of time-of-use rate design experiments had been concluded or were in progress. Much research has been undertaken to evaluate the response to time-of-use rates, and the evidence indicates that desirable changes in consumption patterns can be achieved. Many load-control activities are either under study, being used experimentally or already in effect. It has been estimated that by the end of 1983, about 1.2 million load-management devices, some remotely controlled by electric utilities, had been installed. It has been projected that by 1992, the electrical demands of up to 7 million customers will be regulated by load-management devices, in some cases in synchronization with time-of-day rates.

I The Selection of Time Periods for Electricity Pricing

The first and foremost consideration in the selection of rating periods is the extent to which costs differ, taking into account demand and supply factors (including maintenance requirements). Since rates must be set in advance, rating-period selection must depend on the probability that costs will differ among certain groups of hours based on these factors. Climatic conditions will usually play an important role in the selection of rating periods because of their influence on primary and secondary peak demands. Weather conditions within seasons, by contrast, are rather unpredictable and would generally not be considered as a major factor in time-of-use rate design. Other load-management techniques, such as interruptible sales, are more effective in dealing with weather-induced peak demands.

A second consideration is that the rating periods chosen must be simple and understandable to customers. If there are many periods and a lack of uniformity, customers are unlikely to be able to respond in a rational way. The structure of rating periods must also take into account the metering and administrative costs involved.

A third factor in the selection of rating periods is the implication of the structure for load shifting and consequent system costs. For example, if a peak period is defined for only a short period of time, customers may simply shift demands to a neighbouring time period, which will have little effect on reducing capacity requirements. On the other hand, if the period is too long there may be little incentive for customers to reduce peak-period demands, because the average of costs over a long peak period will tend to obscure the extreme costs of the true peak hours. Long peak periods can also result in needle peaks, where demands are reduced except in the case of extreme weather conditions.

Based on these factors, it may be desirable to select different rating periods for different customer classes.

J Difficulties in Applying Marginal-Cost Pricing to Electricity

Economic theory indicates that the achievement of efficiency requires that prices be based on short-run marginal costs – that is, those costs which are incurred when capacity cannot be adjusted. The prescriptions for measuring and applying of the concept of marginal cost to electricity pricing vary, however, depending on the assumptions made and on the array of factors taken into account.

Assuming certainty in supply and demand and a least-cost system, economic theory indicates that in off-peak periods, prices should be equal to the incremental running cost (or the opportunity cost, in the case of hydro) of the most costly unit in operation to meet demand. This contrasts with the case of prices based on average cost, where prices would reflect a weighted average of the cost of all fuels consumed. Under certainty conditions, no capacity costs would be levied in off-peak periods since additional capacity would not be required to meet small increments in demand.[1] At the peak hour, however, an increase in demand would require an increase in capacity, with the result that the marginal cost in that hour should be the sum of the marginal running and capacity cost for the least costly peaking unit.

Despite the theoretical prescription, long-run rather than short-run marginal costs have generally been favoured as a basis for electricity pricing. In equilibrium, which assumes correct forecasting, long-run marginal costs are equal to short-run marginal costs, so that there is no conflict.[2] The reason advanced for using long-run marginal costs is that short-run marginal costs, because of changing circumstances, would tend to be more volatile. As a result, their use would not contribute to the objective of rate stability and continuity and would not provide consumers with proper information in making decisions on investments associated with electricity consumption. Furthermore, there must be a cost-effective mechanism for communicating price changes to users. Except in the case of a limited number of large customers, it is generally impractical to employ volatile short-run marginal costs as a basis for pricing because of the additional expense incurred for the more complex metering facilities required and of the extra administrative and regulatory costs that would arise.

No electrical system can ever be expected to be in perfect equilibrium for more than limited periods of time, if ever. As long as it is not too far out of equilibrium, there is no major conflict between short-run and long-run marginal costs. A problem arises, however, when there are large deviations between short-run and long-run marginal costs as a result, for example, of significant changes in relative prices or substantial excess capacity caused by forecasting errors. Where short-run marginal costs exceed long-run marginal costs (e.g., in the case of oil-fired capacity), basing prices on the latter would result in excess consumption of costly fuel oil over the short term. Conversely, where there is excess hydro capacity, for example, basing prices on long-run marginal cost would result in the underutilization of hydraulic energy that cannot be reused and the incremental cost of which is negligible.

There is no clear ideal path for prices to move from a situation of disequilibrium to a new long-run equilibrium. Perhaps the best that can be done is to "mothball" (or retire) capacity that is likely to be obsolete and to offer incremental sales at a discount, provided that it is made clear to users that the price reductions are only temporary.

Two factors, in particular, have created confusion because they can result in different conceptual and empirical results for marginal costs. The first is the extent to which the system reflects optimum efficiency, and the second is the nature of the assumed changes in demand. In the first instance, some of the methods that have been proposed involve estimating the long-run marginal costs for a system by measuring the change in system costs that result from an acceleration or delay in the system expansion plan, in response to an assumed change in demand. This approach is adopted on the grounds that these are the actual marginal costs for the utility.[3] If the system is notably out of equilibrium, these results will differ from actual short-run marginal costs and from the long-run, marginal-cost estimates derived on the basis of the assumption that a least-cost system is in existence.[4]

The second factor – the nature of the change in demand under study – is highlighted by the following quotation: "There are as many marginal costs as there are conceivable load increments."[5] Thus the "long-run incremental cost" approach, for example, derives an estimate for long-run marginal costs based on projected or assumed increments in the whole annual load curve over time. It provides a weighted average marginal cost for changes in demand over all hours of the year. The estimates of marginal costs for changes in demand for one hour or for a segment of the annual load duration curve will yield different results, depending on the time period in question.

When the probabilistic nature of demand and supply factors – such as weather, forced outages and water conditions – as well as maintenance requirements are taken into account, the marginal-cost pricing rule becomes generalized. In these circumstances, the rule is that "prices should be set equal to the expected marginal running cost, plus the expected marginal shortage costs." In equilibrium, capacity should be added at the point where the marginal capacity costs equal the marginal shortage costs, which is the optimal investment decision rule. From the probabilistic perspective, the capacity costs should be shared by off-peak and peak users, since there is a risk of shortage in many hours of the year. The rule that marginal capacity should equal marginal marginal shortage costs provides a conceptual mechanism for distributing capacity costs over the load curve, depending on the relative probabilities of shortages.

The problem of a "shifting peak," which may be induced by instituting time-of-use rates based on marginal costs, is an additional complicating – but important – aspect in the allocation of capital costs. Thus the marginal costs must take into account the changes in demand that will be induced. However, reliable estimates of own-period and cross-period price elasticities of demand that would be necessary to determine how demand patterns would change are simply not available.

Given a set of rating periods and marginal costs, the expected revenues will not necessarily equal the revenue requirement. Thus some adjustments to marginal costs will generally have to be made. Applying the economic pricing rules requires elasticity estimates that may not be available; and, in any case, adjustments on this basis may be perceived by some as unfair. One way to reduce conflict in this area is to respect revenue requirements by customer class based on accounting-cost allocations, although there is no economic justification for this. Furthermore, a marginal-cost analysis may indicate that current customer classifications should be changed.[6]

K Benefits and Disadvantages of Electricity Exchanges

While the nature of the benefits and disadvantages of electricity exchanges, as classified below, involve distinct aspects, there are often close interrelationships between some of them.[1]

Benefits

Reliability and reserve sharing — By sharing capacity, utilities can reduce reserve margins and/or increase reliability. This is possible because the likelihood that two or more generating units will be nonoperable at the same time is less than the sum of the probabilities for the individual units.

Load diversity — When two systems experience peak loads in different seasons, the combined system can be served with less total capacity at a given reliability level than when each of the two systems is operated separately.

Surplus energy sales — Energy that is not needed at the time it is available can be used to reduce energy costs in other systems. This possibility often arises for generating systems based on natural forces. For example, there could be excess energy available from run-of-the-river facilities on a seasonal basis or from high-water conditions at major base-load installations on a cyclical basis. Future possibilities could include solar and wind generation and tidal power.

Economy Interchanges — These are possible when the cost of producing additional energy in one system is less than in another. For example, in the summer a U.S. utility would be using high-cost generation facilities when demand is close to its peak, while a Canadian utility might have lower-cost facilities available (after maintenance requirements) since demand would be much below its peak. The reverse would be the case in winter. Economy interchanges are often made on a day-to-day basis or even an hour-to-hour basis, as utilities may be facing different running costs for the last unit(s) being utilized. Transmission losses must be taken into account in determining whether savings can be realized.

Economies of scale in generating units — A utility may not be able, by itself, to realize cost reductions made possible by larger units because it cannot use all the output or because, given the size of its system, the cost of reserve capacity may be prohibitive. Utilities can jointly plan the expansion of their systems so that the cost savings of larger units can be realized. This type of benefit can be realized by prebuilding facilities with long-term external sales contracts, with the quantities decreasing over time as the selling utility's demand increases.

Coordinated operating schedules — By coordinating their maintenance schedules, utilities can ensure that lower-cost facilities are operated as long as possible.

Use of complementary technologies — Thermal and hydraulic technologies can complement each other in various ways. In high-water years, hydro generation can displace more costly thermal generation; in low-water years, hydro units can provide peaking capacity while thermal units supply base-load energy. A second example is the use of pumped-storage hydro installations, which can be supplied using low-cost thermal units in off-peak periods and can then be used to displace thermal generation in high-demand periods.

Reduced oil dependency — Increased interchanges could reduce the use of oil for electrical generation. Prince Edward Island now purchases most of its electricity from New Brunswick to displace its oil-fired generation. Exports to the U.S. northeastern states are largely accounted for by the displacement of oil-fired generation.

Carrier transfers — This takes place when a utility transfers power to its own customers through another utility to save transmission costs. For example, B.C. Hydro transfers power to the Columbia Valley-East Kootenay system by "wheeling" it through the United States in order to avoid having to build transmission lines over the Rocky Mountains.

Corresponding to the types of benefits that can be achieved are a variety of types of transactions. For example, firm sales of power and/or energy require delivery as scheduled, usually for an extended period, unless adequate supply to the vendors' customers is threatened. By contrast, nonfirm contracts allow for interruption on fairly short notice. Short-term capacity and/or energy sales are firm in nature but are made for relatively short periods. Emergency sales are made on a daily or hourly basis to alleviate temporary periods of insufficient capacity. The nomenclature and definitions of transaction types have not yet been standardized across North America but are defined in individual agreements.

Disadvantages

Transmission losses — With greater distances, losses in transmission increase, thus requiring greater capacity and fuel use in the case of thermal generation.

Circulatory power flows — Increased Canada-U.S. interconnections could increase circulatory power flows between states. Such circulatory flows, which now occur around Lakes Erie and Ontario, can limit transfer capability and increase transmission losses in some cases, although overall losses should decrease.

Transmission reinforcement — In addition to new lines to carry additional exchanges, greater exports will require additional intrasystem transmission reinforcement, which may involve significant costs.

System security — Increasing interconnections raises the potential for cascading failure, so that suitable protective equipment is required as the system becomes more complex. Overall, with greater interconnections there is a greater risk that a failure will impact over a much wider area.

Autonomy — Greater consideration requires each utility to give up some autonomy in its planning and operations. Unfortunate circumstances or planning or operating errors in one system can affect the reliability of other systems.

L Policy Simulations: Conventional Oil and Natural Gas

In an attempt to measure the quantitative implications of some of the changes in energy policy that we proposed in Chapter 8, a series of simulations were prepared using an energy macroeconomic model, MACE, developed by Professor J. F. Helliwell and his team at the University of British Columbia.[1] While the detailed results of these and other simulations must be interpreted with caution, the general directions indicated by the results appear to be reliable.

Assumptions

The Three Base Cases

First, a base case was run through the model, based on the assumptions of a *flat real world oil price* (Base Case A-1). The nominal price of oil was assumed to grow at the same pace as the rate of inflation in the United States.

To test the robustness of our policy package, two alternative base cases were developed, based on variations in world oil prices. In the *rising world oil price* scenario (Base Case A-2), the price of oil (f.o.b. Persian Gulf) is assumed to increase at the rate of 5 per cent per year in real terms between 1985 and the year 2000. In the *declining world oil price* base case (Base Case A-3), the Persian Gulf price is assumed to decrease at 5 per cent per annum in real terms over the same period.

In all three base cases, the nominal world price of oil is assumed to be U.S.$29/bbl (f.o.b. Persian Gulf) in 1983. In addition, the current set of energy taxation and pricing policies is maintained: oil discovered before 31 March 1974 receives 75 per cent of the new-oil reference price (NORP) but is never allowed to fall below $29.75/bbl. It is assumed that no new oilsands plants or frontier sources will come on stream during the period 1985-2000.

Natural gas at the Toronto city gate is priced at a 65 per cent BTU-parity with domestic oil to the end of 1984. In 1985-86, producers receive an annual increase of 50¢/mcf and the BTU-parity price is allowed to rise once the natural gas and gas liquids tax (NGGLT) falls to zero. After 1986, the producers forgo any increase in the wellhead price until the 65 per cent BTU-parity is regained. The BTU-parity rises in the 1990s to reflect the increasing scarcity of natural gas. The approved export quantities of natural gas are reduced over the period 1983-87, as are export prices, to reflect softness in the U.S. market.

The rates of real growth and inflation in the other OECD countries are assumed to follow the U.S. rates.

In Base Case A-2, the higher world price of oil affects the rest of the world economy, as does, under Base Case A-3, the lower world price. This has a particularly important impact on an economy like Canada's, which is so heavily dependent on foreign trade. Accordingly, exogenous assumptions have been made with respect to the impact of higher and lower world oil prices on real and nominal GNP, the GNP deflator and interest rates in the United States and on the output deflator in the OECD.

The "Shock" Simulations

We then performed two "shock" simulations. The first reflected our recommendation that oil prices be deregulated and that the deregulation of natural gas prices be phased in. The second simulation, termed "policy package" in the forthcoming discussion, included oil and gas price deregulation, plus a modified petroleum and gas revenue tax, which becomes a tax on production revenues, net of operating costs and of investment expenditures on oil and natural gas exploration, development and production in each year.[2]

Price Deregulation: Case I

Under this scenario, it is assumed that all Canadian oil is priced at the world level beginning in 1985 and that a phased-in deregulation of domestic natural gas prices also begins in the same year. The BTU-parity price of natural gas at the Toronto city gate is assumed to be 60 per cent of the oil price in 1985 and 55 per cent from 1986 to 1990. In the 1990s the BTU-parity ratio begins to rise as the gas surplus is reduced or eliminated. By 1994 the parity is back to 65 per cent, and it rises thereafter.

The Canadian ownership special charge (COSC) is shifted at the retail level to oil products only – it does not apply to gas – and is assumed to be about 3 per cent.

Policy Package: Cases II, III and IV

The phased deregulation of natural gas prices is assumed to result in gas prices at 55 per cent of the BTU equivalent of oil prices between 1986 and 1990; the BTU-parity rises back to 65 per cent by 1994. The Case I assumption with respect to the COSC applies in these scenarios as well.

The basic and effective rates of the PGRT and the small producers' exemption are kept unchanged. It is assumed that there is no small producer's exemption when there is no PGRT to pay.

Concurrently, a federal off-oil charge on all oil products of approximately 1 per cent is introduced. In fact, the COSC could become a Canadian ownership and off-oil charge. (The federal government is assumed to continue to levy a gasoline excise tax.)

Results[3]

Case I: Price Deregulation Under Flat World Oil Prices

The simulation results suggest that the combined effect of deregulating both oil and natural gas prices would be to lower overall energy prices, which in turn would lower the inflation rate and stimulate growth in the Canadian economy. The overall rate of inflation, as measured by the GNP deflator, would be lower by about 0.6 percentage points in 1985 and 1 percentage point in 1986. Real GNP would increase by an average of about 0.5 per cent per year over the period 1985-90 (Table L-1). Charts L-1 and L-2 show the detailed results for real GNP and the rate of inflation. The level of unemployment – which now stands at about 1.5 million – would be reduced slightly over the next few years, and employment could be created for approximately 100,000 workers (Chart L-3).

Table L-1

Macroeconomic Effects of Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1] Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	(Per cent)			
Change in:				
Real GNP				
1985	0.18	0.20	0.08	0.33
1986	0.69	0.70	0.44	0.97
1985-90 (average)	0.47	0.53	0.42	0.91
1995	0.35	0.49	0.51	1.11
Real energy investment				
1985	-0.25	0.58	0.72	0.44
1986	-0.54	-0.08	0.14	-0.29
1985-90 (average)	-0.38	0.60	0.16	-0.19
1995	0.01	0.13	0.17	-0.08
Real nonenergy investment				
1985	0.99	0.95	0.53	1.37
1986	2.73	2.71	1.81	3.59
1985-90 (average)	1.42	1.52	1.38	2.53
1995	0.88	1.02	0.98	2.82
	(Percentage points)			
Inflation rate				
1985	-0.58	-0.41	-0.10	-0.74
1986	-1.09	-1.10	-0.79	-1.40
1985-90 (average)	-0.17	-0.16	-0.17	-0.34
1995	-0.34	-0.36	-0.41	-0.60
Unemployment rate				
1985	-0.08	-0.08	-0.05	-0.11
1986	-0.24	-0.24	-0.16	-0.32
1985-90 (average)	-0.04	-0.07	-0.08	-0.14
1995	0.20	0.16	0.14	0.29

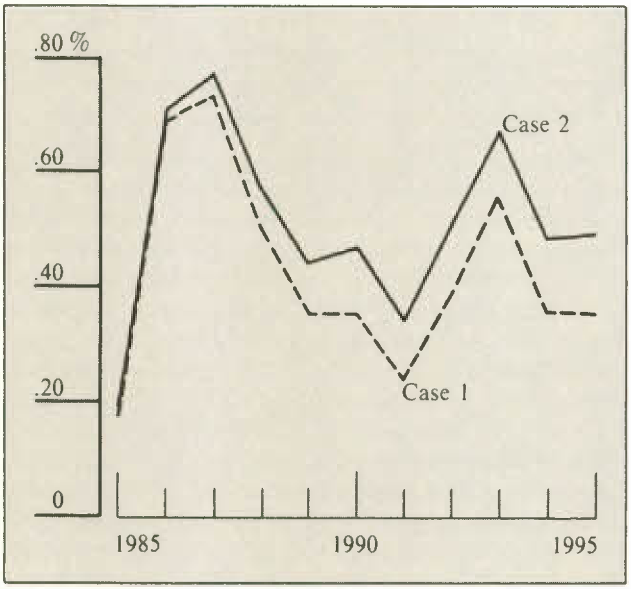
Table L-1 (Concl'd.)

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1] Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
		(Index)		
User price index for energy				
1985	-2.94	-2.49	-1.19	-3.78
1986	-5.10	-5.18	-3.89	-6.38
1985-90 (average)	-1.15	-1.11	-1.07	-2.16
1995	0.04	0.02	-0.07	-0.12
		($ Billions)		
Current account balance				
1985	0.59	0.73	0.66	0.77
1986	1.05	1.18	1.02	1.30
1985-90 (average)	1.73	1.91	1.82	2.48
1995	4.77	5.25	5.56	7.33

1 Includes price deregulation, modified PGRT and modified COSC.
2 In this scenario, the natural gas and gas liquids tax (NGGLT) is set at zero. The Canadian ownership special charge (COSC) is modified and shifted onto oil products only, at the retail level.
3 These figures are deviations from Base Case A-1 values.
4 These figures are deviations from Base Case A-2 values.
5 These figures are deviations from Base Case A-3 values.
SOURCE Economic Council of Canada, MACE Model, July 1984.

Chart L-1

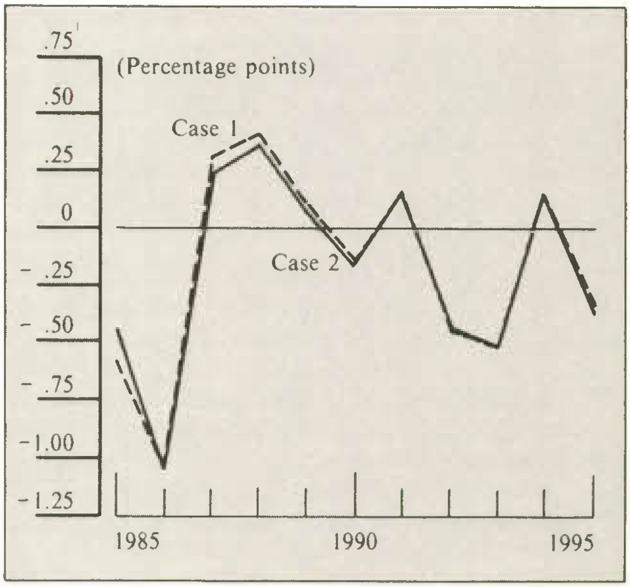
Effect[1] of Alternative Energy Tax and Pricing Policies on Real Gross National Product, Canada, 1985-95



1 Expressed as a change relative to the base case values.

Chart L-2

Effect[1] of Alternative Energy Tax and Pricing Policies on the Rate of Inflation, Canada, 1985-95



1 Expressed as a change relative to the base case values.

Table L-2

Effects of Alternative Energy Tax and Pricing Policies on Consumer Prices and Energy Demand, Canada, 1985-95

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1]		
		Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	(Per cent)			
Change in:				
Average user price of oil				
1985	2.14	3.07	3.22	2.77
1986	1.31	2.23	2.50	1.89
1985-90 (average)	1.32	2.22	2.53	1.65
1995	-0.27	0.46	0.41	-0.86
Average user price of natural gas				
1985	-12.16	-12.20	-8.52	-15.70
1986	-22.60	-22.66	-16.33	-28.61
1985-90 (average)	-17.32	-17.38	-14.51	-26.74
1995	-4.29	-4.52	-4.08	-18.90
Canadian demand for crude oil				
1985	-2.94	-3.38	-2.88	-3.77
1986	-5.04	-5.59	-4.57	-6.51
1985-90 (average)	-4.19	-4.76	-4.43	-6.30
1995	-0.88	-1.43	-1.35	-3.32
Canadian demand for natural gas				
1985	6.55	6.66	4.62	8.72
1986	14.81	14.99	10.21	20.14
1985-90 (average)	12.69	12.87	10.23	21.55
1995	3.04	3.32	2.96	14.87
Imports of crude oil per day				
1985	-7.07	-8.96	-8.04	-9.60
1986	-11.13	-13.35	-11.86	-14.53
1985-90 (average)	-9.19	-11.67	-12.17	-13.45
1995	-1.66	-3.67	-5.09	-5.39
Demand for energy				
1985	1.06	0.90	0.43	1.40
1986	3.30	3.13	1.97	4.32
1985-90 (average)	3.33	3.17	2.40	5.50
1995	1.15	1.08	0.95	5.09

NOTE For the footnotes, see Table L-1.
SOURCE Economic Council of Canada, MACE Model, July 1984.

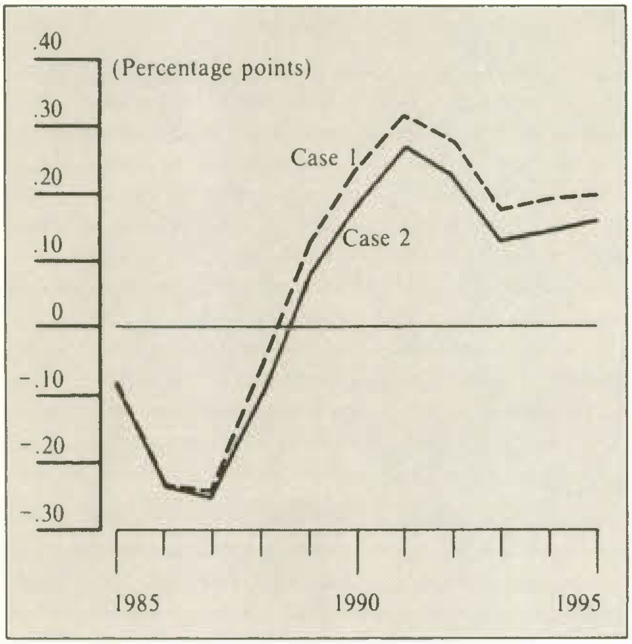
Deregulation would affect the composition of energy demand in the economy and the supply of oil and natural gas. This would have important consequences for real energy investment. Relative to continued oil and gas price controls, this policy would raise the average price of oil consumed in Canada by about $1.30/barrel in 1985. The demand for oil would drop by an average of 4 per cent in the late 1980s, while the demand for natural gas would rise by about 13 per cent (Table L-2). This would result in a drop of oil imports of about 9 per cent and in a slight improvement in the balance of trade in energy and, consequently, in the current account of the balance of payments. Chart L-4 shows the effects on the imports of crude oil.

On the supply side, our results suggest that the deregulation of oil and natural gas prices would stimulate domestic oil production and promote oil exploration and development over the next few years. Gas production would also increase, but gas-directed exploration and development would be reduced. The results show that new oil reserve discoveries from nonfrontier sources would be quite responsive to increased investment in oil.

The drop in natural gas prices would reduce the incentive to discover new gas. As can be seen in Table L-3, the percentage drop in natural gas investment would be slightly larger than the increase in oil invest-

Chart L-3

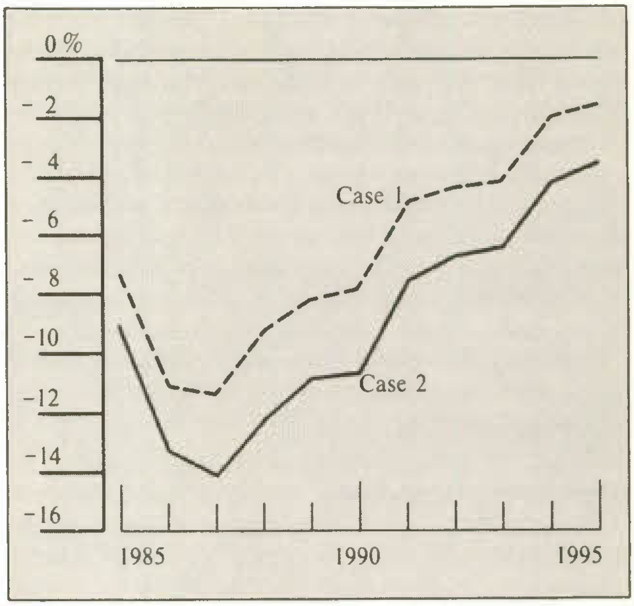
Effect[1] of Alternative Energy Tax and Pricing Policies on the Unemployment Rate, Canada, 1985-95



1 Expressed as a change relative to the base case values.

Chart L-4

Effect[1] of Alternative Energy Tax and Pricing Policies on Imports of Crude Oil, Canada, 1985-95



1 Expressed as a change relative to the base case values.

Table L-3

Effects of Alternative Energy Tax and Pricing Policies on Oil and Natural Gas Discoveries, Production and Investment, Canada, 1985-95

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1] Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	(Per cent)			
Change in:				
Discoveries of oil (reserve additions) per annum				
1985	1.99	9.99	9.26	10.61
1986	4.84	11.14	9.17	13.29
1985-90 (average)	2.27	8.37	7.20	11.20
1995	0.84	3.83	2.23	8.62
Actual oil production per day				
1985	0.14	0.70	0.68	0.70
1986	0.32	1.12	1.07	1.15
1985-90 (average)	0.43	1.58	1.52	1.69
1995	0.82	3.43	3.02	4.13
Discoveries of natural gas (reserve additions) per annum				
1985	-4.49	-0.27	1.56	-2.02
1986	-8.86	-5.72	-2.69	-8.78
1985-90 (average)	-6.63	-3.76	-2.36	-8.21
1995	0.18	1.58	1.35	-6.53

Table L-3 (Concl'd.)

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1] Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	(Per cent)			
Actual natural gas production per day				
1985	4.21	4.30	3.01	5.62
1986	8.76	8.86	6.06	11.89
1985-90 (average)	7.40	7.54	5.93	9.92
1995	2.27	2.49	2.08	-1.74
Investment in nonfrontier oil				
1985	1.10	7.16	7.00	7.21
1986	1.95	5.95	5.56	6.27
1985-90 (average)	0.91	5.05	4.94	5.38
1995	-0.41	2.92	2.16	3.66
Investment in nonfrontier gas				
1985	-4.82	-0.61	1.42	-2.59
1986	-9.99	-6.67	-3.31	-10.21
1985-90 (average)	-7.35	-4.42	-2.87	-9.22
1995	-2.64	-0.94	-0.77	-10.77
Wellhead price of oil				
1985	14.47	14.35	14.22	12.38
1986	13.06	12.93	12.72	11.47
1985-90 (average)	10.69	10.57	10.35	9.42
1995	3.68	3.38	2.23	3.66
Wellhead price of oil after taxes and royalties				
1985	0.01	5.80	5.72	5.87
1986	-0.04	3.80	3.71	3.91
1985-90 (average)	-0.54	3.55	3.47	3.66
1995	-1.76	0.89	0.36	0.51
Wellhead price of natural gas				
1985	-8.51	-8.63	-5.32	-11.88
1986	-16.88	-17.06	-11.43	-22.78
1985-90 (average)	-12.75	-12.92	-9.56	-21.41
1995	-2.91	-3.27	-3.34	-18.50
Wellhead price of natural gas after taxes and royalties				
1985	-7.69	-1.42	1.74	-4.51
1985	-15.39	-10.89	-5.57	-16.24
1985-90 (average)	-11.65	-7.54	-4.90	-15.30
1995	-2.77	-0.92	-0.92	-14.26

NOTE For the footnotes, see Table L-1.
SOURCE Economic Council of Canada, MACE Model, July 1984.

ment, and hence total real energy investment would decline slightly (Table L-1), even though there would be an increase in the overall industry cash flow. Total investment in the nonenergy sector, however, would increase by more than the decline in the energy sector.

Industry cash flows would rise under price deregulation, assuming that royalty and tax rates remain at their present levels. The industry's cumulative cash flow, after taxes, royalties and operating costs – but before investment – would increase by about $240 million over the period 1985-95 (Table L-4). The energy revenues of both the federal government and the provinces would be affected. As can be seen from Table L-5, the estimates suggest that the federal government would gain a total of $1.9 billion in cumulated revenues over the period 1985-95, while the provincial governments would lose about $0.9 billion (Chart L-5).

Table L-4

Effects of Alternative Energy Tax and Pricing Policies on the Cumulative Cash Flow of Industry (After Taxes, Royalties and Operating Costs, and Before Investment), Canada, 1985-95

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1]		
		Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	($ Billions)			
Change in:				
1985	0.32	1.02	1.13	0.86
1986	0.07	0.66	0.86	0.42
Cumulative cash flow 1985-95	0.24	7.04	9.73	0.08

NOTE For the footnotes, see Table L-1.
SOURCE Economic Council of Canada, MACE Model, July 1984.

Table L-5

Change in Cumulative Revenue-Sharing Estimates Under Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Case 1: price deregulation[2] under flat world oil prices[3]	Policy package[1]		
		Case 2: flat world oil prices[3]	Case 3: rising world oil prices[4]	Case 4: declining world oil prices[5]
	($ Billions)			
Change in:				
Federal government revenues	1.9	2.2	7.1	-12.1
Provincial government revenues	-0.9	-0.1	0.7	-11.4
Industry revenues	1.8	8.8	11.4	1.3
Total government and industry revenues	2.7	10.9	19.2	-22.1

NOTE For the footnotes, see Table L-1.
SOURCE Economic Council of Canada, MACE Model, July 1984.

Case II: Policy Package Under Flat World Oil Prices

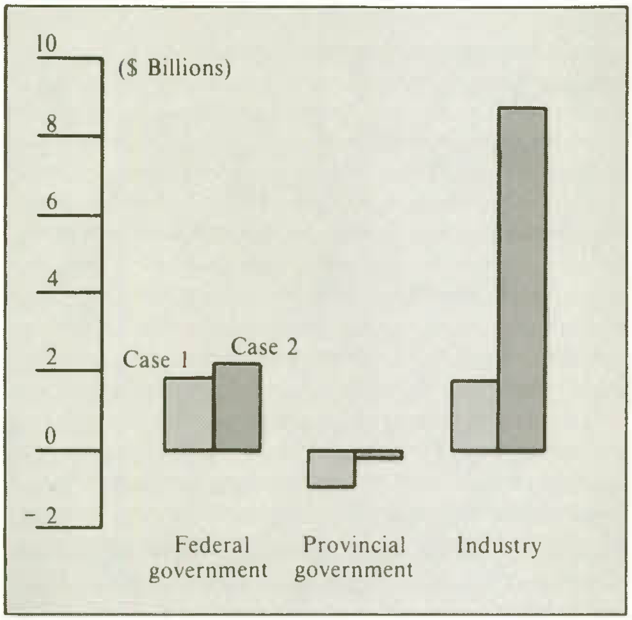
The results for the policy package show that oil reserve additions and investment in conventional oil would increase significantly, relative to the base case levels. Although new gas would not receive the same stimulus as oil from modifying the PGRT, the change in overall real energy investment would be marginally positive (Table L-1). The modest increase in energy investment would have a positive impact on real growth and employment in the economy overall, while the increased supply of oil would reduce imports and would have a positive effect on the current account balance and on the exchange rate. The package would offer scope for noninflationary economic growth. Real GNP would increase by an average of about 0.5 per cent per year over the period 1985-90, and inflation would be lower by about 0.4 percentage points in 1985 and 1 percentage point in 1986 (Table L-1).

The results show that, relative to the base case, the impact on the price of oil to the consumer would average about 2 per cent per year over the period to 1990 (Table L-2). The package would reduce the demand for oil by an average of 5 per cent per year during the period to 1990.

There is no indication that the deregulation of oil and gas prices would cause a surge of price increases, and there is considerable assurance that Canada's capacity to develop indigenous supplies of oil would be

Chart L-5

Effect[1] of Alternative Energy Tax and Pricing Policies on Cumulative Revenue Shares, Canada, 1985-95



1 Expressed as a change relative to the base case values.

increased, giving greater security of supply over the longer term. The main elements of our proposals would thus provide a robust and lasting solution.

This package would also affect the economy as a whole through its effects on government balances. The results in Table L-5 indicate that over the decade to 1995 the federal government would collect $2.2 billion in additional revenues. Provincial revenues would be lower by $100 million, while cumulative industry revenues would rise by $8.8 billion over the period 1985-95 (Chart L-5).

The increase in federal energy revenues would average about $175 million annually to 1995 (in current dollars). These revenue changes can be related to the projected 1984-85 revenues from existing federal oil and gas industry and commodity taxes, as shown in Table L-6. At present, the total energy revenues of the federal government are about $8 billion, with the PGRT amounting to $2.4 billion and the COSC bringing in about $1 billion. The February 1984 federal budget contains estimates for the four years to 1987-88 that show some improvements in revenues and some slight declines in costs.

Case III: Policy Package Under Rising World Oil Prices

The policy package in Case III is the same as in Case II – that is, it includes oil and gas price deregulation, plus a modified PGRT – but it is based on rising world oil prices.

The results show that the introduction of this package under these circumstances would have the following major impacts: real GNP would rise in all years, and the unemployment rate would be reduced during the period 1985-90. The chief source of the favourable impact on real GNP would be investment in both the energy and the nonenergy sectors, closely followed by consumption. The rate of inflation would decline fractionally in 1985 and 1986 – by about 0.79 percentage points in the latter year. The lower inflation rate would be mainly attributable to the lower domestic price index for energy, which would be down by about 1.19 per cent in 1985 and 3.89 per cent in 1986.

In the case of the foreign sector, Canada's balance of trade in energy would be higher by approximately $10.3 billion over the period 1985-90. The overall balance of trade account would increase above base case levels by about $11 billion over the period 1985-90, and the exchange rate would appreciate.

The average user price of oil would increase by 3.2 per cent above base case levels in 1985 and by an average of 2.5 per cent per year over the period

Table L-6

Summary of Federal Revenues and Expenses in the Oil and Gas Industry, Canada, 1984-85

($ Millions)	
"Upstream" revenues	6.210
Corporate income taxes (estimated)	2.800
Petroleum and gas revenue tax	2.380
Incremental oil revenue tax	70
Canadian ownership special charge[1]	960
"Downstream" revenues	1.455
Corporate income taxes (estimated)	200
Gasoline excise tax	410
Sales taxes on gasoline (estimated)	720
Oil export charge	125
Total revenues	7.665
Expenditures	
PIP grants: Canada Lands and Alberta provincial payments	1.600
Other energy initiatives (includes nonoil and gas)[2]	2.125
Total expenditures	3.725
Net federal position	3.940

1 The Canadian ownership special charge is treated as an upstream revenue, although it could be treated as a downstream revenue if oil prices were deregulated.
2 Excludes the $291 million of imbalance in the petroleum compensation account.
SOURCE Estimates by the Economic Council of Canada, based on data from the 15 February 1984 federal budget.

1985-90. This would cause the demand for oil to be lower by approximately 26.6 per cent by 1990, and oil imports would decline by about 12.2 per cent per year, on average, over the period 1985-90. The average user price of natural gas would decline by about 14.5 per cent, and the demand for natural gas would be higher by about 10 per cent per year during the same period.

The simulation results show that the policy package would generate a positive supply response as producer netbacks (wellhead price after taxes, royalties and operating costs) from conventional oil would increase by about 4.9 per cent, on average, over the period 1985-90 (Table L-3). The rate of oil discoveries would increase by about 9 per cent in 1985 and would remain above base case levels throughout the rest of the decade. They would be higher by 4.5 per cent in 1990 and by 2 per cent in 1995. The netbacks to natural gas producers would be lower by an average of 5 per cent per year over the period 1985-90, and the decrease in natural gas discoveries would be about 2.4 per cent annually over the same period.

The industry's cumulative cash flow (after taxes, royalties and operating costs, but before investment) would increase by about $9.7 billion over the period 1985-95 (Table L-4). Table L-5 shows the revenue-sharing estimates for the federal government, the provincial governments and industry. Under the policy package, the revenues of all three would rise. The estimates suggest that industry would gain a total of $11.4 billion in cumulative revenues over the period 1985-95, while the gain to the federal government would be $7 billion and, to the provincial governments, $710 million.

In summary, this policy package would tend to insulate the economy from destabilizing effects during periods of rising world oil prices, and it would stimulate noninflationary economic growth. The package would also reduce oil imports by lowering oil demand and stimulating domestic oil production and exploration through increased investment. The revenues of the federal and provincial governments and of industry would increase. This assumes that royalty and tax rates would remain as at present.

Case IV: Policy Package Under Declining World Oil Prices

What would happen if the policy package were introduced during a regime of declining world oil prices? The simulation results suggest that the results of these measures would be lower Canadian energy prices overall, which would lead to lower inflation, a reduction in unemployment and an average annual real economic growth of 0.9 per cent between 1985 and 1990. An additional consequence would be a change in the composition of energy supply and demand.

The results indicate that the oil price would be higher than those in Base Case A-3 by about 1.6 per cent between 1985 and 1990. The demand for oil would drop by about 6 per cent by the late 1980s, leading to a drop in oil imports of about 13 per cent between 1985 and 1990, therefore resulting in an increased security of oil supplies. Natural gas would drop in price by about 27 per cent between 1985 and 1990, leading to an increase in demand of about 22 per cent.

On the supply side, the results suggest that domestic oil exploration and production would be stimulated. Gas production would also increase, but exploration and development would decrease as the lower gas prices would reduce incentives to find new reserves.

Consequently, total real energy investment would fall slightly – by 0.19 per cent between 1985 and 1990. The drop in gas investment would be larger than the increase in oil investment. The industry cash flows would rise, but, if the existing royalty and tax policies were maintained, federal and provincial revenues would fall.

M Policy Simulations: Electricity

As part of our study of the energy sector, we undertook a complementary research program in cooperation with the Canadian Energy Research Institute in Calgary in order to develop a "Canadian regional electricity model" (CANREM). CANREM is a policy simulation model of the electric utility industry at the provincial level that articulates the interactions between demand, supply costs, the financial and regulatory regime, and investment. The project involved a number of major changes and improvements to the regional electricity model developed by Dr. M. Baughman and P. Joskow for the United States, as well as the development of a database for the application of the model to Canada. Many Canadian utilities provided extensive data and advice, and CERI received financial support for this project through the Canadian Electrical Association.

In order to assess the performance of CANREM, a test run to the year 2000 was developed for each of the provinces.[1] These simulations were based on a calibration of the model with actual data for the period 1976-81 and a set of assumptions chosen for their reasonableness and convenience rather than as a forecast of future developments. The key assumptions were: flat real oil prices at U.S.$29 in 1983, 5 per cent inflation per annum, and population and real economic growth rates that varied by province. These test runs provided a means by which utility representatives could assess the model without necessarily accepting the assumptions or endorsing the model.

The test runs were used as a base case against which to estimate the possible impact of a number of changes in financial policies that were discussed in Chapter 6 of this report. Simulations were conducted for Nova Scotia, Ontario, Saskatchewan and British Columbia.[2] These provinces were chosen to reflect various characteristics of the industry in Canada: the four major regions of Canada are represented, and the electrical sectors selected vary from very large in Ontario to relatively small utilities in Nova Scotia and Saskatchewan; a range of generation mixes are represented: from predominantly hydraulic generation in British Columbia, to mainly coal-fired generation in Nova Scotia and Saskatchewan, as well as the increasingly important nuclear industry in Ontario. Various degrees of exchanges with other utilities in Canada and the United States are also covered – from little trade in Nova Scotia and Saskatchewan to the greater importance of exports for Ontario and British Columbia.

The simulations modeled the impact of the following changes in financial policy:

A Beginning in 1986:

1 Introduction of trended original-cost accounting from the accounting base in 1985;

2 A real rate of return on equity before tax of 12 per cent per year;

3 An income tax rate of 40 per cent;

4 Full taxation by the provincial government of net profits on external sales;

5 Water power rentals of $10/MWh, in real terms, on the volume of hydraulic generation used to meet domestic demand in 1979. This replaced the current rates, which were assumed in the test run to be maintained in real terms. This assumes that there will be no economic rent to the year 2000 on hydraulic facilities built after 1979, given the fall in the price of oil since then and the assumption of a flat price over the projection period. Additionally, the water power rental rate used reflects the uncertainty in the estimates developed in the two studies for 1979, as well as a moderate government policy of collecting the economic rent on hydraulic generation.

B Beginning in 1990:

6 An increase in the real cost of debt of 2 percentage points, to reflect the extreme impact of the termination of the provincial government guarantee on debt.

It should be noted that it is not possible to simulate the impact of introducing time-of-use rates with CANREM in its current form.

Table M-1 presents, in addition to the rates assumed for economic and population growth in the four provinces, the results of the simulations for selected major variables over the period 1985-2000.

In the year 2000, these policy changes would result in price increases ranging from 30 per cent in Nova Scotia to 65 per cent in Ontario. Average prices in Saskatchewan and British Columbia would be 44 and

Table M-1

General Assumptions and Simulation Results for Major Variables

	Nova Scotia	Ontario	Saskatchewan	British Columbia
		(Per cent)		
Annual average rate of growth, 1985-2000:				
General assumptions				
Real economic growth	3.3	2.7	2.2	3.2
Population growth	0.4	0.7	0.3	1.0
Inflation	5.0	5.0	5.0	5.0
Price of electricity				
Base case	2.9	4.1	4.1	5.0
Simulation	4.7	7.6	6.6	8.1
Energy demand				
Base case	3.0	3.4	2.3	3.7
Simulation	2.3	1.9	1.4	2.5
Capacity				
Base case	2.2	2.7	2.4	1.9
Simulation	1.4	1.4	1.2	0.6
Change between the base case and the simulation in 2000:				
Price of electricity	29.5	64.7	43.8	54.3
Energy demand	-10.0	-19.2	-12.9	-15.9
Capacity	-10.8	-18.0	-16.2	-17.5
Government revenue as a proportion of domestic sales in 2000:				
Base case	0.9	2.6	2.3	22.7
Simulation	15.4	27.8	20.8	36.1
Proportion of increased domestic sales revenue accounted for by increase in government revenue in 2000:				
Simulation	102.4	106.5	94.4	81.2

54 per cent higher, respectively, at the end of the simulation period. While prices in all four provinces rise at or below the rate of inflation in the test run, with the exception of Nova Scotia they rise in real terms in the simulations – by as much as 3 per cent per annum, on average, in British Columbia.

As a result of these price increases, energy demand is projected to be lower in the year 2000 – by 10 per cent in Nova Scotia and by as much as 19 per cent in Ontario. Correspondingly, the capacity that is required to maintain the same reserve levels as in the test run decreases, by the year 2000, by about 11 per cent in Nova Scotia and by between 16 and 18 per cent in the three other provinces.

As a result of the increase in taxes and water power rentals, government revenues as a proportion of revenues from domestic customers in the year 2000 rise to 15 per cent in Nova Scotia, 28 per cent in Ontario and 21 per cent in Saskatchewan. While the proportion is even higher in British Columbia – 36 per cent – mainly because of higher water power rentals, the increase is proportionately lower in this province because fairly large water power rentals had been assumed in the test run.

In all four provinces, the increase in government revenues accounts for the bulk of the increase in revenues from domestic customers. In fact, in Nova Scotia and Ontario the increase in government revenue exceeds the increase in revenue from domestic sales. This is because the move to a trended rate base and the decrease in capacity requirements in the simulation have the effect of decreasing the revenue requirement, relative to the test run. These revenue increases are not lost for the province: they could be available for other purposes – for economic development or increased services or to compensate for reductions in debt or other taxes – rather than be used to reduce electricity rates.

It should be noted that the implementation of time-of-use rates and other load-management techniques could be expected to reduce the requirements for capacity and higher-cost fuels and thus lower the rate of price increases projected in the simulations.

Notes

Chapter 2

1 This section is largely based on Glen Toner and G. Bruce Doern, *The NEP and the Politics of Energy* (Toronto: Methuen, 1984).

2 Canada, House of Commons, *Debates*, 13 March 1953, pp. 2928-9.

3 Commons, *Debates*, p. 2929.

4 In a previous report by the Council, it was estimated that, following the second oil price shock in 1979, the potential resource revenues on Canadian oil and gas production in 1980 were in the order of $22 to 26 billion, or between 7 and 9 per cent of GNP that year. See: Economic Council of Canada, *Financing Confederation: Today and Tomorrow* (Ottawa: Supply and Services Canada, 1982), Appendix B.

5 Energy, Mines and Resources Canada, "Energy Statistics Handbook," Update 88, Ottawa, 1984, p. 7.1.

6 Energy, Mines and Resources Canada, *The National Energy Program, 1980* (Ottawa: Supply and Services Canada, 1980).

7 Television address by Premier Lougheed of Alberta in reaction to the federal budget and to the NEP, 30 October 1980, p. 9.

8 Government of Canada, *Economic Development for Canada in the 1980s* (Ottawa: Supply and Services Canada, November 1981).

9 "Memorandum of Agreement Between the Government of Canada and the Government of Alberta Relating to Energy Pricing and Taxation," Ottawa, 1 September 1981.

10 Energy, Mines and Resources Canada, *The National Energy Program: Update, 1982* (Ottawa: Supply and Services Canada, 1982).

11 "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," Calgary, 30 June 1983.

12 This section is largely based on Marie-Hélène Pastor, "Héritage du passé – Histoire des compagnies d'électricité au Canada," Discussion Paper, Economic Council of Canada, Ottawa (forthcoming).

13 A. R. Vining, "Provincial Hydro Utilities," in *Public Corporations and Public Policy in Canada*, ed. A. Tupper and G. Bruce Doern (Toronto: Institute for Research on Public Policy, 1981), p. 154.

Chapter 3

1 EMR, *National Energy Program*, pp. 13-16 and 33.

2 EMR, *National Energy Program*, p. 13.

3 Economic Council of Canada, *Two Cheers for the Eighties: Sixteenth Annual Review* (Ottawa: Supply and Services Canada, 1979), p. 57.

4 Energy, Mines and Resources Canada, *An Energy Strategy for Canada: Policies for Self-Reliance* (Ottawa: Supply and Services Canada, 1976), pp. 123-25.

5 Electricity exports by province in 1983 were distributed as follows: Ontario, 32 per cent; Quebec, 27 per cent; Manitoba, 16 per cent; New Brunswick, 14 per cent; and British Columbia, 12 per cent.

6 Michèle Bourque, "Évolution du prix international du pétrole de 1870 à nos jours," Discussion Paper 257, Economic Council of Canada, Ottawa, April 1984.

7 These comments on the world oil situation in the past decade are based on Peter Eglington, "A Framework for Understanding the World Oil Market," Peter Eglington Associates Limited, Ottawa, 1982.

8 The total worldwide inventories of crude oil and products, less those essential to keep pipelines flowing, are estimated to be about 6 billion barrels – some 100 days of supply.

9 See: "Stockpiles Urged," *The Globe and Mail*, 3 March 1984, p. B-8.

10 EMR, *National Energy Program*, p. 93.

11 The level of foreign ownership is given by the proportion of the total voting shares of a Canadian company that is held either directly or indirectly by nonresidents. A company is said to be foreign-controlled when 50 per cent or more of its shares are held directly or indirectly by nonresidents.

12 EMR, *National Energy Program*, p. 17.

13 Energy, Mines and Resources Canada, *Canadian Petroleum Industry Survey, 1979* (Ottawa: Supply and Services Canada, 1980), p. 2.

Chapter 4

1 National Energy Board, *1981 Annual Report* (Ottawa: Supply and Services, Canada, 1982).

2 See: G. C. Watkins, "Conservation and Economic Efficiency," *Journal of Environmental Economics and Management* 4 (March 1977); and Michael Crommelin, Peter H. Pearse and Anthony Scott, "Management of Oil and Gas Resources in Alberta," *Natural Resources Journal* 8 (April 1978).

3 See: Peter Eglington and Maris Uffelmann, "Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979," Discussion Paper 235, Economic Council of Canada, Ottawa, October 1983. In that paper, the supply cost calculations are based on 1981 dollars, but the figures based on 1983 dollars show identical trends.

4 See: Energy, Mines and Resources Canada, *An Energy Policy for Canada: Phase I*, vol. II – Appendices (Ottawa: Information Canada, 1973), p. 224; and Petroleum Monitoring Agency, *Canadian Petroleum Industry: Monitoring Survey, 1982* (Ottawa: Supply and Services Canada, 1983), p. 6-1.

5 National Energy Board, *Canadian Energy Supply and Demand, 1983-2005* (Ottawa: Supply and Services Canada, 1984). The NEB uses productive capacity as a measure of supply. First, it looks at the remaining established reserves of conventional light and heavy crude and estimates potential additions to the reserves over the forecast period. Then calculations are made to determine the potential rate of development of those reserves and the future productive capacity of conventional crude oil. The productive capacity of pentanes plus is added to this, following an assessment of future natural gas production. The analysis is completed by assumptions on future supply from the oilsands, the heavy-oil projects and frontier development. In arriving at its estimate of future supply, the NEB states that it considers geological potential, technological limitations, crude oil prices and government policy as the main determinants of supply potential.

6 Alberta Energy Resource Conservation Board, "Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur at December 31st, 1982," Calgary, 1983.

7 Canadian Petroleum Association, *Statistical Handbook*, Calgary, Section II, Report at 31 December 1983.

8 R. M. Procter, G. C. Taylor and J. A. Nade, *Oil and Natural Gas Resources of Canada, 1983*, Geological Survey of Canada (Ottawa: Supply and Services Canada, 1984).

9 National Energy Board, *Canadian Energy Supply and Demand, 1980-2000* (Ottawa: Supply and Services Canada, 1981), p. 143.

10 National Energy Board, *Canadian Oil Supply and Requirements* (Ottawa, 1975).

11 For a discussion of the assignment of oil and gas costs, see: Eglington and Uffelmann, "Oil and Gas Reserves in Alberta," p. 12.

12 The large companies have been involved in many more farm-out deals with smaller companies than previously (small producers are exempt from the PGRT). This, presumably, is a result of the poor economic incentives.

13 Peter Eglington, "The Economics of Industry Petroleum Exploration," unpublished Ph.D. thesis, University of British Columbia, Vancouver, 1975.

14 Russell S. Uhler, with Peter Eglington, "The Potential of Crude Oil and Natural Gas Reserves in the Alberta Basin," a paper prepared for the Economic Council of Canada, Ottawa, December 1983.

15 See, for example: NEB, *Supply and Demand, 1980-2000*; J. P. Prince, *Enhanced Oil Recovery Potential in Canada*, Study No. 9 (Calgary: Canadian Energy Research Institute, 1980); and the submission by the Independent Petroleum Association of Canada to the National Energy Board, September 1980.

16 Brian Scarfe and Edwin W. Rilkoff, "Financing Oil and Gas Exploration and Development Activity," a paper prepared for the Economic Council of Canada, Ottawa, February 1984.

17 National Energy Board, *Canadian Oil Supply and Requirements* (Ottawa, February 1977); and NEB, *Supply and Demand, 1983-2005.*

18 Update, dated 20 March 1984, to "Detailed Revenue Sharing and Netback Assumptions, Canada/Alberta Amending Agreement," Energy, Mines and Resources Canada, Ottawa, 1983.

19 Three of these projects are reviewed in Peter Eglington and James Nugent, "An Economic Analysis of Enhanced Oil Recovery in Conventional Light Oil Pools in Alberta," Discussion Paper 260, Economic Council of Canada, Ottawa, June 1984.

20 See: Peter Eglington and Maris Uffelmann, "An Economic Analysis of Oilsands Policy in Canada: The Case of Alsands and Wolf Lake," Discussion Paper 259, Economic Council of Canada, Ottawa, June 1984.

21 Mineable oilsands are considered to be those with no more than 76 metres of "overburden" – surface layers of rock, vegetation or water covering the mineable area. The Alsands site has about 12 metres of muskeg and other overburden material. The mining process involves a method combining draglines and bucket wheels for collecting the oilsands. The oilsand feedstock is processed in an extraction plant that applies hot water, sodium hydroxide and steam to extract the bitumen from the sand and clay. The bitumen recovered is then upgraded by the fluid-coking refining process to produce coke, by-product gases and a crude-oil liquid. The gas by-products are used in the plant as a utility fuel. The crude-oil liquid is upgraded to a synthetic light oil with a 34-36° API gravity and a sulfur content of about 0.2 per cent. This upgrading is undertaken by means of a hydrogen treatment process, with the hydrogen coming from the gasification of the coke produced in the bitumen-cracking process.

22 The *in situ* process for Wolf Lake involves the injection of high-pressure steam and combustion to lower the viscosity of the bitumen. It has been field-tested since 1976, and the tests will continue through 1985. The oilsand formation that is being tested – the Clearwater formation – is between 410 and 485 metres below the surface and has an average thickness of 23 metres. Initially, the project will use cyclic steam stimulation, although steam flooding and/or *in situ* combustion may be used later.

23 See: Peter Eglington and Maris Uffelmann, "An Economic Analysis of Hydrocarbon Developments in the Beaufort Sea," Discussion Paper 258, Economic Council of Canada, Ottawa, June 1984.

24 Donald McIvor, quoted in Paul Taylor, "Early Development Seen for Beaufort Oil," *The Globe and Mail*, 7 May 1984, p. B-1.

25 See Peter Eglington and Maris Uffelmann, "An Economic Analysis of the Venture Development Project and Hibernia," Discussion Paper 261, Economic Council of Canada, Ottawa, June 1984.

26 Distributed as follows: production platforms, $3,230 million; dredging, $30 million; subsea equipment, $500 million; development drilling, $1,550 million; and loading column, $90 million.

27 It may be noted that a 50 per cent change in the reserve price using the numbers in Table 4-7 could be induced by a decrease of some 54 per cent in taxes and royalties.

28 EMR, *National Energy Program*, p. 27.

29 EMR, *National Energy Program*, p. 26.

Chapter 5

1 EMR, *Handbook*, Update 88.

2 NEB, *Supply and Demand, 1983-2005*.

3 In 1983, there were, at one time or another, some 11,000 "shut-in" gas wells in Alberta. See: J. G. Stabback, "Riding the Natural Gas Roller-Coaster," a speech to the Canadian Gas Association, Jasper, June 1983.

4 NEB, *1983 Annual Report*, p. 32.

5 This section of the text uses data from the Canadian Petroleum Association, as the data compiled by the National Energy Board start only in 1965. We note that after 1965, differences can exist between the reserve and production estimates of the CPA and those published by the NEB.

6 CPA, *Handbook*. The average wellhead price is based on weighted averages of domestic and export revenues.

7 NEB, *Supply and Demand, 1983-2005*, p. A-97.

8 National Energy Board, *Gas Export Omnibus Hearing, 1982* (Ottawa: Supply and Services Canada, 1983), p. 15.

9 See, for example: National Energy Board, *Reasons for Decision: Northern Pipelines*, vols. 1 to 3 (Ottawa: Supply and Services Canada, 1977).

10 See Eglington and Uffelmann, "The Venture Development Project and Hibernia."

11 P. Bradley, "Costs and Supply of Natural Gas from Alberta: An Empirical Analysis," Discussion Paper 251, Economic Council of Canada, Ottawa, March 1984.

12 Uhler, "Potential of Crude Oil and Natural Gas Reserves."

13 "Full directionality" restricts the analysis to exploration that is specifically targeted at finding gas rather than oil; the "no directionality" assumption implies that exploration drilling cannot successfully discriminate between gas and oil findings.

14 NEB, *Supply and Demand, 1983-2005*, p. A-95.

15 George W. Govier, *A Report on the Marketing of British Columbia Natural Gas* (Victoria, B.C.: Queen's Printer for British Columbia, February 1983).

Chapter 6

1 The equivalence is derived by using conversion factors of 3,600 gigajoules of electrical energy per gigawatt-hour for heat energy and 38.5 GJ/m^3, for crude oil. An alternative method of approximating the energy equivalence of electricity production is to estimate the amount of crude oil that would be needed to *produce* a given amount of electrical energy. The conversion factor that is used in this case is 10,540 GJ/GWh, the very substantial difference with the previous factor being accounted for by heat losses that occur in thermal production. For 1982, the energy equivalence of total electricity production in Canada, using this second approach, was some 280,000 m^3 of oil per day.

2 The Lapointe Commission was appointed to find ways to prevent private electric companies from exploiting the public. It should be noted that the Commission stopped short of recommending public ownership.

3 On the other hand, in the case of declining costs, for example, it has been argued that efficiency could be achieved by pricing all units at their marginal cost and providing a government subsidy to make up the differences between revenues and total costs. That would, however, require an increase in taxes and thus entail inefficiency in other sectors of the economy. After much debate, it has generally been concluded that, in principle, customers should be charged for the full cost of service and that cost recovery provides a better framework for monitoring and assessing the performance of the utility. Furthermore, pricing structures have been devised to pursue efficiency under a given revenue constraint.

4 The interest-coverage ratio can be calculated in different ways. One measure is the ratio of net income plus gross interest on debt to gross interest on debt.

5 Standard & Poor's International, *Credit Week* (First Quarter 1984):10-12.

6 More generally, this is referred to as the "allowance for funds used during construction" (AFUDC).

7 Meeting given interest-coverage and debt/equity targets will generally require higher rate levels, the greater the value of construction work in progress. Traditionally, the value of the assets under construction has not been included in the rate base under rate-of-return regulations. Some regulatory commissions in the United States have recently allowed part or all of the construction work in progress to be included to reduce the financial problems facing some utilities. Some of these problems could be alleviated by introducing some form of inflation accounting.

8 Other factors include the profile of construction expenditures over time and the timing of the project – i.e., the fraction that may be brought into service during the construction period.

9 See: Stewart C. Myers, A. Lawrence Kolbe and William B. Tye, "Inflation and Rate of Return Regulation," Cambridge, Mass., April 1981.

10 While this method requires that inflation be projected over the remaining useful life of the asset to calculate the annual charge, it can allow for adjustments in tariff levels over time if expectations change. See: Sally Hunt Streiter, "Trending the Rate Base to Reflect Inflation: How?" in *Pipeline Regulation and Inflation: An Evaluation of Tariff Levelling*, ed. R. N. Morrison and R. J. Schultz, Proceedings of a conference sponsored by the National Energy Board and the Centre for the Study of Regulated Industries, McGill University, Montreal, 17-19 November 1982.

11 One of the major concerns expressed at the conference held at McGill University in 1982 under the sponsorship of the National Energy Board and the Centre for the Study of Regulated Industries was that the delay in earnings arising from "tariff leveling" would increase risk and thus increase the real cost of capital to the companies. The effect of a higher cost of capital is that the tariff reductions in the early years would not be as great, while even higher tariffs would be required in later years. Given this and some other concerns, many participants doubted that radical changes would solve the regulatory struggle with inflationary biases in price setting. They concluded that any changes should be introduced "very carefully and on a limited scale." See: *Pipeline Regulation and Inflation*, p. 9.

12 For normally structured projects, with up-front capital costs followed by revenues and operating costs over their useful lives.

13 See: Richard C. Zuker and Glenn P. Jenkins, with H. Lim and P. Poirier, *Blue Gold: Hydro-Electric Rent in Canada*, Economic Council of Canada (Ottawa: Supply and Services Canada, 1984); and J.-T. Bernard, G. E. Bridges and Anthony Scott, "An Evaluation of Potential Canadian Hydro Electric Rents," Resources Paper 78, Department of Economics, University of British Columbia, Vancouver, February 1982.

14 A second method proposed to pursue efficiency under a revenue constraint is the use of so-called "Ramsey prices." This approach, which allows only a single price to each customer, involves discriminating between independent customer classes with different demand characteristics.

The operative rule is that the percentage deviation of prices from marginal costs in the separated markets must be inversely proportional to the degree of responsiveness to prices in these markets (i.e., to their price elasticities). Thus the origin of the name "inverse-elasticity rule." The rationale for this rule is that it results in a minimum amount of change in resource use. A larger price distortion is imposed on customers who respond relatively little to price changes, while a small change is applied to those whose demand is very sensitive to price changes.

This second approach can be combined with the two-part-tariff approach to set prices in the electricity sector. For example, with significant scale economies, a two-part tariff may require a prohibitive hook-up charge to meet the revenue requirement. The inverse-elasticity rule could, instead, be used to raise the tailing block rates after restoring the first block charges to more reasonable levels.

It is interesting to note that "Ramsey prices" could also be used to pursue efficiency, if the revenue constraint were not respected while electricity prices were set equal to marginal costs. For example, in the case of a revenue deficiency, this method could be used to set tax rates in other sectors of the economy in order to recover the shortfall. See: W. J. Baumol and D. T. Bradford, "Optimal Departures from Marginal Cost Pricing," *American Economic Review* 6, no. 3 (June 1970):265-83.

15 The pattern will reflect climatic and temperature variations, consumer lifestyles, production schedules and the pricing structure for electricity.

16 Ontario Energy Board, "Report to the Minister of Energy on Principles of Electricity Costing and Pricing for Ontario Hydro," Toronto, 20 December 1979, p. 36.

17 OEB, "Report," p. 54.

18 See: Bridger M. Mitchell, Willard G. Manning, Jr. and Jan Paul Acton, *Peak-Load Pricing: European Lessons for U.S. Energy Policy* (Cambridge, Mass.: Ballinger Publishing Company, 1978).

19 National Association of Regulatory Utility Commissioners, *Annual Report on Utility and Carrier Regulation, 1981* (Washington, D.C.: NARUC, 1982), Tables 71(a), 71(b), and 71(c).

20 See: Statement of National Power Policy by the Honourable Mitchell Sharp, Minister of Trade and Commerce, Ottawa, 8 October 1963.

21 EMR, *National Energy Program: Update*, p. 66.

22 Ellen F. Battle, Gordon S. Gislason and Gordon W. Douglas, *Potential Benefits and Costs of Canadian Electricity Exports*, Research Report 83-1, Canadian Energy Research Institute (Calgary: CERI, April 1983).

Chapter 7

1 At present, only the Bruce nuclear plant, in Ontario, produces steam energy from nuclear sources, to supply industrial-steam customers.

2 The elasticities discussed in this chapter and provided in Table 7-5 were compiled from the following sources: Datametrics Limited, "Canadian Regional Energy Demand Elasticities," a paper prepared for the Economic Council of Canada, Calgary, 1982; Canadian Energy Research Institute, "Canrem: A Regional Model of the Canadian Electric Power Industry," a report prepared for the Canadian Electrical Association, August 1983; National Energy Board, "Demand Model Update: Summary of Results," Ottawa, 7 May 1982; R. K. Sahi and R. W. Erdmann, "A Policy Model of Canadian Interfuel Substitution Demands," in *Energy Policy Modeling: United States and Canadian Experiences*, Volume I: Specialized energy policy models, ed. W. T. Ziemba, J. L. Schwartz and E. Koenigsberg (Boston: Martinus Nijhoff Publishing, 1980); E. R. Berndt, "Canadian Energy Demand and Economic Growth," in *Oil in the Seventies*, ed. G. C. Watkins and M. Walker (Vancouver: The Fraser Institute, 1977); R. W. Erdmann and F. W. Gorbet, "Energy Demand Projections for Canada: An Integrated Approach," in *International Studies of the Demand for Energy*, ed. W. Nordhaus and R. Goldstein (Amsterdam: North Holland Publishing Company, 1977); R. N. McRae, "Primary Energy Demand in Canada," *Energy Economics* (October 1979); "Why Do Energy Demand Elasticities Differ?", a discussion paper submitted to Working Party No. 1 of the Economic Policy Committee, OECD, Paris, October 1980; and other sources.

3 Datametrics, "Energy Demand Elasticities."

4 An exception is made in the low-oil-price scenario, where the gas/oil price parity is allowed to exceed 65 per cent. Under rapidly declining oil prices, a 65 per cent parity cannot be maintained without subsidies to consumers because the agreements between the governments of Canada and Alberta determine prices at the Alberta border to 1987. Therefore, in the low-oil-price scenario, the gas/oil price parity rises gradually to reach 100 per cent by the year 2000.

5 In the summer of 1983, Energy, Mines and Resources Canada projected a primary demand growth rate of between 3.2 and 3.3 per cent a year from 1983 to the year 2000. The projections were revised in the spring of 1984, when EMR forecasts suggested growth rates of between 2.4 per cent for a "conservation" case and 2.9 per cent for the base case. By comparison, submissions to the recent hearings of the National Energy Board placed primary demand growth rates for the period 1983-2000 at between 1.3 and 3.0 per cent; the NEB itself projected a 2.0 per cent demand growth rate. See: Energy, Mines and Resources Canada, "Long Term Energy Supply/Demand Outlook, Summer '83 Forecast," Energy Strategy Branch, EMR, Ottawa, July 1983; Energy, Mines and Resources Canada, "Long Term Energy Supply/Demand Outlook, Spring '84 Forecast," Energy Strategy Branch, EMR, Ottawa, May 1984; and NEB, *Supply and Demand, 1983-2005.*

6 In 1979, the seven countries other than Canada listed in Table 7-7 were net importers of energy; in some of those countries – France, Italy and Japan – net imports represented more than 75 per cent of total domestic requirements. The hydro share of primary energy in the seven countries was below 10 per cent, with the exception of Sweden, where hydro supplied 28 per cent of primary energy.

7 Energy, Mines and Resources Canada, *Government of Canada Internal Energy Conservation Program: Fifth Annual Report, 1981* (Ottawa: Supply and Services Canada, 1982).

8 For further reading, see: D. B. Brooks, J. B. Robinson and R. D. Torrie, *2025: Soft Energy Futures for Canada*, presented to the Departments of Energy, Mines and Resources and Environment Canada by Friends of the Earth Canada (Ottawa: Energy, Mines and Resources Canada, February 1983); D. B. Brooks, *Zero Energy Growth for Canada* (Toronto: McClelland and Stewart, 1981); and A. B. Lovins, *Soft Energy Paths: Toward a Durable Peace* (Cambridge, Mass.: Ballinger Publishing Company, 1977).

9 See Steven G. Diener and Serge Dupont, "An Assessment of the Competitiveness of Selected Energy Conservation and Alternative Energy Technologies," Discussion Paper 262, Economic Council of Canada, Ottawa, July 1984.

10 The price is for crude oil landed in Montreal.

11 The parity is applied at the Toronto city gate.

12 The evaluation in Diener and Dupont, "Selected Energy Conservation and Alternative Energy Technologies," shows that, for the pulp and paper and wood industries, the use of wood wastes is more economical; it is, in effect, already widespread. To limit our discussion, however, the costs given in this chapter are based on the assumption that natural gas is used in all industries. Moreover, natural gas is assumed to be available in Nova Scotia and New Brunswick by 1995.

13 A project was set up by an Ontario subsidiary of the federal government's Canertech Corporation.

14 Some incentives for energy-from-waste projects are available at present in the form of capital grants to potential investors through the expanded "forest industry renewable energy" program.

15 In Newfoundland, Prince Edward Island, New Brunswick, Ontario, Manitoba and British Columbia, fuel taxes on diesel are higher by about 20 per cent, on average. In Nova Scotia and Quebec, taxes on diesel are slightly less than on gasoline. There are no fuel taxes in Saskatchewan and Alberta. These figures are based on 1983 averages. See: EMR, "Handbook," Update 86.

Chapter 8

1 For a brief history of equalization, see: Finance Canada, "Canada's Fiscal Equalization Program," Ottawa, October 1984, pp. 14 and 16.

2 Economic Council, *Financing Confederation.*

3 *Financing Confederation*, p. 122.

4 *Financing Confederation*, p. 122.

5 Thomas J. Courchene, "Canada's New Equalization Program: Description and Evaluation," *Canadian Public Policy* 9, no. 4 (December, 1983):458-75.

6 See, for example: John F. Helliwell and Anthony Scott, *Canada in Fiscal Conflict: Resources and the West* (Vancouver: Pemberton Securities, 1981).

7 Energy, Mines and Resources Canada, "Oil Import Security in the 1980s," Energy Strategy Branch, Ottawa, July 1979.

8 See: John F. Helliwell et al., "Energy and the National Economy: An Overview of the MACE Model," Resources Paper 89, Department of Economics, University of British Columbia, Vancouver, March 1983.

9 Royal Commission on Electric Power Planning, *Report*, vol. I: Concepts, Conclusions and Recommendations (Toronto, February 1980), p. xxiii.

10 Economic Council, *Financing Confederation*, pp. 39-43.

11 Mathewson Economic Consultants Inc., "Policy Alternatives for Product Misrepresentation," a report submitted to Consumer and Corporate Affairs Canada, Ottawa, March 1983.

12 Generally, programs of product labeling can be implemented at a moderate cost. The cost of the Energuide program is in the neighbourhood of $500,000 a year. It is estimated that extending the Energuide program to furnaces, water heaters and heat pumps would represent an additional cost of some $5 million a year for the first five years and $1 million a year thereafter. See: Marbek Resource Consultants, "A Collection of Second Generation Energy Conservation Programs," a report submitted to Energy, Mines and Resources Canada, Ottawa, November 1983.

13 The available subsidies include a $400 vehicle conversion grant from the federal government and, in Ontario, a waiving of the sales tax on the total value of the vehicle. As noted previously, additional incentives in Ontario and other provinces arise from fuel tax differentials.

APPENDIX D

1 The Power Plant and industrial Fuels Act of 1978 prohibits the purchase of new oil or gas boilers by industry, as a means of encouraging the use of coal or other sources of energy.

APPENDIX E

1 The price escalations were typically in the order of $0.10/thousand m^3 per year. The price-redetermination clause was to enable producers and buyers to revise price agreements periodically, generally at intervals of five to ten years, subject to the decisions of an arbitrator, if necessary. The favoured-nation clause was to enable producers to ask a price revision if a competing producer was receiving a higher price from the same purchaser.

APPENDIX H

1 See Mitchell, Manning and Acton, *Peak-Load Pricing*, Tables 5 and 20.

2 National Association of Regulatory Utility Commissioners, *Annual Report on Utility and Carrier Regulation, 1981* (Washington, D.C., 1982), Tables 71 (a), (b), and (c); Robert G. Uhler, *Rate Design and Load Control: Issues and Directions*, a report to the National Association of Regulatory Utility Commissioners (Palo Alto, Calif., November 1977); *Public Utilities Fortnightly* 114, no. 3 (2 August 1984):28; and Robert G. Uhler, "Electric Utility Pricing Issues: Old and New," in *Current Issues in Public-Utility Economics: Essays in Honor of James C. Bonbright*, ed. A. L. Danielson and D. R. Kamerschen (Lexington, Mass.: D. C. Health & Co., 1983).

APPENDIX J

1 See: S. C. Littlechild, "Marginal-Cost Pricing with Joint Costs," *Economic Journal* 80, no. 318 (June 1970):323-38.

2 R. Turvey, *Optimal Pricing and Investment in Electricity Supply* (London: Allan and Unwin, 1968), pp. 91-93.

3 See: R. Turvey, "Marginal Cost," *Economic Journal* 79, no. 314 (June 1969):282-99; and C. L. Cicchetti, W. L. Gillen and P. Smolensky, *The Marginal Cost and Pricing of Electricity: An Applied Approach* (Cambridge, Mass.: Ballinger Publishing Company, 1977).

4 See: Ontario Hydro, *Electricity Costing and Pricing Study*, volume VII: "Costing Methodology for Determining Marginal Costs" (Toronto, 1976), for the solution outlined by the National Economic Research Associates, Inc., under optimum conditions.

5 Turvey, *Optimal Pricing*, p. 59.

6 Uhler, *Rate Design and Load Control.*

APPENDIX K

1 This appendix is based on data from the U.S. Department of Energy, and on Energy, Mines and Resources Canada, *Canada/United States Electricity Exchanges* (Ottawa: Supply and Services Canada, May 1979).

APPENDIX L

1 For a detailed description of the structure of the model, see: John F. Helliwell et al., "Energy and the National Economy."

2 For further details on these simulations, see: Surendra Gera and Mary McGregor, "Economy-Wide Implications of Alternative Energy Sector Tax and Pricing Policies: Simulations with the MACE Model," Discussion Paper, Economic Council of Canada, Ottawa (forthcoming).

3 Note that the simulation results for Cases I and II, as reported in Tables L-1 to L-6, are deviations from Base Case A-1, while the results for Case III are deviations from Base Case A-2 and the results for Case IV are deviations from Base Case A-3. Since the base cases involved are different, the simulation results are not directly comparable.

APPENDIX M

1 For further details on the test runs, see: Canadian Energy Research Institute, "CANREM: A Regional Model of the Canadian Electric Power Industry," a paper prepared for the Canadian Electrical Association, Calgary, December 1983.

2 For further details on the simulations using CANREM, see: R. Zuker, "Alternative Financial Policies for Electric Utilities: Some Simulations with the Canadian Regional Electricity Model," Discussion Paper, Economic Council of Canada, Ottawa (forthcoming).

List of Tables and Illustrations

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1 From 1 January 1982 to 31 December 1983; consultant from 1 January 1984.

2 From 1 January 1984.

The individuals, agencies and organizations named below were consulted during the Economic Council's research on energy:

Alberta and Southern Gas Co. Ltd.
Alberta Electric Energy
Marketing Agency
Alberta Electric Utilities
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Alberta Energy Company
Alberta Energy Resources
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