THE SENATE OF CANADA LE SÉNAT DU CANADA

PETRO-CANADA

Report of the Standing Senate Committee on Energy and Natural Resources

Chairman
The Honourable Daniel Hays

Deputy Chairman
The Honourable James Balfour

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PETRO-CANADA

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June 1990

MEMBERSHIP

STANDING SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES

The Honourable Dan Hays, Chairman

The Honourable James Balfour, Deputy Chairman

The Honourable Senators:

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Jack Austin, P.C.
James Balfour
Earl Hastings
Daniel Hays
William Kelly
Colin Kenny
Thomas Lefebvre
• Allan MacEachen, P.C. (or Royce Frith)
• Lowell Murray, P.C. (or William Doody)
H.A. Olson, P.C.
Gerald Ottenheimer
Jean-Marie Poitras
Duff Roblin, P.C.

• *Ex Officio* Members

<u>NOTE:</u> The Honourable Senator Barootes also served on the Committee.

Research Staff:

Mr. Dean Clay, Dean Clay Associates
Mr. Richard Harris, Harris Consultants Limited
Mr. Michael Jarvis, Jarvis Consultants Limited
Mr. Ken Winger, Seagrave Steward Investments Limited

Line Gravel

Clerk of the Committee

ORDER OF REFERENCE

Extract from the Minutes of the Proceedings of the Senate, Wednesday, June 21, 1989:

The Honourable Senator Hays moved, seconded by the Honourable Senator Neiman:

That the Standing Senate Committee on Energy and Natural Resources be authorized to review the extent to which Petro-Canada has met its original purpose, and to evaluate this purpose with respect to Petro-Canada's evolving role in the Canadian energy scene; and

That the Committee present its final report no later than 31st March 1990. •

The question being put on the motion, it was –
Resolved in the affirmative.

Gordon Barnhart
Clerk of the Senate

• By order of the Senate dated March 22, 1990, the date of tabling the final report was extended to May 15, 1990. By order of the Senate dated May 9, 1990, the date of tabling the final report was extended to June 15, 1990.

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Foreword

The policy initiatives resulting in the 1975 creation and subsequent development of Petro-Canada have been and remain controversial. The 1984 directive by the present government that Petro-Canada conduct its affairs as a private-sector company – ending its pursuit of public policy purposes – has been followed by the February 1990 budget announcement that the government intends to privatize our national oil company. In the spring of 1989, this Committee decided that more attention should be paid to the question of Petro-Canada's role as a state oil company, particularly in the broader context of Canadian policy development, and sought a reference from the Senate to study this matter.

As a national oil company, Petro-Canada's operations reflect various Canadian issues – balancing national and regional interests, reconciling consumer and producer interests, and weighing free market operation against government objectives, to name but three. This report attempts to gauge Petro-Canada's accomplishments of the past in both its business and public policy roles, and presents the Committee's views regarding appropriate choices for its future.

The following subjects were considered in the context of this study:

(a) Canada's high per capita use of energy by reason of climate, geography, industrialization and lifestyle;

(b) the international price of oil is not based on a freely functioning market – OPEC supplied 46% of the 52 million barrels of oil consumed daily in the non-Communist world in 1989 and holds almost all of the world's surplus producing capacity, allowing it to set production quotas and determine market conditions;

(c) the increasing dependence of the United States on imported and in particular OPEC oil, and the degree to which the U.S. weakness in oil supply has the potential in a continental market which it dominates to create a problem for Canada should the U.S. Government deem that intervention in the energy sector is necessary;

(d) the commitments that Canada has made in the Free Trade Agreement;

(e) the opportunity Canadians have to preserve a preferred position in energy supply in a market-based environment, with a policy which has that as an objective; and

(f) the growing recognition of the impact that energy development is having on the environment.

Simply stated the issue is: Does Petro-Canada still have a public policy role to play in Canada? The current government maintains that it does not. Others allege that it does. If one takes the position that our national oil company does have a continuing function in federal policy-making, then it remains to articulate what part Petro-Canada might play in an energy policy that addresses Canada's interests now and in the foreseeable future.

The government of the day asserts that the energy sector will be better regulated by the market alone, and the Committee received a substantial body of testimony in support of this view. Other witnesses contested this conclusion.

To gain a broader perspective on the debate, the Committee studied the operations of four national oil companies operating in Japan, Norway, Italy and Venezuela. The governments of many countries – both oil exporters and importers – have judged it in the national interest to be involved in their energy sectors and to develop policy that meets strategic needs peculiar to their situations. They are often our competitors in world markets and we must learn from their good and bad experiences as well as our own, and act accordingly in our best interests. For example, the United States is currently developing a National Energy Strategy (NES). The importance that the U.S. Administration attaches to this process is evident in the remarks of President George Bush in the NES Interim Report of April 1990:

> We cannot and will not wait for the next energy crisis to force us to respond.
>
> Our task – our bipartisan task – is to build the national consensus necessary to support this strategy and to make this strategy a living and dynamic document, responsive to new knowledge and new ideas, and to global, environmental, and international changes.
>
> A keystone of this strategy is going to be the continuation of the successful policy of market reliance. And it's not going to be easy. We must balance – achieve balance – our increasing need for energy at reasonable prices, our commitment to a safer and healthier environment, our determination to maintain an economy that is second to none, and our goal to reduce dependence by ourselves and our friends and allies on potentially unreliable energy suppliers.
>
> I am confident that America's can-do attitude and scientific know-how and old fashion plain common sense will prevail. By acting now, we can bequeath a legacy to the next century of a cleaner, more prosperous and, yes, more secure America.
> (U.S., DOE, 1990, p. 1)

This quotation also indicates the challenge that policy-makers face in reconciling the free market approach with current circumstances: President Bush first credits "the successful policy of market reliance" and then hints strongly at the government intervention that will be required to guarantee America's future energy security and ensure a healthier environment.

Energy policy-making is not a question of black and white: it has become tinged with many shades of grey (and now green). Simplistic answers addressed to complex questions serve no one well. The Committee believes that the role of Petro-Canada in a Canadian energy strategy is a question that can be better explored as a result of information and comment brought together in this report.

The Committee heard from a variety of witnesses, who have made an important contribution to our knowledge and understanding of Petro-Canada's operations and its past and future roles. We thank these witnesses for their contribution to our work and Mr. W.H. Hopper of Petro-Canada in particular for agreeing to be our lead witness and for offering the cooperation of his organization.

We thank our report writer and consultant Dean Clay; Richard Harris and Ken Winger for their analysis of Petro-Canada's financial situation; Michael Jarvis for his review of four other national oil companies; and our Clerks, Line Gravel and her predecessor Timothy Ross Wilson, for their contribution to the work of the report. The Committee is also indebted to the translators and revisor at Secretary of State who prepared the French text – Francine Nantel, Marielle Papineau, Louise Goyette, Huguette Lemieux, Denis Samson, Sylvie Trottier and Ronald Barber; to Diane Pugliese, Nicole Raymond and Lucie Gaulin who prepared the French manuscript; to Mario Pelletier whose editing ensured an accurate translation; and to Bob Kingham who prepared the computerized organization charts of Chapter Five.

Senator Dan Hays
Chairman

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We thank our report writer and consultant Dean Clay, Richard Harris and Ken Vernon for their analysis of Petro-Canada's financial situation, Michael Jarvie for his review of four other national oil companies and our Clerks, Line Gravel and her predecessor Timothy Sage Wilson, for their contribution to the work of the report. The Committee is also indebted to the translators and revisers of Secretary of State who prepared the French text — Francine Nantel, Marielle Papineau, Louise Goyette, Hugues Lemieux-Ostiguy, Simon Stenning, Sylvie Trottier and Ronald Rudberg; to Diane Pugliese, Nicole Raymond and Lucie Gaulin who prepared the French manuscript; to Marc Pelletier whose editing ensured an accurate translation; and to Bob Kingham who developed the computerized organization charts of Chapter Five.

Introduction

On June 21, 1989, the Standing Senate Committee on Energy and Natural Resources received an Order of Reference from the Senate of Canada to the effect:

> That the Standing Senate Committee on Energy and Natural Resources be authorized to review the extent to which Petro-Canada has met its original purpose, and to evaluate this purpose with respect to Petro-Canada's evolving role in the Canadian energy scene; and
>
> That the Committee present its final report no later than 31st March 1990.

The Committee requested this mandate because of the widening public and political debate about the future of Canada's national oil company. Committee members considered it important on two grounds that an assessment of Petro-Canada's past activities and future operations be done: (1) because more than $4 billion in public funds has been invested in the operations and acquisitions of Canada's state-owned oil company and it is important to evaluate what that investment has accomplished; and (2) in the event that the federal government introduces legislation to privatize Petro-Canada, the Committee has provided a body of analysis against which such an initiative can be judged.

As events transpired, the Government of Canada announced in its budget presentation of February 20, 1990 that "...the time has come to allow direct public ownership of Petro-Canada" and that legislation to accomplish this will be introduced during 1990. As the Honourable Michael Wilson, Minister of Finance, expressed it, "We will continue to privatize Crown corporations and sell investments where government ownership is no longer needed to meet public policy objectives." That issue – whether Petro-Canada should continue to serve any public policy function – has been a prime concern of this study.

As the announcement of Petro-Canada's intended privatization and the release of the Corporation's new 1989 and restated 1988 financial results (arising from a changed accounting practice) required modification of its report, the Committee asked for an extension of the reporting deadline to accommodate these new developments.

The Committee initiated its study of Petro-Canada with public hearings in Calgary on November 16, 1989, and continued with a series of hearings in Ottawa. In total the Committee heard ten witnesses on the subject; a larger number of prospective witnesses declined invitations to appear. The witnesses who appeared before the Committee are listed in Appendix A.

To supplement this testimony and its own research work, the Committee contracted the services of three individuals who contributed to the analytical base of this study. The Committee also benefitted from a three-day trip to Washington in November of 1989, the purpose of which was a broad review of the U.S. energy situation, and from a private meeting with senior officials of Petróleos de Venezuela in Caracas, while attending the Third Latin American and Caribbean Meeting of Parliamentarians on Energy and Petroleum in July 1989.

To assist the reader who may not be familiar with the terms, abbreviations and units that characterize this subject, Appendices B and C briefly cover the appropriate abbreviations, acronyms, definitions, units and conversion factors. Although energy industry statistics are now commonly reported in SI (Système International) or "metric" units in Canada, the practice in other countries varies. The United States uses English units. The Japan National Oil Corporation, in a more imaginative departure, reports oil production in barrels and the size of Japanese oil stockpiles in kilolitres; Petróleos de Venezuela reports oil production in barrels and gas production in cubic metres. This report presents most energy statistics in both English and SI units. Unless otherwise indicated, monetary figures are reported in Canadian dollars.

Reports and other documents that have been utilized in the Committee's work are listed in the Selected References at the end of the report.

In reviewing the operations of four other national oil companies for comparison with Petro-Canada, the Committee collected information not readily available to the Canadian reader. Including this additional material in the report would have made it too lengthy. This information is available, however, on request from the Clerk of the Committee and includes the law and/or regulations under which Petróleos de Venezuela, Japan National Oil Company, Statoil and ENI operate.

Conclusions and Recommendations

Petro-Canada – A Future Role?

The difficulty in judging whether or not Petro-Canada has a future role to play as a national oil company arises from the government's failure to present Canadians with a comprehensive statement of its energy policy. In 1984, a newly elected Progressive Conservative Government began to dismantle the National Energy Program and deregulate domestic energy markets, as promised in the election campaign. As an adjunct of these initiatives, Petro-Canada was directed to operate as any other private-sector oil company. Its public policy purposes were declared either to have been satisfied or to be no longer relevant.

Freeing oil and gas prices and disposing of the complex tax and regulatory structure that had supported lower-than-market prices benefitted the day-to-day operations of the energy marketplace. But it soon became apparent that market forces alone were not a suitable proxy for policy across the entire spectrum of issues confronting the energy sector. Consequently on 13 April 1987, the Hon. Marcel Masse, then Minister of Energy, Mines and Resources, announced Energy Options, a process "designed to review and assess Canada's energy prospects and options into the twenty-first century." Under the guidance of the appointed Energy Options Advisory Committee, chaired by Thomas Kierans, Canadians were solicited for their views about our country's energy future.

The product of this unique consultative process was *Energy and Canadians: Into the 21st Century*, an advisory report to the federal government, completed in August of 1988. Although the report observes that: "Virtually all participants in the Energy Options process stated that market forces should be allowed to allocate resources and determine prices for energy" (Canada, EMR, 1988, p. 65), it also acknowledges that the participants believed: "Intervention is appropriate when markets are not sufficiently competitive and when there are social costs such as environmental damage that prices do not reflect or social benefits such as basic research which markets do not reward adequately" (*Ibid*., p. 6).

The Government of Canada began this process of energy policy-making three years ago. It appears today, however, that the Energy Options process has stalled: Canadians lack a government response to the policy proposals discussed in the advisory report released almost two years ago. In the interim, the government announced four costly energy "megaprojects" – Hibernia oil field development, the OSLO oil sands project (for which federal support was subsequently withdrawn), the Lloydminster heavy oil upgrader and the Vancouver Island natural gas pipeline – to which it promised to contribute as much as $2 billion of the $11 billion in total capital costs, not including federally guaranteed loans, interest-free loans, and further capital contributions or interest rebates linked to the future price of oil. These projects have been variously defended as vital contributors to Canada's energy security and as regional development initiatives whose primary objective is to create jobs and economic spin-offs to regional economies. Whatever the rationale for this intervention, it does reveal that the federal government, like the Energy Options participants, recognizes the inadequacy of market forces as a stimulant for certain types of investment or activity. Canadians have not yet been presented with a policy, however, to explain such federal interventions in the energy sector.

Parliament can respond to this policy uncertainty in various ways in assessing the future role of Petro-Canada. Legislators can accept the current situation, that Petro-Canada has operated as a commercial enterprise without a public policy function for more than five years, that the federal government has announced its impending privatization, and that Petro-Canada is no longer a chosen instrument of government policy. In this view, the commercial and policy aspects of Petro-Canada's former operations should be decoupled, attributing the policy functions to another agency of government and allowing privatization to proceed as a separate issue. In a variation of this argument, the policy functions should not only be decoupled but disregarded as the market alone is the best arbiter of Canadian energy development.

A contrasting opinion holds that it is inappropriate to proceed with Petro-Canada's privatization until the government has defined a policy environment within which the merits of disposing of our national oil company can be properly debated and resolved. Privatizing Petro-Canada represents an irreversible step in dismantling a past and possibly future tool in implementing government policy, and the debate should be based on pragmatic, not ideological, grounds.

The majority view of the Committee (not subscribed to by all Members) is that no decision should be made regarding Petro-Canada's privatization until the government has established the policy framework within which the issue can be properly debated. Therefore:

(1) The Committee recommends that the privatization of Petro-Canada not be proceeded with until the federal government has completed the process begun in Energy Options and articulated an energy policy.

In examining what the future may hold for Petro-Canada, the Committee considered such issues as Canada's security of energy supply, the Corporation's role in rationalizing the domestic oil industry, and the environmental impact of rising energy use. The Committee in this study has anticipated elements of its other order of reference, a review of the Energy Options report *Energy and Canadians: Into the 21st Century*. As this report argues, the federal government must take a long-term view of Canadian energy development, of substituting new forms of energy for conventional ones, of making available new energy technologies and of reducing our profligate use of energy, for two compelling reasons – our environmental depredations, many resulting from energy exploitation, are becoming insupportable; and OPEC will increasingly dominate world oil trade. Canadian policy must be as concerned with modifying energy demand and promoting the efficient use of energy in the future as it has been with promoting energy supply in the past. The Committee's review of the Energy Options report will emphasize this approach to energy policy-making. In this study, the Committee has confined its recommendations to matters directly linked to Petro-Canada and to energy supply.

Petro-Canada – A Review of Operations

The Committee examined Petro-Canada's operations from two perspectives: as an investment compared with Imperial Oil and Shell Canada, and as an instrument of public policy.

As an Investment

The management of Petro-Canada has done a remarkable job in creating a large, competitive, fully integrated petroleum company from an idea in less than 15 years. A cohesive and leading corporation has been assembled from five major acquisitions – an impressive accomplishment by any standard.

When assessed by accepted financial tests, however, Petro-Canada's success as an investment has been less notable. In terms of corporate efficiency, shareholder efficiency and creditor efficiency, Petro-Canada has generally under-performed when compared with the two private-sector competitors against which it has been judged in this report: Imperial Oil and Shell Canada. Petro-Canada has not only provided its shareholder, the federal government, with poorer rates of return on investment, it has done so while placing its shareholder at greater financial risk than have Imperial and Shell when creditor efficiency tests are considered.

Under-performance as measured by these financial tests worsened significantly in the most recent three-year and five-year periods, calling into question the claims made by Petro-Canada's management in the *1989 Annual Report* that the Corporation's poor financial performance was the result of imposed policy objectives, rapid growth through acquisitions and the necessary integration of predecessor companies, and low oil and gas prices. Five full fiscal years have passed since Petro-Canada was asked to serve any policy purpose and since its major acquisitions were completed, yet no clear improvement in the return relationship relative to Imperial Oil and Shell Canada is apparent.

As an Instrument of Public Policy

Under the former Liberal Government, Petro-Canada was charged with several policy functions. Foremost among these were: (1) to enhance domestic energy security through increasing the supply of petroleum available to Canada; (2) to provide government with a "window" on the petroleum industry, thereby assisting in the formulation of appropriate energy policies; and (3) to help increase the Canadian presence in the domestic petroleum sector. Petro-Canada's Chairman, Wilbert Hopper, acknowledged in his testimony before the Committee that these were the "three key thrusts" in government's use of the Corporation as a policy instrument in its earlier years (Canada, Senate, Standing Committee on Energy and Natural Resources, 16 November 1989, pp. 8-9). To these primary functions the Committee has added Petro-Canada as a vehicle for distributing petroleum-related, bilateral foreign aid (through its wholly-owned subsidiary Petro-Canada International Assistance Corporation), and for promoting and performing energy research and development (through its former subsidiary Canertech and through its in-house R&D work).

(1) Security of Energy Supply

Using Petro-Canada to promote Canadian energy security through petroleum (oil and gas) development involved several distinct activities.

Petro-Canada's Role in Frontier Petroleum Exploration and Development

Petro-Canada was directed by the former Liberal Government to promote petroleum exploration and development on Canada Lands ("frontier" lands north of the 60th parallel and in the East Coast offshore). The Corporation's extensive activity on Canada Lands has provided information not obtainable in any other fashion. Although the exploratory effort has not been as successful in adding petroleum reserves as had been hoped, knowledge was gained about the occurrence of hydrocarbons in the high-risk Canada Lands and about the geology of these areas. Information is still information whether promising or discouraging and, because of Petro-Canada's activity, we have a better understanding of Canada's frontier petroleum resource potential than would otherwise be the case.

Petro-Canada as an International Petroleum Explorer and Developer

Petro-Canada's success in developing foreign petroleum reserves that could be contracted for Canadian markets is potentially an element in securing our future supply of conventional crude oil. Although the company's success has been limited to date, the accomplishments of Japan National Oil Corporation demonstrate that such activity can contribute to domestic energy security. The Committee considers Petro-Canada's foreign activities to be an appropriate although high-risk extension of its exploration and development work. Mr. Hopper acknowledged that this had indeed been a consideration: "...Petro-Canada was to work to increase the petroleum supplies available to Canada...by developing opportunities for increased security in foreign supplies" (Canada, Senate, Standing Committee on Energy and Natural Resources, 16 November 1989, p. 8).

Petro-Canada is active, however, in several unstable, international frontier areas. Some Committee members question whether this overseas work contributes to Canadian energy security in a comparable way to what might be gained through channeling these resources into Canadian frontier exploration. This is an expensive activity – in 1989, Petro-Canada directed 14% of its upstream capital expenditures in support of exploration initiatives in South America, South East Asia and the Middle East. Despite the size of this expenditure, the *1989 Annual Report* provides little information on how exploration funds were spent and what oil and gas production may have resulted from this overseas activity.

Petro-Canada's Involvement in State-to-state Transactions

Petro-Canada acted as an agent of the Government of Canada between 1980 and 1985 for the importation of Mexican crude oil. This was the only state-to-state oil transaction negotiated and managed by Petro-Canada. The current surplus of oil in world markets has made this function seem less important to Canada's interests, but one cannot conclude on this basis that state-to-state transactions will always be unimportant in the future. There are advantages in having a national oil company in contact with other state agencies, because such linkages and familiarity can add stability in state-to-state negotiations during periods of disruption or uncertainty in world oil trade. Large oil companies have a longer life than governments and energy ministers, which contributes to continuity in planning, a deeper understanding of the issues and stronger relationships with other participants in the industry.

Petro-Canada's Energy R&D

Petro-Canada has invested substantial funds in R&D directed to exploiting Canada's abundant resources of bitumen and heavy oil. Given our declining production of conventional light crude oil, Canada will have the choice of either importing more oil in the future or developing its heavy hydrocarbon resources at home. Major advances in extraction and processing technology are needed to lower the cost of heavy hydrocarbon use and Petro-Canada's R&D in this area can be considered as an investment in Canada's future energy security.

Strategic Petroleum Reserves and IEA Commitments

Canada does not maintain a strategic oil stockpile nor is it required to under International Energy Agency (IEA) oil-sharing provisions, given our current status as a net oil-exporting member country. Canada is closely tied, however, through the terms of the Free Trade Agreement to a country that is running a large and growing domestic oil production deficit and which operates a large and growing Strategic Petroleum

Reserve (SPR). As this report discusses, Canada will probably revert to being a net oil-importing nation. Japan and Italy are oil-deficient nations that use their state oil companies to manage national petroleum stockpiles. The House of Commons Standing Committee on Energy, Mines and Resources recommended in 1987 that "...the federal government establish a government-owned strategic oil reserve, equal to 90 days of net light crude oil imports, with the cost of filling and maintaining the reserve to be recovered through a tax on oil products at the refinery level" (Canada, House of Commons, Standing Committee on Energy, Mines and Resources, 1987, p. 6). This recommendation acknowledged the fact that Eastern Canada's dependence on offshore oil was returning to a pre-1973 condition. If Canada were to adopt a policy of stockpiling oil as its domestic output of conventional light crude oil continues to fall, then Petro-Canada may be the logical agency to manage the stockpile.

Prior to the passage in 1990 of Bill C-4, *An Act to amend the Energy Supplies Emergency Act and to amend the Access to Information Act in consequence thereof*, one member of Canada's seven-member Energy Supplies Allocation Board was to be a senior official of Petro-Canada, and Petro-Canada was Canada's representative on the IEA's Standing Group on Emergency Questions. This legislation ended the Corporation's direct participation in national and IEA actions in the event of an oil emergency.

(2) Government's Window on the Industry

Petro-Canada, operating as a fully integrated oil company in competition and sometimes in cooperation with other oil companies, unquestionably has an insider's view of the workings of the petroleum industry that cannot be duplicated by the Department of Energy, Mines and Resources or the Petroleum Monitoring Agency, or by a regulatory body such as the National Energy Board. Nor is it a view that can be articulated by an industry association that necessarily reflects the group's collective self-interest. Petro-Canada is a highly effective window on the industry by virtue of its multi-faceted activities and a unique one in its availability to the federal government.

The Committee does not know the extent to which the federal government has availed itself of the opportunity to use Petro-Canada in this fashion. There is no reliable means by which an outsider can judge how well the window on the industry function has worked, or even the degree to which it has been exercised.

(3) The Public's Window on Petro-Canada

The Committee's review of four other national oil companies reveals that Petro-Canada operates with less formal government scrutiny. The other state companies are subject to closer political control and to stricter financial review through auditing and other procedures.

Petro-Canada's accountability to the public through Parliament is minimal. Its annual reports have not conveyed as much information as those of comparable publicly traded, private-sector oil companies. Petro-Canada does not issue quarterly reports. Parliamentary committees of the House of Commons and Senate can call the Corporation as a witness on its annual report, but haven't consistently done so in the past. When Petro-Canada was still receiving Parliamentary appropriations, it appeared before the House Committee on Energy, Mines and Resources (formerly National Resources and Public Works) on Estimates. Unfortunately for the Members of Parliament who had the obligation of scrutinizing Petro-Canada's appropriation, the Corporate Plan submitted to the Minister remains confidential (as it does for all Crown corporations) and only a brief Corporate Plan Summary was tabled in Parliament. This document did not provide the basis for a detailed review of operations.

There should be more information about Petro-Canada's operations readily available to the public. For example, Petro-Canada should provide information equivalent to that required by the Ontario Securities Commission for its Annual Information Form, or that required by the U.S. Securities and Exchange Commission for its 10K and 10Q filings. Therefore:

(2) The Committee recommends that Petro-Canada be required to present as much information in the public domain as is required of comparable publicly traded, private-sector companies.

It is also this Committee's conclusion that Senate scrutiny of Petro-Canada has not been sufficient. Therefore:

(3) The Committee recommends that the Senate establish a practice of calling Petro-Canada before committee on a regular basis to review its operations.

The Senate Committee on Energy and Natural Resources intends to call Petro-Canada before it in the near future, on its *1989 Annual Report*.

(4) Canadianizing the Industry

Petro-Canada has contributed to Canadianizing the domestic petroleum industry in several ways:

- through the purchase of foreign interests and the Corporation's consequent growth as an operator in its own right;
- through the federal government's "back-in" provisions allowing Petro-Canada to acquire a 25% interest in exploration activity on Canada Lands, and through other land acquisitions; and

• by participating with private industry, particularly in the high-risk activities of frontier exploration and technology development.

Petro-Canada was not the principal mechanism, however, driving Canadianization during the decade from 1976 to 1985. A more potent force was the federal initiatives providing financial incentives and tax changes that preferentially encouraged Canadian companies to expand their operations, especially on Canada Lands. Canadian ownership and control responded to these actions and rose substantially, as the Petroleum Monitoring Agency (PMA) has documented. Since 1985, Canadian ownership and control in the oil industry have generally been declining. When presenting its energy policy, the federal government should indicate how it intends to achieve the stated target of 50% Canadian ownership in the petroleum industry.

Although the Committee recognizes that Petro-Canada's activities have been a factor in Canadianizing the petroleum industry, with an increased Canadian presence being favoured by the Committee in principle, nonetheless it does not believe that Canadianization should be fostered by discriminatory legislation. The Committee concludes, therefore, that Petro-Canada's acquisitions should not be driven by a government policy that uses our national oil company as a tool for such an objective.

(5) Foreign Aid

Through the wholly-owned subsidiary Petro-Canada International Assistance Corporation (PCIAC), Petro-Canada has been used as an instrument of Canadian foreign policy in distributing bilateral aid. Using Petro-Canada's administrative resources, contracting practices and knowledge of the petroleum business, PCIAC directs aid to Third World countries qualifying for Canadian assistance and importing part or all of their petroleum requirements. Canadian expertise and technology is utilized to perform the contracted services. Although a form of tied aid, the program has benefitted recipient countries as well as the domestic petroleum industry. The Committee concludes that this is a beneficial aspect of Petro-Canada's operations that should be continued if Petro-Canada is privatized.

(6) Energy R&D

Although energy R&D can be considered as another aspect of energy security, the Committee considers this function sufficiently important to warrant separate mention. Apart from its research into the extraction of heavy hydrocarbons and their processing, Petro-Canada previously had appended to it a venture capital company – Canertech – whose function was to promote alternative energy and conservation R&D in the Canadian private sector. During Canertech's short existence of about four years, it took equity positions in a variety of small companies and entered into research partnerships, but there was disappointment regarding its effectiveness as a catalyst for such R&D. The situation was worsened by falling oil prices and the impression that this was an activity for which Petro-Canada had little enthusiasm.

The Committee does not see Petro-Canada evolving into the more diversified energy conglomerate that might want to undertake such activities and concludes that Petro-Canada was not the appropriate vehicle for this R&D. Nevertheless, Canada requires a vehicle for the diverse energy R&D previously performed under the lead of the Energy Division at the National Research Council, and the government should specify how this function will be carried out in the future.

Rationalization of the Downstream Petroleum Sector

Petro-Canada has played a major part in rationalizing Canada's domestic petroleum industry. The Corporation has grown to account for approximately one-fifth of Canadian oil refining and marketing – second only to Imperial Oil with its 28% share of refining capacity and 24% market share – at the same time as the number of its competitors has been decreasing (with Petro-Canada's acquisitions being a major factor in their disappearance). There are two possible effects of this rationalization. On one hand, having fewer participants in the downstream industry holds the potential for improved efficiency of operation through economies of scale and rationalized refining, distribution and marketing systems. On the other hand, Canadian consumers may have experienced higher retail prices in having fewer competitors for their business.

The Committee concludes that the federal government erred in allowing Petro-Canada to become such a dominant part of the downstream industry, where it appears that the Corporation has chosen to compete primarily through acquisition and advertising rather than through the price mechanism. Mr. Hopper testified to the Committee that diversification into the downstream sector was essential to the long-term survival of his company. In his words:

> ...I don't think Donald Macdonald fundamentally understood what this company was about in the long term. Look, if you were to set up a company and have it explore only in the frontier and not acquire anybody, in five years we would have been totally bust...I mean, if I were to survive in this company and have the company survive, which was my ambition, I had to acquire some assets. I had to acquire cash flow. I had to build a corporation that could stand on its own. Governments change and have changed. It was clear that this company could simply not go out and drill holes in the frontier without any source of cash other than from government. It was far too tenuous a proposition.
> (Canada, Senate, Standing Committee on Energy and Natural Resources, 16 November 1989, pp. 29-30)

We do not believe that the government should direct Petro-Canada in its marketing strategy, since this would be highly damaging to the industry; there may, however, be justification in considering a dispersal of Petro-Canada's downstream assets in a way that encourages competition, whether it is privatized or not.

(4) The Committee recommends that further study be done of the rationalization of the downstream petroleum industry and its possible adverse effects on competition generally, with particular emphasis on Petro-Canada's role.

A National Energy Supply Agency

Having reviewed the various policy purposes for which Petro-Canada has been used in the past and having considered energy issues which Canada will face in the future, the Committee concludes that there remain valid reasons for the federal government to be involved in the energy sector. If Petro-Canada is to continue operating as a commercial enterprise only or is privatized, then there needs to be some other agency of government that can serve as the vehicle for these policy functions.

Committee members have been particularly interested in the Japanese Government's use of the Japan National Oil Corporation (JNOC) as a facilitator of national energy policy in the petroleum sector, without attributing to it any operational role. JNOC invests with private-sector Japanese companies in oil exploration and development in many areas of the world, sharing the risks and underwriting part of the cost. In those cases where exploration is successful and leads to production, JNOC recovers its investment and reinvests in new ventures, minimizing the funds that the Japanese Government has to provide in support of these activities. JNOC-assisted companies in 1988 produced approximately 1.3 million barrels of oil per day in various regions of the world; one-third of this output was marketed in Japan and accounted for 12.4% of domestic consumption. JNOC also manages Japan's strategic oil reserve, accumulating large stocks of oil in partnership with the private sector, and performs an important research and development function for the Japanese petroleum industry.

In the opinion of most Committee members, Canada would benefit from having a national petroleum agency whose function is to work cooperatively – and not in competition with – the private sector in securing Canada's future supplies of oil and natural gas. If the government is not prepared to attribute this role to Petro-Canada, then the Committee recommends that a new agency be established.

(5) The Committee recommends that the federal government consider establishing a national energy supply agency whose primary function is to facilitate the development of Canada's petroleum resources, working cooperatively with the private sector. This

Crown agency should not have an operational role in competition with the private sector.

Although the Committee is addressing the issue of energy supply in recommendation #5, Committee members want to emphasize their position that future energy policy-making in Canada must incorporate demand modification and increased efficiency of use as fundamental elements – policy cannot be directed to issues of energy supply alone. A balanced, far-sighted energy policy is crucial to lessening our environmental problems, to enhancing our national energy security, and to improving our economic competitiveness. These will be major themes of the Committee's review of the Energy Options report.

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Chapter One

A Review of Petro-Canada's Operations

A. Startup and Evolution

In December of 1973, the Government of Canada announced a decision in principle to create a national petroleum company. The government of that time foresaw that a Crown oil company would engage in the following activities:

- explore for conventional oil and gas in Canada;
- make investments to develop Canada's oil and gas resources and, in particular, to accelerate development in those parts of Western Canada's oil sands not exploitable with existing technology;
- operate as a state purchasing agency for foreign oil; and
- possibly engage in the refining and marketing of petroleum products.

The *Petro-Canada Act* was introduced into Parliament on 3 October 1974 and received Royal Assent on 30 July 1975. Petro-Canada began operating in January 1976.

The purpose of the Corporation is stated in section 3 of the Act:

> **3.** The purpose of this Act is to establish within the energy industries in Canada a Crown owned company with authority to explore for hydrocarbon deposits, to negotiate for and acquire petroleum and petroleum products from abroad to assure the continuity of supply for the needs of Canada, to develop and exploit deposits of hydrocarbons within and outside Canada in the interests of Canada, to carry out research and development projects in relation to hydrocarbons and other fuels, and to engage in exploration for, and the production, distribution, refining and marketing of, fuels.

The five formal objectives of the Corporation are given in section 6:

> **6.** The objects of the Corporation are
>
> (a) to engage in exploration for and the development of hydrocarbons and other types of fuel or energy;

(b) to engage in research and development projects relating to fuel and energy resources;

(c) to import, produce, transport, distribute, refine and market hydrocarbons of all descriptions;

(d) to produce, distribute, transport and market other fuels and energy; and

(e) to engage or invest in ventures or enterprises related to the exploration, production, importation, distribution, refining and marketing of fuel, energy and related resources.

The legislation conferred broad operating authority on the new company, allowing it to participate in all aspects of the oil business and deal with all forms of energy, not just petroleum. Nonetheless, it was initially intended that Petro-Canada would concentrate on upstream activities in the domestic oil business. Appearing before the House of Commons Standing Committee on National Resources and Public Works on Bill C-8, *An Act to establish a national petroleum company*, the Minister of Energy, Mines and Resources, Donald Macdonald, said:

> ...to repeat an observation which we previously made, the intention is to supplement the capacities of the Canadian petroleum community to explore for and develop additional hydrocarbon deposits and in this sense the entering into the refining or marketing business would not be one of the primary objects of the Corporation at this particular time. I cannot speak for other Ministers or other ministries, as time may go on, but the primary purpose and the direction to which the Corporation would be put would be in the exploration and development field.
> (Canada, House of Commons, Standing Committee on National Resources and Public Works, 24 April 1975, p. 8)

Within three years, however, Petro-Canada would exercise the authority granted to it under the Act to expand its operations into the downstream sector.

Apart from the objectives formally stated in the Act, which allowed Petro-Canada to operate as an integrated oil company, other objectives of a public policy nature were attributed to the Corporation. Foremost among its initial public policy functions were its expected contribution to securing Canada's oil supplies (by promoting petroleum exploration and development on Canada Lands and through state-to-state contracting for offshore oil), and its "window on the industry" role.

Larry Pratt has commented on Petro-Canada's policy functions in the following manner:

> Of the numerous functions that a national oil company might perform, two above all preoccupied the Trudeau administration in late

1973. First, a state corporation might be required to assure the security of imported oil supplies. Second, the government's "need to know" the extent and cost of Canadian oil and gas reserves was in conflict with the normal commercial behaviour of the private oil sector; a national oil company under government control could discount the future differently and thereby satisfy the goals of public policy...
(Pratt, 1988, pp. 159-160)

...While the option of moving later into into refining and marketing was not ruled out, the corporation sketched out by Liberal energy advisors in late 1973 was not intended to displace the private oil sector. Nor was its principal objective to "Canadianize" the oil industry. Its main function would not be that of a rent collector, since to be an efficient rent collector it would have to hold a monopolistic position in the industry – and this had been rejected. Rather, its initial mandate would be to pursue self-sufficiency by accelerating the *timing* of high-risk exploration and development; by supplementing the market-generated rate of frontier exploration and by encouraging joint ventures with private capital, the national oil company would attempt to redress the problem of underinvestment caused by the excessive discount rates of the petroleum industry. Because a Crown corporation could afford to use a lower rate of discount than a private enterprise, its investments in exploration and research could be undertaken without a commitment to the early production of discovered reserves. By thus severing the commercial link between exploration and production, it was hoped to increase the domestic reserves-to-production ratio, giving Canada an increased capacity to withstand a shortfall in world oil supply.
(*Ibid.*, pp. 164-165)

In its first annual report, the new Corporation acknowledged its mandate to further three government objectives (Petro-Canada, 1977, p. 4):

- to increase the supply of energy available to Canadians;
- to assist the government in the formulation of its national energy policy; and
- to increase the Canadian presence in the petroleum industry.

Shortly after Petro-Canada was incorporated, the Crown's 45% share of Panarctic Oils Ltd. was assigned to it at a book value of $78.1 million. In April 1976, Petro-Canada was given the federal government's 15% share in the Syncrude oil sands project and assumed the government's participation in it. The book value of the transfer was $93.8 million and additional financing during 1976 brought the investment in Syncrude to $170.4 million at year-end. The Corporation's ultimate contribution to Syncrude's estimated total construction costs of $2.1 billion was expected to reach $315 million. Petro-Canada also entered the Polar Gas Project, honouring a government commitment. Begun in 1972 as a research consortium, the Polar Gas Project was investigating the feasibility of transporting Arctic Islands natural gas to southern markets, and Petro-Canada put $7.0 million into the Project in 1976.

To provide the means for Petro-Canada to acquire a land position in Canada's frontier regions, the government proposed in a policy statement of May 1976 to accord the new state oil company with preferential rights. Under new Regulations arising from the *Petroleum and Natural Gas Act*, Petro-Canada could select up to 25% of any lands surrendered to the Crown. An additional preferential process, introduced in the National Energy Program (NEP) of 1980, conferred an option to acquire a 25% working interest on Crown lands:

> ...This interest will be exercised by Petro-Canada or some other designated Crown corporation, and will be in the form of a carried interest, convertible to a working interest at any time prior to the authorization of a production system for a particular field. It will be applicable to all existing interests, however acquired.
> (Canada, EMR, 1980, p. 47)

This "back-in" could be exercised by Petro-Canada without any payback of previous exploratory expenditures. Petro-Canada would, however, pay all production costs associated with the 25% Crown share. Under pressure from the United States Government, which regarded this provision as a form of confiscation, the Canadian Government subsequently announced that it would make ex gratia payments to petroleum companies for certain past expenditures in the case of a Petro-Canada back-in, but only for oil or gas discoveries made prior to year-end 1982 and only for discovery wells initiated before year-end 1981.

Petro-Canada began a series of private-sector acquistions that would culminate in its becoming one of the largest integrated oil companies operating in Canada. Effective 1 August 1976, the Company acquired 100% of the outstanding shares of Atlantic Richfield Canada Ltd. and these assets became a wholly-owned subsidiary, Petro-Canada Exploration Inc. The cost of this acquisition was $342.44 million.

On 10 November 1978, Petro-Canada acquired control of Pacific Petroleums Ltd. through the acquisition of 52% of its shares from Phillips Petroleum Co. of Oklahoma. In early 1979, Petro-Canada extended its ownership to more than 90% and subsequently acquired all of the outstanding shares in Pacific Petroleums. Through this acquisition, Petro-Canada became a 32% shareholder in Westcoast Transmission Co. Ltd. which was a major partner with Alberta Gas Trunk Line Company (later NOVA) in several joint ventures.

During 1980, Petro-Canada began negotiating for the purchase of Petrofina Canada Inc. from Petrofina S.A. of Belgium. The federal government approved this proposed purchase, which would give Petro-Canada retail outlets across the country, and, in April 1981, announced that it would implement the Canadian Ownership Special Charge (COSC) on domestic sales of petroleum products and natural gas to cover 85% of the costs of the acquisition. The total cost of Petrofina Canada's outstanding shares on 2 May 1981 was $1,460 million, and an additional $350 million was set aside to cover financing costs, which would depend on the timing of share tendering during the 25-month acquisition period. The acquisition was completed in

1983, at an aggregate cost of $1,600.5 million. The Petrofina purchase gave Petro-Canada a major refinery in Montreal and a Canada-wide petroleum marketing system. The purchase boosted the Corporation's interest in the Syncrude consortium to 17% and its holding in the Alsands Group to 17%. In 1981, the Board of Directors approved spending $117 million to construct a 5,000 barrels/day heavy oil refining unit in Montreal to demonstrate the CANMET residuum hydrocracking process.

In October 1982, Petro-Canada extended an offer to BP Refining and Marketing Canada Limited to acquire all of its shares. The following March, Petro-Canada acquired 100% of the outstanding voting shares and 9.4% of the non-voting shares, at a cost of $115.781 million. Under the terms of the offer, Petro-Canada had to acquire the remaining non-voting shares in 1984 and 1985 at an escalating price. The purchase was completed in 1985, at a total cost of $424.8 million. These assets became Petro-Canada Products Inc. and included 1,640 BP service stations in Ontario and Quebec, and BP's refinery in Oakville.

Despite a statement by Petro-Canada's Chairman in November 1983 that the Company was finished making major acquisitions with the purchase of BP Refining and Marketing and would enter a period of consolidation, Petro-Canada made yet another purchase, Gulf Canada's downstream assets, for which it paid $1,014.9 million, completing the transaction in 1986. In a decade, Petro-Canada had become one of the largest players in the Canadian "oil patch". Its acquisitions, listed in Table 1, had cost almost $4.9 billion in as-spent dollars.

In 1980, Petro-Canada and NOVA joined forces to construct Canada's fourth oil-sands mining complex. The Suncor (formerly Great Canadian Oil Sands, GCOS) and Syncrude extraction plants were already in production and the Alsands project (in which Petro-Canada's interest stood at 17% after the acquisition of Petrofina) was under development. The Petro-Canada/ Alberta Gas Trunk Line joint venture, known as Canstar Oil Sands Limited and announced in May 1980, was to be the first Canadian-owned and managed oil-sands mining operation, and was to be comparable in size to Syncrude (130,000 barrels/day of synthetic crude) and Alsands (140,000 barrels/day of syncrude). As prices fell after the second oil price shock, however, both the Alsands and Canstar projects were abandoned.

Petro-Canada's growth in assets was accompanied by an expanded role as an agent of federal policy. The threat of oil shortages resulting from the Iranian crisis in 1979 prompted Canada to develop new sources of supply. Following lengthy negotiations, Mexico's President signed an agreement in May 1980 which included an undertaking to sell to Canada, through a state-to-state contract, 50,000 barrels/day of crude oil. This would be Petro-Canada's only involvement in state-to-state oil trading.

Pratt has argued that the subsequent broadening of Petro-Canada's mandate was prompted in particular by two events: the introduction of the National Energy Program (NEP) in 1980 following the second oil price shock, and the financial crisis that overtook the petroleum industry in the 1980s as oil consumption and prices fell. He writes:

...[Petro-Canada] was now expected to perform not only as a catalyst by accelerating the pace of frontier exploration and oil sands development, it was also required to help restructure and Canadianize the oil and gas industries, to be an instrument to collect economic rents and industrial benefits; to provide information and insights into the industry and, in Petro-Canada's own words, to be "a federal presence to understand and influence the timing and priority of projects in a number of the industry's spheres of activity, for example, upgrading of heavy fuel oil in Montreal, new tarsands plants, and East Coast development." The government was even creating a new subsidiary, Petro-Canada International, to assist Third World nations in their search for petroleum resources... (Pratt, 1980, p. 183)

Table 1: Petro-Canada's Assets and Acquisitions, 1976-1989

Year	Total Assets ($ millions)	Acquisition	Cash Consideration ($ millions)
1976	$714.0	Atlantic Richfield Canada	$342.4
1977	878.7		
1978	3,348.9	Pacific Petroleums	746.9
1979	3,411.3	Pacific Petroleums	749.5
1980	3,766.8		
1981	6,617.5	Petrofina Canada	825.5
1982	7,552.1	Petrofina Canada	350.3
1983	8,239.0	Petrofina Canada	424.7
		BP Canada	121.6
1984	9,055.3	BP Canada	1.2
1985	8,846.1	BP Canada	302.0
		Gulf Canada	713.9
1986	8,139	Gulf Canada	301
1987	8,453		
1988	8,611		
1988 (restated)	6,752 (a)		
1989	6,818		

Note (a): Effective 1 January 1989, Petro-Canada changed its method of accounting and restated its 1988 balances in the *1989 Annual Report*.

Source: Halpern, Paul, André Plourde and Leonard Waverman, *Petro-Canada: Its Role, Control and Operations*, Report Prepared for the Economic Council of Canada, Ottawa, Table 2-1, page 15, 1988; Petro-Canada, *Annual Reports*, Calgary, 1986-1989.

In May 1980, the federal government created Canertech as a wholly-owned subsidiary of Petro-Canada, designed to function as a venture capital development company for energy conservation and renewable energy technology. Canertech, headquartered in Winnipeg and given an initial budget of $20 million, was directed to support Canadian business either through joint ventures or equity investments. The Corporation, which was shut down when the new government took office in 1984, is described in the following subsection.

In August 1980, Petro-Canada International Assistance Corporation (PCIAC) was established as another subsidiary of Petro-Canada. PCIAC offers Canadian technology and expertise to developing countries to help them reduce or eliminate their dependence on foreign oil. The Corporation acts as a direct delivery mechanism for Canadian development assistance by participating in the exploration for hydrocarbon resources, conducting geological and geophysical studies, and providing technical assistance and training. The use of tied aid ensures that Canada's petroleum industry also benefits from this program. PCIAC continues to operate today and is also described in more detail later in Chapter One.

Following the second oil price shock, the international oil industry began a dramatic structural change. World oil demand fell and refinery utilization rates dropped below the breakeven point for many companies. State-to-state oil trading declined in favour and futures trading in oil and gas became commonplace. Survival in the integrated oil industry now depended on rationalizing capacity, adapting to shifting markets and rapid technical innovation. Petro-Canada's strategy of promoting high-cost megaprojects for long-term security of supply threatened the company's viability.

The Progressive Conservative Government elected in 1984 directed Petro-Canada to operate in the same manner as other commercial, private-sector oil companies, as the Corporation stated in its *1984 Annual Report*.

> ...The Corporation has now been given a new mandate by its shareholder – to operate in a commercial, private sector fashion, with emphasis on profitability and the need to maximize the return on the Government of Canada's investment. In this regard, Petro-Canada is not to be perceived in the future as an instrument in the pursuit of the Government's policy objectives. However, the Government maintains the right as the shareholder to formally direct Petro-Canada to carry out certain activities in the national interest.
> (Petro-Canada, 1985, p. 2)

During 1989, Petro-Canada changed from the full cost to the successful efforts method of accounting for its upstream operations, and reported a significantly reduced equity. The Corporation also announced a major overhaul of its operations to cut costs, reduce staff, alter operating practices and change the asset balance. It has already divested itself of almost $120 million in assets and plans to sell a substantial amount of its interests over the next several years, thereby improving its competitive position and enhancing its financial performance.

On 20 February 1990, Minister of Finance Michael Wilson announced that the Government of Canada would proceed with Petro-Canada's privatization. The following day, John McDermid, Minister of State for Privatization, revealed several of the conditions under which the privatization would take place. The initial offering would represent about 15% of the company. Individual ownership will be limited to 10% and foreign ownership to 25% of the publicly held shares of Petro-Canada. The Minister of State for Privatization will retain the federal holding and manage it as an investment. Petro-Canada is to operate as a private-sector company at arms-length from the federal government.

Petro-Canada conducts its business primarily through its wholly-owned subsidiary Petro-Canada Inc., which is incorporated under the *Canada Business Corporations Act*. Exploration, development and production activities are carried on by the Petro-Canada Resources Division; refining, distribution and marketing operations are carried on by the Petro-Canada Products Division.

2. Canertech

Canertech Inc. was created pursuant to the National Energy Program of November 1980, as the Government of Canada's venture capital development company mandated to invest in energy conservation technology and renewable energy conversion systems. Its purpose derived from the NEP goals of energy self-sufficiency, energy conservation and oil substitution. Canertech was created by an Order-in-Council of 4 December 1980 and incorporated as a wholly-owned subsidiary of Petro-Canada under the *Canada Business Corporations Act* on 11 December 1980, with headquarters in Winnipeg. The company opened for business in January 1981.

Canertech's mandate, as reflected in its Articles of Incorporation, was to (Canertech, 1983, p. 4):

a) invest or engage, alone or with others, in the production, distribution, marketing, sale, research, development and demonstration of new or rediscovered forms of energy and in energy conservation technology, products and services and such other activities necessarily incidental thereto;

b) acquire and hold shares or assets of any person or firm carrying on the activities referred to in paragraph (a).

Canertech's field of interest included "...energy conservation products, systems and services, and biomass, solar, wind, wave, small hydro and geothermal energy conversion". (Canertech, 1982, p. 4) It was set up as an investment company with a development function; it was not a source of debt financing or grants. The Corporation was initially capitalized in the amount of $20 million by an advance from its parent company from the Government of Canada's share subscription to Petro-Canada. This and subsequent advances were intended to be transferred back at cost when Canertech became an autonomous Corporation, which was the government's intent.

In addition to investing in and acquiring a number of small companies, Canertech in October 1982 created a wholly-owned subsidiary, Canertech Conservation Inc., for the purpose of providing, through operating subsidiaries, energy conservation retrofit services for the institutional/commercial/industrial market. By late 1984, Canertech Conservation had established subsidiary ventures in Nova Scotia, New Brunswick/Prince Edward Island, and Ontario, and had announced its intention to establish similar subsidiaries in Western Canada. The Corporation guaranteed its clients that energy savings would pay for retrofit costs – including Canertech Conservation's profit and carrying costs – within five years.

Canertech directed its strategy of development along three lines: energy conservation, retrofit services, and renewable energy. In 1984, Canertech's investment portfolio in the conservation line included interests in companies producing mineral wool insulation, programmable thermostats, insulating concrete blocks for dry-stack wall systems, and specialized combustion systems. To address the retrofit market, Canertech had invested in a company specializing in energy-conserving retrofits, and in Canada's leading supplier of packaged electrical power systems for remote and off-grid sites, while building up Canertech Conservation Inc. To promote renewable energy use, the Corporation acquired an interest in a company developing biomass conversion systems based on fluidized bed gasification technology, and in another producing heating systems using wood, wood/electricity, wood/oil and wood/coal fueling. Canertech was a partner in two special projects, one building a commercial gasifier to process sawmill waste and the other developing a technology for producing fuel ethanol from wood cellulose.

In its November 1984 Economic Statement, the new Progressive Conservative Government announced that "Canertech will be wound up and its assets sold", observing that "Certain programs have reached the stage where they should now be eliminated or gradually phased out" (Canada, Treasury Board, 1984, pp. C.2 and 9). In the same Statement, the government announced that "a planned equity injection of $275 million to Petro-Canada will not be made" (p. 8).

3. Petro-Canada International Assistance Corporation

The NEP first mentioned the concept of PCIAC as a "major new initiative to help developing countries", and noted that preliminary discussions had already taken place with the national oil companies in Mexico and Venezuela about a "major joint assistance effort to assist petroleum development in Latin America and the Caribbean" (Canada, EMR, 1980, p. 53). In August of 1981, Prime Minister Trudeau announced the creation of PCIAC at the Nairobi Conference on New and Renewable Sources of Energy, stating that its purpose was to assist oil-importing developing countries to exploit their own energy resources, particularly hydrocarbons. The new company would provide development assistance directly to Third World countries, and would be available as an executing agent for other institutions, such as the World Bank.

PCIAC's status is unique. Although incorporated (in December 1981) as a wholly-owned subsidiary of Petro-Canada, it is a non-profit instrument of Canadian development assistance, using government aid funds voted in Parliamentary appropriations. PCIAC has access to Petro-Canada's resources and personnel as required, on a cost-recovery basis. Petro-Canada also serves as PCIAC's executing agent for operations abroad, and lets out all contracts with Canadian industry.

The Articles of Incorporation authorize PCIAC:

(a) to assist developing countries to reduce or eliminate their dependence on imported oil by using, where possible, Canadian technology and expertise for hydrocarbon exploration and related activities, and to function as a direct delivery mechanism for Canadian official development assistance and as an executing agent for other development assistance institutions, to carry out the following activities in developing countries eligible to receive Canadian bilateral development assistance and which are dependent on imported oil:

- to participate in exploration for hydrocarbon resources particularly oil and gas, in developing countries;
- to conduct pre-exploration and related studies in developing countries; and
- to provide technical assistance and training to personnel from developing countries in hydrocarbon resource exploration, development and production related activities.

(b) to operate as an instrument of Canadian official development assistance in a manner consistent with the government's foreign aid objectives and programs.

PCIAC assistance may take a variety of forms:

- pre-project assessment, feasibility studies and comprehensive basin evaluations;
- new or additional surveys to attract exploration by industry, including onshore and offshore gravity, magnetic and seismic surveys;
- exploration for oil and gas where industry is not presently active, including onshore and offshore drilling;
- technical assistance and on-the-job training for personnel for oil and gas exploration, development and production; and
- management, institutional, economic or legal assistance and training for Third World officials responsible for the assessment, negotiation, monitoring and management

of oil and gas exploration and development arrangements.

Prospective project countries submit proposals for consideration, and these are evaluated against the following criteria:

- the traditional development assistance relationship between Canada and the country applying for assistance;
- the geological potential of the area;
- the needs of the country making the application, including in particular the degree of dependence on foreign oil;
- the capacity of the recipient country to develop and utilize an oil or gas discovery to advance its economic development; and
- the opportunity for Canadian firms to supply goods and services and gain international expertise.

Project proposals are assessed and approved by the PCIAC Board of Directors, and carried out by Canadian firms through Petro-Canada's procurement and contracting services. Since its creation in 1981 through the 1988-89 fiscal year (PCIAC's annual report for fiscal 1989-90 is not yet available), PCIAC has initiated more than 50 projects in 40-odd developing countries. In 1988-89, PCIAC secured the services of 161 Canadian firms and consultants.

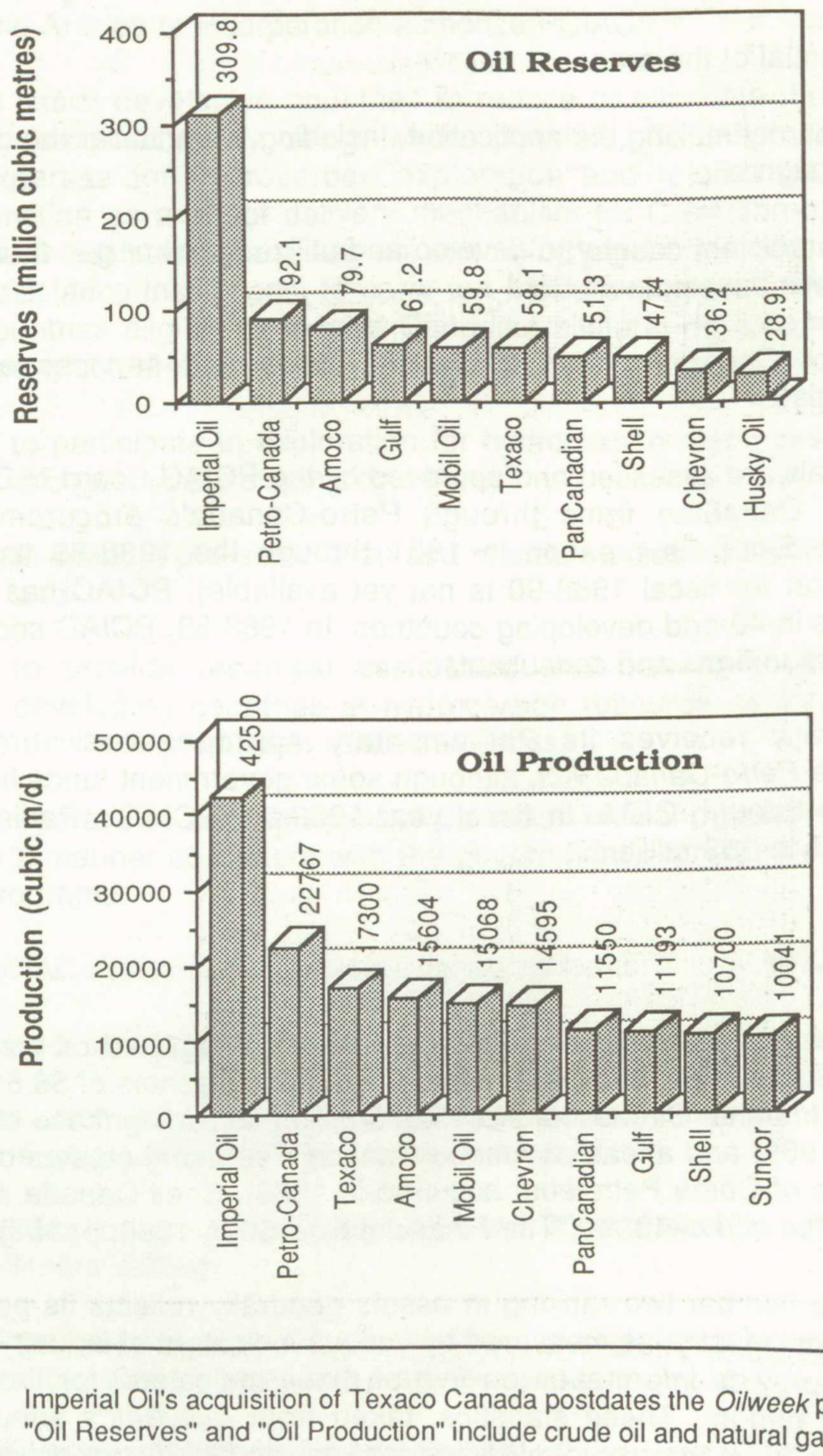
PCIAC generally receives its Parliamentary appropriations pursuant to subsection 24.2 of the *Petro-Canada Act*, although some government funds have also been made available through CIDA. In fiscal year 1990-91, PCIAC's Parliamentary appropriation amounts to $53 million.

B. Industry Activity

Petro-Canada has become one of Canada's largest integrated oil companies. Measured by total assets at year-end 1989, Petro-Canada with assets of $6.818 billion stood second behind Imperial Oil (assets of $15.576 billion, including those of Texaco Canada acquired in 1989) and ahead of Amoco Canada Petroleum (assets of $6.728 billion, including those of Dome Petroleum acquired in 1988). Shell Canada at $5.668 billion stood fourth at the end of 1989. ("The Financial Post 500", 1990, p. 157)

Petro-Canada's number two ranking in assets generally reflects its position in the domestic petroleum industry, as measured by various indicators of industry activity. Figures 1 through 3 provide information on five of these indicators, for the top ten companies in each category. These statistics, taken from *Oilweek's* annual June review of the top 100 oil and gas companies, are for year-end 1988 and do not reflect Imperial's purchase of Texaco Canada's assets.

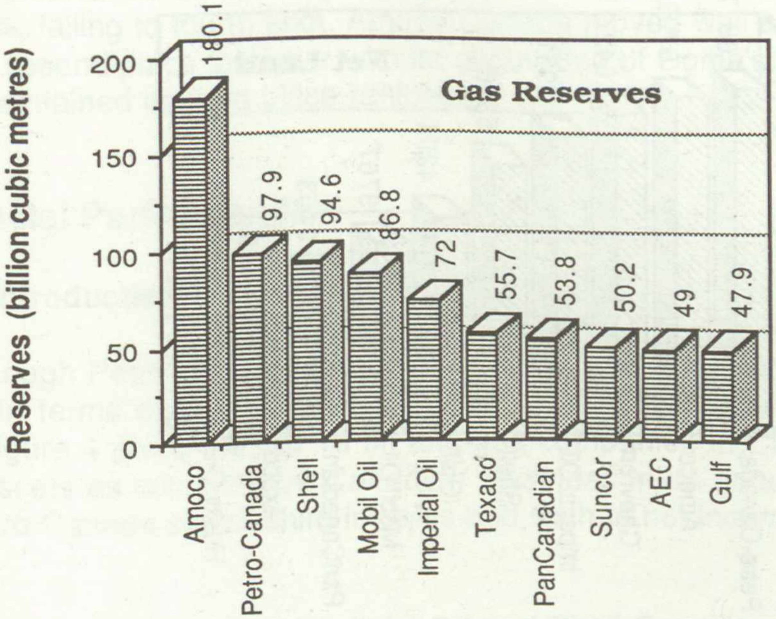
Figure 1: The Top 10 Companies in Canadian Liquid Hydrocarbon Reserves and Production, 1988

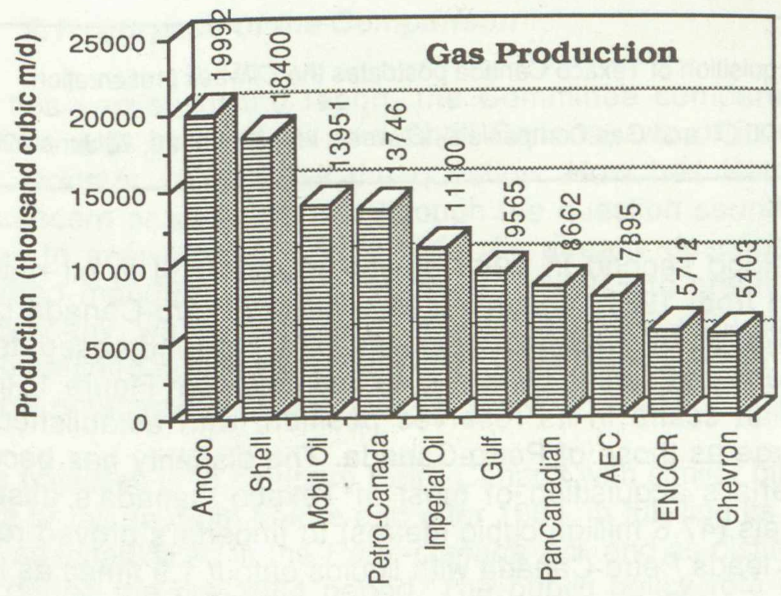


Notes: Imperial Oil's acquisition of Texaco Canada postdates the *Oilweek* presentation. "Oil Reserves" and "Oil Production" include crude oil and natural gas liquids.

Source: "Canada's Top 100 Oil and Gas Companies", *Oilweek*, vol. 40, no. 20, 26 June 1989, p. 7.

Figure 2: The Top 10 Companies in Canadian Natural Gas Reserves and Production, 1988

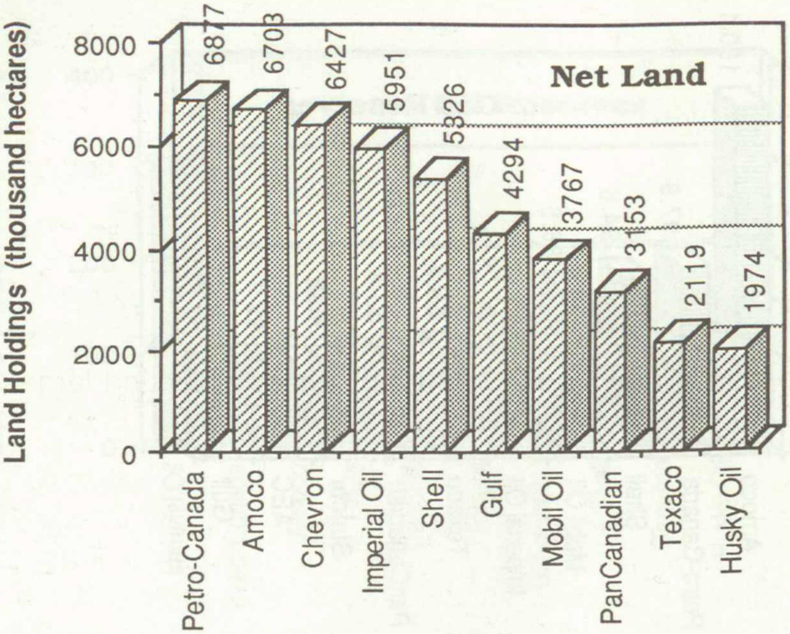




Notes: Imperial Oil's acquisition of Texaco Canada postdates the *Oilweek* presentation. "Gas Reserves" and "Gas Production" refer to marketable natural gas.

Source: "Canada's Top 100 Oil and Gas Companies", *Oilweek*, vol. 40, no. 20, 26 June 1989, pp. 8 and 10.

Figure 3: The Top 10 Companies in Canadian Net Land Holdings, 1988



Note: Imperial Oil's acquisition of Texaco Canada postdates the *Oilweek* presentation.

Source: "Canada's Top 100 Oil and Gas Companies", *Oilweek*, vol. 40, no. 20, 26 June 1989, p. 10.

Petro-Canada stood second in 1988 behind Imperial Oil in oil reserves and production, unchanged from 1987. According to *Oilweek*, Petro-Canada boosted its output of oil and gas liquids by 1.8% in 1988 over 1987, and increased its year-end proven reserves of oil and gas liquids by 4.1%. As is apparent in Figure 1, Imperial Oil dominates the Canadian scene in its reserves position, with established reserves almost 3.4 times as large as those of Petro-Canada. The disparity has become more pronounced with Imperial's acquisition of most of Texaco Canada's assets, which added 300 million barrels (47.6 million cubic metres) to Imperial's proved reserves. In oil production, Imperial leads Petro-Canada with liquids output 1.9 times as large.

Figure 2 indicates Petro-Canada's standing in natural gas reserves and production for 1988. Although Petro-Canada increased gas production by 11.6% in 1988 over 1987, the Company still fell from second to fourth place among gas producers. Amoco Canada moved from fourth to first place, the result of acquiring Dome Petroleum, while Shell Canada dropped from first to second place. Mobil Oil Canada also moved ahead of Petro-Canada, boosting annual output by 14.3%. Considering reserves, Petro-Canada yielded its number one ranking to Amoco, falling to second place ahead of Shell Canada. Imperial's purchase of Texaco Canada added 1.5 trillion cubic feet (41.7 billion cubic metres) of gas to its proved reserves.

Despite a decrease of 2.6% in its net land holdings in 1988 compared with 1987, Petro-Canada still moved from second to first place in the ranking (Figure 3). Imperial Oil surrendered its 1987 first place ranking by decreasing its land holdings almost 21%, falling to fourth spot. Amoco Canada moved well ahead, from ninth place in 1987 to second place last year with its acquisition of Dome's land position. Chevron Canada maintained its third place ranking.

C. Financial Performance

1. Introduction

Although Petro-Canada ranked in 1989 as Canada's second largest petroleum company in terms of total assets, it fared less well when ranked by sales and net income. Figure 4 gives the top 10 oil and gas companies in Canada in 1989 listed in order of assets as compiled by *Canadian Business* in its annual review. Among this group, Petro-Canada stands third in sales and sixth in net income.

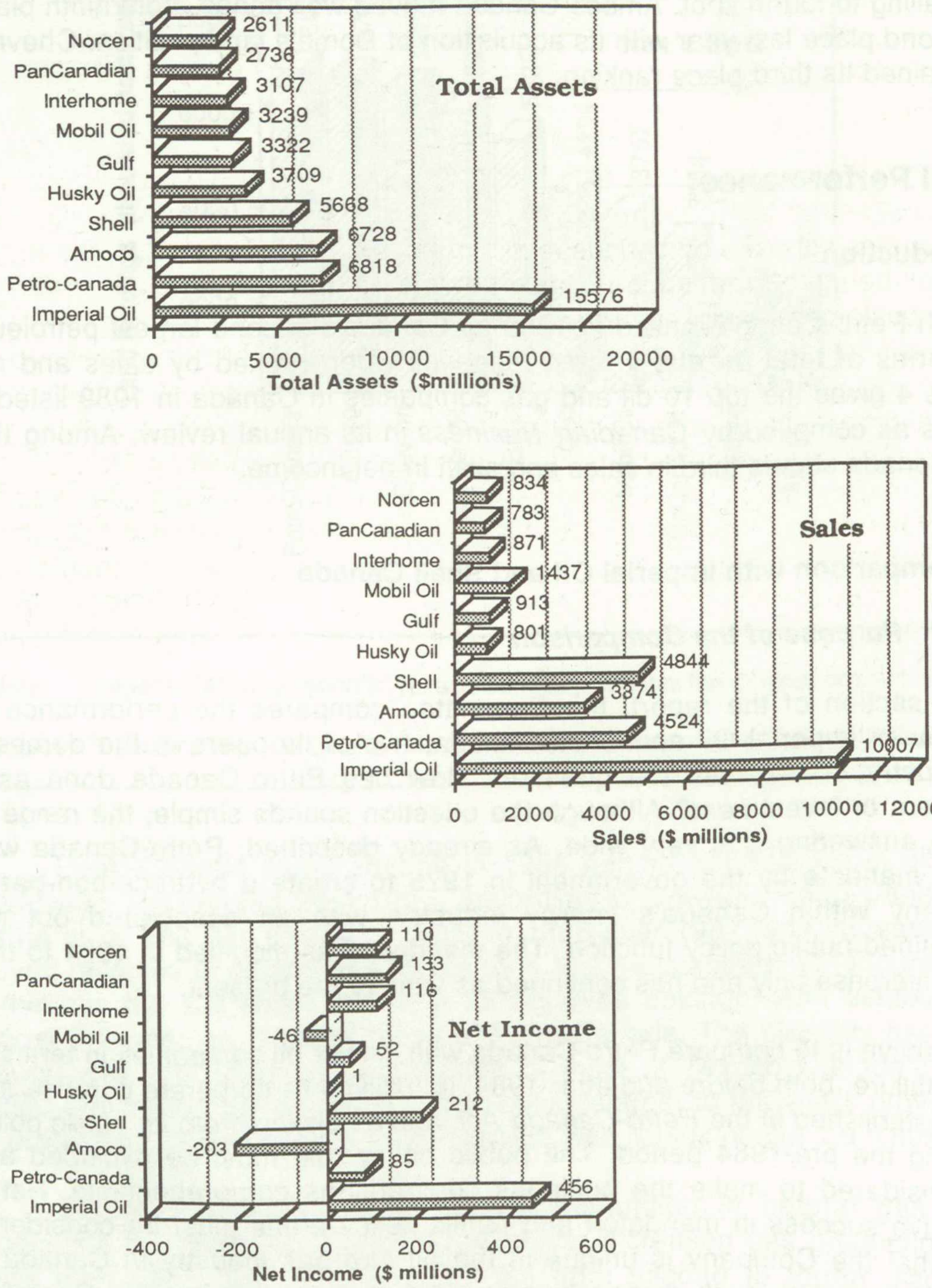
2. A Comparison with Imperial Oil and Shell Canada

2.1 Purpose of the Comparison

In this section of the report, the Committee compares the performance of Petro-Canada with Imperial Oil and Shell Canada, two of its peers in the domestic petroleum industry, to address the question: How has Petro-Canada done as a business concern or investment? Although the question sounds simple, the range of approaches to answering it is very wide. As already described, Petro-Canada was given a broad mandate by the government in 1975 to create a hydrocarbon-based energy company within Canada's energy industry, with an associated but not legislatively defined public policy function. The mandate was modified in 1984 to that of a for-profit enterprise only and has continued as such to the present.

The objective is to compare Petro-Canada with similar oil companies in terms of its success or failure, both before and after 1984, in fulfilling its corporate purpose and objectives as established in the *Petro-Canada Act*, and as distinct from its public policy functions during the pre-1984 period. The public policy role must be excluded and separately considered to make the business comparisons comprehensible. Petro-Canada's relative success in mandated and public policy areas must be considered separately in that the Company is unique in the oil and gas industry in Canada in having been charged with such responsibilities. There are no comparable Canadian enterprises against which to measure public policy success: in Chapter Five, the study compares Petro-Canada with four other national oil companies to consider this aspect of the Company's operations.

Figure 4: Canada's Top 10 Petroleum Companies in 1989, Ranked by Assets and Including Sales and Net Income



Source: "The Canadian Business 500", *Canadian Business*, June 1990, p. 74ff.

Business success is a difficult concept to quantify. Clearly, Petro-Canada has been very successful in establishing a dominant, integrated oil and gas company in Canada from a standing start in 1976. This achievement and the visibility in the retail marketplace which accrues to Petro-Canada is within the scope of business success. Business success is measured by demonstrating how well or how poorly the shareholders of a company have done over a given period of time. Where did the investors start, financially, at the opening of the review period; how much in cash or assets have they received and when during the period; how much in cash and assets have they contributed and when during the period; and how are they, financially, at the end of the period.

To preserve and enhance the shareholders' economic position, directors and management must see to the proper conduct of the business in terms of existing laws, rules and regulations imposed by various levels of government. They must see to the reasonable well-being of the various stakeholders in the business beyond the shareholders – customers, suppliers, employees, creditors and debt holders. To have a successful business, directors and management must install, maintain and update various systems, methods, programs, plans and policies to ensure the continuing functioning, improvement, modernization and revitalization of the business, its operations, stakeholder relationships and strategic direction. Success includes the revitalization of management itself. Comparing Petro-Canada's success in these areas would be a relevant and interesting measure of the relative performance of the Company. Neither the information, resources nor time is available to the Committee to attempt this major undertaking. Petro-Canada's success in these respects will be measured by future events which will inevitably test the strength of today's infrastructure and business approaches.

Financial and cash flow data, hydrocarbon reserve estimates and information on downstream operations are available from the annual reports and other publications and filings of the three companies. There are, however, several limitations on the amount of detailed data available and on the comparability of the data. Our approach has been to utilize the available financial and operating data, to manipulate the data so as to make the most meaningful comparisons, and to draw conclusions regarding the relative success of Petro-Canada within the limitations of the information.

The financial information for the periods under review has been taken from the Canoils Database compiled by Woodside Research Ltd. and published by the Reuters news and data service. The information for each period is on an "as reported in that period" basis; that is, no attempt is made to restate the corporate data for retroactive accounting changes. We take the view that this is the most appropriate way to report because this is the information the stakeholders and financial markets received at the time with respect to Imperial and Shell. The originally published information was the information used by all parties in making decisions about all three companies.

It is arguable that conclusions ought not to be drawn from limited data. There is merit to this position. We do not operate in a perfect world. From a business person's standpoint, however, one is forced to draw conclusions and make business judgments every day which may have a significant positive or negative effect on the future of the business. The conclusions and judgements are invariably based on the fullest and most accurate information available but that information is almost always restricted or limited in some fashion.

2.2 Scope of the Comparison

Given the limitations imposed by using only publicly available information and given limited financial and operational disclosure, particularly on the part of Petro-Canada, the report can deal only with the overall performance of the companies rather than with the results of comparable business segments. Petro-Canada has not until very recently provided the segmented information normally available from a major corporation in a similar business. This limitation means that the relative success, for example, of Petro-Canada's downstream operations – petroleum refining, distribution and marketing – cannot be readily compared with that of Imperial Oil or Shell Canada operating in the same business segment. Consequently, when valuations of the business are considered, such valuations cannot be made on a segment by segment basis. One segment may well have completely different capital requirements, rates of return and business risk profile from another segment, resulting in differing valuations.

Different analytical criteria are more important for one business segment than another. Success in one area may vary widely from that of another corporation in a different area. Certain corporations are better at some things than others, or have particular strengths or market positions which are difficult to compete with or to dislodge. One would expect, for example, that Petro-Canada had to invest a large amount of money in marketing relative to Imperial Oil to redirect the public view of its retail gasoline outlets purchased in a series of acquisitions. That investment may be on the verge of paying back the shareholder handsomely. Our report will not be able to deal directly with this type of issue.

Imperial Oil and Shell Canada have been chosen as Petro-Canada's peers for the purpose of this study because of their size, the comparability of the types of operations, the national scope of their operations, and the fact that both have a dominant shareholder. Both have significant Canadian-based upstream operations – exploration, development and production – and significant downstream operations – petroleum refining, distribution, sales and marketing. Both operate in the downstream business across Canada. Both companies have major frontier or future-oriented oil and gas development projects. Imperial Oil has Cold Lake and Syncrude; Shell Canada has the Caroline natural gas field development.

Each of the three companies may be considered to suffer restrictions on its activities imposed by the major shareholder. These include the restriction on Imperial and Shell to operating almost solely within Canada, each being part of a much larger international group which does not want its subsidiaries to have overlapping mandates. Almost certainly there are areas of activity for each within its mandate that the controlling shareholder has a predilection for or against. Mandates imposed by a controlling shareholder, which encourage certain business activities and restrict or eliminate others, have a direct impact on the returns achieved by the business.

The mandate initially imposed on Petro-Canada has been described by Petro-Canada management and others as having adversely affected the company's financial performance. Most certainly, Petro-Canada's financial performance was adversely affected by the mandate. The extent and duration of the impact would likely be impossible to determine, however, with any degree of accuracy. Further, the extent to which Petro-Canada was impacted by its restrictions or public policy directions when compared with the restrictions or directions imposed on Imperial and Shell is difficult to know. As a practical matter, given the high public profile and politically sensitive position of Petro-Canada during the review period compared with Imperial and Shell, one would be compelled by the view that Petro-Canada management – and its directors and chairman in particular – would have much more success in influencing its shareholder to modify a particularly onerous, offensive or wasteful restriction or direction than would the other two. The prospect of the directors, chairman and management of Petro-Canada objecting publicly that a particular policy thrust did not make much sense would not be one that the shareholder would be likely to relish. The directors, chairman and management of Imperial and Shell would undoubtedly have much less influence on Exxon and Royal Dutch Shell.

We take the position that the management of each of the three companies agreed with and supported the selection of business investments by and large, and therefore each must abide with the results of those decisions. Further, the comparison since Petro-Canada's mandate became a commercial one is fair.

We recognize that there are also significant differences among the three corporations. Imperial has oil and gas liquids reserves estimated to be four times those of Petro-Canada and six times those of Shell, and is by far the leading oil producer in Canada with twice Petro-Canada's annual production and six times Shell's. Shell, on the other hand, has about 25% more natural gas reserves than Petro-Canada, but 24% less than Imperial. Shell has about the same annual natural gas production as Imperial and 11% more than Petro-Canada.

Petro-Canada has 2.6 times the net land holdings of Imperial Oil and 1.7 times that of Shell Canada. However, almost 30% of Petro-Canada's net acreage is outside the country in South America, South East Asia, the Middle East and elsewhere. A further 49% of Petro-Canada's acreage is on federal rather than provincial lands, which means a substantial proportion of its large land position is frontier acreage. In terms of provincial land holdings (conventional producing regions), Petro-Canada has 22% fewer net acres than Imperial and 63% more than Shell. Much of Petro-Canada's federal or frontier acreage results from the National Energy Program's 25% "back-in" arrangement in favour of Petro-Canada in the early 1980s.

Each of the three companies has significant refining and distribution capacity. Imperial has 4,700 service stations in Canada, Petro-Canada 3,295 and Shell 2,700.

Imperial employs about 15,000 people, Petro-Canada 6,500 and Shell 7,200.

Regardless of the historic reasons for these differences and similarities, they have a great influence on the strategies, cost structures, cash flow patterns and capital expenditures of each corporation. With the acquisition of Texaco Canada, Imperial's business and its dominance in certain areas has been substantially increased.

Table 2 summarizes the principal financial and operating statistics for Imperial Oil, Shell Canada and Petro-Canada, providing a comparison of the main features of the three corporations. Other corporations among the ten largest Canadian oil and gas companies were considered for comparison but found to have, or lack, certain features that could significantly distort the comparisons.

Business results for Petro-Canada, Imperial Oil and Shell Canada are analyzed over a ten-year period beginning December 31, 1979 and ending December 31, 1989. From the ten-year period, statistics are analyzed for the most recent seven-year period, five-year period, three-year period and the latest year, 1989. By year-end 1979, Petro-Canada had achieved an asset size and operating scope allowing reasonable comparison with Imperial and Shell. With the later acquisitions of Petrofina and the downstream assets BP Canada and Gulf Canada by 1985, Petro-Canada was certainly comparable with the other two. It is fair to consider the period from 1976 through 1979 as the "start-up" for Petro-Canada.

From 1979 through 1985, major additions were made to form the basis of a much more mature corporation. It is in this latter period when most shareholder value is normally added through major and infill acquisitions and growing corporate scope and, therefore, stability.

It is not within the bounds of this study to judge whether any particular acquisition by Petro-Canada was a "good deal". Nor should it be. The question to be answered is not one of good deals or bad deals in particular. Directors and management make acquisitions or spend capital funds in the normal course of business on what are perceived by the stakeholders to be a good or bad use of corporate funds. Time and what the company does with the acquired assets make the ultimate and sometimes harsh judgment on that. The question to be addressed is how well or how poorly has each company done with the funds placed under its stewardship, relative to the circumstances of its markets.

Comparison over time with other corporations is a method designed to remove arbitrary judgements about how difficult or easy the market environment was in which each company operated. It is somewhat similar to judging the performance of a specific security – stock or bond – against the performance over the same period of a basket of comparable securities. Presumably, the impact of general market conditions is the same for each and a judgment can be made about how the market viewed the particular security at any given time. The concept of performance relative to peers is particularly important for an integrated oil and gas company because of the demonstrated volatility of the markets for these commodities over the last 15 years.

TABLE 2: GENERAL CORPORATE SUMMARY

	AS OF DECEMBER 31, 1989 IN CN$ (1)		
	IMPERIAL	PETRO-CANADA	SHELL
• CORPORATE FINANCIAL SUMMARY			
Capital Employed, $	13,929,000,000	5,227,000,000	5,070,000,000
Revenues, $	10,104,000,000	5,017,000,000	4,917,000,000
Common Cash Flow, $	1,353,000,000	569,000,000	642,000,000
Common Earnings, $	456,000,000	31,000,000	212,000,000
Common Dividends, $	322,000,000	0	101,000,000
Market Capitalization, $	12,140,000,000	-	4,706,000,000
• CORPORATE OPERATING SUMMARY (2)			
Net Oil + NGL Reserves, Barrels	2,264,000,000	527,300,000	382,432,000
Net Gas Reserves, Mcf	5,114,675,000	3,300,000,000	4,127,944,000
Net Oil + NGL Production, Bbls/Day	347,208	145,200	59,126
Net Gas Production, Mcf/Day	610,000	570,800	635,342
Coal Production, Long Tons/Year	1,574,714		1,903,928
Sulphur Production, Long Tons/Year	-	365,000	1,082,616
Products Production, Bbls/Day	520,166	279,267	225,804
Chemical Production, Long Tons/Day	6,102	-	2,384
Oil And Gas Lands, Net Acres			
Federal	1,729,700	11,400,000	10,351,019
Provincial	6,671,700	5,200,000	3,199,945
International	494,200	6,700,000	-
TOTAL	8,895,600	23,300,000	13,550,964
Refining And Marketing			
Refineries	6	4	4
Processing, Bbls/Day	488,717	292,476	240,899
Utilization	93.00%	86.00%	88.00%
Service Stations	4,700	3,295	2,700
Employees	15,248	6,468	7,219
Shareholders (3)	24,344	1	6,107

(1) Extracted from annual reports to shareholders for years ended December 31, 1989 (2) Before royalties

(3) Exxon owns approximately 70 percent of Imperial Oil; Royal Dutch owns about 78 percent of Shell Canada

2.3 Basis of the Comparison

Financial information has been obtained from published statements of the three companies and from the Canoils Database. Additional information for Imperial Oil and Shell Canada has been obtained from their Form 10K and 10Q filings with the Securities and Exchange Commission in the United States.

The basis of the analysis is a comparison of the three companies using an accounting model and a cash flow model, beginning January 1, 1980. The ten-year period, the seven-year period, the five-year period, the three-year period, the one-year period and the opening and closing positions for each period form the analytical base. The financial condition of each company is analyzed using three of the approaches that a bond rating service would use to assess the risk of a debt issue or a preferred share issue: corporate efficiency, shareholder investment efficiency, and creditor efficiency.

2.4 Assumptions in the Analysis

Cash Flow Model

The concept underlying the comparison of Petro-Canada, Imperial Oil and Shell Canada is cash in, cash out, and the time value of money. In simplest terms the shareholders of each company have, at each relevant time, an investment in shares which can be sold, theoretically, and the proceeds invested in more attractive places or held because the shareholders perceive the particular investment to be attractive when compared with the alternatives available. The shareholder in each case realizes a return on investment during the holding period, by the receipt of cash dividends and by an increase or decrease in the value of the investment. To compute a rate of return on the particular investment, opening and closing values of the investment must be assumed and the cash returned to or paid in by the shareholder during the period identified. The cash in and out is, of course, readily obtainable from the financial statements of each company. The opening and closing investment values are much more difficult to identify with any degree of accuracy.

A range of opening and closing values for Petro-Canada has been based on the range of current-year cash flow multiples enjoyed in the public stock markets by both Imperial Oil and Shell Canada. It is essential to note that using market-derived cash flow multiples is not intended to produce a sale valuation for any of the three companies. The intent is to give a comparative evaluation to Petro-Canada based on market perception of the other two companies at the relevant times. Three comparisons have been made for each of the opening and closing positions for the five review periods. In the first case, the higher of the two cash flow multiples of Imperial and Shell has been applied to Petro-Canada. In the second case, the average of their two closing multiples has been used. In the third case, the lower of the two closing multiples has been applied. The data on cash flow multiples are summarized in Table 3.

TABLE 3: GENERAL FINANCIAL SUMMARY

SUMMARY OF FINANCIALS IN CN$ 000 AS REPORTED AT YEAR END (1)					CASH FLOW MULTIPLES		
YEAR	ITEM	IMPERIAL	PETRO-CAN	SHELL	IMPERIAL	PETRO-CAN	SHELL
1979	Retained Earnings	$2,140,000	$55,050	$989,000			
	Common Equity	$2,440,000	$635,050	$1,496,000			
	Capital Employed	$3,751,000	$3,168,088	$2,420,000			
	Market Capitalization	$5,781,081	$1,723,116	$3,533,045			
	Common Cash Flow	$907,000	$261,838	$520,496	6.37	6.58	6.79
	Common Earnings	$493,000	$30,159	$244,496			
	Common Dividends	$150,000	$0	$72,154			
1980	Retained Earnings	$2,621,000	$110,799	$1,234,000			
	Common Equity	$3,789,000	$690,799	$1,742,000			
	Capital Employed	$5,288,000	$3,419,306	$2,707,000			
	Market Capitalization	$5,159,132	$1,466,913	$2,456,139			
	Common Cash Flow	$1,127,000	$349,613	$644,000	4.58	4.20	3.81
	Common Earnings	$682,000	$55,749	$335,000			
	Common Dividends	$201,000	$0	$90,000			
1981	Retained Earnings	$2,866,000	$175,672	$1,357,000			
	Common Equity	$4,042,000	$775,722	$1,865,000			
	Capital Employed	$5,963,000	$6,102,869	$3,055,000			
	Market Capitalization	$4,007,882	$1,488,876	$1,925,000			
	Common Cash Flow	$878,000	$387,999	$619,000	4.56	3.84	3.11
	Common Earnings	$465,000	$64,873	$213,000			
	Common Dividends	$220,000	$0	$90,000			
1982	Retained Earnings	$2,913,000	$186,232	$1,376,000			
	Common Equity	$4,103,000	$2,369,076	$1,884,000			
	Capital Employed	$6,422,000	$6,799,451	$3,950,000			
	Market Capitalization	$4,535,613	$1,549,147	$2,081,808			
	Common Cash Flow	$952,000	$380,189	$615,000	4.76	4.07	3.39
	Common Earnings	$267,000	$10,560	$109,000			
	Common Dividends	$220,000	$0	$90,000			
1983	Retained Earnings	$2,981,000	$212,027	$1,387,000			
	Common Equity	$4,231,000	$3,037,788	$2,186,000			
	Capital Employed	$6,790,000	$7,416,242	$4,495,000			
	Market Capitalization	$5,924,768	$3,955,029	$2,625,837			
	Common Cash Flow	$708,000	$589,937	$521,000	8.37	6.70	5.04
	Common Earnings	$290,000	$30,170	$84,000			
	Common Dividends	$222,000	$0	$63,000			
1984	Retained Earnings	$3,281,000	$353,046	$1,427,000			
	Common Equity	$4,605,000	$3,603,807	$2,228,000			
	Capital Employed	$7,333,000	$8,200,267	$4,717,000			
	Market Capitalization	$6,846,744	$4,727,035	$2,481,989			
	Common Cash Flow	$958,000	$839,446	$603,104	7.15	5.63	4.12
	Common Earnings	$533,000	$151,449	$107,104			
	Common Dividends	$233,000	$0	$66,930			
1985	Retained Earnings	$3,647,000	-$518,706	$1,490,000			
	Common Equity	$5,047,000	$2,669,594	$2,291,000			
	Capital Employed	$7,876,000	$6,782,619	$4,902,000			
	Market Capitalization	$8,322,228	$4,488,130	$2,565,964			
	Common Cash Flow	$1,199,000	$791,924	$584,000	6.94	5.67	4.39
	Common Earnings	$634,000	-$769,335	$130,000			
	Common Dividends	$268,000	$50,000	$67,000			
1986	Retained Earnings	$3,667,000	-$450,000	$1,562,000			
	Common Equity	$5,090,000	$2,738,000	$2,363,000			
	Capital Employed	$7,741,000	$7,105,000	$4,616,000			
	Market Capitalization	$8,386,856	$4,296,541	$2,903,433			
	Common Cash Flow	$967,000	$669,000	$696,000	8.67	6.42	4.17
	Common Earnings	$285,000	$123,000	$139,000			
	Common Dividends	$262,000	$0	$67,000			
1987	Retained Earnings	$4,142,000	-$289,000	$1,820,000			
	Common Equity	$5,566,000	$2,899,000	$2,629,000			
	Capital Employed	$8,449,000	$7,270,000	$4,657,000			
	Market Capitalization	$9,104,347	$4,741,991	$3,931,146			
	Common Cash Flow	$1,249,000	$743,000	$718,000	7.29	6.38	5.48
	Common Earnings	$745,000	$172,000	$336,000			
	Common Dividends	$270,000	$0	$78,000			
1988	Retained Earnings	$4,348,000	-$246,000	$2,152,000			
	Common Equity	$5,774,000	$2,942,000	$2,962,000			
	Capital Employed	$8,778,000	$6,872,000	$4,725,000			
	Market Capitalization	$8,185,174	$3,951,130	$4,757,758			
	Common Cash Flow	$1,198,000	$614,000	$788,000	6.83	6.44	6.04
	Common Earnings	$501,000	$94,000	$422,000			
	Common Dividends	$293,000	$0	$90,000			
1989	Retained Earnings	$4,436,000	$31,000	$2,263,000			
	Common Equity	$7,182,000	$1,785,000	$3,075,000			
	Capital Employed	$13,929,000	$5,227,000	$5,070,000			
	Market Capitalization	$12,140,390	$4,638,259	$4,706,022			
	Common Cash Flow	$1,353,000	$569,000	$642,000	8.97	8.15	7.33
	Common Earnings	$456,000	$31,000	$212,000			
	Common Dividends	$322,000	$0	$101,000			

(1) Petro-Canada market capitalization derived from the average cash flow multiples for Imperial and Shell

The internal rate of return has been computed for each company in each case, for each time period. This computation is one of the standard measures employed by investment managers to compare the relative success of an investment.

Accounting Model

If the cash flow model has the flaw of employing derived opening and closing investment evaluations, any accounting model is also substantially flawed. Without belabouring the point, the announcement by Petro-Canada of a change from the full cost method of accounting to the successful efforts method changed the previously reported shareholder's equity at December 31, 1988 from $3,915 million to $2,727 million. This $1.2 billion write-down for a company which had stated assets of $8.6 billion at the end of 1988 was the result of substituting one acceptable accounting method for another, although the new accounting method clearly is more appropriate for a corporation of Petro-Canada's size. No economic change has occurred but there has been a huge retroactive change in stated assets, capital employed, book net worth and earnings. Cash flow, it is important to point out, stays the same as previously reported.

Despite flaws in utilizing published financial statements for comparative purposes, there are nevertheless useful analyses to be performed providing one keeps in mind the nature of the flaws. This is especially true when longer periods of time are tested because the impact of accounting anomalies is reduced and an internal consistency within each company is developed.

There are many well-known and acceptable financial tests used to measure aspects of the performance and financial strength of a business. Those selected for this comparative review are generally accepted measures of corporate performance. The measures employed tend to treat each of the corporations fairly in that they are used consistently over the years by the corporations themselves in their published reports to their shareholders. There tends not to be a particular bias which would favour one corporation over the other. To illustrate this point, the financial tests based on cash flows and capital and dividends remove the impact of alternate accounting methods and of debt and equity structure.

The following measures form the basis on which this report draws its conclusions.

1. Corporate efficiency

   (a) Net Cash Flow Return on Average Capital Employed (Table 4 and Figure 5).

   (b) Net Earnings Return on Average Capital Employed (Table 4 and Figure 6).

2. Shareholder investment efficiency

   (a) Net Earnings Return on Average Shareholder Equity (Table 4 and Figure 7).

   (b) Internal Rate of Return to Shareholders (Table 4 and Figure 8).

3. Creditor efficiency

   (a) Interest Coverage Ratio (Table 5 and Figure 9).

   (b) Debt to Cash Flow Ratio (Table 5 and Figure 10).

These measures indicate in the first case how well the corporations have employed the assets under their care; in the second case how the shareholders have fared in the various time periods; and, in the third case, how relatively well protected creditors and debt holders are or, conversely, how financially stable the corporations are. These comparative tests give a good "snapshot" of how Petro-Canada compares with its peers. Table 6 summarizes the relative rankings of the three companies over the five time periods analysed for corporate efficiency, shareholder efficiency and creditor efficiency.

2.5 Background on Imperial Oil

Imperial Oil Limited has been operating in Canada for over 100 years. With the acquisition of Texaco Canada in February 1989, Imperial became by far the largest integrated oil and gas company in Canada, whether measured by assets or sales volumes. Imperial is a leading explorer, developer and producer of oil and natural gas, and a major producer of industrial and agricultural chemicals. Imperial is a leading refiner and marketer of oil and gas products across the country.

Exxon Corporation of the United States controls the Company, holding about 70% of the common shares. Imperial's shares are listed on the American, Toronto and Montreal Stock Exchanges. With about 190 million common shares outstanding, Imperial had a market capitalization of $12.1 billion and total assets of $15.6 billion at year-end 1989. The Company has a broad base of relatively low-cost, conventional producing oil and gas properties in Western Canada and is the largest domestic oil producer. Imperial has been engaged in frontier and non-conventional oil and gas development and has significant investments in Syncrude and Cold Lake.

2.6 Background on Shell Canada

Shell Canada Ltd. has been operating in Canada since 1911. With assets of over $5.5 billion and revenues of about $5.0 billion, Shell is one of Canada's largest integrated oil and gas companies. Shell is Canada's leading natural gas producer and is significantly engaged in oil exploration, development and production; sulphur production and marketing; industrial and agricultural chemicals production and sales; and oil refining and marketing.

TABLE 4: SUMMARY OF RETURNS ON INVESTMENT (1)

TIME PERIOD	DURATION	TYPE OF RETURN	INVESTMENT BASE	AVERAGE ANNUAL RETURNS		
				IMPERIAL	PETRO-CANADA	SHELL
1980-89	10 Years	Cash Flow	Average Capital Employed	15.82%	10.87%	17.67%
		Earnings	Average Capital Employed	7.93%	1.97%	6.91%
		Earnings	Average Shareholders' Equity	10.80%	1.43%	9.46%
		Total (2)	Dividends & Capital Gain	10.81%	10.59%	4.92%
1983-89	7 Years	Cash Flow	Average Capital Employed	14.30%	10.98%	15.43%
		Earnings	Average Capital Employed	7.06%	1.03%	5.85%
		Earnings	Average Shareholders' Equity	9.66%	-0.52%	8.04%
		Total (2)	Dividends & Capital Gain	19.04%	17.30%	14.92%
1985-89	5 Years	Cash Flow	Average Capital Employed	14.80%	11.00%	15.76%
		Earnings	Average Capital Employed	7.13%	0.42%	6.57%
		Earnings	Average Shareholders' Equity	9.72%	-1.87%	9.46%
		Total (2)	Dividends & Capital Gain	15.44%	-0.17%	16.14%
1987-89	3 Years	Cash Flow	Average Capital Employed	14.79%	10.75%	16.19%
		Earnings	Average Capital Employed	7.39%	2.68%	7.92%
		Earnings	Average Shareholders' Equity	9.95%	3.54%	11.86%
		Total (2)	Dividends & Capital Gain	16.23%	2.58%	20.08%
1988-89	1 Year	Cash Flow	Average Capital Employed	13.93%	11.08%	13.88%
		Earnings	Average Capital Employed	6.03%	2.18%	5.10%
		Earnings	Average Shareholders' Equity	7.04%	1.31%	7.02%
		Total (2)	Dividends & Capital Gain	52.26%	17.39%	1.04%

(1) Calculations based on audited, year-end data as reported by the companies; averages are based on a simple average of the average of the relevant years except Total Return is based on the internal rate of return over the relevant time period; assumes an average 50 percent tax rate

(2) Total Return is the rate of return of shareholders' future income stream based on an investment at initial market price, the receipt of interim dividends, and a capital gain following disposition at final market price; Petro-Canada's theoretical market capitalizations were estimated for relative comparisons only based on the average cash flow multiples of Imperial and Shell; see Table 3

FIGURE 5: CASH FLOW RETURN ON AVERAGE CAPITAL EMPLOYED

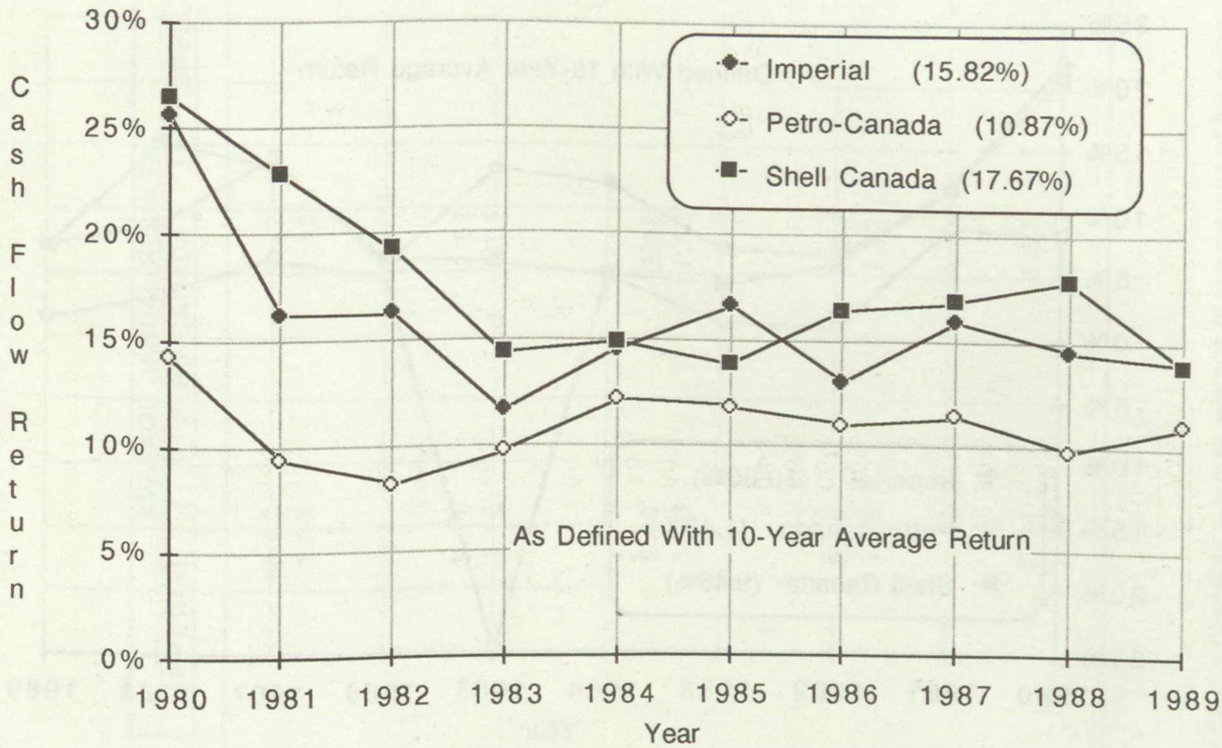


FIGURE 6: NET EARNINGS RETURN ON AVERAGE CAPITAL EMPLOYED

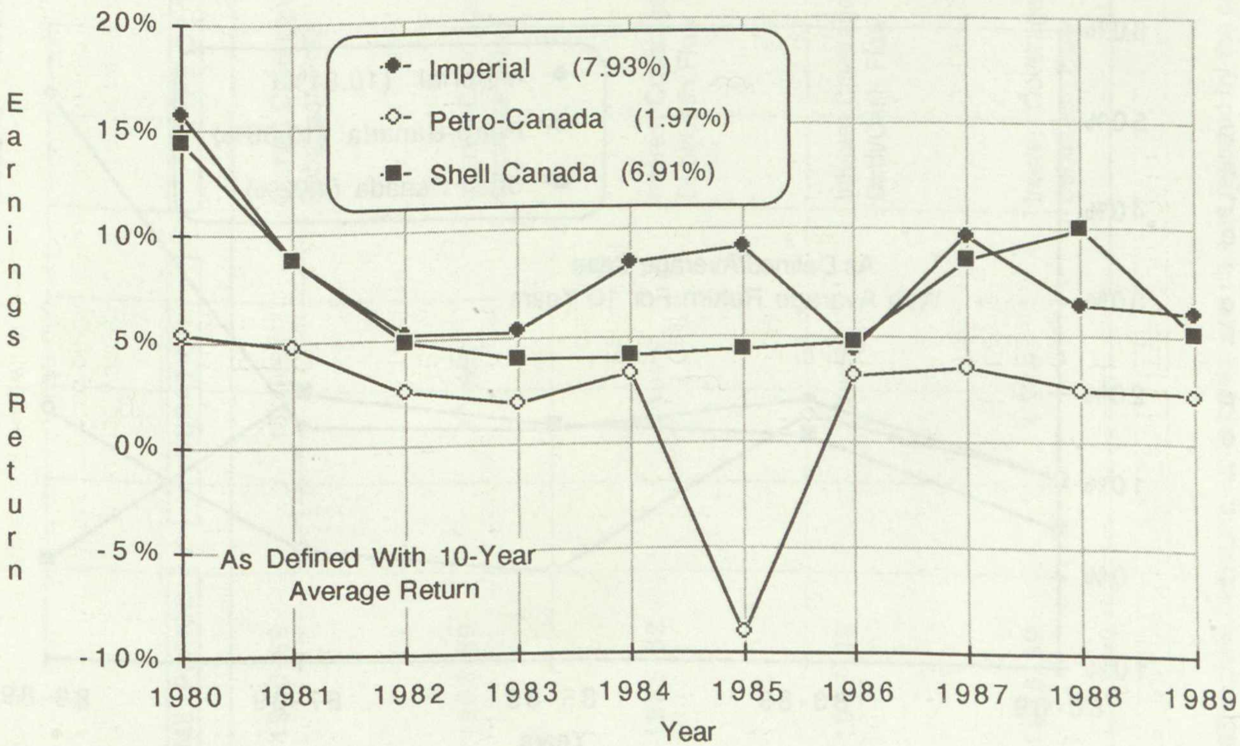


FIGURE 7: COMMON EARNINGS RETURN ON AVERAGE COMMON EQUITY

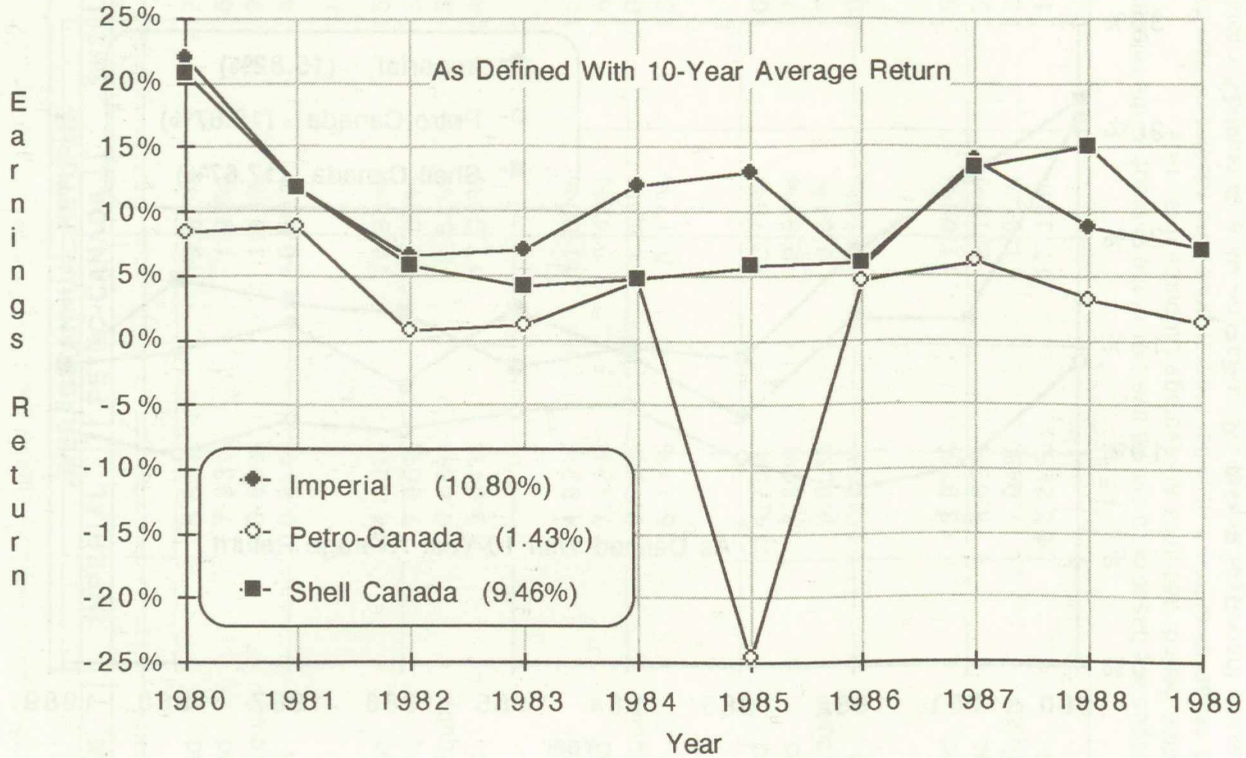


FIGURE 8: INTERNAL RATE OF RETURN OF COMMON SHAREHOLDERS TOTAL RETURN

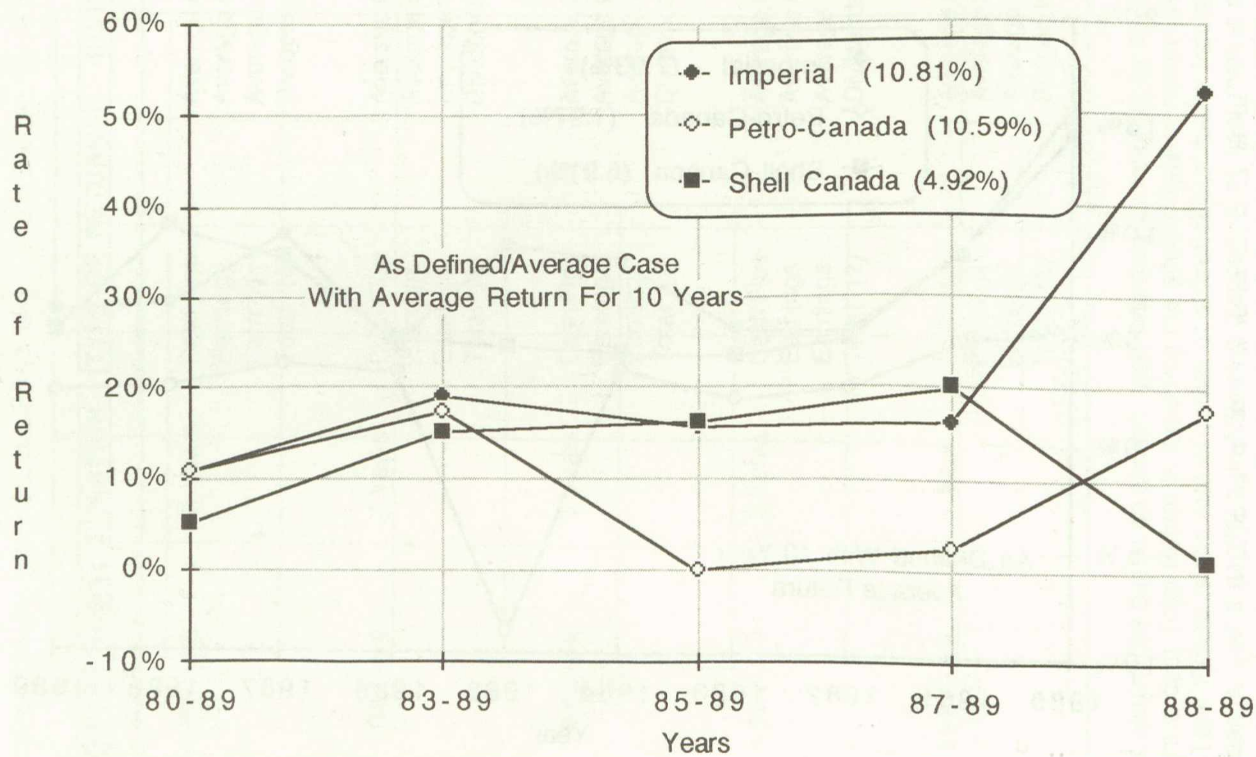


TABLE 5: SUMMARY OF CREDITWORTHINESS (1)

TIME PERIOD	DURATION	TYPE OF TEST	AVERAGE ANNUAL RESULTS		
			IMPERIAL	PETRO-CANADA	SHELL
1980-89	10 Years	Interest Coverage	10.66	2.47	5.50
		Debt/Cash Flow	1.06	1.13	1.26
1983-89	7 Years	Interest Coverage	9.21	2.67	4.84
		Debt/Cash Flow	1.16	0.97	1.40
1985-89	5 Years	Interest Coverage	9.69	2.18	5.53
		Debt/Cash Flow	1.13	1.28	1.24
1987-89	3 Years	Interest Coverage	8.69	2.53	7.01
		Debt/Cash Flow	1.38	1.62	1.07
1988-89	1 Year	Interest Coverage	2.54	1.57	7.39
		Debt/Cash Flow	2.82	2.17	1.41

(1) Calculations based on audited, year-end data as reported by the companies; averages are based on a simple average of the average of the relevant years; cash flow is after deducting preferred dividends

FIGURE 9: INTEREST COVERAGE RATIO

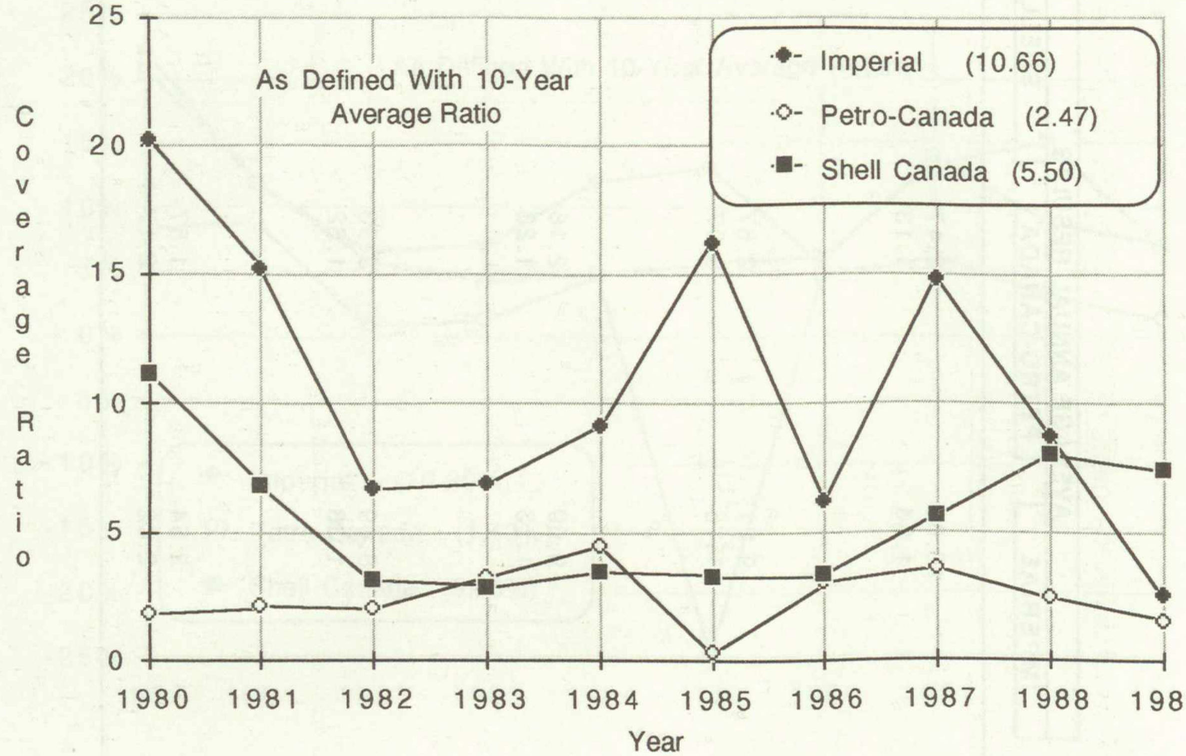


FIGURE 10: LONG-TERM DEBT/NET CASH FLOW RATIO

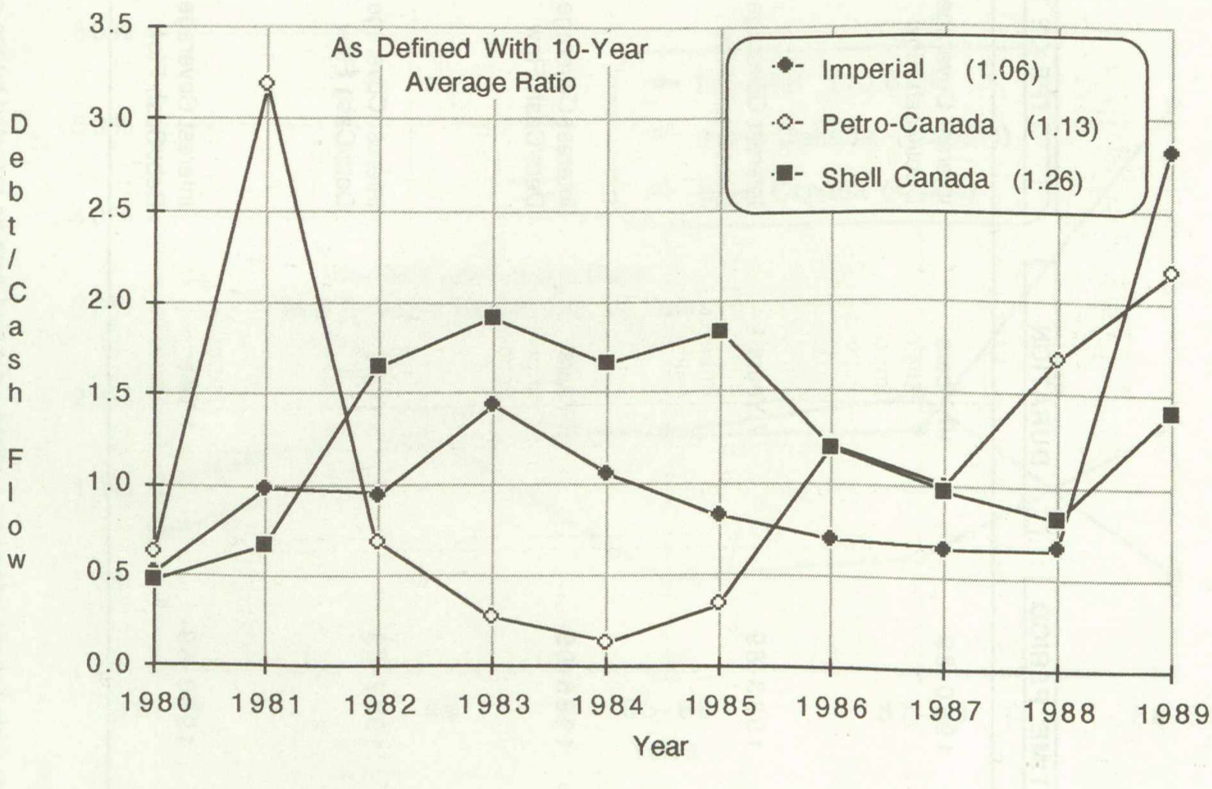


TABLE 6: SUMMARY OF RELATIVE RANKING OF COMPANIES (1)

			CORPORATE EFFICIENCY		SHAREHOLDER EFFICIENCY		CREDITOR EFFICIENCY	
TIME PERIOD	PERIOD DURATION	CO RANK	CASH FLOW RETURN ON AVG CAPITAL EMPLOYED	EARNINGS RETURN ON AVG CAPITAL EMPLOYED	EARNINGS RETURN ON AVG SHAREHOLDERS' EQUITY	TOTAL RETURN FROM DIVIDENDS AND CAPITAL GAIN (2)	INTEREST COVERAGE	DEBT/CASH FLOW RATIO
1980-89	10 Years	1	Shell	Imperial	Imperial	Imperial	Imperial	Imperial
		2	Imperial	Shell	Shell	Petro-Canada	Shell	Petro-Canada
		3	Petro-Canada	Petro-Canada	Petro-Canada	Shell	Petro-Canada	Shell
1983-89	7 Years	1	Shell	Imperial	Imperial	Imperial	Imperial	Petro-Canada
		2	Imperial	Shell	Shell	Petro-Canada	Shell	Imperial
		3	Petro-Canada	Petro-Canada	Petro-Canada	Shell	Petro-Canada	Shell
1985-89	5 Years	1	Shell	Imperial	Imperial	Shell	Imperial	Imperial
		2	Imperial	Shell	Shell	Imperial	Shell	Shell
		3	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada
1987-89	3 Years	1	Shell	Shell	Shell	Shell	Imperial	Shell
		2	Imperial	Imperial	Imperial	Imperial	Shell	Imperial
		3	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada	Petro-Canada
1988-89	1 Years	1	Imperial	Imperial	Imperial	Imperial	Shell	Shell
		2	Shell	Shell	Shell	Petro-Canada	Imperial	Petro-Canada
		3	Petro-Canada	Petro-Canada	Petro-Canada	Shell	Petro-Canada	Imperial

(1) Rankings based on audited data as reported by the companies; see Figures 6, 7, 8, and 9 and Tables 4, 5, and 6

(2) Petro-Canada's theoretical market capitalizations were estimated for relative comparisons only based on the AVERAGE cash flow multiples of Imperial and Shell; relative rankings do not change if Petro-Canada's theoretical market capitalizations were based on the LOW or HIGH cash flow multiples of Imperial and Shell except in the HIGH case for the 10-year period the rankings become Petro-Canada, Imperial, and Shell; see Table 3

The company has been active in frontier areas offshore of British Columbia and Eastern Canada at Venture, and in heavy oil in the Peace River area in Alberta. Shell Canada is controlled approximately 78% by Royal Dutch Shell. The company's Class A common shares are listed on the Toronto, Montreal, Vancouver and Alberta Stock Exchanges. About 112 million Class A common shares are issued. The market capitalization of the common shares was $4.7 billion at year-end 1989.

2.7 Conclusions

In less than 15 years, Petro-Canada has grown from an idea to one of the leading Canadian oil and gas explorers, producers, refiners and marketers. Its service stations and emblem have become part of the everyday landscape in all regions of Canada. Petro-Canada competes successfully in every facet of its business with long-established international oil companies of recognized skill.

The effort and dedication of the management and staff of Petro-Canada to build a cohesive and leading corporation from five major acquisitions in that period of time is truly admirable. Unless one is familiar with the myriad of difficulties, large and small, that must be overcome, reconciled and turned to advantage in bringing together diverse corporate cultures to produce one consistent business direction, it is impossible to explain. From the outside and in the absence of empirical evidence, it appears that the Petro-Canada people have done an outstanding job of building a multidivisional corporation with common corporate goals and identification.

Success as determined by standard financial measures has clearly been more difficult to achieve. By all of the measures applied here, Petro-Canada has achieved no better than a second place ranking and for the most part has been firmly established in third place behind Imperial and Shell. Interestingly, Petro-Canada has not only provided its shareholder with poorer rates of return during the reviewed periods, it has done so while putting its shareholder at greater financial risk than the other two when the creditor efficiency tests are considered.

The returns to the shareholder worsened significantly in the most recent three years and five years, as measured by the shareholder efficiency tests. By the beginning of each of these two periods, the bulk of the major corporate acquisitions was complete. One would expect steadily improving results relative to Imperial and Shell in the most recent five-, three- and one-year periods as time passed to weed out and rationalize assets for greater productivity and to rationalize and reduce overhead costs. On the face of the tests and despite various rationalization and cost reduction plans announced by Petro-Canada, the assets of the Corporation appear to have produced relatively poorer results in the later years as compared with earlier (ten-year and seven-year) results. The one-year "Dividends and Capital Gain" return (see Table 4) did significantly surpass Shell's poor showing, but was only one-third that of Imperial.

The amounts used in the tests were on an "as reported" basis from the particular company's annual report. Petro-Canada made the significant accounting change from "full cost" accounting to the "successful efforts" method. This change reduced the average capital employed for 1989 by about $1.8 billion or 27%. In spite of that, the 1989 cash flow return on average capital employed rose only to 11.08% when compared with the three-year average of 10.75% upon which the change would have a much reduced impact.

In terms of corporate efficiency, shareholder efficiency and creditor efficiency, Petro-Canada has under-performed, with minor exceptions, when compared with Imperial and Shell. Of more relevance is the fact that the under-performance was not in the earlier years of major asset and business acquisition as one would have expected.

Rather, the under-performance in terms of the financial tests has become more marked in the recent periods, indicating in a broad sense that management has either failed to rationalize and streamline the assets or operations purchased through 1985 or 1986, or has invested in assets which do not have the capability of yielding returns comparable to its competitors, or a combination of both. In other words, the tests indicate that Petro-Canada has failed to invest in and to utilize assets in such a way as to move the various return and efficiency ratios closer to those of its major competitors.

Petro-Canada's President addresses two issues on pages 7 and 8 of the Corporation's *1989 Annual Report* regarding poor performance. The first issue, respecting Petro-Canada's financial results, is the special mandate given the company from inception until 1984. The report says: "The Company's focus was on making a contribution to national energy policy objectives, such as security of supply, rather than on profitability...The legacy of the earlier mandate continued to be reflected in the Corporation's financial performance indicators". Five complete fiscal years have passed since the mandate was changed to a commercial one without a clear trend to relative improvement in those indicators. Over a period of five years there should have been improvement as management has had ample opportunity to take the steps it deemed necessary to effect the appropriate changes.

Another reason given in the annual report for poor performance is "...because it [Petro-Canada] grew rapidly through acquisitions in both the upstream and downstream segments of the industry, and in an era of high energy prices and industry optimism". During the ten-year period under review, Petro-Canada made capital expenditures of one type or another totalling $7,986,820,000, compared with $15,693,000,000 by Imperial (including the purchase of Texaco) and $6,440,000,000 by Shell. From January 1, 1985 to December 31, 1989, a five-year period during which Petro-Canada's mandate was a commercial one – a for-profit mandate – the Corporation spent 50.4% of the ten-year amount while Imperial spent 65.9% and Shell spent 40.5%. Whether or not January 1, 1985 to December 31, 1989 is considered a period of high prices or industry optimism is not the issue here. The point is that significant funds were spent after the mandate was changed and those expenditures bear a reasonable relationship to those expended by Petro-Canada's two peers. No clear narrowing of the return relationship is evident.

The final reason for under-performance noted in the report is the "...considerable effort and expense integrating operations, systems and cultures of the various predecessor companies". Again, without doubt, the effort and cost were very high. However, the last major acquisition was closed in 1985. It would seem logical that improvements should be apparent by the end of 1989 if there are to be any.

Chapter Two

Canada's Evolving Energy Policy

During Petro-Canada's lifetime, Canada's energy policy environment divides into two distinct periods, reflecting the dramatic differences that prevailed before and after the 1984 federal election. Petro-Canada was established during an interventionist phase of Canadian energy policy-making. Today Petro-Canada operates under a government that has championed the cause of market forces and deregulation in the energy field. The former Liberal Government ascribed an active public policy role to Petro-Canada; the subsequent Progressive Conservative Government directed Petro-Canada to operate like any other major oil company in the private sector, and announced that Canada's state oil company no longer served a public policy function.

This chapter reviews the changing energy policy environment within which Petro-Canada has operated.

A. 1976–1984

In 1973, oil dominated Canada's energy system, accounting for approximately half of the domestic demand for primary energy. This national average, however, concealed wide regional variations. Alberta used oil to satisfy only 28% of its primary energy needs (depending upon natural gas for almost 60%), while Atlantic Canada relied on oil for 86% of its primary energy and Quebec for 73%. Although Canada was a net exporter of oil in 1973, there was no transportation system to carry this commodity from Western Canada to Quebec and Atlantic Canada, which depended on offshore sources of supply. The eastern part of the country consequently found itself strategically exposed when the international flow of oil was disrupted. Two consequences of the 1973-74 disruption were a system of administered oil prices and the subsidized extension of the Interprovincial Pipe Line (IPL) system from its former Toronto-area terminus to Montreal.

At the time of the second oil price shock in 1979-80, following the Iranian Revolution, Canada was a net importer of oil. Although crude oil purchases from the Organization of Petroleum Exporting Countries (OPEC) had fallen from 796,000 barrels/day (126,500 cubic metres/day) in 1973 to 500,000 b/d (79,400 cubic m/d) in 1979, domestic output had dropped by 20% over the intervening six years while demand had risen by 11%. The National Energy Board (NEB) was forecasting a declining availability of conventional light crude oil in Western Canada. In its 1978 report, *Canadian Energy Supply and Demand 1983-2005*, the NEB estimated that the average rate of production from established, conventional oil reserves would fall by about 8% annually.

Canada's National Energy Program (NEP), announced 28 October 1980, was founded on the assumption that international oil prices would continue to rise (the NEP scheduled domestic price increases through 1990), and on the belief that Canadian prices could be shielded from developments in volatile world markets. Import compensation, a system of subsidization introduced in 1974 to maintain a lower-than-international price for crude oil in Canada, continued under the NEP.

Three objectives were advanced to justify this far-reaching federal initiative.

(1) The NEP was to establish the basis for Canadians to control their energy future through security of supply and ultimate independence from the world oil market. The primary goal was for Canada to regain self-sufficiency in oil by 1990.

(2) The NEP was to offer Canadians the opportunity to participate in the energy industry in general and the petroleum industry in particular, and to share in the benefits of industry expansion. The principal goal was 50% Canadian ownership and control of the domestic petroleum industry by 1990.

(3) The NEP was to establish a petroleum-pricing and revenue-sharing regime that would be fair to all Canadians. The federal government intended to continue its scheme of "made-in-Canada" prices for consumers and to claim a larger share of rapidly rising oil and gas revenues.

The last objective was especially important to the Government of Canada, given that Alberta at year-end 1979 held 84% of Canada's established reserves of conventional crude oil and 85% of established natural gas reserves (excluding unconnected northern reserves). Alberta, with 10% of Canada's population, was receiving more than 60% of the oil and gas revenues accruing to the federal and provincial governments. Given its projection that revenues from domestic oil and gas production would approach $90 billion over the four-year period 1980-83, the federal government concluded that the distribution of benefits would be "extraordinarily unfavourable to the national government" if it did not act to increase its share of the economic rent.

Beyond these declared objectives were unofficial goals arising from the politics of the Canadian energy situation. Foremost was a restructuring of political power favouring the central government at the expense of the oil-producing provinces and the petroleum industry.

The NEP's failures overwhelmed its successes, although those successes should not be disregarded. On the positive side, this Program raised the issue of modifying growth in energy demand to a more equal footing with that of securing new energy supplies. The federal government intended to reduce oil's share of domestic energy use by more than a third by 1990, corresponding to a decline in forecast oil consumption of 20%. To achieve this, three approaches were taken to modify energy demand: energy conservation was vigorously promoted; off-oil conversions to other energy forms were encouraged; and renewable energy development was supported.

Having deflected much of the potential impact of the oil price shock on Canada's energy-using practices, the federal government moved to establish incentive programs to encourage Canadians to conserve energy and to substitute other fuels for oil. A key element of the conservation effort was the Canadian Home Insulation Program (CHIP). Under the NEP, the annual CHIP budget rose from $80 million to $265 million; the objective was insulation upgrading in 70% of Canadian homes by 1987. Conservation initiatives in the industrial, transportation and government sectors complemented the residential program.

The centrepiece of the off-oil strategy was the Canada Oil Substitution Program (COSP), which supported the conversion of oil-based heating systems in homes and businesses to alternative fuels. The natural gas distribution system was extended, benefitting Quebec in particular, and the federal government offered grants to convert motor vehicles to compressed natural gas (CNG) or propane fueling.

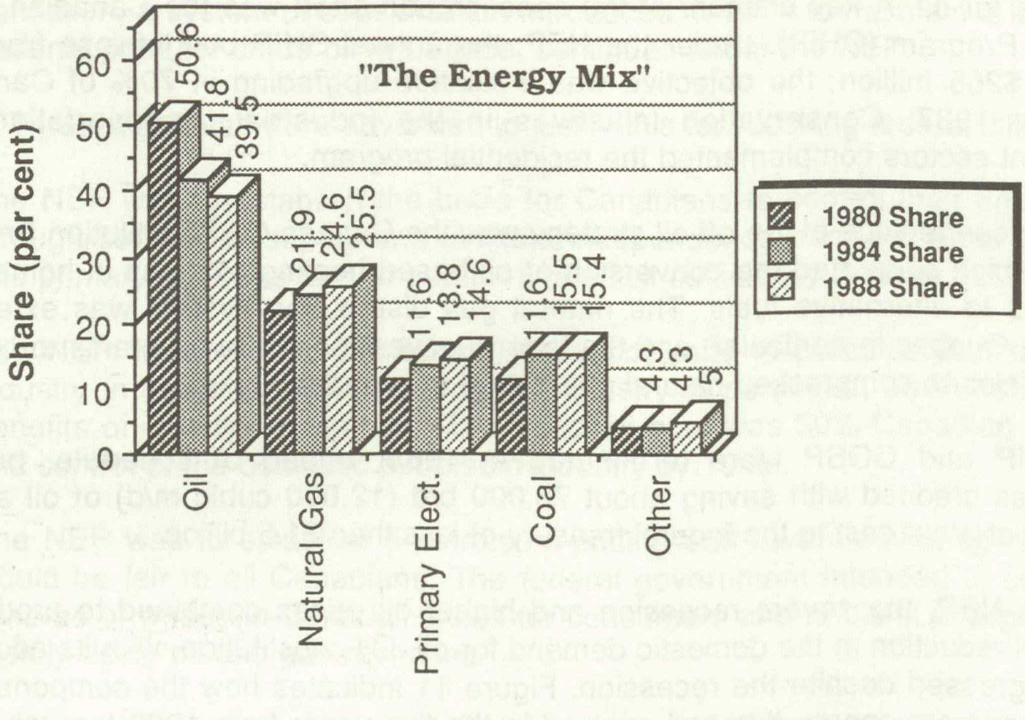
CHIP and COSP were terminated in 1985, ahead of schedule, but are nonetheless credited with saving about 75,000 b/d (12,000 cubic m/d) of oil and oil equivalent at a net cost to the federal treasury of less than $1.5 billion.

The NEP, the severe recession and higher oil prices combined to produce a substantial reduction in the domestic demand for oil. Oil substitution, with its additional costs, progressed despite the recession. Figure 11 indicates how the components of Canadian primary energy demand evolved in the five years from 1980 through 1984, and thereafter through 1988.

A second strength of the NEP was its expanded support of new energy options. In July 1978, the federal government had announced a $380 million package of renewable energy programs extending through 1985. The National Energy Program of 1980 foresaw "a much greater role for renewable energy" and boosted funding for research, development and demonstration (R,D&D) across a range of new energy sources, technologies and fuels. This financial support grew during each year of the NEP and was evidence of federal interest in longer-range energy planning. The federal government also created a new subsidiary of Petro-Canada, Canertech, to foster conservation technology and the commercial production of renewable energy through the provision of venture capital.

In 1983, Canada stood second only to the United States among International Energy Agency (IEA) nations in its financial support of conservation R,D&D and fourth in funding renewable energy R,D&D. This impressive commitment was being maintained even though the value of Canadian energy exports exceeded imports by $8 billion that year. In several areas of conservation and renewable energy R,D&D, Canada was acknowledged to be a leader in developing economically and technically viable alternatives to conventional energy sources and technologies.

Figure 11: The Components of Canada's Primary Energy Demand, 1980, 1984 and 1988



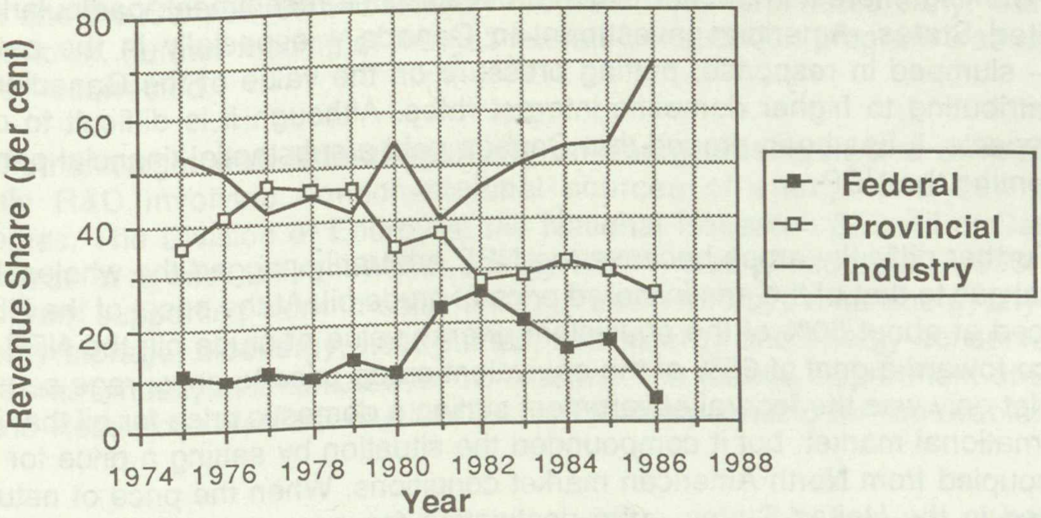
Note: Primary electricity is valued here by its true energy content of 3.6 megajoules per kilowatt-hour (MJ/kWh). Although the "fossil fuel displacement value" of 10.5 MJ/kWh is favoured in some statistical applications, it overstates the importance of electricity in Canada's energy system.

Source: Canada, Department of Energy, Mines and Resources, Energy Statistics Division, *Energy Statistics Handbook*, Ottawa, undated, Table 2.0.5.

The most dramatic failure of the NEP stemmed from the unwillingness of its architects to contemplate a decline in world oil prices. The Program established a wellhead price for conventional crude oil rising in stages from $14.75 per barrel in January 1980 to $66.75 per barrel in July 1990. The oil sands reference price was set at $38.00 per barrel in January 1981 and was to rise to $79.65 in January 1990, "subject to [the] cap of international price".

The federal government was successful in securing a larger share of upstream oil and gas revenues at the expense of the producing provinces and the petroleum industry. Unfortunately, the total amount of money to be shared had shrunk dramatically from the forecasts of 1980 and 1981, as the world price weakened, the economic recession took hold and Canadian oil consumption fell. The array of petroleum-related fiscal instruments which were such a crucial part of the NEP soon required modification – some were modified or withdrawn even before being introduced – and the federal government relaxed its taxing provisions. Figure 12 displays the evolution in oil and gas revenue sharing from 1975 through 1986, subdivided into the federal, provincial and petroleum industry components. The Petroleum Monitoring Agency stopped reporting revenue sharing in 1987, responding to industry and provincial complaints that the methodology for calculating revenue shares was unsatisfactory (see the footnote to Figure 12).

Figure 12: Petroleum Revenue Sharing in Canada, 1975-1986



Note: The PMA stopped reporting revenue-sharing statistics in 1987, because of complaints from industry and the provincial governments about the reporting methodology. "Total revenues available for sharing", based on the upstream industry only, were defined by the PMA as: revenue = upstream gross revenues - operating costs + oil export charge + Canadian ownership charge + change in PCC account. The industry argued that its share should be calculated as cash flow minus capital expenditures; this would result in a negative industry share in some years. The provinces objected to this proposal because they would be seen in some years as receiving more than 100% of the revenues. The PMA decided the best approach was simply to stop reporting any values for revenue sharing.

Source: Doern, G. Bruce and Glen Toner, *The Politics of Energy: The Development and Implementation of the NEP*, Methuen, Toronto, 1985, p. 341 [for the 1975-78 values]; Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry Monitoring Survey (1979-1986)*, Supply and Services Canada, Ottawa, 1980-87, [for the 1979-86 values]; and Personal communication, Petroleum Monitoring Agency, 25 May 1990.

Not only was federal budgeting in general disrupted when the anticipated revenues were not forthcoming but also the costs of the NEP itself became more onerous.

The major cost was funding extended through the Petroleum Incentives Program (PIP) to encourage petroleum exploration on federal lands in Canada's "frontier" areas; that is, Canada north of the 60th parallel and the East Coast offshore. PIP preferentially supported Canadian companies operating on the frontier, enabling them to compete on a more equal footing with foreign-owned companies. By the time PIP was phased out, approximately $7.5 billion in federal funds had been invested in frontier exploration.

The drive to "Canadianize" the domestic petroleum industry through preferred treatment of Canadian companies operating on federal lands and the 25% back-in provision (whereby the Crown in the form of Petro-Canada could acquire a one-quarter working interest in frontier plays) aroused much resentment, particularly within the United States. American investment in Canada – especially in the petroleum sector – slumped in response, putting pressure on the value of the Canadian dollar and contributing to higher domestic interest rates. Although it is difficult to quantify these impacts, it has been argued that Canada paid a substantial financial penalty for implementing the NEP.

Further difficulty arose because the NEP arbitrarily pegged the wholesale price of natural gas to that of the administered price of crude oil. At the onset of the NEP, gas was priced at about 80% of the equivalent energy value of crude oil; the NEP moved that price toward a goal of 65% of the equivalent crude price to encourage substitution for oil. Not only was the federal government setting a domestic price for oil that ignored the international market, but it compounded the situation by setting a price for natural gas decoupled from North American market conditions. When the price of natural gas weakened in the United States – the destination for more than a third of Canada's marketed gas production at the time – the administered price for gas also became insupportable.

The federal government was forced into a series of modifications of the NEP as world events made its provisions obsolete. The NEP Update, announced on 31 May 1982, introduced much of this change as the federal government acted to assist an ailing petroleum industry. Continuing modification of the NEP led to uncertainty, however, as doubt grew about the ability of the central government to establish a stable energy regime in Canada. Moreover, rancorous federal-provincial relations prolonged energy negotiations, delaying adjustments to changing circumstances.

A longer-term effect was the blunted impact of high international oil prices on the Canadian economy, reducing the incentive to use energy more efficiently. Today, Canada is the largest per capita consumer of energy among the industrialized nations of the world, placing us at a competitive disadvantage, worsening the environmental impact of energy use, and pushing the country into costly investments in energy "megaprojects" to maintain supplies.

B. 1984–1990

In the federal election of September 1984, the Progressive Conservative Opposition campaigned against the National Energy Program. After winning the election, the new Conservative government began to dismantle the NEP.

Faced with a large budget deficit, the new government was under pressure to trim federal expenditures and moreover was philosophically opposed to the interventionist style of the preceding government. On 8 November 1984, the Conservative Government announced a package of fiscal restraint measures in an "Economic Statement" and thereby made its first alterations to the NEP (Canada, Treasury Board, 1984).

Many energy programs were affected by the 1984 budget reductions. Spending on the Petroleum Incentives Program was reduced. The Canadian Home Insulation Program and the Canada Oil Substitution Program were terminated early. Canertech was shut down. Further funding of the gas laterals construction program was deferred and never resurrected.

Another target was federal spending on energy research and development, especially R&D involving nonconventional sources of energy and new energy technologies. The Division of Energy at the National Research Council of Canada – the lead federal agency for renewable energy R&D – was phased out. A $60 million/ year program supporting work in solar energy, fusion energy, wind energy, hydrogen and energy storage, bioenergy, heat pumps, tidal energy and energy conservation in buildings was virtually dismantled over 18 months. The federal Department of Energy, Mines and Resources also lost much of its discretionary funding for renewable energy R&D.

Through this budgetary initiative, the federal government largely withdrew its support of alternative energy R&D and signalled that it would be much less involved in the development of Canada's energy system.

More sweeping changes in federal energy policy soon followed. During 1985 the Government of Canada negotiated two pivotal agreements with the producing provinces of Western Canada. In the Western Accord of 28 March 1985 and the Agreement on Natural Gas Markets and Prices of 31 October 1985, the federal government moved to deregulate the marketing of crude oil and natural gas.

The Western Accord decontrolled the price of crude oil on 1 June 1985, allowing the price to move in response to market forces. This marked the end of Canada's Oil Import Compensation Program. The Canadian Government removed the Natural Gas and Gas Liquids Tax, the Incremental Oil Revenue Tax, the Canadian Ownership Special Charge, the Crude Oil Export Charge and the Petroleum Compensation Charge. The Petroleum and Gas Revenue Tax was removed from new production and phased out on prior oil and gas production by year-end 1988. All of these taxes and charges had been part of the pre-existing system of administered prices. In rescinding these taxes, the federal government sacrificed revenue to the benefit of the petroleum industry. In return, industry spokesmen predicted that as many as 300,000 new jobs could be created by a healthy petroleum sector. Plummeting oil prices in 1986 ended these optimistic forecasts.

The National Energy Board removed its restrictions on short-term exports of both light and heavy crude oil to the United States, allowing Western Canadian producers to address the concern of shut-in production. The Petroleum Incentives Program was terminated one year after the announcement of the Accord, although an extension applied to existing Exploration Agreements on federal lands.

The Natural Gas Agreement dealt with a more complicated marketing situation in Canada. Natural gas, unlike crude oil, had traditionally been sold in Canada and in the U.S. export market through long-term contractual arrangements which provided the financial underpinning for developing an expensive infrastructure for transporting and distributing natural gas. Given the uncertainties involved in future financial arrangements to underwrite these costs, the federal government announced a one-year transition during which domestic wholesale prices for natural gas were frozen. This transitional period expired on 31 October 1986, following which the purchase and sale of gas became freely negotiated.

Although price deregulation removed most of the distortions in energy markets, it was nonetheless becoming apparent that market forces were not a complete substitute for energy policy-making in all circumstances. The unencumbered market was behaving well on a day-to-day basis, but issues with a longer-term focus and resolution – exemplified by national energy security, the linkage between energy development and regional development, and such environmental concerns as acid gas and greenhouse gas emissions – were not being properly addressed. For these and other reasons the federal government launched the Energy Options process, a year-long canvassing of views in all regions of the country and from all interested parties on energy policy-making. The result was the August 1988 document *Energy and Canadians: Into the 21st Century. A Report on the Energy Options Process.*

The Energy Options report was referred to the House of Commons Standing Committee on Energy, Mines and Resources, which is expected to report on the subject about the time that this report goes to print. The Standing Senate Committee on Energy and Natural Resources requested and received from the Senate a reference to study the Energy Options report as well, and will engage in that task upon completion of this study of Petro-Canada. The federal government has yet to comment publicly on the Energy Options findings.

C. The Free Trade Agreement

One of the most far-reaching policy initiatives of the Progressive Conservative Government was its negotiation of the Canada/United States Free Trade Agreement (FTA), which came into effect on 1 January 1989. Chapter Nine of the FTA is a comprehensive and controversial arrangement covering all aspects of energy trade between the two countries.

The FTA subjects Canadian-U.S. energy trade to a much more explicit regime of trade rules than that embodied in the General Agreement on Tariffs and Trade (GATT). Energy trade in the mid-1980s comprised about 10% of the total bilateral trade in goods in what is the world's largest and most complex trading relationship. Approximately 85% of all Canadian energy exports are sold into the United States, including more than one-third of our domestic crude oil and natural gas production. An important feature of the FTA is an implicit obligation on the part of the two national governments to address the impact of domestic energy regulation on the cross-border trading relationship.

As analysts have pointed out, the FTA is not a symmetrical trading relationship between Canada and the United States.

> ...A guaranteed open market between the two nations without other concessions from Canada would not have been acceptable to the U.S. Congress, since Canada is effectively gaining access to a market ten-times the size of its own and the U.S. to one only one-tenth the size of its domestic market. In exchange for assured continued open access to the larger American market to Canada, the U.S. obtained concessions in other areas such as American access to Canadian investment and financial markets, automotive policy, trade in services and energy policy. (Battram and Lock, 1988, p. 332)

Canada's overarching objective in negotiating the energy provisions in the Free Trade Agreement was to secure and enhance Canadian access to the U.S. market. The desire on the part of U.S. negotiators was to assure access to reliable supplies of Canadian energy, viewed as a potentially significant contributor to U.S. security. This difference in approach reflected the fact that Canadian negotiators thought of energy primarily as an economic commodity while U.S. negotiators viewed energy much more as a strategic commodity. It has also been claimed that the successful conclusion of the FTA negotiations was linked by the American side to Canada's willingness to include the energy stipulations of Chapter Nine in the agreement.

Provisions governing energy trade are not limited to Chapter Nine. The FTA incorporates the GATT requirement that each party accord "national treatment" to the goods of the other party. In the case of energy, the national treatment provision amounts essentially to a non-discrimination rule. On the other hand, the FTA did not resolve the issue of domestic subsidies on bilateral trade.

The FTA broadly defines the energy goods covered by its provisions to include: solid fuels (coal, coal, peat, etc.); liquid fuels (crude oil, refined products and liquefied petroleum gases); gaseous fuels (natural gas, ethane, coal gas, etc.); electricity; and nuclear fuels (uranium, spent fuel, heavy water, etc.).

Article 902 refers to import and export restrictions. Although the GATT covers trade in energy goods, the FTA underscores the intent of the U.S. and Canadian Governments that bilateral energy trade should hereafter be governed by a more explicitly stated regime. The intent of the FTA is that energy goods from one country should be able to compete in the markets of the other country without facing regulatory barriers that discriminate on the basis of national origin. Three specific restrictions – two imposed on the United States and one imposed on Canada – received special treatment. The United States is required to exempt Canada from any restriction on the enrichment of foreign uranium under the Atomic Energy Act. Canada is also given a partial exemption from the U.S. prohibition on exporting Alaskan oil, imposed by the Export Administration Act of 1979. Under the FTA, up to 50,000 barrels per day of Alaskan oil may be exported to Canada on an annual average basis, subject to the condition that the oil be transported to Canada from a location within the lower 48 states. This condition triggers the "Jones Act" requirement that U.S.-flagged vessels be used in this export trade. The third provision requires Canada to exempt the United States from the Canadian Uranium Upgrading Policy.

It should be noted in this context that the oil-sharing provisions of the IEA take precedence in the event that an oil emergency is declared and there is any incompatibility between the FTA and the IEA stipulations.

Article XX of the GATT allows a broad range of circumstances in which nations can restrict export trade. The Energy Chapter of the FTA extends the GATT approach in two respects. First, it curtails more severely than does the GATT the circumstances in which a domestic supply shortfall can be used to justify restrictions on exports. Second, the FTA narrows the "national security" exception contained in the GATT.

Because the breadth and generality of the GATT exceptions were viewed as too permissive for the purposes of the FTA, Article 904 was written to narrow those exceptions. Under paragraph (a) of Article 904, if either party reduces the supply of an energy good, that reduction must be shared in the same proportions by both the domestic and export markets. Paragraph (b) prohibits the imposition of a higher price for exports of an energy good than the price of comparable domestic sales when that higher price results from licences, fees, taxation or minimum price requirements. Paragraph (c) prohibits the disruption of normal channels of supply or of normal proportions among specific energy goods supplied to the other party. These constraints were designed to counter the restrictions that pervaded the energy export policies of both countries in the 1970s and early 1980s.

> The FTA should provide a solid basis for achieving the principal goals of the two countries in entering into the energy negotiations – for Canada, achieving assured access to U.S. markets, free of "energy policy" interventions for protectionists distortions and for the U.S., the ability to procure Canadian energy supplies on a long-term, reliable basis, free of "energy policy" and nationalistic interventions in times of perceived shortage.
> (Battram and Lock, 1988, p. 384)

The major trade-off for Canada to obtain guaranteed U.S. market access, given the preponderant southern flow of energy, has been to surrender an element of freedom in domestic energy policy-making.

D. Harmonizing Deregulation and Strategic Planning

During Petro-Canada's lifetime, Canada has had two profoundly different energy policy regimes. Prior to the election of late 1984, the Liberal Government intervened extensively in the energy sector, manipulating prices, directing petroleum industry activity, promoting energy conservation and alternative energy development, and fostering off-oil initiatives. Since the 1984 election, the Progressive Conservative Government has moved to deregulate energy markets, end most of the incentives for conservation, alternative energy development and off-oil substitution, and has championed market forces as the arbiter of energy development. The Committee knows of no other industrialized nation that has undergone such a remarkable energy policy swing in the 1980s.

In the opinion of some of the Committee's witnesses, Petro-Canada no longer serves any useful policy role nor should it. Not only is our national oil company an inappropriate policy vehicle but there is no need for government to be involved in policy-making at all. Referring to the issue of national energy security, Ron Hirshhorn, a senior economist with the Economic Council of Canada, said to the Committee:

> ...Emergency planning – including, perhaps, the establishment of an oil stockpile in Eastern Canada – is necessary to reduce the country's vulnerability to any short-term disruptions in oil supply. But long-term security is a different issue. This is best sought not through government planning and direction but by fully exposing Canadians to world energy market fluctuations and allowing supply and demand to respond to market signals.
> (Canada, Senate, Standing Committee on Energy and Natural Resources, 11 December 1989, p. 8)

Thomas Kierans stated that he was generally unconcerned about the issue of Canadian energy security, with one exception and that was natural gas. He observed that the notion of a Free Trade Agreement rests on the concept of a market economy and markets clearing. The gas market does not work that way because there isn't an inexpensive transportation network and there aren't enough players in the game.

Michael Walker of the Fraser Institute expressed his strong support for privatizing Petro-Canada. Referring to Petro-Canada's origins, he characterized the Corporation as an historical mistake "conceived in paranoia and suspicions about the petroleum industry" and "born in the general atmosphere of contempt for the private sector and mistrust of the competitive market system generally" (*Ibid.*, 18 December 1989, p. 37). Canadians were mistaken in believing that Petro-Canada would provide for national energy security. In fact, according to Dr. Walker, assessing Petro-Canada's performance in achieving its public policy goals in general is "a useless preoccupation because the goals themselves were inappropriate" (*Ibid.*, p. 38).

The Canadian Association of Oilwell Drilling Contractors brought a different perspective. In their opinion, Petro-Canada had harmed the petroleum service industry and had ignored the most cost-effective Canadian targets for developing new petroleum reserves by taking over three "aggressive explorers" in Western Canada – ARCO, Pacific Petroleums and Petrofina Canada – and redirecting much of their exploratory effort into the frontiers. Most of Petro-Canada's subsequent drilling activity in Western Canada has been in developing existing fields. "The company has, for the most part, purchased existing production in the [Western Canada sedimentary] basin and drilled development wells to keep pace with the depletion rates" (*Ibid.*, 16 November 1989, p. 68).

Herschel Hardin, an author and consultant, argued for retaining Crown corporations like Petro-Canada because they can be a powerful vehicle for regional development and are more disposed to a "community-centred impulse". Moreover, in contrast to the view frequently advanced, publicly owned companies often enhance market competition:

> ...Where in a market situation you have companies that have diverse ownerships, diverse cultural roots, let's say, or diverse social roots, where you have privately owned companies, you have publicly owned companies, you have co-operatively owned companies, you are less likely to have – it doesn't follow absolutely all the time – tight oligopolies, you are less likely to have the kind of conspiratorial agreement or even make-do agreement that results in oligopoly to the cost of the consumer. (*Ibid.*, p. 90)

In the Committee's view, a return to freer energy markets has served Canada well in the day-to-day operations of the energy marketplace. In other respects, however, the Committee contends that the free market is insufficient to serve national energy interests. This inadequacy is evident in at least three respects.

First, market forces by virtue of their limited time horizon and concern with the corporate bottom line are not adequate to protect the public in the area of environmental concern. The private sector has a long history of externalizing environmental costs, which has led to a daunting array of pollution problems facing society today. Governments are increasingly recognizing the need for intervention to address environmental problems.

Second, long-term R&D programs to develop new sources of energy and new energy technologies for our future require sustained funding for years and sometimes decades before the commercial potential of these technologies is realized. Governments cannot depend on fluctuating market forces to provide the continuity that industry would require in many cases to sustain such long-term R&D programs. It is evidently in the national interest, therefore, that governments engage in or support such sustained research and development to insure that new energy sources and technologies become available when required in our future energy development. The costly and decades-long drive to commercialize fusion power is one example of energy R&D almost entirely underwritten by government. Much of the renewable energy R&D performed in the 1970s and 1980s in industrialized countries has been funded, and often performed, by governments.

Third, energy is more than an economic good; it is a strategic commodity whose ready availability at a reasonable price is fundamental to the economic and social well-being of all nations. This fact is recognized in most industrialized countries and acknowledged in their energy policy-making. Whether this concern with energy security takes the form of a strategic oil stockpile, the maintenance of a national distribution system, state-to-state negotiations, incentives to develop energy sources that may not currently be economic, or some other form, most countries recognize that such planning and the costs of such initiatives constitute a form of national insurance.

In launching the Energy Options process, the Canadian Government was implicitly acknowledging that energy policy had to be based on something more than the operation of the free market. From another perspective, the attempt by Canada's Environment Minister to formulate policy proposals addressing environmental concerns – many of which derive from our use of energy – confirms the need for a guiding hand in energy development. This guidance should be based on a long-range strategic plan formulated by the government, to address issues whose resolution lies beyond the restricted horizon of market forces.

In fact, market forces can serve as a tool in reaching long-term goals. Today's energy markets are often tilted with subsidy programs of various types, usually directed at aspects of conventional energy supply at the expense of energy conservation and renewable energy development. As was argued by Amory Lovins in his remarks to the Committee, there are numerous opportunities to conserve energy that provide a net economic return – opportunities that should be market driven on a "level playing field". They are not being pursued diligently because of inertia in our large energy institutions, because of subsidies that may tilt the economics in favour of a supply-side solution, because of rate structures that may reward consumers for greater energy use, and because of a lack of information about new energy-conserving technologies. Government can play a positive role in overcoming these impediments without unduly influencing the market. The approach is gentle guidance over the long run, not brute force to make rapid changes in the energy system because of a failure in policy to anticipate disruptions and to build flexibility into the energy supply system.

Chapter Three

The International Energy Situation

A. OPEC's Resurgence

Oil and natural gas resources are distributed irregularly over the world. According to data compiled by Joseph Riva Jr. (Riva, 1987), the world's original endowment (prior to any production) of recoverable, conventional light and medium crude oil totalled an estimated 1,635 billion barrels. Of this calculated amount, about 32% has been consumed and an estimated 30% remains to be discovered. The other 38% constitutes present proved reserves of conventional light-medium crude oil. Of the more than 1,100 billion barrels of light-medium crude oil yet to be consumed (proved reserves plus undiscovered, recoverable crude oil), 78% is thought to lie in the Eastern Hemisphere.

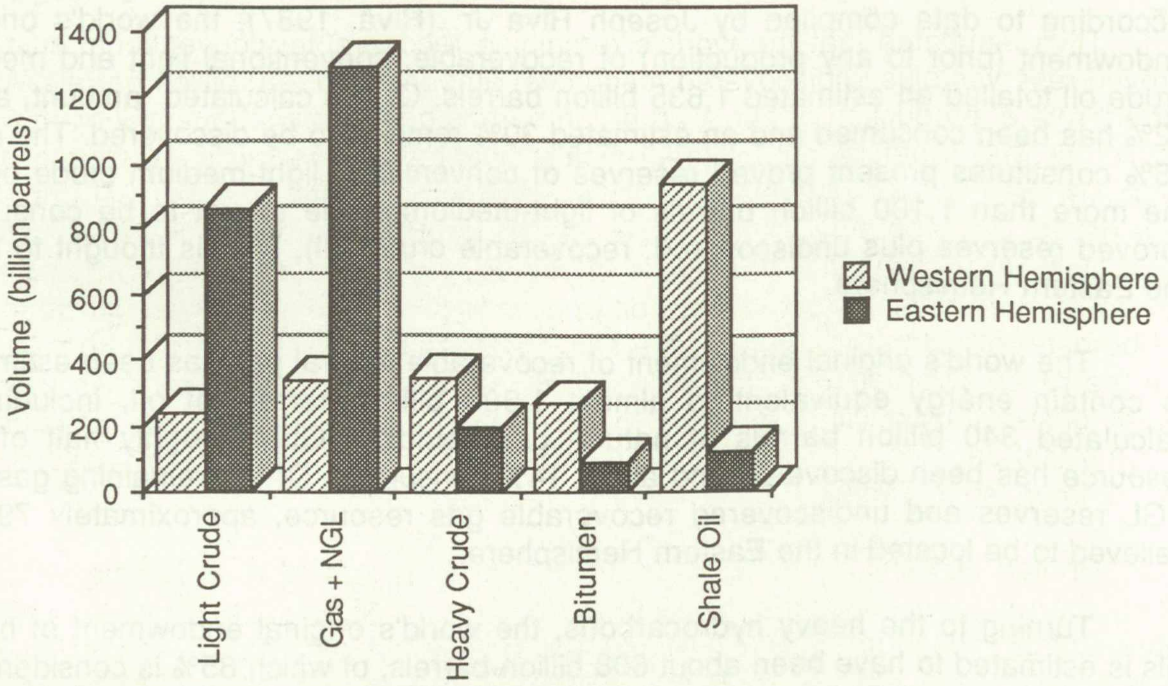
The world's original endowment of recoverable natural gas has been estimated to contain energy equivalent to almost 1,900 billion barrels of oil, including a calculated 340 billion barrels of natural gas liquids (NGL). Roughly half of this resource has been discovered and about 14% consumed. Of the remaining gas and NGL reserves and undiscovered recoverable gas resource, approximately 79% is believed to be located in the Eastern Hemisphere.

Turning to the heavy hydrocarbons, the world's original endowment of heavy oils is estimated to have been about 608 billion barrels, of which 85% is considered to have been discovered but only 11% consumed. Of the 540 billion barrels of unconsumed heavy oil, 64% is assigned to the Western Hemisphere.

Known bitumen deposits are assessed by Riva to contain roughly 354 billion barrels of recoverable crude oil, with 76% of this resource lying in the Western Hemisphere. Known oil shale deposits may hold about 1,065 billion barrels of recoverable oil; 88% of this resource is thought to reside in the Western Hemisphere. Such estimates are at best only a rough guide to the amount of the resource which may be recoverable, since they depend on the cut-off assumed in bitumen or shale oil content for economic extraction, and on limits of overburden thickness and deposit thickness for economic recovery. Some Canadian experts would attribute substantially larger quantities of recoverable bitumen to the oil sands of Alberta than does Riva.

Such uncertainty does not detract from the point to be made regarding Riva's analysis. The lighter, more desirable petroleum fuels, which are less costly to produce and process, lie predominantly in the Eastern Hemisphere. The heavier, less desirable petroleum fuels, which are more costly to produce and process, lie predominantly in the Western Hemisphere. Riva has calculated that the world's total, original endowment of all forms of petroleum was roughly equivalent to 5,560 billion barrels of oil. Figure 13 displays the hemispheric disposition of remaining reserves and recoverable undiscovered resources of petroleum, using the Riva estimates.

Figure 13: Remaining Recoverable Petroleum Resources in the Western and Eastern Hemispheres



Source: Riva, Joseph P., Jr., "Fossil Fuels", *Encyclopedia Britannica*, 1987, p. 588-612.

Approximately 40,000 oil fields have been discovered worldwide since 1860. Thirty-seven "supergiant" fields – fields containing more than five billion barrels of recoverable crude oil – have been found and these fields originally contained an estimated 51% of all the conventional crude oil discovered to date. The Persian Gulf region contains 26 of the 37 supergiant fields and 11 are located in Saudi Arabia. The world's largest oil field, Ghawar, was found in 1948 and its 86 billion barrels of recoverable oil transformed Saudi Arabia into the world's leading oil nation. Kuwait's Burgan field, the second largest, originally contained 75 billion barrels of recoverable oil. Two supergiant fields have been discovered in each of the United States (East Texas and Prudhoe Bay), the Soviet Union, Mexico and Libya. Algeria, Venezuela and China hold one each.

Almost 300 "giant" oil fields – those containing 500 million to 5 billion barrels of recoverable oil – account for another 30% of recoverable crude oil. Approximately 1,000 additional fields each hold from 50 million to 500 million barrels of recoverable oil and represent about 15% of the world's known oil. Thus 95% of the world's known recoverable crude oil is contained in less than 5% of discovered oil fields.

This pattern of oil occurrence and 130 years of petroleum exploitation have established two principles applying to global oil resources. First, most of the world's oil is contained in relatively few large fields, but most fields are small. Second, average field size and the quantity of oil found per unit of drilling decrease as exploration progresses. In any oil-producing region, the large fields tend to be discovered early in the cycle of oil production.

Riva estimates that the world's remaining recoverable, conventional crude oil (proved reserves plus undiscovered resources) amounts to 1,200 billion barrels. At the current rate of production of about 20 billion barrels per year, that quantity of oil would last for 50 years before output theoretically became limited by the resource base. Because this oil is so unevenly distributed, however, future oil availability must be considered on a country-by-country basis to determine when and where supply constraints will appear. Riva has assessed the oil-producing prospects of 29 countries, ranked by their original recoverable oil endowment. Assuming that proved reserves will be established in the future at the same statistical rate observed in the past and that the reserves/production ratio will not fall below nine in these countries (a value characteristic of producing regions in their declining years), he calculated the number of years that each country could sustain its 1986 level of oil production. These results are summarized in Table 7.

Proved remaining reserves of conventional crude oil are approximately 1,000 billion barrels. Two-thirds of this amount lies in the Middle East, as the data for year-end 1989 taken from *Oil & Gas Journal* in Figure 14 illustrate. Reserves in Figure 14 are first characterized as OPEC or non-OPEC. The non-OPEC reserves are subdivided into OECD, LDC (less developed countries) and CPE (centrally planned economies or the Communist countries).

OPEC holds an estimated 76.5% or 767 billion barrels of proved reserves of conventional crude oil. The OECD claims just 5.3% or 53 billion barrels. The United States and Canada together hold little more than 3% of world reserves. The North Sea holds less than 2%, despite its current influence in world oil trade. Of particular note, the OECD countries consume more than half of the world's oil but hold only about one-twentieth of proved conventional oil reserves.

Within OPEC, Saudi Arabia, Kuwait, Iran and Iraq dominate. These four nations are estimated to hold 55% of the world's conventional crude reserves, and 71% of OPEC's reserves. Among non-OPEC producers, the Soviet Union and Mexico stand first and second respectively. Between them, they account for 49% of non-OPEC reserves and 11.5% of world crude reserves.

Table 7: Projections of Future Oil Production Capabilities

Production Decline Begins (a)	Country	Production Potential in 2000 Compared to 1986 (b)
1987-1990	United States	Decline between 25% and 50%
	Peru	Decline between 25% and 50%
	United Kingdom	Decline greater than 50%
	Brazil	Decline between 25% and 50%
	Colombia	Decline between 25% and 50%
1991-1995	Argentina	Decline between 25% and 50%
	Egypt	Decline between 25% and 50%
	Canada	Decline less than 10%
	Soviet Union	Decline between 10% and 25%
1996-2000	Australia & New Zealand	Decline between 25% and 50%
	India	Level production
	Malaysia & Brunei	Level production
2001-2005	Ecuador •	Level production
	Oman	Level production
2006-2010	Qatar •	Level production
	Indonesia •	Level production
2021-2025	China	Level production
2026-2030	Nigeria •	2 times 1986 production
2031-2035	Algeria •	3 times 1986 production
2036-2040	Mexico	2 times 1986 production
2056-2060	Venezuela • & Trinidad	3 times 1986 production
2061-2065	Libya •	4 times 1986 production
2066-2070	Norway	2 times 1986 production
2071-2075	Tunisia	2 times 1986 production
2076-2080	United Arab Emirates •	5 times 1986 production
2091-2095	Saudi Arabia •	7 times 1986 production
2096-2100	Iran •	6 times 1986 production
2106-2110	Iraq •	5 times 1986 production
2171-2175	Kuwait •	12 times 1986 production

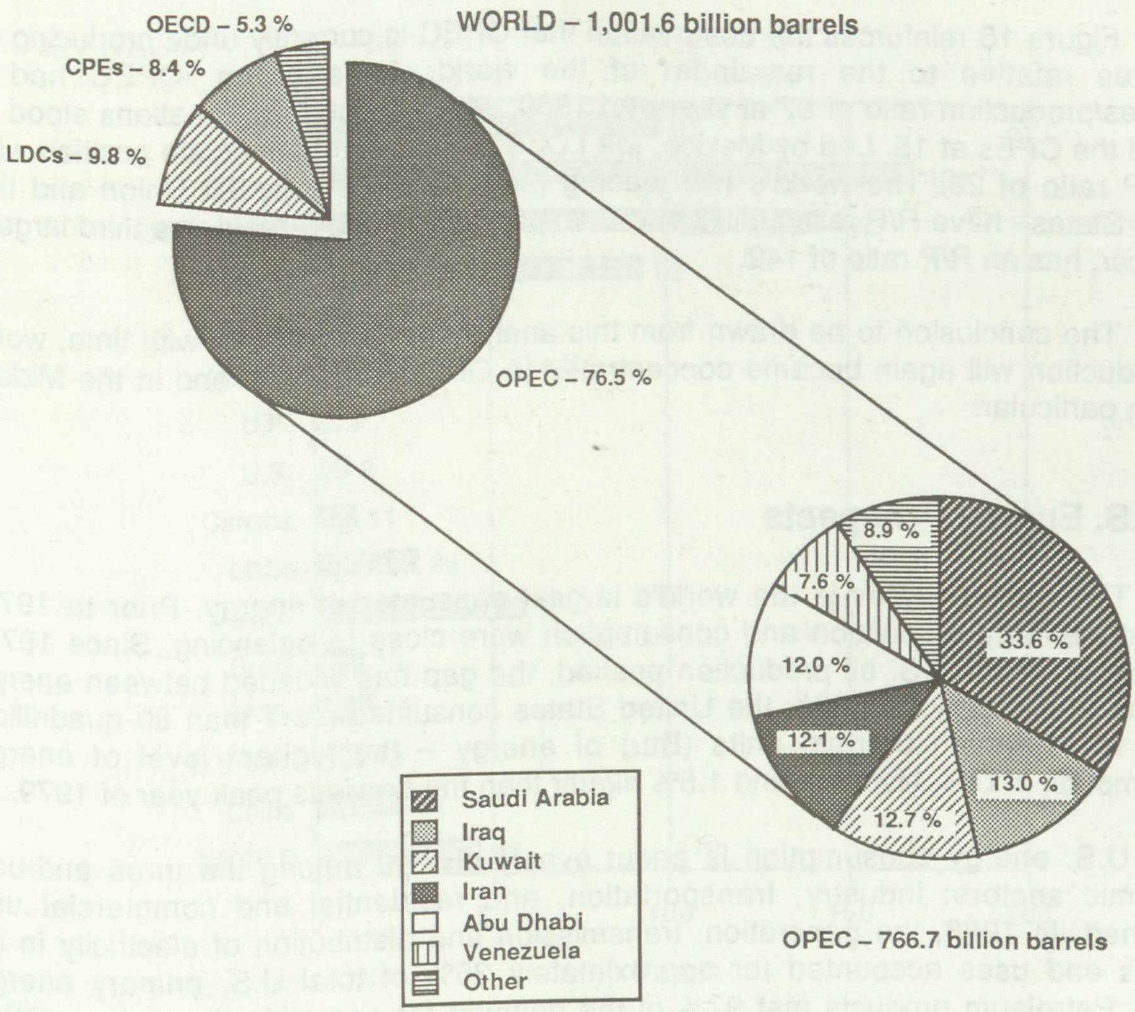
Notes: (a) The analysis was divided into five-year increments.

(b) The value given is not a production forecast but an indication of what could be achieved if the oil resource base calculated to exist were exploited at the maximum rate.

• Denotes a member of OPEC.

Source: Riva, Joseph P. Jr., *The World's Conventional Oil Production Capability Projected into the Future by Country*, Report #87-414 SPR, Congressional Research Service, Library of Congress, Washington, May 1987, pp. 16-17 and 19.

Figure 14: Share of World Proved Oil Reserves by Geopolitical Distribution



Source: "OPEC's Reserves Shares Up in Turbulent '80s", *Oil & Gas Journal*, 25 December 1989, pp. 41-45.

The global pattern of oil reserves does not match the pattern of crude oil production. Some countries are producing their reserves at high rates – notably the U.S.S.R., the United States, the United Kingdom and Canada – and other countries are producing their reserves at comparatively low rates – such as Kuwait, Saudi Arabia, Iraq and Mexico. The ratio of year-end proved reserves to production over the year is known as the reserves/production ratio (R/P ratio) and provides a measure of the longevity of current reserves. To illustrate, year-end 1989 proved reserves of crude oil in the United States were 25.86 billion barrels and 1989 production averaged 7.68 million barrels/day. Thus the R/P ratio for the U.S. at year-end 1989 was 25.86 billion ÷ (7.68 million x 365 days) = 9.2/1 (usually written simply as 9.2). Figure 15 displays reserves/production ratios for the world as a whole; for OPEC, the OECD, the LDCs and the CPEs; and for important producers within each of these groupings.

Figure 15 reinforces the observation that OPEC is currently underproducing its reserves relative to the remainder of the world. As a group, OPEC had a reserves/production ratio of 97 at year-end 1989, whereas the OECD nations stood at 11 and the CPEs at 15. Led by Mexico, the LDCs occupy an intermediate position with an R/P ratio of 29. The world's two leading producers – the Soviet Union and the United States– have R/P ratios of 13 and 9 respectively. Saudi Arabia, the third largest producer, has an R/P ratio of 142.

The conclusion to be drawn from this analysis is inescapable: with time, world oil production will again become concentrated in OPEC in general and in the Middle East in particular.

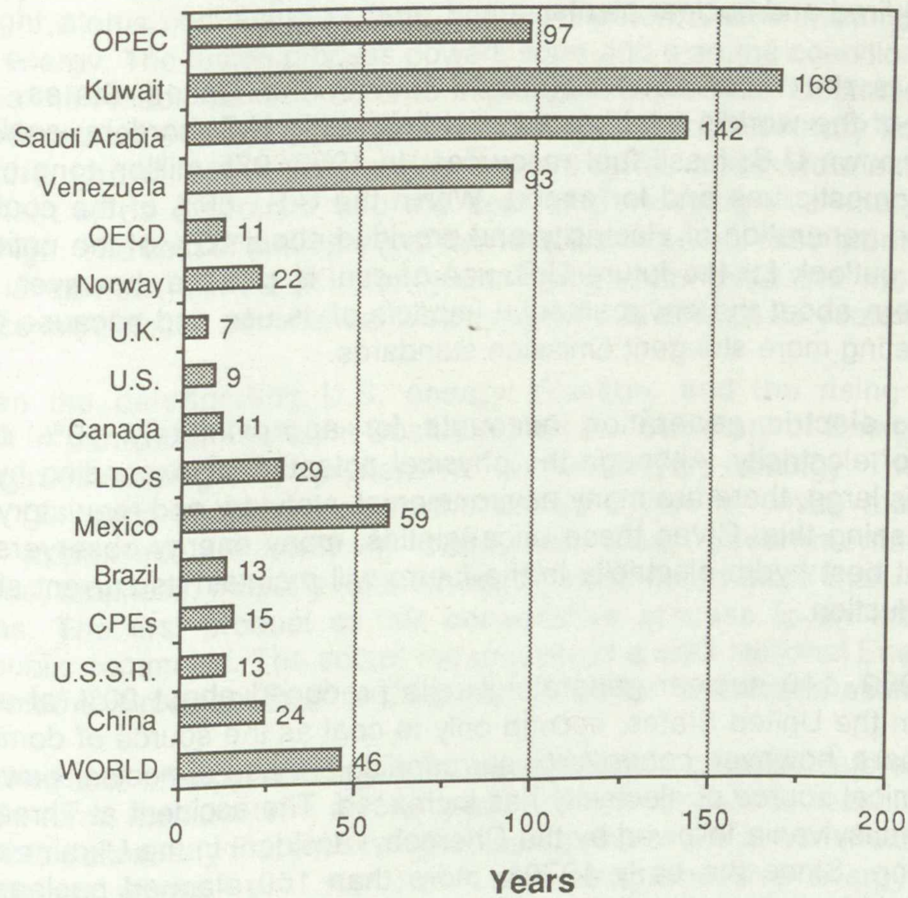
B. U.S. Energy Prospects

The United States is the world's largest consumer of energy. Prior to 1970, domestic energy production and consumption were close to balancing. Since 1970, the year in which U.S. oil production peaked, the gap has widened between energy demand and supply. In 1988, the United States consumed more than 80 quadrillion (80×10^{15}) British thermal units (Btu) of energy – the highest level of energy consumption in U.S. history – and 1.5% higher than the previous peak year of 1979.

U.S. energy consumption is about evenly divided among the three end-use economic sectors: industry, transportation, and residential and commercial use combined. In 1988, the generation, transmission and distribution of electricity in its various end uses accounted for approximately 35% of total U.S. primary energy needs. Petroleum products met 97% of the demand for energy in the transportation sector and transportation accounted for more than 60% of the 1988 consumption of oil in the United States.

Oil, including natural gas liquids, is the dominant energy commodity in the U.S. economy, currently satisfying about 43% of the American requirement for primary energy. Although the United States is the world's second largest oil producer after the Soviet Union, domestic oil production is declining slowly. This decline continued in 1989, with oil production falling to an average level of 9.2 million barrels per day, the lowest output in 25 years. During 1989, domestic oil demand averaged 17.2 million barrels/day which, although lower than the 1978 peak demand of 18.8 million barrels/day, was still higher than production by approximately 8 million barrels/day. Imported oil in 1989 averaged 41% of domestic use; in recent months imports have represented more than 50% of domestic demand. The cost of importing oil in 1989 was $US 49 billion, about 45% of the $US 109 billion trade deficit.

Figure 15: Conventional Crude Oil Reserves/Production Ratios at Year-end 1989



Source: Derived from "OPEC's Reserves Share Up in Turbulent '80s", *Oil & Gas Journal*, 25 December 1989, pp. 44-45.

Natural gas provides almost one-quarter of the energy used in the United States today. This fuel is especially important in the residential sector, where it handles nearly half of end-use energy needs. In 1988, 18 trillion cubic feet (Tcf) of domestic natural gas was marketed in the United States, supplemented by more than 1.2 Tcf of Canadian gas imports. Although the U.S. gas "bubble" – a surplus in deliverability over domestic demand – has persisted for a number of years, this excess availability has largely disappeared. Today, imports from Canada satisfy approximately 7% of the U.S. demand for gas and this share is expected to rise throughout the 1990s.

Domestic proved reserves of natural gas are about ten times as large as current annual production and estimates of undiscovered gas supplies are encouraging, but it remains questionable whether rising domestic demand can be adequately supplied by domestic production. The environmental advantages of using natural gas in preference to other fossil fuels is strengthening demand. This is particularly true in the case of new electrical generating capacity where legislation and environmental concern are promoting the development of gas-fired cogenerating units in preference to large coal-fired and nuclear plants.

Coal is the most abundant fossil fuel in the United States. More than one-quarter of the world's total known coal lies within U.S. borders; coal represents 90% of all known U.S. fossil fuel resources. In 1989, 975 million tons of coal were mined for domestic use and for export. Within the U.S., 86% of the coal consumed went into the generation of electricity and provided about 55% of the nation's electric power. The outlook for the future U.S. use of coal is clouded, however, because of public concern about the environmental impacts of its use and because of the rising costs of meeting more stringent emission standards.

Hydro-electric generation accounts for approximately 10% of the U.S. production of electricity. Although the physical potential for expanding hydro-electric generation is large, there are many environmental, statutory and regulatory constraints to accomplishing this. Given these uncertainties, many energy observers consider it likely that at best hydro-electricity in the future will maintain its current share of U.S. energy production.

In 1989, 110 nuclear generating units produced about 20% of all electricity generated in the United States, second only to coal as the source of domestic power. In recent years, however, controversy surrounding the use of nuclear power as a safe and economical source of electricity has increased. The accident at Three Mile Island Unit 2 in Pennsylvania followed by the Chernobyl accident in the Ukraine raised public apprehension. Since the early 1970s, more than 100 planned nuclear generating units have either been cancelled or deferred indefinitely. Only three units remain in construction and no new power reactors are being ordered. The growth of the nuclear industry in the United States is at a virtual standstill.

Public concern is particularly focused on the safe permanent disposal of high-level radioactive waste materials. Recognizing this public mood, the U.S. government has identified a specific site at Yucca Mountain in Nevada as the location for the nation's first radioactive waste disposal facility. If site studies indicate that Yucca Mountain is a suitable location for such a facility, the U.S. Department of Energy will recommend it to the President for construction of a repository.

In addition to the so-called conventional forms of energy – crude oil, natural gas, coal, hydro-electricity, and nuclear-electricity – there is the prospect of using renewable sources to a much greater extent in the future. Apart from hydro-electricity, the three fundamental sources of renewable energy are solar energy (including direct solar radiation, biomass, wind energy, ocean currents and wave energy), geothermal energy and tidal energy. Although the United States formerly had a large and active R&D program to exploit renewable energy sources, much of this activity was curtailed during the Reagan Administration. It will take some years to re-establish a vigorous R&D program for the renewables.

A longer-term energy option is nuclear fusion. As opposed to fission power where heavy atoms are split accompanied by the release of energy, the fusion process involves light atoms combining to form heavier elements, also accompanied by the release of energy. The fusion process powers stars and extreme conditions have to be created in a man-made fusion reactor to duplicate this process. Controlled fusion has not yet produced net power and the economics of producing electricity from fusion are not, therefore, known. Many engineering barriers to the commercialization of fusion power remain to be overcome and the cost of developing this energy source is extremely high. The cost of attempting to harness fusion power is so great that much of the effort is carried forward in international programs. Even the more optimistic observers consider that a commerical fusion reactor lies at least 25 years in the future.

Given the deteriorating U.S. energy situation, and the rising reliance on imported oil in particular, President Bush directed the Secretary of Energy on 26 July 1989 to begin developing a comprehensive National Energy Strategy. The department conducted 15 public hearings across the United States at which more than 375 witnesses appeared. In addition, state and local governments, consumer organizations, business, industry and individuals contributed more than 1,000 written submissions. The first product of this consultative process is an Interim Report compiling public comments. The end of the process is a draft National Energy Strategy to be presented to President Bush in December 1990 for his consideration.

The National Energy Strategy will use 1990 as a baseline reference and will contain short-term, medium-term and long-term recommendations reaching out to the year 2030. It is noteworthy that the Interim Report stresses the need for examining U.S. energy prospects within the "...framework of a comprehensive energy strategy..." Lacking a comprehensive strategy, "Piecemeal and divisive tactics, whether promoting one option or obstructing another, will increasingly become the order of the day."

> Taken to its extreme, this mode of conducting our energy, strategic, economic, and environmental affairs threatens to result in national paralysis. We will have policies by default, rather than deliberation. Costs and benefits will not be adequately assessed or balanced – frustrating our Nation's ability to compete, and putting at risk our future standard of living.
>
> For the United States to move successfully into the 21st Century, we must dedicate ourselves to increased communication, broadened perspectives, better understanding of concerns and issues, and renewed resolve to meet complex challenges with creativity and vigor. An integrated

National Energy Strategy, developed in concert with the American people, can provide a unifying means for moving towards these ends. (U.S., DOE, 1990, p. 3)

The Interim Report was organized around four themes identified in the public hearings: (1) increase the efficiency of energy use; (2) secure future energy supplies; (3) respect the environment: and (4) fortify the foundations of the energy system through basic science and research, improved education education and technology transfer.

The National Energy Strategy is an ambitious attempt to formulate a coherent energy plan for the United States. It remains to be seen how successful this attempt will be in the face of entrenched energy interests, both producer and consumer, and a wide divergence of views regarding what an appropriate energy policy should be. It also remains to be seen how a new U.S. energy strategy will bear on Canada, given our close energy linkage to the United States through the Free Trade Agreement.

Chapter Four

Public Policy Considerations

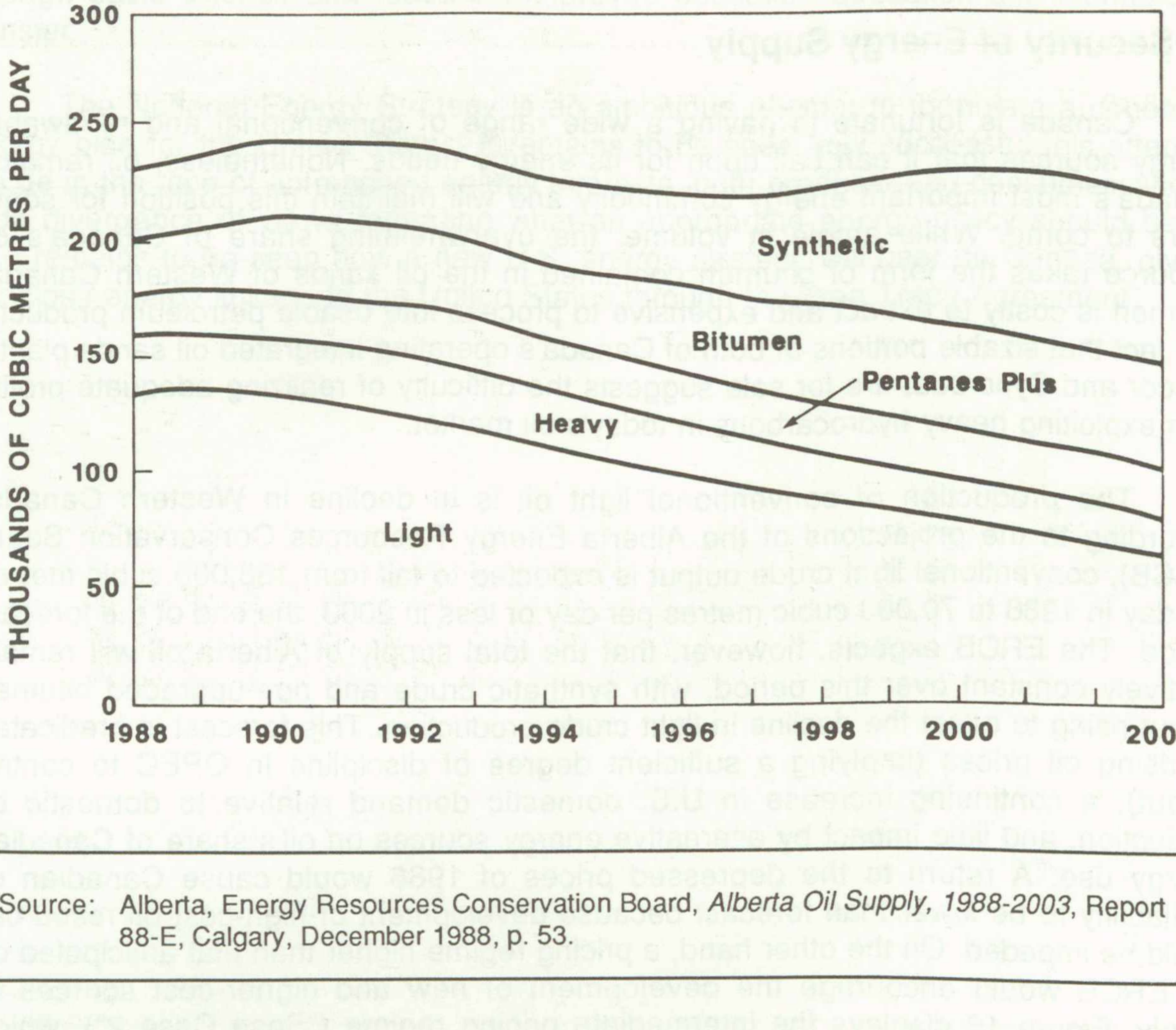
A. Security of Energy Supply

Canada is fortunate in having a wide range of conventional and renewable energy sources that it can call upon for its energy needs. Nonetheless, oil remains Canada's most important energy commodity and will maintain this position for some years to come. While ample in volume, the overwhelming share of Canada's oil resource takes the form of bitumen contained in the oil sands of Western Canada. Bitumen is costly to extract and expensive to process into usable petroleum products. The fact that sizable portions of both of Canada's operating integrated oil sands plants, Suncor and Syncrude, are for sale suggests the difficulty of realizing adequate profits from exploiting heavy hydrocarbons in today's oil market.

The production of conventional light oil is in decline in Western Canada. According to the projections of the Alberta Energy Resources Conservation Board (ERCB), conventional light crude output is expected to fall from 138,000 cubic metres per day in 1988 to 70,000 cubic metres per day or less in 2003, the end of the forecast period. The ERCB expects, however, that the total supply of Alberta oil will remain relatively constant over this period, with synthetic crude and non-upgraded bitumen output rising to offset the decline in light crude production. This forecast is predicated on rising oil prices (implying a sufficient degree of discipline in OPEC to control output), a continuing increase in U.S. domestic demand relative to domestic oil production, and little impact by alternative energy sources on oil's share of Canadian energy use. A return to the depressed prices of 1986 would cause Canadian oil availability to be lower than forecast because development of high-cost oil resources would be impeded. On the other hand, a pricing regime higher than that anticipated by the ERCB would encourage the development of new and higher-cost sources of supply. Figure 16 displays the intermediate pricing regime ("Base Case 2"), which assumes an average real increase in the price of crude oil of 3% yearly through 2003.

The Canadian Energy Research Institute (CERI) has projected Canadian crude oil supply and demand balances to the year 2008, in base case, high price and low price scenarios. Canada's domestic shortfall of light crude oil persists throughout the forecast period in both the base case and low price case. Under the high price assumption, Canada's production of light oil rises above domestic demand at the end of the forecast period. For the overall supply/demand situation, the CERI analysis indicates that Canada may again become a net importer of oil by the mid-1990s. Beyond the year 2000, the analysis indicates the strong possibility that Canada will be a net oil-importing nation.

Figure 16: Total Supply of Alberta Crude Oil and Equivalent as Projected by the ERCB, Base Case #2, 1988-2003



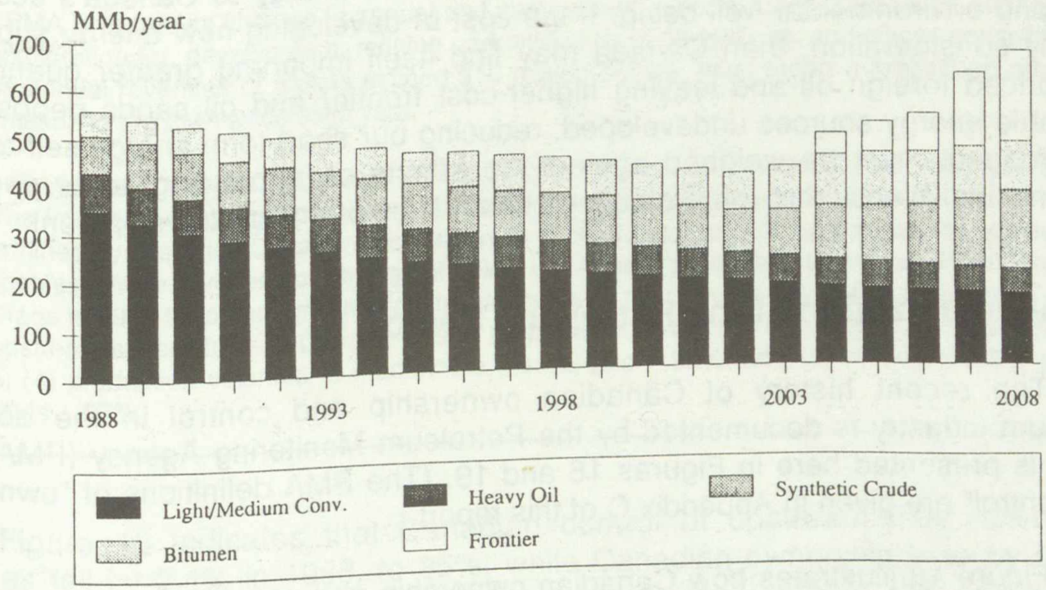
Source: Alberta, Energy Resources Conservation Board, *Alberta Oil Supply, 1988-2003*, Report 88-E, Calgary, December 1988, p. 53.

Figure 17 presents CERI's base case projection, using the intermediate pricing forecast, for all of Canada. CERI appears to be more optimistic about the rate of development of synthetic crude production in Western Canada than the ERCB.

Canada's internal oil supply/demand situation is much less balanced than the nationally aggregated statistics suggest. Responding to the Arab Oil embargo and price shock, the former Liberal Government extended the Interprovincial Pipe Line from its Sarnia, Ontario terminus to Montreal and subsidized the shipment of Western Canadian oil into the Quebec market. With the advent of deregulation under the new Government and the end of transportation subsidies, Western Canadian oil again began to flow south in large quantities into the United States. As they were in the

1960s and 1970s, Atlantic Canada and Quebec have again become dependent on imported oil for a substantial share of their energy requirements. Eastern Canada is less vulnerable to an OPEC-engineered disruption in world oil supply today because it purchases the bulk of its crude oil from the North Sea. Production in the U.K. sector of the North Sea, however, appears to have peaked and output in the Norwegian sector will probably peak in the 1990s. As non-OPEC oil production declines in the longer term, Eastern Canada will be compelled once again to turn to OPEC for the majority of its petroleum needs.

Figure 17: Canadian Production of Crude Oil from All Sources as Projected by CERI, Base Case, 1988-2008



Source: Tanner, James N. and Anthony E. Reinsch, *Canadian Crude Oil: Supply/Demand Balances*, Study No. 31, Canadian Energy Research Institute, Calgary, August 1989, p. 74.

In the case of natural gas, Canada has extensive reserves – approximately 100 trillion cubic feet – but about one-quarter of this gas lies in Canada's frontier regions and is not connected to southern markets.

Over the last two years, exports of natural gas to the United States have risen sharply, driven in part by an increasing public concern about the environmental impact of energy development which has made it more difficult for American utilities to build large coal-fired generating stations. Much of this new gas moving south is being purchased in long-term contracts for gas-fired cogenerating capacity. The rate at which Western Canada's remaining uncommitted reserves of natural gas are being dedicated to the export market in long-term arrangements is a source of concern to this Committee and one which it addressed in its report, *Natural Gas: 1988*. Given that Canada cannot restrict the flow of natural gas to U.S. buyers under normal circumstances without invoking proportional sharing, the Committee recommended in its 1988 report that core market or "essential service" customers be required to contract their gas requirements for a minimum of ten years. The government has not responded to this recommendation.

Canada's potential for experiencing energy supply problems is not – or should not become – a function of deficiencies in our energy resource base; rather the Committee concludes that should energy supply difficulties arrive in the future, they are more likely to be the product of mismanaging our domestic energy resources and failing to take a long-term view of the importance of energy to Canada's economic, social and environmental well-being. If the cost of developing new energy supplies is the only consideration, then Canada may find itself importing greater quantities of lower-priced foreign oil and leaving higher-cost frontier and oil sands deposits and renewable energy sources undeveloped, reducing our short-term energy self-reliance. This prospect must be weighed against the effects of introducing some degree of economic inefficiency through promoting certain lines of energy development.

B. Canadianization of the Petroleum Sector

The recent history of Canadian ownership and control in the domestic petroleum industry is documented by the Petroleum Monitoring Agency (PMA). That history is presented here in Figures 18 and 19. (The PMA definitions of "ownership" and "control" are given in Appendix C of this report.)

Figure 18 illustrates how Canadian ownership and control have changed since 1980 in the domestic petroleum industry (based on upstream plus downstream revenues). Figure 18 presents ownership and control information based on upstream revenues alone. The data are year-end values and the period covered is the nine years from 1980 through 1988.

In both the total industry and upstream cases, Canadian ownership and control grew from 1980 through 1985. Since 1985, Canadian ownership and control have declined substantially in both the upstream sector and the total industry, although the trends across the total industry have been more divergent.

According to the PMA, three events in 1988 accounted for the major part of changes in Canadian ownership and control: the Amoco Canada takeover of Dome Petroleum, the British Gas partial purchase of Bow Valley Industries, and the Husky Oil takeover of Canterra Energy. Offsetting part of this foreign takeover activity were two factors identified by the PMA: (1) revenues of foreign-controlled companies declined by 14% compared with a 9% drop in Canadian-controlled companies, having a positive effect on the level of Canadian control; and (2) there was an increase in participation by Canadian investors in publicly-traded, integrated, foreign-controlled companies, which had a positive effect on the Canadian ownership rate.

The **Petroleum Monitoring Agency** was established in 1980 as an independent agency whose Chairman reports directly to the Minister of Energy, Mines and Resources. The PMA's goals "...are to provide the federal government and Canadians generally with comprehensive and objective information on and analysis of the financial performance of the petroleum industry in Canada:

(a) to enable the Government of Canada to better plan and develop policies for the management of Canada's energy supplies and resources, and,

(b) to provide the Government of Canada and Canadians generally with assurances that those policies are being pursued and are effective." [Canada, PMA, 1989, p. 97]

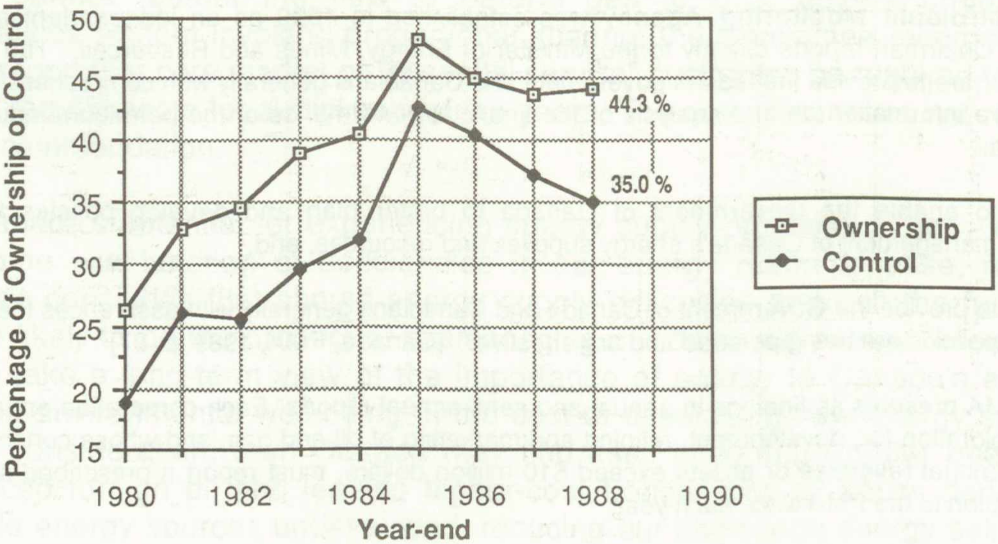
The PMA presents its findings in annual and semi-annual reports. Each corporation engaged in the exploration for, development, refining and marketing of oil and gas, and whose consolidated gross annual revenues or assets exceed $10 million dollars, must report a prescribed array of information to the PMA twice each year.

The PMA states that the petroleum industry's gross revenues covered by its 1988 survey of returns from 127 reporting companies account for 89% of total upstream industry revenues as determined by Statistics Canada. The remaining 11% of upstream industry revenues accrued to companies whose revenues or assets fell below the Agency's reporting threshold. The degree of coverage in 1988 for other performance indicators was: (1) upstream production revenues – 89%; (2) upstream expenditures in Canada – 89%; (3) production volumes of crude oil and gas liquids – 87%; (4) production volumes of marketable natural gas – 92%; and (5) refined product sales volumes – 97%.

Figure 18 indicates that Canadian control of upstream plus downstream revenues fell by 2.4% in 1988, to 35%, while Canadian ownership rose by 0.5% to 44.3%. The increase in Canadian ownership "...was largely the result of an elimination of a minority position held by a foreign-controlled company in a large Canadian-controlled company which had significant downstream revenues" (Canada, PMA, 1989, p. 36). The decline in Canadian control was the result of foreign takeovers.

In Figure 19 the sharper 1988 decline in Canadian control than in Canadian ownership is attributed by the PMA to two factors: (1) there was a relatively small amount of Canadian equity involved in the takeover of one large Canadian-controlled company; and (2) the takeovers of two other companies were partial and affected the ownership level less than the control measure.

Figure 18: Canadian Ownership and Control of the Domestic Petroleum Industry Based on Upstream Plus Downstream Revenues



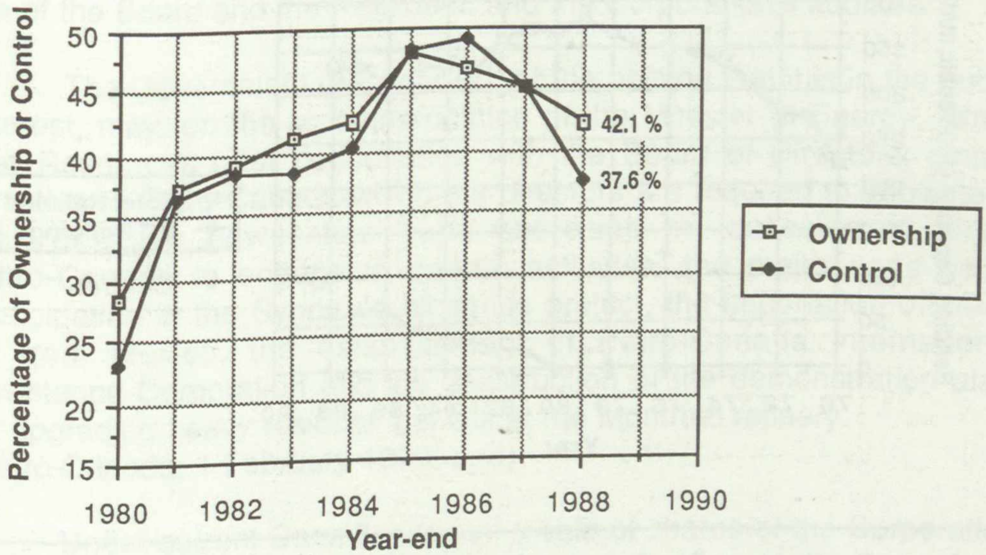
Source: Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry – 1988 Monitoring Report*, Communications Branch, Department of Energy, Mines and Resources, Ottawa, July 1989, p. 35.

C. Rationalization of the Domestic Petroleum Industry

The pattern of Canadian energy use changed significantly after the Arab oil embargo and two price shocks. Atlantic Canada and Quebec, which were highly dependent on oil in their primary energy supplies, have made strong efforts to reduce the importance of oil in their energy mix. Quebec has looked to electricity and natural gas as substitutes for oil, while Atlantic Canada has turned more to its indigenous coal resources. Despite these efforts, however, both regions still import substantial quantities of foreign crude, especially North Sea oil.

One of the most dramatic structural changes has taken place in the refining sector, led by the closure of refineries in Quebec. At the time of Petro-Canada's creation, there were seven refineries operating in that province; today there are three. Figure 20 displays the change in Canada's total refining capacity against the growth of Petro-Canada's refining capacity.

Figure 19: Canadian Ownership and Control of the Domestic Petroleum Industry Based on Upstream Revenues Only



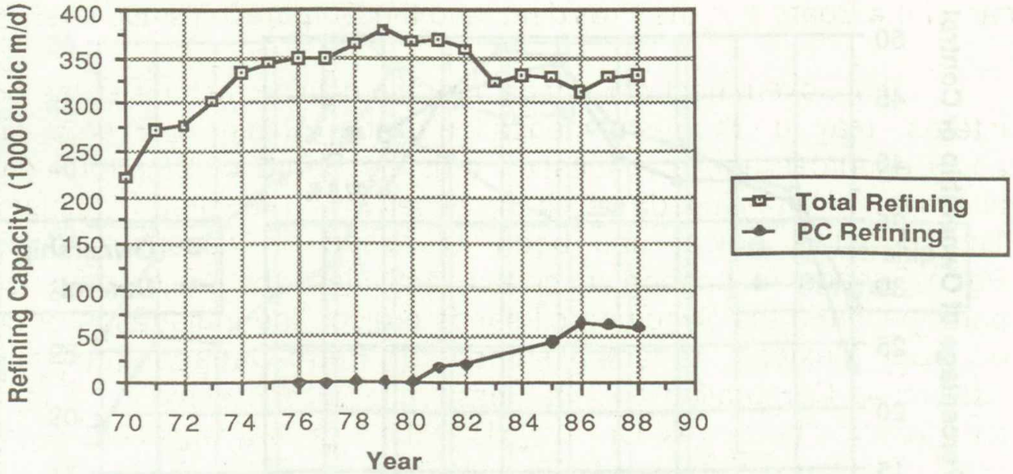
Source: Canada, Petroleum Monitoring Agency, *Canadian Petroleum Industry – 1988 Monitoring Report*, Communications Branch, Department of Energy, Mines and Resources, Ottawa, July 1989, p. 35.

Petro-Canada has achieved a comparable position in its share of the domestic retail market. At the Committee's request, Petro-Canada provided data on its market share by province, as of June 1989. Those shares are indicated in Table 8. In June 1989, Petro Canada had 3,396 retail outlets across Canada. Of this total, 1,258 were in Western Canada; 1,226 were in Ontario; and 912 were located in Eastern Canada. Of the 3,396 total retail outlets, only 165 were company-owned and operated. A further 649 were operated by retail commissioned agents, 876 by lessees, and 1,706 by independent dealers. (Personal communication, Petro-Canada, 10 January 1990)

D. Relationship with the Federal Government

Petro-Canada is a Crown corporation as defined in the *Financial Administrations Act*. Its shares are held in the name of the Minister of Energy, Mines and Resources in trust for Canada and are not transferable. The Corporation is an agent of Canada and all of its property belongs to Canada.

Figure 20: Canada's and Petro-Canada's Refining Capacity, 1970-1988



Source: Canadian Petroleum Association, *Statistical Handbook*, Calgary, undated, Table 3, Section VIII; Petro-Canada, *Annual Reports*, 1976-88, Calgary.

Table 8: Petro-Canada's Retail Market Share by Province or Territory, as of June 1989

Northwest Territories	11.97%
Yukon	25.22%
British Columbia	20.15%
Alberta	14.57%
Saskatchewan	17.84%
Manitoba	24.86%
Ontario	23.96%
Quebec	17.3%
New Brunswick	12.4%
Nova Scotia	15.0%
Prince Edward Island	7.5%
Newfoundland	6.3%
Average for Canada	**19.75%**

Source: Personal communication, Petro-Canada, 10 January 1990.

The *Financial Administration Act* provides for certain measures of control and accountability for Crown corporations. Petro-Canada is required to submit annually a corporate plan and a capital budget to the federal government for its approval and is required to carry on its business according to that approval. Subject to the *Financial Administration Act*, the Board of Directors is responsible for managing the activities of the Corporation. The Government of Canada appoints the directors, including the Chairman of the Board and the President, and the Corporation's auditors.

> The Government of Canada, if of the opinion that it is in the public interest, may, on the recommendation of the Minister of Energy, Mines and Resources after consultation with the Board of Directors, give a directive to Petro-Canada which the directors are required to implement. This directive power has been exercised on occasion to direct Petro-Canada to engage in certain activities, the major ones being participation in the Syncrude oil sands project, the importation of crude oil from Mexico, the establishment of Petro-Canada International Assistance Corporation and the construction of the demonstration plant for upgrading heavy residual fuel oils at the Montreal refinery.
> (Petro-Canada, 1 February 1990, p. 4)

> Under current Canadian law, if a sale of shares of the Corporation to the public took place, Debt Securities outstanding at the time of the sale would continue to constitute direct unconditional obligations of Canada and payment of the principal thereof and interest thereon would continue to constitute a charge on and be payable out of the Consolidated Revenue Fund of Canada.
> (*Ibid.*, p. 5)

At year-end 1988, total capital, issued to the Government of Canada, consisted of 31,883 common shares with a par value of $100,000 each and 972,771,853 preferred shares with a par value of one dollar each, for an aggregate amount of $4,161 million in share capital. During 1989, the Board of Governors approved the adoption of the successful efforts method of accounting, which resulted in a decrease in retained earnings to a deficit of $1,434 million at 1 January 1989. On 21 February 1990, the Governor in Council approved the surrender for cancellation of 14,343 common shares resulting in a total share capital of $2,727 million.

At year-end 1988, Petro-Canada owed $1,036 million in long-term debt and $974 million in short-term notes payable (including $6 million representing the current portion of long-term debt). At year-end 1989, the Corporation's long-term debt had increased to $1,232 million and short-term notes payable had declined to $716 million (again including $6 million for the current portion of long-term debt). In January 1990, Petro-Canada issued $US 300 million in 20-year debentures to reduce short-term indebtedness.

Petro-Canada differs from the other four NOCS surveyed in the longevity of its chief executive. Maurice Strong, the Corporation's first Chairman of the Board, recruited then Senior Vice-President Wilbert Hopper to be Petro-Canada's President and Chief Executive Officer (CEO). When Strong left Petro-Canada in 1978, Hopper became the Board's Chairman in his place. Since then, Mr. Hopper has served as Chairman and CEO. PDVSA has had five chief executives since 1975, Statoil has had two since 1972, and JNOC six since 1967. ENI has had 11 presidents since 1953.

Contrasting with the stability of Petro-Canada's chief executive has been the turnover in its Board of Directors. In 14 full years of operation, during which time Petro-Canada's Board of Directors has grown from ten to 15, 41 different people have served on the Board. Mr. Hopper is its only remaining original member. Following the election of 1984, the new government replaced 11 of the 15 Directors on 21 December 1984. Whereas three Deputy Ministers (Energy, Mines and Resources, Finance, and Indian and Northern Affairs) served on the 10-member original Board, today no representative of the federal bureaucracy sits on a Board that is 50% larger.

Chapter Five

A Comparison with Four other National Oil Companies

A. Introduction

In 1970, approximately 70% of world oil trade was handled by seven multinational companies (MNCs) – Exxon (then Esso), Royal Dutch/Shell, Mobil, Texaco, Standard Oil of California, Gulf and British Petroleum, known colloquially as the "majors" or "Seven Sisters". This remarkable degree of corporate control was exercised from three countries: the United States, the United Kingdom and the Netherlands. A decade later, the share held by the multinationals had declined to about 50%. Some of the displaced trade had moved into the growing spot market for oil, in which both the MNCs and national oil companies (NOCs) participate, but a larger share had shifted to markets served by NOCs of the producing and consuming countries. Although countries such as France, Italy and Mexico have a long tradition of intervention in their oil sectors, many of the NOCs originated in the 1970s (for example, Statoil in 1972, Petro-Canada in 1975 and Petróleos de Venezuela in 1975).

The Arab oil embargo of 1973-74 and the accompanying price shock forced industrialized countries to acknowledge their critical dependence on a previously inexpensive and readily available resource. This was especially true of the Western European nations and Japan. Reaction took two forms.

First, "...the embargo made European governments acutely aware of their lack of knowledge about the energy business. They resolved to rectify this situation by further direct participation, which would also enable them to react more effectively to any future crisis" (Grayson, 1981, p. 7). It led as well to the creation of the International Energy Agency (IEA) in 1974 and the adoption of its oil-sharing provisions.

Second, the new circumstances prompted many countries including Canada to adopt "off-oil" policies, substituting other forms of energy such as natural gas, coal and electricity for oil. Quebec, for example, saw hydro-electricity and natural gas as partial substitutes for oil; France embarked on a massive program of nuclear-electric power generation to reduce its dependence on offshore oil. The United States created its Synfuels Corporation whose principal objective was greater use of coal. Energy conservation and alternative energy development also benefitted from this concern about future oil availability. An important element of IEA cooperation has been international collaboration on alternative energy R&D.

National oil companies have been most prominent in OPEC and Western Europe. Despite their importance, however, the term "national oil company" has remained ill-defined. Although the British Government formerly held a majority interest in British Petroleum, for example, the company was allowed to operate as a private enterprise. Grayson (1981, p. 5) suggests that NOCs be defined as "those companies that have been used for national purposes".

In reviewing the mandate and operations of Petro-Canada, the Committee decided it would be instructive to look at the purpose, organization and operations of other national oil companies for similarities with and alternatives to the Canadian approach. The Committee examined the roles that four national oil companies have played in the energy affairs and policy-making of their respective countries: Petróleos de Venezuela, S.A. (PDVSA); Japan National Oil Corporation (JNOC); Den norske stats oljeselskap a.s (Statoil) of Norway; and Ente Nazionale Idrocarburi (ENI) of Italy. Although none is identical to Petro-Canada in mandate and structure, nor do they operate in the same circumstances, they do encompass a range of activities against which Petro-Canada's operations can be considered.

Petróleos de Venezuela was formed to take over foreign interests when Venezuela's substantial oil industry was nationalized in 1975. The Company has since consolidated and expanded its holdings, and is becoming increasingly active internationally. Developing the technology needed to exploit its massive heavy oil and oil sands reserves is an important part of its task.

Japan National Oil Corporation's principal objective is to help secure a dependable, long-term supply of oil for the nation. Created in 1967 as the Japan Petroleum Development Corporation, JNOC cooperates with the Japanese private sector in locating and developing new sources of petroleum. Assistance, which is withdrawn once a project is operational, is limited to equity, loan guarantees and other financial measures. JNOC also carries out petroleum-related research and manages Japan's strategic petroleum stockpile.

Statoil was formed in 1972 after the discovery of large oil and gas reserves in the Norwegian sector of the North Sea. It has developed into a major integrated oil company with growing interests in Western Europe and elsewhere. The Company provided the impetus for the Norwegian shipbuilding and engineering industries to enter the ranks of the world's leaders in the design and construction of cold-water technology and equipment. Statoil supports an extensive R&D program.

ENI is a large Italian energy-based conglomerate with a limited domestic resource base. Created in 1953, ENI has spread its activities in numerous directions both inside and outside the country. It has been used on occasion to serve social and economic purposes, and is responsible for Italy's strategic oil stockpile. In common with the other three NOCs, ENI carries out an active research program.

Before examining the four companies in detail, it is useful to review the major players in the global petroleum industry as a backdrop for the discussion.

B. The World's Major Oil Companies

Petroleum Intelligence Weekly (PIW) has ranked the world's "top 50" oil companies after surveying approximately 100 firms in the non-Communist world. Relative standing was determined by adding the rankings of the companies in each of six operational areas – oil reserves, oil production, gas reserves, gas production, product sales, and refining capacity – to determine an aggregated standing. The results are summarized in Table 9.

Table 9: The Top 50 Oil Companies in 1988, Based on a Ranking by Six Operational Criteria

Overall Rank	Company	Country	Reserves Liquids	Reserves Gas	Production Liquids	Production Gas	Refining Capacity	Product Sales
1	Saudi Aramco	Saudi Arabia	1	2	1	6	9	7
2	Royal Dutch/Shell¶	Neth/UK	11	13	7	1	2	1
2	Exxon¶	USA	12	12	6	2	1	2
4	PDVSA	Venezuela	6	6	5	12	6	8
5	NIOC	Iran	4	1	4	10	21	18
6	Chevron¶	USA	16	22	13	7	3	6
6	Mobil¶	USA	17	18	19	4	4	5
8	British Petroleum	UK	13	21	8	19	5	4
9	Texaco	USA	19	25	11	8	7	3
10	KPC	Kuwait	3	11	9	29	13	14
11	Amoco	USA	21	19	17	5	11	10
12	Pemex	Mexico	7	8	3	46	8	12
13	Pertamina	Indonesia	15	10	15	9	15	25
14	Sonatrach	Algeria	10	5	10	3	34	33
15	Arco	USA	18	23	18	14	19	19
16	ENI	Italy	25	20	27	13	14	13
17	INOC	Iraq	2	7	2	31	40	36
18	Libya NOC	Libya	8	15	14	35	37	39
19	Elf Aquitaine¶	France	29	33	23	15	27	30
19	Du Pont (Conoco)§¶	USA	30	36	24	20	26	21
21	Adnoc	UAE	5	4	16	21	58	55
22	NNPC	Nigeria	9	9	12	52	35	50
23	EGPC	Egypt	22	24	22	37	32	32
24	Unocal	USA	34	28	33	17	31	29
25	Petrobras	Brazil	20	35	21	...	10	9
26	USX (Marathon)§	USA	35	34	36	18	24	28
27	YPF¶	Argentina	26	16	26	11	36	61
27	Phillips Petroleum¶	USA	33	32	25	16	43	27
29	Total CFP	France	47	76	31	24	12	11
30	Petrofina	Belgium	46	42	43	38	22	20

Table Continues...

Table 9: The Top 50 Oil Companies in 1988, Based on a Ranking by Six Operational Criteria *(Continued)*

			Individual Rankings					
Overall			Reserves		Production		Refining	Product
Rank	Company	Country	Liquids	Gas	Liquids	Gas	Capacity	Sales
31	*ONGC¶*	*India*	*14*	*17*	*20*	*23*	...	...
31	*OGPC¶*	*Qatar*	*23*	*3*	*30*	*30*	*65*	*71*
33	Amerada Hess	USA	41	46	40	33	25	37
34	*Petronas*	*Malaysia*	*27*	*14*	*32*	*26*	*71*	*63*
35	Sun	USA	62	72	39	28	18	17
36	***Petro-Canada***	***Canada***	***40***	***37***	***45***	***34***	***38***	***46***
37	*Ecopetrol*	*Colombia*	*28*	*39*	*35*	*57*	*50*	*53*
38	BHP Petroleum§	Australia	36	29	38	32	63	67
39	*Indian Oil*	*India*	*44*	*47*	*54*	*70*	*33*	*26*
40	***Statoil***	***Norway***	***31***	***49***	***29***	***49***	***59***	***60***
41	*PDO (State)*	*Oman*	*24*	*31*	*28*	*64*	*64*	*68*
42	*Banoco*	*Bahrain*	*63*	*27*	*61*	*25*	*52*	*52*
43	Occidental	USA	37	40	34	22	...	...
44	Oryx	USA	39	44	42	27	...	...
45	Veba Oil¶	West Germany	38	52	44	66	60	43
45	*Repsol¶*	*Spain*	*51*	*75*	*41*	*71*	*30*	*35*
47	*Petroecuador¶*	*Ecuador*	*32*	*41*	*37*	*76*	*62*	*66*
47	*Norsk Hydro¶*	*Norway*	*42*	*30*	*64*	*40*	*68*	*70*
49	*TPAO*	*Turkey*	*53*	*66*	*68*	*75*	*20*	*34*
50	Ultramar	UK	67	38	69	36	53	58

Notes: (a) Companies whose entries are in *italics* are state-owned. These companies are wholly state-owned, with the exceptions of Elf Aquitaine (60%), Total CFP (40%) and Norsk Hydro (51%).

(b) Companies whose entries are in **bold print** are national oil companies selected for review in this report.

¶ Ties in the aggregated standing are indicated by equal rankings.

§ Energy segments of these companies only.

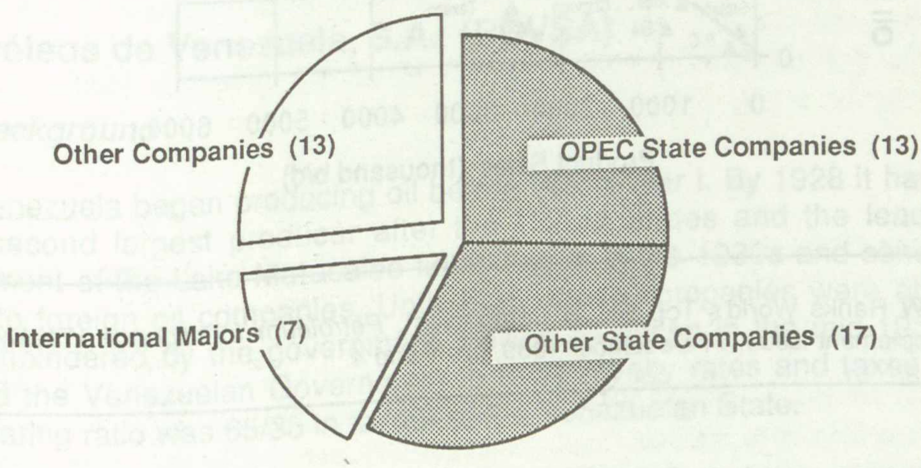
Source: "PIW Ranks World's Top 50 Oil Companies", *Petroleum Intelligence Weekly*, Special Supplement Issue, 11 December 1989, p. 4.

Petróleos de Venezuela (ranked #4), ENI (#16), Petro-Canada (#36), and Statoil (#40) are members of this group; JNOC is not an operational oil company. Petro-Canada in 1988 ranked 40th in oil reserves, 45th in oil production, 37th in gas reserves, 34th in gas production, 38th in refining capacity, and 46th in product sales.

PIW also determined 1988 company rankings by assets, revenues, net income and number of employees. Although Petro-Canada stood 35th in value of assets ($US 6,997 million, prior to its revaluation of assets in 1989) and 42nd in number of employees (7,373), it stood only 54th in revenues ($US 3,901 million) and 53rd in net income ($US 76 million). PIW observes, however, that rankings based on financial information are less meaningful than those derived from operational data because accounting practices vary widely and because PIW is unable in some cases to obtain company information regarding assets, revenues and net income. Although PIW uses secondary sources and estimates where necessary to arrive at revenue figures for all 50 companies, it has been unable to provide data on assets and net income for 13 of the top 50 companies. Thus one can only infer that, relative to the other ranked oil companies, Petro-Canada's assets have not performed as well on average.

Among the PIW top 50 companies, national oil companies outnumber private-sector companies by 30 to 20. Figure 21 displays the breakdown of the 50 companies at two levels: (1) the NOCs (shaded segments) versus the private-sector companies (unshaded segments); and (2) the NOCs subdivided into OPEC state companies and other state companies, and the private-sector companies subdivided into the international majors and other commercially-held oil companies.

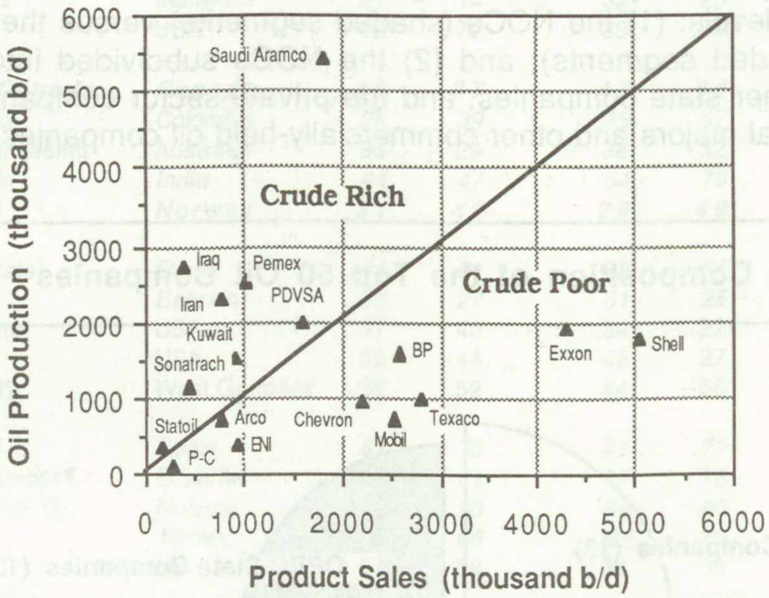
Figure 21: The Composition of the Top 50 Oil Companies



Source: "PIW Ranks World's Top 50 Oil Companies", *Petroleum Intelligence Weekly*, Special Supplement Issue, 11 December 1989, p. 8.

The PIW analysis also reveals a fundamental split in the international oil industry. Most of the companies fall well short of "full integration" which PIW defines as a balance between upstream and downstream operations; that is, oil production and product sales are seldom close to balancing within any given oil company. Most of the larger NOCs are oriented towards the production side of the business (they are "crude-rich"), whereas the international majors, having lost their foreign oil-producing concessions, are primarily oil refiners and marketers (they are "crude-poor"). Figure 22 displays this lack of balance with representative examples.

Figure 22: The Lack of Balance in Oil Production and Product Sales for Selected Oil Companies



Source: "PIW Ranks World's Top 50 Oil Companies", *Petroleum Intelligence Weekly*, Special Supplement Issue, 11 December 1989, pp. 1 and 4.

Arco is the most balanced or "integrated" company represented in the listing. Among the five companies examined in this study, Petróleos de Venezuela comes closest to the PIW notion of a fully integrated company. In 1988, PDVSA's oil output was equivalent to 125% of its petroleum product sales; Statoil's output was 234% of product sales. On the crude-deficient side, ENI's production was 41% of sales and Petro-Canada's production was 38%. JNOC does not enter into this discussion because it has no operational component.

Given the crude-short positions of the majors, the growing international influence of the large NOCs in producing countries is virtually assured in the 1990s. The 30 state companies in Table 9 control more than 90% of the oil reserves of the entire group. The ten largest holders of natural gas reserves outside of the Communist bloc are OPEC members, except for Mexico's Pemex, and accounted for more than 70% of non-Communist proved gas reserves at year-end 1988. In the words of PIW:

> In essence, the largest state companies are the future of oil production, with reserves-to-production ratios that far exceed those of the international majors and others. For example, almost all of the largest national oil companies can produce for 50-200 years at current rates, while the international majors only have 8-14 years of supply. And with programs already under way in most of the Gulf countries to substantially boost reserves and output capacity, the gap between the large state firms and the rest of the industry is likely to widen...
>
> If natural gas is truly the fuel of the future, as many believe, the large national oil companies definitely have the high ground. Although production is now dominated by international majors, other commercially held companies and smaller state firms, the big government-owned oil companies hold the bulk of the reserves...The four largest [non-Communist holders of gas reserves] – Iran's NIOC, Saudi Aramco, Qatar's QGPC and Abu Dhabi's Adnoc – hold more than 50% outside the communist countries.
> (PIW, 11 December 1989, p. 3)

C. Petróleos de Venezuela, S.A. (PDVSA)

Background

Venezuela began producing oil before World War I. By 1928 it had become the world's second largest producer after the United States and the leading exporter. Development of the Lake Maracaibo fields began in the 1930s and concessions were granted to foreign oil companies. Until 1935, these companies were able to operate almost unhindered by the government. Falling oil prices in the mid-1930s, however, prompted the Venezuelan Government to raise royalty rates and taxes. By 1958 the profit-sharing ratio was 65/35 in favour of the Venezuelan State.

In 1960, the year Venezuela helped found OPEC, the state-owned Corporación Venezolana del Petróleo (CVP) was established and given control over part of the domestic oil market. Several service contracts with foreign companies were subsequently signed and CVP operated in partnership with them. The government extended control over the petroleum industry in 1971, enacting the *Hydrocarbons Reversion Law* which placed additional constraints on the operations of foreign companies and stipulated that all concessions would revert to state ownership as existing licences expired. (U.S., DOE, 1977)

In 1974, a new Venezuelan Administration was determined to take advantage of OPEC's aggressive pricing policies and, on 29 August 1975, passed legislation reserving the petroleum industry to the state. Nationalization with compensation became effective 1 January 1976 and the largest pool of U.S. investment in Latin America passed to state control. A national oil company, Petróleos de Venezuela, S.A., was created to manage the assets of the 13 foreign concessionaires acquired through nationalization and of CVP, the original state-owned oil company. In several reorganizations ending in 1986, the 14 former operating units were consolidated into three fully integrated subsidiaries of PDVSA.

Petróleos de Venezuela is described as the largest company in the Third World and Venezuela's economic well-being is profoundly dependent on the operations of its state oil enterprise. Sales in 1988 totalled $US 9.5 billion and foreign exchange earnings were $US 8.2 billion. Venezuela's oil industry in 1987 accounted for 58% of government revenue and 85% of foreign exchange earnings. PDVSA generates about one-fifth of Venezuela's GNP.

The Corporation is heavily taxed. The applicable income tax rate in 1988 was 67.7% (less a reduction of up to 2% of taxable income for new investments) and a tax of 16 2/3% is applied to liquid hydrocarbon production. A tax is also levied on the export value of hydrocarbons; in 1988, the export tax was set at 20% of the average realized sales price per barrel.

PDVSA's total income in 1988 was $C 3.61 billion (Bs 137.9 billion, converted at an exchange rate of one Canadian dollar to 38.2 Bolivars). After deducting costs and expenses of $C 1.12 billion, exploitation tax of $C 0.62 billion, and income tax of $C 1.48 billion, net income was $C 387 million. Total assets at year-end 1988 amounted to $C 4.9 billion; total equity was $C 4.2 billion. (PDVSA, 1989, pp. 58-59)

Mandate

PDVSA's mandate is set out in Decree No. 1123 of 30 August 1975, the main provisions of which follow.

PDVSA's **purpose** is to plan, coordinate and supervise the activities of the companies it owns, and to ensure that they carry out reliable and efficient operations with regard to exploration, extraction, transport, manufacture, refining, storage, sale and all other pertinent activities involving oil and other fossil fuels. In carrying out these responsibilities, the Corporation is to be governed by the *Organic Law reserving the Fossil Fuel Industry and Trade for the Government* of 1975 which nationalized foreign-owned petroleum holdings in Venezuela.

The Corporation was established with an initial **capital** of $C 65.4 million (2.5 billion Bolivars). To year-end 1988, the Corporation's subscribed capital had grown to $C 3.36 billion. PDVSA also received the bulk of the expropriated foreign assets, which the U.S. Department of Energy estimates to have been worth up to $US 5 billion.

There are nine **Directors** appointed by the President of the Republic, one of whom is a representative of the employees. The Chairman and Vice Chairman are designated by the President, preferentially selected from existing members of the Board. The term of office is four years.

Regarding PDVSA's **finances**, the Board is responsible for examining, approving and coordinating the investment and operations budgets of affiliated companies and agencies. The Board presents the annual report on operations, the balance sheet and the statement of profit and loss at the General Stockholder's Meeting. It plans the Corporation's activities and evaluates the results of PDVSA's decisions. The principal Controller (and a substitute) is appointed at the annual stockholder's meeting for a term of one year, and may be reappointed. His powers are those set out in the Venezuelan Business Code.

Relationship with the Venezuelan Government

The Venezuelan Government is the Corporation's sole shareholder and is responsible for the overall direction and management of the Corporation. Meetings are chaired by the Minister of Mines and Fossil Fuels (now the Minister of Energy and Mines). The Government is also represented by such other ministers as are designated by the Venezuelan President. Decisions taken at these meetings are binding on the Corporation.

Petroleum policy comes from the Ministry and is interpreted by PDVSA in joint discussions. PDVSA provides the overall corporate planning and the individual companies submit budgets to PDVSA for approval, following which the budgets are presented to the government for approval. Although state-owned, PDVSA is commercially managed; it is not a social enterprise.

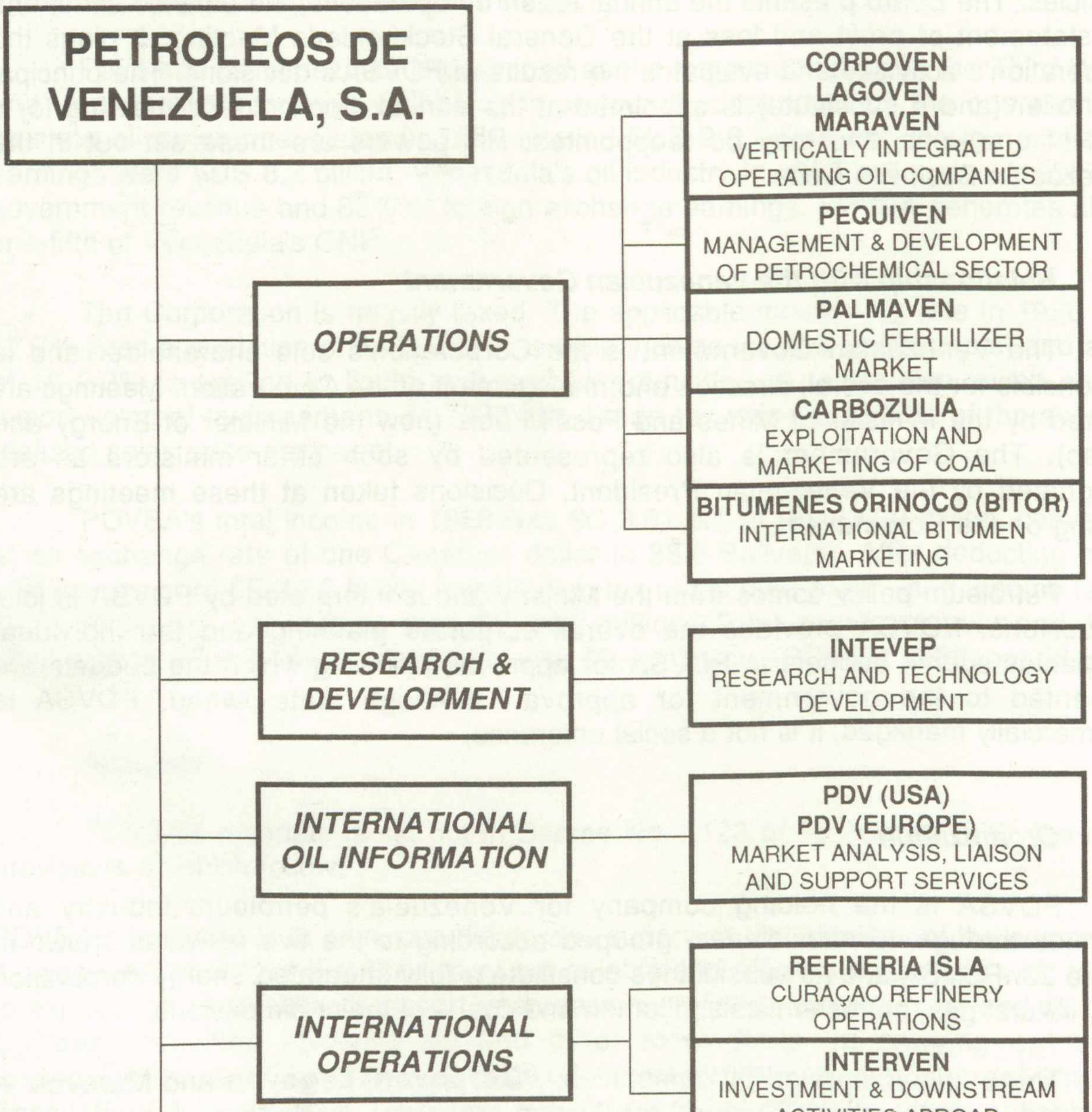
Organization

PDVSA is the holding company for Venezuela's petroleum industry and operates through 13 subsidiaries, grouped according to the five activities shown in Figure 23. PDVSA and its subsidiaries constitute a fully integrated energy corporation – oil, natural gas, petrochemicals, bitumen and coal – of major dimensions.

Three fully integrated oil companies – **Corpoven**, **Lagoven** and **Maraven** – carry out petroleum exploration, production, refining, marketing, exporting and overland and marine transportation. They compete in achieving corporate objectives, for company resources, and in service to the public; they do not compete in retail pricing, which is set by the government. Lagoven's maritime transport system is Venezuela's largest shipping line.

Pequiven operates the Venezuelan petrochemical industry through wholly-owned facilities and in partnership with national and foreign investors. A continuing expansion in petrochemical production is aimed particularly at adding value to Venezuela's substantial reserves of natural gas.

Figure 23: Corporate Structure of Petróleos de Venezuela



Source: Petróleos de Venezuela, S.A., *Annual Report 1988*, Caracas, April 1989, pp. 2-3; and notes supplied by PDVSA on Bariven, S.A..

Palmaven, created in 1987, distributes fertilizers in the Venezuelan market and provides technical assistance to agriculture. The domestic use of fertilizers is subsidized and Palmaven is compensated for the reduced sales prices.

Carbozulia became a PDVSA subsidiary in 1986 and is responsible for the commercial production of coal from the Guasare fields of western Venezuela. In a joint venture with ARCO Coal Corporation and AGIP Carbone (a member of the ENI Group), PDVSA is expanding production for the international market.

Bitumenes Orinoco (Bitor), established in 1988, is responsible for developing and marketing bitumen from the Orinoco Belt. Bitor has constructed a facility to produce "Orimulsión", a nonconventional fuel consisting of 70% bitumen and 30% water, which it has begun marketing in Europe in partnership with BP Bitor Ltd.

Intevep carries out research and development for the PDVSA group, concentrating its activities on the handling and upgrading of heavy and extra-heavy crudes and on nonconventional fuels.

Interven manages PDVSA's international program, providing specialized services for downstream investments in the United States and Europe. PDVSA has four overseas joint ventures.

(1) PDVSA owns 50% of Nynas Petroleum of Sweden, which operates two refineries in Sweden and one in Belgium. This provides a marketing channel for 40,000 barrels/day of Venezuelan heavy crudes to be refined into lubricants and asphalt products and marketed in Europe.

(2) PDVSA and Veba Oel each own 50% of Ruhr Oel GmbH, operating three refineries in West Germany through which PDVSA has the right to process approximately 145,000 barrels of crude oil per day. Veba markets the resulting petroleum products and petrochemicals in Germany, crediting PDVSA with the proceeds after deducting its refining, transportation and marketing costs.

(3) PDVSA and The Southland Corp. each hold a 50% interest in Citgo Petroleum Corp., operating the Lake Charles refinery in the United States. PDVSA has the right to process 130,000 b/d of heavy, high-sulphur crudes and intermediate products, with the possibility of increasing the volume to 200,000 b/d. Citgo distributes to about 8,000 service stations in the United States.

(4) PDVSA owns 100% of Champlin Refining Company and its Corpus Christie, Texas refinery, purchased from Union Pacific Corporation. It has a contract to supply 140,000 barrels of crude oil and intermediate products per day, with the possibility of raising this to 160,000 b/d. Champlin markets unbranded products through independent terminals in the United States.

PDVSA has signed a letter of intent with UNOCAL Corporation to operate a joint refining, distribution and marketing company based on an existing refinery in the

Chicago area and almost 4,000 branded outlets. PDVSA would supply this refinery with 135,000 b/d of Venezuelan crude. The Corporation has also signed a letter of intent with British Petroleum to establish a joint-venture marine bunkering business in the United States and northern Europe, which would provide Venezuela with an outlet for 60,000 b/d of high-sulphur oil.

These initiatives illustrate PDVSA's strategy for ensuring long-term foreign markets for Venezuela's crude oil and for generating greater downstream profits through value-added sales..

Refineria Isla was established to manage operations at a leased refinery and marine terminal in Curaçao. This refinery operates exclusively on Venezuelan oil and can process up to 300,000 barrels of crude per day.

Bariven is responsible for the international purchase of equipment and materials not available in Venezuela. Bariven buys on behalf of the Venezuelan petroleum, petrochemical and coal industries, centralizing this function for quality control, timely delivery and minimum cost.

PDV (USA) in New York and **PDV (Europe)** in London are market intelligence centres providing analysis, liaison and support services.

PDVSA operates a specialized education centre responsible for managerial development and staff training for the Corporation's 45,000-employee workforce.

Activities

Venezuela's oil output averaged 1.9 million b/d in 1988, up 204,000 b/d over 1987. Natural gas liquids production of 98,000 b/d brought total 1988 liquid hydrocarbon production to 2.0 million b/d. Of particular note, the output of light and medium crude oil rose by 198,000 b/d (an increase partially offset by reduced heavy crude production).

Venezuela deliberately maintains productive capacity above the level of output. Through exploratory and development drilling, well reworking and enhanced recovery, productive capacity was boosted by 522,000 b/d in 1988 to 2.67 million b/d, compared to actual output of 1.90 million b/d. This surplus capacity gives Venezuela the latitude to blend its export crudes for particular refinery requirements and to boost production on short notice in the event of disturbances in international oil supply.

Natural gas production reached 3.7 billion cubic feet/day (3.7 Bcf/d) in 1988, of which 1.2 Bcf/d was reinjected for reservoir repressuring and 2.1 Bcf/d was consumed within Venezuela for petrochemical production and refinery use.

At year-end 1988, Venezuela's proved reserves of conventional crude oil were assessed at 58.5 billion barrels, a net increase of 420 million barrels over 1987.

Proved reserves of natural gas amounted to 101.5 trillion cubic feet (101.5 Tcf), a net increase of 710 Bcf over 1987. Venezuela's huge deposits of heavy oil and bitumen in the Orinoco Belt are thought to contain about 270 billion barrels of oil, of which 12 billion barrels is considered recoverable under current conditions.

Venezuelan refineries processed an average of 945,000 b/d of crude oil in 1988 and the Curaçao refinery processed an additional 190,000 b/d. Domestic refining capacity totals approximately 1,250,000 b/d, to which the Curaçao refinery adds 300,000 b/d. Venezuela's interests in U.S., West German, Swedish and Belgian refineries contribute another 500,000 b/d of capacity. Total PDVSA refining capacity, national and overseas, enabled Venezuela to process 82% of its total crude oil production in 1988, compared to 77% in 1987.

During 1988, Venezuela exported an average of 1.65 million b/d of crude oil and refined products. Product sales totalled 1.24 million b/d and sales of crude oil to third parties accounted for 0.38 million b/d. Thus three-quarters of Venezuela's oil export was in the form of products. Of the products exports in turn, 52% was distillates, gasoline and other high added-value material.

PDVSA's downstream activities abroad focus on further development of existing joint ventures and on identifying new investment opportunities. Particular attention is given to maximizing flexibility and yields in refining and petrochemical operations, rationalizing existing distribution and marketing channels, developing new markets and reducing costs.

Venezuela is a member of the San José accord which guarantees a supply of up to 130,000 b/d of oil from Mexico and Venezuela to nine countries in Central America and the Caribbean. PDVSA receives payment on commercial terms with the cost of any concessions being met by the Department of Finance. The Corporation provides no other form of assistance to developing countries.

Comments

PDVSA operates much as a private company, even though owned by the Venezuelan Government. Its legislation nonetheless places it firmly under government control, through the selection of its Board of Directors by the Venezuelan President and through binding decisions taken at shareholder's meetings chaired by the Minister of Energy and Mines.

The Committee did not obtain specific information about the system of financial control, except that PDVSA is reviewed by private auditors. Unlike the other NOCs surveyed in this study, PDVSA does not appear to have legislative provisions reserving a role for the government in its operations.

PDVSA is expanding its operations overseas and surplus domestic oil production is key to this initiative. Refining and petrochemical investments abroad ensure market outlets for oil production and value-added sales. The Corporation now processes more than four-fifths of its crude oil output through its own refineries in Venezuela and elsewhere. PDVSA is expanding domestic petrochemical production, with the intent of adding value to its rising natural gas output.

PDVSA emphasizes the development of new technology, especially to expand market opportunities for Venezuela's huge resources of heavy oil and bitumen. The Corporation has successfully tested a bitumen-water emulsion as a boiler fuel in several countries, including Canada. PDVSA sold 50,000 b/d of Orimulsión in 1989 on a trial basis and is hoping to develop substantial sales in Europe by the mid-1990s.

PDVSA has a program of substituting domestic purchases of equipment and supplies for import purchases. Working groups oversee more than 100 import substitution projects for such products as valves, tubing, rotary equipment, chemicals, drilling equipment and instrumentation. From 1984 through 1988, PDVSA spending on domestic goods increased by approximately 250%. These measures to strengthen, integrate and rationalize the Venezuelan manufacturing sector are also expected to encourage penetration of export markets. Similar efforts are proceeding to source engineering and technical services within Venezuela.

Petróleos de Venezuela appears to have developed a highly-coordinated and far-sighted strategic plan to position itself solidly in the international oil market, while strengthening its domestic base of operations.

D. Japan National Oil Corporation (JNOC)

Background

Government and business have a long-standing, close working relationship in Japan. In the 1950s, Japan rebuilt its war-damaged petroleum refining and marketing facilities with the assistance of international oil companies. In return, these companies secured long-term contracts to supply the Japanese market. They also gained control of about 75% of Japan's refining capacity. In response, the government passed the *Basic Petroleum Law* in 1962, limiting activities of foreign oil companies and allowing Japanese companies to develop more diversified sources of oil. (U.S., DOE, 1977)

Japan National Oil Corporation (JNOC) was established in October 1967 as the Japan Petroleum Development Corporation (JPDC), at a time when oil's importance as an energy source was growing rapidly. Japan has no significant domestic petroleum resources and depends on imports to meet its growing oil requirements. Securing reliable, long-term supplies of oil is considered vital to the nation's economic and social survival. Japan imports more than 80% of its energy needs and oil accounts for approximately 56% of Japan's total energy demand.

JPDC's functions were limited initially to providing equity capital, loans and loan guarantees for overseas oil exploration projects, and technical guidance to the private sector. In 1971, exploration on the Japanese continental shelf was added. In 1972, the Technology Research Center was established to collect data, to perform research and to develop technologies in such fields as geology, geophysics, drilling and production. JPDC began in 1972 to provide financing to private oil companies in the form of loans for purchasing oil to augment existing commercial stockpiles.

In 1975, providing equity capital and loans for a joint oil-stockpiling company was added to JPDC's activities. JPDC also started to make equity capital and loans available for oil sands and oil shale projects, and was granted the authority to negotiate directly with oil-producing nations and to acquire exploration rights.

In June 1978, JPDC changed its name to the Japan National Oil Corporation, and began to stockpile oil beyond the 90 days of supply already accumulated by private oil companies. As of mid-1988, JNOC had completed three national stockpiling facilities and had seven under construction. JNOC has carried out geological surveys of overseas resources since 1980. As part of this program, it has conducted geological and geophysical surveys in the seas off Antarctica each year since 1980.

Late in 1988, construction of JNOC's new Technology Research Center complex was completed. This Research Center fulfills four roles:

- performing R&D to generate new technology for oil exploration and production;
- supplying technical services to private companies and others utilizing the research findings and facilities of the Center;
- training to upgrade the skills of Japanese and foreign petroleum engineers; and
- performing joint research with oil-producing countries and cooperating in the exchange of advanced technologies.

The scale on which JNOC carries out its activities is impressive. From 1967 through 1988, the Corporation provided approximately $C 10.8 billion (1,357 billion yen converted at a rate of 125 yen to the Canadian dollar, although the rate was much lower in the 1970s) in equity and loans, and gave loan guarantees amounting to $C 6.4 billion. In 1988, some 25 project companies assisted by JNOC were producing or about to produce gas and oil. About 70 companies were carrying out exploration and development activities, including five on offshore Japanese locations. During 1988, oil production by JNOC-assisted companies totalled 1.3 million barrels/day, of which approximately 427,000 b/d went to Japan and constituted 12.4% of the country's total crude oil imports of 3,448,000 b/d. The government objective is to have 30% of Japan's crude oil requirements supplied from JNOC-assisted sources by 1995.

To the end of fiscal year 1987-88, the Japanese Government had invested $C 9.6 billion in JNOC in the form of equity. An additional $C 25.6 billion had been provided by the government to cover interest and research and development costs. Further funds were received from the sale of debentures, borrowing from government and private lenders, and from other sources. Total receipts over the period 1967-1988 exceeded $C 100 billion, an amount that emphasizes the importance that Japan attaches to the secure, long-term supply of petroleum. Major expenditures over the period 1967-1988 include $C 48.1 billion for various stockpiling activities and $C 10.7 billion as equity capital and loans for petroleum exploration.

Mandate

JNOC's mandate is set out in Law Number 83, the *Japan National Oil Corporation Law* of 1978. The main provisions of this law are summarized below.

The **purpose** of Japan National Oil Corporation is to secure a stable and economical supply of oil and natural gas for Japan by providing financial assistance for their exploration and development, and by enlarging the national petroleum stockpile.

The **initial capital** of the Corporation was four billion yen (approximately $C 32 million today), to which the government adds as it deems necessary.

The Corporation has a maximum of **ten officers**, including a President, Vice-President and eight Directors, and not more than two auditors. The President and the auditors are appointed by the Minister of International Trade and Industry; the Vice-President and the Directors are appointed by the President, subject to the approval of the Minister. Officers are appointed for a three-year term and may be reappointed.

To fulfill its mandate, the Corporation engages in the following **activities**:

- investing funds in petroleum exploration;
- loaning funds for petroleum development, the loans being limited to foreign governmental agencies;
- guaranteeing funds used for overseas exploration and development activities;
- surveying potential oil- and gas-bearing geological structures;
- acquiring overseas exploration rights where this can only be done by a government agency; and
- loaning funds to construct, fill and maintain the national petroleum stockpile.

JNOC frequently negotiates on behalf of Japanese oil companies with host governments concerning the terms and conditions of exploration interests.

Regarding **financial control**, an annual budget, business program, financial plan and financial statement, including a statement of profit and loss, are prepared for the Minister of International Trade and Industry.

The Corporation may acquire short- and long- term **loans** and issue **debentures** with the approval of the Minister of International Trade and Industry. Liabilities relating to long-term loans and debentures may be guaranteed by the government.

The Minister of International Trade and Industry **supervises** the Corporation, and may issue orders to JNOC in view of that supervision.

Relationship with the Japanese Government

The Japanese Government is the sole stockholder in the Corporation and exercises its authority through the Minister of International Trade and Industry. The Agency of Natural Resources and Energy, a division of the Ministry of International Trade and Industry (MITI), sets targets for petroleum exploration and production activity by Japanese companies. The Agency advises on the forms of assistance to be used by JNOC in pursuing its objectives, and sets oil stockpiling objectives for the private and public sectors. These objectives are contingent upon the Ministry of Finance accepting the budget for these activities. How JNOC interacts with the Japanese Government, banks and private-sector companies is displayed in Figure 24.

Organization

JNOC's organization can be broken down along three functional lines:

(1) oil and gas exploration and development;

(2) oil stockpiling; and

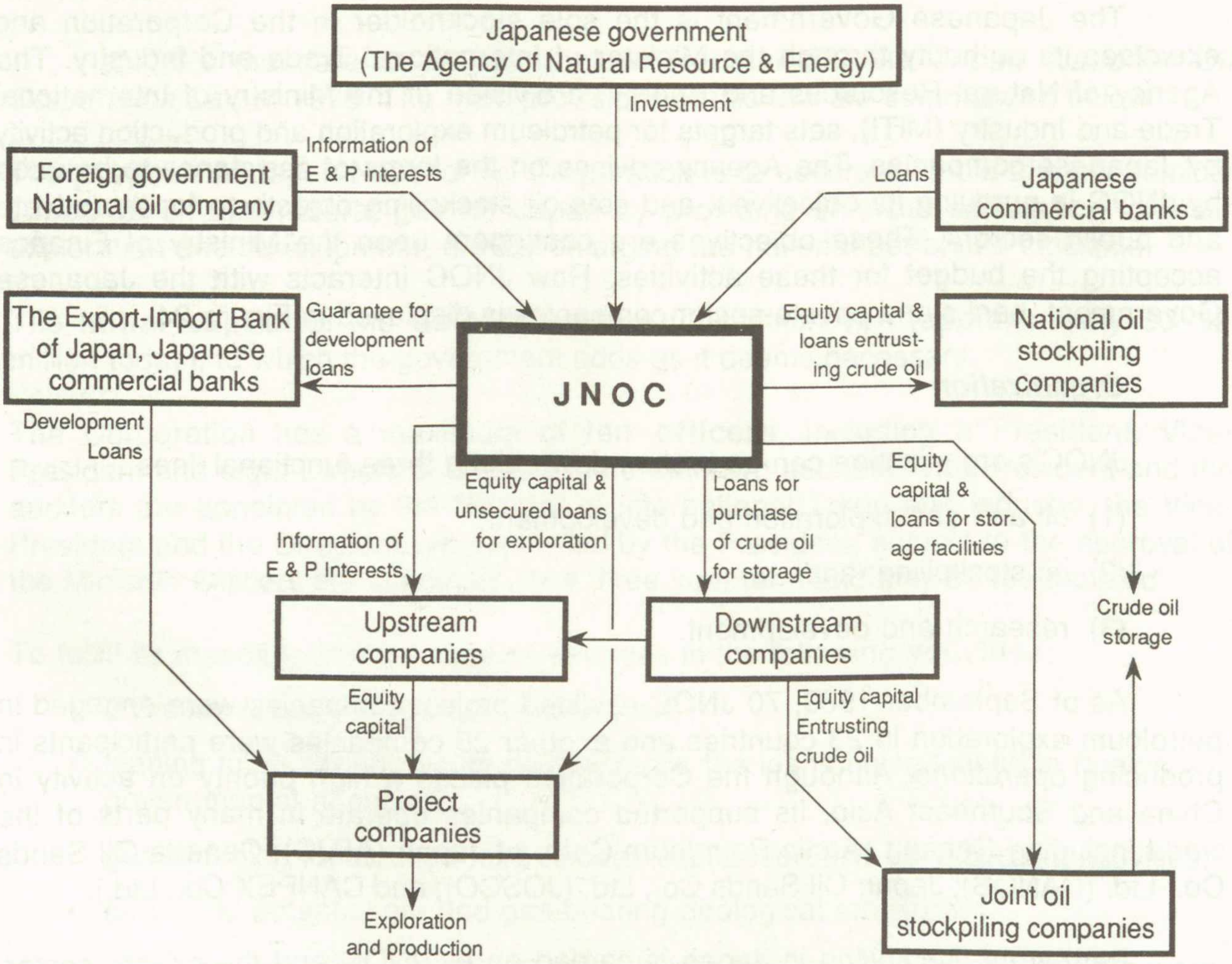
(3) research and development.

As of September 1989, 70 JNOC-assisted project companies were engaged in petroleum exploration in 23 countries and another 25 companies were participants in producing operations. Although the Corporation places a high priority on activity in China and Southeast Asia, its supported companies operate in many parts of the world including Canada (Arctic Petroleum Corp. of Japan (APJC); Canada Oil Sands Co., Ltd. (CANOS); Japan Oil Sands Co., Ltd. (JOSCO); and CANPEX Co., Ltd.).

Petroleum stockpiling in Japan is carried on by JNOC and the private sector. JNOC has provided financial assistance to Japanese oil companies since 1972 to aid their stockpiling efforts and the objective of a 90-day oil supply in the private sector was achieved in 1980. The Japanese Government decided,however, that this level of security was insufficient and directed JNOC in 1978 to begin a supplementary stockpiling program. The national oil stockpile will be contained in ten permanent bases around the country; three of which were operational in 1989. As of September 1988, stockpiling by private companies equated to 99 days of domestic consumption and JNOC's national oil stockpile was equal to 47 days of consumption.

Because Japan's demand for LPG (liquefied petroleum gases) has been rising sharply and about three-quarters of this commodity is imported, the government instituted an LPG stockpiling program in 1981. JNOC also provides loans in support of this program and the objective of a 50-day supply was reached in 1988.

Figure 24: The Interrelated Roles of JNOC and other Institutions Associated with the Japanese Petroleum Industry



Source: Japan National Oil Corporation, *JNOC*, Annual Report, Tokyo, September 1989, p. 3.

JNOC's newly completed Technology Research Center facility is central to the Corporation's objective of improving Japanese petroleum exploration and production technologies. It is also used through its training programs to strengthen relations between Japan and developing oil-producing countries.

To support its various activities, JNOC maintains eight Overseas Representative Offices in London, Houston, Washington, Lima, Paris, Beijing, Bahrain and Jakarta. The Corporation also operates nine Domestic Stockpiling Representative Offices at sites where national stockpiling bases have been established or are under construction. An organization chart for JNOC is presented in Figure 25.

Activities

For practical purposes, JNOC's mandate translates into seven functions.

(1) **Provision of exploration funds**

JNOC provides equity capital and unsecured loans for petroleum exploration conducted by Japanese private-sector companies operating overseas or offshore of Japan, including exploration for natural gas, oil shale and oil sands. Seventy to 80% of a project's cost is underwritten by a company jointly created by JNOC and the Japanese private sector for that project.

(2) **Guarantees for development loans from banks**

When oil exploration is successful and moves to the development stage, the project company borrows development funds from the Export-Import Bank of Japan and from Japanese commercial banks. JNOC can guarantee 60 to 70% of these development loans.

(3) **Conducting geological and geophysical surveys**

If foreign governments or national oil companies so request, JNOC will perform geological and geophysical surveys free of charge. These programs may include surface geological surveys, seismic surveys, stratigraphic wells or technical training. Reports on all survey work are provided to the host country.

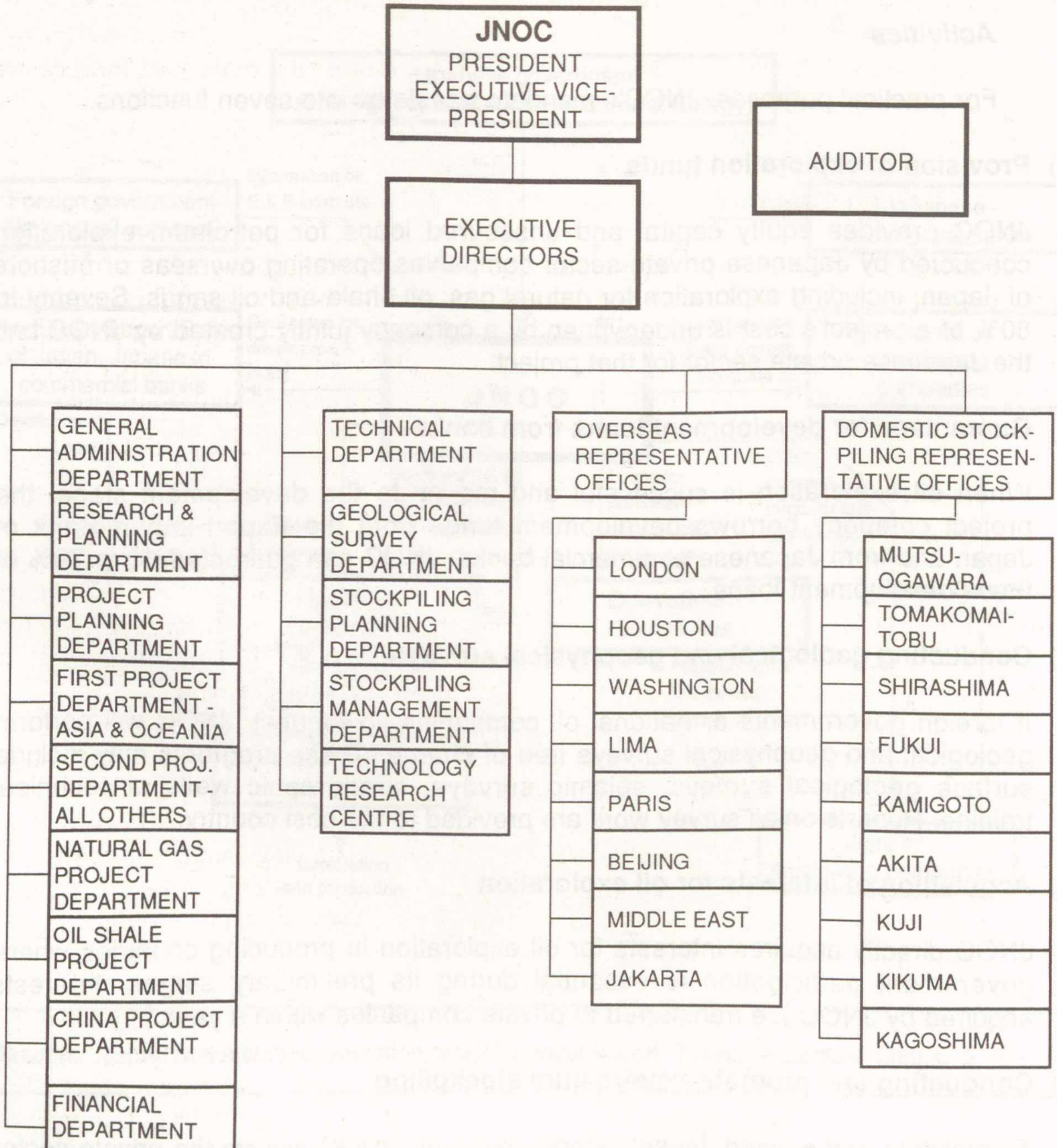
(4) **Acquisition of interests for oil exploration**

JNOC directly acquires interests for oil exploration in producing countries where government participation is essential during its preliminary stages. Interests acquired by JNOC are transferred to private companies within a year.

(5) **Conducting and promoting petroleum stockpiling**

To maintain and expand Japan's stockpiles of oil, JNOC assists the private sector by making loans for the purchase of oil for stockpiling and by providing equity capital and loans to joint oil stockpiling companies incorporated specifically to construct and operate additional storage facilities leased to companies storing petroleum. JNOC also operates the national stockpiling program to develop strategic petroleum reserves.

Figure 25: Corporate Structure of Japan National Oil Corporation



Source: Japan National Oil Corporation, *JNOC*, Annual Report, Tokyo, September 1989, pp. 22-23.

(6) **Research and development**

JNOC promotes research and development in petroleum technology through the facilities of its Technology Research Center, established in 1972 with the cooperation of the private sector, and now housed in a new facility.

(7) **Gathering information about global petroleum development**

JNOC gathers information concerning world petroleum development through its representative offices located in eight cities around the world.

Developing Countries

Since 1980, JNOC has performed geological and geophysical surveys in developing countries. This work is not charged for and there is no formal requirement that any oil or gas thereby discovered be shipped to Japan. JNOC's average budget for this activity is approximately $C 20 million annually. There is also provision for trainees from developing countries to attend JNOC's Technology Research Center.

Comments

Like Petro-Canada, JNOC was established to help secure a stable supply of petroleum for the nation. JNOC, however, has a mandate limited to petroleum (Petro-Canada can deal with any aspect of "energy"); its role is facilitative and not operational; and it is not involved in any downstream activities. In some respects, its responsibilities are not unlike those originally ascribed to Petro-Canada.

Apart from being able to act on behalf of the Japanese Government in state-to-state transactions, JNOC is able to reduce the risk to the private sector of less certain, longer-term exploration and development projects. Because its monetary support is intended to be recovered, JNOC's capital minus any losses is eventually freed for subsequent projects. By proceeding only in partnership with the private sector, the Corporation is assured that once started, projects will carry forward without further direct government involvement.

Placement of up to two auditors on the Board of Directors, answerable to the Minister of International Trade and Industry, ensures that financial activities and those activities with financial implications can be monitored on a continuing basis. The requirement that annual budgets, financial plans, and profit and loss statements be submitted to the same Minister provides the Japanese Government with a periodic and detailed review of the Corporation's financial activities and situation.

Integration of JNOC's activities into Japan's overall energy strategy is achieved through the Agency of Natural Resources and Energy, a branch of MITI. The Agency, in setting objectives for petroleum exploration and production and in determining the amount and nature of the support (in conjunction with the Department of Finance) provided by JNOC to its private-sector partners, exerts a strong influence on the Corporation's activities.

JNOC supports private sector exploration and production activities intended to supply oil and natural gas to Japan within the framework of government energy policy and with full financial disclosure and accountability.

E. Den norske stats oljeselskap a.s (Statoil)

Background

The Norwegian oil industry is an amalgam of several groups: the national oil company Statoil, established in 1972; international oil companies such as Shell, BP, Conoco, Phillips and Elf Aquitaine; the Norwegian electrochemical company Norsk Hydro, which operates as a private-sector company but whose principal shareholder is the Norwegian Government; and Saga Petroleum, a consortium formed by Norwegian private companies engaged in North Sea Operations. (U.S., DOE, 1977)

Norway declared sovereignty over its continental shelf for the purposes of exploiting natural resources in 1963 and began issuing exploration licences that same year. The first production licences followed in 1965 and had no state participation. Beginning in 1969, the state retained an interest in the licences awarded, in the form either of an option to participate directly in a commercial find or of a guaranteed negotiated share of the net profits.

Following a decision of the Norwegian Parliament of 14 June 1972, a national petroleum company, Den norske stats oljeselskap a.s (Statoil) was established with a broad mandate to manage the state's ownership interests in petroleum exploitation. In the nine production licences allocated in the period 1974-76, Statoil retained a 50-55% share with the option of increasing it to 66-75%, depending on the level of production attained. While not required to help with exploration costs, the Company was obliged to contribute its share of development costs should a discovery be made and it wish to participate. This share was in addition to the government's direct financial interest.

Until the 1970s, when oil prices surged and Norway's estimates of recoverable reserves of crude oil and natural gas rose sharply, the country's oil industry had been largely foreign controlled. The Norwegian private sector was not strong and the government looked to Statoil to ensure that it received maximum benefit from rapidly expanding oil and gas production. It also sought through Statoil to extend its involvement in oil-related activities such as pipelining, refining, retailing, petrochemical production and the manufacture of offshore equipment. As Statoil was still short of experienced personnel, Norsk Hydro and Saga Petroleum were also encouraged to participate.

The 1988 operating income for the Statoil group was $C 10.4 billion (NKr 56.3 billion converted at an exchange rate of 5.4 Norwegian kroner to the Canadian dollar). Operating costs amounted to $C 9.3 billion, leaving an operating profit of $C 1.1 billion. After allowance for extraordinary costs (such as the write-down of the Mongstad refinery) and net financial items, the Group's consolidated profit amounted to $C 63 million. Statoil's fixed assets at year-end 1988 totalled $C 9.1 billion.

Mandate

The mandate of Statoil is set out in the Company's Articles of Association, passed by the Norwegian Parliament in 1972. Their main provisions follow.

The Corporation's **purpose** is to carry out the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products as well as other reasonably related activities, either by itself or in cooperation with other companies.

The **share capital** of the Company is NKr 2,943,500,000 (approximately $C 545.1 million), divided into 29,435,000 shares of Nkr 100 each.

The **Board of Directors** consists of a maximum of nine directors, of which up to six including the Chairman and Vice-Chairman are elected at the annual General Meeting. Up to three additional directors are elected by and among the employees of Statoil in accordance with the requirements of the Norwegian Companies Act. The normal term of office is two years. The Board appoints the Company's President. The Company also has a **Corporate Assembly** consisting of 12 members, eight elected at the General Meeting and four elected by and among the employees of Statoil.

Regarding **financial matters**, the shareholder (the Norwegian Government as represented by the Minister of Petroleum and Energy), the Board of Directors and the Corporate Assembly deal with the following matters at the annual General Meeting:

- adoption of the profit and loss account and the balance sheet;
- the disposition of the annual profit or coverage of loss, and the declaration of dividends; and
- adoption of the consolidated profit and loss account and the consolidated balance sheet.

With respect to **planning**, the Board of Directors is required to submit to an ordinary or extraordinary General Meeting all matters presumed to involve significant political questions of principle, or which may have important effects on the nation and its economy, including:

- plans for the following year or essential changes to those plans;
- plans for longer-term activities;
- plans which necessitate the additional appropriation of government funds;

- plans to participate in the exploitation of petroleum reserves inside or outside of Norway; and
- twice-yearly reports on the Company's activities, including the activities of subsidiaries and important joint ventures with other companies.

The General Meeting decides whether to accept the Board's proposals as submitted, to approve them or to alter them.

The Company is **responsible** for managing and preparing the accounts relating to the Norwegian Government's interests in joint ventures for the exploration for and development, production and transportation of petroleum produced on or in association with the Norwegian continental shelf.

The provisions of the **Norwegian Companies Act** are supplementary to the Statoil Articles of Association.

Relationship with the Norwegian Government

The Norwegian Government holds all of Statoil's equity. Under the provisions of the Norwegian Companies Act, the Minister of Petroleum and Energy determines the membership of the Board of Directors. The Minister also has effective control over the Company's budget, operations and planning, and may call ordinary or extraordinary General Meetings on his own initiative. This control is exercised not only to ensure that the Company acts in accordance with Norwegian energy policy, but also that its activities support, where possible, social and other objectives.

The Office of the Auditor General is empowered to request information needed to verify the Company's financial situation and transactions, both from the administrative head of the Company and from the Board of Directors and the appointed auditor. The Office can, if necessary, examine the accounts of the Company. Parliament can issue rules concerning inspection by the Auditor General's Office of the state's interest in Statoil. The Office must be informed of, and has the right to attend, the General Meeting and certain other meetings of the Company.

Statoil manages the government's direct oil and gas interests. By the mid-1980s, however, Statoil's position had become powerful enough to cause the government to assign part of its holdings to the Department of Finance. The government also replaced the founding President, in part because of alleged responsibility for the heavy losses incurred enlarging the Mongstad refinery. The auditors were replaced on one occasion for opposing the government's wish to provide in Statoil's balance sheet for the eventual cost of removing the fixed, concrete production platforms used in developing some Norwegian fields.

As part of the government's requirement that the petroleum sector provide benefits to all sectors of the Norwegian economy, Statoil worked closely with the shipbuilding and construction industries to help them supply as much petroleum-related equipment as possible. Thus, for example, the Norwegian share of equipment supplied rose from 30% for the Ekofisk field to 80% for the Gullfaks field.

Organization

The Statoil Group consists of the parent company (Statoil) and 14 subsidiaries in which Statoil owns a controlling interest of at least 50%. These include subsidiaries in Sweden, Denmark, Finland, Belgium, the Netherlands, Britain, West Germany and the United States. The Group's activities include geological and geophysical surveying, exploration, development, production, transportation, refining, marketing and petrochemical manufacture.

Statoil is divided into three Business Units, each under a Company President: (1) Exploration and Production; (2) Refining and Marketing; and (3) Petrochemicals and Plastics. An organization chart for the Statoil Group is presented in Figure 26.

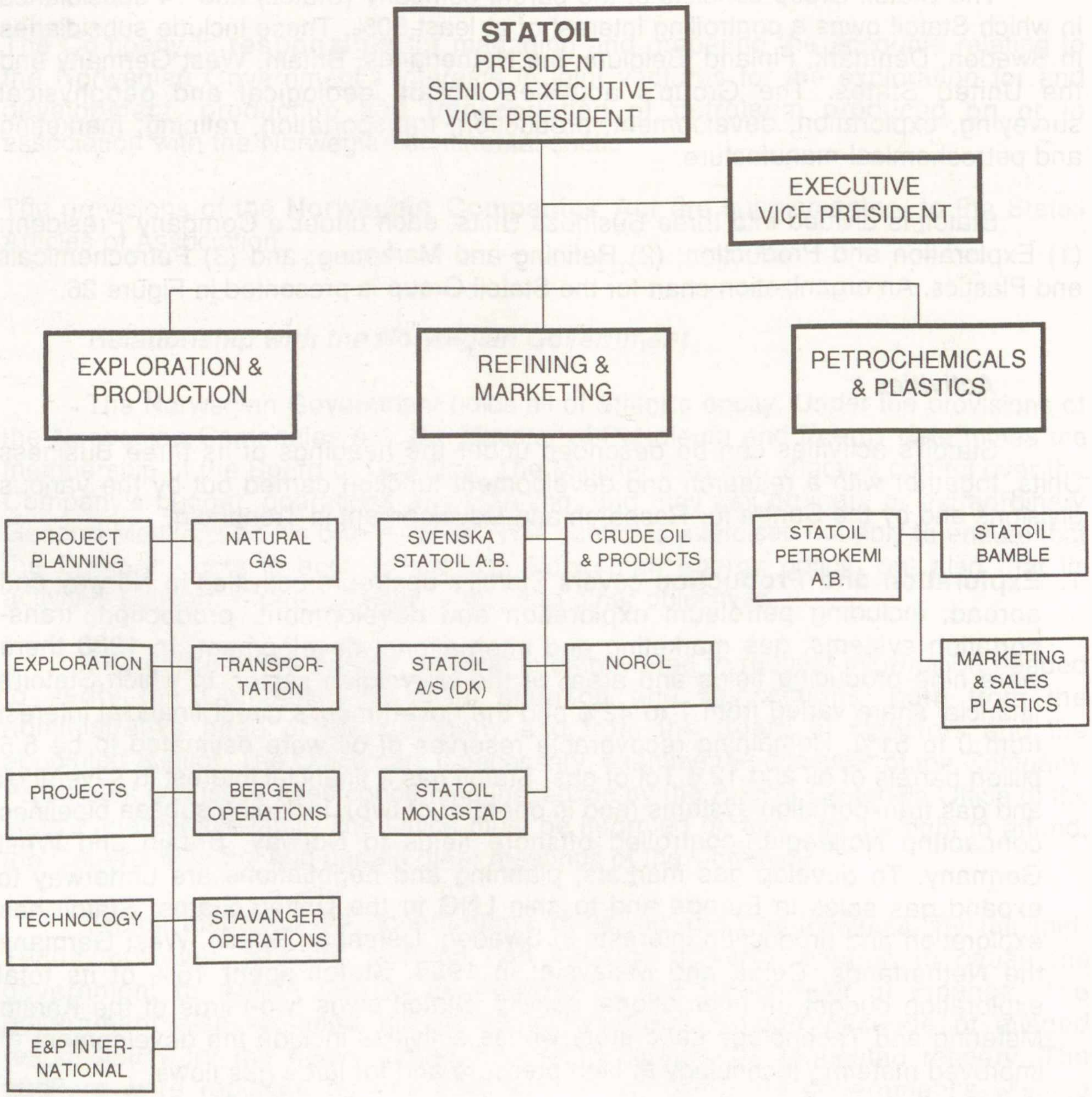
Activities

Statoil's activities can be described under the headings of its three Business Units, together with a research and development function carried out by the various divisions and by the Centre for Research and Development in Trondheim.

1. **Exploration and Production** covers Statoil's upstream activities in Norway and abroad, including petroleum exploration and development, production, transportation systems, gas marketing and international development. In 1988 there were nine producing fields and areas in the Norwegian sector, in which Statoil's financial share varied from 1 to 42% and the government's direct financial interest from 0 to 51%. Remaining recoverable reserves of oil were estimated to be 5.5 billion barrels of oil and 12.6 Tcf of gas. Statoil has a financial interest in several oil and gas transportation systems (and is operator of two), including subsea pipelines connecting Norwegian-controlled offshore fields to Norway, Britain and West Germany. To develop gas markets, planning and negotiations are underway to expand gas sales in Europe and to ship LNG to the United States. Statoil has exploration and production interests in Sweden, Denmark, Britain, West Germany the Netherlands, China and Malaysia; in 1988, Statoil spent 15% of its total exploration budget on international activity. Statoil owns two-thirds of the Kårstø Metering and Technology Laboratory whose activities include the development of improved metering technology at high pressure and for large gas flows.

2. **Refining and Marketing** includes marketing crude oil and products, tanker transportation, and the operation of two refineries and retail stations in Norway, Sweden and Denmark. Recent low operating profits reflect high financing costs and the prolonged shutdown of Statoil's principal refinery at Mongstad.

Figure 26: Corporate Structure of Statoil



Source: Statoil, *Annual Report and Accounts 1988*, Stavanger, Norway, March 1989, p. 4.

3. **Petrochemicals and Plastics** includes the production of petrochemical products and plastics raw materials (especially ethylene and propylene) at facilities in Norway, Sweden and West Germany, and their marketing by Statoil Group subsidiaries in Western Europe.

4. **Research and Development** is carried out by Statoil's various divisions as well as by its Centre for Research and Development, which has the responsibility for coordinating R&D activities throughout the Group. Statoil's main research work centres on: (a) simpler and more economic concepts for deep water exploration, transportation and production; (b) an economically competitive diverless subsea production system; (c) offshore LNG processing and transportation in areas with no infrastructure; and (d) multiphase pipeline systems. Prompted by the Piper Alpha platform disaster in the British sector of the North Sea, Statoil has given a higher priority to offshore safety.

Developing Countries

Statoil has no formal program to assist developing countries explore for and develop their petroleum resources. The Company has assisted in only one instance, in Tanzania where Statoil worked with the Norwegian Development Assistance Agency. There are no announced plans to undertake similar projects in other countries.

Comments

Statoil was established to ensure that Norway, which had no Norwegian-owned upstream petroleum industry, participated to the greatest extent possible in developing the country's substantial offshore petroleum resources. To accomplish this, the Company had to overcome a number of obstacles, including:

- there were few Norwegians with experience in offshore oil and gas exploration and development;
- there were equally few with corporate experience to match that of the major international oil companies with which Statoil would have to work and, in some instances, compete; and
- there were few precedents to guide the policy-makers responsible for ensuring a reasonable rate of development while, at the same time, protecting the Norwegian interest.

In these circumstances, Statoil has come a long way in a relatively short time. It has expanded into a wide range of petroleum-related activities. As a result of close cooperation between Statoil and Norwegian shipbuilding and engineering firms, Norway has become a world leader in certain types of cold-water technologies and equipment. With the exception of the financial setback at the Mongstad refinery, Statoil has been generally successful in combining its responsibilities as a major oil company and as a policy arm of the Norwegian Government.

The Norwegian Government is closely associated with the Company's operations through the key position of the Minister of Petroleum and Energy and the requirement that Statoil keep the Ministry fully and regularly informed of all important planning and operational matters. The Auditor General has continuing access to the Company's financial records, which also promotes accountability.

F. Ente Nazionale Idrocarburi (ENI)

Background

Italy is a petroleum-deficient nation in search of reliable new supply. In 1926, as part of Italy's search for oil, the Azienda Generale Italiana Petrolii (AGIP) was formed as a private corporation. Despite an active exploration program, AGIP found no significant deposits of oil in Italy but did acquire interests in Romanian and Iraqi production. It was later incorporated into ENI, the Ente Nazionale Idrocarburi (ENI), a state-owned company formed in 1953 as a holding company for equities owned by the Italian Government in the petroleum industry. ENI is one of Italy's three major state holding companies and was created in anticipation of the important role that oil would assume in meeting Italy's energy requirements.

The Government's Petroleum Plan called for ENI to become the major supplier of Italy's energy needs, and by 1977 it had become the largest domestic oil company, holding approximately 20% of Italy's petroleum market. The rest of the market was held by private Italian and foreign oil companies, many of which subsequently withdrew because of the unsatisfactory trading conditions.

In addition to being the leading Italian company in oil exploration, distribution and refining, ENI was to be the main agent of government oil supply policy, representing Italy abroad through its various specialized subsidiary companies. It also developed performance standards for the production and procurement of oil and for refining and marketing operations.

Following the oil shocks of the 1970s, ENI's role in ensuring that Italy, which imports about 80% of its energy requirements, had access to adequate long-term supplies increased in importance. To strengthen its position, ENI has moved beyond exploration and production into refining, transportation and marketing.

Net revenues for the ENI group in 1988 were $US 25.4 billion, of which $US 16.4 billion was derived from energy, including coal. Gross profits before taxes were $US 1.3 billion and net profit after taxes was $US 1.0 billion. Total 1988 investment in capital expenditures, intangibles and exploration was $US 3.9 billion, and expenditures in research and development were $US 327 million.

Mandate

ENI's mandate is set out in Law No. 136 of 10 February 1953 as amended, and in Regulations of 22 December 1954.

The **purpose** of ENI, as set forward in 1953, was to promote and carry on undertakings in the national interest in the field of hydrocarbons and natural steam. ENI was subsequently assigned similar responsibilities in the chemical sector and in the nuclear fuel research, fabrication, reprocessing and sales sector as well as in nuclear-related mining, exploration and production activities. Intervention in other sectors is permitted only to the extent that the intervention is instrumental, accessorial or complementary to the basic hydrocarbon, natural steam, chemical and nuclear fuel interests. Such intervention is subject to prior authorization by the Minister of State Holdings. Responsibilities added at later dates include setting up and managing Italy's strategic petroleum reserve, and restoring to sound financial condition or otherwise managing for a limited time several businesses outside the company's statutory scope.

The **initial capital endowment** of ENI was 30 billion lire, an amount since raised to a total of 7,747 billion lire ($C 7.308 billion, converted at an exchange rate of approximately 1,060 lire to the Canadian dollar).

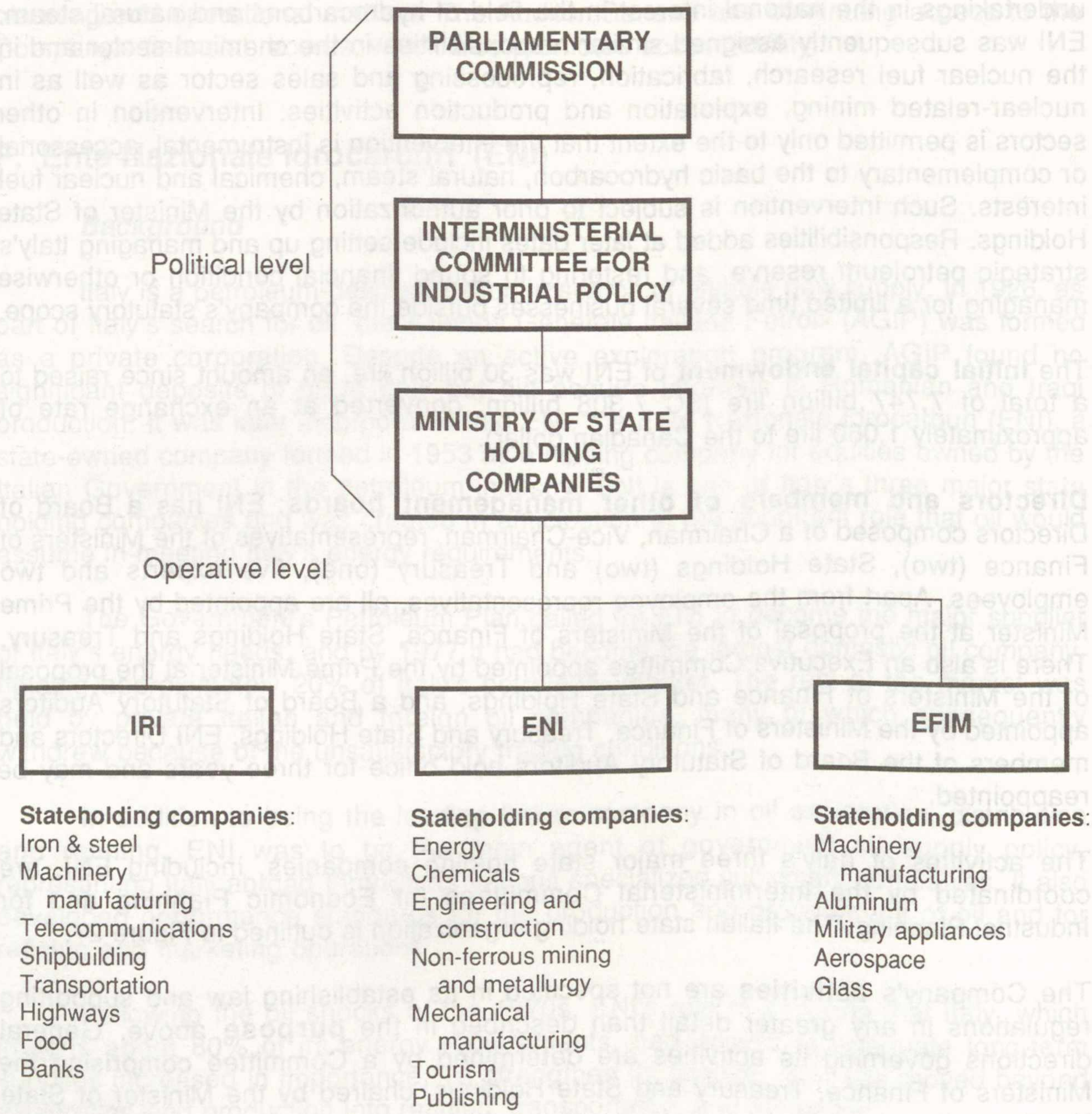
Directors and members of other management boards: ENI has a Board of Directors composed of a Chairman, Vice-Chairman, representatives of the Ministers of Finance (two), State Holdings (two) and Treasury (one), five experts and two employees. Apart from the employee representatives, all are appointed by the Prime Minister at the proposal of the Ministers of Finance, State Holdings and Treasury. There is also an Executive Committee appointed by the Prime Minister at the proposal of the Ministers of Finance and State Holdings, and a Board of Statutory Auditors appointed by the Ministers of Finance, Treasury and State Holdings. ENI Directors and members of the Board of Statutory Auditors hold office for three years and may be reappointed.

The activities of Italy's three major state holding companies, including ENI, are coordinated by the Interministerial Committees for Economic Planning and for Industrial Planning. The Italian state holding organization is outlined in Figure 27.

The Company's **activities** are not specified in its establishing law and supporting regulations in any greater detail than described in the **purpose** above. General directions governing its activities are determined by a Committee comprising the Ministers of Finance, Treasury and State Holdings, chaired by the Minister of State Holdings.

The Company's annual **financial** statements include the balance sheet and the profit and loss account, and must be submitted within four months of the close of the financial year. These statements are accompanied by reports of the Boards of Directors and Auditors, and are submitted for approval to the Minister of State Holdings. Budgetary variations are the responsibility of the Minister of the Treasury.

Figure 27: The Italian System of State Holding Companies



Source: Reviglio, Franco, "State Holdings in Italy: A Lesson from Theory and Experience", Talk delivered by the Chairman of ENI in Calcutta, 14 November 1989, p. 16.

Loans and debentures may be issued with terms and conditions approved by the Ministers of the Treasury and State Holdings. They may be guaranteed by the state as to interest and principal with the agreement of the Council of Ministers.

Relationship with the Italian Government

The Prime Minister appoints the Board of Directors, including the Chairman and Vice Chairman, and the Executive Committee. The Ministries of Finance, State Holdings and Treasury are represented on the Board of Directors. Members of the Board of Statutory Auditors are appointed by the Ministers of Finance, Treasury and State Holdings. Finance and State Holdings have members on this Board, which is chaired by a representative of the State Comptroller-General's Office.

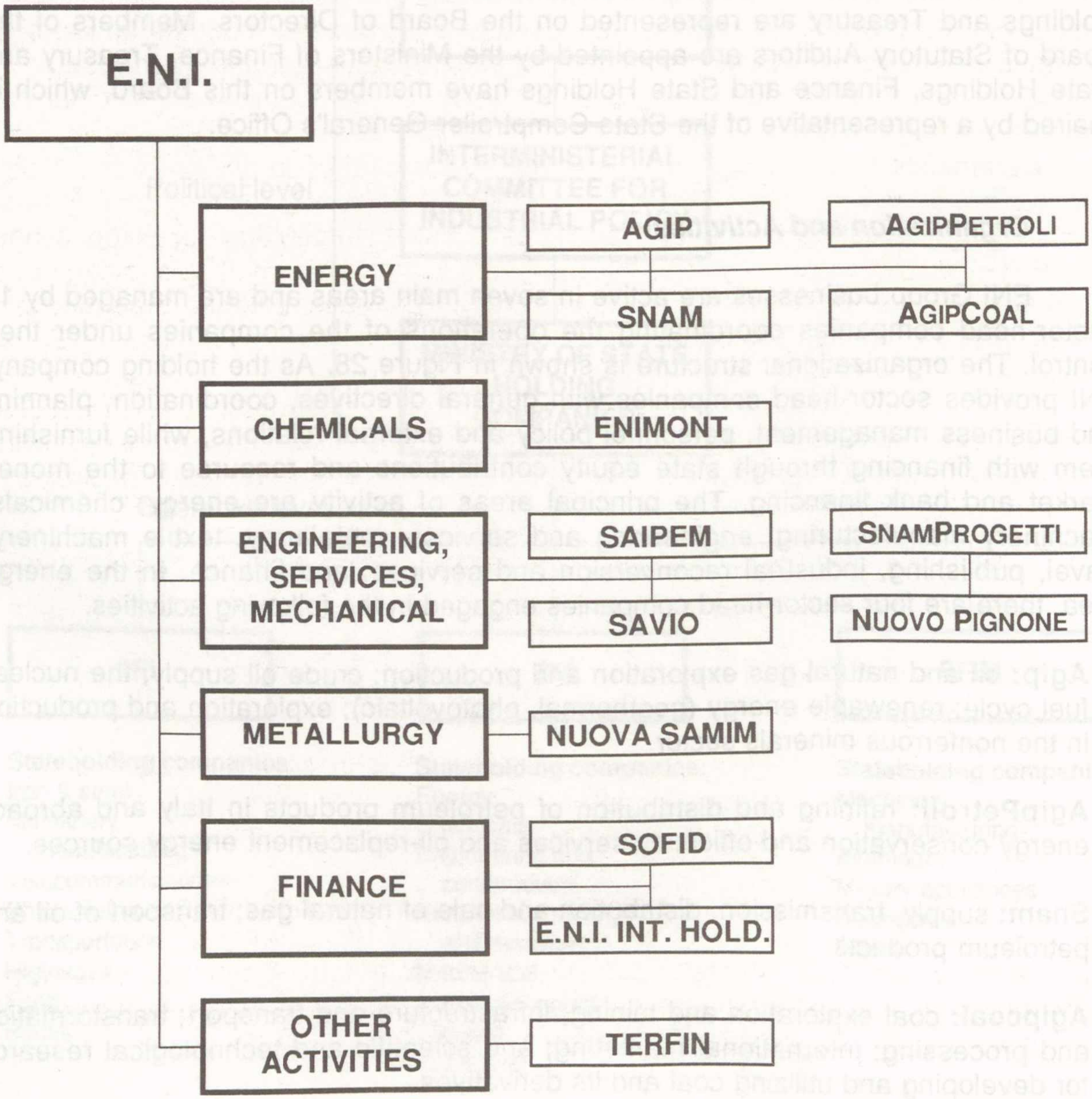
Organization and Activities

ENI Group businesses are active in seven main areas and are managed by 13 sector-head companies coordinating the operations of the companies under their control. The organizational structure is shown in Figure 28. As the holding company, ENI provides sector-head companies with general directives, coordination, planning and business management, personnel policy and external relations, while furnishing them with financing through state equity contributions and recourse to the money market and bank financing. The principal areas of activity are energy; chemicals; machinery manufacturing, engineering and services; metallurgy; textile machinery; travel, publishing, industrial reconversion and services; and finance. In the energy area, there are four sector-head companies engaged in the following activities.

- **Agip:** oil and natural gas exploration and production; crude oil supply; the nuclear fuel cycle; renewable energy (geothermal, photovoltaic); exploration and production in the nonferrous minerals sector.
- **AgipPetroli:** refining and distribution of petroleum products in Italy and abroad; energy conservation and efficency services and oil-replacement energy sources.
- **Snam:** supply, transmission, distribution and sale of natural gas; transport of oil and petroleum products.
- **Agipcoal:** coal exploration and mining; infrastructure and transport; transformation and processing; international marketing; and scientific and technological research for developing and utilizing coal and its derivatives.

Sector-head companies in the other groups are also involved in energy-related activities. EniChem manufactures petrochemicals. NuovoPignone designs and manufactures equipment and instruments for Italy's energy industries. Snamprogetti designs and constructs petrochemical plants, refineries and gas treatment plants, and has developed some of the world's leading pipeline technology. Saipem performs onshore and offshore drilling and builds offshore works such as platforms and terminals.

Figure 28: Corporate Structure of ENI



Source: Ente Nazionale Idrocarburi, *Presentation of the ENI Group*, February 1990, p. 5.

The coordination and overall direction of ENI's research and development program is the responsibility of a permanent Research Committee, a centralized research company and structures within the various operating companies that provide direct support to their industrial activities.

Developing Countries

ENI investment in developing countries over the period 1984-1988 totalled about $US 3.9 billion. A consortium composed of ENI, a major industrial group and two financial institutions is looking for joint venture opportunities in the Third World.

Comments

ENI is interesting on several accounts. First is the extent to which it has expanded its operations outside Italy – growth in this regard is remarkable given Italy's limited domestic resources of energy. Despite this limited base, ENI has expanded into a world-class energy conglomerate.

A second feature of interest is ENI's apparent ability to support selected national and social objectives as well as fulfill its energy mandate. The company has entered into joint ventures in key sectors to ensure a measure of national participation. Objectives of this joint venturing have included:

- achieving a minimum critical mass for efficient competition in the global market;
- entering into foreign markets;
- acquiring technologies;
- attaining commercial synergies; and
- operating inside the highly competitive European, Japanese and U.S. markets.

Where state interests were clearly served, additional funding was provided.

Apart from helping to offset uneven economic growth, ENI has played a social role by promoting development in backward regions of the country. For a period of time, however, political interests dominated this role and a number of unwise investments made. A better balance between economic and social considerations has been restored, and such difficulties have been reduced.

As is apparent from ENI's organization chart, government at both the political and bureaucratic levels participates directly and continuously in ENI's management process. The success of the company suggests that this involvement need not have an inhibiting effect.

G. A Comparison of Roles

When moving in the House of Commons on 12 March 1975 that the bill to establish a national petroleum company be given second reading, the Minister of Energy, Mines and Resources, Donald Macdonald, listed the concerns that had led the government to propose the initiative. These were:

- the government was not assured that the private sector could be relied upon to mobilize the capital necessary to secure Canada's longer-term energy needs;
- given the opportunities outside Canada, it was also uncertain that the private sector would undertake the effort needed within Canada to meet future domestic energy requirements; and
- a situation could develop where oil could be more advantageously imported by a nationally-owned Canadian company than by the private sector.

Before commenting on the relevance to the Canadian situation of these four companies, several general observations are helpful. In all instances, the companies are closely tied to their governments' policy mechanism, either structurally or through the selection of the executive and board of directors, or both. In the cases of JNOC and Statoil, budgets and operational plans are subject to parliamentary comment. With the exception of PDVSA, state auditors are part of the management structure and are consequently aware of the companies' on-going operational and financial activities. Operational plans in all cases are subject to review by the government.

Petróleos de Venezuela, S.A.

With its activities representing 20% of Venezuela's GNP, PDVSA is of great importance to the country's economy. The government realizes the danger inherent in such dependence and is trying to diversify Venezuela's economic base. It is also encouraging joint ventures with foreign interests where this is not prohibited by law, including such petroleum-related activities as petrochemical manufacture.

The main interest in PDVSA for purposes of this study lies in technology. With the bulk of Canada's petroleum resource taking the form of bitumen in Western Canada's oil sands, there is a common interest in new and more efficient means of developing heavy hydrocarbons. The water-bitumen emulsion being marketed by PDVSA is an example of the progress it is making. While there are significant differences between the technical and chemical characteristics of the reserves in the two countries, the need to develop new markets is common to both.

The level of oil sands and heavy oil research in Canada is substantial. What may be lacking is good coordination in what is being done and making sure that promising technologies are field tested and given the earliest opportunity for commercial application. Development of commercial *in situ* oil sands technology was one of the priority items mentioned by the government when introducing the Petro-Canada legislation. Would the national interest have been better served by directing at least some of the resources that Petro-Canada invested in the downstream industry instead into more oil sands research?

Japan National Oil Corporation

To the extent that Petro-Canada was originally intended to serve as a catalyst for petroleum activity, as opposed to taking an operational lead, JNOC's activities come closest to meeting the original Canadian mandate. Its method of operation benefits the state in that it can initiate projects before there is economic justification and by so doing ensure that part of the resulting production goes to Japan. Not only does the private sector gain by the initial financial and sometimes organizational involvement of JNOC, but it assumes JNOC's share once a project is operational and the risk reduced. Further support is given to the private sector through the availability of JNOC's Technology Research Center.

The Japanese Government undoubtedly has the financial and technical resources to secure its long-term petroleum requirements by giving JNOC an operational role to the exclusion of the private sector. Instead, the government has chosen to limit its role to stimulating industry, moving on when this stimulation is no longer necessary.

High priority is accorded in Canada to private sector involvement and, given our currently modest financial means, the JNOC model would seem to have much to offer. An increasing share of Canada's remaining petroleum resources are high-cost and high-risk, and Petro-Canada could take the lead in promoting their development, although the question of funding would have to be addressed. Avoiding an operational role would limit conflict with the free market principle. Starting projects that would not otherwise have begun, or advancing their timing, benefits the private sector as well as the country through the increased activity.

Statoil

To the extent that Petro-Canada was created to enable Canadians to participate through government in the development of the country's petroleum resources, it has a common objective with Statoil. In the Norwegian case, there was a further need arising from the lack of any significant government or Norwegian private-sector experience in oil and gas development. If responsibility for development of this essential resource was not to be left entirely to foreign companies, the state had to intervene.

Beyond the wish of both governments to participate directly in an important economic activity, the similarities end. In Canada, there was already a well-developed domestic oil industry with significant Canadian participation. Development of our petroleum resources was already well underway. Although Petro-Canada's initial activities were concentrated on the frontiers and in the oil sands, where its leadership was useful, there is still no production from frontier deposits. Indeed, the one field where it appeared economic to move into production (Panuke-Cohasset off the Nova Scotia coast), Petro-Canada turned over the operatorship to other companies. In the case of the oil sands, substantial acreage was acquired by Petro-Canada and several projects to develop *in situ* extraction technology were started. The Company does have production from this source, although it is not clear how much is directly due to Petro-Canada's involvement. Petro-Canada as recently been criticized by the Alberta Government for not making a greater effort to develop its oil sands reserves.

In Statoil's case, efforts were initially concentrated on production. Expansion into transportation, refining, marketing and petrochemical production generally came later. Statoil has been uniquely successful in working with the Norwegian shipbuilding and engineering industries. Conditions of North Sea petroleum exploitation were unprecedented in the oil industry's history of offshore development, requiring new technology and new design and construction concepts. Norwegian companies have gradually assumed a leading role in offshore development and will probably play an important part in developing the Hibernia field off Newfoundland. By taking this initiative, Statoil helped found an important new Norwegian industry.

Although Canada has extensive cold-water experience in working in the north and off the East Coast, Petro-Canada has not taken a leadership role like Statoil. As a result, Canadian capabilities have not been adequately exploited and the opportunity to develop Canadian industry in this respect has not been significantly exploited.

ENI

The use by the Italian Government of a state holding company to pursue a combination of economic, political and social objectives pre-dates World War II. There is no Canadian analogue and no need for one at a time when government policy is based on the free market and the principle of deregulation. ENI is of interest as a resource-based company which has been able to grow and prosper despite Italy's limited energy resources. ENI has developed through its subsidiaries a range of energy infrastructure design and construction capabilities, together with a sound technological base.

Appendix A

List of Witnesses

THURSDAY, November 16, 1989

Morning Session

From Petro-Canada:
Mr. Wilbert Hopper, President.

From Doig's Digest:
Mr. Ian M. Doig, Editor.

Afternoon Session

From the Canadian Association of Oilwell Driling Contractors:
Mr. Brian M. Krausert, President;
Mr. Don M. Herring, Managing Director.

Mr. Herschel Hardin, Private Citizen.

From the Canadian Energy Research Institute:
Mr. Anthony E. Reinsch, Vice President.

THURSDAY, November 27, 1989

From the C.D. Howe Institute:
Mr. Thomas E. Kierans, President.

MONDAY, December 11, 1989

From the Economic Council of Canada:
Mr. Ron Hirshhorn, Senior Economist.

Mr. Jim Conrad, Private Citizen.

MONDAY, December 18, 1989

Afternoon Session

Appearing:

The Honourable Jake Epp, P.C., M.P., Minister of Energy, Mines and Resources.

From the Ministry of Energy, Mines and Resources:

Mr. G.R.M. Anderson, Assistant Deputy Minister, Energy Sector;
Mr. R. Lyman, Acting Director General, Energy Policy Branch.

Evening Session

From the Fraser Institute:

Mr. Michael Walker, Executive Director.

Appendix B

Abbreviations and Acronyms

AOSTRA	Alberta Oil Sands Technology and Research Authority
CANMET	Canada Centre for Mineral and Energy Technology
CEDIP	Canadian Exploration and Development Incentive Program
CEIP	Canadian Exploration Incentive Program
CERI	Canadian Energy Research Institute
DoE	Department of Energy (United States)
EMR	(Department of) Energy, Mines and Resources
ENI	Ente Nazionale Idrocarburi (Italy)
ERCB	Energy Resources Conservation Board (Alberta)
FERC	Federal Energy Regulatory Commission (United States)
FTA	Free Trade Agreement
JNOC	Japan National Oil Corporation
JPDC	Japan Petroleum Development Corporation (the forerunner of JNOC)
LNG	liquefied natural gas
LPG	liquefied petroleum gases
MITI	Ministry of International Trade and Industry (Japan)
MNCs	multinational oil companies (e.g. Exxon, Royal Dutch/Shell, Chevron)
NEB	National Energy Board
NEP	National Energy Program
NES	National Energy Strategy (United States)
NGL	natural gas liquids
NOCs	national oil companies (e.g. Petro-Canada, Statoil, Petrobras)
OAPEC	Organization of Arab Petroleum Exporting Countries
OPEC	Organization of Petroleum Exporting Countries
PDVSA	Petróleos de Venezuela, S.A.

PGRT	Petroleum and Gas Revenue Tax
PIW	*Petroleum Intelligence Weekly*
PMA	Petroleum Monitoring Agency
PIP	Petroleum Incentives Program
Statoil	Den norske stats oljeselskap a.s (Norway)

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Tcf	trillion cubic feet
b/d	barrels/day
Bcf/d	billion cubic feet/day

Appendix C

Definitions, Units and Conversion Factors

Definitions

Canada Lands: Physical areas of Canada outside provincial boundaries. [Canada, PMA, 1989, p. 89] Canada Lands include the Canadian landmass of Yukon and Northwest Territories, and the offshore regions of the East Coast, West Coast and the Arctic.

Canadian Control: In general, a company is Canadian-controlled when 50% or more of its voting shares are held by Canadian residents either directly or indirectly. In a few exceptional cases, when a significant block of shares is held by Canadian residents and the remaining shares are widely held, a company may be effectively Canadian-controlled even though more than 50% of the voting shares are held by non-residents. [Canada, PMA, 1989, p. 81]

Canadian Ownership: Is the proportion of the total voting shares of a company held, either directly or indirectly (through other corporations), by Canadian residents. [Canada, PMA, 1989, p. 81]

Concession: An agreement (usually from a host government) permitting a foreign petroleum company to prospect for and produce oil in the area subject to the agreement. The terms ordinarily include a time limitation and a provision for royalty to be paid to the government. [Williams and Myers, 1981, p. 126]

Downstream: That segment of the petroleum industry including refining, marketing, transportation and petrochemical operations. [Canada, PMA, 1989, p. 82]

Integrated Companies: Individual companies that have significant revenues in both the upstream and downstream segments. [Canada, PMA, 1989, p. 82]

Junior Producers: Companies that are predominantly exploration and production oriented, and that individually generate less than 1% of industry upstream revenues. [Canada, PMA, 1989, p. 90]

Royalty: The landowner's share of production, free of expenses of production. Royalty may be payable in kind (that is, the royalty owner is entitled to a share of the oil or gas as produced), or it may be payable in money (that is, the royalty owner is to be paid in money for the value or market price of his share of the product. [Wiliams and Myers, 1981, p. 656]

Senior Producers: Companies that are predominantly exploration and production oriented, and that individually generate more than 1% of industry upstream revenues. [Canada, PMA, 1989, p. 91]

Upstream: That segment of the petroleum industry including activities and operations related to the search for, and development, production, extraction and recovery of crude oil, natural gas, natural gas liquids and sulphur, as well as the production of synthetic oil. [Canada, PMA, 1989, p. 83]

Glossary of Financial Ratio Terms (as applied by Petro-Canada)
[Petro-Canada, 1990, p. 30]

Cash Flow: Working capital provided from operations (as disclosed in the financial statement) less dividends on redeemable preferred shares plus investment tax credits, exploration tax credits and changes in advances on future natural gas deliveries.

Capital Employed: Total assets less current liabilities excluding short-term notes payable and the current portion of long-term debt.

Debt: Long-term debt including the current portion of long-term debt, short-term notes payable, outstanding cheques less cash, advances on future natural gas deliveries, and redeemable preferred shares valued at year-end.

Equity: Shareholder's equity adjusted for the valuation of redeemable preferred shares at year-end.

Cash Flow to Debt: Cash flow divided by debt.

Interest Coverage:

Earnings Basis: Earnings before interest expenses, provisions for income taxes, extraordinary and unusual items, and dividends on redeemable preferred shares divided by interest expense plus capitalized interest plus dividends on redeemable preferred shares multiplied by 1/(1-tax rate).

Cash Flow Basis: Working capital provided from operations before interest expenses and provision for current income taxes plus changes in advances on future natural gas deliveries divided by interest expense plus capitalized interest plus dividends on redeemable preferred shares multiplied by 1/(1-tax rate).

Reinvestment Ratio: Expenditures on property, plant and equipment and exploration less Petroleum Incentive Program grants divided by cash flow.

Cash Flow Return on Capital Employed: Cash flow plus tax-adjusted interest expense and dividends on redeemable preferred shares divided by average capital employed.

Return on Capital Employed: Earnings before extraordinary and unusual items and dividends on redeemable preferred shares plus tax-adjusted interest expense, divided by average capital employed.

Return on Equity: Earnings before extraordinary and unusual items and after dividends for redeemable preferred shares, divided by average equity.

Units and Conversion Factors

In the SI scheme of measurement, the unit of energy is the **joule (J)**. The rate of delivery or conversion of energy – power – is measured in **watts (W)**. One watt is defined as the delivery of one joule of energy per second. Because the units of energy and power are small, one usually works with multiples of these units. In SI, prefixes are used as multipliers of the basic units, as illustrated in the following examples.

multiplication factor		prefix/symbol		example/symbol	
1,000,000,000,000,000,000	$= 10^{18}$	exa	E	exajoules	EJ
1,000,000,000,000,000	$= 10^{15}$	peta	P	petajoules	PJ
1,000,000,000,000	$= 10^{12}$	tera	T	terawatts	TW
1,000,000,000	$= 10^{9}$	giga	G	gigawatt-hours	GWh
1,000,000	$= 10^{6}$	mega	M	megawatts	MW
1,000	$= 10^{3}$	kilo	k	kilopascals	kPa

Conversion Factors (exact or correct to four significant figures)

Distance:
1 foot = 0.3048 metre
1 statute mile = 1.609 kilometres
1 metre = 3.281 feet
1 kilometre = 0.6214 statute mile

Area:
1 square foot = 0.09290 square metre
1 square mile = 640 acres
1 square mile = 259.0 hectares
1 square mile = 2.590 square kilometres
1 square metre = 10.76 square feet
1 square kilometre = 247.1 acres
1 square kilometre = 100 hectares
1 square kilometre = 0.3861 square mile

Volume:
1 cubic foot = 0.02832 cubic metre
1 American barrel = 42 American gallons
1 American barrel = 34.97 Imperial gallons
1 American barrel = 0.1590 cubic metre
1 American barrel = 159.0 litres
1 cubic metre = 35.31 cubic feet
1 American gallon = 3.785 litres
1 Imperial gallon = 4.546 litres
1 cubic metre = 6.290 American barrels
1 cubic metre = 1,000 litres

Mass:	1 long ton = 2,240 pounds	1 short ton = 2,000 pounds
	1 long ton = 1.12 short tons	1 short ton = 0.8929 long ton
	1 long ton = 1.016 tonnes (metric tons)	1 short ton = 0.9072 tonne
	1 pound = 0.4536 kilogram	1 kilogram = 2.205 pounds
	1 tonne = 1,000 kilograms	1 tonne = 2,205 pounds
Energy:	1 kilowatt-hour = 3,600,000 joules	1 kilowatt-hour = 3,412 Btu
	1 British thermal unit (Btu) = 1,054 joules	
	1 "quad" = 1 quadrillion Btu = 10^{15} Btu = 1,054 petajoules = 1,054 x 10^{15} joules	
Power:	1 kilowatt = 3,600,000 joules/hour	1 kilowatt = 1.341 Imperial horesepower
	1 Imperial horespower = 745.7 watts	1 Btu/hour = 0.2931 watt

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