ENERGY IN CANADA:

A BACKGROUND PAPER

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FOREWARD

This discussion paper was prepared by the Department of Energy, Mines and Resources Canada to provide information about Canada's resource potential, the contribution of energy to the Canadian economy, Canada's place in the world energy market, and the outlook for the development of Canadian energy resources. In addition, it provides background information on issues such as: energy and the environment, energy security, Canadian ownership of energy resources, energy R&D, and energy conservation. Finally, it concludes with an indication of some of the key challenges facing the energy sector. The paper is intended to inform the public and to serve as a reference document for those participating in the review of Canada's energy options.

The paper was prepared before Canada and the U.S. agreed in principle on a free trade agreement (FTA) and does not include a discussion of the FTA or its potential impacts on the energy sector.

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1.0 Energy in Canada - An Overview

Through the course of history, the economic development of nations has been closely linked to the increased use of energy and to changes in the predominant form of energy supplies. The evolution of developed countries from agricultural to industrial to post-industrial societies has been accompanied by equally major changes in the energy sources upon which the economy relies. Over time, changes in technology and an increased demand for reliable, convenient and economical fuel sources, have resulted in a shift from energy systems based on wood to those based on coal to those based on oil and gas.

In contrast to earlier periods when a single energy source clearly predominated, the 1980's have been characterized by a much more diverse mixture of energy forms (see figure 1.1). Many forecasters expect this trend towards a multiple energy system to continue with individual energy sources increasingly dedicated to those specialized uses for which they are most suited. In particular, it is expected that the economy will become less dependent on oil, more electricity intensive, and will generally be based on a more flexible, more diversified energy system.

1.1 Energy in the Economy

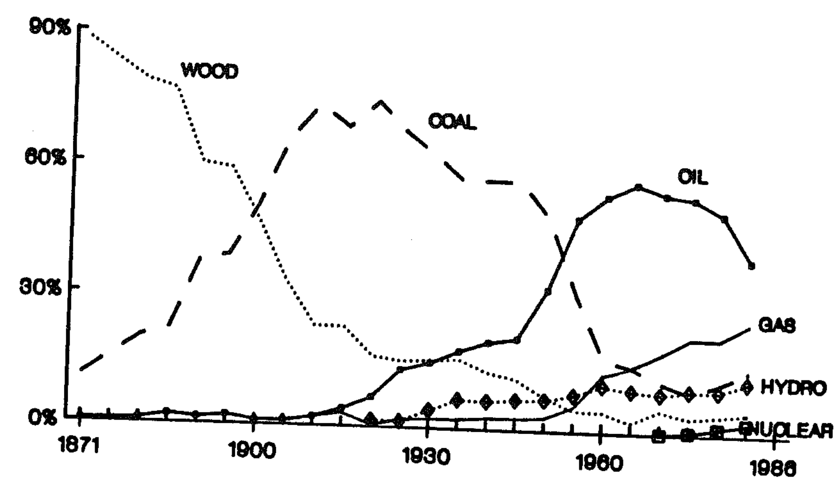
The Canadian energy sector encompasses those sectors of the economy engaged in the location and recovery of natural gas and crude oil and the mining of coal and uranium. It also includes establishments engaged in the production and distribution of petroleum and coal products, electrical power and fuel or heat from renewable energy sources. In addition, it includes those occupied with energy management.

In March 1987, the energy sector employed 305,000 people, constituting 2.7% of total employment in Canada or 3.4% of non-agricultural employment. Within the energy sector, more than one-quarter of these jobs were in the electric power sub-sector, and almost another quarter were in retail gasoline distribution. Crude petroleum and natural gas accounted for about 13% of energy sector jobs and petroleum refining for about 6%.

The energy sector is also a major contributor to Canadian incomes. Gross revenues for the sector of over $60 billion provide an indicator of the dollar value of energy activity in the Canadian economy (see table 1.1).

Figure 1.1

PRIMARY ENERGY BY SOURCE, CANADA
1870 - 1986



Investment spending indicates not only the present contribution of a sector to the economy but also its potential future contribution to economic activity. In 1986, total energy investment in the Canadian economy amounted to about $11.4 billion (1981 purchasing power), down from $14.8 billion in 1985. This figure represented 14% of total investment (compared to 19% in 1985) and 3.4% of Gross Domestic Product (GDP) - see figure 1.2. Thus, even in a year in which energy investment was considerably below average, the energy sector played a major role in generating activity in the Canadian economy.

Table 1.1
Energy Sector Sales

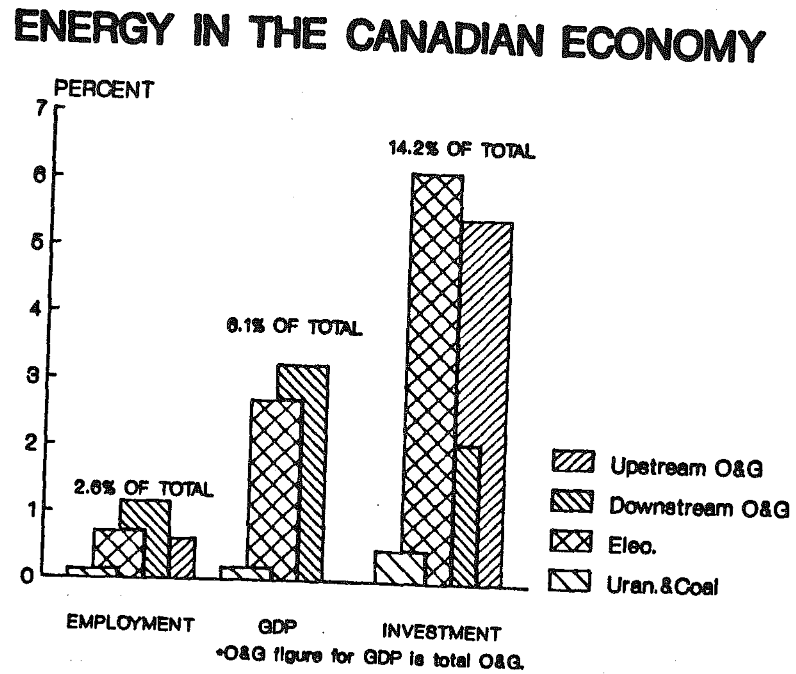
	1986 Gross Revenues ($ billion)	Increase (Decrease) From Previous Year
Oil and Gas		
Upstream*	16.9	(40%)
Downstream*	26.4	(23%)
Electric Power Generation (1985)	16.2	12%
Coal Shipped from Mines	1.6	(15%)
Uranium in Concentrate	0.9	(8%)
Renewable Energy Sector (1985)	0.5	

* . Upstream activities include those related to exploration, development, extraction, production and recovery.

. Downstream activities include refining, marketing, transportation and petrochemical operations.

Source: Energy, Mines and Resources Canada (EMR)

Figure 1.2

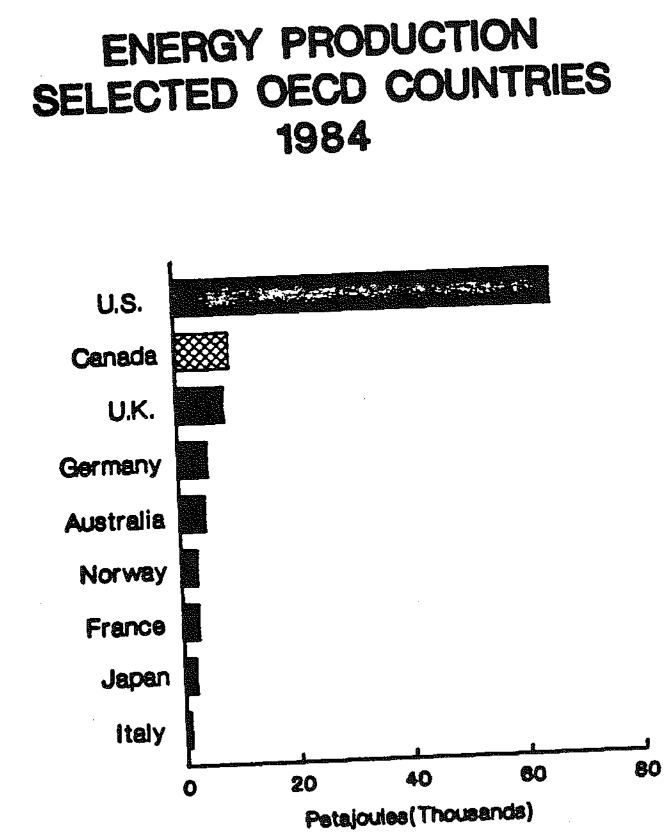


In addition to its direct contribution to the economy, the energy sector has a significant indirect influence on economic activity as many other activities depend critically on energy as an input. The activities most affected in this indirect way are pulp and paper, non-metallic mineral products (lime, cement, etc.), chemical products and smelting and refining of primary metals. A quantitative measure of the "energy-intensity" of any manufacturing activity is provided by the ratio of the cost of fuel and electricity to the industry's value added (the total value of its sales less the value of materials it purchases from other firms). Using this measure, the most energy-intensive activities in the Canadian economy were lime (68.9%), cement (35.4%), abrasives (33.26%), paperboard (39.9%), newsprint (31.3%), pulp (26.6%), and smelting (18.6%). These industries depend in large part for their viability on the ready availability of competitively-priced energy supplies.

1.2 Interprovincial and International Trade

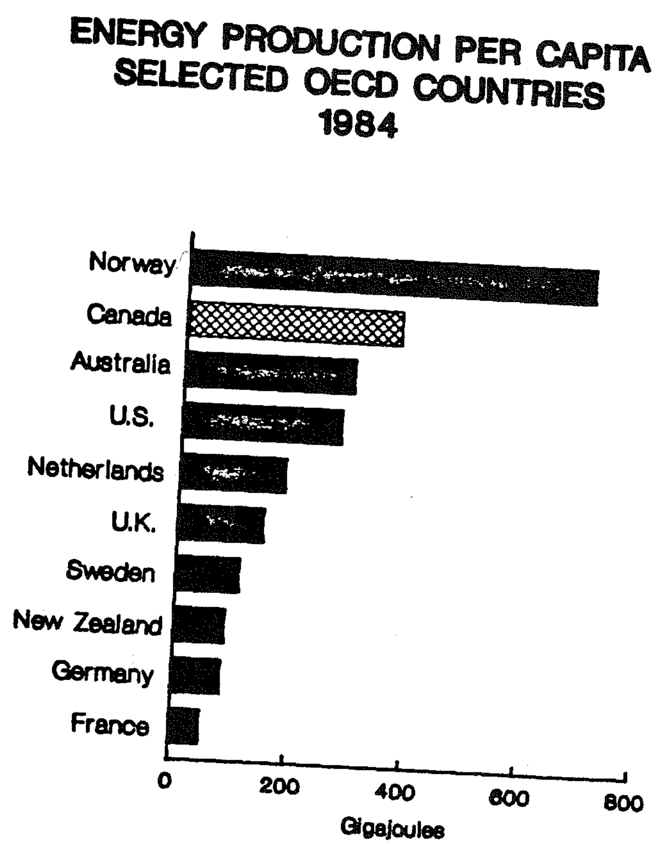
Canada produces about 4% of the world's primary energy supply and is the second largest producer of energy in the Organization for Economic Cooperation and Development (OECD) - see figure 1.3a. Moreover, it is a large producer considering

Figure 1.3a



its population. In per capita terms, Canada was one of the largest energy producers among OECD countries in 1984 (see figure 1.3b).

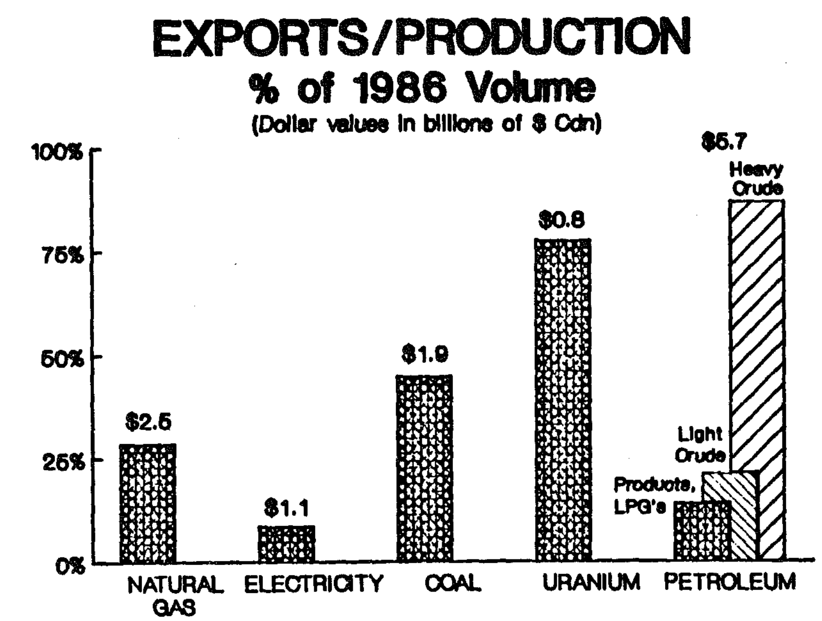
Figure 1.3b



In regional terms, the consumption of energy in Canada largely mirrors the distribution of population and of manufacturing activity. The production of energy, on the other hand, is largely a matter of resource endowments. The bulk of Canada's oil, gas and coal production, for example, is concentrated in the western provinces, while uranium production is confined to Ontario and Saskatchewan. Only hydro has a broad distribution across the country, but here too some provinces like Alberta, Prince Edward Island, and Nova Scotia, are seriously under-represented. A major result of this regional concentration of Canada's energy sector is the considerable volume of interprovincial energy flows.

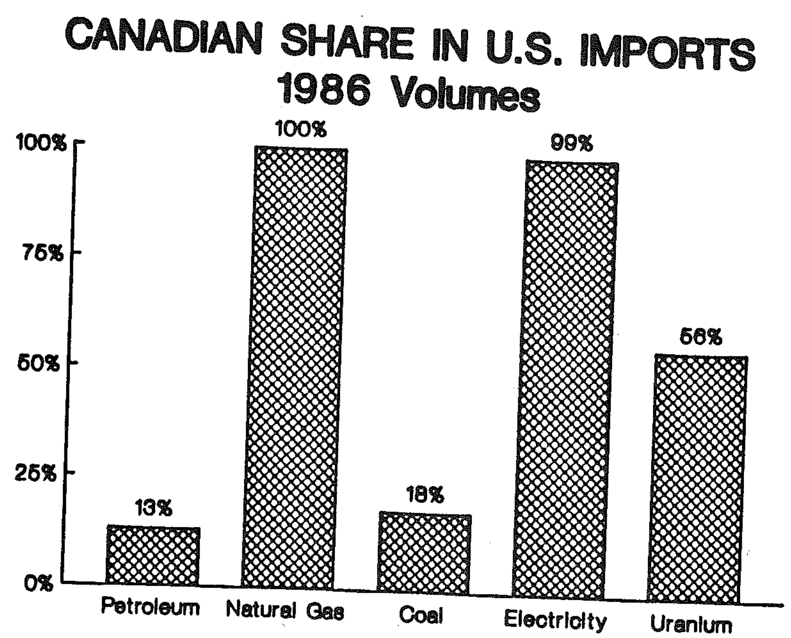
In addition to large interprovincial energy flows, energy exports are a prominent characteristic of Canada's energy sector. In fact, in some cases, the majority of Canadian production is sold abroad (see figure 1.4). The

Figure 1.4



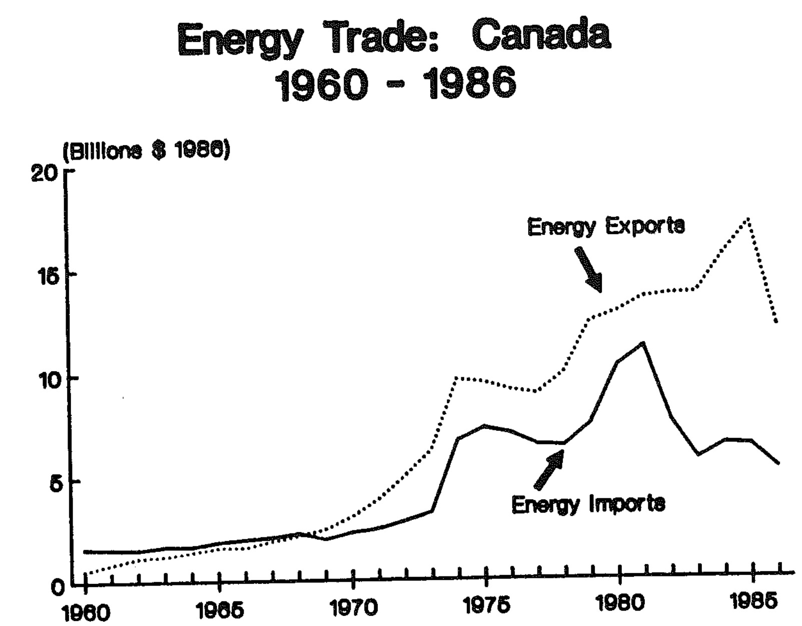
U.S. is our largest energy trading partner, accounting for 81% of our energy exports. Canada is, in turn, an important energy supplier for the U.S. (see figure 1.5). We are the biggest foreign supplier to the U.S. of petroleum, gas and electricity and Canadian supplies of these energy sources are especially important for border states.

Figure 1.5



Energy has played an increasing role in Canada's overall international trade (see figure 1.6). The share of energy exports in total Canadian exports has increased from 6% in 1970 to 10% in 1986. At present, Canada's major energy exports are crude oil (especially heavy crude oil which can only be refined in Canada in limited quantities) and natural gas, both of which go to the U.S. Canada's major energy imports are crude oil (mainly from the U.K., Nigeria and Venezuela) and petroleum products (from the U.S.).

Figure 1.6



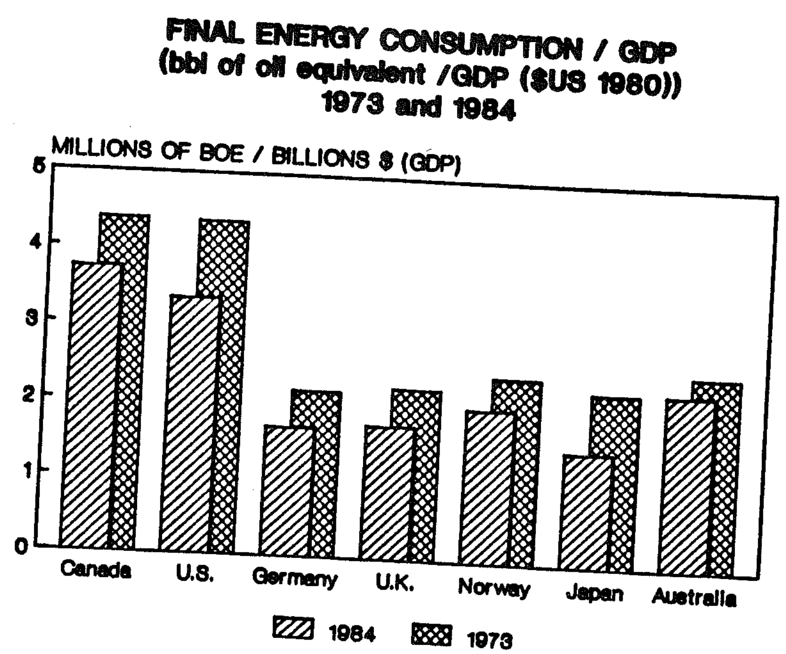
Canada became a net exporter of energy, in total, in 1969 and has been a net exporter of all energy commodities including crude oil, since 1983. In 1986, total energy export revenues were $12.1 billion, compared with total energy import costs of $5.3 billion.

1.3 Energy Consumption

Canada is the most energy-intensive industrialized country in the world. In part, this results from Canada's cold climate and long distances. In part, it reflects the impact Canada's ample energy resource endowment and relatively low prices has had on the evolution of its industrial sector.

In common with the world's other major industrial nations, Canadian energy consumption patterns have changed significantly since the first oil price shock in 1973. Changes have been conditioned by the alternatives available to consumers and the policies pursued by governments. In Canada, for example, the widespread availability of substitutes for oil (particularly natural gas) led consumers and governments to place relatively more emphasis on substitution than on conservation in responding to the "oil crisis". As a result, decreases in overall energy consumption have lagged somewhat behind other OECD countries (see figure 1.7) while reductions in oil consumption <u>per se</u> compare favourably.

Figure 1.7



2.0 A Situation Report by Sector

Canada's various energy sectors have different characteristics, have followed different development paths and are currently faced with different market prospects as a result of international market forces, technological changes, environmental considerations, and other factors. This chapter discusses the historical development, current situation, and outlook for Canada's energy resources on a sector-by-sector basis.

2.1. Oil

2.1.1 Characteristics of Oil

Through much of the post-war period, the growth of the developed nations has been fueled by oil. Despite a generally more diverse energy sector, oil remains a strategic commodity for certain key uses such as transportation, and in regions where close substitutes are not readily available. Moreover, oil is still the most important overall energy source in Canada, accounting for about 40% of our total energy consumption.

Oil is a homogeneous commodity amenable to transportation by various means. It is characterized by its high energy value relative to the costs of transporting it, particularly when transported by ship. In addition, in continental markets, it can be efficiently transported by pipeline. As a result of these characteristics, oil is a truly international commodity and is, in fact, by far the world's most important traded commodity, in terms of value.

Oil resource endowments vary enormously from the oil rich states of the Middle East to heavily industrialized countries which must import essentially all their oil requirements. This distribution of oil resources gives some producers market power - the ability to affect world prices by placing restrictions on supply. Recent history has shown that the market power of the Organization of Petroleum Exporting Countries (OPEC), while significant, is not unlimited. It can be reduced over the long term by increases in non-OPEC supplies, by conservation, and by substitution. Nevertheless from the point of view of relatively small producers and consumers, oil prices are established by supply and demand in a world market over which they have little control.

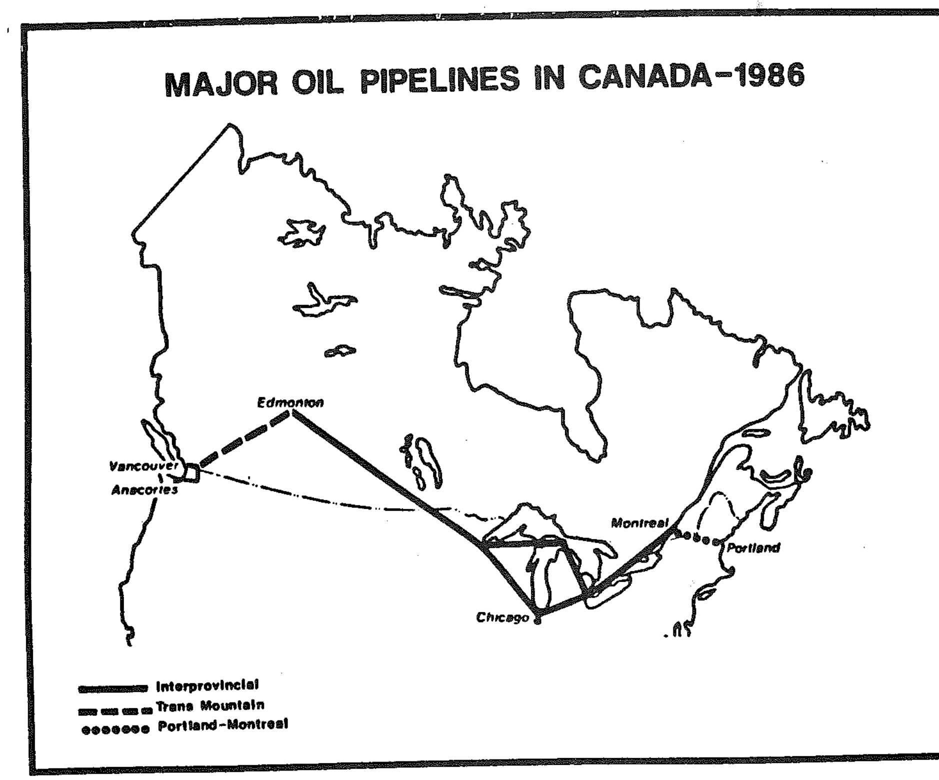
Canada is a small player in international terms (producing 2.7% of the world's output of crude oil in 1986). Given our small size relative to the global market, Canada, acting alone, cannot influence world oil prices. This means that as a small exporter, we can always export as much as we choose at the current world price and as a small importer, our purchases on the international market cannot influence the going price.

2.1.2 Development of the Canadian Oil Industry

The discovery of the Leduc field, 18 miles southwest of Edmonton, in 1947, marked the beginning of Canada's rise as a significant oil producer. In the 10 years after 1947, oil reserves increased fourty-three times and production twenty-three times. The major concern of the petroleum industry during this period was finding markets where the oil could be sold. The late 1940's and the 1950's witnessed the construction of major new oil pipeline systems to enable Alberta oil to be transported economically to new markets. The Interprovincial pipeline was constructed eastwards from Alberta reaching the Manitoba - South Dakota border by 1949. On the U.S. side of the border, the pipeline extended to Superior, Wisconsin where oil was then shipped by tanker through the Great Lakes to refiners in Sarnia, Ontario. In 1953, the pipeline was extended from Superior through the Michigan peninsula to Sarnia. Four years later, the pipeline was extended to Toronto. The Trans Mountain pipeline from Edmonton to British Columbia and the state of Washington was inaugurated in 1953. (See map 1 for a depiction of current Canadian oil pipelines.)

Despite the construction of the above pipelines, oil imports in 1960 still accounted for about one-half of domestic consumption. Alberta and Saskatchewan could easily supply all of the western provinces, but in central and eastern Canada, imported oil remained preferable because it was cheaper. The National Oil Policy of 1961 guaranteed western producers the Canadian market west of the Ottawa Valley and encouraged exports. This action triggered a new period of intensified production and development. Domestic oil production increased from 543,000 barrels per day in 1960 to 2.1 million barrels per day by 1973. During this same period, exports, as a percentage of domestic production, rose from 23% to 66% (see figure 2.0).

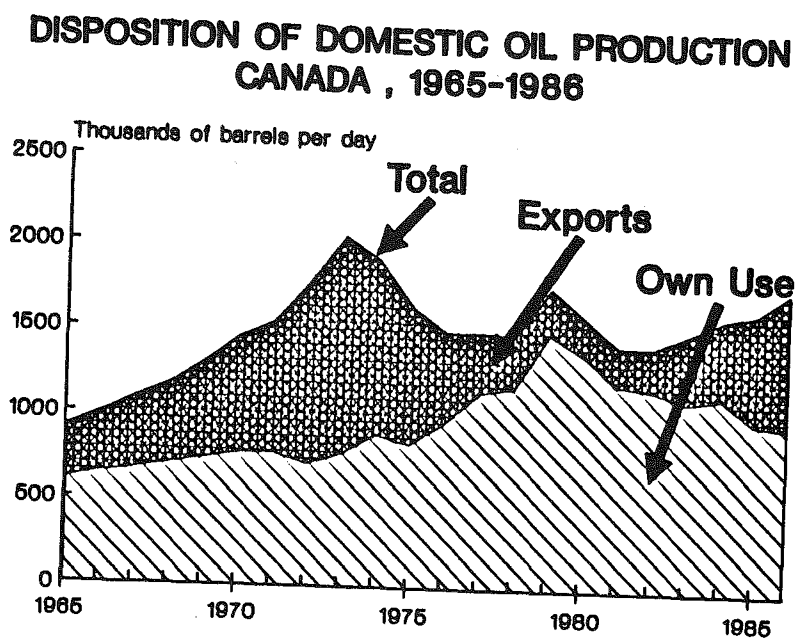
Map I



The 1960s and early 1970s witnessed the debut of non-conventional oil production and frontier exploration. With the discovery rate for large oilfields decreasing in western Canada, the major oil companies began to move to the Canada Lands (lands under federal control in the territories and offshore), and to focus on increasing the recovery of oil from the reserves that had already been established. Suncor (formerly Great Canadian Oil Sands) officially opened its plant near Fort McMurray in 1968, pioneering tar sands mining. In 1971, ESSO Resources built the first artificial island in the shallow Arctic waters of the Beaufort Sea.

Canada's production of light crude oil peaked in 1973. The subsequent decline in production occurred for a number of reasons. Throughout the 1970s, reserves additions of crude oil were low compared to

Figure 2.0



the previous two decades. This resulted at least in part from the rapidly increasing cost of finding and developing reserves while wellhead crude prices remained regulated at below market levels. In addition, large volumes of oil were shut-in as authorities reduced export licences in the belief that, with lower estimates of reserves, oil should be kept for future use domestically. Through the latter half of the 1970s, it was more profitable to drill for natural gas than for oil, as wellhead gas prices rose substantially.

The rising world oil prices improved the prospects for mining the oilsands, but such projects were hampered by considerable economic uncertainty. With provincial and federal government participation, a second oilsands plant, Syncrude, was built at Fort

McMurray at a cost of $2.5 billion, opening in 1979. A third mining project, the Alsands megaproject was proposed in 1977, but after some five years of planning, the project sponsors announced its suspension in April 1982. In the frontier regions, a significant oil discovery - the Hibernia discovery - was made in the Newfoundland offshore in 1979. The 1970s also saw the extension of the Interprovincial pipeline from Sarnia to Montreal.

After hitting a low in 1982 of about 1.3 million barrels per day, Canadian oil production has increased over the past five years. Total crude oil production in 1986 was approximately 1.8 million barrels per day of which about 45 percent was exported.

The fastest growing source of oil supply in recent years has been the production of bitumen. This "in-situ" bitumen is recovered from wells in the Western Canadian oil sands by injecting heat, generally in the form of steam, into the well. It is not upgraded, as is the case with the bitumen mined at the Suncor and Syncrude plants, but rather is mixed with a diluent to make it transportable by pipeline and is then shipped to markets, primarily in the U.S., often for use as asphalt. Projects such as Suncor and Syncrude, on the other hand, recover oil sands deposits by mining techniques, separate the sands from the bitumen and then upgrade the bitumen to a synthetic oil that is suitable for processing by refiners. Such mining techniques are only suitable for deposits close to the surface. The economics of mining are such that these projects are much larger and hence more capital intensive with much longer construction periods than is the case for in-situ projects. As a result, they are riskier especially in times of high price volatility.

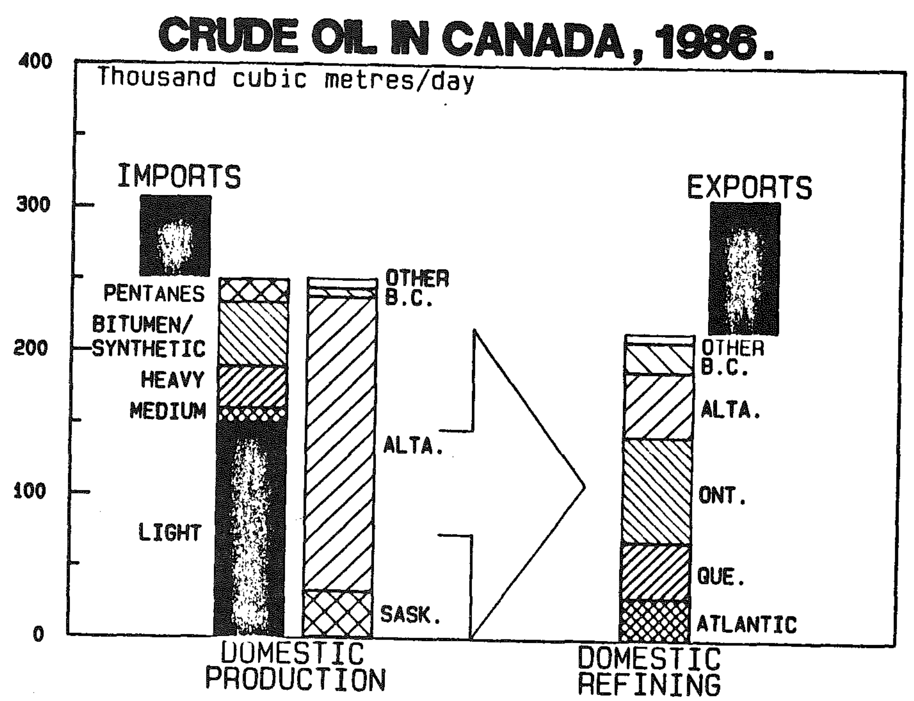
While the major decline in world oil prices in 1985/86 had only a minor impact on current oil production, it had a significant impact on exploration activity. Industry cash flow fell by 35% from $11.3 billion in 1985 to $7.4 billion in 1986, with a resultant depressing effect on investment. The number of oil wells drilled dropped sharply from 12,500 in 1985 to slightly less than 6,000 in 1986.

With the return to higher world oil prices in 1987, activity in Canada has picked up again and in September 1987 there were over twice as many rigs active in Western Canada as at the same time in the previous year. In addition, several major projects are now proceeding. In the oil sands, Syncrude is carrying out a $650 million addition and Suncor has announced expansion plans worth $150 million. In the heavy oil area, BP and Petro-Canada have announced the $200 million phase 2 of the Wolf Lake heavy oil project and Esso is expanding its Cold Lake heavy oil production at a cost of over $200 million.

2.1.3 The Oil Sector in Canada

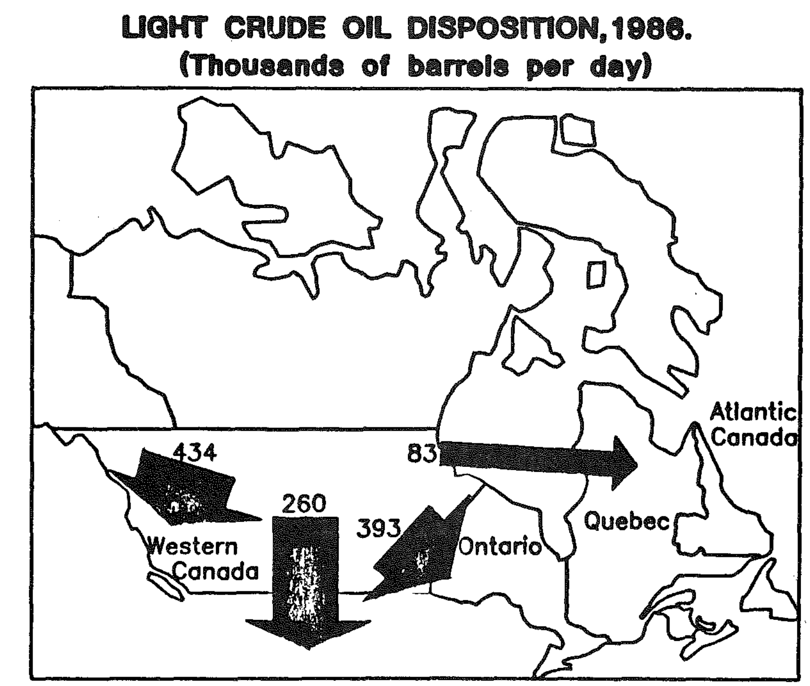
The oil industry consists of explorers, producers, pipeline companies, petroleum refiners and distributors, and independent marketers. In Canada,

Figure 2.1



the sector is characterized by major interregional and international flows (see figures 2.1, 2.2 and 2.3), with significant differences between light crude oil, heavy crude oil and petroleum products.

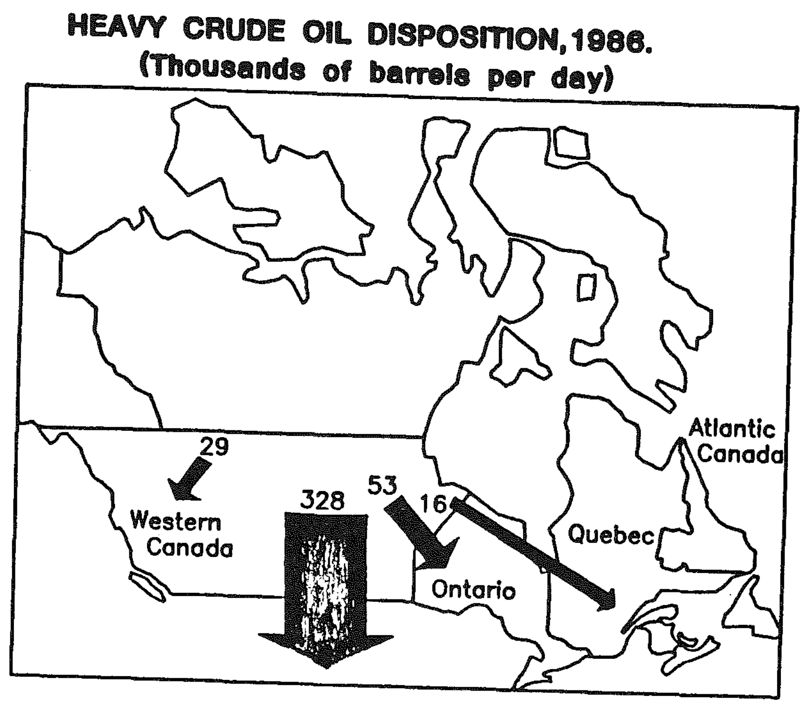
Figure 2.2



Alberta produces 82% of Canadian crude oil and equivalent and Alberta and Saskatchewan together produce 95%. Canada is, at present, a net exporter of crude oil with exports from Western Canada more than offsetting imports destined for Quebec and Atlantic Canada. Canada has 35 oil refineries, with capacity as of January 1986 distributed as follows: Western Canada 36%, Ontario 35%, Quebec 17%, and Atlantic Canada 12%. Canadian refineries, however, have only limited capacity to refine heavy crude. As a result, there is a significant difference in trading patterns for light and heavy crude oil. In 1986, more of Western Canada's output of light crude oil and equivalent was dispatched to refineries in

Ontario and Quebec (41%) than was refined in Western Canada (37%). In addition, more than 20% of Canadian light crude oil production was exported. In terms of heavy crude oil, however, exports represented 87% of production.

Figure 2.3



Finally, Canada is both an importer and exporter of refined petroleum products. Although petroleum product imports have increased significantly since 1981, Canada continues to be a net exporter of petroleum products. Currently, exports represent about 10% of refinery production while imports are equal to 8%. In 1981 the share of petroleum products in total Canadian petroleum imports was less than 10%. By 1986, this share had increased to 25%.

2.1.4 Canada's Oil Resource Potential

Canada has substantial remaining reserves of oil. These are very highly concentrated in Western Canada. Alberta accounts for 76% of Canada's remaining reserves of conventional oil which would be economically producible with current technology. In addition, production of conventional oil supplies from the western sedimentary basin can be increased, at some additional cost, by means of enhanced recovery techniques using steam or water to recover oil which would otherwise be unrecoverable.

Major crude oil and gas discoveries have also been made in the frontier regions. The exact size of these resources is, at present, subject to considerable uncertainty. Major oil discoveries have been made in the Beaufort Sea and off the eastern shore of Newfoundland. These frontier resources are not necessarily economic at current oil prices. They may, however, be less costly to develop than some non-conventional resources located in more accessible areas.

By far Canada's largest potential source of oil is the tar sands. The potential of Western Canada's tar sands has been estimated as equivalent to the combined proven reserves of Saudia Arabia, Kuwait and the United Arab Emirates. The Canadian tar sands have been well delineated geologically. The two existing tar sands plants - Syncrude and Suncor - have both contributed enormously to our technical understanding of oil recovery from the tar sands and of the production of synthetic light crude through upgrading. As well, both projects have significantly improved the economics of their operations, for example Syncrude has reduced its production costs from $19US a barrel when the plant opened in 1979 to between $11 and $12 at present. Such cost reductions have permitted both projects to proceed with expansions of their existing base plants. The economics for new, stand alone oil sands plants are generally less favourable, but both the Syncrude partners and the Original Six Lease Owners (OSLO) consortium are seriously considering new plants in the vicinity of Fort McMurray, Alberta.

The cost of producing oil from each of Canada's possible sources of supply tends to increase as the richest and most accessible resources are depleted.

In addition, our various potential oil resources become economically viable at different prices and, therefore, will be developed at different times. As oil prices rise, it becomes increasingly worthwhile to extract additional supplies from existing sources and to develop new sources of supply. The huge costs and long lead times associated with certain frontier and non-conventional developments, however, mean that such sources of supply are likely to contribute only modestly to Canadian oil supplies prior to the year 2000.

2.1.5 The Outlook for the Canadian Oil Sector

With the recent return to higher world oil prices, activity has begun to recover in Canada's oil sector and several major projects have been announced. While cyclical variations will occur as circumstances change there are some evident longer-term trends for oil production in Canada.

The vast majority (over 80%) of Canada's current total productive capacity of crude oil is based on the conventional areas of Western Canada. Canadian oil companies have emerged more efficient from the very difficult conditions they faced in 1986 and are replacing production with new conventional reserves in Western Canada at costs which are competitive in world terms. Production from this area is, therefore, expected to remain important for some time. Geologically, however, it has been well explored and new discoveries are unlikely to be sufficient to replace conventional crude production over the next 20 years.

The majority of Canada's unexploited base of conventional crude oil resources (70% according to EMR estimates) is located in the frontier regions of the north and offshore. The East Coast offshore and the Beaufort Sea area appear particularly promising. A number of mega-projects in these areas are now at the planning or conceptual stage. In the offshore, these include: the Hibernia project sponsored by Mobil Oil with an estimated pre-production capital cost of $3.4 billion ($1987), the Terra Nova project sponsored by Petro-Canada with an estimated pre-production capital cost in the range of $500 million-$900 million ($1987) and the Cohasset project also sponsored by Mobil Oil with an estimated pre-production capital cost of $200 million ($1987).

In the Beaufort Sea, the Amauligak project sponsored by Gulf with an estimated pre- production capital cost of $4.5 billion ($1987) is also at the planning stage. Some or all of these projects could go forward before the year 2000 and oil from the offshore or northern frontier could begin contributing to Canadian supplies as early as the late 1990s.

In terms of geological potential, almost 90% of Canada's total remaining unexploited oil resource base is estimated to be bitumen from Alberta's oil sands. The fastest growing source of Canadian oil supply in recent years has, in fact, been the production of bitumen. While Canada presently has two large oil sands mining and upgrading plants, Syncrude and Suncor, most of this recent increase in bitumen output has come from in-situ bitumen production. Several more in-situ bitumen production projects are presently being planned. These include expansions to the Cold Lake and Wolf Lake projects which have been announced by Esso and by BP and Petro-Canada. In addition, Suncor is considering a $125 million project at Burnt Lake. Esso and Husky also are developing plans for possible bitumen upgrading projects, each of which would cost approximately $1 billion. Finally, both Syncrude and Suncor have announced plans to expand their existing oil sands mining and upgrading plants and while new plants based on oil sands mining would be expensive, it is possible that the new Syncrude or OSLO projects will go ahead. In the next 10-15 years, therefore, it is likely that there will be additional development of Canada's largest remaining oil resource - bitumen - at least on an in-situ basis and at expanded existing oil sands mining plants. While other oil sands projects are less certain, several are currently being considered.

2.1.6 Federal Government Statement on Mega-Projects

As a result of their location, and the geological, technological and economic circumstances associated with developing frontier and non-conventional resources, developments in these areas can be expected to occur largely on the basis of mega-projects.

Both federal and provincial governments are from time-to-time approached with requests to assist energy mega-projects. On June 19, 1987 the Honourable Marcel Masse announced a number of broad principles which the federal government will apply in considering requests for special government measures to assist mega-projects in the oil and gas sector.

Sponsors must demonstrate that projects are capable of meeting market tests. This includes an indication that projects are backed by significant private sector equity and will be able to produce and to market oil or natural gas at a reasonable cost.

Subject to this condition, the following broad principles will be applied:

- First, projects will need to be of national importance to Canada's energy economy.
- Second, sharing of the risks and rewards between the project sponsors and the participating governments must be fair and equitable.
- Third, any support negotiated with project sponsors will be delivered outside the tax system but subject to the prevailing tax rules.
- Finally, the Government of Canada will seek an acceptable return, based on reasonable project assumptions, on its total investment in any project.

2.2 Natural Gas

2.2.1 Characteristics of Gas

Unlike oil, natural gas is not a liquid at normal temperatures. Its gaseous state requires transportation by pipeline unless expensive liquefaction techniques are applied. In addition, natural gas is approximately six times more expensive to transport than oil on an energy- equivalent basis. As a result, gas is not traded nearly as widely as oil and is not a truly international commodity.

For Canada, supply and demand for gas are determined within the North American market, as this is the area which can be served by pipeline. The U.S. is Canada's only gas export market and Canada is the only source of gas imports to the United States (currently accounting for almost 5% of U.S. gas requirements).

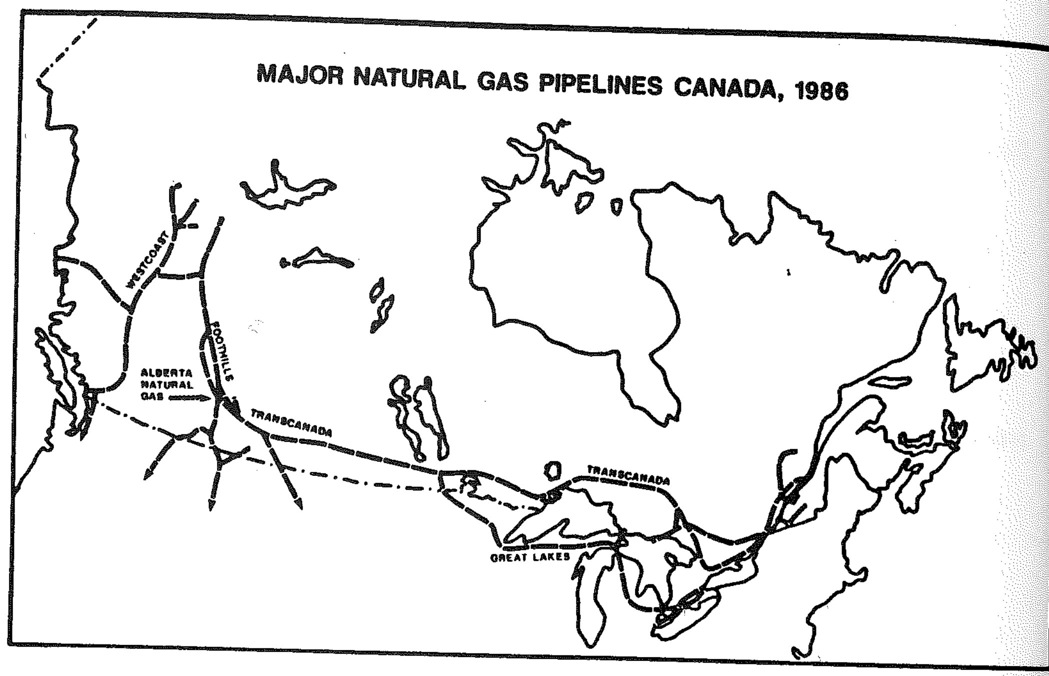
While natural gas has only limited use as a transportation fuel, it competes with oil in many applications. As a result, its price tends to track the price of oil. At present, there is a surplus of gas in North American markets with significant gas-to-gas competition. Lower oil prices and gas-to-gas competition pushed Canadian gas export prices down by about 21% in 1986 from their level the previous year before oil prices fell.

2.2.2 Development of the Canadian Natural Gas Industry

Although natural gas was produced in Canada as early as the 1880s, the history of the Canadian natural gas industry really commences with the Leduc oil discovery of 1947. Initially, discoveries of natural gas were the accidental by-product of the search for oil and were little valued. The gas reserves that were found were shut-in, flared or consumed within the vicinity of the wells. By the 1950s, however, the cumulative discoveries of natural gas had become quite significant, creating the need for a transportation infrastructure to move the gas to market.

The late 1950s and early 1960s saw the construction of three major natural gas pipelines. The Westcoast pipeline was constructed in the late 1950s from northeastern British Columbia, and a small area in the Peace River district of Alberta, to markets in British Columbia and in the Pacific Northwest of the United States. The TransCanada pipeline, which adopted an all-Canadian route from Alberta to southern Ontario, was completed by 1958. A pipeline from Alberta to California was completed in 1961 (see map 2 for a depiction of current gas pipelines in Canada). Between 1960 and 1973, the domestic gas industry grew rapidly, with production increasing at an average annual rate of 14% to reach 2.5 trillion cubic feet by 1973. While most of this production originated in Alberta, a sizeable natural gas industry developed in British Columbia, with the latter accounting for 18% of total production in 1973. During this period there was also a tenfold increase in natural gas exports which, by 1973, had grown to represent some 40% of production (see figure 2.4).

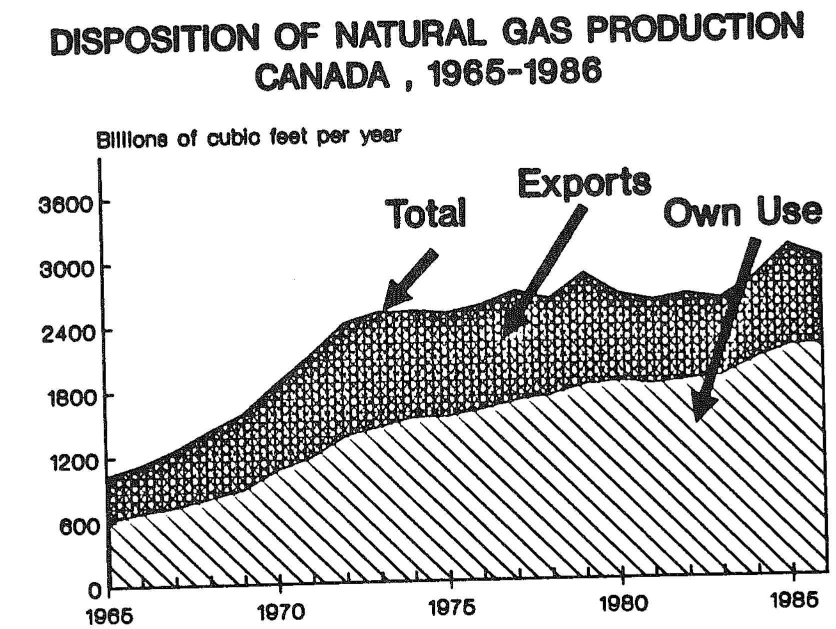
Map 2



By the mid-1970s, there were major concerns about whether natural gas production would be able to keep up with the increase in demand. The National Energy Board (NEB) stopped granting new export licenses in 1971 and, in 1975, it issued a warning that Canadian natural gas supply could fall short of meeting total demand, including existing export commitments, in the latter part of the 1970s. In this environment of rising energy prices and projected shortages, a great deal of public attention became focussed on Canada's frontier regions.

After the 1968 announcement of the discovery of major oil and gas reserves in the Prudhoe Bay area of Alaska, significant exploration activity in Canada took place in the MacKenzie Delta, Beaufort Sea and Arctic Islands. Although a major oil find proved elusive, several large discoveries of natural gas were made. By the 1970s, serious consideration was

Figure 2.4



being given to projects to bring northern gas to southern markets. Two proposals, the Canadian Arctic Gas Pipeline Project and the Foothills (Yukon) Project, competed for the right to transport Canadian and U.S. natural gas out of the north by pipeline. In 1977, the National Energy Board approved the Foothills (Yukon) Project which was intended to transport Alaskan gas through Alaska, the Yukon and northern British Columbia to Alberta where it would then be shipped to the U.S. There were plans for a lateral connecting the MacKenzie Delta to this pipeline to enable Canadian gas to be brought to market as well. Two other proposals, the Polar Gas Project - a pipeline project - and the Arctic Pilot Project - a plan to use LNG tankers - were subsequently put forward for transporting gas from the Arctic Islands to southern markets. All of these projects, however, were eventually placed in abeyance. During the time it had taken to draw up the plans for frontier development, market conditions had changed dramatically.

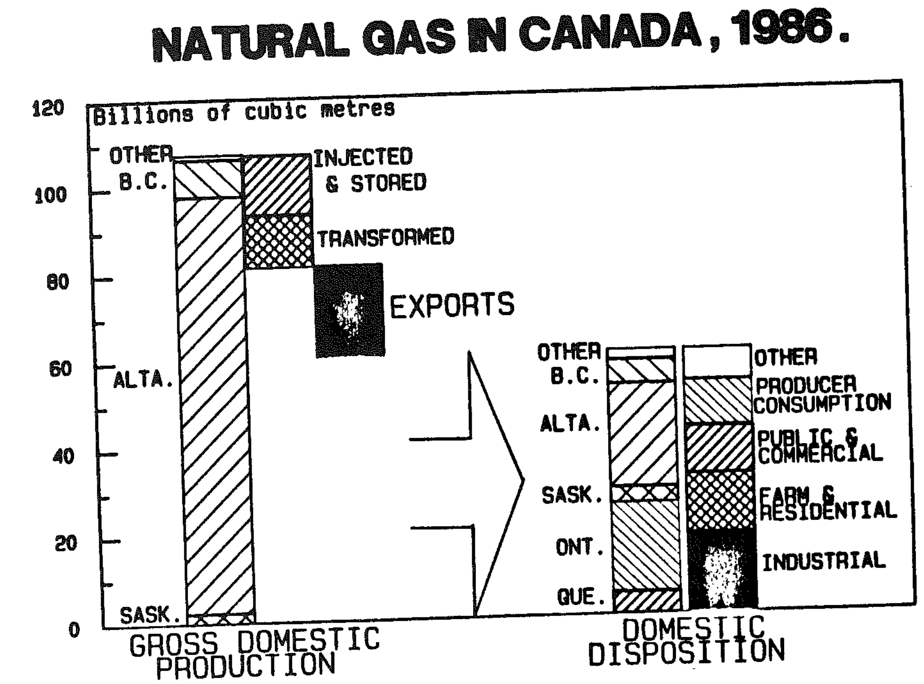
The rise in the average wellhead price of gas, from $0.16 per thousand cubic feet in 1973 to $1.50 per thousand cubic feet in 1979 provided ample incentive for the industry not only to intensify gas exploration but, because gas prices increased faster than oil prices, to shift the emphasis of exploration from oil towards gas. As a result, established gas reserves increased rapidly in the conventional areas of western Canada. By contrast, domestic demand began to stagnate after 1979, while exports fell significantly. The combined effect of increased reserves and reduced demand served to lift the ratio of reserves to production to about 35 years - well above a level that would indicate a supply/demand balance on the market. This situation was only slightly alleviated by the extension of the TransCanada pipeline system to Québec. The creation of a natural gas surplus moderated the industry's interest in finding and developing new gas reserves in the Western Basin and sharply reduced interest in frontier gas. More recently, interest in natural gas exploration and development has rekindled somewhat as there are some signs that the current "gas bubble" will disappear by the end of the decade.

2.2.3 The Gas Sector in Canada

The Canadian gas sector is composed of explorers producers, pipeline and distribution companies, brokers and export licence holders. The majority (89%) of Canada's natural gas is produced in Alberta. Gas is, however, widely traded within Canada and the U.S. (see figure 2.5). In 1986, more than one quarter (25.5%) of Canada's natural gas was exported. An additional 24.8% went to customers in Ontario and 28.6% to customers in Alberta.

The natural gas market, particularly in the U.S., is presently characterized by overcapacity, declining demand, increased competition between oil and gas, intense gas-to-gas competition, and low prices. During 1986, Canadian gas export volumes decreased by 20% and export prices at the border declined by 21%. Domestic sales of natural gas also dropped slightly as some users switched to heavy fuel oil.

Figure 2.5



2.2.4 Canada's Gas Resource Potential

In contrast to oil, there continues to be a steady increase in productive capacity in the conventional gas fields of Western Canada. The Canadian western and arctic regions are, moreover, geologically gas prone. In both the conventional and frontier regions, established Canadian gas reserves are more than twice as large, on an oil equivalent basis, as crude oil reserves. Not all of these potential resources, however, could be economically produced at existing prices. Remaining reserves of gas which have been geologically established by development drilling and which could be economically produced using current technology are concentrated in Western Canada. Alberta accounts for 84% of such reserves and B.C. for 12%.

Major gas discoveries have also been made in the frontier regions, particularly the MacKenzie Delta/Beaufort Sea, the Arctic Islands and the east coast offshore. The economic viability of these resources remains uncertain, but Delta gas in particular, might contribute to Canadian energy supplies in the late 1990s, if a gas pipeline from the north were built. In the Nova Scotia offshore, Mobil is considering a gas mega-project (the Venture project) with an estimated pre-production capital cost of $2.3 billion.

Frontier gas could ultimately make a large contribution to Canadian energy supplies, depending on economic circumstances. Gas discoveries in the Arctic and offshore Nova Scotia are now estimated to be almost half as large as remaining reserves of Canadian gas which could be economically produced under current conditions.

2.2.5 The Outlook for the Canadian Gas Sector

Natural gas is, and can be expected to remain, an important energy commodity in Canada. Domestically, there has been considerable substitution in the past decade of natural gas for oil. Existing domestic markets west of Québec City are now relatively mature and likely to grow less rapidly. Substantial expansion of domestic markets, moreover, would require major infrastructure investments.

At present, competition in the U.S. market is intense and this situation is likely to continue in the short-term . The longer-term outlook for Canadian gas sales in the U.S. market is, however, more favourable. As non-Alaskan U.S. supplies begin to decline, Canadian exports could potentially double from 1985 levels.

The National Energy Board examined the outlook for the Canadian energy sector in its report, Energy Supply and Demand 1985-2005. The report provided two scenarios for future oil prices. Under its high-price scenario, the NEB forecasts frontier gas production commencing in 1990, rising to 14% of total productive capacity by the late 1990's. The NEB forecast, however, only includes exports which have been authorized. If, as many analysts predict, new export opportunities were to arise this could prove to be an underestimate.

2.3 Electricity

2.3.1 Characteristics of Electricity

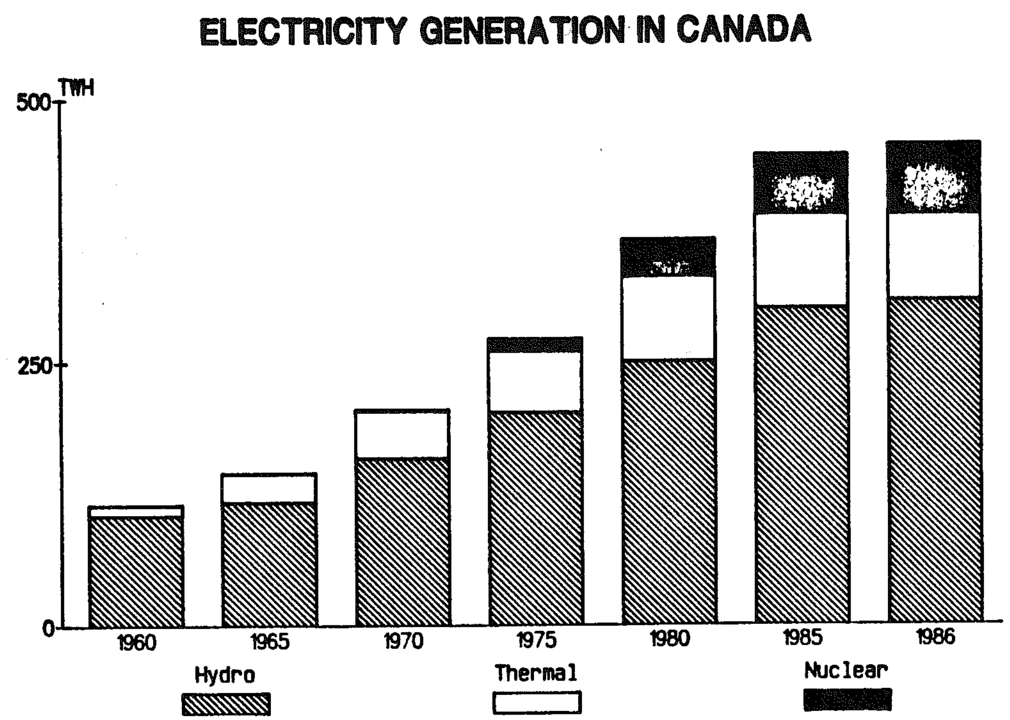
Canadian electricity supplies were originally developed largely to serve local markets. With improvements in distribution technology, markets have widened but distance continues to impose limits on the range within which a market can be served efficiently.

Under the Canadian Constitution, electricity is primarily within the jurisdiction of the provinces. Electric power in Canada is provided largely by provincially owned utilities. The mandate of these corporations is generally to provide secure supplies of electricity to provincial residents at reasonable cost. Because reliability of supply is considered extremely important, large reserve margins are maintained. As a result, non-provincial markets were generally only considered in cases of overcapacity (with the significant exception of sales from Newfoundland to Quebec) and early exports to the U.S. were often on an interruptible basis. While more than 70% of 1986 exports continued to be on an interruptible basis, the trend in export sales in recent years has been towards firm, long-term sales. Consideration is being given, moreover, to projects to "prebuild" electricity capacity, in advance of Canadian demand, partly for long term, firm export to U.S. markets.

2.3.2 Development of the Canadian Electricity Industry

As in the oil and gas sector, the fifties and sixties were decades of growth and development for the electricity sector. Output of electricity doubled in the fifties and in the sixties and increased by 80% in the seventies. Like other energy sectors, the electricity sector was affected by the oil price shocks of the mid and late seventies. As Canadian utilities are, on average, much less reliant on oil-based generation than utilities in other countries, the impact was felt less directly and immediately. The indirect effects resulting from reduced economic growth, however, were significant. Additional factors acting to slow the growth rate of electricity demand since 1973 included slower population growth, an increased general interest in energy conservation, and increases in the real price of electricity. In addition, the composition of energy sources used to generate electricity has changed significantly since 1973 (see figure 2.6).

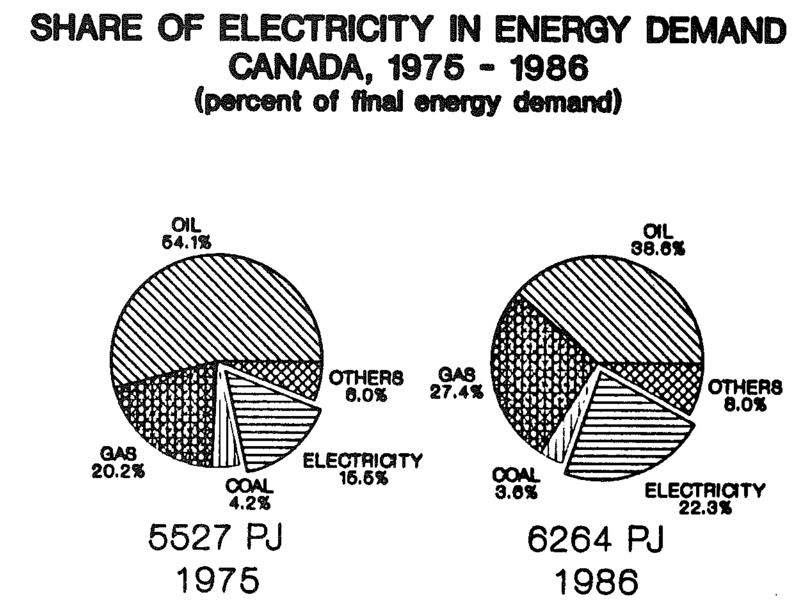
Figure 2.6



Despite the post-1973 slowdown in the growth of electricity demand, electricity has increased its share of final energy consumption in Canada (growing from approximately 15% in 1973 to over 20% at present) (see figure 2.7). Moreover, Canada was one of the few developed countries with a high rate of growth in electricity consumption in the 1983-1985 period. Canada's economy today is far more electricity intensive than any other nation's.

At present, most Canadian utilities have excess capacity in the short term as a result of demand forecasts which have not been realized. Given the long lead times associated with additions to electrical generating capacity, however, decisions to invest in new capacity will need to be made soon.

Figure 2.7



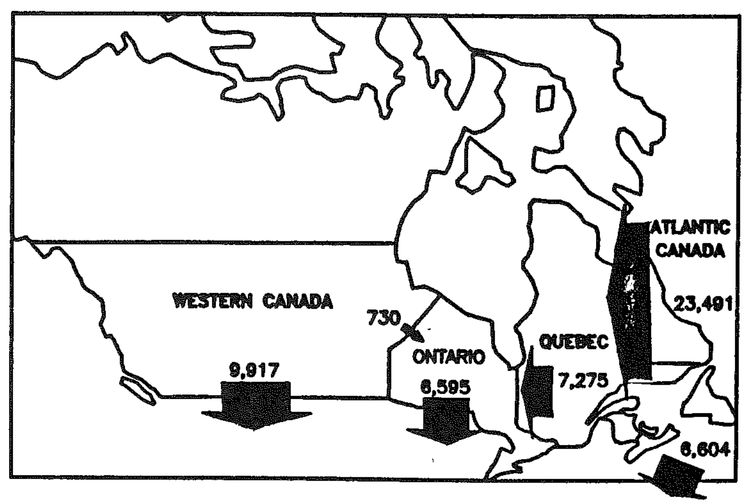
2.3.3 The Electricity Sector in Canada

There are 15 major electric utilities in Canada, 8 of which are provincially owned. The provincial electric utilities produced 84% of the electricity which was generated in Canada in 1986. Four investor-owned utilities produced an additional 7% of total electricity. Municipally-owned utilities in Manitoba and Alberta and the company which generates and distributes most of the electricity supplied in the Yukon and Northwest Territories together accounted for an additional 0.5% of generation. In addition to the 15 major electric utilities, there are about 63 industrial establishments which generated electricity mainly for their own use.

Inter-regional transactions in electric power, except in the case of sales from Québec to Ontario and from Newfoundland to Québec, are much smaller in scale than interprovincial sales of other energy commodities. Canada is, however, a significant exporter of electricity to the U.S. (see figure 2.8). In 1986, electricity exports to the United States accounted for 7.7% of Canada's total generation. This amounted to 1.4% of total U.S. electrical energy demand in 1986. In regions other than B.C., substantial increases in exports would require transmission line construction and reinforcement.

Figure 2.8

NET TRADE IN ELECTRICITY, 1986
(GWh)



2.3.4 The Outlook for the Canadian Electricity Sector

The electricity sector was, historically, characterized by strong, steady growth and since 1973, the Canadian economy has become more electricity intensive. As reserves of conventional crude oil and natural gas decline, the role of electricity can be expected to become even more prominent.

The NEB predicts that Canadian demand for electricity will grow at 2.8% annually for its low oil price case and 2.6% annually for the high price case.

One challenge associated with increasing supplies of electricity will be environmental protection. Large scale, centralized generating facilities with their associated distribution networks raise environmental concerns whether fueled by coal or nuclear power, or based on large-scale hydro developments.

2.3A Hydro

(i) Characteristics of Hydro Electricity

Hydroelectricity is the renewable energy resource which is in most widespread use in Canada today. It is reliable, and existing developed sites are economically competitive. While hydro is substantially less polluting than some other sources of electricity, its development is not without environmental concerns as such projects alter the initial ecosystems in the affected areas.

(ii) Development of Canadian Hydroelectric Supplies

Historically, the development of hydro sites has been the first choice for meeting electricity demands in Canada. In 1950, over 96% of the total kilowatt-hours generated was derived from hydraulic sources.

During the 1950's, in Ontario, with continuing rapid growth in demand, it was clear that the hydraulic power potential of the province was inadequate and a major thermal (coal-fired) power plant construction programme was initiated. The last major hydroelectric development in Ontario, was the Robert H. Saunders Generating Station on the St. Lawrence River which opened in 1958.

In other regions, the 1960's and 70's witnessed several enormous hydroelectric projects. There was extensive construction activity in Western Canada to develop major hydraulic resources such as the Columbia, Nelson, and Peace Rivers. In 1962, the Québec government nationalized privately owned power utilities, following which Québec entered a period of extensive hydroelectric development culminating in the James Bay project. The $1 billion Churchill Falls project in Labrador was completed in 1974 and was, at the time, one of the largest civil engineering projects in the world. The first hydraulic station in the first phase of the James Bay project, with a capacity of 5.3 million kilowatts, slightly larger than Churchill Falls, was officially opened in 1979.

(iii) The Hydraulic Power Sector in Canada

Canada was the largest hydroelectric energy producer in the world in 1985, accounting for about 15% of total hydro production. Canadian hydro generation increased 2.3% in 1986 and hydro remained the largest source of electric power generation in Canada, providing 67% of the country's electricity. Québec, British Columbia, and Manitoba supply virtually all of their electricity requirements from hydraulic sources. In addition, electricity exports from Québec, Manitoba and B.C. are generated almost entirely from hydroelectric stations in which marginal costs of production are very low.

(iv) Hydroelectric Resources

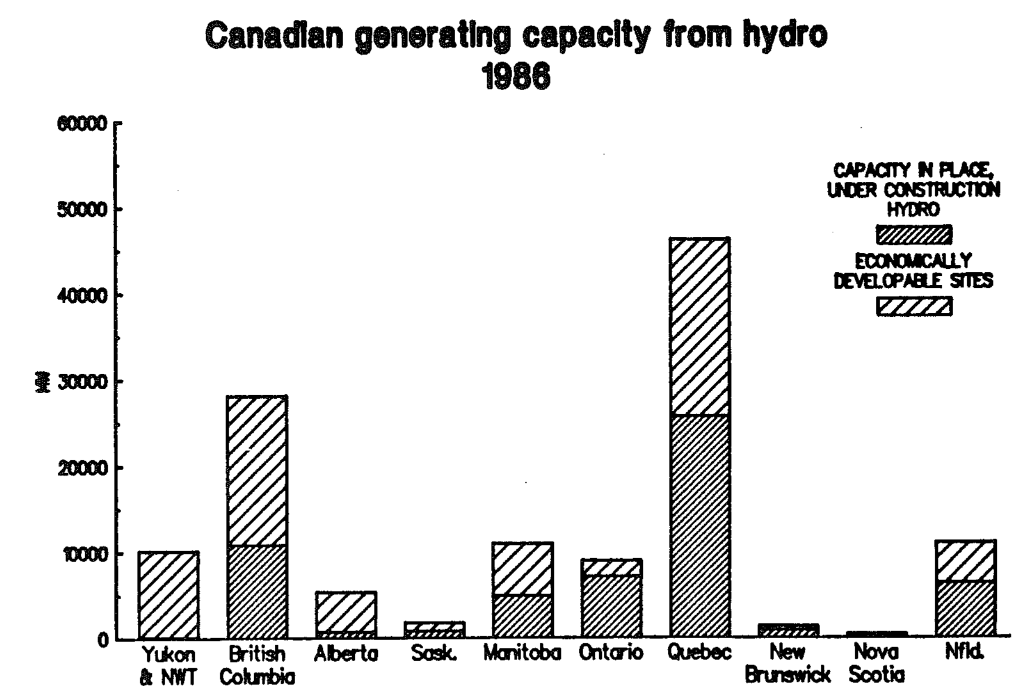
While hydro resources are more evenly distributed across the country than other energy resources, Québec accounts for 45% of all Canadian hydro capacity presently in place. B.C. enjoys the next largest share of hydro capacity, with 18% and Newfoundland has a share of 11%. Similarly, Quebec accounts for over 30% of those hydro sites which the electric utilities judge to be both technically feasible and economically developable and B.C.for over 25% (see figure 2.9).

(v) The Outlook for Hydroelectricity

The NEB expects hydro's share of electricity generation in Canada to drop to about 60% by 2005 (from 67% at present). Although the most accessible, and least costly, sites have been developed, even by 2005, several provinces will

have significant undeveloped hydro sites. A major factor affecting electricity trade for the provinces with the largest endowment of existing and potentially competitive hydro resources (Québec, British Columbia, Newfoundland and Manitoba) will be transmission constraints.

Figure 2.9



2.3B Coal

(i) Characteristics of Coal

The major use of Canadian coal is for the domestic generation of electricity, especially in those provinces with substantial coal reserves. In addition, about 40% of Canadian coal production is sold to steel industries to make coke for blast furnaces. The majority of this coking coal is exported - primarily to

Japan and Korea. Coal is very expensive to transport from inland mines in comparison to its energy value. As a result, although Canada has enormous coal resources, particularly in Western Canada, Ontario relies to a considerable extent on closer (U.S.) sources of supply.

In addition to the substantial effects of distance on coal's competitiveness, a second major factor affecting the demand for thermal coal is concern for the environment. The burning of fossil fuels, such as coal and heavy oil, produces sulphur gas emmissions which are precursors of acid rain. Scrubbers or the application of other clean coal technologies can control emissions, but add significantly to the costs. Utilization of low sulphur coal is another option. Ontario Hydro, for example, blends about 25% of low sulphur coal from western Canada with higher sulphur U.S. coal.

(ii) Development of the Canadian Coal Industry

In the early decades of the century, coal was the dominant source of primary energy in Canada. In the 1940's, coal began to yield to its successor - oil and gas. The fifties and sixties were a period marked, for the coal industry, by decline. A turnaround, however, occurred in the seventies. While this was primarily the result of the opening up of metallurgical coal resources in B.C. for export to Japan, the oil price shocks also enhanced the competitive position of thermal coal for the generation of electricity.

Canadian coal production has increased steadily since 1973, more than doubling in quantity during the decade of the seventies. The 60.7 million tonnes of coal produced in 1985 represented the highest level of production since 1965. Ninety-four percent of this output was mined in Western Canada.

During the seventies, imports declined slightly and exports more than tripled and in 1981, Canada became a net exporter of coal for the first time. Coal is now Canada's third

largest mineral export after oil and natural gas. The export business, however, has been developed primarily to meet the needs of Japanese and Korean steelmakers, which together account for 70% of the tonnage shipped abroad (see figure 2.10). This market as flattened and is experiencing sharply reduced prices triggered by world overcapacity.

(iii) The Coal Sector in Canada

Canada's coal mining industry is concentrated among 10 producers in the three western provinces and one major producer in each of Nova Scotia and New Brunswick.

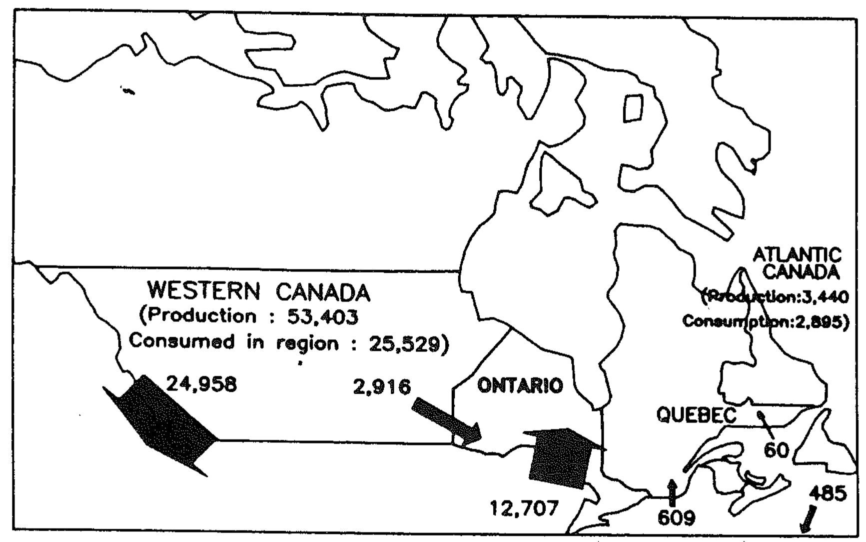
Domestically, 97% of Canadian coal production consumed within Canada is used as fuel by electric power utilities in four provinces: Alberta, Saskatchewan, Ontario and Nova Scotia (see figure 2.11). Alberta is the largest user of coal for electricity generation, accounting in 1986 for 47% of the coal used in Canada for that purpose. Within Alberta, coal-fired stations comprised 92% of total electricity generation in 1986. Coal is also quite important in Nova Scotia and Saskatchewan where it accounted respectively for 78% and 68% of electricity generation.

Generation of electricity from coal decreased by 8% from 1985 to 1986. This decline is mainly attributed to a 27% decline in export sales of electricity from Ontario. In 1986, about 89% of Ontario's electricity exports were based on coal-fired generation compared with 96% in 1985.

Transportation costs severely disadvantage Canada in the international thermal coal market. Up to 50% of the cost of Canadian thermal coal at the port consists of rail transportation from inland mines. Although Canada's costs per tonne-kilometre are very competitive, the distances to be travelled (900-1,000 Km) result in large total transportation costs.

Figure 2.10

COAL PRODUCTION AND DISPOSITION IN CANADA,1986.
(KILOTONNES)



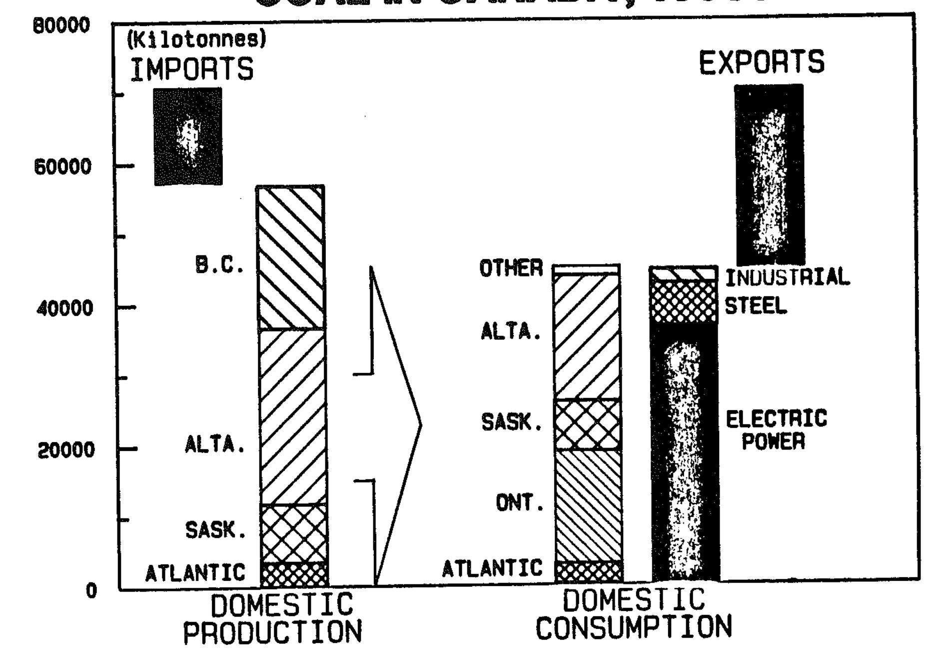
In 1986, for the first time since 1974, Canada's coal industry did not grow. Production, consumption, exports and imports all decreased. Total production fell by 3.6 million tonnes to 57 million, with the decline divided about evenly between metallurgical coal and thermal coal. This decline is largely the result of the current oversupply of coal on world markets. Tight market conditions are now expected to endure into the 1990's.

(iv) Canada's Coal Resource Potential

Canada has very large remaining reserves of coal. On a barrels of oil equivalent basis, coal reserves for which feasibility studies have been done with favourable results are estimated to be more than one and a half times

Figure 2.11

COAL IN CANADA, 1986.



as large as conventional reserves of oil and gas which have been established by development drilling and would be economically producible with present technology. At today's rate of production, these coal reserves would last over 100 years. Remaining coal reserves are concentrated principally in BC (42%) and Saskatchewan and Alberta (50%). While smaller in national terms, reserves in Nova Scotia are of regional importance.

Coal deposits that would be more costly to produce because of their quality or location are much larger than currently economic reserves. Estimates of the size of these resources range in excess of 200 times the proven reserves which are of current interest. These resources for the future are concentrated in western Canada and in the north.

(v) The Outlook for Coal

At present, thermal coal competes mainly with nuclear sources as a generator of electricity. Domestically, the NEB predicts that coal's share of electricity production will remain relatively stable at about 20%. A major uncertainty regarding this share relates to Ontario Hydro's decisions regarding any expansion in its capacity. The NEB assumes that Ontario will decide to use coal rather than nuclear stations for its capacity additions to 2005. A major challenge for thermal coal is to commercialize new clean coal technologies that are more cost effective in controlling acid gas emissions than the scrubber technologies currently available.

In total, the NEB forecasts the demand for Canadian coal remaining constant until 1990 followed by growth in the range of 3% - 4% per annum. Technological advancements may expand the market for thermal coal both domestically and internationally. New uses for coal, based on research and pilot scale tests in Canada and the U.S., include: conversion into liquid fuels, through co-processing with bitumen or heavy oil, and the use of coal as a fuel for generating steam for enhanced oil recovery.

2.3 C Nuclear and Uranium

(i) Characteristics of Nuclear Power

The generation of electric power by nuclear reactors is characterized by high capital costs and relatively low operating costs. As such, it is a technology suitable for base load generation.

CANDU nuclear reactors operating in Canada have accumulated a remarkable performance record for economy, safety, and reliability. Concerns remain, however, regarding the long term management of radioactive wastes, the safety of reactor operation and the possible impacts of nuclear energy on human health and the natural environment.

(ii) Development of the Canadian Nuclear Industry

Facilities established for purposes of wartime research provided the means for Canada to pursue peaceful uses of atomic energy. The National Research Experimental reactor (NRX), using heavy water, went into operation in 1947 and led to the development of the CANDU Nuclear Power System in the 1950's. The Nuclear Power Demonstration (NPD) prototype reactor started up at Rolphton, Ontario in 1962. This was followed by Canada's first full-scale nuclear power station, the Douglas Point CANDU Station at Tiverton, Ontario, which began production in 1966.

During the 1970's, an extensive nuclear reactor construction program was completed in Canada, including 4 units at Pickering, Ontario, the 4 units of Ontario Hydro's Bruce Generating Station (both with subsequent expansions), the Gentilly Nuclear Power Station in Québec and the Point Lepreau Generating Station in New Brunswick. Between 1970 and 1984 nuclear's share of total Canadian electricity generation increased from 0.5% to 13%. Expansion has been concentrated in Ontario. Currently there are 22 large CANDU power reactors operating or under construction in Canada, of which 20 are located in Ontario. Canada has sold 9 reactor units internationally - 2 research reactors (to India and Taiwan) and 7 power reactors (one each to Pakistan, Argentina and South Korea and two each to India and Romania).

(iii) The Nuclear Industry in Canada

The Canadian nuclear industry is a mixture of public sector Crown Corporations (at both the federal and provincial levels) and the private sector. Atomic Energy of Canada Limited (AECL), a federal Crown corporation, performs research, development and basic CANDU design and engineering work and has the mandate for marketing the CANDU abroad. Provincial electric utilities, most notably Ontario Hydro, decide, in consultation with provincial governments, whether and when to order nuclear reactors. In addition, they are responsible for construction, operation, and maintenance of reactors and Ontario Hydro has developed its own substantial design and engineering capabilities. Finally, private sector firms (mostly multi-product, multi- national firms) manufacture the components for the CANDU. They also undertake engineering and project management work for reactors outside Canada and, to a lesser extent, in provinces outside of Ontario.

(iv) Uranium Mining in Canada

In order to produce nuclear energy it is necessary to have a supply of fissionable material as a fuel source. Canada is fortunate in being well endowed with uranium reserves and has a substantial uranium mining industry.

In 1985, Canada was, in fact, the leading uranium producer and exporter in the Western world. There are only 5 producers of uranium in the country - two operating in the Elliot Lake area of Ontario with underground operations and three operators producing primarily from open pit mines in northern Saskatchewan. One of the Saskatchewan mines, the Key Lake operation, is now the largest producer in the world in terms of output. Whereas the majority of Canada's production comes from Saskatchewan, over 80% of employment is associated with the Elliot Lake operations.

In addition to uranium mines, Canada has a single uranium refinery with facilities located in Ontario. The facilities are owned by Eldorado Resources Limited, a federal Crown corporation. It is one of only five such companies in the western world.

(v) The Outlook for the Nuclear Sector

The global export market for nuclear reactors in the coming decade will likely be small and highly competitive. The potential domestic market for CANDUs is concentrated in Ontario although some possibilities exist in Atlantic Canada. Even if Ontario chooses coal-fired stations for future capacity additions, the NEB predicts that Canadian

energy produced from nuclear sources will increase, based on capacity currently in place or under construction, from a 1984 share of 12% to 20% by 1990, (falling back slightly to about 18% by 2005). If instead, Ontario continues to pursue a nuclear option, nuclear's share of electricity generation would be significantly higher.

2.4 Renewable Energy

The use of renewable resources is not new in Canada. During the 1800s, almost all of Canada's energy supply was biomass, primarily wood. Gradually this was replaced by coal and then by oil, natural gas, and electricity.

Today renewable energy sources play an important role in Canada's energy scene. About 19 percent of Canada's energy demand is supplied by solar, wind, water, geothermal, and biomass resources which are used to provide liquid fuels, process heat, or electricity. Some 63 percent of this renewable energy supply is large scale hydroelectric resources with greater than 10 megawatts capacity. The hydroelectric sector was discussed earlier. The following discussion, therefore, will consider only developments in the use of biomass, solar, wind, small scale water resources and geothermal power. Together, these supply about 7 percent of primary energy demand in Canada.

Bioenergy - mainly wood - accounts for about 90 percent of renewable energy consumption. Small scale hydro facilities account for about 8 percent and solar power represents the remaining 2 percent.

The growth in demand for bioenergy since the first energy crisis has lead to the development of a significant bioenergy equipment manufacturing capability in Canada and to an improvement in the efficiency of available equipment. These developments have been complemented with progress in novel technologies to utilize bioenergy. Examples include the conversion of biomass to ethanol to power automobiles, the development of wood gasification, and waste combustion technologies. Some of these technologies are already penetrating the market.

The contribution of solar energy sources to Canada's energy picture is only a small fraction of total energy use. However, significant advances have been made in the knowledge base and in building an industrial capacity for the effective use of solar sources. Research in passive solar design (the design of buildings to take maximum advantage of natural sunlight for light and heat) has led to the creation of an industry specializing in the use of solar features in low energy building designs. Photovoltaic conversion of sunlight to electricity is feasible for low power applications in remote areas where the cost of servicing conventional energy equipment is very high. However, due to their high cost, active solar systems (systems requiring equipment to convert sunlight to energy) remain uncompetitive where large-scale electricity is available.

The development of small hydro sites has experienced a revival in the past decade, with the total energy contribution from sites with less than 10 megawatts of capacity amounting to about one and one-half percent of total energy demand in Canada. An industrial capability has been developed to manufacture and install small hydro equipment and Canadian companies have achieved success in marketing their equipment in other countries.

In wind energy, Canadians have developed a manufacturing capability to build wind turbines. Also, developments are occuring in the use of a wind driven pumping machine which might be applied for water management and irrigation.

Overall, renewable energy systems can be economically attractive energy supply alternatives and are likely to be most economic if displacing oil products or electricity. The recent decline in world oil prices has reduced the economic attractiveness of some renewable systems. There are, however, many renewable energy technologies which remain competitive. In the short term, renewable energy systems will continue to be most attractive in northern remote communities and in certain higher cost regions of Canada, including the Atlantic provinces. Over the medium term, the success of many renewable energy technologies depends vitally on their cost and the cost of alternative fuels. In some areas, production costs have dropped dramatically over the last few years. With further technological developments, these costs could be further reduced to where many of today's marginal initiatives could replace the use of conventional fuels. In addition, energy from waste projects represent a renewable energy option which could have the potential to contribute simultaneously to environmental and energy supply needs.

3.0 Energy and The Environment

Society's needs and wants for goods and services are met by combinations of materials, energy and human effort. Waste products are left over at various stages in the creation of these goods and services. In the energy sector, extraction of energy resources, their transformation into usable forms of energy, and delivery to end-users each generate waste. These waste by-products travel through and eventually come to reside in the earth's air, water and land. Some wastes are absorbed and rendered harmless by the "assimilative capacity" of these three zones: many others are not. Society's choices about the amount of energy needed, the types of energy harnessed to meet demand and the degree of pollution control practiced in the exploitation of these resources will largely determine the quantity of energy-related wastes released into the environment.

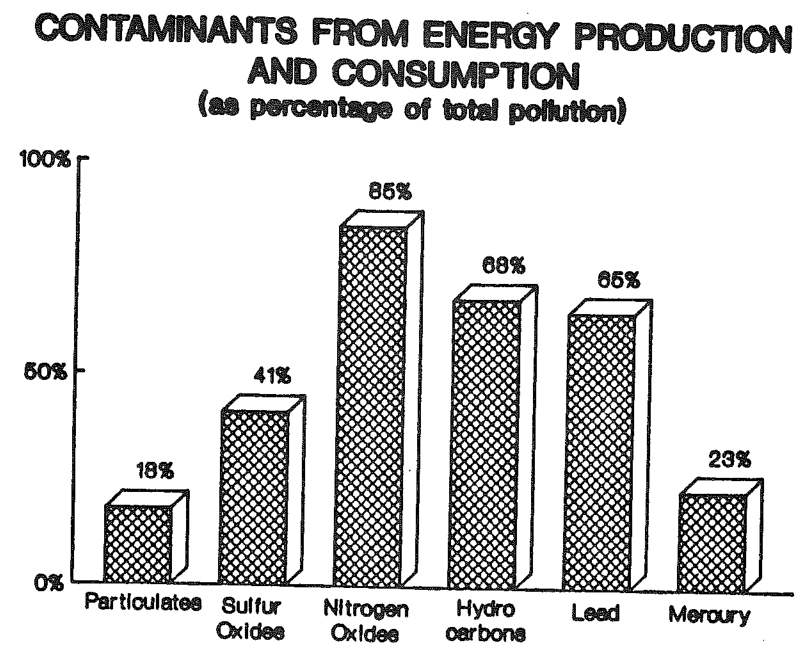
The term pollution is commonly understood as the release of waste products in ways which harm the ability of our environment to sustain life in all its diversity. The development and use of energy resources has been, and remains a significant source of actual and potential environmental damage. Figure 3.1 presents estimates, for selected contaminants, of the amount of total pollution generated in Canada from the production and consumption of energy.

3.1 Environmental Impacts and Risks of Energy Resource Cycles

A variety of impacts of energy resource cycles have captured public attention. At the extraction stage, the mining of coal, uranium and tar sands can disturb large tracts of land which have value in alternative uses (agriculture, forestry, recreation) or left undisturbed (wildlife habitat and areas for general ecosystem renewal). Water systems may also be fouled by these practices unless stringent measures are taken to contain pollutants. Harvesting the hydraulic power of our rivers has created enormous reservoirs where none previously existed, altering forever the initial ecosystem in affected areas. Drilling for oil and natural gas brings the risks of blowouts and pipeline ruptures on fragile ecosystems and human health.

The transformation of resources into useful energy is a stage with characteristic environmental impacts and risks. The combustion of fossil fuels to generate electricity, drive transportation vehicles, power industrial processes and heat buildings generates combustion gases, waste heat and direct solid and liquid wastes. The effects of waste combustion

Figure 3.1



gases have received perhaps the most attention. Oxides of carbon, nitrogen and sulphur, incompletely burned particles and ozone are the principal sources of urban smog, acid rain and the "greenhouse effect" on global climate which are the focus of much current popular concern. So too, are the perceived risks of operating nuclear-electric stations. While their regular operation generates no combustion gases, the possibility of radiation-releasing accidents is a major public preoccupation. In addition, the safe, long-term disposal of spent nuclear fuel and worn-out reactor core hardware is, as yet, unresolved technically and in the public mind.

The energy delivery stage also imposes environmental and health hazards. Super-tanker accidents during ocean transportation of crude oil probably did more to crystalize widespread concern and compel action in favour of environmental protection than any other single category of

mishap. The transportation and handling of liquified natural gas (LNG) imposes risks to safety. Oil and natural gas pipelines are subject to the risk of accidental rupture with the associated impacts on safety and environmental quality. In addition, the possible impact of electro-magnetic radiation from electrical power lines on human health has received closer public scrutiny recently.

The renewable forms of energy - wind, solar, tidal, biomass, hydrogen, and energy from waste - are generally regarded as being intrinsically less polluting than the more conventional, higher technology energy systems. Most forms of renewables, however, are not, in fact, environmentally neutral. Increased use of wood as a fuel could potentially involve problems of deforestation as well as the release of carbon dioxide, hydrocarbons and particulates, if not managed properly. Tidal power projects have the potential to alter fish habitat in ways that damage the fishery resource. So-called "energy from waste" projects, involving incineration of municipal solid wastes can produce usable heat and significantly reduce the volume of this waste being sent to landfill sites with attendant risks to water supplies. However, this reduction in waste volume may be achieved, at the expense of increases in undesirable air emissions and the release of highly toxic organic compounds, such as dioxins, unless these substances are deliberately controlled, at some economic cost. Switching to renewable energy alternatives, even if this were possible on a large scale, would therefore not automatically eliminate energy-related environmental problems but exchange others for the ones we now experience.

3.2 Health, Safety and Environmental Quality - The Unavoidable Linkages

The previous discussion categorizes environmental hazards in a number of ways: by stages of energy extraction, transformation and delivery; by air, water and land zones receiving pollution; and by risks to environmental quality or human health, or safety. In fact, these divisions are not clear cut. As our knowledge improves about which wastes are potentially harmful, and how they travel from their sources to exposure to living organisms, a number of linkages become much clearer. Combustion gases can wind up on land or water and do their damage in a variety of ways. Toxic substances can leach (or be leached) from fly ash disposal piles at coal-fired electrical stations into nearby water courses. Evaporation can recycle and concentrate other toxic wastes in the food chain.

Perhaps the most important linkage is the one between the quality of our environment and the health of living creatures within it. For the more we foul the global habitat upon which we depend, the more impaired will our environment be in its ability to yield the necessities of life. What sometimes obscures this linkage is the delay between cause and effect for many types of pollution. We clearly appreciate the most obvious types of pollution: oil spills from super- tankers unambiguously foul adjacent coastlines, kill fish and sea birds and take considerable time to dissipate. A killer-smog has immediate impacts demanding immediate responses. The accident at the Chernobyl reactor killed more than thirty people in the first few weeks after it occurred, spoiled agricultural produce for regions receiving resultant fallout and rendered habitat for humans and wildlife unlivable in the most affected areas for a very long time. All of the aforementioned episodes involve pollution hazards which, to a considerable extent, we can measure and take concrete steps to counter. However, many other types of pollution - acid rain and the "greenhouse effect" are good examples - can take years to reveal their serious nature. Pollution of this sort introduces an element of uncertainty about the timing, extent and identification of exposed people and areas. This uncertainty tends to weaken private and public willingness to reduce this kind of environmental hazard; it does not reduce the ultimate threat to human well-being imposed by continuing to pollute.

3.3 Management of Environmental Quality in the Canadian Energy Sector

The choice of how to handle wastes created in the various stages of energy production and consumption is framed by the economic, technical and legal conditions which apply in particular circumstances. For example, an electric utility faced with a regulatory requirement to reduce acid gas emissions from coal-burning stations may choose to use cleaner fuel, remove pollutants from combustion gases, or practice some combination of each approach. Where there is no prescribed limit on pollution and polluters do not directly suffer the economic costs of the damages their wastes cause, a third choice is commonly made: doing nothing to reduce pollution.

The virtually uniform failure of the free market system to force the economic cost of environmental pollution back upon polluters has lead to the development of laws and regulations to encourage compliance with environmental standards. In Canada, responsibility for environmental regulation is shared between the federal, provincial and

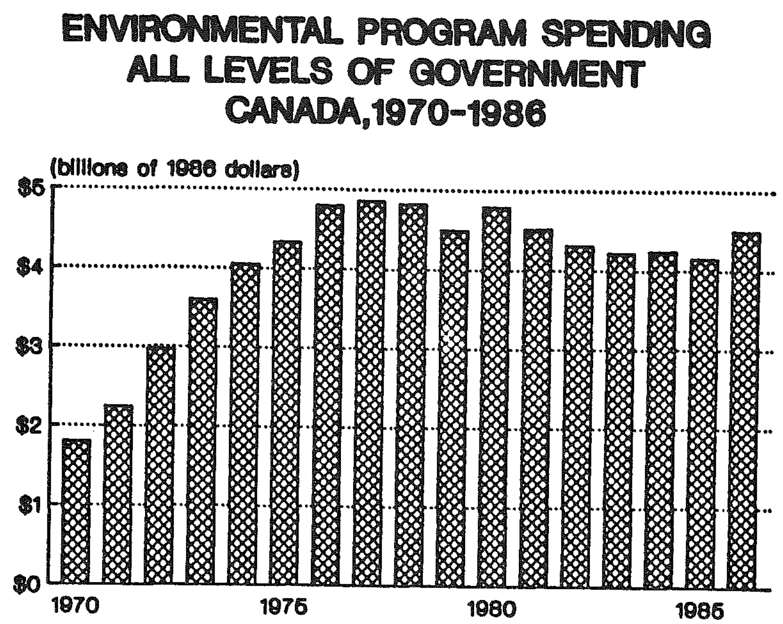
territorial governments and the people who use or abuse the land, air and water resources that comprise our environment. The provinces have a predominant authority over resource management (including environmental quality) and use. Federal jurisdiction generally applies to transboundary concerns - interprovincially, or internationally - and to certain special areas (for example, "the offshore") or substances (for example, nuclear). The Canadian approach to pollution control is to prevent pollution before it happens. This approach is based on the judgement that prevention is preferable to, and far less expensive, than allowing environmental and human health damages to occur and trying to correct for them "after the fact".

The energy sector has been at the centre of the development of regulations, institutions, technology and practices to minimize environmental and health and safety risks. The Federal Environmental Assessment and Review Process, established by Order-in-Council in 1973, gave a thorough treatment of the possible environmental impacts of a natural gas pipeline in Canada's north during the mid-1970s. Energy projects in Canada now routinely incorporate environmental guidelines during their planning stages to the benefit of both project sponsors and the environment. The Atomic Energy Control Board (AECB) takes great care to ensure that all of Canada's nuclear-related facilities - from uranium mines to power plants - are designed and operated in ways that minimize risks to the environment, workers and the public. Environment Canada continues to fund scientific research, disseminate information, assist users of environmental resources to minimize their negative impacts and generally safeguard our natural heritage.

3.4 Progress on Pollution Abatement

The mobilization of public concern about environmental protection during the 1960s put the issue squarely on the political agenda of the federal and provincial governments. Environmental regulations and standards were passed into law and ministries of the environment were created to carry out the task of environmental protection. As our concern and knowledge about serious sources and types of pollution have grown, so has the search for practical technology and operating techniques to minimize energy-related pollution at all stages of the resource cycle. Local, provincial and federal governments spend in the order of $4-5 billion annually on environmental programs (ranging from the treatment of drinking water and disposal and treatment of municipal and industrial wastes to regulation) and scientific research (see figure 3.2). Industry as well spends several hundred million dollars each year to meet environmental quality standards.

Figure 3.2



A number of practices and types of equipment have been developed to minimize energy-related pollution. Land reclamation practices following surface mining of energy resources are well understood and effective. Tar sands operations are designed to meet environmental standards. Blending of cleaner coals into electric utility fuel supplies and the physical and chemical cleaning of coal are proving effective at reducing pollution before combustion. Burning processes themselves, such as fluidized bed combustion for coal, hold much promise to reduce contaminants in the combustion gases of electric utilities and industries. Cleaning combustion gases with scrubbers, filters and electrostatic precipitators are among the other effective ways of reducing acid gas emissions when fossil fuels are burned. The use of nuclear reactors to generate electricity in Ontario and New Brunswick has kept acid gas emissions in check even as electric power systems have grown.

Direct waste management practices in energy production and consumption are developing. In industries and electric utilities that burn fossil fuels, post combustion wastes are now routinely collected, stabilized and rendered virtually neutral. Research into the safe, long-term disposal of nuclear waste is proceeding. The technology and practices to burn solid wastes are being successfully developed. Instead of sending all of these wastes to landfill sites, some are being incinerated, greatly reduced in volume (up to 95%) and tapped for their by-product heat to heat buildings, run industrial processes and generate electricity. The economic value of by-product heat is helping to offset the cost of this waste management alternative, making it competitive with the landfill option in regions where landfill sites are becoming scarce and relatively expensive. Currently available technology can control combustion gas emissions and stabilize toxic substances in post-combustion solid wastes acceptably from an environmental and health perspective.

In the transportation sector, the more stringent regulation of motor vehicle tailpipe emissions of hydrocarbons, nitrous oxides and carbon monoxide has been the principal factor in reducing environmental impact. These tighter emission standards were responsible for the introduction and subsequent widespread use of unleaded gasoline and for the development of non-lead octane-boosters.

Conservation investments and practices and structural changes in the Canadian economy towards less energy-intensive activities have also made a significant contribution to controlling environmental damages. The production and consumption of energy and associated wastes have, thereby, been kept below what they would otherwise have been. Additional benefits have been realized when greater energy efficiency has been achieved through more complete combustion of fuels with fewer resultant wastes.

These efforts are beginning to have positive results, especially regarding pollutants from the consumption of fossil fuels. Total emissions in Canada of sulphur dioxide have dropped by about 30 percent since 1965. Other contaminants, such as particulates, oxides of nitrogen and lead have been dropping as well. Carbon dioxide and ozone are the significant contaminants which are continuing to increase in concentration.

3.5 The Challenge Ahead for the Energy Sector

Progress to date in making energy production and consumption cleaner, safer and more efficient has been encouraging. Much remains to be done, despite progress to date, if longer-run, cumulative environmental damages are to be avoided, and destructive processes already begun are to be reversed. Significant improvements must be made across a wide front, if necessary recovery in environmental quality is to be accomplished. The need for better understanding of pollution causes, effects and prevention is undeniable. The real challenge ahead for the Canadian energy sector is not simply to recognize what needs doing, however, but to choose to exploit those processes, technologies and materials that minimize environmental and economic costs in the provision of all kinds of energy services.

Conservation could contribute by moderating, and perhaps reducing, society's appetite for energy, and the wastes associated with it. Moreover, society could choose to satisfy requirements for new energy supplies in ways that minimize environmental impacts. In some regions of the country and in particular applications, renewable and relatively decentralized energy options will likely have a role to play. In other regions and applications, exploitation of more conventional energy options in environmentally responsible ways will likely prove to be the sensible course. The need to put in place reliable measures and procedures to prevent pollution damages will be particularly critical as development and production of oil and gas reserves proceed in offshore and frontier areas where operating conditions can be hostile and ecosystems are extremely fragile. Expenditures by the private and public sectors on the research, development and demonstration of cleaner technologies and processes will support the recovery of a healthier natural environment and foster the development of an innovative environmental protection industry.

Demand for energy is derived from needs and wants for the services it provides: heat and cooling, light, transportation etc. Society's choices about many things strictly outside the energy sector - housing, vehicles, consumer products, food - impact upon the production of energy-related wastes. The environmental problems of energy production and consumption, and their solutions, begin and end with the broad choices society at large makes.

Perhaps the broadest and most difficult challenge is posed by the international scope of environmental concerns stemming from the production and consumption of energy. Acid rain, the long-term climatic impact of increasing carbon dioxide concentration, safe operation of nuclear power plants and depletion of the earth's ozone layer are environmental and health issues facing all nations. Successful resolution of these and other issues will determine whether the global

habitat remains a fit place to support life. Cooperation among all countries, developed and developing, producers of pollutants and recipients alike, is crucial if the challenge is to be met to benefit both economically and environmentally from harnessing energy resources.

4.0 Energy Security

The debate on energy security, both in Canada and elsewhere, has focussed primarily on the availability and price of oil supplies. Despite considerable progress in reducing dependence on oil as an energy source, major industrialized countries still rely heavily on oil. In Canada, oil is our most important energy source, accounting for about 40 percent of our total energy consumption (down from 56 percent in 1973). It also represents Canada's major energy import.

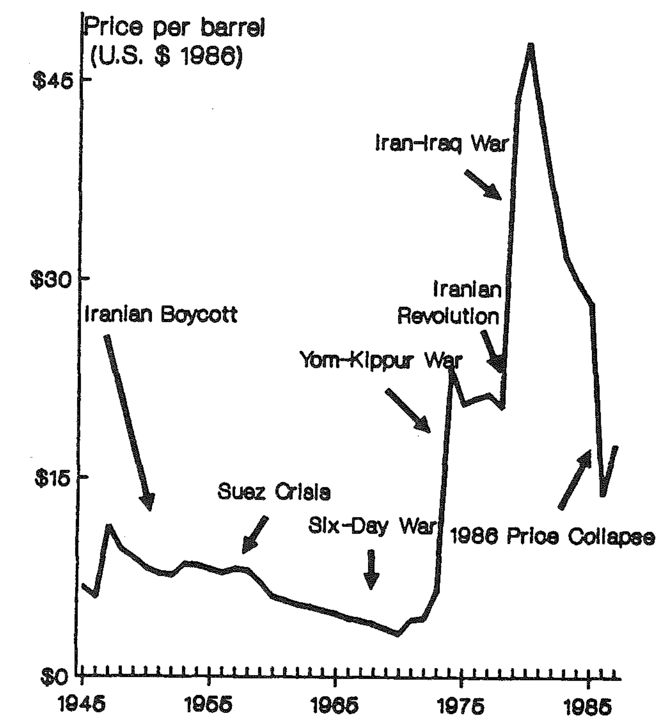
Security of supply relates both to physical supplies and price shocks. In terms of physical availability, security of oil supply means adequate assurance that, in an emergency, sufficient oil supplies are obtainable by all Canadians to maintain reasonable levels of economic activity, comfort and mobility. Concerning price effects, security of oil supply means the protection of the economy from sudden sharp increases in the price of oil (and close energy substitutes) which, in the past, have radically altered terms of trade and reduced national income.

There have been six disruptions in world oil supplies since 1950, all originating in the Middle East (see figure 4.1). Most were of short duration, lasting from one to six months. Three caused relatively little dislocation in the economies of the consuming countries and relatively insignificant price increases, largely because of adequate excess capacity in the world oil market to replace supply losses. The Suez crisis of 1956 caused hardships in Europe. The 1973 and 1979 disruptions had widespread effects, most notably the huge run-ups in the price of oil which contributed to the major economic recessions experienced in much of the world.

A disruption in world oil supplies could occur at any time, as the current tensions in the Gulf demonstrate. Under existing market conditions, only a disruption considerably larger than those experienced in the past would likely cause significant or lasting hardships for consumers. The non-OPEC share of world production - which increased dramatically as a result of the oil price shocks - is much larger now than it was in the 1970s. World excess capacity is in the order of 9.3 million barrels a day, equivalent to 16 percent of world oil consumption or 27 percent of the oil consumption of western industrialized nations. Thus, even quite a large disruption in deliveries would likely soon be replaced by alternative sources, though there is always a risk of short-term price shocks based on fear and speculation.

Figure 4.1

REAL OIL PRICES, 1945-1987



1987 Estimated.

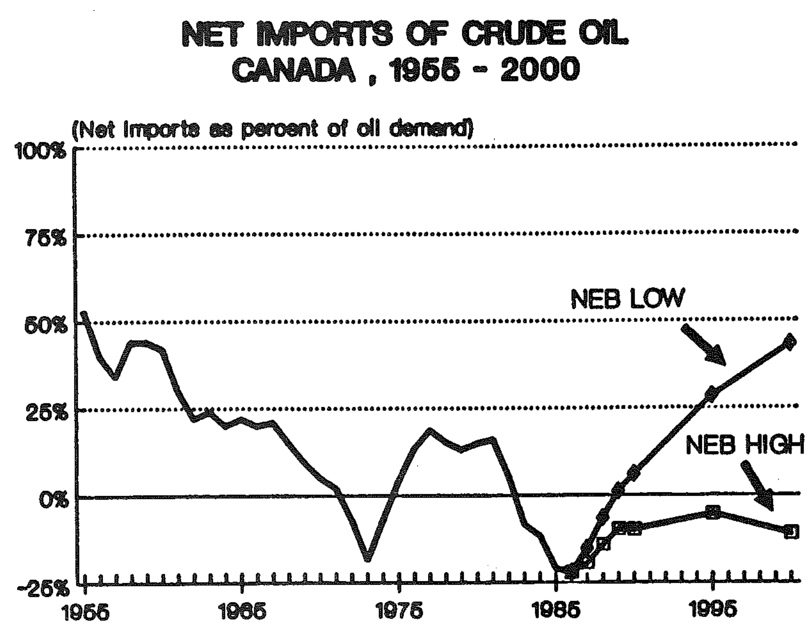
In the medium to long-term, prolonged lower oil prices would dampen non-OPEC production, reduce the incentive to conserve oil and substitute other energy sources, and lead to an oil market once again significantly dependent on potentially unstable producing regions. By the mid-1990s, a world oil supply disruption could once again give rise to more lasting shortages and price shocks. The disruptive effects may not be as large as they were in the 1970s, because oil has a smaller share of energy markets, there is more flexibility between energy commodities, and many governments have planned emergency demand restraint measures and/or possess emergency oil stocks. As well, OPEC producers are less likely to see very high prices as being in their longer term interests.

4.1 Energy Security In Canada

Canada is in a highly favoured position among industrialized countries in terms of its energy endowment. Moreover, Canada entered the current downturn in the oil cycle in a strong position, having become a net oil exporter in 1983. As recently as 1981, Canada was a net crude oil importer of 350,000 barrels per day. Net imports of light and medium crude oil were even larger at 510,000 barrels per day. This situation turned around substantially in the 1980s as both consumers and producers responded to higher oil prices. In 1986, Canada was a net crude oil exporter of 225,000 barrels per day, though we were still a net importer of 100,000 barrels per day of light and medium crude. Both figures are modest compared to our total oil consumption of about 1.5 million barrels per day in 1986.

The National Energy Board provided a detailed examination of Canada's energy prospects, subsequent to the oil price collapse, in its report Canadian Energy Supply and Demand 1985-2005, published in October 1986.

Figure 4.2



In its higher oil price case*, Canada would remain a net crude oil exporter beyond 2005, while in its lower price case*, Canada would become a net crude oil importer by 1989 (see figure 4.2). In both scenarios, Canada would continue to be a net importer of light and medium crude oil, as reserves from conventional producing areas in western Canada are depleted. Depending on future prices, Canada is forecast to become a net importer of light and medium crude of between 465,000 and 585,000 barrels per day by 1995 (36 to 43 percent of projected demand) and of between 370,000 and 750,000 barrels per day by 2000 (28 to 54 percent of projected demand). In the higher price case, there is forecast to be considerable production of light and medium crude oil in the frontier by the late 1990s, plus a much higher level of heavy crude oil production. However, it is expected that there will continue to be a limited capability in Canada to upgrade heavy crude oil to the lighter petroleum products most desired by consumers (gasoline and home heating fuels).

In 1986, Atlantic Canada relied on imports for 99 percent of its oil needs while Quebec imported 60 percent of its oil requirements. In the lower price case, virtually all of the oil needs of Quebec and the Atlantic provinces would be imported by the mid-1990s and 56 percent of Ontario's oil requirements would be imported by 2000. In the higher price case, Quebec would still import virtually all of its oil needs after 1995. Atlantic Canada, however, is forecast to import only 29 percent of its oil requirements, and Ontario only 9 percent of its needs, by 2000, as East Coast and Beaufort production comes on stream. Both of the NEB's scenarios suggest that by 2000, transportation will account for about two-thirds of our total oil consumption. The Atlantic provinces are expected to remain more dependent on oil in the residential, commercial and industrial sectors than the rest of Canada in both price scenarios (see figures 4.3 and 4.4).

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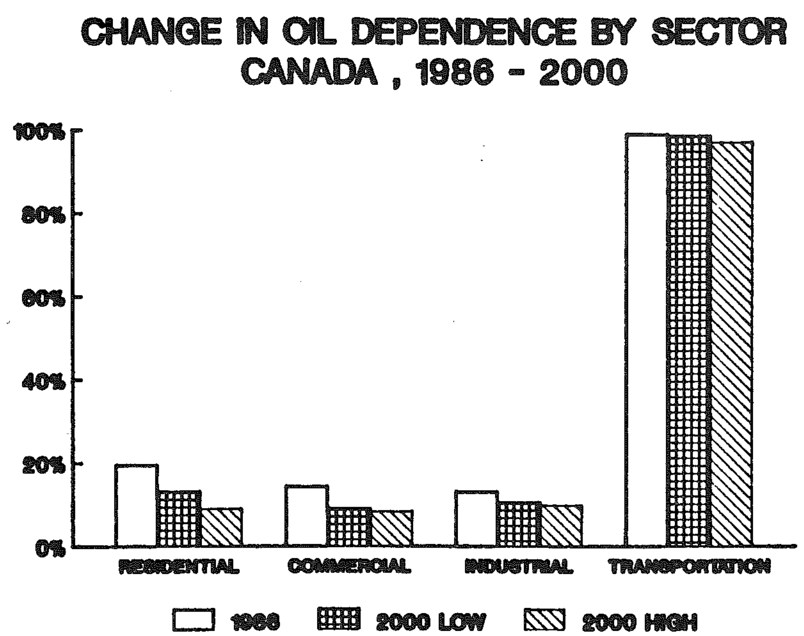
* In the high oil price case, prices rise to $27 (1986, US) per barrel by 1995 and remain at that level until 2005. In the low oil price case, prices rise to $18 (1986, US) per barrel by 1995 and remain at that level until 2005.

Figure 4.3

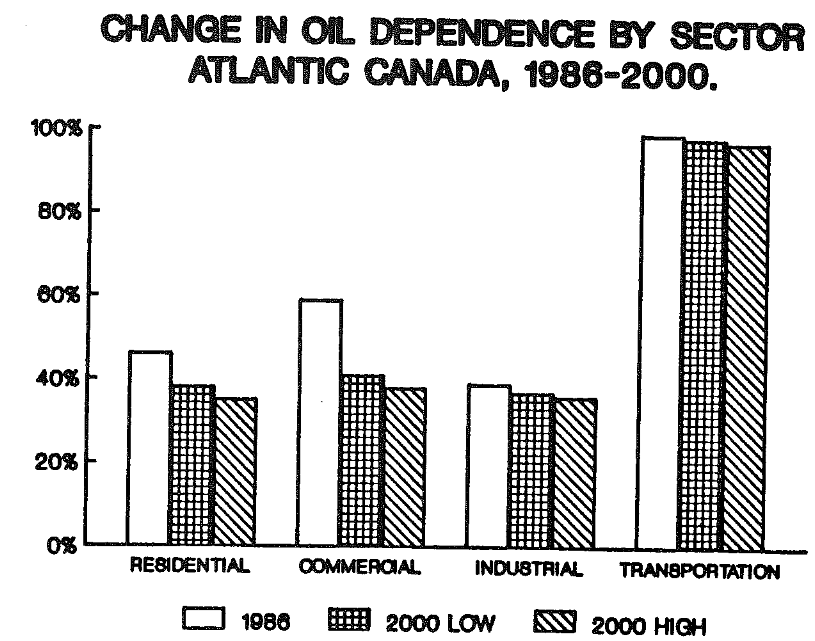


The NEB's scenarios represent a possible range of prices for the 1990s and early 2000s. Views on longer-term price developments are, of course, continually revised as new events unfold and additional information becomes available. Many recent surveys have concluded that the NEB's higher price scenario is more likely than its lower one. Very broadly, many forecasters anticipate the real oil price will be around $25 per barrel in the mid-1990s, and above $30 per barrel by the end of the next decade. Thus, it is not entirely clear that Canada will become a major oil importer relative to its own past experience or in comparison to other industrialized countries.

4.2 Existing Measures for Achieving Security of Supply

Measures for achieving security of supply can be pursued in two ways; as domestic responses, which Canada can pursue

Figure 4.4



alone, and as international responses, which Canada would pursue in cooperation with its trading partners. Since Canada is a relatively small consumer and producer of oil on a world scale, it cannot, by acting alone, preempt a world disruption or dampen the price shock.

If a disruption of oil imports were to occur today, Canada is capable of responding in several ways. Surge production from the existing supply base and fuel switching in the industrial sector could offset an import disruption equal to about 5 percent of oil consumption. Voluntary restraint measures could possibly reduce oil requirements by about 3 to 4 percent. There might also be some drawdown in private stocks. Allocation and rationing controls could be implemented by the Government of Canada under a declared emergency. Obligatory restrictions on oil use could be imposed by provincial governments.

Canada is also a founding member of the International Energy Agency (IEA), which was created in November of 1974. The IEA requires its members to maintain emergency oil reserves equal to 90 days of net oil imports (at present, this requirement is not relevant to Canada since we are a net oil exporter). A central feature of the IEA is the Emergency Sharing System (ESS) which may be activated when one or more member countries experience a reduction in normal oil supplies equal to 7 percent or more of current consumption. The oil allocation procedure involves sharing the oil available within the IEA Group. Each member country is required to restrain oil demand by 7% and/or draw upon its emergency reserves.

The oil made available by these measures is then shared among the member countries. If the supply reduction reached 12%, the same procedure would apply, except that demand would be restrained by 10%. In an emergency, Canada would likely be in a net "sharing" position since most other IEA countries are not significant oil producers and hence would be more adversely affected than Canada by a world supply disruption. This means that Canada would therefore likely be required not only to maintain its exports to other IEA countries but to increase them.

The oil supply disruption of 1979 showed that considerable economic damage could still be caused by price shocks even if the volume of oil disrupted was not sufficient to activate the general IEA Emergency Sharing System. A decision by the IEA Governing Board in July of 1984 requires all IEA member governments to take collective and coordinated action to help calm oil markets in a "pre-trigger" situation. Governments can choose from a variety of complementary measures, including the drawdown of emergency stocks, the imposition of demand restraint measures, surge production and fuel switching. The IEA has developed a set of procedures to implement the July 1984 decision with respect to the coordinated emergency response measures (CERM) and will test these procedures in early 1988.

While the IEA devotes much of its time to emergency preparations, the adoption of common energy policy principles in the early years of the organization's existence has contributed to the success registered by member governments in reducing their dependence on oil. These involve the use of alternative energy sources and oil substitution, collective participation in research and development initiatives, concerted conservation efforts and increased domestic production of oil and other energy forms such as gas, coal, nuclear power and hydro-electricity.

Since 1973, due to high energy prices and concerted government policies, IEA countries have been successful in reducing their requirement for oil from outside sources from 23.7 million barrels per day (63% of their consumption) to 14.9 million barrels per day (46% of consumption) in 1985. This reduced the vulnerability of IEA countries to an oil supply disruption and it contributed to the large excesses in oil production capacity which were a factor in precipitating the major fall in oil prices.

4.3 Options for Enhancing Security

To the extent that it were deemed desirable to enhance security of supply there are two general approaches which could be adopted. There are emergency measures (in addition to the existing ability to implement allocation and rationing controls) for responding to the disruption at the time it occurs. As well, there are certain fundamental measures which could be pursued to reduce oil imports or to reduce the proportion of imports likely to be disrupted.

Emergency Measures

(1) Regulating the Price Of Oil

Price shocks can affect the Canadian economy in two ways. There are the direct effects emanating from the rise in the domestic price of oil (plus associated increases in the prices of competing fuels). And there are the trade effects emanating from the increase in the price of our energy exports and imports and from the reduced demand for all Canadian goods and services by our trading partners to the extent that their economies experience a slowdown. Price controls would only respond to the direct effects of the price shock. They would not protect Canada from the adverse trade effects. Price controls did not prevent Canada from sharing in the worldwide inflation and recessions that followed the oil price shocks of 1973 and 1979.

(2) Emergency Oil Supplies

Virtually all oil stocks in Canada are held privately by companies. In terms of days of consumption, Canadian stocks are somewhat lower than those of most other IEA countries, including other oil exporting countries such as the United Kingdom and Norway. Japan and most European OECD countries require oil companies to maintain oil stocks equivalent to 90 days or more of sales. In Canada, it is uncertain whether the federal government has the authority to mandate company stocks, other than during an emergency.

A number of countries have established government-owned stockpiles; notably the United States, Germany and Japan. A government stockpile in Canada could be located close to Quebec and Atlantic Canada, the regions that would be most vulnerable to a supply disruption.

Emergency stocks can be an effective instrument in terms of speed, administrative simplicity and lack of unwanted distributional and equity effects, and appear to be well suited for responding to the kind of sudden but brief disruptions that have occurred in the past. They require significant investment in advance of the emergency and may be ineffective if the shortage is very long and severe.

(3) "Shutting In" Spare Productive Capacity

In a market-oriented environment, companies normally produce at close to capacity levels. Nevertheless, there exists some short-term capability to increase production, estimated, at present, to be about 50,000 barrels per day of light and medium crude oil. In theory, governments could create additional surge capacity for use in an emergency by restricting output from existing fields. The Government of Canada, however, does not have the direct authority to order producers to shut-in part of their reserves. Since only a small fraction of reserves in the ground can be produced at any one time, establishing a significant emergency response capability would require the shutting in of many barrels of potential crude supply. For example, if additional surge capacity of 100,000 barrels per day were required, it would be necessary to shut in about 365 million barrels.

(4) Enhancing Multi-Fuel Capability

In the event of an oil supply disruption, oil users possessing multi-fuel capability might be able to switch to an alternative fuel. While this kind of substitution capability is currently limited in the transportation and residential sectors, some industrial and commercial enterprises possess an installed switching capability that enables rapid fuel substitution, usually in less

than five days. The existing oil switching capability in Canada is equal to about 20,000 barrels per day, most of it located in Ontario and Quebec, with natural gas the dominant alternative fuel.

While increased multi-fuel capability may lead to more efficient energy markets, its usefulness in an emergency will depend on two factors: the extent to which those possessing this capability are consuming oil at the time the emergency occurs; and the existence of surplus production and transportation capacity for the alternative fuel. This option is significantly constrained in the Atlantic provinces because of lack of access to natural gas.

(5) Diverting Oil Exports

Canada responded to the 1973 world oil crisis by introducing an oil export tax, followed by a phase-out of oil exports. If the world oil supply disruption were large enough to activate the IEA Emergency Oil Sharing system, Canada would likely be obligated to increase its oil exports. Even if Canada were not bound by its current international obligations, much of our oil exports could not be directly substituted for imports. Eastern Canadian refineries, the chief users of imported oil, have limited capabilities to handle the heavy and synthetic crudes which make up an increasing proportion of Canada's oil exports.

Fundamental Measures

In addition to the emergency responses, more fundamental changes could be pursued aimed at altering Canada's pattern of energy consumption, production and trade in order to reduce our vulnerability to a supply disruption. Governments could encourage the desired changes through a variety of instruments such as grants, taxation measures, and support for research and development.

(1) Reducing Oil Imports

A reduced level of oil imports could be achieved by enhancing domestic oil supplies, conserving oil use or substituting alternative forms of energy for oil. There are a number of barriers which could limit further progress towards reducing oil demand and enhancing supply in Canada.

° The demand for all forms of energy, including oil, will increase due to economic growth and demographic changes.

- It is probable that Canada has already extracted the cheapest oil from the conventional producing areas of western Canada. New reserves of oil are becoming increasingly costly and difficult to find.

- Many of the least costly substitution and conservation opportunities have already been exploited.

- There are significant economic and technological limitations to substitution in transportation, which remains almost entirely dependent on oil.

- There are limited opportunities for oil substitution in Atlantic Canada because natural gas is not currently available and electricity is expensive.

Thus, considerable government effort, and expense, might be required to bring about a significant and sustained reduction in oil imports, particularly if oil prices remain at their current level. Moreover, substitution, conservation and oil supply enhancement measures may not always lead to a reduction in imports from unstable suppliers and hence to an increase in oil security. These measures might instead lead to increased exports or to reduced purchases of oil that are unlikely to be disrupted.

(2) Diversifying Imports

Some imports are more likely to be terminated without warning than others. Imports from the Middle East appear to be the most insecure, given the political instability in that part of the world and the fact that nations in this area have, in the past, attempted to use oil exports as a political weapon (e.g., the 1967 and 1973 embargoes). Canada is not heavily dependent on Middle East supplies at present, but our import mix could be quite different 10 years from now.

Diversifying imports will not necessarily enhance oil security. The world oil market is so highly integrated and short-term in nature that purchasing patterns prior to the disruption may be irrelevant. Even if Canada were able to avoid an oil import disruption by purchasing from "secure" foreign sources, under the IEA Emergency Oil Sharing System, we would still be required to cut back on our imports, or increase our exports, and share our oil supplies with other IEA countries.

Some of the options to enhance security -- stock drawdown, enhancing multi-fuel capability, reducing imports -- could be pursued alone or in cooperation with our trading partners. A more detailed examination of all of the above options is contained in an EMR discussion paper entitled Energy Security in Canada, which is available on request.

5.0 Canadian Ownership and Control in the Energy Sector

5.1 Ownership and Control

Canadians historically have been concerned about the extent of foreign dominance in strategic domestic energy industries. The degree of foreign dominance, and conversely the level of Canadian participation, is gauged through the extent of Canadian and non-Canadian ownership and control of these industries.

Ownership and control are used to measure different aspects of corporate structure. Ownership is a measure of the proportion of equity held, either directly or indirectly (through intermediate owners) by Canadian or foreign residents. Government policy might focus on ownership, if the main concern were with ensuring that the returns from ownership of the resource (such as dividend payments in times of high profitability) accrue to Canadians.

Control, on the other hand, indicates whether business decisions are made by foreign or Canadian interests, and is determined by the size of equity holdings and the composition of the Board of Directors. A control policy therefore might be more appropriate if the main concern is influencing corporate behaviour. An entity is generally considered to be Canadian-controlled if 50 percent or more of its voting shares are held by Canadian residents. In a few exceptional cases, when a significant block of shares in a corporation is held by Canadian residents and the remaining shares are widely held, an entity may be effectively Canadian-controlled even though more than 50 percent of its voting interests are held by non-residents.

5.2 Government Policy Objectives for Ownership and Control in the Energy Sector

In view of the concern over foreign dominance, successive governments have set objectives for the extent of Canadian ownership and control in the energy sector. Policy varies somewhat by industry, reflecting the different nature of the industries and their traditional extent of Canadian participation.

a) Petroleum

The government's overall objective in the petroleum industry is to promote 50 percent Canadian ownership of the production of oil and gas. Given that the frontier lands will be developed largely through major projects, it has a further objective to ensure that each development in the frontier is 50 percent Canadian owned upon production.

b) Uranium

The government's existing policy in the uranium industry is to ensure that new uranium mines in Canada are at least 50 percent (preferably 67 percent) Canadian owned at the production stage. A level as low as 50 percent ownership would be allowed <u>only if</u> the project were Canadian controlled, or it were determined to be of net benefit to Canada, otherwise the mine must be 67% Canadian-owned.

c) Coal

In the coal sector, the government's policy is to maintain at least 50 percent Canadian control of the industry.

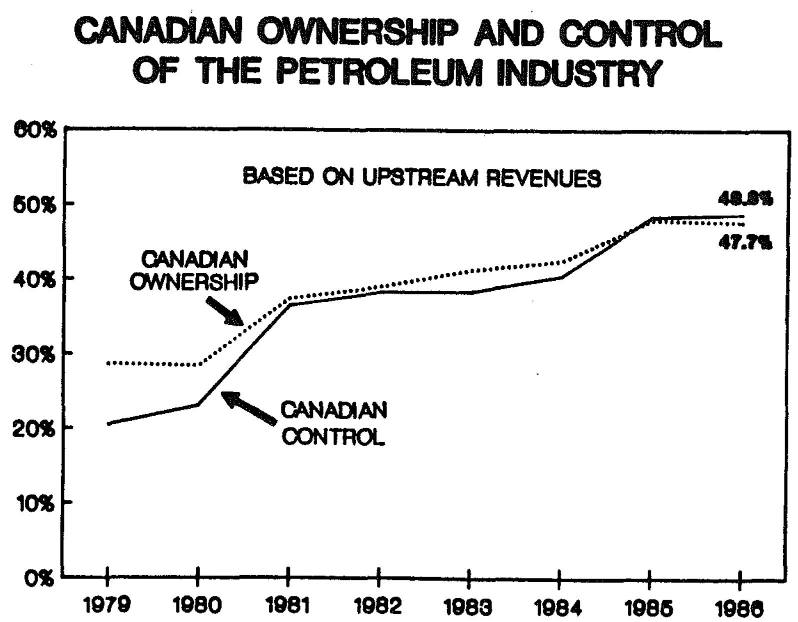
5.3 Current Levels of Canadian Ownership and Control

a) Petroleum

The oil and gas industry has historically been dominated by foreign interests. In 1957, 75 percent of proven oil reserves in Western Canada were controlled by 6 of the largest international companies. In 1979, Canadians owned only about 28.5 percent of revenues generated by oil and gas production, and controlled only about 20.5 percent of revenues. Canadian ownership and control of the industry have increased significantly since 1979, reaching 47.7 percent and 48.8 percent respectively in 1986 (see figure 5.1).

The increase in Canadian ownership and control over the last decade has been largely the result of a combination of the creation of Crown corporations, takeover activity, and more rapid growth among the smaller companies which typically had higher Canadian content. The pattern of ownership in the industry began to change in the mid-1970s with the creation of a number of Crown corporations including Petro-Canada, CDC Oil and Gas (now Canterra), Alberta Energy Corporation and Saskatchewan Oil and Gas. These companies, as well as private sector Canadian firms, undertook a number of acquisitions of foreign-controlled companies which expanded the Canadian segment of the industry.

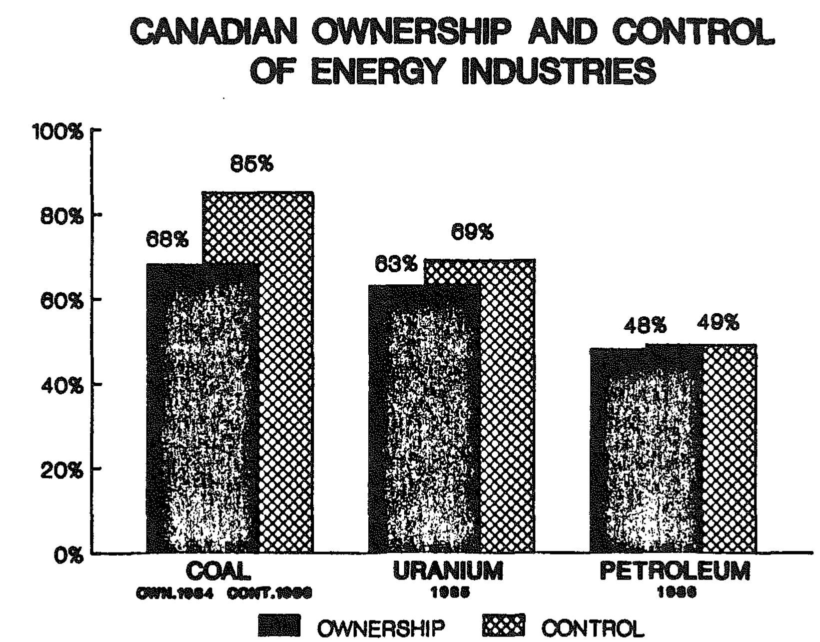
Figure 5.1



Petro-Canada made three major acquisitions which gave it a significant presence in the upstream industry - Atlantic Richfield, Pacific Petroleum and Petrofina. CDC Oil and Gas acquired Aquitaine and Texasgulf.

Among the private sector firms, Dome was the most active. It made $5.8 billion worth of acquisitions from 1979 to 1981, including Mesa Petroleum, Siebens, Kaiser Petroleum and Hudson's Bay Oil and Gas. The most significant recent takeover which increased Canadian ownership and control was that of Gulf Canada by Olympia and York in 1985. This transaction increased ownership by 4.2 percent and control by 6.8 percent. Canadian ownership in the industry is now close to the government target of 50 percent (see figure 5.2).

Figure 5.2



b) <u>Uranium</u>

In contrast to the petroleum sector, Canadians have traditionally owned and controlled a significant majority of uranium mining capacity in Canada. The industry has been characterized by direct government participation through Crown corporations. The extent of Canadian ownership currently exceeds the government's objective.

c) <u>Coal</u>

Canadians have also traditionally owned and controlled a majority of the coal produced in Canada. The coal industry has recently attracted foreign investors seeking to develop supplies for industrial consumption in their own countries, but Canadians continue to have a strong ownership and control position in the sector, significantly exceeding the government's ownership objective.

5.4 Regulation of Foreign Ownership and Control in Canada

Foreign ownership and control of the energy sector is regulated through the general application of the Investment Canada Act, and through regulations specific to each sector.

i) Investment Canada Act

Direct foreign investment in all sectors of the Canadian economy is regulated through the Investment Canada Act. The Act requires that acquisitions of control of large Canadian businesses by non- Canadians be approved by the government. Direct takeovers of businesses with assets of at least $5 million are subject to government approval. Indirect acquisitions (i.e. acquisitions resulting from a foreign parent being taken over outside of Canada) must also be approved if the value of the assets involved is at least $50 million. (Indirect takeovers of assets between $5 million and $50 million are reviewed only if the majority of the assets acquired are in Canada.) For government review purposes, the acquisition of at least one-third of the voting shares (but less than a majority) is presumed to be acquisition of control unless it can be established otherwise. The acquisition of a majority of the voting interests, however, is deemed to be acquisition of control regardless of the circumstances. The establishment of new businesses by non-Canadians is not subject to government approval.

Acquisition proposals are approved if Investment Canada determines that they will likely be of net benefit to Canada. Investment Canada must take into account a number of factors of assessment in its determination, one of which is the compatibility of the proposal with federal and provincial government policies.

The government's ownership objectives for the energy sector outlined above are taken into account in the net benefit determination. Acquisitions in the petroleum industry, however, have special status in the review procedure due to concerns about the high degree of foreign ownership and control in the industry.

ii) Regulations Specific to Each Sector

a) Petroleum

The government's ownership policies in the petroleum sector are applied through two policy instruments - an acquisitions policy which applies to all proposed acquisitions reviewed by Investment Canada, and the Canada Petroleum Resources Act (CPR Act), which applies specifically to developments on the Canada Lands.

The acquisitions policy was approved by Cabinet in December 1985. It applies to foreign takeovers of both Canadian-controlled and already foreign-controlled businesses which own producing petroleum reserves. The policy allows takeovers of foreign-controlled businesses subject to a negotiated increase in Canadian ownership and improved investment spending. Takeovers of Canadian-controlled businesses, however, are considered only if the business is in demonstrable financial difficulty - takeovers of healthy Canadian-controlled businesses are not allowed.

The CPR Act replaced the Canada Oil and Gas Act in 1986. It provides the regulatory framework for the administration of petroleum development on the Canada Lands. The Act requires that Canadians must have at least 50 percent ownership interest in a discovery before the government can grant a production licence. (This provision applies to discoveries made after March, 1982.)

A development plan for the project must be submitted to the government before a production licence can be issued. If, at the time the plan is submitted, Canadians do not own 50 percent of the project, the interest holders must show in the plan how the level can be raised to 50% by the time the production licence is to be awarded. In a case where the development stage is completed and a Canadian ownership deficiency still exists, the Act sets out two alternatives. The appropriate Minister may postpone or waive the ownership requirement and award the licence if, notwithstanding the best efforts of the interest holders, 50% Canadian ownership could not be achieved. Alternatively, the Minister may require a sale by public tender of a share in the project sufficient to increase the level of Canadian ownership to 50%.

b) Uranium

The government's Canadian ownership policy for the uranium industry is a guideline for the industry in developing mining projects, and therefore it is not established in the form of legislation. It is, however, applicable through the Investment Canada review of acquisitions of uranium mining businesses, although a specific acquisitions policy is not in place as in the case of the petroleum industry.

The uranium industry is also subject to the Canada Mining Regulations (issued under the authority of the Territorial Lands Act) which apply to mining in the Northwest Territories. Current regulations require foreign entities to have 50 percent Canadian ownership or be listed on a Canadian stock exchange in order to qualify for an exploration lease. This provision, however, has been eliminated from the revised regulations which will soon come into effect.

c) Coal

Since Canadian presence in the industry has historically significantly exceeded the government's goal, the objective is not enforced through specific legislation or a sector specific acquisitions policy. The policy does require, however, that EMR monitor the industry and report to the Minister any significant decline in Canadian control.

The Canadian Mining Regulations also apply to the coal industry in the Northwest Territories.

6.0 Energy R&D

R&D critically influences the choices available to consumers and producers through its impacts on the cost of resource extraction, methods of production and transportation, the uses to which energy resources can be put, and the efficiency with which they are used. In addition, energy R&D activities affect such important areas as regulation, standards and safety, and respect for the environment.

6.1 International Comparison

Canada's performance in terms of overall R&D spending as a percentage of GDP (which was 1.3% in 1985) has traditionally lagged behind most of the major OECD countries. Canada is, however, a large spender in terms of energy R&D, particularly when the size of its economy is taken into account. Furthermore, Canada is one of the few IEA countries whose energy R&D budgets have continued to grow in real terms since 1975. Compared to other countries, it is also interesting to note that the share of private sector funding of total energy R&D in Canada is generally greater than elsewhere, with the notable exception of the U.S (see figure 6.1).

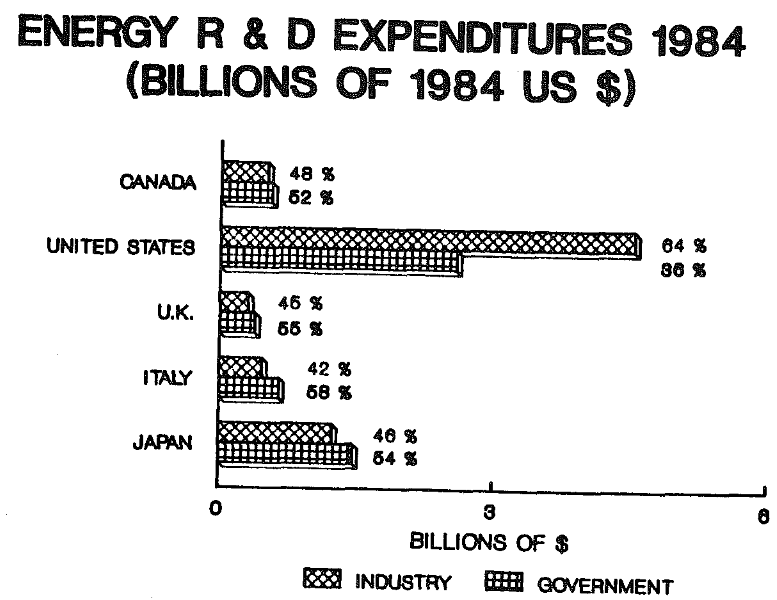
6.2 Energy R&D Within Canada - An Overview

In 1985, twenty percent of Canadian R&D spending was dedicated to the energy sector. The funding of energy R&D expenditures within Canada in that year was split evenly between the public and private sectors. The private sector, with expenditures of close to $500 million, was the single largest contributor, while the federal government accounted for more than 80% of the public sector half of energy R&D funding (see figure 6.2).

The single largest component of overall Canadian energy R&D expenditures is nuclear R&D. Funding for this activity amounted to almost $250 million in 1985, or just over one-quarter of total expenditures. This is followed closely by expenditures for the development of fossil fuels, including oil sands, heavy oil and coal.

The distribution of private and public sector funding varies considerably across the principal areas of R&D activity. The private sector, for example, accounts for a full two thirds of total expenditures in the areas of new liquid fuels, conventional oil, gas and electricity, and fossil fuels R&D (see figure 6.3). In contrast, the federal government accounts for 80% of the funds allocated to nuclear R&D and 50% in the case of renewables.

Figure 6.1

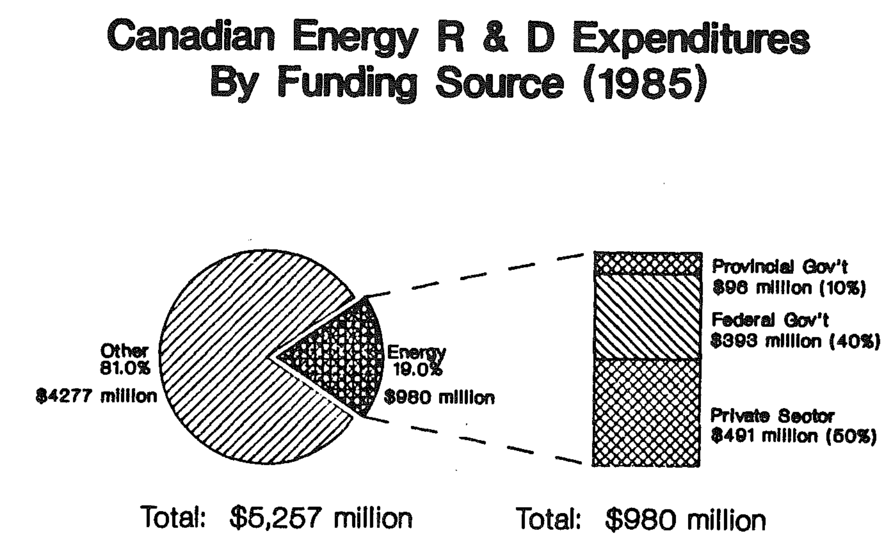


6.3 Energy R&D in The Private Sector

A significant proportion (roughly one-fifth) of the Canadian private sector R&D effort is energy related. Of the close to 2,000 firms performing R&D in Canada in 1985, 17% were reported to be engaged in energy-related R&D activities. These 316 companies performed almost 40% of all industrial R&D, including $700 million in non- energy areas.

Private sector energy R&D activities are carried out by a number of industries. These include, for example, the crude oil, natural gas and coal industries, and electric utilities and oil refineries, as well as the pulp and paper, chemical products and various other industries in the manufacturing sector. Despite the wide range of industries involved, private sector energy R&D expenditures tend to be heavily concentrated. Of all the firms performing energy R&D, an

Figure 6.2



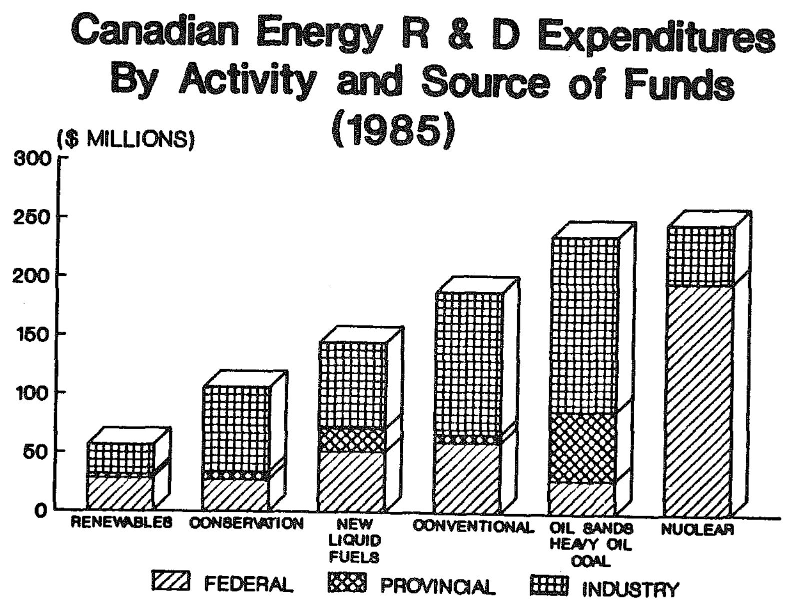
estimated 10%, mainly oil and gas companies and the electrical power industry, were responsible for close to 75% of total energy R&D expenditures. The dominance of this relatively small number of large energy companies is reflected in the distribution of expenditures across main areas of activity.

As figure 6.4 indicates, research and development in the area of oil sands, heavy oil and coal captured the largest share of energy R&D funded by the private sector. The second largest category was comprised of R&D expenditures in conventional oil, natural gas and electricity.

6.4 Public Sector Energy R&D

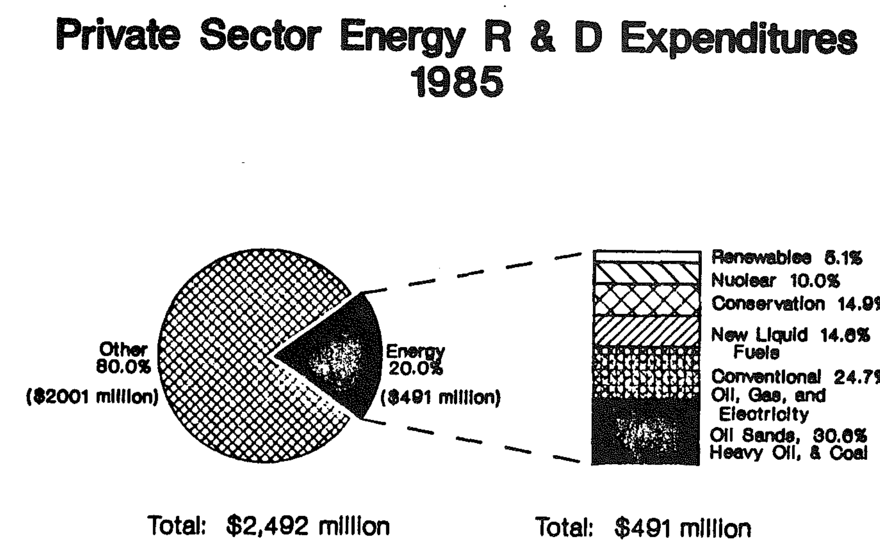
Traditionally, governments become involved in R&D because certain characteristics of research activities make it likely that the private sector will undertake less of them than would

Figure 6.3



desirable for the economy. For example, some research activities, such as those in the area of environmental protection, may be of significant benefit to people other than those making the decision to undertake a particular research program. As a result, these external benefits would not be considered in the decision-making process. In addition, individual companies are often not able to benefit from the results of their breakthroughs in research without simultaneously benefitting their competitors. This is particularly true of basic research. In the energy sector, although much has been accomplished in areas such as the technological development of the CANDU reactor, much basic research remains to be done in areas of particular Canadian interest such as oil sands and heavy oil extraction and upgrading, clean coal technologies and electrical transmission and distribution systems. In addition, much basic research remains to be done in areas of more general interest such as transportation fuels, solar energy storage systems and nuclear fusion.

Figure 6.4



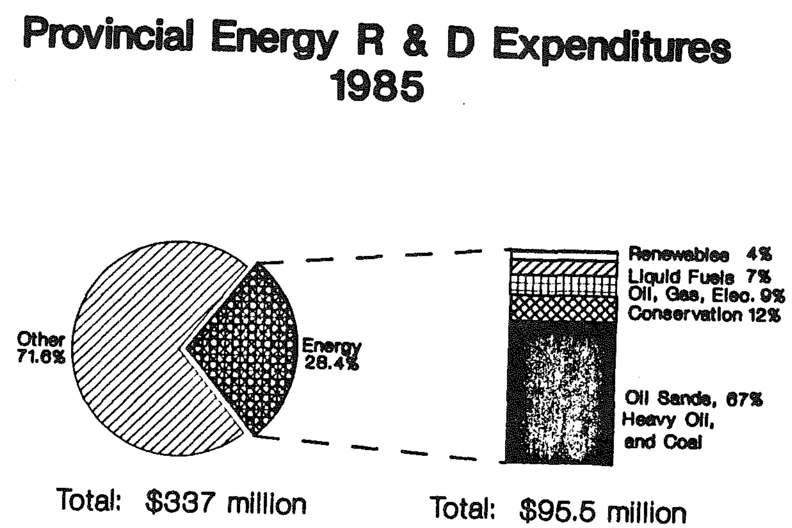
Private firms may also fail to undertake a sufficient amount of R&D because research is a very risky activity. Governments may be better able to spread the risks of R&D in any one particular area over a large range of activities. In addition, R&D often tends to have a long payback period. It is sometimes argued that governments can take a longer term view, in the public interest, than can private firms which must seek a more immediate bottom line return.

In Canada, public sector energy R&D is split between the federal and the provincial governments (as discussed in greater detail below).

6.5 Provincial Government Energy R&D

A sizeable proportion of provincial R&D effort is targetted towards the energy sector. In 1985, almost 30% of total provincially funded R&D expenditures were energy related (see figure 6.5). This proportion will likely increase in 1986 as a result of an increase of more than 20% in provincial energy R&D expenditures.

Figure 6.5



It is estimated that expenditures by the province of Alberta account for some 75% of total provincial energy R&D, while Saskatchewan and Ontario account for 8% and 6% respectively. Provincial governments contribute to energy R&D through direct grants, intramural research and funding of research institutes. A major provincial energy research institute is the Alberta Oil Sands Technology and Research Authority. Funded by the Alberta Heritage Savings Trust Fund, this institute encourages the development of new technologies for the recovery and processing of petroleum from the Alberta oil sands and heavy oil deposits.

Not surprisingly, Alberta's dominant position in the total provincial R&D effort has a substantial impact on the distribution of expenditures across key areas of activity. The principal focus of provincial R&D is in the area of oil sands, heavy oil and coal, accounting for two thirds of total

expenditures in 1986. Another $27 million (23%) was targetted towards conservation, new liquid fuels and renewables technologies, while the remainder was largely expended in conventional oil, natural gas and electricity.

6.6 Federal Government Energy R&D

6.6.1 History and Evolution

Prior to the OPEC oil embargo of 1973, the priority of federal energy R&D was placed on the development, by Atomic Energy of Canada Ltd., of the CANDU nuclear fission reactor, with a smaller ongoing effort in fossil fuels research focussed in EMR laboratories. Other departments, such as the National Research Council, were also engaged in energy research, but mainly as part of their science programs, and not as mission-oriented work. Total funding was in the order of $100 million per year, 90% of which was dedicated to nuclear (CANDU) research and development.

The 1973 "oil crisis" stimulated the federal government to pursue a policy of energy self-reliance. One reaction was to re-examine the government's energy R&D activity with the intention of supporting technologies which could contribute to reducing our dependence on imported oil. As a result, federal energy policy increasingly emphasized energy conservation, renewable energy sources and oil sands as major contributors to the goal of energy self-reliance.

After the introduction of the National Energy Program in 1980, growth in energy R&D funding accompanied similar increases in other federal program expenditures, most notably in the areas of conservation and off-oil substitution. In addition, added emphasis was placed on establishing alternative sources of transportation fuels, including tar sands bitumen, heavy oils, natural gases and alcohols.

Federal energy R&D funding eventually peaked in 1985 at a level of $393 million. A number of factors have since provided the impetus for continued restructuring of the federal government's R&D effort. First, deregulation of oil and natural gas prices increased the likelihood that the appropriate market signals would be received by the private sector. Second, the dramatic collapse in world oil prices and lower energy prices in general lessened the economic attractiveness of energy-related R&D investments.

Under these circumstances, the government has made adjustments to both the size and focus of its energy R&D effort. In 1986-87, federal energy R&D expenditures declined by 10% from the previous year to a level of $352 million. As indicated by figure 6.6, however, federal energy R&D expenditures continue to represent a significant proportion of the Government of Canada's total R&D support.

6.6.2 Current Federal Government Energy R&D Activities

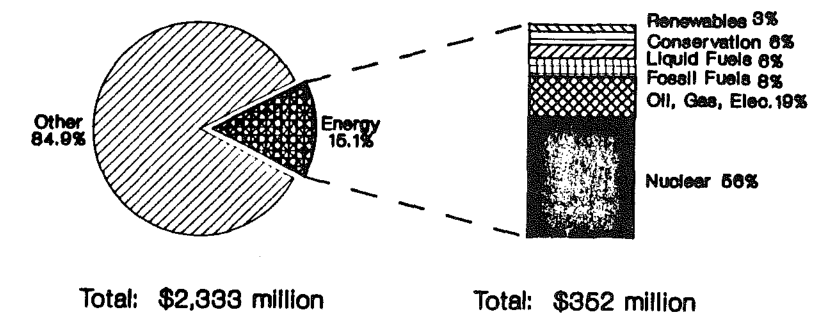
Today, federal energy R&D expenditures can be divided into three main components: funding of nuclear R&D through Atomic Energy of Canada Ltd (52%); expenditures coordinated by the inter-departmental Panel on Energy Research and Development (PERD) (27%); and various other expenditures undertaken by federal departments and agencies as part of their on-going energy R&D efforts (21%). All in all, a dozen or so federal departments and agencies conduct some form of energy R&D, including Agriculture, National Defence , Environment, and Energy, Mines and Resources.

By far, the single largest component of federal energy R&D continues to be nuclear, accounting for over half of total federal energy R&D (see figure 6.6). A large portion of these expenditures is dedicated to the on-going development of the CANDU and other nuclear-related research carried out by AECL, while approximately $9 million is dedicated to Canada's fusion energy research program. In order to achieve a better balance in its energy R&D activities, the federal government has taken steps to implement a five year program to reduce nuclear R&D expenditures to $100 million by 1990.

Secondly, a large portion of current federal energy research activities continues to be coordinated by the interdepartmental panel on Energy Research and Development. The current program of the panel strikes a compromise between the need for longer term research (in areas such as the development of energy efficient and renewable technologies, alternative transportation fuels, and fusion R&D) and the necessity to support economic growth based on Canada's large endowment of fossil fuels.

Figure 6.6

Federal Energy R & D Expenditures 1986



A prerequisite for successful implementation of R&D results is that the developments are made with a clear understanding of the demands of the market place and of competing technologies. The federal energy R&D panel places considerable emphasis, therefore, on cooperation with the private sector. In 1983, for example, about 70% of PERD's budget was used in external contracts.

6.7 The Outlook for Energy R&D

The future of the energy sector will be strongly influenced by the impact of technological developments, as well as by the economic and political environment within which the industry operates. In turn, factors such as increased environmental awareness influence the technological options which are pursued. A number of potential challenges for future energy R&D activities can be identified in light of emerging trends.

Canadian oil supplies will become increasingly less accessible and more expensive to develop as conventional reserves in the western sedimentary basin decline. The development and improvement of techniques for enhanced oil and gas production from conventional areas and for environmentally acceptable means of developing frontier resources cost-effectively will rely on additional R&D efforts.

Canada's largest potential source of future oil supplies is the oil sands. Improved techniques for mining and upgrading such resources, as well as for upgrading heavy crude oil, could contribute to the economic viability of these potential sources of supply.

The transportation sector remains heavily dependent on oil. Reducing this dependency will require additional research in the area of alternative transportation fuels.

The contribution of coal, to Canadian energy supplies has been constrained by environmental concerns. New ways of burning lower quality coal, such as fluid-bed combustion, would be less environmentally damaging. Also on the horizon are new ways of using coal to replace oil such as coal-water slurry fuels and new ways of processing coal such as in the synthesis of gasoline or diesel fuel.

Finally, Canadian energy R&D has traditionally been devoted, in part, to technologies which are only likely to have an impact in the much longer term, such as renewables, nuclear fusion and hydrogen. These alternatives continue to pose major technological challenges in areas such as improved battery technology. There is, therefore, considerable potential for additional research in these areas.

7.0 Conservation

7.1 Changes in Energy Intensity

Canada is the most energy-intensive industrialized country in the world. Between 1973 and 1986, however, energy use per unit of production dropped about 14 percent in Canada. This improvement is the result of consumers responding to energy price increases as well as improvements in technology. It also reflects the impact of various programs undertaken by the federal and provincial governments to accelerate conservation and oil substitution.

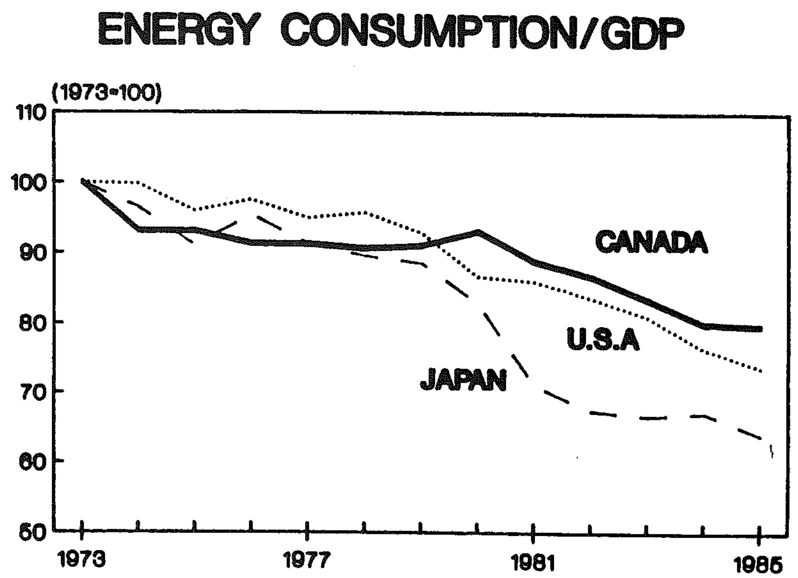
7.2 Intercountry Comparisons

Canadian reductions in the energy intensity of our economy since the first oil crisis have not been as large as those in the U.S. and Japan. This results from the poor energy conservation performance realized in Canada during the mid and late 1970s. In part, achievements during the seventies reflect the fact that at that time the price of oil in Canada was held below that in other countries. This significantly reduced the incentive to invest in energy saving equipment. Furthermore, the abundance of relatively cheap natural gas, coal and electricity and the extension of distribution systems for some of these resources encouraged consumers to switch from oil to alternative fuels rather than investing in energy saving equipment. Other countries, where these energy switching opportunities did not exist in such abundance, may have found it advantageous to invest in relatively more energy saving equipment. The improvements realized in Canada during the 1980's, however, compare favourably with other countries and have been about the same as those realized in the United States and Japan (see figure 7.1).

7.3 Sectoral Performance

The stable level of Canadian energy intensity during the late 1970s compared to more recent improvements is more clearly portrayed through an examination of the various sectors. Only slight reductions in energy intensity were made in the residential, commercial and transportation sectors during the 1970s. However, since 1980, fairly substantial reductions have occurred in all sectors.

Figure 7.1

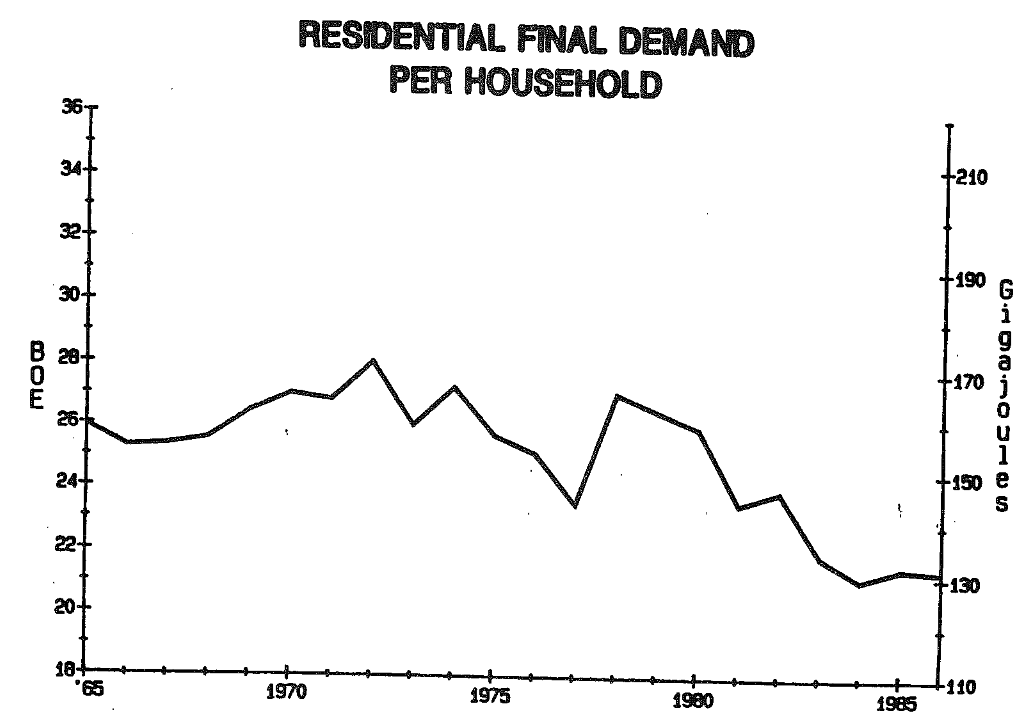


7.3.1 Residential Sector

Since the first oil crisis, hundreds of thousands of households have increased the amount of insulation in existing houses. In addition, hundreds of millions of dollars have been spent by home owners on more efficient furnaces, water heaters, windows, and other energy saving items. Vast improvements have been made in the construction of new houses. They now are built to use about 25 percent less energy than those constructed in 1974. Moreover, over 5,000 highly efficient houses have been built which use only 30 to 40 percent of the energy used by those erected in 1974. Investments such as these have been important elements in reducing energy intensity in the residential sector.

An accurate estimate of the change in energy use in the residential sector is complicated by the fact that a complete historical data series on the use of renewable energy sources such as wood, is not available. Since 1973, however, energy consumption per household (excluding renewables) has declined about 17 percent. Total consumption per household dropped from an equivalent of about 26 barrels of oil in 1973 to almost 21 barrels by 1986 (see figure 7.2). Almost all of these gains occurred after 1979/80. While some of this improvement reflects increased use of

Figure 7.2

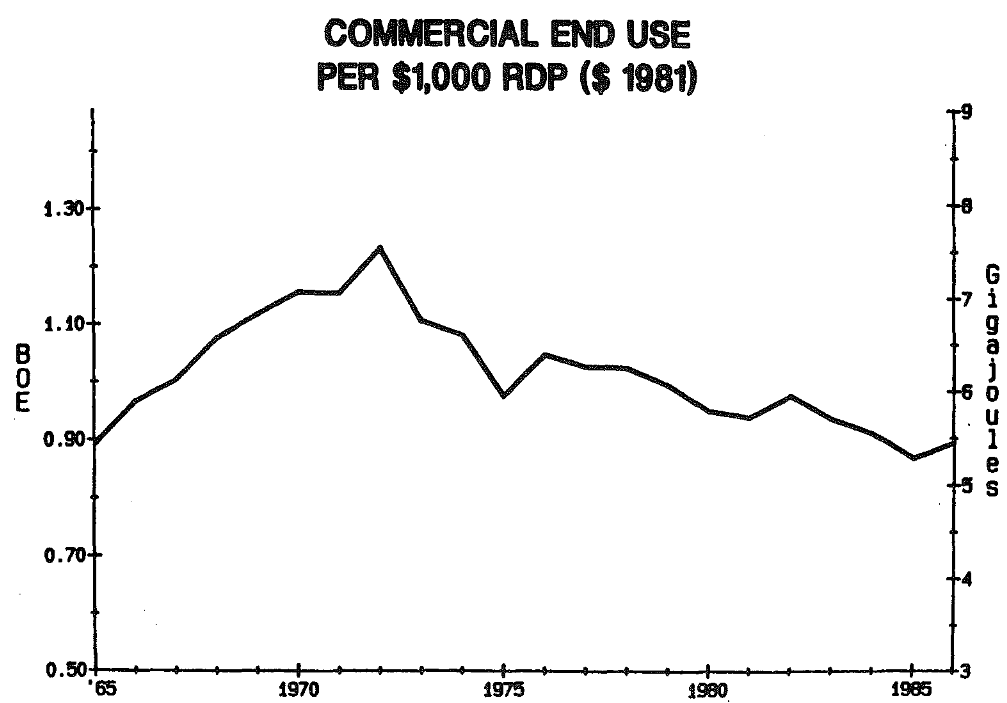


unmeasured energy sources such as wood, it is certain that a substantial reduction in the intensity of energy use has occurred in the residential sector.

7.3.2 Commercial and Industrial Sectors

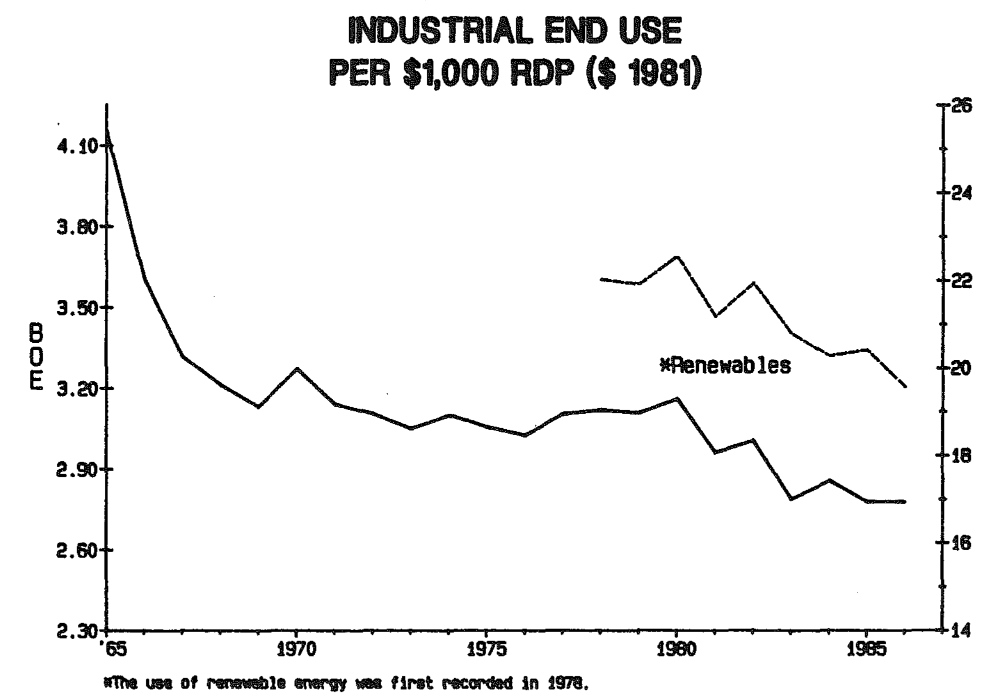
In the commercial sector, energy consumption per unit of real output rose at an average annual rate of about 4.8 percent between 1965 and 1973. Since then, it has fallen about 27 percent (see figure 7.3). Although the improvements were erratic during the late 1970s, conservation of energy played an important role in this sector.

Figure 7.3



In the industrial sector, there has also been a reduction in the use of energy over time. Unlike the residential and commercial sectors, however, a substantial reduction in energy intensity occurred in the period prior to the first world oil price shock (see figure 7.4). In addition, there was no significant decline in overall energy intensity following the 1973 oil price rise. The only major improvement seems to have occurred after the second oil crisis.

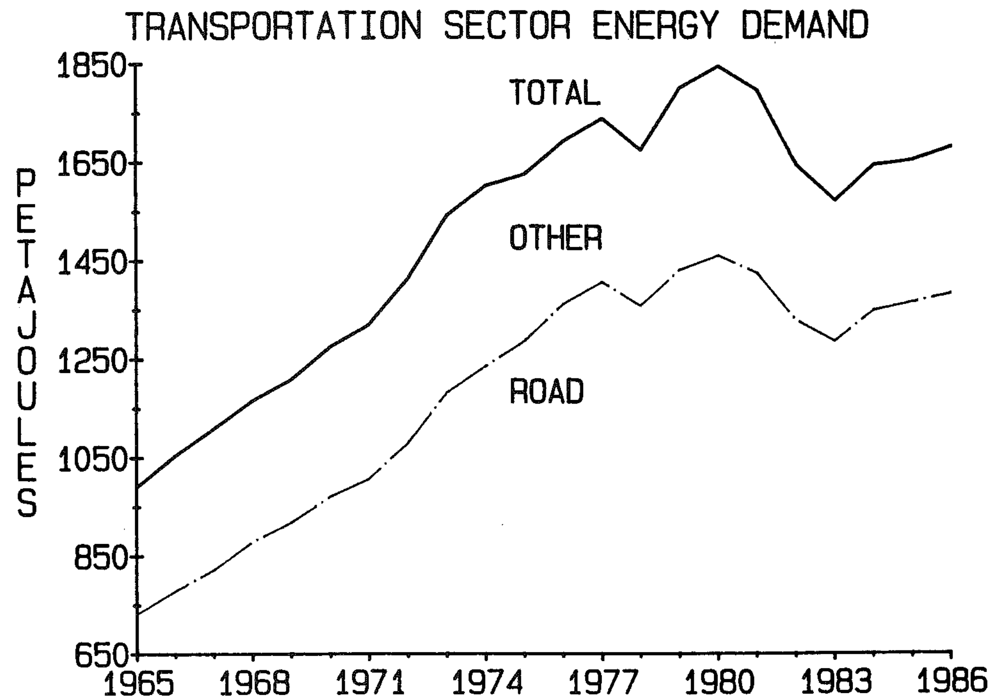
Figure 7.4



7.3.4 Transportation Sector

In the transportation sector, reductions in energy use have been impressive (see figure 7.5). Total demand in this sector grew at an average annual rate of 5.5 percent between 1965 and 1974. Growth in demand slowed appreciably to about 2.4 percent per year between 1974 and 1980. The second oil price rise

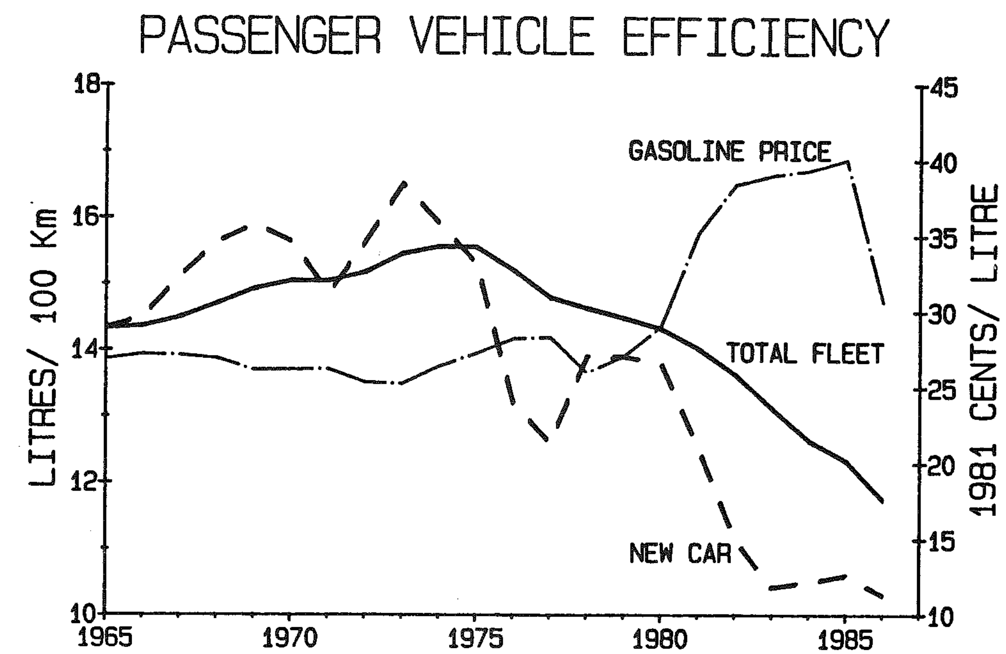
Figure 7. 5



and the ensuing recession precipitated a 15 percent drop in transportation demand for energy between 1980 and 1984. Since that time, total demand has increased slowly. It is, however, still significantly below the 1980 peak. This significant decline in total demand for energy in the transportation sector result from changes in the road transportation subsector. In 1986, road transportation needs accounted for 82 percent of total demand for energy for transportation uses. The reduction in energy intensity and in total demand in the road sector reflect, in part, the impact of the recession in the early 1980s. The change is, however, primarily the result of improved vehicle design and changes in consumer purchasing habits. When the price of gasoline rose during the early 1970s, the intensity of energy use in new automobiles dropped dramatically (see figure 7.6). This trend

was repeated following the oil price rises of 1979/80. Consumers dramatically increased their purchases of more energy efficient, foreign vehicles. This change in consumer demand along with government support for fuel consumption standards in Canada and the U.S. motivated North American automobile manufacturers to redesign vehicles to be more energy efficient.

Figure 7.6



7.4 Energy Programs

The energy savings realized and the switching from oil to other forms of energy have not all been direct responses to increases in energy prices. Many government programs have been a factor in promoting energy saving and energy switching initiatives and investments.

Following the 1973 oil crisis and the decision to protect Canadian consumers from the resultant price shock, the Government of Canada launched major initiatives to encourage conservation and substitution and to disseminate information to consumers. By 1977, the Government had introduced the Canada Home Insulation Program and other grant programs which were designed to encourage investment in energy saving and alternative energy projects.

With the introduction of the National Energy Program in 1980, the allocation of funds to conservation, alternative energy and oil substitution programs grew significantly. By 1984, more than $550 million per year was being allocated to these activities by the Department of Energy, Mines and Resources alone. The large grant programs of the late 1970s and early 1980s were important policy instruments aimed at offsetting the investment distortions created by subsidized domestic oil prices. In addition, they were intended to overcome information and technology development and transfer problems.

By 1984, however, the world and domestic situation had changed considerably. World oil prices had peaked in 1981 and by 1984 Canadian oil prices had almost reached world levels. The announcement of deregulation by the new government eliminated one of the motivating factors for large grant programs. In combination with the government's promise to minimize government intervention in the economy, this led to the demise of almost all of the large grant programs and to a redirection of those which remained.

In 1985, the National Conservation and Alternative Energy Program was announced. Under this program, emphasis was placed on dissemination of information, technology transfer, and demonstration programs, as well as encouraging more research and development. In addition, an attempt was made to increase cooperation between industry and government and between the federal and provincial governments in order to avoid a duplication of effort. At present, memorandums of understanding have been signed with seven provincial governments.

7.5 Outlook for Conservation Activities

Conservation activity in Canada has tended to focus on the substitution of other energy sources for oil. There has been considerable success in this regard. The transportation sector, which is still dependent on oil products, remains the area of greatest uncertainty in terms of substitution potential.

In terms of conservation per se, total energy use is likely to continue to increase as the economy grows. Some progress has been made, however, in reducing the energy intensity of the economy (the amount of energy used per unit of production). In almost all areas of the economy, technical changes have occurred which have reduced the intensity of energy use. The collapse of world oil prices at the start of 1986 and the current perception by many in Canada that there is now an abundance of energy, may discourage additional energy conservation investments.

As many of the changes to date, however, are now embodied in equipment, they will not likely be reversed, even if energy prices remain low. In fact, as old equipment is retired, average intensity should decline further. Moreover, as new capital investment continues, some new energy saving investments will be made. As a result, the decline in energy intensity is expected to continue in most sectors.

Even though improvements will continue, there are factors which unnecessarily inhibit the exploitation of many economic energy gains. Investment barriers are created by incomplete information regarding available energy conservation technology and by an inability of some energy users to adequately access and thus act upon the information that is available.

7.5.1 Residential Sector

The impact of lower oil prices on conservation investments will probably be noticeable in the residential sector. However, there are still many viable investment opportunities.

In existing houses, many benefits could be derived from longer-term, energy saving investments such as heat pumps, high efficiency furnaces, and so on. Further gains could also be obtained from cost-effective implementation of weather-tightening and energy management control activities.

Another area open to substantial improvements is house construction. It is estimated that over 90 percent of houses built in Canada each year are less energy efficient than is economically justified given available technology. The R-2000 program helped develop standards for the construction of energy efficient houses. The adoption of such standards by the market would require both the construction industry and consumers to understand and agree on the value of energy saving techniques and technology.

In all households, there is substantial opportunity for increased use of energy efficient appliances. In the past, consumers have often been unaware of the energy consumption of appliances such as refrigerators. Energuide labelling regulations helped provide consumers with information regarding such consumption. Increased use of labelling and the development of an ability by consumers to evaluate the savings attributable to different levels of energy use could dramatically alter purchasing patterns and thus energy consumption.

7.5.2 Industrial/Commercial/Institutional Sectors

In the industrial and commercial sectors as much as 15 percent of current energy use might be avoided by carefully designed and implemented conservation investments. Some identifiable opportunities include energy management controls such as reduced temperatures, ventilation, and hot water consumption. Other opportunities include the insulation of building shells, weatherstripping, and energy efficient lighting. Larger, more capital intensive investments include waste heat recovery, equipment improvements and industrial process efficiency changes.

In some cases, continued exposure to information about the viability of various investment opportunities will stimulate appropriate investments. In other instances, a more methodological demonstration of the technology and of the benefits might be necessary to overcome any reluctance to invest in new technology.

7.5.3 Transportation Sector

The reaction of the transportation sector to lower world oil prices is still unclear. Demand for energy (primarily oil products) in this sector can respond fairly rapidly to price changes due to the relatively quick turnover of vehicle stock. While one can expect continued improvements in the energy intensity of vehicles of a given size, consumers could react to lower prices by returning to the purchase of larger vehicles. In any event, it is likely that short-term reductions in intensity in this sector will be less than those which have occurred since 1980.

8.0 Conclusions

Historically, the energy market has been characterized by a single, dominant source of energy. In Canada and in other industrialized countries the dominant source has changed, over time, from wood to coal and from coal to oil.

There is evidence that we are now entering a new energy era in which a wide variety of energy sources will compete head-to-head to meet the needs of Canadian individuals and businesses for heat, light, power and transportation. Indeed, in certain sectors of the economy (e.g. the industrial sector in western and central Canada) this is now a reality. In other parts of the economy, however, oil remains the dominant fuel. This is particularly true of the transportation sector which relies on oil for virtually all of its energy needs. There is also a much greater dependence on oil in the Atlantic provinces than elsewhere in Canada. Its residential sector uses more than twice as much, its industrial sector three times as much, and its commercial sector four times as much oil as the national average.

In the past, the tendancy for a single fuel to dominate has raised a number of policy issues. Between World War I and World War II, there were concerns about security of coal supply which resulted in a major debate within Canada about the need to be self-sufficient in coal. Similar concerns arose with respect to oil in the 1970's and early 1980's. On the production side, the dominance of a single fuel has facilitated the emergence of monopolistic forces, such as OPEC, and has meant that the health of the Canadian energy sector has frequently been tied to the short-term outlook for a particular commodity. To the extent that oil continues to dominate in certain uses, such issues are likely to remain, although perhaps in a somewhat reduced form.

At the same time, the increasing diversity of the energy system poses new challenges for energy policy makers. In a market-oriented environment, Canada's future energy mix will largely be determined by millions of separate decisions made by consumers and producers, based to a large extent on relative energy prices. Governments, of course, will continue to establish the fiscal and regulatory framework. For a number of reasons (e.g. the existence of taxes, the presence of externalities such as environmental damage, the exercise of monopoly power to restrict competition) prices may diverge from the costs to society of supplying the commodity and the divergence may be significantly greater for some energy forms than for others. As a result, the "playing field" may become tilted in favour of one commodity at the expense of another leading to an over- or under-consumption of certain forms of energy, to the detriment of overall economic efficiency (see Appendix A). A key policy challenge is to ensure that markets work and the various energy commodities have the opportunity to compete with each other on an equal footing.

Canada's, and the world's, energy future could unfold in a number of different ways. Precise predictions about the future are invariably wrong. At best, it is possible to identify emerging trends in the Canadian energy system which appear likely to persist.

Canada is well endowed with a variety of energy resources. Our petroleum supplies, however, will be increasingly costly to develop, and new supplies can be expected to differ in several important respects from past supplies. In the future, bitumen and heavy oil will make up a larger share of western Canadian oil production and more oil and natural gas will be produced in the frontiers and offshore. These developments will pose new challenges for Canada - including the challenge of responding adequately to environmental concerns.

In addition, the development of these resources will, for geological and economic reasons, be based largely on mega-projects. Because of their scale and complexity, mega-projects provide special opportunities and problems. Mega-projects can have a major impact on Canadian energy supplies. They also have the potential to create a significant demand in Canada for skill intensive products and services for which there is a substantial world market. The industrial and regional benefits associated with such projects may be unobtainable by other means. At the same time, concentrated major projects can lead to unstable "boom and bust" industrial and regional development. Moreover, the enormous disruption surrounding such projects gives rise to particular ecological and environmental concerns.

Canada's economy today is far more electricity intensive than any other nation's. As reserves of conventional crude oil and natural gas decline, electricity can be expected to play an even more prominent role. Electricity can be generated from a number of primary energy sources. In 1960, over 90% of Canadian electricity generation was hydro-electric. Over time, as the more accessible and less costly hydro sites were developed and demand for electricity continued to grow, alternative modes of electrical generation became more cost-effective. Although Canada remains the

largest hydroelectric energy producer in the world, hydro's share of Canadian electrical generation has fallen dramatically. By 1986, hydro's share had declined to 67%, while the shares of thermal and nuclear power were 18% and 15% respectively. Although increased electrification of the economy appears likely, there will continue to be a major controversy concerning the appropriate balance between hydro, coal, and nuclear in the generation of electricity.

There are other renewable energy sources (such as biomass, solar and municipal solid waste) that have large potential - but greater uncertainty is associated with their development. In many cases, the development of these resources will require additional technological improvements or a major technological breakthrough to increase their economic attractiveness to the extent necessary to bring about their widespread use.

Turning to the consumption of energy, industrialized countries responded to the "oil crises" of the seventies and the perceived threat to energy security, by reducing the energy intensity of their economies and by substituting other sources of energy for oil. A result is that oil's share of primary energy demand has fallen from nearly 60% in the mid-sixties to about 40% in 1986 and has become increasingly dedicated to transportation purposes - the major area in which economic substitutes for oil are not, at present, readily available. In the short to medium term, this specialized use of oil supplies is likely to continue and to grow. The transportation sector will therefore likely continue to be vulnerable to a future oil supply disruption.

The substitution of other transportation fuels for oil continues to pose technological challenges. Examples of potential alternative fuels include methanol or ethanol, liquified coal and hydrogen. Given the size of the transportation sector (it accounts for about 25% of all energy use) and its strategic importance, a truly diverse energy system cannot be said to exist until these technological challenges have been overcome.

In the long run a major break with existing trends is possible. In the twenty-first century, it is conceivable that technologies such as photovoltaics, superconductors, or nuclear fusion will be perfected resulting in the emergence of a new dominant energy form that is abundant, cheap and environmentally benign.

APPENDIX A

ENERGY PRICING AND FISCAL REGIMES

1.0 The Level Playing Field

The trend towards a multiple energy system in which the various sources of energy compete increasingly with each other to satisfy the needs of end users has given rise to increasing concern about a "level playing field" for the various commodities. This concept means different things to different people. At its most general, it is taken to mean that all energy commodities should have the chance to compete in the marketplace on an equal footing. In particular, it is suggested that government pricing and fiscal policies should not distort the ability of the various commodities to compete "fairly". Fair competition, however, is not as easy to assess as one might expect.

Competition between energy sources in the marketplace is ultimately determined on the basis of price, taking into account factors such as reliability and convenience which determine the relative quality of the energy source. At first glance, therefore, it might appear that market prices which are not distorted by measures such as unequal tax treatment and project subsidies would be "fair".

In order to compare the effects of government actions on the competitiveness of various commodities, however, it would be necessary to take a much broader view of government policies. Consideration should also be given, for example, to the regulatory environment and trade policy measures, affecting various commodities - both those of Canada and those of our major trading partners. In considering the impacts of government actions, moreover, attention should not be restricted to the federal government. In Canada, provincial governments play an important role in the resource industries. The policies of all levels of government would, therefore, need to be examined simultaneously as they may reinforce or counterbalance each other.

In the end, it must also be recognized that even without government intervention, markets do not always function perfectly. Not all participants have immediate access to all necessary information. Parent corporations may restrain the options of subsidiaries. The need to make large scale capital investments in order to enter a market

may create a situation in which there are few, if any, competitors, leading to situations of "natural monopoly" and higher prices. Institutional arrangements may foreclose actions which would otherwise be taken. These and other instances of market failure may have as great an influence on price as any government activity.

Perhaps most importantly, market prices, even if undistorted, are not always "fair" as there are costs which even a perfectly competitive market would not fully reflect. These hidden costs can be of major significance and concern to society. For example, environmental damages associated with producing or distributing energy from certain sources may impose costs on other sectors of the economy. These costs will not be reflected in the market price of the commodity which is responsible for the damage. If such spillover effects are greater for some energy sources than others, even the undistorted prices of a perfectly competitive market would not fully capture the true cost differentials between energy forms.

Any "bottom line" assessment of the levelness of the playing field between commodities would, therefore, need to bear in mind that various apparent inequities may, in fact, be offsetting. As a case in point, government regulations may have been introduced specifically to compensate for the failure of the market to reflect the total cost to society of producing or using particular forms of energy. As a result, "levelling" such regulations would provide for less "fair", rather than more "fair", competition. Similar situations may apply to other government activities, such as tax incentives and subsidy programs.

Assessing whether or not the playing field is level is a very difficult task and is beyond the scope of this paper. Nevertheless, given the current trend towards greater competition between energy sources, it will be increasingly important for commodity prices to truly reflect the undistorted cost to society of the various alternatives. To assist in the debate of this issue, the next section traces the evolution of pricing and fiscal policies in the oil and gas sector, and area in which the federal government has, at times, been heavily involved.

1.1 Pricing and Fiscal Regimes for Oil and Natural Gas

The search for and production of oil and gas in Canada takes place in a fiscal environment shaped by the decisions of both federal and provincial governments. The rights and responsibilities of the various levels of government in matters relating to the management and taxation of non-renewable resources are set out in Canada's constitution. Broadly speaking, provincial governments are charged with the management of resources within provincial boundaries. The federal government has similar powers over non-renewable resources located on Canada Lands (i.e. Canadian territory outside provincial boundaries). The federal government also has responsibility for the regulation of trade and commerce, including both international and interprovincial trade in resources.

Government measures such as royalties, taxes and incentives influence the rate of production from Canada's oil and gas reserves, the rate of exploration for additional reserves, and the distribution of the benefits from oil and gas activity between consumers and producers on the one hand, and between regions of the country on the other. Such measures have been put in place, and periodically modified, by the different levels of government to fulfill their responsibilities.

Changes to the world price of oil have, over the past fifteen years, resulted in major changes to the distribution of resource revenues in Canada. Indeed, many of the changes to the fiscal regime over that period were aimed at correcting those impacts which were judged to be most damaging to the level of exploration activity or to government revenues. Frequently, taxation or royalty schemes which had been found to work quite well for a given range of values of the world price of crude oil, put great strain on producers or governments when a significant price change occurred. This is illustrated by the brief history provided below.

Crude Oil Taxation and Pricing

Throughout the 1960s and early 1970s the major thrust of federal policy towards the domestic oil industry was embodied in the National Oil Policy, announced by the Diefenbaker government in 1961, according to which domestic oil was granted privileged access to that part of Canada west of the "Ottawa Valley Line". Refiners in the western part of the country were encouraged to purchase domestic crude oil rather than the cheaper imported crude which had recently been making inroads into Ontario. On the fiscal side, Ottawa's major source of revenue was the federal corporate income tax levied on company profits. The provinces obtained income from royalties on crude oil produced on Crown lands and land bonus payments made by companies in exchange for exploration and development rights

on specified tracts of land, as well as from the provincial corporate income tax. Provincial royalty payments were deductible for the purpose of computing corporate income on which federal income tax was payable.

Royalties have traditionally been viewed as the rightful claim of resource owners to a portion of the benefits resulting from the commercial exploitation of the resource. Historically, royalties commonly took the form of a levy on gross revenues, but they have since been modified to make them more sensitive to the higher recovery costs of marginal reserves. Royalty rates currently in force in Alberta, Saskatchewan, British Columbia and Manitoba are lower for "new" higher-cost oil and for oil produced using enhanced recovery methods than they are for "old", or lower cost, oil. (Similar schemes apply to natural gas.)

The deductibility of provincial royalty payments in calculating taxable income for federal tax purposes had the effect that federal tax revenues could be significantly influenced by changes in provincial royalty regimes. Throughout the 1950s and 1960s, royalties were relatively stable with maximum rates of 16-2/3% being typical. In the early 1970s most provinces raised their royalty rates as world crude oil prices drifted upwards, as a means of diverting a larger portion of this windfall. On April 1, 1973, British Columbia's maximum rate went to 40%; Alberta was concurrently experimenting with a reserves tax which was subsequently abandoned in favour of higher royalty rates. The federal government responded in its November 1974 budget to the resulting erosion in its revenues by cancelling royalty deductibility in computing the corporate income tax liability of oil and gas firms. The federal budget of June 1975 provided compensation to producers for this loss in the form of a resource allowance equal to 25% of gross resource income less operating and overhead costs, production royalty payments and capital cost allowances. In the meantime, most provincial royalties had also been reduced with a view to easing the tax burden carried by firms.

In addition to changes designed to lighten the fiscal burden on high cost reserves, royalty schemes have also undergone changes designed to more effectively capture "windfall gains" resulting from price increases. Thus the royalty rate on crude oil under the current Alberta regime is 21-2/3% until the threshold price of $40.90 per cubic metre is attained, after which the rate increases. This feature of the royalty structure reduces the probability of large gains and losses to firms resulting from price movements (as compared with a flat royalty rate equal to the average of the maximum and minimum rates).

Although royalties have commonly been viewed as a tool of revenue generation for resource owners, Canada's provinces have also used them as an inducement to exploration or as a means of smoothing short term cyclical fluctuations in the resource industries. The 1986 collapse in world oil prices, for example, was followed by extensive royalty relief in Canada's producing provinces, both in the form of rate reductions and the extension of royalty holidays.

By 1973, the relative stability enjoyed by the Canadian oil industry under the National Oil Policy was under severe pressure. A major federal oil policy shift took place in September 1973, with the imposition of a price ceiling for domestic crude oil. This change was initially a component of an anti-inflation package but its consequences for energy policy were profound. The following month witnessed the Arabian oil embargo against the U.S. and the Netherlands, followed by the eventual quadrupling of world crude oil prices. Thus what began as a relatively small gap between the Canadian regulated price and the world price was considerably widened. It would take another twelve years before this gap would be closed.

The regulation of crude oil prices had the effect of modifying the distribution of resource rents through non-tax means. To deliver these special pricing provisions, certain programs and fiscal charges were introduced. A federal crude oil export tax was put in place to make up the difference between the regulated price in Canada and the price prevailing in the U.S. This tax would need continuous monitoring and adjustment in the years to follow. An Oil Import Compensation Program was put in place to ensure that refiners using imported crude would not be at a disadvantage relative to those using domestic crude. It was intended that this program would be financed out of the proceeds of the oil export tax. Restrictions on the export of crude oil and regulation of oil prices in the U.S. combined to give disappointing yields from the export tax and this goal was never achieved. Throughout the remainder of the 1970's, the price ceiling on crude oil was periodically adjusted upwards towards world levels.

In order to attract investment in new supplies of oil, some additional measures were introduced. Oil production from oil sands mining operations was allowed to be sold at world prices in the late 1970s. (Syncrude oil from August 1978 and Suncor oil from April 1979 to October 1980). Other changes involved fiscal variables. In November 1975, the provinces of British Columbia and Saskatchewan announced

that "new" oil would be subject to lower royalties. Some exploration incentives were also introduced. British Columbia undertook to refund up to 75% of exploration expenditures. The federal budget of May 1976 raised the rate of capital cost allowance for offshore drilling rigs from 15% to 30%. The March 1977 federal budget introduced a "superdepletion" allowance for frontier exploration. This granted firms an additional tax deduction equal to 66-2/3% of single-well drilling costs exceeding $5 million, bringing the federal tax deduction to 200% of exploration expenditures for large frontier projects (the standard exploration deduction of 100% of expenditures and the earned depletion allowance of 33-1/3% put in place by the November 1974 budget making up the remainder).

In response to the Iranian oil crisis of 1978-79, the National Energy Program (NEP) was introduced by the federal government on October 28, 1980. The NEP consisted of a pricing regime for oil and gas and a fiscal regime designed to promote adequate investment levels in the oil and gas industry. Subsequent provincial discontent with many of the features of the NEP resulted in the federal government entering into a series of bilateral energy pricing and taxation agreements with the provinces of Alberta, British Columbia and Saskatchewan. These agreements, completed in the latter half of 1981, modified the pricing aspects of the NEP while leaving many of the fiscal measures intact.

Two categories of domestic oil were established. New oil (i.e. oil produced from oil sands mining operations, oil discovered after December 31st, 1980 or oil discovered prior to that date but recovered using tertiary recovery schemes beginning operation after December 31st, 1980) would receive the New Oil Reference Price (NORP), based on a moving average of the quality-adjusted world price. Conventional old oil (i.e. oil discovered before January 1st, 1981) would receive the Conventional Old Oil Price (COOP). It was agreed that the COOP would not be allowed to exceed 75% of the average cost of imported crude at Montreal. The additional revenue accruing to firms as a result of this change would be taxed by the federal government at the rate of 50% under the Incremental Oil Revenue Tax (IORT).

All oil consumed or used in Canada would be subject to a Petroleum Compensation Charge which would defray the cost of the price differential offered to producers of new oil and the subsidy to refiners using imported crude. The refinery acquisition cost would thus be equivalent to the delivered price to the refinery on the basis of the old oil price (COOP), plus the Petroleum Compensation Charge.

A major new federal tax was the Petroleum and Gas Revenue Tax (PGRT). This tax was levied on firms' gross production revenues net of operating expenditures, and thus lay somewhere between a royalty on gross revenues and an income tax. Initially, the PGRT was levied at a rate of 8%.

With regard to exploration and development incentives, the NEP sought to deliver these benefits by means of capital grants rather than through tax deductions. The earned depletion allowance, according to which a proportion of eligible expenditures on exploration, development and tangible assets could be deducted in computing federal corporate income tax liability, was phased out and replaced by Petroleum Incentives Program (PIP) grants. The administration of PIP would be such as to promote regional and Canadianization objectives.

Natural Gas Taxation and Pricing

Regulation of natural gas pricing in Canada came about in a different way to that of oil. The prevailing mood of pessimism regarding natural gas supplies resulted in the National Energy Board denying new gas exports in 1971. This reduced the level of competition in the natural gas market. Studies by Alberta's Energy Resources Conservation Board (published in 1972) and British Columbia's Energy Commission (completed in September 1973) as well as testimony by the NEB chairman before the parliamentary Standing Committee on Natural Resources and Public Works all supported the view that natural gas field prices were not rising sufficiently quickly to compensate for cost increases. (The AERCB report identified contract rigidity and concentration among purchasers as contributing to this state of affairs.)

In January 1974, Alberta amended its Arbitration Act to make the energy equivalent value of natural gas the basis of price renegotiations. In April 1975, the Alberta arbitration board awarded an increase in the field price of natural gas produced in the province from 60 cents to $1.15 per thousand cubic feet (mcf), effective November 1st. Had this price increase gone into effect, the Toronto city-gate price would have risen to approximately $1.65 per mcf.

The federal government had recently passed the Petroleum Administration Act giving the federal Cabinet ultimate authority over the pricing of natural gas transported across provincial boundaries for domestic consumption (pricing of natural gas produced and consumed within a province remained under provincial control). This legislation became the basis of a provision in the June 1975 federal budget setting the Toronto city-gate price at $1.25, effective November 1st. This was equal to 85% of the energy equivalent cost of crude oil at Toronto. Throughout the remainder of the decade, successive Canada-Alberta pricing agreements maintained this relationship with the Toronto city-gate price reaching $2.60 on September 1, 1980. A gas deliverability surplus in Alberta was the reason cited for delaying the attainment of the previously stated objective of 100% BTU-parity with imported crude oil.

Price controls for natural gas exports were first implemented on January 1, 1975, with a uniform price of $1.00 per mcf being put in place. Subsequent increases moved the gas export prices closer to a weighted average of competing fuel costs in the U.S. as required by NEB export criteria. In 1977, the export price was linked to the price of crude oil imports into Canada. This change in procedure was announced by the NEB in August 1979 but had been at the basis of the authorized price increase (to US$2.80 per mcf) announced the previous month. In March 1980, the principle of energy equivalent pricing was formalized in an agreement between the U.S. and Canadian governments (the so-called Duncan-Lalonde formula). In the event, the price increases permitted under the agreement were often postponed due to the fears of Canadian producers of the consequences for export volumes. Throughout the early 1980s, the emergence of a deliverability surplus of natural gas in the United States (the "gas bubble") and falling world oil prices led to reductions in the export price of natural gas.

Natural gas pricing was also significantly affected by the National Energy Program and the subsequent federal-provincial agreements. The Toronto city-gate price was replaced by the Alberta border price (ABP) as the reference price of natural gas. The ABP was set to reduce the Toronto city-gate price, inclusive of the Natural Gas and Gas Liquids Tax (NGGLT), from 85% to 65% of the energy equivalent price of crude oil delivered to Toronto. (The NGGLT, introduced under the provisions of the NEP, was a tax on all gas produced in Canada, levied initially at a rate of $0.30 per mcf.) This pricing policy was designed to encourage the substitution of natural gas for oil, thereby reducing Canada's dependence on imported oil. Provision was made for increases in the ABP of $0.25 per mcf every six months, starting February 1, 1982. Rates of NGGLT would be adjusted to maintain the 65% parity relation. The province of Alberta agreed to make Market Development Incentive Payments (MDIP) to the federal government, to be used in financing the extension of gas transmission and distribution systems into new domestic markets.

Recent Developments

In the event, the price schedules outlined in the agreements for both oil and natural gas proved unworkable due to the failure of world oil prices, and hence the prices of various categories of domestic oil, to reach the high levels that had been forecast. Many oil and gas firms experienced great difficulty in meeting their various tax liabilities. As a result, the agreements were renegotiated with a number of modifications being made to crude oil categories, price schedules and taxation rates. The provinces reduced their royalty rates. Such adjustments continued until 1985 when a series of steps were taken to overhaul completely the pricing and fiscal system for oil and gas.

In March 1985, the Western Accord was signed by the governments of Alberta, Saskatchewan, British Columbia and Canada. As a result of this Accord, oil prices were deregulated, oil export charges were eliminated and a number of federal energy taxes were eliminated - NGGLT, COSC (Canadian Ownership Special Charge, the proceeds of which were used to defray part of the cost of the acquisition of Petrofina by Petro-Canada), and PCC (Petroleum Compensation Charge, revenues from which were used for import compensation purposes). The PGRT was eliminated entirely for major new projects and was to be phased out for existing projects by January 1, 1989 through a series of rate reductions. (In response to the collapse of world oil prices, the Government of Canada subsequently accelerated this phase-out, bringing the abolition date forward to October 1, 1986.) PIP grants were terminated on March 31, 1986 but some existing payments will continue until December 31, 1987 under grandfather clauses.

The Agreement on Natural Gas Markets and Prices between the governments of Alberta, Saskatchewan, British Columbia and Canada was announced on October 31, 1985. Natural gas exports had been deregulated, to a large extent, in 1984. The Natural Gas Agreement loosened further the controls on natural exports and established a process which lead to the deregulation of domestic natural gas prices on November 1, 1986.

In addition to these agreements involving oil and gas resources on provincial lands, the federal government undertook a major revision of frontier energy policy. The Atlantic Accord, signed in February 1985 with the government of Newfoundland and Labrador, and the Canada-Nova Scotia Offshore Petroleum Resources Accord, signed in August 1986

with the government of Nova Scotia, granted the respective provincial governments the right to set royalty rates in the relevant offshore areas as well as the proceeds from these royalties.

In October 1985, the federal government announced its intention to establish a new regime to cover frontier areas where the responsibility for setting royalties has not been transferred to a province. The royalty rate on new projects will start at 1% of gross production revenues, rising to 5% in increments of 1% every 18 months. Following "payout" of the initial investment (the date of which will be determined in consultation with the industry and the relevant provincial or territorial government), the royalty will equal the larger of 5% of gross revenues or 30% of net cash flow. For new frontier exploration wells, an Investment Royalty Credit is also available, equal to 25% of well costs up to a limit of $5 million per well. In addition, an Exploration Tax Credit (ETC) is available across Canada. This credit equal to 25% of exploration expenses above $5 million per well, may be written off against federal income taxes. For non-taxpaying investors the ETC is refundable at a rate of 40%.

Table A.1 summarizes the impact of the pricing and fiscal changes discussed above on government and industry revenue shares for the period 1979-86.

TABLE A.1

UPSTREAM REVENUE SHARES: INDUSTRY AND GOVERNMENTS ($ BILLIONS)

	1979	1980	1981	1982	1983	1984	1985	1986
Industry Share								
Cash Flow before Interest	6.3	8.2	7.0	8.3	10.1	11.4	12.7	7.8
PIP and Other Grants	0.1	0.1	0.9	1.6	1.8	1.9	1.8	1.0
Land Payments to Provinces	(1.4)	(1.5)	(0.8)	(0.5)	(0.7)	(0.9)	(1.3)	(0.5)
Total Industry Share	5.0	6.9	7.1	9.4	11.1	12.4	13.2	8.4
Provincial Share								
Royalties and Freehold Tax	4.1	4.5	4.6	5.3	5.7	6.0	5.7	3.1
Land Payments	1.4	1.4	0.8	0.5	0.7	0.9	1.3	0.5
Corporate Income Tax	0.1	0.1	0.2	0.1	0.3	0.6	0.5	(0.2)
Oil Export Charge	0	0.1	0.4	0.2	0.1	0.2	0.2	0
PIP and Other Grants	(0.1)	(0.1)	(0.4)	(0.5)	(0.4)	(0.4)	(0.5)	(0.3)
Total Provincial Share	5.5	6.0	5.6	5.7	6.5	7.3	7.2	3.1
Federal Share								
PGRT and IORT	0	0	1.0	2.1	2.1	2.5	2.3	0.5
Corporate Income Tax	1.0	0.9	1.3	1.7	2.3	2.4	2.5	0.8
NGGLT	0	0.1	0.8	1.2	0.8	0	0	0
Canadian Ownership Charge	0	0	0.6	0.9	0.9	0.9	0.5	0
Oil Export Charge	0.4	0.7	0.4	0.2	0.1	0.2	0.2	0
Net PCC	(1.4)	(2.7)	(0.1)	0.3	(0.2)	(1.0)	(0.3)	0
Land Payments	-	-	-	-	-	-	-	-
PIP Grants Paid	0	0	(0.5)	(1.1)	(1.4)	(1.5)	(1.3)	(0.7)
Total Federal Share	0	(1.0)	3.4	5.3	4.5	3.4	4.0	0.6
Grand Total	10.6	11.9	16.1	20.4	22.1	23.1	24.3	12.0

UPSTREAM REVENUE SHARES: INDUSTRY AND GOVERNMENTS (PERCENTAGE OF TOTAL)

	1979	1980	1981	1982	1983	1984	1985	1986
Industry Share	47.5	57.9	44.2	45.9	50.3	53.6	54.0	69.6
Provincial Share	52.1	50.4	34.6	27.9	29.2	31.5	29.8	25.8
Federal Share	0.4	(8.3)	21.2	26.2	20.4	14.9	16.2	4.6
Grand Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

APPENDIX B

STATISTICAL TABLES

APPENDIX B.1.0

Conversion Factors

	Unit	Energy Content (GJ)
Gas	$10^3 m^3$	37.97
Oil	m^3	39.00
Coal		
Bituminous	T	29.30
Lignite	T	15.36
Sub-Bituminous	T	19 76

Conversion to Millions of Barrels of Oil Equivalent

To Convert	From	Multiply by
Oil	Millions m^3	6.293
Gas	Exajoules	161.36
Coal	Petajoules	0.16136
Bituminous	Megatonnes	4.728
Lignite	Megatonnes	2.483
Sub-Bituminous	Megatonnes	3.188

APPENDIX B.1.1

PRIMARY ENERGY BY SOURCE (PERCENTAGES)

Period	Petroleum	Natural Gas	Coal	Hydro[1]	Nuclear[1]	Renewables
1871	0.5		11.0			88
1881	0.9		20.0			79
1886	2.0		22.0			77
1891	1.4		38.0			60
1895	2.0		39.0			59
1900	1.0		51.0			47
1905	1.0		66.0			33
1910	2.0	2	74.0			23
1915	4.0	3	69.0			23
1920	6.8	0.4	75.0	1.5		16.3
1925	13.3	1.8	68.2	1.4		15.3
1930	15.0	2.2	63.1	4.1		15.3
1935	17.9	2.2	57.2	6.7		16.0
1940	20.1	2.7	57.5	6.5		13.2
1945	21.1	2.7	57.4	7.0		11.8
1950	32.6	3.1	49.2	7.2		7.9
1955	49.2	5.8	31.5	8.5		5.0
1960	54.4	13.2	16.9	10.8		4.7
1965	57.4	15.2	15.1	9.8		2.5
1970	55.1	18.4	11.8	9.2	0.1	5.4
1975	54.2	22.0	9.5	10.0	0.6	3.7
1980	50.6	21.9	11.6	10.0	1.6	4.3
1985	40.1	25.5	14.6	12.1	2.7	5.0
1986	40.2	24.7	13.7	12.8	3.2	5.4

1. Converted at 3.6 MJ/Kwh

Source: 1870-1915 : F.R. Stewart, "Energy Consumption in Canada Since Confederation", *Energy Policy*, Volume 6 No. 3, September 1978

1920-1986 : *Energy Statistics Handbook* Energy, Mines and Resources, 1987

APPENDIX B.1.2.1

GROSS REVENUES IN CANADA'S ENERGY SECTOR 1986

($MILLIONS)

Electric Utilities (1985)	16,218
Oil and Gas	
- Upstream	16,896
- Downstream	26,376
Coal[1]	1,610
Uranium[2]	924
TOTAL	62,024

(1) Value of shipments from mines.

(2) Value of shipments from ore processing plants.

Source : E.M.R.

APPENDIX B.1.2.2

ENERGY EMPLOYMENT IN CANADA MARCH 1987 (THOUSANDS)

Uranium mines	4.3
Coal mines	10.8
Crude petroleum and natural gas	40.7
Contract Drilling for petroleum	8.9
Miscellaneous services incidental to mining	20.7
Petroleum refineries	18.4
Miscellaneous petroleum and coal products	0.7
Pipeline transport	7.8
Electric power	82.8
Gas distribution	12.5
Trade in petroleum products	24.1
Gasoline service stations	73.4
Total	304.3

Source : Statistics Canada, Employment and Earnings, March 1987, Table 1.1.

APPENDIX B.1.2.3

ENERGY INVESTMENT
1986

	Millions of 1981 Dollars
Total Energy Investment	11,355.8
Total Investment	80,272.4

Source : E.M.R.

APPENDIX B.1.2.4

ENERGY INTENSITY OF MAJOR INDUSTRIAL ACTIVITIES
1984

Major Group or Industry	(1) Cost of Fuel and Electricity as a Percent of the Value of Shipments	(2) Cost of Fuel and Electricity as a Percent of Value Added
Food Industries	1.78	6.19
Beverage Industries	2.38	4.08
Tobacco Products Industries	0.70	1.43
Rubber Products Industries	2.86	5.79
Plastic Products Industries	2.29	5.17
Leather & Allied Products Industries	1.24	2.46
Primary Textile Industries	3.72	8.80
Textile Products Industries	2.70	6.13
Clothing Industries	0.80	1.54
Wood Industries	3.52	8.77
Furniture & Fixture Industries	1.43	2.75
Paper & Allied Products Industries	10.36	24.11
- Pulp industry	11.13	26.15
- Newsprint industry	14.78	31.29
- Paperboard industry	17.29	39.94
- Corrugated box industry	1.69	4.96
Primary Metal Industry	6.50	15.58
- Non-ferrous smelting & refining	9.46	18.58
- Steel foundries	6.77	17.49
Fabricated Metal Products Industries	1.84	3.84
Machinery Industries	1.36	2.67
Transportation Equipment Industries	0.89	2.73
Electrical & Electronics Products Industries	1.16	2.22
Non-metallic Mineral Products Industries	9.75	19.12
- Clay products industries	16.79	27.05
- Cement industry	21.20	35.39
- Abrasives industry	14.08	33.26
- Lime Industry	34.84	68.90
Refined Petroleum & Coal Products	1.38	12.27
Chemical & Chemical Products Industries	7.06	17.50
Total (all industries)	3.18	8.24

Source : Calculated from Table 3 of Statistics Canada, Manufacturing Industries of Canada : National and Provincial Areas, Catalogue 31-203

APPENDIX B.1.2.5

CANADA IN WORLD ENERGY, 1986
(PERCENT OF WORLD TOTAL EXCEPT WHERE SPECIFIED)

	Percent
Proved reserves of crude oil	0.99
Proved reserves of natural gas	2.76
Estimated recoverable reserves of coal (1981)	0.66
Primary energy production* (1985)	3.86
Production of crude oil	2.67
Consumption of petroleum products (1984)	2.51
Production of (dry) natural gas (1985)	4.63
Coal production (1985)	1.40
Hydroelectric power generation (1985)	15.03
Nuclear electricity generation (by non-communist countries)	5.42

Source : Annual Energy Review, 1986
Energy Information Administration (E.I.A.),
Department of Energy, Washington, D.C., 1987

* Primary energy includes crude oil, lease condensate, natural gas plant liquids, dry natural gas, coal, net hydroelectric power, and net nuclear power. It excludes woods, waste, geothermal, wind, photovoltaic, and solar thermal energy.

APPENDIX B.1.3a

ENERGY PRODUCTION IN SELECTED OECD COUNTRIES
(Petajoules, 1984)

U.S.	66,231
Canada	9,445
U.K.	8,516
Germany	5,284
Australia	4,632
Norway	2,919
France	2,899
Japan	2,190
Italy	883

Source: National Energy Board, Canadian Energy: Supply and Demand, 1985-2005. (NEB Report, 1986), p. 117.

APPENDIX B.1.3b

ENERGY PRODUCTION PER CAPITA
(Gigajoules, 1984)

Norway	711.9
Canada	374.8
Australia	298.8
U.S.	279.8
Netherlands	185.9
U.K.	150.7
Sweden	112.5
New Zealand	90.3
Germany	86.3
France	52.8

Source: NEB Report (1986) p.117

APPENDIX B.1.4

CANADIAN SHARE OF PRODUCTION EXPORTED
1986

	Production	Export	Export/Production (%)
Natural Gas (excluding natural gas liquids) (Billions m^3)	81,420	21,090	25.90
Electricity (GW.H)	455,820	38,934	8.55
Coal (kilotonnes)	56,843	25,443	44.76
Uranium (tonnes)	11,725[a]	9,096[b]	77.6
Petroleum ('000m^3/day)			
Heavy Crude (including Bitumen and Pentanes)	60.2	52.3	86.9
Light & Medium Crude (including Synthetic and Condensates)	189.7	40.2	21.2
Products, LPG's	272.6	37.0	13.6

Source : Statistics Canada

a. E.M.R.
b. A.E.C.B.

APPENDIX B.1.5

CANADIAN SHARE IN U.S. IMPORTS
1986

	Total U.S. Imports	Imports from Canada	Canadian Share
Crude Oil and Petroleum Products ('000 b/d)	6061	790	13.0%
Natural Gas (billion cubic feet)	754	752	99.7%
Coal ('000 short tons)	2212	400	18.1%
Electricity[a] (billion kilowatt hours)	45.9	45.6	99.3%
Uranium (tonnes of U)	7214	4001[b]	55.5%

Source: Energy Information Administration - Monthly Energy Review, December 1986

a. Electricity Trade Forecast, U.S. Department of Energy, September 1986 (1985 data)

b. Atomic Energy Control Board (A.E.C.B.)

APPENDIX B.1.6.1

ENERGY TRADE
(Millions 1986$)

	Energy Exports	Energy Imports
1960	542.0	1,613.1
1961	853.4	1,567.9
1962	1,152.6	1,550.9
1963	1,230.7	1,702.7
1964	1,408.3	1,688.1
1965	1,612.8	1,901.4
1966	1,612.7	2,011.3
1967	1,906.9	2,101.9
1968	2,146.0	2,285.0
1969	2,455.2	1,996.0
1970	3,049.0	2,312.3
1971	3,876.8	2,487.1
1972	4,966.1	2,839.8
1973	6,224.9	3,261.0
1974	9,660.8	6,703.7
1975	9,511.6	7,321.4
1976	9,153.3	7,060.7
1977	8,945.9	6,500.5
1978	9,958.8	6,424.1
1979	12,413.7	7,499.9
1980	12,876.0	10,278.1
1981	13,558.4	11,214.7
1982	13,715.3	7,619.4
1983	13,765.5	5,760.5
1984	15,600.1	6,488.0
1985	17,140.4	6,417.1
1986	12,128.0	5,293.0

Source : Statistics Canada

APPENDIX B.1.6.2

ENERGY TRADE
(Billions 1986$)

		Imports	Exports
Crude Oil	Total	2.885	3.774
	U.S.	0.220	3.750
	Other	2.665	0.024
Petroleum Products and LPG's	Total	1.494	2.080
	U.S.	0.917	1.972
	Other	0.577	0.108
Natural Gas	Total	--	2.48
	U.S.		2.48
Electricity	Total	0.009	1.080
	U.S.	0.009	1.080
Coal	Total	0.744	1.851
	U.S.	0.744	0.014
	Japan	--	1.312
	Other	--	0.525
Uranium[a]	Total	--	0.800
	U.S.	--	0.356
	Other	--	0.444

Source : Statistics Canada 65-004, 65-007

a. A.E.C.B. volumes to which a price of $89/kg was applied.

APPENDIX B.1.7.1

FINAL ENERGY CONSUMPTION/GDP

(Millions of Barrels of Oil Equivalent per Billions of $US1980)

	1973	1984
Canada	4.3811	3.7317
United States	4.3589	3.3466
Germany	2.1793	1.6919
United Kingdom	2.2508	1.7480
Norway	2.4492	2.0128
Japan	2.2846	1.4973
Australia	2.5373	2.2869

Note : Converted from Mtoe to Mboe with the average world factor of 7.33 boe per toe.

Source : Energy Policies and Programs in IEA Countries. OECD 1986

APPENDIX B.1.7.2

END USE ENERGY DEMAND BY FUEL
1984

Region	Electricity	Oil Products	Natural Gas	Coal, Coke and Coke Oven Gas	Renewables and Steam	Other
	Percent of Total					
Atlantic Canada	18.5	64.1	--	1.6	14.7	1.0
Québec	32.2	47.4	11.6	1.3	5.9	1.6
Ontario	16.6	38.4	29.7	8.4	5.1	1.9
Manitoba	19.7	44.0	29.6	1.2	4.2	1.4
Saskatchewan	12.8	45.8	34.5	1.5	3.8	1.6
Alberta	9.8	30.8	51.0	0.2	1.3	6.9
British Columbia & Territories	18.1	37.4	20.6	0.4	22.5	1.0
Canada	19.0	41.4	26.1	3.6	7.5	2.4

Source : National Energy Board,
Canadian Energy, Supply and Demand, 1985-2005
Table A3-7, pp. 195-210.

APPENDIX B.2.0

DISPOSITION OF CANADIAN CRUDE OIL PRODUCTION
1965-1986
(Thousands of Barrels Per Day)

	Own Use	Exports
1965	603	307
66	641	351
67	666	419
68	699	468
69	734	562
1970	767	677
71	773	764
72	707	1,056
73	770	1,266
74	882	1,030
1975	833	803
76	962	529
77	1,143	353
78	1,173	307
79	1,492	274
1980	1,367	222
81	1,200	225
82	1,170	249
83	1,101	400
84	1,132	458
1985	989	641
86*	967	792

Source: NEB, 1986; Tables A3-3, A6-15 (Historical)

* High Price Case Estimate

APPENDIX B.2.1.1

CRUDE OIL PRODUCTION AND DISPOSITION
1986

(Thousand Cubic Metres Per Day)

Supply	
(1) Domestic Production	
- Saskatchewan	32.1
- Alberta	205.2
- British Columbia	5.9
- Other	6.7
	249.9
(2) Imports	56.4
Total	306.3
Disposition	
(1) Domestic Refining	
- Atlantic Canada	29.5
- Québec	39.6
- Ontario	73.1
- Alberta	45.5
- British Columbia	20.7
- Other	6.3
	214.7
(2) Exports	92.5
Total	307.2
Stock Changes	- 0.9
	306.3

Source : EMR

APPENDIX B.2.1.2

CRUDE OIL PRODUCTION BY TYPE
1986

(Thousand Cubic Metres Per Day)

Production	
- Light	149.4
- Medium	10.6
- Heavy	29.4
- Crude Bitumen	14.8
- Synthetic	29.4
- Condensates/Pentanes	16.3
	249.9

Source : E.M.R.

APPENDIX B.2.4

DISPOSITION OF CANADIAN NATURAL GAS PRODUCTION
1965-1986
(Billions of Cubic Feet Per Year)

	Own Use	Exports
1965	607	423
66	669	451
67	719	536
68	796	631
69	875	711
70	1,054	815
1971	1,169	953
72	1,362	1,055
73	1,441	1,074
74	1,522	1,001
75	1,527	968
1976	1,590	967
77	1,668	1,023
78	1,714	902
79	1,807	1,039
80	1,835	820
1981	1,805	783
82	1,840	803
83	1,868	726
84	2,024	771
85	2,139	942
1986*	2,158	810

Source: NEB, 1986; Tables A3-3, A5-3 (Historical)

* High Price Case Estimate

APPENDIX B.2.5.1

NATURAL GAS PRODUCTION AND DISPOSITION
1986

(Billions of Cubic Metres)

Supply		
	(1) Gross New Production	
	- Saskatchewan	2.43
	- Alberta	95.59
	- British Columbia	8.40
	- Other	1.20
		107.62
less	(2) Gas Injected and Stored	14.06
	Net New Production	93.56
Disposition		
	(1) Transformed to LPGs and C5+	12.14
	(2) Exports	21.09
	(3) Domestic Consumption	60.33
	Total	93.56

Source : EMR

APPENDIX B.2.5.2

NATURAL GAS CONSUMPTION IN CANADA
1986

(Billions of Cubic Metres)

By Province		
- Québec		5.01
- Ontario		20.51
- Saskatchewan		3.63
- Alberta		23.70
- British Columbia		5.43
- Other		2.05
	Total	60.33
By End-Use		
- Industrial		18.23
- Farm and Residential		13.55
- Public and Commercial		10.95
- Producer Consumption		10.44
- Other		7.16
	Total	60.33

Source : EMR

APPENDIX B.2.6

ELECTRICITY GENERATION IN CANADA
TWH

	HYDRO	THERMAL	NUCLEAR
1960	104.70	9.8	0
1965	117.06	27.21	0
1970	158.60	45.10	1.0
1975	202.40	58.10	11.9
1980	250.80	79.90	35.9
1985	300.90	88.40	57.1
1986	308.00	81.00	67.0

Source: E.M.R.

APPENDIX B.2.7

SHARE OF ELECTRICITY IN ENERGY DEMAND CANADA, 1975-1985

FINAL ENERGY DEMAND BY SOURCE
(%)

	1975	1986
Oil	54.2	40.2
Gas	22.0	24.7
Coal	9.5	13.7
Electricity	10.6	16.0
Others	3.7	5.4
Total PJ	5527	6264

Source: Energy Statistics Handbook, EMR

APPENDIX B.2.8

ENERGY TRADE IN CANADA 1986 ELECTRICITY

Deliveries

From	To	GWH
Newfoundland	Québec	30,695
Nova Scotia	New Brunswick	71
New Brunswick	Prince Edward Island	610
New Brunswick	Nova Scotia	620
Québec	New Brunswick	7,204
Québec	Ontario	7,292
Ontario	Québec	17
Ontario	Manitoba	5
Manitoba	Ontario	735
Manitoba	Saskatchewan	1,211
Saskatchewan	Manitoba	1,076
Alberta	British Columbia	617
British Columbia	Alberta	553

Exports to the U.S. from :	GWH
New Brunswick	6,652
Québec	12,640
Ontario	6,757
Manitoba	7,009
Saskatchewan	110
British Columbia	2,103
TOTAL	35,271

Imports from the U.S. to :	GWH
New Brunswick	48
Ontario	162
Saskatchewan	22
Alberta	2
British Columbia	1
TOTAL	235

Source : Electrical Energy Branch, Energy Commodities Sector, EMR

APPENDIX B.2.9

HYDRO RESOURCES

(MW)

	Capacity in Place and Under Construction (1986)	Economically Developable Sites
NWT/Yukon	131	10,000
British Columbia	10,844	17,285
Alberta	734	4,600
Saskatchewan	828	935
Manitoba	4,921	6,060
Ontario	7,173	1,830
New Brunswick	903	460
Nova Scotia	366	48
Québec	25,812	20,500
Newfoundland/Labrador	6,417	4,650
Total	58,129	66,368

Source : E.M.R. Electric Power in Canada, 1986
E.M.R. Electricity Undeveloped Power Sites, 1983

APPENDIX B.2.10

ENERGY TRADE IN CANADA : COAL (1986)

DELIVERIES FROM

KILOTONNES

		Nova Scotia metall.	Nova Scotia therm.	N.B. therm.	Sask. therm.	Alberta metall.	Alberta therm.	B.C. metall.	B.C. therm.	Canada metall.	Canada therm.
	Newfoundland	--	1	--	--	--	--	--	--	--	1
D	P.E.I.	--	5	--	--	--	--	--	--	--	5
E	Nova Scotia	163	2,241	--	--	--	--	--	--	163	2,241
L	New Brunswick	--	--	485	--	--	--	--	--	--	485
I	Québec	--	60	--	--	--	--	--	--	--	60
V	Ontario	--	--	--	997	--	1,336	95	488	95	2,821
E	Manitoba	--	--	--	253	--	1	22	22	22	276
R	Saskatchewan	--	--	--	7,032	--	1	--	40	--	7,073
I	Alberta	--	--	--	--	--	17,826	1	1	1	17,827
E	British Columbia	--	--	--	--	--	73	79	178	79	251
S											
	Canada	163	2,307	485	8,282	--	19,237	197	729	360	31,040
T											
O	Japan	--	100	--	--	3,748	728	11,421	1,051	15,169	1,879
	Other	341	44	--	10	750	382	4,700	2,168	5,791	2,604
	TOTAL	504	2,451	485	8,292	4,498	20,347	16,318	3,948	21,320	35,523

Source : Coal Division, Mineral Policy Sector, E.M.R.

APPENDIX B.2.11.1

COAL SUPPLY AND DISPOSITION
1986

(Kilotonnes)

Supply		
(1) Domestic Production		
- Atlantic Canada		3,440
- Saskatchewan		8,292
- Alberta		24,845
- British Columbia		20,266
		56,843
(2) Imports		13,625
	Total	70,468
Disposition		
(1) Domestic Consumption		45,025
(2) Exports		25,443
	Total	70,468

Source : EMR

APPENDIX B.2.11.2

COAL CONSUMPTION IN CANADA
1986

(Kilotonnes)

By Region		
- Atlantic Canada		2,895
- Ontario		15,933
- Saskatchewan		7,073
- Alberta		17,828
- Other		1,296
		45,025
By End-Use		
- Electrical Power		36,394
- Industrial and steel		8,631
	Total	45,025

Source : EMR

APPENDIX B.3.1

CONTAINMANTS FROM ENERGY PRODUCTION AND CONSUMPTION

Contaminant	Major Category of Contributors (Total Pollution)	(%)	Major Contributor (Energy Related)	% of Category	% of Total From Energy
1. Particulate Matter	Industrial Process	64.0	Coal industry	8.4	5.4
(18%)	Fuel Combustion (Stationary Sources)	16.2	Power Utilities	47.6	7.7
			Fuelwood Combustion	28.3	4.6
					17.7
1. Sulfur Oxides	Industrial Process	67.1	Natural Gas Processing	12.3	8.2
(41%)			Tar Sands Operations	4.8	3.2
	Fuel Combustion (Stationary Sources)	29.9	Utility	55.6	16.6
			Industrial	33.2	9.9
			Commercial	6.1	1.8
			Residential	4.8	1.4
					41.1
1. Nitrogen Oxides (85%)	Transportation	62.1	Gasoline	42.1	26.1
			Diesel	38.7	24.0
			Railroads	10.0	6.2
	Fuel Combustion (Stationary Sources)	33.8	Industrial	45.8	15.4
			Utility	39.4	13.3
					85.0
1. Hydro Carbon (68%)	Industrial Process	28.9	Coal	26.9	7.8
			Petroleum Refining	23.4	6.8

APPENDIX B.3.1

Contaminant	Major Category of Contributors (Total Pollution)	(%)	Major Contributor (Energy Related)	% of Category	% of Total From Energy
			Petrochemicals	36.9	10.7
	Transportation	40.3	Gasoline	77.3	31.2
	Miscellaneous	25.8	Gasoline/diesel	46.1	11.9
					68.4
2. Mercury (23%)	Fuel Combustion (Stationary Sources)	22.7	Coal	55.5	12.6
			Petroleum	30.4	6.9
			Other	14.1	3.2
					22.7
2. Lead (65%)	Fuel Combustion (Transportation)	63.11	Gasoline	96.7	61.05
			Aircraft	2.4	1.51
			Gasoline Marketing	0.9	0.55
	Fuel Combustion (Stationary Sources)	0.22	Power Generation	54.6	0.12
			Other Sectors	45.4	0.10
	Waste incineration	1.73	Waste Oil	65.3	1.13
					64.46

Source: Department of the Environment,
State of the Environment for Canada, May 1986
(1) Table 9.1 (p. 213)
(2) Table 8.21 (p. 191)

APPENDIX B.3.2

ENVIRONMENTAL PROGRAM SPENDING[1]
ALL LEVELS OF GOVERNMENT
CANADA, 1970-1986

(Billions of 1986 Dollars)[2]

1970	1.797
1971	2.238
1972	2.970
1973	3.592
1974	4.045
1975	4.326
1976	4.794
1977	4.856
1978	4.821
1979	4.493
1980	4.790
1981	4.515
1982	4.307
1983	4.215
1984	4.238
1985	4.147
1986	4.493

(1) Programs include: water purification and supply; sewage collection and treatment; solid waste collection and disposal; pollution control; and environmental administration and other. Figures are net of intergovernment transfers.

(2) The data series was converted to 1986 dollars using the CPI.

Source: Statistics Canada 68-202

APPENDIX B.4.1

REAL OIL PRICES, 1945-1987
(1986$US/BBL)

	1986$/bbl		1986$/bbl		1986$/bbl
1945	6.78	1960	6.04	1974	23.28
1946	6.07	1961	5.76	1975	20.68
1947	11.37	1962	5.46	1976	21.10
1948	9.64	1963	5.30	1977	21.38
1949	8.97	1964	5.05	1978	20.47
1950	8.19	1965	4.81	1979	43.44
1951	7.80	1966	4.45	1980	47.90
1952	7.68	1967	4.24	1981	41.77
1953	8.53	1968	4.01	1982	36.36
1954	8.40	1969	3.65	1983	31.68
1955	8.12	1970	3.30	1984	29.74
1956	7.86	1971	4.36	1985	28.21
1957	8.18	1972	4.48	1986	13.84
1958	8.02	1973	6.50	1987	17.56
1959	7.16				

Source: 1945-1959 : Gilbert Jenkins
Oil Economist Handbook 1984
Applied Science Publishers Ltd., London
Table 17, p.19

1960-1985 : Annual Energy Review 1985
Energy Information Administration, Washington, D.C.
Table 114, p. 257

1986-1987 : Petroleum Intelligence Weekly, various issues

Notes : 1945-1959 : Price of Arabian Light posted at Ras Tanura

1960-1987 : Spot price of Saudi Light
1987 : Figure is the average price for the first two quarters of 1987

APPENDIX B.4.2

NET IMPORTS OF CRUDE OIL AS A PERCENT OF TOTAL OIL DEMAND CANADA, 1955-2000

	%		%		Low Price Case	High Price Case
1955	53.0	1970	5.1	1985	-21.1	
1956	40.0	1971	2.1	1986	-22.0	
1957	34.0	1972	- 7.2	1987	-15.2	-19.3
1958	44.0	1973	-18.6	1988	- 6.5	-14.0
1959	44.0	1974	- 7.1	1989	1.2	- 9.6
1960	42.0	1975	4.2	1990	6.1	- 9.7
1961	30.0	1976	13.4			
1962	22.0	1977	18.7	1995	28.5	- 5.2
1963	24.0	1978	15.3			
1964	20.0	1979	13.1	2000	43.3	-10.9
1965	22.0	1980	14.9			
1966	20.0	1981	16.0			
1967	21.0	1982	5.4			
1968	15.0	1983	- 8.4			
1969	9.5	1984	-11.7			

Source : National Energy Board
Canadian Energy : Supply and Demand, 1985-2000
Tables A6-15, A6-16

Note : Negative values indicate Canada is a net exporter of crude oil

APPENDIX B.4.3

PERCENT OF END-USE DEMAND SATISFIED BY OIL IN VARIOUS SECTORS CANADA, 1986-2000

	1986	2000 (low price case)	2000 (high price case)
Residential	19.3	12.7	9.4
Commercial	14.6	9.0	8.4
Industrial	13.4	10.5	9.9
Transportation	98.9	98.5	97.2

Source : National Energy Board
Canadian Energy : Supply and Demand, 1985-2005
Tables A3-2, A3-3, A3-7

EMR

APPENDIX B.4.4

PERCENT OF END-USE DEMAND
SATISFIED BY OIL IN VARIOUS SECTORS
ATLANTIC CANADA, 1986-2000

	1986	2000 (low price case)	2000 (high price case)
Residential	46.2	38.3	34.5
Commercial	59.4	40.5	38.0
Industrial	39.0	37.5	36.4
Transportation	98.9	98.5	97.2

Source : National Energy Board
Canadian Energy : Supply and Demand, 1985-2005
Tables A3-2, A3-3, A3-7

E.M.R.

APPENDIX B.5.1

CANADIAN OWNERSHIP AND CONTROL
OF THE PETROLEUM INDUSTRY
BASED ON UPSTREAM REVENUES
1979-1986

YEAR	CONTROL	OWNERSHIP
1979	20.5	28.6
1980	23.1	28.4
1981	36.5	37.4
1982	38.3	39.0
1983	38.4	41.3
1984	40.5	42.5
1985	48.4	48.0
1986	48.8	47.7

Source : Petroleum Monitoring Agency Surveys 1980-86

APPENDIX B.5.2

CANADIAN OWNERSHIP AND CONTROL OF THE ENERGY INDUSTRIES*

	Ownership	Control
Coal	68	85
Uranium	63	69
Petroleum	48	49

Sources: Mineral Policy Branch, Uranium and Nuclear Energy Branch, E.M.R.

Petroleum Monitoring Agency Survey 1986

* Coal ownership data are from 1984; control data from 1986; uranium data are from 1985; and petroleum data are from 1986.

APPENDIX B.6.1

ENERGY R&D EXPENDITURES 1984

(Millions of 1984US$)

	Industry	Government	Total
Canada	393(47.6)	432(52.4)	825
United States	4531(63.7)	2585(36.3)	7116
United Kingdom	310(44.6)	385(55.4)	695
Italy	471(41.8)	657(58.2)	1128
Japan	1245(45.9)	1467(54.1)	2712

Notes : (1) Numbers in brackets are percentages of total for each country.

(2) Industry expenditures by the United Kingdom refer to activities by nationalized industries only.

(3) Government expenditures by Italy and the United Kingdom do not include their contributions to the European Community programme.

Source : IEA/OECD - Energy Research, Development and Demonstration in the IEA Countries, 1984 Review of National Programmes, Paris, 1986.

APPENDIX B.6.2

CANADIAN ENERGY R&D EXPENDITURES BY FUNDING SOURCE 1985

(Millions of Dollars)

	Energy	Other	Total
Federal Government	393	2035	2428
Provincial Governments	96	241	337
Industry	491	2001	2492
Total	980	4277	5257

Notes : (1) Excludes R&D expenditures funded by Higher Education Institutions ($305 million), private non-profit organizations ($159 million) and foreign sources ($269 million) for which the energy component is not available.

Source : Statistics Canada, EMR.

APPENDIX B.6.3

CANADIAN ENERGY R&D EXPENDITURES BY ACTIVITY AND SOURCE OF FUNDS 1985

(Millions of Dollars)

	Federal Government	Provincial Governments	Industry	Total
Renewables	28.3	3.3	24.8	56.4
Conservation	51.6	19.5	73.6	144.7
New Liquid Fuels	27.1	6.6	72.1	105.8
Conventional Oil Gas & Electricity	60.2	6.9	121.6	188.7
Fossil Fuels (Oil Sands, Heavy Oil and Coal)	28.6	58.9	149.1	236.6
Nuclear	197.0	0.3	49.7	247.0
Total	392.8	95.5	490.9	979.2

Source : Statistics Canada, EMR.

APPENDIX B.6.4

PRIVATE SECTOR ENERGY R&D FUNDING
1985/86

Energy R&D	% Of Energy $ Millions	Total
Renewables	24.8	5.1
Conservation	73.6	15.0
New Liquid Fuels	72.1	14.7
Conventional Oil, Gas & Electricity	121.6	24.8
Fossil Fuels	149.1	30.4
Nuclear	49.7	10.1
Total Energy	490.9	100.0
Other	2001.1	
Total Private Sector R&D	2492.0	
Energy as % of Total	19.7%	

Source : Statistics Canada, EMR.

APPENDIX B.6.5

PROVINCIAL ENERGY R&D FUNDING
1985/86

Energy R&D	$ Millions	% Of Energy Total
Renewables	3.3	3.5
Conservation	19.5	20.4
New Liquid Fuels	6.6	6.9
Conventional Oil, Gas & Electricity	6.9	7.2
Fossil Fuels	58.9	61.7
Nuclear	0.3	0.3
Total Energy	95.5	100.0
Other	241.5	
Total Provincial R&D Funding	337.0	
Energy as % of Total	28.3%	

Source: Statistics Canada, EMR.

APPENDIX B.6.6

FEDERAL ENERGY R&D FUNDING
1985/86

Energy R&D	$ Millions	% Of Energy Total
Renewables	11.7	3.3
Conservation	21.7	6.2
New Liquid Fuels	22.3	6.3
Convential Oil, Gas & Electricity	67.9	19.3
Fossil Fuels	29.8	8.5
Nuclear	198.6	56.4
Total Energy	352.0	100.0
Other	1981.0	
Total Federal R&D Funding	2333.0	
Energy as % of Total	15.1%	

Source: Statistics Canada, EMR.

APPENDIX B.7.1

ENERGY CONSUMPTION / GDP[1]

Year	Canada	U.S.A.	Japan
1973	100.0	100.0	100.0
1974	93.1	99.8	96.5
1975	93.1	96.0	91.1
1976	91.3	97.6	95.5
1977	91.3	95.0	91.3
1978	90.7	95.8	89.6
1979	91.1	93.0	88.7
1980	93.2	86.8	83.0
1981	89.0	86.2	71.2
1982	86.9	83.9	67.5
1983	83.6	81.3	66.7
1984	80.1	76.5	67.2
1985	79.9	73.8	64.0

1 Calculated as total final demand divided by real domestic production (1980 U.S. dollars), all converted into an index with 1973 = 100. The data for this was obtained from various IEA publications.

Source: E.M.R.

APPENDIX B.7.2

RESIDENTIAL FINAL DEMAND PER HOUSEHOLD

Year	Gigajoules Per Household [1]	BOE/ Household [2]
1965	158.8	25.9
66	154.6	25.3
67	155.1	25.3
68	156.5	25.6
69	161.9	26.4
1970	165.3	27.0
71	164.2	26.8
72	171.7	28.1
73	159.2	26.1
74	166.8	27.3
75	157.3	25.7
76	153.7	25.1
77	143.7	23.5
78	165.7	27.1
79	162.2	26.5
1980	158.9	26.0
81	144.0	23.5
82	146.5	23.9
83	134.1	21.9
84	129.6	21.2
85	132.0	21.6
86	131.5	21.5

1 Calculated as total secondary demand in the residential sector in Canada excluding farm diesel and gasoline demand, divided by the number of households in Canada.

2 Conversion at 6.12 gigajoules per barrel of light oil.

Source: E.M.R.

APPENDIX B.7.3

COMMERCIAL DEMAND PER $1,000 RDP ($1981)

	GJ/RDP [1]	BOE/RDP [2]
1965	5.42	0.89
66	5.88	0.96
67	6.10	1.00
68	6.55	1.07
69	6.81	1.12
1970	7.05	1.15
71	7.03	1.15
72	7.52	1.23
73	6.74	1.10
74	6.58	1.08
75	5.93	0.97
76	6.38	1.04
77	6.25	1.02
78	6.23	1.02
79	6.05	0.99
1980	5.78	0.94
81	5.71	0.93
82	5.94	0.97
83	5.70	0.93
84	5.54	0.91
85	5.28	0.86
86	5.48	0.90

1 Represents total secondary demand in the commercial sector divided by commercial real domestic product.

2 Conversion at 6.12 gigajoules per barrel of light oil.

Source: E.M.R.

APPENDIX B.7.4

INDUSTRIAL END USE PER $1,000 RDP ($1981)

Year	Gigajoules [1] (Excluding Renewables)	Gigajoules [2] (Including Renewables)	BOE [3]	BOE (Including Renewables)
1965	25.37		4.15	
66	22.04		3.60	
67	20.27		3.31	
68	19.61		3.20	
69	19.10		3.12	
1970	19.97		3.26	
71	19.16		3.13	
72	18.94		3.09	
73	18 60		3.04	
74	18.92		3.09	
75	18.65		3.05	
76	18.46		3.02	
77	18.95		3.10	
78	19.04	22.01	3.11	3.60
79	18.97	21.91	3.10	3.58
1980	19.29	22.55	3.15	3.69
81	18.08	21.17	2.95	3.46
82	18.34	21.93	2.99	3.58
83	16.99	20.79	2.77	3.40
84	17.41	20.28	2.84	3.31
85	16.94	20.42	2.76	3.34
86	16.81	19.58	2.76	3.20

1 Secondary energy demand per unit of real industrial product.

2 Statistics Canada started reporting on renewable energy use in the industrial sector in 1978.

3 Converted at 6.12 gigajoules per barrel of light oil.

Source: E.M.R.

APPENDIX B.7.5

TRANSPORTATION SECTOR ENERGY DEMAND (PETAJOULES)

Year	Total	Road
1965	989.5	732.4
66	1053.9	779.4
67	1108.3	821.9
68	1165.4	878.9
69	1208.4	918.3
1970	1274.6	970.8
71	1319.5	1006.5
72	1412.6	1079.0
73	1540.7	1181.3
74	1601.4	1235.7
75	1624.3	1286.1
76	1691.4	1361.7
77	1737.2	1406.3
78	1672.9	1357.8
79	1799.3	1430.9
1980	1843.0	1459.5
81	1794.5	1424.1
82	1642.8	1328.3
83	1569.6	1284.7
84	1642.3	1347.5
85	1652.6	1364.4
86	1679.2	1381.5

Source: E.M.R.

APPENDIX B.7.6

PASSENGER VEHICLE EFFICIENCY

Year	Litres/100Km New Car	Litres/100Km Total Fleet	1981 Cents/Litre Gasoline Price
1965	14.33	14.33	26.91
66	14.36	14.50	27.22
67	14.49	15.11	27.15
68	14.70	15.63	26.95
69	14.92	15.89	26.17
1970	15.04	15.63	26.2
71	15.04	14.85	26.23
72	15.17	15.63	25.36
73	15.45	16.50	25.27
74	15.56	15.90	26.44
75	15.55	15.30	27.27
76	15.20	13.20	28.25
77	14.79	12.60	28.34
78	14.63	13.90	26.00
79	14.48	13.90	27.10
1980	14.32	13.79	29.05
81	14.02	12.53	35.22
82	13.63	11.15	38.41
83	13.12	10.42	39.03
84	12.63	10.50	39.37
85	12.33	10.60	40.06
86	11.74	10.30	30.66

Source: E.M.R.